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SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

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FORM 6-K

REPORT OF FOREIGN PRIVATE ISSUER

PURSUANT TO RULE 13a-16 OR 15d-16 OF

THE SECURITIES EXCHANGE ACT OF 1934

For the month of February 2002.

PanCanadian Energy Corporation
(Translation of Registrant's Name Into English)

PROCESSED
MAR 06 2002
THOMSON FINANCIAL P

150 - 9th Avenue S.W.
Calgary, Alberta, Canada T2P 3H9
(Address of Principal Executive Offices)

(Indicate by check mark whether the registrant files or will file annual reports under cover of Form 20-F or Form 40-F.)

Form 20-F ____ Form 40-F __X___

(Indicate by check mark whether the registrant by furnishing the information contained in this form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934.)

Yes _____ No __X__

(If "Yes" is marked, indicate below the file number assigned to the registrant in connection with Rule 12g3-2(b): 82-________.

This report furnished on Form 6-K shall be incorporated by reference into each of the Registration Statements under the Securities Act of 1933 of the registrant: Form S-8 No. 333-13956

PanCanadian energy | News Release

PanCanadian posts record earnings and cash flow in 2001

Calgary, Alberta, February 20, 2002, (TSE - PCE; NYSE - PCX) - PanCanadian Energy Corporation today announced the strongest financial results in its history, reporting a 26 percent increase in net income to $1,304 million, or $5.09 per common share. During 2001, the Company produced cash flow of $2,306 million, or $9.02 per common share, up slightly from 2000.

"In 2001, PanCanadian had an outstanding year delivering strong financial results and making significant progress on a number of our key strategic initiatives," said Michael A. Grandin, President. "We grew our natural gas production by 11 percent in the Western Basin and significantly advanced pre-development work for the Deep Panuke natural gas discovery offshore the East Coast of Canada. We expanded our opportunities in crude oil outside of the Western Basin with the largest discovery in the U.K. Central North Sea in the last decade at Buzzard. We completed delineation of the Llano field and greatly expanded our land inventory in the Gulf of Mexico."

"The year 2002 promises another giant step forward for PanCanadian through its proposed merger of equals with Alberta Energy Company to create EnCana Corporation, a world leader among independent oil and gas companies in terms of enterprise value, reserves and production," added Mr. Grandin. "The merger, if approved by shareholders, would create a company with a more diverse and complementary portfolio of assets, operating and capital cost synergies, greater liquidity, and the size to compete on the global stage. As we undertake larger capital projects and the energy business becomes more international in nature, we believe that scale will be an important determinant of corporate competitiveness and success. The increased scope, scale and reach of EnCana will contribute to its performance and ability to deliver enhanced shareholder value."

2001 Full Year Highlights

- Net income increased by 26 percent to $1,304 million, or $5.09 per common share.
- Cash flow rose marginally to $2,306 million, or $9.02 per common share.
- Return on equity rose to 32 percent.
- Natural gas production rose 11 percent to 1.053 billion cubic feet per day, with realized prices up 33 percent to $6.20 per thousand cubic feet.
- Crude oil and natural gas liquids production declined six percent to 114,400 barrels per day due, in part, to asset rationalization and de-emphasizing oil opportunities. Crude oil realized prices decreased 15 percent to $27.44 per barrel.
- On a proven basis the Company replaced 147 percent of its natural gas production. Excluding acquisitions and dispositions, PanCanadian added 564 billion cubic feet of gas and 31 million barrels of crude oil and natural gas liquids, totalling approximately 125 million barrels of oil equivalent, which represents a reserve replacement rate of 118 percent. On an established basis, the Company replaced 173 percent of its barrels of oil equivalent production.

- Marketing volumes increased 24 percent to 4,643 thousand MMBTUs per day (approximately 71 percent natural gas) and marketing margins grew 40 percent to $176 million.
- Capital expenditures, excluding acquisitions and dispositions, totalled $1,946 million, the largest in the Company's history. Total wells drilled were 2,251, with a success rate of 93 percent.
- Year-end debt to debt plus equity was 36 percent, the 12-month trailing net debt to cash flow was 57 percent, and the year-end cash balance was nearly $1 billion. PanCanadian's financial position remained strong even after a special dividend of $4.60 per share ($1,180 million) was paid to all shareholders in September 2001 as part of the Canadian Pacific Limited reorganization.

The Company achieved the record results in 2001 primarily due to higher natural gas prices in the first part of the year, increased natural gas production, and favourable price hedges, particularly for natural gas. The increase in natural gas production in 2001 mainly reflected higher production from natural gas properties acquired as part of the Montana Power acquisition in the fourth quarter of 2000 and a successful drilling program. The exit rate in 2001 for natural gas production was 1,127 million cubic feet per day.

During the fourth quarter of 2001, net income was $91 million, or $0.35 per common share, compared with $344 million, or $1.35 per common share, for the same period in 2000. Cash flow in the fourth quarter of 2001 was $386 million, or $1.51 per common share, down from $784 million, or $3.09 per common share, in the last quarter of 2000. Higher natural gas production and favourable natural gas and crude oil hedges only partially offset weaker market prices for natural gas and crude oil, and lower crude oil production. Commodity and currency hedges contributed $149 million before tax in the quarter.

In the fourth quarter of 2001, natural gas production averaged 1,077 million cubic feet per day, up about four percent from the same period in 2000. Production of crude oil and natural gas liquids was nine percent lower averaging 113,900 barrels per day, reflecting the disposition of 5,300 barrels per day from Pelican Lake. Realized prices, including hedging, for natural gas declined 41 percent to $4.07 per thousand cubic feet and crude oil decreased 16 percent to $23.81 per barrel.

During the fourth quarter of 2001, the Company changed its method of classifying current and future income taxes with respect to consolidated entities that have a later year-end than the Company. This change was made in order to better match the current income tax provision for a particular year with the earnings and cash flow for that year. As a result, there was a decrease in reported cash flow of $295 million in 2001 and $170 million in 2000. However, this change had no effect on reported earnings, the timing of cash tax payments to governments, or the Company's financial position.

HIGHLIGHTS

($ millions, except amounts per share)	Three Months Ended December 31 2001	Three Months Ended December 31 2000	Year Ended December 31 2001	Year Ended December 31 2000
Revenues	$ **1,662**	$ 2,599	$ **10,098**	$ 7,327
Net income	**91**	344	**1,304**	1,039
Per share - basic	**0.35**	1.35	**5.09**	4.09
Cash flow	**386**	784	**2,306**	2,303
Per share - basic	**1.51**	3.09	**9.02**	9.11
Capital expenditures (excludes net acquisitions / dispositions)	**655**	448	**1,946**	1,415
Net debt			**1,315**	1,115

	Year Ended December 31 2001	Year Ended December 31 2000
Return on average shareholders' equity	**32%**	29%
Return on average capital employed	**24%**	24%
Net debt to cash flow	**57%**	48%
Debt to debt plus equity	**36%**	25%

UPSTREAM

Daily Production *(before royalty)*	Three Months Ended December 31 2001	Three Months Ended December 31 2000	Year Ended December 31 2001	Year Ended December 31 2000
Natural gas (million cubic feet)	**1,077**	1,041	**1,053**	949
Crude oil (barrels)	**100,680**	111,895	**101,967**	109,534
Field natural gas liquids (barrels)*	**13,213**	13,598	**12,481**	12,486
Total crude oil and field natural gas liquids (barrels)*	**113,893**	125,493	**114,448**	122,020

* Prior period volumes have been restated to reflect a reclassification related to internal consumption. The reclassification has an immaterial effect on prior period financial statements.

Average Realized Sales Prices *($ per unit)*	Three Months Ended December 31 2001	Three Months Ended December 31 2000	Year Ended December 31 2001	Year Ended December 31 2000
Natural gas (per thousand cubic feet)*	$ **3.10**	$ 7.10	$ **5.66**	$ 4.77
Hedging**	**0.97**	(0.17)	**0.54**	(0.12)
	$ **4.07**	$ 6.93	$ **6.20**	$ 4.65
Crude oil (per barrel)	$ **18.11**	$ 32.19	$ **26.60**	$ 34.83
Hedging**	**5.70**	(3.94)	**0.84**	(2.49)
	$ **23.81**	$ 28.25	$ **27.44**	$ 32.34
Field natural gas liquids (per barrel)*	$ **21.49**	$ 38.58	$ **30.13**	$ 33.07

* Prior period prices have been restated to reflect a reclassification related to internal consumption. The reclassification has an immaterial effect on prior period financial statements.

** Natural gas hedging activities include both currency and commodity hedging for 2001; 2000 hedging activity was predominantly currency hedging. *Crude oil hedging activities include both currency and commodity hedging for 2001 and 2000.*

Drilling Summary *(gross number of working interest wells drilled)*	Three Months Ended December 31 2001	Three Months Ended December 31 2000	Year Ended December 31 2001	Year Ended December 31 2000
Natural gas	**423**	485	**1,540**	1,793
Crude oil	**103**	93	**421**	530
Coal bed methane	**69**	-	**84**	-
Service	**10**	19	**53**	70
Dry	**39**	30	**153**	137
	644	627	**2,251**	2,530
Success ratio	**94%**	95%	**93%**	95%
Average working interest	**81%**	89%	**82%**	88%

MARKETING AND MIDSTREAM

Marketed Volumes	Three Months Ended December 31 2001	2000	Year Ended December 31 2001	2000
Natural gas (million cubic feet per day)	**3,062**	2,313	**3,313**	2,361
Crude oil (thousand barrels per day)	**176**	170	**175**	170
Natural gas liquids (thousand barrels per day)	**41**	76	**44**	57
Electricity (thousand megawatt hours)	**131**	-	**474**	434
Total *(thousand MMBTUs per day)**	**4,367**	3,783	**4,643**	3,749

* Conversion assumed at: 1 million cubic feet = 1 thousand MMBTU; 1 thousand barrels = 6 thousand MMBTU; 1 thousand megawatt hours = 10 thousand MMBTU.

Midstream Production	Three Months Ended December 31 2001	2000	Year Ended December 31 2001	2000
Natural gas liquids (thousand barrels per day)	**28**	28	**26**	29

Midstream Electricity Megawatt Capacity *(as at December 31, 2001)*	Megawatt Capacity	Ownership (%)	PanCanadian Megawatt Capacity
Kingston	108	25	**27**
Cavalier	85	*100*	**85**
Balzac	85	50	**43**
			155

MERGER ANNOUNCEMENT

PanCanadian and Alberta Energy Company Ltd. (AEC) announced on January 27, 2002, that their respective Boards of Directors had unanimously agreed to recommend a merger of the two companies and to seek necessary approvals from their respective shareholders and the Court of Queen's Bench of Alberta. The combined organization, with an enterprise value of more than $27 billion (calculated as of January 25, 2002), will be headquartered in Calgary. If approved, the combined organization will operate under the name EnCana Corporation. David O'Brien, PanCanadian's Chairman and Chief Executive Officer, will serve as non-executive Chairman, and Gwyn Morgan, AEC's President and Chief Executive Officer, will be President and Chief Executive Officer of the combined company. EnCana's Board of Directors will consist of an equal number of directors from each company. The transaction is expected to close in early April 2002. PanCanadian has called an Annual General and Special Shareholders meeting to be held in Calgary on April 4, 2002 at 12:30 p.m. (Mountain Standard Time) at the TELUS Convention Centre. A joint circular and management information circular will be mailed on or about March 1, 2002 to shareholders of record as of February 27, 2002.

In anticipation of completion of the merger, transition teams consisting of senior personnel from both companies have been brought together to determine the most effective way to integrate the two companies, and achieve the expected $250 million in annual operating and administrative cost synergies and $250 million in improved capital allocation.

OPERATIONAL HIGHLIGHTS

Western Basin:

In 2001, PanCanadian continued to leverage its operating expertise on its vast Western Basin lands, its primary platform for sustainable natural gas growth – the Company's key strategic thrust. The Company spent approximately $880 million on natural gas last year in the Western Basin, where it drilled approximately 1,440 successful wells and produced more than one billion cubic feet per day of natural gas. In the Palliser Business Unit alone, where the bulk of the Company's natural gas prospects are located, PanCanadian drilled 1,267 wells, producing almost 70 percent of the Company's total natural gas production in 2001.

In the Great Plains Business Unit, which encompasses the Montana Power acquisition, the Company produced an average of 105 million cubic feet per day (including royalty interest) in 2001, and plans to triple production from these low-risk plays by 2006.

PanCanadian has started to see success from its activities in the Denver-Julesburg (D-J) Basin. These properties were acquired from Montana Power in the fourth quarter of 2000 and are part of PanCanadian's Great Plains Business Unit. Natural gas production at the end of 2001 was an average of 43 million cubic feet per day, up almost 60 percent from approximately 27 million cubic feet per day at the start of the year. PanCanadian drilled 39 wells in this area in 2001. The Company views the D-J Basin as a potential area of natural gas reserve and production growth, and will be investing funds in this region in 2002 to enhance production in the area.

The Western Basin lands have proven reserves of approximately one billion barrels of oil equivalent, of which approximately 65 percent is natural gas. PanCanadian will continue to assess and acquire undeveloped acreage, especially near its core gas-prone regions.

Ferrier – significant natural gas discovery
The discovery of a large gas pool in the Ferrier area of west central Alberta was tied-in prior to year-end with an initial gross production rate of 25 million cubic feet per day of liquids-rich natural gas. PanCanadian has a 60 percent working interest in the well and has acquired significant mineral rights in the area through Crown land sales and farm-in agreements. The Company plans to pursue this play in 2002 with up to nine wells.

PanCanadian and Quicksilver Resources to expand Alberta coal bed methane program
PanCanadian and MGV Energy Inc., the Canadian subsidiary of Quicksilver Resources Inc., announced that their coal bed methane (CBM) joint venture will be expanding into a large geographic area outside of the southern Alberta Palliser block, to include additional coal bed formations. The program outside the Palliser block consists of 25 exploration wells, of which 12 had been drilled by the end of 2001. A total of 112 exploratory and pilot CBM wells will have been drilled by the end of the first quarter of 2002, of which 100 will be drilled in the Palliser block.

PanCanadian has been encouraged by the results of the pilot program to date, and if successful, could support the move to full-scale development, potentially marking the first coal bed methane production program in Canada. The Company anticipates being in a position to make decisions regarding commercial development by the end of the first half of 2002.

Oil Sands Development:

Christina Lake – on-steam in first quarter of 2002

The Company expects to be injecting steam into the reservoir late in the first quarter of 2002. The first production from Christina Lake is anticipated at the end of the second quarter of this year. Detailed engineering and procurement of equipment is complete. The Phase 1 SAGD well pairs have been drilled and facilities construction is approximately 60 percent complete. Phase 1 is anticipated to produce 10,000 barrels per day of bitumen in 2003. The project, as currently configured, comprises three phases that, when complete, would produce 70,000 barrels per day.

To assist in the development of the Christina Lake reserves, the Senlac steam-assisted gravity drainage (SAGD) project continued to build upon PanCanadian's thermal expertise, achieving unprecedented performance from two new well pairs in Phase C. These 750-metre well pairs incorporate a number of technological enhancements including improvements to completion techniques, steam distribution capability, and reduced sand production. Since start up in late July, the two well pairs have a combined average production rate of 4,400 barrels per day, with peak rates of about 4,800 barrels per day coming in the fourth quarter. These enhancements have established new SAGD production records and also placed the Phase C wells among the most prolific oil producers in all of Western Canada during 2001. This technology and experience will be employed at Christina Lake.

Subsequent to the acquisition of CS Resources Limited in 1997, PanCanadian has acquired, through Crown land sales, approximately 229,000 gross acres of oil sands rights to support the ongoing development of its Christina Lake project and other similar projects in the Athabasca oil sands region of Alberta.

Weyburn Production Response:

During the fourth quarter of 2001, the Weyburn CO_2 flood continued to show better-than-expected production response to the injection of 71 million standard cubic feet a day of CO_2. Incremental oil for the quarter averaged 3,900 barrels per day with a December exit rate of 4,200 barrels per day, exceeding production estimates by approximately 1,200 barrels per day. The enhanced oil recovery project response now accounts for approximately 18 percent of the Weyburn Unit oil production.

In mid-2002, PanCanadian will be implementing a $17 million expansion of the project by converting four existing waterflood patterns to CO_2 injection. The Company plans to have the four additional patterns on CO_2 injection by October 2002. Incremental oil production resulting from this expansion is anticipated in early 2003 at 300 barrels of oil per day (gross) on an annualized basis.

Offshore Core Areas:

U.K. North Sea

PanCanadian announced in January 2002, that it had significantly increased its estimate of recoverable oil on its Buzzard discovery in the U.K. Central North Sea, after drilling two additional appraisal wells on the structure. Results from these two appraisal wells indicate potential oil in place in excess of 800 million barrels within the southern and central parts of the Buzzard accumulation, of which the Company expects to be able to recover in excess of 400 million barrels (180 million barrels net to PanCanadian). This is up substantially from previous estimates, and if proved, would represent a 50 percent increase in

PanCanadian's crude oil and liquids reserves, and there is still a sizeable area left to evaluate. PanCanadian is the operator of the licence.

PanCanadian released flow-test results from the Buzzard 20/6-4 appraisal well, located on the Buzzard structure in the U.K. Central North Sea. The 20/6-4 appraisal well, drilled using a semi-submersible rig, flowed at aggregate rates of 11,100 barrels per day of light oil (4,000 barrels per day and 7,100 barrels per day from the two zones tested) and 2.2 million cubic feet per day of natural gas on a 36/64th inch choke. As was the case in the initial discovery well, flow rates were constrained by the capacity of surface testing equipment. Under a normal production scenario, it is estimated that the wells will be capable of producing up to 20,000 barrels of oil per day on a sustainable basis. The rig will now be used to drill a sidetrack to the 20/6-4 appraisal well. This sidetrack will test the extension of the Buzzard accumulation in block 20/1 of licence P928 (South).

The Company plans to commence drilling a new field exploratory well at its Blackhorse prospect, also in the U.K. Central North Sea, in the first quarter of 2002. PanCanadian is the operator of this well.

East Coast of Canada

The Southampton A-25 exploration well, located about 150 kilometres off the Eastern shore of Nova Scotia, encountered non-commercial quantities of hydrocarbons and was abandoned. PanCanadian holds a 37.5 percent interest in the well and was the operator.

PanCanadian recently completed drilling of the Queensland M-88 well located on the Musquodoboit licence – a bypass sand play testing Jurassic age sandstones. Queensland confirmed the migration path of hydrocarbons, as well as the existence of trap and seal. However, the reservoir quality was not commercial. The Company is in the process of abandoning the well. PanCanadian is the operator of the block and holds a 74 percent interest.

The Southampton and Queensland wells were drilled into separate geological structures near the Company's Deep Panuke natural gas field. While the results are disappointing, the information gained from drilling these wells will be valuable in helping PanCanadian evaluate the geology and geophysics of the area.

The Company is currently participating in a well being drilled in a deep-water prospect on the Annapolis licence. PanCanadian holds a 26-percent interest in this well, operated by Marathon Canada. The drilling of this well is expected to be completed during the first quarter of 2002.

In January 2002, the Company increased its acreage offshore Nova Scotia and Newfoundland. PanCanadian now has a 50 percent working interest in, and is the operator of, Exploration Licences 2408 and 2414 offshore Nova Scotia. Total gross acreage for both licences is approximately 503,400 acres. The Company also acquired three parcels offshore Newfoundland, with gross acreage totalling approximately 1.3 million acres. Interests in the parcels range from 33.33 percent to 100 percent, with PanCanadian as operator of two of the three parcels. These licences increase PanCanadian's total acreage offshore Nova Scotia to approximately 4.9 million gross acres (2.7 million net) and total acreage offshore Newfoundland to approximately 4.3 million gross acres (2.6 million net), in 27 exploration licences.

Gulf of Mexico

PanCanadian confirmed that drilling and evaluation has been completed on the fourth well at the Llano field, located in the deepwater Gulf of Mexico. The well, Garden Banks 385 No. 1, tested the western continuation of the reservoir. It was drilled to a measured depth of 24,813 feet. Logging results confirmed approximately 400 feet of net pay. This is the last well needed to begin evaluating alternatives for field development. Co-venturers will complete the initial development concept selection in the first half of 2002. PanCanadian has a 22.5 percent interest in the Llano field.

The Company announced that it has increased its land inventory in the Gulf by way of two exploration joint ventures, expanding its holdings from 55 to 142 blocks (810,000 gross or 300,000 net acres), with options to further increase its holdings to up to 269 blocks (1,550,000 gross or 500,000 net acres). The two agreements are with ChevronTexaco Corp. and Union Oil Company of California.

As part of its agreement with ChevronTexaco, PanCanadian will participate in four exploratory wells to earn a 25 percent interest in 71 blocks (approximately 409,000 gross or 102,000 net acres). The first of these wells, Sawtooth, located at Atwater Valley 194, encountered non-commercial quantities of hydrocarbons. The second well in the four-well program, Tahiti, spudded in late December. Drilling of the Tahiti well is expected to be completed in the first quarter of 2002.

International New Ventures:

In October 2001, PanCanadian was awarded a 100-percent working interest in two contiguous permits, which are adjacent to the productive area in the Gippsland Basin, located in the Eastern Bass Strait offshore Australia. The two permits comprise approximately 1.3 million acres. PanCanadian also acquired approximately 710 kilometres of new in-fill 2D seismic on the two permits in December to fulfil the initial work commitments. The Company is now evaluating the data to determine prospectivity.

In October 2001, PanCanadian acquired a 40-percent interest in a deep-water block offshore Ghana. The Keta Block is located in the Volta River Delta and covers approximately 1.7 million gross acres (700,000 net acres).

In 2001, PanCanadian also acquired interests in two prospective blocks in Yemen. Block 47 (52.5 percent interest) is centrally located and adjacent to a producing hydrocarbon system, while Block 60 (approximate 39 percent interest) provides access to a play trending south from Saudi Arabia. PanCanadian is the operator of both blocks, which comprise approximately 2.5 million gross acres (1.2 million net acres). In 2002, PanCanadian and its joint venture partner plan to acquire new 2D seismic and drill one well on Block 47, while the Block 60 joint venture may acquire seismic.

Marketing and Midstream:

Balzac Power Station begins selling electricity to the Alberta Power grid
The Balzac Power Station located near Calgary, Alberta, in which PanCanadian holds a 50-percent interest, was brought into service in December 2001. The facility is currently operating at 80 percent capacity. It is anticipated that the plant will achieve full capacity during the first quarter of 2002, at which time it will have a generation capability of 106 megawatts of power.

Empress Plant to undergo ethane expansion
In 2002, the PanCanadian-operated Empress NGL Extraction Plant will expand its ethane-recovery facilities. As a result, ethane production will increase by approximately 19,000 barrels per day. This $50 million expansion will be onstream in the fall of 2003. PanCanadian owns a 35 percent interest in the facilities, which currently process up to 1.2 billion cubic feet per day of natural gas to extract natural gas liquids and ethane.

CORPORATE EVENTS

PanCanadian Energy Corporation amalgamation effected

As part of the corporate reorganization of Canadian Pacific Limited (CPL), CPL distributed its holdings in five operating businesses, one of which was PanCanadian Petroleum Limited, to the CPL common shareholders. As a result, PanCanadian Petroleum Limited became a wholly-owned subsidiary of PanCanadian Energy Corporation. Effective January 1, 2002, PanCanadian Energy Corporation and PanCanadian Petroleum Limited amalgamated and continue as one entity known as PanCanadian Energy Corporation.

Dividend payment

A quarterly dividend of 10 cents per share was paid on December 31, 2001, to shareholders of record as of December 10, 2001.

Small Shareholder Selling Program extended

PanCanadian's Small Shareholder Selling Program has been extended to March 5, 2002, at 4 p.m. Eastern Standard Time. This voluntary program is available to all shareholders of PanCanadian Energy Corporation, and enables registered and beneficial holders who owned 99 or fewer common shares of the Company as of October 5, 2001, to sell their shares without incurring brokerage commissions.

U.S. Internal Revenue Service issues favourable tax ruling

The U.S. Internal Revenue Service has issued a favourable private letter ruling relating to the October 2001 reorganization of Canadian Pacific Limited (CPL). Issued on December 17, 2001, the ruling provides, among other things, that the receipt of common shares in PanCanadian Energy Corporation was tax-deferred both for former shareholders of CPL and for former shareholders of PanCanadian Petroleum Limited who are otherwise subject to U.S. tax.

OUTLOOK

The outlook that follows excludes the effect of the proposed merger transaction between PanCanadian and AEC.

During 2002, PanCanadian's activities will continue to be directed toward delivering strong near-term natural gas production growth from the Western Basin and developing offshore and international projects for medium- and longer-term value creation. Supply/demand fundamentals for natural gas in North America are considered favourable, especially over the medium-term. PanCanadian expects to grow its North American natural gas production by 10 percent in 2002, while overall corporate production growth on a BOE basis is anticipated to be approximately four percent. Consolidated proven reserves are expected to increase by more than 10 percent in 2002, based on the Company's recent successes offshore and internationally.

PanCanadian anticipates that natural gas prices will weaken from 2001 average prices, which reflected exceptional highs in the early part of the year. Sluggish industrial demand and robust storage levels are expected to limit a recovery in natural gas prices until the latter part of 2002. Crude oil prices are also likely to be lower in 2002 than during the previous year under a continuing scenario of weak demand, surplus OPEC capacity and rising non-OPEC supply. For planning purposes, PanCanadian has assumed the following: the NYMEX benchmark price for natural gas will average US$3.00 per million British thermal units while the benchmark WTI crude oil price will average US$20.00 per barrel in 2002. In addition, Canadian heavy crude oil differentials are expected to narrow from the exceptionally high levels experienced since the fourth quarter of 2000. PanCanadian has assumed an average of US$7.00 per barrel for the Bow River differential.

PanCanadian's Board of Directors approved a $1.7 billion capital investment program for 2002, which will be funded largely from cash flow generated from operations. Reflecting PanCanadian's plans to continue to grow natural gas production, approximately $1.1 billion, or 70 percent, of the Company's exploration and production capital investment will be targeted toward natural gas.

Outside the Western Basin, the year 2002 will be very active for PanCanadian as the Company begins the development phases at Buzzard, Deep Panuke and Llano. PanCanadian expects to drill 15 wells in the Canadian East Coast offshore and internationally. 2002 development expenditures for the Deep Panuke natural gas field offshore Nova Scotia are approximately $114 million. Planned crude oil investment spending of almost $500 million includes $41 million at the Buzzard discovery in the U.K Central North Sea, while capital costs at the Llano crude oil discovery in the Gulf of Mexico are expected to be approximately $21 million in 2002.

As of December 31, 2001, PanCanadian had the following hedges in place:

- Approximately 205 million cubic feet per day of natural gas at an average AECO equivalent of $5.97 per thousand cubic feet from January 1, 2002 to October 31, 2002.
- 15,000 barrels per day of crude oil sold forward for the period January 2002 to March 2002 at an average WTI price of US$23.78.
- 10,000 barrels per day of crude oil sold forward for the period April 2002 to June 2002 at an average WTI price of US$23.57.

In addition, PanCanadian has sold call options on 113,600 cubic feet per day of AECO natural gas for the period November 2001 to October 2002 at an average strike price of $6.05 per thousand cubic feet.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") for PanCanadian Energy Corporation ("PanCanadian" or "Company") should be read in conjunction with the unaudited interim consolidated financial statements for the twelve months ended December 31, 2001 and the audited consolidated financial statements and MD&A for the year ended December 31, 2000.

CONSOLIDATED OVERVIEW

In 2001, PanCanadian's net income was a record $1,304 million, or $5.09 per common share, an increase of 26 percent from $1,039 million, or $4.09 per common share, in 2000. Cash flow was $2,306 million, or $9.02 per common share, in 2001, compared with $2,303 million, or $9.11 per common share, in 2000. Net income benefited from higher natural gas prices in the first part of the year, increased natural gas production and favourable price hedges, particularly for natural gas. Cash flow provided a significant portion of the funding for net investing activities of $1,697 million and a Special Dividend of $1,180 million, which was associated with the reorganization of Canadian Pacific Limited (CPL). The Company maintained a solid financial position. At year-end 2001, debt of $2,278 million represented 36 percent of debt plus equity. Cash on hand was $963 million and net debt to cash flow was 57 percent.

In the three months ended December 31, 2001, net income was $91 million, or 35 cents per common share, down from $344 million, or $1.35 per common share, in 2000. In the same period of 2001, cash flow was $386 million, or $1.51 per common share, compared with $784 million, or $3.09 per common share, in the corresponding quarter of 2000. Higher natural gas production and favourable natural gas and crude oil hedges only partially offset weaker market prices for natural gas and crude oil, and lower crude oil production.

BUSINESS ENVIRONMENT

The first part of 2001 was characterized by strong energy prices, particularly for natural gas. In the second half of 2001, prices weakened as demand was adversely affected by a global economic slowdown, which was accelerated by the terrorist attacks in the United States, as well as unusually cool summer and warm winter weather.

	Three Months Ended December 31		Year Ended December 31	
	2001	2000	**2001**	2000
Average AECO Price ($ per thousand cubic feet)	**3.44**	7.75	**6.56**	5.24
Average NYMEX Price (US$ per million British thermal unit)	**2.45**	5.29	**4.27**	3.89
Average WTI (US$ per barrel)	**20.53**	31.90	**25.95**	30.26
WTI Bow River Differential (US$ per barrel)	**9.52**	13.50	**9.87**	7.12
US/Canadian dollar exchange rate (US$)	**0.633**	0.655	**0.646**	0.673

Natural gas prices remained above historical levels throughout most of 2001. The average AECO index price for 2001 was $6.56 per thousand cubic feet, up 25 percent from $5.24 per thousand cubic feet in the prior year. However, by the last quarter of 2001, the average AECO index price softened to $3.44 per thousand cubic feet from $7.75 per thousand cubic feet in the fourth quarter of 2000 and $11.37 per thousand cubic feet in the first quarter of 2001.

The West Texas Intermediate (WTI) crude oil price averaged US$25.95 per barrel in 2001, compared with US$30.26 per barrel in 2000. Averaging US$28.67 per barrel in the first quarter of 2001, the WTI crude oil price weakened throughout 2001 to an average of US$20.53 per barrel in the fourth quarter of 2001 as a slowing economy led to lower crude oil demand. The WTI crude oil price in the fourth quarter of 2000 averaged US$31.90 per barrel. A wider than normal differential between heavier and lighter crude oil prices persisted for most of 2001. The full year average for the WTI-Bow River differential was US$9.87 per barrel up from US$7.12 per barrel in 2000 despite a narrowing in the differential later in the year. In the last three months of 2001, the differential narrowed to US$9.52 per barrel from US$13.50 per barrel in the same period of 2000.

The US/Canadian dollar exchange rate weakened through 2001, averaging US$0.654 cents in the first quarter and US$0.633 cents in the last quarter of 2001. The average exchange rate was US$0.646 in 2001, down from US$0.673 in 2000, favourably affecting the Canadian energy industry. The year-end exchange rates were US$0.628 and US$0.667 in 2001 and 2000, respectively.

RESULTS OF OPERATIONS

Upstream

Financial Results *($ millions)*	Year ended December 31							
	2001				2000			
	Natural gas	**Crude oil**	**Field NGL & other**	**Total**	Natural gas	Crude oil	Field NGL & other	Total
Revenues								
Production	**$ 2,380**	**$ 1,022**	**$ 152**	**$ 3,554**	$ 1,622	$ 1,296	$ 172	$ 3,090
Royalties and similar payments	**(175)**	**(122)**	**(6)**	**(303)**	(107)	(145)	(7)	(259)
	2,205	**900**	**146**	**3,251**	1,515	1,151	165	2,831
Expenses								
Direct operating*	**191**	**254**	**-**	**445**	132	235	-	367
Administrative	**-**	**-**	**-**	**70**	-	-	-	65
Depletion, depreciation and amortization	**-**	**-**	**-**	**828**	-	-	-	753
Upstream income	**$ 2,014**	**$ 646**	**$ 146**	**$ 1,908**	$ 1,383	$ 916	$ 165	$ 1,646
Capital expenditures (excludes net acquisitions / dispositions)				**$ 1,771**				$ 1,322

** Direct operating expenses for field NGL are commingled with natural gas expenses.*

Financial Results *($ millions)*	Three months ended December 31							
	2001				2000			
	Natural gas	**Crude oil**	**Field NGL & other**	**Total**	Natural gas	Crude oil	Field NGL & other	Total
Revenues								
Production	**$ 400**	**$ 221**	**$ 28**	**$ 649**	$ 665	$ 291	$ 57	$ 1,013
Royalties and similar payments	**(33)**	**(26)**	**-**	**(59)**	(46)	(37)	(1)	(84)
	367	**195**	**28**	**590**	619	254	56	929
Expenses								
Direct operating*	**54**	**62**	**-**	**116**	40	67	-	107
Administrative	**-**	**-**	**-**	**9**	-	-	-	22
Depletion, depreciation and amortization	**-**	**-**	**-**	**250**	-	-	-	237
Upstream income	**$ 313**	**$ 133**	**$ 28**	**$ 215**	$ 579	$ 187	$ 56	$ 563
Capital expenditures (excludes net acquisitions / dispositions)				**$ 595**				$ 392

** Direct operating expenses for field NGL are commingled with natural gas expenses.*

Revenue Variances for 2001 compared to 2000 *($ millions)*	Three months ended December 31			Year ended December 31		
	Price	Volume	Total	Price	Volume	Total
Natural gas	$ (308)	$ 43	$ (265)	$ 584	$ 174	$ 758
Crude oil	(39)	(31)	(70)	(182)	(92)	(274)
Field NGL and other	(21)	(8)	(29)	(13)	(7)	(20)
Total production revenue	$ (368)	$ 4	$ (364)	$ 389	$ 75	$ 464

For the year ended December 31, 2001, upstream production revenues of $3,554 million were up $464 million, or 15 percent, over 2000, chiefly because of higher realized natural gas prices and increased natural gas production. The Company's realized gas price increased 33 percent to $6.20 per thousand cubic feet from $4.65 per thousand cubic feet in 2000. A gain from hedging activities of $208 million, or 54 cents per thousand cubic feet, contrasted with a hedging cost of $43 million, or 12 cents per thousand cubic feet, in 2000. Natural gas production averaged 1,053 million cubic feet per day in 2001, up 11 percent from 949 million cubic feet per day in 2000. The increase in natural gas production mainly reflected higher production from natural gas properties acquired from The Montana Power Company (Montana Power) in the fourth quarter of 2000 and a successful drilling program. The exit rate in 2001 for natural gas production was 1,127 million cubic feet per day.

Realized crude oil prices averaged $27.44 per barrel in 2001, down 15 percent from $32.34 per barrel in 2000. A decline in market prices for lighter and heavier crude oils resulted in a 24 percent decline in the average received price, prior to hedging, to $26.60 per barrel from $34.83 per barrel. However, the decline was mitigated by favourable hedging activities that contributed $31 million, or 84 cents per barrel. In 2000, hedging activities had an unfavourable effect of $93 million, or $2.49 per barrel. Production of crude oil averaged 102,000 barrels per day in 2001, down seven percent from 109,500 barrels per day in the prior year. The decline principally reflected the disposition of certain non-core oil properties and the focus on growing natural gas production.

Royalties and similar payments of $303 million in 2001 were up $44 million from $259 million in 2000. The effect of higher production and better prices for natural gas increased payments by $68 million, which was partially offset by lower payments on crude oil production. Royalties and similar payments were also higher in 2001 because of the sale of an 11.7 percent net royalty interest in the Weyburn unit in the fourth quarter of 2000, and the inclusion for a full year of U.S. production taxes associated with the Montana Power assets. Excluding the impact of commodity and currency hedging, royalties and similar payments were approximately nine percent of upstream revenue, compared with eight percent in 2000. The relatively low rates reflect the Company's large production base on fee lands in Canada where only mineral taxes are due.

In the last three months of 2001, upstream production revenues were $649 million, compared with $1,013 million in the same period of 2000. Results principally reflected lower realized natural gas prices that declined 41 percent to average $4.07 per thousand cubic feet, including a gain from hedging activities of 97 cents per thousand cubic feet. Crude oil production declined 10 percent to 100,700 barrels per day and realized crude oil prices also decreased, to $23.81 per barrel from $28.25 per barrel. Commodity and currency hedging increased crude oil revenues by $5.70 per barrel in the fourth quarter of 2001, which contrasted with a cost of $3.94 per barrel in the same quarter of 2000. An increase in natural gas production to 1,077 million cubic feet per day from 1,041 million cubic feet per day partially offset the lower prices. Royalties and similar payments of $59 million compared with $84 million in the last three months of 2000, with the decrease mainly stemming from lower natural gas prices.

	Three months ended December 31		Year ended December 31	
Unit Direct Operating Expenses *($ per unit)*	**2001**	2000	**2001**	2000
Natural gas and field liquids (per thousand cubic feet)*	**$ 0.54**	$ 0.41	**$ 0.50**	$ 0.38
Crude oil (per barrel)	**7.49**	7.36	**7.67**	6.54
Per barrel of oil equivalent**	**4.70**	4.33	**4.64**	3.96

* Field liquids converted to natural gas at 1 barrel = 6 thousand cubic feet
**Natural gas converted to barrel of oil equivalent at 6 thousand cubic feet = 1 barrel of oil equivalent

Upstream direct operating expenses of $445 million, or $4.64 per barrel of oil equivalent for working interest production, in 2001 compared with $367 million, or $3.96 per barrel of oil equivalent, in 2000. Factors underlying the rise in unit costs were increased downhole and lease costs, in addition to higher electricity charges and a compressor maintenance program in the first half of 2001.

In the fourth quarter of 2001, upstream direct operating expenses amounted to $116 million, compared with $107 million in the same quarter of 2000. On a barrel of oil equivalent basis, costs associated with working interest production were $4.70 per barrel of oil equivalent, up from $4.33 per barrel of oil equivalent in the fourth quarter of 2000 due to higher downhole, maintenance and lease expenses. An aggressive cost management program is being pursued to control these and other costs.

Administrative expenses in the upstream division of $70 million in 2001 were up $5 million from 2000. On a barrel of oil equivalent basis, administrative expenses were up four percent to 66 cents per barrel in the year. The increase for the year was principally attributable to new areas of activity. In the fourth quarter of 2001, there was a $13 million decrease to $9 million, due chiefly to the level and the timing of recognition of employee incentive compensation.

Compared with 2000, depletion, depreciation and amortization expenses were up $75 million to $828 million in the twelve months and up $13 million to $250 million in the last three months of 2001. On a barrel of oil equivalent basis, depletion, depreciation and amortization expenses were up seven percent to $7.83 per barrel in the year. The Company recognized writedowns on certain international cost centres of $28 million in 2001 and $49 million in 2000. The international cost centres subject to writedown included Australia and Libya in 2001 and 2000, and South Africa and Ivory Coast in 2000.

Capital expenditures in the upstream division were $1,771 million in the year and $595 million in the fourth quarter, up $449 million and $203 million, respectively, from the corresponding periods of 2000. Most of the capital expenditures related to Western Basin activities, with approximately 60 percent of the investment in 2001 directed to natural gas exploration and development.

Approximately 20 percent of the upstream expenditures was targeted to high impact exploration and other activities internationally and offshore the East Coast of Canada where the Company is building future reserves. In these projects, associated reserves are often delayed and added in large increments to probable and then proven reserves after several years of high exploration and development expenditures. The Company's consolidated finding and development costs on a proven reserve basis were $13.35 per barrel of oil equivalent in 2001, up from $7.80 in 2000. While recent exploration successes in new basins are anticipated to result in significant additions to proven reserves over the coming years, these additions have not yet been reflected in the Company's proven reserves. In 2001, the Company booked probable reserves of 131 million barrels of oil equivalent for its Buzzard discovery in the United Kingdom Central North Sea. The consolidated finding and development cost on an established (proven plus one-half probable) reserve basis was $9.07 per barrel of oil equivalent. As the Company progresses the development of its new basins, the United Kingdom Central North Sea, the Gulf of Mexico and offshore the East Coast of Canada, it is expected that additional probable reserves will be booked and then added to proven reserves to the benefit of future finding and development costs.

In the Western Basin, finding and development costs on a proven reserve basis were $10.40 per barrel of oil equivalent in 2001, compared with $6.47 in 2000. The increase in part reflected expenditures on a number of larger projects, such as SAGD heavy oil development at Christina Lake, the Weyburn CO_2 miscible flood project and the coal bed methane joint venture, which require longer lead-times before reserves are booked. Excluding capital expenditures connected with these projects, Western Basin finding and development costs were $9.04 per barrel of oil equivalent in 2001. There were other factors underlying the rise in finding and development costs. The Company's Great Plains business unit completed a spending program in 2001 targeted at supporting a much larger production program in coming years than previously undertaken on the newly acquired Montana Power and Causeway lands. The Palliser business unit has increasingly undertaken a program of optimizing production from proved undeveloped reserves to capitalize on historically strong natural gas prices. Approximately 40 percent of the capital spending on natural gas activities in the Western Basin was directed towards optimizing production, which creates significant value, but less substantial reserve additions. The Company still maintains a large inventory of natural gas prospects.

Excluding acquisitions and dispositions, the Company added working interest and royalty interest proven reserves totalling 125 million barrels of oil equivalent in 2001 and 163 million barrels of oil equivalent in 2000, representing reserve replacement rates of 118 percent and 158 percent, respectively. Proven reserve additions for natural gas were 564 billion cubic feet in 2001 and 698 billion cubic feet in 2000, virtually all of which were in the Western Basin. The associated reserve replacement rates were 147 percent in 2001 and 201 percent in 2000 as the Company focused on growing its natural gas business in the Western Basin. The Company also added proven crude oil and NGL reserves of 31 million barrels in 2001 and 47 million barrels in 2000, including two million barrels in 2001 and seven million barrels in 2000 added in the U.K. Established reserve additions from capital programs were 184 million barrels of oil equivalent in 2001.

Marketing and Midstream

Financial Results *($ millions)*	Three months ended December 31		Year ended December 31	
	2001	2000	**2001**	2000
Revenues				
Marketing*	**$ 1,512**	$ 2,402	**$ 9,849**	$ 6,911
Midstream	**41**	96	**267**	314
	1,553	2,498	**10,116**	7,225
Direct expenses				
Marketing*	**1,492**	2,332	**9,673**	6,785
Midstream	**41**	77	**228**	229
	1,533	2,409	**9,901**	7,014
Margin	**20**	89	**215**	211
Administrative	**12**	27	**74**	60
Depreciation and amortization	**11**	5	**28**	22
Marketing and Midstream income	**$ (3)**	$ 57	**$ 113**	$ 129
Capital expenditures (excludes net acquisitions / dispositions)	**$ 60**	$ 56	**$ 175**	$ 93

** Results of the Marketing and Midstream segment include the inter-segment sales as disclosed in Note 3 to the unaudited financial statements.*

Marketing

Compared to 2000, Marketing's revenues were up 43 percent to $9,849 million in the twelve months of 2001, but down 37 percent to $1,512 million in the last three months of 2001. While marketing volumes were up throughout the year, variances in marketing revenue and related purchased product costs were affected primarily by energy price trends. In 2001, the total volume of marketed energy products on a MMBTU basis was up 24 percent from 2000, mostly due to higher Company-produced and third-party volumes of natural gas.

The Marketing margin improved $50 million, or 40 percent to $176 million in the twelve months of 2001, primarily due to natural gas volume increases and increased market volatility. Regional market volatility reached unprecedented levels during the first half of 2001 and declined during the second half of the year.

In the fourth quarter of 2001, marketing margins reached their lowest levels for 2001. This reflected lower activity and weaker energy prices that stemmed from the North American economic slowdown and warm winter conditions. The Marketing margin decreased to $20 million in the last quarter of 2001 from $70 million in the same quarter of 2000.

As of January 1, 2001, PanCanadian adopted mark-to-market accounting for all of the Company's financial and physical commodity positions within the marketing business because it more effectively reflects the nature of marketing activities. At December 31, 2001, the additional recognized mark-to-market gain, net of reserves, on the financial and physical positions was approximately $21 million. The impact on prior year's income is not material and prior year's results have not been restated.

Midstream

In 2001, Midstream revenues were $267 million with a margin of $39 million, compared with $314 million and $85 million, respectively, in 2000. NGL revenues in 2001 were down $52 million, or 19 percent, from 2000. Canadian operations experienced a 25 percent decline in volumes because production of extracted product was reduced in early 2001 to realize incremental value through the sale of high-priced natural gas, which would otherwise have been consumed in the NGL production process. Overall NGL volumes were down only 10 percent because of volumes added by a processing plant in Colorado, which was acquired as part of the purchase of the Montana Power assets, effective October 31, 2000.

In the fourth quarter of 2001, Midstream revenues declined $55 million, or 57 percent, to $41 million. A breakeven margin performance contrasted with a margin of $19 million in the last quarter of 2000. NGL production was unchanged at 28,000 barrels per day, but NGL prices were down about 50 percent from the fourth quarter of 2000 due to the warm winter weather and high Canadian inventory levels.

In 2001, Midstream revenue included approximately $12 million from the two new 106-megawatt electricity generation plants. The Midstream unit commenced operations of the Cavalier plant at 80 percent of capacity in the third quarter of 2001 and the Balzac plant, which is 50 percent owned by PanCanadian, commenced operations in December of 2001 at 80 percent of capacity. Both plants are expected to achieve full capacity in the first quarter of 2002.

For Marketing and Midstream operations, administrative expenses were up $14 million to $74 million in 2001 from $60 million in 2000. The increase principally reflected higher staffing levels brought about by an expanded Marketing and Midstream asset and activity base, which supports new opportunities for value-added margins. In addition, employee profit sharing contributed to the higher charges. Compared with the last quarter of 2000, administrative expenses were down $15 million to $12 million in the fourth quarter of 2001, mainly due to the timing of recognition of employee incentive compensation.

Depreciation and amortization expenses in the Marketing and Midstream operations of $28 million in 2001 were up $6 million from 2000, with an increase of $6 million to $11 million in the fourth quarter of 2001. The increase mainly reflected the depreciation charges on the two new electricity generation plants.

Capital expenditures in the Marketing and Midstream segment increased $82 million to $175 million in the year and increased $4 million to $60 million in the quarter. The capital investment in 2001 and 2000 was largely for the construction of the two new electricity generation plants.

Corporate

Compared to 2000, interest revenue was up $20 million to $35 million in the full year 2001 and unchanged at $7 million in the last quarter of 2001. Interest revenue in 2001 increased due to higher cash balances throughout the first nine months of 2001 and proceeds on a debt issue later in the year. Other items are mainly related to the Company's foreign exchange position and contributed revenue of $11 million in 2001, which contrasted with a charge of $14 million in 2000.

Corporate administrative expenses in 2001 included a one-time charge of $13 million associated with the spin off of CPL's approximately 85 percent interest in PanCanadian to CPL's common shareholders as part of the reorganization of CPL.

Interest expense in 2001 was $98 million, up from $90 million in 2000, and for the fourth quarter of 2001 was $37 million, up from $28 million in the corresponding period the previous year. The increases principally reflected the higher borrowing levels in the last quarter of 2001.

Compared to the prior year, the provision for income taxes in 2001 increased $5 million to $652 million and in the fourth quarter of 2001 was down $188 million to $65 million. The effective tax rate was 33 percent in 2001, compared with 38 percent in 2000. The provision for 2001 included an adjustment of $81 million to future income taxes resulting from a reduction in the Alberta corporate tax rate. The provision for 2000 included a charge of $77 million in respect of specific non-recurring items.

In the fourth quarter of 2001, the Company changed the method of classifying current and future taxes with respect to consolidated entities that have a later year-end than the Company. This change was made in order to better match the current income tax provision for a particular year with the earnings and cash flow for that year. Under the revised method, the current income tax provision includes amounts payable or recoverable in respect of these entities' income included in the consolidated financial statements. Previously, these amounts were included in current taxes when payable. This change results in a decrease in reported cash flow, but has no effect on total tax expense, net income, cash from operating activities or the Company's financial position. The effect of the change is disclosed in Note 4 to the Consolidated Financial Statements.

LIQUIDITY, CAPITAL RESOURCES AND RISK MANAGEMENT

PanCanadian delivered a record cash flow of $2,306 million in 2001, up slightly from $2,303 million in 2000, despite a $398 million decline in cash flow to $386 million in the last quarter of 2001. Cash flow contributed a significant portion of the funding for one of the Company's largest capital investment programs and the payment of the dividend of $1,180 million associated with the reorganization of CPL. Net investing activities were $509 million in the last three months of 2001, bringing investment spending to $1,697 million for the year.

The net change in non-cash working capital from operating activities provided $564 million in 2001, which contrasted with a use of $58 million in 2000. The positive variance in working capital changes principally reflected an increase in income taxes payable and a decrease in accounts receivable, offset by a lesser decrease in accounts payable. Accounts receivable and accounts payable declined due chiefly to the effect of lower energy prices on Marketing's accounts.

Debt, including the current portion, was $2,278 million at December 31, 2001 and $1,312 million at December 31, 2000. At year-end 2001, debt to debt plus equity was 36 percent, compared with 25 percent in 2000. In the first half of 2002, a total of US$100 million of medium term notes will mature and be retired. At year-end 2001, interest coverage was 32 times, an improvement from 24 times at year-end 2000, and cash on hand was $963 million, compared with $197 million at December 31, 2000. The net debt to cash flow was 57 percent in 2001 and 48 percent in 2000. The Company's solid financial position is supplemented by a $1.2 billion syndicated credit facility, other bank facilities of $550 million and a $300 million commercial paper program. During the third quarter of 2001, the Company renewed a $1 billion Canadian medium-term note shelf for a two-year term. At December 31, 2001, no issuances were outstanding and the total authorized amounts were available for use.

In October 2001, the Company filed a U.S. shelf prospectus that authorizes the issue from time to time of U.S. dollar denominated debt securities up to an aggregate principal amount of US$1.5 billion. Late in the same month, the Company issued US$850 million of unsecured notes in two tranches with 10 and 30-year maturities. The US$500 million notes due November 1, 2011, have a coupon of 6.3 percent and the US$350 million notes have a coupon of 7.2 percent and mature November 1, 2031. Net proceeds from the notes will be used for the repayment of short-term debt, maturing long-term debt and funding of the Company's capital investment program.

The Company's capital spending was $1,946 million in 2001 and $1,415 million in 2000. Expenditures were aimed at capturing the benefits of strong energy prices in the first part of the year as well as developing long-term growth opportunities. The majority, approximately 67 percent, of the investment in 2001 was directed towards natural gas and crude oil exploration and development in the Western Basin. Approximately 20 percent was targeted to high impact exploration and other activities internationally and offshore the East Coast of Canada. Approximately nine percent was directed towards Marketing and Midstream activities and the remaining four percent invested in other corporate activities. The Company drilled 2,251 wells in 2001, 93 percent of which were successful.

Acquisition and disposition activities resulted in net proceeds of $136 million in 2001 versus a net outlay of $808 million in 2000. PanCanadian's acquisition spending totalled $86 million in 2001, including the purchase in August 2001 of Causeway Energy Corporation, a junior oil and gas company with operations in northern Montana and southwest Saskatchewan, for $65 million, and the assumption of $4 million of Causeway debt. Dispositions in 2001 included the Company's 40-percent non-operated working interest in the Woollybutt field development in June, its Pelican Lake property in February, and other minor properties; total proceeds were $222 million. In 2000, the Company invested $948 million to acquire the Montana Power assets effective October 31 and interests in the Scott and Telford properties effective January 7, as well as $54 million for smaller acquisitions. Proceeds from the disposition of properties in 2000 amounted to $194 million, including $78 million for an 11.7 percent net royalty interest in the Weyburn unit and $41 million for a seven percent working interest in that unit.

On October 1, 2001, PanCanadian received approval from the Toronto Stock Exchange (TSE) for a normal course issuer bid program that allows the Company to purchase for cancellation up to 12.6 million common shares. The program commenced on October 3, 2001 and is in effect for a twelve-month period. The amounts and timing of purchases are at the Company's discretion and will be transacted at prevailing market prices on the TSE. As of February 19, 2002, the Company had purchased for cancellation 172,900 common shares at an average price of $41.69 per common share under the program.

Risk management assets and liabilities recorded on the balance sheet result from the application of mark-to-market accounting for the physical and financial derivative positions in the marketing business, representing primarily current year values. These assets and liabilities are managed strictly in accordance with the Company's prescribed risk limits, and all transactions are executed in accordance with the approved processes and controls set out in the risk management and credit policies and approved by the Company's Board. There were no new significant credit provisions taken in 2000 or 2001.

OUTLOOK

A detailed discussion of PanCanadian's outlook for 2002 will be provided in the information circular regarding the proposed merger of equals of the Company and Alberta Energy Company Ltd. The information circular will be distributed to shareholders in early March 2002. Shareholders will use the information to vote on the merger proposal at the shareholders' meeting expected to be conducted on April 4, 2002.

CONSOLIDATED STATEMENT OF INCOME

(unaudited) *($ millions, except per share amounts)*		Three Months Ended December 31 2001	Three Months Ended December 31 2000	Year Ended December 31 2001	Year Ended December 31 2000
REVENUES	*(note 3)*	**$ 1,662**	$ 2,599	**$ 10,098**	$ 7,327
EXPENSES	*(note 3)*				
Direct		**1,184**	1,683	**7,031**	4,651
Administrative		**24**	49	**157**	125
Interest on long-term debt		**37**	28	**98**	90
Depletion, depreciation and amortization		**261**	242	**856**	775
		1,506	2,002	**8,142**	5,641
INCOME BEFORE INCOME TAXES		**156**	597	**1,956**	1,686
PROVISION FOR INCOME TAXES	*(note 4)*				
Current		**42**	62	**508**	176
Future		**23**	191	**144**	471
		65	253	**652**	647
NET INCOME		**$ 91**	$ 344	**$ 1,304**	$ 1,039
DISTRIBUTIONS ON PREFERRED SECURITIES, NET OF TAX		**(1)**	(2)	**(4)**	(5)
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS		**$ 90**	$ 342	**$ 1,300**	$ 1,034
NET INCOME ATTRIBUTABLE PER COMMON SHARE					
BASIC	*(note 1)*	**$ 0.35**	$ 1.35	**$ 5.09**	$ 4.09
DILUTED	*(note 1)*	**$ 0.35**	$ 1.32	**$ 5.00**	$ 4.04
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING *(millions)*		**254.8**	254.1	**255.6**	252.8

CONSOLIDATED STATEMENT OF RETAINED INCOME

(unaudited) *($ millions)*		Year Ended December 31 2001	Year Ended December 31 2000
Retained income at beginning of year		**$ 3,721**	$ 2,788
Net income		**1,304**	1,039
Dividends		**(1,282)**	(101)
Distributions on preferred securities, net of tax		**(4)**	(5)
Other adjustments	*(note 5)*	**(50)**	-
Retained income at end of year		**$ 3,689**	$ 3,721

See selected notes to consolidated financial statements.

CONSOLIDATED STATEMENT OF CASH FLOWS

(unaudited) *($ millions)*		Three Months Ended December 31 2001	Three Months Ended December 31 2000	Year Ended December 31 2001	Year Ended December 31 2000
OPERATING ACTIVITIES					
Net income		$ **91**	$ 344	$ **1,304**	$ 1,039
Depletion, depreciation and amortization		**261**	242	**856**	775
Future income taxes	*(note 4)*	**23**	191	**144**	471
Other		**11**	7	**2**	18
Cash flow		**386**	784	**2,306**	2,303
Net change in deferred items		**(57)**	40	**(96)**	(16)
Net change in non-cash working capital		**105**	(98)	**564**	(58)
Cash from operating activities		**434**	726	**2,774**	2,229
FINANCING ACTIVITIES					
Issuance of short-term financing		**-**	469	**440**	469
Repayment of short-term financing		**(440)**	(219)	**(690)**	(219)
Issuance of long-term debt		**1,322**	-	**1,566**	76
Repayment of long-term debt		**(150)**	-	**(399)**	(136)
Issuance of common shares		**7**	32	**48**	86
Repurchase of common shares		**(7)**	-	**(7)**	(8)
Dividends on common shares	*(note 2)*	**(26)**	(25)	**(1,282)**	(101)
Distribution on preferred securities		**(1)**	(3)	**(7)**	(9)
Net change in non-cash working capital		**3**	2	**1**	-
		708	256	**(330)**	158
INVESTING ACTIVITIES					
Petroleum and natural gas properties		**(426)**	(288)	**(1,247)**	(994)
Plant, production and other equipment		**(169)**	(104)	**(524)**	(328)
Upstream		**(595)**	(392)	**(1,771)**	(1,322)
Midstream		**(60)**	(56)	**(175)**	(93)
		(655)	(448)	**(1,946)**	(1,415)
Net (acquisitions) dispositions		**(3)**	(656)	**136**	(808)
Net change in other assets		**31**	(112)	**25**	(140)
Net change in non-cash working capital		**118**	77	**88**	42
		(509)	(1,139)	**(1,697)**	(2,321)
FOREIGN EXCHANGE GAIN (LOSS) ON CASH HELD IN FOREIGN CURRENCY		**4**	(1)	**19**	(1)
INCREASE (DECREASE) IN CASH		**637**	(158)	**766**	65
CASH AT BEGINNING OF PERIOD		**326**	355	**197**	132
CASH AT END OF PERIOD		$ **963**	$ 197	$ **963**	$ 197
SUPPLEMENTARY DISCLOSURE OF CASH FLOW INFORMATION					
Interest paid		$ **15**	$ 30	$ **73**	$ 84
Income taxes paid		$ **7**	$ 4	$ **34**	$ 12

See selected notes to consolidated financial statements.

CONSOLIDATED BALANCE SHEET

(unaudited) *($ millions)*		As at December 31 2001	As at December 31 2000
ASSETS			
Current assets			
Cash		$ **963**	$ 197
Accounts receivable		**841**	1,313
Risk management assets	*(note 1)*	**414**	-
Inventories		**157**	118
		2,375	1,628
Property, plant and equipment, at cost		**14,751**	12,981
Less accumulated depletion, depreciation and amortization		**(6,580)**	(5,884)
		8,171	7,097
Deferred charges and other assets		**313**	317
		$ **10,859**	$ 9,042
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities			
Short-term financing		$ **-**	$ 250
Accounts payable and accrued liabilities		**990**	1,207
Income taxes payable	*(note 4)*	**656**	181
Risk management liabilities	*(note 1)*	**378**	-
Current portion of deferred credits and liabilities		**40**	73
Current portion of long-term debt		**160**	150
		2,224	1,861
Long-term debt		**2,118**	912
Deferred credits and liabilities		**419**	315
Future income taxes	*(note 4)*	**2,060**	1,925
Shareholders' equity			
Preferred securities		**126**	126
Common shares	*(note 6)*	**196**	148
Paid in surplus		**27**	34
Retained income	*(note 5)*	**3,689**	3,721
		4,038	4,029
		$ **10,859**	$ 9,042

See selected notes to consolidated financial statements.

PANCANADIAN ENERGY CORPORATION
SELECTED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Twelve months ended December 31, 2001
(unaudited)

The interim consolidated financial statements include the accounts of PanCanadian Energy Corporation and its subsidiaries (the "Company"), and are presented in accordance with Canadian generally accepted accounting principles. The interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements for the year ended December 31, 2000, except as described below. The disclosures provided below are incremental to those included with the annual consolidated financial statements. The interim consolidated financial statements should be read in conjunction with the consolidated financial statements and the notes thereto in the Company's annual report for the year ended December 31, 2000.

Note 1. CHANGES IN ACCOUNTING POLICIES

Net income attributable per common share

In 2001, the Company retroactively adopted the new Canadian Institute of Chartered Accountants' earnings per share standard. The new standard relates to the computation, presentation and disclosure of earnings per share. Under the new standard, the treasury stock method is used instead of the imputed earnings method to determine the dilutive effect of stock options and other dilutive instruments. Under the treasury stock method, proceeds from assumed exercise of in-the-money stock options are used to repurchase common shares at the prevailing market price. The effect on prior period diluted net income attributable per common share, which has been restated for this change, is immaterial.

In computing the diluted net income attributable per common share, 5.8 million shares were added to the weighted average number of common shares during the quarter ended December 31, 2001 (2000 – 5.8 million shares) and 6.0 million shares for the year ended December 31, 2001 (2000 – 4.4 million shares) for the dilutive effect of employee stock options and preferred securities. The distributions on preferred securities were added back to net income attributable to common shareholders in computing diluted per share amounts.

Risk management

Effective January 1, 2001, the Company adopted mark-to-market accounting for all the Company's financial and physical positions in the Marketing and Midstream business segment. This change in accounting policy was applied prospectively and the effect on current and prior period earnings is immaterial.

Note 2. CORPORATE REORGANIZATION

On February 13, 2001, Canadian Pacific Limited ("CPL") announced a reorganization whereby its 85 percent interest in PanCanadian Petroleum Limited would be distributed to CPL shareholders by a Plan of Arrangement. Following shareholder and court approvals, the Arrangement was implemented on October 1, 2001, and PanCanadian Petroleum Limited became a wholly owned subsidiary of the new public company, PanCanadian Energy Corporation. Effective January 1, 2002, these companies were amalgamated and continued under the name of PanCanadian Energy Corporation.

As part of the reorganization, the Company paid a Special Dividend of $1.18 billion ($4.60 per common share) on September 14, 2001. The amounts shown as dividends on the statements of consolidated retained income and cash flows include both the Special Dividend and the regular quarterly dividend.

PANCANADIAN ENERGY CORPORATION
SELECTED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)
Twelve months ended December 31, 2001
(unaudited)

Note 3. SEGMENTED INFORMATION

Statement of Income

($ millions)	Three Months Ended December 31		Year Ended December 31	
	2001	2000	2001	2000
Upstream				
Revenues				
Gas	$ **400**	$ 665	$ **2,380**	$ 1,622
Oil - Light/medium	**197**	243	**889**	1,044
Oil - Heavy	**24**	48	**133**	252
Field liquids	**26**	48	**137**	151
Processing and other income	**2**	9	**15**	21
Royalties and similar payments	**(59)**	(84)	**(303)**	(259)
	590	929	**3,251**	2,831
Expenses				
Direct				
Gas and related products	**51**	37	**181**	122
Oil - Light/medium	**41**	45	**179**	162
Oil - Heavy	**21**	22	**75**	73
Gas processing - royalty interest	**3**	3	**10**	10
	116	107	**445**	367
Administrative	**9**	22	**70**	65
Depletion, depreciation and amortization	**250**	237	**828**	753
	375	366	**1,343**	1,185
Upstream income	**215**	563	**1,908**	1,646
Marketing & Midstream				
Revenues				
Marketing	**1,512**	2,402	**9,849**	6,911
Midstream	**41**	96	**267**	314
	1,553	2,498	**10,116**	7,225
Expenses				
Direct				
Marketing	**1,492**	2,332	**9,673**	6,785
Midstream	**41**	77	**228**	229
	1,533	2,409	**9,901**	7,014
Administrative	**12**	27	**74**	60
Depreciation and amortization	**11**	5	**28**	22
	1,556	2,441	**10,003**	7,096
Marketing and Midstream income	**(3)**	57	**113**	129
Income before corporate activities	**212**	620	**2,021**	1,775
Interest and other revenues	**(16)**	5	**46**	1
Interest expense on long term debt	**(37)**	(28)	**(98)**	(90)
Corporate administrative expenses *	**(3)**	-	**(13)**	-
Income before income taxes	**156**	597	**1,956**	1,686
Provision for income taxes	**65**	253	**652**	647
Consolidated net income	$ **91**	$ 344	$ **1,304**	$ 1,039

* 2001 corporate administrative expenses include costs associated with the CPL reorganization in the amount of $3 million and $13 million for the quarter and year ended, respectively.

PANCANADIAN ENERGY CORPORATION
SELECTED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)
Twelve months ended December 31, 2001
(unaudited)

Note 3. SEGMENTED INFORMATION (continued)

Reconciliation of Segment Results to the Consolidated Income Statement

For the three months ended December 31, 2001 (*$ millions*)	Upstream	Marketing and Midstream	Corporate	Inter-segment Eliminations*	Consolidated Total
Revenues	**$ 590**	**$ 1,553**	**$ (16)**	**$ (465)**	**$ 1,662**
Expenses					
Direct	**116**	**1,533**	**-**	**(465)**	**1,184**
Administrative	**9**	**12**	**3**	**-**	**24**
Interest on long-term debt	**-**	**-**	**37**	**-**	**37**
Depletion, depreciation and amortization	**250**	**11**	**-**	**-**	**261**
Income before income taxes	**$ 215**	**$ (3)**	**$ (56)**	**$ -**	**$ 156**
For the three months ended December 31, 2000 (*$ millions*)					
Revenues	$ 929	$ 2,498	$ 5	$ (833)	$ 2,599
Expenses					
Direct	107	2,409	-	(833)	1,683
Administrative	22	27	-	-	49
Interest on long-term debt	-	-	28	-	28
Depletion, depreciation and amortization	237	5	-	-	242
Income before income taxes	$ 563	$ 57	$ (23)	$ -	$ 597

For the year ended December 31, 2001 (*$ millions*)	Upstream	Marketing and Midstream	Corporate	Inter-segment Eliminations*	Consolidated Total
Revenue	**$ 3,251**	**$ 10,116**	**$ 46**	**$ (3,315)**	**$ 10,098**
Expenses					
Direct	**445**	**9,901**	**-**	**(3,315)**	**7,031**
Administrative	**70**	**74**	**13**	**-**	**157**
Interest on long-term debt	**-**	**-**	**98**	**-**	**98**
Depletion, depreciation and amortization	**828**	**28**	**-**	**-**	**856**
Income before income taxes	**$ 1,908**	**$ 113**	**$ (65)**	**$ -**	**$ 1,956**
For the year ended December 31, 2000 (*$ millions*)					
Revenues	$ 2,831	$ 7,225	$ 1	$ (2,730)	$ 7,327
Expenses					
Direct	367	7,014	-	(2,730)	4,651
Administrative	65	60	-	-	125
Interest on long-term debt	-	-	90	-	90
Depletion, depreciation and amortization	753	22	-	-	775
Income before income taxes	$ 1,646	$ 129	$ (89)	$ -	$ 1,686

* Inter-segment eliminations represent the sales of natural gas, crude oil and NGL from the Upstream segment to the Marketing and Midstream segment.

Note 3. SEGMENTED INFORMATION (continued)

($ millions)	Three Months Ended December 31		Year Ended December 31	
	2001	2000	2001	2000
Additions to capital assets and goodwill, net				
Upstream	**$ 662**	$ 1,031	**$ 1,670**	$ 2,181
Marketing and midstream *	**46**	166	**155**	163
	$ 708	$ 1,197	**$ 1,825**	$ 2,344
Total identifiable assets				
Upstream			**$ 8,321**	$ 7,647
Marketing and midstream			**1,797**	1,806
Corporate and eliminations			**741**	(411)
			$ 10,859	$ 9,042

* 2000 Marketing and midstream additions included $7 million (quarter and year ended) for goodwill.

Note 4. INCOME TAXES

During 2001, the Company changed the method of classifying current and future income taxes with respect to consolidated partnerships that have a later year-end than the Company. Under the revised method, the current income tax provision includes amounts payable or recoverable in respect of the partnerships' income included in the consolidated financial statements. Previously, these amounts were included in current taxes when payable.

This change had no effect on total tax expense, net income or cash from operating activities, but reduced cash flow by $24 million for the quarter ended December 31, 2001 (2000 - $60 million) and $295 million for the year ended December 31, 2001 (2000 - $170 million).

Note 5. RELATED-PARTY TRANSACTIONS

In the second quarter of 2001, the Company recorded a $50 million provision relating to a previously contracted purchase price adjustment in respect of $200 million of capital losses acquired from a subsidiary of CPL (the majority shareholder of the Company prior to the corporate reorganization as described in Note 2) in 1997. The purchase price adjustment, which was contingent on certain economic events, was recorded as a charge to retained income and paid during the fourth quarter.

Note 6. COMMON SHARES

The Company's authorized share capital consists of an unlimited number of common shares.

Issued and Outstanding	Number of Shares		*($ millions)*
Balance at January 1, 2001	254,831,392	$	148
Issued under stock option plan	1,912,480		48
Repurchase of common shares	(172,900)		-
Adjustments due to corporate reorganization	(1,631,121)		-
Balance at December 31, 2001	254,939,851	$	196

The Company has a stock based compensation plan (PanCanadian plan) that allows certain key employees to purchase common shares of the Company. Options granted under the plan are generally fully exercisable after three years and expire five years after the grant date. Options granted under previous plans expire 10 years from the date the options were granted. Option exercise prices approximate the market price for the common shares on the date the options are issued.

As part of the Corporate reorganization, as described in Note 2, CPL stock options were replaced with stock options granted by PanCanadian (CPL replacement plan) in a manner that was consistent with the provisions of the CPL stock option plan. Under CPL's stock option plan, options were granted to certain key employees to purchase common shares of CPL at a price not less than the market value of the shares at the grant date. The options expire 10 years after the grant date and, as a result of the reorganization are all exercisable.

Effective October 31, 2001, the Company adopted a directors stock option plan. Under the terms of the plan, new non-employee directors are given an initial grant of 8,000 options to purchase common shares of the Company. Thereafter, there is an annual grant of 4,000 options to each non-employee director. These options, which expire five years after the grant date, are 100% exercisable on the earlier of the next annual general meeting following the grant date and the first anniversary of the grant date.

Note 6. COMMON SHARES (continued)

Continuity of stock options	Number of Options		Weighted Average Exercise Price
Outstanding at January 1, 2001	6,953,850	$	22.61
Granted under PanCanadian plan	4,531,350		48.08
Granted under CPL replacement plan	1,502,079		22.83
Granted under Directors plan	80,000		39.60
Exercised	(1,912,480)		25.82
Cancelled	(643,621)		37.04
Outstanding at December 31, 2001	10,511,178	$	32.31
Exercisable at December 31, 2001	3,241,753	$	22.92

Note 7. FINANCIAL INSTRUMENTS

Unrecognized gains (losses) on risk management activities:

($ millions)		**December 31, 2001**
Natural gas	$	**145**
Crude oil		**12**
Foreign currency		**(187)**
Interest rates		**9**
Preferred securities		**8**
	$	**(13)**

Information with respect to crude oil, currency, and interest rate hedge contracts at December 31, 2000, is disclosed in Note 13 to the 2000 annual consolidated financial statements. No new material hedging contracts have been entered into subsequent to this disclosure except for the following:

- 28 million cubic feet per day of natural gas sold forward from November 2001 to October 2002 and 77 million cubic feet per day sold forward from December 2001 to October 2002. As at December 31, 2001, the Company sold forward a total of 205 million cubic feet per day of natural gas at an AECO equivalent price of $5.97 per thousand cubic feet.

- 15 thousand barrels per day of crude oil sold forward from January 2002 to March 2002 at an average WTI price of US$23.78 per barrel.

- 10 thousand barrels per day of crude oil sold forward from April 2002 to June 2002 at an average WTI price of US$23.57 per barrel.

In addition, the Company sold call options on 113,600 cubic feet per day of AECO natural gas from November 2001 to October 2002 at an average strike price of $6.05 per thousand cubic feet.

Note 8. SUBSEQUENT EVENT

On January 27, 2002, PanCanadian and Alberta Energy Company Ltd. ("AEC") announced plans to merge their companies to create EnCana Corporation. The proposed merger is to be accomplished through a plan of arrangement (the "Merger Arrangement") under the *Business Corporations Act* (Alberta). The Merger Arrangement includes a common share exchange, pursuant to which common shareholders of AEC would receive 1.472 common shares of PanCanadian for each common share of AEC held. On completion of the Merger Arrangement, PanCanadian shareholders would own approximately 54% and AEC shareholders would own approximately 46% of PanCanadian, which would change its name to EnCana Corporation. AEC would become a wholly-owned subsidiary of EnCana Corporation. Subject to obtaining necessary approvals of the shareholders of both companies, the Court of Queen's Bench of Alberta and appropriate regulatory and other authorities, the Merger Arrangement is anticipated to close early in April 2002.

Note 9. RECLASSIFICATION

Certain information provided for prior periods has been reclassified to conform to the presentation adopted in 2001.

Note 10. CONSOLIDATED FINANCIAL RATIOS

The following ratios, based on the consolidated financial statements, are provided in connection with the Company's continuous offering of medium term notes and debt securities and are for the twelve-month period then ended.

	December 31	
	2001	2000
Interest coverage on long-term debt:		
Net income excluding carrying charges of preferred securities	**21.0**	19.7
Net income including carrying charges of preferred securities	**19.6**	18.0
Cash flow excluding carrying charges of preferred securities	**29.7**	28.4
Cash flow including carrying charges of preferred securities	**27.7**	26.0

PanCanadian Energy Corporation
Wesley Twiss
Executive Vice President and
Chief Financial Officer

Shares listed
Toronto Stock Exchange:
PCE
New York Stock Exchange:
PCX

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News Release

PanCanadian declares March dividend payment

Calgary, February 20, 2002 — The Board of Directors of PanCanadian Energy Corporation today declared a dividend of ten cents (10 cents) per share payable Friday, March 29, 2002, to shareholders of record as of Friday, March 15, 2002.

PanCanadian is a premier North American energy company active in the exploration, development, production and marketing of natural gas, crude oil and natural gas liquids. The company's core areas are the Western Basin including land in Western Canada and the United States, the East Coast of Canada, the Gulf of Mexico and the United Kingdom. These areas are complemented by focused international exploration programs.

On January 27, 2002, PanCanadian and Alberta Energy Company Ltd. announced that their Boards of Directors had unanimously agreed to merge the two companies. The combined organization will be a Canadian-headquartered, world-class independent oil and gas company with an anticipated enterprise value of more than C$27 billion. Upon completion of the transaction, expected in early April, the combined organization will operate under the name EnCana Corporation. The proposed merger is subject to shareholder, Court of Queen's Bench of Alberta and regulatory approvals.

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PanCanadian Energy Corporation
Wesley Twiss
Executive Vice President & Chief Financial Officer

Shares Listed
Toronto Stock Exchange:
PCE
New York Stock Exchange:
PCX

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PanCanadian Energy Corporation
(Registrant)

Date: February 20, 2002

By: [signature]
Name: LAURIE J. SCHULLER
Title: General Counsel and Corporate Secretary

Exhibits Index

The following is a list of Exhibits included as part of this Report on Form 6-K.