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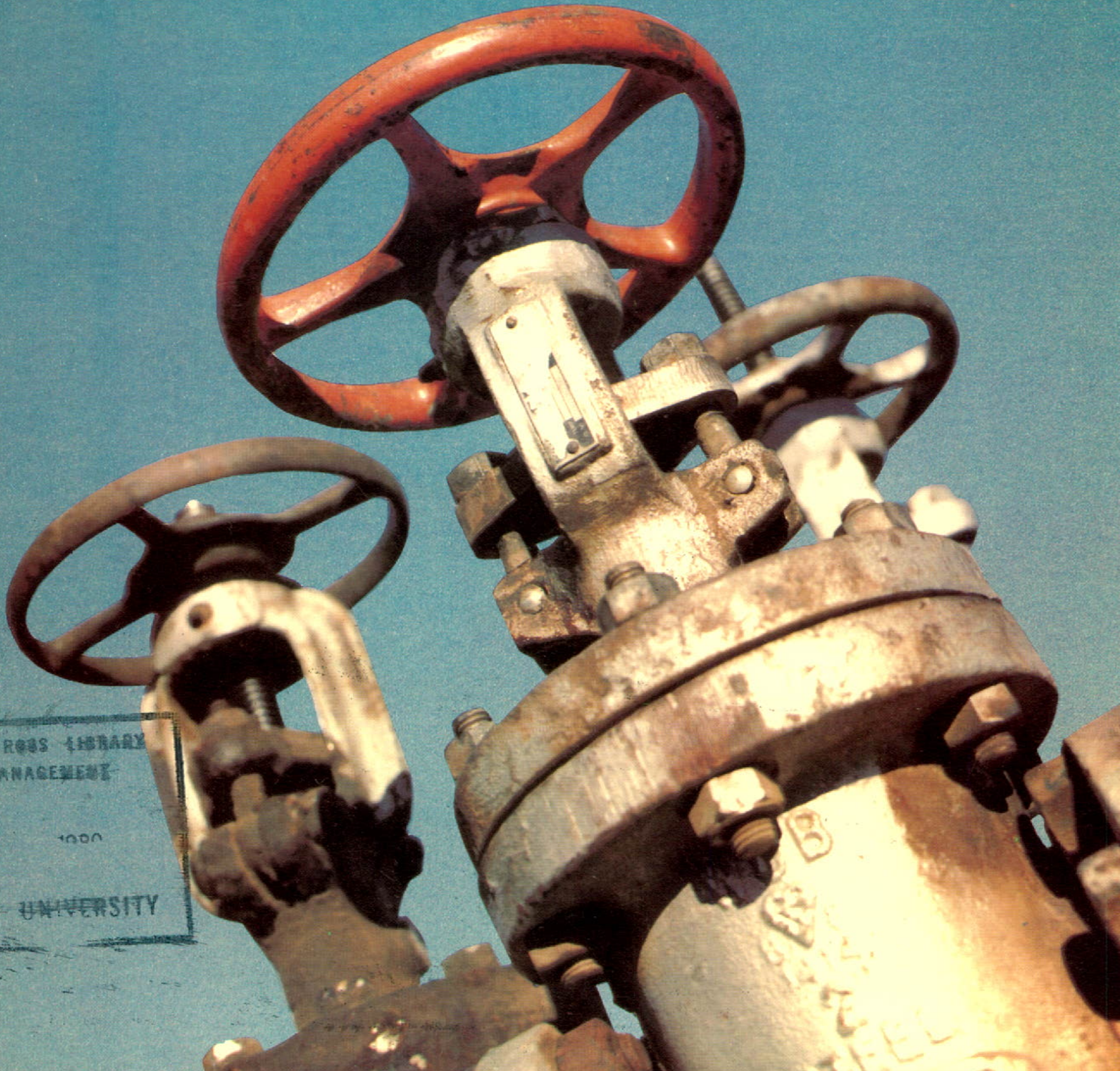
# Page Petroleum Ltd.

# Annual Report 1979



# PAGE PETROLEUM LTD.

Incorporated in Alberta, Canada

## CORPORATE PROFILE

Page Petroleum Ltd. was formed by amalgamation in Alberta on August 13, 1971. The Company has continued and expanded the operations of its predecessor companies, acquiring oil and gas reserves through exploration, development and purchase. Page has traditionally operated in Western Canada, although in 1973 the Company expanded its operations into the United States. The Company's principal reserves and production are located in Western Canada, Utah and Texas. In Western Canada, the Company also engages, through subsidiaries, in services ancillary to the oil and gas industry, including well servicing and the manufacture of service rigs.

As of March 31, 1980, Page's 3,239,475 outstanding common shares were held by 2,025 registered shareholders.

### COVER

The cover picture features an oil shipping valve located at a Page tank battery (12-3-31-20-W3M) in the Dodsland Field in Saskatchewan. A total of 221,975 barrels of Dodsland crude oil was shipped from this battery during 1979.

### CONTENTS



### REPORTING IN METRIC

On January 1, 1979, the Canadian petroleum industry adopted the International System of Units (SI) commonly called the metric system. Page has been using some metric units in its 1979 quarterly reports to shareholders. This annual report includes selective use of metric and, where used, equivalents from the old Imperial system are also given. In future years the Company's annual reports will more fully convert to metric reporting.

The most common conversions relating to volumes of oil and gas will be from barrels and cubic feet to cubic metres; one cubic metre is equal to approximately 6.3 barrels or 35.5 cubic feet. In reporting land areas the conversion will be from acres to hectares; one hectare is roughly equivalent to 2.5 acres.

### SI CONVERSION TABLE

| To convert from | To | Multiply by |
|---|---|---|
| Cubic metre ($m^3$) | barrel (bbl) | 6.293 |
| Thousands of cubic metres ($10^3m^3$) | thousand cubic feet (mcf) | 35.494 |
| Tonne (t) | long ton (t) | 0.984 |
| Metre (m) | foot (ft) | 3.281 |
| Kilometre (km) | mile (mi) | 0.621 |
| Hectare (ha) | acre (ac) | 2.471 |

Examples:

$10^3m^3$ = one thousand cubic metres
$10^6m^3$ = one million cubic metres
$10^9m^3$ = one billion cubic metres

# PAGE PETROLEUM LTD.

## FINANCIAL AND OPERATING HIGHLIGHTS

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

| | 1979 | 1978 (Restated) | Increase (Decrease) Per Cent |
|---|---|---|---|
| **FINANCIAL** | | | |
| Gross income | $ 12,791,000 | $ 5,670,000 | 125.6 |
| Sales of oil and gas | $ 11,606,000 | $ 4,930,000 | 135.4 |
| Well servicing income | $ 1,117,000 | $ 610,000 | 83.1 |
| Investment and other income | $ 68,000 | $ 130,000 | (47.7) |
| Total expenses | $ 12,589,000 | $ 4,648,000 | 170.8 |
| Net income (loss) | $ (33,000) | $ 799,000 | (104.1) |
| Preferred dividends | $ 445,000 | $ 183,000 | 143.2 |
| Net earnings (loss) applicable to common shares | $ (478,000) | $ 616,000 | (177.6) |
| Per common share | $ (0.18) | $ .30 | (160.0) |
| Funds generated from operations | $ 4,533,000 | $ 2,669,000 | 69.8 |
| Per common share | $ 1.66 | $ 1.32 | 25.8 |
| Additions to property and equipment | $ 30,256,000 | $11,358,000 | 166.4 |
| Working capital (deficiency) | $ (744,000) | $ 114,000 | (752.6) |
| Long-term debt | $ 26,645,000 | $10,182,000 | 161.7 |
| Shareholders' equity | $ 21,422,000 | $ 9,384,000 | 128.3 |
| Common shares outstanding | 2,960,868 | 2,065,418 | 43.4 |
| Number of shareholders | 1,747 | 1,142 | 53.0 |
| **OPERATIONS** | | | |
| LAND HOLDINGS | | | |
| Gross acres | 1,536,704 | 917,439 | 67.5 |
| Net acres | 360,367 | 113,900 | 216.4 |
| DRILLING ACTIVITY | | | |
| Gross wells drilled | 146.0 | 113.0 | 29.2 |
| Net wells drilled | 117.3 | 92.6 | 26.7 |
| Net wells productive | 111.1 | 87.5 | 27.0 |
| Net wells dry | 6.2 | 5.1 | 21.6 |
| PRODUCTION — gross (before royalties) | | | |
| Crude oil and liquids — barrels | 861,916 | 467,755 | 84.3 |
| Per day | 2,361 | 1,282 | 84.3 |
| Natural gas — mcf | 1,071,048 | 607,342 | 76.4 |
| Per day | 2,934 | 1,664 | 76.4 |
| RESERVES — gross proven and probable | | | |
| Crude oil — barrels | 29,011,000 | 13,096,000 | 121.5 |
| Natural gas — mcf | 16,841,000 | 12,989,000 | 29.7 |

## 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 |
|---|---|---|---|---|---|---|---|---|---|---|
| Toronto Stock Exchange | 1977 | 2.95 | 2.30 | 3.05 | 2.50 | 3.50 | 2.70 | 7.25 | 4.45 | 1,271,000 |
| | 1978 | 6.75 | 5.00 | 6.12 | 4.95 | 8.62 | 4.85 | 9.00 | 6.37 | 1,254,000 |
| | 1979 | 13.25 | 8.87 | 19.00 | 11.87 | 19.25 | 15.00 | 28.62 | 14.25 | 3,626,000 |
| American Stock Exchange (U.S. dollars) | 1979 | — | — | — | — | — | — | 24.75 | 14.12 | 1,755,000 |

# TO THE SHAREHOLDERS

LAWTON L. CLARK
President

Net oil and gas revenues in 1979 continued the trend established during the last few years, increasing 135% to $11,606,000 from $4,930,000 in 1978. Funds generated from operations amounted to $4,533,000, a 70% increase from the $2,669,000 a year earlier. However, because of substantial increases in all categories of expenses, the Company recorded a net loss of $33,000 for the year. After providing for the cumulative dividends on the preferred shares, the loss applicable to common shares amounted to $478,000 (18¢ per share) compared to net earnings of $616,000 (30¢ per share) in 1978.

At year end, the Company's proved oil and gas reserves, net after royalty, totalled approximately 13 million barrels of crude oil and liquids and 12 billion cubic feet of natural gas. These reserves compare to nine million barrels and nine billion cubic feet, respectively, at December 31, 1978.

A $10 million issue of preferred shares in June 1979, resulted in net proceeds of $9,500,000 to the Company. This was a 1,000,000 share issue designated as 7% Cumulative Redeemable Convertible Preferred Shares Series B with a par value of $10.00 each. These preferred shares are convertible into common shares by the holder prior to July 16, 1989. If such conversion rights were to be fully exercised prior to July 16, 1984, a total of 529,000 common shares would be issued with a lesser number issuable in subsequent years. This issue of preferred shares followed the earlier call for redemption of the then outstanding 7% Cumulative Redeemable Convertible Preferred Shares Series A. Following the call for redemption, 495,285 of the 500,000 Series A Preferred Shares were converted into 717,396 common shares by April 30, 1979 and on May 1, 1979 the remaining 4,715 Series A Preferred Shares were redeemed at $10.50 per share.

During 1979 the Company drilled or participated in a total of 146 wells (117 net). The principal area of activity was in the Dodsland field of west central Saskatchewan where Page drilled and completed 102 wholly owned oil wells. The Company plans to drill at least 80 additional development wells at Dodsland during 1980. At year end Page was producing approximately 1,900 barrels per day from 219 wells in this field. We expect that it will take an additional three to four years to fully develop the Dodsland properties.

The most significant area of U.S. activity was in the Greater Altamont-Bluebell Field of Utah where Page purchased 12 producing Wasatch oil wells (8.5 net) and approximately 25,000 net lease acres at a total cost of $3,048,000 (U.S.). The Company subsequently drilled two successful development wells. The first, Page Ute Tribal 1-9C-6, completed in late July, produced an average of 430 barrels per day for the remainder of the year. A second development well, Page Ute Tribal E-2, commenced in late 1979, was placed on production in February, 1980. Daily production for the month of March averaged 754 barrels and approximately 750 Mcf of casinghead gas. Page plans to drill six Wasatch development wells in this field during the coming year. Production from the Altamont-Bluebell field is expected to be the largest source of revenue for the Company in 1980.

To help assure growth in the years ahead Page accelerated its land acquisition program during the past year. At December 31, 1979, the Company held 1,490,546 acres of undeveloped lands (340,504 net). Since year end Page has acquired more than 100,000 additional net acres in a number of provinces and states including Alberta, Manitoba, Saskatchewan, Kansas, Texas, Oklahoma, Michigan and Ohio.

Page's service rig business, operated through a subsidiary, Northline Well Servicing, Ltd., has expanded considerably in the past 12 months. The Company now operates 10 small service rigs in Saskatchewan and Alberta, with expansion to at least 15 rigs planned for 1980.

Effective July 1, 1979 Page acquired all the shares of Habco Sales Ltd. and two of its affiliated companies, for $1,049,000 and 130,000 common shares of the Company. Habco, a private Alberta company, furnishes various services to the oil and gas industry, including the manufacture and installation of compressor packages, wellhead facilities and gas plant equipment, pipeline construction and the sale of tubular goods. This transaction is subject to approval by the Canadian Foreign Investment Review Agency. If such approval is not obtained Page may be required to divest itself of this investment.

The Company has budgeted a total of $36 million in 1980 to carry out a still expanding development and exploration program. A sizeable part of this program can be funded from the Company's present and anticipated line of bank credit and from projected cash flow.

Page has also filed with the U.S. Securities and Exchange Commission a registration statement for a public issue of $25,000,000 (U.S.) 10% Convertible Subordinated Debentures due 2000. It is anticipated that the proceeds from this issue will be received on April 29, 1980.

In August of 1979 the Board regretfully accepted the resignation of one of our Directors, Mr. C.D. Gould. His contributions as both an Officer and Director of Page and predecessor companies were substantial. We wish him well in his new ventures. To replace Mr. Gould, the Board appointed Mr. H.W. Higgins of Calgary, Alberta. Mr. Higgins is the founder and president of Habco Sales Ltd., now a wholly owned Page subsidiary. We are also pleased to advise that Mr. Tom Jacobsen, formerly a Vice President of the Company, was appointed Executive Vice President in June of 1979.

Page has enjoyed rapid growth during the past few years and the coming year should continue this trend. Company forecasts indicate that 1980 net oil and gas revenues will total at least $24 million and that funds generated from operations will exceed $10 million. Assuming that these predictions prove to be correct, 1980 will be the fourth successive year in which the Company's net oil and gas revenues have doubled those of the preceding year.

Our progress would not have been possible without the help of our shareholders and the willing efforts of our employees. We sincerely appreciate your support.

Lawton L. Clark

April 22, 1980

President

# PAGE PETROLEUM LTD.

## FIVE YEAR STATISTICAL SUMMARY

### FINANCIAL

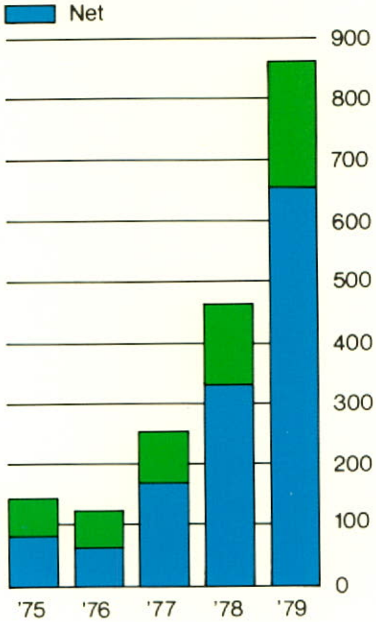
| | 1979 | 1978 (Restated) | 1977 (Restated) | 1976 | 1975 |
|---|---|---|---|---|---|
| **INCOME** | | | | | |
| Oil and gas sales | $15,235,000 | $ 6,682,000 | $2,914,000 | $1,240,000 | $1,304,000 |
| Royalties paid | 3,629,000 | 1,752,000 | 996,000 | 531,000 | 547,000 |
| Net oil and gas sales | 11,606,000 | 4,930,000 | 1,918,000 | 709,000 | 757,000 |
| Well servicing income | 1,117,000 | 610,000 | — | — | — |
| Interest and other income | 68,000 | 130,000 | 99,000 | 11,000 | 67,000 |
| GROSS INCOME | 12,791,000 | 5,670,000 | 2,017,000 | 720,000 | 824,000 |
| Production expenses | 3,429,000 | 1,340,000 | 469,000 | 132,000 | 84,000 |
| Well servicing expenses | 911,000 | 409,000 | — | — | — |
| General and administrative (net) | 1,643,000 | 655,000 | 276,000 | 190,000 | 190,000 |
| Interest expenses | 2,453,000 | 742,000 | 370,000 | 219,000 | 146,000 |
| Current income taxes | (178,000) | (145,000) | (147,000) | (99,000) | (101,000) |
| FUNDS GENERATED FROM OPERATIONS | 4,533,000 | 2,669,000 | 1,049,000 | 278,000 | 505,000 |
| Per common share | 1.66 | 1.32 | .58 | 0.20 | 0.36 |
| Depreciation, depletion, amortization | 4,153,000 | 1,502,000 | 517,000 | 227,000 | 242,000 |
| Deferred income taxes | 413,000 | 368,000 | 235,000 | 44,000 | 107,000 |
| NET EARNINGS (LOSS) | (33,000) | 799,000 | 297,000 | 7,000 | 157,000 |
| Preferred dividends | 445,000 | 183,000 | — | — | — |
| Net earnings (loss) applicable to common shares | (478,000) | 616,000 | 297,000 | 7,000 | 157,000 |
| Per common share | (.18) | .30 | .17 | .005 | 0.11 |
| **BALANCE SHEET** | | | | | |
| Working capital (deficiency) | (744,000) | 114,000 | 668,000 | 91,000 | 192,000 |
| Investments and advances | 3,620,000 | — | — | — | — |
| Property and equipment | 45,074,000 | 18,880,000 | 8,998,000 | 4,293,000 | 3,565,000 |
| Other assets | 1,539,000 | 1,581,000 | 65,000 | 50,000 | 55,000 |
| CAPITAL EMPLOYED | 49,489,000 | 20,575,000 | 9,731,000 | 4,434,000 | 3,812,000 |
| Deduct: Long term debt | 26,645,000 | 10,182,000 | 5,547,000 | 2,408,000 | 1,846,000 |
| Deferred income taxes | 1,422,000 | 1,009,000 | 641,000 | 344,000 | 301,000 |
| Shareholders' equity | 21,422,000 | 9,384,000 | 3,543,000 | 1,682,000 | 1,665,000 |
| Common shares outstanding | 2,960,868 | 2,065,418 | 1,999,252 | 1,410,086 | 1,408,486 |
| **CAPITAL EXPENDITURES** | | | | | |
| Exploration and development (net) | 27,859,000 | 10,059,000 | 2,870,000 | 944,000 | 751,000 |
| Well servicing | 1,300,000 | 666,000 | — | — | — |
| Other | 1,097,000 | 633,000 | 59,000 | — | 71,000 |
| | 30,256,000 | 11,358,000 | 2,929,000 | 944,000 | 822,000 |

### OPERATIONS

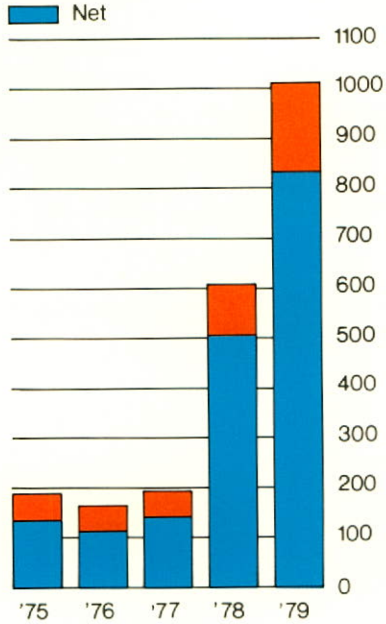
| | 1979 | 1978 | 1977 | 1976 | 1975 |
|---|---|---|---|---|---|
| **LAND HOLDINGS** (working interest) | | | | | |
| Gross acreage held | 1,537,000 | 882,000 | 1,627,000 | 1,639,000 | 2,482,000 |
| North America — net | 360,000 | 89,000 | 111,000 | 92,000 | 138,000 |
| Overseas — net | — | 24,000 | 43,000 | 47,000 | 178,000 |
| TOTAL NET ACREAGE | 360,000 | 113,000 | 154,000 | 139,000 | 316,000 |
| **DRILLING ACTIVITY** | | | | | |
| Gross wells drilled | 146.0 | 113.0 | 53.0 | 11.0 | 60.0 |
| Net wells drilled | 117.3 | 92.6 | 42.6 | 2.4 | 6.6 |
| Productive | 111.1 | 87.5 | 42.3 | 1.5 | 3.3 |
| Dry | 6.2 | 5.1 | 0.3 | 0.9 | 3.3 |
| **PRODUCTION** — gross (before royalties) | | | | | |
| Crude oil and liquids — barrels | 862,000 | 468,000 | 266,000 | 125,000 | 144,000 |
| Average daily, barrels | 2,361 | 1,282 | 730 | 341 | 395 |
| Natural gas — mcf | 1,071,000 | 607,000 | 195,000 | 164,000 | 191,000 |
| Average daily, mcf | 2,934 | 1,664 | 534 | 448 | 522 |
| **GROSS RESERVES** — proven and probable | | | | | |
| Crude oil — thousand barrels | 29,011 | 13,096 | 7,235 | 4,527 | 4,352 |
| Natural gas — mmcf | 16,841 | 12,989 | 9,589 | 5,767 | 4,961 |

## OPERATING AND FINANCIAL TRENDS

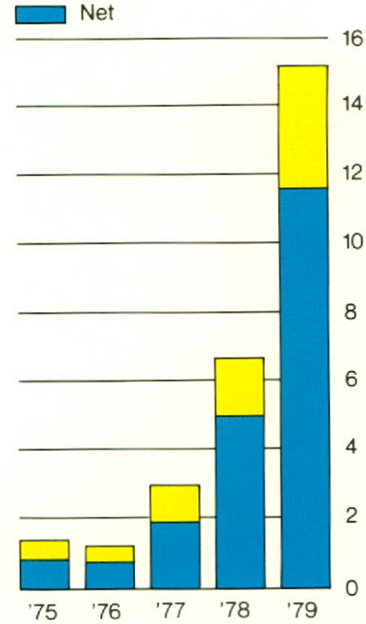
### Oil Production
Thousands of Barrels
Gross
Net



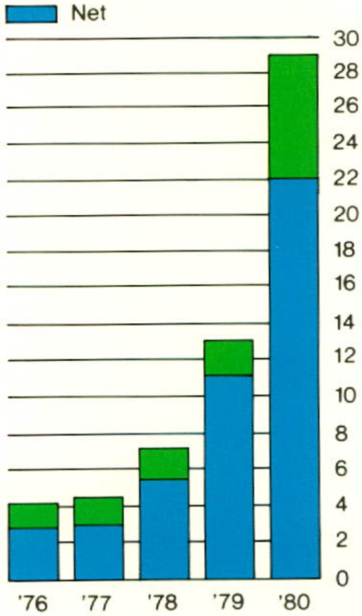

### Natural Gas Production
Thousands of Cubic Feet
Gross
Net



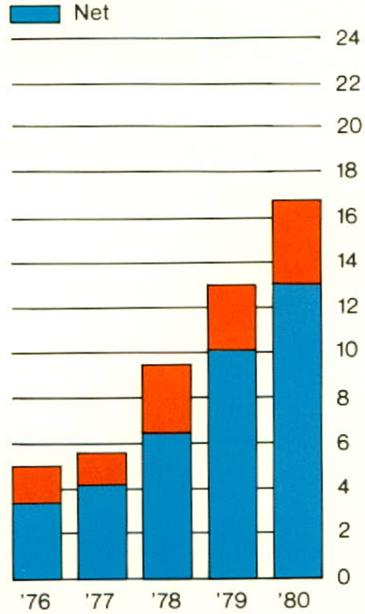

### Gross and Net Oil and Gas Revenues
Millions of Dollars
Gross
Net



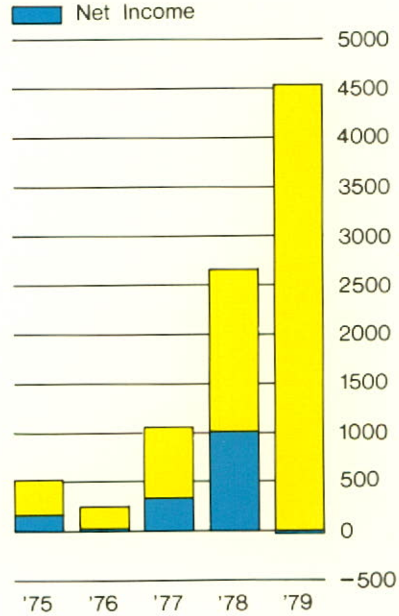

### Oil Reserves
*(Proven and Probable) as of January 1.*
Millions of Barrels
Gross
Net




### Natural Gas Reserves
*(Proven and Probable) as of January 1.*
Millions of Cubic Feet
Gross
Net




### Cash Flow and Net Income
Thousands of Dollars
Cash Flow
Net Income



## PRODUCTION AND RESERVES

The Company's daily net oil production was twice that of the previous year, increasing from an average of 146 cubic metres (920 barrels) per day in 1978 to 290 cubic metres (1825 barrels) per day in 1979. Essentially all of this increase was from the Dodsland field in west central Saskatchewan and from the Altamont-Bluebell Field in the Uinta Basin of Utah. Net gas production, still comparatively small, increased from 39 thousand cubic metres (1.4 million cubic feet) per day to 65 thousand cubic metres (2.3 million) per day.

Independent engineering firms in the U.S. and Canada have estimated Page's total recoverable proven oil reserves at December 31, 1979 to be 2,061,000 cubic metres (12,967,000 barrels) up 51% from 1 362 000 cubic metres (8,570,000 barrels) at December 31, 1978. Proven gas reserves increased 42% to 341 000 thousand cubic metres (12.1 billion cubic feet) from 240 000 thousand cubic metres (8.5 billion cubic feet). The future undiscounted cash flow from these proven reserves was calculated to be $276 million. Using 15% and 17.5% discount factors this cash flow was determined to have present worths of $112 million and $101 million respectively. These reserves differ from those calculated in accordance with the rules by the U.S. Securities and Exchange Commission, which are set forth in the Reserve Recognition Accounting presentation included in the Notes to Consolidated Financial Statements.

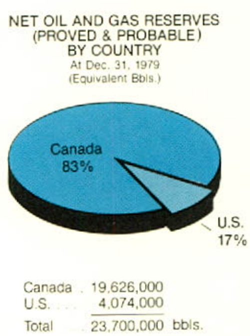
In addition to the proven reserves there were an estimated 1 443 000 cubic metres (9,085,000 barrels) of oil and 31 000 thousand cubic metres (1.1 billion cubic feet) of natural gas in the probable additional category, having undiscounted future net cash flow of $142 million. Using 15% and 17.5% discount factors this cash flow (from probable reserves only) was determined to have present worths of $32 million and $27 million, respectively.

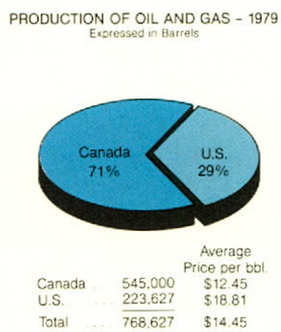
All amounts are net after deduction of estimated royalties, operating costs and future capital costs. Most of the Company's U.S. oil production is categorized as "new" (Tier 3) oil or that oil discovered after Jan. 1, 1979. The tax imposed on new oil under the recently enacted U.S. Crude Oil Windfall Profit Tax Act of 1980 is 30% of the difference between the actual selling price of the oil produced after February 29, 1980 and an average base price of $16.55 (U.S.),

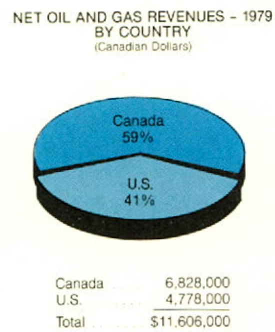
| RESERVES | JAN. 1, 1980 | | | | JAN. 1, 1979 | | | |
|---|---|---|---|---|---|---|---|---|
| | METRIC | | IMPERIAL | | METRIC | | IMPERIAL | |
| | GROSS | NET | GROSS | NET | GROSS | NET | GROSS | NET |
| **OIL** | (thousands of cubic metres) | | (thousands of barrels) | | (thousands of cubic metres) | | (thousands of barrels) | |
| proven - Alberta | 231 | 162 | 1,451 | 1,020 | 248 | 150 | 1,563 | 941 |
| - Saskatchewan | 1 863 | 1 538 | 11,726 | 9,676 | 1 358 | 1 208 | 8,548 | 7,604 |
| - Utah | 454 | 356 | 2,856 | 2,242 | — | — | — | — |
| - Texas | 6 | 5 | 41 | 29 | 6 | 4 | 35 | 25 |
| | 2 554 | 2 061 | 16,074 | 12,967 | 1 612 | 1 362 | 10,146 | 8,570 |
| probable - Alberta | 187 | 170 | 1,176 | 1,072 | 83 | 69 | 522 | 434 |
| - Saskatchewan | 1 831 | 1 243 | 11,525 | 7,823 | 384 | 359 | 2,419 | 2,257 |
| - Utah | 36 | 29 | 226 | 183 | — | — | — | — |
| - Texas | .2 | 1 | 10 | 7 | 1 | 1 | 9 | 7 |
| Total Oil | 4 610 | 3 504 | 29,011 | 22,052 | 2 080 | 1 791 | 13,096 | 11,268 |
| **GAS** | (millions of cubic metres) | | (millions of cubic feet) | | (millions of cubic metres) | | (millions of cubic feet) | |
| proven - Alberta | 117 | 86 | 4,140 | 3,059 | 93 | 67 | 3,302 | 2,390 |
| - Saskatchewan | 71 | 68 | 2,503 | 2,427 | 67 | 65 | 2,378 | 2,319 |
| - Utah | 127 | 100 | 4,509 | 3,533 | — | — | — | — |
| - Texas | 114 | 82 | 4,062 | 2,916 | 139 | 104 | 4,932 | 3,654 |
| - Oklahoma | 5 | 5 | 179 | 152 | 5 | 4 | 161 | 139 |
| | 434 | 341 | 15,393 | 12,087 | 304 | 240 | 10,773 | 8,502 |
| probable - Alberta | 8 | 8 | 283 | 277 | 1 | 1 | 44 | 32 |
| - Utah | 10 | 8 | 340 | 276 | — | — | — | — |
| - Texas | 23 | 15 | 825 | 545 | 61 | 44 | 2,172 | 1,549 |
| Total Gas | 475 | 372 | 16,841 | 13,185 | 366 | 285 | 12,989 | 10,083 |

adjusted for inflation occurring since the second quarter of 1979, plus 2% per year and for differences in quality and location, with an adjustment for the State severance tax on the windfall profit. Proven reserves are defined by the consultants as those reserves which are considered to be recoverable to a high degree of certainty at commercial rates assuming present depletion methods and recoveries, operating conditions, price forecasts and costs. Probable additional reserves are defined as those situated in the vicinity of proven properties, but where geologic or engineering control indicates some degree of risk.

In 1979 Page received approximately 70% of its total oil and gas revenues from two fields: the Dodsland Field in west central Saskatchewan with net sales of $4,848,000 (42%) and the Altamont-Bluebell Field in Utah with net sales of $3,212,000 (28%).



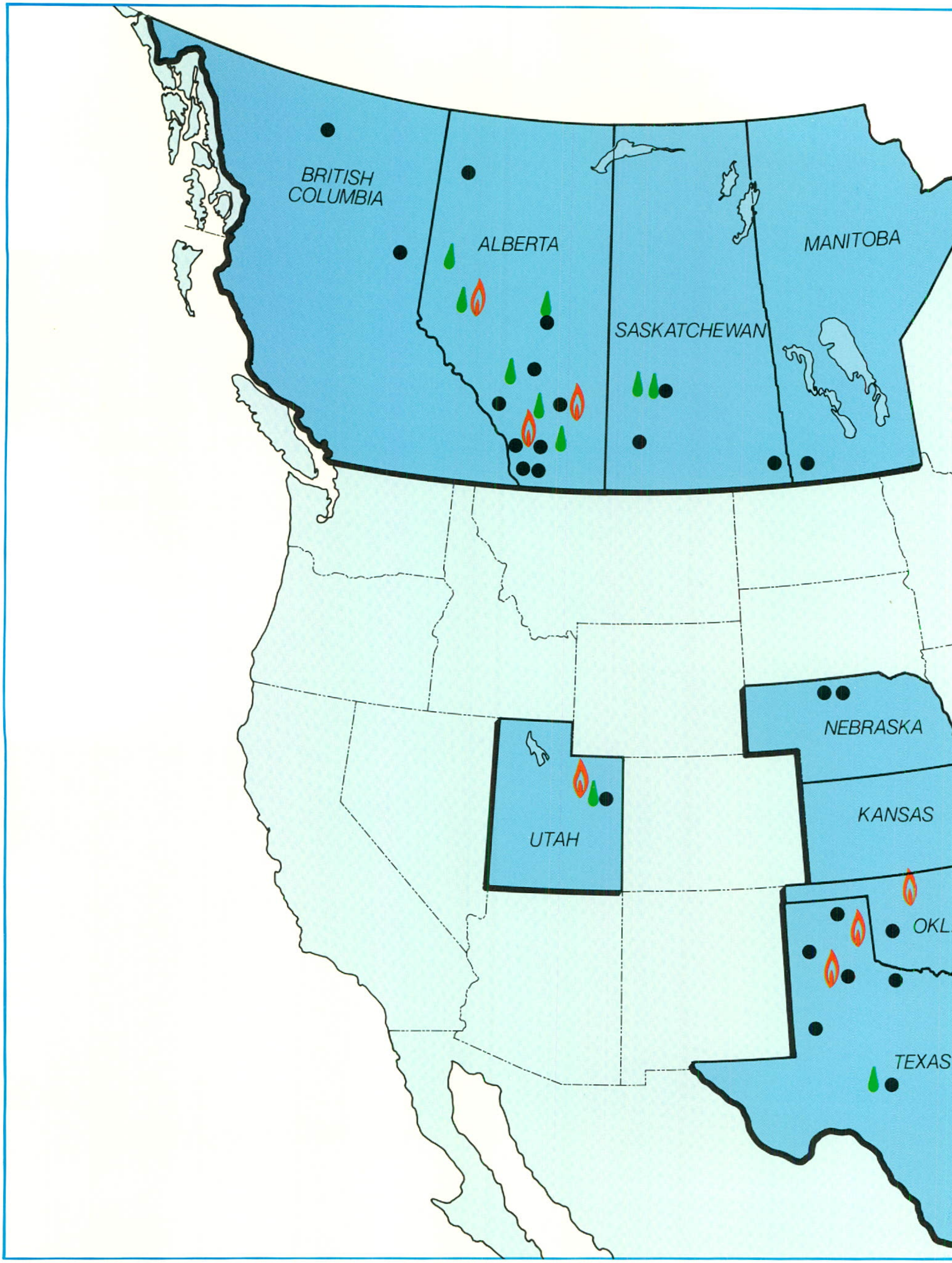





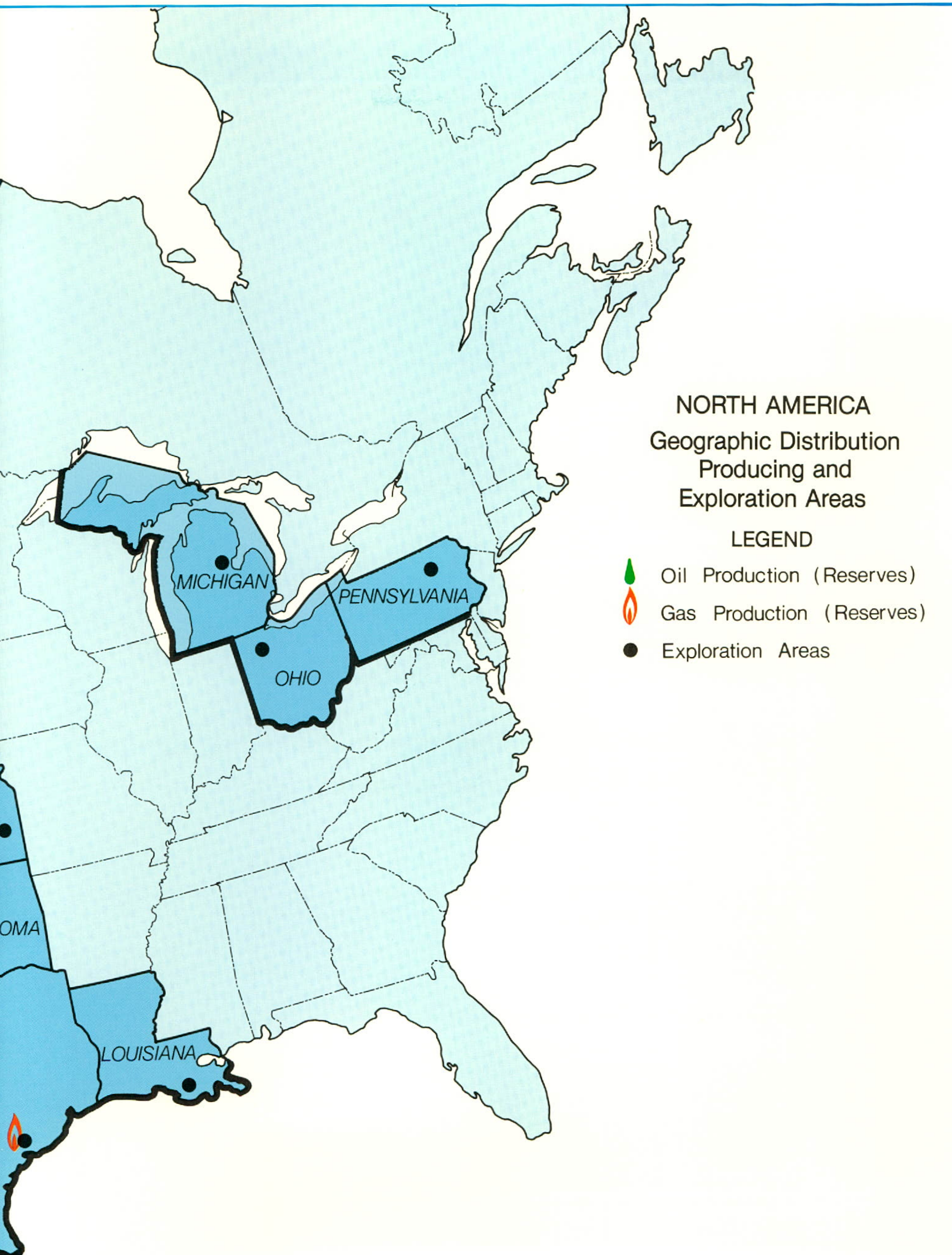
## LAND HOLDINGS

| | DEVELOPED ACREAGE | | UNDEVELOPED ACREAGE | |
|---|---|---|---|---|
| | Gross Acres | Net Acres | Gross Acres | Net Acres |
| **CANADA** | | | | |
| Alberta | 15,128 | 3,456 | 55,921 | 31,245 |
| British Columbia | — | — | 7,890 | 1,589 |
| Manitoba | — | — | 8,160 | 2,360 |
| Saskatchewan | 9,392 | 9,197 | 40,115 | 35,573 |
| Arctic | — | — | 341,292 | 29,284 |
| Total | 24,520 | 12,653 | 453,378 | 100,051 |
| **UNITED STATES** | | | | |
| Kansas | — | — | 210,000 | 56,875 |
| Louisiana | — | — | 1,338 | 686 |
| Nebraska | — | — | 776,000 | 155,200 |
| Oklahoma | 1,280 | 243 | 5,949 | 1,531 |
| Texas | 14,191 | 2,157 | 27,583 | 10,128 |
| Utah | 6,167 | 4,810 | 16,298 | 16,033 |
| Total | 21,638 | 7,210 | 1,037,168 | 240,453 |
| Total Canada and United States | 46,158 | 19,863 | 1,490,546 | 340,504 |

*The above table excludes varying royalty interests in 20,626 gross acres.*



BRITISH COLUMBIA
ALBERTA
SASKATCHEWAN
MANITOBA
NEBRASKA
KANSAS
UTAH
OKL
TEXAS


NORTH AMERICA
Geographic Distribution
Producing and
Exploration Areas
LEGEND
Oil Production (Reserves)
Gas Production (Reserves)
Exploration Areas
MICHIGAN
PENNSYLVANIA
OHIO
OMA
LOUISIANA

# EXPLORATION AND DEVELOPMENT

Page spent $28 million on exploration and development in Canada and the United States during 1979. This included $4.7 million for land purchases and $5.2 million to acquire producing properties. Of the $28 million in capital expenditures, approximately 51% was spent in Canada and 49% in the U.S. Page participated in the drilling of 146 wells, of which 110 were development and 36 exploratory. This program resulted in 114 oil wells (108.7 net), nine gas wells (2.4 net) and 23 dry holes (6.2 net).

A total of $36 million has been budgeted for exploration and development in 1980, with slightly more than half of this amount allocated to Canada. Estimated expenditures include $8 million for development drilling in Dodsland, Saskatchewan, $10 million for development drilling and workovers in the Altamont-Bluebell Field, Utah, and $10 million for exploration and development in Alberta. Approximately $8 million is budgeted for various prospects in Texas, Kansas, Nebraska, Pennsylvania, Ohio, Oklahoma, Michigan, British Columbia, Saskatchewan and Manitoba.

The majority of the Company's oil and gas exploration is conducted from the Calgary office, under the direction of Alex Cathcart, Vice President of Exploration. His staff includes four geologists and a landman. A full-time geological consultant and a landman located in the Amarillo office are primarily engaged in exploration in the Texas and Oklahoma Panhandles. The Company retains half-time geological consultants in Midland and Houston.

## CANADA

Again, Saskatchewan drilling highlighted the year with the completion of 102 wholly owned oil wells in the Dodsland field. The Company drilled a total of 113 wells (108.6 net) in Western Canada resulting in 109 oil wells (106.2 net) and one wholly owned gas well. Page spent $12.6 million on exploration and development in Western Canada or approximately 56% of the Company total.

In addition to another large development program at Dodsland, Page will drill a number of wildcats in Alberta and Saskatchewan. The Company has budgeted $10 million for exploration in Alberta, including an estimated $2 million for land acquisitions and $2 million for geophysics.

### SASKATCHEWAN

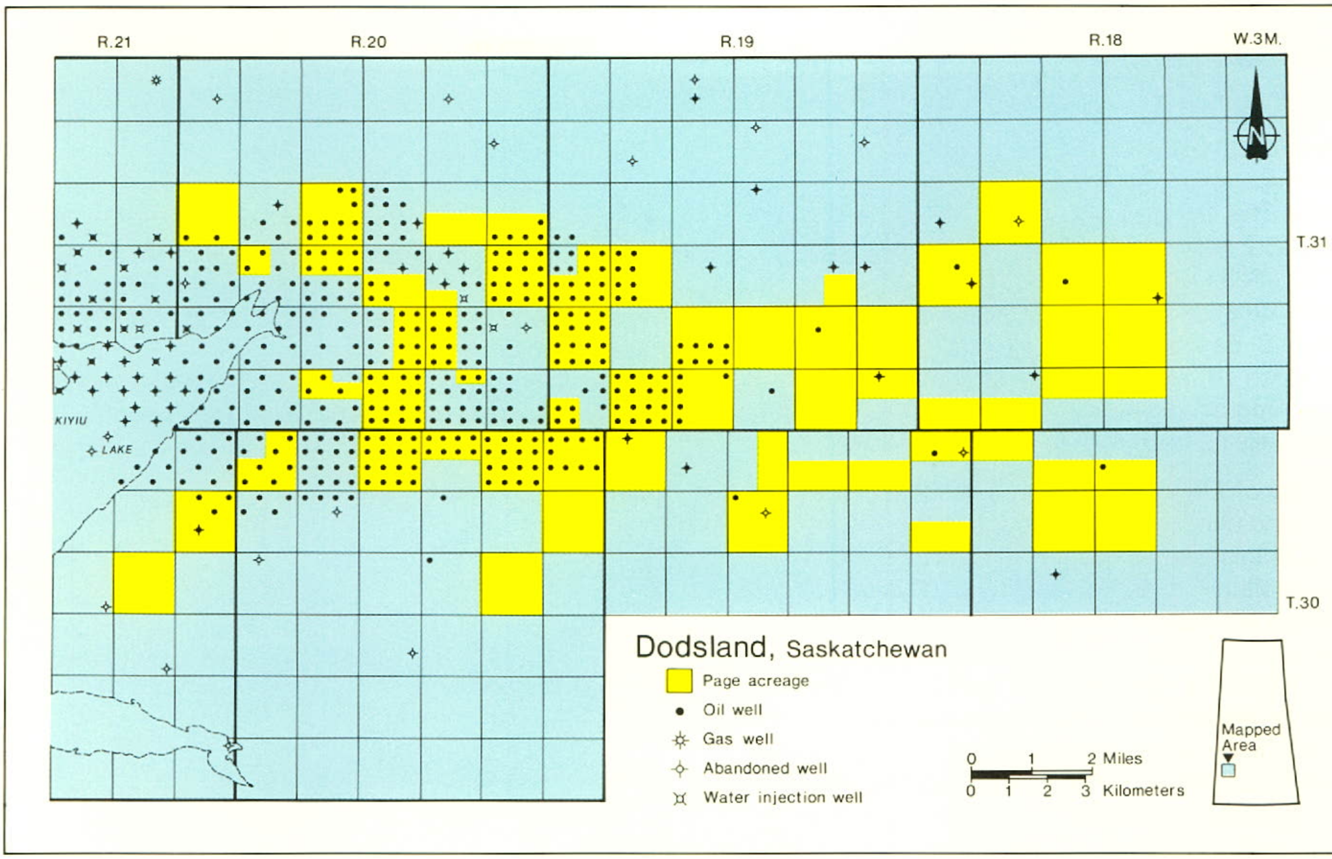
#### Dodsland

Page operates 219 wells (215 net) in the Dodsland field and plans an 80 to 100 well development drilling program in 1980. In April of 1979 Page acquired a 21,760 acre permit, immediately east of the Dodsland field at a cost of $1,123,000. Later in the year, after drilling six exploratory wells, the permit was converted to 10,372 lease acres. The Company's holdings at Dodsland as of December 31, 1979 totalled 23,398 net acres of leases and mineral titles.

The Dodsland field produces 34° gravity oil from the Viking Sand at 2,200 feet. The Company's wells during the first quarter of 1980 produced approximately 1,900 barrels per day. The low royalty rates and long producing life assures that this will be an area of major importance to the Company for many years. The present oil price is $14.92 per barrel and operating costs averaged $3.10 per barrel during 1979. Revenues from this field, after deduction of royalties, totalled $4,848,000 in 1979 or 42% of the Company total.

#### Antler River

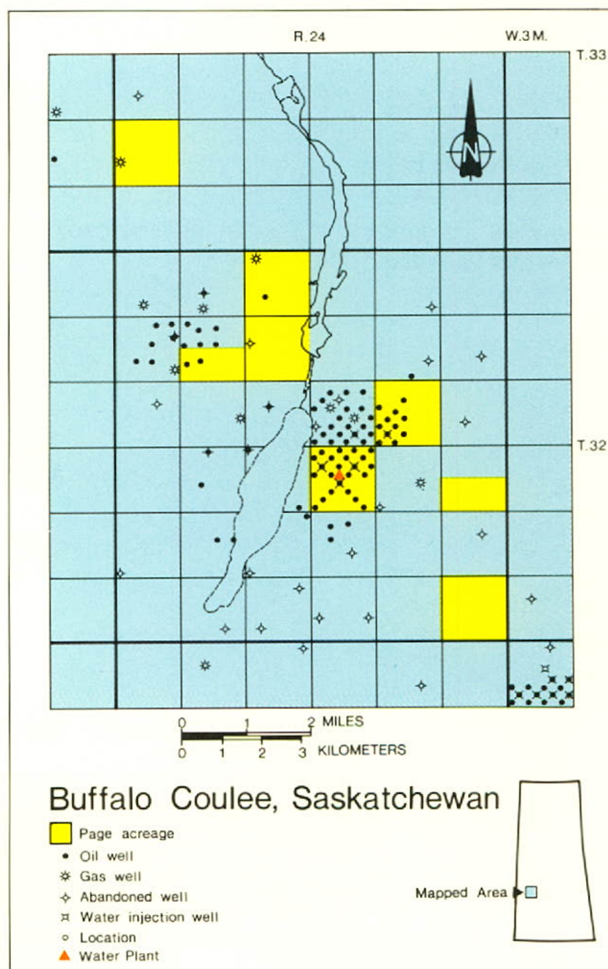
The Company owns a 50% interest in 5,681 acres in the Antler River area of southeast Saskatchewan. This acreage is prospective for Mississippian light to medium gravity crude oil in several erosional-stratigraphic prospects. Page plans to drill three 3,200 foot wildcat wells on the acreage during the latter half of 1980.

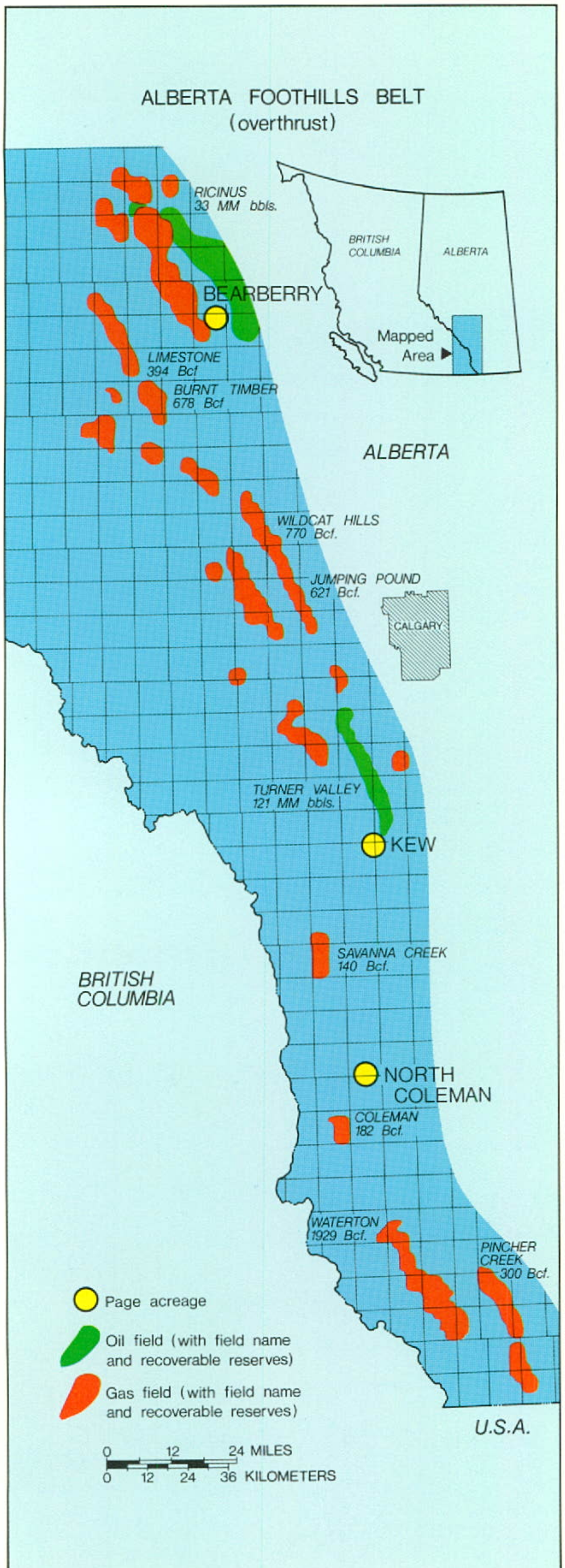



## Buffalo Coulee

At year end the Company owned interests in 3,839 acres of leases in the Buffalo Coulee area of southwest Saskatchewan. Page has 24 wholly owned producing oil wells, four water injection wells and five shut in wells in this field. The wells produce 13.5° gravity oil from the Mississippian (Bakken) sand. Waterflood facilities were installed in the fourth quarter of 1979 with water injection commencing in February, 1980. It is anticipated that the waterflood will double the present production of approximately 175 barrels per day.

Page also has three cased wells northwest of the field. Two of these, 5-29 and 6-29, are commercial Bakken oil wells and the Company is planning to drill three adjacent development wells in 1980. The third well (6-33) appears to be marginal and further production testing will be done to determine the feasibility of additional drilling in Section 33.






## ALBERTA

During 1979 Page increased its land holdings in Alberta by 21,576 gross acres. This acreage is located primarily in the southern part of Alberta in areas prospective for oil, although some of the lands do cover some high potential gas prospects. The location of these lands also reflects the Company's decision to gain increased exposure in the deeper portions of the Alberta Basin and Foothills which have the potential for large reserves.

### Foothills (Overthrust) Belt

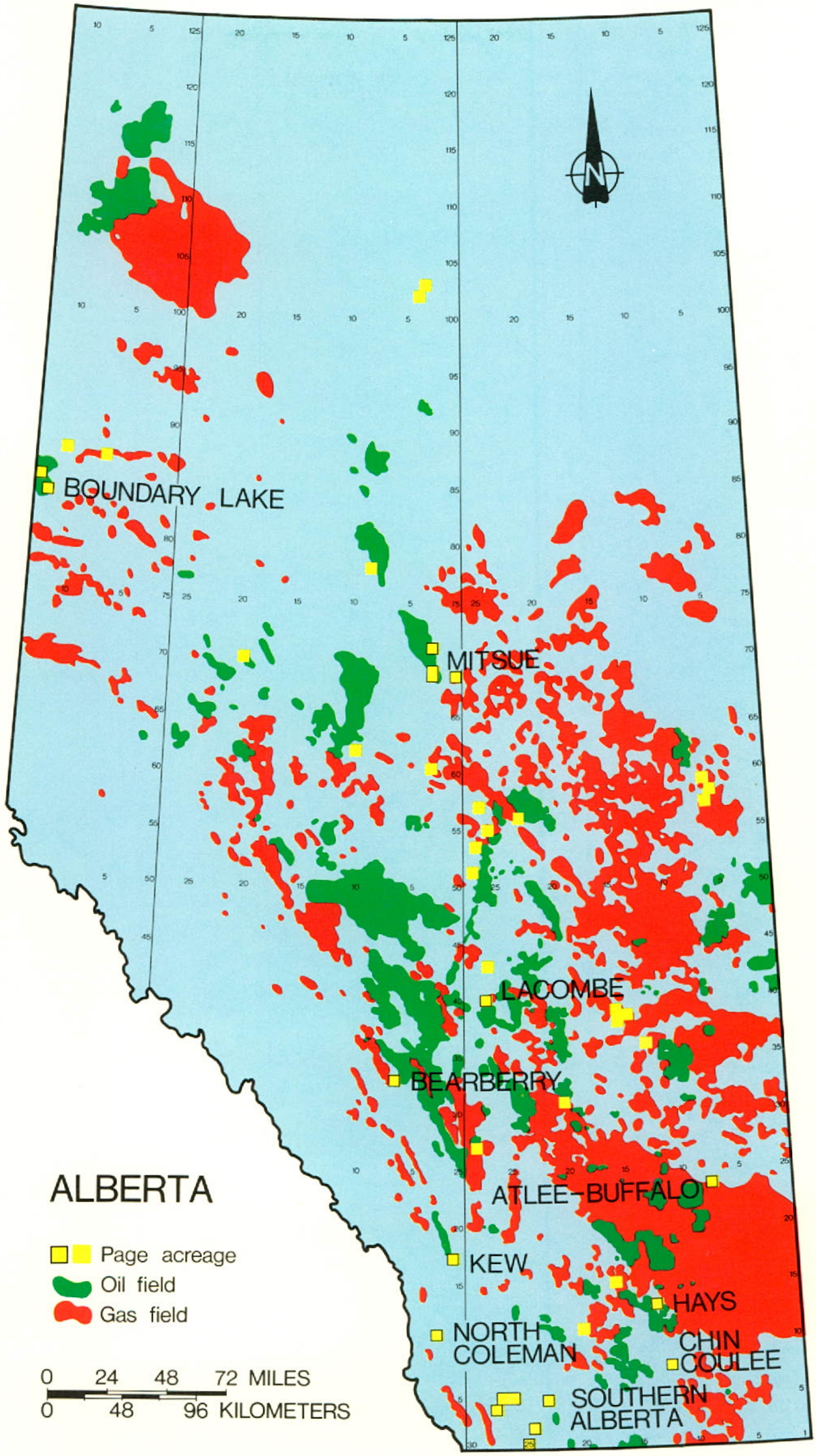
Page holds significant acreage positions on three Foothills prospects. At Kew, the Company has a 20% interest in a 5,760 acre Petroleum and Natural Gas Licence which was purchased in June, 1979 for a bonus cost of approximately $2 million. A 4,200 foot wildcat well will be drilled by Page and its partners during the first half of 1980 to test this seismically controlled Mississippian oil prospect. The other two overthrust prospects, located at Bearberry and North Coleman, are prospective for gas. The decision to drill these two prospects will be dependent upon the results of additional geophysical work and an improved gas marketing situation in Western Canada.

### Southern Alberta

Page controls through lease ownership and farmout agreements a significant amount of land in southern Alberta, south of the Blood Indian Reserve. Geophysical programs during the first half of 1980 are expected to lead to a multi-well exploratory program to be commenced during 1980. Well depths will range from 6,500 to 9,000 feet.

### Atlee Buffalo

The Company drilled a 3,200 foot dual zone gas discovery on a 12,160 acre block of leases in October, 1979. This acreage is subject to an existing Pan Alberta gas contract which, in turn, is dependent upon additional gas export approvals. Follow-up drilling will be deferred until it is apparent that the gas can be marketed.



BOUNDARY LAKE
MITSUE
LACOMBE
BEARBERRY
ATLEE-BUFFALO
KEW
HAYS
NORTH COLEMAN
CHIN COULEE
SOUTHERN ALBERTA
ALBERTA
Page acreage
Oil field
Gas field
0 24 48 72 MILES
0 48 96 KILOMETERS

### Hays

The Company drilled a 3,218 foot Cretaceous (Lower Mannville) oil well during the latter part of 1979. Page is applying improved technology in an attempt to produce oil commercially from a previously discovered and uneconomic oil accumulation. The well is being production tested and should results be successful, three or four development wells could be drilled in 1980. Page holds a 100% interest in 1,120 acres and a 55% interest in 640 acres.

### Chin Coulee

At the Alberta Crown Sale of March 26, 1980, Page purchased a 3,840 acre Petroleum and Natural Gas Licence for $546,000 ($142 per acre). This licence covers an oil prospect defined by sub-surface studies and geophysics. A 3,200 foot wildcat planned for late in the year will test this play.

## MANITOBA

In 1979, the Company bought a 33 ⅓% working interest in 7,080 acres in the Williston Basin area of southwest Manitoba. An extensive seismic program has been conducted over the acreage and several prospects have been outlined. The area is prospective for oil at moderate depths in the Mississippian and Devonian carbonates. A 5,000 foot wildcat will be drilled in the latter half of 1980.

In the first quarter of 1980 Page earned a one-sixth interest in an additional 3,280 acres by paying one-third of the cost of an unsuccessful 5,500 foot Devonian well.

## UNITED STATES

Page operates in the U.S. through Page Petroleum Inc., a wholly owned subsidiary headquartered in Amarillo, Texas. The Company participated in 33 wells during the year, resulting in eight gas wells (1.43 net), five oil wells (2.47 net) and 20 dry holes (4.82 net). The wells were drilled in Utah, Texas, Louisiana, Oklahoma and Kansas. The large number of dry holes resulted from an extensive wildcat program and also included four wells drilled as step-outs from existing fields. Five of the unsuccessful exploratory wells were drilled by others at no cost to Page. U.S. net oil and gas revenues were $4,778,000, or approximately 41% of the Company total.

## UTAH

### Greater Altamont-Bluebell Field

Page purchased in February and November, 1979 at a total cost of $3,048,000 (U.S.), approximately 25,000 net acres of oil and gas leases within, and adjacent to, the Greater Altamont-Bluebell Field in the Uinta Basin of Utah. Included in these acquisitions were interests in 17 oil wells, comprising working interest of 100% in five wells, working interest in seven wells ranging from 49.9% to 98.3% and minor working interests in five wells ranging from 1.5% to 6.2%. The Company's interests are subject to a 5% overriding royalty which, if converted to a working interest after payout, would reduce Page's working interest to 87.5% of those shown above. The first four development wells drilled by Page on the acquired acreage are subject to an additional 5% overriding royalty which may also be converted to a 12.5% working interest after payout.

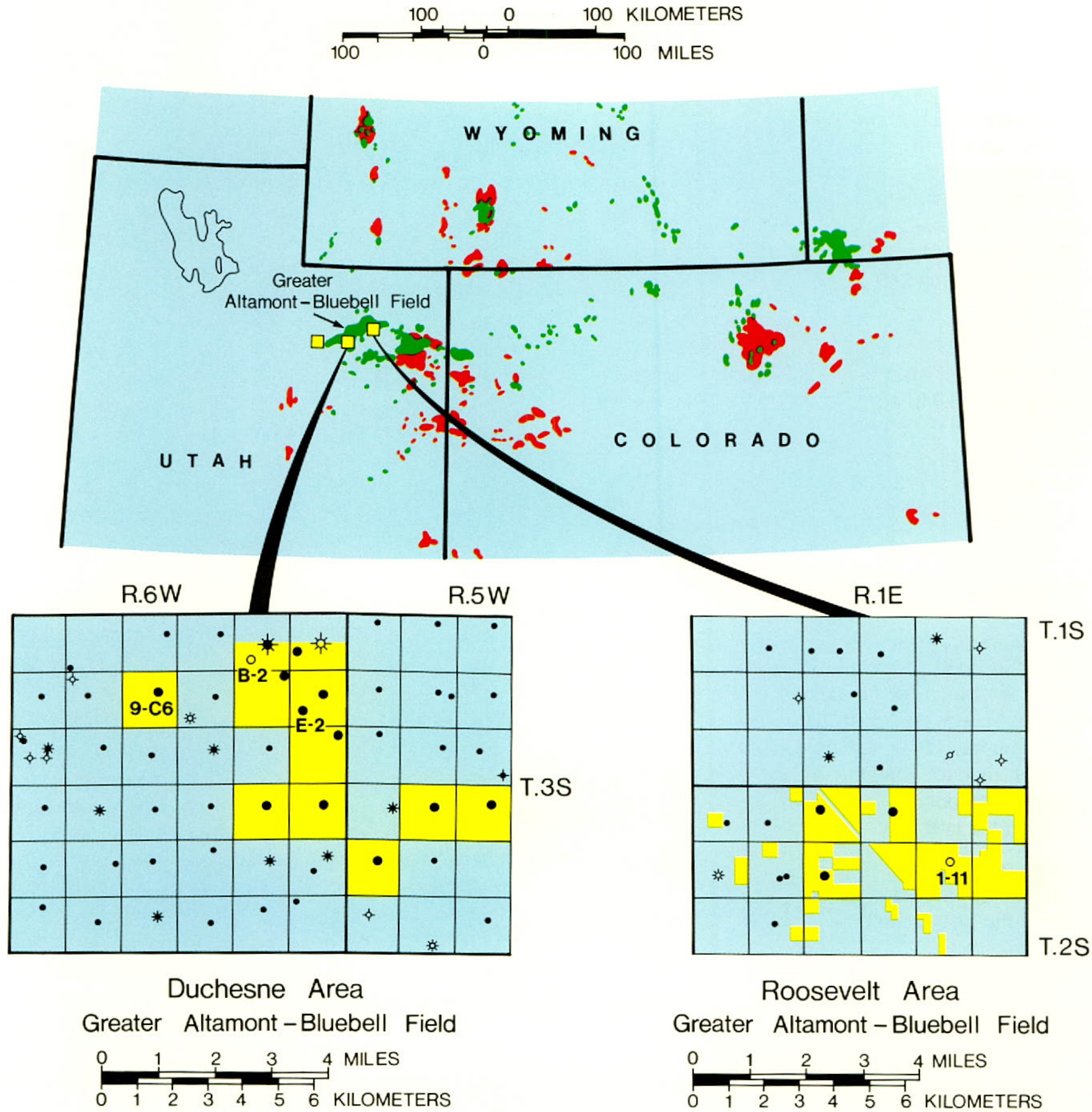
Production at the time of purchase averaged approximately 360 barrels and 355 Mcf of casinghead gas per day. Several wells were re-worked and, by year end, production from the purchased wells increased to approximately 540 barrels of oil and 900 Mcf of casinghead gas per day.

Page drilled two development wells on the acquired acreage during 1979. The Page Ute Tribal 1-9C-6 (Page 100%) was completed in late July, flowing 800 barrels per day. Production for the remainder of 1979 averaged 430 barrels per day. The second well, Page Ute Tribal E-2 (Page 100%), reached total depth on December 13, 1979 and was completed in mid-January. It was placed on continuous production February 10, 1980 and produced 31,125 barrels of oil through March 31st, for an average rate of 622 barrels per day. Casinghead gas production was approximately 750 Mcf per day. With the current "new oil" price in excess of $35 (U.S.) per barrel, wells of this caliber can be expected to pay out in less than six months.

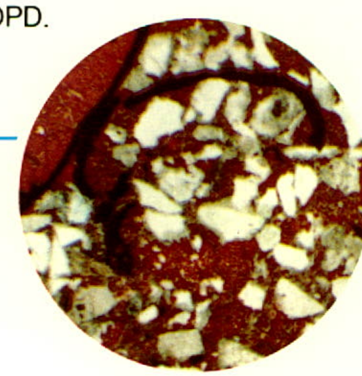
Under a separate farmout agreement the Company participated for a 25% working interest in the Utex Ute Tribal 1-21-C5 well. This well was completed in July and averaged over 230 barrels of oil per day during the remainder of 1979.

The Wasatch formation is the principal producing zone in the Altamont-Bluebell Field. It ranges up to 4,000 feet in thickness and comprises a thinly bedded

## Oil And Gas Field Map Showing Geographic Location Of Page's Utah Properties




9C–6 On Production July 24, 1979. — Cumulative Production Dec. 31, 1979 66,462 Bbls. Oil
E–2 On Production Jan. 18, 1980. — Initial Production 742 BOPD.
B–2 And 1–11 Locations To Be Spudded 1st. Half 1980.



Thin section of fine grained sandstone, (Magnified 48 times) taken from sidewall core, cut from the Wasatch formation of Tertiary age, in the Page Ute Tribal E-2 well drilled in late 1979, (photographed plane-polarized light). Data of this type is invaluable in determining Paleo-Environment as well as in optimizing completion techniques.

sequence of shales, silts and calcareous sands. The sands have low porosity; however production is greatly enhanced by the presence of extensive natural fracturing and a higher than normal reservoir pressure. The oil is a high paraffin, light gravity crude (42° - 44° API) requiring special handling, including year round heating of production and transportation facilities. Operating costs in 1979 averaged $4.87 (U.S.) per barrel but are expected to be reduced by approximately one-third in 1980. Historically the wells have been drilled on 640-acre spacing although the trend is to 320-acre spacing. Based on present information, approximately 16 development locations remain to be drilled on Page lands in this field. Drilling depths on Page's lands range from 10,000 to 13,000 feet.

Page has budgeted approximately $10 million during 1980 to drill six Wasatch wells and to re-work a number of older wells. Revenues from this field in 1979, after deduction of royalties, totalled $3,212,000 or 28% of the Company total.

## NORTHEASTERN UNITED STATES

During the first quarter of 1980 the Company obtained land holdings in three areas in the northeastern United States. In Saginaw County, Michigan, Page acquired 10,640 acres of leases in an area of multi-zone prospects for oil. Geophysical and geological studies, expected to be completed by the summer of 1980, may lead to a multi-well program starting later in the year. In Fayette County, Ohio, Page purchased approximately 15,000 acres of leases over an area prospective for shallow oil. A geophysical program will be conducted during the spring of 1980 in order to select potential drill sites. In Lycoming County, Pennsylvania, the Company acquired an option on 36,000 acres of leases over an area of multi-zone gas potential, at depths ranging from 2,000 to 14,000 feet. Geological and geophysical studies should be completed by the end of April 1980. At that time Page will elect whether or not to exercise the option which, if exercised, would require a cash payment and the drilling of two 2,000 foot test wells.

## KANSAS

In the fourth quarter of 1979 Page acquired significant interests in two large land blocks in eastern Kansas which are prospective for oil in several zones at relatively shallow depths. On the Nemaha South prospect, Page owned at year end a 20% interest in approximately 125,000 net acres of oil and gas leases. The Company participated in an extensive seismic program on these lands. It is expected that at least five locations will be drilled on the prospect lands during the first half of 1980.

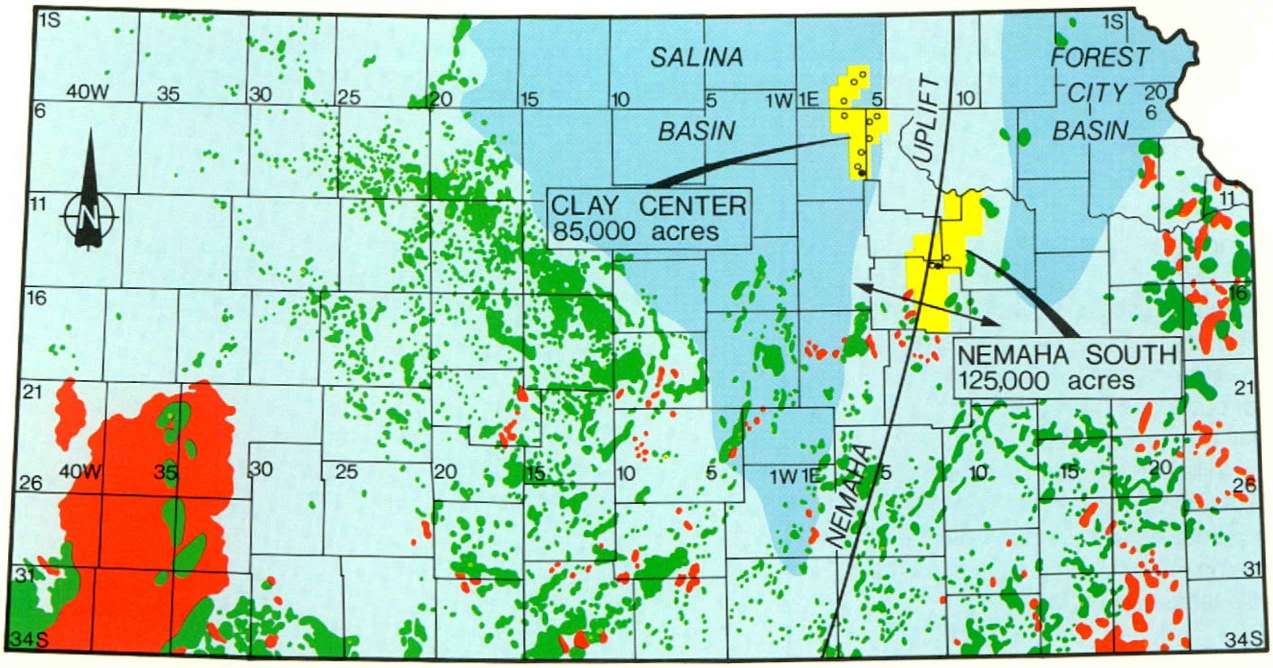
On the Clay Center prospect Page owns a 37.5% interest in approximately 85,000 acres. Ten stratigraphic wildcat well locations have been selected and will be drilled during the first half of 1980 to test the regional pinchout of the prospective Mississippian. A reconnaisance seismic program has disclosed a number of interesting anomalies. Additional seismic will be required to outline possible drillable prospects.

## NEBRASKA

Page owns a 20% interest in 776,000 acres of oil and gas leases in north central Nebraska. The leases have 10 year primary terms, expiring in 1989. This acreage provides Page with a significant land representation on the shallow Niobrara gas play that has expanded from northeastern Colorado and northwestern Kansas into Nebraska. The prospective Niobrara zone is found at approximately 2,000 feet throughout this area. Gas production rates are traditionally low from this formation, however new fracturing methods should enhance productivity. This, together with increased gas prices and readily available markets, has provided a continuing stimulus for exploration in this area.

A recent Pennsylvanian oil discovery located in adjacent southwestern South Dakota at a depth of approximately 6,000 feet has awakened industry's interest in the deeper potential of this general region. Two wells have recently been cased to 4,100 and 4,693 feet, respectively, near certain of Page's leases. Information on these wells is being held confidential by the operators, however the casing depths indicate possible productive zones deeper than the Niobrara.

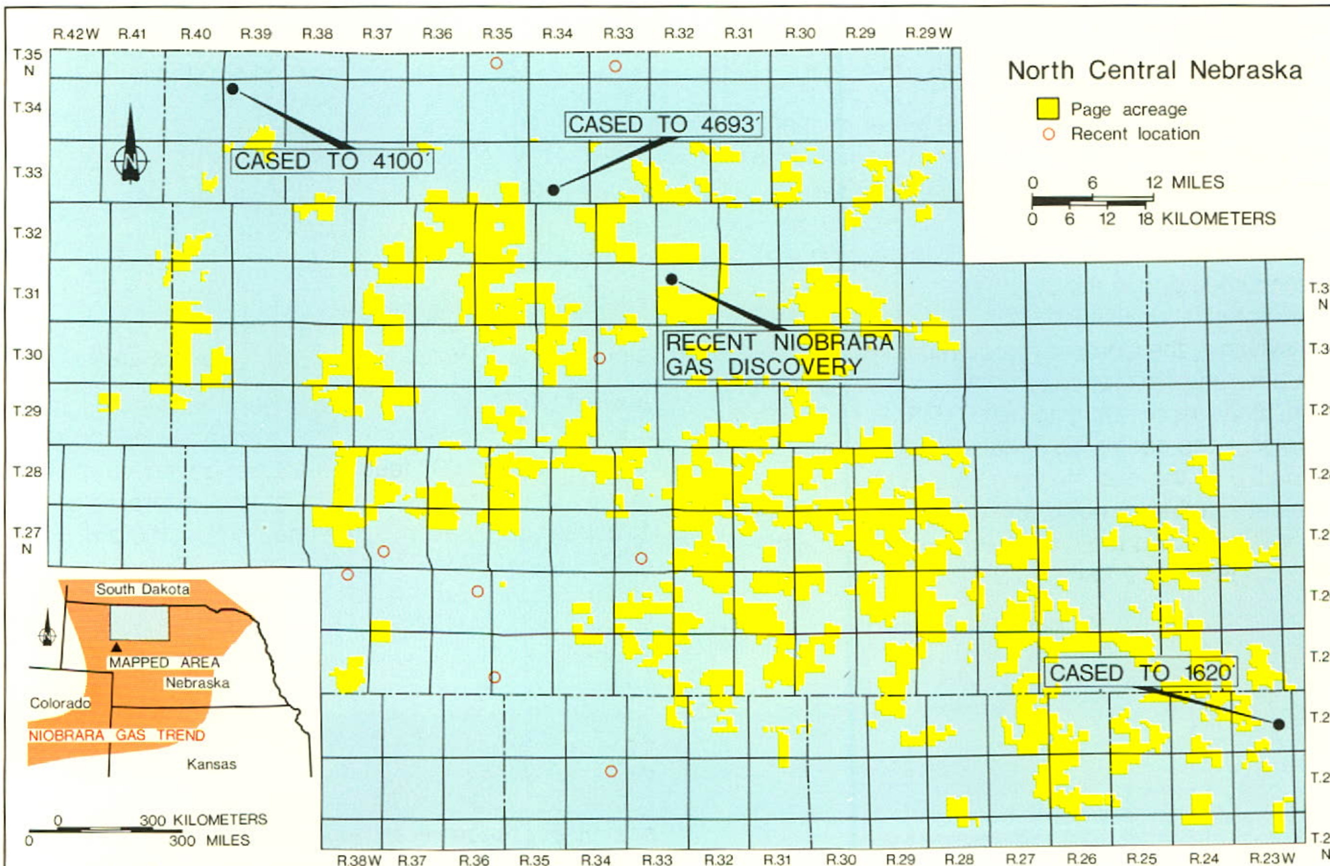
Other operators have recently acquired several million acres on this play. Multi-well drilling programs near our lands are scheduled for 1980 by two major oil companies. Page and its partners intend to conduct a preliminary reconnaisance geophysical program over a portion of our leases during the first half of 1980. Drilling may follow by year end.




Clay Center and Nemaha South, Kansas.

- Page acreage
- ∘ Locations to be drilled first half 1980.
- • Cased well drilled first quarter 1980.
- Oil field
- Gas field

0 100 200 MILES
0 100 200 300 KILOMETERS




North Central Nebraska

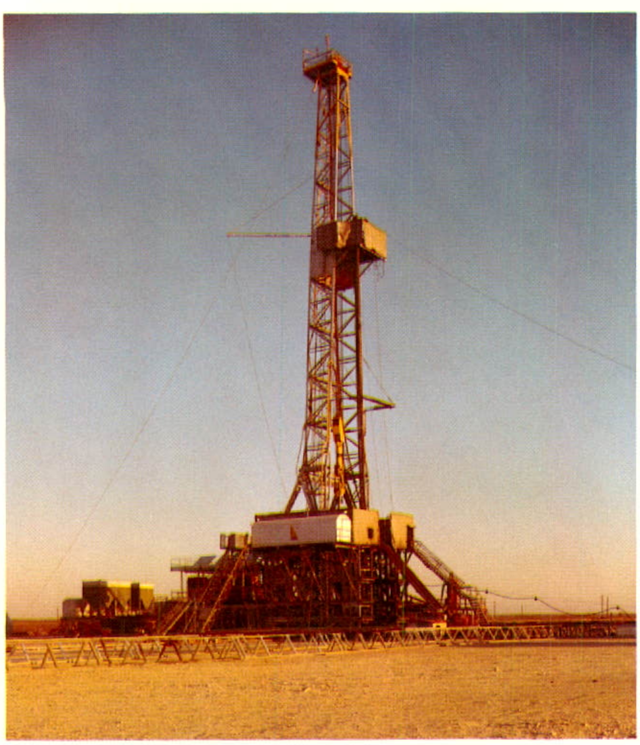
- Page acreage
- ○ Recent location

0 6 12 MILES
0 6 12 18 KILOMETERS

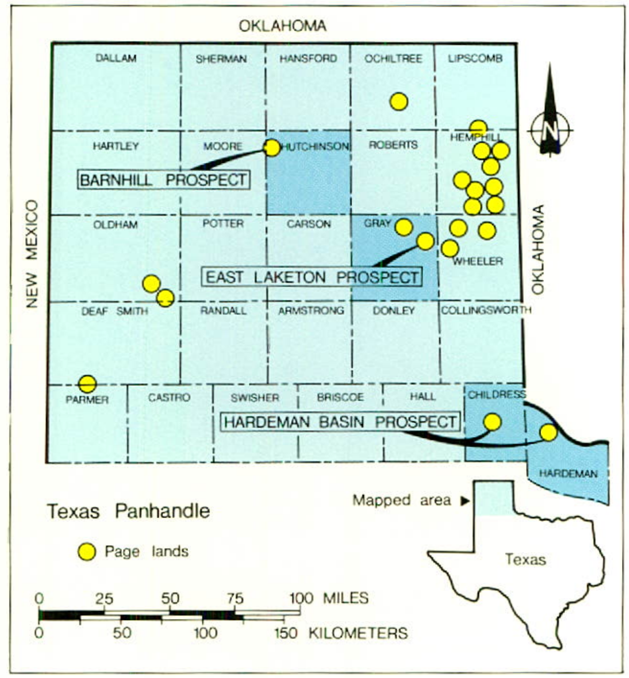
## TEXAS

### Gomez Field

Page has a 25% working interest in a currently drilling 22,700 foot Ellenburger test located on a 640 acre unit in the southern part of the Gomez gas field of central Pecos County, Texas. At April 1, 1980, the well, Tom Marsh No. 1 Gomez-Eaton, was drilling below 21,000 feet with total depth expected in June. The Gomez field has estimated reserves in excess of 10 trillion cubic feet of gas underlying approximately 100,000 acres with 3 trillion cubic feet produced to date. The Gomez-Eaton well is surrounded by production. Two east offset wells have together produced a total of 67 billion cubic feet of gas. Combined daily production for the two wells currently average 17.5 million cubic feet of gas per day. To the west, within one and one half miles, three wells currently produce at a combined rate of 14 million cubic feet of gas per day. Page's 25% working interest will revert to 18.75% after it has recovered its 25% share of estimated well costs of approximately $3.5 million (U.S.). The initial gas price is expected to be at least $3.50 (U.S.) per Mcf.



Rig drilling below 20,000 feet on Tom Marsh No. 1 Gomez-Eaton, a projected 22,700 foot Ellenburger test located within the confines of the Gomez Field, Pecos County, Texas. Page has a 25% working interest in this well.




### Panhandle Area

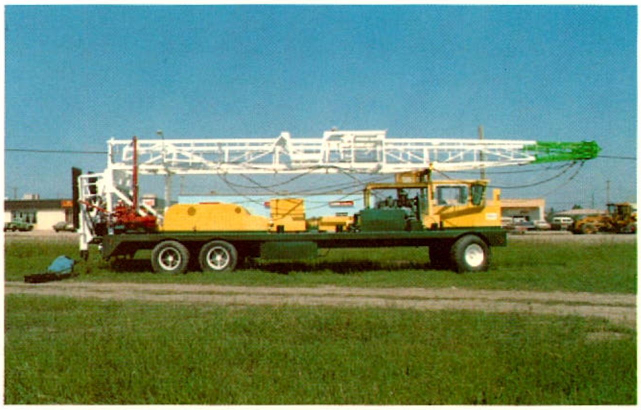
#### Barnhill Prospect

Page has an 80% working interest in a 1,600 acre lease located in Hutchinson County, Texas, within the confines of the Panhandle Field. Page has now drilled four 3,300 foot oil wells with one now undergoing production testing. The other three are cased and awaiting completion. Most of the lease acreage is subject to partial drainage from previous wells that were plugged over 10 years ago. However, shallow depths, an oil price of approximately $40 (U.S.) per barrel and the casinghead gas price of approximately $2.50 (U.S.) per Mcf combine to make new wells economic. We anticipate daily production of 5 to 15 barrels and 400 to 500 Mcf of casinghead gas per well. Present plans call for the drilling of at least 15 wells during 1980.

#### Hardeman Basin

Page has recently completed an extensive geophysical program in Childress and Hardeman Counties. Approximately 3,100 acres of leases have now been acquired on three separate reef prospects. Page plans to drill two of the prospects later this year. An 8,500 foot Ellenburger test will be drilled on the Childress Prospect with Mississippian and Pennsylvanian reefs being the principal zones of interest. The North Conley Prospect will be evaluated by a 6,000 foot Pennsylvanian reef test. All zones are prospective for oil rather than gas.

# OILFIELD SERVICING ACTIVITIES



Kin-Rig service rig Model #1430 (3,500 foot capacity), now Northline Rig #9.

## Northline Well Servicing Ltd.

This 90% owned subsidiary commenced operations in March, 1978, with the purchase of five service rigs. Northline currently owns 10 service rigs that operate in eastern Alberta and western Saskatchewan. The rated operational depth for the rigs ranges from 3,000 to 4,000 feet. Initially, these rigs were acquired as a means to adequately service the Company's properties at Dodsland and Buffalo Coulee. The rigs now work for Page and others in the Kindersley, Maidstone, Lloydminster and Wainwright areas of Saskatchewan and Alberta.

Kin-Rig Manufacturing Ltd., now a division of Northline, was incorporated in 1979, primarily to build specialized service rigs for the heavy crude area of Lloydminster. In 1979 a total of seven rigs were built by Kin-Rig for use in the Company's well servicing operations. It is planned that 12 additional rigs will be built in 1980 with three to be retained by Northline and nine to be sold to others.

Northline revenues for 1979, after eliminating charges for work done on Company wells, amounted to $1,117,000. This compares with revenues of $610,000 in 1978. Although the net losses from these operations were $8,000 in 1978 and $112,000 in 1979, it is expected that Northline will become a profitable operation in 1980.

## Habco Sales Ltd.

In November 1979, the Company acquired all of the outstanding shares of Habco Sales Ltd. and two affiliated companies, effective July 1, 1979, for $1,049,000 in cash and 130,000 common shares of the Company. Habco is engaged in the construction and installation of small diameter pipelines, primarily gas flow lines. The construction and installation projects are carried out primarily for other oil and gas companies. Habco is also engaged in well servicing operations with two service rigs and in the manufacture and installation of wellhead facilities, compressor packages and gas plants.

The Company intends to apply for required governmental consent pursuant to the Foreign Investment Review Act (Canada) in connection with the Habco acquisition. If such consent is not granted Page may be required to dispose of Habco.

# FINANCIAL REVIEW

Despite a significant increase in revenues over 1978, the Company recorded a net loss of $33,000 during the year, and after providing for cumulative dividends on the outstanding preferred shares, the net loss applicable to common shares totalled $478,000, or 18¢ per common share. This compares with the restated net earnings applicable to common shares in 1978 of $616,000 or 30¢ per common share. Substantial increases in all expense categories contributed to the net loss for the year. The higher production level and increased exploration and development activities resulted in the increased operating and administrative costs. Higher interest rates experienced during the latter part of 1979, coupled with the large borrowings made to finance the capital expenditures incurred during the last two years, resulted in the 230% increase in interest expense. The 176% increase in depletion, depreciation and amortization expense resulted from not only the high level of production and the capital expenditures incurred to date but also the large capital expenditures which will be required to develop the proved undeveloped reserves. Further information is presented under "Management's Discussion and Analysis of the Summary of Operations" presented elsewhere in this report.

In 1979, the Company changed its method of calculating depletion within the full cost method of accounting for oil and gas operations, adopting the rules issued by the U.S. Securities and Exchange Commission. These rules require a separate cost center for each of Canada and the United States rather than one cost center for all of North America as previously used. This change was applied retroactive to 1977.

Funds generated from operations totalled $4,533,000, an increase of 70% over the $2,669,000 in 1978. Capital expenditures increased 166% to $30,256,000 in 1979 from $11,358,000 in 1978. The 1979 total included $5,162,000 expended on the acquisition of proved properties in Canada and the United States. The capital expenditures in 1979 were 6.7 times the funds generated from operations, compared with the multiple of 4.3 in 1978. To carry out the substantial exploration and development program, the Company supplemented the funds generated from operations by borrowings under its Production Loan lines of credit and an issue of convertible preferred shares.

The preferred shares were issued in Canada in June, 1979 and comprised 1,000,000 shares designated as 7% Cumulative Redeemable Convertible Preferred Shares Series B, with a par value of $10 each. The net proceeds were applied as a temporary reduction of the Company's then outstanding bank production loans, which have subsequently been re-borrowed. This issue of preferred shares followed the earlier call for redemption of the then outstanding 7% Cumulative Redeemable Convertible Preferred Shares Series A. Following the call for redemption, 495,285 of the 500,000 Series A Preferred Shares were converted into 717,396 common shares by April 30, 1979 and on May 1, 1979 the remaining 4,715 Series A Preferred Shares were redeemed at $10.50 per share.

The bank Production Loan lines of credit, at December 31, 1979, comprised $26 million in Canada and $7.5 million (U.S.) in the United States. The Company was able to borrow $4 million (U.S.) under the U.S. line immediately and the remaining $3.5 million (U.S.) will become available when security documentation is finalized and updated independent reserve evaluations are submitted. These lines of credit are reviewable semi-annually based on reserve evaluations.

The Company has budgeted $36 million in capital expenditures for 1980. It is anticipated that cash flow from operations and bank financings will provide the funds for a large part of this program. These sources of capital will be supplemented by a proposed sale in the U.S. of $25 million (U.S.) aggregate principal amount of 10% Convertible Subordinated Debentures due 2000. A registration statement related to this issue was filed with the Securities and Exchange Commission on April 22, 1980 and the Company expects to complete this issue before the end of April, 1980.

The Board of Directors is proposing an increase in the authorized capital of the Company at the next shareholders meeting. The proposed creation of an additional 5,000,000 common shares, no par value, and 9,000,000 preferred shares, $10 par value each, will provide greater flexibility for future financings should the need arise.

As part of the financial statements, the Company has presented supplementary information based upon the Reserve Recognition Accounting rules issued by the Securities and Exchange Commission. However, the Company cautions that this method of accounting is still in the development stage and the actual method adopted may differ from that presently in existence. Particular attention should be directed to the "Management's Discussion and Analysis of the Summary of Operations Prepared on the Basis of RRA" portion of the supplementary information.

# PAGE PETROLEUM LTD.

## CONSOLIDATED STATEMENTS OF EARNINGS

### YEARS ENDED DECEMBER 31, 1979 and 1978

(Thousands of Canadian dollars)

| | 1979 | 1978 (Restated) |
|---|---|---|
| **INCOME** | | |
| Oil and gas sales, net of royalties | $ 11,606 | $ 4,930 |
| Well servicing | 1,117 | 610 |
| Investment and other income | 68 | 130 |
| | 12,791 | 5,670 |
| **EXPENSES** | | |
| Production | 3,429 | 1,340 |
| Well servicing | 911 | 409 |
| General and administrative | 1,643 | 655 |
| Interest on long-term debt | 2,453 | 742 |
| Depreciation, depletion and amortization | 4,062 | 1,476 |
| Amortization of deferred financing changes | 91 | 26 |
| | 12,589 | 4,648 |
| EARNINGS (LOSS) BEFORE INCOME TAXES | 202 | 1,022 |
| **INCOME TAXES** | | |
| Current | (178) | (145) |
| Deferred | 413 | 368 |
| | 235 | 223 |
| Net earnings (loss) | (33) | 799 |
| Preferred dividends | 445 | 183 |
| Net earnings (loss) applicable to common shares | $ (478) | $ 616 |
| Net earnings (loss) per common share (primary and fully diluted) | $ (0.18) | $ 0.30 |
| Weighted average number of common shares outstanding | 2,724,250 | 2,027,709 |

## CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

### YEARS ENDED DECEMBER 31, 1979 and 1978

(Thousands of Canadian dollars)

| | 1979 | 1978 |
|---|---|---|
| Retained earnings, beginning of year | | |
| As previously reported | $1,436 | $ 615 |
| Adjustment for retroactive change in application of full cost method of accounting (Note 1(b)) | (226) | (21) |
| As restated | 1,210 | 594 |
| Net earnings (loss) | (33) | 799 |
| | 1,177 | 1,393 |
| Dividends on preferred shares | 445 | 183 |
| Premium on preferred shares redeemed | 2 | — |
| Retained earnings transferred to capital redemption reserve fund (Note 8(b)) | 47 | — |
| Retained earnings, end of year | $ 683 | $1,210 |

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

# PAGE PETROLEUM LTD.

## CONSOLIDATED BALANCE SHEETS

DECEMBER 31, 1979 and 1978
(Thousands of Canadian dollars)

| ASSETS | 1979 | 1978 (Restated) |
|---|---|---|
| CURRENT ASSETS | | |
| Cash | $ 120 | $ — |
| Cash subject to usage restriction (Note 6) | 253 | — |
| Accounts receivable (Note 6) | 4,721 | 1,550 |
| Note receivable | — | 960 |
| Provincial royalty tax credit | 201 | 171 |
| Inventories – at cost | 1,089 | 226 |
| Prepaid expenses | 31 | 67 |
| | 6,415 | 2,974 |
| INVESTMENTS AND ADVANCES – at cost (Note 3) | 3,620 | — |
| PROPERTY, PLANT AND EQUIPMENT – at cost (including full cost method of accounting for oil and gas operations) (Notes 4 and 6) | 52,172 | 21,943 |
| Less: Accumulated depreciation, depletion and amortization | 7,098 | 3,063 |
| | 45,074 | 18,880 |
| OTHER ASSETS (Note 5) | 1,539 | 1,581 |
| | $56,648 | $23,435 |

Approved on behalf of the Board

LAWTON L. CLARK , Director

T. J. JACOBSEN , Director

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

| LIABILITIES | 1979 | 1978 (Restated) |
|---|---|---|
| CURRENT LIABILITIES | | |
| Outstanding cheques | $ — | $ 1,564 |
| Accounts payable and accrued liabilities | 5,799 | 538 |
| Current maturities of long-term debt (Note 6) | 1,360 | 758 |
| | 7,159 | 2,860 |
| LONG-TERM DEBT (Note 6) | 26,645 | 10,182 |
| DEFERRED INCOME TAXES | 1,422 | 1,009 |
| COMMITMENTS AND CONTINGENT LIABILITY (NOTE 7) | | |
| **SHAREHOLDERS' EQUITY** | | |
| SHARE CAPITAL (Notes 8, 9 and 13) | | |
| Authorized | | |
| 1,000,000 Preferred Shares with a par value of $10 | | |
| 5,000,000 Common Shares without par value | | |
| Issued and outstanding | | |
| 968,700 7% Cumulative Redeemable Convertible Preferred Shares Series B | 9,687 | — |
| 500,000 7% Cumulative Redeemable Convertible Preferred Shares Series A | — | 5,000 |
| 2,960,868 Common Shares (2,065,418 shares in 1978) | 10,755 | 2,924 |
| | 20,442 | 7,924 |
| Contributed surplus | 250 | 250 |
| Capital redemption reserve fund (Note 8 (b)) | 47 | — |
| Retained earnings | 683 | 1,210 |
| | 21,422 | 9,384 |
| | $56,648 | $23,435 |

# PAGE PETROLEUM LTD.

## CONSOLIDATED STATEMENTS OF CHANGES IN FINANCIAL POSITION

### YEARS ENDED DECEMBER 31, 1979 and 1978

(Thousands of Canadian dollars)

| | 1979 | 1978 (Restated) |
|---|---|---|
| **SOURCES OF FUNDS** | | |
| Net earnings (loss) | $ (33) | $ 799 |
| Charges to earnings not involving funds: | | |
| Depreciation, depletion and amortization | 4,153 | 1,502 |
| Deferred income taxes | 413 | 368 |
| Funds generated from operations | 4,533 | 2,669 |
| Proceeds from issuance of common shares | 2,569 | 177 |
| Proceeds from issuance of preferred shares | 10,000 | 5,000 |
| Increase in long-term debt | 28,126 | 6,668 |
| Proceeds from notes receivable | — | 48 |
| Total sources of funds | 45,228 | 14,562 |
| **USES OF FUNDS** | | |
| Investment in and advances to Habco Sales Ltd. and affiliated companies | 3,620 | — |
| Dividends on preferred shares | 445 | 183 |
| Redemption of preferred shares | 53 | — |
| Net additions to property, plant and equipment | 30,256 | 11,358 |
| Additions to other assets | 49 | 1,542 |
| Repayment and current maturities of long-term debt | 11,663 | 2,033 |
| Total uses of funds | 46,086 | 15,116 |
| Decrease in working capital | (858) | (554) |
| Working capital, beginning of year | 114 | 668 |
| Working capital (deficiency), end of year | $ (744) | $ 114 |
| **WORKING CAPITAL CHANGES** | | |
| Increase (decrease) in current assets | | |
| Cash | $ 120 | $ (286) |
| Cash subject to usage restriction | 253 | — |
| Accounts receivable | 3,171 | (16) |
| Note receivable | (960) | 960 |
| Provincial royalty tax credit | 30 | 25 |
| Inventories | 863 | 207 |
| Prepaid expenses | (36) | 60 |
| | 3,441 | 950 |
| Increase (decrease) in current liabilities | | |
| Outstanding cheques | (1,564) | 1,564 |
| Bank operating loan | — | (150) |
| Accounts payable and accrued liabilities | 5,261 | (640) |
| Current maturities of long-term debt | 602 | 730 |
| | 4,299 | 1,504 |
| | $ (858) | $ (554) |

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

## PAGE PETROLEUM LTD.

# STATEMENTS OF CONSOLIDATED INCOME TAXES

### YEARS ENDED DECEMBER 31, 1979 and 1978

(Thousands of Canadian dollars)

| | 1979 | 1978 (Restated) |
|---|---|---|
| Computation of Income Taxes – The total provision for income taxes differs from the amount which would be computed by applying the statutory Federal income tax rate to book income before income tax. The major reasons for this difference are as follows: | | |
| Book income before provision for income taxes | $ 202 | $1,022 |
| Computed "expected" tax expense | $ 93 | $ 470 |
| Royalties and other payments to provincial governments which are disallowed as deductions for Canadian federal income tax | 953 | 610 |
| Rebates by provincial governments related to payments disallowed for Canadian federal income tax | (234) | (171) |
| Depletion allowance on oil and gas production income | (62) | (182) |
| Federal resource allowance | (575) | (399) |
| Provincial income taxes less federal abatements | 16 | (50) |
| Other – net | 44 | (55) |
| Actual tax expense – current and deferred | $ 235 | $ 223 |
| Canadian federal tax rate | 46% | 46% |
| Actual tax expense (as a percentage of pre-tax earnings) | 116% | 22% |
| An analysis of actual tax expense follows: | | |
| Canadian | $ (29) | $ 199 |
| United States | 264 | 24 |
| | $ 235 | $ 223 |
| 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: | | |
| Excess of income tax capital cost allowances over amount provided for depreciation in the accounts | $ 273 | $ (184) |
| Excess of exploration and development expenditures claimed for income tax purposes over amount provided for depletion in the accounts | 140 | 552 |
| | $ 413 | $ 368 |

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

# PAGE PETROLEUM LTD.

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

### DECEMBER 31, 1979

(Tabular amounts shown in thousands of Canadian dollars, except share data)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Principles of Consolidation

Except as described in Note 3 below, the consolidated financial statements include the accounts of subsidiary companies, all of which are wholly-owned. The amount by which the cost of purchased subsidiary companies exceeded the underlying net book value at dates of acquisition has been included in property, plant and equipment and is subject to the accounting policies outlined below.

(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 below. 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 and overhead expense related to exploration activities. The costs are accumulated in cost centers as follows:

(i) Canada
(ii) United States
(iii) The United Kingdom

Since January 1, 1977 the costs accumulated in the Canada and United States cost centers, together with estimated future capital costs associated with proved reserves, are depleted using the unit of production method based upon estimated total proved reserves in each country, as determined by independent engineers. Prior to January 1, 1977, the depletion was calculated based on total North American reserves and production. See Note 2 for information regarding the effect of this change in method of calculating depletion, which was adopted during the year ended December 31, 1979, and retroactively applied to the financial statements of the years 1977 and 1978. In calculating depletion, natural gas reserves and production are converted to equivalent barrels of oil based upon the relative sales value of each product (which approximates conversion based upon the relative energy content of each product). Proceeds on disposal of properties are ordinarily 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.

Costs associated with the United Kingdom cost center are amortized in line with the terms of the leases.

(c) Depreciation

Depreciation of production equipment is provided for on the unit of production method. Depreciation on sundry equipment is computed on the diminishing balance method at rates varying from 20% to 30%. Well servicing equipment is depreciated based upon the number of hours of operation. The hourly rate will amortize the cost, less estimated salvage values, over the estimated economic service lives of the equipment.

(d) Maintenance and Repairs

Maintenance and repairs are charged to earnings when incurred and major renewals and betterments which extend the serviceable life of the properties are capitalized.

(e) Joint Venture Accounting

Substantially all of the Company's exploration and production activities related to oil and gas are conducted jointly with others and accordingly the accounts reflect only the Company's proportionate interest in such activities.

(f) Limited Partnerships

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

(g) Foreign Currency Translation

Current assets and current liabilities of foreign subsidiaries are translated to Canadian dollars using the exchange rates in effect at the dates of the balance sheets. Other assets and liabilities are translated at the rate in effect at the date the original transactions took place. Revenue and expense items are translated using average rates of exchange prevailing throughout the year. The aggregate exchange gains or losses included in net earnings in each of the two years ended December 31, 1979 were not significant.

(h) Income Taxes

The Company follows interperiod tax allocation with respect to timing differences in the recognition of revenues and expenses for tax and accounting purposes. It is not expected that the cash outlay for income taxes will exceed income tax expense in any of the next three years. Reference is made to the Statements of Consolidated Income Taxes for the components of and additional information relating to income taxes.

(i) Earnings per Common Share

Earnings per common share have been computed in accordance with Canadian generally accepted accounting principles by dividing the net earnings applicable to common shares (after deducting cumulative dividends on preferred shares) by the weighted average number of common shares outstanding during the periods. In determining the aggregate of common shares, no consideration has been given to the number of common shares issuable on the exercise of employee stock options. In determining such aggregate, the number of common shares issued on conversion of securities convertible into common shares were considered to be outstanding from the date of the last dividend or interest payment date.

Earnings per common share assuming full dilution was determined on the assumption that all employee stock options were exercised and all securities convertible into common shares were converted at the beginning of each year (or the time of issuance if later). The earnings were adjusted to give effect to an assumed after-tax amount attributable to the proceeds which would have been received on the exercise of employee stock options and the after-tax effect of interest savings on convertible debt securities. Such calculations were not dilutive.

(j) Accounting Principles

The financial statements have been prepared in accordance with Canadian generally accepted accounting principles. The amounts by which net earnings and shareholders' equity would have been reduced if United States generally accepted accounting principles had been followed would not be material.

2. RESTATEMENT OF PREVIOUSLY REPORTED RESULTS

The Company adopted in 1979 the new United States Securities and Exchange Commission ("SEC") accounting standards issued December 19, 1978 for oil and gas producing activities of companies following the full cost method of accounting. The Company's previous method of full cost accounting was different from the new SEC standards, primarily in the calculation of depletion based on one cost center for North America instead of a separate cost center for each of Canada and the United States. The effect of this change was to decrease earnings applicable to common shares by $21,000 ($0.01 per share) in 1977 and $205,000 ($0.11 per share) in 1978. The financial statements for periods prior to 1977 are not restated because the difference in method would not result in a significant change from the earnings previously reported.

3. INVESTMENT IN HABCO SALES LTD. AND AFFILIATED COMPANIES

In November 1979, the Company acquired, effective July 1, 1979, all of the outstanding shares of Habco Sales Ltd. and its affiliated companies ("Habco") for a consideration of $3,506,000 ($1,049,000 cash and 130,000 common shares of the Company at an ascribed value of $2,457,000). The acquired companies are engaged in small-diameter pipeline construction, manufacturing of certain facilities supplied to the oil and gas industry and in oil and gas exploration and production. Under the Foreign Investment Review Act (Canada), the Company is presumed to be a non-eligible person and therefore requires the consent of the Canadian federal government authorities when acquiring an existing business or establishing new businesses in Canada. In order to obtain such consent, a non-eligible person has to demonstrate that the acquisition or establishment of such business is, or is likely to be, of "significant benefit to Canada" as such term is used in the Act.

The acquisition of Habco was made without the prior consent of the federal authorities as required under the Foreign Investment Review Act. Although the Company intends to apply for such consent, there is no assurance that the consent will be forthcoming. If the Company is unsuccessful in obtaining the consent, it may be forced to dispose of Habco, and such disposition may be on unfavourable terms.

Because of the uncertainty relating to whether or not the Company will receive the necessary consent for the acquisition under the terms of the Foreign Investment Review Act (Canada), the Company has recorded its acquisition of Habco as an investment, carried on the balance sheet at cost. In the opinion of management, there has been no impairment to the recorded amount of the investment in Habco since its acquisition. If the Company receives the necessary consent to retain its shares of Habco, the 1979 financial statements will be retroactively restated to reflect Habco on a consolidated basis and Habco's loss for 1979 ($401,000) will be added to the Company's consolidated net loss for 1979, which would result in a restated net loss applicable to Common Shares of $879,000, $.32 per common share.

Set forth below is the summarized combined financial information of the acquired companies as at December 31, 1979:

| | |
|---|---|
| Current assets, principally trade accounts receivable | $2,264 |
| Demand bank loans, bearing interest at the bank's minimum lending rate plus 1% (guaranteed by Page Petroleum Ltd.) | (3,640) |
| Trade accounts payable, accrued liabilities and current income taxes | (1,216) |
| Advances from Page Petroleum Ltd. | (114) |
| | (2,706) |
| Oil and gas properties and equipment, at cost | 1,009 |
| Land, buildings, aircraft, vehicles, machinery and equipment, at cost less accumulated depreciation of $1,582,000 | 2,735 |
| Deferred income taxes | (310) |
| Shareholders' equity | $ 728 |

The excess of the Company's cost of shares of these companies over the book value of acquired net assets is allocable to oil and gas properties, which have not yet commenced significant production. At December 31, 1979 the present value of future net revenues from estimated production of proved reserves, as determined by independent engineers, from Habco's oil and gas properties, computed in accordance with SEC regulations, was $7,175,000 (unaudited).

The combined operating results since acquisition (six months for the Habco companies and four months for a group of companies acquired by Habco) are as follows:

| | |
|---|---|
| Operating revenues | $3,258 |
| Operating expenses | 3,144 |
| | 114 |
| Interest | (142) |
| Depreciation | (300) |
| Loss before income taxes | 328 |
| Deferred income taxes | 73 |
| Loss for the period | $ 401 |

Income taxes occur because the losses in some of the companies may not be used as deductions from profits in others.

4. PROPERTY, PLANT AND EQUIPMENT

The amounts at which property, plant and equipment are stated do not purport to represent present or future realizable values. The following is a breakdown of the costs 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, 1978 | | | |
| Petroleum and natural gas leases and rights, including exploration, development and production equipment costs thereon | | | |
| North America | | | |
| Canada | $15,164 | $1,943 | $13,221 |
| United States | 5,112 | 682 | 4,430 |
| United Kingdom | 230 | 205 | 25 |
| | 20,506 | 2,830 | 17,676 |
| Well servicing equipment | 667 | 58 | 609 |
| Sundry | 770 | 175 | 595 |
| Total December 31, 1978 | $21,943 | $3,063 | $18,880 |

| | Assets at Cost | Accumulated Depreciation, Depletion and Amortization | Net Investment |
|---|---|---|---|
| December 31, 1979 | | | |
| Petroleum and natural gas leases and rights, including exploration, development and production equipment costs thereon | | | |
| North America | | | |
| Canada | $29,345 | $3,643 | $25,702 |
| United States | 18,789 | 2,425 | 16,364 |
| United Kingdom | 231 | 223 | 8 |
| | 48,365 | 6,291 | 42,074 |
| Well servicing equipment | 1,967 | 332 | 1,635 |
| Sundry | 1,840 | 475 | 1,365 |
| Total December 31, 1979 | $52,172 | $7,098 | $45,074 |

5. OTHER ASSETS

| | December 31 1979 | 1978 |
|---|---|---|
| Prepayments, drilling deposits and miscellaneous assets | $ 137 | $ 109 |
| Real estate held for resale | 601 | 1,140 |
| Unamortized deferred financing costs | 801 | 332 |
| | $1,539 | $1,581 |

The deferred financing costs were incurred in connection with the issue of the Company's 7% Cumulative Redeemable Convertible Preferred Shares Series A and 7% Cumulative Redeemable Convertible Preferred Shares Series B (see Note 8). These costs are being amortized using the straight line method over seven years from the date of the respective issues.

6. LONG-TERM DEBT

| | December 31 1979 | 1978 |
|---|---|---|
| Page Petroleum Ltd. | | |
| Canadian Bank Production Loan, evidenced by promissory notes at the bank's minimum lending rate plus ¾ of 1% | $20,150 | $ 7,923 |
| Mortgage loan, due 1982 | 243 | — |
| Northline Well Servicing Ltd. | | |
| Canadian Bank Loan, evidenced by promissory notes at the bank's minimum lending rate plus 1¼%, repayable at $35,000 per month | 1,721 | 459 |
| Page Petroleum Inc. | | |
| U.S. Bank Production Loan, evidenced by promissory notes at the bank's prime rate plus 1½% ($3,500,000 U.S.) | 4,094 | — |
| 6% Note payable ($682,000 U.S.) | 798 | 1,173 |
| 9½% Notes payable ($683,000 U.S.) | 799 | 1,283 |
| Other (includes $16,000 U.S.) | 200 | 102 |
| | 28,005 | 10,940 |
| Less current minimum maturities | 1,360 | 758 |
| | $26,645 | $10,182 |

All U.S. long-term debts are recorded on the balance sheet in Canadian dollars based on the exchange rate in effect at the date of receipt of the proceeds. None of the Bank Production Loan amounts have been classified as a current liability as they are secured by, and repayable from, future production proceeds and will not require the use of existing current assets. If the monthly reduction of the Production Loan Lines of Credit were to be treated as current portion, the estimated amount of long-term debt maturities for the five years subsequent to December 31, 1979 are as follows:

| | Production Loans | Other | Total |
|---|---|---|---|
| 1980 | $6,955 | $1,380 | $8,335 |
| 1981 | 6,955 | 722 | 7,677 |
| 1982 | 6,955 | 882 | 7,837 |
| 1983 | 6,955 | 656 | 7,611 |
| 1984 | 6,955 | 77 | 7,032 |

A portion of the proceeds of production from the Laketon properties, which are pledged as security for the 9½% Notes Payable, are deposited into escrow accounts, to be used for payment of the instalments on the Notes as they become due. The Bank Production Loans are secured by a general assignment of accounts receivable and certain specific oil and gas properties. The Canadian Bank Loan is secured by an assignment of certain accounts receivable and service rigs.

7. COMMITMENTS AND CONTINGENT LIABILITY

The Company has guaranteed bank and other indebtedness of Habco (see Note 3) and its subsidiaries to a maximum of $4,000,000.

Reference is made to Note 10 for commitments under leases.

8. PREFERRED SHARES

(a) Series B Preferred Shares

At December 31, 1979 there were 968,700 7% Cumulative Redeemable Convertible Preferred Shares Series B, with a par value of $10 each, issued and outstanding. The Series B Preferred Shares were issued in June, 1979 for cash, the net proceeds to the Company, after underwriting commission, being $9,500,000 and prior to December 31, 1979, 31,300 of the Preferred Shares had been converted into 16,554 common shares. Each Series B Preferred Share is convertible at the holder's option into common shares of the Company, unless previously redeemed, as follows:

| If Converted During The Period | Number of Common Shares Issuable on Conversion |
|---|---|
| July 5, 1979 - July 15, 1984 | .529 |
| July 16, 1984 - July 15, 1987 | .454 |
| July 16, 1987 - July 15, 1989 | .397 |

The Series B Preferred Shares are not redeemable on or prior to July 15, 1984 unless the weighted average price at which the common shares have traded on The Toronto Stock Exchange is at least 125% of the conversion price of the common shares then in effect for a period of at least 20 trading days (which need not be consecutive) ending not more than 21 days prior to the call for redemption, in which event the Series B Preferred Shares will be redeemable at $10.50 per share. See Note 13. The Series B Preferred Shares will be redeemable commencing July 16, 1984 at a price of $10.50 per share if redeemed on or prior to July 15, 1985, the redemption premium reducing by $0.10 per share on July 16, 1985 and each July 16 thereafter, and if redeemed on or after July 16, 1989, the redemption price will be $10 per share, plus in each case any dividends that have been declared and unpaid.

In each calendar year commencing with the year 1982, the Company is required to make all reasonable efforts to purchase for cancellation up to 5% annually of the Series B Preferred Shares outstanding on December 31, 1981, on a quarterly basis, to the extent such shares are available at a purchase price not exceeding $10 per share plus costs of purchase.

Any Series B Preferred Shares redeemed, purchased or converted will revert to the status of authorized but unissued preferred shares not included in any series of preferred shares.

(b) Series A Preferred Shares

The Company called for redemption on May 1, 1979 at $10.50 per share all of the outstanding 7% Cumulative Redeemable Convertible Preferred Shares Series A not converted to common shares on or before April 30, 1979. By April 30, 1979, 495,285 of the Series A Preferred Shares had been converted into 717,396 common shares, and on May 1, 1979 the remainder were redeemed. In accordance with the provisions of The Alberta Companies Act, an amount ($47,000) equal to the par value of the shares redeemed was transferred from Retained Earnings to the Capital Redemption Reserve Fund.

9. COMMON SHARES

(a) Shares Reserved for Conversion of Preferred Shares

There were 512,446 common shares reserved at December 31, 1979 for issuance upon the conversion of the 968,700 7% Cumulative Redeemable Convertible Preferred Shares Series B (see Note 8(a)).

(b) Options to Purchase Common Shares

There were 128,667 common shares reserved at December 31, 1979 for issuance upon the exercise to 1984 of employee stock options at prices ranging from $2.59 to $22.16 per share.

The stock options have been granted from time to time to certain employees at a price equal to 90% (85% prior to August, 1978) of the fair market value of the common shares on the date of grant. Options granted prior to January 1, 1979 were for a term of three 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 first, second and third years after the date of the grant. Options granted after December 31, 1978 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. As a result the options have become or will become exercisable without restriction in varying amounts at varying dates and by December 6, 1982 all of the options outstanding on December 31, 1979 will have become exercisable in full.

The following is a summary of transactions relating to optioned shares:

| | Directors and Officers | Other Employees | Total | Cash Consideration Received |
|---|---|---|---|---|
| Outstanding January 1, 1978 | 90,000 | 5,000 | 95,000 | |
| Granted at $4.21 | 20,000 | 22,000 | 42,000 | |
| Granted at $6.08 | — | 20,000 | 20,000 | |
| Exercised at $1.52 | (20,000) | — | (20,000) | $30 |
| Exercised at $2.59 | (33,333) | — | (33,333) | $87 |
| Exercised at $4.21 | — | (5,833) | (5,833) | $25 |
| Exercised at $6.08 | — | (5,000) | (5,000) | $30 |
| Surrendered and cancelled | (20,000) | (21,667) | (41,667) | |
| Outstanding December 31, 1978 | 36,667 | 14,500 | 51,167 | |
| Granted at $8.21 | 25,000 | — | 25,000 | |
| Granted at $9.79 | 15,000 | 12,500 | 27,500 | |
| Granted at $10.58 | 20,000 | — | 20,000 | |
| Granted at $11.59 | — | 7,000 | 7,000 | |
| Granted at $12.38 | 20,000 | 4,000 | 24,000 | |
| Granted at $14.85 | — | 2,000 | 2,000 | |
| Granted at $15.75 | — | 2,500 | 2,500 | |
| Granted at $22.16 | — | 3,000 | 3,000 | |
| Exercised at $2.59 | (15,000) | — | (15,000) | $39 |
| Exercised at $3.79 | — | (5,000) | (5,000) | $19 |
| Exercised at $4.21 | (6,667) | (1,500) | (8,167) | $34 |
| Exercised at $6.08 | — | (3,333) | (3,333) | $20 |
| Surrendered and cancelled | — | (2,000) | (2,000) | |
| Outstanding December 31, 1979 | 95,000 | 33,667 | 128,667 | |

The Company makes no charges to earnings with respect to stock options, including discounts from market value allowed on the granting of stock options. To date, such amounts have not been material. When optioned shares are issued, the proceeds are credited to the capital stock account.

(c) Changes in common shares for the two years ended December 31, 1979:

The following is a summary of changes in common shares:

| | Number of Common Shares Issued | |
|---|---|---|
| Balance December 31, 1977 | 1,999,252 | $ 2,747 |
| Conversion of 7% convertible debentures | 2,000 | 5 |
| Exercise of employee options | 64,166 | 172 |
| Balance December 31, 1978 | 2,065,418 | 2,924 |
| Conversion of Preferred Shares: | | |
| Series A | 717,396 | 4,949 |
| Series B | 16,554 | 313 |
| Acquisition of Habco Sales Ltd. | 130,000 | 2,457 |
| Exercise of employee options | 31,500 | 112 |
| Balance December 31, 1979 | 2,960,868 | $10,755 |

10. LEASED ASSETS AND LEASE COMMITMENTS

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

| | |
|---|---|
| Year ending December 31, 1980 | $182 |
| 1981 | 173 |
| 1982 | 159 |
| 1983 | 159 |
| 1984 | 159 |
| Five years ending December 31, 1989 | 40 |
| | $872 |

11. BUSINESS SEGMENTS

The Company's operations consist of two business segments: oil and gas production and, since March 1, 1978, well servicing operations. Presented below are segmented data relative to these segments:

| | Year Ended December 31 | | | |
|---|---|---|---|---|
| | 1979 | | 1978 | |
| | Operating Revenue | Segment Earnings | Operating Revenue | Segment Earnings |
| Oil and Gas | $11,606 | $4,684 | $4,930 | $2,314 |
| Well Servicing | 1,678 | (78) | 610 | 143 |
| | 13,284 | 4,606 | 5,540 | 2,457 |
| Intersegment Sales | (561) | — | — | — |
| Operating Income | 12,723 | 4,606 | 5,540 | 2,457 |
| Other Income | 68 | 68 | 130 | 130 |
| | $12,791 | 4,674 | $ 5,670 | 2,587 |
| General and Administrative | | (1,643) | | (655) |
| Other Depreciation | | (285) | | (142) |
| Interest Expense and Finance Charges | | (2,544) | | (768) |
| Income Taxes | | (235) | | (223) |
| Net Earnings (Loss) | | $ (33) | | $ 799 |

| | Year Ended December 31 | |
|---|---|---|
| | 1979 | 1978 |
| **Identifiable Assets** | | |
| Oil and Gas | $42,074 | $17,676 |
| Well Servicing | 1,635 | 609 |
| Other | 12,939 | 5,150 |
| | $56,648 | $23,435 |
| **Capital Expenditures** | | |
| Oil and Gas | $27,859 | $10,059 |
| Well Servicing | 1,300 | 666 |
| Other | 1,097 | 633 |
| | $30,256 | $11,358 |
| **Depreciation, Depletion and Amortization** | | |
| Oil and Gas | $ 3,493 | $ 1,276 |
| Well Servicing | 284 | 58 |
| Other | 285 | 142 |
| | $ 4,062 | $ 1,476 |

The following table sets forth for the periods indicated the revenue, production income, net of lifting costs, operating profits and identifiable assets attributable to the geographic regions in which the Company has reserves and production:

| | Year Ended December 31 | |
|---|---|---|
| | 1979 | 1978 |
| **Revenue** | | |
| Canada | | |
| Oil and Gas | $ 6,828 | $ 4,090 |
| Well Servicing | 1,117 | 610 |
| United States – Oil and Gas | 4,778 | 840 |
| | $12,723 | $ 5,540 |
| **Production Income, Net of Lifting Costs** | | |
| Canada | $ 4,666 | $2,809 |
| United States | 3,511 | 781 |
| | $ 8,177 | $ 3,590 |
| **Operating Profit** | | |
| Canada | | |
| Oil and Gas | $ 3,025 | $ 1,959 |
| Well Servicing | (78) | 143 |
| United States – Oil and Gas | 1,679 | 406 |
| | $ 4,626 | $ 2,508 |
| **Identifiable Assets** | | |
| Canada | | |
| Oil and Gas | $25,702 | $13,221 |
| Well Servicing | 1,635 | 609 |
| United States – Oil and Gas | 16,364 | 4,430 |
| | $43,701 | $18,260 |

12. REMUNERATION OF DIRECTORS AND OFFICERS

The total remuneration paid to directors and officers of the Company amounted to $327,000 (1978 - $247,000).

13. SUBSEQUENT EVENTS

(a) As of March 10, 1980, the common shares of the Company had traded on The Toronto Stock Exchange at a daily weighted average price per share for at least 20 trading days, including March 10, 1980, in excess of 125% of the current conversion price per common share at which the 7% Cumulative Redeemable Convertible Preferred Shares Series B are convertible into common shares. As a result, the Series B Preferred Shares may be called for redemption at any time within 21 days at the option of the Company at the redemption prices shown in Note 8. This redemption privilege will continue until the weighted average trading price of the common shares on The Toronto Stock Exchange falls below 125% of the current conversion price and for a period of 21 days thereafter. Because the 20 trading days need not be consecutive and because the 20 day test has now been met, the redemption privilege will run for 21 days after any day the weighted average selling price of the common shares on such stock exchange exceeds 125% of the current conversion price.

(b) On April 22, 1980 the Company entered into an agreement for the sale at par to underwriters of $25,000,000 (U.S.) aggregate principal amount of 10% Convertible Subordinated Debentures due 2000. The net proceeds are estimated to be $24,087,500 (U.S.) before deducting expenses of issue estimated at $550,000 (U.S.).

14. OIL AND GAS RESERVES AND RELATED RESERVE RECOGNITION ACCOUNTING ("RRA") DATA

*Estimated Quantities of Proved Reserves (Unaudited)*

The following tables set forth certain information with respect to the Company's proved and proved developed reserves, computed in accordance with rules of the SEC. The quantities of proved and proved developed reserves for December 31, 1978 and 1979 are based upon reports of D & S Petroleum Consultants (1974) Ltd., independent oil consultants (as to Canadian reserves), and Sipes, Williamson & Associates, Inc., independent consulting engineers (as to United States reserves).

| | Total | | Canada | | United States | |
|---|---|---|---|---|---|---|
| | Oil (thousands of barrels) | Gas (Mmcf) | Oil (thousands of barrels) | Gas (Mmcf) | Oil (thousands of barrels) | Gas (Mmcf) |
| **Changes in Quantities of Proved Reserves:** | | | | | | |
| Balance, December 31, 1977 | 4,387 | 4,366 | 4,368 | 1,890 | 19 | 2,476 |
| Revisions to previous estimates | (205) | (1,826) | (204) | 185 | (1) | (2,011) |
| | 4,182 | 2,540 | 4,164 | 2,075 | 18 | 465 |
| New field discoveries and extensions | 4,953 | 6,314 | 4,946 | 3,065 | 7 | 3,249 |
| Purchases of reserves | 5 | 490 | — | — | 5 | 490 |
| Production | (336) | (504) | (331) | (93) | (5) | (411) |
| Sales of reserves | — | (288) | — | (288) | — | — |
| Balance, December 31, 1978 | 8,804 | 8,552 | 8,779 | 4,759 | 25 | 3,793 |
| Revisions to previous estimates | (1,019) | 812 | (1,023) | 833 | 4 | (21) |
| | 7,785 | 9,364 | 7,756 | 5,592 | 29 | 3,772 |
| New field discoveries and extensions | 4,410 | 711 | 3,865 | — | 545 | 711 |
| Purchases of reserves | 2,065 | 2,837 | 278 | — | 1,787 | 2,837 |
| Production | (666) | (821) | (534) | (84) | (132) | (737) |
| Sales of reserves | (219) | — | (219) | — | — | — |
| Balance, December 31, 1979 | 13,375 | 12,091 | 11,146 | 5,508 | 2,229 | 6,583 |
| **Quantities of Proved Developed Reserves:** | | | | | | |
| December 31, 1978 | 6,319 | 4,254 | 6,296 | 545 | 23 | 3,709 |
| December 31, 1979 | 8,693 | 3,961 | 7,942 | 593 | 751 | 3,368 |

*Future Net Revenue Information (Unaudited)*

The following table sets forth certain information, computed in accordance with rules of the SEC, regarding the future net revenues from estimated production of the Company's proved and proved developed oil and gas reserves. The future net revenues have been computed based on prices of oil and gas at December 31, 1979, adjusted only for fixed and determinable escalation provisions in gas contracts, as described below in "Recognition of Assets and Earnings under RRA".

| | Proved Reserves | | | Proved Developed Reserves | | |
|---|---|---|---|---|---|---|
| Future Net Revenue Undiscontinued | Total | Canada | United States | Total | Canada | United States |
| 1980 | $ 14,446 | $ 5,918 | $ 8,528 | $13,943 | $ 8,665 | $ 5,278 |
| 1981 | 24,441 | 8,442 | 15,999 | 10,565 | 6,895 | 3,670 |
| 1982 | 15,458 | 7,082 | 8,376 | 8,277 | 6,005 | 2,272 |
| Remaining | 123,804 | 82,495 | 41,309 | 59,784 | 48,339 | 11,445 |
| Total | $178,149 | $103,937 | $74,212 | $92,569 | $69,904 | $22,665 |

*Reserve Recognition Accounting (Unaudited)*

### (a) Statement of Reserve Recognition Accounting Policies

Beginning in 1979, the SEC required that companies present unaudited financial information on the basis of RRA. The accounting policies set forth below have been followed in preparing the RRA presentations.

*Recognition of Assets and Earnings Under RRA*

Under RRA, an asset is recognized and earnings are recorded when proved reserves are added through exploration and development activities.

A dollar valuation (the "RRA valuation") of proved reserves is developed as follows:

(1) Estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on year-end economic conditions;

(2) The estimated future production of proved reserves is priced on the basis of year-end prices except that future prices of gas are increased for fixed and determinable escalation provisions in contracts;

(3) The resulting future gross revenue streams are reduced by estimated future costs to develop and to produce the proved reserves, based on year-end cost estimates;

(4) The resulting future net revenue streams are reduced to present value amounts by applying a 10 percent discount factor.

As acknowledged by the SEC, this valuation procedure does not necessarily yield the best estimate of the fair market value of a company's oil and gas properties. An estimate of fair market value should also take into account, among other factors, the likelihood of future recoveries of oil and gas in excess of proved reserves and anticipated future prices of oil and gas and related development and production costs.

Subsequent revision to the RRA valuation of proved reserves are included in RRA earnings as they occur. The estimated impact of major factors affecting annual changes in proved reserves based on year-end RRA valuations of proved reserves was developed as described below:

(1) "New Field Discoveries and Extensions" represents proved reserves added from drilling exploratory and development wells.

(2) "Increases in Prices of Oil and Gas, Net of Related Lifting Costs" represents the approximate effect of changes from one period to the next in the prices and lifting costs used in the RRA valuation calculation.

(3) "Interest Factor – Accretion of Discount" is computed by applying 10 percent to the RRA valuation as of the beginning of the year in recognition of the increase resulting from the impact of the passage of time on the discounted cash flow approach to the valuation of the proved reserves.

(4) "Other" includes the net effect of all changes affecting the RRA valuation not otherwise reported. See "Management's Discussion and Analysis of the Summary of Operations Prepared on the Basis of RRA."

Exploration and Development Costs

The costs of acquiring unproved properties and drilling exploratory wells are deferred until the properties are evaluated and determined to be either productive or nonproductive, at which time they are charged to expense. Other exploration costs are charged to expense as incurred. Costs of acquiring unproved properties aggregating $2,202,000 have been deferred at December 31, 1979. No costs were deferred at December 31, 1978.

Estimated future costs to develop proved reserves are deducted in the RRA valuation of proved reserves. Subsequent revisions to estimated future development costs are included in revisions to reserves proved in prior years. Other development costs are charged to expense when related proved reserves are recognized.

Purchase and Sales of Proved Reserves

Differences, when not significant, between the consideration paid or received and the RRA valuation of proved reserves purchased or sold have been included in RRA operating results in the periods that the transactions occurred. In 1979, the purchase of proved reserves in Utah resulted in a significant excess of RRA valuation of proved reserves purchased over the purchase price paid. At December 31, 1979, the Company deferred $30,821,000 of such excess, which will be brought into the RRA summary of operations over the life of the reserves purchased.

Production and Funds Flow

Under RRA, because earnings are recognized when proved reserves are discovered and as the RRA valuation of proved reserves changes, no earnings are reported when oil and gas are produced. Consequently, RRA earnings may differ substantially from funds generated or required by current exploration, development and producing operations.

Income Taxes

The provision for income taxes has been calculated separately for Canada and the U.S. using the income tax rates as calculated after making provision for the tax base for oil and gas properties, deductions for depletion and provisions for non-allowable royalties and other expenses.

(b) RRA Presentation

The RRA Presentation is comprised of two tables for the year ended December 31, 1979: (1) Summary of Operations and (2) Summary of Changes in the Present Value of Estimated Future Net Revenues from Proved Reserves.

## SUMMARY OF OPERATIONS

Year Ended December 31, 1979

Prepared on the Basis of Reserve Recognition Accounting

(Unaudited)

| | Total | Canada | U.S.A |
|---|---|---|---|
| Additions to Proved Reserves: | | | |
| New field discoveries and extensions | $29,496 | $15,677 | $13,819 |
| Revisions to reserves proved in prior years: | | | |
| Increases in prices of oil and gas, net of related lifting costs | 6,239 | 5,779 | 460 |
| Interest factor-accretion of discount | 4,250 | 3,682 | 568 |
| Other | (15,155) | (12,939) | (2,216) |
| Total revisions to proved reserves | (4,666) | (3,478) | (1,188) |
| Total additions to proved reserves | 24,830 | 12,199 | 12,631 |
| Related exploration and development costs | 15,278 | 7,005 | 8,273 |
| Additions to proved reserves in excess of related costs | 9,552 | 5,194 | 4,358 |
| Amortization of deferred excess of RRA value of proved reserves over purchase price | 1,606 | — | 1,606 |
| RRA Income Before Income Taxes* | 11,158 | 5,194 | 5,964 |
| Provision for Income Taxes | 3,942 | 1,974 | 1,968 |
| Income from oil and gas producing activities on the basis of RRA (before other income and expenses) | $ 7,216 | $ 3,220 | $ 3,996 |

* Comparable amounts included in the Consolidated Financial Statements (before general and administrative expense, interest and finance charges, and income taxes) are: total – $4,684; Canada – $3,025; U.S. – $1,679; and U.K. – $(20).

## SUMMARY OF CHANGES IN THE PRESENT VALUE OF ESTIMATED FUTURE NET REVENUE FROM PROVED RESERVES

Year Ended December 31, 1979
Prepared on the Basis of Reserve Recognition Accounting
(Unaudited)

| | Total | Canada | U.S.A |
|---|---|---|---|
| Balance, December 31, 1978 | $ 42,510 | $36,821 | $ 5,689 |
| Revisions to reserves proved in prior years | (4,666) | (3,478) | (1,188) |
| | 37,844 | 33,343 | 4,501 |
| New field discoveries and extensions | 29,496 | 15,677 | 13,819 |
| Purchases of proved reserves | 37,589 | 1,531 | 36,058 |
| Projected development costs incurred | 5,605 | 5,027 | 578 |
| Production, net of lifting costs | (8,177) | (4,666) | (3,511) |
| Sales of reserves | (130) | (130) | — |
| Balance, December 31, 1979 | $102,227 | $50,782 | $51,445 |

**Present Value of Proved Developed Reserves:**

| | | | |
|---|---|---|---|
| December 31, 1978 | $ 32,106 | $26,514 | $ 5,592 |
| December 31, 1979 | $ 55,045 | $38,575 | $16,470 |

### (c) Management's Discussion and Analysis of the Summary of Operations Prepared on the Basis of RRA

Under RRA, operating results are determined based upon additions to proved reserves from new field discoveries and extensions and revisions to the RRA valuation of reserves proved in prior years and upon costs incurred in exploration and development activities. The additions to proved reserves from new field discoveries and extensions could vary significantly from year-to-year, depending upon the number and success ratio of exploratory and development wells drilled and the estimated reserves discovered.

The RRA valuation of future net revenues is based on year-end prices, adjusted only for fixed and determinable contractual escalation. Any price increases, net of increases in lifting costs, on proved reserves is included in RRA earnings when the increases occur. The estimated future net revenues are after deducting estimated future lifting costs and future recompletion and development costs, both based on comparable prices in effect at December 31, 1979. Production and ad valorem taxes have been deducted in arriving at future net revenues, but no provision has been made for any income taxes or windfall profits tax. The Company estimates that the combined effect of the U.S. windfall profits tax and phased decontrol program would be to reduce revenues attributable to total proved oil reserves at December 31, 1979 by approximately $5,000,000, discounted at 10% ($7,400,000 undiscounted). Such estimates are based on the assumptions that the price of the Company's controlled oil will be decontrolled by October 1, 1981, and will rise to the price of its uncontrolled oil as of December 31, 1979. Any changes in the facts underlying these assumptions could result in a material change in this estimated effect.

The caption "Interest Factor – Accretion of Discount" results from applying the discounted cash flow technique in the RRA valuation of the proved reserves. As the time of producing the reserves approaches, the discount becomes smaller because of the time value of money, and the RRA valuation increases. This interest factor was approximated by applying the 10% discount rate to the RRA valuation amount as of the beginning of the year.

The caption "Revisions to reserves proved in prior years – Other" includes the net impact of all remaining factors causing revision to the RRA valuation of reserves proved in prior years. Major factors which have given rise to this amount are changes in estimated quantities and changes in the estimated future costs of developing and producing reserves. The revisions to estimated quantities during the years 1978 and 1979 are presented in the schedule "Changes in Quantities of Proved Reserves". Approximately 35% of the Company's oil reserves and 67% of the Company's gas reserves are classified as proved undeveloped. Estimates of such proved reserves typically must be revised on the basis of development drilling and production performance.

Related exploration and development costs reflect the actual costs incurred during the year, adjusted as described above. The costs incurred include only the Company's share of costs and not those of the other participants in its drilling programs.

The effective tax rates resulting from the calculation of the RRA provision for income taxes were 38% in Canada and 33% in the U.S.

The Company cautions against projecting future RRA results on the experience in 1979. RRA seeks to reflect events relating to exploration and development as they occur; whereas under generally accepted accounting principles, the impact of such events are reported over many future years. A number of years may lapse, however, between incurring costs and knowing the economic results of the expenditures. Information about reservoir characteristics may significantly change previous estimates of proved reserves and their valuation.

All of these uncertainties should be considered in reviewing the RRA data. Future RRA results will depend on the outcome of the Company's exploration and development programs and the matters discussed in the preceding paragraphs.

# AUDITORS' REPORTS

To the Shareholders of Page Petroleum Ltd.:

We have examined the consolidated balance sheet of Page Petroleum Ltd. (an Alberta company) and subsidiaries as of December 31, 1979, and the related consolidated statements of earnings, retained earnings, changes in financial position and income taxes for the year then ended. Our examination was 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. and subsidiaries as of December 31, 1979, and the results of their operations and the changes in their financial position for the year then ended, in accordance with generally accepted accounting principles applied on a basis consistent with that of the preceding year after giving retroactive effect to the change (with which we concur) in the application of the full cost method of accounting, as described in Note 2 of the Notes to Consolidated Financial Statements.

We also reviewed the adjustments described in Note 2 of the Notes to Consolidated Financial Statements that were applied to restate the 1978 financial statements. In our opinion, such adjustments are appropriate and have been properly applied to the 1978 financial statements.

ARTHUR ANDERSEN & CO.
Chartered Accountants

Calgary, Canada
March 10, 1980
*(Except with respect to the matter discussed in Note 13(b), as to which the date is April 22, 1980).*

To the Shareholders of Page Petroleum Ltd.:

We have examined the consolidated balance sheet of Page Petroleum Ltd. as at December 31, 1978 and the consolidated statements of earnings, retained earnings, changes in financial position and income taxes for the year then ended, before the restatement to give effect to the change in the application of the full cost method of accounting as described in Note 2. Our examination was 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, these financial statements present fairly the financial position of the company as at December 31, 1978 and the results of its operations and changes in its financial position for the year then ended in accordance with generally accepted accounting principles applied on a consistent basis, before the restatement to give effect to the change in the application of the full cost method of accounting as described in Note 2.

COLLINS BARROW
Chartered Accountants

Calgary, Canada
March 12, 1979

# MANAGEMENT'S DISCUSSION AND ANALYSIS OF THE SUMMARY OF OPERATIONS

The summary of operations below should be read in conjunction with the Notes to Consolidated Summary of Operations which appear herein and with respect to the years ended December 31, 1979 and 1978 reference should be made to the Consolidated Financial Statements and Notes thereto which appear elsewhere in this Annual Report.

| | Years Ended December 31 | | | | |
|---|---|---|---|---|---|
| | 1979 | 1978* | 1977* | 1976 | 1975 |
| | (Thousands of Canadian dollars except per share data) | | | | |
| Total Income | $ 12,791 | $ 5,670 | $ 2,017 | $ 720 | $ 824 |
| Operating costs and expenses | 5,983 | 2,404 | 745 | 322 | 274 |
| Depreciation, depletion and amortization | 4,062 | 1,476 | 490 | 215 | 233 |
| Interest on long-term debt | 2,453 | 742 | 370 | 219 | 146 |
| Amortization of deferred financing charges | 91 | 26 | 27 | 12 | 9 |
| Provision for income taxes | 235 | 223 | 88 | (55) | 5 |
| | 12,824 | 4,871 | 1,720 | 713 | 667 |
| Net Earnings (Loss) | (33) | 799 | 297 | 7 | 157 |
| Preferred Dividends | 445 | 183 | — | — | — |
| Net Earnings (Loss) Applicable to Common Shares | $ (478) | $ 616 | $ 297 | $ 7 | $ 157 |
| Earnings (Loss) per Common Share | $ (0.18) | $ 0.30 | $ 0.17 | $ 0.005 | $ 0.11 |
| Weighted Average Number of Common Shares Outstanding | 2,724,250 | 2,027,709 | 1,704,661 | 1,408,753 | 1,408,486 |

*Restated. See Note A.

(A) In 1979, the Company retroactively changed its method of calculating depletion within the full cost method of accounting for its oil and gas operations to conform with S.E.C. accounting standards issued in December, 1978. Reference is made to Note 2 of the Notes to Consolidated Financial Statements for information relating to the effect of this change.

(B) Earnings per common share are based on the weighted average number of common shares outstanding. Reference is made to Note 1(i) of the Notes to Consolidated Financial Statements for information related to the method of determining the weighted average number of common shares outstanding.

### 1979 Compared with 1978

Total income increased $7,121,000 (126%) over 1978, including an increase of $6,676,000 (135%) in oil and gas sales. Oil production increased 98%, while the weighted average sales price per barrel increased 24%. Gas production increased 63%, while the weighted average sales price per mcf increased 15%. The increased oil volumes resulted from a 106-well drilling program carried out in 1979 in the Dodsland and Buffalo Coulee areas of west central Saskatchewan and production from the Altamont-Bluebell Field in the Uinta Basin of Utah, where the Company purchased most of its interests in February 1979. Total revenues attributable to the Utah properties aggregated $3,212,000. Increased gas volumes resulted primarily from including a full year of production from the Laketon Field of Gray County, Texas, where the Company purchased its interests in April 1978. Well servicing revenues increased $507,000 (83%) over 1978, reflecting the first full year of operations and additional rigs utilized by the Company.

Total expenses increased $7,941,000 (171%) over 1978. The $2,089,000 (156%) increase in production costs was attributable to the lifting costs associated with the higher levels of production and the new oil production in the Altamont-Bluebell field. Costs associated with production in this field which aggregated $1,058,000 are higher than average because of special heating equipment necessary to produce high paraffin content oil. Well servicing costs increased $502,000 (123%) reflecting the higher level of activity. General and administrative costs increased $988,000 (151%) primarily as a result of the increased number of employees required to administer a larger exploration and development program.

The increase of $2,586,000 (175%) in depreciation, depletion and amortization reflects the impact of the high level of capital expenditures during 1978 and 1979 and the increased level of production. Estimated future capital expenditures attributable to proved reserves aggregated $16,400,000 at December 31, 1979, compared with $4,800,000 a year earlier. These future capital expenditures are reflected in the calculation of depletion for 1979 and 1978, respectively, and are in addition to the actual costs incurred.

Interest costs increased $1,711,000 (230%) reflecting higher interest rates and increased borrowings to finance the capital expenditure program.

Total income taxes increased $12,000 (5%). However, the total income tax expense amounted to 116% of pre-tax earnings, compared with 22% in 1978. See "Statements of Consolidated Income Taxes."

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### 1978 Compared with 1977

Total income increased $3,653,000 (181%) over 1977, including an increase of $3,012,000 (157%) in oil and gas sales. Oil production increased 95%, while the weighted average sales price per barrel increased 21%. Gas production increased 272%, while the weighted average sales price per Mcf increased 55%. The increased volumes resulted from a 79-well development program carried out in 1978 in the Dodsland and Buffalo Coulee areas of west central Saskatchewan and new production, which provided income aggregating $603,000, from the Laketon Field of Gray County, Texas. Well servicing operations which commenced early in 1978 contributed $610,000 to revenues.

Total expenses increased $3,016,000 (185%) over 1977. The $871,000 (186%) increase in production costs was attributable primarily to the lifting costs associated with the higher levels of production and costs incurred in re-working wells to maintain production in the older fields. Operating costs related to the Company's well servicing operations commenced in 1978. General and administrative costs increased $379,000 (137%) as a result of the higher level of operations.

The increase of $986,000 (201%) in depreciation, depletion and amortization reflects the higher levels of production and the impact of the high levels of exploration and development activities carried out in 1977 and 1978.

Interest costs increased $372,000 (101%) reflecting higher interest rates and increased borrowings to finance the capital expenditure program.

Total income taxes increased $135,000 (153%) but did not change materially as a percentage of pre-tax earnings, being 22% in 1978 compared with 23% in 1977.

### Management Report

The Board of Directors has approved the information contained in this Annual Report. The accompanying financial statements have been prepared by management in conformity with those generally accepted accounting principles most appropriate for the nature of the Company's business. All financial information contained in the Annual Report is consistent with the financial statements

# PAGE PETROLEUM LTD.

## OFFICES

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Calgary, Alberta
T2P 1C9

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901 Bank of the Southwest Bldg.
Amarillo, Texas, 79109

## DIRECTORS

LAWTON L. CLARK
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Amarillo, Texas

HENRY W. HIGGINS
President, Habco Sales Ltd.
Calgary, Alberta

HARRY A. IRVING
President, Irving Industries
(Irving Wire Products Division) Ltd.
Calgary, Alberta

THOMAS J. JACOBSEN
Executive Vice President, Page Petroleum Ltd.
Calgary, Alberta

BRIAN G. McCOMBE
Barrister and Solicitor,
McCombe Cameron
Calgary, Alberta

## OFFICERS

LAWTON L. CLARK, President
THOMAS J. JACOBSEN, Executive Vice President
ALEX S. CATHCART, Vice-President Exploration
C. BARRIE CLARK, Vice-President Finance
GEORGE E. PATEY, Vice-President Production
BRIAN G. McCOMBE, Secretary

## TRANSFER AGENT AND REGISTRAR

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505 - 3rd Street S.W.
Calgary, Alberta T2P 3E6

The Bank of New York
90 Washington Street
New York, New York 10015

## AUDITORS

Arthur Andersen & Co.
Calgary, Alberta

## LEGAL COUNSEL

McCombe Cameron
Calgary, Alberta

## BANKING

The Canadian Imperial Bank of Commerce
Calgary, Alberta

## STOCK LISTINGS

The Toronto Stock Exchange
American Stock Exchange
Symbol "PGE"

## ACTIVE SUBSIDIARIES

Page Petroleum Inc.
Page Petroleum (U.K.) Limited
Cowzanoil Ltd.
Magnolia Petroleum Ltd.
Northline Well Servicing Ltd.
Leaf Petroleums Ltd.
109085 Oil & Gas Ltd.
109086 Oil & Gas Ltd.
Habco Sales Ltd.
McCullough Ditching & Welding Ltd.
R.D.R. Well Servicing Ltd.

## FORM 10-K

The Company's 1979 Annual Report on Form 10-K, filed with the Securities and Exchange Commission of the United States, is available to shareholders who request it by writing to Page Petroleum Ltd. at 11th Floor Royal Bank Building, 335 - 8th Avenue South West, Calgary, Alberta, Canada T2P 1C9.

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