BlueSky Oil & Gas Ltd.

1985 ANNUAL REPORT

Contents

BlueSky's Annual Shareholders Meeting will be held September 11, 1985, at 3:00 P.M. in the Britannia Room of the Westin Hotel, Calgary, Alberta.

Highlights for 1985

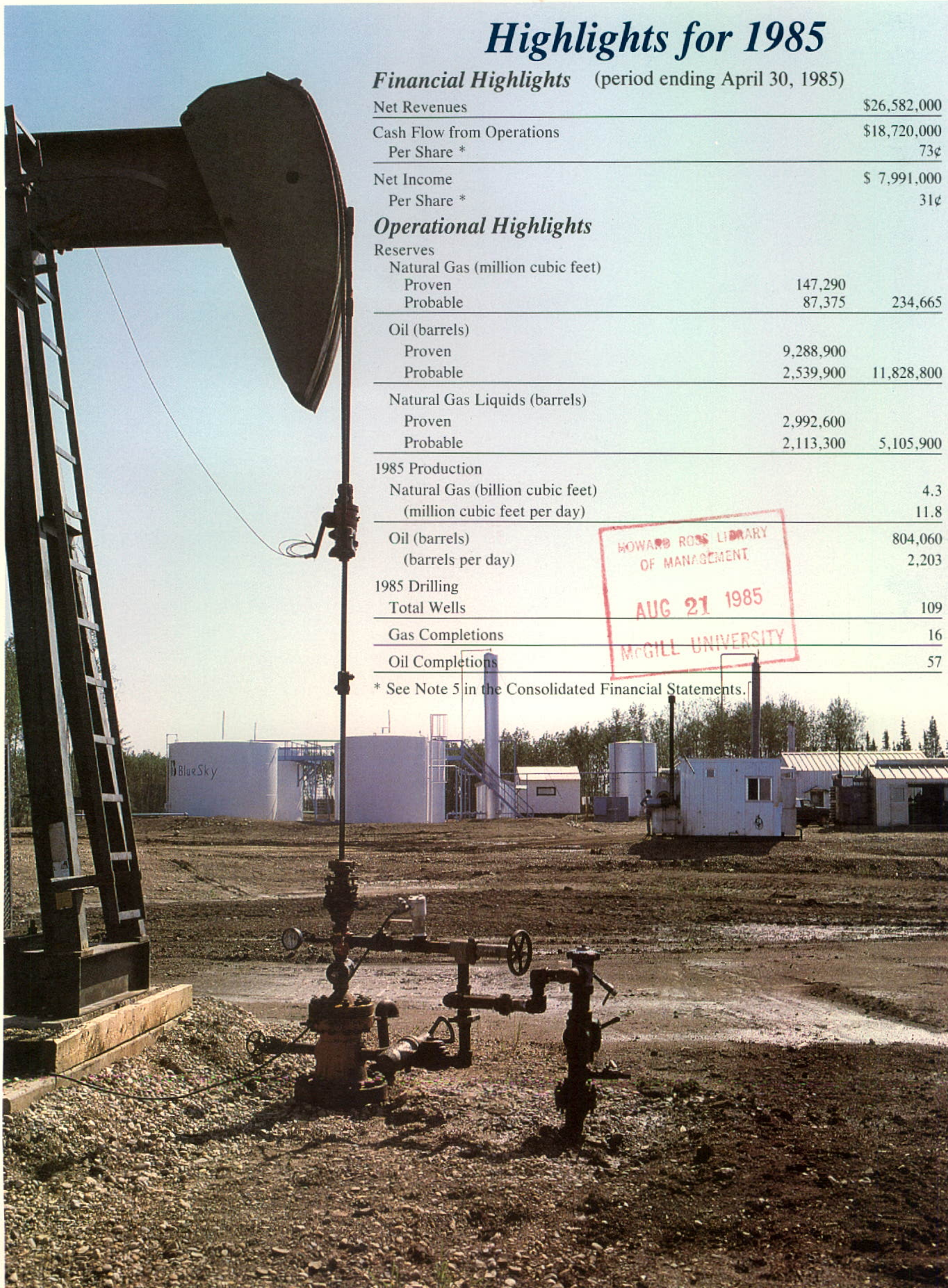
Financial Highlights (period ending April 30, 1985)

Net Revenues		$26,582,000
Cash Flow from Operations		$18,720,000
Per Share *		73¢
Net Income		$ 7,991,000
Per Share *		31¢

Operational Highlights

Reserves		
Natural Gas (million cubic feet)		
Proven	147,290	
Probable	87,375	234,665
Oil (barrels)		
Proven	9,288,900	
Probable	2,539,900	11,828,800
Natural Gas Liquids (barrels)		
Proven	2,992,600	
Probable	2,113,300	5,105,900
1985 Production		
Natural Gas (billion cubic feet)		4.3
(million cubic feet per day)		11.8
Oil (barrels)		804,060
(barrels per day)		2,203
1985 Drilling		
Total Wells		109
Gas Completions		16
Oil Completions		57

* See Note 5 in the Consolidated Financial Statements.



Report To Shareholders

Barry W. Harrison, President & Chief Executive Officer.

The Canadian Petroleum and Natural Gas Industry was dominated during the past year by uncertainty in world prices and by dramatic changes in government policy. In my previous report, I emphasized the need for change in Canada's fiscal regime regarding industry taxes. Those changes were introduced by the new Federal Government in March of 1985. The agreement reached by the Minister of Energy and her counterparts in the three Western Provinces introduced new life into an industry that had been dealt a near death blow by the illfounded National Energy Program of 1980. Deregulation of energy prices, the elimination of the Petroleum and Gas Revenue Tax over the next three years and the recognition that Domestic Natural Gas must be priced on a market orientated basis will during the next five years greatly assist our industry. In addition, a clear indication by Government that Canada is prepared to once again accept foreign capital should reap rewards for those companies who elect to seek financing outside of this country. The changes were long overdue and are, for those of us who look with enthusiasm towards the next decade, extremely positive.

Fiscal 1985 saw a continuation of growth in Bluesky's production income notwithstanding a disappointing drop in natural gas sales. Production derived income, after royalties and Petroleum and Gas Revenue Tax (PGRT) increased 18% to $20,464,039 from $17,412,739 for fiscal 1984. Net revenue from the Company's share of its 78% interest in ten West German Limited Partnerships added additional income of $4,585,106 versus $4,555,270 in the previous year. Net income for the period ended April 30, 1985 totalled $7,990,839 or 31¢ per share as compared to net income of $9,213,072 or 34¢ per share in the previous year.

For the third consecutive year, cash flow continued to rise increasing to $18,720,305 or 73¢ per share from $18,387,738 or 68¢ in fiscal 1984. This increase was achieved despite a drop in the Company's average daily natural gas sales during fiscal 1985. This decrease resulted from a lack of market demand during the months of December through March, a period that historically experiences high demand. In addition, the Alberta Royalty Tax Credit was reduced during the year from a maximum of $4 million in fiscal 1984 to a maximum of $2 million in fiscal 1985. As a result income and cash flow were each reduced by approximately $993,000 in 1985 due to this Governmental change.

For the fifth consecutive year, Bluesky has experienced growth in its daily oil production. From an average production rate of 443 barrels per day in 1980, the Company has increased its daily volume to a record 2,203 barrels per day in 1985, a respectable 397% increase. Our development program scheduled for fiscal 1986 is budgeted to add an additional 300 barrels of oil production per day. As previously mentioned, natural gas sales during this year were weaker than in our previous year with the Company averaging gas sales of 11.8 million cubic feet per day. 1985's lack of market demand caused an average decrease of 3 million cubic feet per day when compared to volumes in 1984. Notwithstanding this year's drop, the Company's daily average natural gas sales have increased 326% since 1980. Bluesky expects natural gas sales to return to 1984 levels during our next fiscal year and we are budgeting for an average production rate of 15.7 million cubic feet per day in 1986. With the completion of the Alberta Straddle Plants at Elmworth and Wapiti, the production of natural gas liquids will also show a substantial increase averaging 390 barrels per day in the upcoming year.

Bluesky continued to concentrate its petroleum and natural gas exploration and development in Western Canada. During the year, the Company participated in the drilling of 104 wells in Canada and five wells in the United States, resulting in 57 oil wells and 16 gas wells for an overall success ratio of 74%. These statistics include not only wells drilled by Bluesky but also wells drilled by third parties at no cost to the Company on farmouts of Bluesky acreage. Of total wells drilled, 52% were exploratory wells and 48% were drilled as development wells. The Company anticipates that it will participate in the drilling of 86 gross wells during the next fiscal year and we expect an additional 15 wells to be drilled through farmout. Seventy five percent of our 1986 wells will be development drilling which, due to the terms of the recently announced Western Accord, will be free of PGRT. This, in effect, improves the economic net back on these wells by adding approximately $3.00 to each barrel of production for wells drilled after April 1, 1985.

At year end, the Company's proven plus probable reserves as calculated by independent engineers totalled 11.8 million barrels of oil, 234.7 billion cubic feet of natural gas and 5.1 million barrels of natural gas liquids. Bluesky's total reserves have an undiscounted future cash flow value of $1,655,535,000 over the production life of the properties. At a discount rate of 15%, the present worth value of this future cash flow is $300,889,000. At a discount rate of 12%, the present worth value is $381,882,000. These reserves have been evaluated incorporating the effects of the Western Accord and prices reflect the changes that occured as a result of deregulation of oil prices on June 1, 1985.

Over the past twelve months, the Company added, through drilling, proven and probable oil reserves of 948,000 barrels and natural gas reserves of 3.6 billion cubic feet. Production during this period was 804,000 barrels of oil and 4.3 billion cubic feet of natural gas. Performance adjustments on the Company's 739 producing wells were also made, resulting in a slight overall decrease in oil reserves when compared to last year and a 6% decrease in natural gas reserves, mainly in the Deep Basin Area of Alberta.

In recent months, the Province of Alberta has made changes to its Crown royalty and incentive systems which, when fully in place, will augment the industries' cash flow. Any decrease in world oil prices will, of course, minimize this increase, however, these amendments have long term effects and they will result in expanded budgets for exploration and development. Bluesky will greatly benefit from the increase in the Alberta Royalty Tax Credit. At present, the maximum claim under this program is 50% of the Company's royalty liability to a maximum of $2,000,000. Under the new program, this claim will be increased to 75% of the Company's royalty liability to a maximum of $3,000,000. This change will take place April 1, 1986 and Bluesky will receive maximum benefit from this change. The addition of royalty free holidays for all wells drilled outside existing pool boundaries will also benefit our current year's budget. Many of our proposed development wells are being drilled to expand existing pools and a twelve month royalty free period will result in quicker payout and will allow for almost immediate reinvestment. Attractive incentives have also been added for the drilling of deeper gas wells. We are quickly approaching a period when the Company must place greater emphasis on drilling natural gas plays. This incentive should improve the economics of such drilling and the Company will, in the next year, thoroughly review its position on increased drilling for natural gas reserves.

The Board wishes to express its appreciation to all employees for their continued contribution and dedication during the past year. The long awaited changes in government policy have taken place and the challenge of maximizing the benefits that accrue to the Company as a result of these changes awaits us all. We know that we can count on our staff's continued efforts in this regard.

On Behalf of the Directors

B. W. Harrison

BARRY W. HARRISON
President & Chief Executive Officer

July 19, 1985
Calgary, Alberta

Exploration Highlights

Standing: (Left to Right) Ardis Chen-See; Leah Gray; Roy Fabbro; Jeff Bracken.
Sitting: (Left to Right) Darrell Shaw; Barb Surplus; Clem Benteau, Exploration Manager.

During the reporting period, the Company continued its philosophy of generating exploration opportunities to produce immediate cash flow and sound long-term investments for Bluesky. To help meet this objective, the Company has elected to commit its manpower and financial resources to Western Canada and to discontinue all exploration programs within the United States other than those to which it is contractually committed. This entrenchment into the Alberta Basin has been predicated by the renewed economic climate in Canada and by favourable political changes within the past six months.

In fiscal 1985, the Company participated in the drilling of 104 wells in Canada and five wells in the United States resulting in 57 oil wells and 16 gas wells for a success ratio of 74%. This includes not only wells drilled by Bluesky but also wells drilled by industry partners on farmouts of Company acreage. Of the wells drilled, 52% were exploratory wells and, while this percentage is significantly higher than it has been over the past two years, the Company has managed to maintain a high overall success ratio. Based on the results of this program, the Company will, in its next fiscal period, invest the majority of its drilling dollars in lower risk development wells that will take maximum advantage of the terms of the "Western Accord" plus the new incentives offered by the Alberta Government.

As of April 30, 1985, Bluesky held 2,481,773 gross acres and 170,410 net acres in Canada and the United States. In addition, the Company holds a 5% carried interest in 889,057 gross acres in the Llanos Basin located in Colombia, South America.

During the year, the Company's gross drilling budget was $32,516,384 with Bluesky's net share equalling $7,188,121. In addition, we participated in seismic programs totalling $309,657 to Bluesky and we expended $4,144,915 on the acquisition of new mineral rights. Our share of capital expenditures on tangible equipment totalled $3,149,941. In fiscal 1986, our gross drilling budget will be $26,000,000 with Bluesky's net share equalling $10,900,000. Seismic programs are budgeted to cost $1,200,000, projected land acquisitions at $3,400,000 and tangible equipment acquisitions at $2,500,000.

Land

During the past fiscal year, Bluesky expended $4.1 million on the acquisition of mineral rights in Alberta and Saskatchewan. Of this amount, $2.7 million was spent in Alberta where the Company acquired 14,158 net acres (22,431 gross acres) at an average price per net acre of $195. A total of 5,840 net acres (9,600 gross acres) were acquired in Saskatchewan at an average price of $235 per net acre.

Acquisitions were made on oil prospects in the Clive, Onoway, Heath-Ribstone, Edgerton, Malmo, Red Earth and Utikuma North areas in Alberta and in the Coleville, Hoosier and Battrum areas of Saskatchewan.

At Heath-Ribstone in east central Alberta, the Company participated for a 47.5% working interest in the acquisition of a 3,200 acre Crown parcel for $3 million. In the Utikuma North area, the Company participated as to a 50% working interest in a $580,000 purchase of 1,440 net acres offsetting a Slave Point oil discovery made by Bluesky and its partners during the year.

In the Coleville area of southwestern Saskatchewan, the Company entered into a land acquisition program with an industry partner which resulted in 7,360 gross acres being acquired at a total expenditure of $2,071,557. Bluesky holds a 50% working interest in this acreage, but as we were carried by our partner for $250,000 in expenditures on this program, our net share of the total cost was $785,718.

During the year, the Company disposed of its United States acreage holdings in New York, Pennsylvania, Maryland and West Virginia through sale and/or surrenders. In accordance with our exploration philosophy to concentrate on Canada, we will continue to pursue sales of our remaining undeveloped acreage holdings in the United States.

The elimination of PGRT on new production, together with the continuation of royalty holidays presently in existence in both Alberta and Saskatchewan, will result in higher land values in the Western provinces and increased activity at Land Sales. In recognition of this, Bluesky has budgeted $3.4 million for the acquisition of new mineral rights in Alberta and Saskatchewan during fiscal 1986.

(Left to Right) Dave Lough; Shelley Franklin; Wayne Tait, Vice-President, Land; Janeen Morice; Linda Shields.

Undeveloped Land Holdings as of April 30, 1985

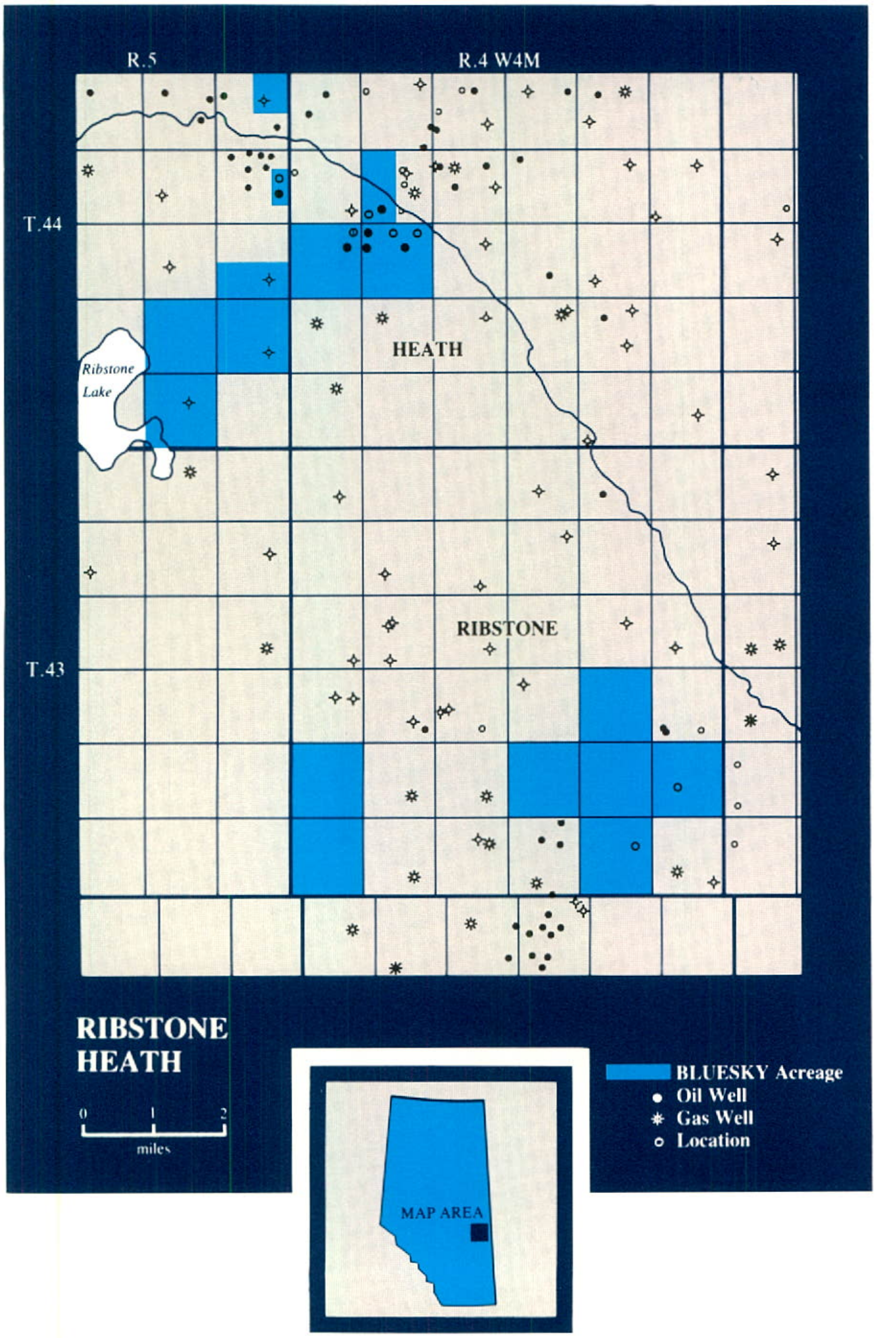
	GROSS	NET
CANADA:		
Alberta	403,424	72,520
British Columbia	176,544	17,085
Saskatchewan	11,522	6,028
Sub-Total	591,490	95,633
Canadian Hunter Lands	1,512,017	22,180
Sub-Total	**2,103,507**	**117,813**
UNITED STATES:		
Company Lands	27,605	7,137
Coho JV	350,661	3,229
American Hunter JV	1,982,725	38,855
Sub-Total	**2,360,991**	**49,221**
Sub-Total	4,464,498	167,034
Company Share of Partnerships	—	42,231
Sub-Total	**4,464,498**	**209,265**
INTERNATIONAL:		
Colombia	889,057	111,548
TOTAL	**5,353,555**	**320,813**

North America

Heath-Ribstone

The Heath prospect is located six miles southeast of the Wainwright oil field in east central Alberta. This prospect has developed into a significant new pool discovery for the Company. To date, Bluesky has an interest in 4,080 gross acres and five producing oil wells with the Company's interest varying from 55.5% to 90.5%. It is anticipated that this field will be drilled on 40 acre spacing with each spacing unit having reserves of 50,000 barrels of recoverable oil with an allowable of 45 barrels of oil per day. The Company plans to drill six wells on this prospect within the next three months and we anticipate that by the fall of 1985 20 wells will have been drilled by adjacent land owners within a two mile radius of Bluesky's acreage.

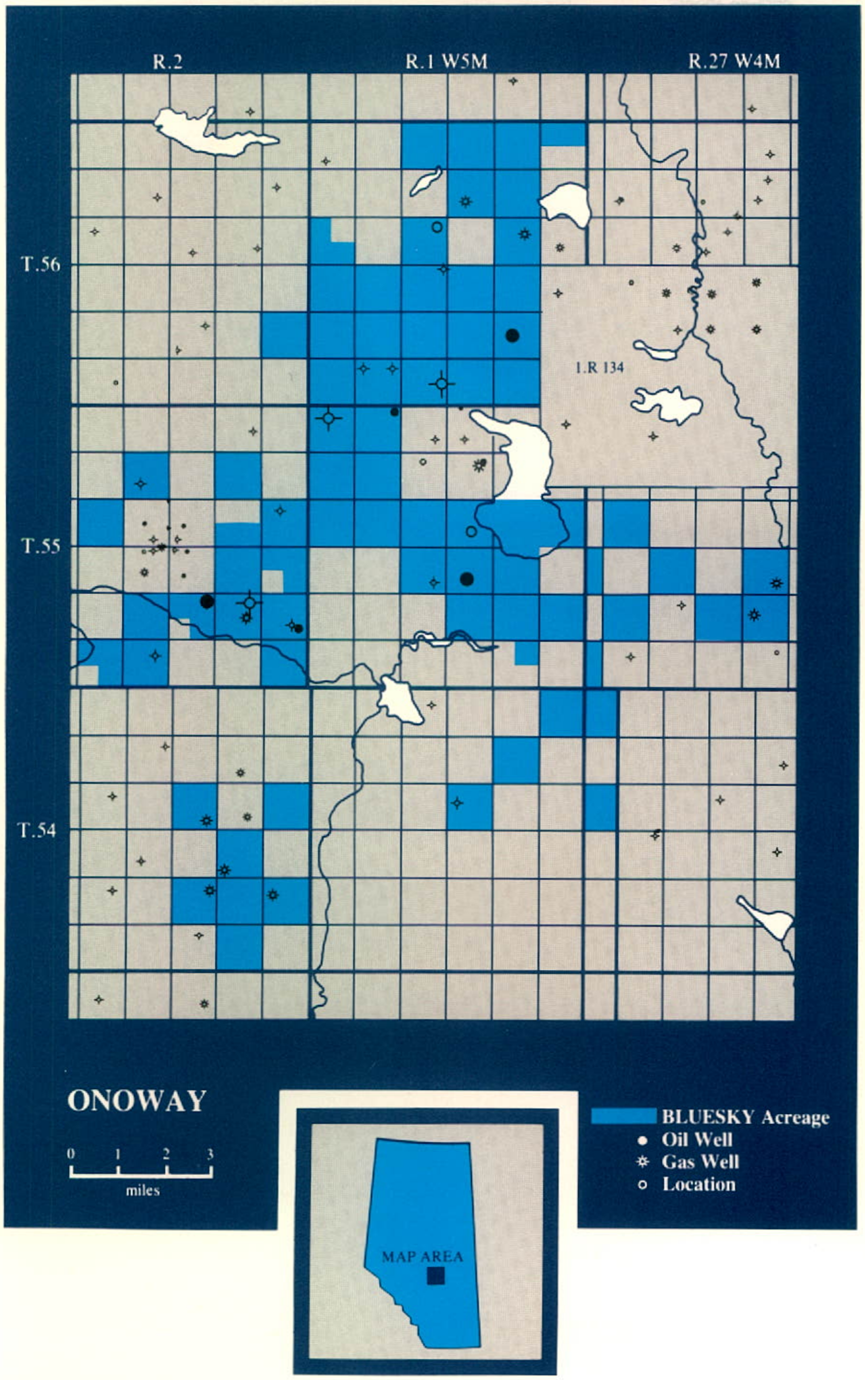
Based on the attractive economics of this shallow Nisku oil prospect, Bluesky has also acquired a 47.5% interest in 3,200 gross acres in the Ribstone area located seven miles southeast of the Heath prospect. This acreage is geologically analogous to Heath and it is anticipated that this prospect will possess the same reserve potential. The Company plans to drill the first two exploratory wells on this prospect in early fiscal 1986.



Onoway

In September, 1984, Bluesky and its partners reached agreement with Murphy Oil Company Ltd. whereby Murphy committed to drill 17 exploratory tests in this area located 50 miles northwest of Edmonton. The farmout group holds approximately 110 sections of land of which the Company has an interest in 65 sections. Eleven of the commitment wells will be on lands in which Bluesky has an interest. Bluesky's average working interest in this acreage after Murphy has fulfilled its commitment and has earned its interest will be 14%. Prior to the Murphy farmout, the Company participated in four wells in this area, two of which were cased awaiting further evaluation and two were dry and abandoned. To date, Murphy has drilled three of its commitment wells resulting in two dry holes and one potential Wabamun oil well.

This area holds potential for hydrocarbon production from the Cretaceous Mannville sandstones or the Devonian Wabamun dolomites and the Murphy program will substantially evaluate both these potentials.

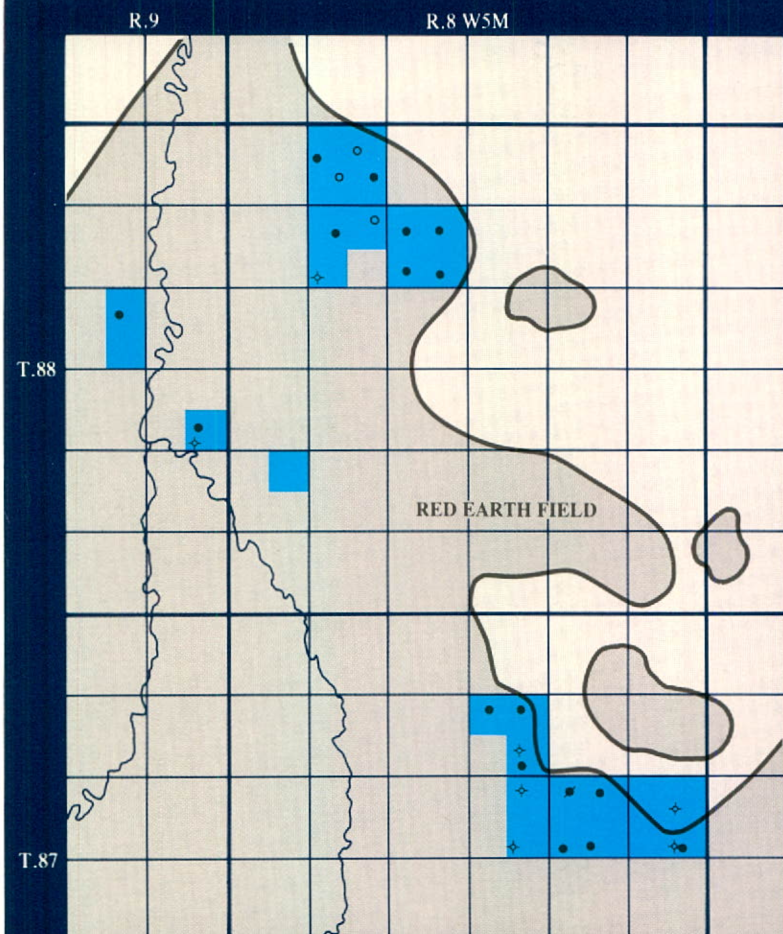


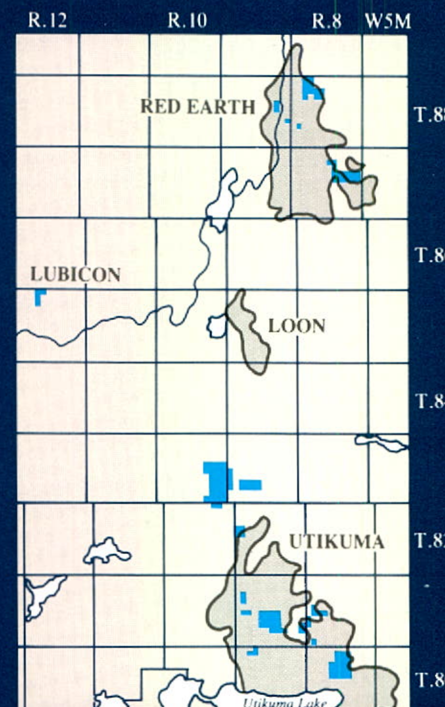
Utikuma and Red Earth

As in past years, Bluesky continued to be active in the Utikuma/Red Earth areas of north central Alberta through land acquisition and drilling. The Company participated in the drilling of six wells in the area, resulting in five oil wells and one dry hole. The drilling program resulted in the additions of 199,000 net barrels of reserves to Bluesky's account from gross reserves of 595,000 barrels assigned to these wells.

On the Utikuma North prospect, the Company participated in the drilling of a Slave Point oil discovery in November of 1984. As a result of this discovery and of seismic shot subsequent thereto, Bluesky acquired an additional 1,440 gross acres in proximity to the discovery well. This brings the total acreage held on this play to 4,000 acres with Bluesky holding 2,440 net acres or an average 61% interest. The Company plans to drill three exploratory wells on this prospect in fiscal 1986 and to further increase its land holdings within the area.

At Red Earth, Bluesky participated in the drilling of three wells which resulted in two Slave Point oil wells and one Granite Wash oil well. Bluesky acquired 320 net acres on the Granite Wash play, bringing the Company's land holdings to 3,840 gross acres in which Bluesky has an average 24% interest. At Red Earth, the Company has an interest in three wells producing from the Granite Wash and eight wells producing from the Slave Point zone. The three oil wells drilled in fiscal 1985 were drilled late in the drilling season and due to spring breakup they had not been completed at year-end. A number of measures are being undertaken in an effort to increase production and efficiency of the Red Earth operation. The most significant project is the laying of flow lines to tie all wells to a central battery thus allowing for uninterrupted year long production. The Slave Point formation in this area has excellent secondary recovery possibilities through waterflood. Approval has been received to implement a waterflood recovery scheme in Section 28-88-8 W5M and it is projected that water injection will commence in the summer of 1985.





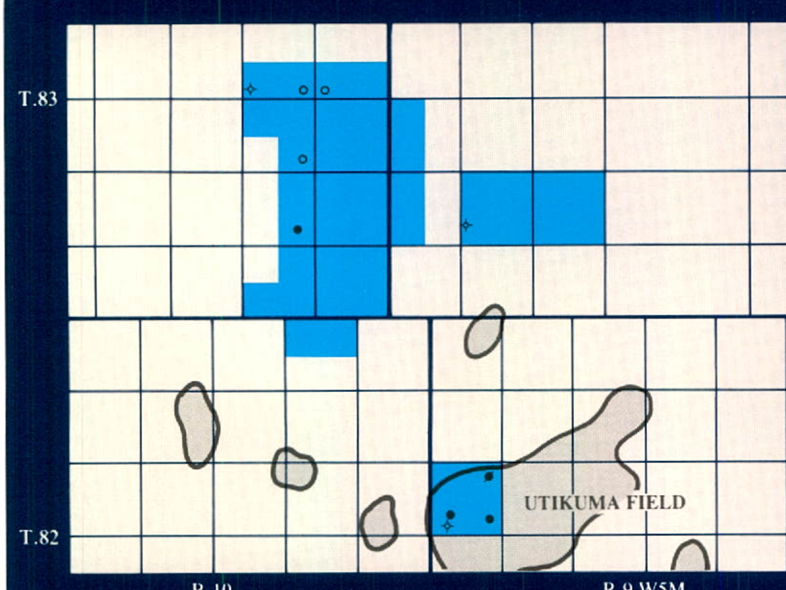
0 1 2
miles

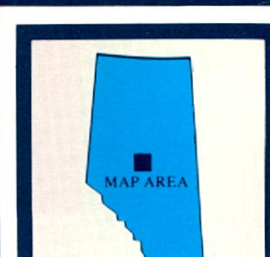
RED EARTH

- BLUESKY Acreage
- Oil Well
- Gas Well
- Location

UTIKUMA NORTH

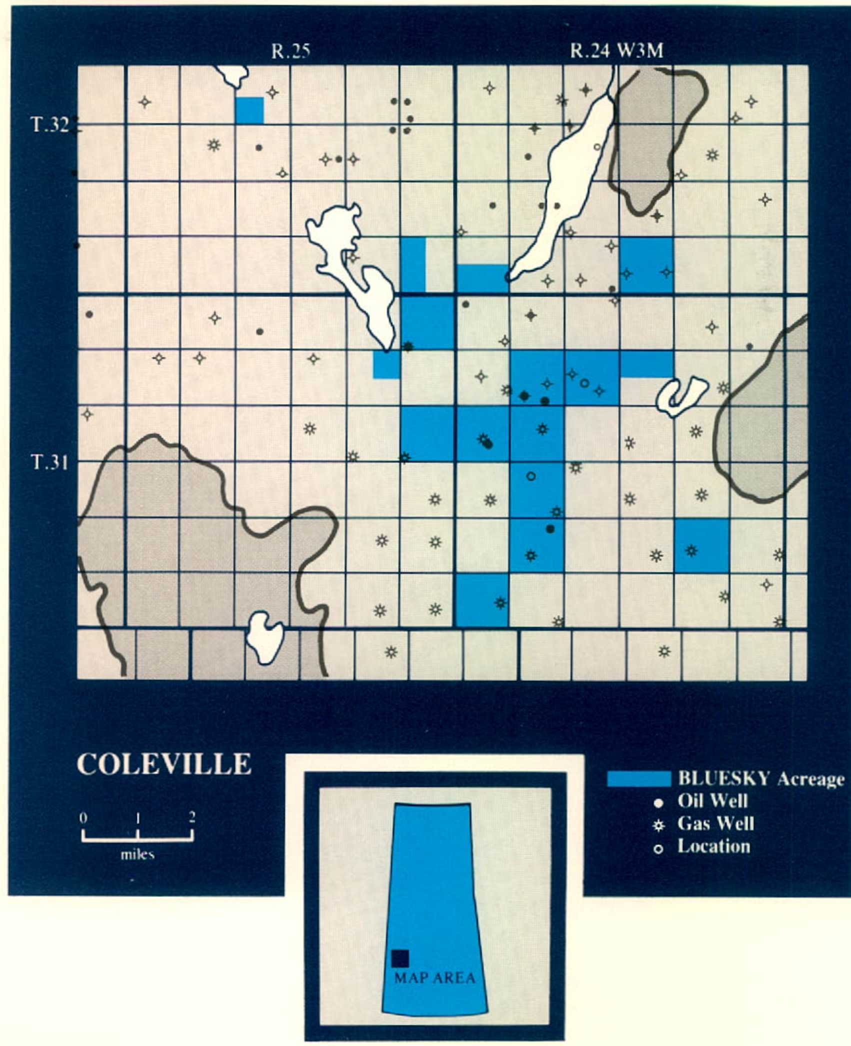
miles
0 1 2





Chigwell (Ponoka)

Drilling continued at Ponoka in central Alberta. In the past three years, the Company has drilled 28 wells in this area, resulting in 24 oil wells and two gas wells. In fiscal 1985, we drilled a total of twelve wells within this field designated the Chigwell Viking "E" Field by the Alberta Energy Resources Conservation Board. Construction of central gathering and production facilities has commenced and should be completed by mid-summer. Bluesky will have a 48% interest in this project and the Company will act as operator of these centralized facilities. Engineering studies are in progress to evaluate the feasibility of water flooding the Viking Sand for enhanced oil recovery with a decision in this regard expected by October of 1985. An additional twelve wells will be drilled in this area during fiscal 1986 with the majority being development wells to be completed prior to November.



Southwestern Saskatchewan

During 1985, the Company initiated a lease acquisition program in the Coleville area of southwestern Saskatchewan. To reduce the Company's risk and to maximize the exposure of its exploration dollars, Bluesky participated in this play with an industry partner who paid 75% of all land costs for a 50% working interest. This joint venture terminated upon land expenditures of $1,000,000 and it resulted in the acquisition of 7,360 gross acres. The Company also acquired an additional 320 net acres in the Coleville area and 1,600 net acres in the Battrum area for its own account.

Four wells were drilled at Coleville during fiscal 1985 and all have been cased. The most significant of these was a test well drilled in Lsd 4-36-31-25 W3M which encountered gas saturated reservoirs in the Cretaceous McClaren formation and the Mississippian Bakken formation. Independent engineers have given this well gross reserves of 6.3 billion cubic feet. The Company has completed the Bakken formation and production testing indicates the well has a deliverability of 6.9 million cubic feet per day at pressures of 400 psi. It is anticipated that this well will be placed on production during fiscal 1987 with an allowable of 1.7 million cubic feet per day. Pursuant to Saskatchewan's incentive program, the first three years of production will be royalty free. Bluesky has a 50% working interest in the well and the surrounding 1,440 gross acres.

The Company is very pleased with its initial success in southwestern Saskatchewan and plans have been made to drill seven additional wells in Saskatchewan during fiscal 1986.

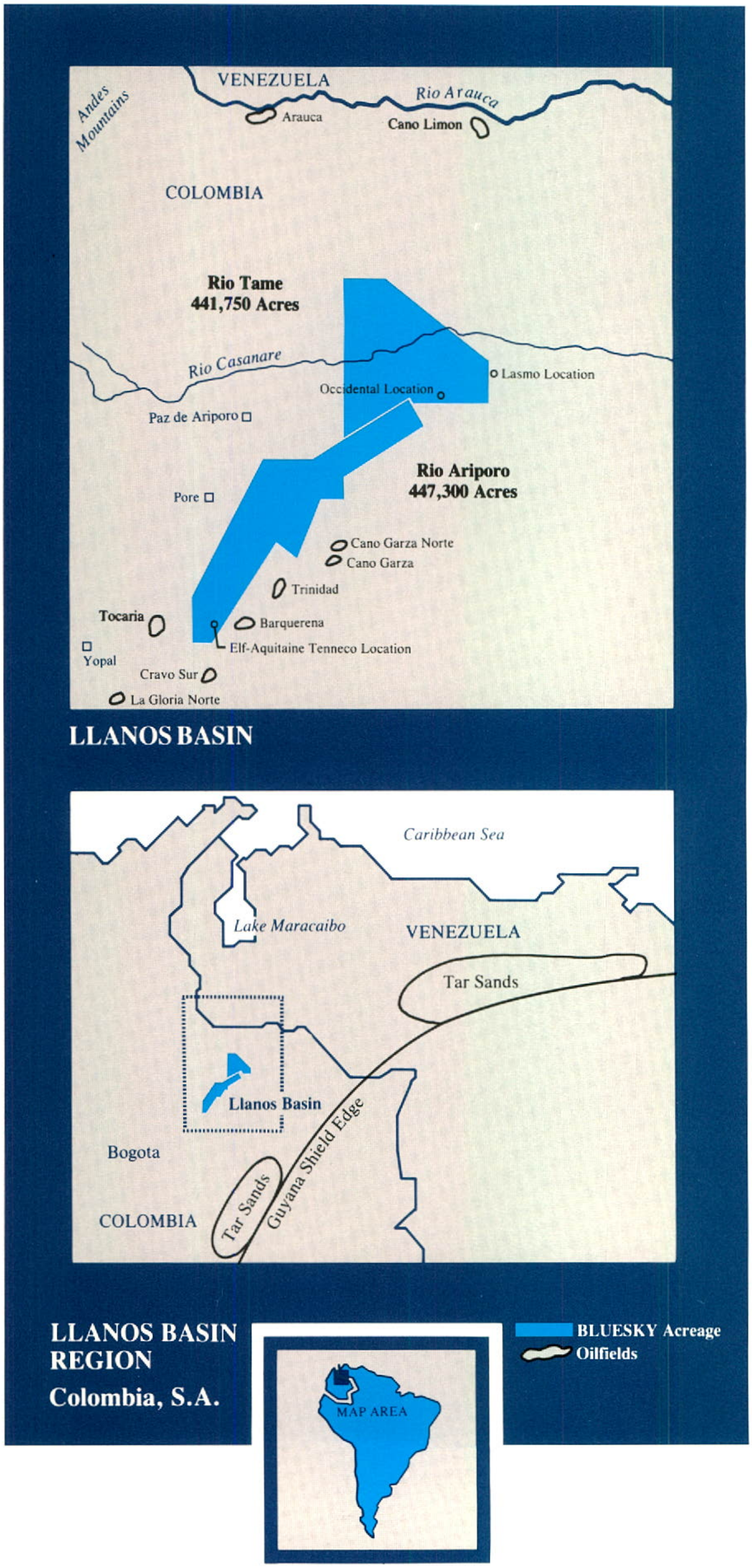
International

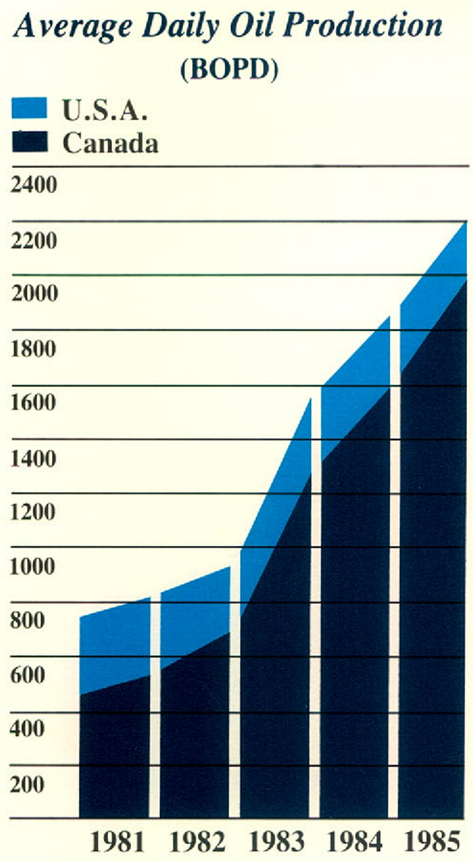
Colombia, South America

The discovery by Occidental Petroleum Corporation of the one billion barrel Cano Limon oil field is evidence that the Llanos Basin of Colombia is emerging as a world class producing province. Bluesky has been involved in this area since 1983 originally acquiring a 20% working interest in two Association Contracts covering 889,050 gross acres in the center of the Basin.

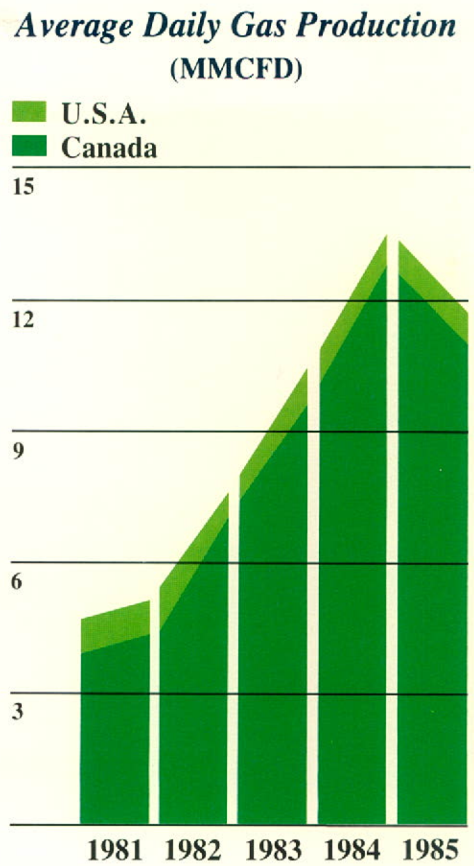
On January 31, 1985, the Company and its partners farmed out its northern holdings, the Rio Tame Association Contract, to Occidental for the drilling of a 10,400 foot exploratory well plus a cash payment of $333,000 (U.S.). Bluesky retained a 5% carried interest in the test well and in the 441,750 acres encompassing the Association Contract. The Joropo #1 well was spudded on February 17, 1985 and reached its total depth in March at which point it was cased. Further evaluations will be conducted by Occidental at its sole cost in November when weather conditions will permit access to this remote area. This is the first well to test the stratigraphic trapping potential of this area and, although classified as a high risk exploratory wildcat, it did encounter zones of interest. Occidental must drill a second well on the contract lands and make a further payment of $333,000 during 1986 in order to satisfy its contractual earning commitment.

On the southern holdings, the Rio Ariporo Association Contract, Bluesky and its partners have successfully farmed out this acreage to a second international explorer. The Elf-Aquitaine-Hocol Group have committed to spud a test well on this block by the end of July, 1985. Bluesky will retain a 5% carried interest in the well and in the 447,300 acres covered by the Contract. The test well will be located a few miles west of Elf-Aquitaine's Barquerena #1 discovery well which is capable of producing 7,019 barrels of oil per day.

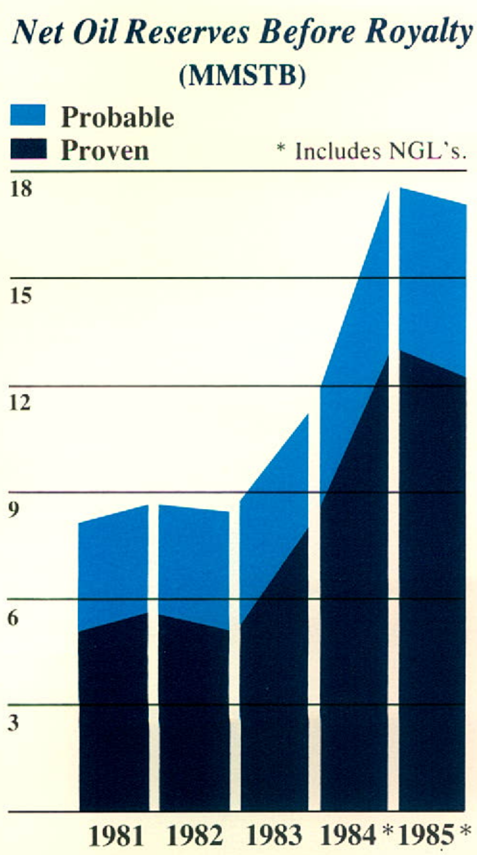




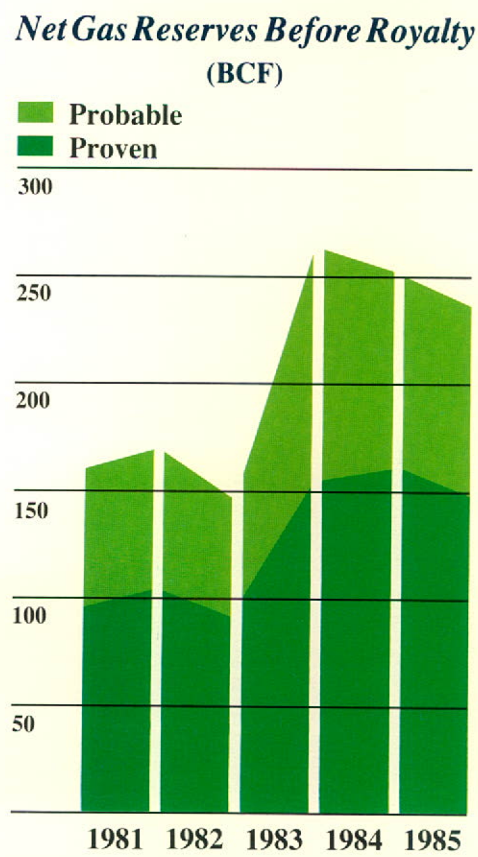
Average Daily Oil Production
(BOPD)
U.S.A.
Canada
2400
2200
2000
1800
1600
1400
1200
1000
800
600
400
200
1981 1982 1983 1984 1985



Average Daily Gas Production
(MMCFD)
U.S.A.
Canada
15
12
9
6
3
1981 1982 1983 1984 1985



Net Oil Reserves Before Royalty
(MMSTB)
Probable
Proven
* Includes NGL's.
18
15
12
9
6
3
1981 1982 1983 1984* 1985*



Net Gas Reserves Before Royalty
(BCF)
Probable
Proven
300
250
200
150
100
50
1981 1982 1983 1984 1985

Operations — Production

(Left to Right) Art Eastly, Vice-President, Production; Daryl Cook; Jim Feeney.

On March 28th, 1985, the Government of Canada and the three Western Provinces announced their Western Accord which is an agreement on oil and gas pricing and taxation and heralds the end of the National Energy Program.

The feature of this agreement which is most significant to the Company is the elimination of the PGRT (Petroleum and Gas Revenue Tax) on new wells drilled after April 1st, 1985, and the gradual phasing out of the 12% tax on existing production by December 31, 1988. The removal of PGRT increases the net-back on oil production by an average 15 percent and is the major concession in the agreement.

Deregulation of crude oil pricing effective June 1st, 1985, ensures that Bluesky's crude oil production will be sold at a price determined by free market forces, both domestic and international. Bluesky's crude oil production qualified as NORP (New Oil Reference Price) under the previous system and we are anticipating a decrease in average price from \$40 to the range of \$35 per barrel after deregulation. This decrease in price will be offset by the phasing out of the PGRT and will have a minimal effect on the Company's cash flow.

Deregulation requires each company to negotiate crude oil sales contracts for production from operated properties to insure orderly and continued marketing after June 1st. Bluesky has contracted for the sale of all its production to major refining and transmission companies, with a view to obtaining long term market access and minimizing financial risk. We expect the crude oil price to fluctuate during the first few months until supply-demand, transportation costs, and international price effects stabilize.

In the Western Accord it was agreed to go to a market-oriented pricing mechanism for Domestic Natural Gas by November 1st, 1985. To date, no decisions have been announced so the effects of this pricing accord on the producing industry cannot be judged at this time. Deregulation of gas prices and a move towards market oriented prices would be a positive step towards larger gas sales volumes for Alberta Producers into the U.S. Export Market.

Oil Production

Crude oil production during the twelve months achieved record levels increasing by 18.4 percent from one year ago to a total of 804,060 barrels, for an average of 2,203 barrels per day. Because pipeline capacity on the Interprovincial Line to Eastern Canada is limited, there were five months during the period when Alberta's Well Allowables were lowered which reduced our net production by up to 75 barrels per day. Increasing crude oil sales has been a major objective of the company as an offset to the weak natural gas markets of recent years and since April 30, 1982, when production was averaging 937 barrels per day, we have experienced a growth of 135% to current levels.

In the coming year, oil production is forecast to average 2,492 barrels per day based on wells currently completed and on production. In addition, the production of Natural Gas Liquids, which will commence during the summer of 1985, is forecast to average 394 barrels per day for the year.

Historically, our production has been light gravity oil concentrated in Alberta and British Columbia but during the past year the first wells in the traditionally heavy oil areas were drilled and, at year end, there were five wells on production at Heath in Alberta, each pumping between 30 and 50 barrels per day of 15° API gravity oil and one well at Coleville in Saskatchewan which is not yet fully evaluated. With further drilling in the coming months the sale of heavy oil will become a significant part of Bluesky's production income.

Gas Production

Natural gas production for the year totaled 4,311.6 million cubic feet for a daily average of 11.8 million cubic feet. Increased seasonal demand during our fourth quarter resulted in average daily production of 14.9 million cubic feet for the period.

Markets for natural gas have been depressed for several years but despite this fact our gas sales have increased by 55% from the 1982 level of 7.6 million cubic feet per day and in the next year, with a moderate improvement in gas exports, we are forecasting a production level of 15.7 million cubic feet per day. It is anticipated that natural gas markets will improve over the next three years enabling Bluesky's gas production volumes to significantly exceed those being attained currently.

In the last annual report we estimated that the market for Canadian natural gas would be approximately 50% of contracted volumes during 1984-85 and this has proven to be accurate. Sales to both the domestic and export market have suffered from several consecutive winters of above normal average temperatures in North America.

Statistically a return to more normal winter temperatures can be expected and would improve sales volumes. Also, it appears that in the United States natural gas supply and market consumption are approaching a balance position and this fact, along with reduced export prices for Canadian gas, should combine to improve production volumes in our contract areas probably starting in 1986 and growing from there towards normal contract nominations.

(Left to Right) George Blunderfield; Terry Birkbeck.

Pat Newton, Don Maki.

Reserves

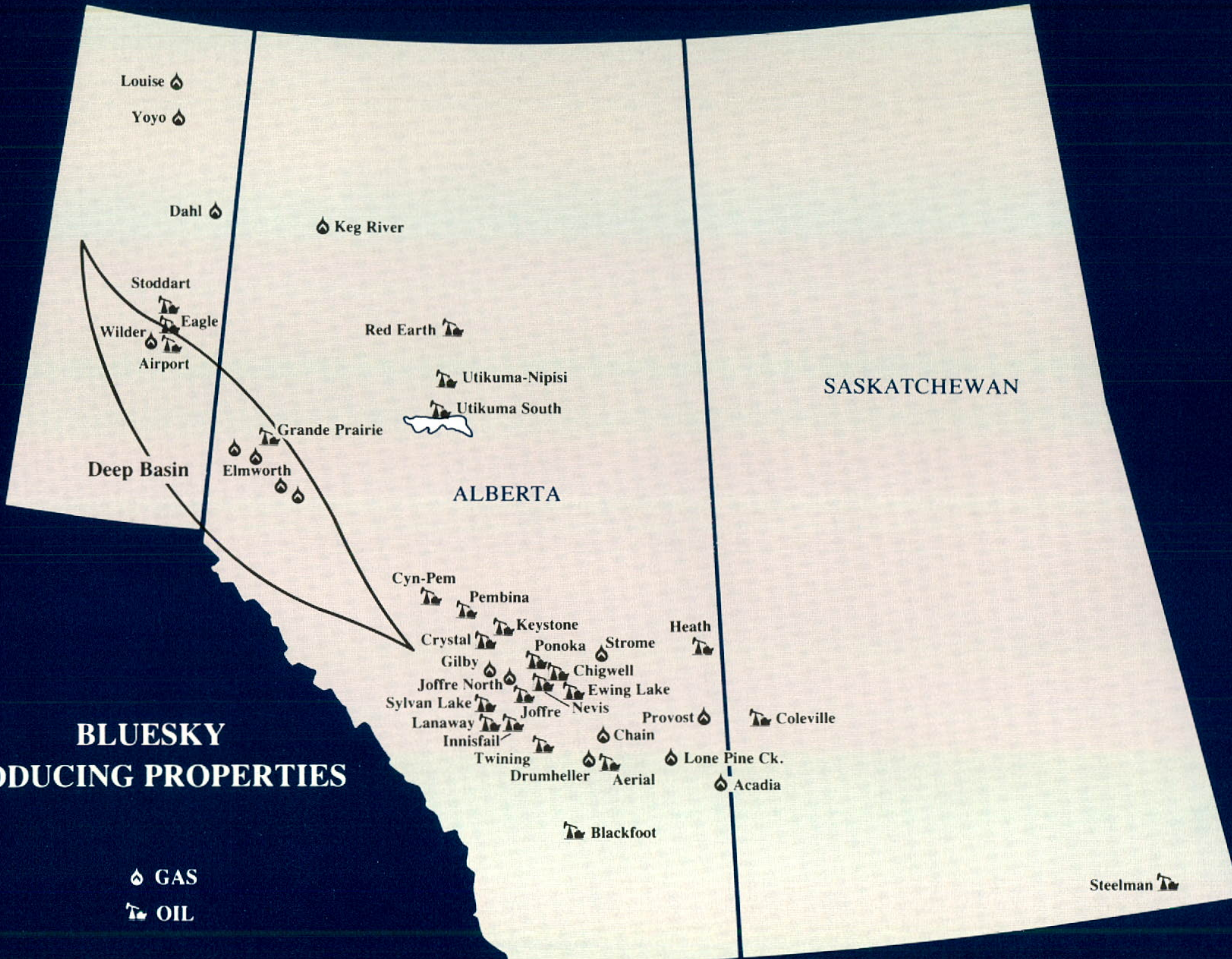
Independent engineering studies of the Company's properties dated April 30, 1985, show the Company's reserves of crude oil, natural gas liquids, and natural gas to be 11,828,800 barrels of oil, 5,105,900 barrels of natural gas liquids, and 234.7 billion cubic feet of natural gas.

These reserves will generate an undiscounted future cash flow of $1,655,535,000 over the life of the properties. At a discount rate of 15% the present worth value of this future cash flow is $300,889,000. These forecasts incorporate changes in crude oil and natural gas prices as a result of the Western Accord of March 28th and reflect current market realities.

Reserve changes over the past year are shown in the following table:

	OIL (MBbls)	NGL (MBbls)	NATURAL GAS (MMCF)
Reserves at April 30, 1984	**12,173.1**	**5,436.5**	**250,754**
Less Production	(804)		(4,311)
Exploration Drilling	297	—	3,600
Development Drilling	651	—	—
Performance Adjustment	(488.1)	(330.6)	(15,378)
Reserves at April 30, 1985	**11,829.0**	**5,105.9**	**234,665**

BLUESKY PRODUCING PROPERTIES



Operations

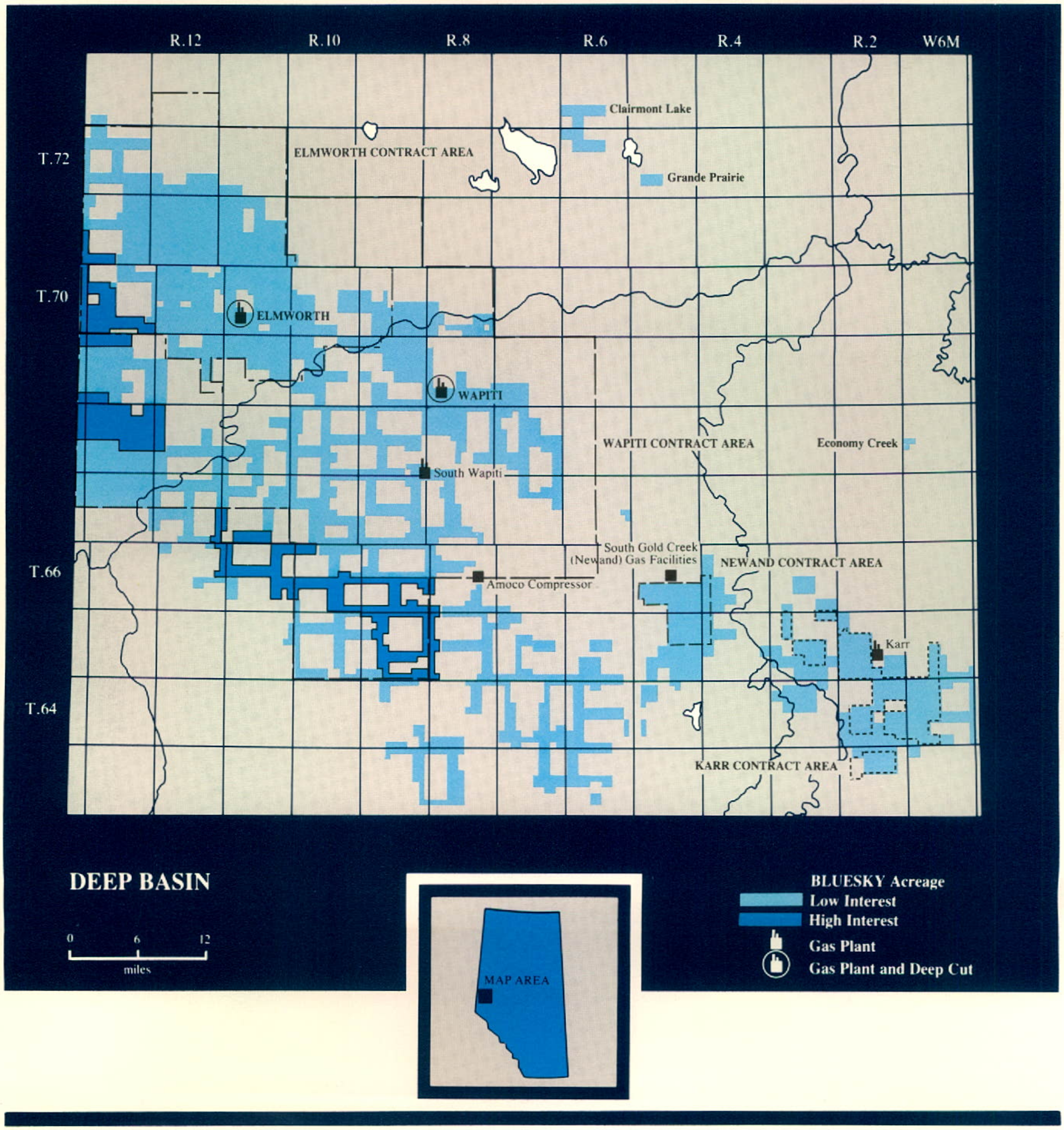
Straddle Plants

Construction of Straddle Plants at Elmworth and Wapiti in the Deep Basin Area of Alberta has proceeded on schedule. The Elmworth Plant commenced production on June 1st and at Wapiti the plant is expected to be completed by September 1st.

Bluesky's share of the cost of these plants will be $1,212,000 and will give the Company the capacity to extract a maximum of 885 barrels per day of natural gas liquids.

In the Deep Basin gas contract areas the Company has an interest in 185 gas wells, 88 of which are currently tied into the production facilities having the capacity to extract liquids from 595 million cubic feet per day.

It is our expectation that throughput at the two plants will average 55 percent of gas contract volumes during the 1985-86 fiscal year resulting in an average recovery of 490 barrels per operating day, net to the Company, or an average of 394 barrels per day for the twelve month period.

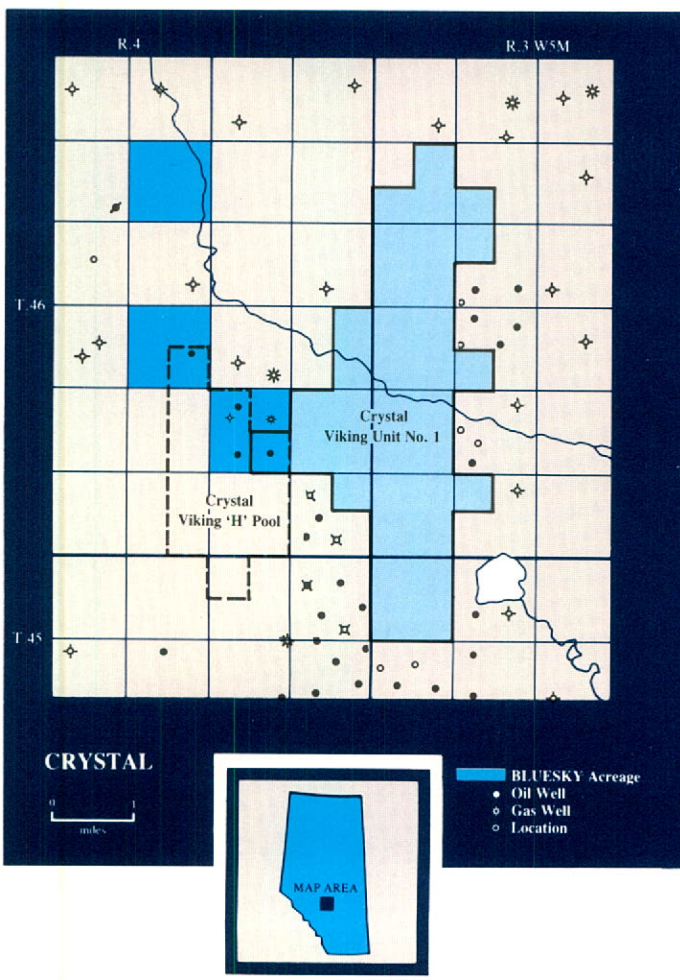


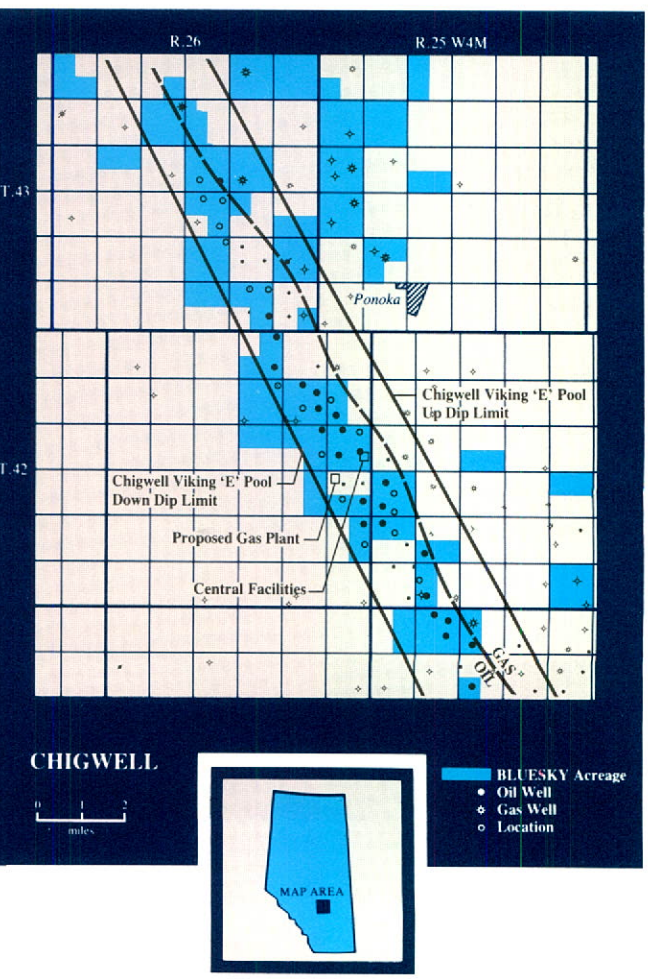
Crystal Field

In the Crystal Viking Unit at Winfield in central Alberta there are now 45 producing wells and 15 water injection wells. Central gathering and production facilities and water flood facilities have been completed at a gross cost of $10 million and water injection into the Viking formation commenced on November 6th, 1984 at a rate of 6,890 barrels of water per day. On February 1st, 1985, the waterflood allowable was received from the Alberta Energy Resources Conservation Board resulting in an increase in the production rate from an initial 2,200 barrels per day to current rates of 6,000 barrels per day. Bluesky's 7.6% interest in this production is now averaging 450 barrels per day and is expected to result in an ultimate oil recovery of 2.2 million barrels net to the Company over the life of the project. Gas Processing Facilities will be in place by the fall of 1985 to conserve five million cubic feet per day of solution gas being produced with the oil. This plant will extract the Natural Gas Liquids for shipment to market and compress and deliver the Natural Gas under the Gas Sales Contract.

Chigwell Viking Field

Bluesky has continued to develop the Chigwell Viking "E" Pool located near Ponoka in central Alberta and now has an average 48% interest in 21 operated wells and five outside operated wells with plans to drill an additional nine wells. These wells initially produce on minimum allowable and currently average 40 barrels per day. Bluesky and its partners will construct central gathering and production facilities during the summer of 1985 at a gross cost of $1,100,000 to treat the oil to pipeline specifications and to allow for gathering and sales of approximately one million cubic feet of solution gas per day. Engineering studies are currently being conducted to determine the feasibility of waterflooding this pool for enhanced recovery of oil.





Financial Review

(Left to Right) Ann Pariseau; Ron Springer, Vice-President, Finance & Secretary; Wayne DeBoice; Andy Gale.

During the past year, the Company realized continued growth in its production derived income, cash flow from operations and its net income before extraordinary income and income tax. However, due to the reduction of the Alberta Royalty Tax Credit from \$2,993,000 to \$2,000,000, the Company's net income before extraordinary income was reduced from \$9,213,000 to \$7,869,000. In addition, the Company realized an extraordinary gain during the year of \$122,000 (net of income tax) which increased the net income to \$7,991,000 for the current year.

On September 30, 1984, the Company redeemed 1,142,244 Series A preferred shares, being all of that class of shares outstanding at that date, at \$5.00 per share for a total cash consideration of \$5,711,000 as required in accordance with the conditions of the shares when issued. The redemption was financed out of the Company's unused bank line of credit which accounts for the majority of the interest expense increase from \$4,998,000 to \$5,912,000. The favorable effect of this redemption is readily shown by the cash flow increase from \$18,388,000 to \$18,720,000 (1.8%) with the resulting cash flow per share increase from 68¢ to 73¢ (7.4%) due to the reduction of the weighted average number of shares outstanding during the year.

The Company's bank line of credit was also increased during the year from \$55,000,000 to \$60,000,000 at prime rate, to maintain the average unused bank line of credit at approximately \$10,000,000 as was available prior to the redemption of the Series A preferred shares.

Effective May 1, 1984, the Company adopted the recommendation of the Canadian Insitute of Chartered Accountants with regard to the translation of its wholly-owned foreign subsidiary's financial statements. Accordingly, all assets and liabilities of Bluesky Oil & Gas Inc., as at April 30, 1985, have been translated at the rate of exchange as at that date while income and expenses have been translated at the average rate in effect during the year. The effect of adopting this policy results in a decrease in the current year's net income of \$170,000 (due to increased depreciation and depletion expenses), an increase in consolidated net assets of \$1,652,000 and an increase in the "equity adjustment from foreign currency translation", being credited to shareholders' equity of \$1,719,000.

Subsequent to the year-end, on June 24, 1985, the Company together with the General Partner of the nine (9) Alberta Limited Partnerships (of which the Company owns an average interest of 78%) submitted a joint request to Revenue Canada for an advance income tax ruling which, if successful, will allow for the winding-up of all of the Alberta Limited Partnerships and for the amalgamation of all of the West German Limited Partnerships into one West German Limited Partnership. The main benefit of this Ruling, if successful, will be the reduction of the Company's share of the Limited Partnerships' general and administrative expenses of approximately \$400,000 to \$500,000 per year.

The Company continues to closely budget both operating income, expenses and capital expenditures and projects a continued growth in gross revenue, net income and cash flow for the 1986 fiscal year. The following table sets forth our projections in thousands of dollars which are prepared on the assumptions set forth in the footnotes that follow.

	Projected 1986		Actual 1985	
	Amount	Per Share	Amount	Per Share
Gross revenue	$34,415	—	$26,582	—
Net income	11,037	42¢	7,991	30¢
Cash flow from operations	24,197	93¢	18,720	73¢

(1) Production derived income is from completed wells as at March 31, 1985 plus projected income from development wells drilled in 1986.

(2) Crude oil and gas prices and production rates:

Oil pricing (per barrel)		Gas pricing (per mcf)		Gas production (% of contract)	
Canadian	$35.00	Canadian — Alberta	$2.40	Alberta	50%
U.S.A.	$26.00	— B.C.	$1.70	B.C.	40%
		U.S.A.	$3.10		

(3) U.S. exchange rate to Canadian funds has been estimated at $1.37:1 for the year.

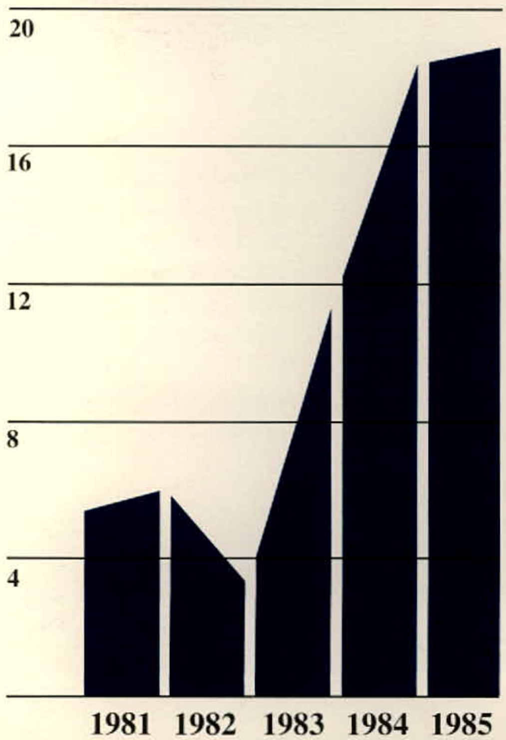
(4) Interest expense has been calculated at the bank prime rate and has been projected to average 10½% for Canadian funds and 10% for U.S. funds for the year.

(5) Alberta Royalty Tax Credit has been calculated at the maximum claim of $2,080.

(6) The Company's June 24, 1985 request for an advance income tax ruling, as explained above, will be approved with the resulting expense reductions commencing January 1, 1986.

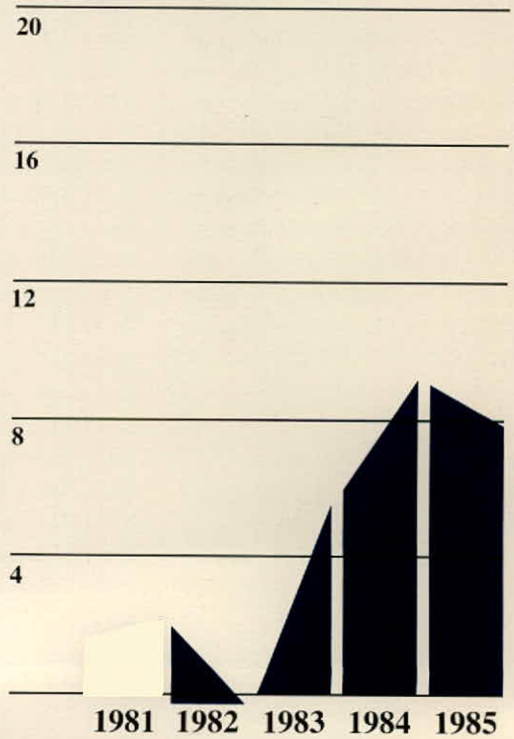
Cash Flow

Millions of dollars



Net Income Before Extraordinary Income

Millions of dollars



BlueSky
Oil & Gas Ltd.

Consolidated Financial Statements

Consolidated Balance Sheet

As At April 30, 1985
(Thousands of Dollars)

	1985	1984
ASSETS		
Current		
Cash in bank	**$ 21**	$ 78
Accounts receivable, trade	**10,507**	9,826
Alberta royalty tax credit receivable	**164**	465
Current portion of agreement receivable (Note 4)	**2,286**	—
Investment in shares, at cost	**12**	2,286
Marketable securities, (market value $1; $108)	**1**	108
Inventories	**253**	209
Current portion of loans receivable	**2,792**	2,621
Prepaid expenses	**97**	99
Share of Limited Partnerships' working capital (Note 2)	**3,496**	3
	19,629	15,695
Property and equipment, at cost		
Petroleum and natural gas properties including well development expenditures	**165,214**	148,719
Share of Limited Partnerships' petroleum and natural gas properties (Note 2)	**39,811**	38,455
Plant and equipment (Note 3)	**26,913**	23,298
Mineral properties	**2,965**	2,680
	234,903	213,152
Less accumulated depreciation and depletion	**19,938**	14,399
	214,965	198,753
Loans receivable on sale of petroleum and natural gas properties	**30,848**	30,923
Less deferred net income thereon	**(30,848)**	(30,923)
	—	—
Other assets		
Other loans receivable	**1,365**	1,384
Notes receivable (Note 10(b))	**1,797**	1,657
Agreement receivable (Note 4)	**2,286**	—
Investment in shares, at cost (Note 4)	**—**	4,392
	5,448	7,433
	$240,042	$221,881

On Behalf Of The Board

Director

Director

The accompanying notes form an integral part of this statement.

	1985	1984
LIABILITIES		
Current		
Accounts payable and accruals	**$ 10,561**	$ 14,189
Deposit on future services	**89**	196
Deferred income	**158**	212
Petroleum and gas revenue tax payable	**253**	849
Income tax payable	**2,408**	80
	13,469	15,526
Deferred take-or-pay income	**6,446**	6,774
Deferred income taxes	**23,283**	18,646
Long term debt (Note 6)	**51,426**	39,568
Deferred exchange gain	**—**	51
	94,624	**80,565**
SHAREHOLDERS' EQUITY		
Share capital (Note 5)		
Common		
Authorized		
100,000,000 shares without par value		
Issued and outstanding		
25,473,792 shares	**110,146**	109,599
Preferred		
Authorized		
2,000,000 shares with a par value of $10.00 each		
Issued and outstanding		
7% Series A cumulative redeemable convertible shares	**—**	5,955
Contributed surplus	**772**	772
Retained earnings	**32,781**	24,990
Equity adjustment from foreign currency translation	**1,719**	—
	145,418	141,316
	$240,042	$221,881

Consolidated Statement of Income and Retained Earnings

For the Year Ended April 30, 1985
(Thousands of Dollars)

	1985	1984
Revenue		
Production derived income, net of royalties and petroleum and gas revenue tax	**$20,464**	$17,413
Turnkey drilling and land net income	**239**	268
Management fees	**65**	104
Interest income	**437**	175
Dividend income	**90**	514
Other income	**702**	470
Share of Limited Partnerships' income (Note 2)	**4,585**	4,555
	26,582	23,499
Expenses		
Production	**2,180**	1,609
General and administrative	**1,806**	1,719
Interest	**5,912**	4,998
Depletion and depreciation	**4,021**	2,945
	13,919	11,271
Net income before income tax and extraordinary income	**12,663**	12,228
Income tax		
Alberta royalty tax credit	**(2,000)**	(2,993)
Income tax provision (Note 7)	**6,794**	6,008
Net income before extraordinary income	**7,869**	9,213
Extraordinary income		
Gain on redemption of preferred shares, net of $70 of income tax (Note 4)	**122**	—
Net income	**7,991**	9,213
Retained earnings, beginning of period	**24,990**	16,194
Preferred share dividends	**(200)**	(417)
Retained earnings, end of period	**$32,781**	$24,990

The accompanying notes form an integral part of this statement.

Consolidated Statement of Changes in Financial Position

For The Year Ended April 30, 1985
(Thousands of Dollars)

	1985	1984
Financial resources were provided by		
Operations		
Net income before extraordinary income	**$ 7,869**	$ 9,213
Add non-cash items		
Depletion and depreciation	**4,731**	3,601
Deferred income tax	**6,120**	5,574
	18,720	18,388
Proceeds on sale of securities	**—**	1,057
Less notes applicable thereto	**—**	(1,057)
	—	—
Proceeds on redemption of preferred shares (Note 4)	**4,556**	—
Less agreement receivable	**(2,286)**	—
	2,270	—
Decrease in investment in shares	**12**	2,286
Foreign exchange translation adjustment	**75**	44
Proceeds on issue of shares		
Common	**547**	605
Series A Preferred converted to common	**(244)**	—
Less notes applicable thereto	**(140)**	(600)
	163	5
Increase (decrease) in long term debt	**10,261**	(2,561)
Decrease (increase) in other loans receivable	**33**	(1,203)
	31,534	16,959
Financial resources were used for		
Purchase of property and equipment		
Petroleum and natural gas properties	**13,865**	12,225
Plant and equipment	**2,802**	1,803
Mineral properties, net of recoveries	**(19)**	(138)
Share of Limited Partnerships' petroleum and natural gas properties	**1,356**	1,903
	18,004	15,793
Decrease (increase) in deferred take-or-pay	**328**	(80)
Current income tax on previously reported extraordinary gain	**1,300**	—
Redemption of Series A preferred shares	**5,711**	—
Preferred share dividend	**200**	417
	25,543	16,130
Increase in working capital	**5,991**	829
Working capital (deficiency), beginning of period	**169**	(660)
Working capital, end of period	**$ 6,160**	$ 169

The accompanying notes form an integral part of this statement.

Notes to Consolidated Financial Statements

As At April 30, 1985

(Amounts Expressed in Thousands of Dollars Except for Per Share Amounts)

1. Significant Accounting Policies

These financial statements have been prepared in accordance with generally accepted accounting principles in Canada, which do not differ significantly from International Accounting Standards except no presentation has been made to provide for the effects of either specific or general price level changes. Accordingly, these financial statements reflect the following policies:

Basis of consolidation

The consolidated financial statements have been prepared based on the April 30, 1985 financial statements of the Company and its wholly-owned subsidiaries Bluesky Oil & Gas Inc. and Bluesky Mining Ltd.

Translation of foreign subsidiary accounts

The accounts of the Company's wholly-owned United States subsidiary, Bluesky Oil & Gas Inc., have been translated to Canadian dollars using the current rate method applicable to a self-sustaining operation. Accordingly, assets and liabilities are translated at the year end exchange rate, while income and expenses are translated at average rates in effect during the year. Exchange gains or losses arising from the translation of assets and liabilities are included as a separate component of Shareholders' Equity.

The Company has adopted this policy on a prospective basis effective May 1, 1984. For all prior periods, the Company translated the accounts of Bluesky Oil & Gas Inc. on the following basis:

Classification	Rate of Exchange
a) Current assets and liabilities	— rates in effect at balance sheet date
b) Loans receivable and deferred income thereon	— rates in effect at balance sheet date
c) Other non-current assets and liabilities	— historic rates in effect when incurred
d) Revenue and expense accounts	— average rate in effect throughout the year.

The effect of adopting this policy results in a decrease in net income of $170 and an increase in net assets of $1,652.

Sale of interest in petroleum and natural gas properties

The Company has sold its interest in various petroleum and natural gas properties pursuant to a number of drilling program agreements. Under the terms of the agreements, the amounts receivable by the Company are due in annual instalments over a period of 30 years commencing in 1978, 1979, 1981, 1982 and 1985. Because of the extended period over which these amounts are due, the Company intends to recognize income from the sale of its interests in these petroleum and natural gas properties in the year in which payments are received.

Under the various drilling program agreements, the Company earns an income calculated as the amount by which from 18% to 40% of the annual net production revenue to the purchaser from each petroleum and natural gas well, sold under the agreements, exceeds the loan principal payable during the year.

Costs of interests in petroleum and natural gas properties

The Company accounts for its investment in exploration and development activities under the full cost method of accounting. All costs related to the acquisition and development of petroleum and natural gas properties are capitalized. Such costs include land acquisition costs, geological and geophysical costs, lease costs on non-producing properties, costs of drilling both productive and non-productive wells, and overhead related to exploration activities. These costs are reduced by the proceeds from the sale of oil and gas properties and by government grants.

The Company compares the carrying value of its investment in petroleum and natural gas properties to the estimated net present value of cash flow from its oil and gas properties discounted at the Company's cost of capital, net of a provision for income taxes. Any excess of carrying values over estimated future cash flow resulting from this comparison is charged against operations.

Mineral properties

Acquisition and exploration costs of mineral properties are capitalized pending further development of the properties and accordingly the recovery of this investment is dependent upon the discovery of mineral reserves in commercial quantities. These costs are reduced by royalty advances received pursuant to various farmout agreements.

Inventories

Inventories consist of oilfield supplies and are carried at the lower of cost and net realizable value.

Depletion

Exploration and development costs are accumulated in a North American cost centre and depleted under the revenue method of depletion.

Depreciation

Depreciation of plant and equipment is provided under the straight-line method at rates considered to be sufficient to amortize the costs of these assets over their estimated useful lives.

Deferred income

Deferred income is comprised of drilling, geological and management fee income to be earned pursuant to various drilling program agreements. The Company follows the completed-well method of accounting for drilling income and costs, pursuant to the various drilling program agreements. Under this method the income and costs thereon of each well are deferred until the well is completed and all costs pertaining thereto have been approved and recorded, at which time they are taken into income. Management fee income is deferred until the well is spudded, at which time it is taken into income.

Income taxes

The Company follows the tax allocation method of accounting for income taxes. Under this method, the Company provides for deferred income taxes to the extent that income taxes otherwise payable are deferred by claiming capital cost allowance and expensing exploration and development costs, for tax purposes, in excess of the depreciation and depletion provisions reflected in the financial statements.

2. Investment in Limited Partnerships

The Company holds interests in ten West German Limited Partnerships varying from 66.0% to 84.6% of the total Limited Partnerships' interest. Accordingly, the Company has recorded its proportionate share of increases and decreases of the Limited Partnerships' assets, liabilities and earnings since acquisition.

The Company's proportionate share of increases and decreases of the Limited Partnerships' assets, liabilities and earnings for the year ended April 30, 1985 are as follows:

A. Investment in Limited Partnerships

	Share Of Working Capital	Share Of Petroleum and Natural Gas Properties	Total
As at April 30, 1984, net	$ 3	$ 37,138	$ 37,141
Share of net income May 1, 1984 to April 30, 1985	4,585	—	4,585
Share of petroleum and natural gas property additions	(1,356)	1,356	—
Depletion expense	710	(710)	—
Company's proportionate share of interest income eliminated against interest expense paid by the Company	246	—	246
Withdrawals	(692)	—	(692)
As at April 30, 1985, net	$ 3,496	37,784	$ 41,280
Accumulated depletion as at April 30, 1985		2,027	
As at April 30, 1985, gross		$ 39,811	

B. **Share of Limited Partnerships' Income**

	1985	1984
Revenue		
Production derived income, net of royalties	$9,365	$10,404
Interest income	215	232
Other income	84	81
	9,664	10,717
Expenses		
Production	1,549	1,517
General and administrative	785	1,168
Interest	2,035	2,821
Depletion	710	656
	5,079	6,162
Share of Limited Partnerships' income	$4,585	$ 4,555

3. Plant and Equipment

	April 30, 1985			April 30, 1984
	Cost	Accumulated Depreciation	Net Book Value	Net Book Value
Production equipment	$15,257	$4,962	$10,295	$ 9,712
Plant and gathering equipment	9,485	2,913	6,572	5,497
Office equipment	2,171	1,427	744	1,011
	$26,913	$9,302	$17,611	$16,220

4. Agreement Receivable

Pursuant to the terms of an agreement dated July 3, 1984, 381,041 cumulative 7½% preferred shares with a par value of $18.00 per share in a private company were redeemed. Under the terms of the agreement the first principal payment of $2,286 was received on July 3, 1984. The remaining principal owing of $4,572 is payable in two equal instalments of $2,286 together with accrued interest at 7½% per annum due January 31, 1986 and January 31, 1987. Both payments of principal and interest are secured by irrevocable bank letters of credit.

In accordance with the terms of payment, $2,286 plus accrued interest has been classified as a current asset as at April 30, 1985.

5. Share Capital

A. **Common Shares**

(a) During the year, the Company issued the following common shares:

	Number Of Shares Issued	Amount
Pursuant to conversion of Series A preferred shares	48,680	$ 244
Pursuant to exercise of employee share options	96,733	303
Balance issued April 30, 1984	28,503,179	109,599
	28,648,592	110,146
Less shares held by subsidiary at cost	3,174,800	—
Issued and outstanding, April 30, 1985	25,473,792	$110,146

As at April 30, 1985, the Company's wholly-owned subsidiary, Bluesky Oil & Gas Inc., owned 3,174,800 shares of the Company's common shares which represents 11.08% of the common shares then issued. Under an Agreement dated October 11, 1979, the Company has granted an option to a Director to purchase 48,000 of the shares then owned by the subsidiary at a price of $5.00 per share. Under the Agreement, the Director may elect to purchase 25% of the shares each year commencing October 1, 1979 of which 12,000 have been exercised.

(b) Employee Stock Option Plan

Options granted during the year at a price of $3.57 per share	25,000
Options granted during the year at a price of $4.20 per share	35,000
Options cancelled during the year	(43,667)
Net granted during the year	16,333
Options exercised during the year	(96,733)
Balance outstanding, April 30, 1984	678,750
Balance outstanding, April 30, 1985	598,350
Shares reserved under the Employee Stock Option Plan as at April 30, 1985	403,317

The above options are exercisable at prices ranging from $3.00 per share to $4.20 per share and expire within 1 or 3 years.

B. **Preferred Shares**

During the year, the authorized share capital of the Company was increased to $20,000 through the creation of 2,000,000 Preferred Shares with a par value of $10.00 per share. These shares may be issued in series. The existing 3,000,000 Preferred Shares having a par value of $5.00 per share were cancelled.

C. **Series A 7% Cumulative, Redeemable, Convertible Preferred Shares**

Balance issued, April 30, 1984	1,190,924
Converted to common shares	(48,680)
Redeemed	(1,142,244)
Balance issued, April 30, 1985	—

In accordance with the conditions of the Series A preferred shares, all of the Series A preferred shares outstanding as at September 30, 1984 were redeemed by the Company. Accordingly, 1,142,244 preferred shares were redeemed at $5.00 per share for a total cash consideration of $5,711.

6. Long Term Debt

During the year, the Company renewed its bank line of credit of $60,000 with interest at the bank prime rate, letter of credit availability of $5,600, tender credit facility of $1,000 for purposes of bidding at Crown lease sales and its $500 cheque cashing facility in New York for Bluesky Oil & Gas Inc. The bank line and additional credit facilities are secured by a debenture with a floating charge on the assets of the Company. The bank line may be utilized by the Company at any time up to December 1, 1986 and the Company has the option to convert the outstanding balance to a five year term loan with interest at bank prime rate plus ½%.

In accordance with the terms of the loan agreement, the April 30, 1985 loan balance of $51,426 has been classified as a long term debt. This amount includes $11,000 of U.S. dollar loans.

7. Income taxes

The provision for income taxes for the year ended April 30, 1985 of $6,794, (1984 - $6,008) has been determined as follows:

	1985	1984
Income before extraordinary income and taxes	$ 12,663	$ 12,228
Corporate income tax at 47.32% (1984 - 47.32%)	$ 5,992	$ 5,786
Add (deduct) the tax effect of		
Non-deductible crown charges	5,489	5,382
Earned depletion and resource allowance	(4,972)	(5,033)
Elimination of partnerships' net revenue interest income disallowed as a deduction for income tax	500	419
Provincial resource royalty rebates	(206)	(42)
Federal investment tax credit	(111)	(127)
Depletion provision with no corresponding tax deduction	94	(245)
Non-taxable dividend income	(42)	(243)
Corporate surtax	—	109
Miscellaneous	50	2
Total income tax provision	$ 6,794	$ 6,008

8. Net Earnings Per Common Share

	1985	1984
(a) Basic		
Net earnings, before extraordinary income	30.2¢	34.9¢
Net earnings	30.6¢	34.9¢
(b) Fully diluted		
Net earnings, before extraordinary income	—	34.0¢
Net earnings	—	34.0¢

Net earnings per common share calculations exclude shares owned by the Company's wholly-owned subsidiary and are based on the monthly weighted average number of common shares outstanding after dividend requirements on the Series A preferred shares.

Where the exercise of the options referred to in Note 5 are non-dilutive, the fully diluted earnings have not been presented.

9. Remuneration of Directors and Senior Officers

Remuneration paid to directors amounted to $12 and to senior officers (including the five highest paid employees) of the Company amounted to $742.

10. Related Party Transactions

(a) The various drilling program agreements under which the Company earns revenue, as referred to in Note 1, are with the ten West German Limited Partnerships in which the Company holds an interest as per Note 2.

(b) During the year, the Company issued loans to two officers of the Company totalling $140 at an interest rate of 10% per annum pursuant to the exercise of share options as referred to in Note 5A(b). As at April 30, 1985 loans outstanding to officers of the Company totalled $1,797 of which $1,057 is interest free and $740 bears interest at a rate of 10% per annum.

11. Segmented Information

In view of the different economic environment under which the oil and gas industry operates in Canada and the United States, segmented information is presented on a geographical basis separating the Company's operations and total assets between Canada and the United States. The Company operates only in one business segment.

	1985			1984		
	Canada	United States	Total	Canada	United States	Total
Revenue	$ 23,540	$ 3,042	$ 26,582	$ 20,781	$ 2,718	$ 23,499
Expenses						
Depletion and depreciation	3,199	822	4,021	2,367	578	2,945
Other	3,559	427	3,986	2,935	393	3,328
	6,758	1,249	8,007	5,302	971	6,273
Segmented income before undernoted items	$ 16,782	$ 1,793	$ 18,575	$ 15,479	$ 1,747	$ 17,226
Interest expense			5,912			4,998
Income tax			4,794			3,015
Net income before extraordinary income			7,869			9,213
Gain on shares, net of $70 of income tax			122			—
Net income			$ 7,991			$ 9,213
Total Assets	$218,541	$21,501	$240,042	$191,854	$30,027	$221,881

Auditors' Report

TO THE SHAREHOLDERS

We have examined the consolidated balance sheet of Bluesky Oil & Gas Ltd. as at April 30, 1985 and the consolidated statements of income and retained earnings and of changes in financial position for the year then ended. Our examination was made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as we considered necessary in the circumstances.

In our opinion, these consolidated financial statements present fairly the financial position of the Company as at April 30, 1985 and results of its operations and the changes in its financial position for the year then ended in accordance with generally accepted accounting principles applied, except for the change in method of accounting for foreign currency translation as explained in Note 1 to the financial statements, on a basis consistent with that of the preceding year.

Deloitte Haskins + Sells.
Chartered Accountants

Calgary, Alberta
July 4, 1985

Consolidated Five Year Summary

For The Years Ended April 30

	1985	1984	1983	1982	1981
Financial					
Earnings					
Production derived income, net of royalties	**$ 20,464**	$ 17,413	$ 13,441	$ 9,649	$ 8,021
Total revenue	**$ 26,582**	$ 23,499	$ 18,615	$ 14,656	$ 11,074
Net income (loss) before extraordinary income	**$ 7,869**	$ 9,213	$ 5,345	$ (144)	$ 2,170
Cash flow from operations	**$ 18,720**	$ 18,388	$ 11,574	$ 3,231	$ 6,653
Earnings (loss) per share, before extraordinary income	**30.2¢**	34.0¢	19.9¢	(6.6)¢	11.5¢
Cash flow per share	**72.8¢**	67.9¢	45.0¢	15.8¢	40.6¢
Capital					
Property and equipment	**$234,903**	$213,152	$197,359	$151,161	$108,116
Total assets	**$240,042**	$221,881	$204,747	$179,041	$187,866
Operational					
Reserves					
Natural gas (million cubic feet)	**234,665**	250,754	263,900	147,530	168,900
Oil (thousands of barrels)	**11,829**	12,173	11,342	8,453	8,609
Natural gas liquids (thousands of barrels)	**5,106**	5,437	—	—	—
Year's production					
Natural gas (million cubic feet)	**4,312**	5,339	3,845	2,797	1,872
(million cubic feet per day)	**11.81**	14.59	10.53	7.66	5.13
Oil (thousands of barrels)	**804**	679	569	342	297
(barrels per day)	**2,203**	1,856	1,560	937	812
Drilling					
Total wells	**109**	85	51	126	297
Gas completions	**16**	22	15	43	145
Oil completions	**57**	48	28	49	95
Success ratio (percentage)	**74%**	82%	84%	76%	81%
Land holdings					
Gross (thousand acres)	**5,354**	5,740	7,994	13,005	12,843
Net (thousand acres)	**321**	353	479	415	480

Corporate Information

Directors

Dr. Ulrich Christopeit
Managing Director, Deutsche Tiefbohr AG, Bad Bentheim, West Germany

Barry W. Harrison*
President & Chief Executive Officer
Calgary, Alberta

Klaus Hebben*
President, eee Gesellschaft zur Exploration von Erdol und Erdgas mbh
Munich, West Germany

John A. Masters
President, Canadian Hunter Exploration Ltd.
Calgary, Alberta

Ronald W. Springer*
Vice-President, Finance & Secretary
Calgary, Alberta

Dr. Dietrich H. Welte
Director of Institute of Research for Petroleum and Organic Chemistry at the Nuclear Research Centre
Juelich, West Germany

Robert A. Wisener*
Managing Partner, The MerBanco Group
Calgary, Alberta

*Member of the Executive Committee

Key Employees

Barry W. Harrison
President & Chief Executive Officer

Arthur C. Eastly
Vice-President, Production

Ronald W. Springer
Vice-President, Finance & Secretary

Wayne S. Tait
Vice-President, Land

Clem J. Benteau
Exploration Manager

Gordon J. Kerr
Corporate Controller

Daryl W. Cook
Manager of Engineering

James G. Feeney
Manager of Operations

Wholly-owned Subsidiaries

Bluesky Oil & Gas Inc.
Bluesky Mining Ltd.

Auditors

Deloitte Haskins & Sells
#2300 Bow Valley Square III
225 - 5th Avenue S.W.
Calgary, Alberta
T2P 3G6

Registrar & Transfer Agent

Canada Trust Company Ltd.
Calgary, Toronto, Vancouver

Exchange Listings

The Toronto Stock Exchange
Trading Symbol: BKY

NASDAQ (U.S.A.)
Trading Symbol: BLUSF

Offices

Bluesky Oil & Gas Ltd.
#700 BP House
333 - 5th Avenue S.W.
Calgary, Alberta
T2P 3B6 (403) 263-0690

Metric Conversion Table

Traditional Unit	S1 Unit	Conversion Factor
Barrel	Cubic Metre (m^3)	1 Barrel = 0.15891 Cubic Metre 1 Cubic Metre = 6.293 Barrels
Cubic Foot	Cubic Metre (m^3)	1 Cubic Foot = 0.02817 Cubic Metre 1 Cubic Metre = 35.494 Cubic Feet
Foot	Metre (m)	1 Foot = 0.30480 Metre 1 Metre = 3.281 Feet
Mile	Kilometre (km)	1 Mile = 1.60934 Kilometres 1 Kilometre = .621 Mile
Acre	Hectare (ha)	1 Acre = 0.40469 Hectare 1 Hectare = 2.471 Acres

BlueSky

Oil & Gas Ltd.

1985 ANNUAL REPORT

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