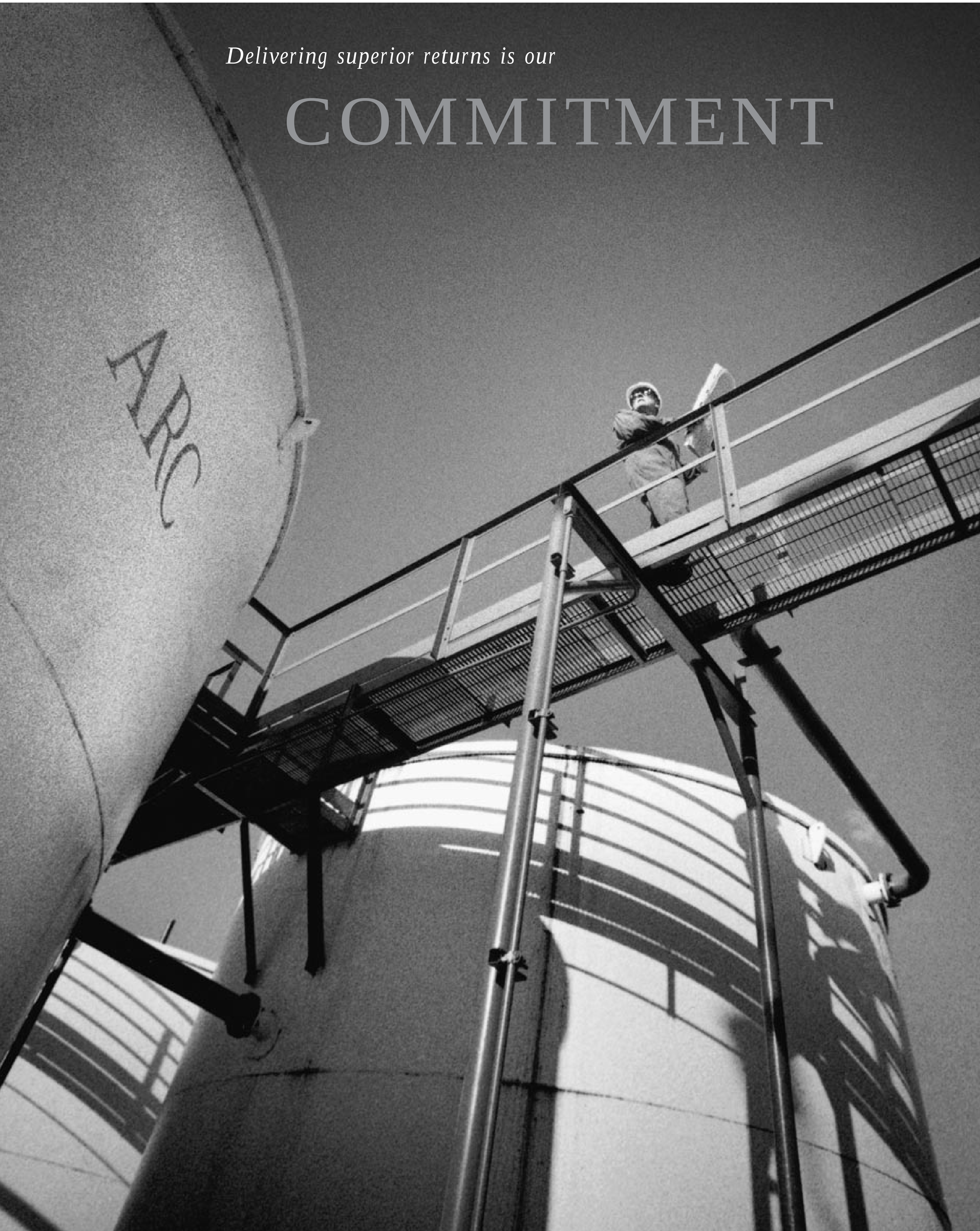
Expertise is our

ADVANTAGE

1999 ANNUAL REPORT ARC ENERGY TRUST

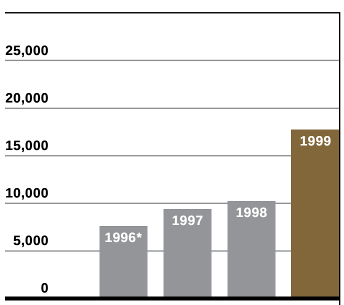
Delivering superior returns is our

COMMITMENT



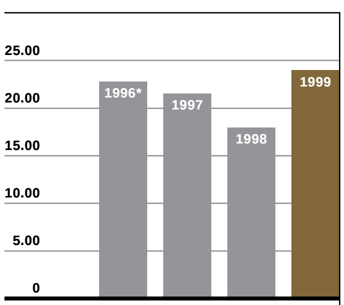
Vision ARC ENERGY TRUST (THE "TRUST") WAS FORMED IN 1996 WITH THE VISION OF BECOMING THE PREMIER "BLUE CHIP" CONVENTIONAL OIL AND GAS TRUST IN CANADA AS MEASURED BY QUALITY OF ASSETS, MANAGEMENT EXPERTISE AND LONG-TERM INVESTOR RETURNS. SINCE ITS INCEPTION, THE TRUST HAS BEEN A TOP PERFORMER IN THE ROYALTY TRUST SECTOR AND HAS EMERGED AS A LEADER IN THE SECTOR AS INVESTORS INCREASINGLY DISCRIMINATE ON THE BASIS OF PERFORMANCE AND POSITIVE UNDERLYING FUNDAMENTALS. THE TRUST'S CONTINUED GROWTH AND STRONG PERFORMANCE IN 1999 HAS FURTHER ENHANCED OUR LEADERSHIP POSITION AND HAS GREATLY ADVANCED OUR PROGRESS TOWARDS REALIZING OUR VISION.

PRODUCTION (Boe/d)



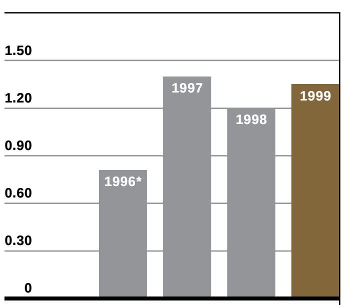
*for the six-month period

SALES PRICE ($/Boe)



*for the six-month period

CASH DISTRIBUTIONS ($/unit)



*for the six-month period

Highlights

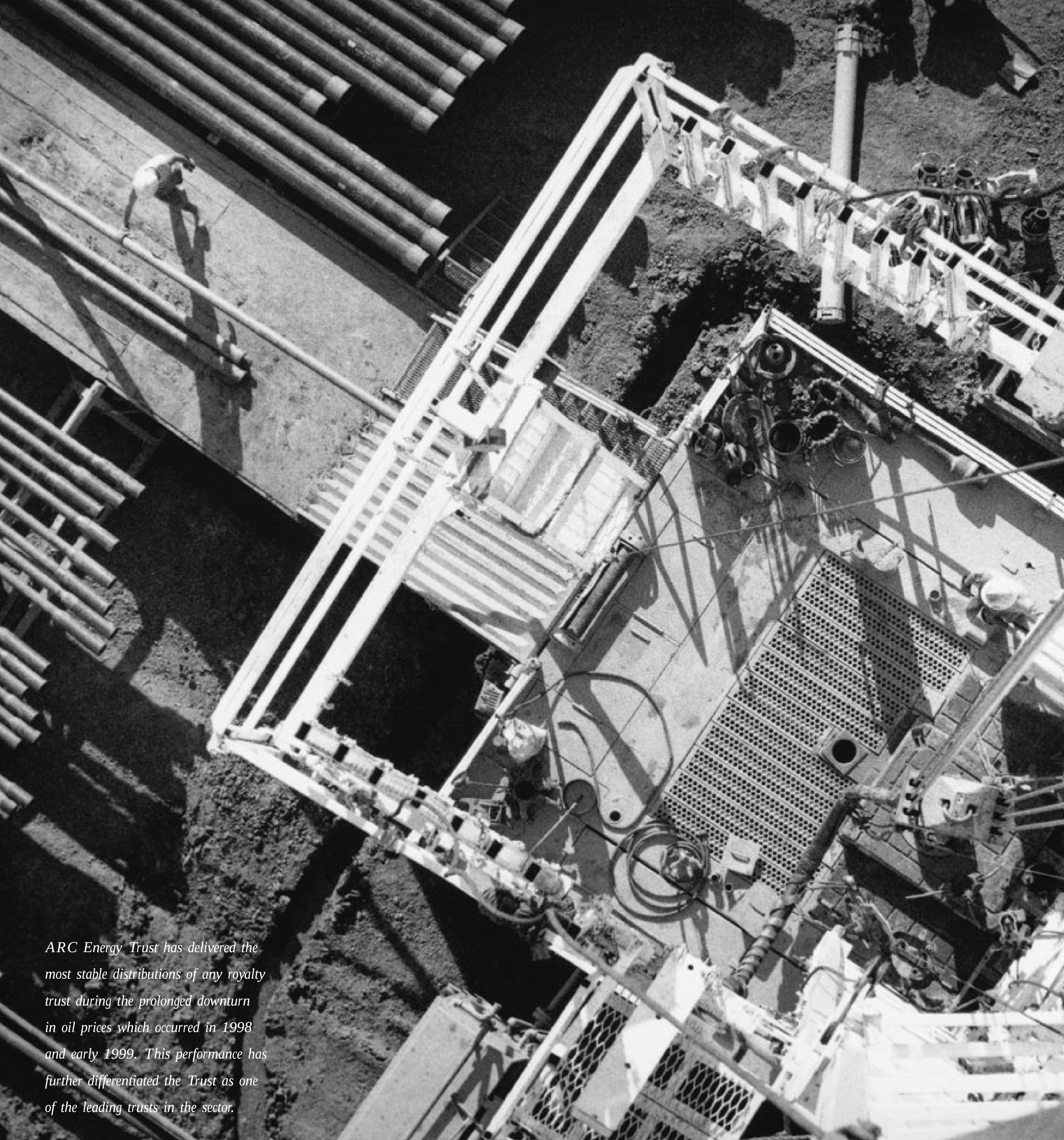
Years ended December 31, ($ thousands, except per unit amounts)	1999	1998	% Change
FINANCIAL			
Revenue before royalties	155,191	67,124	131
Per unit	$ 3.34	$ 2.62	27
Cash flow	80,814	30,040	169
Per unit	$ 1.74	$ 1.17	49
Net income*	29,835	(14,093)	n/a
Per unit	$ 0.64	$ (0.55)	n/a
Cash distributions	63,773	30,724	108
Per unit**	$ 1.35	$ 1.20	13
Working capital	15,761	(1,688)	n/a
Long-term debt	141,000	72,499	94
Unitholders' equity	324,010	167,323	94
Weighted average units (thousands)	46,480	25,604	82
Units outstanding at year-end (thousands)	53,607	25,604	109

* Reflects $14.7 million ceiling test writedown in 1998
** Based on the number of units outstanding at each cash distribution date

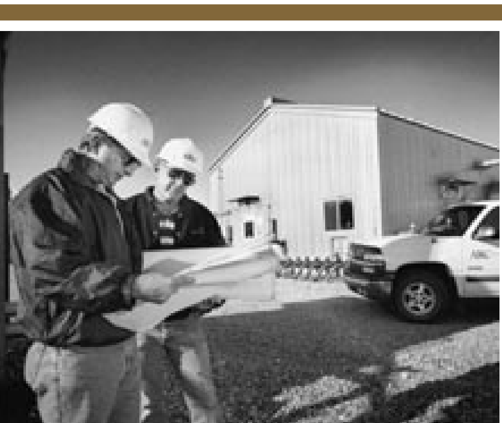
	1999	1998	% Change
OPERATING			
Production			
Crude oil (Bbl/d)	8,408	4,439	89
Natural gas (Mmcf/d)	66.46	37.68	76
Natural gas liquids (Bbl/d)	2,687	2,018	33
Total (Boe/d)	17,741	10,225	74
Average prices			
Crude oil ($/Bbl)	24.85	18.99	31
Natural gas ($/Mcf)	2.54	1.93	32
Natural gas liquids ($/Bbl)	17.43	13.17	32
Oil equivalent ($/Boe)	23.97	17.99	33
Reserves			
Proved (Mboe)	68,547	39,665	73
Proved plus risked probable (Mboe)	83,813	47,226	77

(based on daily closing price)

	1999	1998	% Change
TRUST UNIT TRADING			
Prices ($)			
High	9.25	11.40	(19)
Low	6.15	6.10	1
Close	8.75	6.15	42
Average daily volume (thousands)	68	32	113
TRUST WARRANT TRADING (Warrants began trading on March 17, 1999)			
Prices ($)			
High	1.95	–	n/a
Low	0.11	–	n/a
Close	1.30	–	n/a
Average daily volume (thousands)	18	–	n/a



ARC Energy Trust has delivered the most stable distributions of any royalty trust during the prolonged downturn in oil prices which occurred in 1998 and early 1999. This performance has further differentiated the Trust as one of the leading trusts in the sector.



MAC H. VAN WIELINGEN
DIRECTOR, VICE-CHAIRMAN AND
CHIEF EXECUTIVE OFFICER

JOHN P. DIELWART
DIRECTOR AND PRESIDENT

Message to Unitholders

What a difference a year makes. Last year at this time, our industry was in the midst of the most protracted bear market ever experienced in the modern era of the oil and gas business with world oil prices at approximately $12.00 US per barrel ("Bbl"). At the time of this writing, world oil prices exceed $30.00 US per Bbl which represents the highest peacetime price since deregulation of the industry in Canada in 1986. While commodity price volatility is a fact of life in our industry, this extreme level of volatility over such a short time period is unusual and can have adverse consequences for many companies and investors in the oil and gas sector. However, such periods of volatility are also periods of opportunity. We believe that our unitholders will enjoy significant long-term benefits from a number of such opportunities that we have been able to exploit in this volatile environment.

Since inception of ARC Energy Trust (the "Trust") in 1996, we have repeatedly stated that "expertise is our advantage" which will allow us to fulfill our commitment to deliver superior returns to our investors. It is our view that the Trust's performance in the volatile business environment in 1999 underscores this position:

— The Trust outperformed the TSE Oil and Gas Producers Index on a total return basis by 46 percent (56 percent since inception) and the Royalty Trust Index by 10 percent (29 percent since inception). The Trust's compound annual return since inception is approximately 12 percent as compared to minus two percent for the TSE Oil and Gas Producers Index and five percent for the Royalty Trust Index.

— The Trust maintained its monthly distribution at $0.10 per unit through the entire downturn in oil prices and has had the most stable distributions in the sector over the past three years.

— The Trust completed the acquisition of Orion Energy Trust ("Orion") and Starcor Energy Royalty Fund ("Starcor") at the bottom of the oil price cycle which significantly enhanced our asset base just prior to the dramatic increases in commodity prices.

— With the strong recovery in the oil price in the second half of 1999, the Trust completed an equity issue, disposed of non-core assets and initiated a program of discretionary debt repayment which resulted in the Trust having one of the strongest balance sheets in the sector at December 31, 1999.

— This exceptional performance in 1999 has solidified the Trust's leadership position in the sector and has further advanced the Trust towards realizing its vision of becoming the premier conventional oil and gas royalty trust in Canada.

ACQUISITION AND DISPOSITION ACTIVITY The most notable transactions in 1999 were the March 12 acquisitions of Starcor and Orion. These acquisitions increased production and reserves by 85 percent and 91 percent, respectively, while increasing the Trust's reserve life index ("RLI") from 11.6 to 11.8 years. The reserves were acquired for $5.13 per barrel of oil equivalent ("Boe") based upon proved plus risked probable reserves. These opportunistically timed acquisitions with oil prices at all time lows added several new core areas to the Trust and increased the breadth of development and exploitation opportunities within our asset base.

In addition to being accretive to unitholder distributions, the acquisitions had a dramatic impact on the Trust's market capitalization which increased from approximately $175 million to $325 million at closing of the transactions. With our equity issue during the third quarter and strong recovery in the unit price, market capitalization at year-end was approximately $480 million. The increased size of the Trust allowed us to further develop our organizational resources and enhance our already strong managerial and technical expertise.

The acquisition of the new properties and the increase in commodity prices during 1999 created the opportunity for the Trust to dispose of a number of small, non-core properties for total proceeds of $21.6 million during the year. The Trust will continue to optimize its portfolio of properties in the future to lower general and administrative costs by reducing our total property count, thereby allowing technical staff more time to concentrate on value-adding initiatives associated with our core properties.

RESERVE ADDITIONS Capital expenditures during 1999 totalled $24.2 million, up from $10.5 million in 1998. Extensive development activity, which added significant production and reserves, was undertaken in Buick Creek, House Mountain, Progress and Valhalla. The Trust also initiated several highly successful drilling programs within its main core operated area of Pembina where a number of prolific vertical infill wells were drilled at Lindale and MIPA; follow-up drilling will continue in 2000. The Trust's drilling and development activities and reserve revisions to its existing assets resulted in the addition of 3.8 million Boe of established reserves at a cost of $6.36 per Boe.

The Trust's capital program, in combination with the acquisitions and minor property disposition program, resulted in the Trust replacing 665 percent of its 1999 production at a net effective cost of $5.94 per Boe. This overall reserve replacement cost is well below industry oil and gas finding and development costs which were in the range of $7 to $12 per Boe. Since inception, the Trust's all in reserve replacement cost has been $5.83 per Boe on a proved plus risked probable basis. The Trust's ability to acquire high quality reserves at an attractive price has been the single most important factor setting it apart from the rest of the royalty trust sector and most full cycle oil and gas exploration and production companies.

FINANCIAL AND OPERATING PERFORMANCE Production during 1999 was 17,741 Boe per day which was 74 percent greater than 1998 production of 10,225 Boe per day. During 1999, oil production increased 89 percent to 8,408 Bbl per day, natural gas production increased 76 percent to 66.5 million cubic feet ("Mmcf") per day and natural gas liquids production increased 33 percent to 2,687 Bbl per day.

As a result of significantly increased production and commodity prices, revenue before royalties for the year increased 131 percent to $155.2 million. Cash flow during the year increased 169 percent to $80.8 million ($1.74 per unit) from $30.0 million ($1.17 per unit) in 1998. The average commodity prices for the year were $24.85 per Bbl for oil, $2.54 per thousand cubic feet ("Mcf") for gas and $17.43 per Bbl for natural gas liquids. On an oil equivalent basis, the average price was $23.97 per Bbl, which was 33 percent higher than 1998. The Trust's operating netback for the year was $14.80 per Boe as compared to $10.38 per Boe in 1998.

Operating costs for 1999 were $5.52 per Boe; general and administrative costs net of recoveries and reimbursements were $0.55 per Boe and management fees were $0.46 per Boe, resulting in overall costs of $6.53 per Boe. This compares to $6.23 per Boe for 1998.

The Trust's net income was $29.8 million for the year compared to a net loss of $14.1 million for 1998. The 1998 loss included the impact of a writedown in the book value of the Trust's assets of $14.7 million which was attributable to the dramatic decrease in oil prices in 1998.

CASH DISTRIBUTIONS AND DISTRIBUTION POLICY As previously stated, 1999 began with the lowest oil prices experienced in our industry in over 20 years. In mid-March, OPEC announced significant production cuts which resulted in a dramatic increase in world oil prices through the balance of the year. The Trust was able to maintain monthly distributions at $0.10 per unit through the entire oil price downturn and has delivered the most stable distributions of any oil and gas royalty trust during the past three years. This stability in distributions has been a major focus of ARC Financial Corporation (the "Manager") and has resulted in the Trust positively differentiating itself from all of the other trusts.

With the strength in commodity prices during the second half of 1999, the Board of Directors determined that a portion of the cash available for distribution in excess of the regular monthly distribution of $0.10 per unit would be paid to unitholders with the balance used to strengthen the financial position of the Trust through discretionary debt reduction. For the fourth quarter of 1999, 50 percent of the surplus cash available was distributed to unitholders and 50 percent was directed towards debt repayment. As a result, distributions to unitholders in 1999 totalled $1.35 per unit compared to $1.20 per unit in 1998; discretionary debt repayments from distributions in 1999 totalled $8.0 million ($0.15 per unit). In addition, at December 31, 1999, the Trust had accumulated an accrued undistributed working capital surplus of $6.1 million ($0.11 per unit), 50 percent of which will be paid out to unitholders in 2000 and 50 percent of which will be applied towards debt reduction. It is our intention to continue this policy of discretionary debt repayments during 2000 with the relative portions directed towards debt and unitholders reviewed on an ongoing basis and adjusted if deemed appropriate by the Board of Directors.

2000 OUTLOOK On January 31, 2000, the Trust entered into an agreement to acquire a group of producing oil and gas properties in Alberta and Saskatchewan for $135 million. Upon completion of the acquisition, which is expected to occur by March 31, 2000, the Trust's reserves and production will increase 33 percent and 27 percent, respectively. The Manager's debt reduction activities during 1999 and the resulting strong balance sheet and expanded credit facility have created the flexibility to accommodate the financing of this acquisition.

Key attributes of the new property purchase are as follows: (a) an acquisition cost on an established reserves basis of $4.93 per Boe; (b) increased production of approximately 4,700 Boe per day at a cost of $28,700 per producing Bbl; and (c) acquisition of four 90 to 100 percent working interest operated properties with significant identified development and exploitation opportunities.

On March 1, 2000, the Trust announced the closing of an equity financing under which 5.8 million units were sold to an underwriting syndicate at $8.65 per unit for gross proceeds of $50.2 million ($47.7 million net). In addition, the underwriting syndicate exercised an over allotment option to purchase an additional 600,000 units at the same price which closed on March 10, 2000. As a result, the total gross proceeds of the issue were $55.4 million ($52.6 million net).

With regard to the business environment, it is the Manager's assessment that current trading levels of common shares and trust units in the oil and gas sector do not reflect the exceptionally positive financial fundamentals associated with prevailing high commodity prices. Although the price of oil is in excess of $30.00 US per Bbl and natural gas is in excess of $3.50 Cdn per Mcf at the "AECO" hub in Alberta, we believe the market reflects prices in the order of $20.00 US per Bbl for oil and $2.75 Cdn per Mcf for gas. It is clearly understood that oil prices at the current level are not sustainable and that OPEC will have to increase production to ease the current situation of very low and declining inventories of crude oil and refined products. However, even with material production increases by OPEC, the current inventory levels are such that the oil price could remain above the normal trading range of $18.00 to $22.00 US per Bbl for some time yet. We do not expect the eventuality of a lower oil price to have a material adverse affect on our unit price since we believe this expectation is currently factored into equity markets.

With regard to natural gas, despite another warmer than normal winter in North America, storage inventories are significantly below last year's levels. Accordingly, it is our expectation that gas prices will remain strong and in fact strengthen during the year and significantly exceed last year's prices. With the Trust's expanding asset base and strong commodity prices, 2000 is expected to achieve record performance in terms of production, cash flow and distributable income. The Manager will use this as an opportunity to reward our investors with higher distributions as well as to further strengthen our already strong balance sheet.

Respectfully submitted on behalf of the Board of Directors.

(SIGNED)

MAC H. VAN WIELINGEN

DIRECTOR, VICE-CHAIRMAN AND CHIEF EXECUTIVE OFFICER

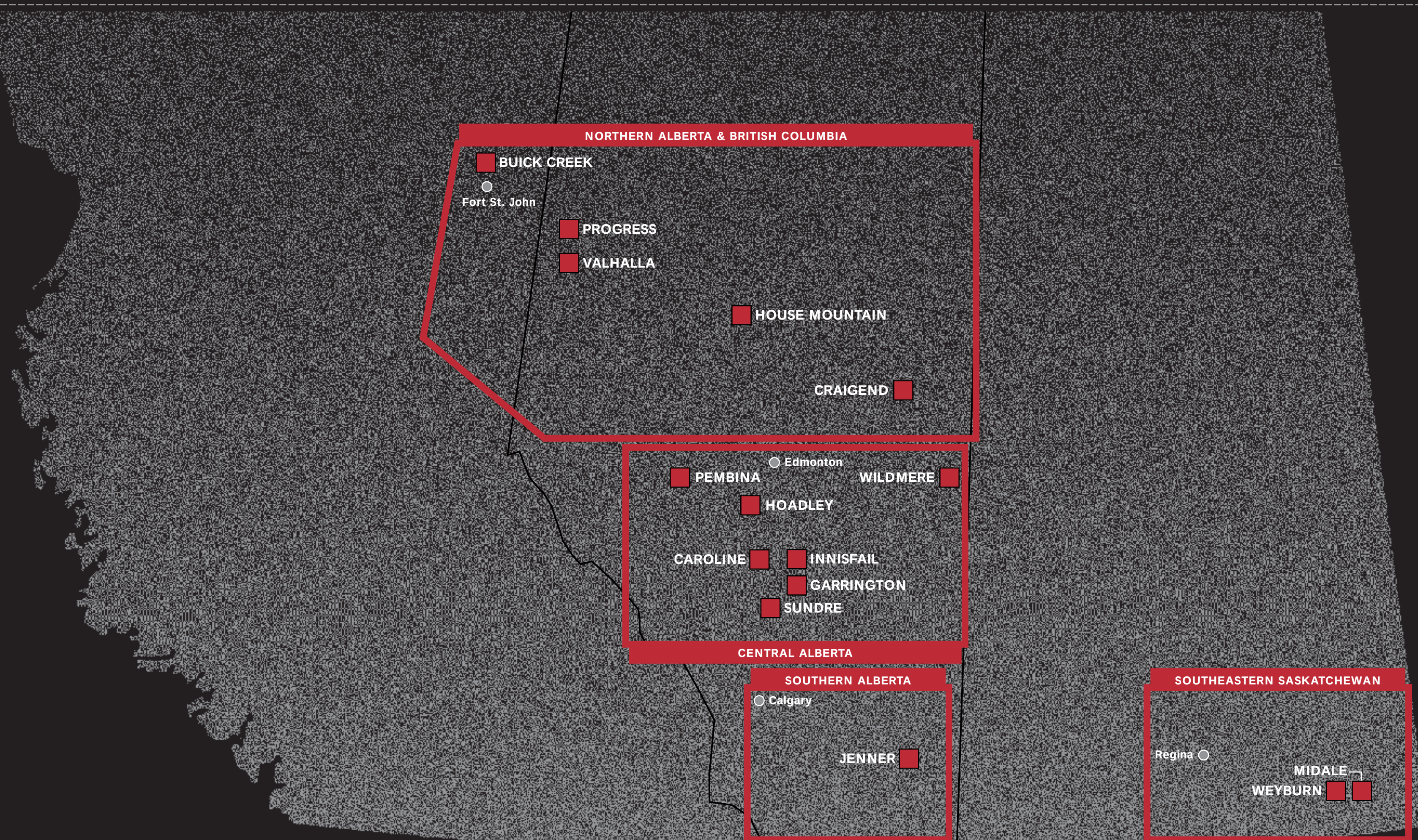
(SIGNED)

JOHN P. DIELWART

DIRECTOR AND PRESIDENT

Advantage SINCE INCEPTION, THE TRUST HAS DEMONSTRATED SUPERIOR PERFORMANCE IN TERMS OF BOTH FINANCIAL RETURNS TO UNITHOLDERS AND GROWTH OF OUR ASSET BASE. THE TRUST REPLACED 665 PERCENT OF ITS 1999 PRODUCTION AT A NET EFFECTIVE COST OF $5.94 PER BARREL OF OIL EQUIVALENT (PROVED PLUS RISKED PROBABLE RESERVES). THE TRUST'S ALL-IN RESERVE REPLACEMENT COST SINCE INCEPTION HAS BEEN $5.83 PER BARREL OF OIL EQUIVALENT. THE UNIQUE FINANCIAL AND TECHNICAL EXPERTISE OF ARC FINANCIAL CORPORATION IS THE BASIS FOR THIS EXCEPTIONAL PERFORMANCE AND IS OUR COMPETITIVE ADVANTAGE.

Location of Principal Properties



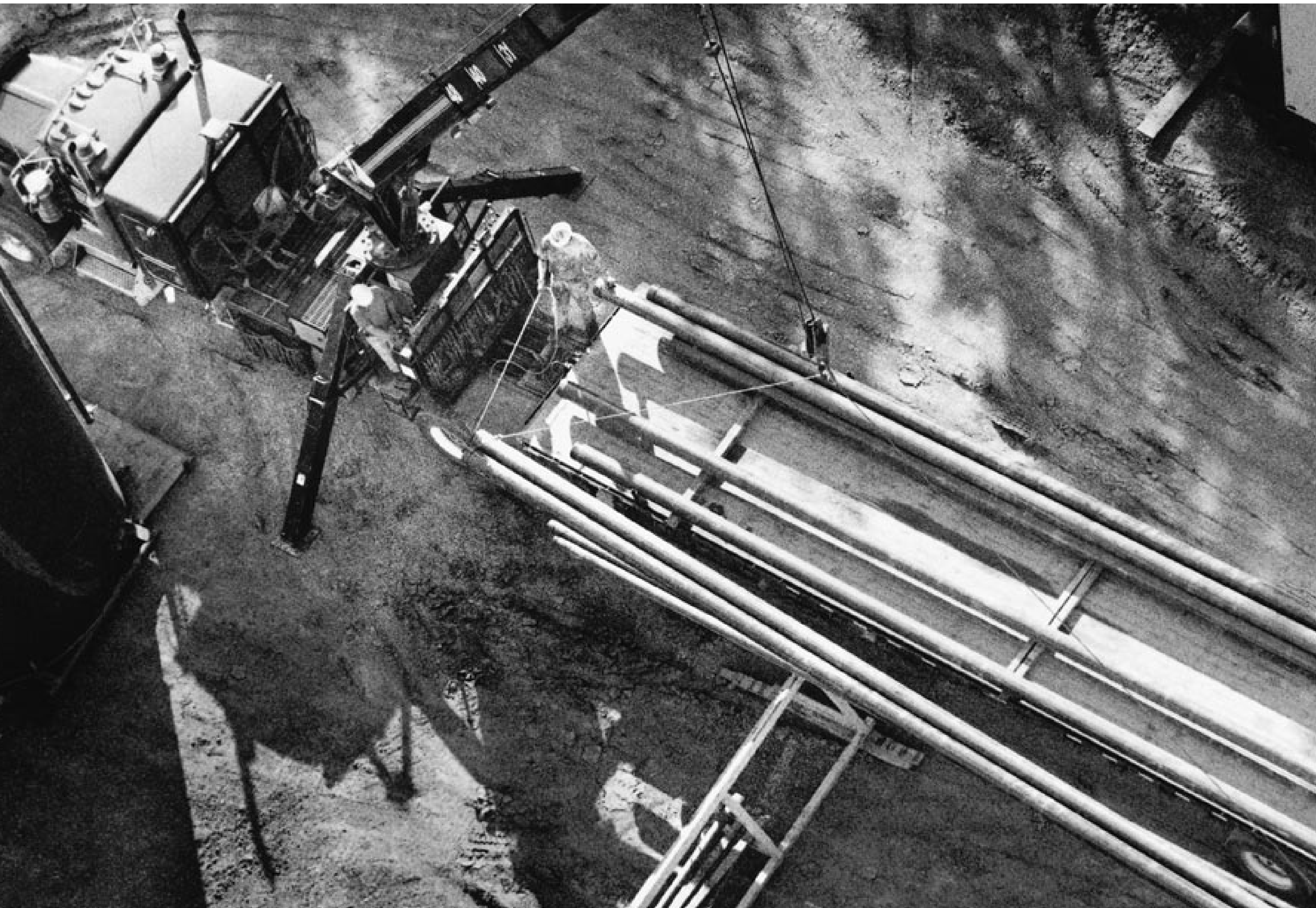
1999 PRODUCTION BY AREA	OIL (Bbl/d)	GAS (Mcf/d)	NGLs (Bbl/d)	TOTAL (Boe/d)
PEMBINA AREA	2,844	2,820	189	3,315
CAROLINE	351	3,250	1,224	1,900
SUNDRE	993	2,238	54	1,271
JENNER	1	12,587	–	1,260
WEYBURN	939	181	–	957
HOADLEY	151	4,341	268	853
MIDALE	755	42	–	759
GARRINGTON	183	3,204	242	745
PROGRESS	–	3,472	54	401
WILDMERE	397	–	–	397
VALHALLA	351	356	10	397
BUICK CREEK	–	3,053	46	351
INNISFAIL	189	958	61	346
CRAIGEND	–	3,314	–	331
HOUSE MOUNTAIN	311	21	15	328
OTHER AREAS	943	26,622	524	4,129
TOTAL	8,408	66,459	2,687	17,741

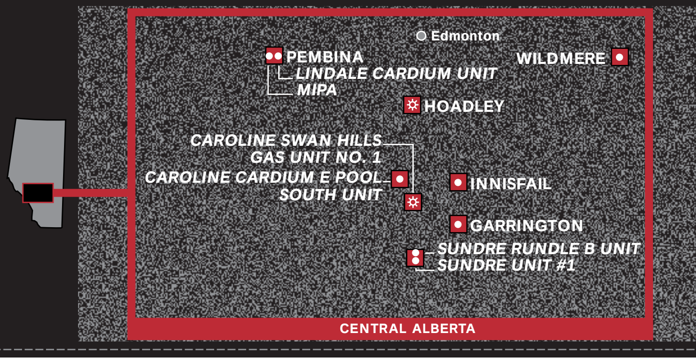
Operations Review

PRODUCTION VOLUMES WERE SIGNIFICANTLY INCREASED DURING 1999 AS A RESULT OF DEVELOPMENT AND ACQUISITION ACTIVITIES. THE 1999 AVERAGE PRODUCTION RATE WAS 17,741 BOE PER DAY, UP 74 PERCENT, COMPARED TO 10,225 BOE PER DAY IN 1998.

OVER THE YEAR, NATURAL GAS SALES AVERAGED 66.5 MMCF PER DAY, UP 76 PERCENT, OIL PRODUCTION AVERAGED 8,408 BBL PER DAY, UP 89 PERCENT, AND CONDENSATE AND NATURAL GAS LIQUIDS VOLUMES AVERAGED 2,687 BBL PER DAY, UP 33 PERCENT. OPERATING COSTS AVERAGED $5.52 PER BOE FOR THE YEAR, UP SLIGHTLY FROM $5.04 PER BOE IN 1998.

IN 1999, $24.2 MILLION OF CAPITAL WAS EXPENDED TO INCREASE PRODUCTION AND RESERVES AND MAINTAIN EXISTING FACILITIES, THEREBY STRENGTHENING UNITHOLDER DISTRIBUTIONS. NUMEROUS INITIATIVES INVOLVING DRILLING, COMPLETIONS, TIE-INS, FACILITY MODIFICATIONS AND PRODUCTION OPTIMIZATION WERE UNDERTAKEN ON MANY OF OUR PROPERTIES; NOTABLY LINDALE, MIPA, CAROLINE, SUNDRE, PROGRESS, BUICK CREEK, JENNER, MARTEN HILLS, MINNEHIK BUCK LAKE, HOUSE MOUNTAIN, MIDALE AND VALHALLA.





1999 HIGHLIGHTS

— ARC INCREASED ITS OWNERSHIP IN SEVERAL PEMBINA PROPERTIES AND THEN COMMENCED A VERY SUCCESSFUL INFILL DRILLING PROGRAM.

— ARC TOOK OVER OPERATORSHIP IN SEVERAL SUNDRE AND CAROLINE UNITS AND ACTIVELY BEGAN OPTIMIZING PRODUCTION.

Central Alberta

PEMBINA

LINDALE CARDIUM UNIT A detailed technical evaluation of the Lindale Cardium Unit was completed in 1999 that identified significant infill drilling opportunities and waterflood optimization potential in the western portion of the Unit. Prior to implementing the development plan, ARC Resources Ltd. ("ARC Resources") increased its ownership in the Unit from 43.7 percent to 53.5 percent. A multi-phase infill drilling program was initiated in the second quarter which included eight wells being drilled in 1999 and which resulted in doubling the Unit oil production; per unit operating costs were reduced by more than 30 percent. Significant positive reserve additions were realized as a result of this program.

During 2000, additional phases of the infill drilling program will be carried out and will include drilling additional water injection wells and converting some producers to injection wells. Other activities will focus on optimizing the Unit's waterflood performance by ensuring waterflood voidage is directed towards increasing production and ultimate reserve recovery. Anticipated operational activities include re-activation of a number of suspended wells and re-fracturing numerous producing wells.

MIPA An updated technical evaluation of the MIPA non-unit area during 1999 confirmed the opportunity for infill drilling. ARC Resources increased its ownership from 66.7 percent to 83.3 percent prior to pursuing this opportunity. ARC Resources commenced logistical efforts in 1999 to implement a phased infill drilling program designed to ensure the highest potential, lowest risk wells were drilled first to validate the technical work. Three successful infill wells were drilled in December. Having optimized a portion of the MIPA waterflood in 1998 with positive results, ARC Resources completed the optimization of the remaining areas of the waterflood in 1999. Additional operating cost reductions were achieved in 1999 with actual costs well below budget projections.

ARC Resources' plans for 2000 include a continuation of the infill drilling program to build on the success of the 1999 program. As well, operational activities in 1999 confirmed the viability and solid economics of production well refractures which will continue in 2000. Artificial lift upgrades will also be undertaken to improve oil production performance.

OTHER PEMBINA PROPERTIES Acquisition of additional Pembina area properties through the Orion transaction provided a broader asset base to pursue optimization techniques that have been proven successful in improving production performance. Economies of scale also allowed ARC Resources to manage these properties more cost effectively. The optimization activities undertaken in 1999 on these assets successfully offset the natural decline of the production.

In the upcoming year, ARC Resources will continue optimizing these assets via production well refractures, conversion of some former water injection wells to producers and other optimization activities. We will continue to focus on cost control and containment and will seek to acquire additional area assets when attractive opportunities present themselves.

CAROLINE

CAROLINE CARDIUM E POOL SOUTH UNIT As part of the Orion acquisition, ARC Resources acquired an 86.6 percent working interest in this mature, high quality waterflood. The working interest owners approved ARC Resources as the operator in June 1999. By year-end, ARC Resources had acquired additional working interests increasing ownership in the unit to 94.7 percent. During 1999, ARC Resources undertook operational reviews of artificial lift performance that resulted in several equipment upgrades which successfully increased production. As well, underperforming wells were identified and several successful well stimulations were performed.

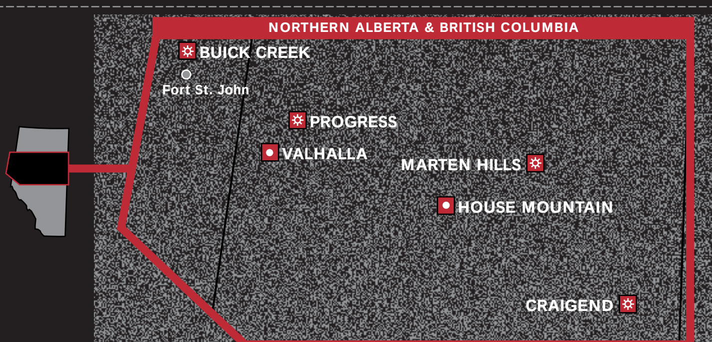
In 2000, ARC Resources will continue its optimization program on under-performing wells including reperforation and refracturing work. Waterflood optimization opportunities and bypassed pay access activities will also be pursued. One well will be deepened to access increased Cardium production.

CAROLINE SWAN HILLS GAS UNIT NO. 1 Unit production was again maintained constant during 1999 at the maximum plant throughput level. Although we have a minor non-operated working interest in this Unit, it is the largest gas pool discovered in Canada in the last 20 years and is a core property which is significant to the Trust in terms of working interest production.

SUNDRE

SUNDRE UNIT #1 AND SUNDRE RUNDLE B UNIT With the Orion acquisition, ARC Resources acquired significant working interests in these mature waterflood oil properties. ARC Resources was appointed interim operator in June 1999 and, after demonstrating the ability to successfully manage the two units' activities, was formally recognized as operator by year-end. ARC Resources exercised an option to acquire over 200 kilometres of seismic at a substantially reduced cost which led to a geophysical/geological study which has substantially enhanced our understanding of the reservoir and associated performance. A waterflood optimization effort is commencing in conjunction with the completion of the geological/geophysical studies. A number of battery upgrades were conducted to ensure long-term operability and guarantee compliance with government regulations. An artificial lift review and field performance study led to several artificial lift upgrades and a number of successful well stimulations.

The budget for 2000 calls for continued artificial lift upgrades, well stimulations and reperforation activities. A number of well reactivation opportunities were identified in 1999 which will be pursued in 2000. The completion of the waterflood optimization study in conjunction with a detailed geological picture is expected to identify other production improvement activities which will be pursued.



1999 HIGHLIGHTS

— GAS DEVELOPMENT DRILLING ACTIVITY WAS STRONG IN 1999 WITH NUMEROUS WELLS DRILLED EARLY IN THE YEAR IN BUICK CREEK AND LATE IN THE YEAR IN MARTEN HILLS.

— AS PRICES IMPROVED, OIL DEVELOPMENT DRILLING RAMPED UP OVER THE YEAR IN HOUSE MOUNTAIN AND VALHALLA.

Northern Alberta and British Columbia

PROGRESS In the Progress Halfway Gas Unit, the operator continued to support production levels and plant throughput levels by drilling, completing, and tieing-in an infill gas well. The operator pursued opportunities to tie-in additional third-party gas production to reduce overall operating costs to the unit working interest owners.

In the Progress non-unit area, ARC Resources installed additional compression to enhance area gas production.

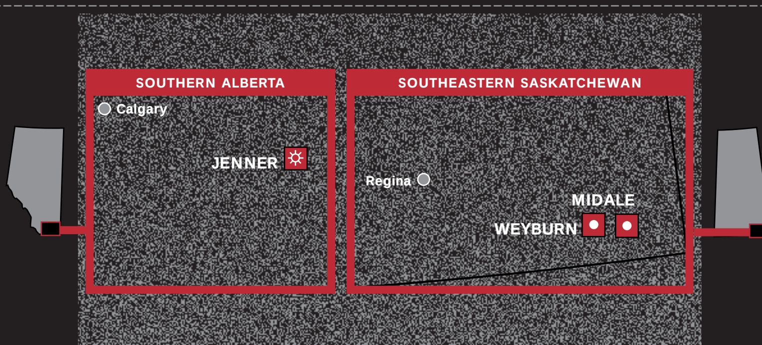
BUICK CREEK ARC Resources participated in the drilling of several development wells in Buick Creek during 1999. As a result of this successful drilling program along with well workovers, suspended well tie-ins and minor facility additions, ARC Resources' net production in the area doubled versus the initial 1999 budget; large reserve increases were also realized as a result of these activities.

VALHALLA DOE CREEK I UNIT NO. 2 After acquiring these assets from Orion, ARC Resources participated in the drilling of four successful infill wells in 1999 which resulted in production being maintained at a constant level. Increased reserves were also achieved as a result of improved ultimate oil recovery. The operator has identified several additional locations and waterflood optimization projects which will be undertaken in early 2000.

MARTEN HILLS SOUTH GAS UNIT NO. 1 ARC Resources increased its working interest ownership in this unit from 13.7 percent to 17.1 percent during 1999. Two 2D seismic programs were conducted on unit lands during the year which led to approval of a 19-well drilling program for the 1999/2000 winter drilling season. In addition, three new compressors and several facility debottlenecking projects were approved. Preliminary results indicate this program was very successful and will add significant reserves and production.

HOUSE MOUNTAIN UNIT NO. 1 The operator continued to utilize 3D seismic acquired in 1998 to further define waterflood optimization opportunities for the Unit. Several horizontal re-entry drilling candidates were identified and drilled which has increased the estimate of ultimate recovery and reserves for this property.

Apache Canada Ltd. ("Apache") purchased Shell Canada Limited's ("Shell") interest in House Mountain Unit No. 1 in 1999 and took over as operator. Apache intends to significantly accelerate production via the use of horizontal re-entry and horizontal drilling technology and to further optimize the existing waterflood. The operator has already obtained partner approval for four additional locations for the remainder of the 1999/2000 winter drilling season.



1999 HIGHLIGHTS

— IN SASKATCHEWAN, THE OPERATOR IN MIDALE COMMENCED AN ACTIVE DRILLING PROGRAM, WHILE IN WEYBURN A CO_2 FLOOD IS BEING IMPLEMENTED.

— IN SOUTHERN ALBERTA, ARC TOOK OVER OPERATORSHIP AT JENNER AND IMMEDIATELY COMMENCED OPTIMIZING PRODUCTION AND REDUCING COSTS.

Southern Alberta and Southeastern Saskatchewan

JENNER This is a major new core area which was acquired in the Starcor transaction. This shallow gas property located in southeastern Alberta has a long reserve life and has significant development and optimization potential; ARC Resources has an average 87 percent working interest and operates the property. Upon taking over as operator in the second quarter of 1999, ARC consolidated facilities and field staff which resulted in cost savings of $25,000 per month. In addition, production increased 365 Mcf per day as a result of optimization activities.

ARC Resources undertook a geological study which expanded a program initiated by the previous operator of pursuing Belly River potential in the area. During the fourth quarter of 1999, ARC Resources re-completed eight wells in the Belly River; six of these became producing Belly River gas wells which added production very cost effectively.

A coiled tubing fracture pilot project was initiated on the property in the third quarter of 1999. The program involved seven wells and was designed to assess the applicability of coiled tubing fracture treatments on the existing shallow gas wells. The information and knowledge gained from this program identified both the benefits and limitations of this technology.

In the year 2000, the capital program for Jenner includes additional Belly River re-completions, an expanded program of coiled tubing fracture treatments on existing wells and pursuing a development drilling program.

MIDALE UNIT Apache purchased Shell's interest in the Midale Unit and took over as operator. Apache's intent is to aggressively pursue infill drilling opportunities and waterflood optimization via the extensive use of horizontal re-entry and horizontal drilling technology. Significant capital expenditures are forecast for 2000 to pursue this program which has the potential of providing a significant gain in oil production.

WEYBURN UNIT Starting late in the second quarter of 1999, the operator began extensive capital expenditures in preparation for the implementation of a large-scale CO_2 flood to improve oil recovery from the Weyburn Unit. Anticipated start-up of the project is in the third quarter of 2000 after which longer term production increases should occur as the injected CO_2 moves previously unswept oil to the producing wells.

1999 ACQUISITIONS AND DIVESTMENTS Effective management of the Trust's assets requires both the acquisition and disposition of oil and gas assets to optimize the property portfolio and take advantage of opportunities which occur in the market. ARC Resources was very active on behalf of the Trust during 1999, completing several significant value-adding transactions.

The most significant acquisitions were the completion of the business combinations with Starcor and Orion for a combination of cash, ARC Energy Trust Units and ARC Energy Trust warrants. These opportunistically timed acquisitions, when oil prices were at all time lows, added several new core areas to the Trust and increased the breadth of development and exploitation opportunities within our asset base. With the strong recovery in commodity prices during the three quarters following completion of these acquisitions, significant accretion occurred to unitholder distributions. The reserves were acquired for $5.13 per Boe based upon proved plus risked probable reserves and consisted of high quality, concentrated assets. The acquired properties increased the Trust's reserve life index to 11.8 years from 11.6 years, increased established reserves by 91 percent, increased the natural gas component of our production from 34 percent to 39 percent, increased production by 85 percent and increased the operated component of our production from 20 percent to 33 percent.

Total acquisitions during the year added 43.3 million barrels of oil equivalent ("Mmboe") while dispositions of minor, non-strategic assets resulted in the sale of 4.1 Mmboe resulting in a net acquisition of 39.2 Mmboe at a price of $5.90 per Boe which is well below the industry average. The divested assets were non-core to ARC generally having some combination of low working interest, high operating costs, low netbacks, little upside, or limited remaining reserve life and represented near-term abandonment liabilities.

The net acquisitions replaced 606 percent of the Trust's 1999 production and increased the Trust's reserves by 83 percent.

1999 ACQUISITION/DISPOSITION SUMMARY

	Purchase Price ($ millions)	Risked Reserves (Mboe)	Reserve Purchase Price ($/Boe)	Production Rate (Boe/d)	Production Purchase Price ($/Boe/d)	Reserve Life Index (years)
Acquisitions	253.1	43,332	5.84	9,672	26,163	12.3
Dispositions	(21.6)	(4,083)	(5.28)	(1,476)	(14,611)	7.6
Net acquisitions	231.5	39,249	5.90	8,196	28,243	13.1

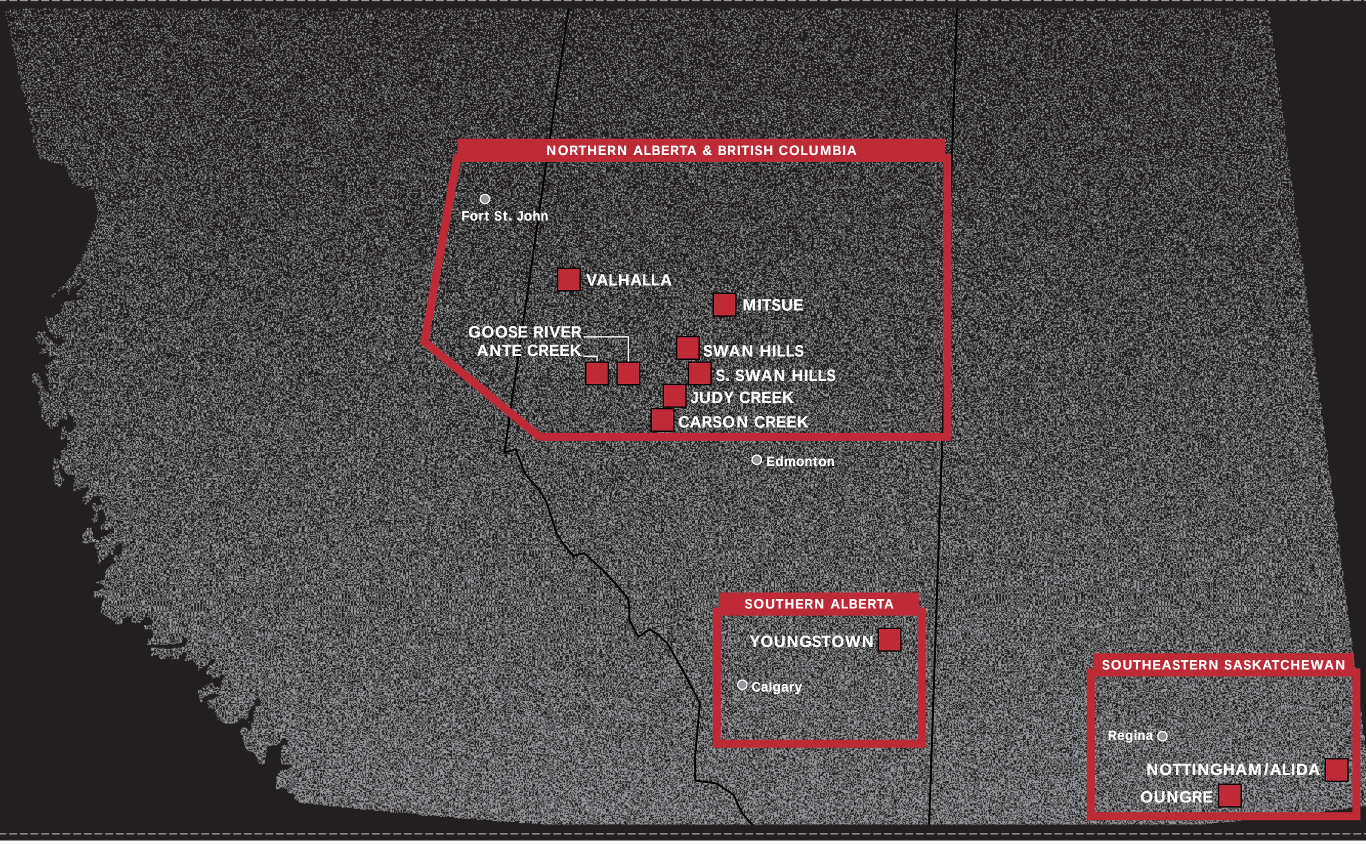
2000 ACQUISITIONS On January 31, 2000, the Trust entered into an agreement to acquire a group of producing oil and gas properties in Alberta and Saskatchewan for $135 million. The transaction was effective January 1, 2000 with an anticipated closing date of March 31, 2000. The reserve acquisition price was $4.93 per Boe based upon proved plus 50 percent probable reserves assigned by Gilbert Laustsen Jung Associates Ltd. ("GLJ"). This price is well below current industry finding and development costs of approximately $7.00 to $12.00 per Boe and also well below prevailing prices in the acquisition market.

The acquisition will positively impact all of ARC's key operating and financial measures as shown below:

	Existing	Pro Forma	Percentage Change Total	Percentage Change Per Unit**
INCREASE THE TRUST'S ALREADY LONG RESERVES LIFE				
Established reserve life index (years)	11.8	12.6	+7%	n/a
SIGNIFICANTLY INCREASE ESTABLISHED RESERVES				
Reserves at December 31, 1999 (Mmboe)	83.8	111.2	+33%	+19%
SIGNIFICANTLY INCREASE PRODUCTION				
Average 2000 rate (Boe/d)	18,000	21,600	+20%	+7%
INCREASE OPERATED COMPONENT OF PRODUCTION				
Percent operated	33%	40%	+21%	n/a
ACCRETIVE TO CASH FLOW				
Estimated 2000 cash flow* ($ millions)	92.8	114.1	+23%	+13%
ACCRETIVE TO DISTRIBUTIONS				
Estimated 2000 distributions* ($ millions)	78.3	89.1	+14%	+5%
INCREASE IN NET ASSET VALUE PER UNIT				
10% pre-tax present values ($ millions)	7.92	8.73	+10%	+10%

* Based upon oil price of $21.00 US per barrel and gas price of $2.85 Cdn per Mcf.

** Based on inclusion of March 2000 equity financing.



The new properties have an attractive production profile and long reserve life ideally suited to a royalty trust.

Property	Working Interest	Forecast 2000 Production (Boe/d)	Established Reserves (Mboe)	Reserve Life Index (years)
Ante Creek	99.0%	1,520	13,012	23.5
Oungre	89.0%	800	5,130	17.5
Swan Hills Unit No. 1	1.5%	310	2,324	19.6
Youngstown	98.0%	530	2,072	10.9
Valhalla/LaGlace	89.0%	460	1,211	6.6
Carson Creek North BHL Unit	5.0%	300	960	8.4
Nottingham/Alida	8.6/5.9%	285	695	6.5
Judy Creek West BHL Unit	3.8%	75	551	19.7
South Swan Hills Unit	1.0%	65	428	18.2
Goose River Unit No. 1	3.3%	110	414	9.8
Mitsue Gilwood Unit No. 1	1.2%	100	299	8.0
Lindbergh Royalty	GORR	170	266	4.2
Total		4,725	27,361	15.6

The new assets provide the Trust with a major new core area at Ante Creek. The remainder of the new assets are all high quality, mature properties with long-term upside potential.

Ante Creek is the most significant property being acquired and will become our fourth largest operated area. It has significant development and exploitation potential in terms of infill drilling opportunities and potential for implementation of a waterflood to enhance recovery. ARC Resources will be pursuing these opportunities in a staged manner which we expect will allow us to maintain constant production levels at Ante Creek for three to five years.

On March 1, 2000, the Trust announced the closing of an equity financing under which 5.8 million units were sold to an underwriting syndicate at $8.65 per unit for gross proceeds of $50.2 million ($47.7 million net). On March 10, 2000, the Trust announced the closing of the sale of an additional 600,000 units to the underwriting syndicate at the same price under an Over Allotment Option. With the exercise of this Over Allotment Option, total gross proceeds from the offering were $55.4 million ($52.6 million net) which were used to partially fund the acquisition of the new properties. The Manager's debt reduction activities undertaken during 1999 and the resulting strong balance sheet and expanded credit facility created the flexibility to accommodate the financing of the balance of the purchase price with debt.

Based upon an independent engineering evaluations conducted by GLJ effective December 31, 1999, ARC Resources had proved plus risked probable reserves of 241.0 billion cubic feet ("Bcf") of natural gas and 59.7 million barrels ("Mmbbl") of crude oil and natural gas liquids. On an oil equivalent basis, reserves at December 31, 1999 were 83.8 Mmbbl which was 78 percent greater than the Trust's reserves at December 31, 1998. Approximately 70 percent of ARC Resources' reserves are crude oil and natural gas liquids and 30 percent are natural gas on a 10:1 barrel of oil equivalent basis.

The following tables summarize reserves of natural gas, crude oil and natural gas liquids as evaluated by GLJ. Reserves are company interest before royalties and probable reserves have been risked at 50 percent to calculate the established reserves. All estimates of future net cash flow in these tables are calculated without any provision for income taxes, general and administrative costs or management fees, but include provisions for future abandonment liabilities.

RLI is calculated by dividing the reserves by annual production (either current year annual production or the independent evaluator's forecast of the first year's production). This provides a simplified representation of the number of years of reserves remaining if production remained constant at that rate. The actual productive life of the reserves is significantly longer than this value due to a declining production rate over time. Due to the impact and timing of acquisition and divestment activity, the following tables use the independent evaluator's forecast of the first year's production in determining RLI, as this results in a more consistent representation of RLI over time.

RESERVE SUMMARY AND RESERVE LIFE INDEX

	1999	1998	1997	1996
Crude Oil				
Proved producing (Mbbl)	32,454	20,090	18,554	10,729
Proved non-producing (Mbbl)	7,541	2,677	394	–
Total proved (Mbbl)	39,995	22,767	18,948	10,729
Proved reserve life index (years)(1)	12.1	12.1	11.3	10.5
Established (Mbbl)(2)	50,245	27,896	24,155	14,147
Established reserve life index (years)(1)	14.8	14.8	14.5	13.9
Natural Gas Liquids				
Proved producing (Mbbl)	7,774	6,066	6,956	6,868
Proved non-producing (Mbbl)	389	475	500	819
Total proved (Mbbl)	8,163	6,542	7,459	7,687
Proved reserve life index (years)(1)	8.1	8.7	8.8	12.0
Established (Mbbl)(2)	9,467	7,138	8,218	8,367
Established reserve life index (years)(1)	9.2	9.5	9.7	13.1
Natural Gas				
Proved producing (Bcf)	184.2	83.9	97.9	76.5
Proved non-producing (Bcf)	19.7	19.7	29.8	24.0
Total proved (Bcf)	203.9	103.6	127.7	100.5
Proved reserve life index (years)(1)	7.9	7.2	7.4	9.2
Established (Bcf)(2)	241.0	121.9	148.2	112.0
Established reserve life index (years)(1)	9.0	8.5	8.6	10.3
Oil Equivalent				
Proved producing (Mboe)	58,647	34,543	35,299	25,249
Proved non-producing (Mboe)	9,900	5,121	3,875	3,214
Total proved (Mboe)	68,547	39,665	39,175	28,463
Proved reserve life index (years)(1)	10.0	9.8	9.2	10.4
Established (Mboe)(2)	83,813	47,226	47,190	33,710
Established reserve life index (years)(1)	11.8	11.6	11.1	12.3

(1) RLI calculated using independent evaluator's forecast of production
(2) Established = Proved plus risked probable (risked at 50 percent)

RESERVES RECONCILIATION

	Crude Oil (Mbbl)		Natural Gas (Bcf)		Natural Gas Liquids (Mbbl)		Total (Mboe)	
	Proved	Risked Probable	Proved	Risked Probable	Proved	Risked Probable	Proved	Risked Probable
Reserves at December 31, 1996	10,729	3,418	100.5	11.5	7,687	680	28,463	5,247
Acquisitions and divestments	7,961	1,552	38.8	10.3	1,104	232	12,943	2,809
Drilling and development	176	13	4.7	0.3	49	5	695	46
Production	(1,334)	–	(14.0)	–	(704)	–	(3,440)	–
Revisions	1,416	224	(2.3)	(1.6)	(677)	(158)	514	(87)
Reserves at December 31, 1997	18,948	5,207	127.7	20.5	7,459	759	39,175	8,015
Acquisitions and divestments(1)	2,465	648	(15.1)	(2.7)	(195)	(36)	759	338
Drilling and development	981	844	4.0	1.2	7	(104)	1,388	860
Production	(1,620)	–	(13.8)	–	(737)	–	(3,732)	–
Revisions(2)	1,993	(1,570)	0.8	(0.6)	8	(23)	2,080	(1,653)
Reserves at December 31, 1998	22,767	5,129	103.6	18.4	6,542	596	39,665	7,560
Acquisitions and divestments(1)	17,769	4,286	118.0	15.4	3,375	476	32,942	6,307
Drilling and development	1,992	631	5.8	1.7	204	1	2,778	798
Production	(3,069)	–	(24.3)	–	(981)	–	(6,475)	–
Revisions(2)	536	204	0.7	1.7	(977)	232	(369)	605
Reserves at December 31, 1999	39,995	10,250	203.9	37.1	8,163	1,304	68,547	15,266

(1) As evaluated by the independent evaluator at the time of the acquisition/divestment
(2) Revisions and production adjustment

PRESENT VALUE OF RESERVES

($ thousands before income taxes)	1999			1998			1997			1996		
Discount factor	10%	12%	15%	10%	12%	15%	10%	12%	15%	10%	12%	15%
Proved producing	413,791	384,558	348,774	209,733	193,488	173,600	258,290	236,639	210,767	192,352	173,207	151,036
Proved non-producing	40,228	34,451	27,529	29,643	26,330	22,295	27,670	24,945	21,523	24,921	22,389	19,285
Total proved	454,020	419,009	376,303	239,376	219,818	195,895	285,960	261,584	232,290	217,273	195,590	170,321
Risked probable	76,380	65,300	52,789	38,977	33,711	27,627	34,063	28,656	22,845	21,999	18,068	14,156
Established	530,400	484,309	429,091	278,353	253,529	223,522	320,024	290,240	255,136	239,272	213,658	184,478

NET ASSET VALUE

	December 31, 1999		December 31, 1998		December 31, 1997		December 31, 1996	
($ thousands, except per unit amounts)	10%	12%	10%	12%	10%	12%	10%	12%
Value of established oil and gas reserves	530,400	484,309	278,353	253,529	320,024	290,240	239,272	213,658
Add: Undeveloped lands	11,994	11,994	2,655	2,655	1,500	1,500	1,800	1,800
Working capital	15,761	15,761	(1,688)	(1,688)	4,647	4,647	1,647	1,647
Reclamation fund	7,165	7,165	4,504	4,504	3,016	3,016	908	908
Deduct: Debt	(141,000)	(141,000)	(72,499)	(72,499)	(65,955)	(65,955)	(37,998)	(37,998)
Net asset value	424,320	378,229	211,325	186,501	262,232	233,448	205,629	180,015
Units outstanding (thousands)	53,607	53,607	25,604	25,604	25,604	25,604	18,000	18,000
Per unit	$ 7.92	$ 7.06	$ 8.25	$ 7.28	$ 10.24	$ 9.12	$ 11.42	$ 10.00

PRICING ASSUMPTIONS – INDUSTRY CONSENSUS[1]

	WTI Crude Oil ($ US/Bbl)				Edmonton Crude Oil[2] ($ Cdn/Bbl)				Natural Gas[3] ($ Cdn/MmBtu)			
Year	1999	1998	1997	1996	1999	1998	1997	1996	1999	1998	1997	1996
1997	–		–	20.00	–	–	–	26.58	–	–	–	1.63
1998	–	–	20.31	20.39	–	–	26.71	26.85	–	–	1.83	1.77
1999	–	14.67	20.85	21.27	–	21.06	27.15	27.77	–	2.25	1.97	2.06
2000	20.67	16.61	21.44	22.18	28.72	23.07	27.79	29.00	2.80	2.28	2.11	2.17
2001	20.10	18.57	22.06	23.13	27.24	24.98	28.60	30.28	2.68	2.31	2.21	2.30
2002	20.37	20.05	22.72	24.12	27.18	26.37	29.41	31.61	2.62	2.37	2.31	2.42
2003	20.64	20.69	23.38	25.16	27.39	27.18	30.26	33.01	2.63	2.45	2.42	2.56
2004	21.04	21.13	24.09	26.23	27.86	27.70	31.10	34.46	2.64	2.53	2.52	2.70
2005	21.37	21.57	24.83	27.36	28.37	28.25	32.10	35.98	2.66	2.61	2.64	2.84
2006	21.69	22.01	25.61	28.53	28.76	28.86	33.08	37.56	2.69	2.66	2.73	2.94
2007	22.10	22.45	26.39	29.75	29.24	29.47	34.13	39.21	2.74	2.72	2.82	3.05
2008	22.46	22.85	27.22	31.03	29.79	30.07	35.22	40.93	2.80	2.78	2.92	3.15
2009	22.82	23.34	28.08	32.26	30.34	30.67	36.38	42.73	2.85	2.84	3.03	3.26
2010	23.27	23.82	28.95	33.75	30.81	31.25	37.55	44.60	2.90	2.89	3.13	3.37
2011	23.64	24.32	29.86	34.76	31.33	31.86	38.75	45.94	2.94	2.96	3.24	3.47
2012	24.00	24.81	30.78	35.81	31.89	32.47	40.00	47.32	3.01	3.01	3.32	3.58
2013	24.37	25.31	31.73	36.88	32.44	33.13	41.25	48.74	3.06	3.07	3.42	3.68
2014	24.75	25.81	32.73	38.00	32.97	33.84	42.58	50.20	3.11	3.12	3.54	3.79
2015	25.12	26.31	33.16	39.13	33.53	34.54	43.13	51.70	3.16	3.18	3.59	3.91
There-after	1%/yr	1.3%/yr	1.3%/yr	3%/yr	1%/yr	1.3%/yr	1.3%/yr	3%/yr	1%/yr	1.3%/yr	1.3%/yr	3%/yr

(1) Average of GLJ, Sproule Associates Limited and McDaniel & Associates Consultants Ltd. then current price forecasts
(2) Edmonton Refinery Postings for 40° API, 0.4 percent sulphur content crude
(3) Average Alberta plantgate price

Marketing

NATURAL GAS During 1999, ARC Resources continued its marketing strategy to diversify its sales and transportation portfolio and increase the level of direct control over the marketing of its natural gas production. This diversity provides the combination of control and risk-management required to maximize production netbacks.

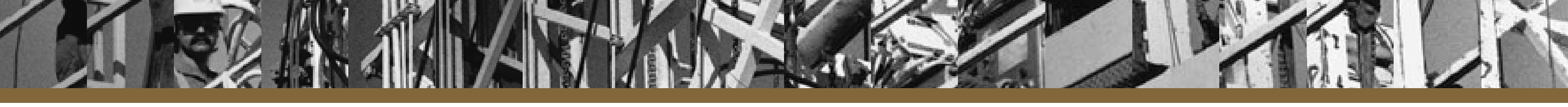
The average natural gas price received during 1999 was $2.54 per Mcf as compared to $1.93 for 1998. This price was achieved with a portfolio mix that on average through the year received fixed pricing for 33 percent of total production, AECO pricing for 30 percent, NYMEX pricing for 27 percent and Sumas pricing for the remaining 10 percent of production.

To manage natural gas price volatility and to stabilize the revenue stream, the natural gas portfolio is directed towards maintaining:

1. a balanced exposure to both U.S., Canadian and fixed price markets;
2. market-sensitive and hedgable pricing terms and contract flexibility; and
3. a high utilization of contracted pipeline and processing capacity.

CRUDE OIL AND NATURAL GAS LIQUIDS Liquids production in 1999 was comprised of 44 percent light gravity (>35° API) oil, 24 percent medium gravity (25° to 35° API) oil, four percent condensate and 24 percent natural gas liquids. Heavier gravity (<25° API) crude oil accounted for only four percent of production.

During 1999, average sales prices were $24.85 per Bbl for oil and $17.43 per Bbl for natural gas liquids; these prices compare to 1998 prices of $18.99 per Bbl for oil and $13.17 per Bbl for natural gas liquids. Crude oil is sold under 30-day evergreen contracts while natural gas liquids are sold under annual arrangements. Industry pricing benchmarks for crude oil and natural gas liquids are continuously monitored to ensure optimal netbacks.



Hedging

ARC Resources' Board of Directors approved an expanded hedging program in 1999 under which financial hedges can be entered into in respect of commodity prices and foreign currency exchange rates in addition to physical hedges. The Board approved the hedging of up to 50 percent of the Trust's production on a Boe basis for up to 12 months in the future, up to 25 percent of production for the period commencing one year in the future for a maximum of 12 months and up to 15 percent of production for the period commencing two years into the future for up to 36 months.

A summary of financial and physical contracts in respect of hedging activities can be found in Management's Discussion and Analysis.

Environment and Safety

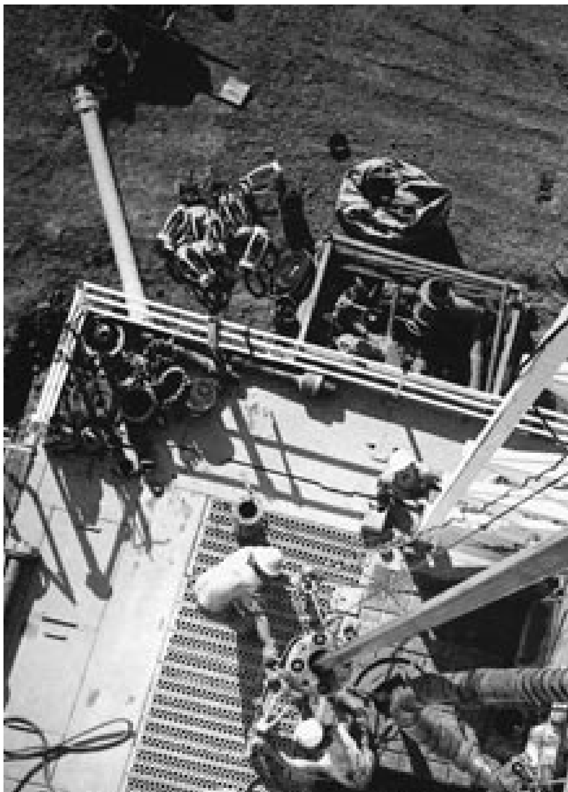
ARC Resources is firmly committed to conducting its operations in a safe and environmentally responsible manner. Management, staff and contractors are responsible for ensuring that operations are conducted in accordance with all current environmental and occupational health and safety laws and regulations. During 1999, all ARC Resources' personnel conducted safe operations with zero lost-time accidents.

The ARC Resources' Operations Safety Policies and Guidelines and ARC Resources' Emergency Response Procedures were updated during the year to include the sour operations that were acquired in the Starcor and Orion transactions.

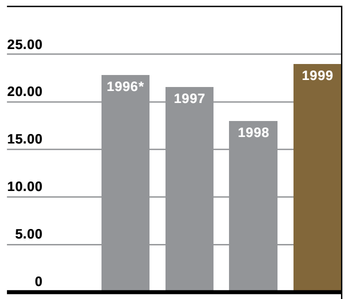
During 1999, initiatives to reduce previously flared gas streams were successfully implemented. Highlights include the installation of a vapour recovery unit ("VRU") and the installation of an emissions-free, dessicant-based gas dehydration system at the Sundre Unit #1 battery. Based on the technical and environmental success of these projects, further installations are planned at other locations. In addition, the flare stack at the Sundre waterflood was completely removed and gases from this facility are now conserved by the VRU.

A reclamation fund has been established to ensure that the necessary funds are available for future reclamation and abandonment of all wells, plants and facilities. Total funding during the year net of actual abandonment expenditures amounted to $2.4 million, increasing the balance in the Fund at December 31, 1999 to $7.2 million. ARC Resources has a continuing program of well-site abandonment, cleanup and restoration to reduce future environmental liabilities.

Commitment AS MANAGER OF THE TRUST, ARC FINANCIAL CORPORATION IS COMMITTED TO DELIVERING SUPERIOR RETURNS AND VALUE TO UNITHOLDERS THROUGHOUT ALL PHASES OF THE SECTOR'S BUSINESS CYCLE. OUR SUCCESS IN THIS REGARD IS EVIDENCED BY THE STABILITY IN OUR DISTRIBUTIONS DURING THE OIL PRICE DECLINE EXPERIENCED IN 1998 AND EARLY 1999 AND OUR CONTINUED ABILITY TO PRODUCE SUPERIOR GROWTH AND PERFORMANCE IN A COST-EFFECTIVE MANNER.

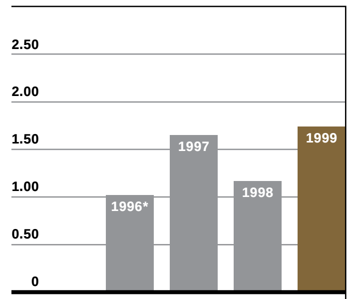


SALES PRICE ($/Boe)



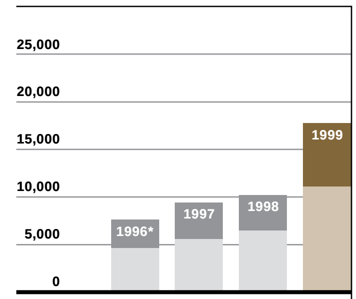
*for the six-month period

CASH FLOW ($/unit)



*for the six-month period

PRODUCTION (Boe/d)



*for the six-month period

Gas Oil & NGLs

Management's Discussion and Analysis

HIGHLIGHTS The Trust's 1999 operating results were positively impacted by the following key events:

(a) the Trust acquired both the Starcor and Orion trusts on March 12, 1999 when oil prices were in the early stages of recovering from a 20-year low;

(b) an active development drilling and exploitation program was conducted in 1999. The results of the development program, the above-noted acquisitions and minor property dispositions resulted in net reserve additions of 43.1 million Boe at an average cost of $5.94 per Boe;

(c) the rebound in oil prices coupled with the Starcor and Orion acquisitions resulted in record levels of production, cash flow and cash distributions in 1999;

(d) in July of 1999, the Trust completed an equity financing under which 4.6 million Trust Units were issued for $36.3 million of gross proceeds; and

(e) the Trust revised its distribution policy such that cash available for distribution in excess of $0.10 per unit per month is split between payments to Unitholders and discretionary debt reduction. This initiative combined with the equity financing and the minor property dispositions resulted in year-end debt levels declining to an amount approximately equal to annualized fourth quarter cash flow.

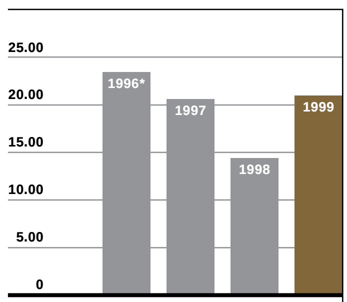
Higher commodity prices resulted in 1999 earnings of $29.8 million compared to a net loss in 1998 of $14.1 million. The 1998 loss was due to a writedown in the book value of the Trust's property, plant and equipment by $14.7 million due to a ceiling test calculation using a depressed oil price performed at December 31, 1998.

PRODUCTION Production volumes for 1999 averaged 17,741 Boe per day, up 74 percent from the 1998 average of 10,225 Boe per day. This increase was primarily the result of the Starcor and Orion acquisitions completed in the first quarter of 1999 as well as ongoing development activities. Crude oil and natural gas liquids represented 63 percent of production in 1999 and 1998 with natural gas production accounting for the remaining 37 percent of production.

The Trust expanded its core areas in 1999, adding Jenner and Sundre to the existing Pembina and Caroline core areas. Production from these four areas accounted for approximately 43 percent of both the Trust's production and the Trust's revenue, as follows:

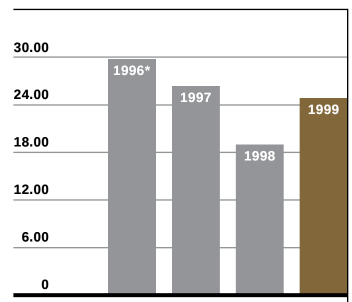
Area	Production (Boe/d)	Revenue ($ millions)
Pembina	3,315	30.0
Caroline	1,900	12.9
Sundre	1,271	11.1
Jenner	1,260	11.1
All other areas	9,995	90.1
Total	17,741	155.2

WEST TEXAS INTERMEDIATE ($ US/Bbl)



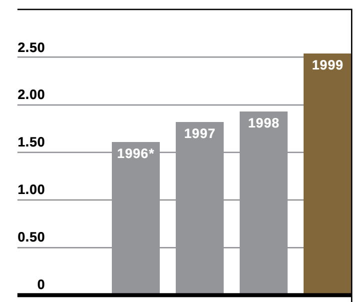
*for the six-month period

OIL SALES PRICE ($ Cdn/Bbl)



*for the six-month period

GAS SALES PRICE ($ Cdn/Mcf)



*for the six-month period

PRICES The Trust's average oil price increased 31 percent in 1999 to $24.85 per Bbl as compared to $18.99 per Bbl in 1998. In US dollar terms, the benchmark West Texas Intermediate ("WTI") oil price averaged $20.96 US per Bbl in 1999 up from $14.40 US per Bbl in 1998. A concerted effort by OPEC to curtail production resulted in the rebound in oil prices.

Natural gas prices continue to strengthen, reflecting pipeline expansions that have occurred which allow improved access for Canadian gas to US markets. The Trust's 1998 average wellhead gas price increased to $2.54 per Mcf in 1999 from $1.93 per Mcf in 1998.

ARC Resources' Board of Directors approved an expanded hedging program in 1999 under which financial hedges can be entered into in respect of commodity prices and foreign currency exchange rates. The Board approved the hedging of up to 50 percent of the Trust's production on a Boe basis for up to 12 months in the future, up to 25 percent of production for the period commencing one year in the future for a maximum of 12 months, and up to 15 percent of production for the period commencing two years into the future for up to 36 months. The hedging program was expanded to encompass the following items:

(a) the formation of a Risk Management Committee ("RMC") to ensure the integrity of the program, the implementation of controls and limit the amount of production hedged;

(b) the RMC sets policies and procedures and reviews all transactions for the final approval of the Chief Executive Officer and the President of ARC Resources;

(c) two highly experienced professionals are designated risk managers and as such recommend transactions to the RMC;

(d) a portfolio approach is used under which the total exposure is split into segments with each segment hedged at specific target prices using the most effective hedging instrument including swaps, collars and floors;

(e) transactions are consummated with counterparties meeting certain credit criteria and approved by the RMC; and

(f) all hedged positions are tracked internally and a mark to market report is provided to the RMC weekly.

A summary of the contracts outstanding as at December 31, 1999 is as follows (no contracts were outstanding at December 31, 1998):

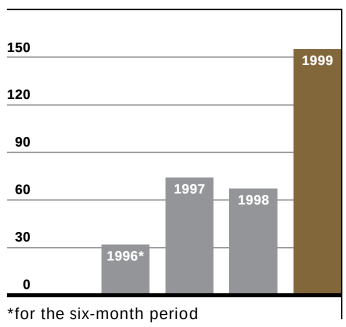
	Quantity (Bbl/d)	Average Contract Prices ($/Bbl)	Term
Crude oil fixed price contracts	800	31.38	January to December 2000
	900	34.00	January to September 2000
Crude oil collared contracts	600	28.25 – 44.50	January to March 2000
	1,200	30.00 – 41.00	January to March 2000
	1,800	30.00 – 33.35	April to June 2000

Contract prices shown above are based upon the Canadian dollar equivalent of WTI and are an average of prices of contracts that were put in place on a calendar quarter basis, with prices varying by quarter.

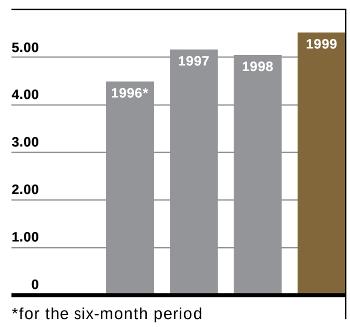
In all the above-noted contracts, the Trust has agreed to the fixed price or a price which varies between the floor and the ceiling of the collar. The counterparty to the contracts has accepted the risks and benefits in the event the monthly settlement price of oil is below or above the contract prices.

As at December 31, 1999, the Trust would have had to pay approximately $457,000 to settle these contracts.

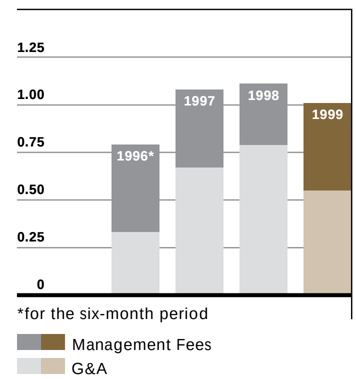
REVENUE ($ millions)



OPERATING COSTS ($/Boe)



G&A AND MANAGEMENT FEES ($/Boe)



In addition, the Trust had the following physical contracts in place as at December 31, 1999:

	Quantity (GJ/d)	Average Contract Prices ($/GJ)	Term
Gas fixed price contracts	5,000	2.85	January to October 2000

REVENUE AND CASH FLOW Revenues in 1999 increased to $155.2 million compared to $67.1 million in 1998 as a result of increased production volumes associated with the Starcor and Orion acquisitions, the 31 percent increase in oil prices and 32 percent increase in natural gas prices. Royalties increased to 15.2 percent of revenues in 1999 from 14.3 percent in 1998, due primarily to higher natural gas prices which increase the crown royalty rate. Operating costs in 1999 increased to $5.52 per Boe up from $5.04 per Boe in 1998 with Starcor and Orion properties having slightly higher operating costs per unit of production than the Trust's other properties.

NETBACKS Operating netbacks increased to $14.80 per Boe in 1999 compared to $10.38 per Boe in 1998.

The components of operating netbacks are shown below:

($/Boe)	1999	1998	1997	1996
Selling price	23.97	17.99	21.54	22.31
Royalties	(3.65)	(2.57)	(3.56)	(3.61)
Operating costs	(5.52)	(5.04)	(5.16)	(4.49)
Netback	14.80	10.38	12.82	14.21

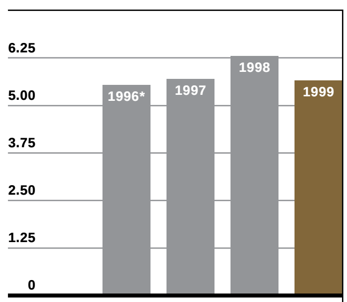
GENERAL AND ADMINISTRATIVE EXPENSES General and administrative expenses, after deduction of the residual one percent royalty reimbursement, declined in 1999 to $0.55 per Boe from $0.79 per Boe in 1998 due to increased production volumes.

($ thousands, except per Boe amounts)	1999	1998	1997	1996
General and administrative expenses	4,381	3,246	2,735	652
Residual 1% of income retained by the Trust	(808)	(300)	(377)	(184)
Net general and administrative expenses	3,573	2,946	2,358	468
Per Boe	$ 0.55	$ 0.79	$ 0.69	$ 0.34

MANAGEMENT FEES The Manager receives a management fee of three percent of net operating revenue which equalled $3.0 million or $0.46 per Boe in 1999 bringing the total general and administrative expenses and management fee costs for 1999 to $1.01 per Boe which compares to $1.11 per Boe in 1998. In 1998, management fees were $1.2 million or $0.32 per Boe.

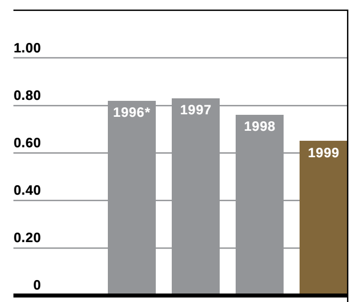
INTEREST EXPENSE Interest expense increased to $7.4 million in 1999 from $4.1 million in 1998 as a result of $74 million of debt assumed on the Starcor and Orion acquisitions. Interest expense was minimized over the course of the year by the issuance of bankers' acceptances which were issued at a discount to the prevailing bank prime interest rates at the time.

DEPLETION, DEPRECIATION AND AMORTIZATION ($/Boe)



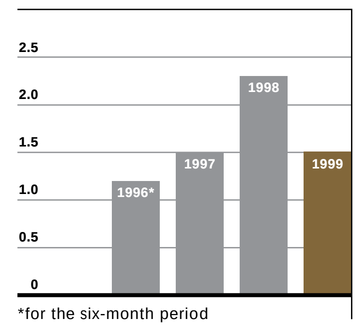
*for the six-month period
(based upon a 6:1 energy equivalent factor)

RECLAMATION AND ABANDONMENT ($/Boe)



*for the six-month period
(based upon a 6:1 energy equivalent factor)

DEBT AS A MULTIPLE OF ANNUAL CASH FLOW



*for the six-month period

TAXES Capital taxes paid by ARC Resources based on debt and equity levels at the end of the year equalled $257,000 in 1999 versus $150,000 in 1998.

DEPLETION, DEPRECIATION AND FUTURE SITE RECLAMATION EXPENSES The 1999 and 1998 depletion and depreciation rates were $5.66 and $5.58 per Boe, respectively, based on a 6:1 energy equivalent factor. The calculation of the 1999 rate includes an estimated $69 million for future development costs of proved undeveloped reserves and excluded $12 million for future net realizable salvage value of existing production facilities and $12 million for unevaluated properties. The provision for future site reclamation and abandonment equalled $0.64 per Boe in 1999 compared to $0.76 per Boe in 1998. A ceiling test writedown of $14.7 million was charged to earnings as additional depletion, depreciation and amortization in 1998.

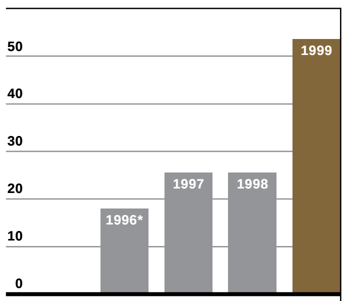
CAPITAL EXPENDITURES ARC Resources completed a number of minor acquisitions and divestments in 1999 to enhance its asset base in addition to the Starcor and Orion acquisitions. Also in 1999, development drilling occurred on a number of properties to maintain or increase production. Total reserve acquisition and development costs for 1999 were $5.94 per Boe. A breakdown of capital expenditures by category is shown below:

($ thousands)	1999	1998	1997	1996
Lease rentals and acquisition	346	593	857	109
Geological and geophysical expenditures	186	339	74	–
Development drilling	20,974	6,967	7,362	116
Plant and facilities	2,743	2,636	462	977
Producing property net acquisitions (net of post-closing adjustments)	231,482	60	93,962	206,231
Total capital	255,731	10,595	102,717	207,433

ABANDONMENTS ARC Resources abandons wells and associated well and facility site locations on an ongoing basis, as required. In 1999, actual abandonment and site reclamation costs incurred were $326,000, up from $113,000 in 1998. The Trust, in conjunction with ARC Resources, has established a reclamation fund (the “Fund”) into which $2.4 million cash was contributed, over and above the $326,000 used for actual expenditures in 1999, bringing the balance in the Fund including interest earned on the Fund to $7.2 million as at December 31, 1999. The Fund is invested in short-term market instruments to provide for future abandonment liabilities. Future contributions to the Fund are currently set at a minimum of $2.4 million per year in order to fund the total estimated future abandonment and site reclamation over a 20-year period.

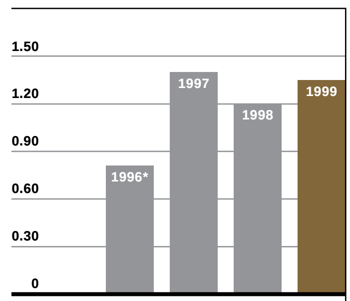
EQUITY AND FINANCIAL RESOURCES Working capital at December 31, 1999 was $15.8 million after year-end accruals and the inclusion of a $4.8 million receivable from the disposition of minor properties sold in December, which were subject to rights of first refusal. Bank debt stood at $141 million at December 31, 1999 with $59 million of unutilized lines of credit available based on a total $200 million credit facility in place with three major Canadian financial institutions.

OUTSTANDING UNITS (millions)



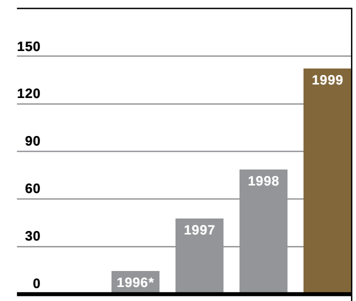
*for the six-month period

DISTRIBUTIONS ($/unit)



*for the six-month period

CUMULATIVE DISTRIBUTIONS ($ millions)



*for the six-month period

The debt is supported by the Trust's diverse, mature, high-quality, long-life assets.

End-of-year debt to total capitalization was approximately 20 percent and debt to cash flow payout was approximately one year based upon annualized fourth quarter cash flow.

($ thousands, except market price amounts)	1999	1998	1997	1996
Bank debt	141,000	72,499	65,955	37,998
Less: Working capital (deficiency)	15,761	(1,688)	4,647	1,647
Reclamation fund	7,165	4,504	3,016	908
Net debt obligations	118,076	69,683	58,292	35,443
Outstanding units	53,607	25,604	25,604	18,000
Market price at end of period	$ 8.75	$ 6.15	$ 10.45	$ 12.25
Total Trust capitalization	587,136	227,148	325,854	255,943
Debt as a percentage of total capitalization	20.0%	30.7%	17.9%	13.8%

UNITHOLDERS' EQUITY The acquisition of the Starcor and Orion net assets were made in part by the issuance of 21.3 million Trust Units to the former Starcor and Orion unitholders. In addition 890,723 Trust Units were issued to the managers of the Starcor and Orion trusts as compensation for the termination of their management contracts. The Manager of the Trust agreed to reinvest a portion of its fee earned on the acquisition which resulted in 392,799 Trust Units being issued. All Trust Units issued in the Starcor and Orion transactions were issued at $6.57 per Trust Unit.

In July 1999, the Trust completed an equity financing which raised $36.3 million of gross proceeds ($34.3 million net) on the issuance of 4.6 million Trust Units. Net proceeds of the offering were applied against debt.

In conjunction with the Starcor and Orion acquisitions, 4,261,899 warrants to acquire Trust Units were issued to the former unitholders of Starcor and Orion. The warrants are exercisable at any time up to June 15, 2000 at $7.25 per warrant to obtain one Trust Unit. As at December 31, 1999, a total of 766,948 warrants had been exercised.

Unitholders electing to reinvest distributions or make optional cash payments to acquire Trust Units from treasury under the Distribution Reinvestment Incentive Plan ("DRIP") resulted in 43,317 Trust Units being issued in 1999.

At the Trust's annual meeting held June 7, 1999, the prior Trust option plan was terminated and all options cancelled. A new Trust Unit Rights Incentive Plan was approved under which 1,200,000 rights were issued to all office and field employees, long-term consultants and independent directors. The rights were issued at an initial exercise price of $8.20 per Trust Unit which is adjusted downward over time by the amount, if any, that distributions for the quarter exceed 2.5 percent of net book value of property, plant and equipment. As at December 31, 1999, rights to purchase 1,192,000 Trust Units were outstanding at an exercise price of $7.86 subject to vesting provisions. These rights expire in May, 2004.

CASH DISTRIBUTIONS Cash distributions of $0.10 per Trust Unit per month for nine months and $0.15 per Trust Unit per month for three months in 1999 resulted in a total of $1.35 per Trust Unit distribution in 1999 ($1.20 in 1998) for total cumulative distributions since inception of $142.3 million ($4.76 per Trust Unit). Actual cash available for distribution is reviewed each quarter and, to the extent excess undistributed cash is available, it is distributed to Unitholders as an extra distribution. As previously stated, the Trust has implemented a policy which splits cash that is available for distribution above $0.10 per Trust Unit per month between the Unitholders and debt reduction. This resulted in an $8.0 million discretionary debt repayment in 1999.

ASSESSMENT OF BUSINESS RISKS The oil and gas business is subject to numerous risks, including, but not limited to, the following: (a) operational risk associated with the production of oil and natural gas; (b) reserve risk in respect to the quantity and quality of recoverable reserves; (c) market risk relating to the availability of transportation systems to move the product to market; (d) commodity risk as oil and natural gas prices fluctuate due to market forces; (e) financial risks such as the Canadian/US dollar exchange rate, interest rates and debt service obligations; (f) environmental and safety risks associated with well and production facilities; and (g) changing government royalty legislation, income tax laws and incentive programs relating to the oil and gas industry.

The Trust's policies and procedures to mitigate these risks include: (a) acquire mature production to reduce technical risks; (b) acquire long life reserves to ensure relatively stable production and to reduce the economic risks associated with commodity price cycles; (c) maintain a low cost structure to maximize product netbacks; (d) diversify properties to mitigate individual property risk; (e) seek to maintain a relatively balanced commodity exposure; (f) subject all property acquisitions to rigorous review; (g) closely monitor pricing trends and develop a mix of contractual arrangements for the marketing of products; (h) implement a hedging program to hedge commodity prices and foreign currency rates; (i) continuously obtain the services of technical experts when required; (j) ensure strong third-party operators for non-operated properties; (k) adhere to the Trust's safety program and keep abreast of current operating practices; (l) carry insurance to cover losses and business interruption; and (m) establish and build cash resources to pay for future abandonment and site restoration costs.

YEAR 2000 As at March 31, 2000, the Manager has not experienced any significant year 2000 computer problems and all office and field operations continue as normal. A nominal amount was spent on upgrading software to avoid potential year 2000 problems.

OUTLOOK The outlook for 2000 is positive with the current oil prices in excess of $25 US per Bbl for the benchmark WTI and with a significant acquisition of new properties in the first quarter of 2000. This acquisition is accretive on all measures and will increase production and reserves by approximately 33 percent and 27 percent, respectively. This acquisition of $135 million will also increase total assets to approximately $640 million. With the Trust raising $52.6 million of net proceeds by issuing 6.4 million Trust Units, debt will increase to approximately $217 million. The debt will be 1.8 times estimated year 2000 cash flow, a level which is commensurate with the current average for the overall royalty trust sector.

Management's Responsibility

ARC Financial Corporation (the "Manager"), as manager of ARC Energy Trust and ARC Resources Ltd., is responsible for the preparation of the accompanying combined financial statements and for the consistency therewith of all other financial and operating data presented in this annual report. The statements have been prepared in accordance with the accounting policies detailed in the accounting policies note to the combined financial statements. In the Manager's opinion, the combined financial statements are in accordance with generally accepted accounting principles, have been prepared within acceptable limits of materiality, and have utilized supportable reasonable estimates.

Management maintains a system of internal controls to provide reasonable assurance that all assets are safeguarded, transactions are appropriately authorized and to facilitate the preparation of relevant, reliable and timely information.

Arthur Andersen LLP, independent auditors appointed by the Trustee, have examined the combined financial statements of the Trust. The Audit Committee, consisting of the independent directors of ARC Resources Ltd., has reviewed these statements with management and the auditors, and has recommended them to the Board of Directors for approval. The Board has approved the combined financial statements of the Trust.

(SIGNED)

JOHN P. DIELWART

PRESIDENT AND DIRECTOR

(SIGNED)

STEVEN W. SINCLAIR

VICE-PRESIDENT FINANCE

Calgary, Alberta. February 4, 2000.

Auditors' Report

To the Unitholders of ARC Energy Trust:

We have audited the combined balance sheet of ARC Energy Trust as at December 31, 1999 and 1998 and the combined statements of income (loss) and accumulated earnings, cash flows, and cash distributions and accumulated cash distributions for the years then ended. These financial statements are the responsibility of the Trust's Management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with 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 combined financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 1999 and 1998 and the results of its operations and its cash flows for the years then ended in accordance with generally accepted accounting principles.

(SIGNED)

ARTHUR ANDERSEN LLP

CHARTERED ACCOUNTANTS

Calgary, Alberta. February 4, 2000 (except as to note 15, which is as of February 9, 2000).

Combined Balance Sheet

As at December 31,
($ thousands)

	1999	1998
ASSETS		
Current Assets		
Cash	$ 9,240	$ 1,390
Properties held for sale (Note 3)	4,800	–
Accounts receivable	29,145	7,747
	43,185	9,137
Reclamation Fund (Note 5)	7,165	4,504
Property, Plant and Equipment (Notes 4 and 6)	455,269	245,374
Total Assets	$ 505,619	$ 259,015
LIABILITIES		
Current Liabilities		
Accounts payable and accrued liabilities	$ 21,386	$ 7,535
Cash distributions payable	5,361	2,560
Payable to the Manager (Note 12)	677	730
	27,424	10,825
Long-Term Debt (Note 7)	141,000	72,499
Future Site Restoration and Abandonment	13,185	8,368
Total Liabilities	181,609	91,692
UNITHOLDERS' EQUITY		
Unitholders' Capital (Note 9)	434,314	243,689
Accumulated Earnings	32,015	2,180
Accumulated Cash Distributions	(142,319)	(78,546)
Total Unitholders' Equity	324,010	167,323
Total Liabilities and Unitholders' Equity	$ 505,619	$ 259,015

Approved on behalf of the Board:

(SIGNED)
MAC H. VAN WIELINGEN, DIRECTOR

(SIGNED)
JOHN P. DIELWART, DIRECTOR

Combined Statement of Income (Loss) and Accumulated Earnings

For the years ended December 31,
($ thousands)

	1999	1998
REVENUE		
Oil, natural gas, natural gas liquids and sulphur sales	$ 155,191	$ 67,124
Royalties	(23,616)	(9,595)
	131,575	57,529
EXPENSES		
Operating	35,730	18,803
General and administrative (Note 12), net of recoveries	4,381	3,246
Management fee (Note 12)	2,965	1,187
Interest on long-term debt	7,428	4,103
Capital taxes (Note 11)	257	150
Depletion, depreciation and amortization (Note 2)	50,979	44,133
	101,740	71,622
NET INCOME (LOSS)	29,835	(14,093)
ACCUMULATED EARNINGS, BEGINNING OF YEAR	2,180	16,273
ACCUMULATED EARNINGS, END OF YEAR	$ 32,015	$ 2,180

Combined Statement of Cash Flows

For the years ended December 31,
($ thousands)

	1999	1998
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 29,835	$ (14,093)
Add items not involving cash:		
Depletion, depreciation and amortization	50,979	44,133
	80,814	30,040
Change in non-cash working capital accounts	(11,147)	5,938
	69,667	35,978
CASH FLOWS FROM FINANCING ACTIVITIES		
Increase (decrease) in long-term debt, net	(5,499)	6,544
Issue of Trust Units and warrants, net of expenses	40,255	–
Cash distributions	(60,972)	(30,724)
	(26,216)	(24,180)
CASH FLOWS FROM INVESTING ACTIVITIES		
Acquisition of Starcor and Orion, net of cash received (Note 4)	(21,980)	–
Proceeds on disposition of properties, net of acquisitions	10,964	(60)
Purchase of capital assets	(21,598)	(11,730)
Reclamation fund contributions	(2,661)	(1,488)
Site restoration and abandonment	(326)	(113)
	(35,601)	(13,391)
INCREASE (DECREASE) IN CASH	7,850	(1,593)
CASH, BEGINNING OF YEAR	1,390	2,983
CASH, END OF YEAR	$ 9,240	$ 1,390

At December 31, 1999, interest paid was $7,840,000 compared to $4,103,000 at December 31, 1998. Large corporation taxes paid totalled $296,000 in 1999 and $119,000 in 1998.

The Trust has adopted the Canadian Institute of Chartered Accountants' recommendations regarding cash flow statements effective January 1, 1999.

Combined Statement of Cash Distributions and Accumulated Cash Distributions

For the years ended December 31,
($ thousands, except per unit amounts)

	1999	1998
NET INCOME (LOSS)	$ 29,835	$ (14,093)
Depletion, depreciation and amortization	50,979	44,133
CASH FROM OPERATIONS	$ 80,814	$ 30,040
CASH FROM OPERATIONS (99 PERCENT)	$ 80,006	$ 29,740
Add (deduct):		
General and administrative expense reimbursement (residual 1 percent)	808	300
Capital expenditures	–	11,634
Proceeds from disposition of royalty interests	21,566	(3,072)
Discretionary debt repayment	(24,472)	(11,020)
Reclamation fund contributions and actual reclamation costs incurred	(2,988)	(1,600)
Current period accruals	(11,147)	4,742
CASH DISTRIBUTIONS	63,773	30,724
ACCUMULATED CASH DISTRIBUTIONS, BEGINNING OF YEAR	78,546	47,822
ACCUMULATED CASH DISTRIBUTIONS, END OF YEAR	$ 142,319	$ 78,546
CASH DISTRIBUTIONS PER UNIT (Note 10)	$ 1.35	$ 1.20

December 31, 1999 and 1998
(all tabular amounts in thousands, except per unit amounts)

1. Structure of the Trust

ARC Energy Trust ("the Trust") was formed on May 7, 1996 pursuant to a trust indenture (the "Trust Indenture"). The Trust was created for the purposes of issuing Trust Units to the public and investing the funds so raised to purchase a royalty in the properties of ARC Resources Ltd. ("ARC Resources"). The Trust Indenture has been amended from time to time and was amended and restated as of June 7, 1999, to convert the Trust from a closed-end to an open-ended investment trust. The Trust is now entitled to invest in securities of a company or other such entities to fund the acquisition, development, exploitation and disposition of all types of petroleum and natural gas related assets. Montreal Trust Company of Canada (the "Trustee") has been appointed as Trustee under the Trust Indenture. The beneficiaries of the Trust are the holders of the Trust Units.

The operations of the Trust consist of the acquisition, development, exploitation and disposition of all types of petroleum and natural gas related assets and the distribution of net cash proceeds from these activities to the unitholders.

2. Summary of Accounting Policies

The combined financial statements have been prepared following accounting policies generally accepted in Canada. The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the combined financial statements, and revenues and expenses during the reporting period. Actual results could differ from those estimated.

In particular, the amounts recorded for depletion and depreciation of the petroleum and natural gas properties and for site restoration and abandonment are based on estimates of reserves and future costs. By their nature, these estimates, and those related to the future cash flows used to assess impairment, are subject to measurement uncertainty and the impact on the financial statements of future periods could be material.

The following significant accounting policies are presented to assist the reader in evaluating these statements.

BASIS OF ACCOUNTING The combined financial statements include the accounts of the Trust and its subsidiaries and the accounts of ARC Resources. All inter-entity transactions have been eliminated.

HEDGING The Trust uses derivative instruments to reduce its exposure to commodity price fluctuations. Gains and losses on these contracts, all of which constitute effective hedges, are deferred and recognized as a component of the related transaction.

PROPERTY, PLANT AND EQUIPMENT The Trust follows the full-cost method of accounting. All costs of acquiring oil and natural gas properties and related development costs are capitalized and accumulated in one cost centre. Maintenance and repairs are charged against earnings, and renewals and enhancements which extend the economic life of the property, plant and equipment are capitalized. Gains and losses are not recognized upon disposition of oil and natural gas properties unless such a disposition would alter the rate of depletion by 20 percent or more.

DEPLETION, DEPRECIATION AND AMORTIZATION Depletion of petroleum and natural gas properties and depreciation of production equipment, except for major gas plant facilities which are depreciated on a straight-line basis over their estimated useful life, are calculated on the unit-of-production method based on:

(a) total estimated proved developed and undeveloped reserves;
(b) total capitalized costs plus estimated future development costs of proved undeveloped reserves less estimated net realizable value of production equipment and facilities after the proved reserves are fully produced; and
(c) relative volumes of oil and natural gas reserves and production converted at the energy equivalent conversion ratio of six thousand cubic feet of natural gas to one barrel of oil.

Future site restoration and abandonment provisions are calculated on the unit-of-production method. Actual site restoration costs are charged against the future site restoration and abandonment liability.

CEILING TEST The Trust places a limit on the aggregate cost of property, plant and equipment which may be carried forward for amortization against revenues of future periods (the "ceiling test"). The ceiling test is a cost recovery test whereby the capitalized costs less accumulated depletion, depreciation and site restoration are limited to an amount equal to estimated undiscounted future net revenues from proved reserves less recurring general and administrative expenses, site reclamation, management fees, future financing costs and income taxes. In calculating the 1999 ceiling test, year-end prices for oil and natural gas were used. No writedown of property, plant and equipment was required at December 31, 1999.

For the purposes of the 1998 ceiling test, average prices for oil and natural gas were used. As a result of using 1998 average prices received by the Trust of $18.99 per Bbl of oil and of $1.93 per Mcf of natural gas, a writedown of $14.7 million was charged to earnings as additional depletion, depreciation and amortization. If the 1998 ceiling test had been calculated using year-end prices of $16.98 per Bbl of oil and $2.39 per Mcf of natural gas, a writedown of approximately $28 million would have been charged to earnings.

UNIT-BASED COMPENSATION PLAN The Trust has a unit-based compensation plan for employees, independent directors and long-term consultants, which is described in Note 9. No compensation expense is recognized for the plan when unit rights are issued. Any consideration received by the Trust on exercise of unit rights is credited to unitholders' capital.

INCOME TAXES The *Income Tax Act* (Canada) requires the Trust to compute its income or loss for a taxation year as though it were an individual. The taxation year of the Trust is the calendar year. Each year the Trustee has agreed to designate the full amount of taxable income to the unitholders (less any amount the Trust may want to bring into income to utilize available deductions and loss carryforwards). As such, no accounting for deferred income taxes is provided in these combined financial statements as future tax liabilities will be borne by the unitholders.

Periodically, current taxes may arise in ARC Resources and the Trust's subsidiaries depending on the timing of income tax deductions and the timing of debt repayments. Should such taxes prove to be unrecoverable, they will be deducted from royalty distributions in accordance with the Royalty Agreement.

3. Properties Held for Sale

Properties held for sale represent dispositions of oil and gas properties, which were subject to rights of first refusal. Subsequent to year end, the dispositions were completed and the Trust received all amounts due.

4. Acquisitions

Effective March 12, 1999, the Trust acquired all of the outstanding trust units of Starcor Energy Royalty Fund ("Starcor") and Orion Energy Trust ("Orion") for total consideration of 22.6 million Trust Units, 4.3 million warrants, the assumption of $74 million of debt and a cash payment of $22.9 million. These acquisitions were accounted for using the purchase method of accounting as follows:

	Total
Net assets acquired:	
Cash	$ 923
Working capital	2,904
Reclamation fund	1,718
Property, plant and equipment	241,728
Total net assets acquired	$ 247,273
Financed by:	
Cash	$ 22,903
Trust Units issued	148,386
Warrants issued	1,984
Long-term debt acquired	74,000
Total purchase price	$ 247,273

5. Reclamation Fund

	1999	1998
Opening balance	$ 4,504	$ 3,016
Contributions, net of actual expenditures	2,430	1,338
Interest income on fund	231	150
Ending balance	$ 7,165	$ 4,504

A reclamation fund was established solely to fund future site restoration and abandonment costs. The Board has approved contributions over a 20-year period which results in annual contributions of a minimum of $2.4 million per year based upon properties owned as at December 31, 1999. Contributions to the reclamation fund have been deducted from cash distributions to the unitholders. During the year, $326,000 ($113,000 in 1998) of actual expenditures were charged against the reclamation fund.

6. Property, Plant and Equipment

	1999	1998
Property, plant and equipment, at cost	$ 576,476	$ 320,745
Accumulated depletion and depreciation	(121,207)	(75,371)
Property, plant and equipment, net	$ 455,269	$ 245,374

The calculation of 1999 depletion and depreciation included an estimated $69.0 million ($30.0 million in 1998) for future development costs of proved undeveloped reserves and excluded $12.0 million ($3.2 million in 1998) for future net realizable value of production equipment and facilities and $12.0 million ($2.6 million in 1998) for unevaluated properties.

7. Long-Term Debt

Long-term debt consists of three demand revolving credit facilities to a combined maximum of $200 million. The lenders review the credit facilities by July 1 each year and determine whether they will extend the revolving periods for another year. In the event that the revolving periods are not extended, the principal becomes repayable over approximately five years in quarterly instalments.

The loans bear interest at bank prime (6.5 percent at December 31, 1999, 6.75 percent at December 31, 1998) or, at the Trust's option, bankers acceptance plus a stamping fee.

Collateral for the loans is in the form of floating charges on all lands and assignments and negative pledges on specific oil and gas properties. The unitholders have no direct liability should the properties securing this debt generate insufficient revenue to repay the outstanding balances.

The payment of the principal and interest are allowable deductions in the calculation of the cash available for distribution to the unitholders.

8. Financial Instruments

Financial instruments of the Trust, carried on the balance sheet, consist mainly of current assets, reclamation fund investments, current liabilities and long-term debt. As at December 31, 1999 and 1998, there were no significant differences between the carrying values of these amounts and their estimated fair value. Substantially all of the Trust's accounts receivable are due from customers in the oil and gas industry and are subject to the normal industry credit risks. The carrying value of accounts receivable reflects the Trust's assessment of the associated credit risks.

The Trust utilizes a variety of derivative instruments to reduce its exposure to changes in commodity prices. The fair values of these derivative instruments are based on an approximation of the amounts that would have been received from or paid to counterparties to settle these instruments prior to maturity.

The Trust is exposed to losses in the event of default by the counterparties to these derivative instruments. The Trust controls this risk by dealing only with financially sound counterparties.

A summary of the contracts outstanding as at December 31, 1999 were as follows (no contracts were outstanding at December 31, 1998):

	Quantity (Bbl/d)	Average Contract Prices ($/Bbl)	Term
Crude oil fixed price contracts	800	31.38	January to December, 2000
	900	34.00	January to September, 2000
Crude oil collared contracts	600	28.25 – 44.50	January to March, 2000
	1,200	30.00 – 41.00	January to March, 2000
	1,800	30.00 – 33.35	April to June, 2000

As at December 31, 1999, the Trust would have had to pay approximately $457,000 to settle these contracts.

9. Unitholders' Capital

In March 1999, the Trust issued 22.6 million units at $6.57 per unit and 4.3 million warrants to acquire Starcor and Orion. The warrants have an exercise price of $7.25 and expire June 15, 2000.

In July 1999, the Trust issued 4.6 million units at $7.90 per unit for net proceeds of $34.3 million.

TRUST UNITS	Number of Trust Units	$
Balance as at December 31, 1997 and December 31, 1998	25,604	$ 243,689
Issued on acquisition of Starcor and Orion	22,593	148,386
Issued for cash	4,600	34,335
Issued on exercise of warrants	767	5,921
Dividend reinvestment program	43	359
Balance at December 31, 1999	53,607	$ 432,690

WARRANTS	Number of Warrants	$
Balance as at December 31, 1997 and December 31, 1998	–	$ –
Issued on acquisition of Starcor and Orion	4,262	1,984
Exercised	(767)	(360)
Balance as at December 31, 1999	3,495	1,624
Total Unitholders' Equity as at December 31, 1999		$ 434,314

During 1999, the Trust established the Trust Unit Incentive Rights Plan, whereby the Trust is authorized to grant up to 4,000,000 rights to its employees, directors and long-term consultants to purchase units. The initial exercise price of each right may not be less than the market price of the units on the date of grant, and a right's maximum term is not to exceed ten years. The exercise price is to be adjusted downwards from time to time by the amount, if any, that distributions to unitholders in any calendar quarter exceed a percentage of the Trust's net book value of property, plant and equipment, as determined by the Trust (the "Excess Distribution").

The Trust Unit Incentive Rights Plan replaced the existing option plan. All options previously granted under the former plan were cancelled.

During the year, the Trust granted 1,200,000 rights to employees, independent directors and consultants to purchase units at an exercise price of $8.20 per unit, subject to a downward adjustment to the extent that distributions to unitholders in any given calendar year exceed 2.5 percent of the Trust's property, plant and equipment. These rights vest annually over a three-year period, and expire in May, 2004. The exercise price of the rights was reduced to $7.86 per unit during the year, as a result of Excess Distributions to unitholders.

A summary of the plan as at December 31, 1999 is as follows:

	Rights	Exercise Price
Initial grant	1,200	$ 7.86(1)
Rights exercised	–	–
Rights cancelled	(8)	7.86
Rights outstanding at December 31, 1999	1,192	$ 7.86
Rights exercisable at December 31, 1999	nil	

(1) Exercise price of rights has been adjusted to reflect the impact of Excess Distributions.

The Trust has adopted a Unitholders Rights Plan which provides for the issuance of additional units in certain events when one party acquires more than 20 percent of the outstanding units of the Trust.

10. Net Income (Loss) and Cash Flow from Operations per Unit

	1999	1998
Net income (loss) – basic (1)	$ 0.64	$ (0.55)
Fully diluted (2)	0.61	(0.55)
Cash flow from operations (3)		
– basic (1)	1.74	1.17
– fully diluted (2)	1.60	1.15

(1) Basic per unit calculations are based on the weighted average number of units outstanding in 1999 of 46,480 (25,604 in 1998).
(2) Fully-diluted calculations include additional interest of $1,666 in 1999 ($461 in 1998), based on the assumed exercise of additional units of 5,124 in 1999 (910 in 1998).
(3) Calculated by adding depletion, depreciation and amortization back to net income (loss) and dividing by the number of units.

Cash distributions per unit reflect the sum of the per unit amounts paid monthly to unitholders.

11. Taxes

No current income taxes were payable in 1999 or 1998, but $257,000 ($150,000 in 1998) of large corporations tax was paid or payable at year end, charged to operations, and deducted from cash distributions.

12. Related Party Transactions

A management agreement was signed on July 11, 1996 with ARC Financial Corporation ("the Manager") to provide management, advisory and administrative services. The fees payable to the Manager include a fee equal to 3 percent of net production revenue; and fees of 1.5 percent, and 1.25 percent of the purchase price of acquisitions and selling price of dispositions, respectively. In 1999, total acquisition and disposition fees paid to the Manager were $3,913,000 ($375,000 in 1998). These fees are accounted for as either part of the purchase price, or as a reduction of proceeds of disposition of property, plant and equipment.

During 1999, the Manager was reimbursed $1,549,000 ($3,385,000 in 1998) for general and administrative expenses incurred on behalf of the Trust.

As part of the Starcor and Orion acquisitions, the Manager agreed to reinvest a portion of its acquisition fees into new Trust Units resulting in 392,799 units being issued for $2.6 million.

13. Uncertainty Due to the Year 2000 Issue

Most entities depend on computerized systems and therefore are exposed to the Year 2000 conversion risk, which, if not properly addressed, could affect an entity's ability to conduct normal business operations. The effects of the Year 2000 Issue may be experienced before, on, or after January 1, 2000. 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 entity, including those related to customers, suppliers or other third parties, have been fully resolved.

14. Commitments and Contingent Liabilities

Operating leases and facility leases have been entered into with the following commitments:

Year	$
2000	$ 1,616
2001	1,925
2002	1,848
2003	1,770
2004	1,693
Remaining	6,301
Total	$ 15,153

The Trust is involved in litigation and claims associated with normal operations, and is of the opinion that any resulting settlements would not materially affect its financial position or reported results of operations.

15. Events Subsequent to December 31, 1999

On January 31, 2000, the Trust entered into an agreement to acquire producing oil and gas properties in Alberta and Saskatchewan for the sum of $135 million.

On February 9, 2000, the Trust entered into an underwriting agreement with a syndicated group of underwriters to issue and sell a minimum of five million units for net proceeds of approximately $40.8 million.

($ thousands, except per unit amounts)	Year Ended December 31, 1999	Year Ended December 31, 1998	Year Ended December 31, 1997	Six Months Ended December 31, 1996
FINANCIAL				
Revenue before royalties	155,191	67,124	74,103	31,908
Per unit	$ 3.34	$ 2.62	$ 3.24	$ 1.77
Cash flow	80,814	30,040	37,757	18,315
Per unit	$ 1.74	$ 1.17	$ 1.65	$ 1.02
Net income	29,835	(14,093)	9,165	7,108
Per unit	$ 0.64	$ (0.55)	$ 0.40	$ 0.39
Cash distributions	63,773	30,724	33,242	14,580
Per unit*	$ 1.35	$ 1.20	$ 1.40	$ 0.81
Working capital	15,761	(1,688)	4,647	1,647
Long-term debt	141,000	72,499	65,955	37,998
Unitholders' equity	324,010	167,323	212,140	160,834
Weighted average units (thousands)	46,480	25,604	22,837	18,000
Units outstanding at year-end (thousands)	53,607	25,604	25,604	18,000

* Based on the number of units outstanding at each cash distribution date

OPERATING				
Production				
Crude oil (Bbl/d)	8,408	4,439	3,656	2,922
Natural gas (Mmcf/d)	66.46	37.68	38.40	29.47
Natural gas liquids (Bbl/d)	2,687	2,018	1,929	1,732
Total (Boe/d)	17,741	10,225	9,425	7,600
Average prices				
Crude oil ($/Bbl)	24.85	18.99	26.35	29.76
Natural gas ($/Mcf)	2.54	1.93	1.82	1.61
Natural gas liquids ($/Bbl)	17.43	13.17	18.27	20.31
Oil equivalent ($/Boe)	23.97	17.99	21.54	22.31
Established (proved plus risked probable) reserves				
Crude oil and NGL (Mbbl)	59,712	35,034	32,373	22,514
Natural gas (Bcf)	241.0	121.9	148.2	112.0
Total (Mboe)	83,813	47,226	47,190	33,710

(based on daily closing price)	1999	1998	1997	1996
TRUST UNIT TRADING				
Prices ($)				
High	9.25	11.40	13.00	12.85
Low	6.15	6.10	10.15	9.90
Close	8.75	6.15	10.45	12.25
Average daily volume (thousands)	68	32	55	98

($ thousands, except per unit amounts)	1999 4Q	1999 3Q	1999 2Q	1999 1Q	1998 4Q	1998 3Q	1998 2Q	1998 1Q
FINANCIAL								
Revenue before royalties	53,647	43,849	35,811	21,884	16,767	16,362	16,474	17,521
Per unit	$ 1.00	$ 0.85	$ 0.74	$ 0.66	$ 0.65	$ 0.64	$ 0.64	$ 0.68
Cash flow	30,818	23,223	17,211	9,562	7,693	6,294	7,801	8,252
Per unit	$ 0.58	$ 0.45	$ 0.36	$ 0.29	$ 0.30	$ 0.25	$ 0.30	$ 0.32
Net income	16,444	9,549	3,636	206	(14,563)	(253)	287	436
Per unit	$ 0.31	$ 0.19	$ 0.08	$ 0.01	$ (0.57)	$ (0.01)	$ 0.01	$ 0.02
Cash distributions	21,377	18,099	14,396	9,901	7,681	7,681	7,681	7,681
Per unit*	$ 0.40	$ 0.35	$ 0.30	$ 0.30	$ 0.30	$ 0.30	$ 0.30	$ 0.30
Working capital	15,761	(1,958)	230	(2,473)	(1,688)	3,968	8,389	5,382
Long-term debt	141,000	130,870	168,135	162,351	72,499	63,633	63,296	69,550
Unitholders' equity	324,010	325,508	297,811	307,997	167,323	189,566	197,501	204,895
Weighted average units (thousands)	53,461	51,469	48,249	33,386	25,604	25,604	25,604	25,604
Units outstanding at year-end (thousands)	53,607	53,153	48,276	48,197	25,604	25,604	25,604	25,604

* Based on the number of units outstanding at each cash distribution date

	1999 4Q	1999 3Q	1999 2Q	1999 1Q	1998 4Q	1998 3Q	1998 2Q	1998 1Q
OPERATING								
Production								
Crude oil (Bbl/d)	9,144	9,250	9,005	6,192	4,420	4,498	4,472	4,365
Natural gas (Mmcf/d)	73.75	71.66	71.93	48.20	34.83	36.18	38.74	41.05
Natural gas liquids (Bbl/d)	3,088	2,614	2,778	2,262	2,085	2,041	1,834	2,113
Total (Boe/d)	19,607	19,030	18,975	13,270	9,988	10,157	10,180	10,583
Average prices								
Crude oil ($/Bbl)	33.38	25.33	20.45	17.69	18.42	18.61	18.85	20.13
Natural gas ($/Mcf)	2.82	2.70	2.32	2.21	2.12	1.92	1.88	1.83
Natural gas liquids ($/Bbl)	22.60	18.75	15.10	11.54	13.16	11.65	13.09	14.75
Oil equivalent ($/Boe)	29.74	25.05	20.74	18.32	18.25	17.51	17.78	18.40

(based on daily closing price)

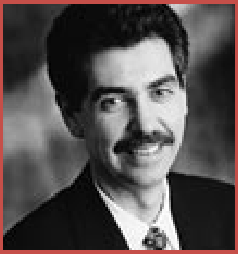
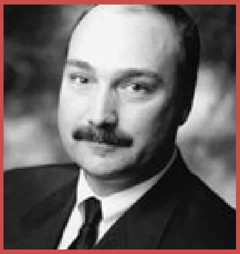
	1999 4Q	1999 3Q	1999 2Q	1999 1Q	1998 4Q	1998 3Q	1998 2Q	1998 1Q
TRUST UNIT TRADING								
Prices ($)								
High	9.20	9.25	8.25	7.50	8.65	9.25	10.50	11.40
Low	8.40	7.85	7.15	6.15	6.10	7.00	8.85	9.40
Close	8.75	9.25	8.0	7.30	6.15	8.95	9.25	10.25
Average daily volume (thousands)	51	101	63	55	35	25	33	35
TRUST WARRANT TRADING (Warrants began trading on March 17, 1999)								
Prices ($)								
High	1.94	1.95	1.03	0.80	–	–	–	–
Low	1.01	0.86	0.55	0.11	–	–	–	–
Close	1.30	1.95	0.93	0.55	–	–	–	–
Average daily volume (thousands)	8	21	24	34	–	–	–	–

Corporate Information




TOP
LEFT TO RIGHT:
Mac H. Van Wielingen
John P. Dielwart
Nancy V. Lever
Doug J. Bonner

BOTTOM
LEFT TO RIGHT:
Steven W. Sinclair
Myron M. Stadnyck
Susan D. Healy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Director, Vice-Chairman and Chief Executive Officer

John P. Dielwart
Director and President

John M. Beddome(1)(2)
Director

Frederic C. Coles(1)(2)
Director

Michael M. Kanovsky(1)(2)
Director

John M. Stewart
Director

Allan R. Twa
Secretary

Doug J. Bonner
Vice-President, Engineering

Susan D. Healy
Vice-President, Land

Nancy V. Lever
Vice-President, Planning

Steven W. Sinclair
Vice-President, Finance and Chief Financial Officer

Myron M. Stadnyk
Vice-President, Operations

(1) Member of Audit Committee
(2) Member of Reserve Audit Committee

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Vice-President, Finance
and Chief Financial Officer

NOTICE OF ANNUAL GENERAL MEETING

The Annual Meeting will be held on Tuesday, May 23, 2000, at 3:30 p.m. in the Britannia Room at The Westin Hotel, 320 - 4th Avenue S.W., Calgary, Alberta.

ABBREVIATIONS

ARTC	Alberta Royalty Tax Credit
Bbl	barrels
Bcf	billion cubic feet
Boe	barrels of oil equivalent
Mboe	thousand barrels of oil equivalent
Mcf	thousand cubic feet
Mmbbl	million barrels
Mmboe	million barrels of oil equivalent
MmBtu	million British thermal units
Mmcf	million cubic feet
/d	per day
WTI	West Texas Intermediate
Barrel of oil equivalence	10 Mcf = 1 Bbl

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ENERGY ◆ TRUST

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