TAPPING OUR RESOURCES

CANADIAN NATURAL RESOURCES LIMITED

ANNUAL REPORT 1999

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Volume Reporting

All production, sales and reserve statistics are Canadian Natural's working interest amounts before deduction of royalties, unless stated otherwise. Where volumes are reported in barrels of oil equivalent, natural gas is converted to oil at six thousand cubic feet per barrel unless otherwise noted. This conversion ratio approximates relative heating values. In previous years, 10 thousand cubic feet per barrel was used as an approximation of historical relative sales values. The six Mcf/Bbl ratio is being adopted by more Canadian oil and natural gas companies and investment analysts and is more common outside of Canada, particularly in the United States.

Notice of Annual Meeting

The annual meeting of shareholders will be held at 3:00 p.m. on Thursday, May 11, 2000 in the Ballroom of the Metropolitan Centre, Calgary, Alberta. All shareholders are invited to attend.

A SOLID BASE FOR GROWTH IN CANADA

Canadian Natural Resources Limited has moved into the 21st century with a proven corporate strategy and world-class asset base.

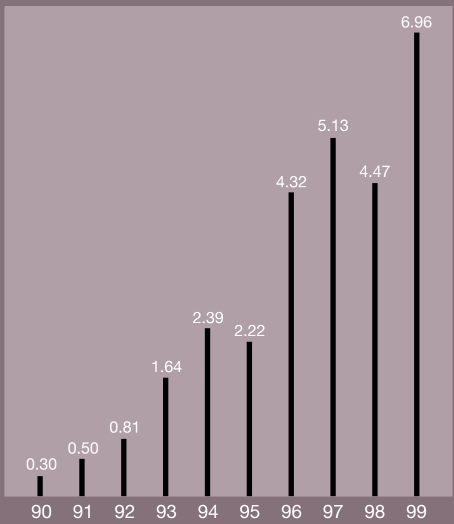
In 1999, the Calgary-based senior oil and natural gas exploration and development company continued its decade-long track record of achieving consistent growth in its operating and financial results by adhering to a corporate strategy of effective cost control, manageable bank debt and a defined growth strategy.

Now, with the completion of the $1 billion acquisition of BP Amoco's oil assets in Alberta, Canadian Natural is well positioned to achieve future growth in production and shareholder value.

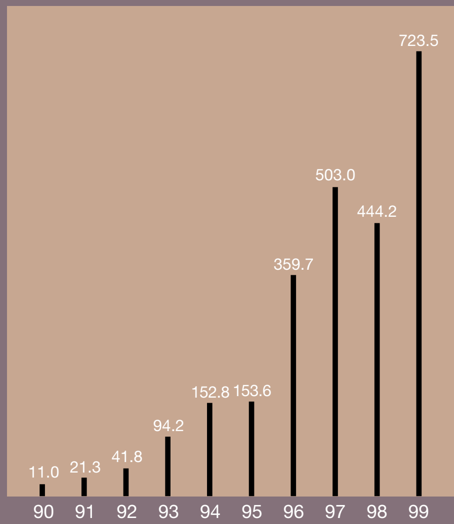
HIGHLIGHTS

($ millions, except per share data)	**1999**	1998	% Change
FINANCIAL			
Gross revenue	**1,286.8**	877.6	+47
Cash flow from operations	**723.5**	444.2	+63
Per share	**6.96**	4.47	+56
Net earnings	**200.2**	59.0	+239
Per share	**1.93**	0.59	+227
Net reserve replacement expenditures	**1,904.4**	581.0	+228
Long-term debt	**2,156.9**	1,425.5	+51
Shareholders' equity	**1,892.0**	1,277.4	+48
OPERATING			
Natural gas production (mmcf/d)	**721.0**	672.6	+7
Average selling price ($Cdn/mcf)	**2.36**	2.12	+11
Crude oil and NGLs production (bbls/d)	**86,750**	75,744	+15
Average selling price ($Cdn/bbl)	**21.04**	12.93	+63
Natural gas reserves (bcf)			
Proven	**2,183.1**	1,905.2	+15
Probable	**364.2**	310.5	+17
Total	**2,547.3**	2,215.7	+15
Crude oil and NGLs reserves (mmbbls)			
Proven	**553.5**	287.0	+93
Probable	**86.4**	97.2	-11
Total	**639.9**	384.2	+67
Drilling activity (net wells)	**727.3**	357.9	+103
Undeveloped land holdings (000s of net acres)	**5,440**	4,795	+13

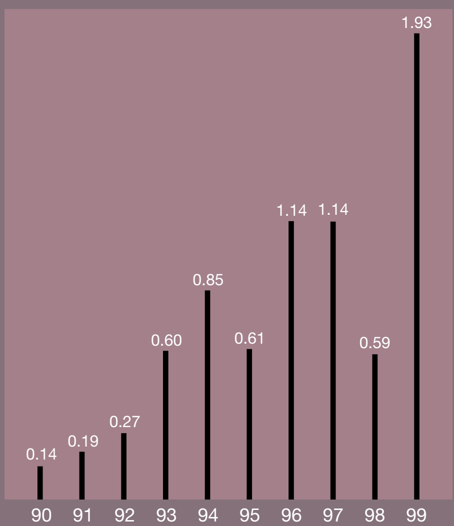
Cash Flow Per Share* ($)



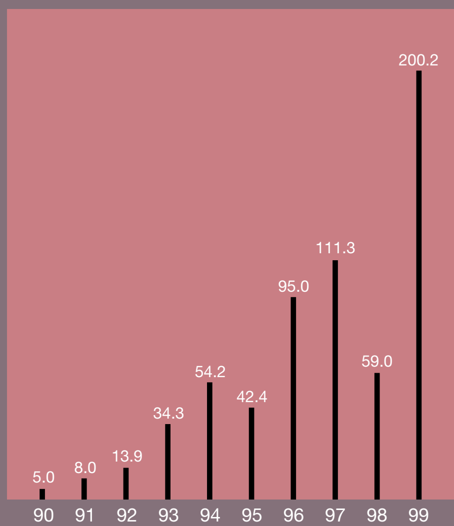
Cash Flow From Operations ($ millions)



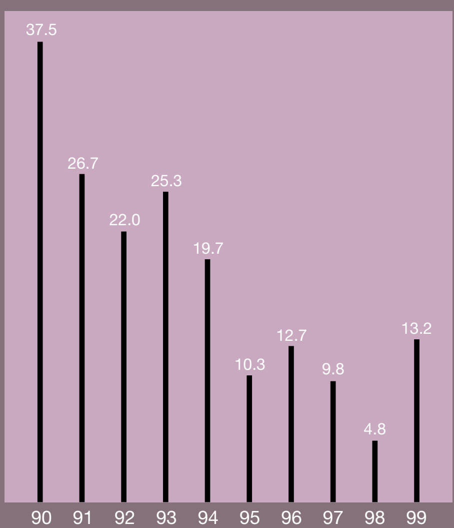
Net Earnings Per Share* ($)



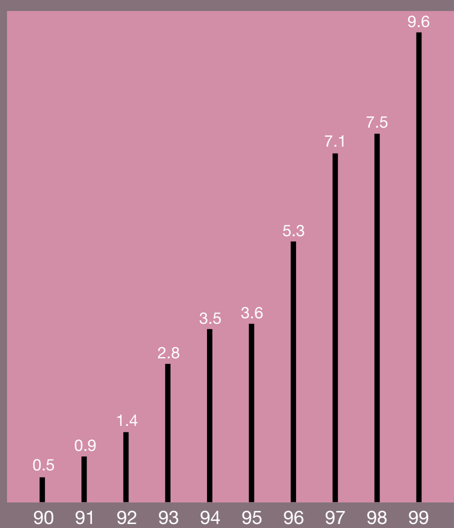
Net Earnings ($ millions)



Return on Equity (%)



Reserves Per Share* (BOE)



** Restated to reflect two for one stock split in June 1993.*

Canadian Natural Resources has established a solid reputation as one of the most consistent performers in the western Canadian energy industry, achieving growth year after year, in both good times and bad.

In 1999, we delivered record financial and operating results, capping a decade of impressive growth for our shareholders and employees.

More importantly, we set the stage in 1999 for an accelerated rate of growth in the future – growth that promises to take our Company to a new, higher level of operational and financial performance. The catalyst for this accelerated growth was the completion of the largest asset acquisition in our Company's history. The $1 billion purchase of all BP Amoco's heavy oil and oil sands properties in Alberta has provided us with low-cost growth and long-life reserves in core heavy oil areas where we have significant experience and expertise. Through the addition of these world-class assets, we are confident that we will achieve double-digit production growth into the 21st century.

Our ability to complete the BP Amoco acquisition is testament to the financial strength and operational flexibility provided by our long-term growth strategy. This strategy, adopted in 1989, is founded upon the principles of effective cost controls, manageable bank debt and a defined growth strategy. By adhering to these principles we were able to maintain a strong balance sheet during the low oil price period of 1998 and early 1999. Consequently, when the BP Amoco assets came on the market, we had the financial strength and flexibility to complete the transaction.

Our growth strategy has been focused on building a diversified asset base that is balanced between heavy oil, light oil and natural gas. The benefit of this balance was clearly evident over the past year. Throughout 1998 and into the first quarter of 1999, our capital program was directed towards natural gas in response to historically low oil prices. Accordingly, our oil production declined. However, in the second quarter, as oil prices began to climb, we rapidly expanded our oil development program. The result was an immediate increase in quarterly oil production and significant increases in cash flow and net income.

Highlights of 1999

With quarterly improvement throughout 1999, Canadian Natural's financial results reached record levels. Cash flow increased 63 percent to $724 million from $444 million in 1998. Net income for the year was $200 million compared to $59 million in 1998, an increase of 239 percent. On a per share basis, cash flow was $6.96

compared to $4.47 in 1998. On a per barrel of oil equivalent basis, using a gas to oil conversion ratio of 6:1, cash flow increased 48 percent to $9.56 from $6.48 in 1998. This increase was driven by higher levels of production and higher realized commodity prices.

Operationally oil production increased 15 percent to 86,750 barrels of oil per day. Natural gas production increased 7 percent to over 720 million cubic feet per day. Growth in production volumes was highlighted in the fourth quarter as production averaged 242 thousand barrels of oil equivalent per day, comprised of 116 thousand barrels of oil and 757 million cubic feet of natural gas.

Reserves of oil and natural gas grew to record levels with proven oil reserves increasing 93 percent to 554 million barrels and proven natural gas reserves, increasing 15 percent to 2.2 trillion cubic feet. On a barrel of oil equivalent basis Canadian Natural's proven and probable reserves grew by 41 percent to 1.1 billion barrels of oil equivalent. To date Canadian Natural has booked only 226 million proven and probable barrels of oil attributable to the BP Amoco acquisitions. Estimates of the reserves associated with the properties so acquired, as confirmed by the Company's independent engineers, exceed one billion barrels of oil equivalent. Additional reserves will be booked as they are developed.

Based on proven reserves only, the reserve life for our oil is 17.5 years while the natural gas reserve life is 8.3 years. During 1999 the Company replaced its yearly production by 5.1 times at a cost of $4.93 per barrel of oil equivalent.

In 1999, in response to the significant increase in the price of oil, our drilling program was more than double that of 1998, with the majority of the activity occurring in the third and fourth quarters. We drilled 727.3 net wells with a success rate of 93 percent up from 88 percent the year before.

Growth strategy

Over the past decade, Canadian Natural has consistently delivered results that exceed the industry average. Year after year, we have recorded positive earnings and growth in asset value through an unwavering commitment to our corporate strategy.

Allan Markin, Chairman

John Langille, President

From left: Steve Laut, Réal Cusson, Lyle Stevens

From left: Brian Illing, Tim McKay, Allen Knight, Greg Adams

The success of this strategy can be seen by our five-year return on equity, which has averaged 10 percent to December 31, 1999. By comparison, the average in our peer group over the same period was 2 percent. In 1999 the Company produced positive earnings ($1.93 per share), contributing to an increase in return on equity to over 13 percent. At the same time, we have remained one of the lowest cost operators in the industry. In 1999, with increasing commodity prices and continuing low overall costs, cash flow per barrel of oil equivalent increased to a level that enabled us to reach our targeted recycle ratio of 2 to 1.

We have achieved these favourable financial and operating results by adhering to our long-term growth strategy of building a large but diversified asset base in western Canada, which we exploit in the most cost effective manner possible. Over the past decade, we have established five core areas, each with its own characteristic production and reserve profile. This allows us to remain focused, yet provides flexibility to adapt our capital program to take advantage of emerging opportunities brought about by changing environments.

Within each core area we develop considerable in-house expertise and amass a very large prospect inventory and we can efficiently identify and prioritize prospects and pursue exploration and development best suited to our short- and long-term objectives. We pursue 100 percent working interests and operatorship, which allows us to control the extent and timing of future development. Our growth is completed by a focused opportunistic property acquisition program which requires that targets are a strategic fit within our existing base of operations. With a large inventory of high quality prospects, we are under no pressure to pursue acquisitions unless they meet our growth parameters.

Moving forward, we do not plan to deviate from this growth strategy. It has served us extremely well over the past decade, and we believe it will propel us to even greater success in the next 10 years.

BP Amoco acquisition

The acquisition of the remaining Canadian oil properties from BP Amoco represents an outstanding opportunity for Canadian Natural to build a new platform for long-term growth in western Canada and move to a new level of operational and financial performance. These properties met our acquisition criteria on all counts. They offer significant immediate, medium-term and long-term, low-cost growth in core areas where we already operate and have considerable expertise. They feature high working interests with potential for high recycle ratio growth.

The development and exploitation potential of these properties is immense. At the time of the acquisition, production was 41,600 barrels of oil equivalent per day, generated through 30,000 barrels a day at Bonnyville, 8,000 barrels at Pelican Lake and 3,600 barrels at Nipisi. However, the medium and long-term potential is where the greatest value lies. The assets have a seven percent decline rate and a 25-year proven reserve life, with estimated proven reserves of 400 million barrels and proven plus probable reserves of 1 billion barrels. Not included in this reserve estimate are the 2.6 billion barrels of mineable bitumen contained in the Mic Mac tar sands lease. In addition, we acquired 700,000 acres of net undeveloped land, royalty interests covering lands throughout western Canada and at Lake Erie, and a 50 percent interest in an Alberta electrical co-generation plant.

Outlook for 2000

Our 2000 base capital expenditure budget (excluding acquisitions) has been set at $750 million, which includes the drilling of approximately 700 wells. In addition, we have anticipated spending $250 million for acquisitions. Approximately 70 per cent of the 1999 budget will be directed towards oil. We have budgeted 2000 cash flow to be in the range of $950 million and $1.1 billion. These estimates are based on average daily production of 125,000 to 135,000 barrels of oil and average daily production of 750 to 775 million cubic feet per day of natural gas with an average WTI price of US$21.00 a barrel and natural gas averaging Cdn$2.75 per thousand cubic feet.

With current production volumes in excess of 262,000 barrels of oil equivalent per day (converting natural gas to oil at a conversion ratio of 6 to 1) and continuing strong commodity prices, Canadian Natural will realize significant increases in its cash flow for the balance of the year. The Board of Directors have presently determined that excess cash flow realized over and above the forecast $1 billion capital expenditure budget will be directed towards repayment of long-term debt. This strategy will provide continued production growth per share, superior returns on equity and the flexibility to pursue future opportunities as they arise.

The success that we have achieved as a company over the past decade is due in large part to the collective effort and commitment of our directors and employees. Together as a team, they have consistently risen to the challenge of delivering results that exceed those of many of our peers. We are proud of their accomplishments and sincerely thank them for the success that they have allowed us to achieve as a whole. And with their ongoing loyalty and commitment, we are confident that we will continue to generate long-term value for our shareholders.

In memory

In 1999 we unfortunately lost one of our team with the passing of Robert Boulware. Bob was one of the founders of Canadian Natural and served as president from 1976 to 1985. A director since the Company's inception, Bob always had a realistic outlook and direction that will be missed. On behalf of the team at Canadian Natural - thank you.

On behalf of the Board of Directors,

John G. Langille President March 24, 2000	Allan P. Markin Chairman

OUR WORLD-CLASS TEAM

Lonnie Abadier
Greg Adams
Cheryl Agnew
Gregory Alexander
Shaun Alspach
Bruce Anderson
Murray Anderson
Jonathan Anderson
Kari-Lou Antolic
Shelley Antonuk
Cheryl Appleton
Jim Archibald
Evalynn Arden
John Argan
Mark Ariss
James Arkley
Markos Armanious
Rob Armstrong
Clifford Atkinson
Aggie Aucoin
Bernard Auger
Leon Auger
Marvin Auger
Charles Badiou
Janice Baik
Dwayne Bailer
Chris Baker
Sam Balaneski
Reginald Baldock
Vaughn Baldwin
Teresa Banny
Jack Bardahl
Garry Bardoel
Lisa Barrett
Carrie Barter
Marty Bartman
Laurier Beaunoyer
David Bechtel
Robert Befus
Jeannette Begg
Lesley Belcourt
Ronald Bell
Josephine Bell
Jon Bell
James Bentley
David Berger
Jeffrey Bergeson
David Biagi
Linda Bigelow
Roger Bintz
Kevin Bjornstad
Kenneth Blackhall
Kerri Blackmore
David Blake
Shamane Blake
Dwayne Blenner-Hassett
Vikki Bochon
Marty Boggust
Shawn Bond
Jill Bonkowsky
Heather Bonnell
Patricia Booklall
Albert Bordeleau
Kerrie Bordeleau
Slade Bowers
Cheryl Bowman
Dale Boychuk
Jeffrey Boyd

Patrick Boyd
Victoria Boyle
Neil Bozak
Marianne Brady
Eleanor Branagh
Myron Brataschuk
Rob Braun
Brad Braun
Colin Brausen
Duane Breit
Joseph Breland
Barry Brick
Clint Brooks
Robert Brownless
Elizabeth Brownrigg
Rick Buchanan
Andrew Buchwitz
Clarence Bur
Trevor Burchenski
Grant Burgess
Jacquie Burke
Leanne Butz
Lorraine Cameron
Tyson Cameron
Robert Campbell
Dean Campbell
Clayton Campbell
Andre Campeau
Maria Campos
John Capstick
Harley Cardinal
Lee Cardinal
Wayne Cardinal
Jim Carey
Ian Carleton
Rick Carr
Allan Carswell
Gary Case
Trevor Cassidy
Mike Catley
Nicky Caven
Dante Cay
Ernest Chachula
Susan Chadwick
Andrea Chalmers
Alan Chaney
Darryl Charabin
Mike Chernichen
Alvin Chim
William Chiverton
Jessica Choi
Raymond Chong
Wayne Chorney
Sherry Chow
Jeannie Choy
Alphonse Chretien
Heather Church
William Clappertom
Mike Clark
Greg Clegg
Dale Coburn
Thelma Codd
Sabrina Colangelo
Lilie Collins
Brad Cook
Kent Cooper
Gordon Cormack
James Corner

Wayne Cote
David Cousins
Gordon Coveney
Keith Cowger
Harry Crabtree
Layne Craig
Bruce Crain
Beverley Creed
Roger Crichton
David Cridland
Lloyd Cross
Christopher Cross
Kirby Crowell
Reynaldo Cruz
Anthony Csabay
Corinna Culler
Arley Currie
Kenneth Cusack
Réal Cusson
Lynne Darlington
Randall Davis
Stephen Davis
Leonard Dawe
Robert Day
Marie de Champlain
Harry Dean
Raymond Dechaine
Roland Dechesne
Ian Degiano
Barbara Deglow
Bonnie Deis
Karen Demers
Edward Deren
Catherine Desjarlais
Michael Desroches
Dease Devine
Noreen Devji
Sandy Diguer
Irene Dikau
Shawn Doble
John Dodman
Conrad Dombowsky
Veronica Dooling
Tim Dootka
Blair Dow
Dahl Dow
Bobby Dreger
Colleen Drury
Albert Duhaime
John Dumais
Gladiola Dumitrescu
Sean Duncan
Scott Dutkiewicz
Gary Earl
Kevin Earle
Suzanne Eaton
Carole Eliuk
Diane Emond
Jerry Enders
Rommel Engler
Joanne English
Sean Estell
Monique Evans
Maureen Evers-Dakers
Andy Fankhauser
Cara Fast
Arthur Faucher
Brian Fehr

Kurt Fenrich
William Ferguson
Magdalena Ficek
Darren Fichter
Michael Filipchuk
Rod Fitzpatrick
Craig Flamand
Ken Fleck
Rodney Flett
Trevor Flood
Edmond Foisy
Hop Chi Fong
Robert Fontaine
Curtis Formanek
Randy Formanek
Devon Fornwald
Robert Fortier
Peter Fowler
Donald Fox
Ron Frank
Ken Frazer
Roger Frere
Brad Friesen
Kenneth Friesen
Kevin Frith
Frank Frosini
Arlene Furjanic
Josephine Gaddi
Sharon Gaehring
Kelly Gagne
Scott Gair
Larry Galea
Ron Gall
Micheal Gallon
Graham Galloway
Yoko Galvin
Maurice Gauthier
William George
Michel Germain
Raymond Germain
Bob Gerwing
Clark Getz
Ralph Gill
Doug Ginn
Francis Gladue
David Golden
Yvon Gosselin
Allan Gould
Treena Groeneveld
Robert Gullion
Swarna Gunaratne
Carolyn Gunderson
Jane Guse
Elaine Gussman
Graham Gustafson
Violet Haddad
Jenise Hagel
Egbert Hagens
Shemin Haji
Dean Halewich
Rick Halkow
Jim Hamilton
Tim Hamilton
Kevin Hamm
Dave Handy
Ken Harke
Roger Harris
Bill Harris

Jody Harris
Mike Harty
Jerry Harvey
Wayne Hatton
Angela Head
Larry Heath
Terry Heck
Ken Hedstrom
Judith Hermann
Michele Herron
Michael Hill
Gordon Hill
Karen Hillstrom
James Hinde
Judith Hinkel
Barbara Hofer
Kevin Hoium
Chris Hojnik
Ian Holmes
David Holt
Shannon Hood
Hans Hoogendam
Bill Horne
Keith Hornseth
Judy Huebert
Mark Hughes
Terry Humbke
Ray Hutscal
Bruce Hutt
Joseph Iaquinta
Matthew Ilchuk
Brian Illing
Brad Inman
Karen Ivan
Ken Jacobson
Chris James
Leonard Janzen
Calvin Jarratt
Brent Jensen
Kevin Jensen
Parry Jensen
Qi Jiang
Terry Jocksch
Greg Johnson
David Johnson
Jeffrey Johnson
Evan Johnson
James Jung
Dale Kachowski
Asif Kachra
Raymond Kahanyshyn
Marcelle Kanderka
Warren Kapaniuk
Brad Karaja
Alice Karg
Lynn Kasper
Christopher Kean
Wayne Kennedy
Carla Kenney
Mary Jane Kerrison
Kimberly Kielt
Stan Kimmie
Richard King
Steve King
Marvin Kinsman
Brent Kissel
Yvonne Kloiber
Allen Knight

Danell Kokol
Eva Komers
Diane Kostiuk
Richard Kowalski
Kevin Kowbel
Cameron Kramer
Trevor Krause
Todd Kreics
Jeffrey Kreiser
Patti Krekoski
Gabriel Krywolt
Frank Kurucz
Harvey Kvile
Angele Kwon
Bob Kyllo
Mitzi LaChance
Philip Lafond
Robert Lagimodiere
Michael Lahure
Cassandra Lai
Mahmud Lalani
Jacqueline Lamb
Eugene Landry
John Langille
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Sydney Lillies
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Darin Lorenson
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Darryl Lowe
Jonathan Lowes
Wendy Lutzen-Askew
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Allan MacKenzie
Ryan MacKenzie
Shawn MacKenzie
Marilyn Macoy
Jane Mactaggart
Bruce Maddex
Markus Maennchen
Bill Mah
Sajid Mahmood
Joey Majerech
Jim Mak
Anita Mak
Lawrence Malek
Peter Manchak
Mike Manchen
Darcy Mandziak
Roy Marceniuk

Ronald Marcichiw
Allan Markin
Robert Martin
Richard May
Brent May
Deirdre Mazur
Stacey McArthur
Toni McCarthy
Brenda McGinnis
Robert McGowan
Mavis McGuire
Rod McKay
Carmen McKay
Tim McKay
David McKinnon
Douglas McLachlan
Casey McWhan
Barry Meier
Belinda Meller
Jean Melnychuk
Timothy Merk
Dwight Mervold
Rick Meyers
Murray Michie
Jane Mikalsky
Jacqueline Miko
Jeffrey Miller
Marsha Miller
Noel Millions
Ronald Mills
John Mills
Michelle Minick
Denis Mino
Kerry Minter
Maria-Celeste Miranda
Stacey Mitchell
Lisa Monkman
Rick Monteith
Judy Montes
Paula Montgomery
Melinda Moore
Jason Moravec
Ray Morin
Wesley Morrow
Carole Morton
Robert Mosoronchon
Luciano Muzzin
Lorna Myers
Scott Myers
David Myshak
Richard Nachtegaele
Elly Nance
Rick Napier
Bill Navratil
Randy December
Vincent Nelson
Brad Nessman
Monty Neudorf
John Newman
Kevin Newton
Thu-Van Nguyen
Lyle Nichols
Josie Nicolajsen
Ian Noble
Scott Noble
Greg Nolin
Robert Norman
John North
Darcy Nowak
Robert Nuytten
Antonella Olivito
Richard Olsen
Vane Orcutt
Flora O'Reilly
Colette Orr
Camille Ouellette
Jolanta Ouellette
Dennis Ozaruk
Doug Page

Marcus Pagnucco
Tammy Palardy
Micheal Palmer
Vladimir Papuga
Bernard Parenteau
Clement Parenteau
Lawrence Paslawski
Randy Passmore
Rick Pay
Dean Payne
David Payne
Laurel Payten
Shawn Pedersen
Brian Pederson
Kevin Pennington
John Perepelecta
Bill Peterson
Brenda Peterson
Rodney Petrie
Henry Petrie
Lucyna Pettigrew
Tom Phan
Ron Pilisko
Susan Pinel
Donna Playfair
Ted Plouffe
Louis Plouffe
Marie-Anne Poirier
Hector Poirier
Eleanor Polson
Jeffrey Poth
Neil Powell
Bonnie Pratt
Maurice Raiwet
Myron Rak
Maritess Ramirez
Kerri Ramsbottom
Stojan Ratkovic
Duane Reber
David Reddecliff
Bernie Redlich
Lori-Anne Reed
Duncan Rehm
Carmon Reich
Jim Reichert
Randolph Rey
Pat Reynolds
Warne Rhoades
George Rhyason
Wesley Richardson
Robert Riddell
Joanne Riggall
Carl Ringdahl
Robert Ringuette
Jimmie Roberts
Gene Robinson
Roger Rodermond
Louis Romanchuk
Dwayne Romanovich
Linda Romness
Dennis Ross
Rick Rosychuk
Tom Roth
Lorraine Rothfus
Scott Rowein
Alvin Rubbelke
Mark Russell
Bruce Russell
Matthew Russett
Brian Rutledge
Hal Rutz
Tony Sabelli
Uranela Samardzic
Sherry Sands
Pearl Sands
John Sargent
Marlene Saunders
Christine Savary
Luc Savoie

Lana Sawatzky
Denise Sawchyn
Judy Schafer
Alison Scheers
Lance Schelske
Sally Schick
Ronald Schlachter
Beat Schmid
Valerie Schmidt
Raquel Schmidt
Craig Schneider
Ronald Schnieder
Stephen Schofield
Norm Schonhoffer
Emily Schroeder
Anna Schuler
Marilyn Schultz
Lorraine Schwetz
Lorne Schwetz
Ronalda Scott
Marjorie Scott
John Scott
Brian Segouin
Roland Senecal
Gilbert Shantz
Dorothy Shea
Robert Shears
Judi Shermerhorn
Annette Shillam
Jill Shipton
Glen Siegle
Wayne Sikorski
Jilleen Simpson
Paul Siree
Christine Siu
Michael Skipper
Dan Skrypichayko
Doreen Smale
Robert Smart
Lawrence Smith
Bonnie Smith
Allen Smyl
Lawson Squire
Glen Squires
Robert St. Amant
Rodney Stahn
Karen Stairs
Randy Stamp
Kris Stark
Scott Stauth
Wayne Steffen
Lyle Stevens
Robert Stevenson
Lorie Stewart
Wendy Stewart
Katrina Stockman
Wade Strand
Rodney Strate
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Pamela Strauss
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Verlynn Taylor
Kurt Tenney
Marilyn Tenold
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Karen Thistleton
George Thomas

Laurie Thomas
Mark Thompson
Scott Thompson
Todd Thomson
Bruce Thornton
Margaret Thurmeier
Terry Tillotson
Brian Timmerman
Al Tokarchik
Catherine Trenouth
Terry Turgeon
Stanley Turner
Gregory Ulrich
Allan Valentine
Louis Vallee
Richard Van Appelen
Vyvette Vanderputt
Collin Vare
Dale Vickery
Leo Vollmin
Joy Wagner
Brien Walker
Gale Wagner
Dwight Wagner
Jodi Walter
Blaise Wangler
Kirk Ward
Wanda Warman
Marguerite Wassmer
Debra Waterhouse
Abena Watson
Jim Webb
Randall Weeks
Isaac Wellard
Mark Wenner
Darcy Weston
Terry Wetzstein
Ken White
Debbie White
Debbie Wiens
Cameron Wietzel
Grant Williams
Bill Williams
Ebonie Williamson
Jeff Willick
Robin Willis
Christian Willson
Shari Wilson
Darryl Wilson
Jeff Wilson
Woodrow Wilson
Patrick Wiltse
Garrett Wirachowsky
Nancy Wolff
Kitty Wong
Jennifer Wong
Roxanne Wood
Bette Wood
Gloria Woods
Daron Woolf
Sidney Wosnack
Raymond Wourms
Brent Wychopen
Valerie Wyonzek
James Yaroslawsky
Jennifer Yates
Gordon Yee
Betty Yee
Tony Yip
Daryl Youck
Richard Young
William Yuill
Arthur Yukim
Glenn Zeebregts
Diane Zeliznik
Denis Zentner

OPERATIONS

Canadian Natural achieved favourable operating results for 1999 through strict adherence to its operating strategy: effective cost controls, managed debt and long-term growth.

Developing its large asset base in a cost effective manner, and focusing on high recycle properties in western Canada have been key to the Company's success.

Canadian Natural established several operating targets, promoting continued growth and increased shareholder value. They are as follows:

Positive earnings and return on equity

Canadian Natural has not recorded a loss in any reporting period over the past eleven years. The Company's growth in oil and natural gas reserves has increased on a per share basis each year. Canadian Natural's return on average equity remains at the top end of its North American peer group.

Low reserve replacement costs

Canadian Natural's reserve replacement costs include all costs incurred in finding, developing and bringing on-stream reserves of oil and natural gas. Our target is to be under $6 per barrel of oil equivalent on an annual basis, regardless of the commodity price.

Control costs

Canadian Natural consistently maintains low costs in all three operating aspects of our business: reserve replacement, operating and administration. The aggregate of costs over an extended period of time are at the low end of the Company's peer group.

Maintain a strong balance sheet

Canadian Natural's debt position is managed in relation to the size and depth of its asset base, providing the Company with the flexibility to adapt its capital program to pursue growth opportunities as they arise.

1999 capped a decade of positive financial and operating results for Canadian Natural. Building upon this momentum, the Company has clearly defined strategies to meet its operating targets.

Generate projects

Canadian Natural has a compliment of technical people and expertise to evaluate and pursue projects that meet the Company's economic criteria.

Acquire properties

Canadian Natural will acquire properties situated within the Company's core operating regions. Focusing operations in areas with contiguous land holdings and complementary infrastructure provides operating synergies and clear economic value for Canadian Natural.

Own and operate

Over 90% of the net wells drilled for Canadian Natural are operated by the Company, as is 90% of the Company's production.

Maintain high working interest

Canadian Natural has an average working interest of 87% in its undeveloped land base. A high working interest affords the Company autonomy, control and the flexibility to define and meet corporate objectives.

Manage risk

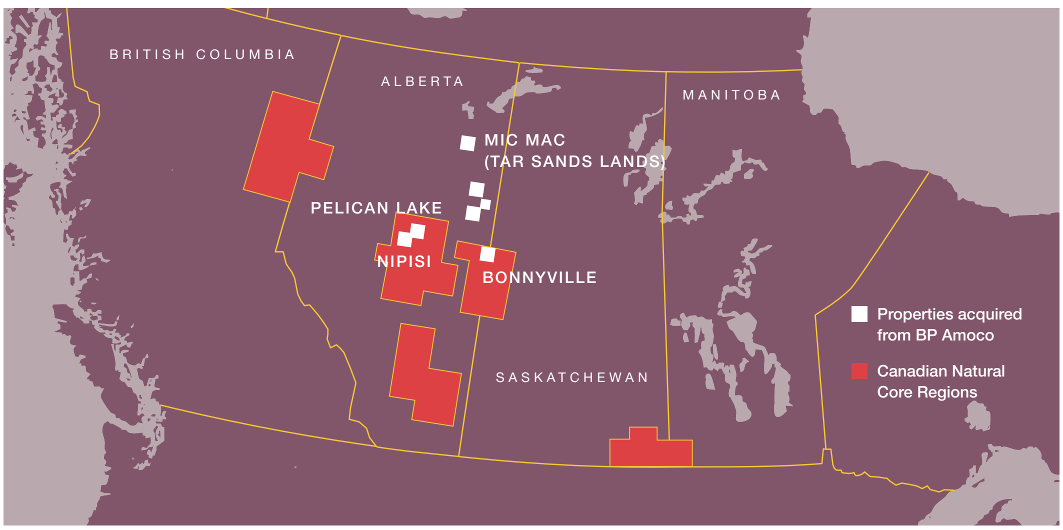
The majority of Canadian Natural's undeveloped land is located in areas with potential for oil and natural gas at varying depths up to 6,000 feet. Recent acquisitions to our asset base fall within these depth parameters, affording the Company considerable medium risk drilling opportunities.

Apply technology

Canadian Natural utilizes new technology to its fullest potential. Providing the technology is proven and economical to daily operations, the Company has used new methods of interpretation by geophysicists, horizontal and sidetrack drilling, underbalanced drilling and enhanced production recovery methods such as Steam Assisted Gravity Drainage.

Focused Operations

Canadian Natural operates in five core regions of western Canada, and will pursue opportunities to acquire additional properties within these core areas. Focused operations in areas with contiguous land holdings and a complementary infrastructure provides operating synergies and clear economic value for the Company.



WORLD CLASS ASSETS, LONG-TERM GROWTH.

In 1999, Canadian Natural Resources completed a $1 billion acquisition of the oil assets of BP Amoco in Alberta. The transaction, the largest in the Company's history, has positioned Canadian Natural for low-cost, long-term growth in western Canada. These assets offer the following:

- 41,600 barrels per day of immediate production;
- Proven reserves of 400 million barrels of oil equivalent;
- Proven and probable reserves of 1 billion barrels of oil equivalent;
- Estimated 2.6 billion barrels of mineable bitumen;
- 700 thousand acres of undeveloped lands;
- High recycle ratio growth;
- Low operating costs;
- Low royalties;
- High working interest; and
- Superb fit within Canadian Natural Resources core regions.

HEAVY OIL

Canadian Natural produces heavy oil using two production recovery mechanisms: primary (cold) production and thermal (hot) production. Our assets are similarly distinguished by characteristics where these two types of production recovery mechanisms provide the most effective recovery of hydrocarbons and the optimum economic returns. Our heavy oil properties provide us with some of the most attractive recycle ratios in the industry.

Typical Operating Parameters

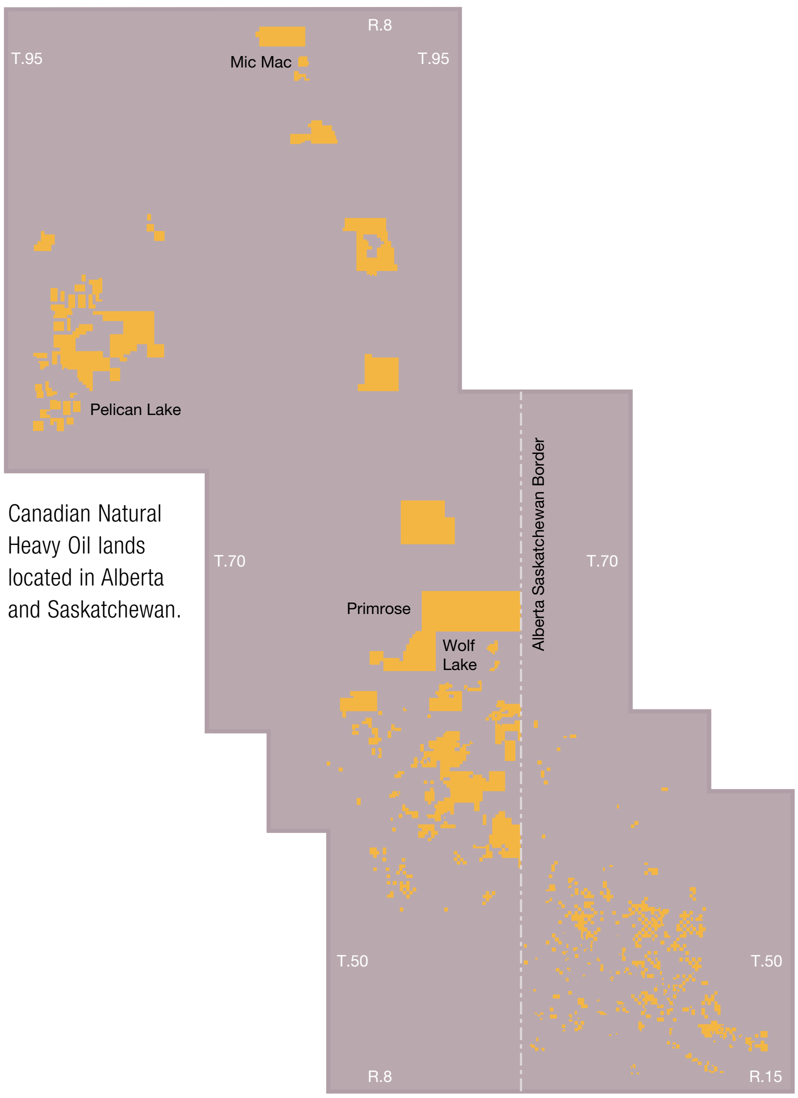
	Initial Rate per well Bbl/d	Reserves Per Well MMSTB	Onstream Costs $/bbl	Operating Costs $/bbl	API°	Recovery Factor %
Vertical/Slant unconsolidated	50 - 150	100 - 200	2.50	5.50	12 - 14	3 - 20
Pelican Horizontal	200 - 400	300 - 500	3.50	2.00	14 - 17	6 - 12
Thermal Cyclic Primrose	100 - 250	500	2.50	5.50	12	18 - 25
Thermal SAGD Wolf Lake	400 - 600	750 - 1000	3.00	6.00	12	40 - 60

Mineable Bitumen

This process is applied to thick sands located near the surface containing bitumen with an API of 6° to 9°. The surface overburden is first stripped away. The oil sands are then removed and trucked to a processing facility, where the sand is separated from the bitumen and the bitumen is processed and upgraded.

Canadian Natural does not currently have any mineable production, but owns the Mic Mac lease, which contains 2.6 billion barrels of mineable bitumen. Similar operators in the area have operating costs of $11.00 to $15.00 per barrel. Capital costs are significant, in the $4 to $5 billion range, but this equates to only $1.00 to $2.00 on a per barrel basis.

Canadian Natural will be undertaking further development and feasibility studies on its mineable leases for long-term growth.

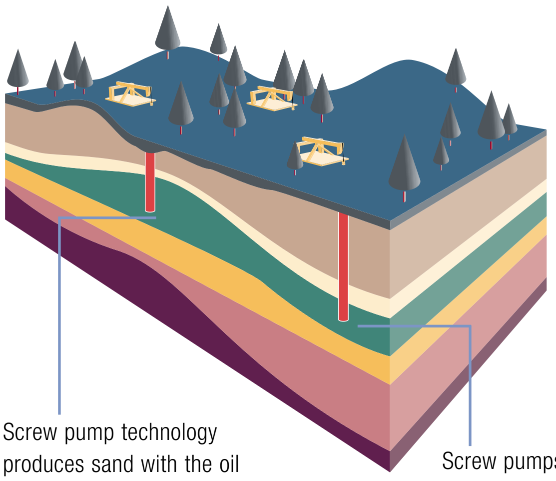


Canadian Natural Heavy Oil lands located in Alberta and Saskatchewan.

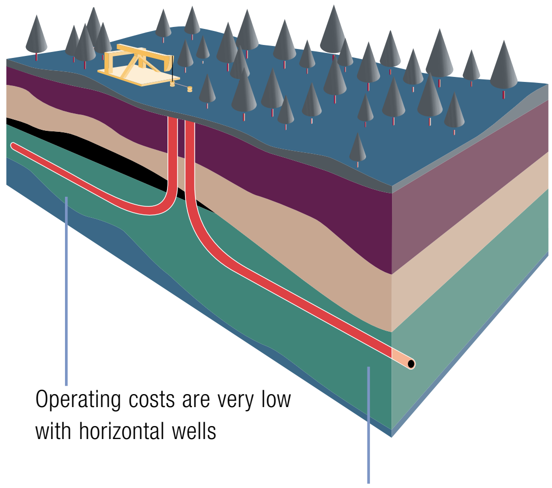
COLD – Primary Heavy Oil

Under primary recovery the energy required to flow heavy oil into the wellbore comes from the expansion of solution gas. The recovery of oil by this method ranges from three to 20 percent of original oil-in-place, depending on the viscosity of the oil and the amount of solution gas. Production can be recovered through vertical, slant or horizontal wells.

VERTICAL



HORIZONTAL PRIMARY



Vertical/Slant Wells in Unconsolidated Sands

Screw pump technology has been a significant advance for producing heavy oil from unconsolidated sands. Screw pumps produce sand with the oil, which improves both the productivity and ultimate recovery of oil from the vertical well. This technology allows wells to be produced at high drawdowns, which has led to development of significant heavy oil reserves that were previously uneconomical.

Canadian Natural currently produces about 55,000 barrels per day of oil from vertical or slant wells. A typical well will take two to three months to reach maximum productivity. This rate is sustained for two to four years and then production declines rapidly. While these decline rates are significantly higher than were realized with previous rod pump technology, the overall recovery is greater.

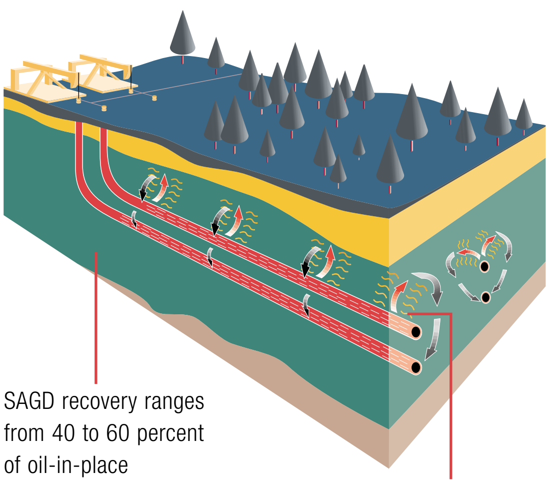
Horizontal Wells

Horizontal wells can be used to recover oil under primary recovery methods if the reservoir sands are more consolidated. It is often possible to drill more than one well bore from the same surface location. This recovery method is employed at Canadian Natural's Pelican Lake field, where the sands are partially consolidated and high drawdowns can be achieved. At Pelican Lake, Canadian Natural currently produces 27,000 barrels per day of oil under this recovery system. Operating costs are $2.00 per barrel, with a capital cost of $3.50 per barrel to bring onstream.

HOT – Thermal Production

A number of different types of thermal processes are available to increase production from heavy oil reserves. The two processes employed by Canadian Natural are cyclic steam injection and steam-assisted gravity drainage (SAGD). In both processes, steam is introduced into the reservoir to heat the heavy oil and reduces its viscosity. This improves the flow characteristics of the oil, greatly increasing the productivity and recovery of oil from the reservoir.

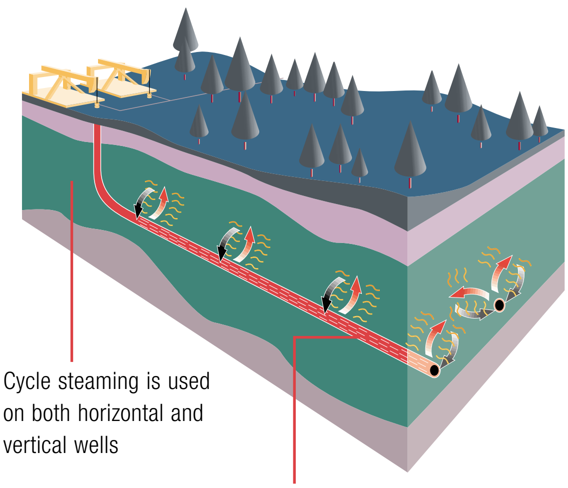
SAGD



SAGD recovery ranges from 40 to 60 percent of oil-in-place

Steam is continuously injected to heat the oil

STEAM CYCLE



Cycle steaming is used on both horizontal and vertical wells

Steam is injected for several weeks, followed by a production phase of several months

Steam Assisted Gravity Drainage (SAGD)

The steam-assisted gravity drainage (SAGD) process requires a pair of horizontal wells. Each pair consists of a producer near the base of the reservoir and an injector located about five metres above it. Steam is continuously injected through the upper well and flows up to the cold reservoir, heating the oils which then condenses. The heated oil and steam condensate drain by gravity to the lower production well and fluids are withdrawn by gas/steam lift. The depleted oil zone, or steam chamber, rises and spreads as production continues. Recoveries for this process range from 40 to 60 percent of the original oil-in-place.

Canadian Natural produces about 8,000 barrels per day of oil under SAGD. Production rates are 400 to 1,000 barrels per day per well and recovery is from 750 thousand to 1.5 million barrels per well pair.

Cyclic Steam Injection

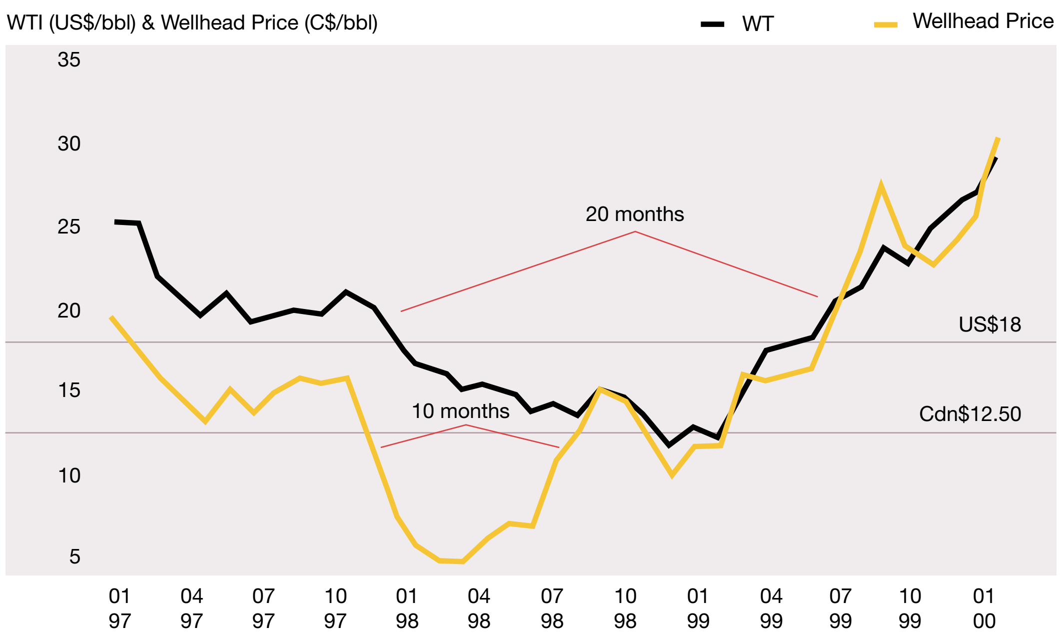
The cyclic steam injection process consists of alternating cycles of steam injection and hot oil production. During the injection phase, steam is injected for several weeks, heating the rock and fluids around the well. After injection, the reservoir will contain a zone of pressurized, highly mobile oil, water, and steam. During the production phase, the wellbore pressure is lowered, allowing the production of the hot fluids. Production continues for several months until fluid production and temperatures drop to low rates, signaling the time to commence another injection cycle. Canadian Natural uses both horizontal and vertical wells for cycle steaming.

Heavy Oil Marketing

The majority of the heavy oil produced in Canada is consumed in the midwestern United States. To transport heavy oil to this market, condensate is required to blend the heavy oil to pipeline specifications. The amount of condensate required is dependent on the viscosity of the heavy oil. For Canadian Natural's production the amount of condensate per barrel of heavy oil ranges from 18% at Pelican Lake to 28% at Primrose.

In addition to the cost of condensate the price of heavy oil is discounted to WTI oil in the form of a quality differential. Therefore the wellhead price of heavy oil is dependant on both the quality differential and WTI price. This increases the volatility of heavy oil wellhead price, when the price of WTI oil changes rapidly, however in the case of a downturn in prices the duration of lower prices is shortened in comparison to WTI pricing. The chart shown below illustrates this phenomenon which occurred in 1998 and in 1999. The chart shows that the WTI price was below US$18.00 a barrel for 20 months, whereas the heavy oil wellhead price was below Cdn$12.50 a barrel for half that time or 10 months. The higher discount occurring in the first half of 1998 was caused by pipeline constraints which have now been reversed. Canadian Natural can still achieve recycle ratios of 2 to 1 at a price of Cdn$12.50.

WTI Prices vs. Wellhead Price Differential



With the BP Amoco acquisition, Canadian Natural now owns one of the largest bases of oil and natural gas in Canada.

The two most significant properties acquired are at Bonnyville and Pelican Lake

BONNYVILLE

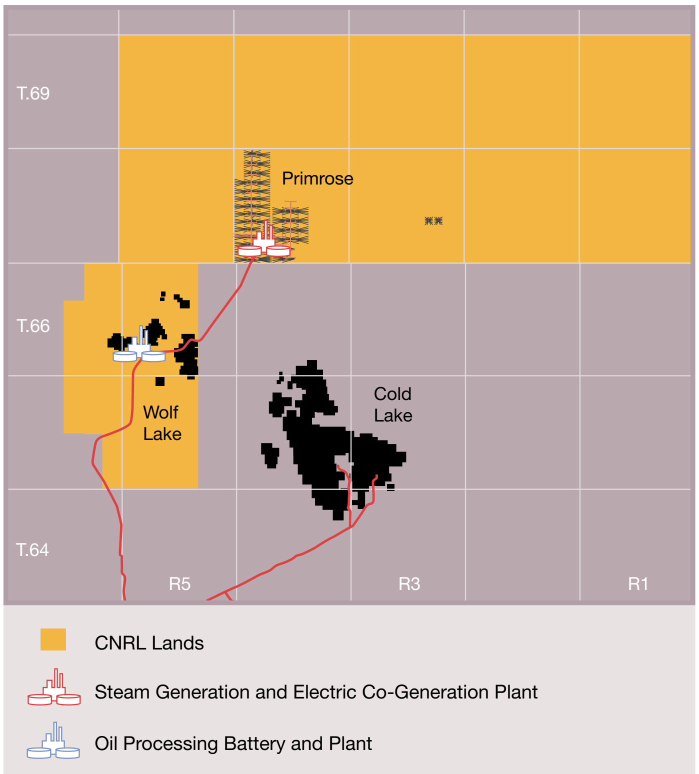
With production of 30,000 barrels of oil per day, Bonnyville was the major producing property acquired. The property is comprised of two producing areas of Wolf Lake and Primrose. These areas are interconnected with road and pipeline facilities.

Production in the Bonnyville area uses the thermal enhanced recovery techniques of a low-pressure cyclic steam process incorporating horizontal wells and from SAGD processes. The property produces 12° API oil primarily from the Clearwater and Grand Rapids formations, with original oil in place of greater than 4 billion barrels of oil.

A significant infrastructure exists at both Wolf Lake and Primrose. Although the plant is capable of processing 60,000 barrels of oil per day, it is currently running at only slightly more than 50 percent utilization. At Primrose, the Company has a 50 percent interest in an electrical co-generation plant which sells electricity into the Alberta power grid.

To ensure the optimal production, Canadian Natural plans to drill 44 wells at Primrose/ Wolf Lake, with full capacity by mid 2001. Engineering and environmental work is currently underway to support a 30,000 barrels per day expansion planned for early 2003. Further expansion to the facility is forecast for 2005 and 2006.

In keeping with Canadian Natural's strategy of cost control, Bonnyville has operating costs of $5.50 per barrel and onstream costs of less than $2.50 per barrel. Early development costs will be well under $2.00 per barrel as the existing infrastructure is optimized.



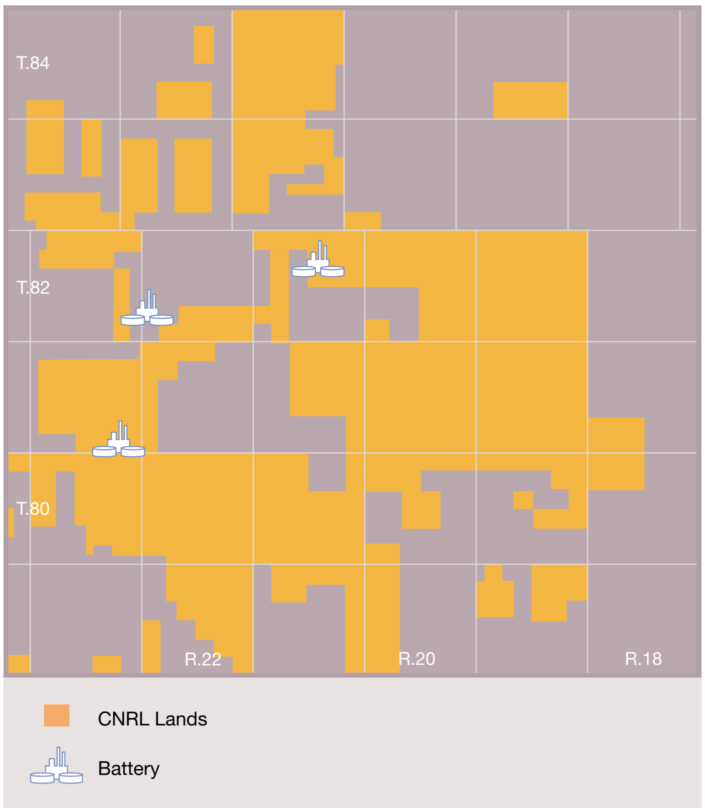
PELICAN LAKE

Pelican Lake was already a significant producing property for Canadian Natural in 1999. This production was augmented with the purchase of the BP Amoco properties, resulting in December, 1999 rates of 21,000 barrels per day. Sixteen wells were drilled in the Pelican Lake area during the last half of 1999.

The Pelican Lake field produces 14° to 17° API oil from the Wabiskaw sands at a depth of roughly 450 m. The field contains approximately 2.3 billion barrels of oil in place, with recoveries in the 6 percent to 10 percent range, depending upon the location within the field. Canadian Natural controls approximately 60 percent of the pool, with 80 percent of this being in the higher-quality thick portion of the pool. It is estimated there are 600 drilling locations for long length horizontal wells.

Canadian Natural plans to develop the Pelican Lake property to its full potential over the next five years. Plans for 2000 include 120 wells along with gas conservation facilities and battery expansions. Current production at the Pelican Lake facility is 27,000 barrels per day, with a capacity for approximately 32,000 barrels per day. Canadian Natural plans to expand capacity to 40,000 barrels per day in 2000.

The considerable facility capacity, along with a vast network of roads, the existing gathering systems, and a 50 percent ownership in the sales pipeline provide Canadian Natural with a dominant infrastructure position in the area. This existing infrastructure serves to keep costs very low, with operating costs of $2.00 per barrel and onstream costs of $3.00 per barrel. This field has by far the most attractive recycle ratios within the Company.



Major Properties Reserves and Values

(as at January 1, 2000)	Crude oil and NGLs		Natural gas		Value*	
Region	mbbls	%	mmcf	%	$ thousands	%
Northwestern British Columbia/ Northwestern Alberta	33,059	5.2	753,422	29.6	1,173,855	16.4
Eastern Alberta/Western Saskatchewan	441,502	69.0	136,761	5.4	2,198,261	30.7
North Central Alberta	106,719	16.7	896,152	35.2	2,251,021	31.4
South Central Alberta	24,774	3.9	605,006	23.7	965,063	13.5
Williston Basin	24,597	3.8	16,935	0.7	200,660	2.8
Other	9,273	1.4	139,041	5.4	336,913	4.7
Alberta Royalty Tax Credit and Corporate Capital Cost Allowance					40,465	0.5
Total	639,924	100.0	2,547,317	100.0	7,166,238	100.0

** Estimated future net revenues before income taxes, discounted at 10 percent, as evaluated in the Reserve Evaluation (page 26).*

Northeastern B.C. / Northwestern Alberta

	1999	2000 Forecast
Average production		
Gas	250 mmcf/d	270 mmcf/d
Oil	11,200 bbls/d	12,000 bbls/d
Drilling activity	74 net wells	100 net wells
Undeveloped land	1,258,000 net acres	

Canadian Natural has been a very active driller in this light oil and liquids-rich natural gas region. Successful exploration and development has positioned Canadian Natural as one of the largest oil and natural gas producers in British Columbia.

Compared to its other core areas, drilling targets are deeper, up to 5,000 vertical feet, however, risk is mitigated by multi-zone potential and larger reserve targets. The Company's success in this geologically complex area has hinged on its technical expertise, employing advanced technology and effective cost controls. The exploration strategy focuses on comprehensive evaluation through two-dimensional and three dimensional seismic and targeting economic geological areas close to existing infrastructure.

A large proportion of the assets acquired during 1999 through the Plan of Arrangement proposed by the Company for the assets of Blue Range Resource Corporation are located in this region.

Eastern Alberta / Western Saskatchewan

	1999	2000 Forecast
Average production		
Gas	28 mmcf/d	35 mmcf/d
Oil	43,100 bbls/d	77,000 bbls/d
Drilling activity	136 net wells	195 net wells
Undeveloped land	695,000 net acres	

Reserves of heavy oil (averaging 13° API) and some natural gas are produced through conventional vertical and horizontal well bores from a number of productive horizons up to 2,500 feet deep.

After reaching historic lows in the first quarter of 1999, the benchmark WTI price recovered commencing in the second quarter of the year. This, combined with the narrowing of the differential for heavier quality crude oil and reduction in the cost of condensate used for blending, resulted in a significant improvement in the price realized for crude oil produced from this region. With the continuance of the Company's overall low operating costs to produce conventional heavy oil, Canadian Natural's netbacks improved significantly throughout the year. Accordingly, in the latter part of the second quarter of the year the Company substantially increased its drilling program in this region.

The properties acquired at Primrose/Wolf Lake are also located in this region. As well as the SAGD process utilized at Primrose/Wolf Lake, the Company also has a 50 percent interest in another successful SAGD application at Tangleflags in Saskatchewan.

North Central Alberta

	1999	2000 Forecast
Average production		
Gas	303 mmcf/d	305 mmcf/d
Oil	18,000 bbls/d	32,000 bbls/d
Drilling activity	159 net wells	230 net wells
Undeveloped land	2,235,000 net acres	

Canadian Natural has grown North Central Alberta into its largest natural gas producing area. The region is also indicative of Canadian Natural's operational flexibility as it encompasses Pelican Lake, the large expanse of oil sands leases at the northern end of this region.

Gas volumes from this region accounted for 42 percent of the corporate total in 1999. Natural gas prospects are typically low risk, multi-zone shallow targets at depths up to 3,000 feet. The profitability of these wells is further enhanced by the large Company-operated infrastructure which allows for drilling and well tie-in at low onstream costs.

At Pelican Lake, in the Brintnell area of this region, the Company has the major ownership position in the necessary infrastructure, including roads, drilling pads, pipelines, batteries and compressors to ensure future economic development of the large oil pool. The Company's holdings in the area were further augmented with the acquisition of contiguous lands and facilities from BP Amoco. With the recovery of oil prices in the second quarter of 1999 the Company re-commenced its horizontal drilling program in this area in the second half of the year.

South Central Alberta

	1999	2000 Forecast
Average production		
Gas	134 mmcf/d	140 mmcf/d
Oil	7,000 bbls/d	7,000 bbls/d
Drilling activity	345 net wells	235 net wells
Undeveloped land	216,000 net acres	

South Central Alberta is characterized by shallow to medium depth natural gas and light oil. Since Canadian Natural entered the area in 1996 through an acquisition, it has focused primarily on development of under-exploited gas reservoirs. The Company has also pursued low risk opportunities to improve oil production from existing pools through infill drilling, work-overs and recompletions. An extensive infrastructure allows wells to be brought onstream quickly and economically. The shallow depth of drilling targets also contributes to the area's profitability. The Company undertook a very active drilling program in 1999, particularly shallow gas wells predominately in areas where Canadian Natural already has gathering and processing facilities. The production from these wells will be low productivity per well but long life reserves.

Williston Basin

	1999	2000 Forecast
Average production		
Gas	2 mmcf/d	2 mmcf/d
Oil	6,800 bbls/d	7,000 bbls/d
Drilling activity	14 net wells	15 net wells
Undeveloped land	445,000 net acres	

The Williston Basin is located in Southeastern Saskatchewan. It is characterized by light sour crude and Canadian Natural entered the area in 1996 through the Sceptre Resources acquisition. In the second half of 1999, with the recovery in the price of oil, Canadian Natural drilled a total of 13 oil wells. The majority of these wells were horizontal infill development wells. With the Company already owning significant amounts of oil processing facilities, these wells can be economic with the higher oil price.

With improving oil prices Canadian Natural re-instituted oil drilling locations and doubled the net oil wells drilled.

Our proven reserve life index increased to 17.5 years for oil properties.

Undeveloped Land

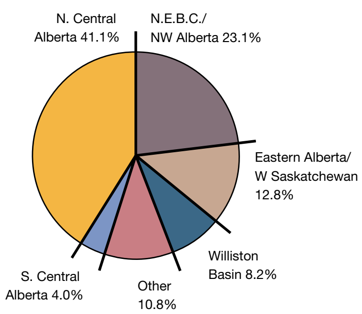
One of the prerequisites to long-term economic growth in exploiting and producing oil and natural gas is to own and control a large base of mineral rights in undeveloped lands. Canadian Natural continues to increase its undeveloped land holdings in proportion to the overall increase in its asset base. At the end of 1999 the Company held in excess of 5.4 million net acres of undeveloped land. In keeping with the Company's focused land acquisition program, 90 percent of the land acquired this year was within the Company's five core regions. The average price paid by Canadian Natural in 1999 on provincial land sales was $41 per acre, compared with the average industry price in 1998 of $49 per acre.

Canadian Natural maintained an average working interest of 87 percent in the newly acquired lands in 1999. This high working interest ensures the Company retains control over any exploration and development opportunities.

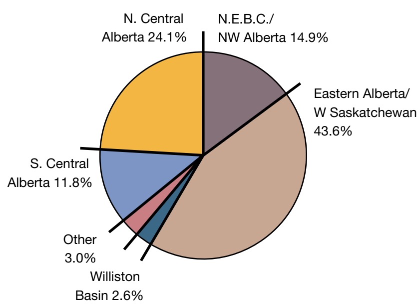
Landholdings

	1999			1998		
	Gross Acres	Net Acres	Average Interest	Gross Acres	Net Acres	Average Interest
Developed	**3,960,455**	**3,150,626**	**80**	3,089,002	2,360,601	76
Undeveloped	**6,231,112**	**5,439,557**	**87**	5,497,129	4,795,719	87
Total	**10,191,567**	**8,590,183**	**84**	8,586,131	7,156,320	83

Undeveloped Land Holdings
(%)



Reserves
(%)



The geographic location of the undeveloped land is as follows:

Net Undeveloped Land (net acres)

	1999	1998
British Columbia	**1,027**	859
Alberta	**3,582**	2,984
Saskatchewan	**481**	577
Other	**350**	375
Total	**5,440**	4,795

Seismic

With the focus on internally-generated prospects, both two- and three-dimensional seismic are an important resource for the Company. In 1999, Canadian Natural invested $17.9 million to acquire new seismic data and to purchase and reprocess existing data. In total, the Company shot 1,920 kilometers of conventional seismic, and 80 square kilometers of three-dimensional data. Canadian Natural also purchased 3,600 kilometers of conventional seismic.

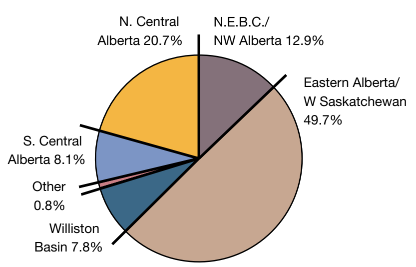
Drilling Activity

Canadian Natural's commitment to its operating strategies has afforded the Company financial flexibility and the ability to respond quickly to the rapidly changing economics of oil and gas. Responding to the volatile price of oil, Canadian Natural was able to adeptly shift the emphasis and timing of its drilling programs without compromising the Company's overall growth pattern.

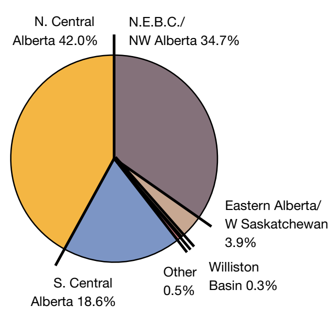
Due to the low net realized price per barrel of oil, Canadian Natural curtailed much of its oil drilling program in the first quarter of 1998 and into the second quarter of 1999. As oil netbacks improved during 1999, Canadian Natural quickly re-instituted drilling locations on oil potential lands resulting in a doubling of net oil well drilling for 1999.

Large portions of Canadian Natural's asset base are accessible year-round and are not restricted by weather or access. Accordingly, in the third quarter of 1999, Canadian Natural drilled over 300 shallow gas wells, predominately in its South Central Alberta region. These gas wells were comprised of infill, step-out development and exploratory wells. In total, the Company drilled a total of 458 net gas wells with the majority of the remaining wells being located in Canadian Natural's traditional gas producing regions of N.E. British Columbia/N.W. Alberta and North Central Alberta.

Crude Oil and NGLs Production
(%)



Natural Gas Production
(%)



Canadian Natural's drilling program for 2000 includes a reasonable balance of 390 natural gas wells and 335 oil wells. Over 90 percent of these wells will be located in Canadian Natural's five core regions.

Drilling Activity

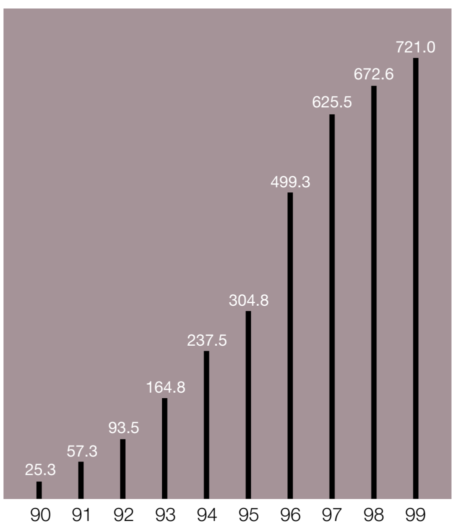
	1999		1998		1997	
(number of wells)	Gross	Net	Gross	Net	Gross	Net
Gas	**481**	**457.6**	216	193.2	237	199.6
Oil	**229**	**211.5**	120	106.5	486	442.9
Injection/strat tests	**11**	**8.9**	20	15.5	2	1.5
Dry	**54**	**49.3**	48	42.7	75	67.0
Total	**775**	**727.3**	404	357.9	800	711.0
Success Rate		**93%**		88%		91%

Production and Sales

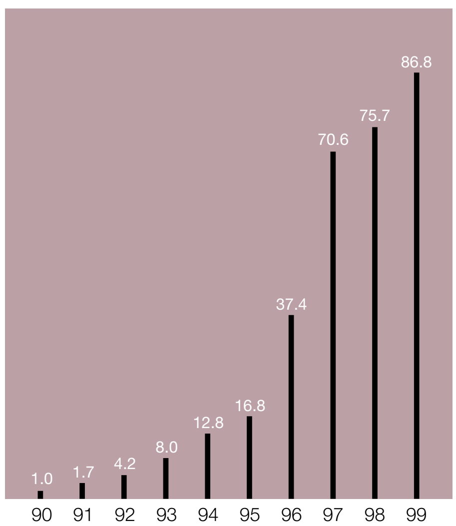
Natural gas sales averaged 721.0 million cubic feet per day in 1999, a 7 percent increase over average sales in 1998 of 672.6 million cubic feet per day. The North Central Alberta region continued to be Canadian Natural's largest natural gas producing region with average sales of 303 million cubic feet per day, or 42 percent of the Company's total natural gas production. In the Northeast British Columbia/Northwest Alberta region natural gas production increased to 250 million cubic feet per day (35 percent of the Company total), while natural gas produced in the South Central Alberta region amounted to 134 million cubic feet per day (19 percent of the Company total).

Record oil production volumes averaging 115,665 barrels per day were reached in the fourth quarter of 1999 and contributed to a 15 percent increase in average yearly liquids sales to 86,750 barrels per day. Crude oil from Canadian Natural's oil producing region in Eastern Alberta/Western Saskatchewan grew to 50 percent of the Company's total oil production. This area includes properties acquired from BP Amoco at Primrose/Wolf Lake. Low cost production from properties at Pelican Lake contributed to average oil production in the North Central Alberta region increasing to 18,000 barrels per day, or 21 percent of the Company's liquids production. Light oil production from the Company's Northeast British Columbia/Northwest Alberta region amounted to 13 percent of total oil production.

Natural Gas Sales (mmcf/d)



Crude Oil and NGLs Sales (Mbbls/d)



On a barrel of oil equivalent basis (using 6:1 natural gas to oil conversion) Canadian Natural's 1999 production averaged over 206,000 barrels of oil equivalent per day, a 10 percent increase over the prior year. More than 80 percent of this production came from three core regions: North Central Alberta, Northeast British Columbia/Northwest Alberta and Eastern Alberta/Western Saskatchewan.

These increases in annual production reflect Canadian Natural's ongoing strategy of pursuing acquisition opportunities in its operating areas while carrying out focused exploration and exploitation activities.

Reserves and Reserve Replacement

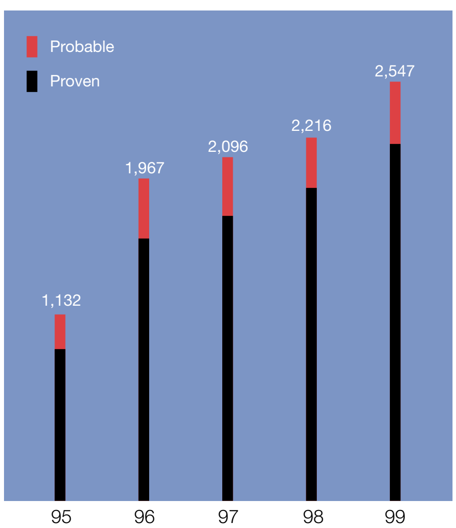
Canadian Natural's proven oil reserves almost doubled in 1999 to end the year at 553.6 million barrels. This increase reflects the 222 million barrels of oil booked as part of the acquisition from BP Amoco and various other acquisitions throughout the year. Proven natural gas reserves of 2,183 billion cubic feet at the end of 1999 were 15 percent higher than at the start of the year. The total reserves added to Canadian Natural's reserve base represented 5.1 times the reserves produced in 1999.

Canadian Natural's reserve life index, based on proven reserves versus the year's production, increased substantially in 1999 to 17.5 years for oil and 8.3 years for natural gas. On a barrel of oil equivalent basis, the reserve life index grew to 12.1 years.

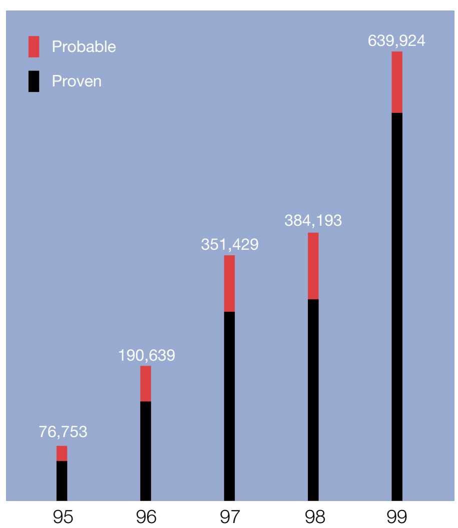
Canadian Natural continued its record of achieving low reserve replacement costs below its targeted level. Based on proven and probable reserve additions, and after accounting for all revisions of prior periods, reserve replacement costs in 1999 amounted to $4.93 per barrel of oil equivalent (6:1 conversion for gas to oil). Based on proven reserves only, after accounting for revisions, reserve replacement costs were reduced to $4.90 per barrel of oil equivalent. For the past three years Canadian Natural's reserve replacement cost has averaged $4.78 per barrel of oil equivalent.

Throughout 1999, commodity prices improved significantly and cash flow per barrel of oil equivalent increased to allow Canadian Natural to achieve its target recycle ratio of 2 to 1. If the cash flow per barrel of oil equivalent reached in the fourth quarter of 1999 prevailed throughout the year the recycle ratio would be 2.4 to 1.

Natural Gas Reserves (bcf)



Crude Oil and Liquids Reserves (mmbbls)



Reserves Reconciliation

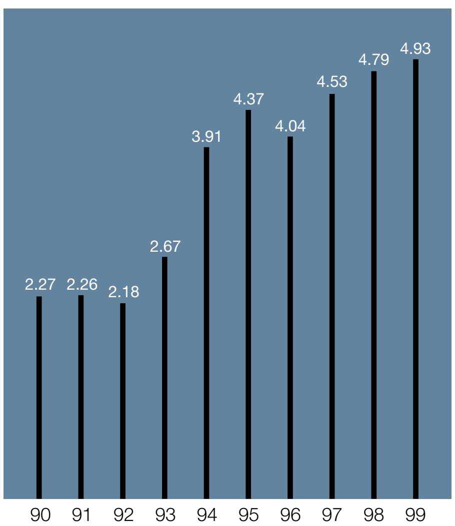
	Crude oil and liquids (mbbls)		Natural gas (mmcf)	
	Proven	Probable	Proven	Probable
Balance, January 1, 1998	270,421	81,008	1,732,735	363,156
Discoveries and purchases	53,365	21,951	425,398	28,518
Property disposals	(5,518)	(3,664)	(37,574)	(13,628)
Production	(27,646)	–	(245,514)	–
Revisions of prior estimates	(3,617)	(2,107)	30,149	(67,499)
Balance, January 1, 1999	287,005	97,188	1,905,194	310,547
Discoveries and purchases	289,223	408	564,941	67,567
Property disposals	(110)	(45)	(19,883)	(7,185)
Production	(31,664)	–	(263,165)	–
Revisions of prior estimates	9,102	(11,183)	(4,013)	(6,686)
Balance, January 1, 2000	**553,556**	**86,368**	**2,183,074**	**364,243**

At the time of acquiring the remaining oil properties held by the oil business unit of BP Amoco, Canadian Natural estimated that the properties contained approximately one billion barrels of identified proven and probable reserves (as has now been confirmed by the Company's independent petroleum engineering consultants), excluding any reserves that are associated with tar sand leases. However, only 222 million proven barrels and four million probable barrels have been booked as reserves attributable to the BP Amoco acquisition.

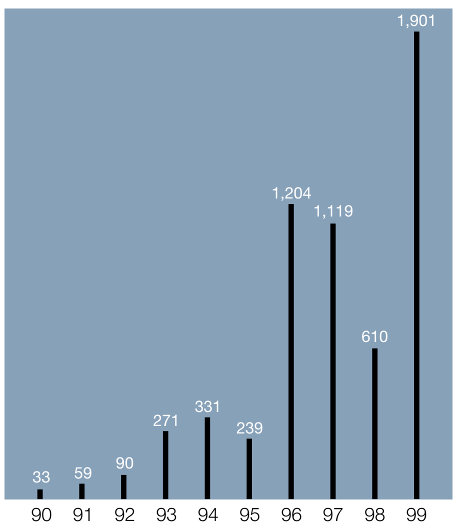
Canadian Natural retains Sproule Associates Ltd., independent petroleum engineering consultants, to evaluate the Company's proven and probable oil and natural gas reserves. Sproule has been retained by Canadian Natural for the past ten years.

For the year ended December 31, 1999 Sproule's Evaluation Report covered 97 percent of the Company's reserves, with the Company internally evaluating the remaining 3 percent of the reserves. The Board of Directors of Canadian Natural has established a Reserve Committee which has met with Sproule and carried out independent due diligence procedures with the engineering firm, including the procedures followed in the preparation of the Evaluation Report.

Finding and Developement Costs ($/boe)



Net Capital Expenditures ($ millions)



Reserve Evaluation

as at January 1, 2000	Company interest reserves before royalty			Present value before tax of future cash flow ($000s) [1]	
	Crude oil	Liquids	Natural gas	10%	15%
	(mbbls)	(mbbls)	(mmcf)	$	$
Proven [2]	537,317	16,239	2,183,074	6,758,875	5,580,874
Probable [3]	82,100	4,268	364,243	407,365	304,309
Total January 1, 2000	619,417	20,507	2,547,317	7,166,240	5,885,183
Total January 1, 1999	367,554	16,639	2,215,741	4,233,538	3,454,972
Change (%)	+69%	+23%	+15%	+69%	+70%

Ninety-seven percent of the Company's reserves are evaluated by Sproule Associates Limited ("Sproule") with the remaining 3 percent evaluated internally by the Company's engineers.

1. Value includes additions for processing revenue, the Alberta Royalty Tax Credit and the value of the corporate capital cost allowance.
2. The proven reserves are categorized as follows:

	Crude oil & liquids	Natural gas	Present Value before tax of future cash flow ($000s)	
	(mbbls)	(mmcf)	10%	15%
Proven developed producing	291,807	1,595,772	4,706,006	3,987,402
Proven developed non-producing	37,739	189,098	475,227	388,903
Proven undeveloped	224,010	398,204	1,577,642	1,204,569
	553,556	2,183,074	6,758,875	5,580,874

3. Value of the probable reserves are reduced by 50 percent to account for risk.
4. Future oil price forecasts used in the Evaluation Report were based on Sproule's October, 1999 pricing model and adjusted for quality of reserves, while future natural gas price forecasts were provided by the Company based on existing and forecasted future gas marketing arrangements entered into by the Company. The prices used in the Evaluation Reports are as follows:

			Average company sales prices – proven reserves			
	Crude oil WTI at Cushing (US$ per barrel)		Crude oil ($Cdn per barrel)		Natural gas ($ per mcf)	
	Jan. 1, 2000	Jan 1, 1999	Jan. 1, 2000	Jan. 1, 1999	Jan. 1, 2000	Jan. 1, 1999
2000	20.00	16.32	20.53	16.97	3.14	2.44
2001	20.30	18.21	19.42	18.05	3.12	2.62
2002	20.60	20.16	18.80	20.17	3.22	2.65
2003	20.91	20.57	18.97	20.26	3.31	2.72
2004	21.23	20.98	19.24	20.85	3.40	2.78
2005	21.55	21.40	19.55	21.47	3.48	2.84
2006	21.87	21.83	19.86	22.05	3.56	2.90
2007	22.20	22.26	20.18	22.48	3.64	2.96
2008	22.53	22.71	20.49	23.27	3.72	3.02
2009	22.87	23.16	20.91	23.98	3.83	3.10
Thereafter	+1.5%	+2.0%	+2.7%	+3.1%	+1.5%	+2.2%

Natural Gas

The very warm 1998/99 winter in Canada and the United States resulted in an uncharacteristic profile for gas prices with the lowest prices experienced in the first quarter of the year. The 1999 North American NYMEX benchmark price averaged US$2.27 per mmbtu, up six percent over 1998. Domestic prices followed a similar pattern, but were stronger than United States prices. The 1999 average Alberta price improved 42 percent over 1998 to $2.92 per mmbtu. The price differential between Alberta and NYMEX narrowed by 64 percent to an average of $0.43 per mmbtu.

Although a record 6,510 gas wells were completed in the Western Canadian Sedimentary Basin in 1999, the average depth per well declined by 12 percent. Many shallow well programs were implemented in response to challenging drilling economics in the first half of the year. The net incremental Alberta volumes in 1999 amounted to 200 mmcfd for a 1.5 percent increase over 1998. Despite this increase, there was a surplus export pipeline capacity which resulted in stronger domestic prices relative to export markets. Record gas completions in the United States in 1999 netted an overall marginal decline in dry gas production of 0.5 percent compared to the previous year.

The volume of Canadian Natural's gas sales in 1999 increased by seven percent to 721 million cubic feet per day from 673 million cubic feet per day in 1998. The portfolio of direct sales represented 71 percent of the total volume, with the remaining 29 percent split among the main supply aggregators to which the Company has dedicated reserves.

In 1999, Canadian Natural realized an average wellhead price for gas of $2.36 per thousand cubic feet, up 11 percent from the $2.12 per thousand cubic feet achieved in 1998. The current supply and market fundamentals are very positive and suggest an excellent pricing environment for the next several years. The addition of the Alliance Pipeline, available in November 2000, will increase capacity by more than 2 billion cubic feet per day. This volume increase will ensure a further narrowing of the price differential compared with American markets, providing Canadian Natural economic incentive to aggressively drill for gas. Based on current market conditions and the Company's pricing forecasts, Canadian Natural expects to realize an average price of $3.00 per thousand cubic feet in 2000.

Crude Oil

Crude Oil prices recovered spectacularly in 1999. The North American West Texas Intermediate (WTI) benchmark averaged US $19.24 per barrel, up 33 percent from the US$14.43 realized in 1998. From a low of US $12.02 per barrel in February, the price began to rise steadily following the March Vienna Accord on reduced production quotas. By December 1999 the price of oil per barrel had increased 117 percent to a high of US $26.09. Worldwide production shortfalls resulted in record low inventory positions for crude and refined products at year end and a very bullish pricing environment.

The very low crude oil prices experienced in the last quarter of 1998 and first quarter of 1999 significantly reduced drilling activity forcing many wells to be shut in. As a result Canadian heavy oil yearly average differential for Lloydminister blends improved by 22 percent in 1999 to US $4.30 per barrel.

Canadian Natural's 1999 crude oil production increased by 15 percent from 1998 to 86,750 barrels per day. The Company's production mix is 30 percent light and medium oil, 64 percent heavy oil (15 API or less) and six percent natural gas liquids. There were no pipeline constraints during the year and condensate supplies were adequate to satisfy heavy oil blending requirements.

The Company realized an overall average wellhead price of $21.04 per barrel in 1999, up 63 percent from the previous year. Canadian Natural plans significant growth in medium and heavy oil volumes for 2000. Production is expected to average 135,000 barrels per day for the year, comprised of 37 percent light and medium oil, 60 percent heavy oil and three percent natural gas liquids.

Based on a price forecast of US $21.00 per barrel for WTI and a differential of US $5.25 per barrel for Lloyd blends, Canadian Natural would realized a wellhead price of $19.90 per barrel in 2000. Market conditions in the first quarter of 2000 with WTI averaging over US $29 suggest we may be very conservative in our annual price forecast.

Canadian Natural achieved record results in many areas of financial and operational performance in 1999 while continuing to focus on low cost, low risk and high return assets.

The following discussion details Canadian Natural's 1999 financial results compared to 1998, including its capital program and outlook for 2000.

This discussion should be read in conjunction with the consolidated financial statements and notes for a full understanding of the Company's financial position and results of operations. Certain information regarding the Company contained herein may constitute forward-looking statements under applicable securities laws. Such statements are subject to known or unknown risks and uncertainties that may cause actual results to differ materially from those anticipated or implied in the forward-looking statements. All data is presented in Canadian dollars. For the purpose of calculating a barrel of oil equivalent, Canadian Natural has moved to using a factor of six to one ("6:1") for converting thousand cubic feet of natural gas to a barrel of oil equivalent rather than ten to one ("10:1"). This provides more comparable financial and operational data relative to peers in the industry including those based in the United States.

Net Earnings and Cash Flow

	1999	1998	1997
Net earnings ($ millions)	**200.2**	59.0	111.3
Per share	**$ 1.93**	$ 0.59	$ 1.14
Cash flow ($ millions)	**723.5**	444.2	503.0
Per share	**$ 6.96**	$ 4.47	$ 5.13
Earnings as a percentage of cash flow	**27.7%**	13.3%	22.1%
After-tax return on equity	**13.2%**	4.8%	9.8%

Cash flow increased 63 percent in 1999 to $723.5 million ($6.96 per share) from $444.2 million ($4.47 per share) in 1998 as commodity prices improved significantly in 1999, averaging $17.03 per barrel of oil equivalent ("boe") in 1999 versus $12.80 per boe in 1998. Production volumes also increased ten percent to 206,922 boe per day in 1999 from 187,851 in 1998. With increased prices and production volumes, the Company's earnings and earnings per share increased to a record $200.2 million or $1.93 per share, a 239 percent and 227 percent increase respectively, from the prior year's earnings of $59.0 million and $0.59 per share. Canadian Natural's after-tax return on equity climbed to 13.2 percent in 1999 from 4.8 percent in 1998 and has averaged 10 percent per year over the past five years.

Gross Revenue

	1999	1998	1997
Oil and liquids ($ millions)	**666.3**	357.8	485.5
Per barrel	**$ 21.04**	$ 12.93	$ 18.82
Natural gas ($ millions)	**620.5**	519.8	435.6
Per mcf	**$ 2.36**	$ 2.12	$ 1.91
Total gross revenue ($ millions)	**1,286.8**	877.6	921.1
Per boe (6:1)	**$ 17.03**	$ 12.80	$ 14.43

Gross revenue increased 47 percent from $877.6 million in 1998 to nearly $1.3 billion in 1999 as a direct result of strengthened commodity prices and higher production volumes. Crude oil prices showed the greatest increase with West Texas Intermediate (WTI) average 1999 price rising 33 percent to US$19.24 per barrel from US$14.43 per barrel in 1998. World crude oil fundamentals came back into equilibrium in 1999 and, in fact, moved towards an under supply scenario in the fourth quarter with WTI averaging US$26.09 in December, 1999. Heavy oil fundamentals also improved over 1998 as the heavy oil differentials narrowed 28 percent to average Cdn $7.98 per barrel in 1999. This combined affect of a higher crude oil price and lower differentials was reflected in the average liquids price received by Canadian Natural which rose 63 percent from $12.93 per barrel in 1998 to $21.04 per barrel in 1999. The price received was reduced by $1.22 per barrel in 1999 as a result of hedging arrangements entered into by Canadian Natural to fix the price received for its commodities.

Natural gas prices increased 11 percent in 1999 to average $2.36 per thousand cubic feet compared with $2.12 per thousand cubic feet in 1998. While demand was impacted by another warmer than normal winter, Canadian natural gas production had increased access to markets because, as a result of sufficient pipeline expansion, take away capacity existed in 1999 to ensure produced gas could reach higher priced markets in North America. Arrangements entered into by Canadian Natural to fix the price of a portion of its natural gas sales resulted in an opportunity cost of $0.16 per thousand cubic feet ($0.22 per thousand cubic feet in the fourth quarter).

In 1999, 40 percent of Canadian Natural's natural gas sales were subject to these fixed price arrangements, whereas in 2000, 20 percent of the Company's estimated natural gas sales are subject to fixed price arrangements.

Production Volumes

	1999	1998	1997
Oil and liquids (bbl/d)	**86,750**	75,744	70,619
Natural gas (mmcf/d)	**721.0**	672.6	625.5
Barrel of oil equivalent (boe/d) (6:1)	**206,922**	187,851	174,873

The Company's crude oil and liquids production volumes increased 15 percent in 1999 to average 86,750 barrels per day from 75,744 barrels per day in 1998. The most significant increase occurred in the fourth quarter of 1999 as average production volumes increased to 115,665 barrels per day up from 76,133 barrels per day in the fourth quarter of 1998. This was largely due to the impact of additional production from oil producing properties acquired from BP Amoco in the third quarter. The Company also increased its oil drilling program in 1999 due to stronger crude oil prices, drilling 229 successful gross oil wells in 1999 up from 120 successful gross oil wells in 1998.

Natural gas production volumes increased seven percent to 721.0 million cubic feet per day (672.6 million cubic feet per day in 1998) as the Company increased its drilling program in 1999 to 481 successful gross wells from 216 successful gross wells in 1998. Further, Canadian Natural completed an acquisition of primarily natural gas producing assets in the third quarter of 1999.

Analysis of Gross Revenue Increase ($ millions)

Reported 1998 revenue	877.6
Effect on revenue of:	
Increased volumes of crude oil and liquids	52.0
Increased price of crude oil and liquids	256.5
Increased volumes of natural gas	37.4
Increased price of natural gas	63.3
Reported 1999 revenue	1,286.8

Royalties

	1999	1998	1997
Oil and liquids ($ millions)	**71.2**	45.9	77.6
Per barrel	**$ 2.25**	$ 1.66	$ 3.01
Percentage of revenue	**10.7%**	12.8%	16.0%
Natural gas ($ millions)	**116.7**	70.9	74.8
Per mcf	**$ 0.44**	$ 0.29	$ 0.33
Percentage of revenue	**18.6%**	13.7%	17.3%
Total royalties ($ millions)	**187.9**	116.8	152.4
Per boe (6:1)	**$ 2.49**	$ 1.70	$ 2.39
Percentage of revenue	**14.6%**	13.3%	16.5%

Crude oil and liquids royalties increased 36 percent on a per barrel basis to $2.25 in 1999 from $1.66 in 1998 but actually decreased as a percentage of revenue from 12.8 percent in 1998 to 10.7 percent in 1999. This decrease is a direct result of a program to promote development of Alberta's oil sands resources which provides a reduced royalty rate until an oil sands project recovers its capital costs. It is expected that due to the combination of available capital cost balances on the Company's various oil sands projects, budgeted capital expenditures within these projects and increased production from oil sands projects, the resultant corporate average crude oil and liquids royalty rate will decline in 2000 from 1999 levels.

Natural gas royalties increased to $0.44 per thousand cubic feet, being 18.6 percent of revenue, in 1999 from $0.29 per thousand cubic feet or 13.7 percent of revenue in 1998. Natural gas royalties are sensitive to price changes and increased as a percentage of gross sales with the higher sales price received in 1999.

Production Expense

	1999	1998	1997
Oil and liquids ($ millions)	**155.1**	129.8	127.7
Per barrel	**$ 4.90**	$ 4.69	$ 4.95
Natural gas ($ millions)	**96.9**	82.1	77.9
Per mcf	**$ 0.37**	$ 0.33	$ 0.34
Total production expenses ($ millions)	**252.0**	211.9	205.6
Per boe (6:1)	**$ 3.34**	$ 3.09	$ 3.22

Production expenses increased to $3.34 per boe in 1999 compared with $3.09 per boe in 1998 as newly acquired properties were integrated into the Company's operations. These higher costs were also reflective of the technology employed by Canadian Natural in the Primrose heavy oil area and increases in natural gas production from British Columbia properties which have higher gathering and processing charges. Crude oil and liquids production expenses increased four percent to $4.90 per barrel in 1999 from $4.69 per barrel in 1998, while natural gas production expenses increased 12 percent to $0.37 per thousand cubic feet in 1999 from $0.33 per thousand cubic feet in 1998.

Administration Expense

	1999	1998	1997
Gross costs ($ millions)	**37.6**	37.3	35.5
Per boe (6:1)	**$ 0.50**	$ 0.54	$ 0.56
Administration* ($ millions)	**17.0**	18.8	12.8
Per boe (6:1)	**$ 0.23**	$ 0.27	$ 0.20

** after operator recoveries*

On a per barrel of oil equivalent basis, net administration expenses declined from $0.27 in 1998 to $0.23 in 1999. More importantly, the expense declined on a gross basis before operator recoveries to $0.50 per boe in 1999 from $0.54 per boe in 1998 and stayed relatively constant at $37.6 million in 1999 versus $37.3 million in 1998.

Interest Expense

	1999	1998	1997
Total interest expense ($ millions)	**90.4**	76.0	37.0
Per boe (6:1)	**$ 1.20**	$ 1.11	$ 0.58
Average interest rate	**5.4%**	5.6%	4.3%
EBITDA interest coverage	**9.2**	7.0	14.6

In 1999, interest expense increased to $90.4 million or $1.20 per boe from $76.0 million or $1.11 per boe in 1998 due to higher average outstanding debt levels incurred to finance a portion of the Company's 1999 capital program. However, interest coverage improved in 1999 over 1998 as earnings before interest, taxes and depreciation, depletion and amortization ("EBITDA") was 9.2 times interest in 1999 versus 7.0 times in 1998. The average interest rate paid decreased slightly in 1999 to 5.4 percent from 5.6 percent in 1998.

Depreciation, Depletion and Amortization

($ millions)	1999	1998	1997
Depletion and depreciation	**373.7**	320.1	282.9
Site restoration provision	**10.6**	7.3	5.9
Total	**384.3**	327.4	288.8
Per boe (6:1)	**$ 5.08**	$ 4.77	$ 4.53

Depreciation, depletion and amortization increased 17 percent to $384 million in 1999 due to a 10 percent increase in production volumes over 1998 and a larger asset base. On a per barrel of oil equivalent basis, the expense increased from $4.77 in 1998 to $5.08 in 1999.

Unrealized Foreign Exchange Loss

Canadian Natural has a portion of its long-term debt denominated in U.S. dollars (US$196 million). Due to a strengthening Canadian dollar in 1999 versus 1998, the balance of the deferred unrealized foreign exchange loss fell by $17.1 million with $2.2 million being recognized as an expense in 1999.

Taxes

	1999	1998	1997
Deferred income taxes ($ millions)	**136.8**	56.0	94.7
Per boe (6:1)	**$ 1.80**	$ 0.82	$ 1.48
Effective tax rate	**39%**	45%	44%
Capital taxes ($ millions)	**15.9**	9.9	10.3
Per boe (6:1)	**$ 0.21**	$ 0.15	$ 0.16

Canadian Natural's deferred tax provision for 1999 increased to $137 million from $56 million in 1998 due to earnings before taxes increasing to $353 million in 1999 from $125 million in 1998. The Company's effective tax rate declined from 45 percent in 1998 to 39 percent in 1999 due to the decline in non-tax base depletion in 1999 from 1998 and a greater increase in resource allowance in 1999 as compared to previous years.

Currently, the Company is not incurring cash federal income taxes and it is anticipated that, due to the availability of $3.0 billion of tax pools at the end of 1999 in addition to budgeted capital expenditures for 2000, no current cash income tax liability will occur during 2000. The Company is, however, liable for the payment of capital taxes which include the Federal Large Corporation tax, British Columbia capital tax and Saskatchewan capital tax. These capital taxes increased to $15.9 million in 1999 from $9.9 million in 1998 primarily due to increased oil revenues in Saskatchewan which form part of the calculation in determining the liability for Saskatchewan capital tax, and as a result of an increase in the Company's capital base upon which these taxes are calculated.

Liquidity and Capital Resources

Debt

($ millions except ratios)	1999	1998	1997
Working capital deficit (surplus)	**(36.4)**	(57.9)	18.5
Long-term debt	**2,156.9**	1,425.5	1,136.3
Net debt	**2,120.5**	1,367.6	1,154.8
Debt to cash flow	**2.9**	3.1	2.3
Debt to equity	**53%**	52%	49%
Debt to market capitalization	**35%**	37%	28%

In May 1999, Canadian Natural issued $125 million of 5 year Medium Term Notes as a strategy to lengthen the average maturity of its debt portfolio. In August of 1999, as a part of the BP Amoco acquisition, the Company increased its combined bank credit facilities to $2.25 billion from $1.6 billion. The facilities provide for annual review and require no principal repayments provided certain covenants, including specific financial ratios, are maintained. The Company anticipates continuing to meet these requirements under its current operating forecast for 2000.

In September 1999, 10.5 million common shares were issued for gross proceeds of $399 million. A further 1.2 million shares were issued throughout 1999 for proceeds of $21.6 million from the exercise of employee stock options.

Capitalization

	1999		1998	
($ millions)	$	%	$	%
Working capital surplus	**(36.4)**	**(0.5)**	(57.9)	(1.4)
Long-term debt	**2,156.9**	**32.7**	1,425.5	35.0
Deferred credits	**541.4**	**8.2**	408.3	10.0
Warrants at book value	**2.9**	**–**	0.7	–
Common shares at December 31 market value	**3,928.8**	**59.6**	2,295.6	56.4
	6,593.6	**100.0**	4,072.2	100.0

Capital Expenditures

($ millions)	1999	1998	1997
Property acquisitions	**1,448.3**	197.8	423.4
Seismic and geological evaluation	**17.9**	17.2	38.9
Land acquisition and retention	**46.2**	39.0	98.3
Well drilling, completion, equipping	**274.8**	255.2	350.7
Pipeline and production facilities	**143.2**	205.7	240.3
Projects under construction	**(6.5)**	25.4	–
Head office equipment	**2.7**	3.3	4.6
Total capital expenditures	**1,926.6**	743.6	1,156.2
Funded by:			
Cash flow	**723.5**	444.2	503.0
Bank debt and working capital	**769.9**	151.5	597.3
Issue of capital stock	**407.2**	14.0	18.8
Property dispositions	**26.0**	133.9	37.1
	1,926.6	743.6	1,156.2

Capital expenditures totalled $1.9 billion in 1999, up from $610 million in 1998. Property acquisitions increased by $1.2 billion in 1999 over 1998, comprised primarily of acquisitions from BP Amoco and Blue Range Resource Corporation. Expenditures on exploration and development decreased seven percent from $517.1 million in 1998 to $482.1 million in 1999. Facilities expenditures decreased to $143.2 million in 1999 from $205.7 million in 1998 as work on the infrastructure at Pelican Lake was largely completed in 1998. Even though Canadian Natural drilled 727 net wells in 1999, 369 more than were drilled in 1998, expenditures on well drilling, completion and equipping increased only eight percent due to an extensive lower-cost shallow gas drilling program carried out in 1999. Canadian Natural's 1999 capital program was funded through a combination of cash flow, available forms of debt financing, the issue of common share equity and the sale of non-strategic properties.

Five Year Finding and Onstream Costs ($ millions)

	1999	1998	1997	1996	1995	Five year total
Capital expenditures						
Corporate acquisition	**–**	–	–	654.2	–	654.2
Net property acquisitions and dispositions	**1,422.3**	63.9	386.3	164.6	24.0	2,061.1
Seismic and geological evaluation	**17.9**	17.2	38.9	32.5	19.1	125.6
Land acquisition and retention	**46.2**	39.0	98.3	55.6	30.7	269.8
Well drilling, completion, equipping	**274.8**	255.2	350.7	163.8	92.2	1,136.7
Pipeline and production facilities	**143.2**	205.7	240.3	130.1	71.5	790.8
Total net reserve replacement expenditures	**1,904.4**	581.0	1,114.5	1,200.8	237.5	5,038.2
Projects under construction	**(6.5)**	25.4	–	–	–	18.9
Head office equipment	**2.7**	3.3	4.6	2.8	1.3	14.7
Total capital expenditures	**1,900.6**	609.7	1,119.1	1,203.6	238.8	5,071.8
Cost of net reserves replacement ($/boe)						
After reserve revisions (10:1)	**5.49**	5.99	5.02	5.24	5.55	5.37
After reserve revisions (6:1)	**4.93**	4.79	4.53	4.04	4.37	4.56

Business Environment and Outlook

Exploring, developing, producing and marketing of crude oil, natural gas and natural gas liquids consists of several inherent risks including:

- economic risk of finding and producing reserves at a reasonable cost;
- financial risk of marketing reserves at an acceptable price, given market conditions;
- cost of capital risk associated with securing the needed capital to carry out the Company's operations;
- environmental risk of carrying out operations with minimal impact; and
- human resources risk of employing talented, motivated employees who share a vision in congruence with Canadian Natural's shareholders.

Canadian Natural remains focused in the Western Canadian Sedimentary Basin where its expertise lies. Operational control is enhanced by focusing efforts in large core areas with high-working interests and where the Company assumes operatorship of all key facilities. Product mix is diversified ranging from the production of natural gas to the production of crude oil of various grades. Marketing efforts are aimed at various markets to ensure that undue exposure to any one market does not exist. Financial instruments are utilized to help ensure targets are met and to manage exposure to uncertain commodity markets. Finally, the Company employs highly-qualified, motivated employees, who are also shareholders, to ensure these strategies are implemented successfully.

The Company's current position with respect to its hedging arrangements is outlined in Note 7 of the Company's consolidated financial statements. These arrangements and policies concerning the Company's hedging program are under constant review and may change depending upon the prevailing market conditions.

Canadian Natural's capital structure mix is also monitored on a continued basis to ensure that it optimizes flexibility, minimizes cost and offers the greatest opportunity for growth. This includes the determination of a reasonable level of debt and any interest rate exposure risk which may exist.

Canadian Natural continues to employ an Environmental Management Plan to ensure the welfare of its employees, the communities in which it operates and the environment as a whole. Environmental protection is of fundamental importance and is undertaken in accordance with guiding principles approved by the Company's Board of Directors. On an annual basis, the Board of Directors are presented with a detailed copy of the Company's Environmental Management Plan which is updated regularly at quarterly Directors' meetings.

Expectations for 2000 vary depending upon the commodity prices eventually received by the Company and production volumes sold. Cash flow is forecasted to be in the range of $950 million to $1.1 billion based on a corporate average natural gas price of $2.75 per thousand cubic feet and an average WTI of US$21.00. Production volumes, on a six to one barrel of oil equivalent basis, are forecasted to range between 250,000 and 265,000 per day. Canadian Natural's capital budget is set at $1 billion comprising $750 million for exploration and development expenditures and $250 million for property acquisitions. The Board of Directors has determined that at this time any excess cash flow realized over and above the total capital expenditures will be directed towards repayment of long-term debt. Following this course of action will enable Canadian Natural to prudently invest its cash flow to provide continuing production growth per share, superior returns on equity and maintain its ability to pursue future opportunities as they arise.

2000 Sensitivity Analysis

	Cash flow	Cash flow per share
	$ millions	$
Natural gas price ($0.10/mcf)	25.0	0.22
Natural gas volume (10 mmcf/d)	6.5	0.06
Oil price (WTI – U.S. $1.00)	55.0	0.49
Oil volume (1,000 bbls/d)	5.0	0.04
Interest rates (1%)	19.0	0.17

Per-Unit Results

	1999	1998	1997	1996	1995
Crude oil and liquids ($/bbl)					
Revenue	**21.04**	12.93	18.82	23.52	19.82
Royalties	**2.25**	1.66	3.01	4.50	2.99
Production	**4.90**	4.69	4.95	5.04	5.02
Operating netback	**13.89**	6.58	10.86	13.98	11.81
Natural gas ($/mcf)					
Revenue	**2.36**	2.12	1.91	1.71	1.43
Royalties	**0.44**	0.29	0.33	0.23	0.16
Production	**0.37**	0.33	0.34	0.33	0.30
Operating netback	**1.55**	1.50	1.24	1.15	0.97
Barrel of oil equivalent ($/boe) (6:1)					
Revenue	**17.03**	12.80	14.43	14.42	11.39
Royalties	**2.49**	1.70	2.39	2.37	1.44
Production	**3.34**	3.09	3.22	2.94	2.59
Operating netback	**11.20**	8.01	8.82	9.11	7.36
Administration	**0.23**	0.27	0.20	0.17	0.18
Interest	**1.20**	1.11	0.58	0.60	0.85
Capital taxes	**0.21**	0.15	0.16	0.19	0.11
Cash flow netback	**9.56**	6.48	7.88	8.15	6.22
DD&A	**5.08**	4.77	4.53	4.13	3.34
Unrealized foreign exchange loss	**0.03**	0.03	0.13	–	–
Deferred income taxes	**1.80**	0.82	1.48	1.87	1.16
Net earnings	**2.65**	0.86	1.74	2.15	1.72

Quarterly Financial Information (unaudited)

($ millions, except per share)	Q1	Q2	Q3	Q4	Total
1999					
Oil and natural gas revenue	**202.4**	**231.8**	**399.2**	**453.4**	**1,286.8**
Cash flow	**100.7**	**125.4**	**235.0**	**262.4**	**723.5**
Per share	**1.01**	**1.25**	**2.29**	**2.41**	**6.96**
Net earnings	**10.3**	**23.5**	**70.5**	**95.9**	**200.2**
Per share	**0.10**	**0.24**	**0.69**	**0.90**	**1.93**

($ millions, except per share)	Q1	Q2	Q3	Q4	Total
1998					
Oil and natural gas revenue	203.2	206.9	223.8	243.7	877.6
Cash flow	95.4	102.0	119.1	127.7	444.2
Per share	0.97	1.02	1.20	1.28	4.47
Net earnings	8.4	6.2	20.9	23.5	59.0
Per share	0.08	0.07	0.21	0.23	0.59

Trading and Share Statistics

	Q1	Q2	Q3	Q4	1999 Total	1998 Total
Trading volume (thousands)	**27,439**	**31,100**	**26,645**	**22,431**	**107,615**	102,610
Trading value ($ millions)	**665**	**866**	**933**	**763**	**3,227**	2,643
Share price ($/share)						
High	**28.25**	**30.25**	**38.60**	**37.45**	**38.60**	31.50
Low	**19.80**	**24.25**	**29.05**	**30.55**	**19.80**	18.25
Close	**26.00**	**29.00**	**34.40**	**35.25**	**35.25**	23.00
Market capitalization, at December 31						
Shares outstanding (thousands)					**111,454**	99,809
Year-end share price ($/share)					**35.25**	23.00
Total ($ millions)					**3,929**	2,296

MANAGEMENT'S RESPONSIBILITY

The accompanying consolidated financial statements and all information in the annual report are the responsibility of management. The consolidated financial statements have been prepared by management in accordance with the accounting policies in the notes to the consolidated financial statements. Where necessary, management has made informed judgements and estimates in accounting for transactions which were not complete at the balance sheet date. In the opinion of management, the financial statements have been prepared within acceptable limits of materiality and are in accordance with Canadian generally accepted accounting principles appropriate in the circumstances. The financial information elsewhere in the annual report has been reviewed to ensure consistency with that in the consolidated financial statements.

Management maintains appropriate systems of internal control. Policies and procedures are designed to give reasonable assurance that transactions are appropriately authorized, assets are safeguarded from loss or unauthorized use and financial records properly maintained to provide reliable information for preparation of financial statements.

PricewaterhouseCoopers LLP, an independent firm of Chartered Accountants, has been engaged, as approved by a vote of the shareholders at the Company's most recent Annual General Meeting, to examine the consolidated financial statements in accordance with generally accepted auditing standards in Canada and provide an independent professional opinion. Their report is presented with the consolidated financial statements.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through the Audit Committee of the Board. This committee, which is comprised of a majority of non-management directors, meets with management and the external auditors to satisfy itself that management responsibilities are properly discharged and to review the consolidated financial statements before they are presented to the Board of Directors for approval. The consolidated financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

John G. Langille, CA
President
March 6, 2000

Gregory G. Adams, CA
Vice-President, Finance

Randall S. Davis, CA
Manager, Financial Accounting

AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the consolidated balance sheets of Canadian Natural Resources Limited as at December 31, 1999 and 1998 and the consolidated statements of earnings and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated 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, 1999 and 1998 and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in Canada.

PricewaterhouseCoopers LLP

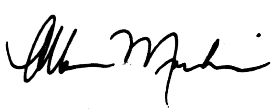
Calgary, Alberta
March 6, 2000

PricewaterhouseCoopers LLP
Chartered Accountants

CONSOLIDATED BALANCE SHEETS

As at December 31 (thousands of dollars)	**1999**	1998
ASSETS		
Current assets		
Cash	**$ 66**	$ 92
Accounts receivable and prepaid expenses	**250,113**	143,660
Inventory	**46,831**	50,440
	297,010	194,192
Property, plant and equipment (note 2)	**4,553,541**	3,033,628
Deferred unrealized foreign exchange loss	**299**	19,598
	4,850,850	3,247,418
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	**260,568**	136,305
Long-term debt (note 3)	**2,156,850**	1,425,479
Provision for site restoration costs	**36,918**	33,318
Deferred income taxes	**504,497**	374,966
	2,958,833	1,970,068
SHAREHOLDERS' EQUITY		
Capital stock and contributed surplus (note 4)	**1,268,218**	853,751
Retained earnings	**623,799**	423,599
	1,892,017	1,277,350
	$ 4,850,850	$ 3,247,418

Signed on behalf of the Board



Allan P. Markin
Director

N. Murray Edwards
Director

CONSOLIDATED STATEMENTS OF EARNINGS AND RETAINED EARNINGS

For the Years Ended December 31 (thousands of dollars)	**1999**	1998
INCOME		
Oil and natural gas	**$ 1,286,763**	$ 877,635
Less: royalties	**(187,877)**	(116,757)
	1,098,886	760,878
EXPENSES		
Production	**252,037**	211,899
Administration	**17,025**	18,820
Interest	**90,447**	75,989
Unrealized foreign exchange loss	**2,182**	1,832
Depreciation, depletion and amortization	**384,311**	327,402
	746,002	635,942
Earnings Before Taxes	**352,884**	124,936
Capital taxes	**15,908**	9,946
Deferred income taxes (note 5)	**136,776**	55,973
Net Earnings for the Year (note 6)	**200,200**	59,017
Retained Earnings – Beginning of Year	**423,599**	364,582
Retained Earnings – End of Year	**$ 623,799**	$ 423,599

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31 (thousands of dollars)	**1999**	1998
OPERATING ACTIVITIES		
Net earnings for the year	**$ 200,200**	$ 59,017
Non-cash items		
Depreciation, depletion and amortization	**384,311**	327,402
Deferred income taxes	**136,776**	55,973
Unrealized foreign exchange loss	**2,182**	1,832
Cash flows provided from operating activities (note 6)	**723,469**	444,224
Net change in non-cash working capital balances related to operating activities	**(54,561)**	(8,192)
	668,908	436,032
FINANCING ACTIVITIES		
Increase in long-term debt	**748,488**	267,773
Issue of capital stock - net of expenses	**404,322**	14,019
Decrease in deferred liabilities	**–**	(39,855)
	1,152,810	241,937
INVESTING ACTIVITIES		
Expenditures on property, plant and equipment	**(1,916,695)**	(741,604)
Expenditures on abandonments	**(6,997)**	(2,026)
Net proceeds on sale of properties, plant and equipment	**25,968**	133,906
Net change in non-cash working capital balances related to investing activities	**75,980**	(68,328)
	(1,821,744)	(678,052)
Decrease in Cash	**(26)**	(83)
Cash – Beginning of Year	**92**	175
Cash – End of Year*	**$ 66**	$ 92

* *Cash consists of demand deposits at Canadian chartered and foreign banks.*

SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

For the Years Ended December 31 (thousands of dollars)	**1999**	1998
Interest paid	**$ 90,049**	$ 71,012
Taxes paid	**$ 14,290**	$ 10,864
Changes in non-cash working capital:		
Accounts receivable and prepaid expenses	**$ (106,453)**	$ 25,156
Inventory	**3,609**	(34,331)
Accounts payable and accrued liabilities	**124,263**	(67,345)
	$ 21,419	$ (76,520)

For the Years Ended December 31, 1999 and 1998
(tabular amounts in thousands of dollars, unless otherwise stated)

1. ACCOUNTING POLICIES

Principles of consolidation

The consolidated financial statements include the accounts of the Company, its wholly-owned subsidiaries and its general partnership.

Inventory

Inventory is comprised of product inventory and oilfield equipment and is valued at the lower of cost and net realizable value.

Petroleum and natural gas properties, plant and equipment

The Company follows the full cost method of accounting for petroleum and natural gas properties and equipment wherein all costs relating to the exploration for and development of oil and natural gas reserves are capitalized. Proceeds on disposal of properties are ordinarily deducted from such costs without recognition of profit or loss except where such disposal constitutes a major portion of the Company's reserves.

The accounts reflect only the Company's proportionate interest in its exploration and production activities where such activities are conducted jointly with others.

The costs related to petroleum and natural gas properties are depleted on the unit-of-production method based on the Company's total estimated proven reserves. Volumes of net production and reserves before royalties are converted to equivalent units on the basis of estimated relative energy content. In determining its depletion base, the Company includes estimated future costs to be incurred in developing proven reserves and excludes the cost of unproven land. Processing facilities, net of salvage, are depreciated based on the estimated useful life of each facility.

The Company carries its petroleum and natural gas properties at the lower of the capitalized cost and net recoverable value. Net capitalized cost is calculated as the net book value of the related assets less the accumulated provisions for deferred income taxes and site restoration costs. Net recoverable value is limited to the sum of future net revenues from proven properties, and the cost of unproved properties net of provisions for impairment less estimated future financing and administrative expenses and income taxes. Future net revenues are based on prices and costs prevailing at the year end.

Provision for site restoration costs

The provision for future removal and site restoration costs, as estimated by the Company, is charged against income on a straight-line basis over 20 years as part of depletion expense. The cumulative amount, net of actual expenditures, is recorded as a provision for site restoration costs.

Depreciation and amortization

Depreciation and amortization on assets other than depletable petroleum and natural gas assets are designed to amortize their cost over their estimated lives.

Foreign currency translation

Foreign currency denominated monetary assets and liabilities are translated to Canadian dollars at the exchange rate in effect at the balance sheet date. Foreign currency denominated revenues are translated to Canadian dollars at the monthly average exchange rate. Foreign exchange gains or losses are included in the determination of net income for the period except for unrealized gains or losses on long-term debt which are deferred and amortized over the remaining term of the debt.

Income taxes

The Company follows the tax allocation method of accounting for the tax effect of the timing differences between taxable income and income as recorded in the financial statements. Timing differences arise when, for income tax purposes, the Company deducts exploration and development expenditures and capital cost allowances in amounts differing from those charged to expense in the financial statements.

Stock based compensation plans

Consideration paid by employees or directors on the exercise of stock options under the employee stock option plan is recorded as share capital. The Company matches employee contributions to the stock savings plan and these cash payments are recorded as compensation expense.

Hedging

The Company uses various financial instruments to reduce its exposure to foreign exchange rates and crude oil and natural gas commodity price fluctuations. The Company does not use these instruments for trading purposes. Gains or losses on these contracts, which constitute effective hedges, are included in production revenue at the time of sale of the related product.

2. PROPERTY, PLANT AND EQUIPMENT

		1999	
	Cost	Accumulated depreciation, depletion and amortization	Net
Petroleum and natural gas properties, plant and equipment	**$ 5,893,744**	**$ 1,349,357**	**$ 4,544,387**
Office equipment and leasehold improvements	**17,887**	**8,733**	**9,154**
	$ 5,911,631	**$ 1,358,090**	**$ 4,553,541**

		1998	
	Cost	Accumulated depreciation, depletion and amortization	Net
Petroleum and natural gas properties, plant and equipment	$ 4,002,772	$ 977,571	$ 3,025,201
Office equipment and leasehold improvements	15,232	6,805	8,427
	$ 4,018,004	$ 984,376	$ 3,033,628

No administrative overhead relating to exploration and development has been capitalized during 1999 and 1998. Unproven land costs of $418,106,291 (1998 – $296,013,537) have been excluded from the Company's depletion base.

3. LONG-TERM DEBT

	1999	1998
Bank credit facilities		
Bankers' acceptances	**$ 1,748,963**	$ 823,568
U.S. $ Bankers' acceptances (U.S. $196 million, 1998 - U.S. $196 million)	**282,887**	299,978
Credit facility bearing interest at prime lending rates	**–**	2,721
Commercial paper	**–**	299,212
	2,031,850	1,425,479
Medium term notes		
6.85% unsecured debentures maturing on May 28, 2004	**125,000**	–
	$ 2,156,850	$ 1,425,479

Bank credit facilities

The Company has unsecured bank credit facilities of $2,250 million comprised of a $100 million operating demand facility, and two revolving credit and term loan facilities totaling $2,150 million. The revolving credit and term loan facilities are fully revolving for 364-day periods with provision for extensions at the option of the lenders and upon notice from the Company. If not extended, the facilities convert to a non-revolving reducing loan with a term of between three and five years. The bank facilities provide that the borrowings may be made by way of operating advance, prime loans, bankers' acceptances, U.S. base rate loans or U.S. dollar LIBOR advances which bear interest at the bank's prime rates or at money market rates plus stamping fee. Principal repayments are not required provided certain convenants with respect to the Company's financial ratios are maintained. Based upon the remaining credit facilities, the indebtedness outstanding at December 31, 1999 and the Company's cash flow, no current portions of these bank credit facilities are required to be paid and therefore no current portions have been recognized.

4. CAPITAL STOCK AND CONTRIBUTED SURPLUS

(a) Authorized

200,000 Class 1 preferred shares with a stated value of $10 each

Unlimited number of common shares

(b) Capital stock and contributed surplus

	1999	1998
Common shares issued	**$ 1,263,397**	$ 851,960
Contributed surplus	**1,943**	1,050
Warrants	**2,878**	741
	$ 1,268,218	$ 853,751

(c) Issued

	1999		1998	
	Number of shares	Amount	Number of shares	Amount
Common shares				
Balance – beginning of year	**99,809,248**	**$ 851,960**	98,818,977	$ 837,941
Issued for cash pursuant to a prospectus offering	**10,500,000**	**399,000**	–	–
Exercise of stock options	**1,228,153**	**21,552**	990,271	14,019
Cancellation of shares	**(83,335)**	**(152)**	–	–
Issue costs – net of deferred tax	**–**	**(8,963)**	–	–
Balance – end of year	**111,454,066**	**$ 1,263,397**	99,809,248	$ 851,960
Warrants				
Balance – beginning of year	**750,000**	**$ 741**	750,000	$ 741
Issued during the year	**500,000**	**2,900**	–	–
Expired during the year	**(750,000)**	**(741)**	–	–
Issue costs – net of deferred tax	**–**	**(22)**	–	–
Balance – end of year	**500,000**	**$ 2,878**	750,000	$ 741

(d) Contributed surplus

	1999	1998
Balance – beginning of year	**$ 1,050**	$ 1,050
Expiry of warrants	**741**	–
Cancellation of shares	**152**	–
Balance – end of year	**$ 1,943**	$ 1,050

(e) Cancellation of shares

During the year, 83,335 shares were returned to treasury and cancelled on the expiry of the conversion period for exchanging previously issued equity and debt instruments into common shares of the Company.

(f) Warrants

During the year, the Company issued 500,000 warrants at an ascribed value of $2,900,000 to acquire property, plant and equipment. Each warrant entitles the holder to acquire one common share of the Company at a price of $30.00 per common share until August 16, 2001. Warrants which were outstanding at December 31, 1998 expired unexercised.

(g) Stock options

The Company's stock option plan provides for granting of options to directors, officers and employees in a total amount up to a maximum of ten percent of the total issued and outstanding common shares of the Company. Options granted under the plan have a maximum term of six years to expiry and vest equally over a five year period starting on the first anniversary date of the grant. The exercise price of each option granted equals the market price of the Company's stock on the date of grant.

The following tables summarize the information relating to stock options outstanding at December 31, 1999 and 1998.

	1999		1998	
	Share options	Weighted average exercise price	Share options	Weighted average exercise price
Outstanding – beginning of year	**9,724,464**	**$ 23.98**	7,399,347	$ 23.62
Granted	**1,888,610**	**31.72**	4,124,145	24.63
Exercised	**(1,228,153)**	**17.55**	(990,271)	14.16
Forfeited	**(720,470)**	**28.16**	(808,757)	26.98
Outstanding – end of year	**9,664,451**	**$ 25.99**	9,724,464	$ 23.98
Exercisable – end of year	**3,331,204**	**$ 24.10**	2,610,181	$ 21.60

		Options Outstanding		Options Exercisable	
Range of exercise prices	Options outstanding	Weighted average remaining term (years)	Weighted average exercise price	Options exercisable	Weighted average exercise price
Under $20.00	1,892,215	0.6	$ 14.88	1,304,781	$ 15.08
$20.00 to 24.99	2,296,226	4.3	22.50	527,446	22.94
$25.00 to 29.99	2,197,000	4.1	27.10	454,352	27.28
Over $30.00	3,279,010	4.1	34.11	1,044,625	34.56
	9,664,451	3.5	$ 25.99	3,331,204	$ 24.10

5. DEFERRED INCOME TAXES

The provision for deferred income taxes is different from the amount computed by applying the combined statutory Canadian federal and provincial income tax rates to earnings before taxes.

The reasons for the difference are as follows:

	1999	1998
Statutory tax rate	**44%**	44%
Tax provision at statutory rate	**$ 155,269**	$ 54,972
Effect on taxes of –		
Non-deductibility of crown royalties, lease rentals and mineral taxes	**64,844**	36,422
Non-tax base depletion	**12,950**	22,641
Alberta royalty tax credit	**(607)**	(612)
Resource allowance	**(95,680)**	(57,450)
	$ 136,776	$ 55,973

6. COMMON SHARE DATA

Common share data, using the weighted average number of common shares outstanding of 103,906,418 (1998 – 99,331,028) is :

		1999	1998
Earnings	– basic	**$ 1.93**	$ 0.59
	– fully diluted	*****	*
Cash flows provided from operating activities	– basic	**$ 6.96**	$ 4.47
	– fully diluted	*****	*

** The effect of dilution on earnings per share and funds provided from operations per share is anti-dilutive in 1998 and 1999 utilizing the Company's rate of return on funds invested.*

7. FINANCIAL INSTRUMENTS

The Company's financial instruments recognized in the consolidated balance sheets consist of cash, accounts receivable, current liabilities and long-term debt.

The estimated fair values of recognized financial instruments have been determined based on the Company's assessment of available market information and appropriate valuation methodologies; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

The carrying value of cash, accounts receivable, current liabilities and long-term debt approximate their fair value with the exception of the medium term notes.

The estimated fair values of the medium term notes and derivative financial instruments are as follows:

	1999		1998	
	Carrying value	Fair value	Carrying value	Fair value
Medium term notes	**$ 125,000**	**$ 122,138**	$ –	$ –
Derivative financial instruments	**$ –**	**$ (69,736)**	$ –	$ (84,555)

The Company uses certain derivative financial instruments to manage its foreign currency and commodity price exposures. These financial instruments are entered into solely for hedging purposes and are not used for trading or other speculative purposes. The Company is exposed to certain losses in the event of non-performance by counterparties to derivative instruments; however, the Company minimizes its financial credit risk by entering into agreements with only highly rated financial institutions. The Company is also exposed to certain losses by non-performance on the part of purchasers of crude oil and natural gas. However, the Company minimizes this credit risk by entering into sales contracts with only highly rated entities.

The following summarizes transactions outstanding at December 31, 1999.

(i) Crude oil

At December 31, 1999 the Company had hedged 20,000 barrels per day for the year 2000 at an average price of U.S. $22.25 per barrel and 30,000 barrels per day for the first quarter of 2000 at an average floor price of U.S. $23.00 per barrel and an average ceiling price of U.S. $26.88 per barrel.

(ii) Natural gas

At December 31, 1999 the Company had hedged 7,900 mmbtu per day at Aeco for the year 2000 at an average price of Cdn. $1.66 per mmbtu.

At December 31, 1999 the Company had hedged the basis between Empress and NYMEX Henry Hub at U.S. $0.73 per mmbtu for 5,500 mmbtu per day for 2000 through 2005 and for 4,600 mmbtu per day for 2006.

At December 31, 1999 the Company had hedged 20,000 mmbtu per day at Sumas for 2000 to 2002 and 16,700 mmbtu per day for 2003 at an average price of Cdn. $2.85.

At December 31, 1999 the Company had hedged 85,800 mmbtu per day at Henry Hub at an average NYMEX price of U.S. $2.02 per mmbtu for 2000; 35,000 mmbtu per day at an average price of U.S. $1.78 for 2001; 10,000 mmbtu per day at an average price of U.S. $1.87 per mmbtu for 2002 to 2005; and 8,300 mmbtu per day at an average price of U.S. $1.87 per mmbtu for 2006.

(iii) Foreign currency

At December 31, 1999 the Company had fixed the exchange rate on U.S. dollars through currency swaps as follows: 2000 – U.S. $12.6 million per month at an average exchange rate of 1.3415; 2001 – U.S. $11.3 million per month at an average exchange rate of 1.3334; and 2002 – U.S. $0.3 million per month at an average exchange rate of 1.3740. The amounts fixed approximate 14 percent of the amounts of U.S. cash received each month from the sale of crude oil and natural gas.

8. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"), which differ in some respects from GAAP in the United States. The significant differences in GAAP, as applicable to these consolidated financial statements and notes, are described in the Company's Form 40-F report, which is filed with the United States Securities and Exchange Commission.

Year Ended December 31	1999	1998	1997
Financial ($ thousands, except per share data)			
Revenues			
Gross revenue	**1,286,763**	877,635	921,114
Oil and natural gas revenues, net of royalties	**1,098,886**	760,878	768,772
Interest income	**–**	–	–
Expenses			
Production	**252,037**	211,899	205,638
Administration	**17,025**	18,820	12,769
Interest	**90,447**	75,989	37,017
Depreciation, depletion and amortization	**384,311**	327,402	288,794
Unrealized foreign exchange loss (gain)	**2,182**	1,832	8,247
Provision for taxes	**152,684**	65,919	104,964
Cash flow from operating activities	**723,469**	444,224	503,012
Per share*	**6.96**	4.47	5.13
Net earnings	**200,200**	59,017	111,293
Per share*	**1.93**	0.59	1.14
Balance Sheet Information			
Capital expenditures (net)	**1,900,624**	609,724	1,119,176
Working capital surplus (deficiency)	**36,442**	57,887	(18,550)
Total assets	**4,850,850**	3,247,418	2,931,143
Long-term debt	**2,156,850**	1,425,479	1,136,276
Shareholders' equity	**1,892,017**	1,277,350	1,204,314
Common shares outstanding (000s)*	**111,454**	99,809	98,819
Weighted average shares outstanding (000s)*	**103,906**	99,331	98,042
Number of Employees (Dec 31)			
Office	**397**	335	339
Field	**278**	212	203
Total	**675**	547	542
Operating			
Reserves (proven and probable)			
Crude oil and NGLs (mbbls)			
Proven	**553,556**	287,005	270,421
Probable	**86,368**	97,188	81,008
Total	**639,924**	384,193	351,429
Natural gas (bcf)			
Proven	**2,183**	1,905	1,733
Probable	**364**	311	363
Total	**2,547**	2,216	2,096
Land Holdings (000s)			
Gross acres	**10,192**	8,586	8,514
Net acres	**8,590**	7,156	6,938
Production			
Crude oil and NGLs (bbls/d)	**86,750**	75,744	70,619
Natural gas (mmcf/d)	**721.0**	672.6	625.5
Average crude oil and NGLs price ($/bbl)	**21.04**	12.93	18.82
Average natural gas price ($/mcf)	**2.36**	2.12	1.91
Drilling activity (net wells)			
Crude oil wells	**211.5**	106.5	442.9
Natural gas wells	**457.6**	193.2	199.6
Injection wells	**8.9**	15.5	1.5
Dry and abandoned	**49.3**	42.7	67.0
Total	**727.3**	357.9	711.0
Success rate (%)	**93**	88	91

** Restated to reflect two for one stock split in June 1993.*

TEN-YEAR REVIEW

1996	1995	1994	1993	1992	1991	1990
636,810	281,065	259,014	157,930	77,031	40,058	20,825
532,347	245,419	221,182	135,419	66,038	34,892	18,061
–	–	–	141	166	263	239
129,901	63,914	51,309	30,867	18,374	9,963	5,031
7,686	4,327	2,775	3,029	1,807	1,248	767
26,693	20,940	12,325	6,495	3,837	2,537	1,423
182,431	82,413	57,121	35,023	18,448	10,123	3,953
36	(43)	–	–	–	–	–
90,574	31,467	43,437	25,831	9,815	3,254	2,107
359,741	153,621	152,765	94,210	41,776	21,324	11,023
4.32	2.22	2.39	1.64	0.81	0.50	0.30
95,026	42,401	54,215	34,315	13,923	8,030	5,019
1.14	0.61	0.85	0.60	0.27	0.19	0.14
1,203,609	238,841	331,153	271,204	89,998	59,206	32,915
(836)	9,712	4,035	2,204	(1,979)	(360)	(1,175)
2,062,633	900,429	737,800	436,866	173,186	99,763	47,153
588,021	237,700	242,856	189,165	60,478	35,561	14,938
1,074,205	496,348	356,182	171,213	81,451	45,224	20,130
97,383	74,074	66,709	59,862	54,441	49,044	41,887
83,246	69,319	63,873	57,596	51,475	42,774	37,044
293	159	118	87	41	27	19
135	46	44	36	20	4	–
428	205	162	123	61	31	19

140,931	53,277	43,201	29,164	13,477	6,953	2,497
49,708	23,476	14,301	13,466	5,173	2,349	794
190,639	76,753	57,502	42,630	18,650	9,302	3,291
1,605	924	894	666	333	188	105
362	208	175	101	25	22	7
1,967	1,132	1,069	767	358	210	112
7,514	4,423	3,764	3,014	1,054	672	438
5,825	3,334	2,714	1,873	738	472	248
37,399	16,836	12,820	8,005	4,184	1,681	966
499.3	304.8	237.5	164.8	93.5	57.3	25.3
23.52	19.82	18.18	18.17	20.84	21.39	22.65
1.71	1.43	1.99	1.72	1.31	1.28	1.39
208.9	112.5	43.7	32.8	9.8	11.0	1.0
128.1	73.9	138.1	68.2	19.8	12.7	13.4
1.0	–	–	–	–	–	–
62.9	22.3	44.5	27.6	21.5	9.0	4.7
400.9	208.7	226.3	128.6	51.1	32.7	19.1
84	89	80	79	58	72	75

CORPORATE INFORMATION

Board of Directors

N. Murray Edwards
President, Edco Financial Holdings Ltd.
Calgary, Alberta

James T. Grenon
Managing Director, Tom Capital Associates Inc.
Calgary, Alberta

John G. Langille
President, Canadian Natural Resources Limited
Calgary, Alberta

Keith A.J. MacPhail
President & C.E.O., Bonavista Petroleum Ltd.
Calgary, Alberta

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Chairman of the Board,
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Calgary, Alberta

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The University of Calgary
Calgary, Alberta

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Vice-President, Corporate Development & Land

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Vice-President, Production

Lyle G. Stevens
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Evaluation Engineers

Sproule Associates Limited
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Stock Listing

The Toronto Stock Exchange
Symbol: CNQ

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