PAGE
PETROLEUM LTD.

1983 Annual Report

PAGE

PETROLEUM LTD.

THE COMPANY

Page Petroleum Ltd., an Alberta Corporation, was organized in 1971 as the successor to two small Canadian oil and gas companies. Page engages directly and through its subsidiaries in the exploration for and development of oil and gas in Canada, the United States and the United Kingdom. Its proved reserves are located primarily in the provinces of Saskatchewan and Alberta in Canada, and the states of Texas and Utah in the United States.

As of March 31, 1984, Page's 3,584,250 outstanding common shares were held by 1,724 registered shareholders. The shares, which are listed on the Toronto and American Stock Exchanges, were held 65% in the U.S. and 35% in Canada.

THE REPORT

This Annual Report contains Page Petroleum Ltd.'s Form 10-K Annual Report to the Securities and Exchange Commission in Washington, D.C. together with additional supplemental information. By incorporation of its Form 10-K in this report the Company is able to provide comprehensive information to the shareholders at a nominal cost.

CONTENTS

METRIC (SI) CONVERSION TABLE

To Convert From	To	Multiply by
Acre(ac)	hectare(ha)	0.404 69
Foot(ft)	metre(m)	0.304 80
Mile(mi)	kilometre(km)	1.609 00
Barrel(bbl)	cubic metre(m^3)	0.158 91
Thousand Cubic Feet (mcf)	cubic metre(m^3)	28.173 99

FINANCIAL AND OPERATING HIGHLIGHTS (1)

(Unless otherwise indicated, all dollar amounts in this report are expressed in thousands of Canadian dollars)

	1983	1982	Increase (Decrease) Per Cent
FINANCIAL			
Gross income	**$ 48,829**	$ 51,480	(5.1)
Sales of oil and gas	**$ 40,067**	$ 42,530	(5.8)
Pipeline operating revenue	**$ 7,277**	$ 7,589	(4.1)
Investment and other income	**$ 874**	$ 174	402.3
Total expenses	**$ 73,806**	$100,889	(26.8)
(Loss) from continuing operations	**$ (27,545)**	$ (49,394)	(44.2)
(Loss) from discontinued operations	**$ —**	$ (919)	—
Net (loss) applicable to common shares	**$ (27,545)**	$ (50,313)	(45.3)
Per common share	**$ (7.58)**	$ (13.89)	(45.4)
Funds generated from operations	**$ 10,630**	$ 3,442	208.8
Additions to property, plant and equipment	**$ 7,497**	$ 49,796	(84.9)
Working capital (deficiency)	**$ (11,831)**	$ (22,347)	(47.1)
Long-term debt	**$143,305**	$147,883	(3.1)
Shareholders' equity (deficit)	**$ (62,185)**	$ (35,928)	73.1
Common shares outstanding	**3,631,750**	3,631,750	—
Number of shareholders	**1,739**	1,895	(8.2)
OPERATIONS			
LAND HOLDINGS			
Gross acres	**2,319,985**	3,909,009	(40.7)
Net acres	**588,316**	996,444	(41.0)
DRILLING ACTIVITY			
Gross wells drilled	**26.0**	122.0	(78.7)
Net wells drilled	**17.7**	82.9	(78.6)
Net wells productive	**17.0**	79.4	(78.6)
Net wells dry	**0.7**	3.5	(80.0)
PRODUCTION — net			
Crude oil and liquids - barrels	**856,000**	958,000	(10.6)
Per day	**2,348**	2,627	(10.6)
Natural gas - mcf	**2,477,000**	2,941,000	(15.8)
Per day	**6,786**	8,058	(15.8)
Reserves - net proven			
Crude oil - barrels	**9,777,000**	10,623,000	(8.0)
Natural gas - mcf	**28,625,000**	23,284,000	22.9

(1) The financial statements included herein have been prepared in accordance with generally accepted accounting principles in the United States and have been restated from Canadian generally accepted accounting principles.

RANGE OF MARKET PRICES ON COMMON SHARES

	Year	1st Quarter High	1st Quarter Low	2nd Quarter High	2nd Quarter Low	3rd Quarter High	3rd Quarter Low	4th Quarter High	4th Quarter Low	Annual Share Volume
The Toronto	1982	16.00	7.25	14.50	7.00	9.25	5.75	10.00	6.50	446,711
Stock Exchange	1983	9.00	5.25	5.87	3.75	5.62	4.15	4.30	2.60	465,962
American (U.S.$)	1982	13.62	5.62	11.75	5.37	7.25	4.25	9.37	5.37	2,981,500
Stock Exchange (U.S.$)	1983	7.25	4.00	4.87	2.62	4.87	3.37	3.75	2.00	2,467,300

LETTER TO THE SHAREHOLDERS

Page is in the midst of a financial restructuring intended to provide relief from cash pressures and necessary time in which the Company can develop the means to pay its debts. The future of the Company, and the extent to which its shareholders will suffer dilution of their interests, will be determined by the Company's efforts in that direction.

In 1983, Page had to recognize asset write-downs in the U.S. and consequent losses which have further substantially increased Page's negative net worth. Nonetheless, cash flow was positive, debt was reduced, and the working capital position was improved. There were operating achievements as well. Within the Dodsland field of Saskatchewan 300 thousand barrels of oil reserves and 8.8 billion cubic feet of gas reserves were added through a drilling program and a casinghead gas market tie-in project. Construction was commenced on a pilot waterflood in the Dodsland field and a 10,200 foot Prairie du Chien test well was spudded in Michigan at year-end. These were accomplished on a $7.9 million capital spending budget. In late 1983, a significant step was taken to address the Company's financial problems. Mr. Donald D. McCuaig was installed by the Board of Directors as Chairman of the Board and Chief Executive Officer, with Mr. Lawton L. Clark remaining as President of Page. Mr. McCuaig's experience in assisting financially troubled companies has been especially important in the restructuring of Page's indebtedness which is now partly completed.

The Company has two opportunities of significant potential; the Dodsland field waterflood project and the exploration of U.S. acreage, especially in Michigan. Both will require the cooperation of Page's lending bank. The Company must also reduce the cash interest payments on its public debentures to secure continued bank cooperation and move ahead.

Accordingly, Page is currently offering to exchange for its $25 million (U.S.) Convertible Subordinated Debentures due 2000, a new Senior Subordinated Convertible Note due 1989, together with stock and warrants. The new Note would give the Company the option to pay interest on its public debt in Common Shares rather than cash. Further, the Company has concluded an agreement with its bank that reschedules $116 million of bank debt, including $30 million which will not require the payment of interest in cash until 1989. It is essential under the debt restructuring agreement that 80% or more of the outstanding debentures be exchanged. The cash interest savings on the restructured bank debt and the debenture exchange (if successful) should assist the Company in having sufficient cash flow to meet its obligations over the next three years so that it will not be faced with a default under any of its long-term indebtedness.

Net oil and gas revenues for the year ended December 31, 1983, were $40.1 million, a decrease of 5.8% from $42.5 million in 1982. Funds generated from operations amounted to $10.6 million compared to $3.4 million the previous year. The net loss applicable to common shares was $27.5 million ($7.58 per common share) as compared to the 1982 loss of $50.3 million ($13.89 per common share). The year's loss resulted in a deficit in shareholders' equity at December 31, 1983, of $62.2 million. Interest, bank charges, depreciation, depletion, amortization and a $20.4 million write-down of capital costs of oil and gas properties were the significant contributors to the substantial loss. Interest and bank charges decreased by $4.6 million to $18.4 million. Depreciation, depletion and amortization decreased by $1.8 million to $15.6 million. The write-down of capital costs was due to decreases in proved reserves and the decreased value of unproved land inventories in the United States and Australia.

Long-term debt, including the current portion at December 31, 1983, was $154.5 million compared to $164.8 million at year-end 1982. Working

capital deficit at year-end was $11.8 million compared to $22.3 million at December 31, 1982. The year-end 1983 deficit includes a $4.8 million note payable to KEP Resources ("KEP") as the remaining amount due for the 1981 purchase of oil and gas leases in the state of Michigan. On March 30, 1984, KEP agreed to extend the due date of the note one year to July 10, 1985. Capital expenditures during 1983 were $7.5 million compared to $49.8 million during 1982.

At year-end, the Company's proved net oil reserves were estimated to be 9.8 million barrels, representing a 7½% decrease from reserves of 10.6 million barrels at December 31, 1982. Proven net gas reserves increased 23% to 28.6 billion cubic feet from 23.3 billion cubic feet. This increase was almost entirely due to the inclusion, for the first time, of Dodsland field gas reserves. Prior to 1983 there were no facilities to market this gas. Using a 10% discount factor and no future price escalations, the cash flow from the Company's proven oil and gas reserves was determined to have a present worth of $109 million compared to $126 million at the end of 1982.

In February 1984, Page commenced injecting water on two pilot waterfloods involving 26 wells in the Dodsland field. This $2 million pilot project follows over a year of feasibility studies. An engineering consultant's final report concluded that a full scale waterflood of 224 of Page's 397 net wells would have a high probability of increasing the Company's recoverable oil reserves by some 14 million barrels at an expected cost of approximately $25 million. Most of the remaining 173 wells are also considered to be prospects for waterflooding. It is hoped that by late this year results will be sufficiently conclusive to proceed with the planning and financing of a full scale waterflood in this field.

In the U.S., Page has continued to conduct seismic and subsurface mapping on its large Michigan holdings. Drilling was started on Page's Big Lake Prospect in Osceola County in late December. The well, BWAB-Page Clark-Rose #1 (Page 43%), was drilled to a total depth of 10,216 feet and plugged back to 5,629 feet to evaluate a number of prospective zones from 4,242 feet to 4,983 feet. Log analysis indicated the possibility of more than 50 feet of net pay which could result in the production of oil and/or gas. Page and partners will not be able to conduct production testing until late April because of spring road bans posted by the various counties. If production testing is satisfactory, it is possible that development drilling could commence by early summer.

Although Page's operating results continued to be disappointing through 1983, there is sufficient future opportunity available from Dodsland and the U.S. land inventory to significantly change the fortunes of the Company. As indicated, the bank restructuring and a successful exchange offer can give Page the time and relief from cash pressures necessary to pursue these opportunities. Management effort in 1984 will be so directed.

Donald D. McCuaig
Chairman of the Board

Lawton L. Clark
President

April 6, 1984

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PETROLEUM LTD.

FIVE YEAR STATISTICAL SUMMARY

FINANCIAL (1)	1983	1982	1981	1980	1979
INCOME					
Net oil and gas sales	**$ 40,067**	$ 42,530	$ 29,482	$ 21,926	$ 11,606
Investment and other income	**874**	174	1,007	579	68
Pipeline operating revenue	**7,277**	7,589	–	–	–
Well servicing and rig lease revenue	**611**	1,187	659	–	–
GROSS INCOME	**48,829**	51,480	31,148	22,505	11,674
Production expense	**7,957**	9,416	8,164	5,797	3,429
Pipeline operating costs	**5,939**	6,099	–	–	–
General and administrative	**3,235**	3,770	4,005	2,613	1,413
Federal production taxes	**2,392**	1,865	2,977	1,122	–
Interest and bank charges	**18,414**	23,015	13,800	5,513	2,355
Well servicing and other	**(378)**	99	533	–	–
Depreciation, depletion and amortization	**15,650**	17,497	8,153	6,671	3,869
Exchange loss (gain)	**207**	4,171	(490)	610	–
Write-down of capital costs in excess of net realizable value	**20,390**	34,957	–	–	–
Loss from discontinued operations	**—**	919	1,022	1,775	406
Current income taxes	**(397)**	(1,230)	(451)	(195)	(178)
Deferred income taxes	**2,965**	1,215	(316)	368	413
NET EARNINGS (LOSS)	**(27,545)**	(50,313)	(6,249)	(1,769)	(33)
Preferred dividends	**—**	–	–	140	445
Net earnings (loss) applicable to common shares	**(27,545)**	(50,313)	(6,249)	(1,909)	(478)
Per common share	**(7.58)**	(13.89)	(1.76)	(0.54)	(0.18)
FUNDS GENERATED FROM OPERATIONS	**10,630**	3,442	2,636	6,295	4,533
BALANCE SHEET					
Working capital (deficiency)	**(11,831)**	(22,347)	(19,575)	(1,089)	(744)
Investments and advances	**—**	35	4,895	6,560	3,620
Property and equipment	**97,480**	135,613	154,402	75,444	45,074
Other assets	**1,200**	2,248	2,993	3,284	1,539
CAPITAL EMPLOYED	**86,849**	115,549	142,715	84,199	49,489
Deduct: Long-term debt	**143,305**	147,883	127,035	62,892	26,645
Deferred income taxes	**5,654**	2,689	1,474	1,790	1,422
Minority interest	**75**	905	26	–	–
Shareholders' equity	**(62,185)**	(35,928)	14,180	19,517	21,422
Common shares outstanding	**3,631,750**	3,631,750	3,594,250	3,492,750	2,960,868
CAPITAL EXPENDITURES					
Exploration and development	**7,065**	36,298	75,956	38,054	25,462
Pipeline facilities	**195**	7,717	8,052	–	–
Sundry equipment	**237**	5,781	1,847	351	2,397
	7,497	49,796	85,855	38,405	27,859
OPERATIONS					
LAND HOLDINGS (working interest)					
Gross acreage held (in thousands)	**2,320**	3,909	115,200	5,233	1,537
North America - net	**568**	802	1,011	829	360
International - net	**20**	194	1,028	442	–
Total net acreage	**588**	996	2,039	1,271	360
DRILLING ACTIVITY					
Gross wells drilled	**26.0**	122.0	156.0	147.0	146.0
Net wells drilled	**17.7**	82.9	103.7	126.0	117.3
Productive	**17.0**	79.4	97.5	116.4	111.1
Dry	**0.7**	3.5	6.2	9.6	6.2
PRODUCTION - net					
Crude oil and liquids - barrels	**856,000**	958,000	977,000	914,000	656,000
Average daily, barrels	**2,348**	2,627	2,677	2,504	1,797
Natural gas - mcf	**2,477,000**	2,941,000	1,359,000	703,000	829,000
Average daily, mcf	**6,786**	8,058	3,723	1,926	2,271
NET RESERVES - proven					
Crude oil - thousand barrels	**9,777**	10,623	18,517	17,883	13,375
Natural gas - mmcf	**28,625**	23,284	36,529	15,153	12,091

(1) The financial statements included herein have been prepared in accordance with generally accepted accounting principles in the United States and have been restated from Canadian generally accepted accounting principles.

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended **DECEMBER 31, 1983** Commission file number **1-7888**

PAGE PETROLEUM LTD.

(Exact name of registrant as specified in its charter)

Province of Alberta, Canada	None
(State or other jurisdiction of incorporated or organization)	(I.R.S. Employer Identification No.)
1000, 635 Eighth Avenue S.W., Calgary, Alberta, Canada	T2P 3M3
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code **(403) 269-8221**

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Shares Without Nominal or Par Value	American Stock Exchange The Toronto Stock Exchange
10% Convertible Subordinated Debentures due 2000	American Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes ✓ No _____

The approximate aggregate market value of the voting stock held by non-affiliates of the registrant as of March 15, 1984 was $7,162,420 (Canadian).

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at March 15, 1984
Common Shares Without Nominal or Par Value	3,584,250 Shares

DOCUMENTS INCORPORATED BY REFERENCE

Certain portions of the registrant's Proxy Statement and Information Circular relating to its Annual General Meeting of Shareholders scheduled to be held May 23, 1984 are incorporated by reference into Part III of this Report.

INDEX TO ANNUAL REPORT
ON FORM 10-K
YEAR ENDED DECEMBER 31, 1983

The information called for by Items 10, 11, 12 and 13 of Form 10-K to the extent not included in Part I of this Report, is incorporated herein by reference to such information to be included under the captions "Proposal on Election of Directors" and "Remuneration of Management and Management Contracts" in the registrant's 1984 Proxy Statement and Information Circular.

Exchange Rates

Unless otherwise indicated, all dollar amounts in this report are expressed in Canadian dollars. The following table sets forth, for each of the years indicated, information with respect to the exchange rate of the Canadian dollar into United States currency:

Rate (1)	1979	1980	1981	1982	1983
December 31	$0.8558	$0.8371	$0.8429	$0.8132	$0.8035
Average (2)	0.8543	0.8546	0.8338	0.8088	0.8108
High	0.8771	0.8754	0.8499	0.8430	0.8201
Low	0.8326	0.8258	0.8048	0.7691	0.7993

(1) The rate of exchange in this table means the noon buying rate in New York City for cable transfers in Canadian dollars, as certified for customs purposes by the Federal Reserve Bank of New York. On March 15, 1984 the noon buying rate for $1.00 Canadian was $0.7852 U.S.

(2) The average of the exchange rates on the last business day of each month during the year.

PART I

ITEM 1 - BUSINESS

Page Petroleum Ltd., an Alberta corporation, was organized in 1971 as the successor to two small Canadian oil and gas companies. As used herein, the terms "Company" and "Page" refer collectively to Page Petroleum Ltd. and its subsidiaries, unless the context otherwise indicates. Page's principal executive offices are located at 1000, 635 - 8th Avenue S.W., Calgary, Alberta, Canada T2P 3M3, Telephone (403) 269-8221.

The Company engages directly and through subsidiaries in the exploration for and development of oil and gas in North America, the United Kingdom and Egypt. Its proved reserves are located primarily in the provinces of Saskatchewan and Alberta in Canada, and in the states of Utah and Texas in the United States.

The Company is also involved in a well servicing operation through R.D.R. Well Servicing Ltd. (a 75% owned subsidiary) and in drilling rig leasing through Springwest-Page Petroleums N.L. (a 74% owned subsidiary) in Australia. In addition, the Company is engaged in natural gas transmission through its 50% partnership interest in Trans-Pan Pipeline Company ("Trans-Pan").

Note 11 of the Notes to Consoldated Financial Statements appearing in Item 8 of this Report, sets forth for the years 1983, 1982, and 1981 the income, operating earnings and identifiable assets attributable to the business segments and geographic regions in which the Company has operations.

OIL AND GAS EXPLORATION AND PRODUCTION

The Company's principal business continues to be exploring for, developing and producing oil and gas. Approximately 83% of the Company's revenues in 1982 and 1983 were derived from oil and gas production. The Company's exploration activities in the United States have gradually expanded and currently include operations in fourteen states. The Company also has exploration interests in Canada, Egypt and the United Kingdom.

The Company's oil and gas operations consist of geological and geophysical evaluation of prospective oil and gas properties, the acquisition of oil and gas leases or other interests in exploratory prospects, the drilling of exploratory test wells on such properties, the development and operation of properties for the production of oil and gas and the transmission and processing of natural gas. The Company acts both as operator of wells and prospects and as a participant in wells and prospects operated by other oil and gas companies.

With some exceptions in the Dodsland and Buffalo Coulee areas of west central Saskatchewan, where the Company has generally retained the entire working interests, the Company conducts most of its operations through joint ventures with other independent and major oil and gas companies.

Competition and Markets

The oil and gas industry is highly competitive in all of its phases, with competition for favorable oil and gas drilling rights being particularly intense. The Company believes that price is the primary determinant in the acquisition of favorable properties. The Company competes with major oil companies and independent operators, many of which have substantially greater technical and financial resources than the Company. Many of such companies not only explore for and produce oil and gas, but also carry on refining and marketing operations.

The availability of a ready market for oil and gas, and the price obtained therefor, depend on numerous factors, including the proximity of the wells to adequate transmission facilities and the effects of governmental regulation on production, transportation, marketing and pricing.

The Company sells most of its production to oil and gas refiners and processors. Imperial Oil Ltd. is the only non-affiliated purchaser which accounted for more than 10% (i.e., 42.9%) of the Company's consolidated net revenues for 1983. Trans-Pan, an associated company, made purchases from the Company aggregating

12.2% of the Company's consolidated net revenues and presently delivers all of its pipeline products to Diamond Shamrock Corporation under a long-term supply contract.

The oil and gas industry competes with other industries in supplying customers' energy requirements.

Regulation and Taxation

United States

Government regulations in the United States affect the prices received by producers of oil and gas and have a direct impact on the industry-wide level of drilling activity and on the Company's oil and gas operations. The types, adequacy of supply and price of energy sources continue to receive extensive attention from legislative, executive and regulatory authorities, which may lead to additional legislation and regulation. It is impossible to predict what effect any such legislation would have on the oil and gas industry. Substantially all of the Company's oil and gas production in the United States is from properties in states in which production is regulated or limited by state production and conservation authorities.

The Crude Oil Windfall Profit Tax Act of 1980 (the "Windfall Profit Tax Act"), as amended, imposes an excise tax on the production of domestic crude oil, measured by the difference between the sale price for such oil at the wellhead and certain specified base price levels. Due to the nature of the Company's oil production and the fact that the Company qualifies as an "independent producer" (a producer who does not engage in refining significant quantities of crude oil and does not make significant retail sales), the impact of the Windfall Profit Tax Act on the Company is minimal. Windfall profit taxes attributable to the Company's 1983 operations amounted to $110,000. Assuming currently forecasted operations, windfall profit tax payable by the Company will decline in future years, due in part to future reductions in the tax rate. The tax imposed under the Windfall Profit Tax Act is to be phased out over a 33-month period which will begin on the date when net revenues from the tax reach $227.3 billion (U.S.), but in no event before January 1988 or after January 1991.

The sale of natural gas is subject to governmental regulation of production, transportation and pricing. Generally, the regulatory agency in the state where a producing gas well is located supervises production activities and the transportation of gas sold intrastate. Certain states in which the Company operates control production through regulations establishing the spacing of wells, limiting the number of days in a given month during which a well can produce, or otherwise limiting the rate of allowable production.

The Federal Energy Regulatory Commission regulates the interstate transportation of gas and the price of intrastate as well as interstate gas under the Natural Gas Policy Act of 1978 (the "NGPA"). Under the NGPA, there are established various categories and corresponding maximum prices for every "first sale" of natural gas produced in the United States. Factors considered in determining categories are the location of a well, the date when drilling began and was completed, the surface distance from existing production, the depth at which production is established, whether the well is onshore or offshore, the date of commencement or renewal of any underlying gas sales agreement, the date of commitment of the underlying gas reserves to interstate commerce, and the rate of productivity. The NGPA permits the states to set prices for intrastate sales of natural gas which are lower than those established under the NGPA, and several states have done so (but not Texas and Utah, the states in which the Company's gas reserves are principally located). In addition, none of the NGPA maximum prices may be collected unless the Company has the contractual authority to receive such prices and has made all required federal filings and obtained any necessary well category determinations.

The NGPA provides that the ceiling prices for certain categories of gas will expire on January 1, 1985, subject to reimposition by the President or Congress for an additional 18-month period beginning between July 1, 1985 and June 30, 1987. Such price deregulation will primarily relate to specified categories of "new natural gas" (natural gas from a reservoir from which natural gas was not produced in commercial quantities before April, 1977); deregulation is not generally provided for gas from older wells. Substantially all of the Company's natural gas reserves qualify as "new natural gas".

The Company's United States oil and gas operations, particularly its ability to finance exploration and drilling activities through direct participation programs, are subject to certain federal income tax laws, including provisions of the Internal Revenue Code of 1954; however, due to loss carryforwards and other available deductions, the Company is not expected to be liable for United States income tax in the current and next several fiscal years.

The Company's United States oil and gas activities are subject to various federal and state laws and regulations governing safety, environmental quality and pollution control. The Company believes that it complies with all such legislation and regulations affecting its operations. To date, compliance has not materially affected the capital expenditures, earnings or competitive position of the Company, although these measures may in some instances add to the cost of operations and in others may operate to reduce activity and production. Further legislation or regulations may be reasonably anticipated and the effect thereof on operations cannot be predicted.

Canada

Government regulations in Canada affect the prices received by producers of oil and natural gas as well as impact the netbacks realized through various forms of production taxes. The types, adequacy of supply and price of energy sources are receiving extensive attention by legislative and regulatory authorities, which may lead to additional legislation and regulation. The impact of any future federal or provincial legislation or regulation on the oil and gas industry is difficult to predict. Federal and provincial production and income tax legislation and regulation, in addition to regulations relating to the calculation of royalties on petroleum and natural gas rights leased from provincial governments are subject to change and the timing and impact of such changes are difficult to anticipate.

The National Energy Program (the "NEP") introduced on October 28, 1980, together with the June 1982 Update of NEP (the "Update") and various incidental pieces of federal legislation have resulted in an energy package for Canada that includes oil and gas price regimes, fiscal measures, expenditure programs, incentive programs and direct federal action to achieve the announced goals of energy security, opportunity and fairness. One of the stated purposes of the NEP is to increase the Canadian ownership and control of the oil and natural gas industry. To this end, substantial incentives are provided to qualified Canadian owned and controlled enterprises carrying on oil and natural gas exploration and development in Canada. The government of Alberta administers and makes these incentive payments in respect of activity in Alberta. The principal factor influencing the level of incentive payments for oil and natural gas exploration and development made to a Canadian controlled enterprise is the Canadian Ownership Rate ("COR") of such enterprise. As the Company is not Canadian controlled it does not, therefore, qualify for any level of the direct incentive payments to encourage the oil and natural gas exploration and development in Canada which are available under the Petroleum Incentive Program Act and regulations made thereunder.

The federal government, after a long series of negotiations, entered into energy pricing and revenue sharing (taxation) agreements with the provinces of Saskatchewan and Alberta. These agreements were entered into on October 26, 1981 (Saskatchewan) and September 1, 1981 (Alberta) and were intended to be in force until 1986. Under these agreements, the NEP and the Update, oil and natural gas revenues were divided among the federal government (in the form of Petroleum and Gas Revenue Tax, Incremental Oil Revenue Tax ("IORT"), Petroleum Incentive Program grants and federal income taxes), the provincial governments (in the form of royalties on production from crown petroleum and natural gas leases, taxes on production from freehold leases, various incentive schemes, tax rebates and provincial income taxes) and the producer in the form of producer netbacks (or the amount left over after operating expenses, royalties and the various taxes).

During 1982, the people of Saskatchewan elected a new provincial government which has implemented a variety of royalty and oil production designation changes that have substantially increased the producer netbacks on production in that province. Reduced crown royalty rates, the replacement of the Saskatchewan Oil Well Income Tax Act with the Freehold Oil and Gas Production Tax Act, and the designation of royalty

exempt periods on certain types of wells drilled between certain dates have all contributed to an improved operating environment in that province, in which the Company conducts the majority of its Canadian operations.

During 1983, the federal government reclassified certain "old oil" production in Alberta and Saskatchewan to qualify for the New Oil Reference Price (calculated with reference to the average cost of oil imported into Canada at Montreal) effective July 1, 1983 having a significant beneficial effect on the Company's Saskatchewan oil revenue in 1983. In addition, the federal government suspended the IORT on the incremental revenue earned by producers of "old oil" through May 31, 1984 and, as indicated in the federal government budget of February 15, 1984, IORT will be suspended through May 31, 1985.

The prices of oil and gas exported from Canada or sold interprovincially are regulated by the National Energy Board pursuant to the Petroleum Administration Act. Such Board also regulates the amount of natural gas that may be exported from Canada. Although the Company does not directly export, nor has it sought to export, any of its Canadian oil and gas production, it is affected by restrictive export policies of the National Energy Board which currently adversely affect the production of gas in Alberta. The provinces of Alberta and Saskatchewan have adopted legislation which regulates the prices to be paid for oil and gas produced within those provinces and the amount of oil and gas that may be shipped out of those provinces. The pricing is currently subject to an agreement under the NEP and Update, whereby the pricing of oil and gas in Canada was to be fixed until 1986. The oil and gas price projections utilized in the agreement assumed continually increasing world oil and gas prices, which have not materialized. Subsequent changes to oil pricing regulations have allowed the average price per barrel of oil to increase by redefining certain categories of low priced oil into a higher price category.

The Foreign Investment Review Act (Canada) requires the approval of federal authorities for the establishment of new businesses or the acquisition of existing businesses in Canada by non-eligible persons, which are essentially non-residents and non-resident controlled corporations. The Company is presumed to be a non-resident controlled corporation with the meaning of such Act and, accordingly, is required to obtain such consent prior to completing the acquisition or establishment of any Canadian business. Such consent requires a determination by the federal authorities that the establishment of a new business or the acquisition of existing businesses is, or is likely to be, "of significant benefit to Canada." The Foreign Investment Review Act could restrict or inhibit future expansion by the Company of its businesses in Canada, particularly an expansion through acquisitions.

The Company's Canadian activities are subject to various laws and regulations governing safety, environmental quality and pollution control. The Company believes that it complies with all such legislation and regulations affecting its operations. To date, compliance has not materially affected the capital expenditures, earnings or competitive position of the Company, although these measures may in some instances add to the cost of operations and in others may operate to reduce activity and production. Further legislation or regulations may be reasonably anticipated and the effect thereof on operations cannot be predicted.

The Canadian provinces in which the Company conducts its operations have various additional regulations and programs directly related to oil and gas production, including incentive credit programs and variable royalty rates and royalty holidays designed to encourage oil and gas exploration and development. The provincial governments also have special land tenure requirements governing mineral leases on government-owned lands, which generally provide that the mineral rights with respect to such lands will revert to the provincial governments unless prescribed steps have been taken by lessees within specified periods of time. Provincial regulatory boards in Canada regulate all drilling and production activity in several provinces, including quantities of oil and gas that may be produced.

The Company's oil and gas operations, as well as its ancillary service activities, are significantly affected by Canadian income tax laws applicable to the petroleum industry, and changes in such laws could adversely affect the Company's operations. In Canada, payments of royalties, lease rentals and mineral taxes to provincial authorities are not currently allowed as a deduction from income for Canadian federal income tax

purposes. However, the provinces in which the Company operates rebate a portion of income taxes attributable to such disallowed items.

Operating Hazards

Oil and gas exploration and development involves the expenditure of large sums of money for the acquisition of prospects and the drilling of exploratory and development wells. Such exploration may result in many failures and losses before discovery of oil or gas in accumulations capable of being economically produced.

The Company's operations are subject to all of the risks inherent in exploring for and producing oil and gas, including blowouts, cratering and fires, which could result in damage to or destruction of oil and gas wells or formations, production facilities or other property, or in injury or loss of life. Although the Company has extensive insurance coverage, it is not practical to insure against virtually every possible loss. The occurrence of an event not fully insured could result in substantial loss to the Company and thereby severely impair its ability to continue operations.

Title to Properties

As is customary in the oil and gas industry, the Company performs only a perfunctory title examination at the time properties believed suitable for drilling operations are acquired. Prior to the commencement of drilling, a thorough title examination is usually conducted and significant title defects are remedied.

The oil and gas properties owned by the Company are subject to royalty, overriding royalty and other interests which are customary in the industry, as well as other burdens, minor encumbrances, easements and restrictions.

OTHER SEGMENTS

The Trans-Pan operations, located in the Texas Panhandle, involve the purchase, transmission and sales of natural gas and related products. The Company is Trans-Pan's primary supplier of natural gas.

R.D.R. Well Servicing Ltd. owns one service rig operating in Alberta and Springwest-Page Petroleums N.L. owns one drilling rig and related ancillary equipment for lease in Australia.

EMPLOYEES

At March 15, 1984, the Company had approximately 63 employees, none of whom was represented by a union. The Company has not experienced any work stoppages or strikes and considers its relationship with its employees to be satisfactory.

ITEM 2 - PROPERTIES

Principal Canadian Properties

In Dodsland, Saskatchewan, the Company has 397 gross (367.1 net) wells which contributed 78.4% of the Company's Canadian net oil producton in 1983. The Dodsland field contains approximately 69.4% of the Company's estimated 8,721,000 net proved barrels of oil in Canada and 46.6% of the Company's estimated 16,967,000 Mcf net proved gas reserves in Canada. Production is from the Viking Formation (approximately 2,400 ft. wells) with the average well producing less than ten barrels of oil per day. A $2 million waterflood facility installed by the Company in the Dodsland field commenced operations during February 1984. This waterflood facility was designed as a pilot project, the results of which will be evaluated to determine whether to construct a full scale waterflood facility for the Dodsland field.

Principal United States Properties

The Company has two major producing properties in the United States. Approximately 25% of the Company's proved oil reserves and 68% of the proved gas reserves in the United States at December 31, 1983 were attributable to properties located in Hutchinson County, Texas. Another 69% of the total proved oil reserves and 11% of the total proved gas reserves were attributable to the Altamont-Bluebell field in the Uintah Basin of northeastern Utah.

Reserves

Information concerning the Company's oil and gas reserves can be found in the Unaudited Supplementary Information appearing in Item 8 of this Report.

The estimated net proved gas reserves in Canada increased 8,785,000 Mcf, primarily due to the inclusion for the first time of Dodsland, Saskatchewan gas reserves. Prior to 1983, no facilities to market the Dodsland gas existed. In the U.S., a significant portion of the 1,198,000 Mcf downward revision of gas reserves and approximately one-half of the 158,000 barrel downward revision of oil reserves was attributable to the Company's Texas Panhandle properties. The balance of the reduction of U.S. oil reserves was attributable to various other U.S. properties. The revisions, primarily a result of U.S. production levels not meeting the December 31, 1982 expectations of independent engineers and Company staff, accounted for approximately one-half of the $15 million (U.S.) write-down of assets recorded in 1983.

No reports concerning the Company's net oil or gas reserves have been filed with any United States federal authority or agency covering any period since January 1, 1983, and no major discovery or other favorable or adverse event is believed to have caused a significant change in the Company's proved reserves since December 31, 1983.

Production-Average Prices and Costs

The following table sets forth, for the periods and locations indicated, the Company's average sales price per barrel of oil and liquids and per mcf of natural gas, and average production costs (lifting cost) per net unit of production:

	Year Ended December 31		
	1983	1982	1981
	(Canadian dollars)		
Average Sales Price			
Crude oil and liquids			
Canada	$35.20	$28.54	$18.86
United States	34.36	39.49	39.84
Natural gas			
Canada	1.94	2.05	1.94
United States	4.16	3.76	3.05
Average Production Cost (1)			
Canada	6.42	6.86	5.86
United States	6.06	5.23	7.39

(1) Gas production is converted to oil barrel equivalents at the rate of 6 mcf per barrel.

The Canadian crude oil price has increased to approximate world oil prices under the provisions of the Canadian National Energy Program and Federal-Provincial energy pricing agreements. See "Oil and Gas Exploration and Production - Regulation and Taxation - Canada". The decline in United States oil prices directly reflects the decline in world oil prices. Prices and costs for any period should not be considered indicative of those for future periods.

Drilling Activity

The following table sets forth the results of the Company's drilling activity for the periods indicated. "Total" wells shown in each category are the number of wells completed, both productive and dry, during the periods indicated, regardless of when drilling was initiated. "Exploratory Wells" are wells drilled to find or produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir. "Development Wells" are wells drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive. "Dry" wells are wells found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well. "Productive" wells are wells that are not "Dry" wells. "Gross" wells are the total wells in which the Company has a working interest. "Net" wells are equal to the sum of fractional working interests owned by the Company in Gross wells.

		Exploratory Wells			Development Wells		
Year Ended		Productive	Dry	Total	Productive	Dry	Total
December 31, 1981							
Canada	– Gross	5.00	2.00	7.00	14.00	–	14.00
	– Net	2.75	0.42	3.17	13.33	–	13.33
United States	– Gross	12.00	20.00	32.00	102.00	1.00	103.00
	– Net	2.76	4.79	7.55	78.66	1.00	79.66
December 31, 1982							
Canada	– Gross	4.00	4.00	8.00	59.00	–	59.00
	– Net	0.26	0.32	0.58	41.82	–	41.82
United States	– Gross	3.00	7.00	10.00	44.00	1.00	45.00
	– Net	0.91	2.83	3.74	36.40	0.37	36.77
December 31, 1983							
Canada	– Gross	–	–	–	24.00	–	24.00
	– Net	–	–	–	17.00	–	17.00
United States	– Gross	–	2.00	2.00	–	–	–
	– Net	–	0.67	0.67	–	–	–

As previously noted, the above table includes drilling statistics only for wells in which the Company participated as a working interest owner. The Company also owned "carried" working interests ranging from 1.02% to 25% in four wells drilled in 1983. A carried working interest owner generally does not share in the drilling costs but participates as a working interest owner in the completed well operations. Of the four wells drilled, three were dry and one was unevaluated at March 15, 1984.

The Company owns a 10% net profits interest commencing June 14, 1984 in 48 successful Dodsland, Saskatchewan, oil wells drilled in 1983 and early 1984.

An additional 11 wells were drilled during 1983, in which the Company owned overriding royalty interests ranging from .52% to 15%. The Company netted overriding royalty interests ranging from 1.25% to 15% in five oil wells and a .52% overriding royalty in one successful gas well; the other five wells were dry.

Seven exploratory wells were also drilled during 1983 in the United States (all dry) in which the Company would have had a reversionary interest after payout.

During the period January 1, 1984 to March 15, 1984 the Company participated in the drilling of a total of 18 gross wells resulting in 16 gross (5.6 net) oil wells. At March 15, 1984, the Company was not participating in the drilling of any wells.

Productive Wells

A productive well is a well producing or capable of producing oil or gas in commercial quantities. The following table summarizes the gross and net interests of the Company in productive wells at December 31, 1983:

	Productive Wells			
	Oil		Gas	
	Gross	Net	Gross	Net
Canada	752	425.2	43	19.8
United States	217	127.4	26	5.7
Total	969	552.6	69	25.5

Acreage

The following table sets forth information with respect to developed and undeveloped acreage in which the Company had an interest at December 31, 1983:

	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
Canada:				
Alberta	17,211	9,929	69,421	47,466
British Columbia	647	81	6,027	1,313
Manitoba	–	–	7,790	1,302
Saskatchewan	21,481	19,628	17,762	13,505
Total	39,339	29,638	101,000	63,586
United States:				
Alabama	–	–	760	253
Colorado	–	–	3,520	132
Michigan	80	55	157,029	75,461
Mississippi	750	228	77,843	19,925
Montana	–	–	27,354	7,167
Nebraska	80	60	–	–
Nevada	–	–	97,389	97,389
New Mexico	–	–	24,156	3,908
North Dakota	–	–	131,460	16,222
Ohio	–	–	28,601	14,533
Oklahoma	2,080	419	–	–
Pennsylvania	–	–	38,823	37,949
Texas	21,564	3,875	34,088	9,616
Utah	11,255	4,662	187,534	183,228
Total	35,809	9,299	808,557	465,783
Other:				
Egypt	–	–	1,310,000	19,650
U.K. North Sea	–	–	25,280	360
Total	–	–	1,335,280	20,010
Total, Canada, U.S.A. and Other	75,148	38,937	2,244,837	549,379

In the foregoing table, "Developed Acres" are acres spaced or assignable to productive wells and "Undeveloped Acres" are those on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or gas, regardless of whether or not such acres contain proved reserves. "Gross" refers to the total number of acres in which the Company had a working interest, and "Net" refers to the aggregate of the numbers obtained by multiplying each acre in which the Company had a working interest by the percentage working interest of the Company therein.

ITEM 3 - LEGAL PROCEEDINGS

There are no material pending legal proceedings to which the Company or any of its subsidiaries is a party, or to which any of their property is subject, other than routine litigation.

ITEM 4 - SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

During the fourth quarter of the Company's fiscal year ended December 31, 1983, no matter was submitted to a vote of the Company's shareholders through the solicitation of proxies or otherwise.

EXECUTIVE OFFICERS OF THE REGISTRANT

The executive officers of the Company, their ages as at March 15, 1984 and their business experience since January 1, 1979 are as follows:

Name and Age as of March 15, 1984	Positions with the Company	Principal Occupation for Past Five Years
Donald D. McCuaig, 50	Chairman of the Board of Directors and Chief Executive Officer	Chairman of the Board and Chief Executive Officer of the Company since November 1983; also, since October 1982, President, Director and Chief Executive Officer of American Resources Management Corporation, a public company engaged in oil and gas development and having an asset value at December 31, 1983 of approximately $50 million (U.S.); also, since May 1981, Chairman of the Board, and from May 1981 to October 1983, also President and Chief Executive Officer, of Commonwealth Oil Refining Company, a public company engaged in oil refining in Puerto Rico and having an asset value at December 31, 1983 of approximately $57 million (U.S.); Vice-Chairman of Commonwealth Oil Refining Company from January 1979 to May 1981
Lawton L. Clark, 59	President and Director	President of the Company
William R. Harrison, 35	Vice-President Finance, General Manager of Canadian Operations and Director	Vice-President, Finance and General Manager of Canadian Operations of the Company since March 1983; prior thereto Controller of the Company from March 1981; prior thereto Financial Advisor with Esso Resources Canada Ltd.

Except for Mr. McCuaig, all officers hold their positions at the pleasure of the Board of Directors, without employment contracts. Mr. McCuaig's services are available to the Company under an amended agreement with the Stanwick Organization Incorporated, which is wholly-owned by Mr. McCuaig. The agreement is presently terminable on 30 days' notice by either party except that the term of the agreement shall extend one year from the closing date of the proposed Exchange Offer [See Note 12(b) of the Notes to Consolidated Financial Statements appearing in Item 8 of this Report].

PART II

ITEM 5 - MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

The Company's Common Shares are listed on The Toronto Stock Exchange and on the American Stock Exchange. High and low sales prices as reported by a Canadian investment banking firm for each quarterly period during the two years ended December 31, 1983 are set forth below:

			1st Quarter		2nd Quarter		3rd Quarter		4th Quarter	
		Year	High	Low	High	Low	High	Low	High	Low
The Toronto		1982	16.00	7.25	14.50	7.00	9.25	5.75	10.00	6.50
Stock Exchange		1983	9.00	5.25	5.87	3.75	5.62	4.15	4.30	2.60
American	(U.S.$)	1982	13.62	5.62	11.75	5.37	7.25	4.25	9.37	5.37
Stock Exchange	(U.S.$)	1983	7.25	4.00	4.87	2.62	4.87	3.37	3.75	2.00

The number of shareholders of record of the Company's Common Shares at March 15, 1984 was 1,712.

The Company has never paid a dividend on the Common Shares and, by reason of its financial condition, is currently legally prohibited from paying cash dividends. The Company's Board of Directors has no plans to declare a dividend on the Common Shares in the foreseeable future. Any such declaration of dividends would depend on the Company's earnings, capital requirements, financial condition and other factors deemed relevant by the Board of Directors. In addition, the Indenture pursuant to which the Company's 10% Convertible Subordinated Debentures due 2000 ("Debentures") have been issued contains certain restrictions on the payment of dividends.

Under the provisions of the Income Tax Act (Canada), Page would be required to withhold income tax from dividends paid to non-residents of Canada. The tax treaty between Canada and the United States limits the withholding rate to no more than 15% of such dividends. Citizens or residents of the United States and United States corporations (and, in certain circumstances, other persons or entities engaged in trade or business in the United States) are, subject to certain limitations, entitled with respect to their United States Federal Income Tax to a credit or, alternatively, a deduction for the Canadian taxes so withheld.

Although Canada no longer has a federal estate tax, upon the death of a shareholder the shares may be subject to succession duties imposed by various Canadian provinces.

ITEM 6 - SELECTED FINANCIAL DATA (1)

The following table summarizes selected consolidated financial data of the Company and is qualified in its entirety by more detailed information contained in the Consolidated Financial Statements and Notes thereto appearing elsewhere in this Report.

	1983	1982	1981	1980	1979(2)
	(Thousands of Canadian dollars, except per share data)				
Income	$ 48,829	$ 51,480	$ 31,148	$22,505	$11,674
Earnings (loss) from continuing operations	(27,545)	(49,394)	(5,227)	6	373
Earnings (loss) per Common Share from continuing operations – primary and fully diluted	(7.58)	(13.63)	(1.47)	–	(0.03)
(Loss) from operations of discontinued businesses	–	–	–	(800)	(406)
Provision for (loss) on disposal of discontinued businesses	–	(919)	(1,022)	(975)	–
Net (loss) applicable to Common Shares	(27,545)	(50,313)	(6,249)	(1,909)	(478)
Net (loss) per Common Share-primary and fully diluted	(7.58)	(13.89)	(1.76)	(0.54)	(0.18)
Funds generated from operations	10,630	3,442	2,636	6,295	4,533
Ratio of earnings to fixed charges(3)	(0.38)	(1.05)	0.56	1.03	1.25
Working capital (deficiency)	(11,831)	(22,347)	(19,575)	(1,089)	(744)
Total assets	114,368	152,993	177,177	94,681	56,648
Book value per Common Share	(17.12)	(9.89)	3.95	5.59	7.24
Oil and gas capital expenditures	7,497	49,796	85,855	38,405	27,859
Long-term debt, net of current maturities	143,305	147,883	127,035	62,892	26,645
Redeemable preferred shares	–	–	–	–	9,687
Common shareholders' equity	(62,185)	(35,928)	14,180	19,517	21,422

(1) The financial statements included herein have been prepared in accordance with generally accepted accounting principles in the United States and have been restated from Canadian generally accepted accounting principles.

(2) Restated to segregate items applicable to discontinued businesses, so the information presented is comparative with other years presented.

(3) Earnings were inadequate in 1983, 1982 and 1981 to cover fixed charges. Earnings required to cover the deficiency would be $24,977, $50,874 and $6,382, respectively.

ITEM 7 - MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

1983 Fiscal Year

Summary

The Company incurred an overall net loss of $27.5 million ($7.58 per common share) in 1983 compared to a loss of $50.3 million ($13.89 per common share) in 1982. Funds generated from operations increased to $10.6 million from $3.4 million in 1982. A $20.4 million write-down of capital costs in excess of net realizable value was recorded in 1983 compared to a $35 million write-down in 1982. The lower write-down in 1983, reduced interest and bank charges, lower production costs and less depletion, depreciation and amortization were the major factors behind the reduced loss the Company incurred for 1983. The net losses, exclusive of write-downs, were $7.1 million for 1983 and $15.3 million for 1982. Expenditures on property, plant and equipment and exploration and development activities for the year ended December 31, 1983 were $7.4 million, down from $49.8 million in 1982 because of severely restricted cash availability. The long-term debt (including current maturities) was $154.5 million, reduced $10.4 million from the prior year by applying proceeds of sales of oil and gas properties to the outstanding principal. Included in current liabilities at December 31, 1983 is $4.4 million for interest due on two United States production loans. At the Bank's request, interest payments were suspended on the loans May 1, 1983 and amounts paid to the Bank thereafter, by the Company, were retained as collateral to principal and interest owing. The Company and the Bank entered into a Debt Restructure Agreement on February 21, 1984 as described in greater detail in Note 5(d) in the Notes to Consolidated Financial Statements appearing in Item 8 of this Report.

Liquidity

The December 31, 1983 working capital deficit of $11.8 million includes $4.8 million payable to KEP Resources ("KEP") as the remaining amount due on the 1981 purchase of exploration leases in the state of Michigan.

The principal of this obligation is payable in monthly installments of $50,000, with the balance due July 10, 1984. This obligation is secured by mortgages on specific oil and gas leases in Michigan. Forecasted cash flows after all debt service and other loan principal retirements will not be adequate to meet this obligation. The Company is currently negotiating with KEP a one-year extension to July 10, 1985 of the maturity of the $4.8 million obligation.

In the event that the Company cannot renegotiate the term of this loan or replace it with alternate financing these leases could be forfeited by the Company, the Company would be liable for any deficiency and the indebtedness to the Bank may be declared immediately due and payable.

Also included in the $11.8 million working capital deficit is $5.1 million of Bank debt which, under the Debt Restructure Agreement, is scheduled for repayment in monthly installments of $569,000 per month commencing in April 1984.

The Debt Restructure Agreement has, as a condition of default on $116 million in principal amount of debt, a provision calling for the Company to reduce the cash interest expense associated with the existing Debentures. To facilitate the cash interest expense reduction a proposed Exchange Offer is currently being prepared to exchange Notes, common shares and warrants for the existing Debentures [See 12(b) of the Notes to Consolidated Financial Statements appearing in Item 8 of this Report].

In the event that at least 80% of the Debentures are not accepted for exchange under the Exchange Offer prior to July 31, 1984, there will be an event of default, in which case the Bank could call for immediate payment of the $116 million. The Company would not be able to repay these obligations if called.

Five year cash flow projections for the Company, assuming relatively stable interest rates and oil and gas prices, indicate principal and interest payments under the Debt Restructure Agreement can be met

through the end of calendar year 1986. These projections are based on numerous assumptions, certain of which are not under the Company's control. Moreover, under the Debt Restructure Agreement principal and interest due in 1987 and subsequent years cannot be met from cash flows anticipated from existing operations. In addition, obligations under the Debt Restructure Agreement of $30 million due in 1989, interest notes issued in lieu of cash interest on the $30 million and the Notes due in 1989 (to be issued under the proposed Exchange Offer) will not be able to be repaid from expected cash flow.

In the event of bankruptcy, receivership or similar proceedings in Canada it is not expected that there would be sufficient asset value on liquidation to repay the full amount of the Bank's loans. Although the Notes would rank senior to the Debentures, the Company considers it unlikely that any amounts would be available on liquidation of assets for distribution to unsecured creditors, including holders of the Notes or Debentures.

1984 Plans

The primary objective of the Debt Restructure Agreement and of the Exchange Offer is to provide the Company with sufficient time to evaluate the potential of the Company's United States exploration land inventory and the waterflood potential of the Dodsland area of Saskatchewan, Canada. Sufficient discretionary cash flow is expected to be available during this period to carry on limited exploration and development. Any major exploration and/or major development effort can only be accomplished by the Company's obtaining additional funding from the Bank or from other sources with the prior review and approval of the Bank.

Activities of the Company in Canada during 1984 will be concentrated on testing the waterflood potential of the Dodsland field. An experimental waterflood program including two pilot projects was commenced during 1983. Water injection has been underway since late February 1984 and conclusive data resulting from these pilots is expected as early as September 1984. The Company presently anticipates that the pilots will be sufficiently conclusive in 1984 to allow it to decide whether to proceed with a full scale flood and attempt to secure the attendant financing during 1985.

Activities of the Company in the United States will be directed toward identifying specific prospects from Company leases, particularly the leases in Michigan, for further exploration efforts, filling in land positions on prospects, obtaining funding for use in evaluating such prospects and developing any found to be successful.

Results of Operations

Oil and gas sales, net of royalties, were $40.1 million in 1983, down 5.8% from $42.5 million in 1982. Included in the decline in sales is a $7.8 million increased contribution from the Dodsland field (as a result of increased prices and production) offset by a $7.9 million decreased contribution from the Altamont-Bluebell field in Utah (as a result of the sale of 55% of Utah properties in mid-1982 and decreased productivity and prices). 1982 net oil and gas revenues also include a $1.1 million contribution from the Mitsue property in Alberta which was sold effective January 1, 1983. Trans-Pan Pipeline Company ("Trans-Pan"), a partnership in which the Company has a 50% interest, contributed $7.3 million in revenue during 1983 versus $7.6 million for seven months' operation in 1982. Total income for 1983 was $48.8 million, a 5.1% decrease from 1982 income of $51.5 million.

Expenses, with the exception of federal production taxes (petroleum and gas revenue tax plus windfall profit tax) declined in 1983 versus 1982. 1983 production costs declined $1.5 million to $8 million, Trans-Pan feedstock and operating costs were $160,000 lower at $5.9 million and well servicing and rig lease operating costs declined $480,000 to $452,000. Petroleum and gas revenue tax payable on the increased Canadian revenues accounted for the rise in federal production taxes. Total general and administrative costs, capitalized and expensed, declined $980,000, or 15.3% compared to 1982, as a result of reduced staff levels and other cost saving measures implemented by the Company. General and administrative expense (net after recoveries and portion capitalized) was reduced in 1983 by $535,000 to $3.2 million.

Interest and bank charges declined $4.6 million to $18.4 million compared to $23 million in 1982. Interest savings of $5.2 million during 1983 were attributable to an $11.4 million reduction in total current and long-term debt plus a decline in average interest rates from 14.3% in 1982 to 11.6% in 1983. Bank charges increased from $13,000 in 1982 to $626,000 in 1983 as a result of the Bank implementing, for the first time, significant facility fees and administration fees for the extension of new credit and management of existing loans with the Company.

An $18.5 million write-down of United States properties in the third quarter of 1983 was required in addition to the $33.2 million write-down of United States properties taken in 1982. Calculation of the write-down was made by application of the ceiling limitation test (as required by accounting rules of the Securities and Exchange Commission) to the carrying value of the Company's United States proved properties plus a market value comparison to unevaluated properties. The 1983 write-down was due to United States production levels not meeting the December 31, 1982 expectations of independent engineers and Company staff, plus a further decline in value of the Company's undeveloped oil and gas acreage inventory. Write-downs of $1.9 million for 1983 and $1.7 million for 1982 were also recorded for Australian properties no longer held by the Company. The decline of $1.8 million to $15.3 million in 1983 for depreciation, depletion and amortization reflects the carrying cost net after write-downs of the Company's oil and gas properties used in the depreciation, depletion and amortization calculation.

Provision for income taxes, both current and deferred, were incurred by the Canadian operations. Sale of the Canadian Mitsue property resulted in the decline of the Alberta royalty tax credit from $1.2 million in 1982 to $397,000 in 1983. The provision for deferred income tax of $3 million is a result of a book profit for tax purposes in Canada. It is expected the Company will not actually have to pay income tax in Canada until 1987, at the earliest, and it is not expected to pay income tax in the United States assuming currently forecasted levels of operations.

Financial Condition

Property, plant and equipment, at lower of cost or net realizable value, net of depreciation, depletion and amortization, decreased to $97.5 million at December 31, 1983 from $135.6 million at the end of 1982. The net decrease included a $20.4 million write-down of assets to realizable value, $15.3 million of property, plant and equipment depreciation, depletion and amortization expense, $12.2 million realized on the sale of oil and gas properties and is net of $7.5 million of additions.

The working capital deficit at December 31, 1983 was $11.8 million, an improvement of $10.5 million from the $22.3 million deficit at December 31, 1982. This improvement is attributable to a $5.8 million reduction of current maturities of long-term debt and decreased payables of $4.1 million.

The Company's financial condition was adversely affected during 1983 and 1982 by the magnitude of its operating losses. The losses resulted in a deficit in shareholders' equity in 1983 and 1982 in the amounts of $62.2 million and $35.9 million, respectively. No capital stock was issued in 1983.

1982 Fiscal Year

Summary

The Company incurred an overall net loss of $50.3 million ($13.89 per Common Share) in 1982 compared to a loss of $6.2 million ($1.76 per Common Share) in 1981. The loss from continuing operations was $49.4 million in 1982 compared to a loss of $5.2 million in 1981. Cash flow from operations increased to $3.4 million from $2.6 million in 1981. Interest expense of $23 million in 1982 versus $13.8 million in 1981, a $35 million write-down of capital costs in excess of net realizable value and a $9.3 million increase in depreciation, depletion and amortization expense were the major factors in the increased loss of the Company for 1982.

Expenditures on property, plant and equipment and exploration and development activities for the year ended December 31, 1982 were $49.4 million. The long-term debt at year-end was $147.9 million, a net increase of $20.9 million from December 31, 1981. Current liabilities at December 31, 1982, included $3.3 million of accrued interest unpaid on certain bank production loans.

Results of Operations

Oil and gas revenues, net of royalty expense were $42.5 million, in 1982, up 44% from the $29.5 million for 1981. Increased oil and gas revenues were attributable to the placing on stream of a 99-well drilling program in the Texas Panhandle during 1982. Oil and gas revenue fell $9.5 million short of expectations due primarily to this new production not achieving predicted levels and to the mid-year sale of a 55% interest in the Company's producing properties in Utah. Trans-Pan revenue of $7.6 million was generated in 1982 against $6.1 million of feedstock and operating costs in that facility's first seven months of operation. Total income for 1982 was $51.5 million, a 65% increase over 1981 income of $31.1 million.

Expenses in 1982 of $100.9 million were $63.7 million (172%) higher than in 1981. The $35 million write-down of capital costs in excess of net realizable value combined with significant increases in interest expense (up $9.2 million), depreciation, depletion and amortization (up $9.3 million) and the previously mentioned initial year of reporting Trans-Pan feedstock and operating costs ($6.1 million) were the significant contributors to this increase.

Disappointing levels of production and the attendant downward revision of reserve volume estimates and valuation in the Texas Panhandle, combined with an unfavorable market for unproved oil and gas properties in the United States, necessitated a significant write-down of the costs of those assets in the third and fourth quarters of 1982. World oil price reductions to the end of February 1983 were recognized in this write-down of $33.2 million. The balance of the write-down related to the Australian oil and gas properties of the Company.

Interest expense increased 67% from $13.8 million in 1981 to $23 million in 1982. Increased average debt levels for 1982 over 1981 more than offset the positive impact of decreased interest rates in 1982. The most significant drop in prime rates occurred in the second half of the year. Approximately three-quarters of the Company's long-term debt in 1982 was sensitive to changes in prime rates.

A combination of declining value of the Canadian dollar versus the U.S. dollar and the increased U.S. debt resulted in an exchange loss of $4.2 million in 1982. The exchange gain of $490,000 in 1981 was a result of a modest strengthening of the Canadian dollar versus the U.S. dollar.

Depreciation, depletion and amortization expense of $17.5 million in 1982 represented an increase of 115% over the $8.1 million reported for 1981. Increased oil and gas revenues together with increased rates of depletion applied to Canadian and United States revenue resulted in the increase. Significant downward revisions of the reserve estimates and value, particularly in the United States, resulted in significant depletion rate increases.

Production expenses increased 15% from $8.2 million in 1981 to $9.4 million in 1982. This increase was considerably lower than the 44% increase in oil and gas revenues.

Federal production taxes included windfall profit tax from the United States operations and petroleum and gas revenue tax and incremental oil revenue tax in Canada. The decrease of $1.1 million from $3 million in 1981 to $1.9 million in 1982 reflects previously unaccounted-for refunds of windfall profit tax from 1980 and 1981 that were recognized on filing the returns in 1982 for those years.

General and administrative expense decreased 5.9% from $4 million in 1981 to $3.8 million in 1982. Staff level reductions and a general effort toward overhead cost reductions commencing in the second quarter of 1982 resulted in the decrease. General and administrative expense was 9% of oil and gas sales.

Income taxes, both current and deferred, were provided for in the Canadian operation. Changes in the Alberta royalty tax credit scheme resulted in an increased recovery of current income tax of $779,000 to $1.2 million in 1982. The provision for deferred income tax of $1.2 million reflects a book profit for tax purposes in Canada.

Financial Condition

Property, plant and equipment, at lower of cost or net realizable value, net of depreciation, depletion and amortization decreased to $135.6 million at December 31, 1982, from $154.4 million at the end of 1981. This net decrease included a $35 million write-down of asset costs to net realizable value, $17.1 million of property, plant and equipment depreciation, depletion and amortization expense, $22 million realized from the sale of oil and gas properties and $55.6 million of additions.

The working capital deficit at year end 1981 of $19.6 million was increased by $2.7 million to a deficit of $22.3 million at December 31, 1982. Included in current liabilities was $3.3 million of unpaid interest deferred by the Bank on outstanding production loans and $14.8 million of production loans scheduled to be repaid in 1983.

Additions to property, plant and equipment were financed using $3.4 million of funds from operations and $20.8 million in net additional long-term debt and proceeds from the above-mentioned sale of oil and gas assets.

The Company's financial condition was adversely affected during 1982 by the magnitude of its operating loss ($50.3 million) which resulted in a deficit in shareholders' equity of $35.9 million at December 31, 1982, compared to positive shareholders' equity of $14.2 million at the end of 1981. Capital stock sales in 1982 were $205,000 on the exercise of an employee stock option.

ITEM 8 - FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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REPORT OF INDEPENDENT CHARTERED ACCOUNTANTS

To the Shareholders and Board of Directors of
Page Petroleum Ltd.

We have examined the consolidated balance sheets of Page Petroleum Ltd. (an Alberta corporation) as of December 31, 1983, 1982 and 1981 and the related consolidated statements of earnings, shareholders' equity, changes in financial position and income taxes for the three years then ended. Our examinations were made in accordance with generally accepted auditing standards in the United States and, accordingly, included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Certain accounting practices applied by the Company in its accounts and in its consolidated financial statements prepared for use in Canada conform with generally accepted accounting principles in Canada but do not conform with generally accepted accounting principles in the United States. The accompanying financial statements have been prepared for use in the United States and as explained in Note 1 reflect the adjustments required to conform them with generally accepted accounting principles in the United States.

As reflected in the accompanying consolidated financial statements, the Company incurred net losses of $27,545,000 in 1983, $50,313,000 in 1982 and $6,249,000 in 1981. As of December 31, 1983, there is a net deficit of $62,185,000 in shareholders' equity and a working capital deficiency of $11,831,000. A significant factor that may have an important effect on the future operations of the Company is the restructuring of the present bank debt and an exchange offer to debentureholders referred to in Note 5. As described in Note 5, the Company is dependent on the continued financial support of its bankers. The financial statements do not include any adjustments relating to the recoverability and classification of recorded asset amounts or the amounts and classification of liabilities that might be necessary should the Company's bankers not continue their financial support.

In our opinion, subject to the effect on the financial statements of such adjustments, if any, as might have been required had the outcome of the uncertainty about the recoverability and classification of recorded asset amounts and the amounts and classification of liabilities referred to in the preceding paragraph been known, the accompanying consolidated financial statements present fairly the financial position of Page Petroleum Ltd. as of December 31, 1983, 1982 and 1981 and the results of its operations and the changes in its financial position for the years then ended in conformity with generally accepted accounting principles (Note 1) which, except for the change (with which we concur) in the method of accounting for foreign currency translation as explained in Note 1 (i) to the financial statements, have been applied on a consistent basis.

Our examinations were made for the purpose of forming an opinion on the basic financial statements taken as a whole. The supplemental Schedules V and VI presented in item 13 are presented for purposes of complying with the Securities and Exchange Commission's rules and regulations under the Securities Exchange Act of 1934 and are not otherwise a required part of the basic financial statements. The supplemental schedules have been subjected to the auditing procedures applied in the examinations of the basic financial statements and, in our opinion, fairly state in all material respects the financial data required to be set forth therein in relation to the basic financial statements taken as a whole.

Calgary, Alberta
February 21, 1984
(except with respect to
the matters discussed in
Note 12, as to which the
date is April 5, 1984)

ARTHUR ANDERSEN & CO.
Chartered Accountants

PAGE PETROLEUM LTD.

CONSOLIDATED STATEMENTS OF EARNINGS

Years Ended December 31, 1983, 1982 and 1981
(Thousands of Canadian dollars, except share data)

	1983	1982	1981
INCOME			
Oil and gas sales, net of royalties	$ 40,067	$ 42,530	$ 29,482
Pipeline operating revenue	7,277	7,589	–
Well servicing and rig lease revenue	611	1,187	659
Investment and other income	874	174	1,007
	48,829	51,480	31,148
EXPENSES			
Production	7,957	9,416	8,164
Pipeline operating costs	5,939	6,099	–
Well servicing and rig lease	452	932	507
Federal production taxes	2,392	1,865	2,977
General and administrative	3,235	3,770	4,005
Interest and bank charges (Note 5)	18,414	23,015	13,800
Depreciation, depletion and amortization	15,275	17,124	7,778
Write-down of capital costs in excess of net realizable value (Note 3)	20,390	34,957	–
Amortization of deferred financing charges	375	373	375
Exchange loss (gain)	207	4,171	(490)
Minority interest	(830)	(833)	26
	73,806	100,889	37,142
(Loss) from continuing operations before income taxes	(24,977)	(49,409)	(5,994)
PROVISION FOR (RECOVERY OF) INCOME TAXES			
Current	(397)	(1,230)	(451)
Deferred	2,965	1,215	(316)
	2,568	(15)	(767)
(Loss) from continuing operations	(27,545)	(49,394)	(5,227)
PROVISION FOR (LOSS) ON DISPOSAL OF DISCONTINUED BUSINESSES	–	(919)	(1,022)
NET (LOSS)	$ (27,545)	$ (50,313)	$ (6,249)
(Loss) from continuing operations per common share (primary and fully diluted)	$ (7.58)	$ (13.63)	$ (1.47)
Net (loss) per common share (primary and fully diluted)	$ (7.58)	$ (13.89)	$ (1.76)
Weighted average number of common shares outstanding	3,631,750	3,623,120	3,562,131

The accompanying notes are an integral part of these consolidated financial statements.

PAGE PETROLEUM LTD.

CONSOLIDATED BALANCE SHEETS

December 31, 1983, 1982 and 1981
(Thousands of Canadian dollars)

	1983	1982	1981
ASSETS			
CURRENT ASSETS			
Cash and short-term investments (including restricted cash [Note 5(d)(i)])	$ 4,704	$ 2,649	$ 1,385
Accounts receivable (Note 5)	9,207	9,634	9,928
Provincial royalty tax credit	14	1,015	452
Inventories	1,660	1,664	3,033
Prepaid expenses	103	135	89
	15,688	15,097	14,887
INVESTMENTS AND ADVANCES (Note 2)	–	35	4,895
PROPERTY, PLANT AND EQUIPMENT – at cost (including oil and gas properties accounted for by the full cost method of accounting) (Notes 3 and 5)	203,965	208,546	175,413
Less accumulated depreciation, depletion and amortization	106,485	72,933	21,011
	97,480	135,613	154,402
OTHER ASSETS (Note 4)	1,200	2,248	2,993
	$114,368	$152,993	$ 177,177
LIABILITIES AND SHAREHOLDERS' EQUITY			
CURRENT LIABILITIES			
Outstanding cheques	$ 1,329	$ 1,731	$ 4,479
Accounts payable and accrued liabilities	15,017	18,764	29,682
Current maturities of long-term debt (Note 5)	11,173	16,949	301
	27,519	37,444	34,462
LONG-TERM DEBT (Note 5)	143,305	147,883	127,035
DEFERRED INCOME TAXES	5,654	2,689	1,474
MINORITY INTEREST	75	905	26
COMMITMENTS AND CONTINGENCIES (Notes 5, 6 and 9)			
SHAREHOLDERS' EQUITY			
Share capital (Notes 7 and 8)			
Authorized			
10,000,000 Preferred Shares without nominal or par value			
20,000,000 Common Shares without nominal or par value			
Issued and outstanding Common Shares	21,570	21,570	21,365
Contributed surplus	250	250	250
Capital redemption reserve fund (Note 7)	204	204	204
(Deficit)	(85,497)	(57,952)	(7,639)
Cumulative foreign currency translation adjustment (Note 1(i))	1,288	–	–
	(62,185)	(35,928)	14,180
	$114,368	$152,993	$ 177,177

Approved on Behalf of the Board

DIRECTOR Donald D. McCuaig

DIRECTOR Lawton L. Clark

The accompanying notes are an integral part of these consolidated financial statements.

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CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

Years Ended December 31, 1983, 1982 and 1981
(Thousands of Canadian dollars, except share data)

	Common Shares		Contributed Surplus	Capital Redemption Reserve Fund	(Deficit)	Cumulative Foreign Currency Translation Adjustment (Note 1(i))
	Shares	Amount				
Balances, December 31, 1980	3,492,750	$20,453	$250	$204	$ (1,390)	$ –
Lease acquisition	55,000	808	–	–	–	–
Exercise of employee stock options	11,500	104	–	–	–	–
Common shares granted under Employee Incentive Share Purchase Plan (Note 8)	35,000	–	–	–	–	–
Net (loss)	–	–	–	–	(6,249)	–
Balances, December 31, 1981	3,594,250	21,365	250	204	(7,639)	–
Exercise of employee stock options	25,000	205	–	–	–	–
Common shares granted under Employee Incentive Share Purchase Plan (Note 8)	12,500	–	–	–	–	–
Net (loss)	–	–	–	–	(50,313)	–
Balances, December 31, 1982	3,631,750	21,570	250	204	(57,952)	–
Cumulative foreign currency translation adjustment as of January 1, 1983	–	–	–	–	–	1,870
Net change in cumulative foreign currency translation adjustment	–	–	–	–	–	(582)
Net (loss)	–	–	–	–	(27,545)	–
Balances, December 31, 1983	3,631,750	$21,570	$250	$204	$(85,497)	$1,288

The accompanying notes are an integral part of these consolidated financial statements.

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CONSOLIDATED STATEMENTS OF CHANGES IN FINANCIAL POSITION

Years Ended December 31, 1983, 1982 and 1981
(Thousands of Canadian dollars)

	1983	1982	1981
SOURCES OF FUNDS			
(Loss) from continuing operations	$(27,545)	$(49,394)	$ (5,227)
(Loss) from discontinued operations	–	(919)	(1,022)
Charges (credits) to earnings not involving funds			
Depreciation, depletion and amortization	15,650	17,497	8,153
Write-down of capital costs in excess of net realizable value	20,390	34,957	–
Deferred income taxes	2,965	1,215	(316)
Provision for loss on disposal or discontinuance	–	919	1,022
Minority interest	(830)	(833)	26
Funds generated from operations	10,630	3,442	2,636
Proceeds from issuance of common shares	–	205	912
Increase in long-term debt	779	37,204	115,144
Proceeds from sale of property, plant and equipment	12,252	22,006	–
Proceeds on disposition of assets of subsidiaries	–	1,068	3,042
Reduction of other assets	673	372	(84)
	24,334	64,297	121,650
USES OF FUNDS			
Additions to property, plant and equipment	7,596	49,370	86,736
Additions to property, plant and equipment on consolidation of Springwest-Page Petroleums N.L., net of working capital acquired and minority interest	–	2,426	–
Repayment and current maturities of long-term debt	5,357	15,230	51,001
Effect of exchange rate changes on working capital	900	–	–
Investment in and advances to unconsolidated and affiliated companies	(35)	43	2,399
	13,818	67,069	140,136
Increase (decrease) in working capital	10,516	(2,772)	(18,486)
Working capital (deficiency), beginning of year	(22,347)	(19,575)	(1,089)
Working capital (deficiency), end of year	$(11,831)	$(22,347)	$ (19,575)
WORKING CAPITAL CHANGES			
Increase (decrease) in current assets			
Cash	$ 2,055	$ 1,264	$ 1,181
Accounts receivable	(427)	(294)	2,536
Provincial royalty tax credit	(1,001)	563	197
Inventories	(4)	(1,369)	1,564
Prepaid expenses	(32)	46	16
	591	210	5,494
Increase (decrease) in current liabilities			
Outstanding cheques	(402)	(2,748)	2,391
Accounts payable and accrued liabilities	(3,747)	(10,918)	21,517
Current maturities of long-term debt	(5,776)	16,648	72
	(9,925)	2,982	23,980
Increase (decrease) in working capital	$ 10,516	$ (2,772)	$ (18,486)

The accompanying notes are an integral part of these consolidated financial statements.

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CONSOLIDATED STATEMENTS OF INCOME TAXES

Years Ended December 31, 1983, 1982 and 1981
(Thousands of Canadian dollars)

	1983	1982	1981
Computation of Income Taxes – The total provision for (recovery of) income taxes differs from the amount which would be computed by applying the statutory income tax rates to book (loss) before income taxes. The reasons for this difference are as follows:			
Book (loss) from continuing operations before provision for income taxes	$(24,977)	$(49,409)	$(5,994)
Computed "expected" tax (recovery)	$(11,989)	$(23,716)	$ (2,877)
Tax effect of royalties and other payments to provincial governments which are disallowed as deductions for Canadian federal income tax	2,248	2,961	2,596
Rebates by provincial governments related to payments disallowed for Canadian federal income tax	(397)	(1,237)	(452)
Depletion allowance on oil and gas production income	(1,005)	(495)	–
Federal resource allowance	(2,487)	(1,811)	(1,241)
Tax losses not booked due to a lack of virtual certainty of recovery	16,156	24,198	1,266
Provincial income taxes less federal abatements	50	(70)	5
Incremental Oil Revenue – tax exempt income	–	(141)	–
Other	(8)	296	(64)
Actual tax expense (recovery)	$ 2,568	$ (15)	$ (767)
Tax rate	48%	48%	48%
An analysis of actual tax expense (recovery) follows:			
Canada	$ 2,568	$ (15)	$ 33
United States	–	–	(800)
	$ 2,568	$ (15)	$ (767)
Deferred Income Taxes – Result from timing differences in the recognition of expenses for tax and accounting purposes. The source of these differences and tax effect of each are as follows:			
Difference between income tax depreciation and amount provided for depreciation in the accounts	$ (450)	$ (82)	$ (762)
Difference between exploration and development expenditures claimed for income tax purposes and amount provided for depletion in the accounts	3,415	1,297	446
	$ 2,965	$ 1,215	$ (316)

The accompanying notes are an integral part of these consolidated financial statements.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Amounts shown in thousands of Canadian dollars, except share data and where otherwise indicated)

1 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements have been prepared on a going concern basis (See Note 5) in accordance with generally accepted accounting principles ("GAAP") in the United States and conform in all material respects with the standards of the International Accounting Standards Committee. These consolidated financial statements differ from the consolidated financial statements prepared for use in Canada, where the Company is located. The differences between the Canadian and U.S. consolidated financial statements are as follows:

	Consolidated Balance Sheets			Consolidated Statements of Earnings			
	Property, Plant and Equipment	Long-Term Debt	Shareholders' Equity	(Loss) from Continuing Operations	Net (Loss)	(Loss) from Continuing Operations Per Common Share	Net (Loss) Per Common Share
Year Ended December 31:							
1981							
Canadian GAAP..	$154,402	$126,915	$ 14,300	$ (5,717)	$ (6,739)	$ (1.60)	$ (1.89)
Difference	–	120	(120)	490	490	.13	.13
U.S. GAAP	$154,402	$127,035	$ 14,180	$ (5,227)	$ (6,249)	$ (1.47)	$ (1.76)
1982							
Canadian GAAP..	$135,613	$143,666	$(31,711)	$(45,297)	$(46,216)	$(12.50)	$(12.76)
Difference	–	4,217	(4,217)	(4,097)	(4,097)	(1.13)	(1.13)
U.S. GAAP	$135,613	$147,883	$(35,928)	$(49,394)	$(50,313)	$(13.63)	$(13.89)
1983							
Canadian GAAP..	$ 96,027	$138,061	$(58,394)	$(26,683)	$(26,683)	$ (7.35)	$ (7.35)
Difference	1,453	5,244	(3,791)	(862)	(862)	(.23)	(.23)
U.S. GAAP	$ 97,480	$143,305	$(62,185)	$(27,545)	$(27,545)	$ (7.58)	$ (7.58)

The differences are due to the adoption of FASB Statement No. 8 (foreign currency translation) for U.S. GAAP reporting in years prior to 1983 and FASB Statement No. 52 (foreign currency translation) thereafter.

The cumulative impact of the differences for years prior to 1981 is to increase long-term debt and decrease shareholders' equity by $610. This is included in the above analysis.

(a) Principles of Consolidation

The consolidated financial statements include the accounts of the Company's wholly owned subsidiaries, Page Petroleum Inc. and Page Petroleum (U.K.) Limited, and its controlling interests in Springwest-Page Petroleums N.L. (commencing in 1982) and R.D.R. Well Servicing Ltd. The investment in Pirate Drilling Ltd. was accounted for by the equity method (See Note 2).

(b) Full Cost Method of Accounting

The Company and its subsidiaries follow the full cost method of accounting for oil and gas operations whereby all costs of exploring for and developing oil and gas reserves are capitalized and charged against earnings as set out in Note 1(c). Such costs include land acquisition costs, geological and geophysical expense, carrying charges of non-producing property, costs of drilling both productive and non-productive wells, production equipment and overhead expense related to exploration and development activities. The costs are accumulated in cost centres as follows; Canada, United States, United Kingdom and Australia.

1 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Costs associated with a purchase of leases in Michigan, excluded from the U.S. cost centre for depletion purposes in 1981, have been included in the full cost pool since October 1, 1982. The capital costs associated with the previously excluded leases are $16,565, including $1,853 of interest capitalized.

Proceeds on disposal of properties are deducted from accumulated costs without recognition of gain or loss. Any gain or loss realized on the disposition of a major property would be recognized in the statement of earnings.

(c) Depletion

The costs accumulated in the Canadian and U.S. cost centres, together with estimated future capital costs associated with developing proved reserves, are depleted using the future revenue method based upon estimated future cash flows, with no price escalations and net of royalties, to be derived from total proved reserves as determined by independent engineers.

Costs associated with the United Kingdom cost centre are amortized in line with the terms of the leases. During 1983, the Company relinquished all of its remaining interest in its Australian oil and gas properties. All costs associated with the Australian cost centre are fully depleted at December 31, 1983.

(d) Depreciation

Depreciation of the pipeline facilities is computed on the diminishing balance method using a rate of 20%. Well servicing equipment in Canada is depreciated on a straight line basis over an estimated 7 year service life. Rig equipment located in Australia is depreciated on a straight line basis over an estimated 10 year service life. Depreciation of sundry equipment is computed on the diminishing balance method at rates varying from 20% to 30%.

(e) Inventories

Inventories are recorded at the lower of cost or net realizable value and consist of equipment and supplies for the Company's oil and gas operations.

(f) Joint Venture Accounting

Substantially all the Company's exploration, production and pipeline operations are conducted jointly with others and accordingly the accounts reflect only the Company's proportionate interest in such activities.

(g) Limited Partnerships

The Company is involved in certain limited partnerships for the purpose of producing oil and gas. The Company's investment in these limited partnerships is reflected on a proportionate consolidation basis.

(h) Deferred Financing Costs

Costs incurred in connection with the issuance of capital stock and the debentures are deferred and amortized using the straight line method over seven years from the date of the respective issues.

(i) Foreign Currency Translation

In 1983, the Company adopted on a prospective basis Financial Accounting Standards Board (FASB) Statement No. 52 which provided for changes in the method of accounting for foreign currency translation and transactions based on the functional currency applicable to an entity's foreign operations.

1 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

The functional currency applicable to the Company's foreign oil and gas operations, except the United States (which uses the U.S. dollar), is the Canadian dollar as, in management's opinion, there is an extensive dependence of the foreign operations on Canadian management resources and financing.

The foreign currency exchange gains or losses resulting from translating foreign entities' functional currency balance sheets into the Canadian dollar using rates of exchange in effect at December 31, 1983 are reported in the cumulative foreign currency translation adjustment account in shareholders' equity.

The effect of this accounting change on prior years was recorded at January 1, 1983.

Individual assets and liabilities of an entity denominated in currencies other than its functional currency are translated at the rates of exchange in effect at the end of each period. Revenue and expenses of an entity denominated in currencies other than its functional currency are translated at the average rates of exchange prevailing during the period. Gains and losses resulting from the effect of exchange rate changes on these transactions are included in determining net income and resulted in a loss of $207 for the year ended December 31, 1983.

(j) Income Taxes

The Company follows interperiod tax allocation with respect to timing differences in the recognition of income and expenses for tax and accounting purposes. See the Consolidated Statements of Income Taxes for the components of and additional information relating to income taxes.

(k) Interest Costs

Interest is charged against earnings with the exception of $1,465 capitalized in 1982 and $388 capitalized in 1981 as being applicable to the cost of acquiring leases formerly excluded from the U.S. full cost pool [See Note 1(b)].

(l) Earnings per Common Share

Primary earnings per common share have been computed by dividing the net earnings applicable to common shares by the weighted average number of common shares outstanding during the years. In determining the weighted average number of shares, no consideration has been given to the number of common shares issuable on the exercise of employee stock options, or common shares issuable on conversion of securities convertible into common shares, as shares issued on these securities would have the effect of decreasing the loss per share.

Fully diluted earnings per share is consistent with primary earnings per share as the exercise of employee stock options or conversion of convertible securities was not considered for the reason stated above.

2 — INVESTMENTS AND ADVANCES

During February, 1982 the Company increased its investment in Springwest-Page Petroleums N.L. from 33.33% to 73.72% and as a result, Springwest-Page Petroleums N.L. has been consolidated since that date. It was formerly accounted for by the equity method.

The Company sold its remaining interest in Pirate Drilling Ltd. effective March 31, 1983 for $105, a gain of $70 over the Company's investment of $35.

3 — PROPERTY, PLANT AND EQUIPMENT

The following is a breakdown of property, plant and equipment and accumulated depreciation, depletion and amortization by major classification:

	Assets at Cost	Accumulated Depreciation, Depletion and Amortization	Net Investment
December 31, 1983			
Petroleum and natural gas leases and rights, including exploration, development and production equipment costs thereon			
Canada	$ 56,647	$ 13,541	$ 43,106
United States	125,426	78,743	46,683
United Kingdom	285	262	23
Australia	3,633	3,633	–
	185,991	96,179	89,812
Pipeline facilities	9,834	7,030	2,804
Other	8,140	3,276	4,864
	$203,965	$106,485	$ 97,480
December 31, 1982			
Petroleum and natural gas leases and rights, including exploration, development and production equipment costs thereon			
Canada	$ 62,379	$ 10,349	$ 52,030
United States	117,549	48,313	69,236
United Kingdom	259	248	11
Australia	3,941	1,730	2,211
	184,128	60,640	123,488
Pipeline facilities	15,769	9,983	5,786
Other	8,649	2,310	6,339
	$208,546	$ 72,933	$135,613
December 31, 1981			
Petroleum and natural gas leases and rights, including exploration, development and production equipment costs thereon			
Canada	$ 54,083	$ 7,390	$ 46,693
United States	109,728	12,122	97,606
United Kingdom	244	233	11
	164,055	19,745	144,310
Pipeline facilities	8,052	–	8,052
Other	3,306	1,266	2,040
	$175,413	$ 21,011	$154,402

In 1983, an $18,486 write-down of U.S. assets ($33,227 write-down in 1982) and a $1,904 write-down of Page's interest in Australian assets ($1,730 write-down in 1982) were recorded to reflect properties at a realizable value less than their original costs. The write-downs are included in accumulated depreciation, depletion and amortization in the above table.

4 — OTHER ASSETS

	December 31		
	1983	1982	1981
Prepayments, drilling deposits and miscellaneous assets	$ 43	$ 129	$ 564
Lease deposits	63	63	–
Real estate held for resale	–	587	587
Unamortized deferred financing costs	1,094	1,469	1,842
	$ 1,200	$ 2,248	$ 2,993

The deferred financing costs were incurred in connection with the issue of the Company's 7% Cumulative Redeemable Convertible Preferred Shares and 10% Convertible Subordinated Debentures.

5 — LONG-TERM DEBT

	December 31		
	1983	1982	1981
Page Petroleum Ltd.			
Canadian bank loan, evidenced by promissory notes, at the bank's prime lending rate plus 1% [See (d)]	$ 10,307	$ 11,837	$ 7,203
10% Convertible Subordinated Debentures ($25,000 U.S.) [See (a) and (d)]	31,152	30,872	29,812
Other	–	–	290
Page Petroleum Inc.			
U.S. bank loans, evidenced by promissory notes [See (d)]			
– at the bank's prime rate plus ¼% to ½% ($54,739 U.S.)	68,210	75,312	58,911
– at LIBOR plus ½% ($30,000 U.S.)	37,383	37,047	29,812
KEP Resources – 10% ($3,866 U.S.) [See (b)]	4,817	5,093	–
6% Note payable	–	722	698
Springwest-Page Petroleums N.L. loans [See (c)]	2,536	3,499	–
Miscellaneous	73	450	610
	154,478	164,832	127,336
Less minimum current maturities	11,173	16,949	301
	$143,305	$147,883	$127,035

Interest on long-term debt amounted to $17,788 in 1983, $23,002 in 1982 and $13,800 in 1981. Bank charges and other fees amounted to $626 in 1983 and $13 in 1982.

(a) The 10% Convertible Subordinated Debentures are unsecured subordinated obligations maturing April 1, 2000. The debentures are convertible into 1,250,000 common shares at $20 (U.S.) per share, subject to adjustment under certain conditions and to prior redemption. The debentures are redeemable:

(i) At any time at the Company's option at prices declining from 108.42% to 100%.

(ii) Commencing April 1, 1991, at the principal amount through operation of a sinking fund, in an annual amount not less than 10% nor more than 20% of the debentures outstanding on March 31, 1990.

An exchange offer to holders of the debentures is currently being prepared. Mailing date is anticipated to be April, 1984 [See (d) and Note 12].

5 — LONG-TERM DEBT (Continued)

(b) The KEP Resources loan is secured by a mortgage on various oil and gas leases in Michigan. The principal amount is repayable in equal monthly installments of $50 (U.S.) with the final balance due July 10, 1984. It is a condition of the restructured bank indebtedness [See (d)], that the final balance due be extended to July 10, 1985. The Company is currently negotiating extension of the due date (See Note 12).

(c) The Export Development Corporation and other loans are secured by the assets of Springwest-Page Petroleums N.L. and/or guarantees of the shareholders of that company. The principal amounts are repayable in equal semi-annual installments during the next three years.

(d) The bank loans, both U.S. and Canadian, are secured by a general assignment of accounts receivable and certain oil and gas properties.

(i) During 1983, the bank continued to segregate and retain funds in a restricted account as further collateral against U.S. loans. Funds in this account as of December 31, 1983 and 1982 amounted to $3,318 (U.S.) and $2,364 (U.S.) respectively. Unpaid interest on the loans included in accrued liabilities as of December 31, 1983 amounted to $3,540 (U.S.).

The Company made principal repayments of $2,000 (U.S.) of the total $12,000 (U.S.) principal repayments due during 1983 as required by one of its U.S. loans.

As a result of the interest arrearages and the deficient installments due under the terms of the U.S. loans, the Company is in default. The bank has waived all rights and remedies in respect of the defaults. [See (d)(ii), (iii) and (iv)].

(ii) On February 21, 1984, the Company reached agreement in principle with its bank with respect to the restructuring of the Canadian and U.S. bank loans (See Note 12). The restructured bank indebtedness will be secured and will consist of the following:

– $15 million revolving working capital line, payable on demand after three years, bearing interest at the bank's prime lending rate plus 1%.

– $75 million 12 year term loan, bearing interest at the bank's prime lending rate plus 1%, repayable monthly, commencing April 1, 1984 on the following schedule:

9 equal monthly payments of	$569
12 equal monthly payments of	$404
12 equal monthly payments of	$332
96 equal monthly payments of	$565
11 equal monthly payments of	$566
1 final payment of	$581

– $30 million debenture, five year term, repayable on demand after five years, bearing interest at the greater of 10% or the bank's U.S. prime lending rate plus 1%. Interest of 10% is payable in cash or interest notes (due in 1989) at the option of the Company. Interest in excess of 10% is payable in convertible Preferred Shares. The bank will be entitled to receive warrants to purchase a maximum of one-third of the Company's common shares outstanding in 1989 (on the fifth anniversary of the closing). The exercise price of the bank warrants will be the lesser of $7.50 (U.S.) or the weighted average market price of the common shares on the American Stock Exchange and The Toronto Stock Exchange during the three years ending five days before April 1, 1989.

(iii) As compensation for the restructuring, the bank is to receive a restructuring fee of 450,000 fully paid common shares of the Company and $2 million represented by a promissory note due in 1987 (on the third anniversary of the closing) bearing interest compounded annually at 12%.

5 — LONG-TERM DEBT (Continued)

(iv) The restructuring is dependent upon approval by various regulatory commissions and acceptance by July 31, 1984 of an exchange offer by a sufficient number of debentureholders which would result in a reduction by at least 80% in the cash interest expense on the existing $25 million (U.S.) 10% Convertible Subordinated Debentures [See (a) and Note 12]. It is a default condition under the terms of the Debt Restructure Agreement if the Company is unable to extend the due date of the KEP Resources loan [See (b) and Note 12]. It is also a condition that the bank must consent to any future transaction which would have the effect of diluting its equity interest in the Company.

The Company is dependent on the continued financial support of its bankers and the completion of the restructuring, including the acceptance by July 31, 1984 of the exchange offer referred to above. If support is withdrawn, the Company may be unable to continue realizing its assets and discharging its liabilities in the normal course of business. The financial statements do not include any adjustments relating to the recoverability and classification of recorded asset amounts or the amounts and classification of liabilities that might be necessary should the support of the bankers be withdrawn.

6 — COMMITMENTS AND CONTINGENCIES

The Company has guaranteed bank and other indebtedness of others to a maximum amount of $3,955.

7 — PREFERRED SHARES

During 1980, 953,276 of the Preferred Shares were converted into 504,283 common shares and the remainder were redeemed at $10.50 per share. In accordance with the provisions of The Alberta Companies Act, an amount of $204, equal to the par value of the shares redeemed, was transferred from retained earnings to the capital redemption reserve fund.

8 — COMMON SHARES

(a) *Shares Reserved for Conversion of 10% Convertible Subordinated Debentures*

There were 1,250,000 common shares reserved at December 31, 1983 for issuance upon the possible conversion of the $25,000 (U.S.) 10% Convertible Subordinated Debentures [See Note 5(a)].

(b) *Options to Purchase Common Shares*

There were 230,500 common shares reserved at December 31, 1983 for issuance upon the exercise, to 1988, of employee stock options at prices ranging from $2.38 to $4.84 per share. The total number of common shares reserved for options amounted to 500,000 at December 31, 1983.

The stock options have been granted from time to time to certain employees at a price equal to 85%, 100% and 110% of the fair market value of the common shares on the date of grant. New options granted are for a term of five years from the date of grant and are exercisable, on a cumulative basis, as to one-third of the option shares in each of the second, third and fourth years after the date of the grant. Stock options granted to replace existing options are also for a term of five years, and are exercisable on a cumulative basis, as to one-third of the option shares in each of the first, second and third years after the date of the grant. The options have become or will become exercisable without restriction in varying amounts at varying dates and by December 22, 1986, all of the options outstanding on December 31, 1983, will have become exercisable in full.

During 1982 and 1981 options for 25,000 and 11,500 common shares, respectively, were exercised at prices of $8.21 in 1982 and from $4.21 to $9.79 per common share in 1981. No stock options were exercised during 1983.

8 — COMMON SHARES (Continued)

(c) *Employee Incentive Share Purchase Plan*

A total of 47,500 shares were issued under an Employee Incentive Share Purchase Plan during 1982 and 1981 and were included in common shares outstanding at December 31, 1983. The Plan was amended in January 1984 to permit the Company to cancel loans to employees for the purchase of shares if the employees agreed to relinquish their rights in regard to shares issued under the Plan. In February 1984 the 47,500 shares were returned to authorized but unissued share capital. As of December 31, 1983, 300,000 common shares were reserved for issuance under the Plan.

9 — LEASE COMMITMENTS

The Company has certain lease obligations covering rental of computer facilities and office space. The minimum annual rental commitments under all leases are as follows:

1984	$ 543
1985	543
1986	327
1987	198
1988	149
	$1,760

10 — RELATED PARTY TRANSACTIONS

Legal services were provided to the Company by McCombe & Company, of which Mr. Brian G. McCombe, a Company director, is a partner. The Company and its subsidiaries paid $133, $131 and $141 in legal fees to McCombe & Company for the years 1983, 1982 and 1981 respectively.

Engineering consulting services were provided to the Company by Gregg Petroleum Consultants Ltd., of which a director, Mr. John W. Gregg, is a principal. The Company and subsidiaries paid $137 for these services in 1983.

11 — BUSINESS SEGMENTS

The Company is engaged primarily in oil and gas exploration and production and also has interests in well servicing, rig leasing and pipeline facilities.

The only arms-length purchaser which accounted for more than 10% of the Company's consolidated net revenues for 1983 was Imperial Oil Limited which purchased 42.9%. Trans-Pan also made purchases of 12.2% of the Company's consolidated income and presently delivers all of its pipeline products to Diamond Shamrock Corporation under a long-term supply contract.

The Company has oil and gas reserves and production and conducts its well servicing and pipeline operations in Canada and the United States. No reserves have been assigned for the United Kingdom cost centre. Rig leasing in Australia and the United Kingdom operations have been grouped as Other Foreign in the Geographic Regions table following:

11 — BUSINESS SEGMENTS (Continued)

	Year Ended December 31		
	1983	1982	1981
BUSINESS SEGMENTS			
Income			
Oil and gas	$ 40,067	$ 42,530	$ 29,482
Well servicing and rig leasing	611	1,187	659
Pipeline facilities	7,277	7,589	–
	$ 47,955	$ 51,306	$ 30,141
Depreciation, depletion and amortization			
Oil and gas	$ 13,138	$ 14,122	$ 7,738
Well servicing and rig leasing	966	877	40
Pipeline facilities	1,171	2,125	–
	$ 15,275	$ 17,124	$ 7,778
Write-down of capital costs in excess of net realizable value			
Oil and gas	$ 20,390	$ 27,099	$ –
Well servicing and rig leasing	–	–	–
Pipeline facilities	–	7,858	–
	$ 20,390	$ 34,957	$ –
Operating earnings (loss)			
Oil and gas	$ (3,810)	$ (9,116)	$ 10,603
Well servicing and rig leasing	(807)	(622)	112
Pipeline facilities	167	(9,349)	–
	(4,450)	(19,087)	10,715
Corporate and other			
Investment and other income	(874)	(174)	(1,007)
General and administrative	3,235	3,770	4,005
Interest and bank charges	18,414	23,015	13,800
Amortization of deferred financing charges	375	373	375
Exchange loss (gain)	207	4,171	(490)
Minority interest	(830)	(833)	26
Income taxes	2,568	(15)	(767)
Loss on disposal of discontinued businesses	–	919	1,022
	23,095	31,226	16,964
Net (loss)	$ (27,545)	$ (50,313)	$ (6,249)
Identifiable assets			
Oil and gas	$106,399	$139,187	$168,914
Well servicing and rig leasing	4,007	5,866	939
Pipeline facilities	2,804	5,786	–
	113,210	150,839	169,853
Other	1,158	2,154	7,324
	$114,368	$152,993	$177,177

11 — BUSINESS SEGMENTS (Continued)

	Year Ended December 31		
	1983	1982	1981
GEOGRAPHIC REGIONS			
Income			
Canada	$ 25,109	$ 17,509	$ 13,363
United States	22,606	33,396	16,778
Other foreign	240	401	–
	$ 47,955	$ 51,306	$ 30,141
Depreciation, depletion and amortization			
Canada	$ 3,386	$ 3,263	$ 1,846
United States	11,005	13,125	5,924
Other foreign	884	736	8
	$ 15,275	$ 17,124	$ 7,778
Write-down of capital costs in excess of net realizable value			
Canada	$ –	$ –	$ –
United States	18,486	33,227	–
Other foreign	1,904	1,730	–
	$ 20,390	$ 34,957	$ –
Operating earnings (loss)			
Canada	$ 14,394	$ 7,590	$ 6,035
United States	(16,261)	(24,555)	4,688
Other foreign	(2,583)	(2,122)	(8)
	(4,450)	(19,087)	10,715
Corporate and other	23,095	31,226	16,964
Net (loss)	$ (27,545)	$ (50,313)	$ (6,249)
Identifiable assets			
Canada	$ 51,687	$ 60,376	$ 59,496
United States	58,911	85,319	117,669
Other foreign	3,770	7,298	12
	$114,368	$152,993	$177,177

12 — SUBSEQUENT EVENTS

(a) Under the terms of the restructured bank indebtedness [See Note 5(d)(iii)], on closing, the bank will receive 450,000 fully-paid common shares of the Company. As a result, the conversion price of the 10% Convertible Subordinated Debentures due 2000 ("Debentures") will be adjusted to $17.74 (U.S.) per share [See Note 5(a)].

The formal Debt Restructure Agreement was signed April 5, 1984. Modifications to the agreement reached in principle on February 21, 1984 [See Note 5(d)], include rescheduling of the $75 million 12 year term loan as follows:

– $37.5 million 12 year term loan, bearing interest at the bank's prime lending rate plus 1%, repayable monthly, commencing May 1, 1984 on the following schedule:

9 equal monthly payments of	$ 338
12 equal monthly payments of	$ 259
12 equal monthly payments of	$ 215
96 equal monthly payments of	$ 265
11 equal monthly payments of	$ 273
1 final payment of	$ 327

– $37.5 million 3 year term loan, bearing interest at the bank's prime lending rate plus 1%, repayable monthly, commencing May 1, 1984 on the following schedule:

9 equal monthly payments of	$ 225
12 equal monthly payments of	$ 141
12 equal monthly payments of	$ 115
2 equal monthly payments of	$ 294
1 final payment of	$31,815

Of the $75 million, $72 million ($57.6 million U.S.) is denominated and repayable in U.S. dollars.

(b) As of April 5, 1984, the Company intends to make an offer to exchange for each one thousand (U.S.) principal amount of its outstanding Debentures: (i) one thousand (U.S.) principal amount of its Senior Subordinated Convertible Notes due 1989 ("Notes"); (ii) common shares; (iii) warrants to purchase common shares; and (iv) cash which will be withheld by the Company to pay Canadian withholding taxes. The interest rate on the Notes, the number of common shares and warrants and the amount of cash are as yet to be determined.

The exchange offer will be conditioned upon the tender of not less than 80% in principal amount of the Debentures and upon consent by the holders of at least 66⅔% in principal amount of the Debentures to the subordination of the Debentures to the Notes.

The Notes will be unsecured and mature October 1, 1989. Interest will accrue from April 1, 1984 and is payable in cash, or, at the option of the Company, in common shares. The Notes are convertible into common shares on or after July 1, 1989, or prior thereto if called for redemption, at a conversion price of $20 (U.S.) per share which is subject to adjustment under certain conditions. On consummation of the exchange offer, the conversion price would be reduced to an amount as yet to be determined.

Each warrant will represent the right to purchase one common share for an amount to be determined from the date of issuance through May 1, 1989. The Company has the right to call and repurchase any and all warrants under certain conditions.

Cash expenses to be incurred in connection with the exchange offer are estimated at $500 (U.S.). In addition, the Company retained the services of Drexel Burnham Lambert Incorporated as financial advisors for a fee of $125 (U.S.) plus warrants to purchase a number of common shares as yet to be determined.

(c) On March 30, 1984, KEP Resources agreed to extend the due date of the note from July 10, 1984 to July 10, 1985. The Company, in turn, agreed to increase monthly repayments from $50 (U.S.) to $75 (U.S.) effective April 10, 1984.

13 — REMUNERATION OF DIRECTORS AND OFFICERS

The total remuneration paid to directors and officers of the Company amounted to $353 in 1983, $504 in 1982 and $514 in 1981.

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SUPPLENTARY FINANCIAL INFORMATION
(Thousands of Canadian dollars, except where indicated)

OIL AND GAS PRODUCING ACTIVITIES—Unaudited

Information required to be disclosed in accordance with FASB Statement No. 69 "Disclosures About Oil and Gas Producing Activities" is discussed below and further detailed in Tables 1 through 6 immediately following.

The reserve quantity and valuation estimates included in the following tables have been excerpted from or based upon reports prepared by independent consulting engineers from the D & S Petroleum Consulting Group Ltd. (as to Canadian reserves) and Sipes, Williamson & Associates, Inc. (as to United States reserves). No reserves have been assigned for the United Kingdom cost centre.

Estimated quantities of proved developed and total proved reserves of crude oil (including condensate and natural gas liquids) and natural gas are disclosed net after royalty. Proved reserves are estimated quantities of reserves which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are expected to be recovered from existing wells with existing equipment and operating methods. Values were determined using current prices, increased only for fixed and determinable escalation provisions in contracts and in Canada for prices established by the Federal/Provincial Energy Pricing and Taxation Agreements.

The 1983 gas volume increase in Canada due to extensions of existing fields is attributable to the Dodsland field in Saskatchewan. Prior to 1983, no facilities to market the gas existed. The discounted net revenue of the Dodsland gas amounts to $2.6 million at December 31, 1983.

The Company emphasizes the estimates included in the following tables are by their nature inexact and are subject to changing economic, operating and contractual conditions. Some of the amounts may not agree with amounts reported under similar headings presented elsewhere in this Report due to categorization of costs by FASB Statement No. 69. United States reserve values have been converted to Canadian dollar equivalents at rates in effect during the respective reporting periods.

Table 1

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Changes in Quantities of Proved Reserves

For the Years Ended December 31, 1983, 1982 and 1981

	Total		Canada		U.S.A.	
	Oil (thousands of bbls)	Gas (Mmcf)	Oil (thousands of bbls)	Gas (Mmcf)	Oil (thousands of bbls)	Gas (Mmcf)
Proved Reserves, December 31, 1980	17,883	15,153	15,122	7,290	2,761	7,863
Revisions of previous estimates	263	5,875	(87)	(931)	350	6,806
New field discoveries & extensions	1,348	16,860	628	1,205	720	15,655
Purchases of reserves	–	–	–	–	–	–
Production	(977)	(1,359)	(637)	(339)	(340)	(1,020)
Sales of reserves	–	–	–	–	–	–
Proved Reserves, December 31, 1981	18,517	36,529	15,026	7,225	3,491	29,304
Revisions of previous estimates	(6,081)	(9,418)	(5,528)	472	(553)	(9,890)
New field discoveries & extensions	159	1,421	115	237	44	1,184
Purchases of reserves	569	520	569	520	–	–
Production	(958)	(2,941)	(559)	(272)	(399)	(2,669)
Sales of reserves	(1,583)	(2,827)	(316)	–	(1,267)	(2,827)
Proved Reserves, December 31, 1982	10,623	23,284	9,307	8,182	1,316	15,102
Revisions of previous estimates	97	(895)	255	303	(158)	(1,198)
New field discoveries & extensions	97	8,864	27	8,813	70	51
Purchases of reserves	307	–	307	–	–	–
Production	(856)	(2,477)	(684)	(219)	(172)	(2,258)
Sales of reserves	(491)	(151)	(491)	(112)	–	(39)
Proved Reserves, December 31, 1983	9,777	28,625	8,721	16,967	1,056	11,658

Proved Developed Reserves

December 31, 1980	13,474	11,765	12,604	6,785	870	4,980
December 31, 1981	15,518	29,302	13,126	6,952	2,392	22,350
December 31, 1982	9,885	22,260	8,950	7,872	935	14,388
December 31, 1983	8,808	27,257	8,217	16,230	591	11,027

Table 2

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Capitalized Costs Relating to Oil and Gas Producing Activities

As at December 31, 1983, 1982 and 1981

	1983			1982			1981		
	Total	Canada	U.S.A.	Total	Canada	U.S.A.	Total	Canada	U.S.A.
Capitalized costs—									
Unproductive properties not being amortized	$ –	$ –	$ –	$ –	$ –	$ –	$ 15,100	$ –	$15,100
Properties being amortized—									
Productive and non-productive properties	153,867	54,301	99,566	152,749	58,031	94,718	123,710	48,992	74,718
Unevaluated properties	28,206	2,346	25,860	27,179	4,348	22,831	25,001	5,091	19,910
Costs being amortized	182,073	56,647	125,426	179,928	62,379	117,549	148,711	54,083	94,628
Total capitalized costs	182,073	56,647	125,426	179,928	62,379	117,549	163,811	54,083	109,728
Less: Accumulated depreciation, depletion and amortization	92,284	13,541	78,743	58,662	10,349	48,313	19,512	7,390	12,122
Net capitalized costs	$89,789	$43,106	$46,683	$121,266	$52,030	$69,236	$144,299	$46,693	$97,606

Table 3

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Costs Incurred in Property Acquisition, Exploration, and Development Activities

For the Years Ended December 31, 1983, 1982 and 1981

	1983			1982			1981		
	Total	Canada	U.S.A.	Total	Canada	U.S.A.	Total	Canada	U.S.A.
Costs incurred—									
Acquisition of unproved properties	$ 385	$ 182	$ 203	$ 3,443	$ 260	$ 3,183	$ 29,669	$ 836	$28,833
Acquisition of proved properties	774	774	–	2,057	2,057	–	–	–	–
Exploration	2,062	193	1,869	5,328	1,305	4,023	10,612	1,540	9,072
Development	3,931	2,279	1,652	24,788	4,674	20,114	36,991	1,203	35,788
Total costs incurred	$ 7,152	$ 3,428	$ 3,724	$ 35,616	$ 8,296	$27,320	$ 77,272	$ 3,579	$73,693

Table 4

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Results of Operations From Oil and Gas Producing Activities

For the Years Ended December 31, 1983, 1982 and 1981

	1983			1982			1981		
	Total	Canada	U.S.A.	Total	Canada	U.S.A.	Total	Canada	U.S.A.
Revenues from oil and gas producing activities	$ 40,067	$ 24,737	$ 15,330	$ 42,529	$ 16,723	$ 25,806	$ 29,482	$ 12,704	$ 16,778
Production costs and production taxes	10,562	7,124	3,438	11,553	6,053	5,500	11,140	4,975	6,165
Write-down of capital costs	18,486	–	18,486	25,369	–	25,369	–	–	–
Depreciation, depletion and amortization	14,197	3,192	11,005	13,960	2,959	11,001	7,357	1,612	5,745
Total expenses	43,245	10,316	32,929	50,882	9,012	41,870	18,497	6,587	11,910
Pretax income (loss)	(3,178)	14,421	(17,599)	(8,353)	7,711	(16,064)	10,985	6,117	4,868
Income tax expense	(4,528)	(4,528)	–	(3,224)	(3,224)	–	(3,978)	(2,895)	(1,083)
Results of oil and gas producing activities (excluding corporate overhead and interest costs)	$ (7,706)	$ 9,893	$(17,599)	$ (11,577)	$ 4,487	$ (16,064)	$ 7,007	$ 3,222	$ 3,785

Table 5

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Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves*

At December 31, 1983, 1982 and 1981

	1983			1982			1981		
	Total	Canada	U.S.A.	Total	Canada	U.S.A.	Total	Canada	U.S.A.
Future cash inflows	$415,197	$334,354	$ 80,843	$406,098	$302,133	$103,965	$631,309	$404,696	$226,613
Future costs–									
Production	(132,253)	(106,988)	(25,265)	(120,156)	(86,640)	(33,516)	(181,343)	(136,296)	(45,047)
Development and abandonment costs	(4,500)	(3,898)	(602)	(3,432)	(3,297)	(135)	(25,366)	(7,461)	(17,905)
Future net inflows before income tax	278,444	223,468	54,976	282,510	212,196	70,314	424,600	260,939	163,661
Future income taxes	(79,384)	(79,384)	–	(46,913)	(46,913)	–	(102,379)	(66,234)	(36,145)
Future net cash flows	199,060	144,084	54,976	235,597	165,283	70,314	322,221	194,705	127,516
10% discount factor	(89,687)	(72,319)	(17,368)	(109,816)	(87,204)	(22,612)	(155,843)	(122,452)	(33,391)
Standardized measure of discounted future net cash flows	$109,373	$ 71,765	$ 37,608	$125,781	$ 78,079	$ 47,702	$166,378	$ 72,253	$ 94,125

* The present value, discounted at an annual rate of 10%, of estimated future net cash flows related to proved reserves. Estimated future net cash flows are calculated by applying current prices of oil and natural gas (and future price changes to the extent provided by existing contractual arrangements) to proved reserves to arrive at estimated future cash inflows, and subtracting estimated future development and production costs (based on current costs) and estimated future income tax expenses relating to such inflows and costs.

Table 6

PAGE PETROLEUM LTD.

Changes in Standardized Measure of Discounted Future Net Cash Flow

From Proved Reserve Quantities For the Years Ended December 31, 1983, 1982 and 1981

	1983			1982			1981		
	Total	Canada	U.S.A.	Total	Canada	U.S.A.	Total	Canada	U.S.A.
Standardized measure—beginning of year	$125,781	$78,079	$47,702	$166,378	$72,253	$94,125	$106,816	$64,003	$42,813
Sales and transfers, net of production costs	(29,505)	(17,613)	(11,892)	(30,977)	(10,670)	(20,307)	(18,341)	(7,728)	(10,613)
Net change in sales and transfer prices, net of production costs	10,024	6,336	3,688	16,676	20,534	(3,858)	2,558	6,407	(3,849)
Extensions, discoveries and improved recovery, net of future production and development costs	4,666	4,097	569	4,913	1,358	3,555	43,114	4,995	38,119
Development costs incurred during the period which reduced future development costs	1,530	1,200	330	17,900	5,180	12,720	8,675	2,244	6,431
Revisions of quantity estimates	(4,194)	2,944	(7,138)	(83,301)	(40,686)	(42,615)	9,731	(7,541)	17,272
Accretion of discount	14,542	9,772	4,770	19,821	9,136	10,685	13,861	8,453	5,408
Net change in income taxes	(11,580)	(11,580)	–	12,193	(530)	12,723	(36)	1,420	(1,456)
Purchases of reserves in place	4,170	4,170	–	8,605	8,605	–	–	–	–
Sales of reserves in place	(4,725)	(4,632)	(93)	(22,896)	(3,570)	(19,326)	–	–	–
Changes in production rates (timing) and other	(1,336)	(1,008)	(328)	16,469	16,469	–	–	–	–
Standardized measure—end of year	$109,373	$71,765	$37,608	$125,781	$78,079	$47,702	$166,378	$72,253	$94,125

ITEM 9 — DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE — None

PART III

ITEM 10 — DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT
ITEM 11 — EXECUTIVE COMPENSATION
ITEM 12 — SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT
ITEM 13 — CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information called for by Items 10, 11, 12 and 13 of Form 10-K, to the extent not included in Part I of this Report, is incorporated herein by reference to such information appearing under the captions "Proposal on Election of Directors" and "Remuneration of Management and Management Contracts" contained in the Company's Proxy Statement and Information Circular relating to the Annual General Meeting of Shareholders to be held May 23, 1984.

PART IV

ITEM 14 — EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

		Page
(a) **1. Financial Statements and Supplementary Data (See Index)**		20
2. Financial Statement Schedules		
Schedule V	Property, Plant and Equipment	45
Schedule VI	Accumulated Depreciation, Depletion and Amortization of Property, Plant and Equipment	46

Schedules other than those listed above are omitted for the reason that they are not required or are not applicable, or the required information is shown in the financial statements or notes thereto.

3. Exhibits

3(a) Articles of Continuance of Page Petroleum Ltd. (filed as Schedule A to the definitive Proxy Statement and Information Circular of Page Petroleum Ltd. dated May 3, 1983, File No. 1-7888).*

3(b) General By-Law No. 1 of Page Petroleum Ltd. (filed as Schedule B in the definitive Proxy Statement and Information Circular of Page Petroleum Ltd. dated May 3, 1983, File No. 1-7888).*

4(a) Indenture dated as of April 1, 1980 between the Company and the Bank of New York, providing for 10% Convertible Subordinated Debentures due 2000 (filed as Exhibit 4.03 to Registration Statement No. 2-66886).*

4(b) $30,000,000 (U.S.) Revolving Loan Agreement dated as of March 10, 1982 between Page Petroleum Inc. and The Royal Bank of Canada (filed as Exhibit 10(xv) to Annual Report on Form 10-K for the year ended December 31, 1981, File No. 0-6318).*

4(c) $100,000,000 Debenture dated June 9, 1981, granted by Page Petroleum Ltd. to The Royal Bank of Canada (filed as Exhibit 10(xvi) to Annual Report on Form 10-K for the year ended December 31, 1981. File No. 0-6318).*

9 No Exhibit

10(a) Offer to Sublease dated June 3, 1983, between Canbell Leasing Ltd. and Page Petroleum Ltd.

10(b) Agreement dated as of January 1, 1983, between KEP Resources, a Michigan partnership, and Page Petroleum Inc. (filed as Exhibit 10(xii) to Annual Report on Form 10-K for the year ended December 31, 1982, File No. 1-7888).*

*Incorporated herein by reference

3. Exhibits (Continued)

10(c) 1980 Incentive Share Option Plan of Page Petroleum Ltd. (filed as Exhibit 10(xiii) to Annual Report on Form 10-K for the year ended December 31, 1980, File No. 0-6318).*

10(d) Amendments to 1980 Incentive Share Option Plan of Page Petroleum Ltd. (filed as Schedule A to the definitive Proxy Statement and Information Circular of Page Petroleum Ltd. dated April 13, 1982, File No. 1-7888).*

10(e) Form of Share Option Agreement under the 1980 Incentive Share Option Plan of Page Petroleum Ltd. (filed as Exhibit 10(xvii) to Annual Report on Form 10-K for the year ended December 31, 1981, File No. 0-6318).*

10(f) Stock Purchase Plan of Page Petroleum Ltd. (filed as Exhibit 5.02 to Registration Statement No. 2-66886).*

10(g) Form of Agreement under Stock Purchase Plan (filed as Exhibit 5.03 to Registration Statement No. 2-66886).*

10(h) Deferred Compensation Agreement dated as of February 10, 1982, between Page Petroleum Ltd. and Lawton L. Clark.

10(i) Employment Agreement dated November 1, 1983, between The Stanwick Organization, Incorporated and Page Petroleum Ltd., to provide the services of Donald D. McCuaig to act as Chief Executive Officer of the Registrant.

10(j) Bank Debt Terms and Conditions Agreement dated February 21, 1984 between The Royal Bank of Canada, Page Petroleum Ltd. and Page Petroleum Inc.

11 Statement re: Computation of Per Share Earnings

13 No Exhibit

18 No Exhibit

19 No Exhibit

22 Subsidiaries of Page Petroleum Ltd.

23 No Exhibit

24(a) Consent of Arthur Andersen & Co.

(b) Consent of D & S Petroleum Consultants (1974) Ltd.

(c) Consent of Sipes, Williamson & Associates, Inc.

25 Powers of Attorney

28 No Exhibit

Copies of the above Exhibits are available to Shareholders by written request to the Secretary at the principal executive offices of the Registrant and upon payment of a fee covering the expenses of the Registrant in furnishing such Exhibits.

(b) **Reports on Form 8-K**

One report on Form 8-K was filed during the fourth quarter of the year ended December 31, 1983. Said report responded to Item 1 of Form 8-K and disclosed the granting of an irrevocable option to purchase shares of the Company held by Mr. Lawton L. Clark (who may be deemed a "control person" of the Company) to The Royal Bank of Canada.

*Incorporated herein by reference

SCHEDULE V

PAGE PETROLEUM LTD. AND SUBSIDIARIES

PROPERTY, PLANT AND EQUIPMENT
(Thousands of Canadian dollars)

	Balance at Beginning of Year	Additions, at cost	Retirements or Sales	Other Changes Add (Deduct)	Balance at End of Year
Year Ended December 31, 1983					
Petroleum and natural gas leases and rights, including exploration, development and production equipment costs thereon	$184,128	$ 7,302	$ 9,888	$4,449	$185,991
Pipeline facilities	15,769	195	6,372	242	9,834
Sundry equipment	8,649	237	784	38	8,140
	$208,546	$ 7,734	$17,044	$4,729	$203,965
Year Ended December 31, 1982					
Petroleum and natural gas leases and rights, including exploration, development and production equipment costs thereon	$164,055	$42,079	$22,006	$ –	$184,128
Pipeline facilities	8,052	7,717	–	–	15,769
Sundry equipment	3,306	5,781	438	–	8,649
	$175,413	$55,577	$22,444	$ –	$208,546
Year Ended December 31, 1981					
Petroleum and natural gas leases and rights, including exploration, development and production equipment costs thereon	$ 86,775	$77,803	$ 523	$ –	$164,055
Pipeline facilities	–	8,052	–	–	8,052
Sundry equipment	1,789	1,847	443	113	3,306
	$ 88,564	$87,702	$ 966	$ 113	$175,413

See Notes 1(c) and (d) of the Notes to the Consolidated Financial Statements appearing in Item 8 of this Report for disclosure of the methods and rates used in computing the annual provision for depreciation, depletion and amortization of property, plant and equipment.

SCHEDULE VI

PAGE PETROLEUM LTD. AND SUBSIDIARIES

ACCUMULATED DEPRECIATION, DEPLETION AND AMORTIZATION OF PROPERTY, PLANT AND EQUIPMENT
(Thousands of Canadian dollars)

	Balance at Beginning of Year	Provisions and Write-downs Charged to Earnings	Retirements or Sales	Other Changes Add (Deduct)	Balance at End of Year
Year Ended December 31, 1983					
Petroleum and natural gas leases and rights, including exploration, development and production equipment costs thereon	$60,640	$32,551	$ –	$2,988	$ 96,179
Pipeline facilities	9,983	1,147	4,367	267	7,030
Sundry equipment	2,310	1,234	289	21	3,276
	$72,933	$34,932	$ 4,656	$3,276	$106,485
Year Ended December 31, 1982					
Petroleum and natural gas leases and rights, including exploration, development and production equipment costs thereon	$19,745	$40,895	$ –	$ –	$ 60,640
Pipeline facilities	–	9,983	–	–	9,983
Sundry equipment	1,266	1,282	238	–	2,310
	$21,011	$52,160	$ 238	$ –	$ 72,933
Year Ended December 31, 1981					
Petroleum and natural gas leases and rights, including exploration, development and production equipment costs thereon	$12,149	$ 7,596	$ –	$ –	$ 19,745
Pipeline facilities	–	–	–	–	–
Sundry equipment	971	375	193	113	1,266
	$13,120	$ 7,971	$ 193	$ 113	$ 21,011

SIGNATURES

Pursuant to the requirements of the Section 13 or 15(d) 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.

PAGE PETROLEUM LTD.
(Registrant)

By: S/S WILLIAM R. HARRISON
William R. Harrison
Vice-President Finance

March 28, 1984

Pursuant to the requirements of the Securities Act of 1934, this Report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

	Title
Donald D. McCuaig	Director and Chairman of the Board (Principal Executive Officer)
Lawton L. Clark	Director and President
William R. Harrison	Director and Vice-President, Finance (Principal Financial Officer)
Brian G. McCombe	Director
John W. Gregg	Director
John S. Hecht	Controller (Principal Accounting Officer)

By his signature set forth below, William R. Harrison, pursuant to duly executed Powers of Attorney filed with the Securities and Exchange Commission as exhibits to this Report, has signed this Report on behalf of and as Attorney-in-Fact for the persons whose signatures are printed above, in the capacities set forth opposite their respective names.

S/S WILLIAM R. HARRISON
William R. Harrison
Attorney-in-Fact

March 28, 1984

PAGE

PETROLEUM LTD.

April 24, 1984

To the Shareholders of
Page Petroleum Ltd.

Please find attached Page Petroleum Ltd. 1983 financial statements prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). The financial statements contained in Page's 1983 Annual Report are prepared in accordance with United States generally accepted accounting principles ("U.S. GAAP"). Both sets of statements are expressed in Canadian dollars.

In 1983, Page was placed in an unusual position of being required to issue Canadian GAAP statements to satisfy reporting requirements of the Ontario Securities Commission and the Alberta Securities Commission, and U.S. GAAP statements for the Securities and Exchange Commission in Washington, D.C. This change, from reporting only Canadian GAAP in past years to reporting both Canadian and U.S. GAAP for this year, was a result of reporting requirement changes made by the United States Securities and Exchange Commission.

The difference between the two sets of financial statements results from exchange rates used when translating Page's U.S. operations into Canadian dollars. Under Canadian GAAP the long-term debt and fixed assets are converted using historical exchange rates. Under U.S. GAAP long-term debt is converted to Canadian dollars using the current rate, which is the rate in effect at balance sheet date. Fixed assets under U.S. GAAP were converted at historical exchange rates to December 31, 1982 and current rates thereafter. The Canadian/U.S. GAAP differences are further detailed in footnote 1 of the financial statements.

I hope you find the comparison of Canadian and U.S. reporting requirements interesting and informative.

Yours very truly,

PAGE PETROLEUM LTD.

W. R. Harrison
Vice-President Finance

WRH/jg
Attachments

1000, 635 - 8th Avenue S.W., Calgary, Alberta T2P 3M3 Telephone (403) 269-8221 Telex 03-821268

FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX

AUDITORS' REPORT

To the Shareholders of
Page Petroleum Ltd.

We have examined the consolidated balance sheets of Page Petroleum Ltd. (an Alberta corporation) as of December 31, 1983, 1982 and 1981 and the related consolidated statements of earnings, shareholders' equity, changes in financial position and income taxes for the three years then ended. Our examinations were made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as we considered necessary in the circumstances.

In our opinion, the accompanying consolidated financial statements present fairly the financial position of Page Petroleum Ltd. as of December 31, 1983, 1982 and 1981 and the results of its operations and the changes in its financial position for the years then ended in accordance with generally accepted accounting principles applied on a consistent basis.

Calgary, Alberta
February 21, 1984
(except with respect to the matters discussed in Note 12, as to which the date is April 5, 1984)

ARTHUR ANDERSEN & CO.
Chartered Accountants

Comment by Auditors on Differences in
Canada-United States Reporting Standards

In the United States, reporting standards for auditors require the expression of an opinion qualified as being subject to the outcome of significant uncertainties affecting the financial statements such as the significant uncertainty relating to the continued financial support of the Company's bankers referred to in Note 5 to the accompanying consolidated financial statements.

The opinion in our report to the shareholders, dated February 21, 1984, is expressed in accordance with Canadian standards and is not qualified with respect to, and provides no reference to, this uncertainty since such an opinion would not be in accordance with Canadian reporting standards for auditors when the uncertainties are adequately disclosed in the financial statements.

Calgary, Alberta
February 21, 1984
(except with respect to the matters discussed in Note 12, as to which the date is April 5, 1984)

ARTHUR ANDERSEN & CO.
Chartered Accountants

PAGE PETROLEUM LTD.

CONSOLIDATED STATEMENTS OF EARNINGS

Years Ended December 31, 1983, 1982 and 1981
(Thousands of Canadian dollars, except share data)

	1983	1982	1981
INCOME			
Oil and gas sales, net of royalties	$ 40,067	$ 42,530	$ 29,482
Pipeline operating revenue	7,277	7,589	–
Well servicing and rig lease revenue	611	1,187	659
Investment and other income	874	174	1,007
	48,829	51,480	31,148
EXPENSES			
Production	7,957	9,416	8,164
Pipeline operating costs	5,939	6,099	–
Well servicing and rig lease	452	932	507
Federal production taxes	2,392	1,865	2,977
General and administrative	3,315	3,844	4,005
Interest and bank charges (Note 5)	18,414	23,015	13,800
Depreciation, depletion and amortization	15,048	17,124	7,778
Write-down of capital costs in excess of net realizable value (Note 3)	19,882	34,957	–
Amortization of deferred financing charges	375	373	375
Minority interest	(830)	(833)	26
	72,944	96,792	37,632
(Loss) from continuing operations before income taxes	(24,115)	(45,312)	(6,484)
PROVISION FOR (RECOVERY OF) INCOME TAXES			
Current	(397)	(1,230)	(451)
Deferred	2,965	1,215	(316)
	2,568	(15)	(767)
(Loss) from continuing operations	(26,683)	(45,297)	(5,717)
PROVISION FOR (LOSS) ON DISPOSAL OF DISCONTINUED BUSINESSES	–	(919)	(1,022)
NET (LOSS)	$ (26,683)	$ (46,216)	$ (6,739)
(Loss) from continuing operations per common share (basic and fully diluted)	$ (7.35)	$ (12.50)	$ (1.60)
Net (loss) per common share (basic and fully diluted)	$ (7.35)	$ (12.76)	$ (1.89)
Weighted average number of common shares outstanding	3,631,750	3,623,120	3,562,131

The accompanying notes are an integral part of these consolidated financial statements.

PAGE PETROLEUM LTD.

CONSOLIDATED BALANCE SHEETS

December 31, 1983, 1982 and 1981
(Thousands of Canadian dollars)

	1983	1982	1981
ASSETS			
CURRENT ASSETS			
Cash and short-term investments (including restricted cash [Note 5(d)(i)])	$ 4,704	$ 2,649	$ 1,385
Accounts receivable (Note 5)	9,207	9,634	9,928
Provincial royalty tax credit	14	1,015	452
Inventories	1,660	1,664	3,033
Prepaid expenses	103	135	89
	15,688	15,097	14,887
INVESTMENTS AND ADVANCES (Note 2)	–	35	4,895
PROPERTY, PLANT AND EQUIPMENT – at cost (including oil and gas properties accounted for by the full cost method of accounting) (Notes 3 and 5)	199,236	208,546	175,413
Less accumulated depreciation, depletion and amortization	103,209	72,933	21,011
	96,027	135,613	154,402
OTHER ASSETS (Note 4)	1,200	2,248	2,993
	$112,915	$152,993	$ 177,177
LIABILITIES AND SHAREHOLDERS' EQUITY			
CURRENT LIABILITIES			
Outstanding cheques	$ 1,329	$ 1,731	$ 4,479
Accounts payable and accrued liabilities	15,017	18,764	29,682
Current maturities of long-term debt (Note 5)	11,173	16,949	301
	27,519	37,444	34,462
LONG-TERM DEBT (Note 5)	138,061	143,666	126,915
DEFERRED INCOME TAXES	5,654	2,689	1,474
MINORITY INTEREST	75	905	26
COMMITMENTS AND CONTINGENCIES (Notes 5, 6 and 9)			
SHAREHOLDERS' EQUITY			
Share capital (Notes 7 and 8)			
Authorized			
10,000,000 Preferred Shares without nominal or par value			
20,000,000 Common Shares without nominal or par value			
Issued and outstanding Common Shares	21,570	21,570	21,365
Contributed surplus	250	250	250
Capital redemption reserve fund (Note 7)	204	204	204
(Deficit)	(80,418)	(53,735)	(7,519)
	(58,394)	(31,711)	14,300
	$112,915	$152,993	$ 177,177

Approved on Behalf of the Board

DIRECTOR Donald D. McCuaig

DIRECTOR Lawton L. Clark

The accompanying notes are an integral part of these consolidated financial statements.

PAGE PETROLEUM LTD.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

Years Ended December 31, 1983, 1982 and 1981
(Thousands of Canadian dollars, except share data)

	Common Shares		Contributed Surplus	Capital Redemption Reserve Fund	(Deficit)
	Shares	Amount			
Balances, December 31, 1980	3,492,750	$20,453	$250	$204	$ (780)
Lease acquisition	55,000	808	–	–	–
Exercise of employee stock options	11,500	104	–	–	–
Common shares granted under Employee Incentive Share Purchase Plan (Note 8)	35,000	–	–	–	–
Net (loss)	–	–	–	–	(6,739)
Balances, December 31, 1981	3,594,250	21,365	250	204	(7,519)
Exercise of employee stock options	25,000	205	–	–	–
Common shares granted under Employee Incentive Share Purchase Plan (Note 8)	12,500	–	–	–	–
Net (loss)	–	–	–	–	(46,216)
Balances, December 31, 1982	3,631,750	21,570	250	204	(53,735)
Net (loss)	–	–	–	–	(26,683)
Balances, December 31, 1983	3,631,750	$21,570	$250	$204	$(80,418)

The accompanying notes are an integral part of these consolidated financial statements.

PAGE PETROLEUM LTD.

CONSOLIDATED STATEMENTS OF CHANGES IN FINANCIAL POSITION

Years Ended December 31, 1983, 1982 and 1981
(Thousands of Canadian dollars)

	1983	1982	1981
SOURCES OF FUNDS			
(Loss) from continuing operations	$(26,683)	$(45,297)	$ (5,717)
(Loss) from discontinued operations	–	(919)	(1,022)
Charges (credits) to earnings not involving funds			
Depreciation, depletion and amortization	15,423	17,497	8,153
Write-down of capital costs in excess of net realizable value	19,882	34,957	–
Deferred income taxes	2,965	1,215	(316)
Provision for loss on disposal or discontinuance	–	919	1,022
Minority interest	(830)	(833)	26
Funds generated from operations	10,757	7,539	2,146
Proceeds from issuance of common shares	–	205	912
Increase in long-term debt	779	33,107	115,634
Proceeds from sale of property, plant and equipment	12,252	22,006	–
Proceeds on disposition of assets of subsidiaries	–	1,068	3,042
Reduction of other assets	673	372	(84)
	24,461	64,297	121,650
USES OF FUNDS			
Additions to property, plant and equipment	7,596	49,370	86,736
Additions to property, plant and equipment on consolidation of Springwest-Page Petroleums N.L., net of working capital acquired and minority interest	–	2,426	–
Repayment and current maturities of long-term debt	6,384	15,230	51,001
Investment in and advances to unconsolidated and affiliated companies	(35)	43	2,399
	13,945	67,069	140,136
Increase (decrease) in working capital	10,516	(2,772)	(18,486)
Working capital (deficiency), beginning of year	(22,347)	(19,575)	(1,089)
Working capital (deficiency), end of year	$(11,831)	$(22,347)	$ (19,575)
WORKING CAPITAL CHANGES			
Increase (decrease) in current assets			
Cash	$ 2,055	$ 1,264	$ 1,181
Accounts receivable	(427)	(294)	2,536
Provincial royalty tax credit	(1,001)	563	197
Inventories	(4)	(1,369)	1,564
Prepaid expenses	(32)	46	16
	591	210	5,494
Increase (decrease) in current liabilities			
Outstanding cheques	(402)	(2,748)	2,391
Accounts payable and accrued liabilities	(3,747)	(10,918)	21,517
Current maturities of long-term debt	(5,776)	16,648	72
	(9,925)	2,982	23,980
Increase (decrease) in working capital	$ 10,516	$ (2,772)	$ (18,486)

The accompanying notes are an integral part of these consolidated financial statements.

PAGE PETROLEUM LTD.

CONSOLIDATED STATEMENTS OF INCOME TAXES

Years Ended December 31, 1983, 1982 and 1981
(Thousands of Canadian dollars)

	1983	1982	1981
Computation of Income Taxes – The total provision for (recovery of) income taxes differs from the amount which would be computed by applying the statutory income tax rates to book (loss) before income taxes. The reasons for this difference are as follows:			
Book (loss) from continuing operations before provision for income taxes	$(24,115)	$(45,312)	$(6,484)
Computed "expected" tax (recovery)	$(11,470)	$(21,885)	$ (3,127)
Tax effect of royalties and other payments to provincial governments which are disallowed as deductions for Canadian federal income tax	2,248	2,961	2,596
Rebates by provincial governments related to payments disallowed for Canadian federal income tax	(397)	(1,237)	(452)
Depletion allowance on oil and gas production income	(1,005)	(495)	–
Federal resource allowance	(2,487)	(1,811)	(1,241)
Tax losses not booked due to a lack of virtual certainty of recovery	15,637	22,367	1,516
Provincial income taxes less federal abatements	50	(70)	5
Incremental Oil Revenue – tax exempt income	–	(141)	–
Other	(8)	296	(64)
Actual tax expense (recovery)	$ 2,568	$ (15)	$ (767)
Tax rate	48%	48%	48%
An analysis of actual tax expense (recovery) follows:			
Canada	$ 2,568	$ (15)	$ 33
United States	–	–	(800)
	$ 2,568	$ (15)	$ (767)
Deferred Income Taxes – Result from timing differences in the recognition of expenses for tax and accounting purposes. The source of these differences and tax effect of each are as follows:			
Difference between income tax depreciation and amount provided for depreciation in the accounts	$ (450)	$ (82)	$ (762)
Difference between exploration and development expenditures claimed for income tax purposes and amount provided for depletion in the accounts	3,415	1,297	446
	$ 2,965	$ 1,215	$ (316)

The accompanying notes are an integral part of these consolidated financial statements.

1 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements have been prepared on a going concern basis (See Note 5) in accordance with generally accepted accounting principles ("GAAP") in Canada and conform in all material respects with the standards of the International Accounting Standards Committee. These consolidated financial statements differ from the consolidated financial statements prepared in accordance with the requirements of the Securities and Exchange Commission in the United States. The differences between the Canadian and U.S. consolidated financial statements are as follows:

	Consolidated Balance Sheets			Consolidated Statements of Earnings			
	Property, Plant and Equipment	Long-Term Debt	Shareholders' Equity	(Loss) from Continuing Operations	Net (Loss)	(Loss) from Continuing Operations Per Common Share	Net (Loss) Per Common Share
Year Ended December 31:							
1981							
Canadian GAAP..	$154,402	$126,915	$ 14,300	$ (5,717)	$ (6,739)	$ (1.60)	$ (1.89)
Difference	–	120	(120)	490	490	.13	.13
U.S. GAAP	$154,402	$127,035	$ 14,180	$ (5,227)	$ (6,249)	$ (1.47)	$ (1.76)
1982							
Canadian GAAP..	$135,613	$143,666	$(31,711)	$(45,297)	$(46,216)	$(12.50)	$ (12.76)
Difference	–	4,217	(4,217)	(4,097)	(4,097)	(1.13)	(1.13)
U.S. GAAP	$135,613	$147,883	$(35,928)	$(49,394)	$(50,313)	$(13.63)	$ (13.89)
1983							
Canadian GAAP..	$ 96,027	$138,061	$(58,394)	$(26,683)	$(26,683)	$ (7.35)	$ (7.35)
Difference	1,453	5,244	(3,791)	(862)	(862)	(.23)	(.23)
U.S. GAAP	$ 97,480	$143,305	$(62,185)	$(27,545)	$(27,545)	$ (7.58)	$ (7.58)

The differences are due to the adoption of FASB Statement No. 8 (foreign currency translation) for U.S. GAAP reporting in years prior to 1983 and FASB Statement No. 52 (foreign currency translation) thereafter.

The cumulative impact of the differences for years prior to 1981 for U.S. GAAP is to increase long-term debt and decrease shareholders' equity by $610. This is included in the above analysis.

(a) Principles of Consolidation

The consolidated financial statements include the accounts of the Company's wholly owned subsidiaries, Page Petroleum Inc. and Page Petroleum (U.K.) Limited, and its controlling interests in Springwest-Page Petroleums N.L. (commencing in 1982) and R.D.R. Well Servicing Ltd. The investment in Pirate Drilling Ltd. was accounted for by the equity method (See Note 2).

(b) Full Cost Method of Accounting

The Company and its subsidiaries follow the full cost method of accounting for oil and gas operations whereby all costs of exploring for and developing oil and gas reserves are capitalized and charged against earnings as set out in Note 1(c). Such costs include land acquisition costs, geological and geophysical expense, carrying charges of non-producing property, costs of drilling both productive and non-productive wells, production equipment and overhead expense related to exploration and development activities. The costs are accumulated in cost centres as follows; Canada, United States, United Kingdom and Australia.

1 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Costs associated with a purchase of leases in Michigan, excluded from the U.S. cost centre for depletion purposes in 1981, have been included in the full cost pool since October 1, 1982. The capital costs associated with the previously excluded leases are $16,565, including $1,853 of interest capitalized.

Proceeds on disposal of properties are deducted from accumulated costs without recognition of gain or loss. Any gain or loss realized on the disposition of a major property would be recognized in the statement of earnings.

(c) Depletion

The costs accumulated in the Canadian and U.S. cost centres, together with estimated future capital costs associated with developing proved reserves, are depleted using the future revenue method based upon estimated future cash flows, with no price escalations and net of royalties, to be derived from total proved reserves as determined by independent engineers.

Costs associated with the United Kingdom cost centre are amortized in line with the terms of the leases. During 1983, the Company relinquished all of its remaining interest in its Australian oil and gas properties. All costs associated with the Australian cost centre are fully depleted at December 31, 1983.

(d) Depreciation

Depreciation of the pipeline facilities is computed on the diminishing balance method using a rate of 20%. Well servicing equipment in Canada is depreciated on a straight line basis over an estimated 7 year service life. Rig equipment located in Australia is depreciated on a straight line basis over an estimated 10 year service life. Depreciation of sundry equipment is computed on the diminishing balance method at rates varying from 20% to 30%.

(e) Inventories

Inventories are recorded at the lower of cost or net realizable value and consist of equipment and supplies for the Company's oil and gas operations.

(f) Joint Venture Accounting

Substantially all the Company's exploration, production and pipeline operations are conducted jointly with others and accordingly the accounts reflect only the Company's proportionate interest in such activities.

(g) Limited Partnerships

The Company is involved in certain limited partnerships for the purpose of producing oil and gas. The Company's investment in these limited partnerships is reflected on a proportionate consolidation basis.

(h) Deferred Financing Costs

Costs incurred in connection with the issuance of capital stock and the debentures are deferred and amortized using the straight line method over seven years from the date of the respective issues.

(i) Foreign Currency Translation

Current assets and current liabilities of foreign subsidiaries are translated to Canadian dollars using the exchange rates in effect at the year-end. Other assets and liabilities are translated at the rates in effect at the dates the original transactions took place. Income and expense items are translated using average rates of exchange prevailing throughout the year, except for items relating to balance sheet accounts that are translated at historical exchange rates. The aggregate exchange gains or losses in each of the three years ended December 31, 1983 were not significant and have been included in general and administrative expenses.

1 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

(j) Income Taxes

The Company follows interperiod tax allocation with respect to timing differences in the recognition of income and expenses for tax and accounting purposes. See the Consolidated Statements of Income Taxes for the components of and additional information relating to income taxes.

(k) Interest Costs

Interest is charged against earnings with the exception of $1,465 capitalized in 1982 and $388 capitalized in 1981 as being applicable to the cost of acquiring leases formerly excluded from the U.S. full cost pool [See Note 1(b)].

(l) Earnings per Common Share

Basic earnings per common share have been computed by dividing the net earnings applicable to common shares by the weighted average number of common shares outstanding during the years. In determining the weighted average number of shares, no consideration has been given to the number of common shares issuable on the exercise of employee stock options, or common shares issuable on conversion of securities convertible into common shares, as shares issued on these securities would have the effect of decreasing the loss per share.

Fully diluted earnings per share is consistent with basic earnings per share as the exercise of employee stock options or conversion of convertible securities was not considered for the reason stated above.

2 — INVESTMENTS AND ADVANCES

During February, 1982 the Company increased its investment in Springwest-Page Petroleums N.L. from 33.33% to 73.72% and as a result, Springwest-Page Petroleums N.L. has been consolidated since that date. It was formerly accounted for by the equity method.

The Company sold its remaining interest in Pirate Drilling Ltd. effective March 31,1983 for $105, a gain of $70 over the Company's investment of $35.

3 — PROPERTY, PLANT AND EQUIPMENT

The following is a breakdown of property, plant and equipment and accumulated depreciation, depletion and amortization by major classification:

	Assets at Cost	Accumulated Depreciation, Depletion and Amortization	Net Investment
December 31, 1983			
Petroleum and natural gas leases and rights, including exploration, development and production equipment costs thereon			
Canada	$ 56,647	$ 13,541	$ 43,106
United States	120,977	75,755	45,222
United Kingdom	285	262	23
Australia	3,633	3,633	–
	181,542	93,191	88,351
Pipeline facilities	9,592	6,763	2,829
Other	8,102	3,255	4,847
	$199,236	$103,209	$ 96,027
December 31, 1982			
Petroleum and natural gas leases and rights, including exploration, development and production equipment costs thereon			
Canada	$ 62,379	$ 10,349	$ 52,030
United States	117,549	48,313	69,236
United Kingdom	259	248	11
Australia	3,941	1,730	2,211
	184,128	60,640	123,488
Pipeline facilities	15,769	9,983	5,786
Other	8,649	2,310	6,339
	$208,546	$ 72,933	$135,613
December 31, 1981			
Petroleum and natural gas leases and rights, including exploration, development and production equipment costs thereon			
Canada	$ 54,083	$ 7,390	$ 46,693
United States	109,728	12,122	97,606
United Kingdom	244	233	11
	164,055	19,745	144,310
Pipeline facilities	8,052	–	8,052
Other	3,306	1,266	2,040
	$175,413	$ 21,011	$154,402

In 1983, a $17,978 write-down of U.S. assets ($33,227 write-down in 1982) and a $1,904 write-down of Page's interest in Australian assets ($1,730 write-down in 1982) were recorded to reflect properties at a realizable value less than their original costs. The write-downs are included in accumulated depreciation, depletion and amortization in the above table.

4 — OTHER ASSETS

	December 31		
	1983	1982	1981
Prepayments, drilling deposits and miscellaneous assets	$ 43	$ 129	$ 564
Lease deposits	63	63	–
Real estate held for resale	–	587	587
Unamortized deferred financing costs	1,094	1,469	1,842
	$ 1,200	$ 2,248	$ 2,993

The deferred financing costs were incurred in connection with the issue of the Company's 7% Cumulative Redeemable Convertible Preferred Shares and 10% Convertible Subordinated Debentures.

5 — LONG-TERM DEBT

	December 31		
	1983	1982	1981
Page Petroleum Ltd.			
Canadian bank loan, evidenced by promissory notes, at the bank's prime lending rate plus 1% [See (d)]	$ 10,307	$ 11,837	$ 7,203
10% Convertible Subordinated Debentures ($25,000 U.S.) [See (a) and (d)]	29,730	29,730	29,730
Other	–	–	290
Page Petroleum Inc.			
U.S. bank loans, evidenced by promissory notes [See (d)]			
– at the bank's prime rate plus ¼% to ½% ($54,739 U.S.)	65,762	73,269	58,900
– at LIBOR plus ½% ($30,000 U.S.)	36,040	36,040	29,812
KEP Resources – 10% ($3,866 U.S.) [See (b)]	4,786	5,106	–
6% Note payable	–	684	688
Springwest-Page Petroleums N.L. loans [See (c)]	2,536	3,499	–
Miscellaneous	73	450	593
	149,234	160,615	127,216
Less minimum current maturities	11,173	16,949	301
	$138,061	$143,666	$126,915

Interest on long-term debt amounted to $17,788 in 1983, $23,002 in 1982 and $13,800 in 1981. Bank charges and other fees amounted to $626 in 1983 and $13 in 1982.

(a) The 10% Convertible Subordinated Debentures are unsecured subordinated obligations maturing April 1, 2000. The debentures are convertible into 1,250,000 common shares at $20 (U.S.) per share, subject to adjustment under certain conditions and to prior redemption. The debentures are redeemable:

(i) At any time at the Company's option at prices declining from 108.42% to 100%.

(ii) Commencing April 1, 1991, at the principal amount through operation of a sinking fund, in an annual amount not less than 10% nor more than 20% of the debentures outstanding on March 31, 1990.

An exchange offer to holders of the debentures is currently being prepared. Mailing date is anticipated to be April, 1984 [See (d) and Note 12].

5 — LONG-TERM DEBT (Continued)

(b) The KEP Resources loan is secured by a mortgage on various oil and gas leases in Michigan. The principal amount is repayable in equal monthly installments of $50 (U.S.) with the final balance due July 10, 1984. It is a condition of the restructured bank indebtedness [See (d)], that the final balance due be extended to July 10, 1985. The Company is currently negotiating extension of the due date [See Note 12].

(c) The Export Development Corporation and other loans are secured by the assets of Springwest-Page Petroleums N.L. and/or guarantees of the shareholders of that company. The principal amounts are repayable in equal semi-annual installments during the next three years.

(d) The bank loans, both U.S. and Canadian, are secured by a general assignment of accounts receivable and certain oil and gas properties.

(i) During 1983, the bank continued to segregate and retain funds in a restricted account as further collateral against U.S. loans. Funds in this account as of December 31, 1983 and 1982 amounted to $3,318 (U.S.) and $2,364 (U.S.) respectively. Unpaid interest on the loans included in accrued liabilities as of December 31, 1983 amounted to $3,540 (U.S.).

The Company made principal repayments of $2,000 (U.S.) of the total $12,000 (U.S.) principal repayments due during 1983 as required by one of its U.S. loans.

As a result of the interest arrearages and the deficient installments due under the terms of the U.S. loans, the Company is in default. The bank has waived all rights and remedies in respect of the defaults. [See (d)(ii), (iii) and (iv)].

(ii) On February 21, 1984, the Company reached agreement in principle with its bank with respect to the restructuring of the Canadian and U.S. bank loans [See Note 12]. The restructured bank indebtedness will be secured and will consist of the following:

– $15 million revolving working capital line, payable on demand after three years, bearing interest at the bank's prime lending rate plus 1%.

– $75 million 12 year term loan, bearing interest at the bank's prime lending rate plus 1%, repayable monthly, commencing April 1, 1984 on the following schedule:

9 equal monthly payments of $569
12 equal monthly payments of $404
12 equal monthly payments of $332
96 equal monthly payments of $565
11 equal monthly payments of $566
1 final payment of $581

– $30 million debenture, five year term, repayable on demand after five years, bearing interest at the greater of 10% or the bank's U.S. prime lending rate plus 1%. Interest of 10% is payable in cash or interest notes (due in 1989) at the option of the Company. Interest in excess of 10% is payable in convertible Preferred Shares. The bank will be entitled to receive warrants to purchase a maximum of one-third of the Company's common shares outstanding in 1989 (on the fifth anniversary of the closing). The exercise price of the bank warrants will be the lesser of $7.50 (U.S.) or the weighted average market price of the common shares on the American Stock Exchange and The Toronto Stock Exchange during the three years ending five days before April 1, 1989.

(iii) As compensation for the restructuring, the bank is to receive a restructuring fee of 450,000 fully paid common shares of the Company and $2 million represented by a promissory note due in 1987 (on the third anniversary of the closing) bearing interest compounded annually at 12%.

5 — LONG-TERM DEBT (Continued)

(iv) The restructuring is dependent upon approval by various regulatory commissions and acceptance by July 31, 1984 of an exchange offer by a sufficient number of debentureholders which would result in a reduction by at least 80% in the cash interest expense on the existing $25 million (U.S.) 10% Convertible Subordinated Debentures [See (a) and Note 12]. It is a default condition under the terms of the Debt Restructure Agreement if the Company is unable to extend the due date of the KEP Resources loan [See (b) and Note 12]. It is also a condition that the bank must consent to any future transaction which would have the effect of diluting its equity interest in the Company.

The Company is dependent on the continued financial support of its bankers and the completion of the restructuring, including the acceptance by July 31, 1984 of the exchange offer referred to above. If support is withdrawn, the Company may be unable to continue realizing its assets and discharging its liabilities in the normal course of business. The financial statements do not include any adjustments relating to the recoverability and classification of recorded asset amounts or the amounts and classification of liabilities that might be necessary should the support of the bankers be withdrawn.

6 — COMMITMENTS AND CONTINGENCIES

The Company has guaranteed bank and other indebtedness of others to a maximum amount of $3,955.

7 — PREFERRED SHARES

During 1980, 953,276 of the Preferred Shares were converted into 504,283 common shares and the remainder were redeemed at $10.50 per share. In accordance with the provisions of The Alberta Companies Act, an amount of $204, equal to the par value of the shares redeemed, was transferred from retained earnings to the capital redemption reserve fund.

8 — COMMON SHARES

(a) *Shares Reserved for Conversion of 10% Convertible Subordinated Debentures*

There were 1,250,000 common shares reserved at December 31, 1983 for issuance upon the possible conversion of the $25,000 (U.S.) 10% Convertible Subordinated Debentures [See Note 5(a)].

(b) *Options to Purchase Common Shares*

There were 230,500 common shares reserved at December 31, 1983 for issuance upon the exercise, to 1988, of employee stock options at prices ranging from $2.38 to $4.84 per share. The total number of common shares reserved for options amounted to 500,000 at December 31, 1983.

The stock options have been granted from time to time to certain employees at a price equal to 85%, 100% and 110% of the fair market value of the common shares on the date of grant. New options granted are for a term of five years from the date of grant and are exercisable, on a cumulative basis, as to one-third of the option shares in each of the second, third and fourth years after the date of the grant. Stock options granted to replace existing options are also for a term of five years, and are exercisable on a cumulative basis, as to one-third of the option shares in each of the first, second and third years after the date of the grant. The options have become or will become exercisable without restriction in varying amounts at varying dates and by December 22, 1986, all of the options outstanding on December 31, 1983, will have become exercisable in full.

During 1982 and 1981 options for 25,000 and 11,500 common shares, respectively, were exercised at prices of $8.21 in 1982 and from $4.21 to $9.79 per common share in 1981. No stock options were exercised during 1983.

8 — COMMON SHARES (Continued)

(c) *Employee Incentive Share Purchase Plan*

A total of 47,500 shares were issued under an Employee Incentive Share Purchase Plan during 1982 and 1981 and were included in common shares outstanding at December 31, 1983. The Plan was amended in January 1984 to permit the Company to cancel loans to employees for the purchase of shares if the employees agreed to relinquish their rights in regard to shares issued under the Plan. In February 1984 the 47,500 shares were returned to authorized but unissued share capital. As of December 31, 1983, 300,000 common shares were reserved for issuance under the Plan.

9 — LEASE COMMITMENTS

The Company has certain lease obligations covering rental of computer facilities and office space. The minimum annual rental commitments under all leases are as follows:

1984	$ 543
1985	543
1986	327
1987	198
1988	149
	$1,760

10 — RELATED PARTY TRANSACTIONS

Legal services were provided to the Company by McCombe & Company, of which Mr. Brian G. McCombe, a Company director, is a partner. The Company and its subsidiaries paid $133, $131 and $141 in legal fees to McCombe & Company for the years 1983, 1982 and 1981 respectively.

Engineering consulting services were provided to the Company by Gregg Petroleum Consultants Ltd., of which a director, Mr. John W. Gregg, is a principal. The Company and subsidiaries paid $137 for these services in 1983.

11 — BUSINESS SEGMENTS

The Company is engaged primarily in oil and gas exploration and production and also has interests in well servicing, rig leasing and pipeline facilities.

The only arms-length purchaser which accounted for more than 10% of the Company's consolidated net revenues for 1983 was Imperial Oil Limited which purchased 42.9%. Trans-Pan also made purchases of 12.2% of the Company's consolidated income and presently delivers all of its pipeline products to Diamond Shamrock Corporation under a long-term supply contract.

The Company has oil and gas reserves and production and conducts its well servicing and pipeline operations in Canada and the United States. No reserves have been assigned for the United Kingdom cost centre. Rig leasing in Australia and the United Kingdom operations have been grouped as Other Foreign in the Geographic Regions table following:

11 — BUSINESS SEGMENTS (Continued)

	Year Ended December 31		
	1983	1982	1981
BUSINESS SEGMENTS			
Income			
Oil and gas	$ 40,067	$ 42,530	$ 29,482
Well servicing and rig leasing	611	1,187	659
Pipeline facilities	7,277	7,589	–
	$ 47,955	$ 51,306	$ 30,141
Depreciation, depletion and amortization			
Oil and gas	$ 12,935	$ 14,122	$ 7,738
Well servicing and rig leasing	966	877	40
Pipeline facilities	1,147	2,125	–
	$ 15,048	$ 17,124	$ 7,778
Write-down of capital costs in excess of net realizable value			
Oil and gas	$ 19,882	$ 27,099	$ –
Well servicing and rig leasing	–	–	–
Pipeline facilities	–	7,858	–
	$ 19,882	$ 34,957	$ –
Operating earnings (loss)			
Oil and gas	$ (3,099)	$ (9,116)	$ 10,603
Well servicing and rig leasing	(807)	(622)	112
Pipeline facilities	191	(9,349)	–
	(3,715)	(19,087)	10,715
Corporate and other			
Investment and other income	(874)	(174)	(1,007)
General and administrative	3,315	3,844	4,005
Interest and bank charges	18,414	23,015	13,800
Amortization of deferred financing charges	375	373	375
Minority interest	(830)	(833)	26
Income taxes	2,568	(15)	(767)
Loss on disposal of discontinued businesses	–	919	1,022
	22,968	27,129	17,454
Net (loss)	$ (26,683)	$ (46,216)	$ (6,739)
Identifiable assets			
Oil and gas	$104,921	$139,187	$168,914
Well servicing and rig leasing	4,007	5,866	939
Pipeline facilities	2,829	5,786	–
	111,757	150,839	169,853
Other	1,158	2,154	7,324
	$112,915	$152,993	$177,177

11 — BUSINESS SEGMENTS (Continued)

	Year Ended December 31		
	1983	1982	1981
GEOGRAPHIC REGIONS			
Income			
Canada	$ 25,109	$ 17,509	$ 13,363
United States	22,606	33,396	16,778
Other foreign	240	401	–
	$ 47,955	$ 51,306	$ 30,141
Depreciation, depletion and amortization			
Canada	$ 3,386	$ 3,263	$ 1,846
United States	10,778	13,125	5,924
Other foreign	884	736	8
	$ 15,048	$ 17,124	$ 7,778
Write-down of capital costs in excess of net realizable value			
Canada	$ –	$ –	$ –
United States	17,978	33,227	–
Other foreign	1,904	1,730	–
	$ 19,882	$ 34,957	$ –
Operating earnings (loss)			
Canada	$ 14,394	$ 7,590	$ 6,035
United States	(15,526)	(24,555)	4,688
Other foreign	(2,583)	(2,122)	(8)
	(3,715)	(19,087)	10,715
Corporate and other	22,968	27,129	17,454
Net (loss)	$ (26,683)	$ (46,216)	$ (6,739)
Identifiable assets			
Canada	$ 51,687	$ 60,376	$ 59,496
United States	57,458	85,319	117,669
Other foreign	3,770	7,298	12
	$112,915	$152,993	$177,177

12 — SUBSEQUENT EVENTS

(a) Under the terms of the restructured bank indebtedness [See Note 5(d)(iii)], on closing, the bank will receive 450,000 fully-paid common shares of the Company. As a result, the conversion price of the 10% Convertible Subordinated Debentures due 2000 ("Debentures") will be adjusted to $17.74 (U.S.) per share [See Note 5(a)].

The formal Debt Restructure Agreement was signed April 5, 1984. Modifications to the agreement reached in principle on February 21, 1984 [See Note 5(d)], include rescheduling of the $75 million 12 year term loan as follows:

– $37.5 million 12 year term loan, bearing interest at the bank's prime lending rate plus 1%, repayable monthly, commencing May 1, 1984 on the following schedule:

9 equal monthly payments of	$ 338
12 equal monthly payments of	$ 259
12 equal monthly payments of	$ 215
96 equal monthly payments of	$ 265
11 equal monthly payments of	$ 273
1 final payment of	$ 327

– $37.5 million 3 year term loan, bearing interest at the bank's prime lending rate plus 1%, repayable monthly, commencing May 1, 1984 on the following schedule:

9 equal monthly payments of	$ 225
12 equal monthly payments of	$ 141
12 equal monthly payments of	$ 115
2 equal monthly payments of	$ 294
1 final payment of	$31,815

Of the $75 million, $72 million ($57.6 million U.S.) is denominated and repayable in U.S. dollars.

(b) As of April 5, 1984, the Company intends to make an offer to exchange for each one thousand (U.S.) principal amount of its outstanding Debentures: (i) one thousand (U.S.) principal amount of its Senior Subordinated Convertible Notes due 1989 ("Notes"); (ii) common shares; (iii) warrants to purchase common shares; and (iv) cash which will be withheld by the Company to pay Canadian withholding taxes. The interest rate on the Notes, the number of common shares and warrants and the amount of cash are as yet to be determined.

The exchange offer will be conditioned upon the tender of not less than 80% in principal amount of the Debentures and upon consent by the holders of at least 66⅔% in principal amount of the Debentures to the subordination of the Debentures to the Notes.

The Notes will be unsecured and mature October 1, 1989. Interest will accrue from April 1, 1984 and is payable in cash, or, at the option of the Company, in common shares. The Notes are convertible into common shares on or after July 1, 1989, or prior thereto if called for redemption, at a conversion price of $20 (U.S.) per share which is subject to adjustment under certain conditions. On consummation of the exchange offer, the conversion price would be reduced to an amount as yet to be determined.

Each warrant will represent the right to purchase one common share for an amount to be determined from the date of issuance through May 1, 1989. The Company has the right to call and repurchase any and all warrants under certain conditions.

Cash expenses to be incurred in connection with the exchange offer are estimated at $500 (U.S.). In addition, the Company retained the services of Drexel Burnham Lambert Incorporated as financial advisors for a fee of $125 (U.S.) plus warrants to purchase a number of common shares as yet to be determined.

(c) On March 30, 1984, KEP Resources agreed to extend the due date of the note from July 10, 1984 to July 10, 1985. The Company, in turn, agreed to increase monthly repayments from $50 (U.S.) to $75 (U.S.) effective April 10, 1984.

13 — REMUNERATION OF DIRECTORS AND OFFICERS

The total remuneration paid to directors and officers of the Company amounted to $353 in 1983, $504 in 1982 and $514 in 1981.

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SUPPLENTARY FINANCIAL INFORMATION
(Thousands of Canadian dollars, except where indicated)

OIL AND GAS PRODUCING ACTIVITIES—Unaudited

Information required to be disclosed in accordance with FASB Statement No. 69 "Disclosures About Oil and Gas Producing Activities" is discussed below and further detailed in Tables 1 through 6 immediately following.

The reserve quantity and valuation estimates included in the following tables have been excerpted from or based upon reports prepared by independent consulting engineers from the D & S Petroleum Consulting Group Ltd. (as to Canadian reserves) and Sipes, Williamson & Associates, Inc. (as to United States reserves). No reserves have been assigned for the United Kingdom cost centre.

Estimated quantities of proved developed and total proved reserves of crude oil (including condensate and natural gas liquids) and natural gas are disclosed net after royalty. Proved reserves are estimated quantities of reserves which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are expected to be recovered from existing wells with existing equipment and operating methods. Values were determined using current prices, increased only for fixed and determinable escalation provisions in contracts and in Canada for prices established by the Federal/Provincial Energy Pricing and Taxation Agreements.

The 1983 gas volume increase in Canada due to extensions of existing fields is attributable to the Dodsland field in Saskatchewan. Prior to 1983, no facilities to market the gas existed. The discounted net revenue of the Dodsland gas amounts to $2.6 million at December 31, 1983.

The Company emphasizes the estimates included in the following tables are by their nature inexact and are subject to changing economic, operating and contractual conditions. Some of the amounts may not agree with amounts reported under similar headings presented elsewhere in this Report due to categorization of costs by FASB Statement No. 69. United States reserve values have been converted to Canadian dollar equivalents at rates in effect during the respective reporting periods.

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Changes in Quantities of Proved Reserves

For the Years Ended December 31, 1983, 1982 and 1981

	Total		Canada		U.S.A.	
	Oil (thousands of bbls)	Gas (Mmcf)	Oil (thousands of bbls)	Gas (Mmcf)	Oil (thousands of bbls)	Gas (Mmcf)
Proved Reserves, December 31, 1980	17,883	15,153	15,122	7,290	2,761	7,863
Revisions of previous estimates	263	5,875	(87)	(931)	350	6,806
New field discoveries & extensions	1,348	16,860	628	1,205	720	15,655
Purchases of reserves	–	–	–	–	–	–
Production	(977)	(1,359)	(637)	(339)	(340)	(1,020)
Sales of reserves	–	–	–	–	–	–
Proved Reserves, December 31, 1981	18,517	36,529	15,026	7,225	3,491	29,304
Revisions of previous estimates	(6,081)	(9,418)	(5,528)	472	(553)	(9,890)
New field discoveries & extensions	159	1,421	115	237	44	1,184
Purchases of reserves	569	520	569	520	–	–
Production	(958)	(2,941)	(559)	(272)	(399)	(2,669)
Sales of reserves	(1,583)	(2,827)	(316)	–	(1,267)	(2,827)
Proved Reserves, December 31, 1982	10,623	23,284	9,307	8,182	1,316	15,102
Revisions of previous estimates	97	(895)	255	303	(158)	(1,198)
New field discoveries & extensions	97	8,864	27	8,813	70	51
Purchases of reserves	307	–	307	–	–	–
Production	(856)	(2,477)	(684)	(219)	(172)	(2,258)
Sales of reserves	(491)	(151)	(491)	(112)	–	(39)
Proved Reserves, December 31, 1983	9,777	28,625	8,721	16,967	1,056	11,658

Proved Developed Reserves

December 31, 1980	13,474	11,765	12,604	6,785	870	4,980
December 31, 1981	15,518	29,302	13,126	6,952	2,392	22,350
December 31, 1982	9,885	22,260	8,950	7,872	935	14,388
December 31, 1983	8,808	27,257	8,217	16,230	591	11,027

Table 2

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Capitalized Costs Relating to Oil and Gas Producing Activities

As at December 31, 1983, 1982 and 1981

	1983			1982			1981		
	Total	Canada	U.S.A.	Total	Canada	U.S.A.	Total	Canada	U.S.A.
Capitalized costs–									
Unproductive properties not being amortized	$ –	$ –	$ –	$ –	$ –	$ –	$ 15,100	$ –	$15,100
Properties being amortized–									
Productive and non-productive properties	150,335	54,301	96,034	152,749	58,031	94,718	123,710	48,992	74,718
Unevaluated properties	27,289	2,346	24,943	27,179	4,348	22,831	25,001	5,091	19,910
Costs being amortized	177,624	56,647	120,977	179,928	62,379	117,549	148,711	54,083	94,628
Total capitalized costs	177,624	56,647	120,977	179,928	62,379	117,549	163,811	54,083	109,728
Less: Accumulated depreciation, depletion and amortization	89,296	13,541	75,755	58,662	10,349	48,313	19,512	7,390	12,122
Net capitalized costs	$88,328	$43,106	$45,222	$121,266	$52,030	$69,236	$144,299	$46,693	$97,606

Table 3

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Costs Incurred in Property Acquisition, Exploration, and Development Activities

For the Years Ended December 31, 1983, 1982 and 1981

	1983			1982			1981		
	Total	Canada	U.S.A.	Total	Canada	U.S.A.	Total	Canada	U.S.A.
Costs incurred–									
Acquisition of unproved properties	$ 385	$ 182	$ 203	$ 3,443	$ 260	$ 3,183	$ 29,669	$ 836	$28,833
Acquisition of proved properties	774	774	–	2,057	2,057	–	–	–	–
Exploration	2,062	193	1,869	5,328	1,305	4,023	10,612	1,540	9,072
Development	3,931	2,279	1,652	24,788	4,674	20,114	36,991	1,203	35,788
Total costs incurred	$ 7,152	$ 3,428	$ 3,724	$ 35,616	$ 8,296	$27,320	$ 77,272	$ 3,579	$73,693

Table 4

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Results of Operations From Oil and Gas Producing Activities

For the Years Ended December 31, 1983, 1982 and 1981

	1983			1982			1981		
	Total	Canada	U.S.A.	Total	Canada	U.S.A.	Total	Canada	U.S.A.
Revenues from oil and gas producing activities	$ 40,067	$ 24,737	$ 15,330	$ 42,529	$ 16,723	$ 25,806	$ 29,482	$ 12,704	$ 16,778
Production costs and production taxes	10,562	7,124	3,438	11,553	6,053	5,500	11,140	4,975	6,165
Write-down of capital costs	17,978	–	17,978	25,369	–	25,369	–	–	–
Depreciation, depletion and amortization	13,970	3,192	10,778	13,960	2,959	11,001	7,357	1,612	5,745
Total expenses	42,510	10,316	32,194	50,882	9,012	41,870	18,497	6,587	11,910
Pretax income (loss)	(2,443)	14,421	(16,864)	(8,353)	7,711	(16,064)	10,985	6,117	4,868
Income tax expense	(4,528)	(4,528)	–	(3,224)	(3,224)	–	(3,978)	(2,895)	(1,083)
Results of oil and gas producing activities (excluding corporate overhead and interest costs)	$ (6,971)	$ 9,893	$(16,864)	$ (11,577)	$ 4,487	$ (16,064)	$ 7,007	$ 3,222	$ 3,785

Table 5

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Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves*

At December 31, 1983, 1982 and 1981

	1983			1982			1981		
	Total	Canada	U.S.A.	Total	Canada	U.S.A.	Total	Canada	U.S.A.
Future cash inflows	$415,197	$334,354	$ 80,843	$406,098	$302,133	$103,965	$631,309	$404,696	$226,613
Future costs–									
Production	(132,253)	(106,988)	(25,265)	(120,156)	(86,640)	(33,516)	(181,343)	(136,296)	(45,047)
Development and abandonment costs	(4,500)	(3,898)	(602)	(3,432)	(3,297)	(135)	(25,366)	(7,461)	(17,905)
Future net inflows before income tax	278,444	223,468	54,976	282,510	212,196	70,314	424,600	260,939	163,661
Future income taxes	(79,384)	(79,384)	–	(46,913)	(46,913)	–	(102,379)	(66,234)	(36,145)
Future net cash flows	199,060	144,084	54,976	235,597	165,283	70,314	322,221	194,705	127,516
10% discount factor	(89,687)	(72,319)	(17,368)	(109,816)	(87,204)	(22,612)	(155,843)	(122,452)	(33,391)
Standardized measure of discounted future net cash flows	$109,373	$ 71,765	$ 37,608	$125,781	$ 78,079	$ 47,702	$166,378	$ 72,253	$ 94,125

* The present value, discounted at an annual rate of 10%, of estimated future net cash flows related to Proved Reserves. Estimated future net cash flows are calculated by applying current prices of oil and natural gas (and future price changes to the extent provided by existing contractual arrangements) to Proved Reserves to arrive at estimated future cash inflows, and subtracting estimated future development and production costs (based on current costs) and estimated future income tax expenses relating to such inflows and costs.

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Changes in Standardized Measure of Discounted Future Net Cash Flow

From Proved Reserve Quantities For the Years Ended December 31, 1983, 1982 and 1981

	1983			1982			1981		
	Total	Canada	U.S.A.	Total	Canada	U.S.A.	Total	Canada	U.S.A.
Standardized measure— beginning of year	$125,781	$78,079	$47,702	$166,378	$72,253	$94,125	$106,816	$64,003	$42,813
Sales and transfers, net of production costs	(29,505)	(17,613)	(11,892)	(30,977)	(10,670)	(20,307)	(18,341)	(7,728)	(10,613)
Net change in sales and transfer prices, net of production costs	10,024	6,336	3,688	16,676	20,534	(3,858)	2,558	6,407	(3,849)
Extensions, discoveries and improved recovery, net of future production and development costs	4,666	4,097	569	4,913	1,358	3,555	43,114	4,995	38,119
Development costs incurred during the period which reduced future development costs	1,530	1,200	330	17,900	5,180	12,720	8,675	2,244	6,431
Revisions of quantity estimates	(4,194)	2,944	(7,138)	(83,301)	(40,686)	(42,615)	9,731	(7,541)	17,272
Accretion of discount	14,542	9,772	4,770	19,821	9,136	10,685	13,861	8,453	5,408
Net change in income taxes	(11,580)	(11,580)	–	12,193	(530)	12,723	(36)	1,420	(1,456)
Purchases of reserves in place	4,170	4,170	–	8,605	8,605	–	–	–	–
Sales of reserves in place	(4,725)	(4,632)	(93)	(22,896)	(3,570)	(19,326)	–	–	–
Changes in production rates (timing) and other	(1,336)	(1,008)	(328)	16,469	16,469	–	–	–	–
Standardized measure— end of year	$109,373	$71,765	$37,608	$125,781	$78,079	$47,702	$166,378	$72,253	$94,125

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