Alberta Energy Company Ltd.

Annual Report 1983

In the search for oil and gas, core sample analysis is used to obtain subsurface reservoir information. The sample shown on the front cover illustrates unusually high porosity found in a carbonate, oil-bearing reef formation.

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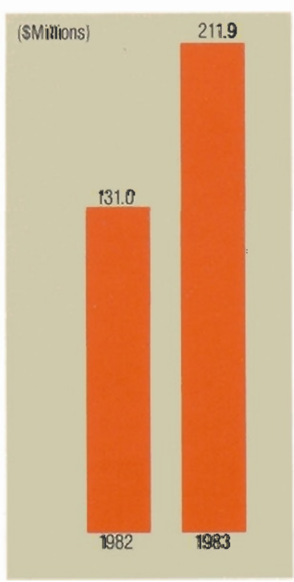
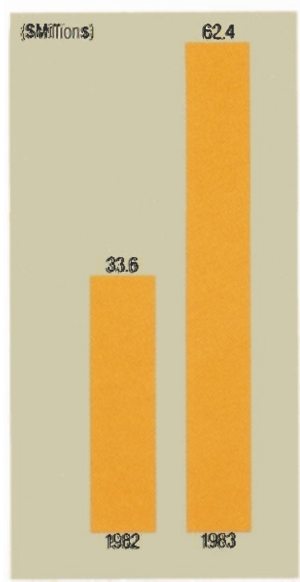
Highlights

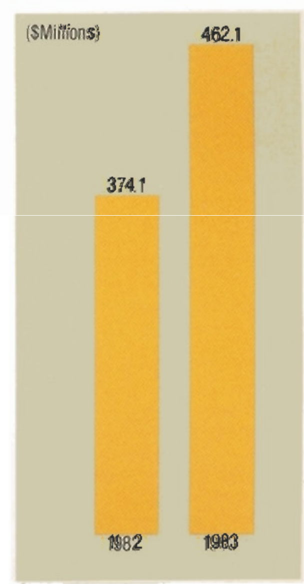
- Record oil production, with Syncrude up 30 percent and conventional oil doubled
- New daily gas production level of 6.3 million cubic metres (224 million cubic feet)
- Record pipeline throughput of 12.2 million cubic metres (77 million barrels), and a $100 million pipeline expansion being planned
- $1.2 billion Syncrude expansion commenced, AEC owning 10 percent share of project
- Exploration for oil and gas significantly increased – discoveries include oil found at Helmet/Desan in B.C. and gas found southwest of Calgary, Alberta
- $33 million invested in natural gas liquids extraction plant
- Lumber shipments increased to 121 million board feet
- On Primrose Range near Cold Lake, two heavy oil pilot plants in progress plus major new exploration and heavy oil activity planned



Cash Flow from Operations
Up 62 percent to a record $211.9 million



Net Earnings (before Extra-ordinary Items)
Up 86 percent to a record $62.4 million



Revenues, Net of Royalties
Up 24 percent to a record $462.1 million


RANGER

Report to Shareholders

AEC is a diversified energy and natural resource company. Its activities include conventional oil and gas exploration and development, Syncrude, pipelines, heavy oil projects, forest products and coal.

1983 was a very good year for AEC with record highs achieved for cash flow, net earnings, oil production, gas production, lumber sales, and pipeline deliveries.

Cash flow from operations increased sharply by 62 percent to $212 million. Net earnings of $62 million, before extraordinary items, represented an 86 percent increase over prior-year results. The Company's strong financial position is evident from data presented elsewhere in this report.

Average oil production of approximately 1 930 cubic metres (12,000 barrels) per day in 1983 underscores the fact that AEC has significant oil interests in addition to being a prominent natural gas producer. The 36 percent gain in oil output was largely due to improved operations at Syncrude. Syncrude has done well and, as more experience is gained, further plant expansion could become feasible. This operation provides an opportunity for substantial, additional, indigenous Canadian oil production from proven reserves at a cost equal to, or less than, known alternative production from the frontiers.

The substantial investment in gas production facilities made in the prior year helped gas sales increase to 6.3 million cubic metres (224 million cubic feet) per day in 1983, despite weak gas markets throughout most of the year. At Suffield in late 1983, AEC demonstrated the capability of delivering 9.7 million cubic metres (345 million cubic feet) per day of gas indicating sizable potential to increase gas sales from the existing production system as markets recover.

On the exploration side of the oil and gas business, the Company's program in Western Canada is proceeding favourably. The successful wells which have already been drilled will add to new sources of production revenue in future years.

Pipelining continues to grow in importance and is AEC's third-highest source of operating revenue. By year-end 1984, the Company's investment in pipelines is expected to be approximately one-quarter billion dollars, and growing.

Forest products operations at Blue Ridge provided a cash flow improvement in 1983, aided by stronger lumber prices. Coal shipments and profits declined from previous-year levels but are forecast to exhibit some recovery in 1984 due to operational improvements which have taken place at Coal Valley.

Particular mention should be made of AEC's substantial ownership of heavy oil at Primrose which amounts to about 2.3 billion cubic metres (14 billion barrels) of in-situ reserves. Considerable exploration/development activity is already under way on the Primrose Range, including two pilot plants. There is a growing awareness that heavy oil reserves, whether mined or recovered by steam (in-situ), will be the prime source of much-needed new oil supplies for Canada.

Industry Comment

The most onerous factor still overhanging the Canadian oil and gas industry is the National Energy Program (NEP) which was imposed in 1980. When the NEP ends, as it surely must, more energy will be found and developed in Canada, at lower cost; and its demise will help develop a more vibrant economy and increase employment.

Removal of the Petroleum and Gas Revenue Tax is particularly vital, so that the tax system would again be based on profits instead of gross revenues. Secondly, a phasing out of the PIP incentive grant scheme would allow oil and gas exploration decisions to once again be based on normal economic and technical considerations rather than being wildly distorted by the wasteful use of taxpayers' money.

Outlook for 1984

In the year ahead, AEC anticipates continuance of strong cash flow and net earnings. Capital investment is expected to exceed $200 million. Plans include participation in more than 75 exploratory wells; assessment of the Desan oil discovery; commencement of field work on a new pipeline to Cold Lake; and various other activities such as continuation of the Syncrude expansion program.

Acknowledgement

Special acknowledgement is certainly in order for the very fine people who have contributed so much to the progress and accomplishments of AEC through their skills and dedication. The extra work and efforts by persons throughout the Company, including the Board of Directors, are much appreciated and have been a major factor in the very positive results achieved in 1983.

David E. Mitchell
President and Chief Executive Officer

Oil and Gas

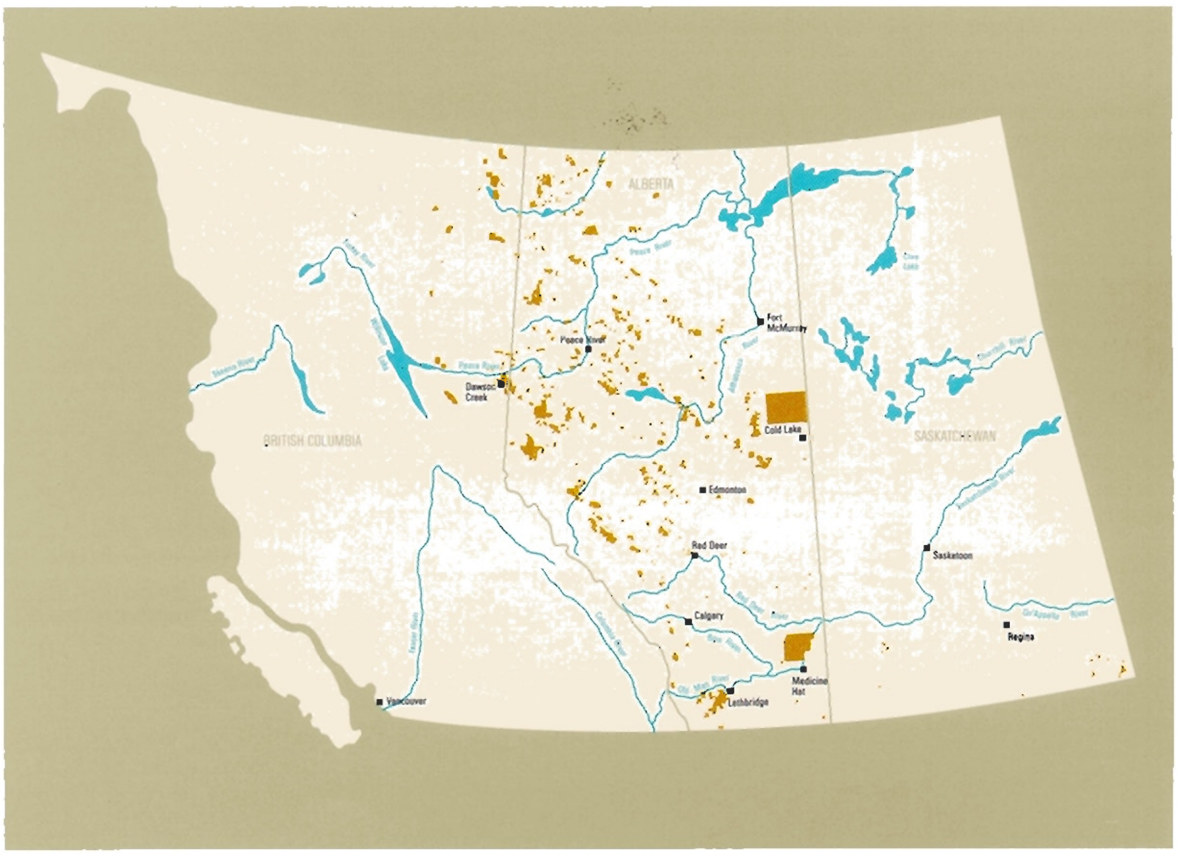
A worker on a drilling rig at an exploratory well site in the Peace River area.

Exploration

Exploration for oil and gas significantly increased during the year. In exploration, as in other Company operations, AEC encourages the development and utilization of new technology at an early stage. These recently developed techniques are important in the effective search for new oil and gas reserves.

During the year, the Company participated in 87 exploratory wells, of which 14 were completed as oil wells and 20 as gas wells. Five have been cased for further evaluation, and one suspended. In 1984, AEC expects exploratory drilling to continue at a very high level.

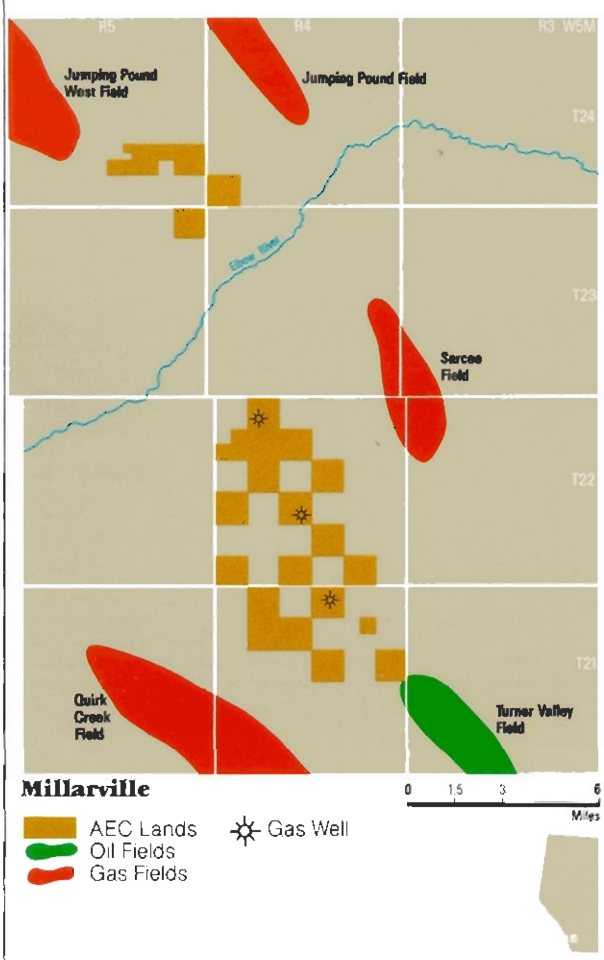
AEC holds rights directly or indirectly in 2.2 million gross hectares (5.6 million gross acres) and 1.1 million net hectares (2.8 million net acres) in the Western Canadian Sedimentary Basin.



AEC Landholdings

Oil and Gas

Exploration



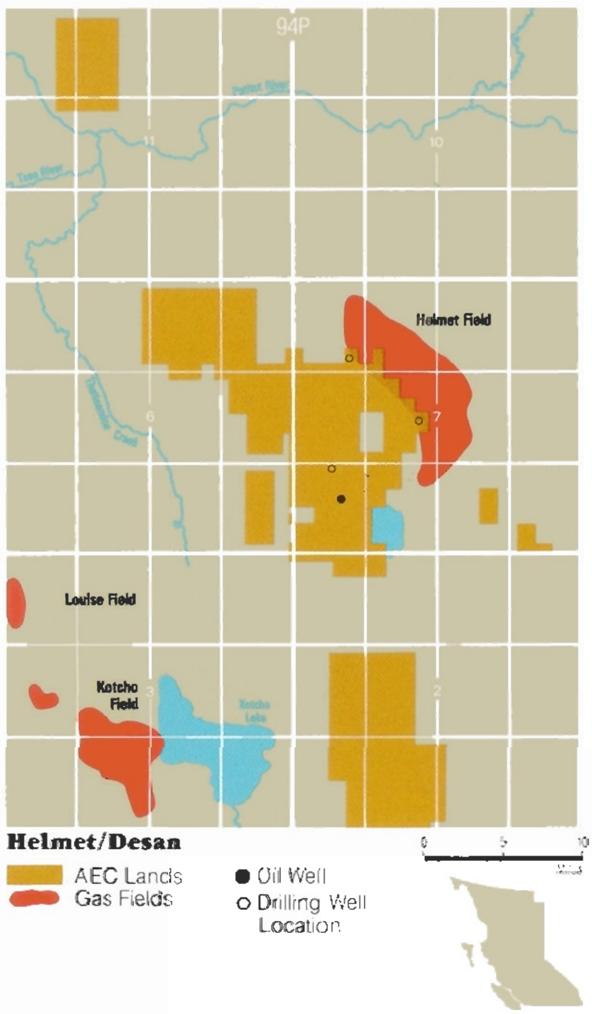
AEC Oil and Gas Company

Due to the increased scope of AEC's current and projected oil and gas activities, AEC Oil and Gas Company, a division of Alberta Energy Company Ltd., was formed in 1983. The Division will handle oil and gas exploration, production and marketing activities.

The Division's exploration program emphasizes land acquisition in oil-prone areas in the Western Canadian Sedimentary Basin. Following are highlights of the 1983 exploration program.

Southwest of Calgary, Alberta, in an area designated as Millarville, a significant natural gas discovery, in which AEC owns 30 percent, tested gas at 225 thousand cubic metres (8 million cubic feet) per day, with 16 cubic metres (100 barrels) of condensate per day. A well located six miles southeast of the Millarville site tested gas at 464 thousand cubic metres (16 million cubic feet) per day, with a daily condensate rate of 52 cubic metres (330 barrels). A third well is currently awaiting production testing, and a fourth is planned for 1984. All of these wells are close to existing production facilities.

Interests are held in 58 000 gross hectares (144,000 gross acres) and 20 000 net hectares (49,000 net acres) in the Peace River Arch area of northcentral Alberta. The drilling of about ten wells and the



acquisition of further lands in this region are anticipated for 1984. There is a high level of industry drilling activity in this area, with oil potential in three oil-productive formations.

Other interests are held in 2 800 gross hectares (7,000 gross acres) of exploratory land in the Rainbow/Zama/Shekilie producing area. In addition, a farmin has been concluded on 28 300 gross hectares (70,000 gross acres) of lands in the Shekilie area. This arrangement provides for AEC to earn interests in each well drilled on these lands until the end of 1989.

In the Helmet/Desan area of northeastern British Columbia, an encouraging oil discovery was made during 1983. A drilling program involving five rigs was launched at the end of the year.

Chieftain Development Co. Ltd.

AEC owns 57 percent of Chieftain, a company engaged in Canadian and international oil and gas exploration and development. In this report, Chieftain's financial, exploration and production results, together with landholdings, are consolidated except in those sections of the report in which specific activities of AEC Oil and Gas Company are discussed. Highlights of Chieftain's activities during 1983 follow:

During 1983, Chieftain's exploration for oil in Alberta resulted in a significant discovery at Rimbey, a discovery at Sawn Lake and several wells at Crystal, Rycroft and Gold Creek. The company started up the second phase of the Hythe-Brainard gas plant, which increased the plant's daily capacity to 3.2 million cubic metres (110 million cubic feet). Chieftain's U.S. activities included the acquisition of 17 highly prospective federal leases in the Gulf of Mexico and a gas and condensate discovery in Texas.

Oil and Gas

Production

This pipeline crew is constructing a portion of the gas gathering system at Suffield.

Average daily natural gas production increased to 6.3 million cubic metres (224 million cubic feet), up 14 percent over 1982 levels, despite 1983 weak gas markets. This was accomplished because of substantial investment in gas wells and facilities in 1982. As markets improve, AEC will realize further gains from this additional production capacity.

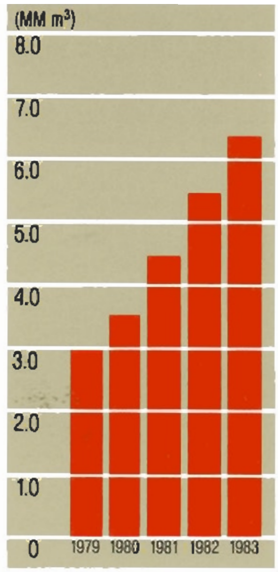
A milestone was reached with the completion of the initial shallow gas development on the Suffield Block. As a result of this enormous, eight-year program, there are approximately 2,300 producing wells integrated into a gas production system that includes over 2 700 kilometres (1,700 miles) of gathering pipeline and ten gas compression plants.

AEC participated in 51 development wells, resulting in 43 wells successful or cased for evaluation; 6 wells were drilling at year-end.

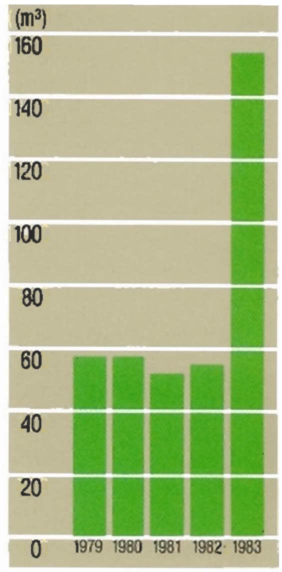
Total gas reserves are estimated by an independent consulting firm to be 61.4 billion cubic metres (2,178 billion cubic feet), with a producing life of over 26 years at 1983 production rates.

Conventional oil production for the year was up 180 percent to 154 cubic metres (970 barrels) per day. Production increases resulted both from further development on the Suffield Block and new discoveries in the Western Canadian Sedimentary Basin.

During 1983, conventional oil reserves increased 61 percent to total 2.2 million cubic metres (13.8 million barrels).



Average Daily Gas Production

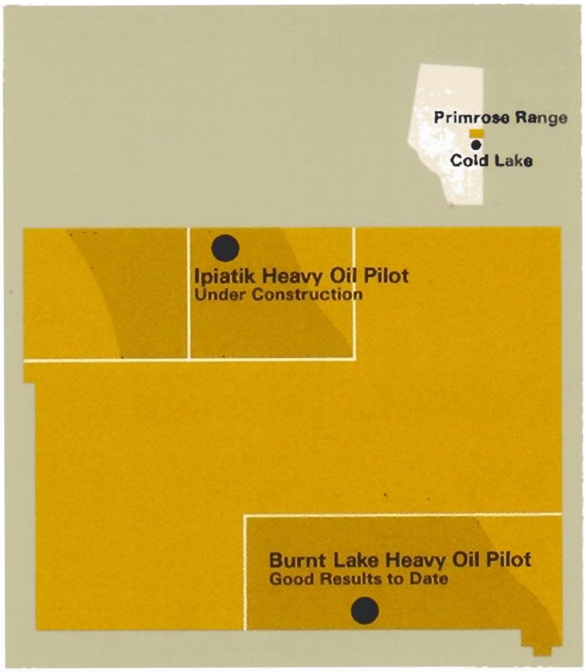


Average Daily Conventional Oil Production

Oil and Gas

Heavy Oil

A pump jack at sunset.



Primrose Range, Alberta

km 0 10 20
miles 6 12

Oil Sands deposits delineated to date
2.3 billion m³ (14 billion bbls) net to AEC

AEC has substantial heavy oil deposits on the Primrose Range near Cold Lake, Alberta. To date, approximately 5 billion cubic metres (32 billion barrels) of heavy oil have been delineated at Primrose, of which AEC retains about 45 percent. With two separate pilot operations under way, AEC is actively investing in and evaluating technology for developing these potential heavy oil reserves.

On AEC lands in the Burnt Lake region of the Primrose Range, extensive piloting activities are being conducted by an oil company. To date, results have been very encouraging. In the Ipiatik Lake region of the Range, AEC and other participants are constructing a pilot facility which is expected to be operational by the spring of 1984. Like others in the Primrose-Cold Lake area, the project will be testing the cyclic steam process for application in this type of heavy oil sands deposits.

Recently, AEC reached agreement with a major oil company for exploration and potential heavy oil sands development in the unexplored southwest region of the Primrose Range. On AEC lands, the farmee will conduct a 300-kilometre (185-mile) seismic program and drill up to 80 wells to earn a 50 percent interest in the petroleum and natural gas rights. The three-year drilling program has commenced. The farmee will have invested $30 million upon completion of this exploration program. Following the exploration program, the farmee plans to pursue heavy oil sands development through the construction and operation of a pilot plant costing at least $20 million. Depending on the success of the piloting efforts, the farmee will have the right to earn additional heavy oil sands rights by developing commercial-scale production.

Since early 1982, pilot activities testing the fire-flooding technique have been ongoing in one of the Suffield Range heavy oil deposits. This field research project will require at least two years' further evaluation.

Syncrude

The bucketwheel reclaimer (opposite) transfers windrowed oil sands to a conveyor belt leading to the extraction plant.

1983 was a year of major achievement. The plant exceeded its design capacity, and a new production record of 6.5 million cubic metres (40.8 million barrels) was established at reduced operating cost.

The Alberta Government provided a major stimulus to further development of the plant. It agreed to defer a portion of its royalties in exchange for a $1.2 billion, five-year capital program to increase production from 17.3 thousand cubic metres (109 thousand barrels) per day to 20.5 thousand cubic metres (129 thousand barrels) per day and to improve plant reliability. This capital project is estimated to create an additional 25,000 man-years of direct and indirect employment between 1983 and 1987.

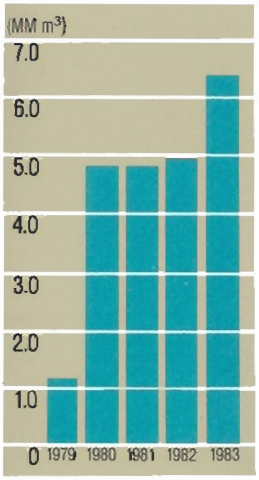
Syncrude is not only contributing to the national goal of achieving oil self-sufficiency – it produced about 8 percent of Canada's oil consumption in 1983 – but it provides employment for 4,187 people directly and approximately 12,500 indirectly.

Further development of the oil sands is highly dependent upon the advancement and application of new methods to reduce costs and increase efficiencies. In the Canadian energy business, Syncrude is a leader in developing such advanced technology. In the mining area, new equipment will be utilized to make the mining process more efficient. In extraction and upgrading, every effort will be made to "squeeze" more bitumen out of the sands and reduce production of low-valued coke. Another future addition is a naphtha vacuum stripping process, which will recover approximately $30 million a year of naphtha that now is being lost.

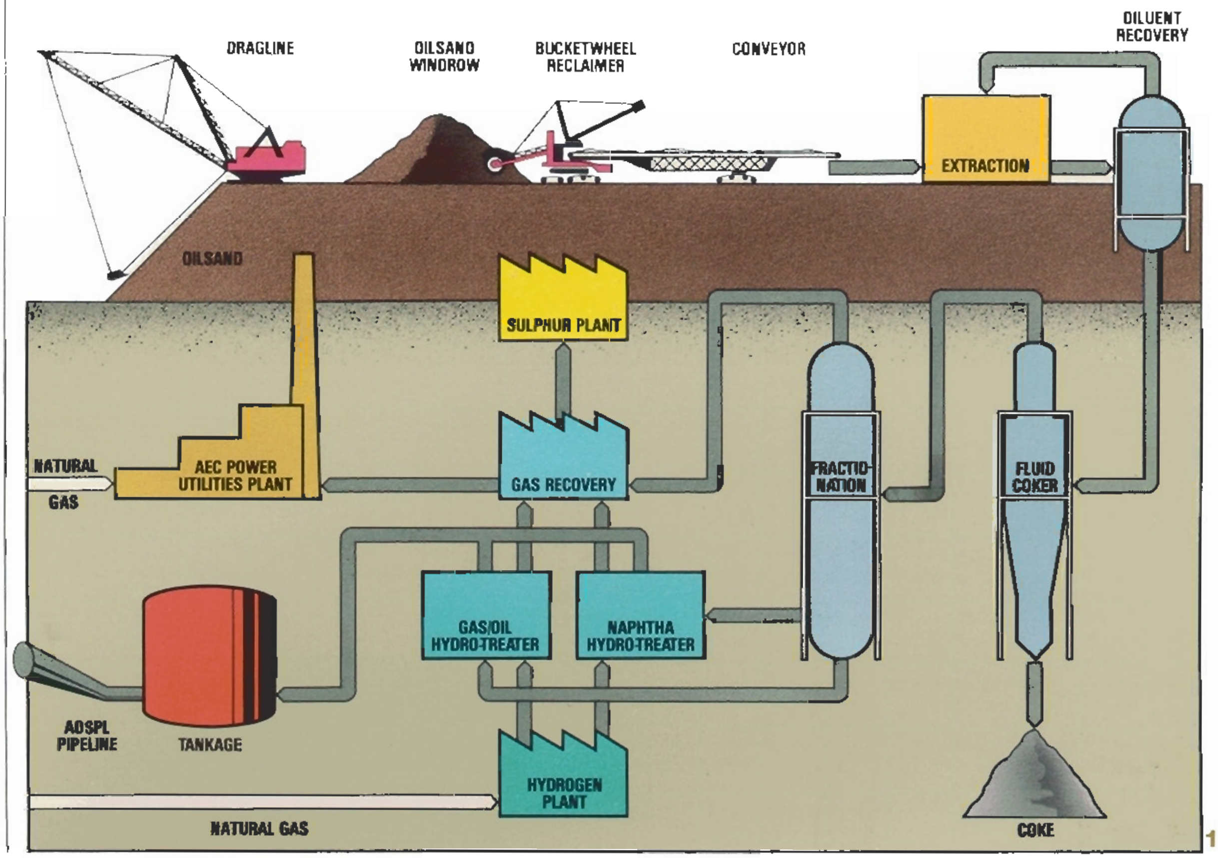
In the foreseeable future, it is quite possible the Syncrude plant could be expanded to a production level of 31.8 thousand cubic metres (200 thousand barrels) per day as technology and financial returns warrant.

AEC owns 10 percent of Syncrude and also retains an average 7 percent gross overriding royalty on an additional 10 percent of plant production. Through an affiliate, AEC owns a two-thirds interest in the power plant which supplies the utilities for the Syncrude project.

In the extraction plant, hot water is used to separate crude bitumen from the oil sands; centrifuges then separate the bitumen from its impurities. In the upgrading process, two fluid cokers crack the bitumen and four hydrotreaters remove the sulphur and nitrogen to produce synthetic oil.



Synthetic Crude Oil Production



EDMONTON / SCOTFORD DELIVERIES
PAGE 1 OF 1
DELIVERIES
FLOW RATE
IOL
GULF
IPL
THPL
TOTAL
STATUS

Pipelines

Technological advances are evident in many of the Company's operations. An example is this pipeline monitoring system, where the Company's oil sands and bitumen blend pipelines are operated and controlled with one computerized supervisory system.

AEC continues to increase its investments in pipeline transportation systems. The Company owns Alberta Oil Sands Pipeline Ltd. and the Cold Lake Bitumen Pipeline System and is a one-third owner of the Alberta Ethane Gathering System.

Alberta Oil Sands Pipeline

Record pipeline throughput for 1983 was 6.5 million cubic metres (40.8 million barrels), a daily average of 17 763 cubic metres (111,781 barrels) of synthetic crude oil. This compares to 1982 throughput of 5.0 million cubic metres (31.3 million barrels).

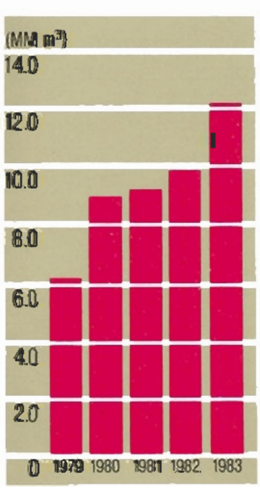
Alberta Oil Sands Pipeline Ltd., a wholly-owned subsidiary of AEC, operates the 430-kilometre (270-mile) pipeline, which transports synthetic crude oil from the Syncrude operation near Fort McMurray to Edmonton. The pipeline is 56 centimetres (22 inches) in diameter and has a daily throughput capacity of 25 980 cubic metres (163,500 barrels). As this report goes to press, a preliminary study is being undertaken to determine the feasibility of increasing daily throughput to 30 190 cubic metres (190,000 barrels).

In June, 1983, the Company received Energy Resources Conservation Board approval to construct a 10-kilometre (6.3-mile) pipeline lateral to a refinery at Scotford. A portion of this line has been completed, and start up is scheduled for mid-1984.

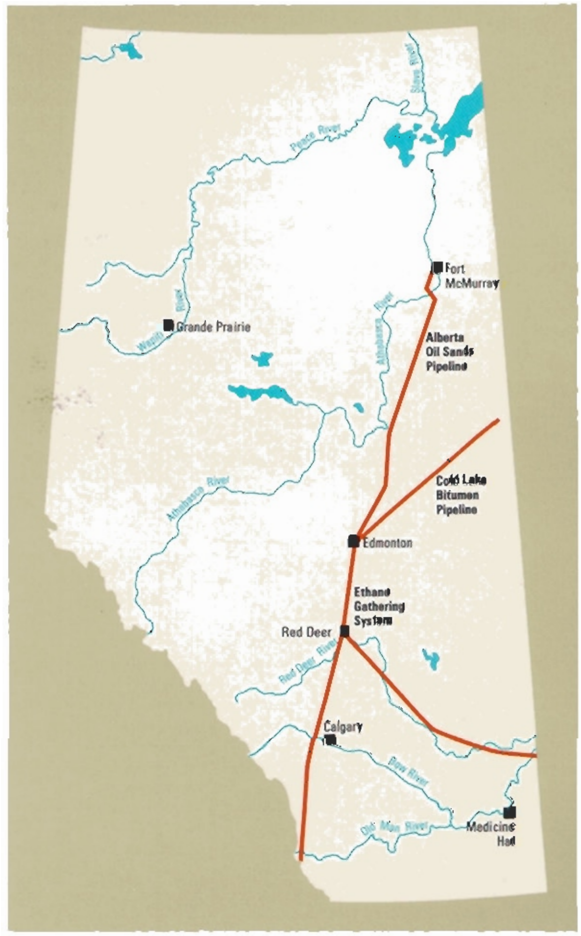
Cold Lake Bitumen Pipeline

Cold Lake Bitumen Pipeline throughput averaged 3 319 cubic metres (20,887 barrels) per day during 1983, which is near current line capacity. This dual-line, 235-kilometre (145-mile) pipeline system transports a light oil to Cold Lake, where it is used to dilute the bitumen produced in an operational heavy oil plant. The blend is then transported back to Edmonton.

Preliminary design work is now under way for construction of capacity additions to accommodate the increasing volumes of oil being produced in the Cold Lake area. Construction of other laterals is under discussion. The total cost of all changes and additions to the Cold Lake Bitumen Pipeline will be approximately $100 million.



Annual Pipeline Throughput



AEC Pipeline Systems

Alberta Ethane Gathering System

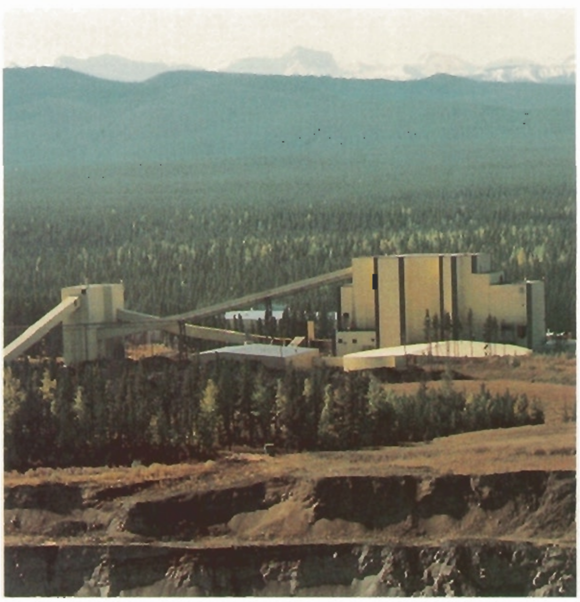
Ethane Gathering System daily throughput was 12 457 cubic metres (78,395 barrels) in 1983, as compared to 11 634 cubic metres (73,210 barrels) in 1982. This system collects ethane from five natural gas processing plants throughout the province and transports it to an ethylene plant near Red Deer.

Completion of an $8 million expansion to the Ethane Gathering System, which will increase the capacity to 21 452 cubic metres (135,000 barrels) per day, is scheduled for late 1985. Negotiations also are continuing with two major oil companies to supply ethane for tertiary crude oil recovery projects in Alberta.

Other Activities

Dimensional lumber and studs from the Blue Ridge mill are marketed under the "Ranger"® brand name.

The Coal Valley mine is situated near Edson, Alberta.



Proper forest management ensures that timber reserves are both maintained and enhanced as a perpetual resource for the industry. The Company owns licenses covering 566 thousand hectares (1.4 million acres) of timber in the Whitecourt, Alberta area.

Forest Products

conomic conditions in the United States improved during 1983, resulting in a stronger lumber products market. In response to increased U.S. housing starts, AEC's wholly-owned subsidiary, Blue Ridge Lumber (1981) Ltd., shipped a record 120.9 million board feet of lumber from its forest products complex near Whitecourt, Alberta.

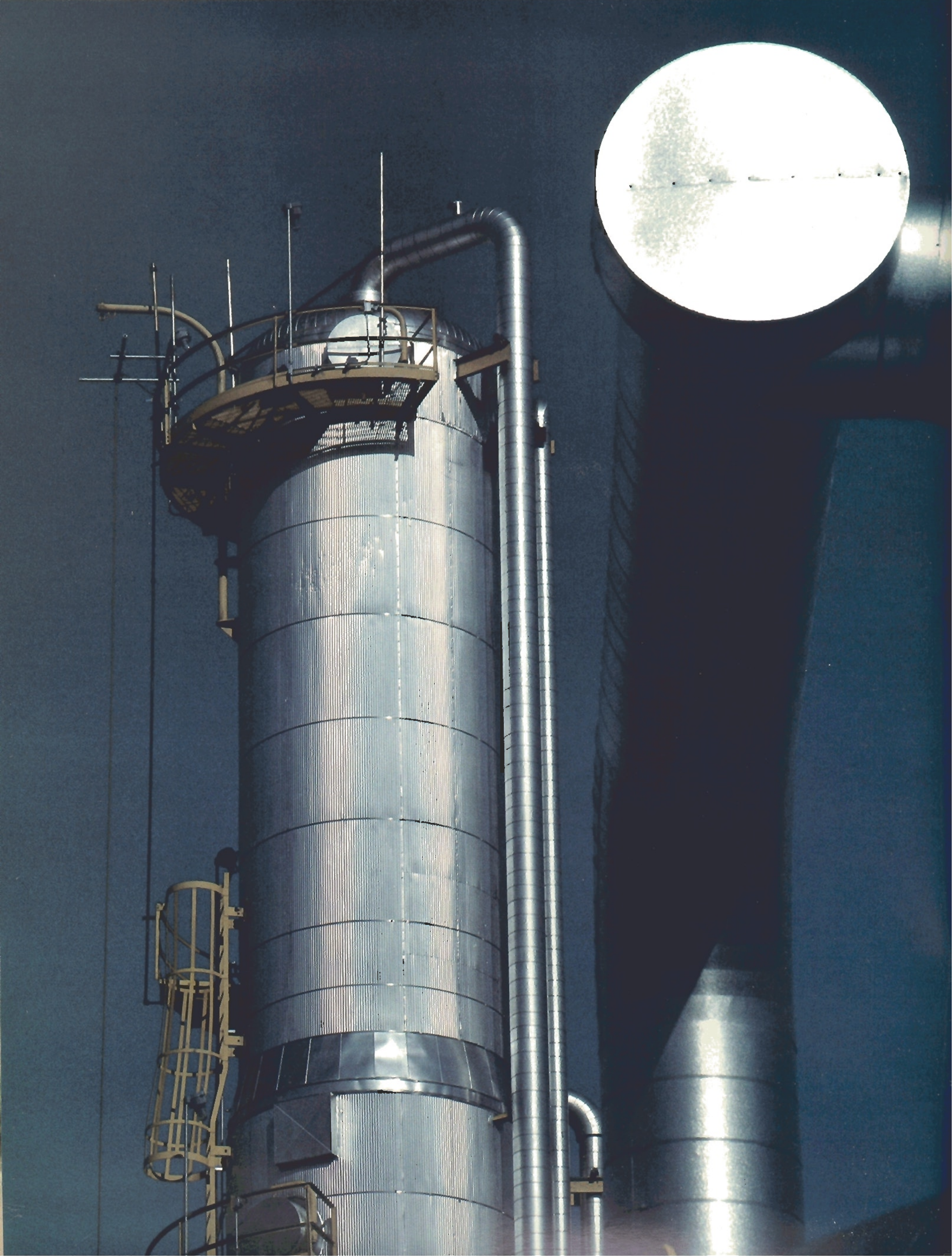
The performance of British Columbia Forest Products Limited, in which AEC holds an 18 percent share ownership, improved over that of 1982. However, BCFP recorded, in 1983, a loss of $32.7 million on sales of $899.7 million.

Coal

he Coal Valley mine's first high-grade thermal coal was produced in 1978 and, with the significant increases in energy prices during 1980 through 1982, the mine was expanded to meet increasing world coal demand. International energy price reductions in early 1983 subsequently resulted in constrained international coal markets, thereby restricting Coal Valley sales.

1983 was, however, a year of increased efficiency and improved productivity. Many of the cost-saving measures implemented to assist in offsetting reduced sales were not fully realized in 1983, but will form the basis for future growth. Among the improvements were more efficient preparation plant coal recovery and reduced rail freight costs.

AEC's 25 percent share of 1983 production was 514.8 thousand tonnes (567.5 thousand tons), compared to 671.8 thousand tonnes (740.6 thousand tons) in 1982.



Other Activities

Natural gas, in addition to methane, contains heavier components (natural gas liquids) such as ethane, propane and butanes. The extraction plant strips these liquids prior to the natural gas being transported from Alberta.

Natural Gas Liquids Extraction Plant

EC has invested $33 million in a natural gas liquids extraction plant through Pan-Alberta Resources Inc., a 50 percent-owned affiliate. The plant has been mechanically complete and producing LPG since November 1983. Ethane is expected to be produced by mid-1984.

The plant, in which AEC has a 25 percent interest, will be one of the largest natural gas extraction plants in the world. Products from this plant will be sold to two Alberta companies on a long-term, cost-of-service basis.

Pan-Alberta Gas Ltd.

EC owns one-half of Pan-Alberta Gas Ltd., which contracts for the purchase of natural gas from over 300 Alberta producers and for the resale of this gas to purchasers in Canada and the United States. Pan-Alberta's 1983 domestic and export gas sales totalled 5.4 billion cubic metres (189 billion cubic feet).

Due to a difficult export market situation and the unforeseeable restrictions imposed on the company by its U.S. customers, Pan-Alberta was heavily involved in negotiations with those customers, Alberta producers and regulatory agencies both in Canada and the United States. Pan-Alberta has now received U.S. and Canadian regulatory approval for these revised contract arrangements. Pan-Alberta will be passing on to its Alberta gas producers payments in compensation for the reduced level of purchases.

Petrochemicals

e-evaluation of potential petrochemical and related opportunities is now being undertaken, following the decision by AEC's joint venture partner not to proceed with a linear polyethylene project.

The petrochemical industry, along with most manufacturing businesses, has been depressed for some time. Specific areas, though, have produced positive results. AEC is continuing to explore ways to make a significant investment in those parts of the industry which appear to have particular advantages with regard to feedstock and markets.

Steel Alberta Ltd.

teel Alberta, in which AEC has a 50 percent interest, holds 20.2 percent of the shares of Interprovincial Steel and Pipe Corporation Ltd. IPSCO is a primary steel producer with manufacturing facilities in Saskatchewan, Alberta and British Columbia. Net earnings for IPSCO in 1983 totalled $9.4 million on sales of $206.8 million.


Canon
1984

he year 1983 was one of very strong financial growth for the Company which saw a year-end working capital position of $51.8 million and available, existing unutilized credit facilities amounting to a further $478.0 million.

Revenues, net of royalties, reached a new high of $462.1 million, an increase of $88.0 million over 1982 with all segments of Company operations, with the exception of coal, recording substantial increases in net revenues. Oil and gas revenues represented the largest increase, which amounted to $56.3 million. This increase results primarily from higher sales of both natural gas and synthetic crude oil. The inclusion of 12 months of Chieftain Development Co. Ltd. ("Chieftain") revenues versus 5 months in 1982, is also a contributing factor to the increase. The increase in pipeline revenue reflects the impact of a full year's operation of the Cold Lake Bitumen Pipeline.

Cash flow from operations grew to $211.9 million, or $3.87 per common share from $131.0 million, or $2.67 per common share in 1982. This significant growth in cash flow is a further indication of the financial strength of the Company.

Before extraordinary items, earnings per common share were $1.03 in 1983 compared to $0.57 in 1982. The 1983 per share earnings figure reflects an increase in equity earnings from affiliates of $25.7 million over the previous year, primarily the result of a change in the accounting for an investment, as outlined in note 6(c) to the Consolidated Financial Statements. Net earnings for the year were $62.4 million, or $1.03 per common share compared to $54.6 million, or $1.03 per common share in 1982, after extraordinary items. In addition to the effect of earnings from affiliates, these per share numbers reflect the impact of the December 1982 issue of 5.3 million common shares and the 1983 increase in preferred share dividends of $2.5 million.

Operating, general and administrative, depreciation, depletion and amortization expense categories also increased in 1983 as a result of the continuing high level of activities, the full year effect of the Cold Lake Bitumen Pipeline and the consolidation of Chieftain. Net interest expense dropped sharply from 1982 due to lower outstanding debt, a lower average effective interest rate and higher interest income.

The provision for income taxes of $63.4 million compares to $22.1 million in 1982. This increase relates, in part, to improved earnings as well as an increase in the effective tax rate. This higher rate reflects the fact that, in 1982, the Company fully utilized a special depletion allowance. Only $3.1 million of this $63.4 million tax provision is currently payable.

While the Company's 1983 investment of $133.0 million in property, plant and equipment was at approximately the same level as in 1982, there was a change in thrust from the development of the Suffield Block, which is largely complete, to investments in new oil and gas exploration and development. Major 1983 expenditures were $87.2 million for exploration and development of conventional oil and gas, ($38.1 million in 1982), and $14.2 million for ongoing development of the Suffield Block ($42.3 million in 1982). The oil and gas related expenditures are net of $28.8 million in recoveries from various exploration, drilling and geophysical incentive programs. Additionally, the Company invested $16.5 million in Syncrude and $4.2 million in its heavy oil pilot project on the Primrose Range. A $33.4 million investment was made, through an affiliate, in a natural gas liquid extraction plant at Empress, Alberta, which was mechanically complete at year-end.

The Company paid $10.2 million in common share dividends ($0.20 per common share) and $12.4 million in preferred share dividends.

The year-end long-term debt balance of $506.3 million represents a decrease from 1982. Repayment requirements on long-term debt amount to approximately $18 million per year over each of the next five years. These nominal repayment requirements, in combination with available unutilized credit facilities and strong working capital, place the Company in a position to aggressively pursue attractive investment opportunities.

Summary of Accounting Policies

Principles of Consolidation

The consolidated financial statements include the accounts of Alberta Energy Company Ltd. (the "Company") and its subsidiary companies.

The Company's proportionate share of revenues, expenses, assets and liabilities in unincorporated joint ventures are consolidated in the Company's accounts.

A listing of subsidiaries, affiliates and unincorporated joint ventures is shown on the inside back cover.

Investments

The Company has adopted the equity method of accounting for investments in those companies for which significant influence is deemed to exist. For other companies the cost method is employed. Details are shown in Note 6.

Property, Plant and Equipment

Oil and Gas

Conventional

The Company employs the full cost method of accounting for oil and gas properties whereby all costs of acquisition, exploration and development of oil and gas reserves are capitalized. Separate cost centres have been established for Western Canada, Canadian Frontier Lands, and each foreign country in which the Company or its subsidiaries have properties. Costs accumulated within each cost centre are amortized on a composite unit-of-production method based upon estimated proven developed reserves. In those cost centres which have no proven developed reserves and where accumulated costs exceed the present value of the properties, such excess costs are amortized on a 20% declining balance method. In the event of the abandonment of a cost centre, the unamortized costs will be charged against earnings at the time of abandonment.

Oil sands

Property, plant and equipment, including preproduction costs, associated with the Syncrude Project are accumulated in a separate cost centre and amortized using the unit-of-production method based on estimated recoverable reserves. Anticipated major maintenance expenditures of an ongoing nature are provided for on the unit-of-production basis.

Pipelines

Property, plant and equipment is carried at cost with depreciation calculated using the straight-line method based on the estimated service life of the asset.

Other

Property, plant and equipment is carried at cost and is depreciated or amortized over the useful life of the assets using either the straight-line or unit-of-production method, whichever is deemed appropriate.

Other Assets and Deferred Charges

Deferred Stripping Costs

Costs of stripping related to producing areas of the coal mine are amortized on the basis of estimated production.

Project Investigation Costs

All project investigation costs on new business opportunities are charged to earnings as incurred until such time as the commercial viability of the project or business is indicated. All subsequent expenditures will be capitalized and charged against earnings using the method deemed appropriate for that particular business or project.

Mineral Exploration and Development

Acquisition costs of undeveloped mineral resource properties are capitalized and amortized over the exploration period or until sufficient reserves are established, at which time the unamortized costs will be charged against earnings using the unit-of-production method.

Mineral exploration expenditures are charged to earnings as incurred until such time as the presence of economically recoverable reserves is established. Subsequent expenditures are capitalized on a project basis and amortized using the unit-of-production method once commercial production commences.

Financing Costs

Financing costs relating to long-term debt are amortized over the life of the related debt.

Foreign Currency Translation

Long-term debt payable in foreign currencies is stated at the rate of exchange prevailing at the end of the accounting period with the resulting adjustment being amortized over the remaining life of the debt.

The accounts of foreign subsidiaries, whose economic activities are substantially self-sustaining, are translated at current exchange rates. The adjustments arising on translation of the foreign subsidiaries' balance sheets are deferred and included as a separate component of shareholders' equity.

Comparative Figures

The 1982 comparative figures in the Consolidated Statements of Earnings and Changes in Financial Position reflect the results of operations of Chieftain Development Co. Ltd. from August 1, 1982.

Consolidated Statement of Earnings
Year Ended December 31
($ millions)

	Note Reference	1983	1982
Revenues, Net of Royalties		$462.1	$374.1
Equity Earnings (Losses) of Affiliates		7.0	(18.7)
		469.1	355.4
Costs and Expenses			
Operating		168.6	146.4
Interest – net	2a	41.8	60.7
General and administrative		23.1	14.9
Depreciation, depletion and amortization		75.2	45.4
		308.7	267.4
Earnings before Income and Revenue Taxes and Minority Interest		160.4	88.0
Income taxes	3	63.4	22.1
Petroleum and gas revenue tax		29.5	29.5
		92.9	51.6
Earnings before Minority Interest		67.5	36.4
Minority Interest		5.1	2.8
Net Earnings before Extraordinary Items		62.4	33.6
Extraordinary Income, after Income Taxes	4	–	21.0
Net Earnings		$ 62.4	$ 54.6
Basic and Fully Diluted Earnings per Common Share			
Before extraordinary items		$ 1.03	$ 0.57
After extraordinary items		$ 1.03	$ 1.03

Consolidated Statement of Retained Earnings
Year Ended December 31
($ millions)

	1983	1982
Balance – Beginning of Year	$177.3	$140.0
Net Earnings	62.4	54.6
	239.7	194.6
Dividends – Preferred Shares	12.4	6.9
– Common Shares	10.2	9.1
Financing Costs –		
– Preferred shares, net of income tax	–	1.3
– Preferred shares of a subsidiary, net of income tax and minority interest	.4	–
	23.0	17.3
Balance – End of Year	$216.7	$177.3

The summary of accounting policies and notes to the financial statements are part of this statement.

Consolidated Balance Sheet

As At December 31
($ millions)

Assets	Note Reference	1983	1982
Current Assets			
Cash and short-term investments at cost which approximates market		$ 92.1	$ 87.3
Accounts receivable and accrued revenue		80.0	87.8
Inventories	5	18.0	19.0
Prepaid expenses		2.0	1.5
		192.1	195.6
Investments	6	260.5	225.8
Property, Plant and Equipment	7	1,155.3	1,108.2
Other Assets and Deferred Charges	8	5.4	9.3
		$1,613.3	$1,538.9

Liabilities and Shareholders' Equity			
Current Liabilities			
Bank indebtedness		$ 40.2	$ 20.8
Accounts payable and accrued liabilities		72.7	81.4
Dividends payable		2.8	.4
Income and revenue taxes payable		2.4	20.3
Deferred revenue	9	3.6	—
Current portion of long-term debt	10	18.6	10.2
		140.3	133.1
Deferred Revenue	9	87.6	89.3
Long-Term Debt	10	506.3	564.0
Deferred Liabilities	11	44.5	45.9
Deferred Income Taxes		212.4	148.2
Interests of Minority Shareholders	12	103.2	79.0
		1,094.3	1,059.5
Shareholders' Equity			
Share capital	13	302.4	302.3
Retained earnings		216.7	177.3
Unrealized foreign exchange loss		(.1)	(.2)
		519.0	479.4
		$1,613.3	$1,538.9

Approved by the Board:

D. Mitchell Director

J. E. Maybin Director

The summary of accounting policies and notes to the financial statements are part of this statement.

Consolidated Statement of Changes in Financial Position

Year Ended December 31
($ millions)

	Note Reference	1983	1982
Source of Funds			
Net earnings before extraordinary items		$ 62.4	$ 33.6
Depreciation, depletion and amortization		75.9	45.8
Deferred income taxes		68.3	24.8
Equity earnings of affiliates		(7.0)	18.7
Minority interest		5.1	2.8
Other		7.2	5.3
Cash flow from operations		211.9	131.0
Extraordinary income	4	–	24.0
Deferred revenue		1.9	68.9
Issue of preferred shares by a subsidiary, net proceeds		23.5	–
Issue of preferred shares – net proceeds		–	67.7
Issue of common shares – net proceeds	13	.1	79.7
Issue of long-term debt		19.6	206.0
Other		7.2	4.7
		264.2	582.0
Use of Funds			
Investment in property, plant and equipment		133.0	122.7
Acquisition of subsidiary, net of working capital acquired of $44.7		–	139.0
Investment in affiliates		30.7	–
Reduction of long-term debt		77.7	239.2
Other assets and deferred charges		–	2.5
Current portion of deferred liabilities and deferred revenue		5.1	–
Redemption of preferred shares issued by a subsidiary		.8	–
Dividends –			
Preferred and common shareholders		22.6	16.0
Minority shareholders of a subsidiary		5.0	1.6
		274.9	521.0
Increase (Decrease) in Working Capital		(10.7)	61.0
Working Capital – Beginning of Year		62.5	1.5
Working Capital – End of Year		$ 51.8	$ 62.5

The summary of accounting policies and notes to the financial statements are part of this statement.

1. Segmented information

($ millions)	Oil and Gas 1983	Oil and Gas 1982*	Pipelines 1983	Pipelines 1982	Other 1983	Other 1982*	Total 1983	Total 1982*
Gross revenue	$405.1	$344.5	$43.1	$ 34.8	$80.9	$ 58.0	$ 529.1	$ 437.3
Royalties	66.3	62.0	–	–	.7	1.2	67.0	63.2
Revenues, net of royalties	338.8	282.5	43.1	34.8	80.2	56.8	462.1	374.1
Operating expenses	95.7	85.2	8.0	6.4	62.6	49.2	166.3	140.8
Depreciation, depletion and amortization	57.1	30.3	7.0	5.8	9.9	8.0	74.0	44.1
Petroleum and gas revenue tax	29.5	29.5	–	–	–	–	29.5	29.5
	182.3	145.0	15.0	12.2	72.5	57.2	269.8	214.4
Segmented operating income (loss)	$156.5	$137.5	$ 28.1	$ 22.6	$ 7.7	$ (.4)	192.3	159.7
Equity earnings (losses) of affiliates							7.0	(18.7)
Corporate expenses							(26.6)	(21.8)
Interest – net							(41.8)	(60.7)
Income taxes							(63.4)	(22.1)
Minority interest							(5.1)	(2.8)
Net earnings before extraordinary items							$ 62.4	$ 33.6
Identifiable assets	$985.3	$930.6	$147.7	$165.5	$101.1	$117.3	$1,234.1	$1,213.4
Corporate assets							118.7	99.7
Investments							260.5	225.8
Total assets							$1,613.3	$1,538.9
Capital expenditures	$122.3	$ 91.2	$ 4.3	$ 25.1	$ 5.7	$ 5.7	$ 132.3	$ 122.0

*Includes results of operations of Chieftain Development Co. Ltd. from August 1, 1982.

Notes to Consolidated Financial Statements

2. Supplementary information

(a) Interest – net

($ millions)	1983	1982
Interest expense – on long-term debt	$ 53.9	$ 72.4
– on short-term debt	3.4	1.3
Interest income	(15.4)	(9.8)
Capitalized interest	(.1)	(3.2)
	$ 41.8	$ 60.7

(b) Joint ventures

The Company has included in its accounts the following aggregate amounts in respect of those unincorporated joint ventures outlined on the inside back cover.

($ millions)	1983	1982
Assets	$305.9	$309.3
Liabilities	34.0	28.9
Gross operating revenue	172.4	153.6
Expenses	106.1	101.7

3. Income taxes

($ millions)	1983	1982
Current	$ 3.1	$ 3.6
Deferred	68.3	24.8
Alberta royalty tax credit	(8.0)	(6.3)
	$ 63.4	$ 22.1

4. Extraordinary items

Extraordinary items in 1982 are comprised of a gain of $21.1 million (net of $2.9 million in income taxes) resulting from a cash payment for granting another company the right to participate in the advancement of heavy oil production technology and a $0.1 million loss (net of minority interest and income taxes) on the sale of a portfolio investment held by a subsidiary.

5. Inventories

Inventories are valued at the lower of cost or estimated net realizable value. They consist of:

($ millions)	1983	1982
Raw materials and supplies	$ 10.3	$ 10.8
Work-in-process	3.0	3.8
Finished goods	4.7	4.4
	$ 18.0	$ 19.0

6. Investments

Accounted for on the equity basis:

($ millions)	Percent Interest	1983	1982
AEC Power Ltd. (50% voting)	66⅔	$ 20.7	$ 20.7
Steel Alberta Ltd.	50	15.9	15.5
Pan-Alberta Gas Ltd. (40% voting)	50	5.9	5.0
Pan-Alberta Resources Inc. (40% voting)	50	33.4	–
		$ 75.9	$ 41.2

Accounted for on the cost basis:

($ millions)	1983		1982	
	Cost	Market	Cost	Market
British Columbia Forest Products Limited	$183.5	$116.4	$183.5	$70.9
Other	1.1	1.2	1.1	1.1
	$184.6	$117.6	$184.6	$72.0

(a) Steel Alberta Ltd.

The principal asset of Steel Alberta Ltd. is a 20.2% equity interest in Interprovincial Steel and Pipe Corporation Ltd., which investment is accounted for on the equity method.

(b) Pan-Alberta Resources Inc. ("PARI")

PARI and another company are jointly constructing a natural gas liquids extraction plant which was mechanically complete as at December 31, 1983, with production expected to begin by mid-1984. In accordance with the cost of service agreement covering the operation of this plant, earnings of PARI for 1983 include an allowance on equity funds employed during the construction period, the Company's share of which is $2.5 million.

(c) British Columbia Forest Products Limited ("BCFP")

The Company owns 8,705,061 common shares of BCFP, representing an 18% interest therein. Prior to December, 1982, the Company accounted for this investment by the equity method.

7. Property, plant and equipment

	1983			1982
($ millions)	Cost	Accumulated depreciation, depletion and amortization	Net	Net
Oil and Gas	$1,041.8	$ 128.5	$ 913.3	$ 850.7
Pipelines	169.7	26.2	143.5	146.6
Other	136.5	38.0	98.5	110.9
	$1,348.0	$ 192.7	$1,155.3	$1,108.2

Notes to Consolidated Financial Statements

8. Other assets and deferred charges

($ millions)	1983	1982
Deferred stripping costs	$3.2	$3.1
Land held for future development	.7	2.4
Mineral properties	—	1.6
Unamortized financing costs	1.0	1.0
Other	.5	1.2
	$5.4	$9.3

9. Deferred revenue

The December 31, 1983, balance of $87.6 million represents payments received under take-or-pay provisions of a major gas sales contract. The delivery of gas in respect of these payments and the recognition of revenue will commence November, 1984, at a rate varying between 10 percent and 20 percent per contract year out of gas production occurring during the first five months of each contract year until the $87.6 million is repaid. Accordingly, $3.6 million estimated to become payable in 1984 is classified as a current liability.

10. Long-term debt

($ millions)	1983	1982
Alberta Energy Company Ltd. ("AEC")		
Borrowings under revolving credit and term loan agreements		
Income debentures	$180.0	$180.0
Bank loans – secured	—	64.4
Bank loan – unsecured	—	23.0
Trust company loans – unsecured	50.0	50.0
Notes payable	163.3	115.9
Mortgage payable	5.4	5.4
Other	9.0	8.5
	407.7	447.2
Alberta Oil Sands Pipeline Ltd. ("AOSPL")		
First Mortgage Sinking Fund Bonds:		
Series A – 9⅝%, due June 15, 1997	21.6	23.3
Series B – 9¾%, due June 15, 1997	24.4	25.8
	46.0	49.1
Chieftain Development Co. Ltd. ("Chieftain")		
Income debentures	35.7	42.9
Bank loan – secured: Chieftain International, Inc.	34.8	34.4
Other	.7	.6
	71.2	77.9
	524.9	574.2
Current portion of long-term debt	18.6	10.2
	$506.3	$564.0

10. Long-term debt (continued)

The aggregate maturities of long-term debt in each of the five years subsequent to December 31, 1983, are as follows:

1984	$18.6
1985	18.7
1986	18.7
1987	18.7
1988	9.9

(a) AEC revolving credit and term loan agreements

The Company has revolving credit and term loan agreements with financial institutions as follows:

	Amount Available	Revolving Until	Repayment Period
Secured			
Income debentures	$180	–	1989-1998
Bank loans	420	1988	1989-1998
Unsecured			
Bank loan	200	1987	1987-1992
Trust company loan	50	1991	1991-2001
Trust company loan	25	1988	1988
	$875		

After allowance for notes payable outstanding, undrawn lines of credit under these agreements amounted to $478.0 million at December 31, 1983.

The bank loans are available in Canadian and/or U.S. dollars and bear interest based on the lenders' prime commercial lending rates plus a factor varying over the terms of the loans up to 1%. Interest on the income debentures is approximately one-half of a similarly determined rate and is not deductible for income tax purposes. Interest on the trust company loans is the prime commercial lending rate of a major Canadian chartered bank minus a factor varying over the revolving term of the loans up to ¾%.

The income debentures and secured bank loans are secured by a portion of the reserves of the Suffield Block, a fixed charge on the related production equipment and an assignment of the related gas sales contracts. The unsecured loan agreements require the Company to maintain certain financial measurements which at December 31, 1983 have been adhered to by the Company.

Notes payable consist of $49.2 million (December 31, 1982 – $49.2 million) in Commercial Paper and $114.1 million (December 31, 1982 – $66.7 million) in Bankers' Acceptances, all maturing at various dates up to March 20, 1984, with a weighted average interest rate of 9.97% (1982 – 12.36%). Notes payable are shown as long-term debt because they are supported by the availability of term loans under the revolving credit facilities.

(b) AOSPL First Mortgage Sinking Fund Bonds

AOSPL is obligated to retire $2.8 million of these bonds annually. The bonds are secured by both a fixed and floating charge on AOSPL's assets that relate to the Syncrude Project. The participants in the Syncrude Project, of which the Company is a participant to the extent of 10%, have guaranteed the repayment of these bonds.

10. Long-term debt (continued)

(c) Chieftain Income debentures

The income debentures issued by Chieftain are secured by assignments of major hydrocarbon reserves and production contracts. The outstanding balance is being repaid in annual installments of $7.1 million. Interest on income debentures at the rate of 52% of bank prime plus ¾%, plus ⅜% (aggregating 6.49% at December 31, 1983) is not deductible for income tax purposes.

(d) Chieftain Secured bank loan

The loan of Chieftain International, Inc. is for a principal amount of U.S. $28 million secured by assignments of major hydrocarbon reserves and production contracts of the company. The interest rate to be paid is, at the borrower's option, the London interbank offered rate (LIBOR) plus 1% or the U.S. prime rate plus ½%. At December 31, 1983, the Company was paying interest at the LIBOR rate plus 1% which aggregated 11.19%. Interest only is payable for the first three years with the principal amount to be repaid in four equal annual installments commencing December 18, 1984. Repayment is permitted at any time without penalty.

11. Deferred liabilities

(a) Suffield

Rights to the Suffield Block were acquired for $54 million of which $24 million has been paid and the balance is payable in three annual installments of $10 million commencing one year after recovery of certain expenditures.

(b) Primrose

The Company acquired rights to the Primrose Range for $57.6 million in cash and work obligations. The balance of the cash obligation of $14.5 million is payable when leases to the remaining portions of the Range are issued.

12. Interests of minority shareholders

($ millions)	1983	1982
Chieftain Development Co. Ltd.		
Preferred equity	$ 59.1	$ 34.9
Common equity	44.1	44.1
	$103.2	$ 79.0

13. Share capital

($ millions)	1983	1982
First Preferred Shares:		
Authorized – 20,000,000 shares with a par value of $25 each		
Issued and fully paid – 2,400,000, 15% Cumulative Redeemable Retractable, Series A	$ 60.0	$ 60.0
Second Preferred Shares:		
Authorized – 20,000,000 shares with a par value of $25 each		
Issued and fully paid – 412,515, 11¼% Deferred Convertible, Series 1	10.3	10.3
Common Shares:		
Authorized – 300,000,000 shares without par value		
Issued and fully paid – 50,813,255 (December 31, 1982 – 50,800,755)	232.1	232.0
	$302.4	$302.3

13. Share capital (continued)

(a) Common Shares

	1983		1982	
	Number of Shares	**Net Proceeds**	Number of Shares	Net Proceeds
Issued for cash	—	$ —	5,312,500	$ 82.4
Issued for cash under Employee Share Option Plan	12,500	.1	—	—
Redeemed for cancellation	—	—	(3,000)	(.1)
Net increase in the year	12,500	.1	5,309,500	82.3
Issued and outstanding Beginning of year	50,800,755	232.0	45,491,255	149.7
Issued and outstanding End of year	**50,813,255**	**$232.1**	50,800,755	$232.0

(b) Preferred Shares

(i) First Preferred Shares – Series A

The Series A Preferred Shares are cumulative and are retractable at the option of the holder on December 1, 1986 or December 1, 1991 at a price of $25.00. The shares are redeemable on December 1, 1986, or at anytime thereafter, at predetermined prices varying from $26.50 to $25.00.

(ii) Second Preferred Shares – Series 1

Series 1 Preferred Shares are cumulative and are retractable at the option of the holder on August 1, 1984 or August 1, 1989 at a price of $26.50. Subject to certain conditions the shares are redeemable at the option of the Company at $26.50 from January 1, 1985 to August 1, 1989 and thereafter at par.

Each Series 1 Preferred Share is convertible during the period July 1, 1984 to July 1, 1989, at the option of the holder into two AEC Common Shares, upon payment by the holder to the Company of a cash amount equal to the difference between the $25.00 par value of such share and the conversion price of two Common Shares. The conversion price per Common Share is equal to 90% of the weighted average price of the Common Shares on The Toronto Stock Exchange for the twenty trading days prior to July 1, 1984, subject to a minimum conversion price of $13.50 per Common Share.

(c) Employee Share Option Plan

The Employee Share Option Plan provides for granting to employees of the Company and its subsidiaries options to purchase Common Shares of the Company. Each option which has been granted under the plan expires after seven years and may be exercised in cumulative annual amounts of 25% on or after each of the first four anniversary dates of the grant.

As at December 31, 1983 the following options to purchase Common Shares under the plan were outstanding:

Date Granted	Expiry Date	Price Per Share	Number of Common Shares
July 15, 1982	July 15, 1989	$10.58	255,500
September 19, 1983	September 19, 1990	17.67	143,000
			398,500

13. Share capital (continued)

(d) Common Shares reserved

At December 31, 1983, Common Shares were reserved for issuance as follows:

Conversion of Second Preferred Shares – Series 1	825,030
Employee Share Option Plan	687,500
Share Purchase Plan (presently inactive)	100,103
	1,612,633

(e) Alberta Energy Company Act

Pursuant to the Alberta Energy Company Act only citizens or residents of Canada are eligible to purchase, own or hold voting shares in the Company. In addition, the maximum ownership of any one shareholder, excluding the Province of Alberta, is limited to 1% of the total number of issued and outstanding voting shares of each class of the Company.

14. Remuneration of directors and senior officers

The aggregate direct remuneration paid by the Company and its subsidiaries to its directors was $183,000 (1982 – $198,000) and to its senior officers as officers was $1,774,000 (1982, for fewer officers – $1,313,000).

Auditors' Report

To the Shareholders of Alberta Energy Company Ltd.

We have examined the consolidated balance sheet of Alberta Energy Company Ltd. as at December 31, 1983 and the consolidated statements of earnings, retained earnings and changes in financial position 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, these consolidated financial statements present fairly the financial position of the company as at December 31, 1983 and the results of its operations and the changes in its financial position for the year then ended, in accordance with generally accepted accounting principles which have been applied on a basis consistent with that of the preceding year.

Price Waterhouse

Chartered Accountants
Edmonton, Alberta
February 6, 1984

Eight-Year Review

(all dollar amounts, except per share amounts, are in millions)	1983	1982	1981	1980	1979	1978	1977	1976
Financial								
Revenue (net of royalties)	**$ 462.1**	$ 374.1	$ 285.1	$ 232.6	$ 90.9	$ 54.8	$ 20.3	$ 13
Net earnings, before extraordinary items	**62.4**	33.6	42.4	57.4	27.4	18.8	14.9	8.5
Net earnings, after extraordinary items	**62.4**	54.6	29.7	57.4	27.4	18.8	14.9	8.5
Cash flow from operations	**211.9**	131.0	90.6	115.6	60.8	32.5	17.1	8.2
Petroleum and Gas Revenue Tax	**29.5**	29.5	15.6					
Oil and gas royalties paid	**66.3**	62.0	55.1	43.1	[illegible]	13.6	7.6	0.3
Working capital	**51.8**	62.5	1.5	10.1	44.3	141.0	15.5	68.4
Investment in property, plant and equipment	**1,155.3**	1,108.2	694.0	593.0	531.9	290.8	206.6	99.3
Long-term debt	**506.3**	564.0	518.1	251.8	309.6	209.2	44.6	
Total assets	**1,613.3**	1,538.9	1,036.9	702.7	651.0	504.1	273.3	216.4
Per Share Data*								
Net earnings, before extraordinary items	**$ 1.03**	$ 0.57	$ 0.93	$ 1.26	$ 0.60	$ 0.41	$ 0.33	$ 0.19
Net earnings, after extraordinary items	**1.03**	1.03	0.65	1.26	0.60	0.41	0.33	0.19
Cash flow	**3.87**	2.67	1.99	2.54	1.34	0.72	0.38	0.18
Shareholders' equity	**8.83**	8.05	6.37	5.90	4.80	4.27	3.85	3.52
Dividend	**0.20**	0.20	0.20	0.15	0.10	–	–	
Shares*								
Number of shareholders	**52,871**	56,894	52,841	54,252	51,725	53,292	54,169	56,394
Common shares outstanding	**50,813,255**	50,800,755	45,491,255	45,460,505	45,446,505	45,335,553	45,272,928	45,206,928
Volume of shares traded	**9,313,891**	6,330,743	4,788,371	9,706,332	8,530,752	5,543,070	5,386,023	7,668,018
Share price range								
– High	**$ 21.25**	$ 20.25	$ 27.75	$ 24.38	$ 14.42	$ 6.58	$ 6.42	$ 4.08
– Low	**13.63**	8.00	14.00	12.50	6.21	4.88	3.92	2.83
– Close	**18.25**	15.00	16.00	23.88	13.50	6.29	5.88	4.00
Operating Data								
Gas production, net before royalties								
– billion cubic metres	**2.3**	2.0	1.6	1.3	1.1	.8	[illegible]	02
– billion cubic feet	**81.7**	71.5	58.5	46.5	38.3	27.0	17.8	.8
Syncrude production								
– thousand cubic metres	**648.3**	497.8	473.2	470.1	108.0			
– million barrels	**4.1**	3.1	3.0	3.0	0.7			
Conventional oil production								
– thousand cubic metres	**56.3**	20.0	19.3	21.5	20.9	24.4	12.3	
– thousand barrels	**354.3**	126.1	121.2	135.4	131.8	153.3	77.4	
Utility plant output								
– thousand megawatt-hours	**903**	869	793	809	788	300		
Coal production								
– thousand tonnes	**515**	672	684	600	488	157		
– thousand tons	**568**	741	754	662	538	173		
Lumber production, Whitecourt complex								
– million board feet	**121**	90	113	115	100	94	63	
Pipeline throughput								
– million cubic metres	**12.2**	9.9	9.3	9.1	6.3	1.9	–	–
– million barrels	**77.0**	62.4	59.1	57.3	39.6	11.7	–	–

Financial and operating data include all results of Chieftain Development Co. Ltd. since August 1, 1982

**Reflects three-for-one stock split*

At Year-End 1983

Net Canadian petroleum and natural gas rights	1.1 million hectares (2.8 million acres)
Natural gas reserves	61.4 billion cubic metres (2,178 billion cubic feet)
* Proven natural gas reserve life	26 years
Oil and natural gas liquids reserves	2.2 million cubic metres (13.8 million barrels)
Proven synthetic oil reserves	18.1 million cubic metres (113.8 million barrels)
* Synthetic oil reserve life	28 years
Primrose heavy oil in place net to AEC	2.3 billion cubic metres (14 billion barrels)
Timber licenses	566 thousand hectares (1.4 million acres)
Coal reserves	8.1 million clean tonnes (8.9 million clean tons)
* Coal reserve life	15 years
Pipelines	1,558 kilometres (974 miles) in three pipelines

* at 1983 production rates

Board of Directors

MATHEW M. BALDWIN
Company Director
Edmonton, Alberta

EDWARD A. GALVIN
Chairman of the Board
Poco Petroleums Ltd.
Calgary, Alberta

DONALD S. MACDONALD
Partner,
McCarthy & McCarthy
Barristers & Solicitors
Toronto, Ontario

PETER L.P. MACDONNELL, QC
Partner, Milner & Steer
Barristers & Solicitors
Edmonton, Alberta

JOHN E. MAYBIN
Executive Director
Petroleum Recovery Institute
Calgary, Alberta

STANLEY A. MILNER
President
Chieftain Development Co. Ltd.
Edmonton, Alberta

DAVID E. MITCHELL
President &
Chief Executive Officer
Alberta Energy Company Ltd.
Calgary, Alberta

RAYMOND J. NELSON
President
Nelson Lumber Company Ltd.
Lloydminster, Alberta

GORDON H. SISSONS
President
I-XL Industries Ltd.
Medicine Hat, Alberta

J. HARRY TIMS
President & General Manager
McTavish McKay & Company
Limited
Calgary, Alberta

Company Officers and Senior Personnel

DAVID E. MITCHELL
President & Chief
Executive Officer

JACK G. ARMSTRONG
Senior Vice-President
Finance

FRANK W. PROTO
Senior Vice-President

GWYN MORGAN
Vice-President
Gas and Oil

ROGER D. DUNN
Vice-President

EDWARD J. MARTIN
Vice-President &
Comptroller

HECTOR J. McFADYEN
Vice-President

ARLENE J. MOORE
Corporate Secretary

SYDNEY R. CHEN-SEE
Assistant Corporate
Secretary

JOHN D. WATSON
Treasurer

BERNIE J. BRADLEY
Vice-President, Alberta
Oil Sands Pipeline

V. NEIL DESAULNIERS
Director, Forest
Products

DEREK S. BWINT
Director, Financial
Evaluations

KEITH O. FOWLER
Director, Corporate
Taxation

WAYNE G. HOLT
General Counsel

LAWRENCE J. HICKEY
Assistant Comptroller

Principal Officers of AEC Oil and Gas Company
A Division of Alberta Energy Company Ltd.

GWYN MORGAN
President

RONALD A. McINTOSH
Senior Vice-President

ROGER N. GIMBY
Vice-President, Production

Corporate Information

Offices
#2400, 639 - 5 Avenue S.W.
Calgary, Alberta T2P 0M9

#1200, 10707 - 100 Avenue
Edmonton, Alberta T5J 3M1

Registrar and Transfer Agent— (Common Shares and First Preferred Shares, Series A)
National Trust Company, Limited
Edmonton, Calgary, Vancouver, Winnipeg, Toronto, Montreal; and its agent, Canada Permanent Trust Company in Regina and Halifax

Registrar and Transfer Agent— (Second Preferred Shares, Series 1)
The Royal Trust Company
Edmonton, Calgary, Vancouver, Winnipeg, Toronto, Montreal, Regina and Halifax

Auditors
Price Waterhouse
Chartered Accountants
Edmonton, Alberta

Stock Exchange Listings
Alberta Stock Exchange
Montreal Exchange
Toronto Stock Exchange
Vancouver Stock Exchange

Subsidiaries

Alberta Oil Sands Pipeline Ltd.	100%
AEC Heavy Oil Ltd.	100%
AEC Coal Company Ltd.	100%
Alberta Industrial Gas Suppliers, Ltd.	100%
Alenco Holdings, Inc.	100%
Blue Ridge Lumber (1981) Ltd.	100%
Chieftain Development Co. Ltd.	57%
Ranger Forest Products Ltd.	100%

Affiliates

AEC Power Ltd.	66⅔%
Pan-Alberta Gas Ltd.	50%
Pan-Alberta Resources Inc.	50%
Steel Alberta Ltd.	50%

Major Joint Ventures

Ethane Gathering System	33⅓%
Coal Valley Project	25%
Syncrude Project	10%

Annual Meeting

The annual general meeting of shareholders of Alberta Energy Company Ltd. will be held in the Alberta Room, Westin Hotel, 10135 - 100 Street, Edmonton, Alberta at 3:00 p.m. local time on Wednesday, April 11, 1984.

Copies of the Company's 1983 annual report may be obtained by contacting the office of the Secretary of the Company at Alberta Energy Company Ltd., #2400, 639 - 5 Avenue S.W., Calgary, Alberta T2P 0M9.

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