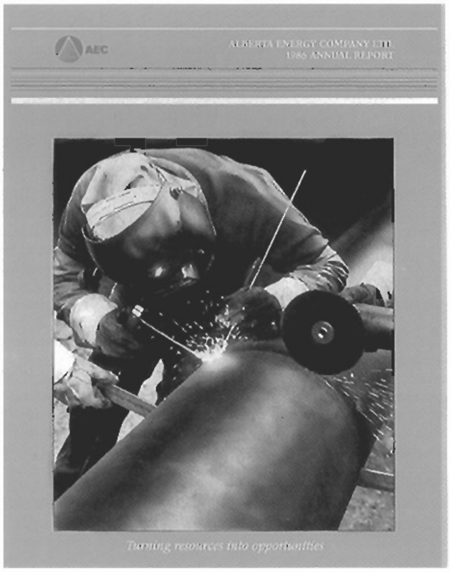
C

ALBERTA ENERGY COMPANY LTD.
1986 ANNUAL REPORT

Turning resources into opportunities



THE COVER

The establishment of AEC Pipelines as a separate operating division reflects the increasing role pipelines play in the Corporation's diversification of resource developments. In 1986, pipelines represented the second largest source of net operating income. This photo of a pipeline weld was taken by Jim Zakowski, AEC Pipelines Projects Manager.

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PRESIDENT'S REPORT TO SHAREHOLDERS

Record operational results

Financial position enhanced

Reduced unit operating costs

Profitability in all divisions

$272 million capital investment

1986 was an unusual year, to put it mildly. AEC adapted quickly to the challenges posed by plummeting oil prices and significant downward pressure on gas prices. The year ended with production records in virtually all of our operations, a high level of new capital investment and an enhanced financial position.

Highlights of 1986 included:

- Record gas production, 252 million cubic feet per day, up 8 percent
- Record conventional oil production, 6,248 barrels per day, up 122 percent
- Oil discoveries at Shekilie, Kidney, Seal, South Jenner and Loon Lake; gas discoveries at Caribou Lake
- Record pipeline throughput, 250,000 barrels per day, up 36 percent
- Record Syncrude oil production, 130,000 barrels per day; with a sharp reduction in operating costs to (Cdn.) $14.83 per barrel
- Record lumber shipments, 152 million board feet, up 8 percent
- Cash flow of $198.2 million, 78 percent of 1985
- Profitability in all divisions
- Reduced unit operating costs in all divisions

The severe economic conditions which prevailed for most of the year required special financial actions, including an $83.3 million write-down of certain assets and the sale of others. Net loss after deduction of extraordinary items was $35.5 million. Earnings before extraordinary items were $47.8 million or 59 percent of those of the prior year.

AEC significantly strengthened its financial structure while still completing a $272 million capital investment program. The Corporation completed an $85 million Common Share Rights Offering; raised $119 million from the sale of shares in a forest products company; redeemed $60 million of 15% First Preferred Shares; replaced $100 million of floating rate debt with long-term fixed interest rate debentures; and reduced its debt by $69.4 million.

Our 1986 capital program included net expenditures of $124.4 million for oil and gas and pipelines; $75.1 million for the nitrogen fertilizer project at Joffre; $8.7 million for the medium-density fibreboard plant at Blue Ridge; and $12.7 million for other projects.

PRESIDENT'S REPORT TO SHAREHOLDERS

Syncrude initiated programs that reduced operating and capital costs while increasing operating efficiency and maximizing production.

The remaining $51 million of the 1986 capital program related to the completion of an agreement with the Government of Alberta regarding the 1975 acquisition of the petroleum and natural gas rights on the Suffield Block. This agreement finalized the purchase, and Suffield is now subject only to normal Crown royalty payments. The agreement provides for the replacement of Net Profits Payments with a commitment to pay $51 million, of which $31.6 million was paid in 1986 and the remaining $19.4 million will be paid in three installments beginning in 1987.

Syncrude's 1986 operating costs were reduced from (Cdn.) $17.74 per barrel to (Cdn.) $14.83. The Syncrude team demonstrated remarkable initiative, reducing both operating and capital costs while increasing efficiency and setting a new production record.

Other events also contributed to the unusually lively and unpredictable nature of the year. These included the deregulation of Canada's natural gas industry and the protectionist attitudes of U.S. authorities in the forest products industry. The November 1 gas deregulation impacted AEC's gas contracts, which were successfully renegotiated to confirm long-term purchaser commitments and establish market-sensitive pricing.

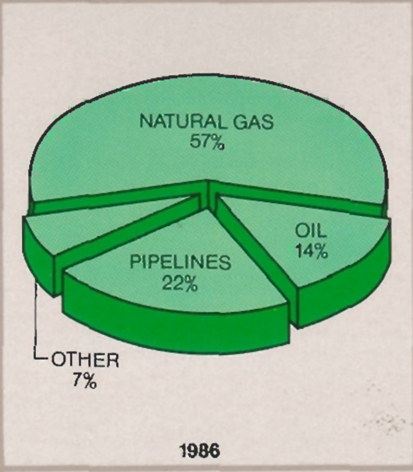
Several factors are tending to improve the economics of exploration and development. Removal of the insidious Petroleum and Gas Revenue Tax (PGRT) on gross revenue, coupled with provincial royalty adjustments, are helping to create a financial environment within which the industry can function; lower crude prices are resulting in lower prices for petroleum land purchases; increased efficiencies are lowering operating costs; and Alberta's royalty holiday for new oil production is aiding the profit potential from new oil discoveries.

The Corporation's *operational success*, which helped offset the downturn in prices, was due in large measure to the dedication of staff. While significant reductions were made in temporary and contract personnel, AEC did not lay off any permanent staff. Twenty people were hired to fulfill operating requirements arising from substantial capital investment in new wells and pipelines during 1985 and 1986. Operating economies were realized through steps such as longer working hours, the assumption of additional duties and responsibilities by employees and a comprehensive review of, and decrease in, costs.

PRESIDENT'S REPORT TO SHAREHOLDERS

The anticipated scenario for 1987 promises more challenges. On the natural gas side, our prices are expected to decline by some 20 to 25 percent in 1987. AEC's oil production is expected to increase, while gas demand likely will be lower. As this report goes to press, crude oil prices are about 60 percent of the average price in 1985. Having weathered the storm of the National Energy Program fiasco with its nightmare of a tax on gross revenue (PGRT), the increase in crude prices from 50 percent to 60 percent of 1985 levels has been a welcome boost for the optimists who exist in the oil patch. The recent trends of greater crude price stability and lower interest rates add to that attitude.

Probably the most significant difference between the oil industry now and that in early 1986 is the greater degree of comfort about the downside. When the oil price was tumbling, its bottom level was unknown; presently, there is more confidence that a level of (U.S.) $15 per barrel or better will prevail.



SOURCES OF CASH FLOW BY SEGMENT

AEC has a diversified cash flow stream, with a good portion of its revenue derived from stable cost-of-service investments. Recent capital programs are starting to yield revenues and the Corporation has a sound financial base. Pipelines have contributed an increasing portion of our diversified revenue stream, and in 1986 were our second largest source of cash flow. Forest products, coal, a power plant, and a natural gas liquids extraction plant also are expected to generate positive cash flow, while the cash contribution from the new fertilizer venture will begin in a small way in the second quarter of 1987 and build in the full year 1988.

The outook for 1987 is favourable, although abundant uncertainties make financial forecasts even more hazardous than usual. The more significant variables include crude oil prices, gas prices, gas deregulation effects, the exchange on the Canadian dollar, interest rates, and even the weather. As this report goes to press, all factors considered, including the anticipated reduction in average gas prices, it seems likely that 1987 cash flow and earnings will tend to equal or exceed the levels of 1986.

The continued loyalty and support of our shareholders is greatly appreciated.

David E. Mitchell, O.C.
President and
Chief Executive Officer

February 11, 1987

OIL AND GAS

Record production levels for natural gas

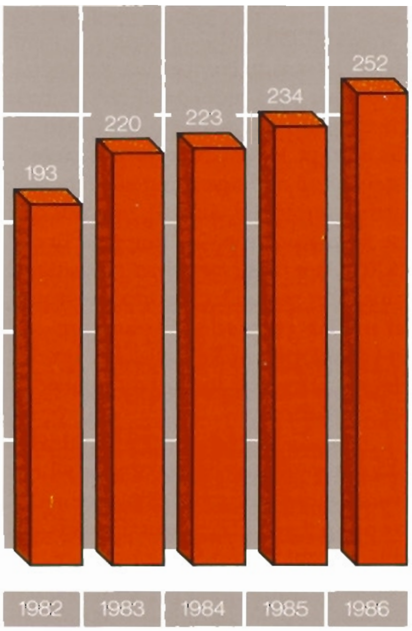
Conventional oil production more than doubled

Renegotiated gas contracts, new direct sales, enhanced market presence

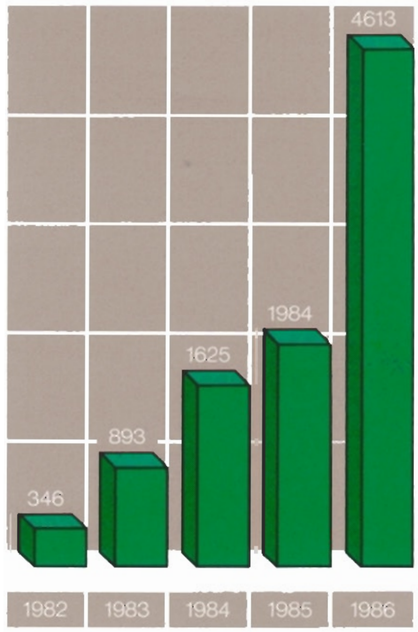
Continued success in reducing production costs, already among the industry's lowest

New oil treating facilities at South Jenner helped to reduce unit operating costs. Operators, Clark Walker, (L) and Rob Tetrault

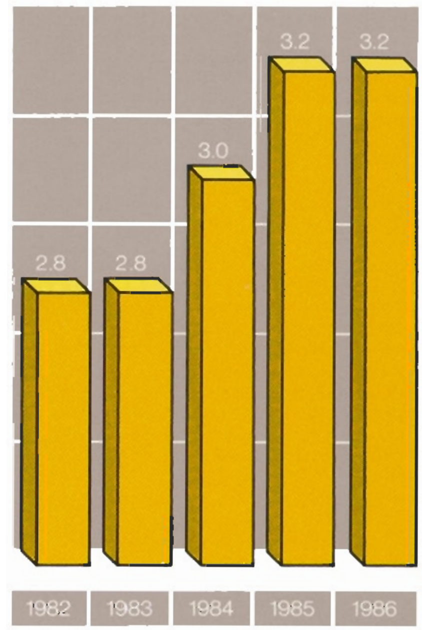
CONSOLIDATED RESULTS*



AVERAGE DAILY WESTERN CANADIAN GAS PRODUCTION
(MILLION CUBIC FEET)



AVERAGE DAILY WESTERN CANADIAN CONVENTIONAL OIL PRODUCTION
(BARRELS)



WESTERN CANADIAN PETROLEUM AND NATURAL GAS LANDHOLDINGS
(NET MILLION ACRES)

Western Canadian Reserves

Independent consultants estimate the Corporation's conventional oil and gas reserves in western Canada to be as follows.

Gas (billion cubic feet)	
• Proven	1,584
• Probable	179
• Total	1,763

Oil (million barrels)	
• Proven	15.0
• Probable	7.5
• Total	22.5

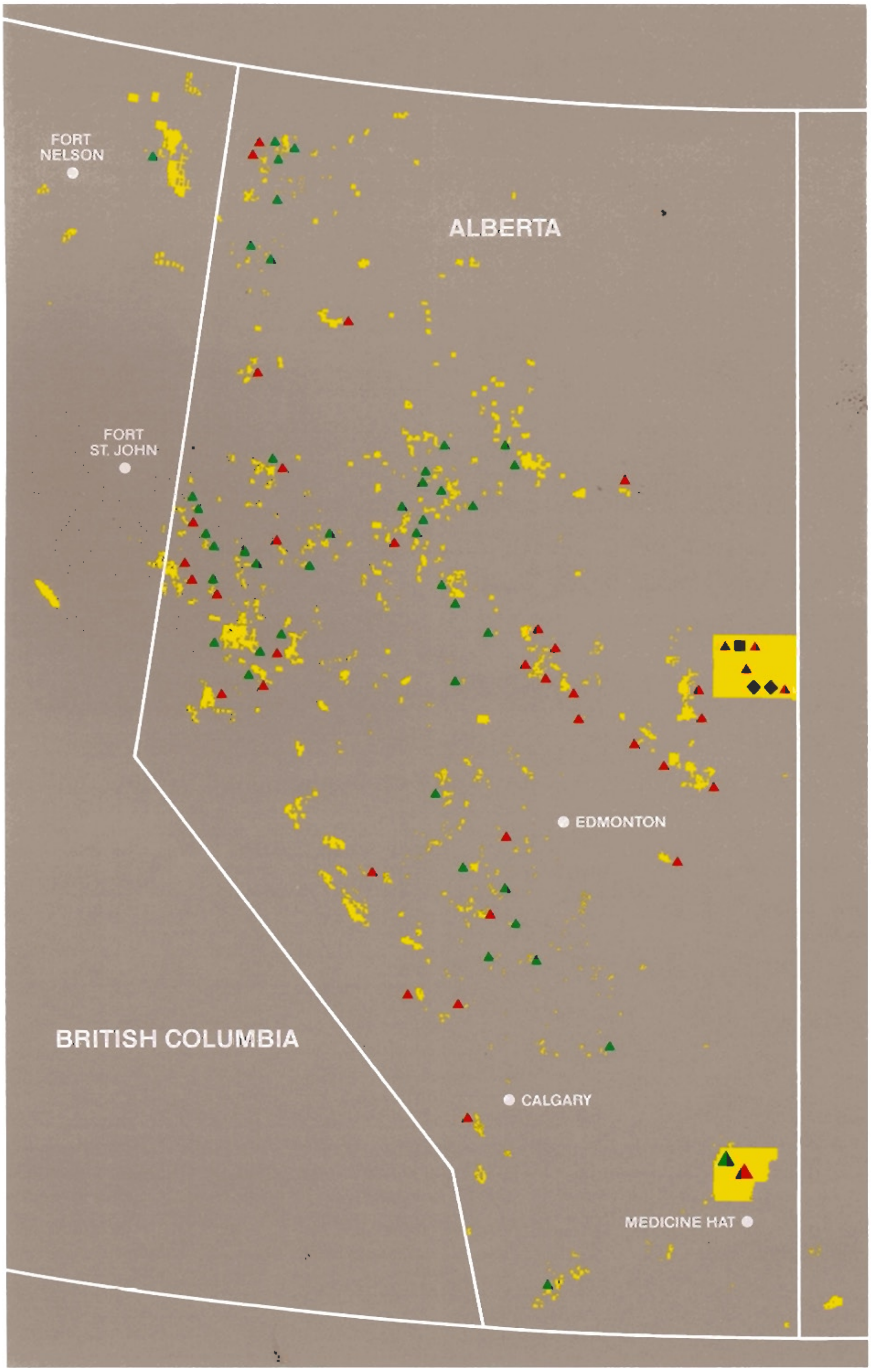
In addition to the above conventional reserves, AEC Oil and Gas Company owns 17 billion barrels of in-situ heavy oil in place. Where commercial projects to recover the oil proceed, typical recovery factors are expected to vary from 10 to 20 percent depending upon reservoir and economic conditions.

Western Canadian Exploratory and Development Well Drilling Activity

	1986		1985		1984	
	Gross	**Net**	Gross	Net	Gross	Net
Oil	**62**	**27**	220	118	58	18
Gas	**89**	**66**	587	569	180	165
Cased Awaiting Evaluation	**11**	**4**	18	6	73	24
Dry and Abandoned	**95**	**35**	129	54	96	41
Total	**257**	**132**	954	747	407	248

** Data related to oil and gas exploration, production, landholdings and reserves shown elsewhere in this report reflect consolidation with Chieftain Development Co. Ltd., of which AEC is the majority shareholder. This is consistent with previous reports and industry practice. Information specific to AEC Oil and Gas Company is contained on pages 6 through 13. In addition to its considerable activities in western Canada, Chieftain holds significant reserves and is involved internationally in oil and gas exploration and production.*

OIL AND GAS



CONSOLIDATED WESTERN CANADA OIL & GAS LANDS

- AEC Interest Land
- Natural Gas
- Oil
- Pending Commercial Heavy Oil Project
- Heavy Oil Pilot

AEC OIL AND GAS COMPANY

Activity Summary

AEC Oil and Gas Company maintained its strong competitive position despite sharply reduced oil prices and the transition to a deregulated natural gas market. Production records were established and operating efficiencies further improved. As well, removal of the Petroleum and Gas Revenue Tax (PGRT) late in the year had a positive impact on net operating income from oil and gas properties. Exploration and development capital expenditures before grants and incentives totalled $88 million.

Production of conventional oil and gas increased during a year when overall industry production declined. Record natural gas production was 223 million cubic feet per day, up 9 percent. Conventional oil production more than doubled to 3,190 barrels per day. New production facilities and continued efforts in reducing costs combined to ensure AEC's oil and gas operating costs remain among the lowest in the industry.

The Company's important long-term natural gas sales contracts were successfully renegotiated as part of the complex transition to price deregulation. AEC also established new direct marketing arrangements for oil and natural gas.

The Company responded quickly to lower prices with significant changes to its exploration strategies.

A major milestone was reached with the settlement of the net production proceeds obligation related to the petroleum and natural gas rights on the Suffield Block. This settlement finalized AEC's purchase of this major oil and gas field, subject only to the normal royalties, which to date have totalled $265 million. Suffield is one of North America's largest natural gas and oil producing fields.

AEC's confidence in the technical and economic potential of the 17 billion barrels of in-situ heavy oil in place on the Primrose Range has been reinforced in a recent report by Canada's National Energy Board. This energy source becomes more integral to Canada's future security of supply as conventional oil production declines. Although low oil prices led to deferment of two approved commercial projects at Primrose, AEC is working to ensure that these projects are ready to proceed when prices return to profitable levels.

Sophisticated computer equipment aids in the analysis of geophysical data.
Keith Young, Project Geophysicist (foreground)
Andrew Mah, Geophysicist

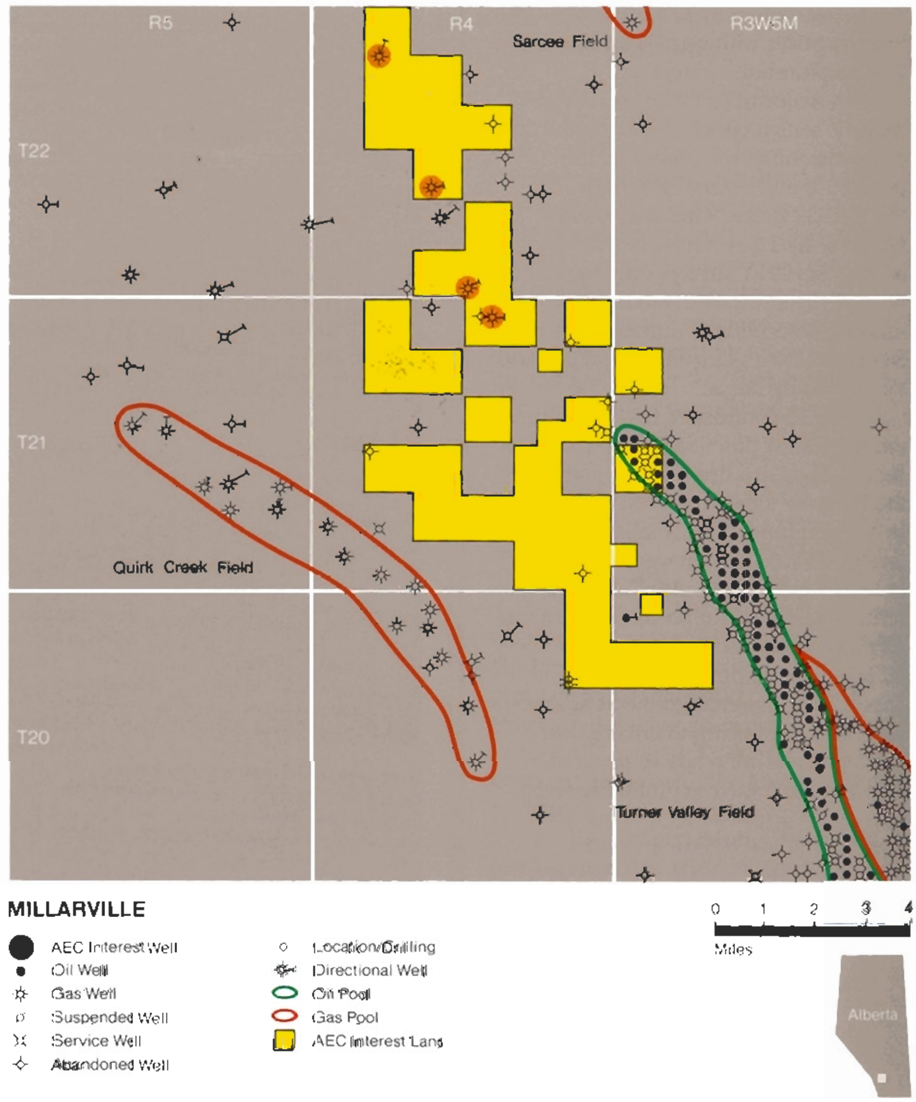
OIL AND GAS

Exploration

1986 exploration success included oil discoveries at Shekilie, Kidney, and Seal in northern Alberta and two oil discoveries near South Jenner west of Medicine Hat. In addition, the Company is encouraged by the results of natural gas exploration in the Caribou Lake area of the Primrose Range.

At Millarville, AEC has varying interests averaging 37 percent in 21,300 acres including an average 22.5 percent interest in four previously drilled deep gas discovery wells. Work is under way towards placing some of these wells on production in late 1987. Further exploratory drilling is planned for Millarville in 1987.

During 1986, 16 exploratory wells were drilled on the 238,000-acre Caribou Lake area of the Primrose Range where AEC has a 50 percent interest in the petroleum and natural gas rights. These wells have tested natural gas at rates up to 1.9 million cubic feet per day and have encountered natural gas in up to five separate reservoir zones. A further 11 wells were drilled in the Caribou Lake area in January, 1987, resulting in 8 additional gas wells. These results have led to acceleration of additional exploration activity on the adjacent 384,000-acre block in which AEC has a 100 percent interest. This additional exploration program will include geophysical acquisition and exploratory drilling.

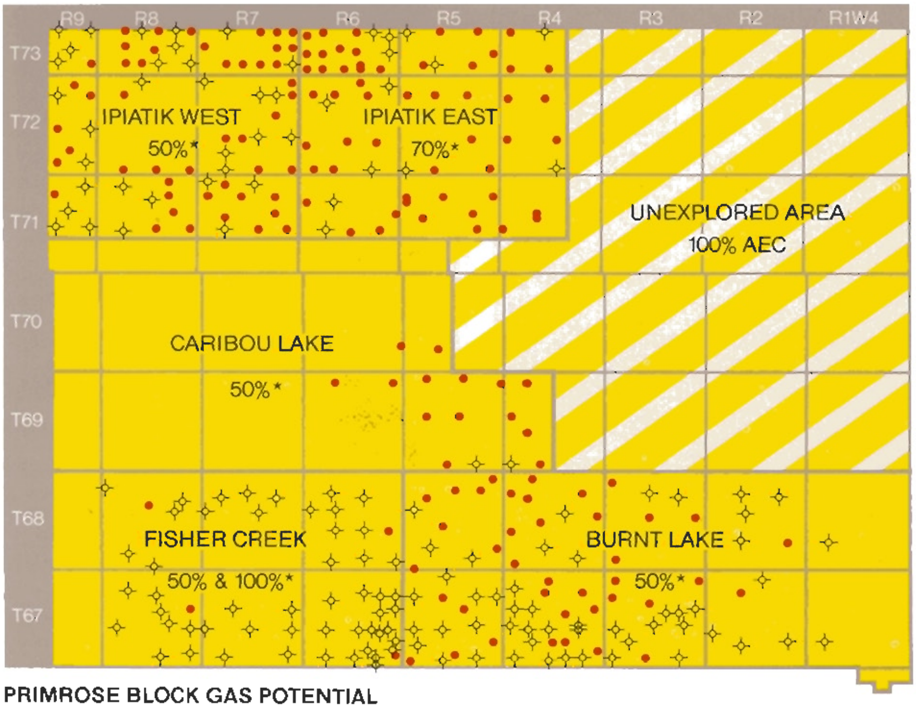


Other gas exploration activity includes a 13,800-foot Leduc test being drilled in the Berland River area of west-central Alberta. AEC holds a 45 percent interest in this prospect which is located on a 19,200-acre land block. This project is one of several high potential deep gas plays on which active exploration programs are under way.

AEC holds an average 41 percent interest in 121,000 acres in the East Peace River Arch. Two exploratory wells are drilling at the time of this report, one as a follow-up to a discovery well drilled last year in the Seal area. In addition, the Company plans to participate in up to four more exploratory tests.

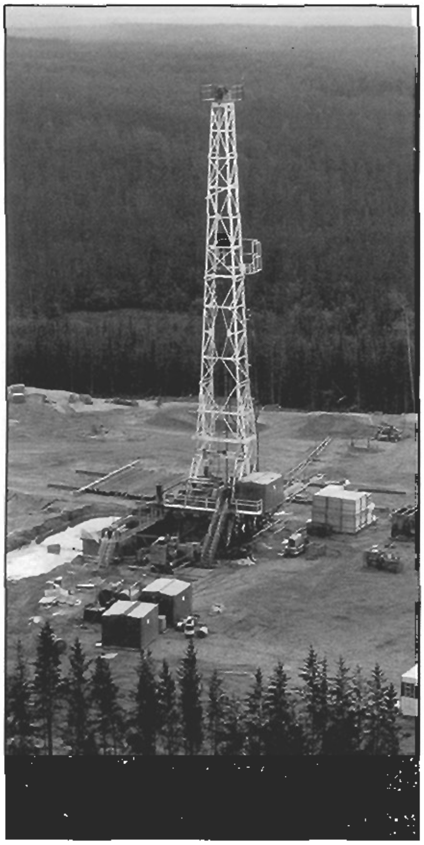
Two oil discoveries were drilled in an area three miles south of the existing South Jenner oil facilities. Both of these wells encountered more than 65 feet of oil pay, and production testing will be completed this spring. AEC has a 70 percent interest in the wells and a 100 percent working interest in nearby lands. Additional exploration work is planned in this area.

AEC responded to falling oil prices with modifications to its exploration strategy. Increased emphasis is being placed on developing higher quality prospects through application of the latest available technology. Future exploration programs must be more selective and focus upon prospects which have the potential to yield economically attractive results in a reduced-pricing environment. A greater emphasis on natural gas exploration is also an integral component of this revised strategy.



PRIMROSE BLOCK GAS POTENTIAL

OIL AND GAS



AEC is encouraged by the preliminary results of natural gas exploration in the Caribou Lake area of the Primrose Range.

Production and Development

AEC Oil and Gas Company holds interests in 2,960 producing gas wells and 265 producing oil wells, located primarily in Alberta.

Natural gas production reached 223 million cubic feet per day compared with 204 million cubic feet per day in 1985. During the year, 680 gas wells were brought on production at Suffield, completing a major development program begun in 1985. Continued operating emphasis was on cost reduction, resulting in unit production operating costs which are significantly less than the estimated industry average.

AEC Oil and Gas Company 1986 Well Statistics

Exploratory

	Operated		Non-Operated		Farmout		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Oil	3	3	4	1	6	2	13	6
Gas	1	1	14	7	7	2	22	10
Cased Awaiting Evaluation	1	1	3	1	4	1	8	3
Dry and Abandoned	11	6	26	5	24	11	61	22
Total	16	11	47	14	41	16	104	41

Development

	Operated		Non-Operated		Farmout		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Oil	21	12	9	3	3	1	33	16
Gas	50	50	1	–	–	–	51	50
Cased Awaiting Evaluation	–	–	1	–	–	–	1	–
Dry and Abandoned	3	2	2	–	–	–	5	2
Total	74	64	13	3	3	1	90	68
						Total Wells	**194**	**109**

AEC Oil and Gas Company Petroleum and Natural Gas Landholdings (Acres)

	1986		1985		1984	
	Gross	**Net**	Gross	Net	Gross	Net
Alberta						
–Suffield	**645,603**	**641,354**	645,603	641,354	642,408	640,360
–Primrose*	**1,472,320**	**1,194,176**	1,275,200	1,061,502	1,275,200	1,059,582
–Other	**1,284,327**	**487,296**	1,381,682	488,620	1,289,417	406,147
Saskatchewan	**81,519**	**50,505**	87,809	54,096	31,153	24,504
British Columbia	**443,915**	**152,937**	449,252	154,649	471,249	151,334
Beaufort	**2,760,472**	**47,771**	349,780	9,551	136,615	2,614
Total	**6,688,156**	**2,574,039**	4,189,326	2,409,772	3,846,042	2,284,541

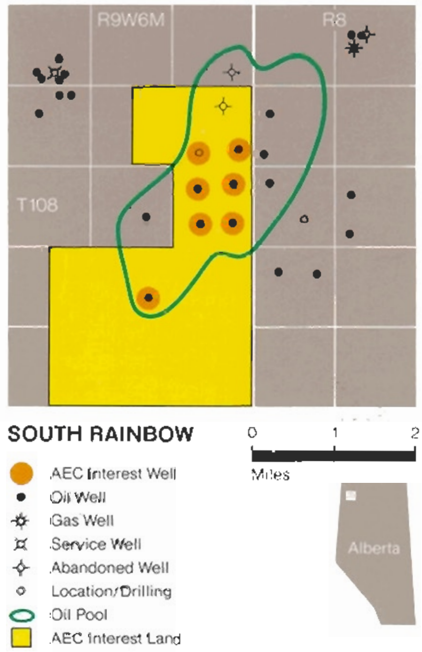
**includes in-situ heavy oil sands acreage not previously reported*

Progress continued towards bringing natural gas production from the Millarville discoveries on stream by late 1987. An application has been filed with the Energy Resources Conservation Board to construct a natural gas gathering system in the area. AEC has an average 22.5 percent interest in the four discovery wells. The production data from these wells will be used to help plan the future development of this new production area south of Calgary.

Conventional oil production increased to a record 3,190 barrels per day compared with 1,260 barrels per day in 1985. Average unit production operating costs were reduced by 11 percent.

A major expansion of oil production from the South Jenner field was completed. A total of 132 oil wells drilled in 1985 and early 1986 were brought onto production, adding an average 1,700 barrels to AEC's 1986 daily conventional oil production. AEC holds a 70 percent interest in the South Jenner oil field and serves as the project operator.

A total of 132 new oil wells were brought into production at South Jenner.



AEC has a 35 percent interest in five development wells drilled following an oil discovery on a 4,800-acre block in the Rainbow area of northwestern Alberta. Three of the wells were on production at year-end at an average gross rate of 110 barrels of oil per day per well. The other two development wells were placed on production in January, 1987, and a sixth development well will be drilled. After further production data is obtained, the potential for continued development drilling will be evaluated.

In-Situ Heavy Oil Sands

In-situ and mineable heavy oil sands constitute 90 percent of Canada's oil resource base, with conventional oil representing the remaining 10 percent. As conventional supplies continue to decline, in-situ heavy oil must play an important role if Canada's future energy needs are to be secured and increased reliance upon offshore imports is to be prevented.

Since 1978, AEC has sequentially explored 70 percent of the land on the 2,000-square-mile Primrose Range in northeastern Alberta where significant heavy oil deposits have been identified.

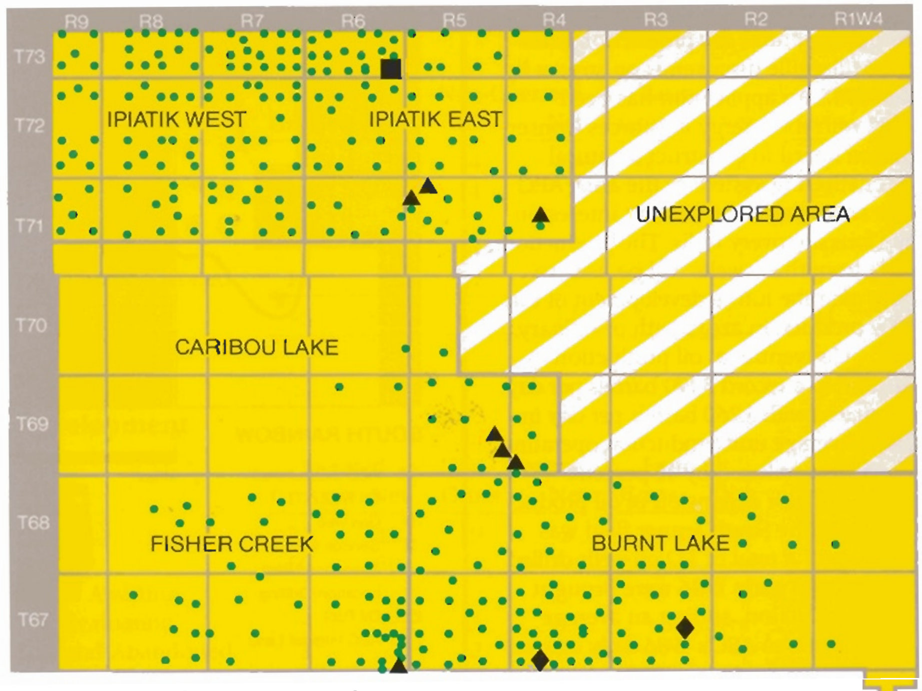
In early 1986, exploration commenced in the Caribou Lake area at Primrose. By the end of 1986, an estimated 2.3 billion barrels of heavy oil in place net to AEC were identified, bringing AEC's total Primrose heavy oil in place to 17 billion barrels. Activity during the year included the drilling of 16 exploratory wells and completion of a 210-mile seismic program. Heavy oil was encountered in all 16 wells. Following construction of an 18-mile access road, three additional wells were drilled for heavy oil evaluation and testing. "Huff and puff" steam tests currently are underway at two of these wells. The third well will be tested later in the year to facilitate design of a full-scale pilot program. On completion of the work obligations of its co-venturer, Husky Oil Operations Ltd., AEC will retain interests in the Caribou Lake heavy oil sands that range from 40 to 50 percent.

Other activity at Primrose included the continuing evaluation and delineation of the heavy oil resources in the Ipiatik area. The steam injection pilot, in which AEC has a 60 percent interest, entered its third year of testing the applicability of the "huff and puff" technology in the Wabiskaw formation. Additional programs commenced to evaluate the potential for better recovery from the deeper McMurray formation. As a follow-up to the two-well McMurray steam test program completed in early 1986, two wells are currently on production following steam injection cycles in early 1987. In addition, four delineation wells were drilled to confirm the extent and commercial potential of the McMurray oil sands in the area.

OIL AND GAS

AEC continued to test the applicability of the "huff and puff" technology at the Ipiatik steam injection pilot.
Rick Wickham, Assistant Foreman

While low oil prices delayed a construction start on two previously approved commercial projects at Primrose, AEC believes that strengthening oil prices and suitable government policy on heavy oil would place these projects on the threshold of development. AEC and the respective project participants have used the delay to re-examine plant designs and potential areas for cost savings with a view to keeping these projects ready for development when oil prices show sustained recovery to the (U.S.) $20 per barrel range and suitable government policies are established.



PRIMROSE BLOCK HEAVY OIL ACTIVITY

- Well Encountering Heavy Oil
- Single Well Test Location
- Pending Commercial Heavy Oil Project
- Heavy Oil Pilot
- AEC Interest Land

0 6 12
Miles

AEC net share of heavy oil in place = 17 billion barrels.

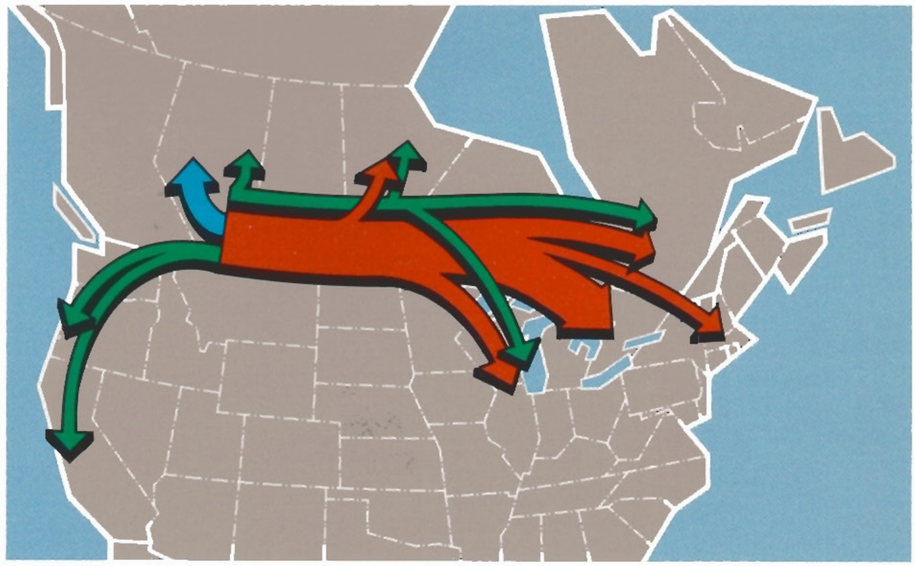
Marketing

While natural gas industry sales generally declined, AEC's sales increased by 9 percent to a record level.

The Company placed a very high priority on maintaining its strong market position as the deregulation of North American natural gas markets continued. Marketing strategies were adapted to take advantage of opportunities in this new environment through the pursuit of new direct sales and the successful renegotiation of existing long-term contracts. These revised market-responsive contracts maintained, and in some cases strengthened, the obligations of gas purchasers.

A major sales strategy was the successful maintenance of pricing levels consistent with AEC's strong portfolio of long-term contracts, rather than adoption of short-term discount prices which became increasingly prevalent within the industry.

The Company entered into its first agreement to sell natural gas directly to U.S. purchasers, a consortium of natural gas utilities in the northeastern United States. AEC Oil and Gas Company is the only direct producer participant. AEC views this market as having great potential for volume expansion and price appreciation. Should this project proceed as scheduled in 1988, following regulatory approval in both Canada and the United States, the Company's participation will be equivalent to 13 percent of its 1986 natural gas sales levels.



1986 NATURAL GAS SALES - AEC OIL AND GAS COMPANY

TransCanada PipeLines — Pan-Alberta Gas & Affiliates — Canadian Western Natural Gas

The thickness of the arrows is indicative of volumes of AEC gas marketed by each of the shippers.

A new long-term sales contract with a major U.S. heavy crude oil refiner provided a direct market for conventional heavy oil production. This arrangement involved a direct pipeline connection to the South Jenner oil field, eliminating trucking costs and thereby enhancing profit margins.

The process of deregulating natural gas prices, as expected, has proven to be very complex. At year-end, substantial progress had been made, and much more remained to be done as the federal and provincial governments continue to restructure regulatory procedures. Fundamental to the industry's viability in a deregulated environment is enhanced access to the very important U.S. natural gas market. The Alberta Energy Resources Conservation Board and Canada's National Energy Board are considering major changes to the previously unwieldy procedures for controlling natural gas exports. These and other modifications, both in Canada and the U.S., are required in order to achieve full implementation of a market-responsive natural gas price and sales environment.

OIL AND GAS

CHIEFTAIN DEVELOPMENT CO. LTD.

AEC owns 57 percent of the voting shares of Chieftain, which is engaged in Canadian and international oil and gas exploration and development. In this report, Chieftain's financial, exploration and production results, as well as landholdings, are consolidated except where specific activities of AEC Oil and Gas Company are discussed. Highlights of Chieftain's 1986 activities follow.

Chieftain participated, with a 37.5 percent interest, in a significant oil discovery and a successful follow-up drilling program in the Loon Lake area of Alberta. During the fourth quarter, Loon Lake contributed approximately 700 barrels per day to Chieftain's production. Chieftain also participated in the construction of a natural gas liquids recovery project at Wembley in Alberta's West Peace River region.

Oil and natural gas liquids production increased by 96 percent from 1985 levels to 3,060 barrels per day during 1986. Natural gas production was relatively unchanged from 1985 at 29 million cubic feet per day.

Chieftain's proven reserves were estimated by independent consultants to be 13.5 million barrels of oil and natural gas liquids and 442 billion cubic feet of natural gas. Independent consultants estimate that Chieftain holds additional probable oil and gas reserves of 2.8 million barrels and 60 billion cubic feet, respectively.

Landholdings in western Canada, the United States, the North Sea, and Australia totalled 4,823,000 gross (1,628,000 net) acres at December 31, 1986. These holdings included 1,766,000 gross (656,000 net) acres in Alberta and 457,000 gross (212,000 net) acres in the United States.

Chieftain participated, with a 37.5 percent interest, in a significant oil discovery and successful follow-up drilling program at Loon Lake.

Chieftain participated in 86 exploratory and development wells in Alberta, the United States and the North Sea during 1986. This drilling program resulted in 23 oil wells, 15 gas wells, 2 oil and gas wells, 2 cased for evaluation, and 1 service well, and 12 wells were drilling at year-end. In Alberta's East Peace River region, eight oil wells were drilled and placed on production at Loon Lake and an oil well was drilled at Panny River. In the West Peace River region, two wells encountered substantial gas pay thicknesses and were connected to production facilities at Hythe, while successful oil wells were drilled at Valhalla, Gold Creek, Gordondale and elsewhere. In the U.S., Chieftain participated in drilling six development oil wells at Ratherford, in the Four Corners area of Utah, and in two oil wells on Wyoming's Moxa Arch.

PAN-ALBERTA GAS LTD.

Pan-Alberta Gas Ltd., half owned by AEC, is one of Canada's major natural gas marketers.

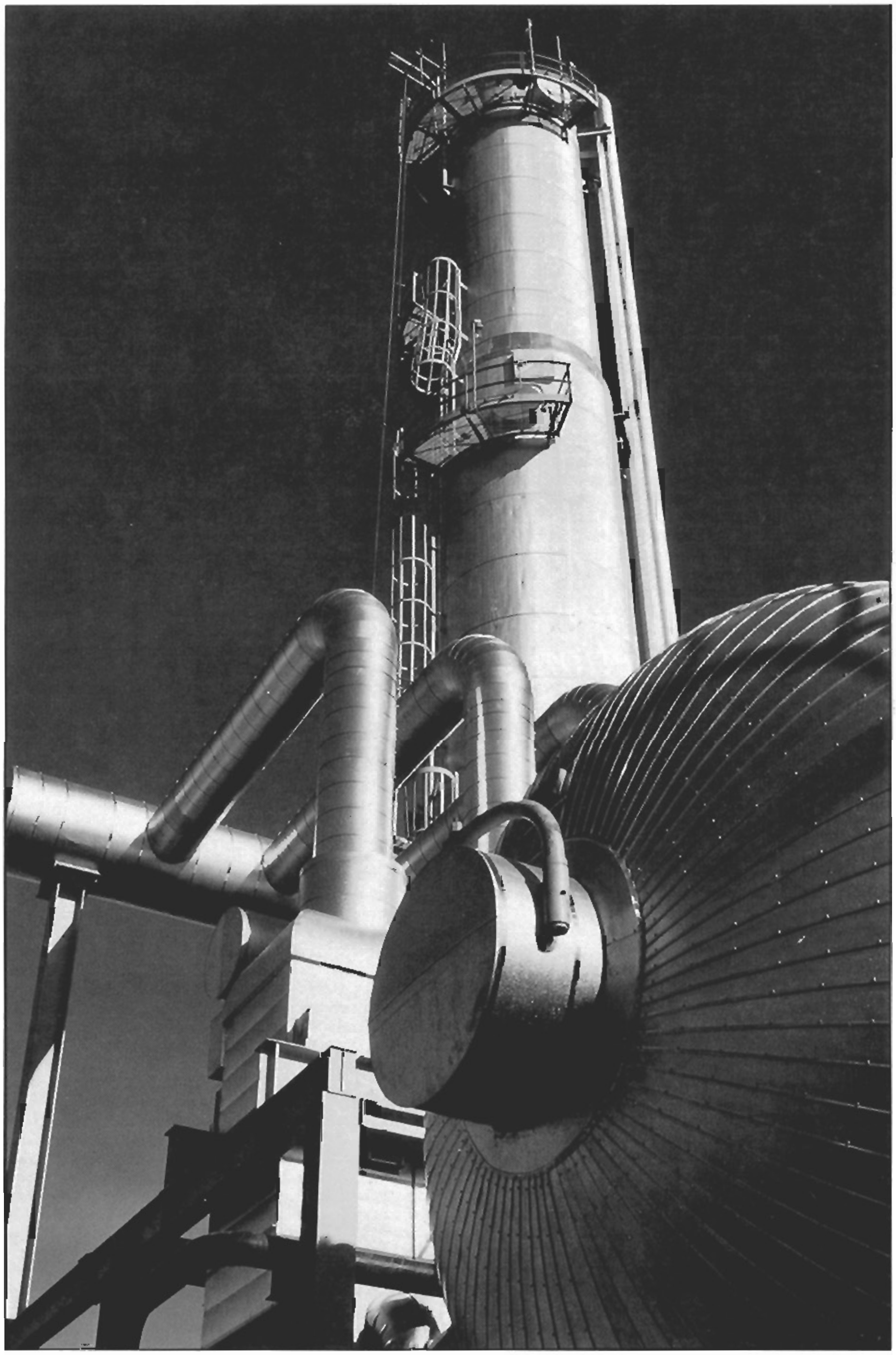
1986 was a year of significant progress and accomplishment for Pan-Alberta despite rapidly changing regulatory and market conditions in the United States. Pan-Alberta retained its position as one of the top exporters of Canadian natural gas to the U.S.; successfully renegotiated its domestic and export gas sales contracts; achieved its second consecutive year of 100 percent takes by Pacific Interstate to the California market; introduced a market-sensitive pricing arrangement with producers and resolved a contractual dispute with a major U.S. gas pipeline company.

Despite the overall drop in Canadian natural gas exports of 21 percent for the contract year ended October 31, 1986, Pan-Alberta's export volumes declined only 17 percent to 190 billion cubic feet. Domestic sales increased 32 percent to 41 billion cubic feet.

Pan-Alberta purchases natural gas from 430 producers in Alberta with its volumes representing 25 percent of Canada's exports to the U.S.

NATURAL GAS LIQUIDS EXTRACTION PLANT

AEC has a 25 percent interest in a natural gas liquids extraction plant located near Empress, Alberta. The natural gas liquids from this plant are sold on a cost-of-service basis. This investment represents a stable source of earnings for AEC.



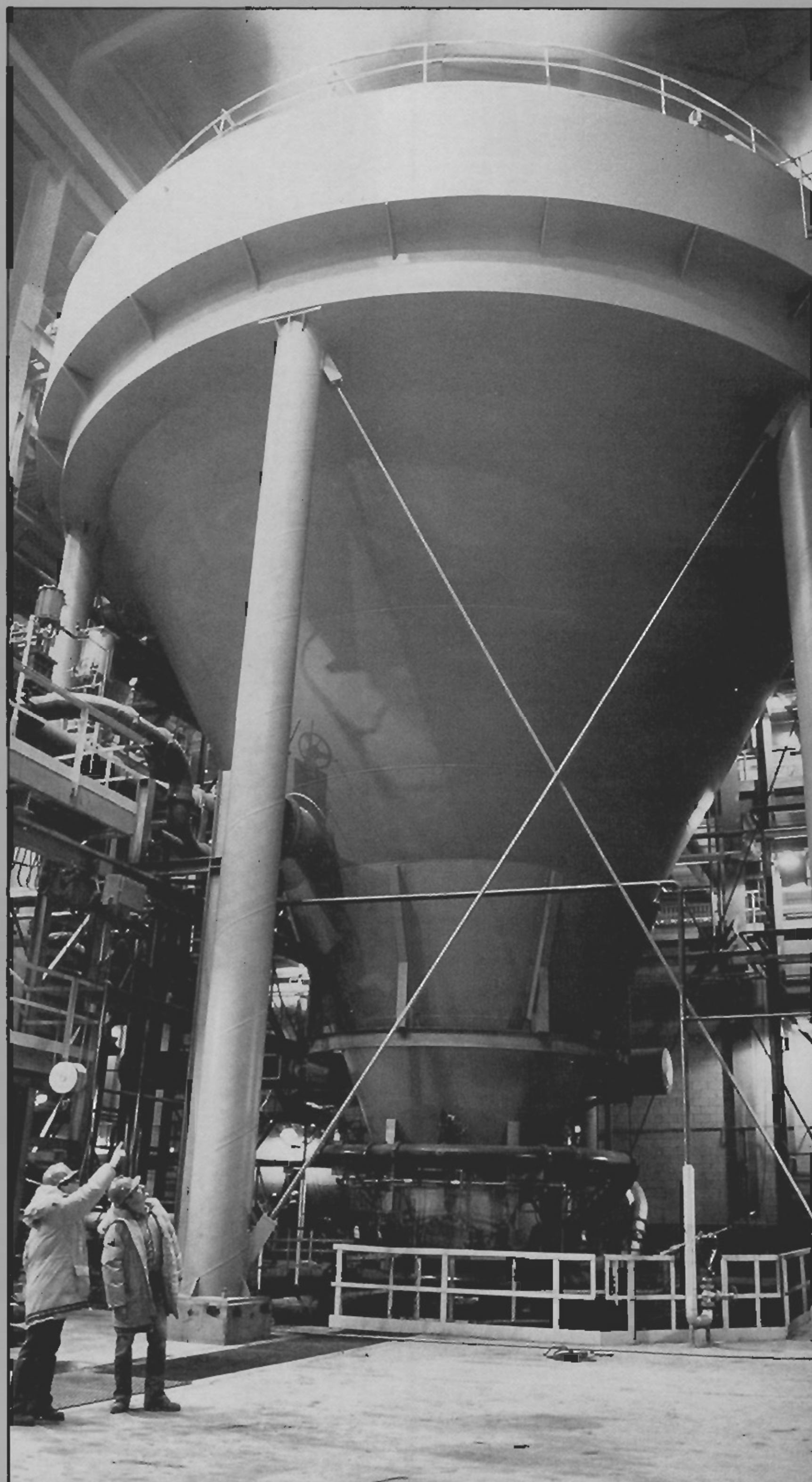
Investment in a natural gas liquids extraction plant represents a stable source of earnings for AEC.

SYNCRUDE

Record Syncrude shipments of 130,000 barrels per day

Cash operating costs below $15 per barrel

20,000 barrels per day Capacity Addition Project on schedule for 1988 completion



Four massive tailings oil recovery vessels are designed to increase bitumen recovery by about 6,000 barrels per day.
Bill Jack, Business Analyst (L)
Bob Wigelsworth,
Senior Mining Engineer (R)

The northeast region of Alberta contains vast quantities of heavy oil sands that occupy an area about the size of the Netherlands. Part of these heavy oil sands deposits are deeply buried and recoverable through in-situ processes, such as at Primrose, while the remainder are recoverable through surface mining. Located in the midst of the surface-mineable area, 320 miles north of Edmonton, is the Syncrude project, the world's largest oil sands plant. AEC holds a 10 percent joint-venture interest in Syncrude, with an average 7 percent overriding royalty on another 10 percent.

During the 1986 period of precipitous oil price decreases, Syncrude met the challenge by reducing operating costs and, at the same time, setting an annual production record.

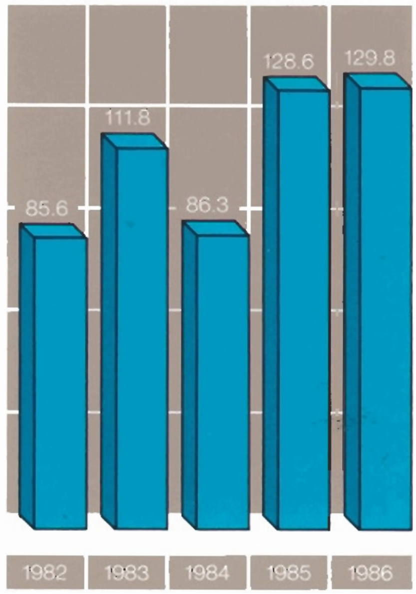
The plant achieved a record average synthetic crude oil production level of 130,000 barrels per day, 10 percent of Canada's daily crude oil consumption. Syncrude responded quickly to lower prices by initiating programs that reduced operating and capital costs, increased operating efficiency, and maximized production. A project to increase the capacity of the fluid cokers was completed in March, 1986. Each of the two fluid cokers are now capable of operating at 87,000 barrels per day of bitumen feed, equivalent to about 75,000 barrels per day of synthetic oil production.

Through these and other achievements, the 1986 cash operating cost was reduced to less than $15 (about U.S. $11.50) per barrel, lower than any previous year and a 15 percent improvement over the average 1985 operating cost.

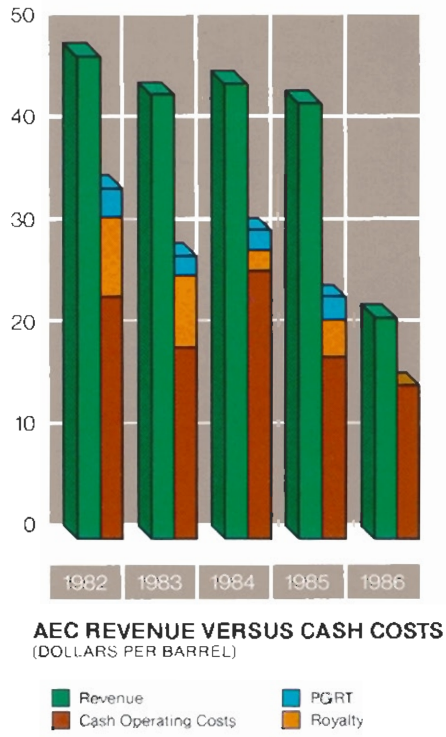
Construction of the Capacity Addition Project (CAP), a $740 million capital program designed to increase Syncrude's daily capability by 20,000 barrels to 150,000 barrels, was about 55 percent complete at year-end. The Syncrude Owners, due to lower oil prices, deferred CAP completion by one year to the end of 1988. As year-end approached, further deferral was imminent due to the prospect of continuing low oil prices. In December, the Province of Alberta offered an interest bearing loan to backstop a portion of Syncrude's net cash flow loss, should it occur as a result of CAP expenditures. The loan will be made available for the period 1987 through 1988 in exchange for a commitment by the Syncrude Owners to complete CAP by 1988. No advances have been made to Syncrude under this backstop loan arrangement. The loan will only be used in the event that large negative net cash flows occur. If any portion of the loan is used, it will be repayable with interest when Crown royalties become due. The Capacity Addition Project creates 750 direct and indirect permanent operating jobs as well as 4,650 person-years of construction employment during 1987 and 1988.

The Syncrude Owners and the Alberta government agreed to continue detailed engineering for a project to expand Syncrude capacity by about 50 percent. The government is funding the $85 million study by means of an interest-free advance to be repaid from future expansion profits. The study is to be completed in 1988 after which the Syncrude Owners will determine whether or not to proceed.

AEC's share of Syncrude's proven reserves as at year-end 1986 was approximately 120 million barrels of synthetic crude oil. At 1986 production rates, this is sufficient for 25 years of operation. AEC's share of proven but undeveloped reserves, an additional 70 million barrels, will be added to the reserve base once the Capacity Addition Project has been completed.



TOTAL SYNCRUDE SHIPMENTS
(THOUSAND BARRELS PER DAY)



AEC REVENUE VERSUS CASH COSTS
(DOLLARS PER BARREL)

AEC Power Ltd.

Alberta Energy Company Ltd. holds a two-thirds interest in AEC Power Ltd., owner of the $311 million power plant which supplies power and steam for Syncrude. Profits are earned on a contractually set cost-of-service basis.

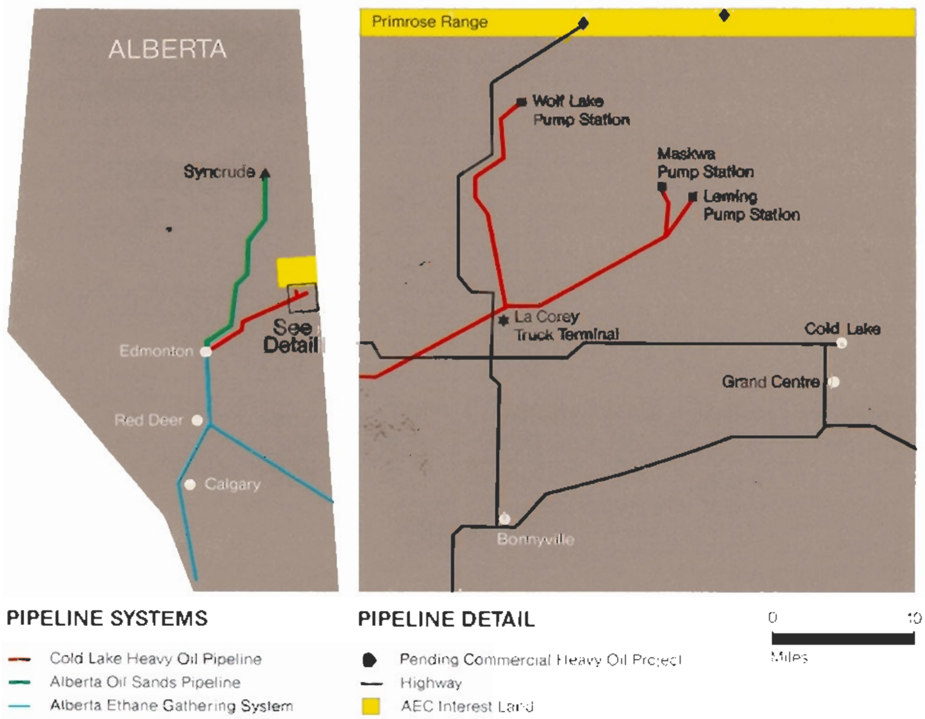
PIPELINES

Record volumes of oil transported

Pipelines now second largest source of net operating income

Capacity additions to both major pipeline systems; investment increases to $293 million

Daily field inspections on the Cold Lake Heavy Oil Pipeline system complement the remote pipeline operation.
Andre Thiem, Pipeliner



AEC PIPELINES

The establishment of AEC Pipelines as a separate operating division of Alberta Energy Company Ltd. reflects the increasing role of pipelines in AEC's diversified resource investments. The Division operates two major oil pipelines in Alberta, the Alberta Oil Sands Pipeline and the Cold Lake Heavy Oil Pipeline, and owns one-third of the Alberta Ethane Gathering System. AEC now transports more oil than any other intra-provincial carrier.

In 1986 record daily volumes of oil were transported, averaging in excess of 250,000 barrels. Expansion activities included capacity additions on both major AEC owned and operated pipeline systems and construction of truck delivery facilities for oil at La Corey on the Cold Lake Heavy Oil Pipeline.

The Division's expertise in engineering design and project management was utilized in constructing the ammonia, nitrogen and water pipelines for the new ammonia plant at Joffre, Alberta.

Alberta Oil Sands Pipeline

Alberta Oil Sands Pipeline is a 270-mile pipeline delivering the oil production from the Fort McMurray-based Syncrude plant to the Edmonton area where it is distributed to local refineries and to other pipeline systems for export from Alberta.

Record daily throughput averaged 129,000 barrels per day. AEC Pipelines invested $5 million in pump station and pipeline modifications to complete a system expansion that increased daily capacity to 187,000 barrels from 163,000 barrels.

In late 1986, the decision was made to relocate a 13-mile section of the pipeline involving an investment of $11 million. The relocation near the Syncrude plant will enhance mining operations on the Syncrude lease.

Engineering design will continue in 1987 on a $19 million system expansion that will accommodate increased output resulting from Syncrude's Capacity Addition Project (CAP) expected in late 1988.

Cold Lake Heavy Oil Pipeline

The Cold Lake Heavy Oil Pipeline system provides the transportation network required to move heavy oil blends from in-situ heavy oil projects in the Primrose/Cold Lake region to Edmonton. Daily system throughput in 1986 averaged 95,000 barrels of blended heavy oil, compared with 44,000 barrels in 1985.

Following regulatory approval in late 1986, work began on increasing capacity by almost 50 percent to 185,000 barrels per day of heavy oil blend with the addition of a pumping station at Bellis, near Smoky Lake, Alberta. This $6 million project will be completed in mid-1987.

The $4 million joint-venture La Corey Truck Terminal was commissioned in 1986. Situated near Bonnyville, Alberta, the oil terminal can serve all of the region's heavy oil producers by accepting truck deliveries of heavy oil for subsequent shipment on the Cold Lake Heavy Oil Pipeline. For many producers, the new terminal has expanded markets beyond the traditional eastern ones by giving access routes to the Edmonton area, where the oil may be utilized or moved west or south.

AEC Pipelines currently carries three-quarters of the province's in-situ heavy oil and is well situated to participate in future expansion of Primrose/Cold Lake area heavy oil production.

Alberta Ethane Gathering System

The Alberta Ethane Gathering System collects ethane from several natural gas processing plants within the province. The system, one-third owned by AEC, delivers ethane to ethylene plants near Red Deer, to storage caverns near Fort Saskatchewan and to several oil pools where it is used in enhanced recovery.

OTHER INVESTMENTS

Record Blue Ridge lumber shipments

Medium-density fibreboard plant commissioned

Canada's first medium-density fibreboard plant was offically opened on September 16, 1986. (L-R) Hector J. McFadyen, President, Blue Ridge Lumber; Hon. Donald Sparrow, Minister of Forestry, Lands & Wildlife; Martin R. McLeod, Vice-President and General Manager, Blue Ridge Lumber.

Joffre Nitrogen Fertilizer Project on schedule, within budget

During the peak construction period, 230 people were employed at the site of the Joffre anhydrous ammonia plant.

FOREST PRODUCTS

Blue Ridge Lumber (1981) Ltd. experienced significant growth in 1986, operating at record levels and commissioning Canada's first medium-density fibreboard plant at the site of the Corporation's lumber mill near Whitecourt, Alberta. Sales revenues totalled a record $37.2 million.

Operating income reached a new high due to stronger market conditions and further improvements in operating efficiencies. Record lumber shipments were 152 million board feet, exceeding the 1985 level by 8 percent.

The medium-density fibreboard plant was officially opened September 16. Start-up of the facility is proceeding with a view to reaching annual design capacity of 50 million board feet (¾-inch basis) by mid-1987. Initial market reaction to "Ranger" brand MDF has been very favourable with sales in Canada and the U.S. as well as in Europe and Southeast Asia. The MDF plant employs more than 60 permanent operational staff.

The Canadian government recently concluded negotiations with the United States whereby additional charges totalling 15 percent will be levied within Canada on shipments of Canadian softwood lumber to U.S. markets. The additional Canadian charges are to replace the preliminary U.S. import duty of 15 percent which had been placed on shipments from Canada in October, 1986, following a complaint by the U.S. industry that Canadian producers were subsidized. The ultimate nature and form of the new charge on Blue Ridge production has not yet been determined and will be the subject of discussions between the federal and Alberta governments. It is anticipated that this will not alter Blue Ridge's plans to operate at capacity in 1987.

AEC believes that the taxation imposed on the Canadian softwood lumber producer in response to the U.S. initiatives cannot be justified. A political motivation to protect the U.S. softwood lumber industry was the significant factor in the final decision. It is hoped that, in time, this matter will be further addressed and the recent decision removed.

JOFFRE NITROGEN FERTILIZER PROJECT

The Nitrogen Fertilizer Project, a joint venture of AEC and Cominco Ltd., remained on schedule and within budget during 1986.

AEC is investing $105 million in this project which includes a new 350 000 tonne per year anhydrous ammonia plant at Joffre, near Red Deer, Alberta, and other associated facilities. In return for its investment, AEC becomes a 25 percent participant in the revenues generated from the Alberta nitrogen fertilizer business of Cominco, one of Canada's largest chemical fertilizer producers.

On-site activities at Joffre employed a workforce of 230 people at the peak construction period last fall. Plant commissioning is expected in the second quarter of 1987.

The Joffre plant will utilize hydrogen and nitrogen feedstocks produced as by-products of nearby petrochemical plants, substantially reducing the capital costs relative to other fertilizer operations of comparable size. State-of-the-art technology will be employed. These factors, combined with the well established Cominco "Elephant" brand market, indicate that this will be a profitable investment even during the current downturn in the fertilizer industry.

AEC will begin to receive its share of cash flow from this venture in the second quarter of 1987.

COAL

AEC owns 25 percent of the Coal Valley mine, located 130 miles west of Edmonton, Alberta. The major market for Coal Valley is a long-term thermal coal supply contract with Ontario Hydro. This domestic market is a stable source of revenue for the mine. World thermal coal prices remained soft during 1986 due to the market pressures of oversupply combined with competition from lower fuel oil prices. However, because of the high quality of Coal Valley coal and an aggressive marketing effort, 72,000 tons of profitable offshore sales were achieved. Coal Valley continues to be a well-run, efficient mine, having made a positive contribution to AEC's earnings and cash flow in each year since its first full year of operation in 1979. AEC's share of 1986 sales amounted to 448,000 tons compared with 432,000 tons in 1985.

TECHNOLOGY DEVELOPMENT

The Technical Services group directs AEC's research and development activities and serves as internal consultants on advanced technological matters. Projects in 1986 included investments in emulsion pipeline technology, the upgrading of bitumen, direct conversion of natural gas to chemicals, methods to suppress clay migration in heavy oil steam projects and technology related to forest products fibreboard.

PORTFOLIO INVESTMENTS

British Columbia Forest Products Limited

During 1986, AEC sold its 18 percent common equity interest in British Columbia Forest Products for $118.8 million. The funds from this sale were received in cash in December, 1986. AEC recorded an extraordinary loss of $64.7 million on this investment which was made in 1981.

IPSCO Inc.

IPSCO Inc., in which AEC holds a 10 percent interest, recorded a net loss of $3.6 million for the nine months ended September 30, 1986. IPSCO, whose products are largely marketed to the oil and gas industry, was negatively impacted by the substantial cutbacks in industry activity.

AEC: ITS PEOPLE AND COMMUNITY

As a result of dedication and commitment by AEC people in all business areas, the Corporation enjoyed its best operational performance to date.

Productivity sessions and staff consultation programs contributed to unit operating cost reductions and operating efficiency improvements.

AEC operates on the philosophy that the best way to cope with changing times and challenges is by having trained, versatile, dedicated employees. The Corporation is proud of its accomplishment in having put together a strong employee team encompassing diverse skills that now constitute one of AEC's major assets. Management is committed to the continued enhancement of employee skills and providing an environment that uses the considerable talents, ideas and energy of all employees.

As part of initiatives to accomplish even more through its trained employees, AEC implemented a special program designed to handle expanding workloads with existing staff to the maximum practical extent. The Corporation also expanded its training programs to help employees meet the challenges of new technology and productivity.

AEC strives to provide a safe work environment and to encourage high individual standards, participation and innovation in its staff. Employees are expected to recognize their responsibility for their own safety and that of fellow employees.

Ron Kokotailo, Senior Accountant, coaches minor hockey at the Atom level.

AEC is also proud of its employees' service to their respective communities, through voluntary initiatives such as coaching and service on community committees or boards. During 1986, a year of particularly great need, employees made record contributions to the United Way campaigns.

The Corporation continued its support of the community through selected sponsorships and its corporate donations to worthwhile endeavours in major areas of health and welfare, community services, education, arts and culture and amateur sports. Employee donations were encouraged through a Matching Gifts program.

1986 FINANCIAL REVIEW

The Corporation significantly strengthened its financial position, reduced debt by $69 million and completed a $272 million capital program.

Results for the year were impacted by the precipitous decline in world oil prices and a reduction of gas prices as the industry made the transition to a deregulated gas market environment. Record production levels, increased operating economies and other steps, taken in response to the sharp reduction in prices, all helped to offset the drop in revenues.

During the year, a number of significant steps were taken to strengthen the Corporation's financial position. In July, $100.0 million of 10.5% fixed rate debentures were issued to replace the more uncertain floating rate debt. In December, the Rights Offering resulted in net proceeds to the Corporation of $85.8 million and these receipts, combined with the proceeds of the BCFP share disposition and the strong cash flow from operations, were more than sufficient to not only meet the requirements for capital expenditures, dividends, and the redemption of the $60.0 million 15% First Preferred Shares, but also to reduce the Corporation's long-term debt.

Cash flow from operations of $198.2 million ($3.94 per Common Share) was 78 percent of the 1985 high of $255.3 million.

Earnings before extraordinary items were $47.8 million, $0.72 per Common Share, down $32.7 million compared with the 1985 record of $80.5 million, $1.44 per Common Share. Net loss after extraordinary items in 1986 was $35.5 million, $1.12 per Common Share.

Revenues, net of royalties, decreased by $86.0 million primarily as a result of significantly lower revenues from the oil and gas segment, which were impacted by lower crude oil prices. Partially offsetting this decrease was continued growth in Pipelines, Forest Products and Coal.

Total operating expenses decreased by 3 percent to $183.5 million with the major decrease occurring in the "Other" segment due to reduced contract drilling activity of a subsidiary. Other reductions occurred as a result of a continued emphasis on cost efficiencies and helped to offset increases resulting from increased production levels. Interest expense, net of interest income and capitalized amounts, totalled $57.0 million in 1986 compared with $47.5 million in 1985. The increase is attributable to a higher average debt level in the first nine months offset by a lower interest rate in the second half. General and administrative costs of $23.6 million represent a drop of $2.8 million from 1985 as expenditures for services in support of operating and capital activities were reduced. The $17.5 million increase in depreciation, depletion and amortization charges is a reflection of the Corporation's increased capital investment and record 1986 production.

The Petroleum and Gas Revenue Tax declined by $21.7 million from 1985 due to the effect of lower revenues, a reduction in rate and its eventual elimination in the last quarter of 1986.

As discussed in Note 14 to the Consolidated Financial Statements, AEC recorded net extraordinary charges during 1986 amounting to $83.3 million, or $1.84 per Common Share. The Corporation disposed of its common shares of British Columbia Forest Products Limited and wrote down to market value its common shares of IPSCO Inc. These actions resulted in extraordinary charges against income of $64.7 million and $8.7 million respectively. The Corporation recorded a further extraordinary charge of $9.9 million, net of income taxes, comprised principally of an accelerated write-off of expenditures related to oil and gas properties located in Canadian Frontier Lands and to expenditures made in connection with certain heavy oil experimental projects.

At year-end 1986, the Corporation prospectively adopted the Canadian Institute of Chartered Accountants guideline on the Full Cost Method of accounting for oil and natural gas properties and is in compliance with those portions of the guideline relating to the ceiling tests. No write-down in asset carrying values is required.

Investment in property, plant and equipment of $271.9 million was 78 percent of 1985 expenditures of $350.5 million. A major portion of this expenditure, $75.1 million, was for the construction of the Joffre nitrogen plant and related facilities. This plant will be completed in the second quarter of 1987, within budget. Expenditures relating to conventional oil and gas amounted to $138.2 million, down from $224.2 million in 1985. These expenditures, incurred primarily in Western Canada, include $25.1 million for the further development of the Suffield Block, principally in the area of heavy oil and gas well completions. Also included is $51.0 million relating to the finalization of the acquisition of petroleum and natural gas rights on the Suffield Block. Syncrude capital expenditures amounted to $27.0 million of which $21.8 million was for the Capacity Addition Program scheduled for 1988 completion. The remaining capital relates to the continued expansion and maintenance of the other areas of the Corporation's operations.

In 1986, the Corporation paid $13.5 million in Common Share dividends, ($0.30 per Common Share), and $13.7 million in preferred share dividends.

With working capital of $31.6 million, nominal debt repayment requirements, unutilized lines of credit and the potential for improved cash flow in 1987, the Corporation's financial strength will permit the ongoing development of the Corporation's investment base.

ALBERTA ENERGY COMPANY LTD.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

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

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

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

Investments

The Corporation has adopted the equity method of accounting for investments in those companies over which significant influence is deemed to exist. For other companies the cost method is employed. Details are shown in Note 5.

Property, Plant and Equipment

Oil and Gas

Conventional

The Corporation 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. Costs accumulated within each cost centre are amortized on a composite unit-of-production method based upon estimated proven developed reserves. The Corporation does not exclude costs related to unproved properties from depletion. Interest is not capitalized with respect to such costs.

Effective December 31, 1986, the Corporation adopted, on a prospective basis, the new CICA accounting guideline relating to full cost accounting in the oil and gas industry, and no write-down was necessary.

Oil sands

Property, plant and equipment, including preproduction costs, associated with the Syncrude Project are accumulated, at cost, 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.

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

Certain 1985 figures have been reclassified and restated for comparative purposes.

ALBERTA ENERGY COMPANY LTD.

CONSOLIDATED STATEMENT OF EARNINGS

Year Ended December 31 ($ millions)	Note Reference	1986	1985
Revenues, Net of Royalties		$460.4	$546.4
Equity Earnings of Affiliates		8.9	8.7
		469.3	555.1
Costs and Expenses			
Operating		183.5	189.3
Interest—net	2(a)	57.0	47.5
General and administrative		23.6	26.4
Depreciation, depletion and amortization		114.4	96.9
		378.5	360.1
Earnings before Taxes and Minority Interest		90.8	195.0
Income taxes	3	29.7	76.2
Petroleum and gas revenue tax		11.5	33.2
Minority interest		1.8	5.1
		43.0	114.5
Earnings before Extraordinary Items		47.8	80.5
Extraordinary Items	14	(83.3)	–
Net Earnings (Loss)		$ (35.5)	$ 80.5
Earnings (Loss) per Common Share			
Before Extraordinary Items			
Basic		$ 0.72	$ 1.44
Fully Diluted		$ 0.66	$ 1.43
After Extraordinary Items			
Basic		$ (1.12)	$ 1.44
Fully Diluted		$ (1.18)	$ 1.43

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

Year Ended December 31 ($ millions)	Note Reference	1986	1985
Balance—Beginning of Year		$221.4	$266.1
Net Earnings (Loss)		(35.5)	80.5
		185.9	346.6
Dividends—Preferred Shares		13.7	13.8
—Common Shares		13.5	13.4
Financing Costs	2(d)	.6	1.7
Premium on Redemption of First Preferred Shares		3.6	–
Discount on Redemption of Preferred Shares by a Subsidiary		(.1)	–
Purchase and Cancellation of Common Shares		–	96.3
		31.3	125.2
Balance—End of Year		$154.6	$221.4

The summary of significant accounting policies and notes to the consolidated financial statements are part of these statements.

ALBERTA ENERGY COMPANY LTD.

CONSOLIDATED BALANCE SHEET

As at December 31 ($ millions)	Note Reference	1986	1985
ASSETS			
Current Assets			
Cash and short-term investments at cost which approximates market		$ 86.8	$ 59.6
Accounts receivable and accrued revenue		63.8	92.4
Inventories	4	19.3	17.5
Prepaid expenses		2.1	2.6
Current portion of notes receivable		5.0	–
		177.0	172.1
Notes Receivable		11.0	–
Investments	5	71.5	263.4
Property, Plant and Equipment	6	1,671.2	1,573.9
Other Assets and Deferred Charges	7	4.4	4.1
		$1,935.1	$2,013.5
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current Liabilities			
Bank indebtedness		$ 2.0	$ 3.1
Accounts payable and accrued liabilities		104.5	108.7
Dividends payable		2.1	4.3
Income and revenue taxes payable		.2	8.6
Deferred revenue and other		23.2	9.4
Current portion of long-term debt	9	13.4	11.8
		145.4	145.9
Deferred Revenue	8	63.7	72.4
Long-Term Debt	9	665.4	734.8
Deferred Liabilities	10	45.5	42.2
Deferred Income Taxes		369.7	341.1
Interests of Minority Shareholders	11	105.5	99.9
		1,395.2	1,436.3
Shareholders' Equity			
Share capital	12	384.0	354.3
Retained earnings		154.6	221.4
Unrealized foreign exchange gain		1.3	1.5
		539.9	577.2
		$1,935.1	$2,013.5

Approved by the Board:

D. Mitchell Director

J. E. Maybin Director

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

ALBERTA ENERGY COMPANY LTD.

CONSOLIDATED STATEMENT OF CHANGES IN FINANCIAL POSITION

Year Ended December 31 ($ millions)	Note Reference	1986	1985
Operating Activities			
Cash flow from operations	2(c)	$ 198.2	$ 255.3
Net change in non-cash working capital		30.9	7.7
Deferred revenue		(9.5)	(8.9)
Other		–	1.4
		219.6	255.5
Investing Activities			
Purchase of property, plant and equipment		(271.9)	(350.5)
Investments in affiliate and subsidiary		(6.5)	(2.9)
Proceeds on disposal of assets		8.5	3.2
Proceeds on disposal of investment		118.8	–
Repayment of advance by affiliate		2.7	8.3
Other		1.7	–
		(146.7)	(341.9)
Dividends			
Preferred share dividends		(13.7)	(13.8)
Common share dividends		(13.5)	(13.4)
Preferred dividends paid by a subsidiary to minority interests		(4.6)	(4.7)
		(31.8)	(31.9)
Net Cash Surplus (Deficiency) before Financing		41.1	(118.3)
Financing Activities			
Issue of long-term debt		146.5	261.1
Repayment of long-term debt		(213.9)	(107.3)
Issue of preferred shares		–	71.8
Issue of common shares	12(b)	89.7	3.2
Increase in deferred liability		17.9	–
Purchase of common shares		–	(125.0)
Redemption of preferred shares	12(a)	(63.6)	–
Redemption of preferred shares of a subsidiary		(1.6)	(.8)
Issue of warrants by a subsidiary to minority interests		13.0	–
Other		(.8)	(1.1)
		(12.8)	101.9
Increase (decrease) in cash and short-term investments less bank indebtedness		$ 28.3	$ (16.4)
Cash and short-term investments less bank indebtedness at year-end		$ 84.8	$ 56.5

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Segmented information

	Oil and Gas		Pipelines		Other		Total	
($ millions)	1986	1985	1986	1985	1986	1985	1986	1985
Gross revenue	$ 344.4	$ 460.9	$ 71.3	$ 59.7	$ 75.6	$ 82.7	$ 491.3	$ 603.3
Royalties	30.8	56.9	–	–	.1	–	30.9	56.9
Revenues, net of royalties	313.6	404.0	71.3	59.7	75.5	82.7	460.4	546.4
Operating expenses	113.4	114.8	13.5	11.8	57.9	62.1	184.8	188.7
Depreciation, depletion and amortization	87.9	74.6	11.5	10.0	12.2	10.3	111.6	94.9
Petroleum and gas revenue tax	11.5	33.2	–	–	–	–	11.5	33.2
	212.8	222.6	25.0	21.8	70.1	72.4	307.9	316.8
Segmented operating income	$ 100.8	$ 181.4	$ 46.3	$ 37.9	$ 5.4	$ 10.3	152.5	229.6
Equity earnings of affiliates							8.9	8.7
Corporate expenses							(25.1)	(29.0)
Interest–net							(57.0)	(47.5)
Income taxes							(29.7)	(76.2)
Minority interest							(1.8)	(5.1)
Earnings before extraordinary items							$ 47.8	$ 80.5
Identifiable assets	$1,312.2	$1,295.4	$ 246.0	$ 249.1	$ 115.0	$ 115.5	$1,673.2	$1,660.0
Corporate assets							111.8	82.5
Fertilizer project under construction							78.6	7.6
Investments							71.5	263.4
Total assets							$1,935.1	$2,013.5
Capital expenditures	$ 165.3	$ 260.3	$ 10.1	$ 41.6	$ 18.7	$ 35.2	$ 194.1	$ 337.1

2. Supplementary information

(a) Interest–net

($ millions)	1986	1985
Interest expense–on long-term debt	$ 65.2	$ 56.9
–on short-term debt	.4	.5
Interest income	(5.8)	(7.5)
Capitalized interest	(2.8)	(2.4)
	$ 57.0	$ 47.5

The Corporation capitalizes interest during the construction phase of large capital projects.

(b) Joint ventures

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

($ millions)	1986	1985
Assets	$405.7	$334.0
Liabilities	53.4	48.4
Revenues, net of royalties	125.2	202.3
Expenses	109.4	115.4

(c) Cash flow from operations

($ millions)	1986	1985
Earnings before extraordinary items	$ 47.8	$ 80.5
Depreciation, depletion and amortization	114.4	96.9
Deferred income taxes	31.0	75.2
Equity earnings of affiliates	(8.9)	(8.7)
Minority interest	1.8	5.1
Other	12.1	6.3
	$198.2	$255.3

(d) Financing costs

($ millions)	1986	1985
Warrant issue costs paid by a subsidiary, net of income tax and minority interest	$ .6	$ –
Preferred share issue costs, net of income tax	–	1.7
	$ .6	$ 1.7

3. Income taxes

The provision for income taxes is comprised as follows:

($ millions)	1986	1985
Current	$ 4.2	$ 5.0
Deferred	31.0	75.2
Alberta royalty tax credit	(5.5)	(4.0)
	$ 29.7	$ 76.2

The following table reconciles the difference between the recorded income tax expense and the expected tax expense obtained by applying the basic tax rate to income before income taxes.

($ millions)	1986	1985
Income before income taxes, equity earnings and minority interest	$ 70.4	$153.1
Expected income tax expense (Statutory Rate: 1986 - 48.8%; 1985 - 47.9%)	$ 34.3	$ 73.3
Effect on taxes resulting from:		
Non-deductibility of–		
Crown royalties and leases	14.3	17.6
Income debenture interest–net	6.0	6.1
Petroleum and gas revenue tax	5.4	15.4
Depreciation and depletion	3.5	3.7
Federal allowances–		
Resource allowance	(22.4)	(32.5)
Earned depletion	(5.9)	(4.8)
Provincial income tax rebates	(5.6)	(4.1)
Other–net	.1	1.5
Income tax expense (Effective Rate: 1986 - 42.2%; 1985 - 49.8%)	$ 29.7	$ 76.2

4. Inventories

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

($ millions)	1986	1985
Raw materials and supplies	$ 10.6	$ 10.4
Work-in-process	4.0	3.7
Finished goods	4.7	3.4
	$ 19.3	$ 17.5

5. Investments

Accounted for on the equity basis:

($ millions)	Percent Interest	1986	1985
AEC Power Ltd. (50% voting)	66⅔	$ 24.4	$ 20.7
Pan-Alberta Gas Ltd. (40% voting)	50	7.7	7.3
Pan-Alberta Resources Inc. (40% voting)	50	28.5	32.0
Steel Alberta Ltd.	50	–	19.4
		$ 60.6	$ 79.4

Accounted for on the cost basis:

($ millions)	1986		1985	
	Cost	Market	Cost	Market
British Columbia Forest Products Limited	$ –	$ –	$183.5	$103.1
IPSCO Inc.	10.4	10.4	–	–
Other	.5	.5	.5	.5
	$ 10.9	$ 10.9	$184.0	$103.6

(a) ***Steel Alberta Ltd.***

During the year, Steel Alberta Ltd. was wound up and the assets, principally an investment in the common shares of IPSCO Inc., were distributed to the shareholders.

(b) ***British Columbia Forest Products Limited ("BCFP")***

During the year, the investment in common shares of BCFP was sold for $118.8 million resulting in an extraordinary loss of $64.7 million.

(c) ***IPSCO Inc.***

The Corporation owns 1,361,813 common shares of IPSCO Inc. representing a 10.0% interest therein. During the year, the Corporation wrote down the investment to market value resulting in an extraordinary loss of $8.7 million.

6. Property, plant and equipment

($ millions)	1986 Cost	1986 Accumulated depreciation, depletion and amortization	1986 Net	1985 Net
Oil and Gas	$1,598.4	$ 357.0	$1,241.4	$1,209.4
Pipelines	293.0	54.7	238.3	241.4
Other	262.0	70.5	191.5	123.1
	$2,153.4	$ 482.2	$1,671.2	$1,573.9

7. Other assets and deferred charges

($ millions)	1986	1985
Deferred stripping costs	$ 1.7	$ 2.0
Land held for future development	.4	.7
Unamortized financing costs	1.9	.7
Other	.4	.7
	$ 4.4	$ 4.1

8. Deferred revenue

These amounts represent 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 occurs out of gas production during the first five months of each contract year (commencing November 1 each year) at rates varying between 10 percent and 20 percent per contract year until the requisite amount of gas is delivered. Accordingly, $7.5 million which is estimated to become due in 1987 is classified as a current liability.

9. Long-term debt

($ millions)	1986	1985
Alberta Energy Company Ltd. ("AEC")		
Borrowings under revolving credit and term loan agreements		
Income debentures	$180.0	$180.0
Bank loan—unsecured	–	10.0
Trust company loans—unsecured	40.0	75.0
Notes payable	145.7	258.3
Unsecured debentures	100.0	–
Mortgage payable	5.3	5.3
Other	8.1	7.7
	479.1	536.3
Alberta Oil Sands Pipeline Ltd. ("AOSPL")		
First Mortgage Sinking Fund Bonds:		
Series A—9⅝%, due June 15, 1997	17.8	19.0
Series B—9¾%, due June 15, 1997	20.2	21.6
	38.0	40.6
Chieftain Development Co. Ltd. ("Chieftain")		
Borrowings under revolving credit and term loan agreement		
Income debentures	14.3	21.4
Bank loans—Chieftain International, Inc.	114.6	111.8
Production loan—Chieftain International, Inc.	31.1	19.6
Purchase obligation	–	14.0
Other	1.7	2.9
	161.7	169.7
	678.8	746.6
Current portion of long-term debt	13.4	11.8
	$665.4	$734.8

The aggregate maturities of long-term debt in each of the five years subsequent to December 31, 1986, are as follows:

1987	$13.4
1988	14.6
1989	21.0
1990	35.4
1991	52.4

(a) *AEC revolving credit and term loan agreements*

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

($ millions)	Amount Available	Revolving Until	Repayment Period
Secured			
Income debentures	$180	–	1989-1998
Bank loans	220	1988	1989-1998
Unsecured			
Bank loan	200	1990	1990-1995
Trust company loan	50	1991	1991-2001
Trust company loan	25	1991	1991
	$675		

The bank loans are available in Canadian and/or U.S. dollar equivalents 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 loan agreements require the Corporation to maintain certain financial measurements which at December 31, 1986 have been adhered to by the Corporation.

Notes payable consist of $8.0 million (December 31, 1985-$98.7 million) in Commercial Paper and $137.7 million (December 31, 1985-$159.6 million) in Bankers' Acceptances, all maturing at various dates up to November 25, 1987 with a weighted average interest rate of 8.88% (1985-9.45%). Notes payable are shown as long-term debt because they are supported by the availability of term loans under the revolving credit facilities.

(b) *Unsecured debentures*

During the year, the Corporation issued $100.0 million in unsecured debentures bearing interest at 10.50% payable semi-annually. The debentures mature on June 30, 1996.

(c) 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 Corporation is a participant to the extent of 10%, have guaranteed the repayment of these bonds.

(d) Chieftain revolving credit and term loan agreement

Chieftain and its wholly-owned subsidiary, Chieftain International, Inc. ("CII") have a credit facility with a Canadian chartered bank in the amount of $150.0 million which facility is fully revolving until 1991, at which time the amount then outstanding is repayable over the next seven years in twenty-eight blended quarterly payments.

The bank loans are available in Canadian and/or U.S. dollar equivalents and bear interest based on the lender's prime commercial lending rates or the London interbank offered rate, plus a factor varying over the term of the loans up to 1%. Interest on the income debentures, at the approximate rate of one half of the prime rate plus ⅜%, is not deductible for income tax purposes.

The income debentures, originally issued in 1979, form part of this credit facility and are limited to the amount currently outstanding, subject to the original terms and conditions of issue. The required repayments of $7.1 million annually do not reduce the total credit available under this loan agreement.

Security for this loan agreement consists of a first floating charge debenture over all Canadian assets of Chieftain and CII, assignment of interests in oil and gas properties and related sales contracts, and accounts receivable. The loan agreement requires Chieftain to maintain certain financial measurements which at December 31, 1986 have been adhered to by Chieftain.

(e) Chieftain production loan

The CII production loan is a U.S. $24.0 million facility secured by assignment of certain U.S. oil and gas properties. Interest is payable based on the lender's prime commercial U.S. lending rate or the London interbank offered rate, plus a factor of ½% or 1% respectively. Repayment is required over an eight-year period beginning December 31, 1986.

10. Deferred liabilities

(a) Suffield

The Corporation acquired the rights to the Suffield Block for $105.0 million. Of this amount, $55.6 million has been paid and the balance is payable in installments of $15.4 million in 1987 and $17.0 million in each of 1988 and 1989.

(b) Primrose

The Corporation acquired rights to the Primrose Range for $57.6 million in cash and work obligations, the latter of which have been met. Of the remaining $11.8 million in cash obligations, $0.3 million is included in current liabilities with the balance of $11.5 million payable when leases to the remaining portions of the Range are issued.

11. Interests of minority shareholders

($ millions)	1986	1985
Chieftain Development Co. Ltd.		
Preferred equity	$ 52.1	$ 53.8
Warrants	14.8	–
Common equity	38.6	46.1
	$105.5	$ 99.9

12. Share capital

($ millions)	1986	1985
First Preferred Shares:		
Authorized–20,000,000 shares		
Issued–None (1985–2,400,000 shares with a paid up amount of $25 each)	$ –	$ 60.0
Second Preferred Shares:		
Authorized–20,000,000 shares		
Issued–412,512 11¼% Deferred Convertible, Series 1 with a paid up amount of $25 each	10.3	10.3
–3,000,000 7.75% Deferred Convertible Redeemable, Series 2 with a paid up amount of $25 each	75.0	75.0
Third Preferred Shares:		
Authorized–20,000,000 shares		
Issued–None	–	–
Common Shares:		
Authorized–300,000,000 shares		
Issued–52,757,339 shares (1985–44,876,570)	298.7	209.0
Non-Voting Shares:		
Authorized–5,000,000 shares		
Issued–None	–	–
	$384.0	$354.3

(a) Preferred Shares

(i) First Preferred Shares–Series A

On December 1, 1986, the Corporation redeemed all 2,400,000 shares outstanding at a price of $26.50 per share.

(ii) Second Preferred Shares–Series 1

Series 1 Preferred Shares are cumulative and are retractable at the option of the holder on August 1, 1989 at a price of $26.50. Subject to certain conditions, the shares are redeemable at the option of the Corporation at $26.50 until August 1, 1989 and thereafter at $25.00.

The holders of Series 1 Preferred Shares have the option, until July 1, 1989, to convert each Series 1 Preferred Share into 2.06 AEC Common Shares, by tendering to the Corporation the sum of $12.30 with each Series 1 Preferred Share to be converted.

(iii) Second Preferred Shares—Series 2

Series 2 Preferred Shares are cumulative and, subject to certain conditions, are redeemable at the option of the Corporation at predetermined prices varying from $26.50 to $25.00 commencing on May 16, 1988.

Each Series 2 Preferred Share is convertible during the period May 16, 1987 to May 16, 1995, at the option of the holder into 1.28 AEC Common Shares, upon payment by the holder to the Corporation of a cash amount equal to the difference between $25.00 and the aggregate conversion price of 1.28 Common Shares. The conversion price per Common Share will be equal to 90% of the weighted average price of the Common Shares on the Toronto Stock Exchange for the twenty trading days ending May 16, 1987, subject to a minimum conversion price of $19.58 per Common Share.

(b) Common Shares

	1986		1985	
	Number of Shares	**Share Capital**	Number of Shares	Share Capital
Issued and outstanding—Beginning of year	**44,876,570**	**$209.0**	50,933,122	$234.5
Purchased for cancellation	**–**	**–**	(6,237,500)	(28.7)
Conversion of Second Preferred Shares, Series 1	**–**	**–**	6	–
Issued under Rights Offering	**7,532,797**	**85.8**	–	–
Issued for cash under Shareholder Investment Plan	**330,472**	**3.7**	158,022	3.0
Issued for cash under Employee Share Option Plan	**17,500**	**.2**	22,920	.2
Issued and outstanding—End of year	**52,757,339**	**$298.7**	44,876,570	$209.0

Pursuant to a Rights Offering, the Corporation issued 7,532,797 Common Shares at $11.50 per share for net proceeds of $85.8 million, after providing for the costs of issue.

(c) Employee Share Option Plan

The Employee Share Option Plan provides for granting to employees of the Corporation and its subsidiaries options to purchase Common Shares of the Corporation. 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, 1986, options, exercisable between 1987 and 1993, were outstanding to purchase 812,080 Common Shares at minimum prices ranging from $9.79 to $17.67 per share.

(d) Common Shares Reserved

At December 31, 1986, Common Shares were reserved for issuance as follows:

Conversion of Second Preferred Shares	4,689,775
Shareholder Investment Plan	403,389
Employee Share Option Plan	1,221,580
Share Purchase Plan (presently inactive)	100,108
	6,414,852

(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 Corporation. In addition, the maximum ownership of any one shareholder, excluding the Government of Alberta, is limited to 1% of the total number of issued and outstanding voting shares of each class of the Corporation.

13. Related Party Transactions

During the year, the Corporation sold approximately $25.4 million (1985 - $39.8 million) of natural gas to affiliates of which $2.2 million (1985 -$3.8 million) is included in accounts receivable at the year end.

14. Extraordinary Items

Extraordinary losses of $83.3 million, net of $4.1 million in income tax, reflect principally the loss on sale of British Columbia Forest Products Limited shares, a write-down of the investment in IPSCO Inc. shares to market value and the write-down of certain experimental oil and gas projects.

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, 1986 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 corporation as at December 31, 1986 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 applied on a basis consistent with that of the preceding year.

Price Waterhouse

Chartered Accountants
Edmonton, Alberta
February 4, 1987

HISTORICAL REVIEW

(all dollar amounts, except per share amounts, are in millions)	1986	1985	1984	1983	1982
Financial					
Revenue (net of royalties)	**$ 460.4**	$ 546.4	$ 484.2	$ 462.1	$ 374.1
Earnings before extraordinary items	**47.8**	80.5	72.3	62.4	33.6
Net earnings (loss) after extraordinary items	**(35.5)**	80.5	72.3	62.4	54.6
Cash flow from operations	**198.2**	255.3	222.6	211.9	131.0
Petroleum and Gas Revenue Tax	**11.5**	33.2	32.5	29.5	29.5
Oil and gas royalties paid	**30.8**	56.9	44.8	66.3	62.0
Working capital	**31.6**	26.2	49.9	51.8	62.5
Investment in property, plant and equipment	**1,671.2**	1,573.9	1,323.7	1,155.3	1,108.2
Long-term debt	**665.4**	734.8	577.4	506.3	564.0
Total assets	**1,935.1**	2,013.5	1,764.9	1,613.3	1,538.9
Per Share Data*					
Basic earnings before extraordinary items	**$ 0.72**	$ 1.44	$ 1.22	$ 1.03	$ 0.57
Basic net earnings (loss) after extraordinary items	**(1.12)**	1.44	1.22	1.03	1.03
Cash flow	**3.94**	5.11	4.08	3.87	2.67
Shareholders' equity	**8.62**	9.62	9.84	8.83	8.05
Common dividend	**0.30**	0.30	0.25	0.20	0.20
Shares*					
Number of shareholders**	**51,125**	52,974	52,460	55,939	58,816
Common shares outstanding	**52,757,339**	44,876,570	50,933,122	50,813,255	50,800,755
Volume of shares traded	**15,327,109**	8,542,225	7,787,853	9,313,891	6,330,743
Share price range					
–High	**$ 17.38**	$ 22.13	$ 23.25	$ 21.25	$ 20.25
–Low	**9.75**	16.13	17.63	13.63	8.00
–Close	**14.88**	17.38	19.88	18.25	15.00
Operating Data					
Gas production –billion cubic feet	**92.1**	85.6	82.1	81.7	71.5
Synthetic crude oil production (net) –million barrels	**4.7**	4.7	3.2	4.1	3.1
Conventional oil production –million barrels	**2.3**	1.0	0.6	0.4	0.1
Utility plant output –thousand megawatt-hours	**1,113**	928	757	903	869
Coal production (net) –thousand tons	**433**	469	579	568	741
Lumber production, Whitecourt complex –million board feet	**152**	140	130	121	90
Pipeline throughput –million barrels	**118.8**	97.8	74.7	77.0	62.4

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

* *Reflects three-for-one stock split*

** *Includes preferred shareholders from 1982-1986*

1981	1980	1979	1978	1977
$ 285.1	$ 232.6	$ 90.9	$ 54.8	$ 20.3
42.4	57.4	27.4	18.8	14.9
29.7	57.4	27.4	18.8	14.9
90.6	115.6	60.8	32.5	17.1
15.6	–	–	–	–
55.1	43.1	18.3	13.6	7.6
1.5	10.1	44.3	141.0	15.5
694.0	593.0	531.9	290.8	206.6
518.1	251.8	309.6	209.2	44.6
1,036.9	702.7	651.0	504.1	273.3
$ 0.93	$ 1.26	$ 0.60	$ 0.41	$ 0.33
0.65	1.26	0.60	0.41	0.33
1.99	2.54	1.34	0.72	0.38
6.37	5.90	4.80	4.27	3.85
0.20	0.15	0.10	–	–
52,841	54,252	51,725	53,292	54,169
45,491,255	45,460,505	45,446,505	45,335,553	45,272,928
4,788,371	9,706,332	8,530,752	5,543,070	5,386,023
$ 27.75	$ 24.38	$ 14.42	$ 6.58	$ 6.42
14.00	12.50	6.21	4.88	3.92
16.00	23.88	13.50	6.29	5.88
58.5	46.5	38.3	27.0	17.8
3.0	3.0	0.7	–	–
0.1	0.1	0.1	0.1	0.1
793	809	788	300	–
754	662	538	173	–
113	115	100	94	63
59.1	57.3	39.6	11.7	–

AT YEAR-END 1986

Net petroleum and natural gas rights .... 4.2 million acres

Natural gas reserves

	Proven	Probable	Total
Billion cubic feet	1,622	183	1,805

‡Proven natural gas reserve life .... 18 years

Oil and natural gas liquids reserves

	Proven	Probable	Total
Million barrels	20.0	7.7	27.7

‡Proven oil and natural gas liquids reserve life .... 9 years

Proven synthetic oil reserves .... 120 million barrels

‡Synthetic oil reserve life .... 25 years

Primrose heavy oil in place net to AEC .... 17 billion barrels

Timber lands .... 1.3 million acres

Coal reserves .... 6.8 million clean tons

‡Coal reserve life .... 15 years

Pipelines (in three pipelines) .... 1,300 miles

‡ At 1986 production rates

DIRECTORS AND OFFICERS

Board of Directors

MATHEW M. BALDWIN
Corporate Director
Edmonton, Alberta

C. MERV LEITCH, Q.C.
Partner
Macleod Dixon
Barristers & Solicitors
Calgary, Alberta

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

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

JOHN E. MAYBIN
President
Colmac Energy Inc.
Calgary, Alberta

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

DAVID E. MITCHELL, O.C.
President
Alberta Energy Company Ltd.
Calgary, Alberta

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

GORDON H. SISSONS
Chairman of the Board
I-XL Industries Ltd.
Medicine Hat, Alberta

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

Corporate Officers and Senior Personnel

DAVID E. MITCHELL, O.C.
President & Chief Executive Officer

JACK G. ARMSTRONG
Senior Vice-President, Finance

GWYN MORGAN
Senior Vice-President

FRANK W. PROTO
Senior Vice-President

ROGER D. DUNN
Vice-President

EDWARD J. MARTIN
Vice-President & Comptroller

HECTOR J. McFADYEN
Vice-President

JOHN D. WATSON
Treasurer

ARLENE J. MOORE
Corporate Secretary

SYDNEY R. CHEN-SEE
Assistant Corporate Secretary

DEREK S. BWINT
Director, Financial Evaluations

LAWRENCE J. HICKEY
Assistant Comptroller

WAYNE G. HOLT
General Counsel

ROBERT A. TOWLER
Director, Petrochemicals

KEITH O. FOWLER
Director,
Tax & Treasury Operations

RICHARD H. WILSON
Director, Public Affairs

Principal Officers of Divisions

AEC Oil and Gas Company

GWYN MORGAN
President

ROGER D. DUNN
Senior Vice-President

RONALD A. McINTOSH
Senior Vice-President

DENNIS W. CORNELSON
Vice-President, Marketing

AEC Pipelines

FRANK W. PROTO
President

JACK G. ARMSTRONG
Senior Vice-President, Finance

BERNIE J. BRADLEY
Vice-President

CORPORATE INFORMATION

Offices

#1200, 10707 - 100 Avenue
Edmonton, Alberta T5J 3M1
(Registered Office)

#2400, 639 - 5 Avenue S. W.
Calgary, Alberta T2P 0M9
(Executive Office)

Transfer Agent and Registrar—(Common Shares)

National Trust Company
Calgary, Edmonton, Montreal, Toronto, Winnipeg, Regina, Vancouver, and its agent, Canada Trust in Halifax

Transfer Agent and Registrar—(Second Preferred Shares, Series 1 and 2)

The Royal Trust Company
Calgary, Edmonton, Montreal, Regina, Toronto, Winnipeg, Vancouver, Halifax

Auditors

Price Waterhouse
Chartered Accountants
Edmonton, Alberta

Stock Exchange Listings

The Alberta Stock Exchange
The Montreal Exchange
The Toronto Stock Exchange
Vancouver Stock Exchange

In newspaper listings, AEC's various share issues are shown as follows:

Alt Energy	Common
Al Enr 1125	Second Preferred, Series 1
Al Enr 775	Second Preferred, Series 2

Subsidiaries

Alberta Oil Sands Pipeline 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. (50% voting)	66⅔%
Pan-Alberta Gas Ltd. (40% voting)	50%
Pan-Alberta Resources Inc. (40% voting)	50%

Major Joint Ventures

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

Duplicate Annual Reports

Receipt of duplicate shareholder material results from a shareholder having shares of the same class or series registered in different names or addresses. You can avoid receiving duplicate shareholder reports and help the Corporation save money by contacting your Transfer Agent (See Transfer Agent and Registrar) to have your holdings registered under one name and address.

Annual Meeting

The Annual Meeting of Shareholders of Alberta Energy Company Ltd. will be held in the Alberta Room, Palliser Hotel, 133 - 9 Avenue S.W., Calgary, Alberta at 3:00 p.m. local time on Wednesday, April 8, 1987.

Copies of the Corporation's 1986 annual report may be obtained by contacting the office of the Corporate Secretary at Alberta Energy Company Ltd., #2400, 639 - 5 Avenue S. W., Calgary, Alberta T2P 0M9.

Shareholder Investment Plan

Eligible registered shareholders wishing to acquire or increase their holdings of Common Shares of Alberta Energy Company Ltd. can take advantage of the Shareholder Investment Plan which offers two options:

Dividend Reinvestment Plan (DRP) provides a convenient method for shareholders to reinvest their cash dividends in new Common Shares of AEC at 95 percent of Average Market Price.

Optional Share Purchase Plan (OSP) allows a shareholder to purchase new Common Shares at Average Market Price up to an aggregate of $5,000 per calendar quarter (minimum $50 per remittance).

No commission, service charges or brokerage fees are payable by shareholders to acquire shares via DRP or OSP as all administrative costs are borne by AEC.

Eligible registered holders are registered holders of Common Shares; 11.25% Deferred Convertible Second Preferred Shares, Series 1; and 7.75% Deferred Convertible Redeemable Second Preferred Shares, Series 2; resident in Canada or Canadian citizens resident in any country except the United States.

Detailed information and copies of the Shareholder Investment Plan can be obtained from:

National Trust Company
Corporate Trust Services
Suite 1008, 324 - 8 Avenue S. W.
Calgary, Alberta
T2P 3B2

Telephone (403) 263-1460

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