ARC Energy Trust Annual Report 2002

THE ARC REPORT

Annual Report 2002

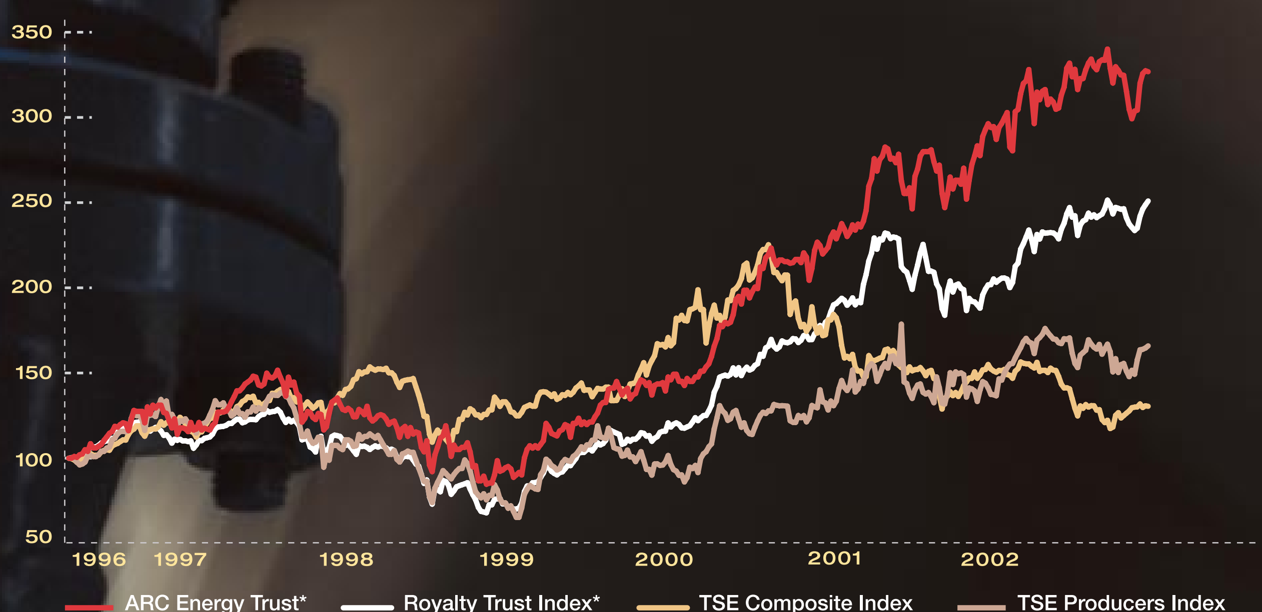
ARC Energy Trust ("the Trust" or "ARC") is one of Canada's largest conventional oil and gas royalty trusts and is Canada's 13th largest independent oil and gas producer. As a royalty trust, we acquire and develop long-life, low-decline oil and gas properties in western Canada. Our unitholders receive a monthly cash distribution through the Trust's royalty interest in cash generating oil and gas assets owned by ARC Resources Ltd.

Since inception we have been consistent in our message and our mission: combine our excellent managerial and technical expertise to maximize value to our unitholders. We have done this through the acquisition and development of a portfolio of high quality, long-life assets. We have built a company of specialists who have the skills required to manage and exploit our asset base for the benefit of our unitholders.

The Trust has outperformed the Royalty Trust Index, the TSX Composite Index and the TSX Producers Index. We have provided our unitholders with a 21 per cent compound annual return (includes distribution reinvestment) since our inception in 1996. Our annual return in 2002 was 11.7 per cent and total returns since inception have averaged 13.4 per cent per year excluding distribution reinvestment. We remain committed to generating superior returns and long-term value.

ARC Energy Trust units trade on the Toronto Stock Exchange under the symbol AET.UN along with its exchangeable shares under the symbol ARX.

TOTAL RETURN PERFORMANCE
(per cent)



*Source: ARC Energy Trust

Front Cover: Al Roberts, Operations

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FINANCIAL HIGHLIGHTS

Years ended December 31

($ thousands, except per unit and volume amounts)	2002	2001
INCOME STATEMENT		
Revenue before royalties (5)	**444,835**	515,596
Per unit (1)	**$ 3.72**	$ 5.05
Cash flow (7)	**223,969**	260,270
Per unit (1)	**$ 1.87**	$ 2.55
Net income (5)	**67,893**	138,202
Per unit (1)	**$ 0.57**	$ 1.36
Payout ratio (per cent) (4)	**82**	90
Cash distributions	**183,617**	234,053
Per unit (2)	**$ 1.56**	$ 2.31
Weighted average trust units and exchangeable shares (3)	**119,613**	101,979
Trust units outstanding and units issuable for exchangeable shares at end of period	**126,444**	111,692
BALANCE SHEET		
Working capital (deficit)	**(10,067)**	5,805
Property, plant and equipment and other assets	**1,410,487**	1,321,453
Long-term debt	**337,728**	294,489
Unitholders' equity	**868,666**	816,795
LONG-TERM DEBT AS A RATIO OF CASH FLOW	**1.5**	1.1
MARKET CAPITALIZATION AS AT DECEMBER 31	**1,504,684**	1,350,950
TOTAL CAPITALIZATION AS AT DECEMBER 31 (6)	**1,852,479**	1,639,634
TRUST UNIT TRADING		
Unit Prices ($)		
High	**$ 13.44**	$ 13.54
Low	**$ 11.04**	$ 10.25
Close	**$ 11.90**	$ 12.10
Daily average trading volume (thousands)	**305**	414

(1) based on weighted average trust units and exchangeable shares

(2) based on number of trust units outstanding at each cash distribution date

(3) includes trust units issuable for outstanding exchangeable shares based on the period end exchange ratio

(4) payout ratio is calculated as cash distributions divided by cash flow

(5) 2001 revenue before royalties, net income and net income per unit have been restated for the retroactive change in accounting policy for deferred foreign exchange translation

(6) equity market capitalization plus net long-term debt

(7) cash flow is calculated as cash flow from operating income before the change in non-cash working capital

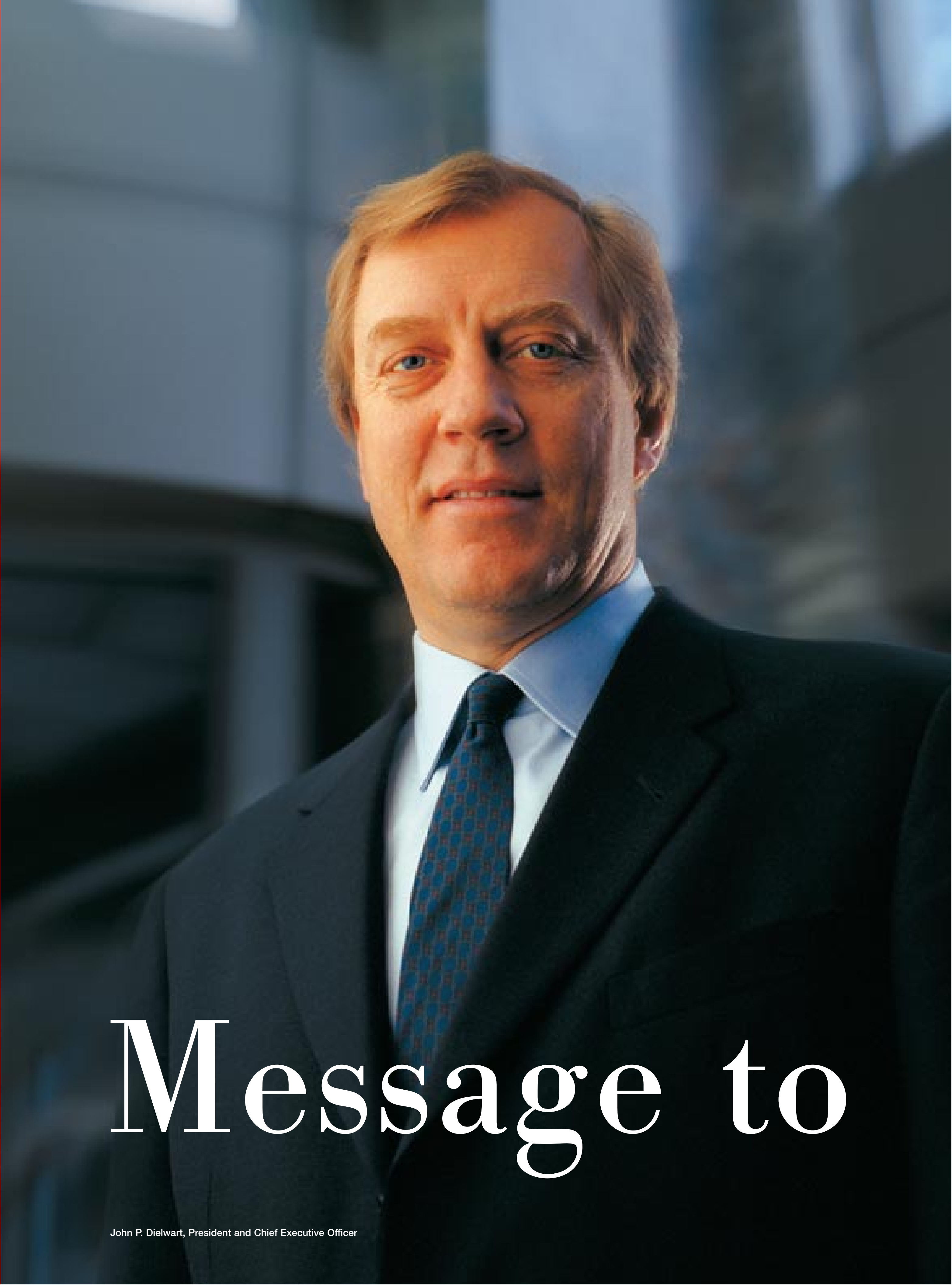
OPERATIONAL HIGHLIGHTS

Years ended December 31

	2002	2001
PRODUCTION		
Crude oil (bbl/d)	**20,655**	20,408
Natural gas (mmcf/d)	**109.8**	115.2
Natural gas liquids (bbl/d)	**3,479**	3,511
Total production (boe/d) (1)	**42,425**	43,111
TOTAL ANNUAL PRODUCTION (mboe) (1)	**15,485**	15,736
AS A PERCENTAGE OF TOTAL PRODUCTION		
Crude oil	**49%**	47%
Natural gas	**43%**	45%
Natural gas liquids	**8%**	8%
AVERAGE PRICES		
Crude oil ($/bbl)	**31.63**	31.70
Natural gas ($/mcf)	**4.41**	5.72
Natural gas liquids ($/bbl)	**24.01**	31.03
Oil equivalent ($/boe) (1)	**28.73**	32.76
RESERVES		
PROVED (mboe 6:1)	**155,634**	147,739
PROVED PLUS RISKED PROBABLE		
Crude oil and natural gas liquids (mbbl)	**117,241**	114,243
Natural gas (bcf)	**408.8**	385.5
TOTAL OIL EQUIVALENT (mboe) (1)	**185,371**	178,496
OPERATING COSTS		
Total ($ thousands)	**99,876**	86,108
Per boe ($)	**6.45**	5.47
GENERAL & ADMINISTRATIVE COSTS		
Total ($ thousands)	**15,365**	11,812
Per boe ($)	**0.99**	0.75
FINDING, DEVELOPMENT & ACQUISITION COSTS (2)		
Total ($ thousands)	**207,391**	624,877
Per boe ($)	**9.27**	9.75
Total ($ thousands)	**1,040,185**	1,088,525
Three-year average ($/boe)	**8.21**	6.94

(1) natural gas is converted to barrels of oil equivalent at 6:1 throughout this report unless otherwise noted

(2) based on established reserves



Message to

John P. Dielwart, President and Chief Executive Officer

The past year was characterized by extreme volatility in oil and gas commodity prices, a seller's market for oil and gas assets and a business environment that led to an increase in the size and number of royalty and income trusts. Despite the challenge of volatile commodity prices, ARC Energy Trust maintained stable distributions throughout the year. We remained absolutely true to our long-standing policies and processes that are designed to create long-term value for our unitholders. Stability and predictability of distributions remain key objectives for the Trust. During 2002, we again demonstrated our commitment to leadership in our sector by becoming the first conventional oil and gas royalty trust to eliminate its external management contract and all associated fees.

STABILITY AND PREDICTABILITY OF DISTRIBUTIONS REMAIN KEY OBJECTIVES FOR THE TRUST.

An important issue facing our industry in 2002 was Canada ratifying the Kyoto Protocol that commits our industry and country to significant reductions in greenhouse gas emissions. As the current Chairman of the Canadian Association of Petroleum Producers ("CAPP"), I was extensively involved in all discussions between our industry and various government bodies regarding this issue. While we believe the Kyoto Protocol is severely flawed for the country as a whole, we do not expect its implementation will have a material impact on our business due to the nature of the Trust's assets.

Looking forward to 2003 and beyond, I believe that our historic approach to managing the Trust's business through all cycles of the market will continue to deliver superior returns to our unitholders.

Commodity Price Environment

Oil prices began 2002 at US$21.00/bbl and fell below US$18.00/bbl in mid-January. Prices recovered to almost US$33.00/bbl in December and closed the year at US$31.20/bbl. The average price in 2002 for West Texas Intermediate crude oil was US$26.10/bbl, the second highest average since 1990. Canadian natural gas spot prices opened the year at $3.18/mcf, increased to over $5.00/mcf in April and declined to $1.28/mcf in July. Prices rallied to $6.33/mcf in December and closed the year at $5.70/mcf. The average price for the year was $4.08/mcf which was 35 per cent lower than 2001. Commodity price cycles are a fact of life in our industry but seldom have we been exposed to such extreme price fluctuations in such a compressed time period. The price volatility was significantly influenced by concerns about near-term supplies of crude oil and near to long-term supplies of natural gas.

The fourth quarter rally in oil prices resulted from a combination of supply disruptions associated with civil unrest in Venezuela and concern over a possible attack on Iraq by the United States. While we expect both of these issues to be resolved in 2003, it will take time to rebuild depleted inventories and consequently, we expect higher prices than the analyst average forecast of US$24.00/bbl.

The current strength of natural gas prices is directly associated with below normal inventory levels and concern about the North American natural gas industry's ability to replace production on an on-going basis. High natural gas prices have occurred despite the dampening of demand caused by the prolonged poor performance of the United States' economy. Improved performance by the U.S. economy should increase demand causing further strain in an already tight natural gas market. Therefore, while consensus forecasts call for an average Canadian gas price of $5.00/mcf in 2003, we believe there is a strong probability of higher actual prices than most analysts predict.

Unitholders

Stable Distributions in 2002

Managing our business in a volatile price environment is challenging, particularly when providing stable, predictable distributions is an objective of the Trust. The Trust reviews distributions on a quarterly basis and may adjust distributions to reflect current commodity prices. Through our price risk management program (hedging) and the flexibility built into our distribution policy, the Trust maintained cash distributions at $0.13 per unit for revenue earned each month during 2002. This was achieved while withholding two per cent of our cash flow to fund future abandonment liabilities and 16 per cent to partially fund our capital program. In 2002, approximately 55 per cent of the Trust's oil and natural gas liquids production was hedged at an average price of US$24.15/bbl; 40 per cent of our natural gas production was hedged at an average price of $4.11/mcf.

By the end of January 2003, ARC had hedged approximately 50 per cent of its total 2003 oil production at an average price of US$26.98/bbl. The highest quarterly hedge price is US$27.77/bbl in the first quarter and the lowest quarterly hedge price is US$26.20 in the fourth quarter, based on current commodity prices. On the gas side, our strategy is to maintain maximum exposure to market prices during the winter months when we could experience price spikes due to low inventory levels and lock in attractive prices during the spring, summer and fall when we typically see price weakness. For the first quarter, ARC has a $4.22/mcf fixed price contract on four per cent of its gas production and has not limited the upside on the remainder. For the second through the fourth quarters of 2003, ARC has hedged approximately 38 per cent of natural gas production at an average price of $5.44/mcf.

THE TRUST HAS DELIVERED AMONG THE MOST STABLE AND CONSISTENT DISTRIBUTIONS IN THE SECTOR.

Cumulative distributions through to the end of 2002 (including the December 2002 distribution paid in January 2003) totaled $10.64 per unit, which represents 106 per cent of our July 1996 initial public offering price of $10.00 per unit. The total return to unitholders for 2002 was 11.7 per cent and total returns since inception have averaged 13.4 per cent per year. Other trusts may have delivered higher total returns than ARC during 2002, but few have performed better over the long-term. We believe long-term, consistent and superior returns are the true measure of success in the trust sector and in this regard we have few equals. Throughout every phase of commodity price cycles, the Trust has delivered among the most stable and consistent distributions in the sector.

Acquisition Market for Oil and Gas Assets

Despite weak commodity prices early in 2002, it was a seller's market for oil and gas assets throughout the year. Not only were prices higher than the Trust was prepared to pay, many of the assets available and acquired by others were, in our view, of relatively low quality and/or had a short reserve life index (RLI). ARC's strategy did not waiver from that which has resulted in superior returns since inception for our unitholders; we opportunistically acquire high quality properties that complement our existing asset base or will add a new core area to support future growth. We completed $119 million of high netback acquisitions net of dispositions at an average cost of $9.18/boe for established reserves with an average RLI of 10 years. The majority of the assets acquired were in existing core areas such as Ante Creek and Medicine River. ARC's total corporate RLI at December 31, 2002 increased slightly to 11.8 years.

ARC's 2002 acquisitions compared favorably to the royalty trust sector where transactions totaling approximately $3.0 billion at an average reported cost of $9.76/boe for established reserves and an average RLI of 7.9 years were completed. While ARC maintained its RLI, many of our sector peers completed acquisitions that resulted in reductions to their RLIs. Complementing our acquisition program was an $88.3 million capital expenditure program that focused on the development of our existing asset base. In total, we replaced 145 per cent of our production at an average cost of $9.27/boe for established reserves. We expect this to once again place the Trust in the top quartile for finding, development and acquisition costs in both the royalty trust sector and the overall oil and gas industry.

Looking forward to 2003, the strong commodity price environment experienced during the first quarter should result in a continued seller's market for assets. With strong cash flow, there may be fewer dispositions by companies needing to improve the strength of their balance sheet. The continued growth of the royalty trust sector and the declining average RLI will result in strong competition for assets as the sector tries to maintain itself. We will continue with our strategy to seek high quality assets outside of the broad competitive acquisition market, including non-traditional assets, to complement our existing asset base.

Business Environment

In 2002, the income and royalty trust sectors outperformed the broader equity market for the third consecutive year. A record $9.7 billion was raised in the equity market in 89 transactions including $5.3 billion from 36 initial public offerings ("IPO"); over $1.0 billion of the total equity raised was in the form of convertible debentures. The royalty trust sector had one small, new IPO as well as 20 follow-on offerings totaling in excess of $1.5 billion. Additionally, one exploration and production ("E&P") company converted to a royalty trust structure and two other E&P companies converted to royalty trusts subsequent to year-end. The total market capitalization of the income fund sector increased 112 per cent in 2002 from $21.4 billion to $45.4 billion. The total market capitalization in the royalty trust sector increased 89 per cent in 2002 from $7.6 billion to $14.4 billion. The outlook for 2003 is a continuation in the growth of both the income and royalty trust sectors.

The end result of all this activity is increased competition for a finite amount of available investment capital. To maintain an edge in this competitive environment, the Trust must maintain its strong franchise in the market through continued superior performance and expand its universe of prospective investors through initiatives such as the elimination of the management contract. To this end, the Trust is taking a lead role in an initiative to lobby the Alberta government to legislate comparable liability protection for unitholders of trusts as that accorded to shareholders of corporations. If we are successful, one of the last remaining obstacles for significant pension fund participation in the sector would be removed. Without this obstacle, we believe the Trust is well-positioned to attract additional institutional capital, given our size, quality of assets, record of performance and the absence of any external management fees.

During 2002, the Trust issued 10 million trust units at a price of $12.05 per unit for total gross proceeds of $121 million. In February 2003, the Trust issued 12.5 million trust units at a price of $11.50 per unit for total gross proceeds of $144.0 million. A new development during the year was two cross border equity issues by two large cap trusts which raised total gross proceeds of CDN$287 million from U.S. investors. In addition, another large cap trust secured a listing on the New York Stock Exchange ("NYSE"). The Trust continues to review the merits of a U.S. listing but has not yet concluded that the benefits outweigh the costs involved. Our focus continues to be on expanding our investor base in Canada but we may in the future pursue a NYSE listing.

Elimination of the Management Contract

The Trust has always been committed to being a leader in our sector in all aspects of our business. When we were formed in 1996, external management contracts were the “norm”. Managers of the trusts received certain base fees calculated as a per cent of cash flow as well as transaction related fees for acquisitions and dispositions. In our case, these fees were always among the lowest in the sector. However, as the Trust grew in size, these fees became significant and the external management structure became less suited to an organization of our size.

THE TRUST HAS ALWAYS BEEN COMMITTED TO BEING A LEADER IN OUR SECTOR IN ALL ASPECTS OF OUR BUSINESS.

On August 28, 2002, the Trust’s unitholders voted in favour of eliminating the external management contract and all related future fees. The contract was purchased for $55 million plus expenses related to the purchase, paid primarily in the form of trust units and exchangeable shares to 73 shareholders of the management company. The transaction was accretive to the Trust and met all of the Trust’s acquisition criteria. In completing this transaction, the Trust became the first conventional oil and gas trust to eliminate its management contract and all related fees. Following our leadership in this matter, five other royalty trusts have since eliminated their management contracts, most of which were done under comparable terms and conditions to our transaction.

Elimination of the management contract improves our competitive position in the acquisition market and should provide greater opportunities going forward for adding value. The Trust’s officers and directors now own approximately two per cent of the outstanding securities. A significant component of these securities are subject to escrow and forfeiture provisions for up to five years. Your management team remains absolutely committed to continuing to deliver top quartile returns and superior performance.

The benefits of the internalization transaction include the potential reduction in the Trust’s cost of capital through the expansion of our investor base. Institutions and pension funds that would not typically invest in an oil and gas royalty trust with external management fees may now invest in the Trust. Corporate governance is improved through transparency in reporting of management compensation and increasing the number of non-management directors from four to six. Overall costs are reduced through the elimination of management fees and acquisition and disposition fees, without impacting the general and administrative expenses of the Trust. Most importantly, the management contract and related fees created concerns about the possible misalignment of management and unitholder interests – this is no longer an issue.

Kyoto Protocol

On December 10, 2002, Canada ratified the Kyoto Protocol committing this country to major reductions in greenhouse gas emissions over the next 10 years. ARC supports the position taken by CAPP that strongly opposed ratification of the accord and instead proposed reductions in emission intensity, thereby allowing our industry and the Canadian economy to continue to grow. First as Vice-Chairman and later as Chairman of CAPP in 2002, I was personally present in meetings with the Prime Minister and senior Cabinet Ministers to discuss the Kyoto Protocol and its impact on the Canadian economy in general and our industry in particular. I believe that ratification occurred purely for political reasons without a firm understanding of how Canada can achieve the targets to which we are now obligated.

Post-ratification, the government came to understand that the investment community was genuinely concerned about the uncertainty created by ratification of the accord and the lack of firm details with regard to the cost of the accord for our industry. CAPP strongly encouraged the government to clarify our industry’s obligations under the accord based on data presented to us in closed meetings. On December 18, 2002, the government confirmed that they would set the emission intensity targets for the oil and gas sector at a level not more than 15 per cent below projected “business as usual” levels for 2010. The government also committed that our industry’s cost of carbon credits to meet these reduction targets would not exceed $15 per tonne.

The targeted reductions focus on the so-called large industrial emitters such as oil sands operations, major sour gas plants and oil and gas transmission facilities. ARC’s production is predominantly light sweet oil and sweet natural gas, which, on a relative basis, have the lowest emission levels per unit of production. As a result, our exposure to increased costs under the government’s identified targets is much less than the industry as a whole.

Our strategy focuses on long-term, stable and superior returns.

Our opposition to the Kyoto Protocol should not be misconstrued as being dismissive about greenhouse gas emissions. Rather it is recognition of the fact that, although well intentioned, the Kyoto accord and Canada's ratification thereof is severely flawed. We believe a better solution exists for our country that takes into consideration the uniqueness of our situation. Our company and our industry will continue to invest in emission reduction initiatives that will benefit future generations of Canadians and we will work constructively with government agencies in all areas of environmental stewardship. As evidence of our commitment in this regard, ARC was recently awarded Gold Champion Level Reporter status (the highest level achievable) from Canada's Voluntary Climate Change Registry.

2003 Outlook

The foregoing discussion already addresses expected trends in certain key aspects of our business and our sector. Looking ahead, we foresee on-going challenges for the industry to replace production in a cost effective manner. We also expect the availability of long-life, high quality assets highly valued by the royalty trust sector to be limited resulting in significant competition among the existing trusts. ARC has consistently replaced production on a cost effective basis while maintaining the high quality nature of our asset base. Despite the competitive market, we will maintain our disciplined approach to selectively pursue attractive assets with upside potential and we believe that our historic, top quartile performance will continue.

ARC's high quality asset base has allowed us to be less reliant on acquisitions than our peers due to a large number of development opportunities on existing properties. Over the past two years, we have spent $193 million on drilling and development activities and our 2003 budget calls for further expenditures of $115 million.

The Trust has consistently maintained a conservative distribution policy to enhance long-term returns to our unitholders. High commodity prices should enhance the overall trust sector performance in 2003; however the trend to a lower average RLI will challenge the sector's ability to maintain current performance levels over time. Our strategy focuses on long-term, stable and superior returns that will allow us to continue to outperform the sector in the future. This will create new opportunities to make value-adding acquisitions for the Trust to further enhance long-term returns.

Respectfully submitted on behalf of the Board of Directors,

John P. Dielwart (signed)
President and Chief Executive Officer

January 28, 2003

Risk

ARC receives many questions from unitholders pertaining to its hedging program. Unitholders seek clarification on what hedging is, why ARC hedges a percentage of its production and what is our approach. The fundamental premise of hedging is to provide downside price protection for our production by giving up some of the potential for price appreciation.

To effectively execute a hedging program a combination of financial expertise and technical and industry knowledge is required. ARC's relationship with ARC Financial Corporation and a management team made up of knowledgeable executives from the engineering and financial fields, provides ARC with the key ingredients to maintain an effective risk management program.

Left to right: Dave Hudson, Business Development; Teresa Contrada, Business Development; David Carey, V.P., Business Development

Hedging simply means locking a fixed price or a price range for a portion of our future oil and gas production. By securing an established price range for a portion of our production, hedging helps us minimize the impact of fluctuating commodity prices on our cash flow. Recently, commodity prices have been extremely volatile. Without hedging, this volatility could result in large swings in cash flow and distributions. ARC believes in stable and sustainable distributions and hedges to achieve these results.

ARC's hedging program has three primary objectives. First, to provide greater certainty and stability to distributions and unitholder returns. Our hedging program is designed to mitigate downward fluctuations of commodity prices on a portion of our production. Should the price of the commodities rise and our cash flow increases, ARC may increase the cash distribution; however, we will only receive part of the benefit of higher prices as we will have given up some of the upside to protect our cash flow in times of low commodity prices, thereby providing more stability. We believe that stable distributions will result in a more stable unit price.The next objective is to ensure profitability of specific oil and gas properties that may be more sensitive to low commodity prices. Hedging production from these properties assures a minimum, reliable cash flow to ensure continuing profitable operations of these properties.

ARC has a Risk Management Committee that is comprised of ARC's senior executive officers and market experts from ARC Financial Corporation. This committee meets on a weekly basis to review ARC's current hedged position and makes decisions on further hedging or modifying hedges already in place. The committee follows an established process put in place to ensure that ARC's objectives are met.

The first step in the process is for the committee to review the current hedging position, not only from a perspective of how much of our volume is hedged but also with whom it is hedged. ARC reviews its exposure to counterparties on a regular basis. We enter into contracts with two types of counterparties by hedging production in two ways. We have financial counterparties with whom we enter into financial contracts through various hedging instruments, all of which are settled with cash. We also have physical counterparties to whom we sell a portion of our oil and gas production at a specific price. It is part of ARC's hedging policy to follow a "portfolio approach" so that we do not have too much exposure to any individual counterparty.

The committee receives information from our market analysts with respect to all aspects of the oil and gas commodity markets – demand and supply for each commodity, storage levels, weather, trading activity and both national and international political situations.

Management

Finally, we want to take advantage of upswings in the market by locking in prices at levels that are significantly higher than historic averages. We understand that oil and gas prices are subject to degrees of volatility and we take into consideration the fact that extremely high prices and very low prices are not sustainable over the long-term. The hedging program is designed to give up a portion of the upside from extremely high commodity prices to avoid the downside of low prices. In January 2003, our industry enjoyed very healthy oil and gas prices; however, history has shown that prices at these levels are not sustainable. Locking in a portion of our production at higher prices allows us to protect our unitholders' return on their investment for a period of time after commodity prices fall.

Based on the committee's review process, a decision is made on whether it is appropriate to enter into additional hedges and if so, what commodity to hedge, how much of the commodity will be hedged, the price and terms. The contracts for the hedges are selected from competitive bids, again, keeping exposure to counterparties in mind. ARC has a policy that we can hedge up to 70 per cent of a commodity for a period of up to one year, but we cannot hedge over 50 per cent of our combined production without specific board approval. There are circumstances where longer term hedging is allowed.

It is important to note that ARC does not hedge to speculate. We take a disciplined approach to assess and take advantage of hedging opportunities to stabilize distributions.

On August 28, 2002, ARC received unitholder approval to eliminate its external management contract and all related fees through the purchase of ARC Resources Management Ltd. ("ARML"). The transaction closed on August 29, 2002. This move marked a change in how our Trust manages its business and set a new trend for our industry that has since been followed by five of our peers.

When most oil and gas trusts were created, including ARC, management teams were external to the trusts' operations. The external management team provided managerial and administrative services as set out through a management contract. Typically, the contract included specific fees for these services calculated as a percentage of net operating revenue, acquisitions and dispositions. The manager was also reimbursed for any out of pocket costs. As the trusts grew in size, concern developed regarding potential misalignment between management and unitholders as a result of the fee structure.

ARC took the position that, given its size and operations, the existing structure was no longer appropriate and elected to conduct a thorough review of alternatives prior to the renewal date of its external management contract. ARC's board of directors determined there were four possible alternatives that could be pursued:

1. Serve notice of termination of the contract;
2. Allow the contract to be automatically renewed;
3. Restructure the contract to eliminate transaction fees and incorporate performance fees; or
4. Internalize management and eliminate the contract altogether.

MANAGEMENT

The board rejected the first alternative, as it would jeopardize the continuity of the existing management team and staff. It was important for ARC to retain its existing management team, as they were pivotal in the success and growth of ARC. The second alternative would leave the structure as it was and would not address the issue of the potential misalignment between the external manager and the unitholders, and hence was rejected. The third alternative was also rejected due to the potential for higher fees as the Trust grows and, again there was a continuing potential misalignment between management and unitholder interests. The board elected to pursue the internalization of the contract, as it was the only alternative to address the structural issues for a trust our size, eliminate fees going forward and remove any potential for misalignment between management and unitholder interests.

An independent committee of the Board of Directors of ARC was formed. CIBC World Markets was retained to provide financial advice to this independent committee and Blake Cassels & Graydon were retained to provide legal advice.

The committee identified certain fundamental principles that had to be met prior to the transaction proceeding. First, the transaction had to be accretive on a per unit basis for distributions, cash flow and net asset value. Secondly, continuity of the management team and staff needed to be ensured to the greatest extent possible.

It is important to note that, unlike the structure of external managers for other trusts, ARML shares were widely held by 73 shareholders made up of management and staff. This group, as a team, was responsible for the success of the Trust. For the internalization to proceed, it needed approval from both ARC's unitholders and ARML's shareholders.

The committee needed to consider a broad range of criteria to find an agreement that would be satisfactory to both ARC's unitholders and ARML shareholders. Some of these criteria included:

- Historical and expected future performance of the management team;
- Broad based ownership of ARML among the Trust's existing staff;
- The Trust's own acquisition criteria needed to be met as in the acquisition of any asset;
- The transaction needed to be accretive to net asset value, cash flow and distributions on a per unit basis;
- No additional G&A costs could result for the Trust which would not otherwise have been incurred; and
- The capital structure of the Trust could not be impaired by the transaction.

Internalization

Once all the criteria were considered, the committee drafted up terms of agreement for the transaction to present to the Board of Directors of ARC and to ARML shareholders. The terms of the transaction provided that, subject to unitholder approval, total consideration for ARML was to be approximately $55 million. ARML shareholders would receive $5.0 million less than the agreed purchase price to allow for retention bonuses declared by ARML to its officers but not paid before closing. The net purchase price to ARML shareholders included $4.25 million in cash and 3.58 million trust units or exchangeable shares valued at a price of $12.78 per unit. The agreement also contained escrow and forfeiture provisions for senior employees.

The escrow provisions guaranteed several factors; the units and exchangeable shares would be retained by management for a significant period of time and management would remain motivated to continue with the Trust and ensure that the units maintain the highest value possible. This is in complete alignment with unitholder interests.

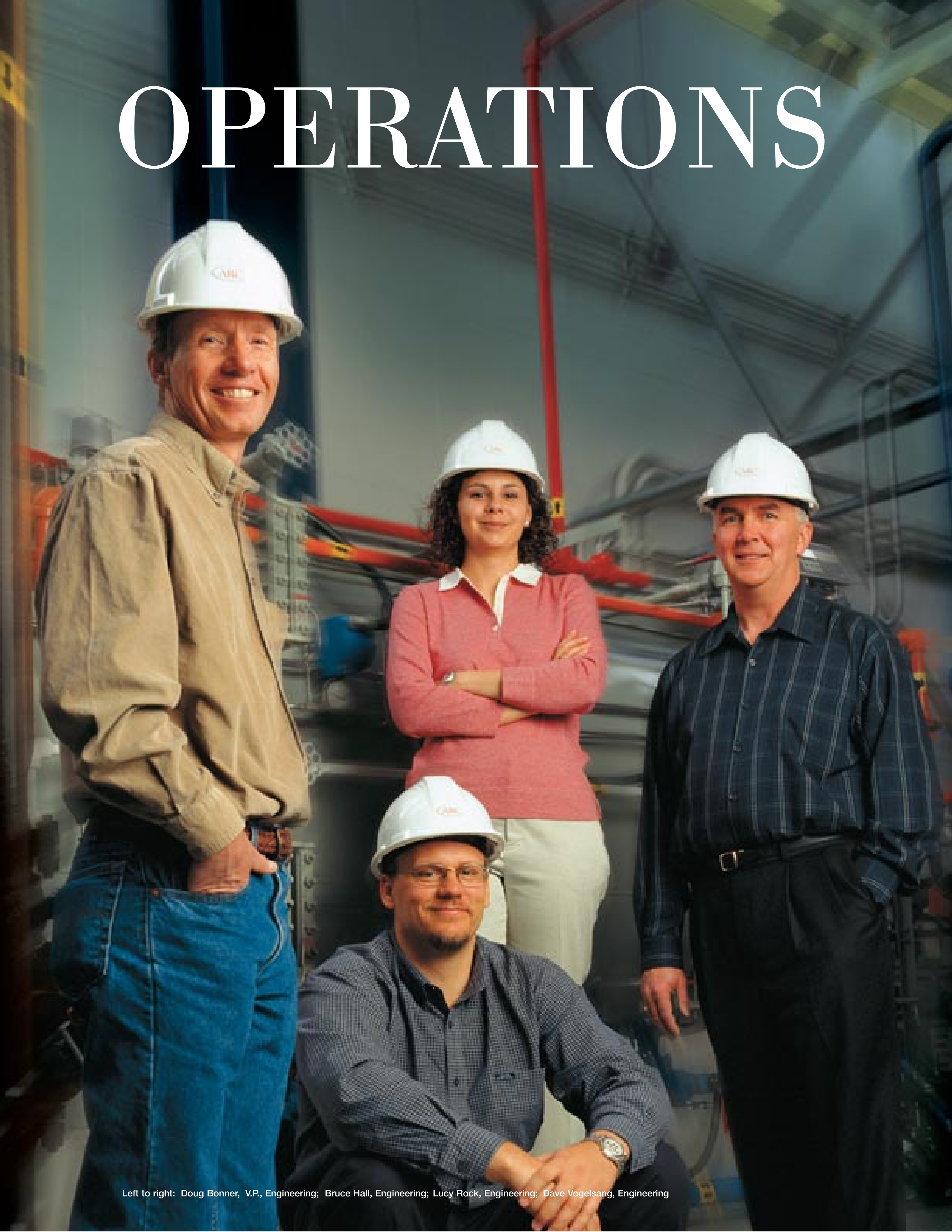
The securities held in escrow for all senior shareholders of ARML are subject to certain forfeiture provisions. Thirty per cent of the securities held in escrow will be forfeited if the individual leaves in the first year after closing. The number of units subject to forfeiture will decline evenly over a five year period.

The terms of the transaction acknowledged the strong past and expected future performance of the management team. Accordingly, the structure of the transaction needed to protect management continuity. We believe the innovative terms included in the agreement will ensure the existing management team will remain intact for the benefit of all unitholders. Additionally, the Trust benefited in the past from the relationship with ARC Financial Corporation with respect to research and strategic advice services. These services were pre-paid as part of the agreement and will continue for a minimum of five years at no further cost to the Trust.

Two assets were acquired in the internalization transaction; a future cash flow equal to three per cent of net operating income and the direct hiring of existing management and approximately 135 employees of the manager. Prior to the transaction, management fees and acquisition fees were paid to the manager. In 2001, the fees were $16.7 million, including $8.8 million for the base management fee and $7.9 million in acquisition fees. Since the transaction, these fees no longer exist. While the accretion to cash flow and distributions will be modest in the short-term, the over life accretion could be significant.

There are many benefits to the internalization of the management contract. The internalization provides absolute alignment between management and unitholders. It broadens our potential investor base by eliminating a component of the Trust's structure that precluded certain institutions from investing in our sector. The transaction improves the Trust's competitiveness for acquisitions and creates greater opportunity to make value-adding acquisitions to the benefit of our unitholders. The internalization eliminates the barrier to pursue consolidation opportunities and positions the trust to take a leading role in any consolidation of the sector that may occur in the future. Our corporate governance is improved through the simplified corporate structure, allowing greater transparency in compensation reporting. The number of non-management directors increased to six out of a total of seven. Finally, long-term commitment of the Trust's existing management team and their vision for the business is maintained.

OPERATIONS



Left to right: Doug Bonner, V.P., Engineering; Bruce Hall, Engineering; Lucy Rock, Engineering; Dave Vogelsang, Engineering

REVIEW

ARC's major development activities in 2002 included drilling, completions and well tie-ins at Ante Creek, Lougheed, Alida, Youngstown, Midale, Weyburn and House Mountain. We drilled 32 operated wells and participated in 216 partner operated wells for a total of 248 gross wells (53 net wells). Major drilling programs were in southeast Alberta in Brooks, in southeast Saskatchewan in Alida and Midale, and at Ante Creek and Valhalla in northern Alberta. Key acquisitions in 2002 were made in Ante Creek, Medicine River/Gilby and Jenner.

Reported operating costs increased in 2002 to $6.45/boe from $5.47/boe in 2001. The increase in costs was primarily due to higher costs on ARC's non-operated properties, as operators performed maintenance and conducted facilities turnarounds, which increased operating costs and temporarily reduced volumes which resulted in higher per unit operating costs. The $6.45/boe cost was also impacted by third-party operators exceeding their approved operating budgets, including some costs related to prior periods which were billed to ARC in 2002. Our current outlook for 2003 operating costs is a modest decrease to $6.25/boe.

In 2002, ARC replaced 145 per cent of its production at an average cost of $9.27/boe for established reserves. Our acquisition costs and our development costs were both lower than in 2001. Since inception, overall finding, development and acquisition ("FD&A") costs have averaged $6.59/boe. We believe both our 2002 and three year average FD&A costs ($8.21/boe) will be amongst the lowest in our sector.

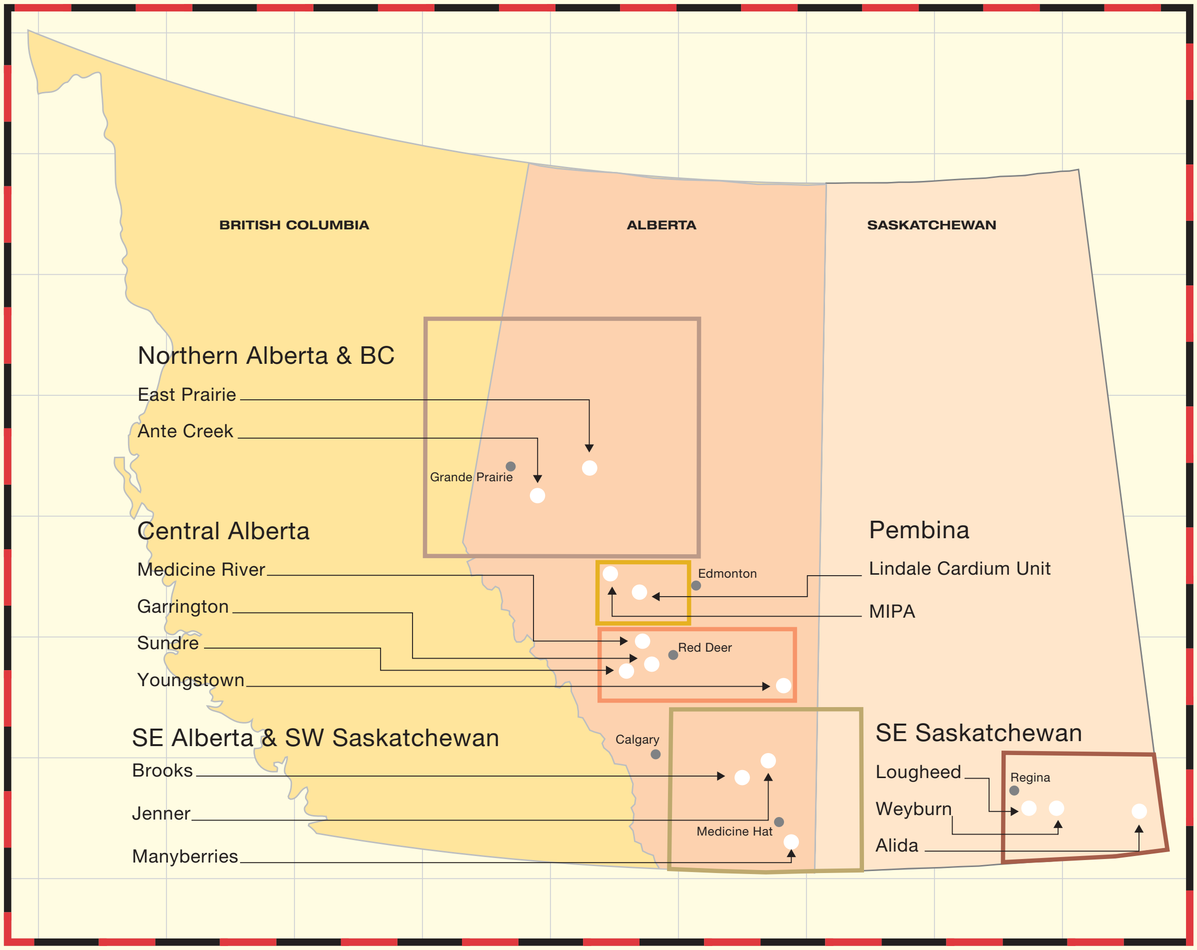
Production volumes for 2002 averaged 42,425 boe/d. Oil production increased 1.2 per cent to 20,655 barrels per day, natural gas production decreased 4.7 per cent to 110 million cubic feet (mmcf) per day and natural gas liquids production decreased 0.9 per cent to 3,479 barrels per day. ARC's production portfolio was weighted 49 per cent to oil, 43 per cent to natural gas and eight per cent to natural gas liquids.

ARC's capital expenditures in 2002 were $88 million, down from $102 million in 2001. These expenditures were incurred on development drilling, geological and geophysical work and facilities expenditures, as ARC continues to develop its asset base. ARC's established reserves increased to 185 mmboe at year-end 2002 from 178 mmboe in 2001.

ARC's 2003 capital program is budgeted at $115 million, which includes drilling 125 operated wells and participation in 90 partner operated wells. Our focus areas will be Ante Creek, Jenner and Lougheed. Well optimization activities will include re-completions, fracs, stimulations and artificial lift upgrades. Waterflood initiatives include optimization at Lougheed, a rejuvenation of a pilot at Glen Ewan and a pilot program at Ante Creek.

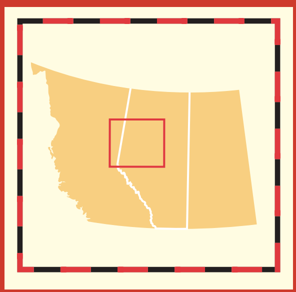
Left to right: Susan Healy, V.P., Land;
Wendy Teare, Land; David Elmer, Land

MAJOR PROPERTIES



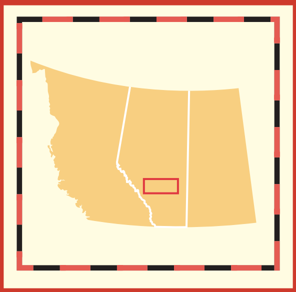
OPERATIONAL

Northern Alberta & BC



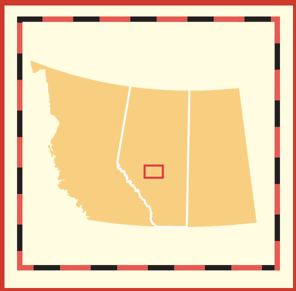
Key Properties	Established Reserves	% of Total Established Reserves	2002 Average Production	% of Total Production	Netback
	(mboe)		(boe)		($/boe)
Ante Creek	18,698	10.1	2,381	5.6	22.53
Dunvegan Gas Unit No. 1	4,350	2.3	611	1.4	13.73
East Prairie	717	0.4	118	0.3	7.60
House Mountain Unit No. 1	2,219	1.2	417	1.0	24.54
Other	20,575	11.1	7,138	16.8	14.84
Northern Alberta & BC	**46,559**	**25.1**	**10,665**	**25.1**	**16.79**

Central Alberta



Key Properties	Established Reserves	% of Total Established Reserves	2002 Average Production	% of Total Production	Netback
	(mboe)		(boe)		($/boe)
Caroline Cardium E Pool Unit	2,133	1.1	582	1.4	12.50
Caroline Swan Hills Unit No. 1	2,726	1.5	1,433	3.4	20.26
East Garrington	3,092	1.7	866	2.0	14.50
Medicine River	3,246	1.7	396	0.9	18.59
Sundre	7,007	3.8	1,175	2.8	15.20
Youngstown	1,929	1.0	597	1.4	25.02
Other	6,773	3.7	2,474	5.8	15.56
Central Alberta	**26,906**	**14.5**	**7,523**	**17.7**	**16.95**

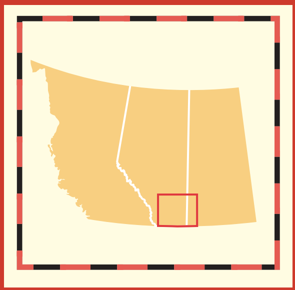
Pembina



Key Properties	Established Reserves	% of Total Established Reserves	2002 Average Production	% of Total Production	Netback
	(mboe)		(boe)		($/boe)
Berrymoor Cardium Unit	6,726	3.6	708	1.7	23.99
Hoadley	2,204	1.2	736	1.7	15.95
Lindale Cardium Unit	2,964	1.6	541	1.3	20.71
Lobstick Cardium Unit	1,069	0.6	112	0.3	13.47
MIPA	12,478	6.7	1,552	3.6	19.06
South Pembina Cardium Unit	842	0.5	127	0.3	24.00
Westerose	582	0.3	192	0.5	16.38
Other	11,008	5.9	3,113	7.3	16.03
Pembina	**37,873**	**20.4**	**7,081**	**16.7**	**17.95**

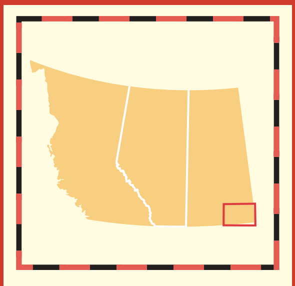
SUMMARY

SE Alberta & SW Saskatchewan



Key Properties	Established Reserves (mboe)	% of Total Established Reserves	2002 Average Production (boe)	% of Total Production	Netback ($/boe)
Brooks	6,063	3.3	1,943	4.6	13.18
Grassy Lake	2,296	1.2	894	2.1	18.02
Jenner	12,035	6.5	2,348	5.5	13.61
Manyberries	945	0.5	163	0.4	20.76
Retlaw	1,527	0.8	532	1.2	13.55
Other	8,440	4.6	2,239	5.3	14.18
SE Alberta & SW Saskatchewan	**31,306**	**16.9**	**8,119**	**19.1**	**14.29**

SE Saskatchewan



Key Properties	Established Reserves (mboe)	% of Total Established Reserves	2002 Average Production (boe)	% of Total Production	Netback ($/boe)
Alida	1,426	0.8	627	1.5	25.09
Lougheed	10,206	5.5	2,881	6.8	23.29
Midale	6,551	3.5	1,287	3.0	18.56
Weyburn	10,519	5.7	1,635	3.9	18.19
Other	14,025	7.5	2,607	6.1	18.30
Southeast Saskatchewan	**42,727**	**23.0**	**9,037**	**21.3**	**20.38**

Total Established Reserves 185,371 mboe

2002 Average Production 42,425 boe/d

Netback $16.78 boe

Northern Alberta & BC

Northern Alberta and BC continue to stand out as ARC's largest core area representing 25 per cent of total production. ARC's strategy of focused acquisitions, combined with deliberate and well-planned exploitation programs, is best exemplified in the Ante Creek area. Since the original acquisition in Ante Creek in 2000, ARC has drilled 20 development and step-out wells with 100 per cent success. Two complementary acquisitions completed in 2002 in Ante Creek offer numerous low risk drilling opportunities which will support an active 2003 drilling program and provide an inventory of high quality drilling locations for several years into the future.

Ante Creek

The main Ante Creek oil pool (located south of Grande Prairie, Alberta) was discovered in 1996; ARC initially purchased land in the area in April 2000. We own an average working interest of 99 per cent in Ante Creek. There were five new wells drilled in Ante Creek in early 2002 as a successful follow-up to a 15 well drilling program in 2001. The fourth phase of drilling started in late 2002 which will result in another 14 wells being drilled in 2003.

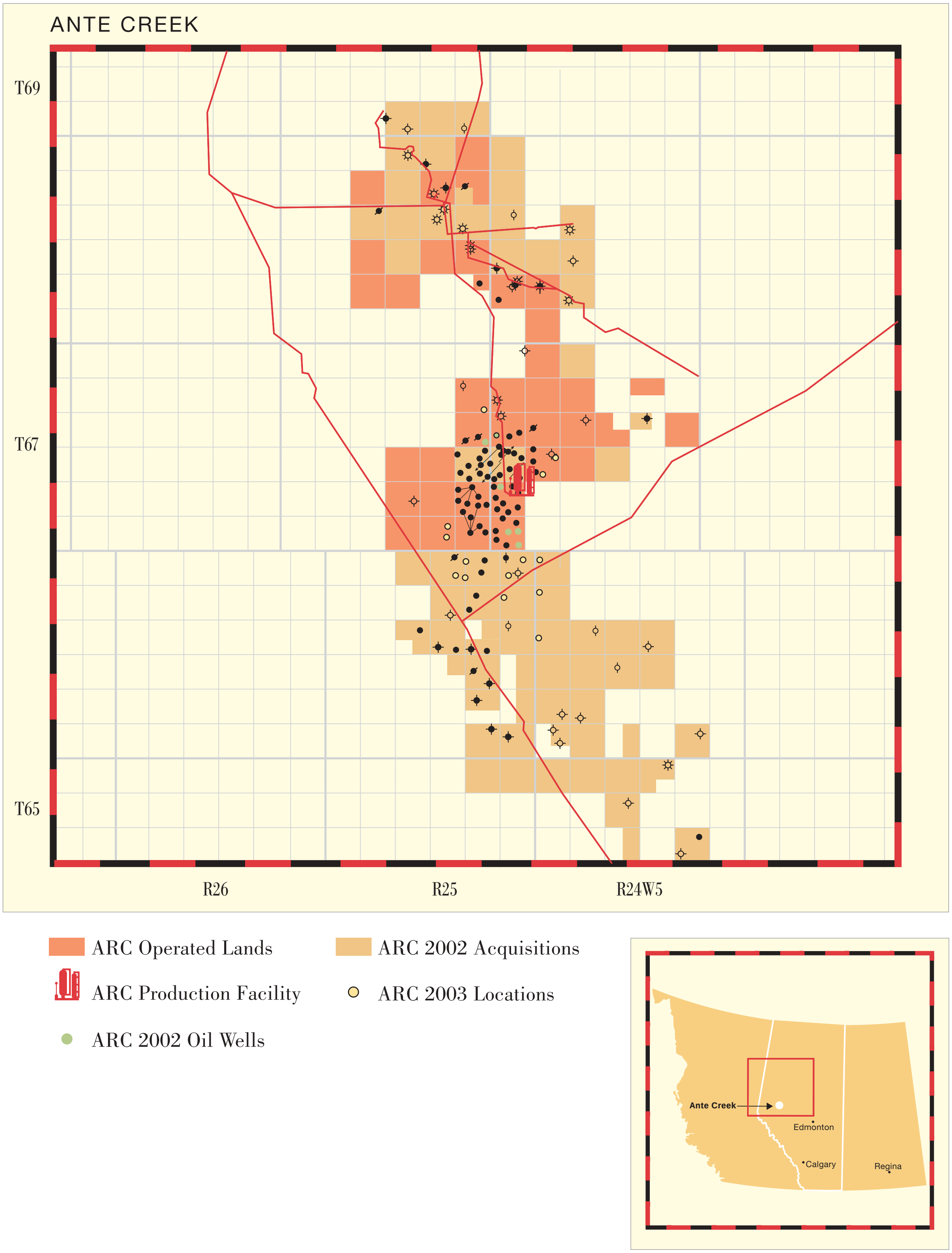
During the year, ARC completed two separate, significant acquisitions in the Ante Creek area. The first purchase took place in August and a subsequent, larger purchase was completed in December, further strengthening our dominant position in the area.

Based on expected 2003 production, these new properties have a proved reserve life index of 10.3 years and an established reserve life index of 11.1 years. The acquisition offers considerable development opportunities and provides excellent long-term growth potential. ARC now has virtual control of the main Ante Creek field. This will allow the implementation of a field wide waterflood if positive response is observed from the existing pilot waterflood. The December acquisition will add 1,200 boe/d to ARC's existing production at Ante Creek.

East Prairie

ARC owns a non-operated average working interest of 37.5 per cent in East Prairie (located east of Grande Prairie, Alberta). ARC purchased interest in this area in 2001 and during that year several wells were drilled. In 2002, four wells were tied-in and began contributing to our production in the area. ARC participated in a 33 km seismic program in the area and purchased a further 150 km of seismic. The seismic data helped identify additional locations for drilling in 2003.

This area presents different opportunities for ARC as the main land holdings are on the East Prairie Metis Settlement (EPMS). ARC owns a substantial contiguous land position with multizone drilling potential. Infrastructure was installed in the area to bring new wells onto production. There are opportunities for increased production in East Prairie and ARC, along with the operator, is pursuing various strategies to achieve this. A Master Agreement completed in 1997 with the EPMS established the necessary ground work for development and drilling in the area and provided a framework so that expansion to our drilling program can go ahead.


ANTE CREEK
T69
T67
T65
R26
R25
R24W5
ARC Operated Lands
ARC 2002 Acquisitions
ARC Production Facility
ARC 2003 Locations
ARC 2002 Oil Wells
Ante Creek
Edmonton
Calgary
Regina

Central Alberta

ARC's Central Alberta properties are composed of a diverse set of assets producing from numerous geological horizons that yield high value, development opportunities. An example of this is Youngstown which was acquired in 2000. Detailed technical evaluation of the property, including the acquisition of 3-D seismic, led to numerous opportunities being identified. A successful drilling program undertaken in 2002 has helped identify additional locations to be drilled in 2003. A significant acquisition of assets in the Medicine River/Gilby area has consolidated and grown our interests in the region and puts a new core area on the map for ARC in Central Alberta.

Medicine River

In May 2002, ARC closed an acquisition in the Medicine River/Gilby area (located north of Calgary, Alberta), establishing ARC as a major operator in the area. The acquisition was a strategic fit and added significant operated and non-operated, long-life production. ARC operates two units in this area – The Gilby Jurassic B and Medicine River Glauconitic A Unit No. 4. Evaluation work is on-going to assess the opportunities to increase production in these two units.

Also in 2002, non-unit production and lands were acquired. Additional unit interests were acquired in five non-operated units where ARC previously had an ownership interest.

Youngstown

ARC has a 98 per cent average working interest in the Youngstown Arcs pool (located east of Red Deer, Alberta), which is a mature oil pool with an active water drive and low decline rates. In 2001, a 3-D seismic program was conducted over the pool. This information, combined with detailed geological and engineering evaluations, identified a number of opportunities. In 2002, ARC drilled three successful horizontal re-entry wells and one successful vertical well. These wells added in excess of 250,000 bbls of established reserves and 175 bopd of deliverability. The 2003 plan calls for three additional horizontal wells and one vertical well to be drilled. In addition, up-hole gas completions are planned for 2003.

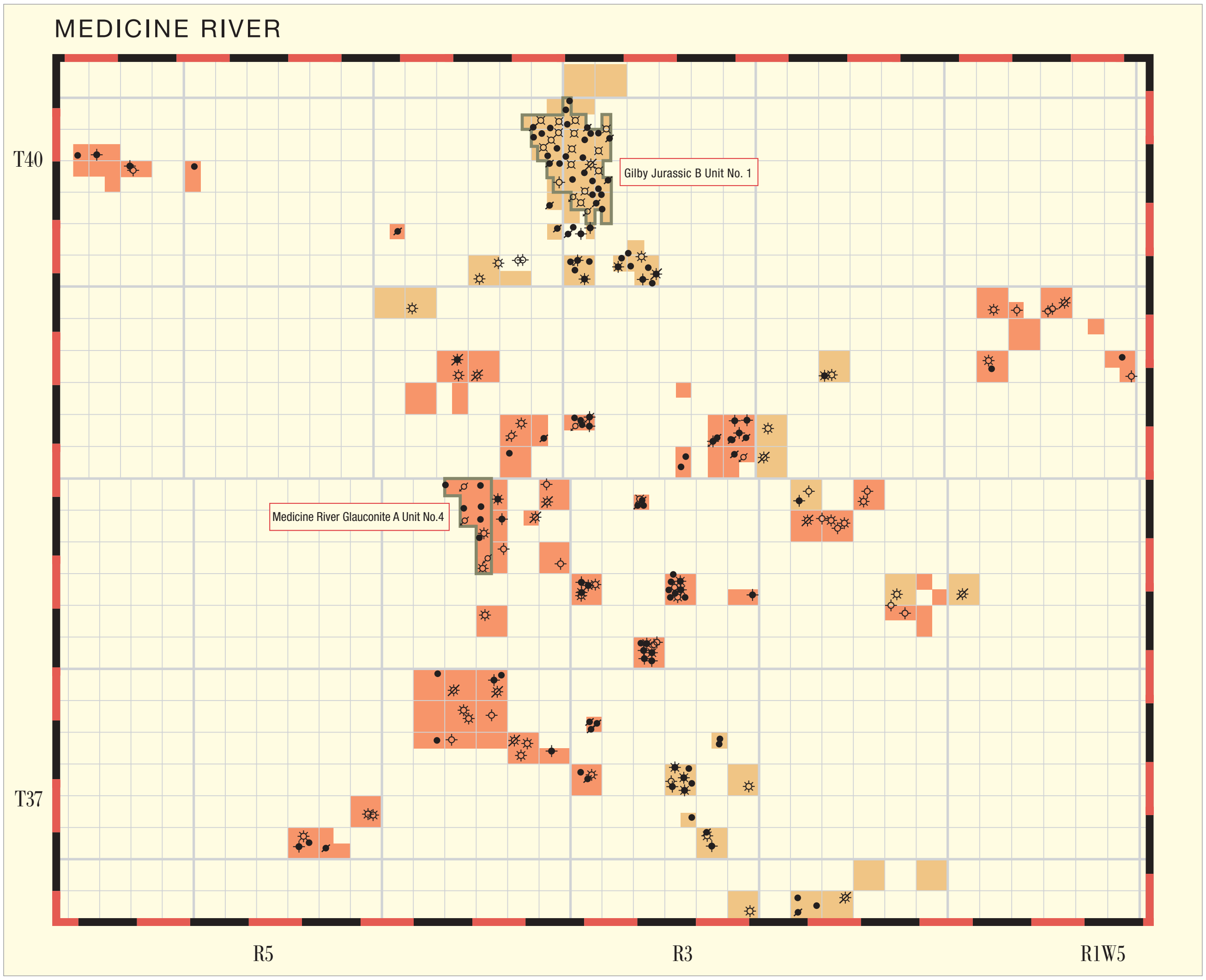
Various acquisitions were made in Youngstown in 2002. ARC has been increasing its interest by buying out partners in the area.

Sundre

ARC has an average working interest of 80 per cent in its lands in the Sundre area (located northwest of Calgary, Alberta). ARC operates three oil units, each of which is a mature oil pool under waterflood. A horizontal re-entry well drilled in December 2002 in the Rundle B Pool Unit (50.5 per cent working interest) is expected to commence production in the early part of 2003.

Garrington

In Garrington, ARC continued its successful re-completion program adding 120 boe/d to existing production. Additional re-completion candidates have been identified for 2003.



ARC Operated Lands

ARC 2002 Acquisitions

Unit Outline

Pembina

Pembina (located west of Edmonton, Alberta) was ARC's first operated core area. The area demonstrates the characteristics of a strong Trust asset and is aligned with ARC's corporate philosophy of owning sustainable, long life assets. The Pembina field produces high quality sweet oil and has an economic reserve life in excess of 50 years. Most of the properties are under waterflood which results in long-term, stable production rates with high reserves recovery. ARC acquired further strategic interests in the area and continues optimization and development activities to ensure the profitability and longevity of these fields.

Lindale Cardium Unit

ARC is the operator of the Lindale Cardium Unit and has increased its working interest to 54.4 per cent through a series of small acquisitions in 2002. This area includes 84 producing Cardium oil wells. Activity focused on optimization of the waterflood and producing wells. Development plans for 2003 include the identification of drilling and stimulation opportunities and further development of the waterflood to support increased production.

MIPA

Through a series of acquisitions, ARC now holds a 100 per cent working interest in the MIPA producing properties. There are presently 248 wells in MIPA producing crude oil and natural gas from the Cardium formation. Recovery from the field is being optimized through the use of a waterflood. In 2002, ARC successfully drilled and completed one Cardium oil well with follow-up locations planned for 2003. Additionally, four refracturing stimulations and one other stimulation were performed, resulting in significant production increases from all the wells. Exploitation and optimization efforts will continue in 2003 along with further detailed engineering and geological work to identify additional drilling and re-completion opportunities.

Other Pembina Properties

ARC has working interests in a number of other producing properties in the Pembina area. These properties include 355 net wells producing crude oil and natural gas from a number of formations. In 2002, ARC acquired the remaining interests in the ARC operated South Pembina Cardium Unit and additional interest in the non-operated Lobstick Cardium Unit. We expect to continue exploitation activities in 2003 to increase production and reserves in these units. In nearby Hoadly/Westerose, ARC participated in the drilling of a number of successful gas wells in 2002. Further drilling is planned for 2003.

SE Alberta/SW Saskatchewan

ARC established a presence in this area in 1999 with the acquisition of the Jenner shallow gas assets. These assets are comprised of sweet gas fields with low operating costs. Since 1999, ARC has drilled low risk, low cost development wells and acquired additional assets. 2002 was no exception – ARC made twelve small acquisitions in southern Alberta. These acquisitions complement our strategy of achieving long-term operating efficiencies and higher netbacks through increased ownership interest in core areas.

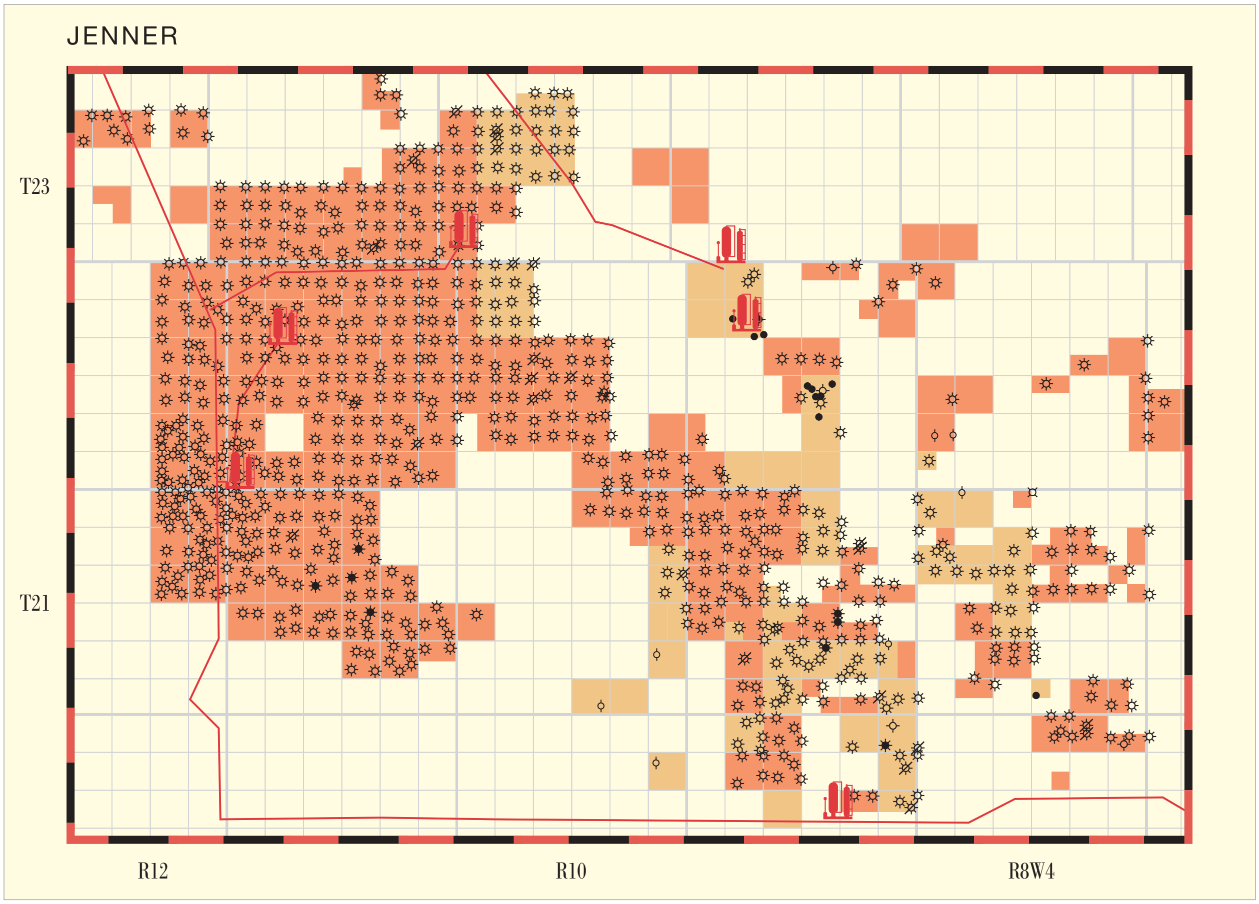
Jenner

Several acquisitions in Jenner North (located east of Calgary, Alberta) assisted an on-going re-completion and optimization program to boost oil and gas production. In Jenner South, gas production increased from a combination of successful acquisitions, uphole re-completions and facility modifications. ARC is pursuing a strategy of growing its core, shallow gas properties in the Jenner area by selectively targeting deeper zones in addition to traditional shallower zones. ARC has an active drilling program planned for 2003.

Other SE Alberta/SW Saskatchewan areas

In Manyberries (located south of Medicine Hat, Alberta), a new waterflood was initiated in the Sunburst MMM oil pool. The new facility, injectors and source well will add significantly to the economic life of this property. In Retlaw, strategic acquisitions added to the inventory of development drilling locations. Two gas wells were placed on production, one was a new drill and the other a re-completion. These wells increased Retlaw production by 100 boe/d which represents a 25 per cent increase in production for the area.

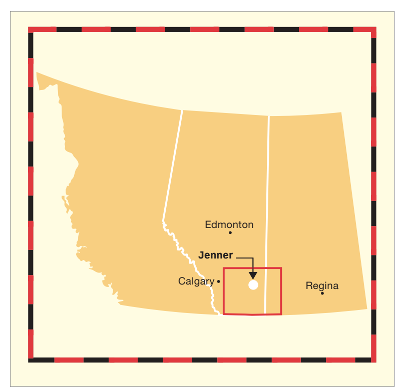
In Brooks (located east of Calgary), four new shallow gas wells were brought on production on the edge of our existing core area. In Grassy Lake, recent 3D seismic has helped define a 2003 drilling program in the area. The purchase of Farpoint Energy in 2002 added 250 boe/d of production at Grassy Lake resulting in year end production of approximately 900 boe/d.



ARC Lands

ARC 2002 Acquisitions

ARC Production Facility



SE Saskatchewan

ARC established a significant presence in the area through the 2001 acquisition of Startech Energy Inc. The assets acquired are high performers for ARC with numerous development opportunities identified and implemented and many yet to come. In Lougheed, ARC acquired two producing properties in 2002 to further consolidate our holdings, reduce operating costs, and augment our drilling inventory. Reservoir simulation results highlighted production enhancement opportunities including new horizontal wells, waterflood implementation and optimization initiatives. In early 2002, ARC commissioned a major gas conservation project in Lougheed that will improve the air quality in this area of Saskatchewan. In Alida, ARC demonstrated that the use of a multi-discipline technical team results in profitable acquisition, drilling, and facility modification opportunities.

Alida

The Alida oil field is one of ARC's core properties in southeast Saskatchewan. During 2001 and 2002, ARC increased its working interest to the current average of 97 per cent over the field's 3,040 acres. This property produces light sour crude oil from the Mississippian aged Frobisher, Kisbey and Alida reservoirs. These reservoirs are ideal candidates for horizontal drilling, thereby maximizing production from individual well bores.

In 2002, ARC achieved 100 per cent success in a five well horizontal drilling program. Production at year-end 2002 from these five wells was approximately 450 boe/d. Also in 2002, ARC consolidated the field's production into a central battery facility that will reduce future operating expenses. Other initiatives in 2002 included upgrades to the fluid gathering system to allow us to accommodate volumes from new drilling and on-going well optimization activities.

Development plans for 2003 will focus on upgrading the field's water disposal system and the drilling of two additional horizontal wells.

Lougheed

The Lougheed area continues to be one of ARC's top producing properties. In 2002, ARC acquired additional non-unit lands in Lougheed providing further exploitation opportunities along with significant operating cost reduction through facility consolidation and economies of scale. A gas plant commissioned in January 2002 resulted in NGL conservation and reduction in total emissions through reduced flaring of gas.

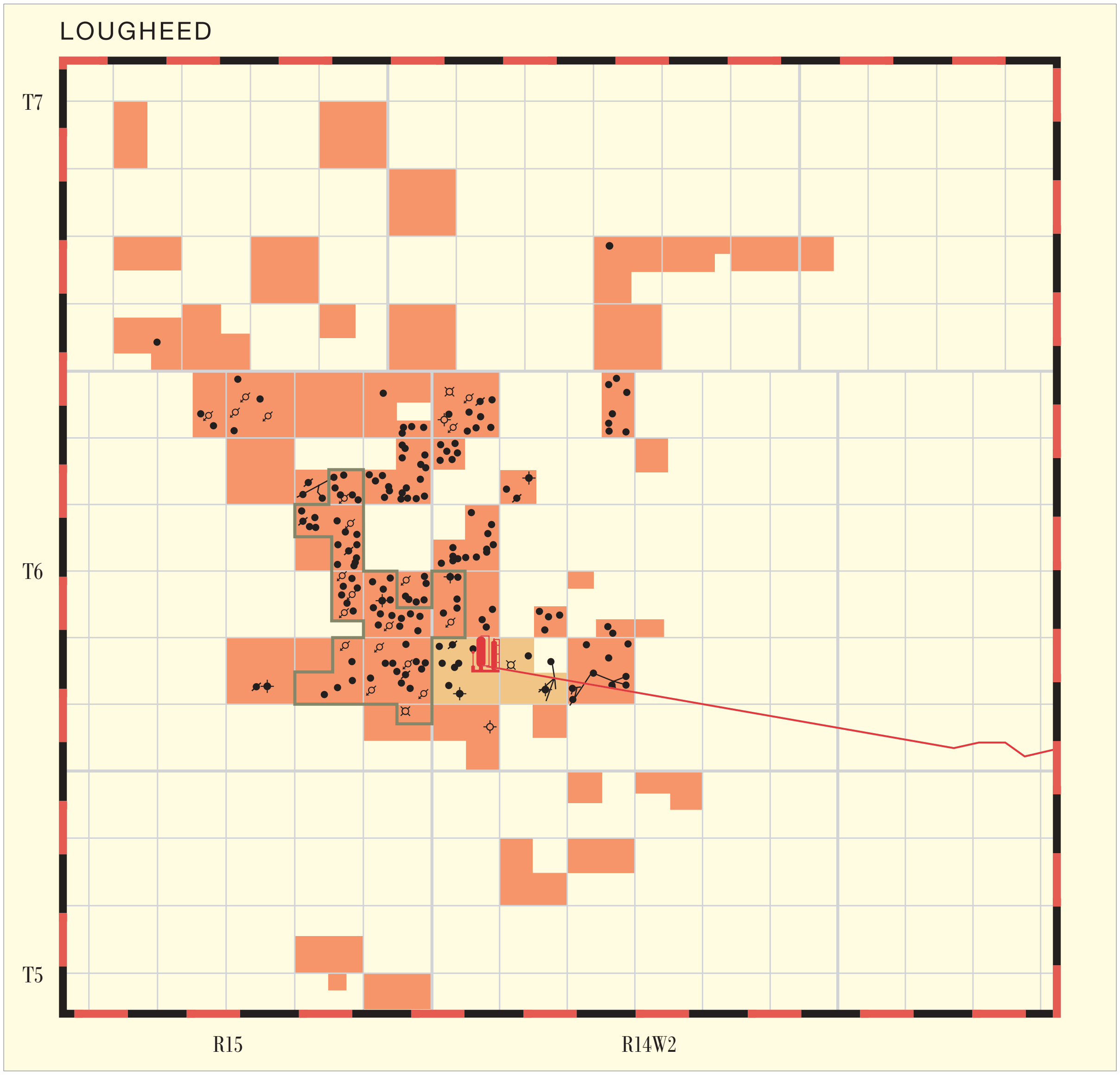
There were three successful horizontal wells drilled with a fourth well currently being completed. Waterflood optimization has resulted in increases in production from both unit and non-unit lands in the last quarter of 2002.

Weyburn

ARC is the third largest working interest owner in the Weyburn Unit. ARC holds a 6.5 per cent interest in this unit yielding net production volumes of 1,345 boe/d making it one of ARC's larger oil properties.

In 2002, an additional phase of the miscible CO_2 injection project was completed which involved the re-completion of six wells. Phase 1b was started which included the drilling of two water injection wells and the conversion of three wells to water injection.

In 2003, the operator plans to implement the next phase of development. This will include eight additional patterns and continued pattern development through well re-completions, conversions and equipment upgrades. In a section of the unit that is still under waterflood, five horizontal wells were completed during 2002. The next phase of activity in this area will involve the drilling of five horizontal infills along with additional well re-completions and conversions.

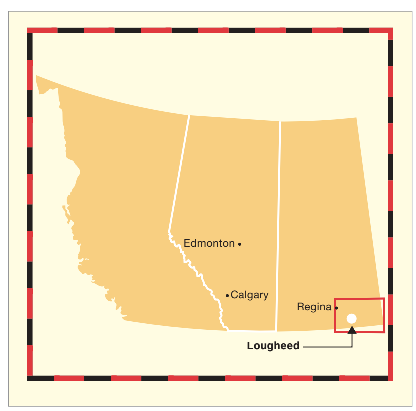


ARC Operated Lands

ARC 2002 Acquisitions

ARC Production Facility

Unit Outline



Acquisitions

ARC's philosophy when acquiring new properties is to purchase high quality, long-life oil and gas assets. We take a disciplined approach to ensure each acquisition enhances unitholder value. ARC's focus for 2002 was on smaller acquisitions that complemented our existing properties and strengthened our presence in established core areas such as Ante Creek, Medicine River and Jenner.

ARC completed a total of $119 million in net acquisitions, concentrated in our central and northern Alberta core areas. The acquisitions added 4,100 boe per day of production and 13.0 mmboe of established reserves at an average cost of $9.18/boe.

ARC's largest acquisition in 2002 was the purchase of two major oil and gas properties for $71.1 million in the Ante Creek and Brown Creek areas. This acquisition strengthened ARC's existing presence in Ante Creek and established a presence in the Brown Creek area. The acquisition will add an estimated 2,000 boe per day to ARC's production.

Acquisitions are important for a trust as they replenish depleting assets and provide fresh development opportunities. In 2003, ARC will continue to focus on potential acquisition opportunities that can add significant value for its unitholders.

Dispositions

Each year ARC reviews its asset base to identify assets for potential disposition. As production declines in mature properties, ARC may divest these properties if there is limited remaining upside potential. In 2002, ARC disposed of $12.6 million of assets.

2002 Acquisition/Disposition Summary

	Purchase Price	Established* Reserves	Reserve Purchase Price	Production Rate	Production Purchase Price	Reserve Life Index
	($ millions)	(mmboe)	($/boe)	(boe/d)	($/boe/d)	(years)
Acquisitions	131.7	14.3	9.22	4,729	27,871	9.6
Dispositions	(12.6)	(1.3)	9.56	(612)	20,588	5.9
Net acquisitions	119.1	13.0	9.18	4,117	28,936	10.2

* Established = proved plus 50 per cent probable

Summary of Finding, Development and Acquisition Costs

($ thousands)	**2002**	2001	2000	1999	1998	1997	1996
Total capital expenditures	**207,391**	624,877	207,917	255,731	10,595	102,717	207,433
Net change in established reserves after production	**6,875**	48,344	30,268	44,528	(1,722)	15,892	41,181
Annual production (mboe)	**15,485**	15,736	10,012	8,093	4,649	4,375	1,751
Annual reserve additions (mboe)	**22,360**	64,080	40,280	52,621	2,927	20,267	42,932
Annual finding, development and acquisition costs ($/boe)	**9.27**	9.75	5.16	4.86	3.62	5.07	4.83
Three-year rolling average ($/boe)	**8.21**	6.94	4.95	4.87	4.85	–	–
Cumulative since inception ($/boe)	**6.59**	6.32	4.93	4.85	4.85	4.91	4.83

Reserves

Based on an independent engineering evaluation conducted by Gilbert Laustsen Jung Associates Ltd. (GLJ) effective December 31, 2002, ARC had proved plus risked probable reserves of 409 bcf of natural gas and 117 mmbbls of crude oil and natural gas liquids. Approximately 63 per cent of ARC's reserves are crude oil and natural gas liquids and 37 per cent are natural gas on a 6:1 boe conversion basis. Total reserves at December 31, 2002 were 185 mmboe, an increase of approximately four per cent from the previous year.

The following tables summarize ARC's reserves of natural gas, crude oil and natural gas liquids as evaluated by GLJ. These reserves reflect ARC's interest before royalties. Probable reserves are risked at 50 per cent to calculate the established reserves. All estimates of future net cash flow in these tables are calculated without any provision for income taxes and general and administrative costs but include provisions for future well abandonment liabilities.

Reserve Life Index (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. The actual productive life of the reserves is significantly longer due to the nature of oil and gas reservoirs which exhibit a declining production rate over time. To account for the impact and timing of acquisition and divestment activity, the tables use the independent evaluator's forecast of the first year's production in determining RLI, as this results in a more consistent representation over time.

Present Value of Reserves

(thousands of $ before income taxes)

	2002			2001		
Discount Factor	**10%**	**12%**	**15%**	10%	12%	15%
Proved producing	**1,026,459**	**953,490**	**864,840**	955,706	886,964	803,266
Proved non-producing	**138,571**	**119,668**	**97,109**	111,778	96,477	78,222
Total proved	**1,165,030**	**1,073,158**	**961,949**	1,067,484	983,441	881,488
Risked probable	**137,340**	**116,431**	**93,498**	148,509	126,642	102,463
Established	**1,302,370**	**1,189,589**	**1,055,447**	1,215,993	1,110,083	983,951

Net Asset Value

($ thousands, except per unit amounts)

	2002		2001		2000		1999		1998	
	10%	**12%**	10%	12%	10%	12%	10%	12%	10%	12%
Value of established										
oil & gas reserves	**1,302,370**	**1,189,589**	1,215,993	1,110,083	944,804	868,071	530,400	484,309	278,353	253,529
Add: Undeveloped lands	**19,700**	**19,700**	22,293	22,293	5,698	5,698	11,994	11,994	2,655	2,655
Working capital	**(10,067)**	**(10,067)**	5,805	5,805	6,339	6,339	15,761	15,761	(1,688)	(1,688)
Reclamation fund	**12,925**	**12,925**	10,147	10,147	9,897	9,897	7,165	7,165	4,504	4,504
Less: Debt*	**(337,728)**	**(337,728)**	(294,489)	(294,489)	(115,068)	(115,068)	(141,000)	(141,000)	(72,499)	(72,499)
Net asset value	**987,200**	**874,419**	959,749	853,839	851,670	774,937	424,320	378,229	211,325	186,501
Units outstanding										
(thousands) (end of year)	**126,444**	**126,444**	111,693	111,693	72,524	72,524	53,607	53,607	25,604	25,604
NAV per Unit	**$ 7.81**	**$ 6.92**	$ 8.59	$ 7.64	$ 11.74	$ 10.69	$ 7.92	$ 7.06	$ 8.25	$ 7.28

* Does not include retention bonuses

The net asset value table (see previous page) shows what is normally referred to as a "produce-out" net asset value ("NAV") calculation under which the current value of the Trust's reserves would be produced at future prices and costs as projected by GLJ. The value is a snapshot in time and is based on various assumptions including commodity prices and foreign exchange rates that vary over time.

In the absence of adding reserves to the Trust, the NAV will decline as the reserves are produced out. The cash flow generated by the production relates directly to the cash distributions paid to unitholders. The evaluation includes future capital expenditure expectations required to bring undeveloped reserves on production.

ARC's technical team continuously works on many of its areas to determine and implement enhancements that improve profitability and increase reserves ultimately adding to the Trust's NAV. This is reflected in the positive reserve revisions that ARC has sustained every year since inception.

In order to determine the "going concern" value of the Trust, a more detailed assessment would be required of the upside potential of specific properties and the ability of the ARC team to continue to make value-adding capital expenditures. At inception of the Trust on July 16, 1996 the NAV was determined to be $10.26 per unit based on a 12 per cent discount rate; since that time, including the January 15, 2003 distribution, the Trust has distributed $10.64 per unit. Despite having distributed more cash than the initial NAV, the NAV as at December 31, 2002 was $7.81 per unit, a decline of only 24 per cent from the NAV at inception, after having distributed a total of $10.64 per unit. NAV per unit declined by $0.78 during 2002, while distributions were $1.56 per unit.

Pricing Assumptions (1)

Year	WTI Crude Oil	Edmonton Crude Oil (2)	Natural Gas (3)
	($US/bbl)	($Cdn/bbl)	($Cdn/mmbtu)
2003	25.50	38.50	5.40
2004	22.00	32.50	4.80
2005	21.00	30.50	4.50
2006	21.00	30.50	4.65
2007	21.25	30.50	4.65
2008	21.75	31.00	4.65
2009	22.00	31.50	4.65
2010	22.25	32.00	4.70
2011	22.50	32.50	4.75
2012	23.00	33.00	4.85
2013	23.25	33.50	4.90
Thereafter	1.5%/yr	1.5%/yr	1.5%/yr

(1) GLJ's January 1, 2003 price forecast

(2) Edmonton Refinery Postings for 40° API, 0.3 per cent sulphur content crude

(3) AECO spot price

It is important to recognize the impact the pricing assumptions used by GLJ have on our NAV. The GLJ pricing assumptions are the most conservative of the forecasts used by the major Calgary based independent engineering evaluators. If we used the pricing assumptions used by one of the other major firms, our NAV discounted at 10 per cent would be approximately $9.75 per unit while using forward curve pricing available in the commodities market at December 31, 2002 would yield a NAV of approximately $10.30 per unit.

Reserves Summary and Reserve Life Index

	2002	2001	2000	1999	1998
CRUDE OIL					
Proved producing (mbbl)	**70,374**	68,408	46,075	32,454	20,090
Proved non-producing (mbbl)	**15,390**	14,287	12,438	7,541	2,677
Total proved (mbbl)	**85,764**	82,695	58,513	39,995	22,767
Proved reserve life index (years)	**11.3**	11.2	12.3	12.1	12.1
Established (mbbl)	**105,141**	102,632	71,663	50,245	27,896
Established reserve life index (years)	**13.5**	13.5	14.7	14.8	14.8
NATURAL GAS LIQUIDS					
Proved producing (mbbl)	**8,863**	8,823	8,175	7,774	6,066
Proved non-producing (mbbl)	**1,640**	1,139	1,137	389	475
Total proved (mbbl)	**10,503**	9,962	9,311	8,163	6,542
Proved reserve life index (years)	**9.0**	8.3	8.6	8.1	8.7
Established (mbbl)	**12,100**	11,611	10,753	9,467	7,138
Established reserve life index (years)	**10.1**	9.5	9.7	9.2	9.5
NATURAL GAS					
Proved producing (bcf)	**296.6**	279.5	202.4	184.2	83.9
Proved non-producing (bcf)	**59.6**	51.0	41.3	19.7	19.7
Total proved (bcf)	**356.2**	330.5	243.7	203.9	103.6
Proved reserve life index (years)	**9.0**	8.5	8.8	7.4	7.2
Established (bcf)	**408.8**	385.5	286.4	241	121.9
Established reserve life index (years)	**10.1**	9.6	10.0	9.0	8.5
OIL EQUIVALENT					
Proved producing (mboe)	**128,664**	123,810	87,987	70,928	40,139
Proved non-producing (mboe)	**26,976**	23,929	20,450	11,213	6,435
Total proved (mboe)	**155,640**	147,739	108,437	82,141	46,576
Proved reserve life index (years)	**10.1**	9.8	10.4	10.1	10.0
Established (mboe)	**185,371**	178,496	130,147	99,879	55,351
Established reserve life index (years)	**11.8**	11.5	12.1	12.0	11.9

Reserve life index is calculated using independent evaluator’s forecast of first year’s production

Established = proved plus 50 per cent probable

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	35,166	6,015
Acquisitions and divestments	7,961	1,552	38.8	10.3	1,104	232	15,532	3,501
Drilling and development	176	13	4.7	0.3	49	5	1,008	68
Production	(1,334)	–	(14.0)	–	(704)	–	(4,371)	–
Revisions	1,416	224	(2.3)	(1.6)	(677)	(158)	355	(201)
RESERVES AT DECEMBER 31, 1997	18,948	5,207	127.7	20.5	7,459	759	47,690	9,383
Acquisitions and divestments	2,465	648	(15.1)	(2.7)	(195)	(36)	(247)	162
Drilling and development	981	844	4.0	1.2	7	(104)	1,655	940
Production	(1,620)	–	(13.8)	–	(737)	–	(4,657)	–
Revisions	1,993	(1,570)	0.8	(0.6)	8	(23)	2,134	(1,693)
RESERVES AT DECEMBER 31, 1998	22,767	5,129	103.6	18.4	6,542	596	46,576	8,792
Acquisitions and divestments	17,769	4,286	118.0	15.4	3,375	476	40,817	7,320
Drilling and development	1,992	631	5.8	1.7	204	1	3,168	912
Production	(3,069)	–	(24.3)	–	(981)	–	(8,100)	–
Revisions	536	204	0.7	1.7	(977)	232	(320)	713
RESERVES AT DECEMBER 31, 1999	39,995	10,250	203.9	37.1	8,163	1,304	82,141	17,737
Acquisitions and divestments	18,650	3,860	47.7	8.0	1,911	328	28,517	5,527
Drilling and development	2,283	(693)	12.9	1.3	119	(25)	4,556	(497)
Production	(4,219)	–	(28.2)	–	(1,085)	–	(10,012)	–
Revisions	1,805	(268)	7.4	(3.8)	203	(166)	3,235	(1,057)
RESERVES AT DECEMBER 31, 2000	58,513	13,149	243.7	42.7	9,311	1,442	108,437	21,710
Acquisitions and divestments	27,932	7,124	101.9	11.1	1,643	241	46,551	9,211
Drilling and development	2,641	275	12.7	3.1	437	81	5,191	865
Production	(7,449)	–	(42.0)	–	(1,282)	–	(15,736)	–
Revisions	1,057	(610)	14.3	(1.8)	(148)	(117)	3,295	(1,029)
RESERVES AT DECEMBER 31, 2001	82,695	19,937	330.5	55.0	9,962	1,649	147,739	30,757
Acquisitions and divestments	5,270	729	36.6	2.0	574	(32)	11,944	1,027
Drilling and development	1,574	224	8.4	1.8	129	28	3,097	545
Production	(7,539)	–	(40.1)	–	(1,270)	–	(15,485)	–
Revisions	3,764	(1,513)	20.8	(6.2)	1,108	(48)	8,345	(2,598)
RESERVES AT DECEMBER 31, 2002	**85,764**	**19,377**	**356.2**	**52.6**	**10,503**	**1,597**	**155,640**	**29,731**

Kevin Jones, Superintendent S.E. Alberta & S.W. Saskatchewan

Left to right: Myron Stadnyk, V.P., Operations; Erwin Sison, Operations; Janie-Rae Hourie, Operations; Jody Wilson, Operations

Environment, Health and Safety

ARC is committed to being a leader in safety management, care and protection of the environment and strives to operate in a socially responsible manner with respect for our employees and the communities that we work and live in.

ARC endeavors to protect the health and safety of its employees, contractors and the public. We develop and implement training programs to enhance health and safety awareness for both employees and contractors. All of our employees clearly understand our goal to have the highest standard in our health and safety practices. We will not compromise our safety standards to achieve other corporate goals.

ARC places a high value on community development and encourages its employees to contribute to the communities in which they live and work. Our goal is to build relationships with industry partners, government and our communities based on mutual trust, transparency and respect.

WE WILL NOT COMPROMISE OUR SAFETY STANDARDS TO ACHIEVE OTHER CORPORATE GOALS.

Safety

In 2002 ARC adopted SAFETY 2000 as its standard for safety training for all our field staff. This course enables our field employees to obtain 16 different certifications over a five-day training period. This exceeds industry recommendations. We conduct emergency response exercises to ensure a high level of response capability from our staff under challenging situations.

ARC maintained its safety record of zero lost time accidents for employees or contract operators directly employed by ARC for the seventh year in a row. ARC also expects a high standard of safety performance from third party contractors, which includes a requirement that these contractors have their own approved safety program. ARC's performance on third party contractor incidents has been 50 per cent better than the most recent Canadian Association of Petroleum Producers ("CAPP") industry benchmarking. ARC strives to achieve its goal of safety for all contractors and employees; therefore, it is with profound regret that we report that a company providing certain technical services to ARC had a fatality on an ARC lease site in Drayton Valley in November 2001. As a result of this incident, ARC is involved in ongoing proceedings that will continue into 2003.

ARC maintains its standards through an internal auditing system. We do self-audits and also perform annual audits on a chosen group of vendors from each business unit. It is important to us that our vendors and contractors have proper safety records and programs in place. In 2003, ARC plans to hire the services of an external expert to perform detailed evaluations of our safety program to look for improvements to our systems and procedures. Also for 2003, ARC is planning awareness programs ensuring technical safety is a primary focus.

Air Quality

ARC recognizes the importance of air quality and consistently looks for improvement in this area. We seek innovative methods to reduce our power consumption, eliminate flaring and venting, and to lessen the impact of our operations on the environment.

We participate in the CAPP Stewardship Program. CAPP defines stewardship as "analysis, planning, implementation, measurement and review of social, environmental and economic performance." CAPP has recognized ARC at the Gold Stewardship level in this area. In 2003, it is our goal to apply for membership in "Partnerships in Health and Safety" and become a CAPP Stewardship Platinum member.

vcr-mvr inc. Gold™ Champion Level Reporter

CAPP Stewardship Initiative

Climate Change

In 2002, ARC filed its third annual report to Canada's Climate Change Voluntary Challenge and Registry (VCR) program. This report provides annual updates on our progress in managing our greenhouse gas (GHG) emissions. We received a "Gold Champion Level Reporter" award for the 2001 reporting year. In the 2001 reporting year, we reduced our GHG emissions by over 24,000 tonnes CO2E (10 per cent of our 2001 CO2E emissions) and we reduced gas flaring by 10 per cent. In early 2002, we commissioned a major gas conservation project at Lougheed, Saskatchewan. This benefit will be realized in the 2002 reporting year, but more importantly, will improve the air quality in this area of Saskatchewan.

Protecting Land and Water

ARC minimizes our current and long-term impact on land use by maintaining pro-active preventative measures and, if necessary, implementing effective remediation programs.

A key focus in land and water protection is minimizing pipeline breaks and spills. By assessing pipeline integrity, installing liners into existing pipelines or building new pipelines, ARC has reduced pipeline leak frequency. In order to ensure that we are prepared for a potential spill, ARC actively participates in mock spill exercises sponsored by the Oil Spill Co-operatives and has representatives on the spill co-operative in all of its operating areas. ARC also has emergency response plans for all areas. Storage tanks and storage areas are routinely inspected to ensure that integrity is proven and no adverse impacts occur.

When oil and gas wells are no longer productive, they are suspended and considered for abandonment. When abandoning a well, we must follow strict regulations for cementing the wellbore, removing all surface facilities, and reclaiming the land back to its original state. By removing wells and facilities from our inventory, we reduce our overall liability.

Whenever possible, we send any contaminated soils obtained during reclamation to a licensed facility for treatment and subsequent return to the native area. This is an effective way to manage contaminated soils rather than simply sending them to a landfill where the problem will have to be dealt with at a later date. In some cases, treatment is not an option and licensed landfills must be utilized.

In conducting its operations, ARC undertakes initiatives to ensure impacts are negligible. We have a minimal disturbance policy in our drilling and construction activity in southeastern Alberta. Land clearing activity for roads and leases is kept to a minimum to ensure that native prairie is maintained.

In northern Alberta, ARC avoids drilling in sensitive wildlife corridors, where possible. This protects wildlife from external influences. In addition, we also drill numerous wells from "pad" locations. This means drilling two to five wells from a single surface location. For example, if we were to drill five separate wells, they would occupy 15 hectares of land. A drilling pad would have five wells on three hectares of land. This minimizes disturbance and ensures preservation and sustainability of the environment.

Reclamation Fund

In 1996, ARC established a reclamation fund to ensure that required funds were available for future reclamation of wells and facilities once they have reached the end of their economic life. ARC contributed $4.8 million cash and interest income to the fund during 2002 and withdrew approximately $2.0 million, which was spent on reclamation activities. Future contributions are set at approximately $4.0 million per year. At December 31, 2002 the fund had a balance of $12.9 million.

Supporting Communities

ARC places high value on community participation and encourages employees to contribute to the communities in which they live and work. Communities in which ARC operates all derive benefits from direct employment. ARC employs over 100 permanent staff and contractors throughout western Canada and an additional 125 employees in Calgary. ARC encourages staff to contribute to their communities through volunteerism. ARC in turn contributes financially to those causes that are important to our employees. ARC also directs funds to organizations within each of the areas that ARC operates in with support going toward environmental programs, education, health and community services, and Canadian amateur sports. Additionally, ARC's support of the United Way topped $207,748 in 2002 in combined corporate and employee contributions.

Management's Discussion and Analysis

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Left to right: Dan Geremia, Treasurer; Lloyd Martin, Tax Manager

Glossary of Abbreviations

API	American Petroleum Institute	mboe*	thousand barrels of oil equivalent
bbls	barrels	mcf	thousand cubic feet
bbls/d	barrels per day	mcf/d	thousand cubic feet per day
bcf	billion cubic feet	mmbbls	million barrels
boe*	barrels of oil equivalent	mmboe*	million barrels of oil equivalent
boe/d*	barrels of oil equivalent per day	mmbtu	million British Thermal Units
Capex	capital expenditures	mmcf	million cubic feet
FD&A costs	finding, development and acquisition costs	mmcf/d	million cubic feet per day
GAAP	generally accepted accounting principles	NAV	net asset value
G&A	general and administrative	NGL	natural gas liquids
GJ	gigajoule	NYMEX	New York Mercantile Exchange
mbbls	thousand barrels	RLI	reserve life index
		WTI	West Texas Intermediate

*6 mcf of gas = 1 barrel of oil

Forward Looking Statements

This disclosure contains certain forward looking estimates that involve substantial known and unknown risks and uncertainties, certain of which are beyond ARC's control, including: the impact of general economic conditions in Canada and the United States; industry conditions including changes in laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; increased competition, and the lack of availability of qualified personnel or management; fluctuations in commodity prices, foreign exchange or interest rates; stock market volatility and obtaining required approvals of regulatory authorities. In addition there are numerous risks and uncertainties associated with oil and gas operations and the evaluation of oil and gas reserves. Therefore ARC's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking estimates and if such actual results, performance or achievements transpire or occur, or if any of them do so, there can be no certainty as to what benefits ARC will derive therefrom.

2002 Highlights

CDN$ millions, except per share and volume data	2002	2001
Cash flow from operations [1]	**$ 224**	$ 260
Cash flow from operations per unit	**$ 1.87**	$ 2.55
Net income	**$ 68**	$ 138
Net income prior to non recurring items [2]	**$ 94**	$ 138
Distributions per Unit	**$ 1.56**	$ 2.31
Daily production (boe/d)	**42,425**	43,111

(1) Before changes in non-cash working capital

(2) Prior to a one-time charge related to the internalization of the management contract

Strong crude oil prices, moderate natural gas prices and excellent drilling results combined to generate superior financial and operating results during 2002. Even with a 23 per cent decline in natural gas and natural gas liquids prices in 2002, cash flow from operations was $224 million with $68 million of earnings generated. The year-over-year decline in cash flow of $36 million was primarily caused by weaker gas prices offset in part by the Trust's hedging activities which resulted in a hedging gain on natural gas production of $0.55/mcf in 2002 compared with a gain of $0.22/mcf in 2001. The Trust also experienced higher operating costs on its non-operated properties, as discussed in the Netbacks section of this report, but benefited from declining interest rates resulting in a $5.0 million decrease in interest expense.

Net income was impacted by all the same factors as cash flow plus the one-time non-cash expense of $25.9 million for the internalization of the management contract that took place in the third quarter of 2002. Other non-cash expenses were relatively consistent from 2001 to 2002.

A capital investment program of $207 million added reserves at an attractive rate of $9.27/boe. Oil and gas production rates declined 1.6 per cent with production additions offsetting natural production declines.

In 2002, ARC took advantage of a significant number of acquisition opportunities in core areas for longer-term growth by purchasing reserves with substantial development drilling upside. The initial development drilling program on newly acquired lands was very successful, resulting in production additions in late 2002. ARC's strategy focused on development of the significant inventory of internally generated development drilling prospects, which will continue to provide a low-risk, stable source of longer-term growth.

ARC takes a very disciplined approach to making acquisitions to ensure accretion to the existing asset base for unitholders. Net acquisitions of $119 million were concentrated in the Trust's five core operating areas increasing production by 4,100 boe per day and reserves by 13.0 mmboe for an average cost of approximately $29,000 per producing boe per day and $9.18/boe of established reserves.

Production

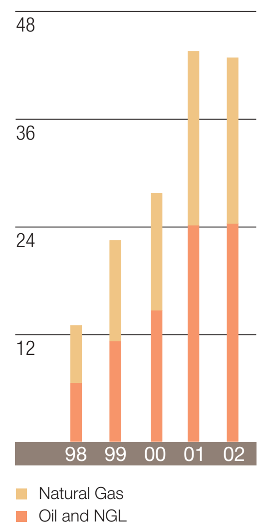
Production volumes for 2002 averaged 42,425 boe per day, representing a modest decrease of 1.6 per cent from the 2001 average of 43,111 boe per day. The Trust's 2002 production portfolio was weighted 49 per cent oil, 43 per cent natural gas and 8 per cent natural gas liquids on a per boe basis.

In 2002, 56 properties located within the Trust's five core areas, accounted for 90 per cent of the Trust's production with no one property accounting for more than seven per cent of total production. This diversification of production enhances the Trust's ability to predict on-going production levels, cash flows from operations and cash distributions.

	2002	2001
Crude oil (bbl/d)	**20,655**	20,408
Natural gas liquids (bbl/d)	**3,479**	3,511
Natural gas (mcf/d)	**109,745**	115,150
TOTAL PRODUCTION (boe/d)	**42,425**	43,111
Crude oil and natural gas liquids	**57%**	55%
Natural gas [(1)]	**43%**	45%
TOTAL PRODUCTION	**100%**	100%

(1) converted to boe on a 6:1 basis

PRODUCTION
(mboe/d)



Marketing and Prices

Crude Oil Pricing

West Texas Intermediate at Cushing, Oklahoma (WTI) is the benchmark for North American oil prices. The WTI oil price averaged US$26.10/bbl in 2002, up slightly from US$25.93/bbl in 2001. Canadian crude oil prices are based upon refiners' postings, primarily at Edmonton, Alberta and represent the WTI price, adjusted for transportation and quality differentials and the Canadian/U.S. exchange rate. ARC's average field price reflects the refiners' posted price at Edmonton, Alberta less deductions for transportation from the field and adjustments for ARC's product quality relative to the posted price. ARC's average field price in 2002 was $35.27/bbl ($33.00/bbl in 2001) compared to $39.71/bbl ($39.29/bbl in 2001) for the average of the light sweet postings at Edmonton. This discount to the average Edmonton posted price reflects the high quality of ARC's crude oil mix, which is comprised of 60 per cent light sweet (greater than 35º API) crude, 30 per cent medium gravity and 10 per cent heavy gravity oil (less than 23º API). ARC's average oil price, net of all hedging transactions, in 2002 was $31.63/bbl, very comparable to the 2001 average of $31.70/bbl. Crude oil is sold under 30 day evergreen contracts while natural gas liquids are sold under annual arrangements.

Natural Gas Pricing

U.S. natural gas prices are typically referenced off NYMEX at Henry Hub, Louisiana, while Alberta and British Columbia natural gas prices are referenced off of the AECO Hub in Alberta and the Sumas Hub in Washington, respectively.

Natural gas prices fluctuated in 2002 with prices under $2.00/mcf in July to in excess of $6.50/mcf in December. ARC's average wellhead gas price, prior to hedging transactions, decreased by 30 per cent to $3.86/mcf in 2002 from $5.50/mcf in 2001. ARC's prices, including hedging gains, were $4.41/mcf in 2002 and $5.72/mcf in 2001. AECO Hub prices were $4.08/mcf and $6.28/mcf for 2002 and 2001, respectively.

Hedging

The Trust's hedging activities are conducted by an internal Risk Management Committee, which has the following objectives as its mandate:

- Protect Unitholder return on investment
- Stabilize monthly distributions
- Employ a portfolio approach to hedging by entering into a number of small positions that build upon each other
- Participate in commodity price upturns to the greatest extent possible, while limiting exposure to price downturns
- Ensure profitability of specific oil and gas properties that are more sensitive to changes in market conditions

The 2002 prices included a hedging gain of $0.55/mcf for natural gas and a loss of $3.64/bbl for oil; 2001 prices included a hedging gain of $0.22/mcf for natural gas and a loss of $1.30/bbl for oil.

At January 1, 2003, ARC has hedged approximately 50 per cent of oil production volumes at an average price of approximately US$26.00/bbl and 30 per cent of natural gas production volumes utilizing a variety of contracts at an average price of approximately $5.30/mcf. The Trust's Risk Management Committee is authorized by the Board of Directors of ARC Resources Ltd. ("ARC Resources" or "ARL") to hedge up to 50 per cent of the Trust's production on a boe basis for a period of up to 12 months, and up to 25 per cent of the Trust's production for the next consecutive 12 month period. The Trust's hedging activities secured prices at a level sufficient enough to allow the Trust to increase first quarter 2003 distributions to $0.15 per unit per month.

Revenue

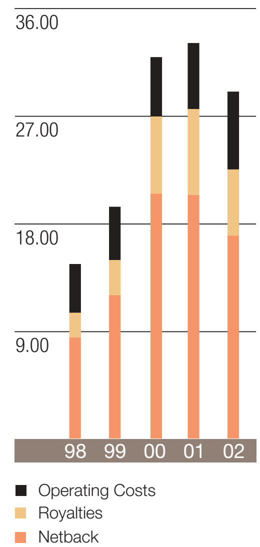
Revenue, prior to hedging transactions, decreased to $451.9 million in 2002 compared with $516.6 million in 2001. The decrease was primarily due to lower natural gas prices and a minor decline in total production volumes. Hedging losses of $7.0 million in 2002 and $1.0 million in 2001 resulted in production revenue net of hedging losses of $444.8 million in 2002 and $515.6 million in 2001.

Netbacks

A 2002 operating netback of $16.78/boe compared with $20.15/boe in 2001, reflected the 23 per cent decline in natural gas and natural gas liquids prices and higher operating costs in 2002. Operating costs, net of processing income, increased to $6.45/boe in 2002 up from $5.47/boe in 2001. This increase can primarily be attributed to higher costs on the Trust's non-operated properties as those operators performed maintenance and conducted turnarounds which increased operating costs and temporarily reduced volumes resulting in higher operating costs per boe. The components of operating netbacks are shown below:

NETBACK ($/boe)	**2002**	2001
Market price	**29.19**	32.82
Cash hedging (loss)	**(0.61)**	(1.26)
Non-cash hedging gain	**0.15**	1.20
Selling price	**28.73**	32.76
Royalties	**(5.50)**	(7.14)
Operating costs	**(6.45)**	(5.47)
Netback	**16.78**	20.15

AVERAGE SELLING PRICE
($/boe)



Recycle Ratio

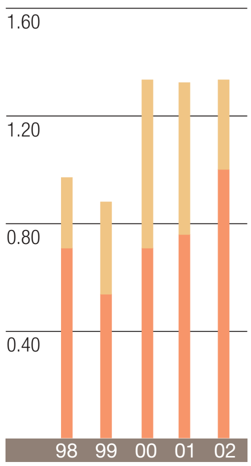
A key indicator of profitability in the oil and gas sector is the recycle ratio, which is defined as the operating netback divided by the three-year average finding, development and acquisition costs ("FD&A"). ARC's recycle ratio continues to be one of the highest in the industry.

RECYCLE RATIO	**2002**	2001
Netback ($/boe)	**16.78**	20.15
Three-year average FD&A ($/boe)	**8.21**	6.94
Recycle ratio	**2.0**	2.9
Inception-to-date FD&A ($/boe)	**6.59**	6.32
Recycle ratio	**2.5**	3.2

General and Administrative Expenses

General and administrative ("G&A") expenses, net of overhead recoveries on operated properties, increased in 2002 to $15.4 million ($0.99/boe) from $11.8 million ($0.75/boe) in 2001. The increase in G&A was due primarily to hiring additional staff and changes to ARC's employee benefits program. This results in a more complete staff complement to provide for the Trust's future growth. The Trust's G&A costs per boe are continuously monitored internally by management and are benchmarked against other comparable sized Trusts. The Trust did not capitalize any G&A in 2002 or 2001.

G&A AND MANAGEMENT FEES
($/boe)



Management Fees
G&A Expenses

Internalization of Management Contract

On August 29, 2002, the Trust eliminated the external management contract and related fees through the purchase of ARC Resources Management Ltd. ("ARML" or the "Manager").

Two assets were acquired in this transaction; a future cash flow equal to three per cent of net operating income, and the direct hiring of existing management and approximately 135 employees of the Manager. ARC has accounted for this transaction by capitalizing the amount that relates to the three per cent of net operating income (based upon an independent reserve evaluation) of ARC's established reserves on a produce-out basis over the remaining five year term of the management contract, and retention bonuses to be paid out over the next five years to senior management. The remainder, which was expensed, consists of the purchase of the three per cent revenue stream over and above the existing established reserves for the next five years and future acquisition and disposition fees.

The purchase price includes an obligation to pay $5.0 million of future retention bonuses to senior management. The bonuses will be paid out in equal amounts over a five year period if the officer stays employed by the Trust. In the event of a departure of any officer, future bonus payments will be forfeited to the benefit of the Trust. The $1.0 million current portion of the bonus is included in accounts payable and accrued liabilities. The remaining $4.0 million has been set up as a long-term liability.

The total purchase price of $55.9 million was paid for with cash, exchangeable shares and trust units. The exchangeable shares and trust units are subject to escrow and forfeiture provisions for most of the shareholders of ARML. The provisions were put in place to ensure management and staff remain employees of ARC and continue to add value for the Trust and its unitholders (see note 5 to the Financial Statements for additional information).

The Manager received a management fee of three per cent of net operating income, which amounted to $5.2 million or $0.33 per boe for the period ended August 29, 2002 compared with $8.8 million or $0.56 per boe for the year ended December 31, 2001.

Interest Expense

Interest expense decreased to $12.6 million in 2002 from $17.1 million in 2001 as a result of a lower monthly average debt balance and lower interest rates. Long-term debt was reduced in May with net proceeds of $114.5 million from the issue of 10.0 million trust units. Interest expense was minimized over the course of the year by financing debt through the issuance of lower cost bankers' acceptances as opposed to borrowing at the prevailing bank prime interest rates.

Foreign Currency Gains and Losses

ARC has $65 million in U.S. denominated long-term debt that is subject to changes in the Canadian/U.S. dollar exchange rate. The unrealized gains and losses associated with the fluctuations in the exchange rate are now recorded in income based upon change in foreign exchange rates between reporting periods (see note 3 to the Financial Statements for additional information).

Prior to 2002, unrealized foreign exchange gains and losses were deferred and amortized over the life of the debt. A new accounting policy effective January 1, 2002 required that such unrealized gains and losses be recorded in income in the period in which they relate rather than be deferred and amortized. As a result of this change in accounting policy, certain 2001 amounts have been restated to reflect the impact of the new accounting policy which was applied retroactively.

In 2002, ARC recorded a foreign exchange gain of $607,000 compared to a loss of $3,297,000 in 2001.

Taxes

Capital taxes paid or payable by ARC, based on debt and equity levels at the end of the year, amounted to $1.4 million in 2002 versus $1.8 million in 2001.

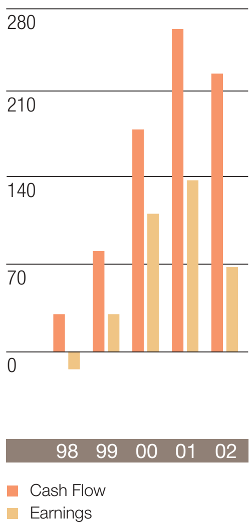
As a result of the Startech acquisition in 2001, a future income tax liability of $203 million was recorded on the balance sheet in accordance with Canadian Generally Accepted Accounting Principles ("Canadian GAAP" or "GAAP"). This liability was initially recorded by multiplying the corporate tax rate of approximately 44 per cent by the difference between the purchase price of the Startech assets and the amount of tax pools at the date of the acquisition. In the Trust's structure, payments are made between ARC Resources and the Trust transferring both income and future tax liability from ARC Resources to the individual unitholders. Therefore, it is the opinion of management that no cash income taxes will be paid by ARC Resources in the future and, as such, the future income tax liability recorded on the balance sheet will be recovered through earnings over time. Future income tax recoveries of $30 million in 2002 and $29 million in 2001 have resulted in a remaining future income tax liability of $144 million at December 31, 2002. In 2002, the tax recovery was $1.91/boe ($1.83/boe in 2001) for an effective net depletion, depreciation and amortization rate ("DD&A") of $8.54/boe ($8.66/boe in 2001).

At year-end 2002, the Trust had approximately $765 million ($657.4 million in 2001) in income tax pools, which will be utilized to reduce the taxable portion of future cash distributions. In addition, ARC Resources had approximately $210 million ($203.6 million in 2001) of income tax pools as at December 31, 2002, which will be utilized to minimize, and potentially eliminate, future corporate income taxes.

Depletion, Depreciation and Future Site Reclamation Expenses

The 2002 depletion, depreciation and amortization (DD&A) rate decreased slightly to $10.45/boe from $10.49/boe in 2001. The DD&A rate includes a provision for future site reclamation and abandonment of $0.69/boe in 2002 compared with $0.59/boe in 2001. The decrease in the DD&A rate in 2002 reflects the impact of 2002 drilling results and the positive year-over-year reserve revisions as determined by the Trust's independent oil and gas reserves evaluators. Assets to be depleted were increased by future development costs of $190.1 million and reduced by $12.6 million for the estimated future net realizable value of production equipment and $19.7 million for the value of unproven properties.

CASH FLOW AND EARNINGS
($ millions)



Capital Expenditures

Total capital expenditures, including acquisitions, aggregated $207 million in 2002 ($625 million in 2001). Of the total, $88 million was incurred on development drilling, geological, geophysical and facilities expenditures as ARC continues to develop its asset base, and $119 million of net acquisitions. Total reserve acquisition and development costs for 2002 were $9.27/boe compared with $9.75/boe in 2001. A breakdown of capital expenditures by category is shown below:

	2002	2001
CAPITAL EXPENDITURES ($ thousands)		
Geological and geophysical	**1,966**	2,215
Development drilling	**70,074**	73,147
Plant and facilities	**14,357**	22,970
Other capital	**1,881**	3,886
Producing property net acquisitions (1)	**119,113**	522,659
Total capital expenditures	**207,391**	624,877
ESTABLISHED RESERVES (mboe)		
Net change in established reserves after production	**6,875**	48,344
Annual production	**15,485**	15,736
Annual established reserve additions	**22,360**	64,080
FINDING, DEVELOPMENT AND ACQUISITION COSTS (2) ($/boe):		
Current year	**9.27**	9.75
Three-year rolling average	**8.21**	6.94
Cumulative since inception	**6.59**	6.32

(1) value is net of post-closing adjustments

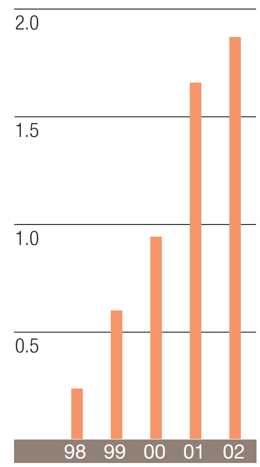
(2) finding, development and acquisition costs ("FD&A") based on established reserves

The Board of Directors of ARC Resources has approved a capital budget for 2003 of $115 million. This budget ranks individual projects to allow for revisions during the year in the event the Trust acquires additional properties with associated development opportunities, or there is a change in the business environment which may result in the acceleration or delay of certain expenditures.

Abandonments

ARC takes a proactive approach to environmental issues and abandonments and reclamation of associated well and facility sites as required. ARC annually carries out a program to abandon and reclaim wells and facilities which have reached the end of their economic lives. ARC has established a reclamation fund into which $4.8 million cash and interest income was contributed during the year ($4.1 million in 2001). During 2002, $3.0 million of actual abandonment costs were incurred of which $2.0 million was funded out of the reclamation fund balance. At December 31, 2002 there was a fund balance of $12.9 million. This fund, invested in money market instruments, is established to provide for future abandonment liabilities. Future contributions are currently set at approximately $4.0 million per year in order to provide for the total estimated future abandonment and site reclamation costs. ARC has been active in improving the quality of its oil and gas reserve base by purchasing properties and then selling, smaller, lower quality reserves which tend to have a shorter reserve life and therefore a shorter time period to the eventual abandonment of the property. This practice will continue in the future in order to mitigate actual future abandonment costs.

TOTAL CAPITALIZATION
($ billions)



Capitalization and Financial Resources

As at December 31, 2002 the Trust had a working capital deficiency of $10.1 million compared to a working capital balance of $5.8 million as at December 31, 2001. The 2002 year end working capital deficit is a result of normal operating conditions in periods when the Trust incurs significant capital expenditures. ARC participated in significant capital expenditures near the end of the year resulting in accrued capital expenditures of $21.6 million at December 31, 2002.

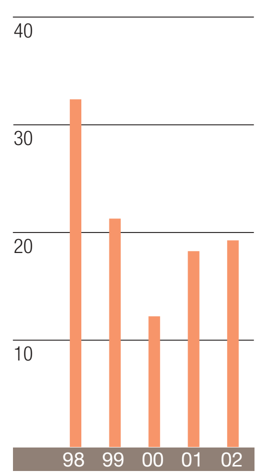
Total debt outstanding at December 31, 2002 was $338 million, which includes bank debt of $235 million and US$65 million (CDN$102.7 million) of Senior Secured Notes. ARC's oil and gas properties secure the debt. The Trust's debt increased by $71 million on December 23, 2002 with the closing of the acquisition of properties in the Ante Creek and Brown Creek areas, resulting in the available line of credit as at December 31, 2002 being reduced to $62 million with total available credit lines of $400 million. The Trust has proceeded with its annual credit review with its lenders with a view of increasing its credit lines from $400 million based upon the increase in the Trust's reserves from 178 mmboe to 185 mmboe.

The Trust's lending facilities consist of bilateral agreements with four Canadian chartered banks and one U.S. insurance company. In 2002, the Trust borrowed an additional US$30 million in senior secured notes at a 4.94 per cent interest rate with an eight year term (six year average life) increasing the total U.S. denominated debt of the Trust to US$65 million. As the Trust's major revenue stream is tied to the value of oil in the United States, the Trust has chosen to borrow approximately one-third of its debt in U.S. dollars. Similarly, the Trust now has one-third of its debt locked in at fixed interest rates averaging 6.6 per cent and the remaining two-thirds floating based upon Canadian banker's acceptance rates plus a bank stamping fee.

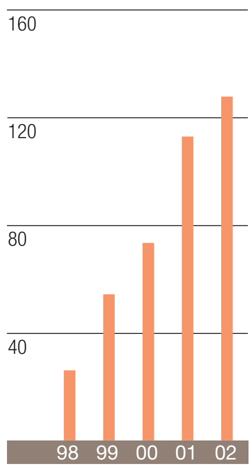
The Trust's current plans are to finance the approved 2003 capital budget of $115 million with a combination of cash flow, debt and equity by issuing units from treasury.

End-of-year 2002 net debt to total capitalization was 18.8 per cent (17.6 per cent in 2001) and debt to cash flow payout was approximately 1.6 years (1.1 years in 2001) based upon cash flow from operations of $224 million and net debt of $348 million.

NET DEBT AS A PERCENTAGE OF TOTAL CAPITALIZATION
(%)



UNITS OUTSTANDING AT YEAR END*
(millions)



*includes units issuable for exchangeable shares

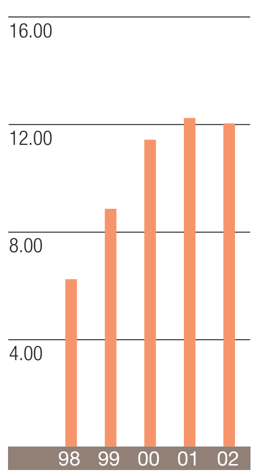
($ thousands except per unit and per cent amounts)	2002	2001
Bank debt	**337,728**	294,489
Less: Working capital (deficiency)	**(10,067)**	5,805
Net debt obligations	**347,795**	288,694
Units outstanding and issuable for exchangeable shares (thousands)	**126,444**	111,693
Market price at end of period	**$11.90**	$12.10
ARC market capitalization	**1,504,684**	1,351,485
Total capitalization	**1,852,479**	1,640,169
Net debt as a percentage of total capitalization	**18.8%**	17.6%
Net debt obligations	**347,795**	288,694
Cash flow	**223,969**	260,270
Net debt to cash flow	**1.6**	1.1

Currently several Canadian conventional oil and gas trusts have obtained stock exchange listings in the United States in order to make their trust units more accessible to U.S. investors. We are monitoring this situation and at this time have chosen not to pursue a U.S. listing. The Trust is a reporting company with the Securities and Exchange Commission ("SEC") in the United States and electronically files its financial statements and other disclosures as required with the SEC for the benefit of current and potential unitholders residing in the United States.

Unitholders' Equity

ARC's total capitalization increased 12 per cent to $1.9 billion during 2002 with the market value of trust units representing 81 per cent of total capitalization. During 2002, the market price of the Trust units traded in a fairly narrow range of $11.11 to $13.29 with an average daily trading volume of 305,000 units per day.

UNIT MARKET PRICE
($/unit at December 31)



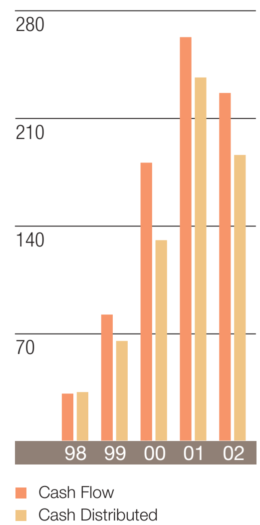
In May 2002, ARC completed an equity financing which raised $120.5 million of gross proceeds ($114.3 million net) on the issuance of 10.0 million trust units at $12.05 per trust unit. The proceeds were used to reduce existing debt levels on an interim basis and to partially fund 2001 and 2002 capital expenditures.

In conjunction with the Startech acquisition which occurred in January of 2001, ARC Resources issued Exchangeable Shares ("ARL Exchangeable Shares") which were listed on the TSX under the symbol "ARX". The Exchangeable Shares can be converted, at the option of the shareholder, into trust units. The number of trust units issuable upon conversion is based on the exchange ratio in effect at the conversion date. The exchange ratio is calculated monthly based on the cash distribution paid divided by the ten day weighted average price preceding the record date. The Exchangeable Shares are not eligible for monthly cash distributions. As at December 31, 2002, there were 637,167 ARL Exchangeable Shares outstanding (914,775 in 2001) at an exchange ratio of 1.3135. In addition, a new series of Exchangeable Shares (ARML Exchangeable Shares) were issued by a subsidiary of the Trust in conjunction with the purchase of the Manager and internalization of the management contract on August 29, 2002. The new series of Exchangeable Shares are not publicly traded. As at December 31, 2002, 2,206,409 ARML Exchangeable Shares were outstanding with a year-end exchange ratio of 1.04337.

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 an additional 242,496 trust units being issued in 2002 at an average price of $12.15 raising a total of $3.0 million. In 2001, 57,117 trust units were issued under the DRIP program at an average price of $11.38 per trust unit.

During 2002, as part of ARC's long-term incentive plan, 1,334,072 trust unit incentive rights (1,509,517 rights in 2001) were issued to office and field employees, long-term consultants and independent directors at prices ranging from $11.47 to $12.80 per trust unit ($10.49 to $12.70 in 2001). The exercise price of the rights is adjusted downward over time by the amount, if any, that annual distributions exceed 10 per cent of the net book value of property, plant and equipment. The rights have a five-year term and vest equally over three years from the date of grant. Rights to purchase 3,040,925 trust units at an average adjusted exercise price of $10.64 were outstanding at December 31, 2002. These rights have an average remaining contractual life of 3.6 years and expire at various dates to December 2007. Of the rights outstanding at December 31, 2002, 599,608 were exercisable at that time.

CASH AVAILABLE FOR DISTRIBUTION
($ millions)



Cash Distributions

Total cash distributions of $1.56 per trust unit were made in fiscal year 2002 ($2.31 in 2001) for total cumulative distributions since inception of $688.9 million ($10.64 per Trust unit). This distribution level was achieved after the deduction of $35.6 million (16 per cent of cash flow) to fund capital expenditures in accordance with ARC's distribution policy to withhold up to 20 per cent of cash flow, net of the reclamation fund contributions, to fund capital expenditures. The actual amount withheld is dependent on the commodity price environment and is at the discretion of the Board of Directors. This holdback policy differs among the conventional oil and gas trusts. ARC believes it is essential to focus on production replacement activities partially funded by cash flow in order to enhance long-term unitholder returns.

Monthly cash distributions for the first quarter of 2003 were set at $0.15 per trust unit subject to review based on commodity price fluctuations. Revisions, if any, to the monthly distribution are normally announced on a quarterly basis in the context of prevailing and anticipated commodity prices at that time. During periods of volatile commodity prices, the Trust may vary the distribution rate monthly. Any differences between cash available for distribution and actual cash distributions in any quarter are adjusted for in the ensuing quarter's monthly distribution.

Historical Distributions by Calendar Year

($)	Distributions	Taxable	Return of Capital
CALENDAR YEAR			
2003	0.13 (1)	0.08 (1)	0.05
2002	1.58	1.07 (2)	0.51 (2)
2001	2.41	1.64	0.77
2000	1.86	0.84	1.02
1999	1.25	0.26	0.99
1998	1.20	0.12	1.08
1997	1.40	0.31	1.09
1996	0.81	–	0.81
Cumulative	10.64	4.32	6.32

(1) based on estimated taxable portion of 60 to 70 per cent for 2003 distributions

(2) based on taxable portion of 68 per cent for 2002 distributions

Taxation of Cash Distributions

Cash distributions are comprised of a return of capital portion (tax deferred) and a return on capital portion (taxable). For cash distributions received by a Canadian resident, outside of a registered pension or retirement plan in the 2002 taxation year, the split between the two is 68 per cent taxable with the remaining 32 per cent being tax deferred. For a more detailed breakdown, please visit our website at **www.arcresources.com.**

For 2003, ARC estimates that 60 to 70 per cent of cash distributions may be taxable; 30 to 40 per cent may be return of capital and used to reduce a unitholder's cost base on trust units held. Actual taxable amounts will be dependent on commodity prices experienced throughout the year.

The exchangeable shares of ARC Resources Ltd. ("ARL"), a corporate subsidiary of the Trust, may provide a more tax-effective basis for investment in the Trust. The ARL exchangeable shares are traded on the TSX under the symbol "ARX" and are convertible into trust units, at the option of the shareholder, based on the current exchange ratio. The exchangeable shareholders are not eligible to receive monthly cash distributions, however the exchange ratio increases on a monthly basis by an amount equal to the current month's trust unit distribution divided by the 10 day weighted average trading price of the trust units at the end of each month. The gain realized as a result of the monthly increase in the exchange ratio is taxed as a capital gain rather than income and is therefore subject to a lower effective tax rate. Tax on the exchangeable shares is deferred until the exchangeable share is sold or converted into a trust unit.

2002 Distributions by Month

($)	Taxable Amount	Tax Deferred Amount (Return of Capital)	Total Distribution
PAYMENT DATE			
January 15, 2002	0.1020	0.0480	0.15
February 15, 2002	0.0884	0.0416	0.13
March 15, 2002	0.0884	0.0416	0.13
April 15, 2002	0.0884	0.0416	0.13
May 15, 2002	0.0884	0.0416	0.13
June 17, 2002	0.0884	0.0416	0.13
July 15, 2002	0.0884	0.0416	0.13
August 15, 2002	0.0884	0.0416	0.13
September 16, 2002	0.0884	0.0416	0.13
October 15, 2002	0.0884	0.0416	0.13
November 15, 2002	0.0884	0.0416	0.13
December 16, 2002	0.0884	0.0416	0.13
Total	1.0744	0.5056	1.58 (1)

(1) Total is based upon cash distributions paid during 2002

Assessment of Business Risks

The ARC management team is focused on long-term strategic planning and has identified the following items as risks and in certain cases opportunities associated with the Trust's business: (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/U.S. 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 to: (a) acquire mature production to reduce technical uncertainty; (b) acquire long life reserves to ensure more 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 with creditworthy counterparties; (h) maintain a hedging program to hedge commodity prices and foreign currency rates with creditworthy counterparties; (i) continuously retain 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.

Below is a table that shows sensitivities to pre-hedging cash flow with operational changes and changes to the business environment:

		Change to Cash Flow	
	Change	$000's	$/Unit
BUSINESS ENVIRONMENT			
Price per barrel of oil (US$ WTI)	$ 1.00	10,500	$ 0.08
Price per mcf of natural gas (CDN$ AECO)	$ 0.10	3,200	$ 0.02
US CDN exchange rate	$ 0.01	3,400	$ 0.02
Interest rate on debt	1.0%	2,500	$ 0.02
OPERATIONAL			
Oil production volume – 100 bbl/d	0.5%	800	$ 0.01
Gas production volumes – 1 mmcf/d	0.9%	1,400	$ 0.01
Operating expenses per $/boe	10.0%	8,900	$ 0.06
General & administrative expenses per boe	10.0%	1,500	$ 0.01

The Trust is continually evaluating potential acquisitions with all acquisitions in excess of $10 million subject to Board approval. The Trust's business plan could result in multiple acquisitions in one fiscal year. As the nature of acquisitions in the energy business is usually by a competitive bid process, we cannot predict whether or not the Trust will execute any acquisitions in the future. The Trust's scope of acquisitions being evaluated encompasses energy assets, including conventional oil and gas assets, oil sands interests, electricity or power generating assets and pipeline, gathering and transportation assets.

The management of the Trust has financed the purchase of conventional oil and gas assets in the past primarily by the issue of trust units and has ensured the Trust's financial ratios are comparable to other similar organizations. If the Trust acquired energy assets other than conventional oil and gas assets, it would review alternatives for financing such acquisitions which may result in a higher use of debt but with the view of having the Trust's debt to total capitalization being comparable to similar sized organizations with the similar mix of assets.

Management and Financial Reporting Systems

The Trust has continuously evolved and documented its management and internal reporting systems to provide assurance that accurate, timely internal and external information is communicated to users.

The Trust's financial and operating results incorporate certain estimates including:

a) estimated revenues, royalties and operating costs on production as at a specific reporting date but for which actual revenues and costs have not yet been received;

b) estimated capital expenditures on projects which are in progress; and

c) estimated depletion, depreciation and amortization and reported FD&A costs which are based on estimates of oil and gas reserves that the Trust expects to recover in the future.

The Trust has hired individuals and consultants who have the skill set to make such estimates and ensures individuals or departments with the most knowledge of the activity are responsible for the estimate. Further, past estimates are reviewed and compared to actual results in order to make more informed decisions on future estimates.

ARC's management team's mandate includes the ongoing development of procedures, standards and systems to allow ARC staff to make the best decisions possible and ensuring those decisions are in compliance with the Trust's environmental, health and safety policies.

Outlook

It is the Trust's objective to provide the highest possible long-term returns to unitholders by focusing on the key strategic objectives of the business plan. This focus has resulted in ARC Energy Trust achieving superior results since inception in July 1996, by providing unitholders with cash distributions of $10.64 per trust unit and capital appreciation of $1.90 per trust unit for a total return of $12.54 per trust unit.

The key future objectives of the business plan, which is reviewed with the Board of Directors, include:

- Annual reserve replacement;
- Ensuring acquisitions are strategic and enhance unitholder returns;
- Controlling costs – FD&A costs, operating costs and G&A expenses;
- Actively hedging a portion of the Trust's production to enhance long-term returns and stabilize distributions;
- Conservative utilization of debt;
- Continuously developing the expertise of our staff and hiring and retaining the best in the industry;
- Building business relationships so as to be viewed as fair and equitable in all business dealings;
- Promoting the use of proven and effective technologies;
- Being an industry leader in the environment, health and safety area; and
- Continuing to actively support local initiatives in the communities in which we operate and live.

In 2002, the Trust was successful in meeting or exceeding all of the above objectives and will continue to focus on and closely monitor these core objectives in 2003 and beyond.

BOARD GOVERNANCE COMMITTEE
Left to right: Mac Van Wielingen, Director; Frederic Coles, Director; Walter DeBoni, Director; John Beddome, Director

Corporate Governance

ARC Energy Trust is committed to the highest standards for its corporate governance practices and procedures. In 1995, the Toronto Stock Exchange (the "TSX") published a set of guidelines (the "Guidelines"), which were revised in 1999, relating to corporate governance. The Guidelines address such matters as the constitution and independence of boards of directors, the functions to be performed by boards and their committees, and the relationship among a corporation's board, management and shareholders.

The Board of Directors (the "Board") of ARC Resources Ltd. has developed systems and procedures that are aligned with the Guidelines and appropriate for the Trust and its business. Set out below is a selection of the highlights of the Trust's corporate governance practices that have been established by the terms of the Trust indenture and the Board. The complete text of the Trust's governance practices can be found in the management proxy circular.

ARC ENERGY TRUST IS COMMITTED TO THE HIGHEST STANDARDS FOR ITS CORPORATE GOVERNANCE PRACTICES AND PROCEDURES.

Mandate of the Board of ARC Resources Ltd.

The Board is responsible for the stewardship of ARC Resources Ltd., the other subsidiaries of the Trust and the Trust to the extent delegated to ARC Resources Ltd. under the Trust Indenture. In discharging its responsibility, the Board exercises the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances and acts honestly and in good faith with a view to the best interests of the Trust.

The Board's mandate includes: the review and approval of strategic operating, capital and financial plans; the identification of the principal risks of the Trust's business and oversight of the implementation of systems to manage such risks; the appointment and performance review of the Chief Executive Officer; the approval of communication policies for the Trust and the integrity of the Trust's internal financial controls and management systems.

Significant operational decisions and all decisions relating to: the acquisition and disposition of properties for a purchase price or proceeds in excess of $10 million; the approval of capital expenditure budgets; the establishment of credit facilities; the issue of Trust Units; and the determination of distributable income, are made by the Board.

The Board holds regularly scheduled meetings at least quarterly to review the business and affairs of ARC Resources Ltd. and the Trust. The Chairman of the Board is not a member of management and has a separate role from the President and Chief Executive officer of ARC Resources Ltd.

Board composition

The Board is presently comprised of seven members, all of whom are "unrelated" directors except for the Chief Executive Officer within the meaning of the current TSX Guidelines. As part of the management internalization transaction, ARC Resources Management Limited agreed to waive its right to select three of the seven directors on the Board of Directors of ARC Resources Ltd., and, accordingly, Unitholders will have the right to select all the members of the Board of Directors of ARC Resources commencing at the annual meeting of Unitholders to be held in 2003.

Committees

The Board of Directors has established an Audit Committee, a Reserve Audit Committee, a Compensation Committee, a Board Governance Committee and a Management Advisory Committee to assist it in the discharge of its duties. All the committees are comprised of unrelated directors and report to the Board of Directors of ARC Resources Ltd.

The Audit Committee is the committee to which the Board has delegated its responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for board of director approval, the audited financial statements and other mandatory disclosure releases containing financial information.

The mandate of the Board Governance Committee includes: reviewing on an ongoing basis the effectiveness of the Board and its committees; determining the proper size of the Board; undertaking periodic performance reviews of each Director; and, the recruitment of new Board members.

The Board has also established a Reserve Audit Committee to review the independence of the engineering firm performing the annual reserve audit and their final reserve report and a Compensation Committee to review compensation matters for the officers and employees of the Trust, including the Chief Executive Officer.

The Board formed the Management Advisory Committee following completion of the management internalization transaction. The mandate of the Management Advisory Committee is to provide executive leadership support and advice to management in various broad areas including: maintaining a long-term vision, assisting management in development and planning of strategies and work on issues relating to human resource development. The committee will also assist management in effecting major transactions and developing effective strategies for investor relations. The Chief Executive Officer attends all the meetings along with other members of the management who may be invited.

With a number of events being reported in the business sector in the past year with regards to ethical practices and reporting by corporations, many new proposals are under consideration by various governing bodies that deal with corporate disclosure. ARC intends to comply with all applicable regulations which are appropriate to the Trust, as set out by governing bodies, with a goal of providing transparency in our corporate governance practices.

FINANCIAL Statements

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2002

Left to right: Steve Sinclair, V.P., Finance & CFO; Van Dafoe, Accounting; Nicolle Cote, Accounting; Jay Billesberger, Information Technology; Ed Fong, Accounting; Charlene Bagu, Accounting

MANAGEMENT'S RESPONSIBILITY

Management is responsible for the preparation of the accompanying consolidated financial statements and for the consistency therewith of all other financial and operating data presented in this annual report. The consolidated financial statements have been prepared in accordance with the accounting policies detailed in the notes thereto. In Management's opinion, the consolidated financial statements are in accordance with Canadian 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.

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

John P. Dielwart

John P. Dielwart (signed)
President and Chief Executive Officer

Steven W. Sinclair

Steven W. Sinclair (signed)
Chief Financial Officer

Calgary, Alberta

January 27, 2003

AUDITORS' REPORT

To the Unitholders of ARC Energy Trust:

We have audited the consolidated balance sheets of ARC Energy Trust as at December 31, 2002 and 2001 and the consolidated statements of income and accumulated earnings and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2002 and 2001 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

Deloitte & Touche LLP (signed)
Chartered Accountants

Calgary, Alberta
January 27, 2003

CONSOLIDATED BALANCE SHEET

As at December 31

(CDN$ thousands)	**2002**	2001
ASSETS		
Current assets		
Cash	**$ 835**	$ 646
Accounts receivable	**49,631**	51,875
Prepaid expenses	**6,965**	6,030
	57,431	58,551
Reclamation fund (Note 7)	**12,924**	10,147
Property, plant and equipment (Note 8)	**1,397,563**	1,311,306
Total assets	**$ 1,467,918**	$ 1,380,004
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	**$ 51,454**	$ 35,595
Cash distributions payable	**16,044**	16,594
Payable to the Manager (Notes 5 and 16)	**–**	557
	67,498	52,746
Long-term debt (Note 9)	**337,728**	294,489
Site reclamation and abandonment	**36,421**	28,837
Commodity and foreign currency contracts (Notes 6 and 10)	**9,210**	13,107
Retention bonuses (Note 5)	**4,000**	–
Future income taxes (Note 15)	**144,395**	174,030
Total liabilities	**599,252**	563,209
UNITHOLDERS' EQUITY		
Unitholders' capital (Note 11)	**1,172,199**	1,029,538
Exchangeable shares (Note 12)	**35,326**	10,392
Accumulated earnings (Note 3)	**350,088**	282,195
Accumulated cash distributions (Note 4)	**(688,947)**	(505,330)
Total unitholders' equity	**868,666**	816,795
Total liabilities and unitholders' equity	**$ 1,467,918**	$ 1,380,004

See accompanying notes to consolidated financial statements

Approval on behalf of the Board

M Van Wielingen

Mac H. Van Wielingen (signed)
Director

John Dielwart

John P. Dielwart (signed)
Director

CONSOLIDATED STATEMENT OF INCOME AND ACCUMULATED EARNINGS

For the years ended December 31

(CDN$ thousands, except per unit amounts)		2002		2001
Revenue				
Oil, natural gas, natural gas liquids and sulphur sales	**$**	**444,835**	$	515,596
Royalties		**(85,155)**		(112,209)
		359,680		403,387
Expenses				
Operating		**99,876**		86,108
General and administrative (Note 16)		**15,365**		11,812
Management fee (Note 16)		**5,161**		8,789
Interest on long-term debt (Note 9)		**12,606**		17,138
Depletion, depreciation and amortization		**161,759**		165,050
Capital taxes		**1,370**		1,794
(Gain)/loss on foreign exchange (Note 3)		**(607)**		3,297
Internalization of management contract (Note 5)		**25,892**		–
		321,422		293,988
Income before future income tax recovery		**38,258**		109,399
Future income tax recovery (Note 15)		**29,635**		28,803
Net income		**67,893**		138,202
Accumulated earnings, beginning of year		**283,575**		142,887
Retroactive application of change in accounting policy (Note 3)		**(1,380)**		1,106
Accumulated earnings, beginning of year, as restated		**282,195**		143,993
Accumulated earnings, end of year	**$**	**350,088**	$	282,195
Net income per unit (Note 14)				
Basic	**$**	**0.57**	$	1.36
Diluted	**$**	**0.56**	$	1.35

See accompanying notes to consolidated financial statements

CONSOLIDATED STATEMENT OF CASH FLOWS

For the years ended December 31

(CDN$ thousands)	2002	2001
Cash flow from operating activities		
Net income	**$ 67,893**	$ 138,202
Add items not involving cash:		
Future income tax recovery	**(29,635)**	(28,803)
Depletion, depreciation and amortization	**161,759**	165,050
Amortization of commodity and foreign currency contracts	**(1,766)**	(17,497)
Internalization of management contract (Note 5)	**25,892**	–
Unrealized (gain)/loss on foreign exchange	**(174)**	3,318
	223,969	260,270
Change in non-cash working capital	**999**	(6,399)
	224,968	253,871
Cash flow from financing activities		
Borrowing (repayments) of long-term debt, net	**(3,750)**	13,103
Issue of Senior Secured Notes	**47,163**	–
Issue of Trust units	**128,481**	93,053
Trust unit issue costs	**(6,459)**	(4,654)
Cash distributions paid	**(184,167)**	(235,590)
	(18,732)	(134,088)
Cash flow from investing activities		
Acquisition of Startech, net of cash received (Note 6)	**–**	(7,970)
Acquisition of oil and gas properties	**(131,761)**	(32,686)
Proceeds on disposition of oil and gas properties	**12,647**	19,775
Capital expenditures	**(75,796)**	(97,207)
Reclamation fund contributions and actual expenditures (Note 7)	**(5,806)**	(4,380)
Internalization of management contract (Note 5)	**(5,331)**	–
	(206,047)	(122,468)
Increase (Decrease) in cash	**189**	(2,685)
Cash, beginning of year	**646**	3,331
Cash, end of year	**$ 835**	$ 646

See accompanying notes to consolidated financial statements

1. Structure of the Trust

ARC Energy Trust ("the Trust") was formed on May 7, 1996 pursuant to a trust indenture (the "Trust Indenture"). Computershare Trust Company of Canada was appointed as Trustee under the Trust Indenture. The beneficiaries of the Trust are the holders of the trust units.

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 was amended on June 7, 1999 to convert the Trust from a closed-end to an open-ended investment trust. The Trust Indenture was most recently amended on May 23, 2000 to expand the scope of the business to include the investment in all types of energy business-related assets including, but not limited to, petroleum and natural gas-related assets, oil sands interests, electricity or power generating assets and pipeline, gathering, processing and transportation assets. The operations of the Trust consist of the acquisition, development, exploitation and disposition of these assets and the distribution of net cash proceeds from these activities to the unitholders.

2. Summary of Accounting Policies

The consolidated financial statements have been prepared by management following Canadian generally accepted accounting principles ("GAAP"). The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingencies at the date of the financial statements, and revenues and expenses during the reporting period. Actual results could differ from those estimated.

In particular, the amounts recorded for depletion, depreciation and amortization of the petroleum and natural gas properties, deferred charges, and for site reclamation and abandonment are based on estimates of reserves and future costs. By their nature, these estimates, and those related to 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.

Principles of Consolidation

The consolidated financial statements include the accounts of the Trust and its subsidiaries. All inter-entity transactions have been eliminated.

Property, Plant and Equipment

The Trust follows the full-cost method of accounting. All costs of acquiring petroleum and natural gas properties and related development costs are capitalized and accumulated in one cost centre. Maintenance and repairs are charged against income, 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 petroleum and natural gas properties unless such a disposition would alter the rate of depletion by 20 per cent or more.

Depletion, Depreciation and Amortization

Depletion of petroleum and natural gas properties and depreciation of production equipment, except for major gas plant facilities, are calculated on the unit-of-production method based on:

(a) total estimated proved 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 petroleum 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.

Major gas plant facilities are depreciated on a straight-line basis over their estimated useful lives.

Ceiling Test

The Trust places a limit on the aggregate carrying value of property, plant and equipment, which may be amortized 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 amortization, site reclamation and abandonment and future income tax liabilities are limited to an amount equal to the estimated undiscounted future net revenues from proved reserves less estimated recurring general and administrative expenses, future site reclamation and abandonment costs, future financing costs and income taxes.

Future Site Reclamation and Abandonment

Provisions for future site reclamation and abandonment costs are calculated on the unit-of-production method over the life of the petroleum and natural gas properties based on total estimated proved reserves. Actual site reclamation costs incurred are charged against the site reclamation and abandonment liability.

Unit-Based Compensation Plan

The Trust has a unit-based compensation plan for employees, independent directors and long-term consultants who otherwise meet the definition of an employee of the Trust. Compensation cost is measured based on the intrinsic value of the award at the date of grant and is recognized over the vesting period. Any consideration received by the Trust on exercise of the unit rights is credited to unitholders’ capital. See Note 13 for a description of the plan and proforma disclosure of associated compensation cost.

Income Taxes

The Trust follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements of the Trust’s corporate subsidiaries and their respective tax base, using enacted income tax rates. The effect of a change in income tax rates on future tax liabilities and assets is recognized in income in the period in which the change occurs. Temporary differences arising on acquisitions result in future income tax assets and liabilities.

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to the unitholders. As the Trust distributes all of its taxable income to the unitholders and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no provision for income taxes has been made in the Trust.

Hedging

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

Foreign Currency Translation

Monetary assets and liabilities denominated in a foreign currency are translated at the rate of exchange in effect at the balance sheet date. Revenues and expenses are translated at the monthly average rates of exchange. Translation gains and losses are included in income in the period in which they arise.

3. Change in Accounting Policy

Effective for fiscal years beginning on or after January 1, 2002, the Canadian Institute of Chartered Accountants ("CICA") introduced new recommendations for the accounting for foreign exchange translation gains and losses on long-term monetary items. Such translation gains and losses are no longer to be deferred and amortized over the remaining term but rather are to be reflected in the statement of income in the period incurred. This change in accounting policy has been applied retroactively with restatement of prior periods.

As a result of this change, net income for the year ended December 31, 2002 increased by $525,000 and net income for the year ended December 31, 2001 decreased by $2.5 million from the net income which would have been reported under the previous accounting policy. The change also resulted in a decrease in the deferred foreign exchange translation loss of $2.1 million and a decrease in future income taxes of $673,000 as at December 31, 2001.

4. Reconciliation of Cash Flow and Distributions

		2002		2001
Cash flow from operations	**$**	**223,969**	$	260,270
Add (deduct):				
Cash withheld to fund capital expenditures		**(35,612)**		(27,933)
Reclamation fund contributions and interest earned on fund		**(4,777)**		(4,095)
Current period accruals		**37**		5,811
Cash Distributions		**183,617**		234,053
Accumulated cash distributions, beginning of year		**505,330**		271,277
Accumulated cash distributions, end of year	**$**	**688,947**	$	505,330
Cash distributions per unit	**$**	**1.56**	$	2.31
Accumulated cash distributions per unit, beginning of year		**9.08**		6.77
Accumulated cash distributions per unit, end of year	**$**	**10.64**	$	9.08

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

5. Internalization of Management Contract

Effective August 29, 2002, the Trust acquired all of the outstanding common shares of ARC Resources Management Ltd., ("ARML"), the Manager of the Trust. Total consideration for the transaction consisted of a cash payment of $4.3 million, the issuance of 298,648 Trust Units and 3,281,279 Exchangeable Shares to the Shareholders of ARML and the assumption of a liability to pay retention bonuses to the Management of the Trust in the amount of $5.0 million as detailed below:

Total consideration:		
Cash	$	4,247
Trust units issued		3,802
Exchangeable shares issued		41,771
Assumption of liability for retention bonuses		5,000
Costs associated with the transaction		1,083
Total purchase price	$	55,903

Prior to the acquisition, the Trust paid fees to ARML equal to three per cent of net production revenue and fees of 1.5 per cent and 1.25 per cent, respectively, on the purchase price of acquisitions and dispositions in accordance with the terms of the management agreement between the Trust and ARML. The acquisition resulted in the elimination of all fees under the existing management agreement which would have otherwise been in effect for a minimum five year period.

Of the total purchase price, $30.0 million was capitalized as property, plant and equipment. The capitalized amount includes $25.0 million for ARML's three per cent interest in the net production revenue of the Trust over the agreement term based on existing established reserves at the time of the transaction and $5.0 million for the retention bonuses. The retention bonuses are to be paid over a five year period to former management of ARML who are continuing in their capacities with the Trust. The remaining portion of the purchase price of $25.9 million was expensed in the current period. The expensed portion represents future management, acquisition and disposition fees on incremental reserves over the remaining five year term of the management agreement and the value of directly hiring existing management and staff of ARML.

6. Acquisition of Startech Energy Inc.

Effective January 31, 2001, the Trust acquired all of the issued and outstanding shares of Startech Energy Inc. ("Startech"). The transaction has been accounted for using the purchase method of accounting with the allocation of the purchase price and consideration paid as follows:

Net assets acquired:		
Cash	$	12,319
Working capital		1,770
Property, plant and equipment		751,198
Site reclamation liability		(5,130)
Commodity and foreign currency contracts (Note 10)		(33,149)
Future income taxes		(203,171)
Total net assets acquired	$	523,837

Financed by:	
Cash	$ 20,289
Trust units issued	256,051
Exchangeable shares issued	84,497
Debt assumed	163,000
Total purchase price	$ 523,837

7. Reclamation Fund

	2002	2001
Balance, beginning of year	**$ 10,147**	$ 9,897
Contributions, net of actual expenditures	**2,000**	(245)
Interest earned on fund	**777**	495
Balance, end of year	**$ 12,924**	$ 10,147

A reclamation fund was established to fund future site reclamation and abandonment costs. The Board of Directors of ARC Resources Ltd. has approved contributions over a 20-year period which results in minimum annual contributions of $4.0 million ($3.6 million in 2001) based upon properties owned as at December 31, 2002. Contributions to the reclamation fund and interest earned on the reclamation fund balance have been deducted from the cash distributions to the unitholders. During the year, $2.0 million ($3.8 million in 2001) of actual expenditures were charged against the reclamation fund.

8. Property, Plant and Equipment

	2002	2001
Property, plant and equipment, at cost	**$ 1,888,122**	$ 1,650,720
Accumulated depletion, depreciation and amortization	**(490,559)**	(339,414)
Property, plant and equipment, net	**$ 1,397,563**	$ 1,311,306

The calculation of 2002 depletion, depreciation and amortization included an estimated $190.1 million ($166.5 million in 2001) for future development costs associated with proved undeveloped reserves and excluded $12.6 million ($12.0 million in 2001) for the estimated future net realizable value of production equipment and facilities and $19.7 million ($22.3 million in 2001) for the estimated value of unproved properties.

9. Long-Term Debt

	2002	2001
Revolving credit facilities	**$ 235,054**	$ 238,748
Senior Secured Notes:		
Senior Secured Notes (2000 Issue – US$35 million)	**55,286**	55,741
Senior Secured Notes (2002 Issue – US$30 million)	**47,388**	–
Total long-term debt	**$ 337,728**	$ 294,489

The Trust has four revolving credit facilities to a combined maximum of $300 million and US$65 million of Senior Secured Notes (the "Notes").

The revolving credit facilities each have a 364 day extendable revolving period and a two year term. Borrowings under the facilities bear interest at bank prime (4.5 per cent at December 31, 2002) or, at the Trust's option, bankers' acceptance plus a stamping fee. The lenders review the credit facilities by April 30 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 loan balance will become repayable over a two year term period with 20 per cent of the loan balance payable on April 30, 2004 followed by three quarterly payments of five per cent of the loan balance and a lump sum payment of 65 per cent of the loan balance at the end of the term period. Collateral for the loans is in the form of floating charges on all lands and assignments and negative pledges on specific petroleum and natural gas properties.

The US$65 million Notes were issued in two separate issues pursuant to an Uncommitted Master Shelf Agreement. The first issue of US$35 million Notes were issued in 2000, bear interest at 8.05 per cent, and require equal principal payments of US$7 million over a five year period commencing in 2004. The second issue of US$30 million Notes were issued in 2002, bear interest at 4.94 per cent, and require equal principal payments of US$6 million over a five year period commencing in 2006. Security for the Notes is in the form of floating charges on all lands and assignments. The Uncommitted Master Shelf Agreement allows for the issuance of an additional US$35 million of Notes at rates and maturity dates to be agreed upon at the date of issuance. The Notes rank pari pasu to the revolving credit facilities.

The payment of principal and interest are allowable deductions in the calculation of cash available for distribution to unitholders and rank in priority to cash distributions payable to unitholders. Should the properties securing this debt generate insufficient revenue to repay the outstanding balances, the unitholders have no direct liability.

Interest paid during the year did not differ significantly from interest expense.

10. Financial Instruments

The Trust is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments are used by the Trust to reduce its exposure to fluctuations in commodity prices and foreign exchange rates. The fair values of these derivative instruments are based on an estimate of the amounts that would have been received or paid 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 manages this risk by diversifying its derivative portfolio amongst a number of financially sound counterparties.

Financial instruments of the Trust carried on the balance sheet consist mainly of current assets, reclamation fund investments, current liabilities, retention bonuses, commodity and foreign currency contracts, and long-term debt. Except as noted below, as at December 31, 2002 and 2001, there were no significant differences between the carrying value of these financial instruments 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 management's assessment of the associated credit risks.

The fair value of the US$65 million (CDN$102.7 million) fixed rate Senior Secured Notes approximated $109.5 million at December 31, 2002.

The following derivative contracts were outstanding as at December 31, 2002. Settlement of these contracts, which have no book value, would have resulted in a net payment by the Trust of $17.5 million as at December 31, 2002.

Commodity Contracts	Daily Quantity	Average Contract Prices ($) (1)	Price Index	Term
Crude oil fixed price contracts	7,100 bbls	41.88	WTI	January 2003 – March 2003
	4,000 bbls	39.78	WTI	April 2003 – September 2003
Crude oil fixed price contracts (embedded put option) (2)	4,000 bbls	39.51 (31.59)	WTI	January 2003 – December 2003
Crude oil collared contracts (embedded put option) (2)	4,000 bbls	42.65-47.39 (35.78)	WTI	April 2003 – June 2003
	2,000 bbls	39.49-45.49 (33.17)	WTI	July 2003 – December 2003
Natural gas fixed price contracts	1,000 GJ	4.00	AECO	January 2003 – March 2003
	27,823 GJ	4.50	AECO	April 2003 – October 2003
Natural gas fixed differential contracts	4,000 GJ	AECO + $1.29	AECO	January 2003 – March 2003
Natural gas put contracts	22,500 GJ	6.00	AECO	January 2003 – March 2003

(1) Commodity contracts denominated in US$ have been converted to CDN$ at the year end exchange rate.

(2) Counterparty may exercise a put option if index falls below the specified price (as denoted in brackets) on a monthly settlement basis.

Foreign Currency Contracts	Average Monthly Contract Amount (US$000)	Average Contract Rate	Term
Fixed rate foreign exchange contracts (sell)	8,049	1.5809	January 2003 – March 2003
	4,494	1.5900	April 2003 – December 2003

The Trust entered into a contract to fix the price of electricity on five megawatts per hour ("MW/h") for the period April 17, 2001 through December 31, 2010 at a price of $63/MW/h. Settlement of this contract would have required a net payment by the Trust of $4.3 million as at December 31, 2002.

In addition to the contracts described above, the following contracts, with a liability book value of $9.2 million, were outstanding as at December 31, 2002. These contracts were acquired in conjunction with the Startech acquisition at which time the market value of such contracts acquired was a net liability of $33.1 million. Settlement of these contracts would have resulted in a net payment by the Trust of $11.2 million as at December 31, 2002.

Commodity Contracts	Daily Quantity	Average Contract Prices ($) [1]	Price Index	Term
Natural gas fixed price contracts	4,000 GJ	2.71	AECO	January 2003 – October 2004

Foreign Currency Contracts	Average Monthly Contract Amount (US$000)	Average Contract Rate	Term
Fixed rate foreign exchange contracts (sell)	1,500	1.4106	January 2003 – December 2003

(1) Commodity contracts denominated in US$ have been converted to CDN$ at the year end exchange rate.

11. Unitholders' Capital

On June 3, 2002, the Trust issued 10,000,000 trust units at $12.05 per unit for proceeds of $120.5 million ($114.3 million net of issue costs) pursuant to a public offering prospectus dated May 22, 2002.

On August 29, 2002, the Trust issued 298,648 units to shareholders of ARML at $12.73 per unit pursuant to the acquisition of all of the outstanding common shares of ARML (see Note 5). The issue price of the units was determined based on the 10 day weighted average trading price of the trust units preceding the date of announcement of the transaction.

The Trust established a Distribution Reinvestment Plan ("DRIP") in conjunction with the Trust's transfer agent to provide the option for Unitholders to reinvest cash distributions into additional trust units issued from treasury. In 2002, the Trust issued 242,496 units for proceeds of $2.9 million (57,177 units for proceeds of $650,000 in 2001).

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

This Trust is authorized to issue 650 million trust units.

	2002		2001	
Trust Units	**Number of Trust Units**	**$**	Number of Trust Units	$
Balance, beginning of year	**110,609**	**1,029,538**	72,524	610,645
Issued for cash	**10,000**	**120,500**	8,050	88,550
Issued on acquisition of Startech (Note 6)	**–**	**–**	22,540	256,051
Issued to ARML shareholders (Note 5)	**299**	**3,802**	–	–
Issued on conversion of ARML exchangeable shares (Note 12)	**1,086**	**13,683**	–	–
Issued on conversion of ARL exchangeable shares (Note 12)	**343**	**3,154**	6,867	74,105
Issued on exercise of employee rights	**726**	**5,035**	571	4,191
Distribution reinvestment program	**242**	**2,946**	57	650
Trust unit issue costs	**–**	**(6,459)**	–	(4,654)
Balance, end of year	**123,305**	**1,172,199**	110,609	1,029,538

12. Exchangeable Shares

On August 29, 2002, the Trust issued 3,281,279 exchangeable shares of ARML ("ARML Exchangeable Shares") to shareholders of ARML at $12.73 per exchangeable share pursuant to the acquisition of all of the outstanding common shares of ARML (see Note 5). The issue price of the exchangeable shares was determined based on the 10 day weighted average trading price of the trust units preceding the date of announcement of the transaction. The exchangeable shares issued to ARML shareholders are a new series of exchangeable shares which are not publicly traded. The ARML exchangeable shares had an exchange ratio of 1:1 at the time of issuance.

The ARML exchangeable shares can be converted (at the option of the holder) into trust units at any time on or after August 29, 2002. The number of trust units issuable upon conversion is based upon the exchange ratio in effect at the conversion date. The exchange ratio is calculated monthly based on the cash distribution paid to unitholders divided by the ten day weighted average unit price preceding the record date. The exchangeable shares are not eligible for distributions and, in the event that they are not converted, any outstanding shares are redeemable by the Trust for trust units on or after August 30, 2005 until August 29, 2012.

During the year, 1,074,870 ARML exchangeable shares were converted to trust units at an average exchange ratio of 1.01002 trust units for each ARML exchangeable share. At December 31, 2002, the ARML exchange ratio was 1.04337 to 1.

	2002		2001	
ARML Exchangeable Shares	**Number of Shares**	**$**	Number of Shares	$
Balance, beginning of period	**–**	**–**	–	–
Issued to ARML shareholders	**3,281**	**41,771**	–	–
Exchanged for trust units	**(1,075)**	**(13,683)**	–	–
Balance, end of year	**2,206**	**28,088**	–	–
Exchange ratio, end of year	**1.04337**	**–**	–	–
Trust units issuable upon conversion, end of year	**2,302**	**28,088**	–	–

On January 31, 2001, the Trust issued 7,438,129 million exchangeable shares of ARC Resources Ltd. at $11.36 per exchangeable share ("ARL Exchangeable Shares") as partial consideration for the Startech acquisition. The issue price of the exchangeable shares was determined based on the weighted average trading price of trust units preceding the date of announcement of the acquisition. The ARL exchangeable shares are publicly traded. The ARL exchangeable shares had an exchange ratio of 1:1 at the time of issuance.

The ARL exchangeable shares can be converted (at the option of the holder) into trust units at any time on or after January 31, 2001. The number of trust units issuable upon conversion is based upon the exchange ratio in effect at the conversion date. The exchange ratio is calculated monthly based on the cash distribution paid divided by the ten day weighted average unit price preceding the record date. The exchangeable shares are not eligible for distributions and, in the event that they are not converted, any outstanding shares are redeemable by the Trust for trust units on or after February 1, 2004 until February 1, 2010.

During the year, 277,608 ARL exchangeable shares (6,523,354 in 2001) were converted to trust units at an average exchange ratio of 1.23661 (1.05227 in 2001) trust units for each ARML exchangeable share. At December 31, 2002, the ARL exchange ratio was 1.31350 to 1.

	2002		2001	
ARL Exchangeable Shares	**Number of Shares**	**$**	Number of Shares	$
Balance, beginning of year	**915**	**10,392**	–	–
Issued on acquisition of Startech	**–**	**–**	7,438	84,497
Exchanged for trust units	**(278)**	**(3,154)**	(6,523)	(74,105)
Balance, end of year	**637**	**7,238**	915	10,392
Exchange ratio, end of year	**1.31350**	**–**	1.18422	–
Trust units issuable upon conversion, end of year	**837**	**7,238**	1,083	10,392

13. Unit Based Compensation Plan

A Trust Unit Incentive Rights Plan (the "Plan") was established in 1999. The Trust is authorized to grant up to 8,000,000 rights to its employees, independent directors and long-term consultants to purchase trust units, of which 4,847,989 rights were granted to December 31, 2002. The initial exercise price of rights granted under the plan may not be less than the current market price of the trust units as at the date of grant and the maximum term of each right is not to exceed ten years. The exercise price of the rights is to be adjusted downwards from time to time by the amount, if any, that distributions to unitholders in any calendar quarter exceed 2.5 per cent (10 per cent annually) of the Trust's net book value of property, plant and equipment (the "Excess Distribution"), as determined by the Trust.

During the year, the Trust granted 1,334,072 rights (1,509,517 in 2001) to employees, independent directors and long-term consultants to purchase trust units at exercise prices ranging from $11.47 to $12.80 per trust unit ($10.49 to $12.70 in 2001). Rights granted under the plan generally have a five year term and vest equally over three years commencing on the first anniversary date of the grant. In accordance with the Plan, the exercise price of the rights granted was reduced as a result of calendar year distributions to unitholders exceeding 10 per cent of the Trust's net book value of property, plant and equipment.

A summary of the changes in rights outstanding under the plan is as follows:

	2002		2001	
	Number of Rights	**Weighted Average Exercise Price**	Number of Rights	Weighted Average Exercise Price
Balance, beginning of year	**2,509**	**$ 9.05**	1,722	$ 7.48
Granted	**1,334**	**12.57**	1,510	11.71
Exercised	**(726)**	**6.94**	(571)	7.34
Cancelled	**(76)**	**10.91**	(152)	9.69
Balance before reduction of exercise price	**3,041**	**11.05**	2,509	9.92
Reduction of exercise price	**–**	**(0.41)**	–	(0.87)
Balance, end of year	**3,041**	**$ 10.64**	2,509	$ 9.05

A summary of the plan as at December 31, 2002 is as follows:

Exercise Price at Grant Date	Adjusted Exercise Price	Number of Rights Outstanding	Remaining Contractual Life of Right (years)	Number of Rights Exercisable
$ 8.20	$ 5.22	149	1.3	149
9.10	6.75	372	2.3	131
11.81	10.71	1,197	3.3	320
12.52	12.28	1,323	4.4	–
11.64	**10.64**	**3,041**	**3.6**	**600**

Effective for fiscal years beginning on or after January 1, 2002, the Trust adopted the recommendations of the CICA on accounting for stock-based compensation which apply to new rights granted on or after January 1, 2002. The Trust has elected to continue to measure compensation cost based on the intrinsic value of the award at the date of the grant and recognize that cost over the vesting period. As the exercise price of the rights granted approximates the market price of the trust units at the time of the grant date, no compensation cost has been provided in the statement of income.

As previously stated, the exercise price of the rights granted under the Trust's rights plan may be reduced in future periods in accordance with the terms of the rights plan. The amount of the reduction cannot be reasonably estimated as it is dependent upon a number of factors including, but not limited to, future prices received on the sale of oil and natural gas, future production of oil and natural gas, determination of amounts to be withheld from future distributions to fund capital expenditures and the purchase and sale of property, plant and equipment. Therefore, it is not possible to determine a fair value for the rights granted under the plan.

As it is not possible to determine the fair value of rights granted under the plan, compensation cost for proforma disclosure purposes has been determined based on the excess of the unit price over the exercise price at the date of the financial statements. For the year ended December 31, 2002, there would be no change in net income for the estimated compensation cost associated with rights granted under the plan on or after January 1, 2002 as the adjusted exercise price of the rights exceeded the market price of the trust units.

14. Net Income and Cash Flow from Operations Per Trust Unit

Net income and cash flow from operations per trust unit are as follows:

		2002		2001 (4)
Net income				
Basic (1)	$	**0.57**	$	1.36
Diluted (2)		**0.56**		1.35
Cash flow from operations (3)				
Basic (1)		**1.87**		2.55
Diluted (2)		**1.86**		2.54

(1) Basic per unit calculations are based on the weighted average number of trust units outstanding in 2002 of 119,613,489 (101,979,000 in 2001) which includes outstanding exchangeable shares converted at the year-end exchange ratio.

(2) Diluted calculations include 560,772 additional trust units in 2002 (620,000 additional trust units in 2001) for the dilutive impact of employee rights. Calculations of diluted shares excluded 1,326,490 rights in 2002 (621,830 rights in 2001) which would have been anti-dilutive. There were no adjustments to net income or cash flow from operations in calculating diluted per share amounts.

(3) Calculated by adding future income tax recovery, unrealized gain/loss on foreign exchange, amortization of commodity and foreign currency contracts, depletion, depreciation and amortization, and internalization of the management contract to net income and dividing by the weighted average number of trust units.

(4) 2001 net income per trust unit has been restated for the change in accounting policy for foreign currency translation.

15. Income Taxes

The tax provision differs from the amount computed by applying the combined Canadian federal and provincial income tax statutory rate to income before future income tax recovery as follows:

		2002		2001 (1)
Income before future income tax recovery	$	**38,258**	$	109,399
Expected income tax expense at statutory rates		**16,298**		46,604
Effect on income tax of:				
Net income of the Trust		**(46,074)**		(72,852)
Effect of change in provincial tax rate		**–**		(9,111)
Resource allowance		**(3,820)**		(3,121)
Non-deductible crown charges		**3,681**		8,431
Alberta Royalty Tax Credit		**(230)**		(191)
Capital Tax		**584**		764
Unrealized (gain) loss on foreign exchange		**(74)**		673
Future income tax recovery	$	**(29,635)**	$	(28,803)

(1) 2001 net income per trust unit has been restated for the change in accounting policy for foreign currency translation.

The net future income tax liability is comprised of:

	2002	2001
Future tax liabilities:		
Capital assets in excess of tax value	**$ 165,351**	$ 192,006
Future tax assets:		
Attributed Canadian Royalty Income	**(6,356)**	(5,165)
Future removal and site restoration costs	**(13,773)**	(11,367)
Deductible share issue costs	**(827)**	(1,444)
Net future income tax liability	**$ 144,395**	$ 174,030

The petroleum and natural gas properties and facilities owned by the Trust's corporate subsidiaries have an approximate tax basis of $210.0 million ($203.6 million in 2001) available for future use as deductions from taxable income. Included in this tax basis are estimated non-capital loss carryforwards of $74.0 million ($65.2 million in 2001) which expire in the years through 2009.

No current income taxes were paid or payable in 2002 or 2001.

16. Related Party Transactions

Effective August 29, 2002, all fees under the management agreement between the Manager and the Trust were eliminated pursuant to the acquisition of all of the outstanding shares of ARML (see Note 5).

Under the management agreement, fees were payable to the Manager for management, advisory and administrative services including a fee equal to three per cent of net production revenue; and fees of 1.5 per cent and 1.25 per cent of the purchase price of acquisitions and the net proceeds of dispositions, respectively. Total acquisition and disposition fees paid to the Manager in 2002, prior to the elimination of the management agreement on August 29, 2002, were $895,000 ($7.9 million in 2001). These fees were accounted for as either part of the purchase price or as a reduction of the proceeds of disposition of property, plant and equipment.

During 2002, the Manager was reimbursed $9,327,000 ($11,715,000 in 2001) for general and administrative expenses incurred on behalf of the Trust to the date of the elimination of the management agreement on August 29, 2002.

17. Contingencies

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

HISTORICAL REVIEW

For the years ended December 31

($ thousands, except per unit and volume amounts)	**2002**	2001	2000	1999	1998
FINANCIAL					
Revenue before royalties	**444,835**	515,596	316,270	155,191	67,124
Per unit (1)	**$ 3.72**	$ 5.05	$ 4.97	$ 3.34	$ 2.62
Cash flow	**223,969**	260,270	179,349	80,814	30,040
Per unit (1)	**$ 1.87**	$ 2.55	$ 2.82	$ 1.74	$ 1.17
Net income (5)	**67,893**	138,202	110,872	29,835	(14,093)
Per unit (1)	**$ 0.57**	$ 1.36	$ 1.74	$ 0.64	$ (0.55)
Cash distributions	**183,617**	234,053	128,958	63,773	30,724
Per unit (2)	**$ 1.56**	$ 2.31	$ 2.01	$ 1.35	$ 1.20
Working capital (deficit)	**(10,067)**	5,805	6,339	15,761	(1,688)
Long-term debt	**337,728**	294,489	115,068	141,000	72,499
Weighted average trust units and exchangeable shares (3)	**119,613**	101,979	63,681	46,480	25,604
Trust units and units issuable for exchangeable shares at end of period (4)	**126,444**	111,692	72,524	53,607	25,604
OPERATING					
Production	**42,425**	43,111	27,355	22,172	12,737
Crude oil (bbl/d)	**20,655**	20,408	11,528	8,408	4,439
Natural gas (mmcf/d)	**109.8**	115.2	77.2	66.5	37.7
Natural gas liquids (bbl/d)	**3,479**	3,511	2,965	2,687	2,018
Average prices					
Crude oil ($/bbl)	**31.63**	31.70	36.74	24.85	18.99
Natural gas ($/mcf)	**4.41**	5.72	4.48	2.54	1.93
Natural gas liquids ($/bbl)	**24.01**	31.03	31.52	17.43	13.17
Oil equivalent ($/boe)	**28.73**	32.76	31.59	19.15	14.41
RESERVES					
Established (proved plus risked probable) reserves					
Crude oil and NGL (mbbl)	**117,241**	114,243	82,419	59,712	35,034
Natural gas (bcf)	**408.8**	385.5	286.4	241.0	121.9
Total (mboe)	**185,371**	178,496	130,147	99,879	55,351
TRUST UNIT TRADING					
Unit Prices ($)					
High	**$ 13.44**	$ 13.54	$ 12.15	$ 9.35	$ 11.40
Low	**$ 11.04**	$ 10.25	$ 8.35	$ 6.10	$ 6.00
Close	**$ 11.90**	$ 12.10	$ 11.30	$ 8.75	$ 6.15
Daily average trading volume (thousands)	**305**	414	151	68	32

(1) based on weighted average trust units and exchangeable shares

(2) based on number of trust units outstanding at each cash distribution date

(3) includes trust units issuable for outstanding exchangeable shares based on the period average exchange ratio

(4) natural gas converted at 6:1

(5) 2001 net income and net income per unit have been restated for the retroactive change in accounting policy for deferred foreign exchange translation

QUARTERLY REVIEW

($ thousands, except per unit amounts)	2002 4Q	2002 3Q	2002 2Q	2002 1Q	2001 4Q	2001 3Q	2001 2Q	2001 1Q
FINANCIAL								
Revenue before royalties	**117,639**	**113,625**	**112,707**	**100,864**	102,609	116,307	132,287	164,393
Per unit (1)	**$ 0.93**	**$ 0.91**	**$ 0.98**	**$ 0.90**	$ 0.94	$ 1.12	$ 1.29	$ 1.77
Cash flow	**61,495**	**56,603**	**56,677**	**49,194**	49,032	54,479	67,478	89,281
Per unit (1)	**$ 0.49**	**$ 0.45**	**$ 0.49**	**$ 0.44**	$ 0.45	$ 0.53	$ 0.66	$ 0.96
Net income (5)	**27,596**	**(3,505)**	**28,831**	**14,970**	12,763	30,349	42,119	52,971
Per unit (1)	**$ 0.22**	**$ (0.03)**	**$ 0.25**	**$ 0.13**	$ 0.12	$ 0.29	$ 0.41	$ 0.57
Cash distributions	**48,060**	**47,644**	**44,684**	**43,229**	48,537	60,813	65,938	58,765
Per unit (2)	**$ 0.39**	**$ 0.39**	**$ 0.39**	**$ 0.39**	$ 0.45	$ 0.60	$ 0.66	$ 0.60
Working capital (deficit)	**(10,067)**	**330**	**3,690**	**3,625**	5,805	–	3,617	9,978
Long-term debt	**337,728**	**271,203**	**213,364**	**316,446**	294,489	338,135	287,012	280,837
Weighted average units (thousands) (3)	**126,370**	**124,794**	**115,235**	**111,838**	108,585	103,449	102,942	92,941
Units outstanding at year-end (4)	**126,444**	**126,270**	**122,359**	**111,957**	111,692	103,523	103,249	102,692
OPERATING								
Production								
Crude oil (bbl/d)	**20,256**	**20,809**	**20,366**	**21,196**	20,753	20,066	20,202	20,614
Natural gas (mmcf/d)	**109.2**	**109.1**	**106.9**	**113.9**	117.5	109.5	112.8	120.9
Natural gas liquids (bbl/d)	**3,355**	**3,408**	**3,527**	**3,631**	3,706	3,740	3,090	3,502
Total (boe/d)	**41,808**	**42,394**	**41,713**	**43,805**	44,034	42,056	42,097	44,271
Average prices								
Crude oil ($/bbl)	**30.20**	**33.68**	**32.40**	**30.22**	27.33	33.27	33.79	32.57
Natural gas ($/mcf)	**5.26**	**4.11**	**4.67**	**3.61**	4.04	4.45	5.86	8.45
Natural gas liquids ($/bbl)	**27.49**	**25.23**	**23.38**	**20.17**	22.20	29.61	35.95	38.12
Oil equivalent ($/boe)	**30.58**	**29.13**	**29.69**	**25.58**	25.31	30.05	34.53	41.26
TRUST UNIT TRADING								
Prices ($)								
High	**12.74**	**12.98**	**13.44**	**13.18**	12.20	12.74	13.54	11.90
Low	**11.04**	**11.05**	**11.85**	**11.35**	10.35	10.25	10.25	10.95
Close	**11.90**	**12.80**	**12.77**	**13.14**	12.10	10.61	11.55	11.24
Daily average trading volume (thousands)	**269**	**256**	**252**	**446**	316	394	447	499

(1) based on weighted average trust units and exchangeable shares

(2) based on number of trust units outstanding at each cash distribution date

(3) includes trust units issuable for outstanding exchangeable shares based on the period average exchange ratio

(4) natural gas converted at 6:1

(5) 2001 quarterly net income and net income per unit have been restated for the retroactive change in accounting policy for deferred foreign exchange translation

OFFICERS AND SENIOR MANAGEMENT

The officers and senior management of ARC Resources are:

John P. Dielwart, B.Sc., P.Eng.

Mr. Dielwart is President and CEO of ARC Resources Ltd. and has overall management responsibility for the Trust. Prior to joining ARC in 1994, Mr. Dielwart spent 12 years with a major Calgary based oil and natural gas engineering consulting firm, as senior vice-president and a director, where he gained extensive technical knowledge of oil and natural gas properties in western Canada. He began his career working for five years with a major oil and natural gas company in Calgary. Mr. Dielwart is currently Chairman of the board of governors for the Canadian Association of Petroleum Producers (CAPP). He holds a Bachelor of Science with Distinction (Civil Engineering) degree, University of Calgary. He has also been a director of ARC since 1996.

Steven W. Sinclair, B. Comm., CA

Mr. Sinclair is Vice-President Finance and Chief Financial Officer of ARC Resources Ltd. and oversees all of the financial affairs of ARC Energy Trust. Mr. Sinclair has a Bachelor of Commerce from the University of Calgary, obtained his Chartered Accountant's designation in 1981 and has over 20 years experience within the finance, accounting and taxation areas of the oil and gas industry. Mr. Sinclair has been with the Trust since 1996.

Doug J. Bonner, B.Sc., P.Eng.

Mr. Bonner is Vice-President, Engineering of ARC Resources Ltd. and is responsible for all exploitation and development activities. He holds a B.Sc. in Geological Engineering from the University of Manitoba. Mr. Bonner's major area of expertise is reservoir engineering and he has extensive technical knowledge of oil and natural gas fields throughout western Canada, the east coast and northern Canada. Prior to joining ARC in 1996, Mr. Bonner spent 18 years with various major oil and natural gas companies in positions of increasing responsibility.

David P. Carey, B.Sc., P.Eng., MBA

Mr. Carey is Vice-President, Business Development of ARC Resources Ltd. and is responsible for all facets of business development and investor relations. He holds both a B.Sc. in Geological Engineering and a MBA from Queen's University. Mr. Carey brings 20 years of diverse experience in the Canadian and International energy industries covering exploration, production and project evaluations in western Canada, oilsands, the Canadian frontiers and internationally. Prior to joining ARC Resources in 2001, Mr. Carey held senior positions with Athabasca Oil Sands Investments Inc. and a major Canadian oil and gas company.

Danny G. Geremia, B. Comm., CA

Mr. Geremia is Treasurer of ARC Resources Ltd. and is responsible for all treasury-related activities. Mr. Geremia has a Bachelor of Commerce from the University of Calgary and obtained his Chartered Accountant's designation in 1999. Prior to joining the Trust in December 1999, Mr. Geremia worked with a major public accounting firm in both their audit and taxation departments. Mr. Geremia is currently a member of the Treasury Management Association of Canada.

Susan D. Healy, P. Land

Ms. Healy, Vice-President, Land is responsible for all Land related activities for ARC Resources Ltd. Ms. Healy joined the Trust at inception in July 1996, bringing with her over 17 years of diverse experience gained from working with junior and senior oil and gas companies.

Myron M. Stadnyk, B.Sc., P.Eng.

Mr. Stadnyk is Vice-President, Operations of ARC Resources Ltd. and is responsible for all of ARC's operational activities. He has 18 years experience in all aspects of oil and gas production operations. Prior to joining ARC Resources Ltd. in 1997, Mr. Stadnyk worked with a major oil and gas company in both domestic and international operations and oil and gas facility design and construction. He has a B.Sc. in Mechanical Engineering and is a member of the Association of Professional Engineers in Alberta and Saskatchewan.

Allan R. Twa, Q.C.

A member of the Alberta Bar since 1971, Mr. Twa is a partner in the law firm Burnet, Duckworth & Palmer LLP. Mr. Twa holds a B.A. (Political Science) from the University of Calgary, a LL.B. from the University of Alberta and a LL.M. from the University of London, England. Over the last 25 years, Mr. Twa has been engaged in a legal practice involving legal administration of public companies and trusts, corporate finance, and mergers and acquisitions. Mr. Twa is the Corporate Secretary.

John M. Beddome, B.Sc. Chem. Eng.

Mr. Beddome has been responsible for many significant projects in oil and gas exploration, production, transportation and processing during a career that included assignments as President of Dome Petroleum Ltd., Chairman of TransCanada Pipelines Ltd., CEO of Alberta Natural Gas Company Ltd. and other executive positions in the industry. Now an independent businessman and consultant, Mr. Beddome recently retired as a Director of PanCanadian Petroleum Ltd. and Chairman of IPSCO Steel Inc. Mr. Beddome is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta. Mr. Beddome has been a Director of ARC since 1996.

Fred C. Coles, B.Sc., P.Eng.

Mr. Coles is founder and President of Menehune Resources Ltd., having previously served as the Executive Chairman of Applied Terravision Systems Inc. to March 15, 2002. In his earlier career Mr. Coles worked as a reservoir engineer for a number of oil and gas companies, prior to undertaking the role of Chairman and President of an engineering consulting firm specializing in oil and gas. Mr. Coles also sits as a Director of a number of junior oil and gas companies and is a member of the Association for Professional Engineers, Geologists and Geophysicists of Alberta and the Canadian Institute of Mining, Metallurgy and Petroleum. Mr. Coles has been a Director of ARC since 1996.

Walter DeBoni, P.Eng., MBA

Mr. DeBoni currently holds the position of VP, Canada Frontier & International Business, for Husky Energy Inc. and was formerly CEO of Bow Valley Energy for a number of years. He has held numerous top executive posts in the oil and gas industry with major corporations. Mr. DeBoni holds a B.A.Sc. Chem. Eng. from the University of British Columbia, a MBA degree with a major in Finance from the University of Calgary and is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta and the Society of Petroleum Engineers. He is a past Chairman of the Petroleum Society of CIM, a past Director of the Society of Petroleum Engineers and has been a Director of ARC Resources since 1996.

John P. Dielwart, B.Sc., P.Eng.

Mr. Dielwart is President and CEO of ARC Resources Ltd. and has overall management responsibility for the Trust. Prior to joining ARC in 1994, Mr. Dielwart spent 12 years with a major Calgary based oil and natural gas engineering consulting firm, as senior vice-president and a director, where he gained extensive technical knowledge of oil and natural gas properties in western Canada. He began his career working for five years with a major oil and natural gas company in Calgary. Mr. Dielwart is currently Chairman of the board of governors for the Canadian Association of Petroleum Producers (CAPP). He holds a Bachelor of Science with Distinction (Civil Engineering) degree, University of Calgary. He has also been a director of ARC since 1996.

Michael M. Kanovsky, B.Sc., P.Eng., MBA

Mr. Kanovsky graduated from Queen's University and the Ivey School of Business. Mr. Kanovsky's business career included the position of VP of Corporate Finance with a major Canadian investment dealer followed by co-founding Northstar Energy Corporation and PowerLink Corporation (electrical cogeneration) where he served as Senior Executive Board Chairman and Director. Mr. Kanovsky is a Director of Bonavista Petroleum Inc. and Devon Energy Corporation. He has been a Director of ARC since 1996.

John M. Stewart, B.Sc., MBA

Mr. Stewart is a founder and Vice-Chairman of ARC Financial Corporation where he holds senior executive responsibilities focused primarily within the area of private equity investment management. He holds a B.Sc. in Engineering from the University of Calgary and a MBA from the University of British Columbia. Prior to ARC Financial, he was a Director and Vice-President of a major national investment firm. His career and experience span nearly thirty years with a focus on oil and gas and finance. Mr. Stewart has been a Director of ARC Resources Ltd. since 1996.

Mac H. Van Wielingen

Mr. Van Wielingen has served as Vice-Chairman and Director of ARC Resources Ltd. since its formation in 1996. He is Chairman and was a founder of ARC Financial Corporation in 1989. Previously Mr. Van Wielingen was a Senior Vice-President and Director of a major national investment dealer responsible for all corporate finance activities in Alberta. He has managed numerous significant corporate merger and acquisition transactions, capital raising projects and equity investments relating to the energy sector. Mr. Van Wielingen holds an Honours Business Degree from the University of Western Ontario Business School and has studied post-graduate Economics at Harvard University.

CORPORATE INFORMATION

Directors

Walter DeBoni (1) (3) (4)
Chairman

Mac H. Van Wielingen (4) (5)
Vice-Chairman

John P. Dielwart
President and Chief Executive Officer

John M. Beddome (1) (3) (4)

Frederic C. Coles (1) (2) (3) (4)

Michael M. Kanovsky (1) (2) (4)

John M. Stewart (5)

(1) Member of Audit Committee
(2) Member of Reserve Audit Committee
(3) Member of Compensation Committee
(4) Member of Board Governance Committee
(5) Member of Management Advisory Committee

Officers

John P. Dielwart
President and Chief Executive Officer

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

Susan D. Healy
Vice-President, Land

Doug J. Bonner
Vice-President, Engineering

Myron M. Stadnyk
Vice-President, Operations

David P. Carey
Vice-President, Business Development

Allan R. Twa
Corporate Secretary

Danny G. Geremia
Treasurer

Executive Offices

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Calgary, Alberta

Engineering Consultants

Gilbert Laustsen Jung Associates Ltd.
Calgary, Alberta

Legal Counsel

Burnet, Duckworth & Palmer LLP
Calgary, Alberta

Stock Exchange Listing

The Toronto Stock Exchange
Trading Symbols:
AET.UN (Trust Units)
ARX (Exchangeable Shares)

Investor Information

Visit our website
www.arcresources.com
or contact:
Investor Relations
(403) 503-8600 or
1-888-272-4900 (Toll Free)

Unitholder Information

Notice of the Annual and Special Meeting

The Annual and Special Meeting will be held on April 17, 2003 at 3:30 pm in the Belair Room at the Westin Hotel, 320 – 4 Avenue S.W., Calgary, Alberta.

Distribution Reinvestment and Optional Cash Payment Program

New ARC Energy Trust unitholders should be aware of the Distribution Reinvestment Plan (DRIP) under which a unitholder can elect to reinvest cash distributions into new ARC Energy Trust units. If distributions are reinvested, a unitholder can elect to make optional cash payment under the DRIP to acquire up to $3,000 of additional trust units per distribution date. All units purchased under the DRIP are made at prevailing market prices without any additional fees or commissions. For further details on the DRIP, please refer to our website, www.arcresources.com or contact Computershare.

Corporate Calendar

2003

April 17	Annual Meeting
April 17	Announcement of 2003 Q2 Distribution Monthly Amounts
May 7	2003 Q1 Results
July 17	Announcement of 2003 Q3 Distribution Monthly Amounts
August 7	2003 Q2 Results
October 17	Announcement of 2003 Q4 Distribution Monthly Amounts

Photography shot on location at the Southern Alberta Institute of Technology (SAIT) Well Site Building.

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