C

Alberta Energy Company Ltd. 1999 Annual Report

HIGH IMPACT GROWTH

GROWTH, VALUE, PERFORMANCE. THESE WORDS REPRESENT THE ESSENCE OF A BUSINESS STRATEGY WHICH CREATES SUSTAINABLE GROWTH AND BUILDS UNDERLYING VALUE. WE HAVE CONSISTENTLY DEMONSTRATED THAT THIS BUSINESS STRATEGY DELIVERS PERFORMANCE FOR SHAREHOLDERS.

CORPORATE PROFILE

HIGH-IMPACT GROWTH HAS CREATED ONE OF THE LARGEST UPSTREAM INDEPENDENT OIL AND GAS COMPANIES. AEC RANKS FIRST IN NATURAL GAS SALES IN CANADA AND SIXTH LARGEST IN NORTH AMERICA. AEC IS ALSO A MAJOR GAS STORAGE DEVELOPER AND A PIPELINER OF CONVENTIONAL, SYNTHETIC AND HEAVY OIL IN NORTH AMERICA. AEC'S VISION IS TO BUILD A "GLOBAL SUPER-INDEPENDENT", WITH GROWING INTERNATIONAL INVESTMENTS INCLUDING ECUADOR, ARGENTINA, AUSTRALIA, AND THE CASPIAN SEA. AEC'S DISCIPLINED ADHERENCE TO ITS "GROWTH, VALUE, PERFORMANCE" BUSINESS STRATEGY HAS RESULTED IN A COMPANY WITH AN ENTERPRISE VALUE OF APPROXIMATELY C$8.5 BILLION.

AEC'S SHARES TRADE ON THE TORONTO STOCK EXCHANGE (AEC) AND ON THE NEW YORK STOCK EXCHANGE (AOG).

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ADVISORY

In the interest of providing AEC shareholders and potential investors with information regarding the Company, including management's assessment of the Company's future plans and operations, certain statements and graphs throughout this Report are 'forward-looking statements', within the meaning of Section 21E of the United States Securities Exchange Act of 1934, as amended, and represent the Company's internal projections, expectations or beliefs concerning, among other things, future operating results and various components thereof or the Company's future economic performance. The projections, estimates and beliefs contained in such forward-looking statements necessarily involve known and unknown risks and uncertainties which may cause the Company's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things: volatility of oil and gas prices; product supply and demand; market competition; risks inherent in the Company's domestic and foreign oil and gas operations; imprecision of reserves estimates; the Company's ability to replace and expand oil and gas reserves; the Company's ability to generate sufficient cash flow from operations to meet its current and future obligations; the Company's ability to access external sources of debt and equity capital, and such other risks and uncertainties described from time to time in the Company's reports and filings with the Canadian securities authorities and the U.S. Securities and Exchange Commission. Accordingly, shareholders and potential investors are cautioned that events or circumstances could cause actual results to differ materially from those predicted.

GROWTH

VALUE

PERFORMANCE

CASH FLOW PER SHARE ↑ 65%

EARNINGS PER SHARE ↑ 500%

SUSTAINABLE GROWTH

Highlights

Five years ago, in 1996, AEC set new high-growth, high-performance targets which included increasing natural gas sales to one billion cubic feet per day and increasing liquids production to 100,000 barrels per day by 2000. The Company expects to exceed these targets in 2000, achieving a 21% five-year average compound growth rate.

What Distinguishes AEC

- **Growth, Value, Performance business strategy**
- **Five-year sustainable internal growth from existing asset base**
- **Canada's largest high growth natural gas producer and the largest Canadian gas storage operator**
- **High-impact domestic and international liquids growth from conventional production, Syncrude and the innovative Steam-Assisted Gravity Drainage process (SAGD)**
- **Dominant, high working interest land and production facilities**
- **High-quality, long-life reserves**
- **Focused, successful exploration program providing broad exposure to a variety of exploration prospects across the Western Sedimentary Basin of North America and selected basins elsewhere in the world**
- **Midstream strength which provides growing cash flow and enhances value for AEC's upstream business**

Financial Highlights	1999	1998	1997	1996	1995	5-Year Compound Growth Rate
Cash Flow from Operations ($ million)	946.9	488.5	544.7	411.9	270.7	37%
$/share fully diluted	6.68	4.06	4.67	3.82	3.51	17%
Net Earnings from Continuing Operations						
($ million, excluding 1997 dilution gain)	179.7	24.4	21.7	68.0	56.3	34%
$/share fully diluted	1.26	0.21	0.23	0.65	0.72	15%
Net Capital Investment						
(including acquisitions, $ million)	2,042.8	1,671.5	893.0	1,977.4	282.7	
Year-end Long-term Debt ($ million)						
Upstream Business Group	1,627.7	1,355.4	519.4	367.0	153.5	
Midstream Business Group	688.4	622.0	497.7	601.3	230.9	
Debt-to-Capitalization Ratio – Consolidated	34:66	41:59	29:71	32:68	24:76	
Upstream Business Group	29:71	36:64	20:80	16:84	13:87	
Midstream Business Group	60:40	60:40	60:40	89:11	64:36	
Debt-to-Cash Flow Ratio – Upstream (times)	1.7	3.1	1.1	1.0	0.8	

Operating Highlights	1999	1998	1997	1996	1995	5-Year Compound Growth Rate
Produced Natural Gas Sales						
(million cubic feet/day)	904	714	575	515	320	30%
Total Liquids Sales (barrels/day)	95,838	60,074	58,940	53,155	42,153	23%
Domestic	68,491	57,857	57,257	51,914	41,063	14%
International	27,347	2,217	1,683	1,241	1,090	123%
Conventional Reserve Additions						
(million barrels of oil equivalent; 6:1)	382	306	159	293	36	
Conventional Production Replacement (%; 6:1)	484	562	341	718	145	

GROWTH

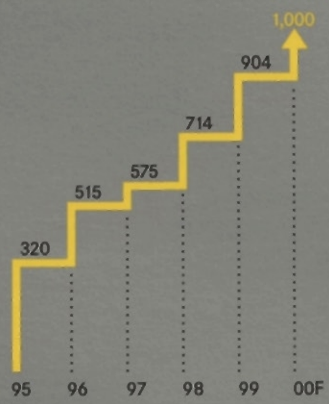
VALUE

PERFORMANCE

Highlights

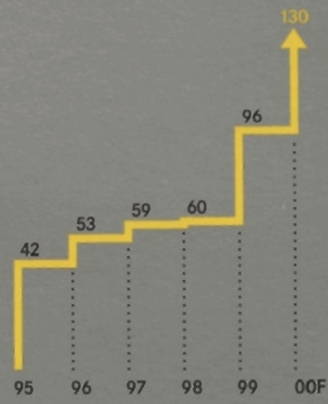
AEC has delivered sustainable growth to its shareholders, having nearly tripled both its production and reserves over the last 5 years.

Produced Natural Gas Sales
(million cubic feet/day)



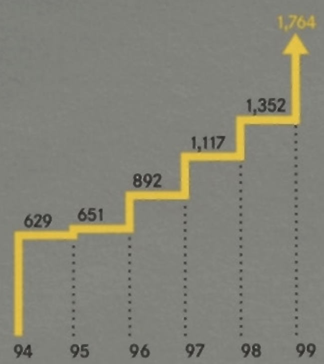
30% 5-year compound growth rate

Total Liquids Sales
(thousand barrels/day)



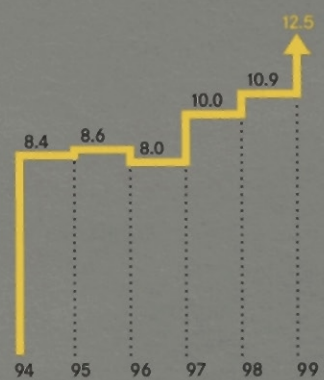
60% growth in 1999

Reserve Base - Total
(million barrels of oil equivalent; 6:1, includes Syncrude proven only)



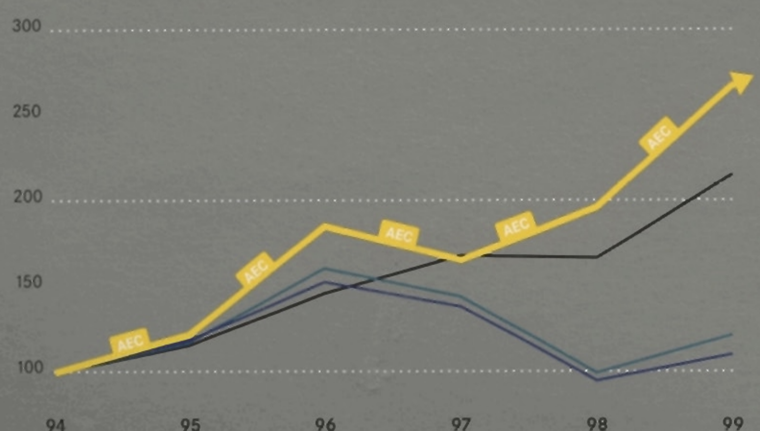
30% growth in total reserves in 1999

Total Reserves per Share
(barrel of oil equivalent, 6:1, includes Syncrude proven only)



One of the largest reserve bases, per share, among North American independent oil and gas producers

AEC Share Price Performance vs. Indices
Relative Performance (%) December 31, 1994 to December 31, 1999

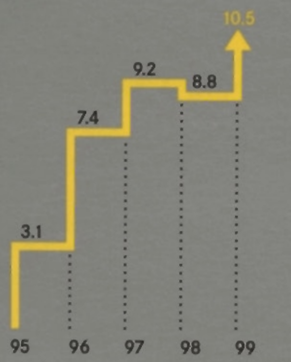


1999 (TSE)
High $48.90 (Aug. 23/99)
Low $30.75 (Mar. 3/99)
Close $45.00 (Dec. 31/99)

— TSE 300
— TSE Oil & Gas Producers Index
— S&P Oil & Gas Index (E&P)

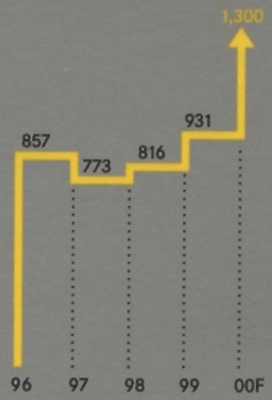
AEC provided a total return to shareholders, including dividends, of 38% in 1999

Exploration Land Base - Global
(million net undeveloped acres)



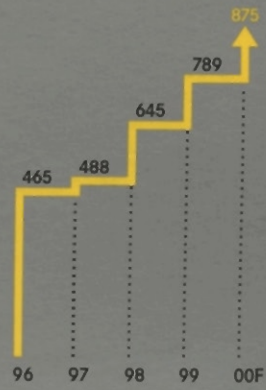
18% growth in exploration land base in 1999

Capital Investment
($ million, net direct core programs, excluding major acquisitions)



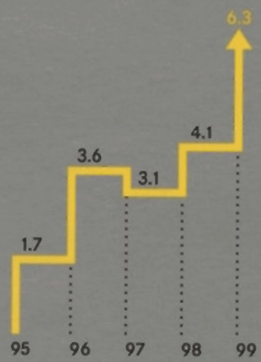
25% of core capital directed at International operations in 2000

Drilling - Total Wells
(gross)



75% of wells are gas targets in 2000

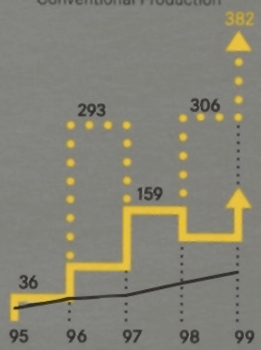
Market Capitalization
($ billion at December 31, 1999)



The largest market capitalization among Canadian independent oil and gas producers

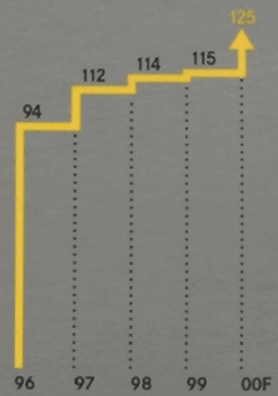
Total Conventional Reserve Additions
(million barrels of oil equivalent, 6:1)

Via Acquisition
Via Exploration
Conventional Production



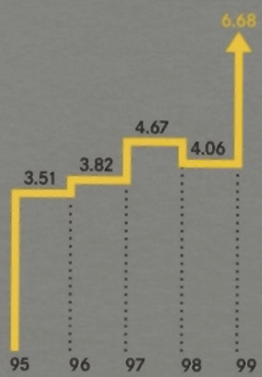
1999 conventional production replacement of 484%

Midstream Operating Cash Flow
($ million)



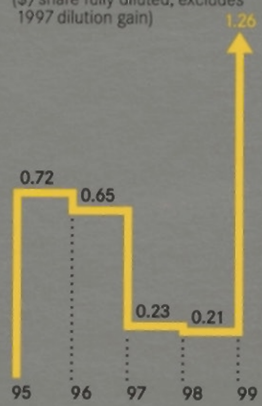
Solid cash flow plus upstream synergies

Cash Flow from Operations
($/share fully diluted)



17% compound growth per share

Net Earnings from Continuing Operations
($/share fully diluted, excludes 1997 dilution gain)



Entering a new era of earnings potential

AEC

FELLOW SHAREHOLDERS

A Track Record of Superior Performance

AEC achieved outstanding operating and financial results for 1999. Even more importantly, our capital investment of $2 billion and our strategic initiatives created substantial additional underlying value and set the stage for further profitable growth. This positions your Company to continue to be one of the highest performing companies in the industry.

CREATED SUBSTANTIAL ADDITIONAL UNDERLYING VALUE

In an industry and a world where consistent, reliable performance is a rarity, AEC has established a track record of superior performance at all points in the commodity price cycle. At its root, performance has to be driven by the development and execution of a well-developed strategic plan.

Over the past five years, AEC's strategic plan focused on building Canada's strongest natural gas reserves and gas storage position, enabling us to become the largest publicly traded producer of Canadian gas at this time of dramatically stronger gas markets. During the precipitous oil price downturn in 1998 and early 1999, AEC used its relative strength to complete two substantial corporate acquisitions, both of which are proving to be highly profitable. After years of building a technical platform for the application of thermal recovery to AEC's huge heavy oilsands resources, we are now moving forward with a major project which is designed to achieve a new industry standard in terms of production costs. These are some of the key strategic moves which have built today's AEC.

SET THE STAGE FOR FURTHER PROFITABLE GROWTH

Investors know that AEC stands out among North American independent oil and gas companies in terms of delivering high performance results through disciplined investment programs and counter-cyclical acquisitions. AEC values its reputation for being a company which, each year through the ups and downs of commodity prices and financial markets, has built a set of assets which have a higher underlying value than the year before, and a better outlook for the future.

As this report goes to press, we have announced plans, subject to regulatory approval, to initiate a Normal Course Issuer Bid to repurchase, over the next 12 months, up to 5% of AEC's issued and outstanding Common Shares in the open market. AEC is constantly seeking to increase shareholder value in every way. The Company's strong financial position will enable us to pursue value based growth with a record capital investment program in 2000 and, subject to market conditions, create further value through repurchasing a portion of our existing outstanding shares.

Our mantra is growth, value and performance. It's a defining philosophy for decision making at AEC. It means we will be entrepreneurial, aggressive and highly competitive in growing your Company but, at the same time, we will be disciplined in striving to deliver per share increases in the underlying value, cash flow and earnings performance of your Company.

CANADA'S STRONGEST NATURAL GAS POSITION

Industry Conditions

1999 began with the lowest world oil prices in over a decade and concluded with some of the highest. World oil prices rose from US$12.05 per barrel on January 1, to end the year at US$25.60, averaging US$19.25 per barrel versus an average of US$14.43 in 1998. AEC's two significant oil-based acquisitions were anchored in the philosophy that very low oil prices were unsustainable. At the bottom of the cycle, many 'experts' believed low oil prices could continue indefinitely because OPEC countries have low production costs.

AEC'S PRODUCTION CAPACITY CONTINUES TO GROW, PROVIDING SHAREHOLDERS WITH POTENTIAL FOR LARGE FUTURE REWARDS.

Missing from this perspective was the fact that key OPEC producers from the Middle East and Latin America depend almost entirely on oil for their economic, social and political stability. When these factors are added to field production costs, it becomes clear that they need to maintain an oil price in the same range as that needed by the rest of the world's oil producers.

HISTORIC CHANGE IN CANADIAN GAS MARKETS

Meanwhile, there was also a set of irrepressible forces at work in Canadian gas markets. Even though the North American benchmark natural gas price averaged US$2.27 per thousand cubic feet, 20% lower than the previous year due to another record warm winter, AEC's average natural gas price increased 22%, to C$2.48 per thousand cubic feet. This resulted from an historic change in the structure of Canadian natural gas markets. For the first time, there is sufficient natural gas pipeline export capacity to accommodate western Canada's production base. Natural gas pipeline transportation space, which was formerly in short supply and therefore commanded a market premium, has become a surplus commodity, trading on the open market at a discount. As a result, the differential between U.S. benchmark NYMEX based gas prices and the Canadian benchmark AECO C Hub™ prices decreased from an average of $1.14 per thousand cubic feet in 1998 to an average of $0.42 per thousand cubic feet in 1999. We believe this dramatic shift is a permanent structural change. There's promise of an even more positive picture since the gap between North American supply and demand continues to tighten and it's highly unlikely that there will be another repeat of El Niño's winter warmth. In the meantime, AEC's production capacity continues to grow, providing shareholders with potential for large future rewards from the Company's position as Canada's strongest natural gas producer.

Financial Results for 1999

Cash Flow from Operations increased 94%; of that total, 44% resulted from growth in natural gas and oil volumes while increased prices accounted for 56% of the improvement. The midstream division continued to supply steady cash flow after disposition of non-core assets. Consolidated net earnings increased 636% to $180 million, up 500% on a fully diluted per share basis. Following capital investment of $2 billion, upstream debt to cash flow decreased to 1.7X and consolidated debt to capitalization was a healthy 34:66. These results include the effect of our $1 billion Pacalta acquisition for consideration of 15.1 million Common Shares, $31 million in cash and the assumption of Pacalta debt.

CASH FLOW UP 94%

At year-end, Canada's bond rating services rated AEC credit at strong investment grade A and A (low) while the two major U.S. rating agencies provided equally strong BBB+/Positive and Baa1. The Company has unused bank lines totalling $1.1 billion.

UNIQUE SYNERGIES BETWEEN UPSTREAM AND MIDSTREAM DIVISIONS ARE BEING APPLIED TO UNLOCK FURTHER POTENTIAL OF THE PACALTA ACQUISITION.

ACHIEVING OUR TARGETS

Operating Performance

It is AEC's practice to set high performance operating targets and to communicate them to shareholders. Here is a brief performance report compared with key targets we set a year ago:

Target	*Achieved*
• Natural gas sales of 900 million cubic feet/day	• Sales of 904 million cubic feet/day
• Liquids sales of 72,000 barrels/day	• Sales of 95,838 barrels/day, including Pacalta
• 600 gross well drilling program	• 789 gross wells (94% success rate)
• Expand gas storage capacity to 109 billion cubic feet	• Capacity expanded to 109 billion cubic feet
• Sustain midstream cash flow at $115 million	• Achieved target cash flow
• Establish thermal heavy oil technical feasibility	• Announced 20,000 barrels/day SAGD commercial project
• Achieve an international acquisition in a key focus basin	• Counter-cyclical purchase of Pacalta in Ecuador for $4.92/barrel of oil
• Increase reserves, after production, at competitive replacement costs	• 484% conventional production replacement at a cost of $5.54/barrel of oil equivalent, established, 6:1
• Position AEC in northern Canada	• Commenced exploration in Norman Wells area

ACQUISITION CRITERIA: VALUE FIT GROWTH

Most of the above items speak for themselves, but I must comment on a few. In late 1998, AEC identified Ecuador as a key focus area for our international division. Factors that favoured the selection of Ecuador's Oriente Basin include very low finding, development, and production costs; reasonable royalty and taxation levels and potential for very large growth in reserves and production. Pacalta was a Canadian company which had achieved dramatic growth in Ecuador over a three-year period. Pacalta's stock had fallen 81% from its record high at the time of AEC's offer. The Pacalta acquisition provided AEC with the industry's strongest production position in the Oriente Basin and substantial exploration upside, which was demonstrated by a 35% post-acquisition increase in reserves through exploration drilling in the last six months of 1999. Current production is 42,000 barrels per day but productive potential from AEC lands is much higher. Here again, the unique synergies between AEC's upstream and midstream divisions are being applied as our pipeline group now takes a leading role in developing a project to substantially expand Ecuadorean oil production.

30% OVERALL RESERVE GROWTH

In 1999, our natural gas reserve additions replaced production while our oil reserves grew dramatically due to the Pacalta acquisition, ongoing exploration and development and the success of our SAGD technology.

At year-end 1999, AEC's reserve life indices were 13 years for natural gas, 24 years for conventional oil, and 42 years for Syncrude - all stronger than industry norms.

FIVE YEARS AGO, WE ADOPTED A NEW VISION; TO BUILD ONE OF CANADA'S STRONGEST, HIGHEST PERFORMING OIL AND GAS COMPANIES.

Challenges Encountered in 1999

While 1999 was an outstanding year for AEC, there are always challenges or areas we can improve. Here are the key items:

- AEC has its entire conventional reserve base evaluated by respected independent engineering firms. While our drillbit proven conventional reserve additions were a very strong 13%, a 1% negative proven reserve revision occurred mostly in Canadian gas. Nevertheless, our total domestic plus international reserve growth, after production, was 30%, including Syncrude proven reserves.
- AEC continued to experience cash flow losses of about $15 million per year due to an affiliate's inability to recover the full cost of its transportation commitments on the Express Pipeline. Resolving this issue is a significant priority for our pipelines group.
- AEC Pipelines, L.P., 70% owned by AEC, experienced an 18% market price decline in its publicly traded units during 1999. The whole pipeline sector was impacted by a variety of factors including higher interest rates and declining investor confidence. We have great confidence in the value and potential of AEC Pipelines, L.P. as a solid and strong performer in this under-valued sector.
- Despite operating in Argentina for a number of years, AEC has not been able to achieve "critical mass" through exploration or acquisition. We continue to believe that Argentina can be a rewarding component of our international program and a natural gas discovery near the end of 1999 has given us encouragement.
- The oil price hedges which had been put in place by Pacalta prior to AEC's acquisition reduced cash flow from Ecuador by $40 million. These hedges all expired at year-end 1999.
- Ecuador has undergone a difficult period of economic and political instability; a high profile, first-ever hostage taking, and natural disasters including flooding and volcanic activity. Through all of this, AEC's people managed a very successful exploration program and conducted production operations with little disruption. We believe that the new President of Ecuador and his Cabinet are moving forward with important policy initiatives and we continue to view Ecuador as a region of great opportunity for AEC.
- During the year, AEC continued to address the aftermath of a two-year campaign of industrial terrorism against oil and gas facilities in northwest Alberta communities. The Company cooperated with Canada's national police force during the investigation of the criminal activity. At the time of this writing, AEC's people are participating as witnesses in the court proceedings.
- All of us at AEC were saddened by the death of a fellow employee, Len Henning, in an airplane accident at one of our Alberta production sites.

STRETCH TARGETS OF 15% ANNUAL GROWTH

Strategic Vision

This year we celebrate 25 years of success and growth. Five years ago, AEC's management team and Board of Directors adopted a new and highly ambitious strategic vision: to build one of Canada's strongest, highest performing oil and gas companies. Following the sale of AEC's non-oil and gas assets and a merger with Conwest Exploration Company Limited, we transformed our Company into a decentralized business unit organization. AEC became a much larger company by growing a group of smaller entrepreneurial business units each with high growth, high performance targets benchmarked against the best. A smaller head office focuses on adding value, not bureaucracy. We established stretch targets of 15% annual growth in production, reserves, midstream returns and underlying asset value. Achieving these targets would double production and reserves over five years, and transform AEC from a middle-range, low-growth producer to one of the strongest companies in the industry.

AT YEAR-END 1999, AEC'S ENTERPRISE VALUE RANKED FIRST AMONG CANADIAN AND THIRD AMONG NORTH AMERICAN INDEPENDENTS.

AEC GROWTH PER SHARE RANKS NEAR TOP OF INDUSTRY

The result was achievement even beyond this ambitious vision. Over that five-year period, ending in 1999, production and reserves have nearly tripled. AEC ranks first in natural gas production among Canadian independent oil and gas companies. At year-end 1999, AEC's enterprise value ranked first among Canadian and third among North American independents. AEC's growth, on a per share basis, also ranks at the top levels of the industry. Elsewhere in this report, shareholders will find graphs which illustrate further measures of AEC's historical performance and, most importantly, the degree to which AEC's share price has consistently outperformed that of its peers.

A New Vision for AEC

Now, I am pleased to share a new strategic vision for your Company: we plan to create a leading global energy company in the upstream and midstream sectors of the oil and gas industry; a *global super-independent* with profitable high-impact growth in Canada and internationally. We are again setting a target of doubling our production from internal growth over the next five years.

BUILDING A GLOBAL SUPER-INDEPENDENT

We can already identify development opportunities to reach this goal from currently known projects within our asset base. It's highly unusual for an oil and gas company to be able to identify specific growth opportunities over a five-year period. AEC has a philosophy that focuses on sustainable growth and we are in an exceptionally strong position to achieve, perhaps exceed, our goal. As we work toward our global super-independent position, there will be an increasing component of international investment but our domestic division will also continue to grow. Our strategy and vision will be accomplished using the same principles that have led AEC's success to date, including:

- Disciplined full-cycle value creation
- Focused, dominant reserves and production facility positions
- High quality assets with long reserve life and upside potential
- Strong internal growth combined with opportunistic acquisitions
- Midstream growth focused on domestic and international pipelines and North American natural gas storage

Objectives for 2000

Once again, AEC has set aggressive targets for 2000:

NEW TARGET TO DOUBLE PRODUCTION IN NEXT 5 YEARS

- Achieve 1 billion cubic feet per day of natural gas sales, up 11%
- Achieve 130,000 barrels per day of liquids sales, up 36%
- Create value through investment of a $1.3 billion core capital program – approximately 75% domestic and 25% international
- Achieve reserve growth through domestic and international exploration and development at competitive finding and development costs, of less than $6 per barrel of oil equivalent on an established basis
- Pursue opportunistic reserves or corporate acquisitions while following AEC's disciplined criteria of value, strategic fit and growth potential
- Continue construction of 20,000 barrels per day SAGD project
- Aggressively pursue the construction of a major new export oil pipeline in Ecuador
- Continued strengthening in financial performance

AEC WAS SELECTED AS THE BEST CANADIAN OIL AND GAS COMPANY TO WORK FOR AND AS ONE OF THE TOP FIVE COMPANIES TO WORK FOR IN CANADA.

People Behind our Success

Much of AEC's success is summed up in the following philosophy: hire and reward the right people; instill in them the core values of the organization; give them clear goals, responsibility and accountability. At AEC, it is our abiding belief that people who have the right stuff to succeed - people with strong values, people who care about their colleagues, their families and their community, people who have a passion to succeed and take pride in their accomplishments and their company - can achieve great things - if they are inspired by a vision, freed from bureaucracy and negative thinking, and given the opportunity to experience the thrill and fulfillment of being part of a winning team.

PEOPLE WITH A PASSION TO SUCCEED

In 1999, AEC reorganized its business units into three divisions responsible for implementing our global super-independent strategy. Randy Eresman, who has two decades of accomplishment, leadership and value creation at AEC, has been appointed President of AEC Oil & Gas, our domestic division. Steve Bell, President, AEC International, has been the leader responsible for AEC's significant international growth over the past two years. He came to AEC from a large U.S. independent with a strong track record as an international oil and gas executive. Hector McFadyen, a well-known and a long-term successful AEC leader, continues in his role as President of AEC Midstream.

We are proud to see that AEC has been selected by *Report on Business Magazine* as one of the top five companies to work for in Canada, and number one in the oil and gas industry. This selection is based principally upon an independent review of input from a substantial number of AEC employees, and a review of the Company's leadership philosophy. We are especially pleased with these results given that the number of employees at AEC has grown by 50% as the result of two mergers in a 15-month period. Acquiring companies on a counter-cyclical basis is only part of the job; more important is our success at integrating the people who have the knowledge and ability to add value to the assets we are purchasing. In this regard, I want to extend a special welcome to the employees of Pacalta: you have performed in an extraordinary manner and continued to add value during and after the acquisition, even in the face of a number of stressful challenges in Ecuador over this period. This welcome not only includes Pacalta employees but also their former Chairman, Michael Chernoff, who has joined AEC's Board of Directors.

A key part of AEC's leadership philosophy is the alignment of employee interests with shareholder interests. AEC employees have a large stake in AEC, including shares and options which total 7% of fully diluted market value of approximately $6 billion. Essentially, all of our domestic employees hold share options and participate in a savings plan where AEC shares are accumulated, and a portion of the annual performance recognition is also paid in shares.

EMPLOYEES HAVE A LARGE STAKE IN AEC SHARES

In further reference to our Board of Directors, we welcomed Ian Delaney, a well-known and successful Canadian businessman. Ian's career includes extensive experience in the investment community and senior executive roles in the resource sector. On behalf of the management, staff and Board, I want to convey appreciation to Mathew Baldwin, who retired from our Board at our 1999 Annual Meeting, and to thank Matt, a founding Director, for his long and substantial contribution to AEC through its first 24 years. Last, but by no means least, Dave Mitchell, AEC's founding CEO and our former non-executive Chairman, reached retirement age and stepped down from AEC's Board at the 1999 Annual Meeting.

AEC WILL REMAIN FOCUSED ON OUTPERFORMING OUR COMPETITORS IN DELIVERING GROWTH IN UNDERLYING VALUE. THIS PHILOSOPHY HAS LED TO SUCCESS AND GENERATED OPPORTUNITIES IN THE PAST. IT WILL AGAIN IN THE FUTURE.

We were proud to recognize Dave with the honourary title of Chairman Emeritus in appreciation of his substantial contribution to building AEC. Replacing Dave as Chairman is Stan Milner, who is also a founding Director of the Company and has a distinguished record of corporate success and community involvement both within and outside Canada.

Corporate Governance

The past few years have seen a substantial increase in the expectations which both regulatory authorities and shareholders have of corporate directors. This has been reflected in The Toronto Stock Exchange Guidelines for Corporate Governance. AEC's Board has been vigilant in responding to these guidelines and rates highly on all measures.

The Audit Committee comprising six independent, unrelated directors, meets quarterly with both external and internal auditors and reviews and approves our annual and interim financial statements. An important part of their mandate is to assess the adequacy of our internal control systems and our processes for managing risk. The Company also has a formal written ethics and integrity policy for all employees.

ENSURING INVESTOR CONFIDENCE

Oil and gas reserves are the most important 'hard' asset of our Company. AEC is one of very few senior Canadian based producers which has its conventional reserves fully evaluated by outside engineering firms. In Canada, our current consultants are McDaniel & Associates Consultants Ltd. and Gilbert Laustsen Jung Associates Ltd., and internationally, Ryder Scott Company. These three firms have solid reputations. In 1999, AEC took an additional step to ensure investor confidence by establishing a Reserve Committee of our Board of Directors. This Committee, the majority of whom have technical qualifications in assessing estimates of oil and natural gas reserves, has the express responsibility of reviewing the qualifications of, and procedures used by, the independent engineering firms responsible for estimation of reserve quantities.

For my part as CEO, I can assure shareholders that AEC has a very capable, knowledgeable, engaged and challenging Board, which is fundamental to both shareholder results and shareholder confidence.

PREPARED TO MEET NEW CHALLENGES

Current Investor Environment

As this report goes to press, our industry and AEC are witnessing a paradox: very strong oil and gas market fundamentals combined with a general lack of capital market recognition for the operating and financial performance of the sector. In this period, as in all other cycles of the past, AEC will remain focused on outperforming our competitors in delivering growth in both underlying value and financial results. This philosophy has led to success and generated opportunities in the past. It will again in the future. We look forward to continuing to implement AEC's new vision in this first year of our global super-independent strategy. Your Company is fully prepared to meet new challenges and to achieve continued success. On behalf of our Board, management team and all employees at AEC, I thank you for your confidence.

Gwyn Morgan
President and Chief Executive Officer

February 16, 2000

AEC

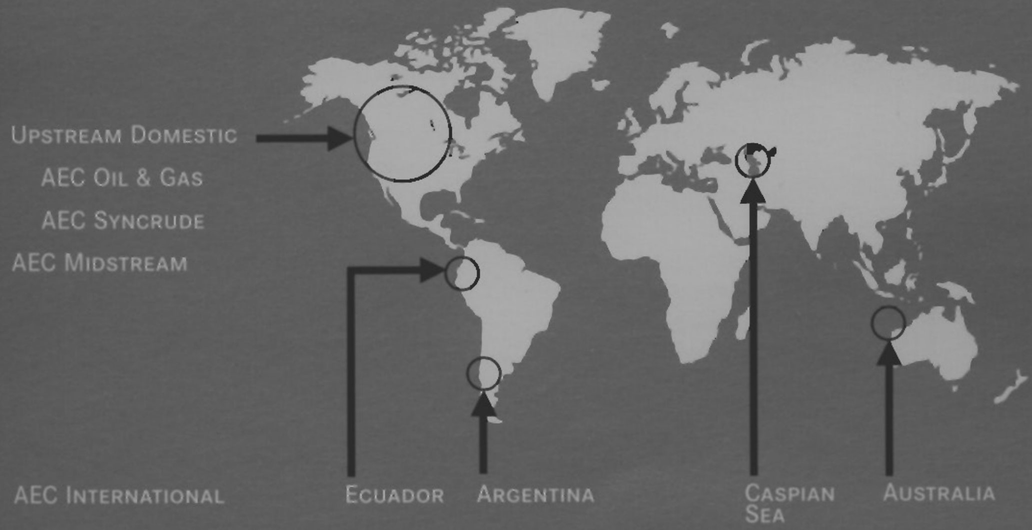
FOCUS REGIONS

SUSTAINABLE GROWTH TARGET OF 15%

TARGET TO DOUBLE PRODUCTION BASE BY 2005

Operations Review

AEC's new strategic vision is to create a global super-independent with profitable, high-impact growth in Canada and internationally. The Company has set a stretch target to double its production by 2005 from its existing asset base. We will achieve this internal growth by following the same operating principles which have been key to AEC's success to date, and will achieve further growth through opportunistic, value creating acquisitions.



Organized for Success

AEC operates in a decentralized manner with three divisions, two in the upstream sector and one in the midstream sector of the industry. The domestic oil and gas division includes our Canadian and northern U.S. exploration, development and production operations and AEC's 13.75% interest in Syncrude. The international division includes the Company's exploration and production operations in South America, Australia and the Caspian Sea.

High-growth, high-performance, entrepreneurial business units in AEC Oil & Gas (domestic) and AEC International are organized on a regional basis. Business units in AEC's conventional domestic operations are aggressive competitors. Each has a specific set of core competencies and focuses on a specific geological and geographical environment. Business units in AEC International are organized by country, have specific core competencies and aggressively pursue opportunities in the areas in which they operate.

The Midstream division comprises two market-driven, entrepreneurial business units which provide stability to operating cash flow and create strategic synergies with the Upstream business. AECO C Hub™, North America's largest independent gas storage facility, adds value to the Company's substantial gas production base. AEC Pipelines & Processing, a major oil transporter in North America, will be integral to realizing the full potential of AEC's Pacalta acquisition through development of a new export pipeline in Ecuador.

Each upstream business unit is accountable for specific reserves, production and financial targets, and for creating value from the shareholders' assets and capital entrusted to it. Midstream business units are measured mainly on earnings and value creation. A compact, effective corporate group supports the achievements of the business units.

Each business unit's individual performance is measured in large part as if it is a separate, publicly traded entity. Business unit teams are rewarded financially according to the degree to which they successfully accomplish their objectives.

AEC maintains a disciplined focus on underlying value creation as the foundation for sustainable growth leading to long-term share price performance.

ON TARGET FOR SALES OF 1 BCF/D IN 2000

CANADA'S LARGEST NATURAL GAS RESERVES

Strategy

- achieve a sustainable growth target of 10% with a stretch target of 15% growth in production, reserves, midstream returns and asset value
- apply the same principles, domestically and internationally, which have been key to AEC's success:
  - full-cycle value creation
  - high working interests
  - dominant land, reserves and production facility positions
  - high-growth assets with long reserve life and upside potential
  - focus on a limited number of regions where these objectives can be attained
- achieve financial returns exceeding our cost of capital
- make efficient use of capital by achieving low costs for reserve replacement, operations and G&A
- maintain a flexible capital investment strategy with a realistic commodity price outlook
- follow a disciplined, opportunistic strategy when seeking acquisitions that meet AEC's criteria of value, strategic fit and growth

Key Assets

- total proven and probable natural gas reserves of 4.3 trillion cubic feet with a reserve life of 13 years - largest among Canadian upstream independents
- proven and probable conventional oil and natural gas liquids reserves of 574 million barrels representing a reserve life of 24 years
- Syncrude proven reserves of 473 million barrels of light sweet oil representing a reserve life of 42 years
- sufficient resources to support future 100,000 barrel/day thermal operation at Primrose
- 1999 production base of 246,500 barrels of oil equivalent/day comprising 61% natural gas, 30% light and medium liquids and 9% heavy oil
- average working interest of 83% on domestic exploration land totalling 7.5 million net acres, comprising high-quality plays on shallow, intermediate and deep exploration prospects
- international land positions in Ecuador, Argentina, Azerbaijan (Caspian Sea) and offshore Australia; totalling 3.0 million net acres
- midstream assets including oil pipelines, natural gas storage and natural gas liquids processing facilities which represent approximately 17% of AEC's asset base:
  - the largest independently owned natural gas storage and trading facility in North America, AECO, representing approximately 15% of Alberta's peak winter capacity
  - 70% ownership in AEC Pipelines, L.P., the largest intra-Alberta oil transporter
- financial strength to fund future growth
- investment grade credit ratings
- a solid reputation on North American stock markets

Operations Summary

- increased produced natural gas sales 27% to 904 million cubic feet/day and exited 1999 at 965 million cubic feet/day
- increased total liquids sales 60% to 95,838 barrels/day and exited 1999 at 120,000 barrels/day
- drilled 789 gross wells adding 162 million barrels of oil equivalent of conventional reserves
- acquired Pacalta Resources Ltd., gaining more than 40,000 barrels/day of conventional oil production and a platform for strong international growth
- Syncrude increased production 6% to 30,649 barrels/day and targets to double production by 2007
- Commercial development of the SAGD project advancing with the first 20,000 barrels/day of production in 2002
- commissioned the 70 million cubic feet/day Maxhamish gas facilities in northeast British Columbia
- commissioned the 25 million net cubic feet/day Ekwan field
- expanded exploration in Argentina
- acquired a position in the ALOV Concession, one of the largest known undrilled prospects in the South Caspian Sea
- added land with drillable prospects in the Northwest Shelf of Australia
- commenced operation of the new 14 billion cubic foot Wild Goose Gas Storage facility in California
- commenced operation of the new 10 billion cubic foot Hythe gas storage facility in northwest Alberta
- completed the first phase of Alberta Oil Sands Pipeline expansion

DISCIPLINED FOCUS ON UNDERLYING VALUE CREATION

Reserves Replacement Costs

(C$/barrel of oil equivalent; 6:1) Before Royalties	Proven	Established	Proven + Probable
1999	6.43	5.54	4.86
3-year Average	6.44	5.39	4.64

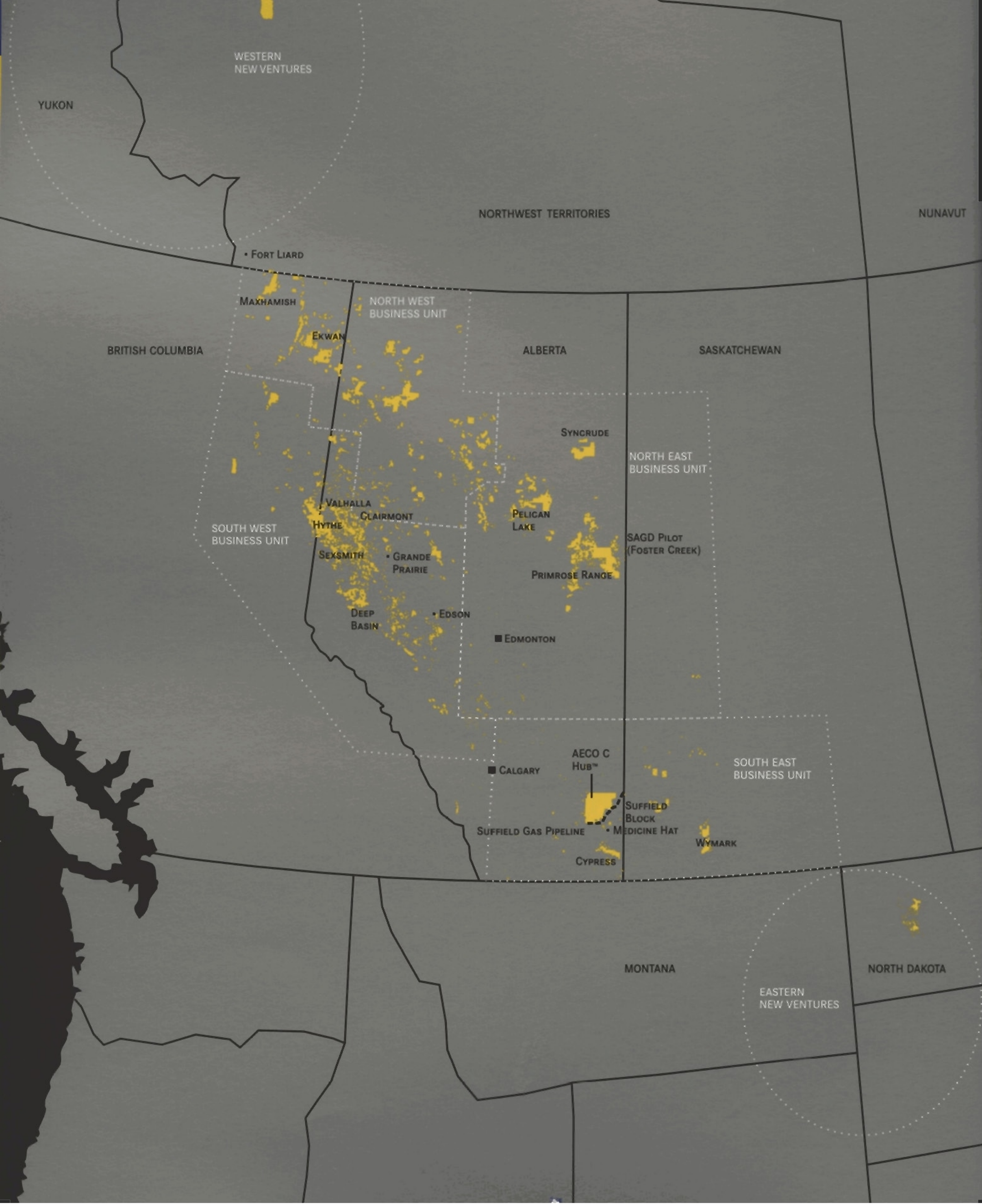
(US$/barrel of oil equivalent; 6:1) After Royalties	Proven	Established	Proven + Probable
1999	5.51	4.72	4.13
3-year Average	5.52	4.63	3.99

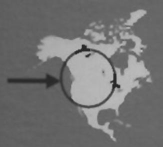
1999 Objectives vs. Performance

Objectives	*Performance*
• increase produced natural gas sales by 26% to 900 million cubic feet/day	• natural gas sales increased to 904 million cubic feet/day, Canada's largest and the sixth largest among publicly traded upstream producers in North America
• continue growing produced natural gas capacity toward being the first Canadian publicly traded producer to achieve average Canadian produced gas sales of 1 billion cubic feet/day	• exited 1999 at 965 million cubic feet/day, on target for achieving 1 billion cubic feet/day in 2000
• increase liquids sales in 1999 by 20% to 72,000 barrels/day	• increased liquids sales 60% to 95,838 barrels/day through internal growth from existing assets and the acquisition of Pacalta Resources
• invest $510 million in grassroots exploration and development to increase conventional reserves and production capacity	• increased net investment to $662 million due to improved oil prices • achieved conventional production replacement of 484%
• drill up to 600 gross wells, 85% targeting natural gas	• drilled 789 gross wells, 77% natural gas wells
• continue advancements in SAGD technology through the Company's pilot plant and reach a decision on the timing of the first 20,000 barrels/day commercial SAGD facility	• advanced engineering design and procurement of equipment, and regulatory applications toward a late 2001 start-up
• sustain midstream operating cash flow of $115 million	• achieved operating cash flow of $115 million
• advance technical and commercial arrangements for new oil pipeline capacity in Ecuador as a result of the Pacalta acquisition	• discussions and negotiations continue at an advanced level

AEC Oil & Gas (7.5 million net undeveloped acres)

AEC's Strategy is to be the most dominant Company in our operating areas. Our asset base is characterized by large, concentrated land holdings, high ownership interests, and control of production facilities.





LARGEST CANADIAN GAS PRODUCER

#1

AEC'S DOMESTIC OIL AND GAS OPERATIONS COMPRISE TWO REGIONS, EASTERN AND WESTERN, EACH CONSISTING OF TWO AGILE AND FOCUSED BUSINESS UNITS AND ONE NEW VENTURES EXPLORATION BUSINESS UNIT. OUR ASSETS IN EACH OF THE TWO REGIONS RANK IN SIZE AMONG THE TOP SENIOR OIL AND GAS PRODUCERS IN CANADA. THE EASTERN REGION FOCUSES ON SHALLOW GAS AND OIL EXPLORATION AND DEVELOPMENT IN THE PLAINS AREAS OF THE WESTERN SEDIMENTARY BASIN IN NORTH AMERICA AND INCLUDES THE COMPANY'S HIGHLY SUCCESSFUL SAGD HEAVY OIL PILOT PROJECT. THE WESTERN REGION TARGETS DEEPER, MULTI-ZONE, LIQUIDS-RICH NATURAL GAS ALONG THE EASTERN SLOPES OF THE FOOTHILLS IN NORTHEASTERN BRITISH COLUMBIA AND WESTERN ALBERTA. DOMESTIC OIL AND GAS ALSO INCLUDES AEC'S INTEREST IN THE SYNCRUDE JOINT VENTURE.

AEC's Competitive Advantage

- high-quality, long-life domestic conventional reserve base totalling one billion barrels of oil equivalent
- entire conventional reserve base was fully evaluated by independent engineers
- Syncrude proven reserves of 473 million barrels
- 7.5 million net acre, high-quality exploration land base across the Western Sedimentary Basin providing sustainable growth opportunities from:
  - large concentrated blocks
  - multi-zone rights on contiguous plays
  - more than 83% average working interest
  - 94% ownership of petroleum and natural gas rights on the 1,000 square mile Suffield Military Block and 97% on the 2,000 square mile Primrose Air Weapons Range
- disciplined acquisitions strategy which meets AEC's criteria of value, strategic fit and growth
- low-cost exploitation opportunities at Suffield, Pelican Lake and Primrose
- deployment of aggressive, entrepreneurial New Ventures exploration business units
- leadership in the application of technologies to unlock resource potential

Natural Gas Strategy

- leverage Canada's strongest natural gas production, reserves and exploration land position to take advantage of the expanding continental gas market
- Western Region: focus on deeper formations which hold significant multi-zone, liquids-rich potential by leveraging dominant land position in the Grande Prairie area, Edson region and northeast British Columbia
- Eastern Region: pursue production and reserves growth targets through low-risk exploration and development of sweet, dry, shallow gas in the plains area of the Western Sedimentary Basin
- build an inventory of exploration prospects in new venture areas to sustain future growth objectives
- maintain advantages of high working interests, low operating costs, low royalties and well-developed infrastructures
- pursue opportunistic, value-creating acquisitions

Oil Strategy

- pursue production and reserves growth targets through low-risk exploration and development of light and heavy oil properties principally in the Eastern Region on the Primrose, Pelican Lake and Suffield properties
- be the most efficient producer of light oil, heavy oil and oil sands
- maintain high working interests, low operating costs, and well-developed infrastructures
- develop and implement innovative recovery technologies
- implement a low-cost commercial-scale SAGD thermal recovery project

AEC has high-quality, long-life reserves of natural gas, conventional oil and heavy oil produced through company controlled oil and gas production facilities.

1 BCF/D IN 2000

30% 5-YEAR COMPOUND GROWTH

Natural Gas Asset Highlights

- 4.2 trillion cubic feet of proven and probable natural gas reserves, the largest in Canada, representing a 13-year reserve life
- large, low cost, gas production centres at Primrose and Suffield
- 904 million cubic feet/day of low cost natural gas sales
- 30% compound growth in natural gas sales over the past five years
- control and operatorship of the Sexsmith and Hythe plants, the two largest sour gas plants in the Grande Prairie area
- 70 million cubic feet/day Maxhamish gas facilities and associated gathering system
- 600 net square mile dominant position in the Ekwan area of northeast British Columbia
- 100% ownership of the 200 million cubic feet/day Suffield Gas Pipeline

Oil and NGLs Asset Highlights

- 302 million barrels of proven and probable conventional liquids reserves representing a 22-year production life
- major oil production facilities at Suffield, Pelican Lake, Valhalla and Clairmont
- 23,284 barrels/day of low cost heavy oil production
- 14,558 barrels/day of conventional light liquids production
- delineated sufficient heavy oil resource at Primrose to support 100,000 barrels/day by 2006

Operations Summary-Conventional	2000F	1999	1998	1997
Sales				
natural gas (million cubic feet/day)	1,000	904	714	575
conventional liquids (barrels/day)	48,000	37,842	28,904	28,810
Proven and Probable Reserves				
natural gas (billion cubic feet)		4,189	4,207	3,685
conventional liquids (million barrels)		302	281	118
Net Capital Expenditures ($ million)	900	662	598	588
Gross Wells				
exploration	225	148	207	145
development	625	620	428	332
Land (thousand net acres)				
developed		2,058	1,727	1,466
undeveloped		7,492	7,090	6,263

4.2 TCF

13-YEAR NATURAL GAS RESERVE LIFE

100,000 BBLS/D SAGD POTENTIAL

1999 Objectives vs. Performance

Overall Objectives	*Performance*
• expand exploration to provide opportunities for sustained growth	• created two new ventures exploration teams focused on high risk/high reward play types in the Alberta foothills, Northwest Territories, U.S. Rockies and Williston Basin; drilled 148 exploration wells
• optimize the combined assets of AEC and Amber Energy through the implementation of a sound development plan	• achieved exploration success at Ekwan and commenced a 60-well drilling program at Pelican Lake

Natural Gas Objectives	*Performance*
• increase natural gas field production 24% to 880 million cubic feet/day	• achieved 882 million cubic feet/day
• maintain operating costs below $0.35/thousand cubic feet of natural gas production for AEC East	• lowered operating costs to $0.33/thousand cubic feet in AEC East
• develop a by-pass pipeline for Primrose natural gas	• continue to evaluate alternative opportunities to ship gas to markets
• complete construction and commission of facilities at Maxhamish by April 1999	• 70 million cubic feet/day Maxhamish production center was brought on stream in April 1999
• evaluate and test high-potential prospects in the Edson deep basin region	• 3 deep Wabamun test wells encountered productivity below expectations

Oil Objectives	*Performance*
• increase liquids production by 35% to 39,000 barrels/day	• increased liquids production by 31% to 37,842 barrels/day
• inventory 1,500 barrels/day of conventional oil development and 12,000 barrels of oil/day of heavy oil development due to low oil prices	• did not proceed with full program due to low oil prices early in the year; reinstated capital investment at Pelican and Suffield in third quarter, leading to significant production growth in 2000
• reduce operating costs to $4.50/barrel for liquids for AEC East	• reduced operating costs by 10% to $4.13/barrel in AEC East
• advance design and construction plans for the 20,000 barrels/day Primrose SAGD commercial project	• announced commercial SAGD facility and made regulatory application; anticipate start-up in the fourth quarter of 2001

AGGRESSIVE COMPETITORS

BUILDING ON CORE COMPETENCIES

DOMESTIC BUSINESS UNIT OVERVIEW

- North East Business Unit
  focuses on low risk exploration and development of high working interest, low operating cost, shallow gas and heavy oil assets on its 1.6 million net acre exploration land base in northeast Alberta and northwest Saskatchewan
  - major shallow gas producing areas include Primrose and Wabasca
  - oil producing areas include Pelican Lake
  - SAGD at Primrose
    - 3 well pairs
    - pilot facilities capable of 2,000 barrels/day of production
    - proceeding with 20,000 barrels/day commercial project
    - sufficient resources to support 100,000 barrels/day commercial facility

- South East Business Unit
  focuses on production and reserves growth targets through low-risk exploration of sweet, dry, shallow gas and heavy oil on its 400,000 net acre exploration land base
  - major shallow gas producing areas include Suffield and Cypress, Alberta and Wymark, Saskatchewan
  - oil development at Suffield
  - signed a multi-party access agreement with the Government of Alberta on September 8, 1999, which facilitates the posting and access to the deep petroleum and natural gas rights on the Suffield Military Block

- Eastern Region New Ventures Business Unit
  focuses on natural gas in the Williston Basin and Northern U.S. Rocky Mountains
  - identify 6-10 high-impact gas plays

- North West Business Unit
  pursues shallow to medium depth gas targets and light oil prospects on its 1.9 million net acre exploration land base in northeast British Columbia and northwest Alberta
  - major targets are medium depth prospects in northwest Alberta and northeast British Columbia
  - major natural gas production at Maxhamish and Ekwan, British Columbia, and Boyer and Fontas, Alberta with oil production at Red Earth and Ogston, Alberta

- South West Business Unit
  pursues deeper formations with significant multi-zone, liquids rich potential in western Alberta and adjoining areas in northeast British Columbia on its 2.3 million net acre exploration land base
  - primary gas producing areas include Hythe, Sexsmith and Edson, with liquids production at Valhalla, Sexsmith and Clairmont

- Western Region New Ventures Business Unit
  focuses on the Northwest Territories and Foothills regions of the Western Sedimentary Basin
  - identify 6-10 high-impact gas plays

Domestic 2000F Business Unit Targets	North East*	South East	North West	South West
Natural Gas Sales (million cubic feet/day)	315	210	185	290
Liquids Sales (barrels/day)	17,000	20,000	3,000	8,000
Total Wells	200	430	110	85
Capital Expenditures ($ million)	315	150	160	175

**includes SAGD*

DOMESTIC OIL & GAS 2000 OBJECTIVES

- Grow total gas sales by 11% to 1 billion cubic feet/day
- Reduce natural gas operating costs to under $0.40/thousand cubic feet
- Grow western Canada conventional liquids sales by 27% to 48,000 barrels/day
- Reduce western Canada conventional oil operating costs to under $4.00/barrel
- Target a recycle ratio exceeding 2.0 times
- Target a reserves replacement cost of less than $6.00/barrel, on an established basis
- Complete regulatory approval process and advance engineering design and procurement of the SAGD commercial project at Foster Creek
- Establish a significant exploration landholding in Mackenzie Valley Corridor

NO EXPLORATION RISK

42 YEAR PROVEN RESERVE LIFE INDEX

AEC is the second largest owner of the Syncrude Project, which is the largest producer of oil in Canada and the largest oil sands plant in the world. Syncrude's light, sweet oil sells at a premium to conventional light oil. A focus on improving recovery technologies has enabled constant increases in production and decreases in operating costs. Syncrude targets to double production by 2007.

Strategy

- expand upgrading infrastructure and resource development to increase production 63% by 2004, and 100% by 2007
- develop and implement new technologies to reduce operating costs to $11.00/barrel by 2004 and to lower SO_2 and CO_2 emissions
- enhance product quality to broaden marketability

Asset Highlights (AEC's Share)

- 13.75% joint venture interest
- 473 million barrels of proven reserves
- crude priced at a $0.75 premium to light oil at Edmonton
- substantial infrastructure
- no exploration risk

Operations Summary (AEC's 13.75% Interest)	2000F	1999	1998	1997
Sales (barrels/day)	**34,000**	**30,649**	**28,953**	**28,447**
Proven Reserves (million barrels)		**473**	**364**	**381**
Probable Reserves (million barrels)		**263**	**355**	**347**
Proven Reserve Life Index (years)		**42**	**34**	**37**
Capital Expenditures ($ million)	**75**	**103**	**68**	**49**

1999 Objectives vs. Performance

Objectives	*Performance*
increase production by 7% to 31,000 barrels/day	increased production by 6% to 30,649 barrels/day
reduce operating costs to $12.40/barrel	reduced operating costs by 7% to $12.69/barrel
maintain Syncrude expansion momentum by completing the first phase of expansion engineering design	expected to be complete in September 2000
obtain AEUB approval for upgrader expansion	approval received

AEC Syncrude 2000 Objectives

- increase production to 34,000 barrels/day
- reduce operating costs 3% to $12.25/barrel
- bring new Aurora Mine to full production

THE SAME PRINCIPLES WHICH MADE AEC SUCCESSFUL IN CANADA ARE BEING APPLIED TO ITS INTERNATIONAL INVESTMENTS: CONCENTRATED HIGH WORKING INTERESTS, FOCUSED, DOMINANT CORE POSITIONS, AND EXPLORATION SUCCESS COMBINED WITH STRATEGIC ACQUISITIONS.

ECUADOR

ARGENTINA

AUSTRALIA

AZERBAIJAN

FOCUS ON SELECT HYDROCARBON BASINS

WORLD-CLASS TEAM

AEC's Competitive Advantage

- exploration and exploitation opportunities on existing land base in Ecuador and Argentina
- aggressive pursuit of new play types and untapped reserve potential
- world-class team having worked and resided in all of the principal global petroleum centres, and participated in major exploration, development and production projects

Strategy

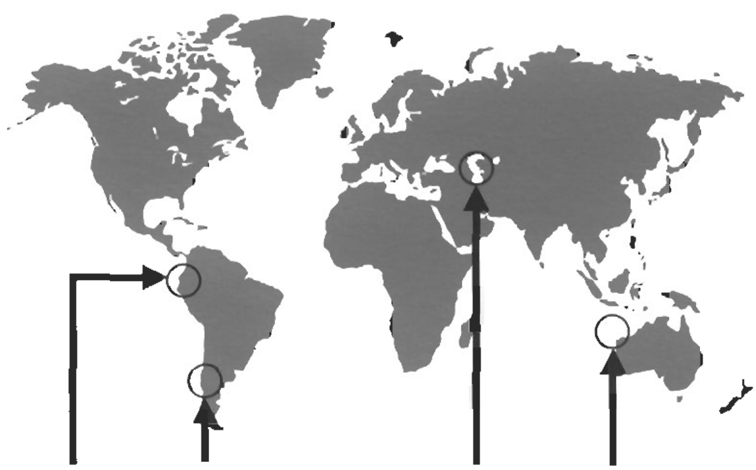
- focus on four to six low to medium-risk, high-reward hydrocarbon basins in selected countries
- build substantial, profitable reserves and production bases through focused, high working interest, dominant core positions
- achieve further growth through exploration and strategic acquisitions
- invest approximately 25% of AEC's total direct core capital budget

Asset Highlights

- 291 million barrels of oil equivalent of proven and probable reserves and, 3.0 million acres of net exploration lands
- more than 40,000 barrels/day of oil production capacity in Ecuador
- successful exploration program capacity in Ecuador added 72 million barrels of reserves at a cost of US$0.89/barrel
- 5% interest in the ALOV prospect in the Azeri portion of the Caspian Sea
- new and emerging exploration plays on existing lands
  - 1.5 million acres of net exploration lands on the Northwest Shelf of Australia, where AEC participated in a major natural gas discovery in 1998
  - 609,000 acres of net exploration lands in Argentina

Potential Growth

- Ecuador
  - AEC is a leading player in a consortium to construct a new oil export pipeline
  - approximately 80,000 barrels/day of oil production potential from existing lands and reserves
  - exploration upside on existing lands
  - opportunity to increase holdings through privatization rounds
- Argentina
  - natural gas exploration and development on prospective land in Neuquen Basin
- Australia
  - appraisal of John Brookes-1 discovery
  - additional drilling prospects in two other basins on the Northwest Shelf
- Azerbaijan
  - drilling of the high potential ALOV prospect in 2001



COUNTER-CYCLICAL ACQUISITION STRATEGY

MAJOR GROWTH PLATFORM IN ECUADOR

Pacalta Acquisition

- Following an in-depth global basin ranking study in late 1998, AEC International targeted the Oriente Basin in Ecuador as a high-quality, oil prone region with very significant opportunities for both exploration and development. In the first quarter of 1999, when the industry was experiencing depressed oil prices, AEC made an offer to purchase Pacalta Resources Ltd. and was successful in acquiring the company with the support of the Board and management of Pacalta. Pacalta's sole base of operations is in the prolific Oriente Basin where the company's reserves base totalled 212 million barrels of oil at January 1, 1999. Pacalta's concentrated, 100% working interest reserves, capable staff and operating facilities gave AEC International a significant critical mass upon which to build a very large position in Ecuador's Oriente Basin. Over 98% of the operations staff in Ecuador have joined AEC. AEC's Ecuador production capability currently exceeds export pipeline capacity. AEC's pipeline business unit is part of a consortium actively pursuing a major expansion of the export system. Current light and medium oil sales are approximately 42,000 barrels/day and are forecast to average approximately 48,000 barrels/day in 2000.

- After the Pacalta acquisition, AEC International immediately recommenced an exploration and development program that Pacalta was unable to fund at a time of low oil prices. The program has been very successful, adding 72 million barrels of proven and probable reserves at US$0.89/barrel in only six months.

Combined International Operations Summary	2000F	1999	1998	1997
Production				
conventional oil (barrels/day)	48,000	27,347	2,217	1,683
Proven and Probable Reserves				
natural gas (billion cubic feet)		113	2	3
conventional oil (million barrels)		272	5.2	4.2
Net Capital Expenditures ($ million)	300	174	65	48
Gross Wells				
exploration	15	10	5	4
development	7	11	5	7
Land (thousand net acres)				
developed		16	29	5
undeveloped		2,959	1,751	2,945

EXPLORATION SUCCESS IN ARGENTINA AND AUSTRALIA

NEW VENTURES: AUSTRALIA AZERBAIJAN & COLOMBIA

1999 Objectives vs. Performance

Objectives	*Performance*
Argentina	
• appraise and develop existing discoveries at Puesto Prado, Ojo de Agua and Puesto Flores Oeste; conduct an exploration drilling program on existing acreage	• drilled 4 appraisal and development wells in the Puesto Prado and Puesto Flores Oeste fields with poor results; an asset sale will likely result during 2000
• exit 1999 with 4,000 barrels/day of production; reduce operating costs to less than US$3.00/barrel by the end of 1999	• exit rate of 1,985 barrels/day instead of 4,000 barrels/day due to lower than expected rates from the Puesto Flores Oeste discovery and delayed waterflood response in the Puesto Prado pilot program • at the lower than expected exit rate, operating cost targets were not met
• build prospect inventory to access natural gas potential in western Neuquen Basin	• drilled two wells at Anticlinal Campamento resulting in a potentially significant gas discovery
Australia	
• appraise and initiate a development plan for the John Brookes-1 discovery	• independent engineering estimates for the John Brookes-1 discovery well resulted in the booking of probable reserves of 36 billion cubic feet of natural gas • drilled an unsuccessful well on an adjacent structure on trend to the John Brookes-1 gas/condensate discovery which had oil and gas shows
• identify and capture farm-in opportunities to build on success at John Brookes-1 in the Carnarvon Basin	• farmed into a second block in the Carnarvon Basin and drilled an unsuccessful exploration well
• plan to evaluate and drill prospects in the Carnarvon Basin	• reviewed and screened prospects in the Carnarvon Basin • expanded exploration focus to the Vulcan-Browse Basin and completed a farm-in into Block AC/P22 which AEC will operate with a 60% interest; exploration well scheduled for second quarter 2000
North Africa/Middle East/Caspian Sea	
• identify and evaluate areas with superior reserves potential	• screened opportunities in several countries in North Africa but did not identify entry opportunities meeting our value, strategic fit and growth criteria at this time
• establish a presence in at least one new core area	• while not in the same geographic area, a new core area was identified and captured in Ecuador
• complete seismic program in Azerbaijan and commence drilling first exploration well	• signing of ALOV project, the largest undrilled oil prospect in the Caspian Sea • seismic program completed on budget; first exploration well deferred to summer of 2001 due to rig availability

International 2000F Business Unit Targets

	2000F		1999	
	Ecuador	Argentina	Ecuador	Argentina
Oil Production (barrels/day)	48,000	–	**25,640**	**1,707**
Total Wells	16	3	**8**	**11**
Net Capital Expenditures ($ million)	150	30	**94**	**41**

AEC International

International Business Unit Overview

- Ecuador Business Unit
  - 567,000 acres of rights in the Oriente Oil Region, part of a hydrocarbon basin that extends through Ecuador, Colombia and Venezuela
    - second most prolific basin in the world
    - wildcat success rate of more than 50%
    - wells average 1,000 barrels of oil/day
  - capital expenditures for 2000 projected at $150 million
  - Ecuador is experiencing an economic crisis which has resulted in the replacement of its President
    - the new President has announced that he will continue with the dollarization program and oil industry privatization measures
    - AEC is confident that Ecuador will maintain its historical record of honouring its commitments under hydrocarbon contracts

- Argentina Business Unit
  - 609,000 acres of exploration land
  - includes plays at Anticlinal Campamento and Covunco in the western part of the Neuquen Basin
  - growing markets for natural gas
  - capital expenditures for 2000 projected at $30 million

- AEC International New Ventures Group
  - Australia
    - appraising John Brookes gas discovery
    - drilling new targets in the Northwest Shelf
  - Azerbaijan
    - 3-D seismic program providing refined exploration picture
    - expecting to drill first well in 2001
  - Colombia
    - 824,000 acres of exploration land in recently acquired blocks
    - run seismic program

AEC International 2000 Objectives

Ecuador

- target reserve additions at less than US$3.00/barrel
- increase annual average production to 48,000 barrels/day
- reduce total operating cost to average less than US$2.00/barrel
- add at least one block to our land base to increase prospect inventory for 2000 and 2001 in anticipation of new pipeline being pursued by AEC Pipelines

Argentina

- rationalize asset portfolio in eastern oil properties in Neuquen Basin
- appraise deep gas discovery by long-term production tests of two existing wells
- obtain markets for gas

Australia

- continue to implement Vulcan-Browse oil fairway entry strategy by:
  - farming into quality exploration blocks
  - drilling three wells to test the play concept
- drill and operate the Puffin prospect on Block AC/P22
- target reserve additions less than US$3.00/barrel

Azerbaijan

- process and interpret 3-D seismic in ALOV block to prepare for drilling in 2001
- evaluate at least one block for addition to prospect inventory

New Ventures

- focus on no more than two basins to obtain new opportunities, either exploration or exploitation, and capture at least one opportunity in new focus area

LARGEST INDEPENDENT GAS STORAGE OPERATOR IN NORTH AMERICA

STORAGE CASH FLOW ↑ 30%

AEC MIDSTREAM COMPRISES TWO BUSINESS UNITS, AEC STORAGE AND HUB SERVICES AND AEC PIPELINES AND GAS PROCESSING, BOTH OF WHICH PURSUE GROWTH OPPORTUNITIES DOMESTICALLY AND INTERNATIONALLY. AEC MIDSTREAM SEEKS TO GROW CASH FLOW AND EARNINGS AND TO ADD FURTHER TO SHAREHOLDER VALUE THROUGH ASSET GROWTH. MIDSTREAM EXPERTISE ASSISTS IN THE ACHIEVEMENT OF UPSTREAM STRATEGIES SUCH AS IN ECUADOREAN AND CANADIAN CRUDE OIL PIPELINES, AND GAS STORAGE IN ALBERTA.

AEC STORAGE AND HUB SERVICES

THE BUSINESS UNIT'S MAJOR ASSETS INCLUDE AECO C HUB™, NORTH AMERICA'S LARGEST INDEPENDENT NATURAL GAS STORAGE AND TRADING FACILITY, AND THE WILD GOOSE GAS STORAGE FACILITY IN CALIFORNIA, THE STATE'S FIRST INDEPENDENT GAS STORAGE FACILITY.

STRATEGY

- maintain leadership in gas storage through innovative, market-responsive customer services and cost-effective operations
- capture new investment opportunities using technical and commercial core competencies
- generate operating cash flow through leasing storage to third parties and by optimizing capacity held by the Company
- develop and implement new investment opportunities in response to natural gas market fundamentals and the restructuring of North America's natural gas industry

ASSET HIGHLIGHTS

- 85 billion cubic foot AECO gas storage reservoir in Alberta
  - Canadian industry pricing point for natural gas trading
  - 1.8 billion cubic feet/day peak withdrawal capacity
- 10 billion cubic foot storage facility at Hythe
- 14 billion cubic foot Wild Goose Gas Storage reservoir in California
  - 200 million cubic feet/day peak withdrawal capacity
- contracts with terms varying from 1-13 years covering 79 billion cubic feet of total capacity

1999 OBJECTIVES VS. PERFORMANCE

Objectives	*Performance*
• increase operating cash flow by 30% to $30 million	• increased operating cash flow 30% to $30 million
• commission the Wild Goose Gas Storage facility in April 1999	• commissioned facility in April; very positive feedback on service
• complete 10 billion cubic foot Hythe gas storage facility in northwest Alberta	• completed facility in August
• continue aggressive growth strategy leading to new facility investment	• various acquisitions and greenfield opportunities pursued; nothing concluded as value criteria not met

GAS STORAGE 2000 OBJECTIVES

- increase operating cash flow by 8% to $32 million
- increase western Canadian storage capacity by 4 billion cubic feet
- connect Hythe facility to the Alliance Pipeline
- add value through innovative strategies in the U.S.

NEW OIL EXPORT PIPELINE IN ECUADOR

LARGEST INTRA-ALBERTA OIL TRANSPORTER

AEC Pipelines & Gas Processing

AEC PIPELINES IS ALBERTA'S LARGEST INTRA-PROVINCIAL OIL TRANSPORTER AND DELIVERS OIL INTO THE U.S. ROCKY MOUNTAIN AND MIDWESTERN STATES. IT HOLDS THESE INTERESTS THROUGH A 70% OWNERSHIP IN AEC PIPELINES, L.P. THIS BUSINESS UNIT ALSO INCLUDES A NATURAL GAS LIQUIDS EXTRACTION FACILITY. AEC PIPELINES WILL LEVERAGE ITS EXPERTISE TO ADVANCE PIPELINE INITIATIVES INTERNATIONALLY CONSISTENT WITH AEC'S INTERNATIONAL EXPLORATION AND DEVELOPMENT STRATEGY.

AEC has an interest of approximately 30% in a five-member consortium seeking to build a new export pipeline in Ecuador. The proposed Oleoducto Crudo Pesado (OCP) will have an initial capacity of 290,000 barrels/day and will ship oil from Ecuador's prolific Oriente Basin to the Pacific port of Esmeraldas. Pending approvals, the pipeline is expected to be in service in late 2001. OCP will facilitate a significant increase in the Company's production base in Ecuador.

Strategy

- pursue pipelines growth opportunities in North America and select regions internationally where expertise can be leveraged
- anticipate and capture emerging market opportunities through creative entrepreneurial business agreements
- focus on customers
- apply the best available commercial technology

Asset Highlights

- 70% ownership in AEC Pipelines, L.P. (TSE-listed ALB.UN), which has:
  - 100% interest in Cold Lake Pipeline System
  - 100% interest in Alberta Oil Sands Pipeline System (AOSPL)
  - indirect 50% ownership in Express Pipeline System
  - long-term shipper contracts
- 35% interest in the Empress Straddle Plant
- 33% interest in Alberta Ethane Gathering System

1999 Objectives vs. Performance

Objectives	*Performance*
achieve operating cash flow of $85 million	achieved operating cash flow of $85 million
implement a growth strategy for the Cold Lake Pipeline in northeast Alberta	discussions continue with key producers
complete repairs for reinstatement of the Platte Pipeline maximum operating pressure by the second quarter of 1999	completed repairs in the second quarter; maximum operating pressure was reinstated in the second quarter
complete detailed engineering and commence construction to increase capacity of AOSPL to 275,000 barrels/day by April 2000	completed AOSPL expansion by year-end increasing capacity to 280,000 barrels/day
divest AEC's interest in Iroquois Gas Transmission System and Pan-Alberta Resources Inc.	divested AEC's 6% interest in the Iroquois Gas Transmission System and its 50% interest in Pan-Alberta Resources Inc. for a net after-tax gain of $24.1 million
advance pipeline initiatives in South America to decision stage	achieved; opportunities being pursued

Pipelines & Gas Processing 2000 Objectives

- increase operating cash flow by 11% to $95 million
- complete negotiations and commence construction of the OCP pipeline in Ecuador
- implement a strategy in northeast Alberta to transport increasing oil production
- assume operation of the Platte Pipeline and reduce operating costs

Corporate Social Responsibility

Stewardship – through People and Resources

AEC is in business to generate value for its shareholders. We increase shareholder value by conducting all aspects of our business with a view to sustainable development, an underlying philosophy which balances and integrates our economic interests, environmental concerns, and the economic and social needs of citizens within the communities where we operate.

This commitment to the good stewardship of human, financial and natural resources in our operating environments is fundamental to our position as an ethical member of the business community. The passion that employees have for their roles as stewards is a credit both to themselves and our Company and is embodied in three important aspects of our business: Our People, Our Community, and Our Environment. AEC is proud of its leadership position in corporate social responsibility as it relates to all three.

Our People

In the most recent survey of the *Report on Business Magazine*, AEC was ranked third highest among the *35 Best Companies in Canada To Work For*, and first among oil and gas companies. This ranking was the result of an independent national evaluation sent to more than 500 companies. It included detailed polling of 250 randomly selected AEC employees and a review of our leadership philosophy.

During the past 15 months, corporate acquisitions increased AEC's employee teams 50% to 1,162 people, supported by an additional 380 consultants providing short-term expertise as required. We take pride in the fact that the Company's voluntary turnover rate of 4% remains less than half of the industry average. This low turnover, and the *Report on Business Magazine* survey, reflect well on the Company's overall employee practices, especially those related to our success in integrating skills and human resources during two major corporate acquisitions.

AEC's core values are also reflected in a number of employee programs related to health and wellness, life-long learning and yes, fun in the workplace! In addition to providing comprehensive, leading-edge and flexible employee benefits, AEC employees enjoy:

- voluntary Fitness & Lifestyle assessments, complemented by an annual fitness program subsidy;
- lunchtime seminars on a broad range of issues, such as personal wellness and financial planning;
- employee continued education reimbursement programs and educational bursaries for children of employees;
- home computer purchase assistance program and in-house computer training.

AEC encourages its employees to participate in charity and community events. The Company and employees join together in events such as the Canadian Liver Foundation's Luge for Liver, the Alberta Lung Association's Bike For Breath, road relays that benefit local charities, and the 'office Olympics' in the annual Calgary Corporate Challenge.

AEC's belief in building strong and qualified employee teams and tying together objectives, accountability and results is reflected in its highly competitive Results Based Compensation program that recognizes the degree of both individual employee and team success in the Company's annual growth and profitability. Performance bonuses are paid as a combination of cash and Common Shares. Employee ownership is also enhanced through a corporate matching, in Common Shares, of employee contributions to an AEC Employee Profit Sharing Plan. Further alignment between shareholder and employee interests are accomplished through a Company-wide stock option program.

AEC has also pioneered a unique donations program, Go AEC, that annually matches the personal contributions employees make to charities. In 1999, total funds directed through this program were $612,000 with more than 350 organizations supported by AEC and its employees.

$3 MILLION INVESTED IN COMMUNITY PARTNERSHIPS

HEALTH AND WELLNESS

EDUCATION

YOUTH PROGRAMS

ÑANPAZ, AN INDUSTRY MODEL FOR LOCAL HARMONY

Our Community

The Company believes its commitment and proactive approach – partnering through time and resources with employees, neighbours and other businesses – help to create and sustain vibrant communities. Vibrant communities contribute, in turn, to a nation's strength. While our community leadership is clearly evident in our domestic operations, it is now expanding to countries impacted by AEC's international business strategy.

In 2000, the Company will re-invest $3 million in its commitment to our communities. This includes our participation as a Caring Company in the National Imagine Program conducted by the Canadian Centre for Philanthropy. It also includes our investment in innovative approaches toward sustainable community development in less developed countries where the Company is active.

AEC's Community Investment Program gives priority to health and wellness, education, and youth program initiatives that reflect the Company's core values. Some examples of our commitment to these important areas include major support for:

- The Integrative Health Institute of Calgary, a community-based resource centre that promotes preventive initiatives for individual wellness and serves as a credible information source for complementary health care practices;
- Lead donations for special programs designed to meet specific community needs such as acquiring a magnetic resonance imager (MRI) in northern Alberta, and contributing to recreation facilities, or community music festivals;
- Alberta Tobacco Reduction Alliance, an aggressive public education campaign on the health risks of tobacco;
- The Manning Awards, which annually recognize the talent and innovation of Canadians and fosters creativity and innovation among our young people;
- The Canada Wide Science Fair, which brings together the top 400 out of 500,000 science students each year who entered science fair projects in schools across Canada;
- Job Safety Skills, a unique high school safety program developed by employees of AEC and other companies, is now part of the Alberta education curriculum and is expanding to other provinces;
- Educational Partnerships with selected high schools in operating regions, and the establishment of student bursaries for the pursuit of post-secondary studies in industry-oriented disciplines;
- National Sport Centre's Youth and Education through Sport (YES) program uses Olympians to convey core values and was presented in 18 AEC community schools;
- Public Policy Forums for Youth, through the Fraser Institute which enables high school students to examine a broad range of current national issues; and
- D.A.R.E., a province-wide drug abuse awareness program aimed at Grade 6 students.

AEC applauds its employees for participation in a unique partnership with the Developmental Disabilities Resource Centre, an organization which works with the mentally and physically challenged in contributing to their personal and societal development. This partnership earned the Company a 1999 Leader in Business Award through Volunteer Calgary.

Aboriginal Capacity Building

Aboriginal communities adjacent to AEC's operations are a particular focus for the Company's capacity building initiatives. The Company works with community leaders investing in the development of programs that improve the capacity of local people to help themselves.

During the past year, AEC has continued that initiative by awarding contracts with Aboriginal-owned or partnered companies in the supply of site services for projects in northern Alberta, northeast British Columbia, and the Northwest Territories. AEC seeks out opportunities to provide onsite job training, and continues to sponsor scholarships specifically for Aboriginal students pursuing oil and gas related studies.

Fundación ÑanPaz

Capacity building is also at the core of AEC's community development program in Ecuador. AEC is currently the principal funder of Fundación ÑanPaz (Road to Peace), a community-based non-profit foundation focused on improving the economic and social well being of indigenous and migrant populations through innovative training programs and economic self-supporting initiatives. ÑanPaz envisions peaceful communities where socio-economic human conditions are improved and natural resources are effectively managed for current and future generations. Although in existence for only three years, ÑanPaz has made an impact and is becoming a model for resource development industries operating in less developed countries. Additional information is available through the foundation's website www.nanpaz.com.

STRONG SAFETY, ENVIRONMENTAL PERFORMANCE

ACHIEVED 2003 FLARING REDUCTION LEVELS IN 1999

INDUSTRY FIRST OMBUDSMAN

Our Environment

The dedicated efforts of employees and consultants have enabled AEC to again maintain its exceptionally strong environmental and safety record.

These activities are monitored by the Environment Health & Safety Committee of our Board of Directors. It is a continuous improvement process, as AEC applies innovative technologies as economics are balanced with effective and efficient environmental protection practices. Innovative approaches were implemented both domestically and internationally and our environmental efforts were also recognized externally. In 1999, AEC was granted Gold-level recognition for its 1998 Voluntary Challenge Registry report, which features innovative ideas by employees to conserve energy and reduce greenhouse gas emissions. AEC was also awarded the Putumayo Civil Order "Francisco de Paula Santander" for submission of an environmental impact assessment for the Tirimani Exploration Block in Colombia. Other achievements included:

- confirming that all of AEC's facilities have lower benzene emission levels than allowable by Alberta's stringent standards;
- already meeting the flare reduction criteria for the 2003 time frame as established by the Clean Air Strategic Alliance and endorsed by the Alberta Energy & Utilities Board;
- pioneering the development of new technology in well-test operations that eliminates, reduces, or improves the efficiency of flaring activity;
- completing a test project that reduced unnecessary burning of natural gas by eliminating continuous stack pilot lights and associated purge gas at selected locations. Alberta's regulatory agencies are now considering province-wide gas conservation guidelines based on this test project;
- initiating changes to process piping at Berland River operations to eliminate the need to flare sour produced gas; and
- commissioning a preliminary regional study on the Peace River airshed, the results of which have led to the establishment of a more formal air quality evaluation involving industry, provincial and municipal governments, environmental and community-based organizations.

AEC created the industry's first oil and gas Ombudsman in 1998 to ensure concerns and complaints of the Company's neighbours were heard and resolved. In 1999, Ombudsman Alister Wilson reported a second year 12% increase in the number of concerns and complaints (188) but a 10% reduction in the number of people involved (97). The biggest area of complaints or concerns involved issues related to construction or drilling activities. Less than 5% of the complaints were related to flaring and less than 4% were related to odours. At year-end, only seven of those 188 files remained open. This demonstrates increased confidence in and reliance on this effective liaison in providing local landowners and concerned individuals with a single point contact in the Company to solve problems as they occur.

Internationally, AEC's environmental initiatives in Ecuador reflect both Canadian technical capability and higher environmental standards. These initiatives included:

- a post-acquisition environmental audit of Ecuadorean production assets;
- extensive remediation and reclamation of decades-old oil by-product disposal pits of previous operators by removing and treating contaminated soil with hydrocarbon-consuming bacteria. This program is being conducted in co-operation with scientists from a local university;
- the commissioning of a 20-megawatt electric generating plant fueled by solution gas, resulting in negligible oilwell flaring and reduced reliance on diesel generators;
- retrofitting older gathering pipelines with corrosion-inhibiting liners;
- the use of directional drilling to complete several wells from each pad, reducing forest clearing and road building; and
- closed-loop, zero discharge fluid systems to eliminate drilling sumps.

In Azerbaijan, AEC is participating with its project partners in an unprecedented deep-water research project to assess deep water ecological processes, biological conditions and the ecology of deep water petroleum seeps.

AEC is known both in Canada and internationally as a Company whose environmental standards and performance record are among the best in our industry.

At AEC, we are proud of the commitment every employee makes to maintain our high standards of corporate stewardship. These standards remain a core indicator of our success as a corporation, and an ethical benchmark for future operations.

In the interest of providing AEC shareholders and potential investors with information regarding the Company, certain statements throughout this report are forward-looking statements within the meaning of section 21E of the United States Securities and Exchange Act of 1934, as amended. Readers are referred to the Advisory on the inside front cover of this Annual Report.

Management's Discussion & Analysis Of Financial Condition

Management's discussion and analysis of the financial condition and results of operations is to be read in conjunction with the Audited Consolidated Financial Statements. The Consolidated Financial Statements have been prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP). A reconciliation to United States GAAP is included in Note 18 of the Notes to the Consolidated Financial Statements.

AEC's results are reported in two business groups: Upstream comprises the Company's Domestic and International gas and oil exploration, production and marketing operations. Midstream includes the Pipelines and Gas Processing operations and the Gas Storage and Hub Services operations.

During 1999, a new Canadian accounting standard was established for Employee Future Benefits applicable for fiscal years beginning in 2000. The impact of implementing the new Employee Future Benefits standard will be a decrease in Net Earnings of approximately $3 million and an increase in Other Liabilities of approximately $13 million in the year 2000, which includes the proportionate share of the Company's interest in Joint Ventures. The Company will adopt this new standard retroactively in the year 2000.

During 1997, a new Canadian accounting standard was established for Income Taxes applicable for fiscal years beginning in 2000. The Company will adopt this new standard in the year 2000. The Emerging Issues Committee is currently considering implementation guidelines that, when finalized, will determine the impact on the Company's Financial Statements.

In May 1999, the Company acquired control of Pacalta Resources Ltd. (Pacalta), an upstream oil exploration and production company with operations primarily in Ecuador, for $1,021.5 million as described in Note 2 of the Notes to the Consolidated Financial Statements. Results of Operations includes the Pacalta results from the date acquired. The acquisition was accounted for using the purchase method.

In October 1998, the Company acquired control of Amber Energy Inc. (Amber) for $813.5 million as described in Note 2 of the Notes to the Consolidated Financial Statements. Of the total, $776.5 million related to Upstream operations and the balance related to Midstream operations. Results of Operations includes the Amber results from the date acquired. The acquisition was accounted for using the purchase method.

Consolidated Summary

Consolidated Net Earnings for 1999 amounted to $179.7 million, a 636% increase, compared to $24.4 million in 1998 (1997 - $199.7 million including a non-recurring dilution gain of $178.0 million). Consolidated Cash Flow from Operations increased 94% to $946.9 million in 1999 from $488.5 million in 1998 (1997 - $544.7 million). Consolidated Net Revenues for 1999 totaled $2,794.5 million, compared to $1,909.9 million in 1998, a 46% increase (1997 - $1,716.9 million).

Consolidated Financial Summary

($ million)	1999	1998	1997
Consolidated Net Earnings	**179.7**	24.4	199.7
Consolidated Cash Flow from Operations	**946.9**	488.5	544.7
Consolidated Net Revenues	**2,794.5**	1,909.9	1,716.9

($/share fully diluted)			
Earnings per share	**1.26**	0.21	1.73
Cash Flow from Operations per share	**6.68**	4.06	4.67

Factors affecting these results are outlined in the following table:

Factors Affecting Consolidated Results

Net Earnings

1999 Compared to 1998

$179.7 million, up $155.3 million
- higher oil prices and Domestic volumes
- higher produced gas volumes and prices
- higher oil volumes in International due to the Pacalta acquisition
- gain on the disposition of assets
- higher income tax
- higher interest charges

1998 Compared to 1997

$24.4 million, down $175.3 million
- $178.0 million lower due to the dilution gain recorded in 1997
- less additional depletion
- lower oil contributions
- higher interest expense
- lower income tax
- decrease in Pipelines' earnings
- lower straddle plant processing earnings

Cash Flow from Operations

1999 Compared to 1998

$946.9 million, up $458.4 million
- higher oil prices and Domestic volumes
- higher produced gas prices and volumes
- higher oil volumes in International due to the Pacalta acquisition
- lower cash income taxes due to prior years' recoveries
- higher purchased gas margins
- higher cash interest expense

1998 Compared to 1997

$488.5 million, down $56.2 million
- decrease in oil Operating Cash Flow
- increase in produced gas Operating Cash Flow
- higher cash interest expense
- lower cash income tax
- increases in Gas Storage and Hub Services and Pipelines' Operating Cash Flow
- decrease in straddle plant processing Operating Cash Flow

Net Revenues

1999 Compared to 1998

$2,794.5 million, up $884.6 million
- higher oil prices and volumes
- higher produced gas prices and volumes
- higher pipeline affiliate oil sales
- higher purchased gas revenues
- higher gas storage optimization revenues
- lower straddle plant processing revenues due to a disposition

1998 Compared to 1997

$1,909.9 million, up $193.0 million
- increased purchased gas prices and volumes
- lower oil and NGL prices
- increased produced gas volumes
- higher gas storage revenues
- lower pipeline affiliate oil sales
- lower Syncrude royalties
- lower straddle plant processing revenues
- higher Pipelines' revenue

Overall expenses increased to $2,631.0 million in 1999, up $763.9 million from the 1998 amount of $1,867.1 million (1997 - $1,680.4 million).

Consolidated Expense Summary

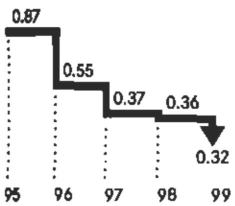
($ million)	1999	1998	1997
Operating	$ 533.9	$ 488.8	$ 450.5
Cost of Product Purchased	1,160.8	816.3	631.0
General and Administrative	37.7	30.4	28.1
Interest, net	158.8	84.7	48.9
Depreciation, Depletion and Amortization	562.6	385.6	356.5
Additional Depletion and Amortization	34.0	14.0	84.9
Income Tax	143.2	47.3	80.5
Total	$ 2,631.0	$ 1,867.1	$ 1,680.4

Factors Affecting Expenses

	1999 Compared to 1998	*1998 Compared to 1997*
Operating	$533.9 million, up $45.1 million • higher oil operating expenses due to Pacalta acquisition • higher produced gas operating costs due to volume increases • addition of full year Amber production • higher gas storage operating costs • lower straddle plant costs	$488.8 million, up $38.3 million • higher produced gas costs were partially due to higher third-party volumes processed • higher Pipeline operating costs • lower straddle plant feedstock costs
Cost of Product Purchased	$1,160.8 million, up $344.5 million • higher affiliate oil purchases • higher purchased gas prices • higher gas storage optimization costs	$816.3 million, up $185.3 million • higher purchased gas volumes and costs • lower crude oil purchase costs • higher gas storage optimization costs
General and Administrative	$37.7 million, up $7.3 million • higher staff levels and benefit costs • higher office rent costs	$30.4 million, up $2.3 million • higher staff levels, information technology and shareholder costs
Net Interest	$158.8 million, up $74.1 million • higher average debt levels • higher foreign exchange costs • lower cost of borrowing	$84.7 million, up $35.8 million • higher monthly average debt levels and cost of borrowing partially offset by a foreign exchange gain related to the Express Pipeline System financing
Depreciation, Depletion and Amortization	$562.6 million, up $177.0 million • higher gas volumes • higher Domestic oil volumes • higher International oil volumes due to the Pacalta acquisition • higher Domestic conventional per-unit rate of $1.00 compared to $0.93/thousand cubic feet equivalent in 1998	$385.6 million, up $29.1 million • higher natural gas volumes were partially offset by a lower per-unit rate of $0.93 compared to $1.02/thousand cubic feet equivalent in 1997
Additional Depletion and Amortization	$34.0 million, up $20.0 million • impairment of U.S. property costs	$14.0 million, down $70.9 million • International ceiling tests
Income Taxes	$143.2 million, up $95.9 million • higher taxable income and higher non-deductible depletion	$47.3 million, down $33.2 million • impact of lower taxable earnings was partially offset by lower non-deductible additional depletion costs

Approximately 70% of the Company's upstream revenue is denominated directly or indirectly in U.S. dollars and is subject to changes in exchange rates. The Canadian dollar average value remained constant relative to the U.S. dollar during 1999. Foreign currency fluctuations had only a nominal impact on the Company's total revenue. As a result of the lower Canadian dollar in 1998 compared to 1997, the Company's 1998 revenue was higher by approximately $35 million.

Upstream G&A Expenses
($/barrel of oil equivalent; 6:1)



Dramatic reduction in G&A expenses

Results Of Operations: Upstream

For 1999, Revenues, Net of Royalties, increased 49% or $683.8 million, to $2,087.2 million. This compares to an increase in 1998 of 16% or $194.8 million, to $1,403.4 million. The accompanying table shows the details of these changes by product.

Changes in Oil and Natural Gas Revenue

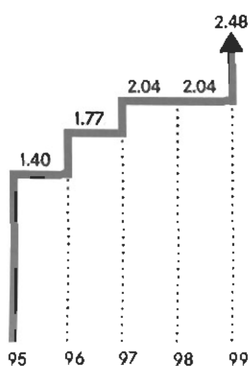
($ million)	1999 Compared to 1998					1998 Compared to 1997				
	Price	Price Hedge	Volume	Royalties & Other	Total	Price	Price Hedge	Volume	Royalties & Other	Total
Domestic										
Natural Gas and NGLs	152.1	-	137.2	(70.2)	219.1	(17.5)	2.3	111.7	(0.3)	96.2
Oil										
Conventional	101.6	-	46.4	(16.9)	131.1	(57.7)	-	(6.8)	16.0	(48.5)
Syncrude	83.9	-	12.7	(5.0)	91.6	(77.7)	-	5.1	26.6	(46.0)
Purchased Gas Sales	182.4	-	(64.9)	0.1	117.6	74.1	-	120.5	-	194.6
International	45.6	(40.1)	191.7	(72.8)	124.4	(6.6)	-	4.8	0.3	(1.5)
Total	565.6	(40.1)	323.1	(164.8)	683.8	(85.4)	2.3	235.3	42.6	194.8

Domestic Results Of Operations

Natural Gas Prices

Natural gas prices averaged $2.48/thousand cubic feet, up 22 % from $2.04/thousand cubic feet in 1998 (1997 - $2.04/thousand cubic feet). The positive price impact is attributed to additional export pipeline capacity that narrowed the U.S. / Canadian pricing differential, as well as a decline in U.S. supply. Despite record levels of gas well completions, supply in western Canada increased only marginally. Natural gas liquids prices increased 21% to $20.47 from $16.86/barrel in 1998, following the trend for crude oil (1997 - $23.97/barrel).

Average Gas Price
($/thousand cubic feet)



22% gas price increase in 1999

Factors Affecting the Price of Natural Gas

1999 Compared to 1998

- the favourable impact of increased export capacity realized was partially offset by warmer than anticipated winter weather
- the favourable impact of competing fuels prices which rose substantially in the latter half of 1999

1998 Compared to 1997

- the anticipated favourable impact of increased export capacity was offset by delays in pipeline start-ups and warmer-than-average fourth quarter weather

Natural Gas Volumes

Production volumes increased to 882 million cubic feet/day from 708 million cubic feet/day in 1998, (1997 - 588 million cubic feet/day). Production in each of 1998 and 1997 includes 19 million cubic feet/day of cushion gas from the AECO Storage Facility reservoir. Natural gas sales increased to 904 million cubic feet/day, up 27% from the 1998 total of 714 million cubic feet/day (1997 - 575 million cubic feet/day). At year-end 1999, produced gas inventory in storage was 7 billion cubic feet, down from 15 billion cubic feet in 1998 as a result of the Company's increased sales (1997 - 18 billion cubic feet).

Factors Affecting Natural Gas Sales and Production Volumes

1999 Compared to 1998

- new production brought on stream at Maxhamish, Suffield, Primrose, Ekwan and further increases at Berland River
- addition of Amber volumes for the full year of 1999
- sale of 8 billion cubic feet of gas held in inventory

1998 Compared to 1997

- new production brought on stream at Primrose, Suffield, Berland River and a second quarter plant expansion at Fontas
- sale of 3 billion cubic feet of gas held in inventory
- addition of Amber volumes from October 24, 1998

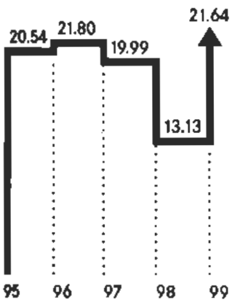
Purchased gas sales decreased to 666 million cubic feet/day from 752 million cubic feet/day in 1998 (1997 - 569 million cubic feet/day). Revenue from the sale of purchased gas increased to $688.3 million from $570.7 million in 1998 as a result of higher unit sales prices (1997 - $376.1 million). At December 31, 1999, the Company had contracts in place to purchase 258.2 billion cubic feet of natural gas over a three-year period. Contracts were also in place to deliver 132.4 billion cubic feet over two years. The Company has entered into U.S. to Canadian dollar foreign exchange agreements for values totalling $421.1 million specifically relating to these agreements. At year-end, there was 18 billion cubic feet of purchased gas in inventory (1998 - 17 billion cubic feet; 1997 - nil).

Crude Oil Prices

Prices for Canadian conventional crude oil averaged $21.64/barrel, a 65% increase from the $13.13/barrel during 1998 (1997 - $19.99/barrel). Prices for Syncrude Sweet Blend oil averaged $27.96/barrel compared to $20.46/barrel in 1998, a 37% increase (1997 - $27.80/barrel).

At the date of acquisition, Pacalta had in place oil price swap contracts on 6,833 barrels/day and sold call contracts on an additional 25,333 barrels/day until December 31, 1999, all of which have expired. A loss of US$14.1 million was accrued at the date of acquisition and included in the purchase price. Losses of C$40.1 million, incurred above the accrued amount and subsequent to the date of the acquisition, reduced oil price realizations.

Average Conventional Oil Price
($/barrel)



65% conventional oil price increase in 1999

Factors Affecting Oil Prices

1999 Compared to 1998

- declining world crude oil inventories due to constrained OPEC production have resulted in West Texas Intermediate (WTI) increasing from an average of US$14.43 in 1998 to US$19.25/barrel in 1999
- oil prices received on Ecuador production
- the heavy oil pricing differential declined to $4.29/barrel in 1999 from $5.75 in 1998

1998 Compared to 1997

- WTI prices declined 30% from an average US$20.61/barrel in 1997 to US$14.43 in 1998; this was partially offset by a decrease in Canadian dollar to U.S. dollar exchange rates average from $0.722 to $0.674
- the general decrease in oil prices was partially offset as the heavy oil pricing differential narrowed

Crude Oil and Natural Gas Liquids Volumes

AEC produced an average of 32,707 barrels/day of Domestic conventional oil in 1999, compared to the 23,027 barrels/day produced in 1998, an increase of 42% (1997 - 23,954 barrels/day). Natural gas liquids volumes decreased 13% to 5,135 barrels/day from 5,877 barrels/day (1997 - 4,856 barrels/day). Syncrude sales averaged 30,649 barrels/day, an increase of 6% over the 28,953 barrels/day sold in 1998 (1997 - 28,447 barrels/day).

Factors Affecting Domestic Oil Production

1999 Compared to 1998

- full year impact of Amber volumes
- increased production at Suffield and Pelican Lake
- 6% higher sales from AEC Syncrude

1998 Compared to 1997

- annual volumes increased due to the Amber acquisition and slightly higher production from AEC Syncrude
- declining oil prices led the Company to reduce conventional crude development
- unscheduled maintenance at Syncrude restricted production in the third and fourth quarters

Product Unit Netbacks

Product unit netbacks represent the Operating Cash Flow the Company receives, on average, for each unit of product sold. Natural gas netbacks increased 22% to $1.62/thousand cubic feet from $1.33/thousand cubic feet in 1998. Netbacks for domestic conventional oil improved 123% to $14.49/barrel in 1999, compared to $6.49 in 1998; and netbacks for Syncrude Sweet Blend averaged $15.33/barrel in 1999, an increase of 109% over the $7.33/barrel received in 1998.

Netbacks received by AEC over the past three years and the factors affecting them are summarized below:

Domestic Product Unit Netback

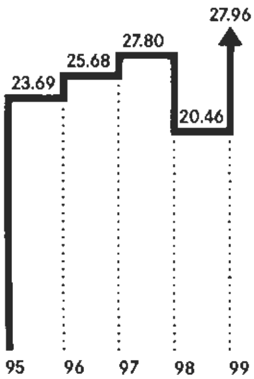
($/unit)	Natural Gas (thousand cubic feet)			Conventional Oil (barrel)			Syncrude (barrel)		
	1999	1998	1997	1999	1998	1997	1999	1998	1997
Revenue	**2.48**	2.04	2.04	**21.64**	13.13	19.99	**27.96**	20.46	27.80
Gross overriding royalty received	-	-	-	-	-	-	**0.58**	0.51	0.69
Royalties	**0.43**	0.29	0.31	**2.70**	1.82	3.58	**0.52**	(0.03)	2.70
Operating Costs*	**0.43**	0.42	0.40	**4.45**	4.82	5.70	**12.69**	13.67	13.82
Netback	**1.62**	1.33	1.33	**14.49**	6.49	10.71	**15.33**	7.33	11.97

**Net of Cost Recoveries*

Factors Affecting Unit Netbacks

	1999 Compared to 1998	*1998 Compared to 1997*
Natural Gas	• higher natural gas prices were partially offset by an associated increase in royalties; operating costs per-unit increased 2% due to new facility start-up costs	• higher per-unit operating costs, due in part to higher custom processing of third-party volumes, were partially offset by processing fee revenue earned
Domestic Conventional Oil	• higher WTI prices and lower heavy oil differentials increased realized oil prices and associated royalties; operating costs declined 8% due to lower per-unit heavy oil operating costs at Suffield • the addition of Amber volumes lowered AEC's average unit operating costs	• a decrease in the average price was partially offset by a decrease in royalties, lower heavy oil price differentials, lower foreign exchange rates and lower operating costs • the addition of Amber volumes lowered AEC's average unit operating costs
Syncrude Sweet Blend Oil	• higher WTI prices and a 7% or $0.98/barrel decrease in per-unit operating costs • higher netbacks resulted in higher royalty payments in the year • an 8% gross overriding royalty received on the lesser of 5% or 2.5 million barrels of Syncrude production, expired in August of 1999	• lower oil prices were partially offset by lower foreign exchange rates and lower operating costs • royalties decreased as a result of new fiscal terms agreed to by the Syncrude Joint Venture and the Government of Alberta

Average Syncrude Price
($/barrel)



37% Syncrude price increase

Upstream Capital

During 1999, the Upstream business group invested net capital of $940.0 million (1998 - $742.4 million), excluding major acquisitions, of which $766.2 million was directed to domestic operations (1998 - $677.7 million) and $173.8 million was directed to international ventures (1998 - $ 64.7 million).

Upstream Capital - net

($ million)	1999	1998
Domestic		
Conventional	$ 662.4	$ 597.7
Syncrude	103.3	68.3
Other	0.5	11.7
International	173.8	64.7
Total	$ 940.0	$ 742.4

Reserve replacement costs are a measure of an oil and gas company's ability to economically replace oil and gas reserves. In 1999, the Company invested $1,857.7 million ($4.86/barrel) on a proven plus probable basis, including acquisitions, compared to $1,438.9 million in 1998 ($4.70/barrel), using a natural gas to oil conversion ratio of six thousand cubic feet of natural gas to one barrel of oil, the international conversion standard.

The Company periodically evaluates the future value of its oil and gas reserves and compares them to the accounting value of those reserves on a country-by-country basis and in total. This evaluation is as prescribed in the Canadian Generally Accepted Accounting Principles Full Cost Accounting Guideline and is known as the ceiling test. At year-end, the Company's total reserve value exceeded the specified cost bases by $3.2 billion.

Domestic Capital

Investment in the Western Sedimentary Basin amounted to $662.4 million (1998 - $597.7 million) which included proceeds received on the disposal of non-core assets amounting to $40.3 million (1998 - $25.3 million).

Major exploration and development activities were undertaken in the Grande Prairie and Deep Basin areas, at Suffield and Primrose, and in newer plays at Edson, Maxhamish and Ekwan. An additional $20.6 million (1998 - $11.7 million) was invested in technical support, $0.5 million net of proceeds of disposition.

Major Capital Projects

1999
- completed construction of the Maxhamish gas facilities
- drilled 286 shallow gas wells at Suffield
- construction of the Ekwan gas plant and gas gathering system
- 22-well exploration drilling program at Ekwan

1998
- started construction of the Maxhamish gas facilities
- completed a 560-well re-completion program and drilled 285 shallow gas wells at Suffield
- developed the Primrose 25 billion cubic foot gas storage facility
- constructed a pipeline connecting the Tupper area in British Columbia to the Hythe gas plant in Alberta

At Maxhamish, production facilities with a design capability of 70 million cubic feet/day were completed during the first quarter of 1999. Production commenced in the second quarter and averaged 68 million cubic feet/day in the last three quarters.

At Ekwan, a successful 22-well exploration drilling program was carried out which resulted in the construction of a 17-mile gas gathering system and gas plant facilities capable of handling 25 million cubic feet/day of production.

At Primrose, the Company drilled 37 gas development wells, tied in 17 gas wells, installed 45 miles of gas gathering system and added 4,000 horsepower of compression facilities.

In 1999, AEC drilled 13 wells at its Steam-Assisted Gravity Drainage (SAGD) project. The Company continued exploration and development of its prospect inventory to maintain its position in the highly competitive Grande Prairie and Deep Basin areas. Additional follow up was undertaken on recent successes in Tupper where gas production of 10 million cubic feet/day commenced in December.

In addition, $16.4 million was invested in exploration projects in North Dakota and Montana. The Company has determined the carrying value for the U.S. exploration program should be reduced which has resulted in Additional Depreciation, Depletion and Amortization (DD&A) charges of $34.0 million.

Investments in AEC Syncrude totaled $103.3 million primarily directed to sustaining production, new equipment installation and the Aurora mine.

International Results of Operations

On May 4, 1999, the Company acquired control of Pacalta, an exploration and production company with operations based primarily in Ecuador. Results of Operations include Pacalta from the date of acquisition.

AEC International's total production amounted to 27,347 barrels/day in 1999, reflecting the part year impact of the Pacalta acquisition. Production from Ecuador averaged 38,833 barrels/day from the date of acquisition to year-end 1999. Argentine production declined to 1,707 barrels/day compared to 2,217 barrels/day produced in 1998 (1997 - 1,683 barrels/day).

In Ecuador, sales volumes are currently constrained by available pipeline transportation which is allocated among shippers based upon the shippers' productive capacity and the quality of crude oil. The Company's current pipeline allocation amounts to 39,000 barrels/day of medium grade crude oil. Shipments of light grade crude oil are not constrained. Negotiations on the construction, ownership and operation of a new pipeline capable of shipping approximately 290,000 barrels/day are in an advanced stage. AEC's midstream business group is actively involved in those negotiations.

The Ecuador oil price average of $25.08/barrel was reduced by payments required under oil price swap and option agreements in place at acquisition of $40.1 million or $4.29/barrel to $20.79/barrel. All price-hedging agreements terminated at December 31, 1999. Argentine oil prices averaged $24.94/barrel, an increase of 43% from the 1998 average price of $17.44/barrel (1997 - $24.66/barrel).

In Argentina, the Company discovered promising quantities of natural gas reserves and has elected to focus future development activities towards the production and sale of those reserves. The Company is considering selling the currently held oil properties and has commenced a process to evaluate this option.

Ecuador Oil Unit Netback

($/barrel)	1999
Revenue	**$ 25.08**
Royalties	**7.64**
Operating Costs	**3.55**
Netback before Hedge Costs	**$ 13.89**
Hedge Costs	**4.29**
Netback after Hedge Costs	**$ 9.60**

International Capital

The acquisition of Pacalta for $1,021.5 million, for a combination of cash, assumed debt and the Company's shares, is described in Note 2 of the Notes to the Consolidated Financial Statements. This acquisition establishes the Company's presence in one of its designated core International areas. Further growth by way of acquisition and exploration and development is contemplated.

Capital programs in AEC's International operations amounted to $174.7 million in 1999 (1998 - $64.7 million) before minor dispositions of $0.9 million (1998 - nil). In addition to continuing exploration and development operations in Ecuador ($94.3 million) and Argentina ($41.4 million), the appraisal of the John Brookes discovery continues on the Australian Northwest Shelf. The Company has a 25% interest in this well. One additional exploration well has been drilled on an adjacent structure and did not encounter economic reserves. Capital investment in Australia amounted to $10.4 million (1998 - $16.8 million). Further drilling will be required to appraise the size of the discovery.

During 1999, the Company acquired a 5% interest in the ALOV project in the Caspian Sea. Capital investment in 1999 amounted to $23.1 million and included a 3-D seismic survey which was completed in late 1999. Drilling of the first exploration well has been deferred to 2001 because of limited rig availability in the Caspian Sea. The ALOV prospect represents the largest known undrilled structure in the Caspian Sea.

Low oil prices at year-end 1998 and a decision to discontinue operations in Thailand resulted in additional depletion in the amount of $14.0 million being recorded relating to International properties in 1998.

Results Of Operations: Midstream

For 1999, Midstream revenues increased 40% to $707.3 million compared to $506.5 million in 1998 (1997 - $508.3 million). The factors contributing to this increase are detailed below:

Factors Affecting Midstream Revenue

	1999 Compared to 1998	*1998 Compared to 1997*
Pipelines	• increased due to higher oil sales revenue of a 50%-owned affiliate shipping on the Express Pipeline System	• decreased due to lower oil sales revenue of a 50%-owned affiliate shipping on the Express Pipeline System; this was partially offset by an increase in revenues due to full-year operation of the Express Pipeline System compared to nine months in 1997
Natural Gas Liquids Processing	• revenues declined due to the first quarter sale of Pan-Alberta Resources Inc., partially offset by an increase in NGL prices	• revenues declined as natural gas liquids prices followed the decline in oil prices
Natural Gas Storage	• revenues increased due to higher sales of purchased gas volumes associated with the optimization of the facilities and the start-up of the Wild Goose and Hythe storage facilities	• revenues increased due to increasing emphasis on the optimization of the facility which involved the purchase and sale of natural gas

Net Capital investment in the Pipelines group amounted to $66.6 million in 1999 (1998 - $68.5 million). Throughput capacity constraints previously imposed on the Express System were removed in 1999 following the regulator's approval to return the Platte Pipeline segment of the system to licensed operating pressure. During 1999, the Company gave notice of its intention to assume operatorship of the Platte System as of March 1, 2000.

During the first quarter of 1999, the Company sold its investment in Pan-Alberta Resources Inc. (PARI) and the Iroquois Gas Transmission System for total proceeds of $56.2 million as described in Note 3 of the Notes to the Consolidated Financial Statements. The Company also received $6.0 million proceeds on the sale of a non-essential gathering line on the Platte Pipeline.

The Company holds a 50% ownership in an affiliate that is a shipper on the Express Pipeline System. The revenue from oil sold and the cost of oil purchased and shipped on the Express System is reflected in revenue and cost of product purchased, respectively. Affiliate revenue included in the Pipelines total amounted to $361.0 million in 1999 as compared to $219.8 million in 1998 reflecting higher average oil prices and higher volumes traded (1997 - $259.5 million).

During 1999, the Company, through its ownership interest in the AEC Pipelines, L.P., undertook and completed an expansion of the Alberta Oil Sands Pipeline Ltd. (AOSPL) pipeline in order to accommodate increased volume throughput from the Syncrude oilsands plant. Syncrude owners compensate AOSPL for the financial carrying cost until the expansion is included in the overall rate base for the system which is expected to occur no later than April 1, 2000.

In 1999, the Company invested $45.6 million in its gas storage operations (1998 - $43.2 million). The new 14-billion cubic foot Wild Goose Gas Storage Facility in California was completed and in service in April 1999. The Company also completed a new 10-billion cubic foot facility near Hythe, Alberta due to increased demand for storage services and in anticipation of the completion of the Alliance Pipeline System.

During the year, the Company accelerated a program of natural gas purchases and sales designed to optimize utilization of its storage facilities. This resulted in gas sales of $145.8 million (1998 - $34.0 million) which is included in Gas Storage Revenue. At year-end 1999, Gas Storage and Hub Services had 14 billion cubic feet of gas in storage in Canada and an additional 5 billion cubic feet in the U.S., substantially all of which has been contracted for delivery and sale in the year 2000.

Liquidity And Capital Resources

Consolidated capital investment totaled $2,042.8 million in 1999 (1998 - $1,671.5 million). On a consolidated basis in 1999, excluding the Pacalta acquisition, the Company invested $1,021.3 million of which $940.0 million, or 92%, was in the upstream business group, and $81.3 million in the midstream business group, including $90.0 million of indirect pipelines capital. In 1998, excluding the Amber acquisition, the Company invested $858.0 million. Factors affecting capital are detailed below:

	1999	*1998*
Domestic *Conventional*	$662.4 million • $356.6 million on exploration and development drilling • $212.5 million on production facilities • $133.6 million on land and seismic • $40.3 million on minor dispositions	$597.7 million • $320.2 million on exploration and development drilling • $188.2 million on production facilities • $114.6 million on land and seismic • $25.3 million on minor dispositions
Syncrude	$103.3 million • ongoing mine expansion and capital improvements	$68.3 million • ongoing mine expansion and capital improvements
Other	$0.5 million	$11.7 million
International	$173.8 million • $94.3 million exploration and development in Ecuador • $41.4 million on exploration and development in Argentina • $23.1 million on the ALOV prospect in the Caspian Sea • $10.4 million on exploration on the Australian Northwest Shelf • $4.6 million in other countries	$64.7 million • $42.8 million on exploration and development in Argentina • $16.8 million on exploration wells on the Australian Northwest Shelf • $5.1 million in other countries
Express Pipeline System	$10.4 million • refurbishing the Platte System from Casper, Wyoming to Wood River, Illinois • ongoing capital improvements • Platte non-essential gathering system disposition	$25.8 million • refurbishing the Platte System from Casper, Wyoming to Wood River, Illinois • ongoing capital improvements
Other Pipelines	$56.2 million • investments in AEC Pipelines, L.P., holder of Alberta Oil Sands and Cold Lake pipelines and in directly-held pipelines • $21.9 million Iroquois disposition	$42.7 million • investments in AEC Pipelines, L.P., holder of Alberta Oil Sands and Cold Lake pipelines and in directly-held pipelines
Gas Storage	$45.6 million • completed construction of the Wild Goose Gas Storage Facility • construction of the AECO storage expansion in northwest Alberta	$43.2 million • construction of the Wild Goose Gas Storage Facility • construction of the AECO storage expansion in northwest Alberta
Natural Gas Liquids Processing	($30.9) million • ongoing capital maintenance • $34.3 million PARI disposition	$3.9 million • facility expansion

The Company funded its investment program primarily through a combination of Cash Flow from Operations of $946.9 million, proceeds on the disposal of non-core assets of $123.7 million, and issue of long-term debt. The acquisitions of Pacalta and Amber were funded with a combination of long-term debt, AEC shares and debt assumed.

On a consolidated basis, long-term debt held directly by the Company was $1,940.4 million at December 31, 1999, up $293.7 million from the 1998 amount of $1,646.7 million. The Company has five revolving credit facilities available. The maximum amount of these lines remains at approximately $1.6 billion with terms ranging from three to five years, if not extended. At December 31, 1999, $399 million or 25% was utilized. The Company has the capability to issue up to an additional $350 million of unsecured debentures by way of a medium-term note shelf prospectus, until July 2001. Total debt is $2,316.1 million (1998 - $1,977.4 million), of which $375.7 million is the Company's proportionate share of debt of affiliates.

The Company maintains a separate capital structure for each of its upstream and midstream business groups, consistent with the norms for those industries, to recognize the different business profiles, risks and rewards associated with each. The midstream business group's debt is comprised of indirect debt held by the Express System, AEC Pipelines, L.P., and allocated AEC debt to establish an industry benchmark debt-to-capitalization ratio of 60:40. At December 31, 1999, $1,627.7 million of long-term debt was related to upstream operations and $688.4 million was included in the midstream operations, of which $375.7 million was indirect debt.

In August 1999, the Company completed a Canadian offering of Preferred Securities totalling $200 million principal amount due September 30, 2048. Each security represents $25 principal amount of unsecured junior subordinated debentures, bears a fixed charge at 8.50%/annum payable quarterly, has a term of approximately 49 years and is redeemable at par by AEC at any time after five years. In September 1999, the Company closed a US$150 million offering of Preferred Securities due September 30, 2048. Each security represents US$25 principal amount of unsecured junior subordinated debentures, bears a fixed charge at 9.50%/annum payable quarterly, has a term of approximately 49 years and is redeemable at par by AEC at any time after five years. Net proceeds from both issues were used to repay indebtedness and for general corporate purposes.

Risk Management

The Company's results are influenced by factors such as product prices, interest and foreign exchange rates, royalties, taxes and operations. Sensitivities to some of these factors are summarized below:

Factor	2000 Impact on Cash Flow from Operations	
	$	Per Share
Change of US$0.10/thousand cubic feet in the price of natural gas	**$ 45 million**	**$0.30**
Change of US$1.00 WTI/barrel in the price of oil	**$ 47 million**	**$0.31**
Change of $0.01 in the value of the Canadian dollar relative to the U.S. dollar	**$ 29 million**	**$0.19**

The Company seeks to manage its risk exposure through a combination of internal controls, sound operating practices, insurance and financial derivatives. Derivatives such as commodity price swap agreements, interest rate swaps, and foreign exchange forward sale contracts are used only to reduce specific risk exposures and are not held for trading purposes.

During 1999, the Company utilized commodity price swaps for produced and purchased gas, and acquired, through Pacalta, oil price swap agreements.

At acquisition, Amber had in place floating-to-fixed interest rate swaps and foreign exchange forward sales contracts. Foreign exchange contract losses of $11.4 million at the date of acquisition were accrued and included in the purchase price.

Foreign exchange contracts in the amount of $421.1 million were contracted to limit U.S. to Canadian exchange rate fluctuations on the Company's natural gas purchase and sale agreements. These contracts fix the U.S. to Canadian rate of exchange to an average of $1.48 until November 2002.

In addition to limits established by the Board of Directors on the use of commodity price swap agreements, a rigorous system of internal control procedures has been established. Credit risks are managed by transacting only with pre-authorized counterparties where agreements are in place. Credit limits are established for all parties with whom a credit risk exposure exists and are closely monitored.

An active program of monitoring and reporting day-to-day operations is designed to provide assurance that environmental and regulatory standards are met. Contingency plans are in place for timely response to an event.

AEC is exposed to risks and uncertainties inherent in foreign operations, including regulatory and legislative changes.

Events in these operations could have a material adverse effect on the Company. The Company has undertaken to mitigate these risks, where considered warranted.

Year 2000 Readiness

The Company advises that its Year 2000 (Y2K) computer readiness plan resulted in a smooth transition into the new year. AEC has experienced no material disruption, upset or loss in its internal operations resulting from any Y2K related issues. Existing contingency and emergency response plans will continue to manage any abnormal circumstance should the need arise. In 1999, approximately $4 million was spent on Y2K issues. This amount does not include AEC's share of Y2K costs that were incurred by partnerships and joint ventures in which the Company participates but is not the operator.

Outlook

The Company's production is forecast to increase by approximately 20% on a BOE basis in the year 2000. Higher prices are anticipated for natural gas, while oil prices are expected to be comparable to the levels realized in 1999. With those assumptions, and in the absence of a material adverse event, our outlook is for continued improvements in both Cash Flow and Net Earnings. Produced gas sales are expected to grow 11% to one billion cubic feet/day in 2000. The Company believes it has secured adequate gas pipeline transportation to achieve its forecasted direct sales volumes. At the time of writing, 48% of AEC's 2000 produced gas sales are committed. The remaining uncommitted volumes consist of 81% of sales targeted to markets inside Alberta and 19% of sales targeted to markets outside Alberta. Storage inventory is forecast to be approximately 13 billion cubic feet of produced gas at the beginning of the 2000 - 2001 winter heating season. Sales of oil and liquids are expected to grow 36% to 130,000 barrels/day with approximately the following mix:

- Light and NGLs 38%
- Ecuador Medium 35%
- Heavy 27%

Alberta natural gas prices have strengthened as additional export capacity came on stream in late 1998 providing access to U.S. markets. The Company expects continuing growth in U.S. natural gas demand, coupled with declining U.S. domestic production, will result in stronger prices for both U.S. and domestic markets in 2000.

During 2000, oil prices are expected to remain near the levels realized in 1999 assuming OPEC continues to manage production levels. Oil netbacks per unit are expected to be comparable to 1999 levels. All fixed differential and term sale agreements in place during 1999 expired by December 31, 1999.

In 2000, AEC expects its direct capital investment in core programs to be approximately $1,300 million, 73% of which is directed to Domestic exploration and production activities, 23% towards International Upstream opportunities and 4% to Midstream ventures. Capital required for acquisitions, if any, would be in addition to these amounts.

AEC is targeting to drill up to 875 gross wells in 2000, the majority of which will target natural gas.

In June, AEC's Board of Directors approved plans for a commercial SAGD project at the Company's Foster Creek location on the Primrose Air Weapons Range in northeast Alberta. The project is currently in the regulatory approval process. This $240 million facility is expected to produce 20,000 barrels/day beginning in late 2001. This first phase of the project area will have an approximate total of 145 million barrels of established reserves. It is also expected to be one of the lowest cost thermal recovery projects in the industry, with operating costs below $5/barrel. The Company has delineated enough resource in the area of the SAGD pilot project to support 100,000 barrels/day of production by the year 2007.

Capital investments in Syncrude of approximately $750 million (AEC's share in 1999 dollars) for expansion projects over the next eight years are expected to approximately double AEC's share of production to over 56,000 barrels/day and reduce production costs to under $10/barrel, in 1999 dollars, by 2007.

Direct midstream operations are targeting $50 million in investments and are expected to generate stable Operating Cash Flow as a result of improvements in the pipeline operations and additional new gas storage capacity, offsetting decreases due to dispositions in 1999.

AEC's rapid growth in recent years has been achieved by a balance of internal growth and strategic acquisitions. The Company continues to pursue opportunities which may include significant corporate or asset acquisitions to develop and expand its business. AEC may finance any such acquisitions with debt or equity or a combination of both.

The Company will continue to assess the way in which it finances its operations to achieve its growth targets in a financially prudent manner. The Company intends to finance its 2000 budgeted capital program through Cash Flow from Operations, long-term debt and other financing vehicles that optimize full-cycle capital returns.

February 16, 2000

Management Report

The accompanying consolidated financial statements and all information in this annual report are the responsibility of Management. The financial statements have been prepared by Management in accordance with Canadian Generally Accepted Accounting Principles and include certain estimates that reflect Management's best judgements. Financial information contained throughout this annual report is consistent with these financial statements.

The Company has a written ethics and integrity policy and has developed and maintains an extensive system of internal control that provides reasonable assurance that all transactions are accurately recorded, that the financial statements realistically report the Company's operating and financial results and that the Company's assets are safeguarded. The Company's Internal Audit department reviews and evaluates the adequacy of and compliance with the Company's internal controls. As well, it is the policy of the Company to maintain the highest standard of ethics in all its activities.

AEC's Board of Directors has approved the information contained in the financial statements. The Board fulfills its responsibility regarding the financial statements mainly through its Audit Committee. The Audit Committee meets on a quarterly basis to review and approve the financial statements.

PricewaterhouseCoopers LLP, an independent firm of chartered accountants, was appointed by a vote of shareholders at the Company's last annual meeting to audit the consolidated financial statements and provide an independent professional opinion.

Gwyn Morgan
President & Chief Executive Officer
February 16, 2000

John D. Watson
Vice-President, Finance & Chief Financial Officer

Auditors' Report

To the Shareholders of Alberta Energy Company Ltd.:

We have audited the consolidated balance sheets of Alberta Energy Company Ltd. as at December 31, 1999 and December 31, 1998 and the consolidated statements of earnings, retained earnings and cash flows for each of the years in the three-year period ended December 31, 1999. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian Generally Accepted Auditing Standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 1999 and December 31, 1998 and the results of its operations and the changes in its cash position for each of the years in the three-year period ended December 31, 1999, in accordance with Canadian Generally Accepted Accounting Principles.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta, Canada
February 4, 2000

CONSOLIDATED STATEMENT OF EARNINGS

Year ended December 31
($ million, except per share amounts)

	1999	1998	1997
Revenues, Net of Royalties			
Upstream	$2,087.2	$1,403.4	$1,208.6
Midstream (Note 3)	707.3	506.5	508.3
	2,794.5	1,909.9	1,716.9
Costs, Expenses and Other			
Operating	533.9	488.8	450.5
Cost of product purchased	1,160.8	816.3	631.0
General and administrative	37.7	30.4	28.1
Interest, net (Note 4)	158.8	84.7	48.9
Depreciation, depletion and amortization	562.6	385.6	356.5
Additional depletion and amortization (Note 7)	34.0	14.0	84.9
Gain on sale of assets / Dilution gain (Note 3)	34.6	–	178.0
Earnings Before the Undernoted	341.3	90.1	295.0
Minority interest	18.4	18.4	14.8
Income taxes (Note 5)	143.2	47.3	80.5
Net Earnings	179.7	24.4	199.7
Preferred Securities charges, net of tax	6.7	–	–
Net Earnings Attributable to Common Shareholders	$ 173.0	$ 24.4	$ 199.7
Earnings per Common Share			
Basic	$ 1.28	$ 0.21	$ 1.78
Fully diluted	$ 1.26	$ 0.21	$ 1.73

See accompanying notes to the Consolidated Financial Statements

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

Year ended December 31
($ million)

	1999	1998	1997
Balance, Beginning of Year	$ 627.6	$ 648.2	$ 493.0
Net Earnings	179.7	24.4	199.7
	807.3	672.6	692.7
Common Share Dividends	(55.9)	(45.0)	(44.5)
Preferred Securities Charges, Net of Tax	(6.7)	–	–
Balance, End of Year	$ 744.7	$ 627.6	$ 648.2

See accompanying notes to the Consolidated Financial Statements

CONSOLIDATED BALANCE SHEET

As at December 31

($ million)	1999	1998
ASSETS		
Current Assets		
Cash	$ 68.6	$ 29.7
Accounts receivable and accrued revenue	531.5	370.2
Inventories (Note 6)	214.5	139.7
	814.6	539.6
Capital Assets (Note 7)	6,786.9	5,224.2
Investments and Other Assets (Note 8)	54.8	95.9
	$7,656.3	$5,859.7
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	$ 525.1	$ 427.0
Current portion of long-term debt	4.5	1.8
	529.6	428.8
Long-Term Debt (Note 9)	1,940.4	1,646.7
Indirect Midstream Long-Term Debt (Note 10)	375.7	330.7
Other Liabilities (Note 11)	142.3	134.6
Deferred Income Taxes	774.3	630.7
Minority Interest, AEC Pipelines, L.P.	102.4	108.3
	3,864.7	3,279.8
Shareholders' Equity		
Preferred Securities (Note 12)	413.5	-
Share capital (Note 12)	2,618.7	1,916.0
Retained earnings	744.7	627.6
Foreign currency translation adjustment	14.7	36.3
	3,791.6	2,579.9
	$7,656.3	$5,859.7

See accompanying notes to the Consolidated Financial Statements

Approved by the Board

DIRECTOR

DIRECTOR

CONSOLIDATED STATEMENT OF CASH FLOWS

Year Ended December 31
($ million, except per share amounts)

	1999	1998	1997
OPERATING ACTIVITIES			
Net Earnings	$ 179.7	$ 24.4	$ 199.7
Depreciation, depletion and amortization	562.6	385.6	356.5
Additional depletion and amortization (Note 7)	34.0	14.0	84.9
Deferred income taxes	172.7	47.9	67.8
Minority interest	18.4	18.4	14.8
Gain on sale of assets / Dilution gain (Note 3)	(34.6)	-	(178.0)
Other	14.1	(1.8)	(1.0)
Cash Flow from Operations	946.9	488.5	544.7
Net change in non-cash working capital (Note 14)	(258.6)	(59.6)	(84.8)
	688.3	428.9	459.9
INVESTING ACTIVITIES			
Acquisitions (Note 2)	(31.3)	(303.2)	-
Capital investment	(1,145.0)	(883.3)	(984.4)
Proceeds on disposal of assets (Note 3)	123.7	25.3	195.0
Net proceeds on sale of AEC Pipelines, L.P. (Note 3)	-	-	295.4
Investments and other	1.6	(10.5)	-
Net change in non-cash working capital (Note 14)	26.8	(9.5)	(9.9)
	(1,024.2)	(1,181.2)	(503.9)
Decrease in cash before financing activities	(335.9)	(752.3)	(44.0)
FINANCING ACTIVITIES			
Issue of long-term debt	452.5	693.7	142.1
Repayment of long-term debt	(416.0)	(110.8)	(100.7)
Issue of preferred securities (Note 12)	413.5	-	-
Issue of common shares (Note 12)	44.1	220.0	14.0
Common share dividends	(55.9)	(45.0)	(44.5)
Preferred Securities charges, net of tax	(6.7)	-	-
AEC Pipelines, L.P. distributions	(24.3)	(24.3)	(13.1)
Net change in non-cash working capital (Note 14)	(5.4)	-	-
Other	(27.0)	3.6	14.3
	374.8	737.2	12.1
Increase (decrease) in cash	$ 38.9	$ (15.1)	$ (31.9)
Cash, beginning of year	$ 29.7	$ 44.8	$ 76.7
Cash, end of year	$ 68.6	$ 29.7	$ 44.8
CASH FLOW FROM OPERATIONS PER COMMON SHARE			
Basic	$ 7.02	$ 4.26	$ 4.87
Fully diluted	$ 6.68	$ 4.06	$ 4.67
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION			
Interest paid	$ 148.4	$ 89.0	$ 51.0
Income taxes paid	$ 11.8	$ 13.2	$ 14.7

1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

THE COMPANY ORGANIZES ITS OPERATIONS INTO TWO BUSINESS GROUPS. UPSTREAM INCLUDES THE DOMESTIC OPERATIONS, INCLUDING THE EXPLORATION FOR AND PRODUCTION OF NATURAL GAS AND OIL IN NORTH AMERICA, AND THE INTERNATIONAL OPERATIONS. MIDSTREAM INCLUDES BOTH THE PIPELINES AND PROCESSING OPERATIONS AND THE GAS STORAGE AND HUB SERVICES OPERATIONS.

(A) PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of Alberta Energy Company Ltd. (the "Company") and its subsidiaries, all of which are wholly owned, except for AEC Pipelines, L.P., which is 70% owned.

Investments in jointly controlled companies, jointly controlled partnerships (collectively called "affiliates") and unincorporated joint ventures are accounted for using the proportionate consolidation method, whereby the Company's proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

Investments in companies and partnerships over which the Company has significant influence are accounted for using the equity method.

A listing of major subsidiaries, affiliates, unincorporated joint ventures and partnerships can be found on the inside back cover.

(B) CAPITAL ASSETS

Upstream

Conventional The Company accounts for conventional oil and gas properties in accordance with the Canadian Institute of Chartered Accountants' guideline on full cost accounting in the oil and gas industry.

All costs associated with the acquisition, exploration and development of oil and gas reserves are capitalized in cost centres on a country by country basis.

Depletion and depreciation are calculated using the unit-of-production method based on estimated proven reserves, before royalties. For purposes of this calculation, oil is converted to gas on an energy equivalent basis. All capitalized costs, except as noted, are subject to depletion and depreciation including costs related to unproven properties as well as estimated future costs to be incurred in developing proven reserves. Costs of exploration and land in international cost centres and certain unproved lands in Canada are excluded from costs subject to depletion until it is determined whether or not proved reserves are attributable to the properties or impairment has occurred.

Future removal and site restoration costs are estimated and recorded over the estimated life of the reserves.

A ceiling test is applied to ensure that capitalized costs do not exceed the sum of estimated undiscounted, unescalated future net revenues from proven reserves less the cost incurred or estimated to develop those reserves, related production, interest and general and administrative costs, and an estimate for restoration costs and applicable taxes. The calculations are based on sales prices and costs at the end of the year.

Syncrude Capital assets associated with the Syncrude project are accumulated, at cost, in a separate cost centre. Substantially all of these costs are amortized using the unit-of-production method based on estimated proven developed reserves, applicable to the project.

Midstream

Capital assets related to pipelines are carried at cost and depreciated using the straight-line method over their economic lives, which range from 20 to 35 years.

Capital assets related to the Company's natural gas liquids extraction plant operations and gas storage facilities are carried at cost and depreciated using the straight-line method over a term of 20 years.

(C) FOREIGN CURRENCY TRANSLATION

Operations outside Canada are considered to be self-sustaining and use their primary currency for recording substantially all transactions. The accounts of self-sustaining foreign subsidiaries are translated using the current rate method, whereby assets and liabilities are translated at year-end exchange rates while revenues and expenses are converted using average annual rates. Translation gains and losses relating to these subsidiaries are deferred and included in shareholders' equity.

Long-term debt payable in U.S. dollars is translated into Canadian dollars at the year-end exchange rate, with any resulting adjustment amortized using the straight-line method over the remaining life of the debt.

(D) INVENTORIES

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

(E) INTEREST CAPITALIZATION

Interest is capitalized during the construction phase of large capital projects.

(F) HEDGING ACTIVITIES

Settlement of crude oil and natural gas price swap agreements, which have been arranged as a hedge against commodity price and currency fluctuations, are reflected in product revenues at the time of sale of the related hedged production.

(G) INCOME TAXES

Income taxes are recorded using the deferral method of accounting.

(H) CASH AND CASH EQUIVALENTS

Cash and cash equivalents include short term investments with a maturity of three months or less when purchased.

(I) STOCK-BASED COMPENSATION

No compensation costs have been recognized in the financial statements for share options granted to employees and directors. (See also Note 18 (F) - United States Accounting Principles and Reporting.)

(J) COMPARATIVE FIGURES

Certain 1998 and 1997 figures have been reclassified for comparative purposes.

2 ACQUISITIONS

In May 1999, the Company acquired control of all of the issued and outstanding common shares of Pacalta Resources Ltd. (Pacalta) for consideration of 15.1 million common shares and cash. Pacalta is engaged in the exploration for and production of crude oil in South America.

In October 1998, the Company acquired Amber Energy Inc. (Amber) for consideration of cash and 4.5 million Common Shares. Concurrent with the acquisition, the Company issued 6.35 million Common Shares for net proceeds of $195.4 million, which was used as part of the cash consideration paid for the shares of Amber. Amber is engaged in the exploration and production of oil and natural gas in Canada.

These acquisitions have been accounted for using the purchase method with the results of operations of Pacalta and Amber included in the consolidated financial statements from the dates of acquisition.

	1999 Pacalta	1998 Amber
The fair value of assets acquired is as follows:		
Non-cash working capital (deficiency)	$ *(91.9)*	$ 1.7
Capital assets	1,098.0	833.1
Other non-current assets	3.4	-
Deferred income taxes	22.4	(7.5)
Other non-current liabilities	(10.4)	(13.8)
Net assets acquired	$ 1,021.5	$ 813.5
Financed By:		
Cash consideration	$ 31.3	$ 303.2
Equity consideration	658.6	150.0
Long-term debt assumed	331.6	360.3
	$ 1,021.5	$ 813.5

3 DISPOSITIONS

Total proceeds on disposal of assets was $123.7 million comprised of:

Midstream Assets

During the first quarter, the Company sold its investment in Pan-Alberta Resources Inc., a 50% owner of a natural gas liquids extraction facility at Empress, Alberta and its investment in Iroquois Gas Transmission System L.P., owner of a natural gas export pipeline shipping natural gas from Ontario, Canada to the eastern United States. Total proceeds received were $56.2 million and the gains on sale were $34.6 million before income tax.

Midstream revenue includes equity earnings from the Company's investments of nil (1998 - $4.7 million; 1997 - $4.6 million).

Disposal of assets

In 1999, the Company sold certain non-core assets for proceeds of $44.8 million (1998 - $25.3 million; 1997 - $92.2 million). In addition, the Company sold $22.7 million of assets that were subsequently leased under a long-term operating lease agreement. In 1997, $102.8 million of oil and gas equipment and storage equipment was sold and subsequently leased under a long-term operating lease agreement.

AEC Pipelines, L.P.

In April 1997, AEC Pipelines, L.P., a limited partnership, completed a public offering of partnership units for cash proceeds of $301.2 million. The partnership acquired the Company's crude oil pipeline assets together with subordinated notes and non-voting shares in AEC Express Holdings Ltd. The Company holds a 70% interest in the partnership and the minority interest has been reflected in these financial statements.

A dilution gain, which represents the increase in the Company's share of the accounting value of the partnership equity, of $178 million ($1.59 per Common Share-basic) was recorded in 1997. Income tax was not provided, as the Company had no plans to dispose of the asset.

4 INTEREST, NET

	1999	1998	1997
Interest expense - long-term debt	$ 151.9	$ 92.5	$ 57.7
Interest expense - other	16.2	(1.6)	1.4
Interest income	(6.9)	(4.9)	(3.3)
	161.2	86.0	55.8
Less:			
Capitalized interest	2.4	1.3	6.9
Interest, net	$ 158.8	$ 84.7	$ 48.9

Included in 1998 interest expense - other is a $7.1 million foreign exchange gain related to the reduction in the Company's net investment in the Express Pipeline System.

5 INCOME TAXES

The provision for income taxes is as follows:

	1999	1998	1997
Current	$ (38.6)	$ (9.3)	$ 7.7
Deferred	172.7	47.9	67.0
Alberta royalty tax credit	(1.4)	(1.2)	(1.5)
Large corporations tax	10.5	9.9	7.3
Income taxes	$ 143.2	$ 47.3	$ 80.5

The following table reconciles income taxes calculated at statutory rates with actual income taxes:

	1999	1998	1997
Earnings before income taxes	$ 322.9	$ 71.7	$ 280.2
Income taxes at statutory rate of 44.62%	$ 144.1	$ 32.0	$ 125.0
Effect on taxes resulting from:			
Non-deductible Canadian crown payments	75.6	42.9	42.7
Non-deductible depreciation, depletion and amortization	41.0	22.2	23.5
Non-deductible additional depletion	1.8	3.6	26.3
Non-taxable dilution gain (Note 3)	-	-	(79.4)
Previously unrecognized losses	(27.8)	-	-
Federal resource allowance	(98.9)	(52.2)	(56.9)
Alberta royalty tax credit	(1.4)	(1.2)	(1.5)
Large corporations tax	10.5	9.9	7.3
Statutory rate differences	(6.7)	-	-
Other	5.0	(9.9)	(6.5)
Income taxes (Effective rate: 1999 - 44.3%; 1998 - 66.0%; 1997 - 28.7%)	$ 143.2	$ 47.3	$ 80.5

The amount of capital assets without a tax base is $1,197.5 million (1998 - $690.5 million). The amount of tax pools available are approximately $3.5 billion (1998 - $2.8 billion).

6 INVENTORIES

	1999	1998
Product		
Upstream	$ 65.5	$ 57.5
Midstream	100.3	36.8
Parts, supplies and other	48.7	45.4
	$ 214.5	$ 139.7

7 CAPITAL ASSETS

	1999 Cost	1999 Accumulated DD&A*	1999 Net	1998 Cost	1998 Accumulated DD&A*	1998 Net
Upstream						
Domestic						
Conventional	$6,535.4	$2,533.3	$4,002.1	$5,877.1	$2,090.2	$3,786.9
Syncrude	715.2	203.5	511.7	613.2	187.6	425.6
International	1,511.0	242.0	1,269.0	183.6	115.7	67.9
Midstream	1,341.7	337.6	1,004.1	1,270.1	326.3	943.8
	$10,103.3	$3,316.4	$6,786.9	$7,944.0	$2,719.8	$5,224.2

Depreciation, depletion and amortization

Included in Midstream is $45.4 million (1998 - $36.8 million) related to cushion gas, required to operate the gas storage facilities, which is not subject to depletion.

In the year ended December 31, 1999, $90.9 million (1998 - $37.9 million; 1997 - $7.0 million) of expenditures in International cost centers and $340.0 million of unproved land (1998 - $117.0 million; 1997 - nil) in Canada were excluded from depletable costs.

The prices used in the ceiling test evaluation of the Company's conventional reserves at December 31, 1999 were as follows:

Domestic		
Natural gas	$	2.70/thousand cubic feet
Crude oil	$	29.15/barrel
Natural gas liquids	$	29.95 /barrel
International		
Ecuador crude oil	US$	20.00/barrel
Argentina crude oil	US$	24.12/barrel

Additional depletion and amortization of $34.0 million relates to an impairment of capital costs incurred in the United States. The ceiling test evaluation on International cost centres in 1998 resulted in a $14.0 million charge (1997 - $72.4 million). Additional amortization of Midstream capital assets in 1997 was $12.5 million.

Depreciation, depletion and amortization includes $88.5 million (1998 - $49.8 million; 1997 - $52.7 million) of depletion related to costs which are not deductible for income tax purposes.

8 INVESTMENTS AND OTHER ASSETS

	1999	1998
Deferred financing costs	**$ 27.7**	**$ 26.9**
Deferred foreign exchange (gain)	**(6.6)**	**21.7**
Assets under capital lease	**20.5**	**21.0**
Investment in Iroquois Gas Transmission System	-	**19.7**
Other	**13.2**	**6.6**
	$ 54.8	**$ 95.9**

9 LONG-TERM DEBT

	Note Reference	1999	1998
Canadian dollar debt			
Revolving credit and term loan borrowings	B	**$ 273.4**	**$ 470.8**
Unsecured debentures			
9.50% due 2000		**25.0**	**25.0**
7.60% due 2001		**50.0**	**50.0**
9.85% due 2002		**25.0**	**25.0**
8.15% due 2003		**100.0**	**100.0**
6.60% due 2004		**50.0**	**50.0**
5.95% due 2007		**200.0**	**200.0**
5.80% due 2008		**100.0**	**100.0**
5.95% due 2008		**100.0**	**100.0**
6.10% due 2009		**150.0**	-
7.15% due 2009		**150.0**	-
8.50% due 2011		**50.0**	**50.0**
7.30% due 2014		**150.0**	-
5.50% / 6.20% due 2028		**50.0**	**50.0**
		1,200.0	**750.0**
U.S. dollar debt			
U.S. unsecured senior notes	C	**343.5**	**364.2**
U.S. revolving credit and term loan borrowings	B	**123.5**	**61.7**
		$1,940.4	**$1,646.7**

(A) MANDATORY FIVE-YEAR DEBT REPAYMENTS

The minimum annual repayments of long-term debt required over each of the next five years are as follows:

2000	2001	2002	2003	2004
$ 39.4	**$ 93.3**	**$ 25.0**	**$ 100.0**	**$ 123.5**

Amounts due within one year are shown as long-term debt as they are not expected to require the use of working capital and are fully supported by the availability of term loans under the revolving credit and term loan facilities.

(B) REVOLVING CREDIT AND TERM LOAN BORROWINGS

Entity	Loan Facility	Currency	$ Utilized
Alberta Energy Company Ltd.	$ 1,400 million	Canadian dollars	$ 248 million
AEC Oil Sands Ltd.	30 million	Canadian dollars	28 million
AEC Oil Sands, L.P.	25 million	Canadian dollars	nil
	$ 1,455 million		$ 276 million
Alenco Inc.	$ 100 million	U.S. dollars	$ 86 million

On a consolidated basis, the Company and its subsidiaries have five revolving credit and term loan facilities in place totaling $1,455 million Canadian of which $276 million was utilized and US$100 million of which US$86 million was utilized. The combined total of all facilities is $1,599 million Canadian equivalent at December 31, 1999.

The Company has two revolving credit and term loan facilities in place totaling $1,400 million. The two facilities are fully revolving for 364-day periods with provisions for extensions at the option of the lenders and upon notice from the Company. If not extended, one facility converts to a non-revolving reducing loan for a term of three years and the other for a term of five years.

The two loan facilities are unsecured and currently bear interest either at the lenders' rates for Canadian prime commercial or U.S. base rate loans, at Bankers' Acceptance rates or at LIBOR plus applicable margins.

The Company's subsidiaries have three unsecured revolving credit and term loan facilities. The facilities are fully revolving for 364-day periods with provisions for extensions at the option of the lender following notice from the subsidiary. If not extended, the facilities convert to non-revolving reducing facilities to be repayable in full in three to five years.

The subsidiary facilities currently bear interest either at the lender's rates for Canadian prime commercial or U.S. base rate loans, at Bankers' Acceptance rates or at LIBOR plus applicable margins.

Revolving credit and term loan borrowings include Bankers' Acceptances and Commercial Paper maturing at various dates with a weighted average interest rate of 5.39% (1998 – 5.51%). Bankers' Acceptances and Commercial Paper shown as long-term debt represent amounts that are not expected to require the use of working capital during the year and are fully supported by the availability of term loans under the revolving credit and term loan facilities. Stand-by fees paid in 1999 relating to these agreements were approximately $1.3 million.

(C) U.S. UNSECURED SENIOR NOTES

The Company has outstanding, under two separate agreements, senior notes in the amount of US$238 million. One agreement consists of two tranches totaling US$125 million. The first tranche in the amount of US$40 million bears interest payable quarterly at 6.99%. The terms of this tranche require principal repayments of US$10 million in August 2000 and US$30 million at maturity in August 2001. The second tranche in the amount of US$85 million bears interest payable quarterly at 7.34% and requires principal repayments of US$28.3 million in August 2004 and August 2005 and US$28.4 million at maturity in August 2006.

The second agreement in the amount of US$113 million bears interest payable quarterly at 6.78% with mandatory annual principal repayments of US$22.6 million commencing in August 2004 and ending August 2008.

10 INDIRECT MIDSTREAM LONG-TERM DEBT

	Note Reference	1999	1998
Canadian dollar debt			
Revolving credit and term loan borrowings	A	$ 92.1	$ 18.4
U.S. dollar debt			
U.S. senior secured notes	B	288.1	305.8
Other		-	8.3
		$ 380.2	$ 332.5
Current portion of long-term debt		4.5	1.8
		$ 375.7	$ 330.7

(A) REVOLVING CREDIT AND TERM LOAN BORROWINGS

AEC Pipelines, L.P. has an unsecured revolving credit and term loan facility of $100 million which is fully revolving for 364-day periods with provisions for extensions at the option of the lender following notice from the L.P. If not extended, the facility converts to a non-revolving reducing facility to be repayable in full by the end of two years. The facility currently bears interest either at the lender's rates for Canadian prime commercial or U.S. base rate loans, at Bankers' Acceptance rates or at LIBOR plus applicable margins.

(B) U.S. SENIOR SECURED NOTES

One of the Company's 50% proportionately consolidated subsidiaries has outstanding US$150 million (AEC share - $75 million) aggregate principal amount of senior secured notes due 2013 bearing interest at 6.47% and US$250 million (AEC share - $125 million) aggregate principal amount of subordinated secured notes due 2019 bearing interest at 7.39% which are non-recourse to the Company. The notes are secured by the assignment of the accounts receivable of the Express Pipeline System and a floating charge over the assets of the Canadian portion of the Express System.

(C) MANDATORY FIVE-YEAR DEBT REPAYMENTS

The minimum annual repayments of *Indirect Midstream Long-Term Debt* required over each of the next five years are as follows:

2000	2001	2002	2003	2004
$ 4.5	$ 7.9	$ 11.1	$ 10.6	$ 11.5

11 OTHER LIABILITIES

	1999	1998
Future removal and site restoration costs	**$ 73.3**	$ 61.8
Deferred revenue and other	**36.6**	45.1
Obligation under capital lease	**20.5**	21.0
Other	**11.9**	6.7
	$ 142.3	$ 134.6

In December 1998, the Company entered into a capital lease agreement relating to its interest in the Suffield Gas Pipeline, a natural gas pipeline from Suffield, Alberta to Burstall, Saskatchewan. The lease obligation bears interest at a floating rate based on the Bankers' Acceptance rate.

12 PREFERRED SECURITIES AND SHARE CAPITAL

PREFERRED SECURITIES

In August 1999, the Company completed a Canadian offering of $200 million principal amount of 8.50% Preferred Securities due September 30, 2048. In September 1999, the Company completed a U.S. offering of US$150 million principal amount of 9.50% Preferred Securities due September 30, 2048. The Preferred Securities are unsecured junior subordinated debentures. Subject to certain conditions, the Company has the right to defer payments of interest on the securities for up to twenty consecutive quarterly periods. Principal amounts and deferred interest are payable in cash, or at the option of the Company, from the proceeds on the sale of equity securities of the Company delivered to the trustee of the Preferred Securities. Accordingly, the Preferred Securities are classed as equity in the Consolidated Balance Sheet. Annual payments, net of applicable income taxes, are charged directly to retained earnings.

SHARE CAPITAL

Authorized

20,000,000	First Preferred Shares
20,000,000	Second Preferred Shares
20,000,000	Third Preferred Shares
Unlimited	Common Shares
5,000,000	Non-Voting Shares

	1999 Number of Shares	1999 Amount	1998 Number of Shares	1998 Amount
Common Shares				
Balance, beginning of year	**124,031,489**	**$1,916.0**	112,107,871	$1,546.0
Issued on Acquisition (Note 2)	**15,092,916**	**658.6**	4,499,921	150.0
Issued for cash				
Subscription Receipts	**-**	**$ -**	6,350,000	$195.4
Employee Share Option Plan	**1,677,887**	**42.1**	1,000,588	22.2
Shareholder Investment Plan	**45,858**	**2.0**	73,109	2.4
	1,723,745	**44.1**	7,423,697	220.0
Balance, end of year	**140,848,150**	**$2,618.7**	124,031,489	$1,916.0

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 granted under the plan prior to April 21, 1999 expires after seven years and options granted after April 20, 1999 expire after five years. All options may be exercised in cumulative annual amounts of 25% on or after each of the first four anniversary dates of the grant.

The following tables summarize the information about the share options at December 31, 1999:

	1999		1998	
	Share Options	Weighted Average Exercise Price	Share Options	Weighted Average Exercise Price
Outstanding, beginning of year	9,232,651	$ 27.25	7,061,714	$ 25.60
Granted	2,149,875	40.24	3,523,850	29.10
Exercised	(1,677,887)	25.20	(1,000,588)	22.19
Forfeited	(345,750)	30.05	(352,325)	27.08
Outstanding, end of year	9,358,889	$ 30.49	9,232,651	$ 27.25
Exercisable, end of year	3,584,911		2,430,214	
Available for grant, end of year	1,392,874		196,999	

	Options Outstanding			Options Exercisable	
Range of Exercise Price	Number of Options Outstanding	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price	Number of Options Outstanding	Weighted Average Exercise Price
$18.25 to $23.00	1,478,452	1.68	$ 21.94	1,278,220	$ 21.78
$23.50 to $27.75	2,415,762	4.29	27.09	772,003	26.47
$28.00 to $32.85	2,855,025	4.83	29.83	1,378,844	29.64
$33.00 to $48.50	2,609,650	5.05	39.22	155,844	34.24
	9,358,889		$ 30.49	3,584,911	$ 26.35

The number of Common Shares reserved for issuance under the Employee Share Option Plan was 10,751,763 at December 31, 1999 (9,429,650 at December 31, 1998).

13 FINANCIAL INSTRUMENTS

The Company's financial instruments that are included in the Consolidated Balance Sheet are comprised of cash, accounts receivable, and all current liabilities and long-term borrowings.

(A) OIL AND GAS PRICE HEDGING

As part of the Company's ongoing purchased gas business, the Company has entered into contracts to purchase 175 million cubic feet/day of natural gas until October 2002, at an average cost of C$3.09/thousand cubic feet, for sales in U.S. dollars. At December 31, 1999, the Company has entered into contracts to sell 111 million cubic feet/day of natural gas until October 2000. At the same time, for the 175 million cubic feet/day of natural gas purchased, the Company has entered into contracts to sell US$ 12 million per month until October 2002. At December 31, 1999, these contracts have an unrealized settlement gain of approximately $7.1 million.

An affiliate utilizes financial futures contracts as a hedge of inventory. At December 31, 1999, AEC's share of the net open interest was 182,000 barrels of crude oil sold forward. AEC's share of the fair value loss on these contracts is $0.6 million at December 31, 1999. Gains and losses on hedge positions are deferred to future periods in which inventory will be sold.

The affiliate has entered into a hedge arrangement to sell US$10.0 million (AEC share) in equal daily amounts at the prevailing daily rates expiring in January 2000 that has a fair value gain of $0.3 million at December 31, 1999. The affiliate also has a forward purchase agreement to buy US$4.0 million (AEC share) that has a fair value loss of $0.1 million at December 31, 1999. These positions are hedges of the affiliate's exposure to net U.S. dollar receivables. Gains and losses are deferred to the future periods in which the receivables are to be realized.

(B) FAIR VALUES OF FINANCIAL ASSETS AND LIABILITIES

The fair values of financial instruments that are included in the Consolidated Balance Sheet, other than long-term borrowings, approximate their carrying amount due to the short-term maturity of those instruments. The estimated fair values of long-term borrowings have been determined based on market information where available, or by discounting future payments of interest and principal at estimated interest rates that would be available to the Company at year end.

	1999		1998	
	Balance Sheet Amount	Fair Value	Balance Sheet Amount	Fair Value
Long-term debt	**$1,940.4**	**$ 1,875.0**	$1,646.7	$1,694.3
Indirect Midstream long-term debt	**375.7**	**369.9**	330.7	341.7

(C) CREDIT RISK

A substantial portion of the Company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. All of the proceeds from the sale of the Company's production in Ecuador are received from one marketing company. Accounts receivable on these sales are supported by letters of credit issued by a major international financial institution. All natural gas swap and foreign currency agreements are with major financial institutions in Canada and the United States.

(D) INTEREST RATE RISK

At December 31, 1999, the increase or decrease in net earnings for each one percent change in interest rates on floating rate debt amounts to $2.9 million (1998 - $3.2 million).

(E) INTEREST RATE AND FOREIGN CURRENCY SWAPS

The Company has an outstanding interest rate swap, which was acquired with Amber, on a total of US$70 million of long-term debt. This swap converts fixed rate interest into floating rate interest until January 2003. At December 31, 1999 this swap results in an unrealized settlement asset of $0.5 million. The Company also has in place a foreign exchange contract to sell U.S. dollars in exchange for Canadian dollars. The contract is for $2.0 million per month until December 2000. The contract was acquired with the purchase of Amber. At December 31, 1999 the contract has an unrealized settlement loss of $0.8 million.

14 SUPPLEMENTARY INFORMATION

(A) INVESTMENTS PROPORTIONATELY CONSOLIDATED

The Company conducts a substantial portion of its oil and gas activity through unincorporated joint ventures, which are accounted for using the proportionate consolidation method. In addition, certain investments in Midstream are proportionately consolidated. These include the 50% owned Express Pipeline System, the 50% owned Marquest Energy Group, the 35% owned Empress Straddle Plant and the 33% owned Alberta Ethane Gathering System. Included in the Company's accounts are the following amounts related to these Midstream activities:

	1999	1998
Current assets	**$ 117.2**	**$ 58.8**
Total assets	**636.8**	622.1
Current liabilities	**80.3**	38.1
Total liabilities	**333.6**	331.0
Revenues	**432.1**	340.0
Net earnings	**(0.4)**	4.3
Cash flow from operations	**8.7**	9.5
Financing activities	**21.2**	25.5
Investing activities	**21.9**	34.0

(B) PENSION PLANS

The Company has both defined benefit pension plans and a defined contribution pension plan that cover substantially all employees. The defined benefit pension plans provide pension benefits upon retirement based on length of service and final average earnings. Defined contribution benefits are determined by the value of contributions and the return on investment of these contributions.

The cost of pension benefits earned by employees is determined using the projected unit credit method and is expensed as services are rendered. This cost is actuarially determined and reflects management's best estimate of the pension plan's expected investment yields and the expected salary escalation, mortality rates, termination dates and retirement ages of pension plan members. The plan is funded as actuarially determined in accordance with regulatory requirements through contributions to a trust fund. The costs of defined contribution pension benefits are based on a percentage of salary.

The cumulative difference between the amounts funded and expensed is reflected as a deferred asset in the Consolidated Balance Sheet.

At December 31, 1999, the market value of defined benefit pension fund assets was $77.6 million (1998 - $73.0 million) and the accrued pension liability, as estimated by the Company's actuaries, was $77.6 million (1998 - $72.6 million).

In addition, one of the Company's joint ventures has a defined benefit pension plan. At December 31, 1999, the market value of the Company's share of pension fund assets was $102.7 million (1998 - $88.6 million) and the Company's share of accrued pension liability, as estimated by the joint venture's actuaries, was $87.3 million (1998 - $80.0 million).

(C) RELATED PARTY TRANSACTIONS

During the year the Company sold approximately nil (1998 - $17.5 million) of natural gas and $84.1 million (1998 - $26.8 million) of crude oil to affiliates at market prices, $13.2 million of which is included in accounts receivable at year-end (1998 - $3.1 million).

(D) NET CHANGE IN NON-CASH WORKING CAPITAL

Source/(Use)	1999	1998	1997
Operating activities			
Accounts receivable and accrued revenue	$ (142.7)	$ (9.7)	$ (121.1)
Inventories	(74.8)	(62.3)	(36.0)
Accounts payable and accrued liabilities	(41.1)	12.4	72.3
	$ (258.6)	$ (59.6)	$ (84.8)
Investing activities			
Accounts payable and accrued liabilities	$ 26.8	$ (9.5)	$ (9.9)
Financing activities			
Accounts payable and accrued liabilities	$ (5.4)	-	-

15 COMMITMENTS

The Company has committed to certain payments over the next five years as follows:

	2000	2001	2002	2003	2004
Natural gas transportation	$ 123.6	$ 95.6	$ 68.9	$ 63.1	$ 61.5
Equipment operating leases	19.7	14.5	14.5	14.5	14.5
Capital lease	1.4	1.4	1.4	1.4	1.4
Office rental	8.5	8.4	8.4	7.0	5.0
Total	$ 153.2	$ 119.9	$ 93.2	$ 86.0	$ 82.4

16 UNCERTAINTY DUE TO THE YEAR 2000

The Year 2000 Issue arises because many computerized systems use two digits rather than four to identify a year. Date-sensitive systems may recognize the year 2000 as 1900 or some other date, resulting in errors when information using Year 2000 dates is processed. In addition, similar problems may arise in some systems which use certain dates in 1999 to represent something other than a date. Although the change in date has occurred, it is not possible to conclude that all aspects of the Year 2000 Issue that may affect the Company, including those related to efforts of customers, suppliers or other third parties, have been fully resolved.

17 SEGMENTED INFORMATION

The Company is managed using four operating segments, which have been determined based on the location of the operations and the nature of the services provided. Upstream includes the Domestic operations, which includes the exploration for and production of natural gas and oil in North America, and the International operations. Midstream includes both the Pipelines and Processing operations and the Gas Storage and Hub Services operations.

(A) RESULTS OF OPERATIONS

UPSTREAM

	Domestic			International			Total Upstream		
($ million)	1999	1998	1997	1999	1998	1997	1999	1998	1997
Revenue	$2,140.2	$1,490.7	$1,328.5	$210.7	$14.5	$16.2	$2,350.9	$1,505.2	$1,344.7
Royalties	190.2	100.1	134.2	73.5	1.7	1.9	263.7	101.8	136.1
Net Revenue	1,950.0	1,390.6	1,194.3	137.2	12.8	14.3	2,087.2	1,403.4	1,208.6
Operating Costs	356.6	318.9	292.3	64.5	19.6	14.3	421.1	338.5	306.6
Cost of Product Purchased	681.1	574.4	378.2	-	-	-	681.1	574.4	378.2
Operating Cash Flow	912.3	497.3	523.8	72.7	(6.8)	-	985.0	490.5	523.8
DD&A	385.4	277.8	254.0	36.9	7.9	6.4	422.3	285.7	260.4
DD&A - Acquisitions	57.5	49.8	52.7	31.0	-	-	88.5	49.8	52.7
Additional DD&A	34.0	-	-	-	14.0	72.4	34.0	14.0	72.4
Segment Income	$ 435.4	$ 169.7	$ 217.1	$ 4.8	$(28.7)	$(78.8)	$ 440.2	$ 141.0	$ 138.3
Less: Corporate Costs									
General & Administrative							29.0	23.3	20.9
Corporate DD&A							7.9	7.8	7.1
Interest, net							119.1	56.5	28.5
Income taxes							120.4	37.2	79.8
Net Earnings							$ 163.8	$ 16.2	$ 2.0

MIDSTREAM

	Pipelines & Gas Processing			Gas Storage & Hub Services			Total Midstream			Consolidated Total		
($ million)	1999	1998	1997	1999	1998	1997	1999	1998	1997	1999	1998	1997
Revenue	$ 518.7	$ 434.6	$ 482.5	$ 188.6	$ 71.9	$ 25.8	$ 707.3	$ 506.5	$ 508.3	$3,058.2	$ 2,011.7	$ 1,853.0
Royalties	-	-	-	-	-	-	-	-	-	263.7	101.8	136.1
Net Revenue	518.7	434.6	482.5	188.6	71.9	25.8	707.3	506.5	508.3	2,794.5	1,909.9	1,716.9
Operating Costs	87.0	136.0	131.3	25.8	14.3	12.6	112.8	150.3	143.9	533.9	488.8	450.5
Cost of Product Purchased	346.4	207.6	252.8	133.3	34.3	-	479.7	241.9	252.8	1,160.8	816.3	631.0
Operating Cash Flow	85.3	91.0	98.4	29.5	23.3	13.2	114.8	114.3	111.6	1,099.8	604.8	635.4
DD&A	35.2	36.0	28.3	7.9	5.2	7.0	43.1	41.2	35.3	465.4	326.9	295.7
DD&A - Acquisitions	-	-	-	-	-	-	-	-	-	88.5	49.8	52.7
Additional DD&A	-	-	12.5	-	-	-	-	-	12.5	34.0	14.0	84.9
Gain on sale of assets/ Dilution Gain	34.6	-	-	-	-	-	34.6	-	178.0	34.6	-	178.0
Segment Income	$84.7	$ 55.0	$ 57.6	$21.6	$ 18.1	$ 6.2	$106.3	$ 73.1	$ 241.8	$546.5	$ 214.1	$ 380.1
Less: Corporate costs												
General & Administrative							8.7	7.1	7.2	37.7	30.4	28.1
Corporate DD&A							0.8	1.1	1.0	8.7	8.9	8.1
Interest, net							39.7	28.2	20.4	158.8	84.7	48.9
Minority interest							18.4	18.4	14.8	18.4	18.4	14.8
Income taxes							22.8	10.1	0.7	143.2	47.3	80.5
Net Earnings							$15.9	$ 8.2	$ 197.7	$179.7	$ 24.4	$ 199.7

(B) CAPITAL INVESTMENT

	1999 Gross Expenditures	1999 Proceeds on Disposal	1999 Net	1998 Gross Expenditures	1998 Proceeds on Disposal	1998 Net
Upstream						
Domestic						
Conventional	$ 702.7	$ 40.3	$ 662.4	$ 623.0	$ 25.3	$ 597.7
Syncrude	103.5	0.2	103.3	68.3	-	68.3
International	174.7	0.9	173.8	64.7	-	64.7
Midstream						
Pipelines and Processing	97.9	62.2	35.7	72.4	-	72.4
Gas Storage and Hub Services	45.6	-	45.6	43.2	-	43.2
Other	20.6	20.1	0.5	11.7	-	11.7
Total*	$ 1,145.0	$ 123.7	$ 1,021.3	$ 883.3	$ 25.3	$ 858.0

* *Excludes the acquisitions of Pacalta ($1,021.5 million) and Amber ($813.5 million)(Note 2)*

(C) TOTAL ASSETS

	1999	1998
Upstream		
Domestic		
Conventional	$4,353.0	$ 4,111.6
Syncrude	574.5	474.6
International	1,404.5	99.8
Midstream		
Pipelines and Processing	1,017.7	970.7
Gas Storage and Hub Services	306.6	203.0
	$7,656.3	$5,859.7

(D) DOMESTIC PRODUCT INFORMATION

	Produced Gas and NGLs 1999	1998	1997	Conventional Oil 1999	1998	1997
Gross Revenue	$ 873.8	$ 587.6	$ 481.4	$ 258.8	$ 110.8	$ 175.1
Royalties	152.1	85.0	75.0	32.3	15.4	31.2
Net Revenue	721.7	502.6	406.4	226.5	95.4	143.9
Operating Costs	158.2	130.4	94.2	53.6	40.9	50.3
Operating Cash Flow	$ 563.5	$ 372.2	$ 312.2	$ 172.9	$ 54.5	$ 93.6

	Purchased Gas 1999	1998	1997	Syncrude 1999	1998	1997
Gross Revenue	$ 688.3	$ 570.7	$ 376.1	$ 319.3	$ 221.6	$ 295.9
Royalties	-	-	-	5.8	(0.3)	28.0
Net Revenue	688.3	570.7	376.1	313.5	221.9	267.9
Operating Costs	7.8	4.2	4.7	137.0	143.4	143.1
Cost of Product Purchased	681.1	574.4	378.2	-	-	-
Operating Cash Flow	$ (0.6)	$ (7.9)	$ (6.8)	$ 176.5	$ 78.5	$ 124.8

(E) GEOGRAPHIC INFORMATION

In addition to Canadian revenues and assets, consolidated revenues and assets include:

UPSTREAM INTERNATIONAL - CRUDE OIL

	Ecuador 1999	1998	1997	Argentina and Other 1999	1998	1997
Gross Revenue	$ 194.6	-	-	$ 16.1	$ 14.5	$ 16.2
Royalties	71.5	-	-	2.0	1.7	1.9
Net Revenue	123.1	-	-	14.1	12.8	14.3
Operating Costs	33.2	-	-	31.3	19.6	14.3
Operating Cash Flow	$ 89.9	-	-	$ (17.2)	$ (6.8)	$ -
Capital Assets	$ 1,134.2	-	-	$ 134.8	$ 67.9	$ 23.8

MIDSTREAM

Pipelines and Processing revenue includes $28.0 million which relates to the Express System for shipments within the United States (1998 - $28.7 million; 1997 - $20.0 million) and Gas Storage and Hub Services revenue includes $33.7 million related to storage activities in the United States (1998 and 1997 - nil).
Midstream capital assets includes assets in the United States related to the Express Pipeline System of $366.7 million (1998 - $388.7 million) and assets related to the Wild Goose Storage facility of $63.5 million (1998 - $43.3 million).

MAJOR CUSTOMERS

All of the Company's crude oil produced in Ecuador is sold to a single marketing company.

18 UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING

The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada (Canadian GAAP) which, in most respects, conform to accounting principles generally accepted in the United States (U.S. GAAP). Canadian GAAP differs from U.S. GAAP in the following respects:

STATEMENT OF EARNINGS

For the year ended December 31,	Note	1999	1998	1997
Net earnings - Canadian GAAP		$ 179.7	$ 24.4	$ 199.7
Impact of U.S. GAAP:				
Foreign exchange	C	28.3	(21.1)	(7.0)
Additional depletion	A	43.9	(277.2)	-
Depletion	B	(72.9)	(39.2)	(37.4)
Interest expense, net	E	(12.2)	-	-
Y2K costs		(4.0)	(0.7)	-
Income taxes	B	48.8	172.1	38.7
Net earnings (loss) - U.S. GAAP		$ 211.6	$ (141.7)	$ 194.0
Earnings (loss) per Common Share	D			
Basic		$ 1.57	$ (1.23)	$ 1.73
Fully diluted		$ 1.57	$ (1.23)	$ 1.73

STATEMENT OF COMPREHENSIVE INCOME

	1999	1998	1997
Net earnings - U.S. GAAP	$ 211.6	$ (141.7)	$ 194.0
Foreign currency translation adjustment	(21.6)	21.6	14.4
Comprehensive income	$ 190.0	$ (120.1)	$ 208.4

CONSOLIDATED BALANCE SHEET

As at December 31,		1999		1998	
	Note	As Reported	U.S. GAAP	As Reported	U.S. GAAP
Assets					
Current assets		$ 814.6	$ 814.6	$ 539.6	$ 539.6
Capital assets	A,B	6,786.9	7,301.0	5,224.2	5,407.9
Investments and other assets	C	54.8	96.8	95.9	74.1
		$7,656.3	$8,212.4	$5,859.7	$6,021.6
Liabilities and Shareholders' Equity					
Current liabilities		$ 529.6	$ 547.2	$ 428.8	$ 428.8
Long-term debt	E	1,940.4	2,361.6	1,646.7	1,646.7
Indirect Midstream long-term debt		375.7	375.7	330.7	330.7
Other liabilities		142.3	142.3	134.6	134.6
Deferred income taxes	B	774.3	1,474.1	630.7	988.0
Minority interest		102.4	102.4	108.3	108.3
Shareholders' equity	E	3,791.6	3,209.1	2,579.9	2,384.5
		$7,656.3	$8,212.4	$5,859.7	$6,021.6

Notes:

A. FULL COST ACCOUNTING

Under Canadian GAAP, a ceiling test is applied to ensure that capitalized costs do not exceed the sum of estimated undiscounted, unescalated future net revenues from proven reserves less the cost incurred or estimated to develop those reserves, related production, interest and general and administrative costs, and an estimate for restoration costs and applicable taxes.

Under the Full Cost method of accounting in the United States, a ceiling test is applied to ensure that the capitalized costs accumulated in each cost centre are limited to an amount equal to the present value, discounted at 10%, of the estimated future net operating revenues from proven reserves, net of restoration costs and income taxes.

In 1998, the Company recorded additional depletion of $277.2 million that reduced the carrying amount of its conventional oil and gas capital assets and related tax savings of $123.7 million as a result of applying the U.S. GAAP ceiling test rules. This additional depletion was not recorded for Canadian GAAP purposes. As a result, depletion expense recorded on these assets under Canadian GAAP, and related tax amounts, have been reduced in the 1999 U.S. GAAP statement of earnings.

B. INCOME TAXES

Under Canadian GAAP, the Company provides for potential future taxes using the deferred credit method under which tax provisions are established using tax rates and regulations applicable in the year the provision is recorded. These remain unchanged despite subsequent changes in rates and regulations.

In the United States, Statement of Financial Accounting Standards No. 109 (FAS 109), "Accounting for Income Taxes," requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been recognized in the Company's financial statements or tax returns. In estimating future tax consequences, FAS 109 generally considers all expected events including enacted changes in laws or rates.

The value assigned to assets and liabilities of acquired entities in business combinations has been increased to pre-tax amounts. Deferred income taxes have also been increased by this amount. This amount is depleted on an annual basis.

The net deferred income tax liability is comprised of:

	1999	1998
Deferred Tax Liabilities		
Depreciation, depletion and amortization	$ 1,512.6	$ 1,004.3
Temporary differences	38.4	45.4
Other	8.3	(2.8)
Total deferred tax liabilities	$ 1,559.3	$ 1,046.9
Deferred Tax Assets		
Accrued expenses and liabilities	$ 62.8	$ 42.6
Net operating losses carried forward	7.7	10.9
Other	14.7	5.4
Total deferred tax assets	$ 85.2	$ 58.9
Deferred Income Tax Liability	$ 1,474.1	$ 988.0

Reconciliation of statutory rate to actual tax rate:

	1999	1998	1997
Using Canadian GAAP			
Earnings before income tax	$ 322.9	$ 71.7	$ 280.2
Income tax at statutory rate of 44.62%	$ 144.1	$ 32.0	$ 125.0
Effect on taxes resulting from:			
Non-deductible Canadian crown payments	75.6	42.9	42.7
Non-deductible depletion	41.0	22.2	23.5
Non-deductible additional depletion	1.8	3.6	26.3
Non-taxable dilution gain	-	-	(79.4)
Previously unrecognized losses	(27.8)	-	-
Federal resource allowance	(98.9)	(52.2)	(56.9)
Large corporations tax	10.5	9.9	7.3
Statutory rate differences	(6.7)	-	-
Other	3.6	(11.1)	(8.0)
	$ 143.2	$ 47.3	$ 80.5
U.S. GAAP adjustments to income before income tax	$ (16.9)	$ (338.2)	$ (44.4)
Income tax at statutory rate of 44.62%	$ (7.5)	$ (150.9)	$ (19.8)
Depletion	(40.4)	(21.7)	(20.7)
Other	(0.9)	0.5	1.8
	$ (48.8)	$ (172.1)	$ (38.7)
Income tax - U.S. GAAP	$ 94.4	$ (124.8)	$ 41.8
Effective tax rate	30.8%	46.8%	17.8%

C. FOREIGN CURRENCY TRANSLATION

Under Canadian GAAP, long-term debt balances in foreign currencies are translated at the rate of exchange in effect at the end of the year. Unrealized exchange gains and losses arising on translation are deferred and amortized over the remaining terms of the debt. U.S. GAAP require that such gains and losses be reflected in the period in which they arise. Gains and losses on the change in the Company's net investments in foreign operations are not included in income under U.S. GAAP.

D. EARNINGS PER SHARE

Under Canadian GAAP, the fully diluted earnings related to the number of shares issued under employee option plans is determined using the average exercise price for all options outstanding. Under U.S. GAAP, the treasury method is used in the determination of the fully diluted earnings per share, whereby the market price of the Company's shares is used to determine the proceeds that would be received and used to repurchase outstanding shares.

E. PREFERRED SECURITIES

Under Canadian GAAP, the Preferred Securities are considered to be equity as the principal amounts and deferred interest are payable in cash, or at the option of the Company, from the proceeds on the sale of equity securities of the Company delivered to the trustee of the Preferred Securities. Accordingly, the annual charges, net of applicable income taxes, are charged directly to retained earnings. Costs associated with the issue of the Preferred Securities are netted against the proceeds received.

Under U.S. GAAP, the Preferred Securities are considered to be long-term debt. Accordingly, the pre-tax charges are included in interest expense and the related income tax included in the provision for income taxes in the Consolidated Statement of Earnings. Any costs associated with the issue of the Preferred Securities are included in other assets on the Consolidated Balance Sheet.

F. STOCK-BASED COMPENSATION

The Company accounts for its stock-based compensation plans under APB Opinion No. 25 and related interpretations, under which no compensation costs have been recognized in the financial statements for share options granted to employees and directors. If compensation costs had been recorded in accordance with Statement of Financial Accounting Standards (SFAS) No. 123, the Company's net earnings (loss) and net earnings (loss) per share would approximate the following pro forma amounts:

($ million, except per share amounts)	1999	1998	1997
Compensation costs	$ 19.9	$ 13.8	$ 8.8
Net earnings (loss)			
as reported	$ 211.6	$ (141.7)	$ 194.0
pro forma	$ 191.7	$ (155.5)	$ 185.2
Net earnings (loss) per share			
Basic			
as reported	$ 1.57	$ (1.23)	$ 1.73
pro forma	$ 1.42	$ (1.35)	$ 1.66
Fully diluted			
as reported	$ 1.57	$ (1.23)	$ 1.73
pro forma	$ 1.42	$ (1.35)	$ 1.66

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with weighted average assumptions for grants as follows:

Risk free interest rate	5.29%	5.18%	5.42%
Expected lives (years)	4.0	4.0	4.0
Expected volatility	0.31	0.23	0.21
Dividend per share	$ 0.40	$ 0.40	$ 0.40

G. PENSION PLANS

The following tables summarize the pension plan disclosure for the Alberta Energy Company Ltd. pension plan, which covers substantially all employees.

	1999	1998	1997
Pension expense			
Accrual for service	$ 3.3	$ 2.9	$ 2.3
Interest on benefit obligations	4.2	3.9	3.6
Interest on plan assets	(4.3)	(3.9)	(4.3)
Amortization of transitional obligation	0.3	0.2	(0.8)
Net actuarial gain (loss)	0.2	(0.3)	(0.7)
	$ 3.7	$ 2.8	$ 0.1
Pension expense for defined contribution plan	$ 2.3	$ 1.6	$ 1.4

	1999	1998
Change in benefit obligation		
Net benefit obligation, beginning of year	$ 72.6	$ 64.9
Service cost	3.3	2.9
Interest cost	4.3	3.9
Actuarial (gain) loss	(0.1)	3.2
Participant contributions	0.4	0.2
Gross benefits paid	(2.9)	(2.5)
Net benefit obligation, end of year	$ 77.6	$ 72.6
Change in plan assets		
Fair value of plan assets, beginning of year	$ 73.0	$ 65.4
Actual return on plan assets	4.5	4.2
Participant contributions	0.4	0.2
Employer contributions	2.6	5.7
Gross benefits paid	(2.9)	(2.5)
Fair value of plan assets, end of year	$ 77.6	$ 73.0
Funded status at December 31,		
Funded status	$ -	$ 0.4
Unrecognized net actuarial loss	0.7	0.7
Unrecognized net transitional obligation	1.3	1.3
Unrecognized prior service cost	0.1	0.2
Net amount recognized	$ 2.1	$ 2.6

The following tables summarize the pension plan disclosure for AEC's proportionate interest in one of the Company's joint venture's pension plan related to the joint venture's employees.

	1999	1998	1997
Pension expense			
Accrual for service	$ 2.2	$ 2.7	$ 2.5
Interest on benefit obligations	7.1	6.6	6.1
Interest on plan assets	(8.0)	(7.2)	(6.3)
Other	(1.2)	(1.5)	(1.3)
	$ 0.1	$ 0.6	$ 1.0

	1999	1998
Change in benefit obligation		
Net benefit obligation, beginning of year	$ 80.0	$ 73.7
Service cost	2.2	2.7
Interest cost	7.1	6.6
Participant contributions	1.5	1.0
Gross benefits paid	(3.3)	(3.6)
Other	(0.2)	(0.4)
Net benefit obligation, end of year	$ 87.3	$ 80.0

	1999	1998
Change in plan assets		
Fair value of plan assets, beginning of year	$ 88.6	$ 80.3
Actual return on plan assets	8.0	7.2
Contributions	3.3	4.0
Gross benefits paid	(3.3)	(3.6)
Other	6.1	0.7
Fair value of plan assets, end of year	$ 102.7	$ 88.6
Funded status at December 31,		
Funded status	$ 15.5	$ 8.6
Unrecognized net actuarial loss	-	2.3
Unrecognized experience gains	(20.7)	(15.8)
Unrecognized benefit changes	-	(2.6)
Net amount recognized	$ (5.2)	$ (7.5)

H. RECENT ACCOUNTING PRONOUNCEMENTS

Accounting for Derivatives

In June 1998, the Financial Accounting Standards Board issued SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, which is effective for fiscal years beginning after June 15, 2000.

SFAS No. 133 establishes accounting and reporting standards for derivative instruments, including certain hedging activities. It also requires that entities recognize all derivatives as either assets or liabilities on the balance sheet and measure those items at fair value. If certain conditions are met, a derivative may be specifically designated as (a) a hedge of the exposure to changes in the fair value of a recognized asset or liability or an unrecognized firm commitment, (b) a hedge of the exposure to variable cash flows of forecasted transactions or (c) a hedge of the foreign currency exposure of a net investment in a foreign operation, an unrecognized commitment, an available for sale security, or a foreign currency denominated forecasted transaction. For U.S. reporting purposes, the Company plans to adopt SFAS No. 133 when required and is currently evaluating the effects of this pronouncement.

Employee Future Benefits

During 1999, the Canadian Institute of Chartered Accountants (CICA) issued a new accounting standard for Employee Future Benefits, which is applicable for fiscal years beginning January 1, 2000.

This standard requires the Company to record the value of Employee Future Benefits on the accrual method whereby the financial statements will reflect the financial effects of the Company's existing promise to provide retirement benefits other than pensions and certain post employment benefits as the employees provide service, instead of when the benefits are paid.

The Company will adopt this standard in 2000, on a retroactive basis. The effect on net earnings is expected to be approximately $3.0 million in 2000.

Income Taxes

In 1997, the CICA issued a new standard for the accounting for income taxes applicable for fiscal years beginning January 1, 2000. It is expected that additional interpretation guidelines will be issued in early 2000 to assist in the implementation of the standard.

This standard requires the Company to record a future income tax asset or liability for the tax effect of any difference between the accounting and income tax basis of an asset or liability.

The Company will adopt this standard in 2000. The Company is currently evaluating the effects of this pronouncement.

The following unaudited supplementary oil and gas information is provided in accordance with the United States Statement of Financial Accounting Standards No. 69. "Disclosures About Oil and Gas Producing Activities".

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS AND CHANGES THEREIN

The following disclosures on standardized measures of discounted cash flows and changes therein relating to proved oil and gas reserves are determined in accordance with United States Statement of Financial Accounting Standards No. 69, "Disclosures About Oil and Gas Producing Activities".

In calculating the standardized measure of discounted future net cash flows, year-end constant prices and cost assumptions were applied to the Company's annual future production from proved reserves to determine cash inflows. Future development costs are based on constant price assumptions and assume the continuation of existing economic, operating and regulatory conditions. Future income taxes are calculated by applying the year-end statutory rate to future pre-tax cash flows after provision for the tax cost of the oil and natural gas properties based upon existing laws and regulations. The discount was computed by application of a 10% discount factor to the future net cash flows.

The Company cautions that the discounted future net cash flows from proved oil and gas reserves are an indication of neither the fair market value of the Company's oil and gas properties, nor of the future net cash flows expected to be generated from such properties. The discounted future net cash flows do not include the fair market value of exploratory properties and probable or possible oil and gas reserves, nor is consideration given to the effect of anticipated future changes in crude oil and natural gas prices, development, site restoration and production costs, and possible changes to tax and royalty regulations. The prescribed discount rate of 10% may not appropriately reflect future interest rates. The computation also excludes values attributable to the Company's Syncrude, marketing, storage, and pipeline interests.

The following standardized measure of discounted net cash flows is based on the following prices:

	1999	1998	1997
Domestic Conventional Operations			
Natural gas ($/thousand cubic feet)	2.70	2.58	2.18
Crude oil ($/barrel)	29.15	11.74	14.64
Natural Gas Liquids ($/barrel)	29.95	13.50	22.73
Ecuador Operations			
Crude oil (US$/barrel)	20.00	-	-
Argentina Operations			
Natural gas (US$/thousand cubic feet)	1.12	1.25	1.20
Crude oil (US$/barrel)	24.12	12.47	14.98

NET PROVED RESERVES (COMPANY SHARE AFTER ROYALTIES)

	Natural Gas (billion cubic feet)			Crude Oil & NGLs (million barrels)					
	Canada	Argentina	Total	Oil Canada	NGLs Canada	Total Canada	Argentina	Ecuador	Total
1999									
Beginning of year	2,317	1	2,318	129.4	12.5	141.9	2.8	-	144.7
Extensions and discoveries	218	34	252	18.1	0.4	18.5	0.3	26.3	45.1
Revisions and improved recovery	(49)	(1)	(50)	3.7	0.2	3.9	(1.0)	0.8	3.7
Purchase of reserves in place	54	-	54	-	-	-	-	129.7	129.7
Sale of reserves in place	-	-	-	(0.8)	(0.1)	(0.9)	-	-	(0.9)
Sales	(273)	-	(273)	(10.4)	(1.4)	(11.8)	(0.6)	(6.8)	(19.2)
End of year	2,267	34	2,301	140.0	11.6	151.6	1.5	150.0	303.1
Developed	1,773	19	1,792	59.1	7.4	66.5	1.5	73.3	141.3
Undeveloped	494	15	509	80.9	4.2	85.1	-	76.7	161.8
Total	2,267	34	2,301	140.0	11.6	151.6	1.5	150.0	303.1
1998									
Beginning of year	2,119	2	2,121	53.3	12.9	66.2	1.6	-	67.8
Extensions and discoveries	384	-	384	25.6	0.7	26.3	2.0	-	28.3
Revisions and improved recovery	(89)	-	(89)	(0.5)	0.4	(0.1)	-	-	(0.1)
Purchase of reserves in place	115	-	115	58.5	-	58.5	-	-	58.5
Sale of reserves in place	-	-	-	-	-	-	-	-	-
Sales	(212)	(1)	(213)	(7.5)	(1.5)	(9.0)	(0.8)	-	(9.8)
End of year	2,317	1	2,318	129.4	12.5	141.9	2.8	-	144.7
Developed	1,531	1	1,532	64.0	7.0	71.0	2.8	-	73.8
Undeveloped	786	-	786	65.4	5.5	70.9	-	-	70.9
Total	2,317	1	2,318	129.4	12.5	141.9	2.8	-	144.7
1997									
Beginning of year	1,777	2	1,779	43.0	13.9	56.9	1.0	-	57.9
Extensions and discoveries	470	-	470	16.1	0.9	17.0	1.1	-	18.1
Revisions and improved recovery	86	1	87	6.0	(0.1)	5.9	-	-	5.9
Purchase of reserves in place	-	-	-	-	-	-	-	-	-
Sale of reserves in place	(30)	-	(30)	(4.4)	(0.6)	(5.0)	-	-	(5.0)
Sales	(184)	(1)	(185)	(7.4)	(1.2)	(8.6)	(0.5)	-	(9.1)
End of year	2,119	2	2,121	53.3	12.9	66.2	1.6	-	67.8
Developed	1,350	2	1,352	34.9	7.2	42.1	1.3	-	43.4
Undeveloped	769	-	769	18.4	5.7	24.1	0.3	-	24.4
Total	2,119	2	2,121	53.3	12.9	66.2	1.6	-	67.8

Supplementary Oil and Gas Information

DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (EXCLUDING SYNCRUDE)

For the year ended December 31,	Canada ($ million)			Argentina ($ million)			Ecuador ($ million)			Total ($ million)		
	1999	1998	1997	1999	1998	1997	1999	1998	1997	1999	1998	1997
RESULTS OF OPERATIONS												
Oil and Gas Revenues,												
net of royalties	$930.3	$ 577.2	$ 539.3	$ 14.2	$ 12.4	$ 14.1	$123.0	$ -	$ -	$1,067.5	$ 589.6	$ 553.4
Operating Costs	194.0	150.2	133.3	13.8	13.3	10.6	33.2	-	-	241.0	163.5	143.9
Depreciation, Depletion												
and Amortization	459.2	310.5	285.8	9.3	14.5	56.1	57.9	-	-	526.4	325.0	341.9
Operating Income (Loss)	277.1	116.5	120.2	(8.9)	(15.4)	(52.6)	31.9	-	-	300.1	101.1	67.6
Income Tax	188.9	70.9	99.3	(0.7)	(5.4)	(17.4)	11.6	-	-	199.8	65.5	81.9
Results of Operations	$ 88.2	$ 45.6	$ 20.9	$ (8.2)	$(10.0)	$(35.2)	$ 20.3	$ -	$ -	$100.3	$ 35.6	$ (14.3)

CAPITALIZED COSTS												
Proved Oil and												
Gas properties	$5,852.2	$5,178.8	$4,009.2	$151.0	$ 93.7	$ 76.3	$1,180.9	$ -	$ -	$7,184.1	$5,272.5	$4,085.5
Unproved Oil and												
Gas Properties	649.2	699.7	341.0	14.5	37.9	7.0	11.1	-	-	674.8	737.6	348.0
Total Capital Cost	6,501.4	5,878.5	4,350.2	165.5	131.6	83.3	1,192.0	-	-	7,858.9	6,010.1	4,433.5
Accumulated DD&A	2,508.2	2,091.1	1,658.9	89.1	85.2	65.2	57.8	-	-	2,655.1	2,176.3	1,724.1
Net Capitalized Costs	$3,993.2	$3,787.4	$2,691.3	$ 76.4	$ 46.4	$ 18.1	$1,134.2	$ -	$ -	$5,203.8	$3,833.8	$2,709.4

COSTS INCURRED												
Acquisitions												
- proven reserves	$50.7	$506.6	$ -	$ -	$ -	$ -	$1,021.5	$ -	$ -	$1,072.2	$506.6	$ -
- unproven reserves	-	289.1	7.8	-	-	-	-	-	-	-	289.1	7.8
Total Acquisitions	50.7	795.7	7.8	-	-	-	1,021.5	-	-	1,072.2	795.7	7.8
Exploration Costs	218.7	161.0	318.0	24.6	18.0	8.8	20.9	-	-	264.2	179.0	326.8
Development	433.3	429.6	343.6	16.8	24.4	15.9	73.8	-	-	523.9	454.0	359.5
Total Capital Expenditures	$702.7	$1,386.3	$ 669.4	$ 41.4	$ 42.4	$ 24.7	$1,116.2	$ -	$ -	$1,860.3	$1,428.7	$ 694.1

DISCOUNTED FUTURE NET CASH FLOWS RELATED TO PROVED OIL AND GAS RESERVES

For the year ended December 31,	Canada			Argentina			Ecuador			Total		
($ million)	1999	1998	1997	1999	1998	1997	1999	1998	1997	1999	1998	1997
Future Cash Flows	$10,942.0	$7,829.3	$5,888.4	$121.5	$53.1	$35.7	$4,366.3	$ -	$ -	$15,429.8	$7,882.4	$5,924.1
Future Production and												
Development Costs	3,392.0	2,551.2	1,789.3	57.0	32.0	21.6	782.3	-	-	4,231.3	2,583.2	1,810.9
Undiscounted												
Pre-Tax Cash Flows	7,550.0	5,278.1	4,099.1	64.5	21.1	14.1	3,584.0	-	-	11,198.5	5,299.2	4,113.2
Future Income Taxes	2,225.6	1,465.0	1,176.3	-	-	-	1,104.7	-	-	3,330.3	1,465.0	1,176.3
Future Net Cash Flows	5,324.4	3,813.1	2,922.8	64.5	21.1	14.1	2,479.3	-	-	7,868.2	3,834.2	2,936.9
Less Discount of Net												
Cash Flows using a												
10% rate	2,142.4	1,524.2	1,168.9	16.6	4.2	2.8	965.3	-	-	3,124.3	1,528.4	1,171.7
Discounted Future												
Net Cash Flows	$3,182.0	$2,288.9	$1,753.9	$47.9	$16.9	$11.3	$1,514.0	$ -	$ -	$4,743.9	$2,305.8	$1,765.2

CHANGES IN STANDARDIZED MEASURE OF FUTURE NET CASH FLOWS RELATING TO PROVED OIL AND GAS RESERVES

For the year ended December 31,	Canada			Argentina			Ecuador			Total		
($ million)	1999	1998	1997	1999	1998	1997	1999	1998	1997	1999	1998	1997
Balance,												
beginning of year	$2,288.9	$1,753.9	$1,767.8	$16.9	$11.3	$11.1	$ -	$ -	$ -	$2,305.8	$1,765.2	$1,778.9
Changes resulting from:												
Sales of oil and gas												
produced during												
the period	(736.4)	(427.0)	(406.0)	(0.4)	0.9	(3.5)	(89.8)	-	-	(826.6)	(426.1)	(409.5)
Discoveries and												
extensions net of												
related costs	345.1	379.5	475.5	25.1	8.3	6.6	359.7	-	-	729.9	387.8	482.1
Purchases of proved												
reserves in place	10.4	327.0	-	-	-	-	1,235.5	-	-	1,245.9	327.0	-
Sales of proved												
reserves in place	-	-	(70.8)	-	-	-	-	-	-	-	-	(70.8)
Net change in prices and												
production costs	1,365.4	277.5	(599.2)	17.1	(2.3)	(3.8)	610.1	-	-	1,992.6	275.2	(603.0)
Revisions to quantity												
estimates	(14.0)	(84.2)	128.2	(7.2)	-	-	10.9	-	-	(10.3)	(84.2)	128.2
Accretion of discount	316.8	246.0	267.7	1.7	1.6	1.7	61.8	-	-	380.3	247.6	269.4
Other	56.4	(10.2)	(13.0)	(5.3)	(2.9)	(0.8)	0.4	-	-	51.5	(13.1)	(13.8)
Net Change in												
income taxes	(450.6)	(173.6)	203.7	-	-	-	(674.6)	-	-	(1,125.2)	(173.6)	203.7
Balance, end of year	$3,182.0	$2,288.9	$1,753.9	$47.9	$16.9	$11.3	$1,514.0	$ -	$ -	$4,743.9	$2,305.8	$1,765.2

Note: Results of Operations, Net Capitalized Costs and Total Capital Expenditures exclude the Company's Joint Venture interest in the Syncrude Oil Sands project. At December 31, 1999, if Syncrude were included, Net Capitalized Costs would be $5,715.5 million and Total Discounted Future Net Cash Flows would be $5,718.9 million.

FINANCIAL STATISTICS

	1999								
Year ended December 31,	Year	Q4	Q3	Q2	Q1	1998	1997	1996	1995
Net earnings ($ million)	179.7	69.2	74.2	18.5	17.8	24.4	199.7[1]	68.0	110.2[2]
Per share ($) - Basic	1.28	0.45	0.55	0.14	0.14	0.21	1.78	0.65	1.47
- Fully diluted	1.26	0.44	0.54	0.14	0.14	0.21	1.73	0.65	1.44
Cash flow from operations ($ million)	946.9	317.3	272.6	222.3	134.7	488.5	544.7	411.9	270.7
Per share ($) - Basic	7.02	2.28	1.97	1.69	1.08	4.26	4.87	3.93	3.61
- Fully diluted	6.68	2.17	1.87	1.60	1.04	4.06	4.67	3.82	3.51
Shares									
Common shares outstanding (million)	140.8	140.8	140.8	140.6	124.5	124.0	112.1	111.5	75.5
Average common shares outstanding (million)	134.8	140.8	140.7	133.1	124.3	114.8	111.9	104.9	75.0
Price range ($ per share)									
TSE									
High	48.90	47.25	48.90	47.45	37.75	39.00	35.50	33.25	23.13
Low	30.75	39.30	40.10	35.10	30.75	25.75	26.00	21.75	16.38
Close	45.00	45.00	42.40	47.30	37.20	33.00	27.75	32.70	21.88
NYSE - US$									
High	32.69	32.44	32.69	32.38	25.38	26.25	25.88	24.13	16.75
Low	20.31	27.13	27.56	23.56	20.31	17.38	18.25	16.00	15.00
Close	31.31	31.31	28.88	32.31	24.56	21.50	19.38	24.00	16.00
Share volume traded (million)	98.1	20.3	18.6	33.7	25.5	67.7	81.2	71.7	42.3
Ratios									
Debt-to-capitalization									
Consolidated	34:66					41:59	29:71	32:68	24:76
Upstream	29:71					36:64	20:80	16:84	13:87
Midstream	60:40					60:40	60:40	89:11	64:36
Debt-to-cash flow									
Upstream	1.7x					3.1x	1.1x	1.0x	0.8x
Interest coverage	6.7x					7.0x	12.4x	8.8x	9.8x
Dividend ($ per common share)	0.40					0.40	0.40	0.40	0.40
Net Capital Investment ($ million)									
Upstream									
Acquisition	$ 1,021.5					$ 813.5	$ -	$ 1,120.9	$ -
Domestic									
Conventional	662.4					597.7	587.5	428.5	188.7
Syncrude	103.3					68.3	48.8	29.4	28.1
International	173.8					64.7	48.3	24.5	16.1
Midstream									
Pipelines and Gas Processing	35.7					72.4	157.1	387.9	15.0
Gas Storage and Hub Services	45.6					43.2	40.2	10.0	15.5
Other	0.5					11.7	11.1	(23.8)	19.3
Total Net Capital Investment	$ 2,042.8					$ 1,671.5	$ 893.0	$ 1,977.4	$ 282.7

(1) Includes a dilution gain on the sale of AEC Pipelines, L.P. of $178 million ($1.59 per share basic; $1.50 per share fully diluted)

(2) Includes results of operations from AEC's forest products division totalling $53.9 million ($0.72 per share basic and fully diluted)

SALES

Years ended December 31,	1999 Year	Q4	Q3	Q2	Q1	1998	1997	1996	1995
Produced Gas (million cubic feet/day)	**904**	**999**	**867**	**842**	**910**	**714**	**575**	**515**	**320**
Oil and Natural Gas Liquids (barrels/day)									
Domestic									
Conventional Light and Medium Oil	9,423	8,637	8,773	9,505	10,809	10,620	10,783	11,856	6,192
Conventional Heavy Oil	23,284	26,695	25,670	21,607	19,052	12,407	13,171	7,651	5,357
Natural Gas Liquids	5,135	4,968	4,942	4,603	6,040	5,877	4,856	4,811	1,691
Total Domestic Conventional	37,842	40,300	39,385	35,715	35,901	28,904	28,810	24,318	13,240
Syncrude	30,649	30,483	31,304	30,467	30,335	28,953	28,447	27,596	27,823
Total Domestic	68,491	70,783	70,689	66,182	66,236	57,857	57,257	51,914	41,063
International	27,347	39,533	38,483	29,110	1,726	2,217	1,683	1,241	1,090
Total	95,838	110,316	109,172	95,292	67,962	60,074	58,940	53,155	42,153

PER-UNIT RESULTS

	1999 Year	Q4	Q3	Q2	Q1	1998	1997	1996	1995
Produced Gas ($/thousand cubic feet)									
Price	2.48	2.90	2.72	2.19	2.04	2.04	2.04	1.77	1.40
Royalties	0.43	0.58	0.40	0.35	0.37	0.29	0.31	0.20	0.13
Operating Costs	0.43	0.46	0.46	0.42	0.37	0.42	0.40	0.43	0.34
Netback	1.62	1.86	1.86	1.42	1.30	1.33	1.33	1.14	0.93
Conventional Light and Medium Oil ($/barrel)									
Price	24.94	32.27	29.15	22.92	17.22	17.49	25.59	23.73	22.75
Royalties	4.07	6.16	5.27	2.45	2.83	2.73	4.81	4.87	3.71
Operating Costs	5.49	4.72	5.97	5.55	5.63	5.26	5.99	4.48	4.76
Netback	15.38	21.39	17.91	14.92	8.76	9.50	14.79	14.38	14.28
Conventional Heavy Oil ($/barrel)									
Price	20.30	25.47	23.67	16.80	12.29	9.40	15.41	18.81	17.99
Royalties	2.15	2.93	2.57	1.39	1.31	1.05	2.57	3.36	3.21
Operating Costs	4.03	4.94	4.05	3.54	3.27	4.54	5.54	4.99	3.44
Netback	14.12	17.60	17.05	11.87	7.71	3.81	7.30	10.46	11.34
Total Conventional Oil ($/barrel)									
Price	21.64	27.13	25.07	18.67	14.08	13.13	19.99	21.80	20.54
Royalties	2.70	3.72	3.26	1.71	1.86	1.82	3.58	4.28	3.48
Operating Costs	4.45	4.89	4.54	4.15	4.11	4.82	5.70	4.69	4.15
Netback	14.49	18.52	17.27	12.81	8.11	6.49	10.71	12.83	12.91
Natural Gas Liquids ($/barrel)									
Price	20.47	28.32	23.07	19.70	12.26	16.86	23.97	23.95	15.74
Royalties	5.58	7.71	6.36	5.25	3.38	4.52	6.11	6.70	5.25
Netback	14.89	20.61	16.71	14.45	8.88	12.34	17.86	17.25	10.49
Syncrude ($/barrel)									
Price, net of tariff	27.96	36.03	31.15	25.16	19.16	20.46	27.80	25.68	23.69
Gross overriding royalty	0.58	0.21	0.57	0.88	0.66	0.51	0.69	0.71	0.60
Royalties	0.52	(0.19)	2.26	0.02	(0.08)	(0.03)	2.70	5.58	3.02
Cash operating costs	12.69	13.37	11.94	12.90	12.59	13.67	13.82	13.71	13.70
Netback	15.33	23.06	17.52	13.12	7.31	7.33	11.97	7.10	7.57
Ecuador Oil ($/barrel)									
Price	25.08	28.83	26.56	17.78					
Royalties	7.64	8.69	8.27	5.30					
Operating costs	3.55	3.35	3.52	3.85					
Netback before hedge costs	13.89	16.79	14.77	8.63					
Hedge costs	4.29	7.35	4.26	-					
Netback after hedge costs	9.60	9.44	10.51	8.63					

GAS PRODUCTION

(million cubic feet/day)	Forecast 2000	For the year ended December 31, 1999	1998	1997	1996	1995
Domestic Conventional	1,022	882	689	569	505	356
Cushion gas from storage	–	–	19	19	–	–
Total field capability	1,022	882	708	588	505	356
Storage withdrawal (injection)	(22)	22	6	(13)	10	(36)
Total produced gas sales	1,000	904	714	575	515	320

PRODUCED GAS SALES BY CONTRACT

(million cubic feet/day)						
TransCanada Gas Services	121	129	87	84	85	111
Pan-Alberta Gas	112	115	92	88	60	31
ProGas	124	137	117	89	50	22
Long-term direct	70	97	113	136	110	90
Other	573	426	305	178	210	66
Total	1,000	904	714	575	515	320

PURCHASED GAS TRANSACTIONS

(million cubic feet/day)						
	463	666	752	569	532	308

OIL AND NGL SALES

(barrels/day)						
Domestic						
Conventional	48,000	37,842	28,904	28,810	24,318	13,240
Syncrude	34,000	30,649	28,953	28,447	27,596	27,823
Total Domestic	82,000	68,491	57,857	57,257	51,914	41,063
International	48,000	27,347	2,217	1,683	1,241	1,090
Total	130,000	95,838	60,074	58,940	53,155	42,153

UPSTREAM

Consolidated Balance Sheet
($ million)

As at December 31	1999	1998
Assets		
Current Assets	$ 538.6	$ 386.6
Capital Assets	5,782.8	4,280.3
Investments and Other Assets	10.6	19.1
	$6,332.0	$4,686.0
Liabilities		
Current Liabilities	$ 366.5	$ 323.2
Long-Term Debt	1,627.7	1,355.4
Deferred Income Taxes & Other Liabilities	823.0	694.7
	2,817.2	2,373.3
Equity Capital Employed	3,514.8	2,312.7
	$6,332.0	$4,686.0

UPSTREAM

Consolidated Statement of Operating and Investing Activities
($ million)

Year Ended December 31	1999	1998	1997
Operating Activities			
Net earnings	$ 163.8	$ 16.2	$ 2.0
Depreciation, depletion and amortization	518.7	343.3	320.2
Additional depletion and amortization	34.0	14.0	72.4
Deferred income taxes	152.4	41.4	74.6
Other	8.7	2.3	(1.0)
Cash Flow from Operations	877.6	417.2	468.2
Investing Activities			
Acquisition	(31.3)	(303.2)	-
Capital investment	(1,001.5)	(767.7)	(780.4)
Proceeds on disposal of assets	61.5	25.3	149.5
	$ (971.3)	$(1,045.6)	$ (630.9)
Cash Flow from Operations per Common Share			
Basic	$ 6.51	$ 3.64	$ 4.19
Fully diluted	$ 6.19	$ 3.47	$ 4.01

MIDSTREAM

Consolidated Balance Sheet

($ million)

As at December 31	1999	1998
Assets		
Current Assets	$ 276.0	$ 153.0
Capital Assets	1,004.1	943.9
Investments and Other Assets	44.2	76.8
	$ 1,324.3	$ 1,173.7
Liabilities		
Current Liabilities	$ 163.1	$ 105.6
Long-Term Debt	312.7	291.3
Indirect Midstream Long-Term Debt	375.7	330.7
Deferred Income Taxes & Other Liabilities	93.6	70.6
Minority Interest	102.4	108.3
	1,047.5	906.5
Equity Capital Employed	276.8	267.2
	$ 1,324.3	$ 1,173.7

MIDSTREAM

Consolidated Statement of Operating and Investing Activities

($ million)

Year Ended December 31	1999	1998	1997
Operating Activities			
Net earnings	$ 15.9	$ 8.2	$ 197.7
Depreciation, depletion and amortization	43.9	42.3	36.3
Additional depletion and amortization	–	–	12.5
Deferred income taxes	20.3	6.5	(6.8)
Gain on sale of assets / Dilution gain	(34.6)	–	(178.0)
Minority interest	18.4	18.4	14.8
Other	5.4	(4.1)	–
Cash Flow from Operations	69.3	71.3	76.5
Investing Activities			
Capital investment	(143.5)	(115.6)	(204.0)
Proceeds on disposal of assets	62.2	–	45.5
	$ (81.3)	$ (115.6)	$ (158.5)
Cash Flow from Operations per Common Share			
Basic	$ 0.51	$ 0.62	$ 0.68
Fully diluted	$ 0.49	$ 0.59	$ 0.66

QUARTERLY RESULTS BY SEGMENT

($ million)	Three Months Ended March 31, 1999 Domestic	International	Total Upstream	Three Months Ended June 30, 1999 Domestic	International	Total Upstream
Revenue	$ 481.3	$ 2.6	$ 483.9	$ 448.5	$ 47.9	$ 496.4
Royalties	36.8	0.3	37.1	33.8	13.7	47.5
Net Revenue	444.5	2.3	446.8	414.7	34.2	448.9
Operating Costs	82.1	6.0	88.1	79.6	17.2	96.8
Cost of Product Purchased	208.0	-	208.0	143.9	-	143.9
Operating Cash Flow	154.4	(3.7)	150.7	191.2	17.0	208.2
DD&A	93.7	1.1	94.8	90.0	8.1	98.1
DD&A - Acquisitions	14.1	-	14.1	13.4	8.3	21.7
Additional Depletion and Amortization	-	-	-	-	-	-
Segment Income	$ 46.6	$ (4.8)	$ 41.8	$ 87.8	$ 0.6	$ 88.4

($ million)	Pipelines & Gas Processing	Gas Storage & Hub Services	Total Midstream	Pipelines & Gas Processing	Gas Storage & Hub Services	Total Midstream
Revenue	$ 89.7	$ 38.7	$ 128.4	$ 110.0	$ 25.1	$ 135.1
Royalties	-	-	-	-	-	-
Net Revenue	89.7	38.7	128.4	110.0	25.1	135.1
Operating Costs	21.4	3.3	24.7	20.8	7.0	27.8
Cost of Product Purchased	48.6	25.5	74.1	68.6	12.6	81.2
Operating Cash Flow	19.7	9.9	29.6	20.6	5.5	26.1
DD&A	8.5	1.4	9.9	8.3	2.0	10.3
DD&A - Acquisitions	-	-	-	-	-	-
Gain on sale of assets	34.6	-	34.6	-	-	-
Segment Income	$ 45.8	$ 8.5	$ 54.3	$ 12.3	$ 3.5	$ 15.8

($ million)	Three Months Ended September 30, 1999 Domestic	International	Total Upstream	Three Months Ended December 31, 1999 Domestic	International	Total Upstream	Year Ended December 31, 1999 Domestic	International	Total Upstream
Revenue	$ 573.8	$ 80.2	$ 654.0	$ 636.6	$ 80.0	$ 716.6	$ 2,140.2	$ 210.7	$2,350.9
Royalties	51.4	28.6	80.0	68.2	30.9	99.1	190.2	73.5	263.7
Net Revenue	522.4	51.6	574.0	568.4	49.1	617.5	1,950.0	137.2	2,087.2
Operating Costs	87.9	19.1	107.0	107.0	22.2	129.2	356.6	64.5	421.1
Cost of Product Purchased	173.0	-	173.0	156.2	-	156.2	681.1	-	681.1
Operating Cash Flow	261.5	32.5	294.0	305.2	26.9	332.1	912.3	72.7	985.0
DD&A	93.6	10.0	103.6	108.1	17.7	125.8	385.4	36.9	422.3
DD&A - Acquisitions	14.1	11.2	25.3	15.9	11.5	27.4	57.5	31.0	88.5
Additional Depletion and Amortization	-	-	-	34.0	-	34.0	34.0	-	34.0
Segment Income	$ 153.8	$ 11.3	$ 165.1	$ 147.2	$ (2.3)	$ 144.9	$ 435.4	$ 4.8	$ 440.2

($ million)	Pipelines & Gas Processing	Gas Storage & Hub Services	Total Midstream	Pipelines & Gas Processing	Gas Storage & Hub Services	Total Midstream	Pipelines & Gas Processing	Gas Storage & Hub Services	Total Midstream
Revenue	$ 149.1	$ 43.0	$ 192.1	$ 169.9	$ 81.8	$ 251.7	$ 518.7	$ 188.6	$ 707.3
Royalties	-	-	-	-	-	-	-	-	-
Net Revenue	149.1	43.0	192.1	169.9	81.8	251.7	518.7	188.6	707.3
Operating Costs	21.0	7.7	28.7	23.8	7.8	31.6	87.0	25.8	112.8
Cost of Product Purchased	105.1	31.3	136.4	124.1	63.9	188.0	346.4	133.3	479.7
Operating Cash Flow	23.0	4.0	27.0	22.0	10.1	32.1	85.3	29.5	114.8
DD&A	9.3	2.1	11.4	9.1	2.4	11.5	35.2	7.9	43.1
DD&A - Acquisitions	-	-	-	-	-	-	-	-	-
Gain on sale of assets	-	-	-	-	-	-	34.6	-	34.6
Segment Income	$ 13.7	$ 1.9	$ 15.6	$ 12.9	$ 7.7	$ 20.6	$ 84.7	$ 21.6	$ 106.3

RESERVES RECONCILIATION - DOMESTIC

	Natural Gas (billion cubic feet)			Conventional Oil & NGLs (million barrels)			Syncrude (million barrels)		
(before royalties)	Prov.	Prob.	Total	Prov.	Prob.	Total	Prov.	Prob.	Total
1997									
Balance at Dec 31, 1996	2,189	871	3,060	69.0	40.8	109.8	269.0	490.0	759.0
Revisions of Established Pools	72	(30)	42	2.0	(0.9)	1.1	-	-	-
Discoveries and Extensions	571	280	851	22.0	3.2	25.2	122.4	(143.3)	(20.9)
Acquisition of Reserves - Net	(33)	(21)	(54)	(5.8)	(2.4)	(8.2)	-	-	-
Production	(214)	-	(214)	(10.4)	-	(10.4)	(10.3)	-	(10.3)
Balance at December 31, 1997	2,585	1,100	3,685	76.8	40.7	117.5	381.1	346.7	727.8
1998									
Revisions of Established Pools	(66)	4	(62)	4.9	(4.5)	0.4	(6.8)	-	(6.8)
Discoveries and Extensions	481	175	656	31.4	7.7	39.1	0.3	7.8	8.1
Acquisition of Reserves - Net	145	42	187	68.8	66.0	134.8	-	-	-
Production	(259)	-	(259)	(10.5)	-	(10.5)	(10.6)	-	(10.6)
Balance at December 31, 1998	2,886	1,321	4,207	171.4	109.9	281.3	364.0	354.5	718.5
1999									
Revisions of Established Pools	(53)	(155)	(208)	0.8	(4.7)	(3.9)	120.4	(91.2)	29.2
Discoveries and Extensions	274	159	433	21.5	19.8	41.3	-	-	-
Acquisition of Reserves - Net	67	20	87	(1.1)	(1.5)	(2.6)	-	-	-
Production	(330)	-	(330)	(13.8)	-	(13.8)	(11.2)	-	(11.2)
Balance at December 31, 1999	2,844	1,345	4,189	178.8	123.5	302.3	473.2	263.3	736.5

RESERVES RECONCILIATION - INTERNATIONAL

1999 ECUADOR						
Balance at December 31, 1998				-	-	-
Revisions of Established Pools				1.1	(0.4)	0.7
Discoveries and Extensions				37.7	33.3	71.0
Acquisition of Reserves - Net				175.7	32.0	207.7
Production				(9.4)	-	(9.4)
Balance at December 31, 1999				205.1	64.9	270.0
1999 ARGENTINA						
Balance at December 31, 1998	1.2	0.5	1.7	3.4	1.8	5.2
Revisions of Established Pools	(0.3)	(0.5)	(0.8)	(1.6)	(1.7)	(3.3)
Discoveries and Extensions	38.6	38.2	76.8	0.3	-	0.3
Acquisition of Reserves - Net			-			-
Production	(0.3)	-	(0.3)	(0.6)	-	(0.6)
Balance at December 31, 1999	39.2	38.2	77.4	1.5	0.1	1.6
1999 AUSTRALIA						
Balance at December 31, 1998			-			-
Revisions of Established Pools			-			-
Discoveries and Extensions	-	35.5	35.5	-	0.2	0.2
Acquisition of Reserves - Net			-			-
Production			-			-
Balance at December 31, 1999	-	35.5	35.5	-	0.2	0.2

Year-end conventional reserves balances have been independently estimated by consulting engineers McDaniel & Associates Consultants Ltd., Gilbert Laustsen Jung Associates Ltd. and Ryder Scott Company

WELLS DRILLED (WESTERN SEDIMENTARY BASIN)

	1999		1998		1997	
	Gross	Net	Gross	Net	Gross	Net
Exploration						
Gas	104	89	152	131	82	76
Oil	10	9	27	24	20	17
Cased	2	2	3	3	8	7
Dry and Abandoned	32	23	25	21	35	33
Total	148	123	207	179	145	133
Success Rate (percent)	78	81	88	88	76	75
Development						
Gas	484	473	377	356	160	133
Oil	123	109	39	31	127	88
Cased	2	2	7	6	27	26
Dry and Abandoned	11	9	5	2	18	11
Total	620	593	428	395	332	258
Success Rate (percent)	98	98	99	99	95	96

OIL AND GAS OPERATING STATISTICS

	1999	1998	1997	1996	1995
Undeveloped Acreage (thousand acres)					
North America					
Gross	8,982	8,408	7,335	5,558	3,240
Net	7,492	7,090	6,263	4,657	2,667
International					
Gross	6,070	4,268	2,945	2,921	452
Net	2,959	1,751	2,945	2,711	452

RESERVES (BEFORE ROYALTIES)

Gas (billion cubic feet)					
Proven	2,883	2,887	2,586	2,191	1,514
Probable	1,419	1,322	1,101	872	379
Total	4,302	4,209	3,687	3,063	1,893
Conventional Oil and Natural Gas Liquids (million barrels)					
Proven	385.4	174.8	78.9	70.5	28.6
Probable	188.7	111.7	42.8	42.6	27.2
Total	574.1	286.5	121.7	113.1	55.8
Syncrude (million barrels)	736.5	718.5	727.8	759.0	280.0

RESERVES REPLACEMENT COST CALCULATION

Proven and Probable					
Conventional Oil and Gas Investment ($ million)					
Exploration	297.7	214.8	360.1	178.9	82.7
Development	523.9	453.7	359.3	273.4	100.0
Acquisitions - net	1,036.1	770.4	(83.6)	956.6	21.2
Total Reserves Replacement Costs	1,857.7	1,438.9	635.8	1,408.9	203.9
Proven Plus Probable Reserves Added					
Gas (billion cubic feet)					
Discoveries and Extensions	545.5	656.2	851.2	458.0	138.0
Revisions	(209.3)	(63.2)	42.1	-	(49.0)
Acquisitions - net	87.6	187.4	(54.1)	900.0	30.1
Total	423.8	780.4	839.2	1,358.0	119.1
Conventional Oil and Natural Gas Liquids (million barrels)					
Discoveries and Extensions	112.8	41.5	26.8	18.6	24.1
Revisions	(6.5)	(0.1)	1.1	-	(8.4)
Acquisitions - net	205.1	134.8	(8.2)	48.2	0.3
Total	311.4	176.2	19.7	66.8	16.0
Total Reserve Additions 6:1 (barrel of oil equivalent)	382.0	306.3	159.4	293.1	35.8
Reserves Replacement Costs ($/barrel of oil equivalent)					
6:1	4.86	4.70	3.99	4.81	5.70
10:1	5.25	5.66	6.14	6.95	7.31

Board of Directors

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Corporate Director
Vancouver, British Columbia

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Toronto, Ontario

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Calgary, Alberta

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Edmonton, Alberta

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

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Corporate Director
Calgary, Alberta

T. Don Stacy (1,2,6)
Corporate Director
Houston, Texas

Honourary Title

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Chairman Emeritus
Calgary, Alberta

Corporate

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President &
Chief Executive Officer

Drude Rimell
Vice-President, Corporate Services

Wayne G. Holt
General Counsel

Thomas A. Oddie
Director, Environment, Health & Safety

Donald E. Smallwood
Director, Human Resource Services

Hayward J. Walls
Director, Information Technology Services

John D. Watson
Vice-President, Finance & Chief Financial Officer

Ronald H. Westcott
Comptroller

Kenneth S. Aberle
Director, Tax & Assistant Treasurer

Derek S. Bwint
Director, Corporate Risk

Bernard K. Lee
Director, Corporate Finance & Assistant Treasurer

Brenda M. Prosser
Director, Internal Audit

Brian C. Ferguson
Director, Corporate Relations & Corporate Secretary

Linda H. Mackid
Assistant Corporate Secretary

Richard H. Wilson
Director, Public Affairs

Committees of the Board

1 *Audit*
2 *Environment, Health & Safety*
3 *Human Resources & Compensation*
4 *Nominating & Corporate Governance*
5 *Pension*
6 *Reserve*
7 *Chairman of the Board. Chairman, Nominating & Corporate Governance Committee and ex-officio member of other Board Committees.*

Domestic - Upstream

AEC Oil & Gas

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President

Ronald H. Westcott
Vice-President, Finance & Chief Financial Officer

Robert A. Grant
Vice-President, Asset Management

North East Business Unit

Roger J. Biemans
Senior Vice-President

Harbir S. Chhina
Vice-President, Thermal Recovery

South East Business Unit

Donald T. Swystun
Vice-President

North West Business Unit

Michael M. Graham
Vice-President

South West Business Unit

Business Unit Leader - Vacant

Keith R. Kirkness
Vice-President

Eastern Region New Ventures Business Unit

Jeff E. Wojahn
Vice-President

Western Region New Ventures Business Unit

Guy C.L. James
Vice-President

AEC Marketing

R.W. (Bill) Oliver
Executive Vice-President

Robert W. Laidlaw
Vice-President, Oil Marketing

AEC Syncrude

Roger D. Dunn
Chairman, Syncrude Management Committee

International - Upstream

AEC International

Steven R. Bell
President

Gary S. Guidry
Senior Vice-President

David A. Winter
Vice-President, International Exploration

Dana Q. Coffield
Vice-President, International New Ventures

Ecuador

Stephen T. Newton
President, City Investing Company Limited

Midstream

AEC Midstream

Hector J. McFadyen
President

J. Andrew Patterson
Vice-President, Finance

AEC Pipelines and Gas Processing

Robert A. Towler
Senior Vice-President, Business Development

Larry D. Drader
Vice-President, Operations & Engineering

Bernie J. Bradley
President, Express Pipeline System

AEC Storage and Hub Services

Richard C. Daniel
Vice-President

Corporate Information

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3900, 421 - 7 Avenue S.W.
Calgary, Alberta T2P 4K9
Phone: (403) 266-8111
Internet Address
www.aec.ca

Transfer Agents & Registrars
Common Shares

CIBC Mellon Trust Company
Calgary, Vancouver, Regina, Winnipeg, Toronto, Montreal, Halifax, and
ChaseMellon Shareholder Services, L.L.C.
New York

Shareholders are encouraged to contact CIBC Mellon Trust Company for information regarding their security holdings. They can be reached via the Answerline (416) 643-5500 or toll-free throughout North America at 1-800-387-0825.

Mailing Address

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www.cibcmellon.com (website)

Trustee & Registrar

CIBC Mellon Trust Company
8.15% Debentures
Calgary, Vancouver, Regina, Winnipeg, Toronto, Montreal, Halifax
Medium Term Note Debentures
Calgary, Toronto

Montreal Trust Company of Canada
8.50% Preferred Securities
Calgary, Toronto

The Bank of New York
9.50% Preferred Securities
New York

Auditors

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta

Independent Engineering Consultants

Domestic

McDaniel & Associates Consultants Ltd.
Calgary, Alberta

Gilbert Laustsen Jung Associates Ltd.
Calgary, Alberta

International

Ryder Scott Company
Houston, Texas

Stock Exchanges
Common Shares
The Toronto Stock Exchange (AEC)
New York Stock Exchange (AOG)

8.50% Preferred Securities
The Toronto Stock Exchange (AEC.PR.A)

9.50% Preferred Securities
New York Stock Exchange (AOG-A)

Annual Information Form (Form 40-F)
AEC's Annual Information Form (AIF) is filed with the securities regulators in Canada and the United States. Under the Multi-Jurisdictional Disclosure System, AEC's AIF is filed as Form 40-F with the U.S. Securities and Exchange Commission.

Dividend Reinvestment & Share Purchase Plan
AEC offers a Plan which provides shareholders with a convenient method to reinvest their cash dividends and/or make cash investments to purchase additional Common Shares. Details may by obtained by contacting CIBC Mellon Trust Company.

Major Operating Subsidiaries, Affiliates and Partnerships

Upstream - Domestic
100% AEC Oil & Gas Partnership
100% AEC Oil Sands Ltd.
100% AEC Oil Sands, L.P.
100% AEC West Ltd.
100% Amber Energy Inc.
100% Alenco Inc.
100% Alenco Oil & Gas [N.D.] Inc.
100% Alenco Resources Inc.
100% AEC Marketing (USA) Inc.

Upstream - International
100% AEC International (Australia) Pty Ltd
100% Alberta Energy Company Argentina S.A.
100% Alberta Energy International (Barbados) Ltd.
100% AEC Exploration & Production (Azerbaijan) Ltd.
100% Pacalta Resources Ltd.
100% City Investing Company Limited

Midstream
100% AEC Express Holdings Ltd.
100% AEC Pipelines Ltd.
70% AEC Pipelines, L.P.
100% AEC Storage and Hub Services Inc.
100% AEC Suffield Gas Pipeline Inc.
100% Alenco Pipelines Inc.
50% Express Pipeline Group
50% Platte Pipe Line Company
50% Marquest Energy Group
100% Wild Goose Storage Inc.

Major Joint Ventures

Upstream
13.75% Syncrude (AEC Oil Sands, L.P.) (includes 75% of AEC Oil Sands Limited Partnership's 5% interest)

Midstream
33.3% Alberta Ethane Gathering System
35% Empress Straddle Plant

ANNUAL MEETING - SHAREHOLDERS OF ALBERTA ENERGY COMPANY LTD. ARE ENCOURAGED TO ATTEND THE ANNUAL MEETING BEING HELD ON WEDNESDAY, APRIL 12, 2000 AT 3:00 PM, LOCAL TIME, AT THE TELUS CONVENTION CENTRE, 120 - 9 AVENUE S.E., CALGARY, ALBERTA
THOSE UNABLE TO DO SO ARE ASKED TO SIGN AND RETURN THE FORM OF PROXY MAILED WITH THIS ANNUAL REPORT.

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Additional information, including copies of the 1999 Alberta Energy Company Ltd. Annual Report, may be obtained from:
Alberta Energy Company Ltd.
Corporate Relations Department
3900, 421 - 7 Avenue SW
Phone: 403-266-8271, or
Visit our Website: www.aec.ca

Investor relations' inquiries should be directed to:

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Director, Corporate Relations
& Corporate Secretary
e-mail: BrianFerguson@aec.ca

or

G.W. (Greg) Kist
Manager, Corporate Relations
e-mail: GregKist@aec.ca

For information on AEC Pipelines, L.P. Contact: G.W. (Greg) Kist