1982 ANNUAL REPORT
WORLDWIDE ENERGY CORPORATION

Shareholder Communications

If you own shares of Worldwide Energy Corporation held in a brokerage name and would like to receive corporate information and reports directly, please write to Lori H. Muth, Shareholder Relations, Suite 1600-1700 Broadway, Denver, Colorado, 80290. Please include the name of the brokerage house that administers your account and the number of shares you own. Similarly, if you receive more than one mailing of materials or your address is incorrect and you wish to have it corrected, please contact Lori H. Muth.

Form 10-K

For the sixth consecutive year, Worldwide Energy Corporation's Form 10-K Annual Report as filed with the Securities and Exchange Commission is included as part of this Annual Report to Shareholders. Exhibits to the Form 10-K are not included, however, copies of such exhibits may be obtained, upon payment of $0.25 per page, by writing to the attention of the Corporate Secretary, Suite 1600-1700 Broadway, Denver, Colorado, 80290.

Annual Meeting Date:
June 10, 1983
10:00 a.m.

Commerce Court
King and Bay Streets
Commerce Hall, Concourse Level
Toronto, Ontario, Canada

Five Year Highlights Comparison
(000's omitted, except per share)

	1982	1981	1980	1979	1978
Financial Data					
Oil and gas sales	**$25,431**	$19,648	$16,530	$ 9,882	$ 7,686
Gas gathering & transmission	**32,187**	33,369	26,312	23,637	3,946
Other	**1,159**	1,457	891	419	456
Total Revenues	**58,777**	54,474	43,733	33,938	12,088
Funds provided by operations	**9,990**	6,072	8,545	5,784	3,598
Income (loss) before taxes	**1,437**	(728)	4,051	2,906	1,743
Net income (loss)	**857**	(574)	3,250	2,705	1,382
Net income (loss) per share	**0.09**	(0.06)	0.35	0.35	0.20
Total assets	**113,267**	90,785	75,376	51,206	45,186
Average shares outstanding	**9,203**	9,110	9,262	7,690	6,972
Operating Data					
Reserves - net					
conventional oil (bbls)	**1,846,453**	2,574,605	3,357,645	3,316,327	3,353,139
heavy oil (bbls)	**3,817,117**	1,324,537	1,165,159	951,036	582,273
natural gas (mmcf)	**61,804**	89,331	73,182	52,088	44,472
Daily production - net					
conventional oil (bbls)	**1,106**	1,109	935	884	966
heavy oil (bbls)	**544**	536	519	376	127
natural gas (mcf)	**14,071**	11,405	10,117	9,477	10,614
Net wells owned					
- oil	**158**	162	161	142	134
- gas	**69**	63	70	69	58
- service	**42**	43	45	47	49
- shut-in*	**195**	172	145	138	122

*includes wells temporarily shut-in for waterfloods

The above highlights are a summary only; your attention is directed to the Form 10-K Annual Report, included herein, for detailed information.

Profile

Worldwide Energy Corporation is a thirty year old company that explores for, develops, and produces petroleum in the United States and Canada. Its operations in Canada are conducted by its 95%-owned Canadian Worldwide Energy Limited, engaged importantly in the development of heavy oil deposits. A principal goal for 1983 is to expand its domestic operating activities through development of the Company's properties and through acquisitions.

To Our Shareholders:

Worldwide Energy Corporation achieved considerable progress in 1982, a year characterized as difficult for both the petroleum industry and world economies in general. While economic indicators at present may not definitively be signalling a recovery and conditions within the petroleum industry remain very unsettled, I am pleased to report that our Company is experiencing the growth we forecast in last year's annual report. We believe that the corporate decisions previously enacted and those in the process of now being implemented will increase significantly our consolidated cash flow as well as position Worldwide Energy Corporation to take advantage of the many opportunities presented by these unsettled times within our industry.

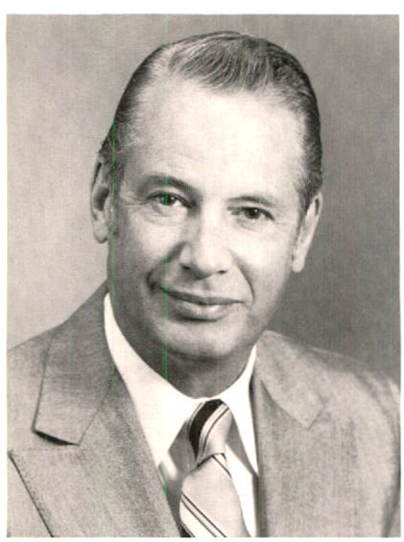
We want our Company to be in a prime position to benefit from the current situation. Toward this aim, let me explain some of the steps we have taken already and will take in the future.

Canadian Worldwide Energy Limited, our Canadian operating subsidiary, commenced the Phase III expansion of the Fort Kent heavy oil project early last year. This C$73 million expansion now is nearing completion, with 92 wells having been drilled at this writing, additional steam generating capacity nearing operation, and the production wells being sequentially steamed and placed on production. Early production results from Phase III are encouraging. In November of 1982, Canadian Worldwide began deliveries of natural gas to Celanese Canada Inc. for its expanded petrochemical plant near Edmonton, Alberta. Changes to our basic agreement with Celanese recently have been initiated which have the effect of increasing our near-term cash flow from this contract.

Over the years we have invested a substantial amount of funds, time and management effort into the development of our Canadian assets. I am pleased to be able to say that the substantial values which we perceived are now becoming realities. Towards this end, we have been taking steps since last Fall to establish our Canadian subsidiary, Canadian Worldwide Energy Limited, as a public entity. In spite of a lethargic investment climate for oil stocks, a C$16 million public offering of 400,000 units at C$40 each was completed in March, 1983. Each unit consists of two C$20 face value convertible preferred shares, with a dividend rate of 9¼%, and one common share of Canadian Worldwide. The preferred shares are convertible into common at a price of C$6.50 for a period of 10 years. Two-thirds of the proceeds were received by Canadian Worldwide for use in further expanding its Canadian oil and natural gas activities, while we received the balance which has been utilized to improve our domestic financial position. Worldwide continues to own approximately 95% of Canadian Worldwide's outstanding common equity and, assuming full dilution from conversion, will own 76%.

Establishing this public market for our Canadian assets is an important step. While increasing the Canadian ownership for purposes of living with the Canadian National Energy Program, it will also help in determining a value for these assets over time. Perhaps more importantly, the cash infusion solidifies Canadian Worldwide's balance sheet. Now public, Canadian Worldwide has greater financial flexibility with direct access to capital markets so that it can be financially self-sufficient.

We have pared and continue to pare our



Left: Robert B. Tenison, President

Right: Arthur R. Smith, Chairman of the Board

Facing Page: 1982 Directors (l-r) James B. Owen, Barron C. Housel, Robert B. Tenison, J. Kenneth Boyles, William C. Jones, III commitments to new ventures domestically, implementing new criteria for evaluating exploratory prospects and development situations. We also implemented a re-evaluation of our existing assets. Those exploratory situations not meeting our criteria will not be undertaken, and those assets not meeting our objectives or needs will be invested in ventures with higher profit potentials. An additional benefit of this re-evaluation has been the elimination of a significant amount of corporate overhead.

Our goal for 1983 is to work toward increasing our domestic operations now that our Canadian operations have been placed on a solid footing. There are two immediate methods by which we intend to attain this goal. One is the exploitation of in-house development opportunities and the other is growth through acquisition, both of which will be made more viable by our strengthening financial condition. As regards the former, we have been examining our existing properties with a view toward their possible further development potentials. These potentials, for instance, may be in different producing horizons, on different spacing arrangements, or may result from the improved capital economics within the industry. This examination has shown considerable initial promise in at least two geographic areas, such that we plan to concentrate a substantial portion of our capital budget this year toward early development of these areas.

Acquisition of producing properties as well as those possessing development possibilities is also an attractive method for us to exploit at this juncture. We believe the difficulties being experienced by the petroleum industry at present, when combined with our increasing financial and fundamental strengths, could place us in an advantageous position to pursue the acquisition of desirable assets. These acquisitions might be of either public or private companies or parts of such, and may be accomplished by ourselves or in conjunction with other companies.

We look forward with enthusiasm to the coming year. Canadian Worldwide Energy Limited is now poised for further growth. Funds it received from its underwriting of convertible preferred shares will place it in an advantageous position to develop new Canadian properties as they become available. Worldwide Energy Corporation will be concentrating its resources domestically upon development drilling opportunities and broadening its financial and operating bases through suitable acquisitions.

We look forward to a period of stabilization and then a resumption of growth for the petroleum industry. However, in the meantime, we must not lose sight of the fact that domestic petroleum companies can sell every barrel of oil they are capable of producing and that, as a general economic recovery progresses, the natural gas market could revive in a dramatic fashion. Ours is an industry that constantly must replenish its basic stock in trade: reserves. We intend to work during this particular period to build our domestic reserve base and productive capability as well as to strengthen our Company financially so that we will emerge stronger than we have been. Your continued understanding of this effort is, as always, appreciated.

Sincerely,

Robert B. Tenison

Robert B. Tenison
President

April 5, 1983

Exploration

The Company sharply reduced exploratory activities last year from 1981 levels as increasing uncertainty regarding product prices emerged during the year. The Company curtailed, except for projects to which it already was committed, its exploration exposure and attendant risks in June. This proved to be a judicious decision, inasmuch as exploration costs have fallen by an important degree, while the quality of potential exploratory ventures being examined has risen. The two domestic exploratory wells in which the Company participated, with an average 30.00% interest, were dry and abandoned. This compared to an exploratory participation in eighteen wells during 1981 with a net interest averaging 37.22%, as more fully set forth in the table below. Not reflected in the table is the Company's participation in three (0.3 net) dry holes in Fiji. A determination of the status of the Company's holdings in Fiji is underway; any abandonment of these holdings would result in a direct charge against earnings.

Exploratory Drilling Activity

	Oil		Gas		Dry		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
1982	—	—	—	—	**2**	**0.6**	**2**	**0.6**
1981	6	1.6	2	1.4	10	3.7	18	6.7
1980	2	1.2	—	—	1	0.2	3	1.4

Development

Development of reserves on a perpetual basis is necessary to sustain as well as rebuild cash flows in a natural resource company; this effort therefore needs to be undertaken throughout the pricing cycle of any commodity. The same factors which have reduced exploratory costs by and large can be applied to development drilling situations. Therefore, the Company's efforts proceeded last year and are scheduled for continued emphasis in 1983.

Development Drilling Activity

	Oil		Gas		Dry		Service		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
1982	**15**	**6.1**	**4**	**0.2**	**2**	**1.3**	—	—	**21**	**7.6**
1981	20	6.6	6	0.7	6	2.3	1	0.7	33	10.3
1980	21	12.5	6	1.3	4	1.4	—	—	31	15.2

Operations

Domestic oil production averaged 976 bpd last year compared to 977 bpd in 1981 while natural gas production averaged 5,569 mcf per day compared to 5,594 mcf per day. Prices received rose 20.4% for natural gas, to $2.18 per mcf; and fell 7.6% for oil to $32.85. Direct production costs per equivalent barrel fell 6.9%, to $9.79.

In the Sunshine Field, Smith County, Texas, development continued in 1982 with the completion of two producing wells; drilling since yearend is believed to have established the reservoir limits. Net Company production from the Sunshine Field in 1982 averaged 400 BOPD and 2,095 mcf of gas per day. This represents a 13% increase in net oil production due to the new well completions and increased operating efficiencies and a 13% increase in gas production in spite of depleting reservoir pressures. These depleting reservoir pressures may increase the efficiency of the proposed Sunshine Field waterflood, which had been planned for 1982 but was delayed due to the on-going field development as described above. Recent engineering studies by the Sunshine Unit Engineering Committee indicate that the Rodessa formation responds more favorably to waterflooding efforts which are begun with lower, rather than higher, initial reservoir pressures. The Company expects substantial, though as yet undetermined, reserves to be added by waterflooding. Unitization of the field should be accomplished by mid-1983 and waterflooding commenced later in the year. Reserve increments as a result of the waterflood may occur as early as the last quarter of 1983. Production will continue to decline during the initial waterflood phase, but then is expected to experience recovery and stabilization.

Worldwide currently operates 64 (gross and net) producing wells and 27 (gross and net) injection and disposal wells on two separate lease areas in Duval County, Texas. Net production from these properties is currently about 340 BOPD, coming from old, shallow (5,000 feet) producing wells, many of which have been under waterflood in excess of twenty years. Many of the leases held by the Company's shallow oil production also contains the deeper oil and gas rights. Worldwide is currently closely following deep development work to the north and east being accomplished by other companies in the Wilcox formation at about 12,000 feet as this may prove its acreage attractive for Wilcox gas development in the future.

In Irion County, Texas, the O.H. Triangle Field was consolidated with the Probandt Field in 1982. Production from the Schlinke 18-1 has been curtailed to about 350 mcf per day by field rules imposed by the Texas Railroad Commission, although the well is capable of producing about 1000 mcf per day. The Schlinke 17-1 has experienced mechanical difficulties which are being corrected. The Schlinke 41-1 has been tested for production in two formations, the Clearfork and the Wolfcamp, and recently was recompleted in the Canyon formation. In the remainder of the Probandt Field, the Company has non-operating working interests in the Bellows, Smith, Richey, Harris, and McManus blocks, with interests varying from 6.25% to 25.00%. During 1982, there were twelve wells drilled on these leases (1.375 net to Worldwide), with eleven (1.125 net) completed as producers and one (0.25) dry hole.

The Company had budgeted for seven gross (1.19 net) development wells in this portion of the Probandt Field in 1983, contingent upon a lifting of the fieldwide curtailments now in effect due to market conditions.

Domestic reserves, estimated by the Company's Reserve and Evaluation Engineering Group were as follows:

Domestic Proven Reserves
(thousands of barrels, millions of cubic feet)

	1982	1981	1980
oil	**1,588**	2,188	2,654
gas	**18,770**	17,614	16,562

In total at this point, the Company has budgeted 22 development wells in which it will have in excess of an average 40% net revenue interest for 1983. It is believed these wells could result in an important addition to the Company's domestic reserves. In addition to the Sunshine Field waterflood activity, the Company will be continuing its development of the prolific Dombey Field in Beaver County, Oklahoma. This gas field has proven itself to be a stable steady producing asset for the many years the Company has owned interests in it. Recent rulings by the Oklahoma Corporation Commission have allowed for increased well density in the field. An in-house analysis has shown the drilling of additional wells (and the reworking of older wells) may add substantially to the Company's domestic reserve base and cash flow with minimal associated risks. Even in today's fluctuating gas market, the Dombey Field development program could realize a very favorable economic return for the dollars invested by the Company.

The Company's undeveloped acreage position in the United States, as of December 31, 1982, was as follows:

Undeveloped Acreage

	Gross	Net
Kansas	18,524	16,656
Texas	12,460	10,776
Montana	11,322	10,729
Wyoming	10,470	9,870
Colorado	7,016	6,737
Nebraska	4,131	4,131
New Mexico	24,432	1,374
North Dakota	1,036	526
Kentucky	475	237
Oklahoma	165	73
Totals	90,031	61,109

The Company has selectively farmed out portions of its undeveloped lease acreage in the past year, based on its analysis of the potential of the acreage involved as well as the length of time remaining before expiration of the leases. In particular, this was accomplished in 1982 on positions in Kentucky, Louisiana, Montana, and Texas. On a smaller scale, farmouts have been arranged thus far in 1983 in Colorado and Montana. The ultimate goals of these farmouts is to upgrade the Company's land holdings as well as retain those with a relatively long remaining lease life, both of which should improve future exploratory results as the industry again expands these efforts.

Central States Gas Company

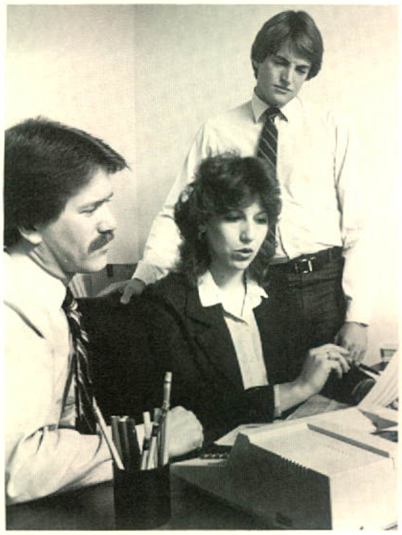
Kansas Power & Light Company remained the largest customer served by Central States Gas Company, accounting for 87.7% of total 1982 sales. Dedicated reserves, as determined by an independent engineering consulting firm, declined by 6.6% after the delivery of 8,139,870 mcf, to 60,187,000 mcf. Capital expenditures on the Central States system were $1,447,000 in 1982 compared to $1,100,000 in 1981. The Company continues to purchase all of its gas in Kansas from unrelated third party producers.

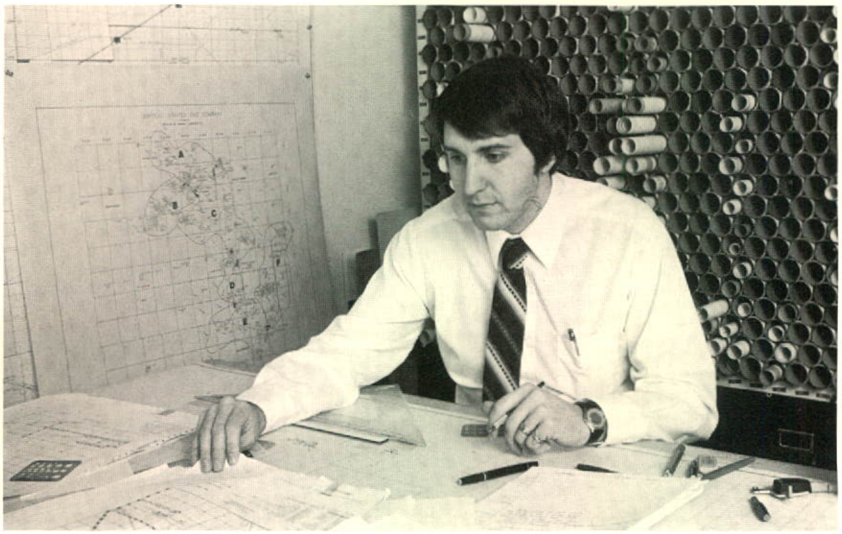
Central States Gas Company experienced difficulties in 1982 which primarily centered around abnormal transmission and gathering line loss problems. Intensive remedial efforts by management largely rectified these problems by yearend. Management also has undertaken an extensive study of the entire system and its individual components, the better to determine actual operating profit centers under varying conditions. This study has led to the implementation of new hook-up and disconnection procedures on a well-by-well basis in addition to new criteria for operating the system under periods of curtailment. Presently, improvements in operating results are being experienced and profitability restored to the system. Investigations are underway to determine additional methods by which this profitability can be further augmented during the present year.

Semco Gas, Inc.

Semco Gas, Inc. is a wholly-owned gas gathering subsidiary operating in Lipscomb, Ochiltree, and Smith Counties, Texas. Semco purchases gas from producers in Lipscomb and Ochiltree Counties and resells this gas to Diamond Shamrock Corporation and InterNorth, Inc. Volumes in 1982 through the Lipscomb and Ochiltree County systems were 372.8 million cubic feet, an increase of 25.9% from 1981.

The Smith County system purchases casinghead gas from the Sunshine Field in Smith County, Texas, processes the gas through an LPG plant, and sells the residue dry gas to United Gas Pipeline Company. The system sold 1.23 million gallons of LPG product and 1,014,185 mcf of residue dry gas in 1982. Total Semco deliveries for 1982 increased 8.5% over 1981, due primarily to performance of the Smith County system. Continued satisfactory performance on the part of Semco is anticipated in 1983, although the quantities of gas and associated products produced from the Sunshine Field may continue to decline due both to depletion and installation of the waterflood this year. At yearend 1982, gross proved gas reserves dedicated to all three Semco systems were 3,410,881 mcf, 54.1% of which were owned by Worldwide Energy Corporation.



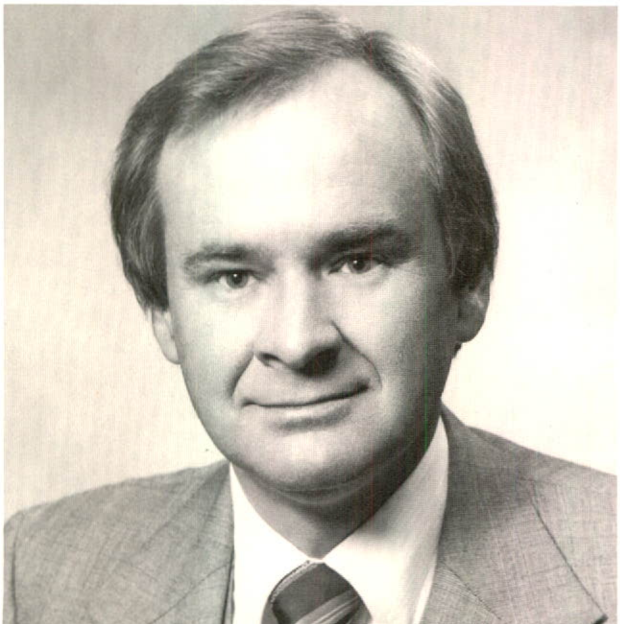


On January 7, 1983, the name of Worldwide Energy Corporation's operating subsidiary in Canada, Worldwide Energy Company Ltd., was changed to Canadian Worldwide Energy Limited. A number of changes to the subsidiary's capital structure were also undertaken at that time to facilitate a public offering of its shares in Canada. This offering was effective on March 24, 1983, and consisted of two parts: a new convertible preferred share issue and a portion of Worldwide Energy Corporation's common stock ownership in Canadian Worldwide Energy Limited. The preferred shares are convertible for a period of ten years into common shares of Canadian Worldwide Energy Limited on the basis of 3.0769 common shares for each preferred share. Upon completion of the offering, Worldwide Energy Corporation held 95%, and assuming that all preferred shares eventually are converted, will own 76% of the equity of Canadian Worldwide Energy Limited. Two-thirds of the net proceeds, about C$9,500,000, will be utilized by Canadian Worldwide to fund a portion of its share (about C$32.9 million) of the estimated C$73 million Fort Kent Phase III expansion project as well as for other capital expenditures. Until these other capital expenditures take place, the proceeds have been utilized temporarily to reduce outstanding indebtedness. Net proceeds from the sale by Worldwide Energy Corporation of common shares of Canadian Worldwide Energy Limited, C$5,333,333, were used to reduce the short term indebtedness of Worldwide Energy Corporation in the United States.

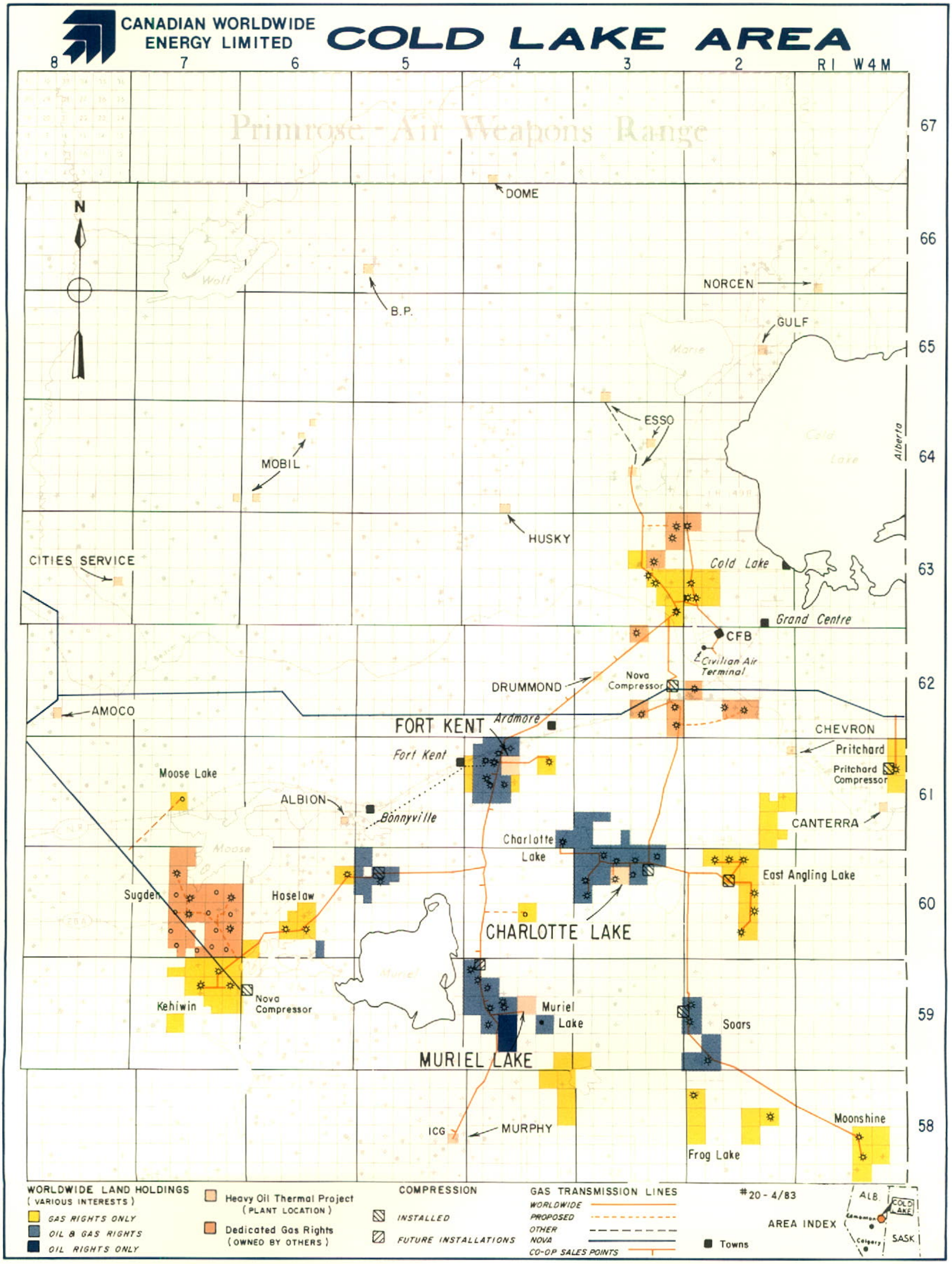
Heavy Oil Projects

Fort Kent

Canadian Worldwide Energy Limited has a 50% working interest in this project, which covers a 4,960 acre lease near Bonnyville, Alberta. As of December 31, 1982, C$17.7 million of an estimated C$32.9 million budget had been expended by Canadian Worldwide Energy Limited on the Phase III expansion, which began in the spring of 1982 after governmental approvals were received and is directed toward increasing the production rate to 5,000 BOPD. A specialized "slant-hole" drilling rig is being used to drill wells at various angles from several clusters, thus minimizing surface damage as well as reducing drilling and other capital costs. Phase III also includes the installation of surface ancillary facilities such as additional steam generation equipment, storage tanks and water treatment facilities for use in steam generation. As of April 5, 1983, 92 wells had been drilled in the expansion program. Production levels at Fort Kent, reflecting Phase III wells as they begin to come on-stream, is rising, averaging 1,767 BOPD for the three months ended March 31, 1983 compared to an average of 1,088 in 1982.



Ronald J. Cargo, President — Canadian Worldwide Energy Limited


CANADIAN WORLDWIDE ENERGY LIMITED
COLD LAKE AREA
Primrose - Air Weapons Range
DOME
B.P.
NORCEN
GULF
ESSO
MOBIL
HUSKY
CITIES SERVICE
Cold Lake
Grand Centre
CFB
Civilian Air Terminal
DRUMMOND
Nova Compressor
AMOCO
FORT KENT
Ardmore
Fort Kent
CHEVRON
Pritchard
Pritchard Compressor
Moose Lake
ALBION
Bonnyville
CANTERRA
Charlotte Lake
East Angling Lake
Sugden
Hoselaw
CHARLOTTE LAKE
Kehiwin
Nova Compressor
Muriel Lake
Soars
MURIEL LAKE
ICG
MURPHY
Moonshine
Frog Lake
WORLDWIDE LAND HOLDINGS (VARIOUS INTERESTS)
GAS RIGHTS ONLY
OIL & GAS RIGHTS
OIL RIGHTS ONLY
Heavy Oil Thermal Project (PLANT LOCATION)
Dedicated Gas Rights (OWNED BY OTHERS)
COMPRESSION
INSTALLED
FUTURE INSTALLATIONS
GAS TRANSMISSION LINES
WORLDWIDE
PROPOSED
OTHER
NOVA
CO-OP SALES POINTS
Towns
#20 - 4/83
AREA INDEX
ALB.
SASK.
COLD LAKE

As part of the Alberta and Federal governments' encouragement of heavy oil production, the Phase III expansion involved a number of important economic incentives. All heavy oil production from the Fort Kent project, including that from the pilot, Phase I, and Phase II, receives the New Oil Reference Price (C$33.60 per barrel as of December 31, 1982 adjusted for gravity and sulphur differentials). The Alberta government has granted an experimental royalty rate of 5% on production through Phase III. Operating costs, including transportation but excluding purchases of gas from Cold Lake Transmission, averaged C$10.15 per barrel of oil produced at December 31, 1982. Canadian Worldwide Energy Limited expects that economies of scale resulting from the Phase III expansion will further reduce the operating costs per barrel of oil produced.

Canadian Worldwide and Suncor Inc., the operator, made application to the Alberta Oil Sands Technology and Research Authority (AOSTRA) in October, 1982 for a program to test enhanced recovery techniques at Fort Kent. The first phase, estimated to cost C$1.2 million and expected to be 50% funded by AOSTRA, consists of laboratory studies by the Alberta Research Council, engineering feasibility studies, and certain engineering tests at Fort Kent. AOSTRA will recover its portion of these expenditures only through increased oil production resulting from enhanced recovery techniques. Based on results of these studies, a second phase could be undertaken, consisting of the installation of a pilot project to inject materials such as carbon dioxide that may increase the heavy oil recovery.

Muriel Lake

Canadian Worldwide Energy Limited has a 41% working interest in the 7,040 acre Muriel Lake heavy oil property. On November 1, 1982, Canadian Worldwide assumed operating responsibility for this project and has committed to spend up to C$3.0 million over a twelve month period (of a total of C$4.2 million) to drill and complete ten new production wells, to develop water source and disposal wells and to modify the existing steam, operating, and production equipment. The Muriel Lake project is planned for development using the same "huff and puff" production techniques successfully utilized at Fort Kent. The objective of the pilot is to refine production techniques and develop economic parameters upon which a decision may be based to proceed into a phased development program. The present expansion of these facilities is designed to raise the production level to a rate of between 300 and 500 BOPD. Production from Muriel Lake receives the same pricing, royalty, and income tax incentives as received for the Fort Kent heavy oil production.

Charlotte Lake

Canadian Worldwide's third heavy oil project is located at Charlotte Lake. It has earned a 25% working interest in the 8,960 acre property and could earn a further 25% working interest upon installation of a pilot project.

Conventional Petroleum And Natural Gas Properties

Canadian Worldwide Energy Limited produces approximately 130 bpd of oil and 8,500 mcf per day of gas from conventional petroleum properties in various locations within Alberta. Gas produced in the Cold Lake area is sold to wholly-owned Cold Lake Transmission Limited. Canadian Worldwide, at December 31, 1982, had leases on 101,978 gross (84,714 net) undeveloped acres, the vast majority of which were located in Alberta.

Canadian Worldwide intends to expand its exploration efforts by drilling to earn leases through farm-in arrangements in a number of areas; toward this aim, its present exploration efforts are concentrated on semi-developmental oil situations. It endeavors to maintain control of its exploration activities by taking a large working interest, for example, a 100% working interest in 46,080 acres of the Thornbury area of northeastern Alberta has been earned by the Company through the drilling of one successful McMurray sand gas well. A further seismic program is underway on the property which is near two major pipelines. An exploratory well is planned early in 1983 on a 5,600 acre property recently optioned in the Primrose area of northeastern Alberta. The lands are prospective for natural gas in the Colony formation and are located within eight miles of a natural gas pipeline.

Exploration and development drilling results for the past three years are summarized in the table below. Ten of the wells included as dry holes in 1982 results are cased and being used for purposes of testing at Fort Kent; depending upon future economics, these may be converted to producing wells.

Canadian Worldwide Energy Limited
Exploratory and Development Drilling

	1982		1981		1980	
	Gross	**Net**	Gross	Net	Gross	Net
Exploratory						
Oil	—	—	—	—	—	—
Natural Gas	**5**	**5.0**	4	2.5	3	3.0
Dry	**2**	**2.0**	1	1.0	6	4.6
Total	**7**	**7.0**	5	3.5	9	7.6
Development						
Oil	**50**	**26.5**	1	0.5	3	2.5
Natural Gas	**1**	**1.0**	3	2.5	6	3.8
Dry	**20**	**10.0**	1	1.0	4	4.0
Total	**71**	**37.5**	5	4.0	13	10.3

The following table summarizes Canadian Worldwide's net petroleum and natural gas production for the three years ended December 31, 1982.

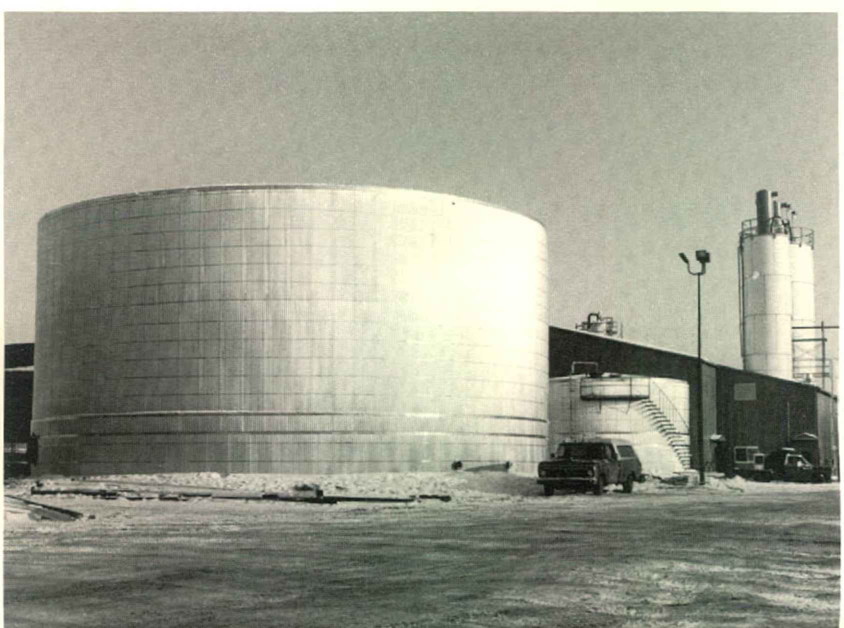
Canadian Worldwide Energy Limited
Production Summary

	1982	1981	1980
Natural Gas (mmcf)	**3,103**	2,121	2,048
Oil (bbls)			
Heavy	**198,500**	195,700	189,800
Conventional	**47,500**	48,100	48,900

Canadian Proven Reserves
(thousands of barrels, millions of feet)

	1982	1981	1980
Natural Gas[1]	**43,034**	71,717	56,620
Conventional Oil	**258**	386	703
Heavy Oil	**3,817**	1,325	1,165

[1]The decrease in 1982 natural gas reserves is due to the use of an outside engineering firm's estimates for purposes of the recent underwriting. That firm calculated reserves using volumetrics and other methods the Company has not historically used.



Natural Gas Operations

Canadian Worldwide's natural gas operations presently are concentrated in the Cold Lake area where it produces its own reserves, purchases natural gas from other producers, and markets natural gas through its wholly-owned transmission and distribution subsidiary, Cold Lake Transmission Limited. At December 31, 1982, Canadian Worldwide's pipeline system consisted of 140 miles of pipeline and six compression stations, with a maximum throughput capacity of approximately 40 million cubic feet per day. Sales are made primarily to heavy oil projects in the immediate Cold Lake area, to a petrochemical plant near Edmonton operated by Celanese Canada Inc. and to the Department of National Defense for its Cold Lake Canadian Forces Base. Natural gas sold to Celanese is transmitted by the Company to third party transmission facilities for delivery to the Celanese plant. The following table illustrates volumes delivered by the Company under its sales contracts for the three years ended December 31, 1982. Total daily deliveries have increased significantly during the first quarter of 1983 as more fully explained below.

Canadian Worldwide Energy Limited
Natural Gas Deliveries
(millions of cubic feet)

	1982	1981	1980
Imperial Heavy Oil Project	**1,431**	2,229	2,330
Department of Defense	**680**	576	609
Canadian Western Natural Gas	**1,082**	—	—
Celanese	**626**	—	—
Other	**922**	701	1,411
Total	**4,741**	3,506	4,350

On November 11, 1982, Canadian Worldwide commenced natural gas deliveries to Celanese Canada Inc. Initial deliveries were constrained by problems within the third party carrier pipeline system to between 10 million to 14 million cubic feet per day. During late February of 1983, in conjunction with a renegotiation of the Celanese agreement, deliveries rose to an average of 22 million cubic feet per day and have been as high as 24 million cubic feet per day. Deliveries through the first quarter of 1983 to Celanese averaged 15.3 million cubic feet per day. The renegotiated contract reduced the average selling price by up to C$0.30 per mcf for two years in exchange for an increase in the Company's share of Celanese's plant requirements from 18% to 23% for four years. This will have the effect of increasing the cash flow derived from this contract over the next several years, providing more available funds for other projects to Canadian Worldwide.

During the first quarter of 1983, the overall daily average deliveries of Cold Lake Transmission Limited, reflecting Celanese sales as described above, rose to 24,908 mcf. Of these daily average deliveries, Canadian Worldwide Energy Limited supplied 19,605 mcf, or 78.9%.

Worldwide Energy Corporation and Subsidiaries

Consolidated Statements of Income

For The Years Ended December 1982 and 1981

	Years Ended December 31	
	1982	1981
Revenue		
Oil and gas production	**$26,972,000**	$22,065,000
Windfall Profit Tax and Canadian revenue tax expense	**(1,541,000)**	(2,417,000)
Gas gathering and transmission	**32,187,000**	33,369,000
Other income (Note 13)	**1,159,000**	1,457,000
	58,777,000	54,474,000
Expenses		
Oil and gas operating expenses	**9,199,000**	7,926,000
Gas purchases	**25,361,000**	26,058,000
General and administrative	**5,915,000**	6,369,000
Depreciation, depletion and amortization	**8,140,000**	6,279,000
Interest	**7,789,000**	7,197,000
Foreign exchange conversion (Note 1)	**7,000**	37,000
Equity in net loss of affiliate (Note 1)	**182,000**	—
Other (Note 12)	**747,000**	1,336,000
	57,340,000	55,202,000
Income (Loss) From Operations Before Provision for Income Taxes	**1,437,000**	(728,000)
Provision (Credit) for Income Taxes (Note 5)	**580,000**	(154,000)
Net Income (Loss)	**$ 857,000**	$ (574,000)
Net Income (Loss) Per Share	**$.09**	$(.06)
Average Shares Outstanding	**9,202,900**	9,109,700

See the full financial statements beginning on page 45 of the Form 10K following.

Worldwide Energy Corporation and Subsidiaries
Consolidated Balance Sheets - As of December 31, 1982 and 1981

Assets	1982	1981
Current Assets		
Cash	$ 2,710,000	$ 188,000
Accounts receivable (Note 3)	11,875,000	12,273,000
Alberta Royalty Tax credits receivable	292,000	648,000
Inventory of supplies - at average cost	1,223,000	1,649,000
Prepaid expenses	82,000	107,000
	16,182,000	14,865,000
Property, Plant and Equipment, at Cost		
(Notes 2 and 3 and Schedules V and VI)		
Oil and gas properties - under full cost method	84,774,000	63,147,000
Gas gathering and transmission facilities	25,834,000	20,544,000
Gas purchase contracts	8,177,000	8,177,000
Other equipment and property	6,859,000	5,530,000
	125,644,000	97,398,000
Less - Accumulated depreciation, depletion and amortization	29,076,000	21,810,000
	96,568,000	75,588,000
Deferred Charges and Other Assets (Note 4)	517,000	332,000
	$113,267,000	$90,785,000

See the full financial statements beginning on page 45 of the Form 10K following.

Consolidated Balance Sheets - as of December 31, 1982 and 1981

Liabilities and Shareholders' Equity

	1982	1981
Current Liabilities		
Long-term debt due within one year (Note 3)	**$ 2,969,000**	$ 588,000
Accounts payable and accrued expenses	**13,557,000**	12,441,000
	16,526,000	13,029,000
Long-Term Debt (Note 3)	**64,458,000**	45,470,000
Deferred Compensation (Note 7)	**220,000**	225,000
Deferred Income Taxes (Note 5)	**2,744,000**	2,595,000
Total Liabilities	**83,948,000**	61,319,000
Commitments and Contingencies (Notes 2, 9 and 13)		
Shareholders' Equity (Note 6)		
Common stock, authorized 20,000,000 shares, par value $.20, issued 9,113,705 shares in 1982 and 1981	**1,823,000**	1,823,000
Capital in excess of par value	**17,018,000**	16,898,000
	18,841,000	18,721,000
Cumulative foreign currency translation adjustment (Note 1)	**(1,117,000)**	—
Retained earnings (Note 3)	**11,645,000**	10,788,000
	29,369,000	29,509,000
Treasury stock, 8,211 shares in 1982 and 6,499 shares in 1981, at cost	**(50,000)**	(43,000)
Total Shareholders' Equity	**29,319,000**	29,466,000
	$113,267,000	$90,785,000

See the full financial statements beginning on page 45 of the Form 10K following.

Worldwide Energy Corporation and Subsidiaries
Consolidated Statements of Changes in Financial Position
For The Years Ended December 31, 1982 and 1981

	Years Ended December 31	
	1982	1981
Funds Were Provided By:		
Operations		
Net income (loss)	$ 857,000	$ (574,000)
Items not requiring outlay of working capital:		
Depreciation, depletion and amortization	8,140,000	6,279,000
Deferred income taxes	494,000	(194,000)
Other items	499,000	561,000
Working capital provided by operations	9,990,000	6,072,000
Issuance of common stock and equity transactions of affiliate, net	113,000	(21,000)
Banks loans, net	18,988,000	16,370,000
Decrease (increase) in deferred charges and other items	(185,000)	62,000
Total funds provided	28,906,000	22,483,000
Funds Were Used For:		
Additions to properties, net	32,010,000	19,815,000
Adjustments resulting from change in method of translating foreign currency:		
Properties, net	(2,391,000)	—
Deferred income tax	345,000	—
Cumulative translation adjustment	1,117,000	—
Other	5,000	—
Total funds used	31,086,000	19,815,000
Increase (Decrease) in Working Capital	(2,180,000)	2,668,000
Working Capital - Beginning of Year	1,836,000	(832,000)
Working Capital — End of Year	$ (344,000)	$ 1,836,000
Changes in Components of Working Capital		
Increase (Decrease) in Current Assets		
Cash	$ 2,522,000	$(1,647,000)
Receivables	(754,000)	3,842,000
Inventory of supplies and prepaid expenses	(451,000)	263,000
	1,317,000	2,458,000
Less Increase (Decrease) in Current Liabilities		
Accounts payable and accrued expenses	1,116,000	(798,000)
Long-term debt due within one year	2,381,000	588,000
	3,497,000	(210,000)
Increase (Decrease) in Working Capital	$(2,180,000)	$2,668,000

See the full financial statements beginning on page 45 of the Form 10K following.

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 1982 Commission File No. 1-7904

Worldwide Energy Corporation

(Exact name of registrant as specified in its charter)

Delaware	84-0624727
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
United Bank Center 1700 Broadway, Suite 1600 Denver, Colorado	80290
(Address of Principal Executive Offices)	(Zip Code)

Registrant's telephone number, including area code (303) 861-8615

Securities registered pursuant to Section 12 (b) of the Act:

Title of Each Class	Name of Each Exchange on which Registered
Common Stock — $0.20 par value	American Stock Exchange, Inc. The Toronto Stock Exchange

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15 (d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No___

The aggregate market value of voting stock held by non-affiliates of the Registrant was $52,288,304 based on the closing price on the American Stock Exchange on March 22, 1983.

There were 9,310,519 shares of common stock outstanding as of March 22, 1983.

DOCUMENTS INCORPORATED BY REFERENCE:

Information called for in Part III of this Form 10-K is incorporated by reference to the Registrant's definitive proxy statement to be filed in connection with the annual meeting to be held on June 10, 1983.

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PART I

Item 1. Business

(a) General Development of Business

Worldwide Energy Corporation is a Delaware corporation with principal and executive offices at United Bank Center, 1700 Broadway, Suite 1600, Denver, Colorado 80290, telephone (303) 861-8615. Worldwide Energy Corporation and its consolidated subsidiaries are referred to as the Company. The Company was organized in December 1971 for the purpose of assuming all of the operations previously carried on by its former parent, Worldwide Energy Company Ltd., (now Canadian Worldwide Energy Limited), an Alberta corporation.

In May 1973, the company acquired PetroDynamics, Inc., an independent oil and gas company with holdings primarily in Texas and Oklahoma. Real estate operations conducted by the Company's former subsidiary, Citrus County Land Bureau, Inc., were spun-off in December 1975 in the form of a dividend of Citrus stock to the Company's shareholders. In November 1978, the Company acquired Central States Gas Company which owned and operated an intrastate gas gathering system and related facilities in south central Kansas. In 1979, Central States was dissolved, and its business is now operated as a division of Worldwide Energy Corporation.

As previously reported, the Company participated during 1982 in the drilling of three wells in Fiji. No commercial shows of oil or gas were encountered during the drilling operations. The consortium decided not to continue operations on the OEL-9 License. The OEL-7 consortium is in the process of trying to extricate the OEL-7 License from the Bennett Petroleum Corporation bankruptcy proceedings and to determine the feasibility of additional operations. Should the Company determine not to continue activity on OEL-7, it will take a direct charge against earnings of the $2,731,000 it has spent in Fiji. (See Note 2 to Consolidated Financial Statements.)

The Company and Canadian Worldwide Energy Limited filed the final prospectus of a $16,000,000 (Cdn.) offering during March of 1983. The offering consists of $40 (Cdn.) units, each unit consisting of two 9¼% Cumulative Redeemable Convertible Preferred Shares and one share of common stock (presently owned by the Company) of Canadian Worldwide. The offering is expected to close in mid-April 1983, but could be withdrawn by the underwriters in certain events. In addition, the Company is selling 527,536 shares of Canadian Worldwide common stock to a newly formed wholly-owned subsidiary in exchange for a $3,130,000 note. Canadian Worldwide, in turn, will purchase the shares from the new subsidiary upon completion of the public offering, which will provide the funds necessary to pay off the note. Upon completion of the offering, in accordance with the terms of the prospectus and the payment of the note, the Company will receive approximately $5.3 million (Cdn.), net of costs, and Canadian Worldwide will receive approximately $9.5 million (Cdn.), net of costs. The Company will own 95% of Canadian Worldwide initially and 76% upon full conversion of the preferred shares.

(b) Financial Information About Industry Segment

Worldwide is engaged in two principal lines of business or industry segments — (1) exploration and production of crude oil and natural gas, and (2) gas gathering and transmission. The following table sets forth for the years indicated, the amounts of revenue, operating profit and identifiable assets attributable to each segment. See also Note 11 of Notes to Consolidated Financial Statements.

(000's Omitted)	1982	1981	1980
Revenue			
Oil and gas production, net of Windfall Profit Tax and Canadian revenue taxes	**$ 25,431**	$19,648	$16,530
Gas gathering and transmission	**32,187**	33,369	26,312
Other	**1,159**	1,457	891
Total Revenue	**$ 58,777**	$54,474	$43,733
Operating Profit			
Oil and gas production	**$ 10,625**	$ 8,401	$ 8,150
Gas gathering and transmission	**4,968**	4,353	2,348
Other	**11**	(189)	247
Total Operating Profit	**$ 15,604**	$12,565	$10,745
Identifiable Assets*			
Oil and gas production	**$ 72,979**	$57,168	$43,685
Gas gathering and transmission	**36,104**	29,446	27,324
Other	**4,184**	4,171	4,367
Total Assets	**$113,267**	$90,785	$75,376

*Primarily property, plant and equipment.

Intercompany purchases of gas amounting to approximately $4.7 million in 1982, $3.8 million in 1981 and $3.4 million in 1980 have been eliminated from gas gathering and transmission revenues. Therefore only the gross profit on such transactions is included in gas gathering and transmission revenues.

(c)(1) Narrative Description of Business

Oil and Gas Exploration and Production Segment

The Company engages in the business of exploring for and developing oil and gas reserves and produces and sells crude oil and natural gas in the United States and Canada. The Company also participated in two joint ventures involving the drilling of a total of three wells on two exploration licenses granted by the Fiji Government. Crude oil and natural gas are produced and marketed in the Provinces of Alberta and Saskatchewan and in the States of Colorado, Kansas, Kentucky, Louisiana, Montana, Nebraska, New Mexico, Oklahoma and Texas. In addition, the Company owns heavy oil properties in the Cold Lake area of northeastern Alberta, including a 41% interest in an experimental thermal project it operates at Muriel Lake, and a 50% interest in the Fort Kent project operated by Suncor Inc. under a joint venture agreement.

Crude oil and natural gas are the principal products attributable to this segment and together accounted for more than 43% of the Company's consolidated revenues in 1982 as compared to approximately 36% in 1981 and 1980. In the U.S., the Company sells its oil to crude oil purchasers at the posted field price in the area applicable to the category of oil involved. Effective January 28, 1981 the prices for all categories of oil still subject to price regulation were decontrolled by order of the President. Decontrol has not resulted in a significant increase in the Company's revenues from sales of crude oil due to the Windfall Profit Tax Act of 1980 and because most of the Company's production already qualified for higher prices applicable to stripper oil and newly discovered oil. In addition, crude oil prices for the Company's U.S. production declined an average of 7½% during 1982. Prices for the production of natural gas in the United States are subject to the maximum prices prescribed by the Natural Gas Policy Act of 1978 (NGPA). Gas production is marketed under long-term contracts most of which provide for price increases tied to the monthly escalations permitted under the NGPA.

In Canada, sales of natural gas and crude oil are subject to regulations which restrict the price which the Company can charge for its production. On October 28, 1980, the Canadian federal government announced its proposed budget and National Energy Program (NEP). On September 1, 1981 the Governments of Canada and Alberta reached an agreement on pricing and taxation issues which had been unclear since the announcement of the NEP. Under this agreement, oil discovered in Alberta after December 31, 1980 receives the New Oil Reference Price effective January 1, 1982 which cannot exceed the price for international oil imported at Montreal. Gas prices will increase by $0.25 (Cdn.) per Mcf every six months over the five year term of the agreement. The price for conventional old oil, currently $28 (Cdn.) per barrel, will escalate every six months based on a schedule in the agreement, subject to a ceiling equal to 75% of the international price for oil. Increases in the price for conventional old oil, however, were subject to a new Incremental Oil Revenue Tax levied at the rate of 50% on the incremental oil revenue after deducting royalty (incremental oil revenue being the difference between actual revenue received and what would have been received under the NEP as originally proposed). The Incremental Oil Revenue Tax has been suspended between June 1, 1982 and May 31, 1983. All oil and gas production in Canada continues to be subject to the Petroleum and Gas Revenue Tax which was levied at the rate of 8% under the NEP but under the federal/provincial agreement is now 11% until June 1, 1983 when it will increase to 12%. Other aspects of the NEP affect the computation of taxable income for Canadian federal income tax purposes and favor companies which have a majority of Canadian ownership.

The application of the federal/provincial pricing agreement to the Company's Fort Kent heavy oil project was not resolved until March 1982, when it was determined that both existing and expanded production from the Fort Kent project received the New Oil Reference Price effective April 1, 1982. This resulted in an approximate doubling of the price received to $33 (Cdn.). The Company and Suncor Inc., the operator and owner of the remaining 50% of the project received approval for the expansion of the project and confirmation that the 5% experimental royalty rate would continue to apply. Accordingly, in 1982 an $88 million (Cdn.) expansion of the project began which calls for the drilling of up to 112 wells to raise production from an average of approximately 1,100 barrels per day in 1981 to 5,000 barrels per day when completed. Recently, the estimated cost of the expansion was reduced to $73 million (Cdn.).

On November 1, 1982, the Company assumed operating responsibility for the Muriel Lake heavy oil project under an agreement with Petro Canada and Aberford Resources. The Company has committed to spend $3 million (Cdn.) over 12 months (of a total of $4.2 million (Cdn.)) to drill and complete ten new production wells, develop water source and disposal wells and modify the existing steam operation and production equipment. Production of heavy oil from the Muriel Lake project presently receives the same pricing, royalty and income tax incentives as are received for heavy oil production at Fort Kent.

The Company's third heavy oil project is located at Charlotte Lake, Alberta. The Company has applied for permits to allow construction of a six well pilot project. By completing the pilot project, estimated to cost $3.85 million (Cdn.), the Company will increase its interest in the project from 25% to 50%. The Company will retain a 100% working interest in the pilot project or any expansion thereof until payout of the Company's capital investment.

The Company is presently in the process of determining whether to proceed with the pilot project at this time. Oil and gas exploration and production are not considered to be of a seasonal nature, although severe weather conditions can temporarily curtail or preclude these activities.

The Company does not own any patents, trademarks, licenses or franchises except for various oil and gas and mineral leases and an interest (presently tied up in the Bennett Petroleum bankruptcy proceedings) in Oil Exploration License No. 7 discussed in Section (a) of this Item 1, above. The Company is subject to significant competition in the acquisition of oil and gas and mineral leases and must pay competitive prices for prospects of a quality which merit the expenditures required for exploration and development. Recently the supply of oil has been too high relative to demand to sustain further price increases in the U.S. and, during 1982, the Company experienced a decrease in the average selling price for its oil from $35.56 to $32.85. As a result of continued price controls in Canada, the average per barrel selling price for the Company's oil increased from $12.88 in 1981 to $24.60 (heavy oil) during 1982 and from $15.19 in 1981 to $20.47 (conventional oil) during 1982.

The Company must also compete for drilling rigs. However, rigs are currently readily available and at lower rates as the amount of drilling activity decreased significantly during 1982 reflecting the softening of crude oil prices. The Company cannot predict how long such favorable conditions will continue.

The Company is a participant in experimental projects in the Cold Lake area in Canada using steam injection to assist in the recovery of heavy oil from shallow formations. In the last three fiscal years, the amounts capitalized in the Company's financial statements for these thermal projects were approximately:

1982	1981	1980
$15,093,000	$300,000	$483,000

The production of oil and natural gas is subject to regulation by the appropriate state regulatory authorities in the United States and by the provinces in Canada in which Worldwide has its producing oil and gas properties. In general, these regulatory authorities are empowered to make and enforce regulations to prevent waste of oil and gas, preserve the natural environment and fix allowable production levels of oil and gas within the limits of maximum efficient rates of production and reasonable market demand for oil and gas. Certain of the Company's activities are also subject to environmental controls, but such controls have not materially affected capital expenditures, earnings or the Company's competitive position.

Gas Gathering and Transmission Segment

The gas gathering and transmission segment of the Company's business involves three separate systems, Central States Gas Company (Central States) which operates gathering facilities in south central Kansas; Semco Gas, Inc. (Semco) whose main operations center around gathering systems in Smith County, Texas and the Panhandle Area of Texas; and Cold Lake Transmission Limited (Cold Lake) which operates a gathering system and transmission pipeline in the Cold Lake area of northeastern Alberta, Canada. In 1982 gross revenues derived from the natural gas sales attributable to these three systems accounted for approximately 55% of the Company's consolidated revenue, as compared to approximately 61% in 1981 and 60% in 1980.

Central States purchases its entire gas supply from independent producers for resale to its principal customers, The Kansas Power & Light Company (KP&L) and Getty Oil Company (Getty). For the fiscal year ending December 31, 1982, sales to KP&L accounted for approximately 87.7% of Central States' total sales and 38.3% of the Company's consolidated revenue. The KP&L gas sales contract was amended effective July 1, 1981, to permit Central States to charge KP&L the applicable NGPA (Natural Gas Policy Act of 1978) ceiling price or an average increase of approximately $.15 per Mcf for 1982 over the old price which was based on the "weighted average cost" to purchase gas plus a $0.50 per Mcf gathering fee. The difference between Central States' weighted average cost to purchase gas and the NGPA ceiling price will fluctuate, thus there is no fixed or assured profit margin. Gross profits will continue to be a function of Central States' ability to continue to purchase gas at less than its resale price to KP&L. The abnormal gas gathering expense (since attributed largely to measurement errors) which the Company reported in its second quarter report has decreased significantly and is not expected to recur.

While Semco operates three separate gathering systems, the main area of operations is the gathering system located in Smith County, Texas, where Semco purchases gas from producers in the Sunshine Field area, including the Registrant, for resale to its one purchaser, United Gas Pipe Line Company (United). For the fiscal year ending December 31, 1982, sales to United accounted for 97.5% of Semco's total sales and 6.6% of the Company's consolidated revenue. The Semco - United gas purchase contract is for a five year term expiring late in 1985 and provides for payment to Semco of applicable NGPA ceiling prices, up to the Section 102 price (the "new gas" category) plus an additional $0.10 per Mcf as a gathering allowance. On January 24, 1983, the Federal Energy Regulatory Commission issued orders and an opinion authorizing the collection of certain production-related costs by "first sellers" such as Semco. It is expected that the additional $0.10 per Mcf will be retroactively collected from United on all gas sold to United from July 25, 1980. Semco is currently able to purchase gas in the Sunshine Field at 80% of the applicable ceiling price under the NGPA.

Cold Lake's principal sales outlets continue to include Northwestern Utilities Limited (NUL) and the Department of National Defense (DND), but deliveries to Celanese Canada and short-term sales to Canadian Western Natural Gas Company Limited were also significant during 1982. Sales to NUL are primarily for the account of ESSO Resources Canada Limited (Esso). Prior to the 1980 contractual arrangements with NUL, Esso was supplied directly by Cold Lake. For the fiscal year ended December

31, 1982, gas supplied to NUL, the DND, Celanese Canada and Canadian Western accounted for 10% of the Company's consolidated revenue.

Initial gas sales under the August 15, 1981 gas sales contract between Canadian Worldwide and Celanese Canada Inc. (Celanese) commenced November 11, 1982. Current sales are averaging 22 MMcf per day. The contract now provides for maximum gas sales of up to 21.5 MMcf per day until February 1, 1983 and, pursuant to an agreement in principle, 23 MMcf per day thereafter.

The amount of natural gas the Company is able to market through its gathering systems is a function of purchaser demand, such demand being subject to, among other things, seasonal temperature changes, the cost of other gas supplies available to the purchasers and general economic conditions affecting end-use industrial customers. Average daily deliveries to KP&L were below the daily average for 1981, and less than expected during 1982, due to a decrease in KP&L's gas requirements, lower peak deliverability, and lower cost gas supplies available to KP&L from older Kansas gas fields in western Kansas.

Semco maintained gas sales to United at an average just below 2,800 Mcf per day during 1982, compared to an average just below 2,400 Mcf per day during 1981.

As of December 31, 1982, Central States was purchasing natural gas from wells owned and operated by indpendent producers having no relationship with the Company. The NGPA, with some exception, imposes ceiling prices on the first sale of various categories of natural gas produced in the U.S., including "intrastate" gas sold by the producers to Central States. NGPA ceiling prices also apply to resales by Central States to KP&L and Getty, in other words, the resales are treated as "first sales" for NGPA pricing purposes. NGPA ceiling prices and their extension to the intrastate market eliminated any competitive pricing advantage Central States might have enjoyed with respect to competing for gas supplies with large interstate pipelines in this area. However, Central States continues to compete effectively for gas supplies in its area of operations by providing better services to the producers and because the characteristics of its gathering system are more compatible with the low pressure gas and casinghead gas wells usually completed in this area than are the high pressure, large volume systems operated by the interstate pipelines.

NGPA ceiling prices also apply to Semco's operations. Semco has been able to compete effectively in its area by performing a gathering service when potential purchasers were not interested in building a lateral pipeline into the Sunshine Field because of initially low reserve estimates. Subsequently, reserves have been increased by further successful field development and, by virtue of being the only gatherer in this area, Semco now has an advantage in contracting for additional gas supplies.

During 1982, Cold Lake's parent, Canadian Worldwide Energy Limited, supplied approximately 75% of the total volumes of gas sold to Cold Lake's purchasers, with the balance being purchased by Cold Lake from independent producers having no relationship with the Company. Cold Lake is able to acquire such outside gas supplies at a discounted price due to the proximity of its system to various gas reserves which otherwise would remain shut-in for lack of suitable sales outlets. Like Central States, the pressure and geographical characteristics of Cold Lake's gathering system and the services provided to outside producers enable Cold Lake to compete effectively for such gas supplies with other purchasers in the area. The fact that there is a general lack of gas sales markets in Alberta and the fact that Cold Lake has been successful in finding new markets for its throughput have also improved its ability to compete with other purchasers.

Principal customers accounting for 10% or more of the Company's consolidated revenues are indicated in Note 11 of Notes to Consolidated Financial Statements under Item 8 of this Form 10-K and in Section (c)(1) of this Item 1, above.

Additional information relating to gas matters involving Central States, Semco and Cold Lake is included in Item 2 (i), Delivery Commitments of this form 10-K.

On December 31, 1982, the Company had 196 employees, including officers.

(d) Financial Information About Foreign and Domestic Operations

Information concerning the Company's foreign and domestic operations are tabulated below for the years indicated:

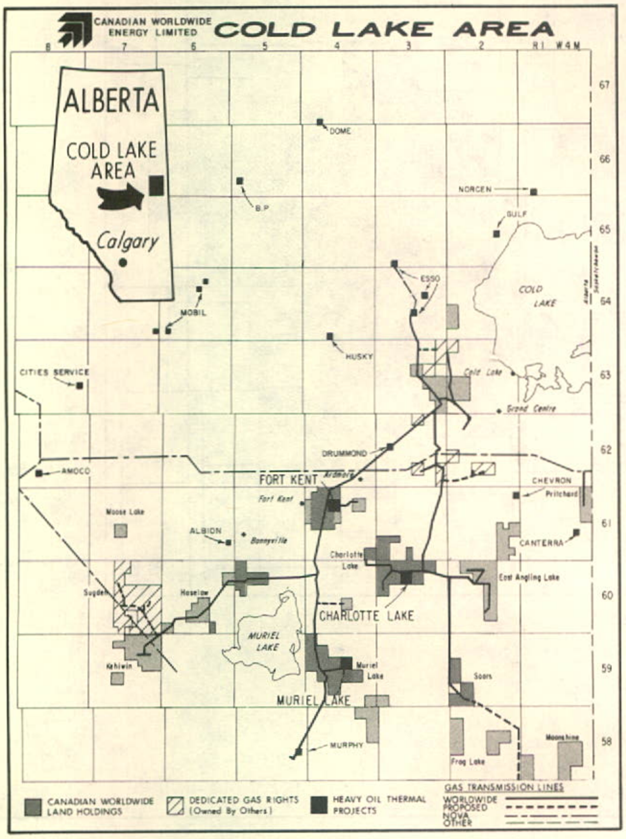
(000's Omitted)	1982	1981	1980
Revenue			
— Canada	**$15,655**	$10,062	$ 9,254
— United States	**$43,122**	$44,412	$34,479
— Fiji	**$ —**	$ —	$ —
Operating Profit			
— Canada	**$ 8,997**	$ 4,283	$ 4,633
— United States	**$ 6,607**	$ 8,282	$ 6,112
— Fiji	**$ —**	$ —	$ —
Identifiable Assets			
— Canada	**$50,988**	$32,711	$29,099
— United States	**$59,548**	$57,273	$46,277
— Fiji	**$ 2,731**	$ 801	$ —

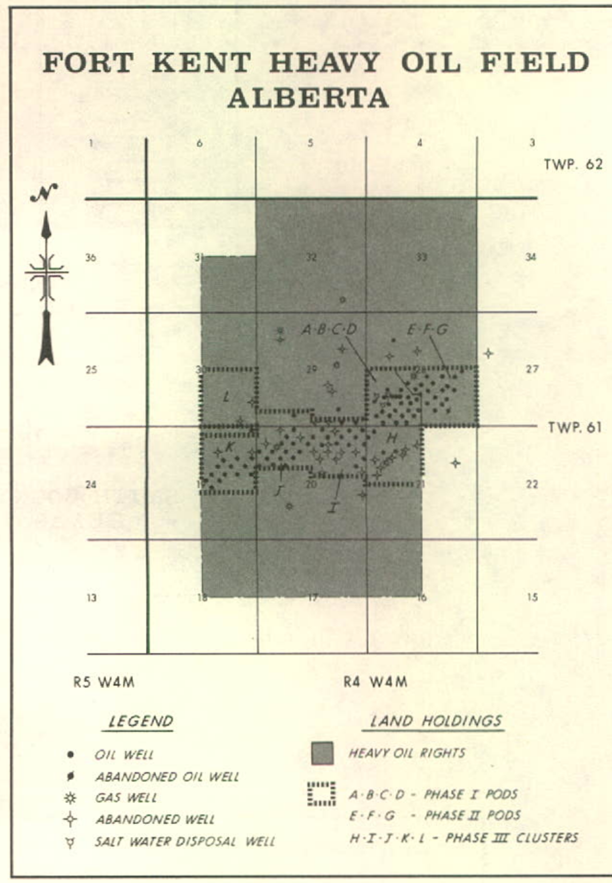
There were no export sales or sales or transfers between geographic areas during the years included in the table above. The results of operation of foreign properties, other than Fiji and Canada, are not material and are included in domestic operations.

In Canada, the Company is subject to the Foreign Investment Review Act of Canada. Under this Act, the acquisition of control of a Canadian business enterprise and the establishment of a new business in Canada are generally subject to review by the Foreign Investment Review Agency which must determine whether or not such activity is or is likely to be of significant benefit to Canada.

For additional information pertaining to the business of the Company, see Item 2, Properties.

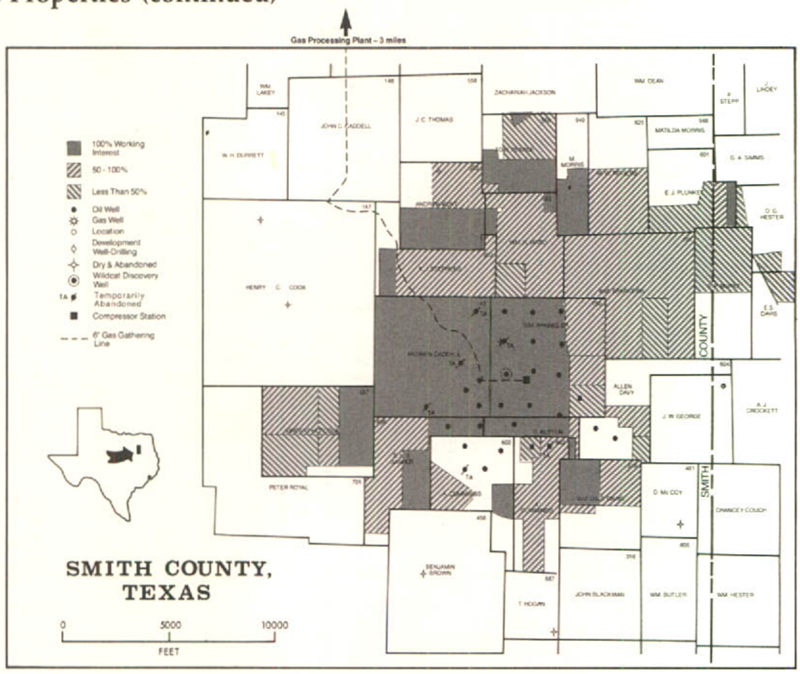
Item 2. Properties
Maps of Significant Properties

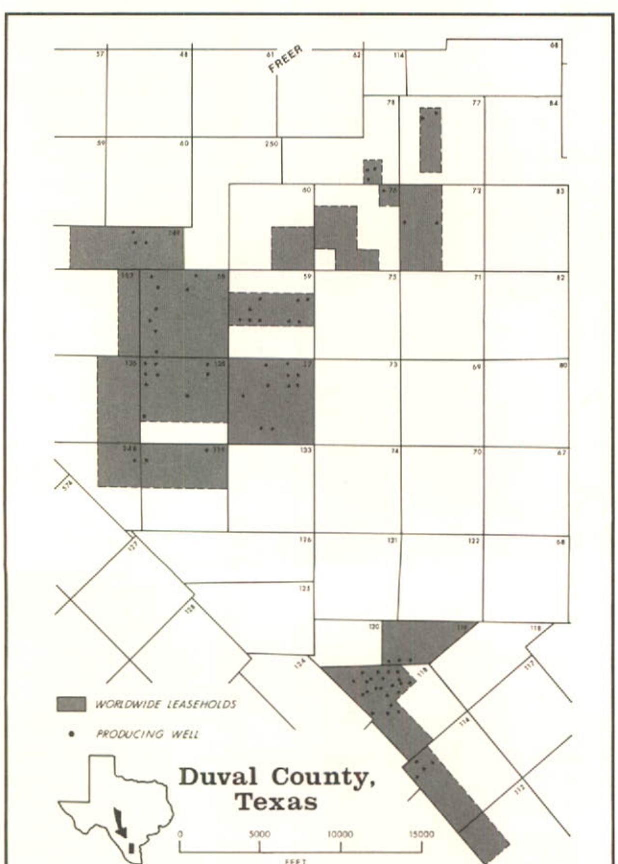


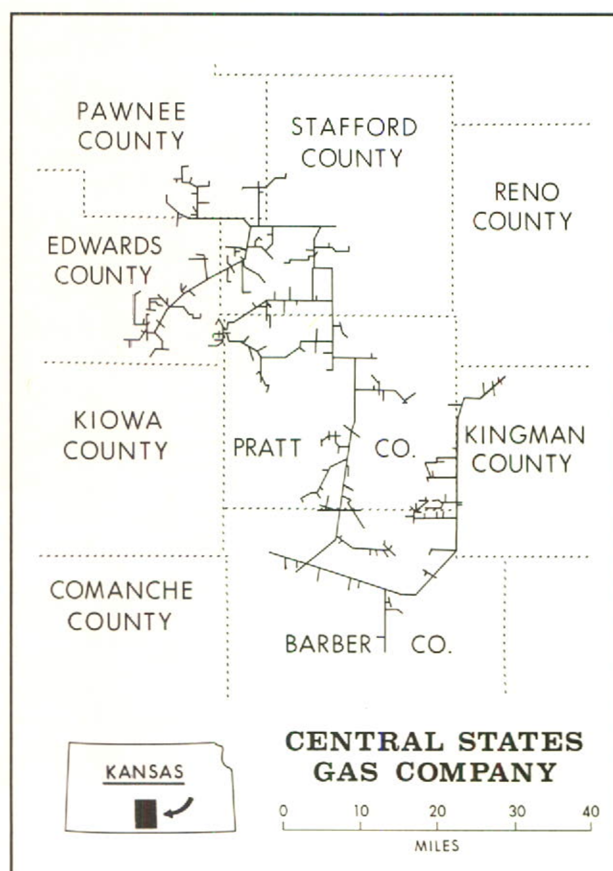


Item 2. Properties (continued)

Maps of Significant Properties (continued)







(a) General

The Company's properties are located in the Provinces of Alberta, Saskatchewan and British Columbia in Canada and in the States of Colorado, Kansas, Kentucky, Louisiana, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, Texas and Wyoming in the United States. In addition, the Company is a party to two ventures which did exploratory drilling on two exploration licenses covering some four million acres in the Fiji Islands. The participants of the second venture on the OEL-9 Exploration License elected, after the drilling of one dry hole, not to earn an interest in such license. Oil and gas production facilities are generally dispersed over wide areas except for the Fort Kent and Muriel Lake heavy oil projects in Alberta where producing wells and facilities are relatively concentrated. Substantially all of the Company's producing oil and gas properties are pledged as collateral for bank loans.

The major portion of the Company's domestic gas gathering and transmission facilities are located in south central Kansas and were acquired with the acquisition of Central States Gas Company in 1978. Central States' gathering system and gas purchase contracts are pledged to a bank as collateral for a bank loan. A subsidiary, Semco Gas, Inc., operates three small gathering systems in Texas. The Company's Cold Lake gathering and transmission facilities are all located in the Cold Lake area of northeastern Alberta.

The Company owns interests in certain uranium properties located in McKinley and Valencia Counties, New Mexico, which properties were operated by third parties under two separate exploration agreements. During 1981 operations under both agreements ceased due to the depressed market price for uranium. Substantially all of these properties with continuing obligations (rents, royalties, minimum work obligations, etc.) have been or are in the process of being surrendered and released. In addition, during 1982 the Company sold its interest in a tungsten mine located in the United Kingdom for a nominal amount and released its interests in unpatented mining claims prospective for gold in Alaska.

(b) Reserves

Information concerning the Company's capitalized costs, costs incurred in producing oil and gas activities, revenues from producing oil and gas activities, oil and gas reserves, estimated future net revenues, and the present value of estimated future net revenues attributable thereto are provided in Note 2 of Notes to Consolidated Financial Statements appearing elsewhere in this Form 10-K.

(c) Reserves Reported to Other Agencies

Except for Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves" filed with the Department of Energy for 1981, there were no reserve estimates filed with any other United States federal authority or agency since January 1, 1982. Reserves reported in Note 2 of the Notes to Consolidated Financial Statements in Item 8 of this Form 10-K are based on the net revenue interest owned by the Company and are therefore not comparable to those reported on Form EIA-23 which are based on gross working interest, including royalty interests.

(d) Production

Net oil and gas production from Company owned net working and royalty interests for each of the last three years is tabulated below:

	Oil (Bbls.)				Gas (Mcf)		
	Canada		U.S.A.		Canada	U.S.A	
	Conventional	Heavy Oil	Working Interest	Royalty Interest		Working Interest	Royalty Interest
1982	**47,500**	**198,500**	**327,000**	**29,100**	**3,102,800**	**1,983,700**	**49,000**
1981	48,100	195,700	322,600	34,000	2,121,500	1,987,100	54,700
1980	48,900	189,800	261,400	32,100	2,048,400	1,581,800	73,100

The average sales price per unit of oil and gas produced by the Company in the United States and Canada during each of years 1980 through 1982 are as follows (Canadian funds have been converted to U.S. currency):

	1982	1981	1980
Gas — per Mcf			
United States	**$ 2.18**	$ 1.81	$ 1.16
Canada	**$ 1.96**	$ 1.71	$ 1.58
Oil — per bbl.			
United States	**$32.85**	$35.56	$37.38
Canada - Heavy Oil	**$24.60**	$12.88	$10.66
Canada - Conventional Oil	**$20.47**	$15.19	$13.31

The average production (lifting) cost per unit of production for each of the last three years is tabulated below. Units of gas produced have been converted to equivalent barrels of oil using the gross revenue method.

Production Costs - per bbl.	1982	1981	1980
United States	**$ 9.79**	$10.51	$10.13
Canada - Heavy Oil	**$ 9.66**	$ 7.47	$ 5.77
Canada - Conventional Oil	**$ 2.60**	$ 2.14	$ 2.11

(e) Productive Wells and Acreage

At December 31, 1982 the Company owned working interests in productive oil and gas wells as follows:

	Canada		U.S.	
	Gross	Net	Gross	Net
Oil Wells	106	44.2	198*	113.6
Gas Wells	39	30.8	74	38.5
Service Wells	19	4.5	38	37.1
Shut In	88	56.5	158	138.8
Total	252	136.0	468	328.0

*Includes 3 wells with multiple oil and gas completions.

Working interest production for 1982 was derived from approximately 134,573 gross (84,079 net) producing acres of which 65,915 gross (45,744 net) acres were in Canada.

(f) Undeveloped Acreage

The Company owns oil and/or gas rights in leases and concessions comprising 2,222,767 gross acres (371,643 net acres) located in Western Canada, the Fiji Islands and in the United States. The leases expire at various dates from 1983 to 1995 and require the payment of an annual rental in lieu of drilling. Leases may be surrendered at any time by notice or non-payment of lease rental.

The following table sets forth the Company's ownership in undeveloped leaseholds as of December 31, 1982:

Country/Province/State	Gross Acres	Net Acres
Alberta	99,346	84,328
British Columbia	2,592	346
Saskatchewan	40	40
Total - Canada	101,978	84,714
Total - Fiji Islands	2,030,758	225,820
Colorado	7,016	6,737
Kansas	18,524	16,656
Kentucky	475	237
Montana	11,322	10,729
Nebraska	4,131	4,131
New Mexico	24,432	1,374
North Dakota	1,036	526
Oklahoma	165	73
Texas	12,460	10,776
Wyoming	10,470	9,870
Total U.S.	90,031	61,109
Total All Countries	2,222,767	371,643

(g) Drilling Activity

During 1982 the Company participated in the drilling of 104 wells of which 75 were successfully completed as summarized below:

	U.S.A.				Canada				Total	
	Exploration		Development		Exploration		Development			
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Oil	—	—	15	6.1	—	—	50	26.5	65	32.6
Gas	—	—	4	0.2	5	5.0	1	1.0	10	6.2
Dry	2	0.6	2	1.3	2	2.0	20*	10.0*	26	13.9
Total	2	0.6	21	7.6	7	7.0	71	37.5	101	52.7

*Includes 10 gross (5 net) wells which have been cased but not completed for production and which are presently being used for testing purposes. Such wells may be completed as heavy oil wells if at such time production therefrom is considered economic.

The Company also participated in the drilling of three gross (.3 net) dry exploration wells in Fiji during 1982.

Similar information for 1981 is as follows:

	U.S.A.				Canada				Total	
	Exploration		Development		Exploration		Development			
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Oil	6	1.6	20	6.6	—	—	1	.5	27	8.7
Gas	2	1.4	6	.7	4	2.5	3	2.5	15	7.1
Dry	10	3.7	6	2.3	1	1.0	1	1.0	18	8.0
Service	—	—	1	.7	—	—	—	—	1	.7
Total	18	6.7	33	10.3	5	3.5	5	4.0	61	24.5

Similar information for 1980 is as follows:

	U.S.A.				Canada				Total	
	Exploration		Development		Exploration		Development			
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Oil	2	1.2	21	12.5	—	—	3	2.5	26	16.2
Gas	—	—	6	1.3	3	3.0	6	3.8	15	8.1
Dry	1	.2	4	1.4	6	4.6	4	4.0	15	10.2
Total	3	1.4	31	15.2	9	7.6	13	10.3	56	34.5

(h) Present Activities

At March 25, 1983 there was no drilling in progress in the United States. In Canada, there were 15 gross (7.27 net) wells in the process of drilling or waiting on completion.

(i) Delivery Commitments

Cold Lake Transmission Limited

In Cold Lake's operating area of northeastern Alberta, Canada, Cold Lake has been supplying gas to the Canadian Department of National Defense (DND) since 1955, ESSO Resources Canada Limited (Esso) since 1974, and Celanese Canada Inc. (Celanese) since 1982.

The renegotiated DND contract expires in 1991, and Cold Lake has the exclusive right to supply the DND's requirements so long as present requirements are met and deliverability available to supply the DND is maintained at a minimum of 3,000 Mcf per day. Cold Lake has consistently met or exceeded this requirement.

Cold Lake and NUL operate under a 1980 agreement whereby NUL purchases gas from Cold Lake for delivery to Esso's experimental heavy oil project (the Leming and Ethel Pilot Plants located in the Cold Lake Area of Alberta). As part of the consideration for NUL entering into this contract, Cold Lake agreed to terminate its contract with NUL, as successor to Beaver River Utilities (BRU), to supply gas for the towns of Cold Lake and Grand Centre. The amount of gas purchased by NUL is directly tied to Esso's demand, which was 3,919 MMcf per day during 1982. There are penalties if Cold Lake fails to deliver amounts Cold Lake nominates in response to Esso's demand; however, Cold Lake has consistently met its obligations to Esso.

During 1981, the Company signed a contract with Celanese to supply a petrochemical plant near Edmonton with natural gas for an initial term of 15 years. The start-up of sales under this contract coincided with the November 1982 completion of the expanded Celanese plant. The original contract called for deliveries of maximum annual volumes of 7 BCF (an average of 19.2 MMCF/D), maximum daily volumes of 21.5 MMCF and a minimum annual volume of 18% of the plant's natural gas requirements (excluding natural gas delivered under a prior purchase contract Celanese has with another company until July 1, 1983).

The natural gas price under the original contract is determined with reference to Celanese's Alberta Cost of Service and the Alberta Border Price. Celanese pays the Company a variable allowance with respect to the Company's transportation costs. The Company also receives, in respect of its Celanese sales, its share of the additional revenues accruing to Alberta natural gas producers from export sales of natural gas.

Celanese recently requested the renegotiation of key provisions of the original contract. As a result of these negotiations, the Company and Celanese have agreed to execute an amendment whereby the Company will reduce the gas price approximately $0.30 (Cdn.) per MCF and Celanese will increase its minimum annual volume to 23% of the expanded plant's gas requirements. The price reduction shall be in effect from February 1, 1983 to January 31, 1985, but can be reduced if there is any reduction to the current Export Adjustment, or if the Natural Gas and Gas Liquids Tax and Canadian Ownership Special Charge are reduced, or if the Canadian dollar falls below 80 cents (U.S.) equals $1.00 (Cdn.), or if there is any reduction in the Alberta Border Price. The maximum reduction can be $0.30 (Cdn.) per MCF. The increased purchase obligation shall be in effect from February 1, 1983 to January 31, 1987. In addition, the Company has agreed to increase maximum daily volume obligations to 23 MMCF as of February 1, 1983, and subject to certain conditions, to supply Celanese with an additional 2 MMCF/D on a "best efforts" basis commencing October 1, 1983, with appropriate adjustments to the Celanese minimum purchase obligation if the Company does not supply all or a portion of the additional 2 MMCF/D when requested by Celanese.

Subject to the Company's existing contracts and certain gas reservations for, among other things, thermal recovery operations, the Company dedicated to the performance of its obligations to Celanese all of its interest in gas reserves underlying lands in seventy-two townships generally described as the Cold Lake Area. The Company's right to sell gas from the dedicated area to new markets will depend on its ability to demonstrate that it has sufficient deliverability from dedicated lands to meet its maximum daily and annual delivery obligations (23 MMCF and 7 BCF, respectively) for a maximum of ten contract years. If the Company cannot demonstrate sufficient reserves and deliverability to meet its obligations, additional acreage will have to be dedicated or Celanese can reduce its minimum annual take requirements, which initially was 18% of gas consumed at the expanded plant. In addition, if the Company fails to deliver gas required by Celanese during the first contract year, ending October 1, 1983, Celanese will have the right to purchase gas from other sources and charge the Company for the difference between the price of the purchased gas and the contract price. The Company has consistently complied with the delivery requirements of the Celanese contract.

As a result of the Celanese contract, Cold Lake may nominate to supply NUL only up to 6 MMcf per day for Esso's account until October 31, 1983, and up to 1.5 MMcf per day thereafter. As discussed above, the Company anticipates that Esso will continue to require reduced volumes, although the Company has the right to supply increased deliveries to meet Esso's requirements provided the Company demonstrates sufficient deliverability and reserves to Celanese to satisfy the delivery obligations in the Celanese contract.

The following table shows gross Mcf volumes delivered by the Company under all contracts for the last three years:

Year	NUL (Esso)	DND	Canadian Western Natural Gas	Celanese	Other Total	Total
1982	**1,430,773**	**680,135**	**1,082,113**	**626,309**	**921,539**	**4,740,869**
1981	2,229,069	575,640	—	—	700,681	3,505,390
1980	2,330,099	609,393	—	—	1,411,113	4,350,605

The sources of the gross volumes shown in the preceding table are set forth below and expressed in Mcf:

Year	Company Owned Gas	Owned by Others		Total
		Produced Jointly with Company Owned Gas	Purchased from Other Sources	
1982	**3,563,499**	**858,139**	**319,231**	**4,740,869**
1981	2,223,209	1,097,660	184,521	3,505,390
1980	2,747,844	905,431	697,330	4,350,605

Capital expenditures have been and continue to be made on Cold Lake's gas gathering and transmission facilities as required to increase deliverability to meet its present and expected contractual commitments. These expenditures for the last three years were:

1982	1981	1980
$4,927,000	$1,492,000	$4,787,000

(Expressed in Canadian funds)

Gross proved gas reserves available to meet the Company's contractual commitments at year-end for each of the last three years expressed in Mcf of gas were as follows:

Year End	Company Owned	Owned by Others	Total Committed
1982	**51,836,000**	**46,845,000**	**98,681,000**
1981	85,793,000	75,142,000	160,935,000
1980	73,574,000	43,207,000	116,781,000

Central States Gas Company

The Central States gathering system in south central Kansas is described under Item 1(c)(1), "Narrative Description of Business" "Gas Gathering and Transmission Segment". Virtually all gas purchased by Central States for resale through its system is sold to The Kansas Power & Light Company (KP&L) and Getty Oil Company (Getty), the latter under a purchase and exchange arrangement between Central States, Getty and KP&L. Central States is not required to maintain a specific reserve base or deliverabilty level for either of these purchasers, although KP&L recently amended its 1975 Gas Purchase and Sales Agreement to state KP&L will "take-or-pay" for a daily contract quantity equal to 70% of Central States' delivery capacity. To date, KP&L and Getty have met or exceeded their minimum take requirements. As discussed in Item 1(c)(1), the amendment to the KP&L contract permits Central States to charge KP&L the applicable NGPA ceiling price, which has been the NGPA Section 102 price (new gas price) since April, 1982. KP&L has a call, with the exception of Getty's volumes, on substantially all gas production now or hereafter acquired by Central States in its present operation area, and it is unlikely Central States will seek additional markets.

The following table shows gross volumes of gas expressed in Mcf delivered by Central States for 1982, 1981 and 1980:

Year	KP&L	Getty	Other	Total
1982	**7,093,984**	**935,732**	**110,154**	**8,139,870**
1981	8,288,973	1,121,026	109,122	9,519,121
1980	8,000,812	964,591	75,543	9,040,946

Capital expenditures for gas gathering and transmission facilities to connect additional reserves and increase deliverability of the Central States system for the fiscal years ended December 31, 1982, 1981, and 1980 were $1,447,000, $1,100,000 and $1,207,000, respectively.

To date, all of the gas sold by Central States has been purchased from independent producers in the area. At year-end 1982, 1981, and 1980, the gross proved reserves expressed in Mcf of gas dedicated to Central States under contracts with these producers and calculated by Keplinger and Associates, Inc., Independent Petroleum Engineering Consultants, were as follows:

	1982	1981	1980
Proved Developed	**43,517,000**	45,702,000	39,086,000
Proved Undeveloped	**16,670,000**	18,770,000	21,631,000
Total Proved Reserves Dedicated (Mcf)	**60,187,000**	64,472,000	60,717,000

Semco Gas, Inc.

A general description of Semco's area and scope of operations is included under Item 1(c)(1), "Narrative Description of Business" "Gas Gathering and Transmission Segment". Over three-fourths of all gas gathered, transported and sold by Semco is derived from the Sunshine Field area of Smith County, Texas. The sole market for Semco's gas in this area is United Gas Pipe Line Company (United) under a Gas Purchase Contract dated May 6, 1980. The contract provides for the payment to Semco of applicable NGPA ceiling prices, up to the Section 102 price (the "new gas" category) plus an additional $.10 per Mcf as a gathering allowance. The primary term of this contract expires in late 1985. Currently, Semco must purchase gas from the Sunshine Field area at a percentage of NGPA ceiling rates in order to keep this operation economically viable. Semco is currently able to purchase gas in the Sunshine Field at 80% of a well's applicable ceiling price. The Semco-United contract does not require Semco to maintain any specific level of reserves or deliverability, however, United has to "take-or-pay" for an annual minimum quantity of gas equal to 85% of Semco's delivery capacity. United has consistently met or exceeded this obligation. Semco has dedicated substantially all of its present and future gas reserves in the Sunshine Field to United, thus, additional sales outlets are not being sought at this time.

The following table shows gross volumes of gas expressed in Mcf delivered by Semco for the last three years:

Year	United	Other	Total
1982	**1,014,185**	**372,835**	**1,387,020**
1981	982,195	296,106	1,278,301
1980	277,082	218,609	495,691

Capital expenditures for Semco's gas gathering, transmission and liquids processing facilities for the fiscal years ended December 31, 1982, 1981 and 1980 were $1,302,000, $913,000, and $476,000, respectively.

Gross proved gas reserves dedicated to Semco at year-end for each of the last three years expressed in Mcf of gas were as follows:

Year	Company Owned	Owned by Others	Total
1982	**1,845,795**	**1,565,086**	**3,410,881**
1981	3,046,803	2,462,910	5,509,713
1980	—	1,012,632	1,012,632

Item 3. Legal Proceedings

As previously reported, the Company was a party to an appeal pending before the Oklahoma Supreme Court in which United Petroleum Exploration, Inc. was seeking to reverse a decision of the District Court of Beaver County, Oklahoma. United Petroleum sought to establish that the Company did not make a timely election to participate in the drilling of a well under an Order of the Corporation Commission of the State of Oklahoma and thereby receive its share of the proceeds from the well. On July 28, 1981, trial was held in the District Court of Beaver County, and on August 3, 1981, the Court ruled in the Company's favor. In early 1983, the Oklahoma Supreme Court assigned the case to the Oklahoma Court of Appeals, Fourth Division for decision. On March 29, 1983, the Court of Appeals unanimously upheld the District Court's decision. If the decision of the Court of Appeals is ultimately reversed, the Company will be denied the right to participate in and receive its share of the proceeds from the well. Revenue from this well reflected in the Company's financial statements for the periods prior to 1979 is approximately $311,000, less the Company's share of estimated drilling costs of $65,000 which amount has been paid to the District Court. Revenue of approximately $446,000, net of the Company's share of royalties, for 1979 through 1982 has not been reflected for financial reporting purposes. Proceeds attributable to the Company's interest in this well are held in escrow pending the final outcome of this litigation.

Altacan Investments Ltd. has filed a Statement of Claim in the Court of the Queen's Bench, Judicial District of Edmonton, Alberta, Canada in which the Company's subsidiary, Canadian Worldwide Energy Limited, and one of its employees are defendants. In December 1978, the Company entered into an agreement to sell two lots of real estate in Bonnyville, Alberta to Wm. Boston & Associates Ltd. (Boston), who is also a defendant in this action. Subsequently, Boston purchased both lots and, pursuant to the agreement, commenced construction of an office building on the first lot. Thereafter, Altacan purchased both lots from Boston and completed the office building. Altacan alleges, among other things, that Worldwide committed to lease 10,000 square feet of space in the building, that Worldwide breached that commitment and that as a result plaintiff has incurred damages of approximately $2.5 million (Cdn.) plus ongoing damages as proven at trial. Worldwide believes that it has met all of its obligations with respect to leasing space in this building and that Altacan's action will not result in any material liability to the Company. In addition, the Company intends to counterclaim against Altacan, as successor to Boston, for breach of its agreement with Worldwide with respect to the development of the second lot.

There are no other material pending legal proceedings.

Item 4. Submission of Matters to a Vote of Security Holders

No matters were submitted during the fourth quarter of 1982 to a vote of security holders through the solicitation of proxies or otherwise.

Executive Officers of the Company

The names and ages of all executive officers of the Company and positions held by each for the last five years are as follows:

Office and Principal Occupation for Last Five Years	Name	Age
President, Chief Executive Officer and Director	Robert B. Tenison	59
Senior Vice President Since June 1980; also since September 1982 - President and Chief Operating Officer of Canadian Worldwide Energy Limited; June 1977 to June 1980 - Vice President of Operations.	Ronald J. Cargo	39
Vice President - Operations Since November 1980; May 1978 to November 1980 - Rocky Mountain Operations Manager with Donald C. Slawson, Oil Producer, Denver, Colorado; December 1973 to May 1978 - Rocky Mountain Operations Manager with American Quasar Petroleum Company, Denver, Colorado.	A. H. Hurley, Jr.	54
Vice President - Exploration Since June 1977.	Blaine S. Day	40
Vice President - Land Since June 1981; August 1978 to June 1981 - Land Manager; 1976 to August 1978 - District Landman with Champlin Petroleum.	Larry D. Van Cleave	38

Office and Principal Occupation for Last Five Years	Name	Age
Vice President - Corporate Development Since September 1980; 1971 to September 1980 - Treasurer.	Walter V. Pelepchan	52
Vice President - Administration Since June 1980; September 1979 to June 1980 - Assistant to the President; August 1978 to September 1979 - Attorney and CPA with Harry S. Bernstein, Attorney-CPA, Aurora, Colorado.	William G. McCanne	44
Treasurer Since September 1980; February to September 1980 - Vice President of Cougar Petroleum Corp., Denver, Colorado; May 1979 to February 1980 - Manager of Management Advisory Services for CPA firm of Stark, Hochstadt, Kark & Co., Denver, Colorado; June 1977 to April 1979 - acting controller with Petro-Lewis Corp., Denver, Colorado; Colorado CPA.	Mark A. Hellerstein	30
Secretary and General Counsel Since May 1982; February 1982 to May 1982 private practice of law, Houston, Texas; June 1980 to January 1982 - Vice President, Corporate Counsel and Secretary, Consolidated Petroleum Industries, Inc., Houston, Texas; February 1978 to June 1980 Associate Counsel, GATX Leasing Corporation, Houston, Texas; member of Colorado and Texas bars.	Eldon L. Hinds	37

The officers are elected annually by the Board of Directors at the first meeting following the Annual Meeting of Shareholders. There is no family relationship between any of the officers, directors or persons nominated to become an officer or director.

PART II

Item 5. Market for Registrant's Common Equity and Related Stockholder Matters

The Company's Common Stock is traded on the American Stock Exchange and, in Canada, on the Toronto Stock Exchange. The following table sets forth the high and low sales prices for the Company's common stock as reported on the American Stock Exchange for each quarter of 1981 and 1982. The reported sales prices have been adjusted to reflect the four for three stock split described below.

	1982			
	1st Quarter	**2nd Quarter**	**3rd Quarter**	**4th Quarter**
High	$ 7¼	$ 6¼	$ 5¾	$ 9¼
Low	4	4¾	4¼	4¾
	1981			
High	$ 17²³⁄₃₂	$ 12¾	$ 12½	$ 10¼
Low	11⅛	9¾	5¼	6¾

As of March 1, 1983, there were approximately 8,669 holders of the Company's common stock based on the number of record owners.

The Company does not have any history of paying cash dividends and believes that the Company's earnings are better reinvested in the Company's continuing operations. Accordingly, the Company does not intend to pay cash dividends in the foreseeable future. In addition, one of the Company's loan agreements limits the amount of any dividends in any 12 month period to 50% of the Company's net earnings for the preceding four full fiscal quarters. On December 3, 1980 the Board of Directors of the Company declared a four for three split in the Company's common stock which was effected on January 26, 1981 by distributing one additional share of the Company's common stock for every three shares owned by shareholders of record on December 22, 1980. Cash was paid in lieu of fractional shares based on the closing price on the American Stock Exchange for the record date adjusted for the split.

Item 6. Selected Financial Data

	Year Ended December 31				
	1982	1981	1980	1979	1978
Selected Statement of Income Data:					
Revenue:					
Oil and gas production, net of Windfall Profit Tax and Canadian revenue tax	**$25,431,000**	$19,648,000	$16,530,000	$ 9,882,000	$ 7,686,000
Gas gathering and transmission	**32,187,000**	33,369,000	26,312,000	23,637,000	3,946,000
Other	**1,159,000**	1,457,000	891,000	419,000	456,000
Total Revenue	**$58,777,000**	$54,474,000	$43,733,000	$33,938,000	$12,088,000
Income (Loss) Before Income Taxes	**$ 1,437,000**	$ (728,000)	$ 4,051,000	$ 2,906,000	$ 1,743,000
Net Income (Loss)	**$ 857,000**	$ (574,000)	$ 3,250,000	$ 2,705,000	$ 1,382,000
Per Share					
Net Income (Loss)	**$.09**	$(.06)	$.35	$.35	$.20
Cash Dividends	—	—	—	—	—

Selected Balance Sheet Data:

	December 31				
	1982	1981	1980	1979	1978
Current Assets	**$ 16,182,000**	$14,865,000	$12,407,000	$ 9,296,000	$10,225,000
Current Liabilities	**16,526,000**	13,029,000	13,239,000	7,103,000	6,507,000
Working Capital (Deficit)	**$ (344,000)**	$ 1,836,000	$ (832,000)	$ 2,193,000	$ 3,718,000
Total Assets	**$113,267,000**	$90,785,000	$75,376,000	$51,206,000	$45,186,000
Long-term Debt	**$ 64,458,000**	$45,470,000	$29,100,000	$21,707,000	$20,146,000
Shareholder's Equity	**$ 29,319,000**	$29,466,000	$30,062,000	$19,771,000	$16,098,000

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Results of Operations

1982 compared to 1981

The Company earned $857,000 compared to a net loss of $574,000 for 1981. The following table summarizes results by country.

	1982	1981	Increase (Decrease)
United States	**$(1,529,000)**	$ 672,000	$(2,201,000)
Canada	**2,386,000**	(1,246,000)	3,632,000
	$ 857,000	$ (574,000)	$ 1,431,000

United States

1982 was a disappointing year for United States operations. Increased finding costs over the last several years combined with reduced oil prices in 1982 have unfavorably impacted the economics of production from existing reserves. In addition, the Company experienced reduced demand as well as operational and measurement problems (since corrected) at its Central States gas gathering system.

A comparison of the results of U.S. operations for 1982 versus 1981 are as follows (amounts in thousands):

	1982	1981	Increase (Decrease)	%
Revenue				
Oil and gas production	**$14,897**	$15,629	$ (732)	(5)
Windfall Profit Tax expense	**(942)**	(1,827)	885	(48)
Gas gathering and transmission	**28,408**	29,579	(1,171)	(4)
Interest and other income	**759**	1,031	(272)	(26)
	43,122	44,412	(1,290)	(3)
Expenses				
Oil and gas operating expenses	**6,033**	5,527	506	9
Gas purchases	**23,845**	24,227	(382)	(2)
General and administrative	**3,400**	3,853	(453)	(12)
Depreciation, depletion and amortization	**6,402**	5,096	1,306	26
Interest	**4,362**	4,034	328	8
Equity in net loss of affiliate	**182**	—	182	N/A
Other	**508**	1,032	(524)	(51)
	44,732	43,769	963	2
Income (loss) before income taxes	**(1,610)**	643	(2,253)	(350)
Provision for income taxes	**(81)**	(29)	52	N/A
Net income (loss)	**$ (1,529)**	$ 672	$(2,201)	(327)

Oil and gas revenues net of Windfall Profit Taxes increased approximately $150,000, while the gross profit from oil and gas operations fell $1,264,000. Oil sales declined $1.4 million, of which approximately $950,000 resulted from a $2.71 per barrel average decrease in oil prices, with the remaining decline caused by a net reduction in volumes sold. The decrease in production from existing wells was offset somewhat by new wells in the Sunshine field. The impact of declining oil prices was moderated by an $885,000 decline in Windfall Profit Taxes. Lower oil prices, increasing adjusted base prices, reduced profitability of older production, and a decline in tax rate from 30% to 27½% for Tier III oil accounted for the decline in Windfall Profit Taxes.

Gas prices increased 20% to $2.18/MCF on the average because of price escalations under the Natural Gas Policy Act of 1978 and newly established production receiving higher prices. These price increases accounted for the $700,000 improvement in gas sales. Gas sales volumes remained constant despite reduced market demand in Oklahoma because of new wells added in Smith and Irion counties in Texas.

Depreciation, depletion and amortization associated with oil and gas rose by 32% to $4,611,000 primarily because of the replacement of lower cost, older reserves with new higher cost reserves and a reduction in reserve estimates.

Oil and gas operating expenses increased $289,000 due to inflation and approximately $150,000 more repair and maintenance work done in 1982.

Revenues and gross profit from gas gathering and transmission fell $1,171,000 and $1,038,000, respectively. The decline in revenues reflects a reduction in the Central States gas sales volumes from 26.1 MMCF/D in 1981 to 22.3 MMCF/D in 1982, due to curtailments by the major purchaser of gas and reduced peak period deliverability of the system. Included in 1981 revenues was the previously deferred income of $457,000 resulting from the expiration of a take-or-pay clause of a sales contract. Gross profit was also hampered by certain gas losses. The Company did extensive work in upgrading its gas measurement facilities and also repaired certain leaks within the system. Consequently, gas losses were well within industry standards by year end. Management expects significantly improved performance from Central States in 1983, based on operational improvements made this year.

General and administrative expenses declined somewhat due to certain cost-cutting measures that have been implemented. The Company is continuing its efforts to improve management of its general and administrative costs.

Interest expense rose approximately $300,000 due to higher overall borrowing levels, which more than offset the impact of lower interest rates.

Other revenues include $441,000 and $834,000 for 1982 and 1981, respectively, resulting from the sale of tax benefits. See Note 13 to Consolidated Financial Statements. In 1982, other expenses include the write-off of $499,000 of costs associated with Alaskan gold claims and uranium claims and leases which have been dropped or which have expired.

During 1982, the Company incorporated Worldwide One, Inc., in which it now owns a 47% interest, to acquire production and reserves from public and private entities. Worldwide One, Inc. has made three small acquisitions, revenues of which are not significant enough to cover general and administrative expenses associated with its acquisition activities.

Fiji

The Company participated in the drilling of two dry holes on the 2,000,000 acre OEL-7 exploration license, in which it now has an approximate 11% working interest due to defaults by two venturers, including the previous operator. A dry hole was drilled subsequently on a second exploration license, in which the Company elected not to exercise an option to earn future rights under the license. Management believes there are still several viable remaining prospects. The assignment to the Company of its rights under OEL-7 has been delayed and hampered by the previous operator's filing of a bankruptcy petition under Chapter 11. Once title is assigned, the Company and its partners plan to farmout the OEL-7 prospect. To date, the Company has capitalized $2,731,000 on the Fiji program. Should (1) title to OEL-7 not be assigned, (2) the operating group not be able to successfully farmout the prospect, or (3) the prospect, once farmed out, proves unsuccessful, a direct charge to earnings for this amount and any future expenditures will be recognized. The Company is unable to definitively state when the Bankruptcy Court may allow title to its rights on OEL-7 to pass.

Canada

Management is comfortable with the substantially improved performance of the Company's Canadian operations. Earnings were $2,386,000 in 1982 compared to a $1,246,000 loss in 1981, reflecting the Company's increased heavy oil and gas production, a virtual doubling of heavy oil prices allowed by the governments of Canada and Alberta, an increase in the Alberta Royalty Tax Credit and increased throughput in the Company's Cold Lake transmission system.

A comparison of the results of Canadian operations for 1982 versus 1981 is as follows (amounts in thousands):

	1982	1981	Increase (Decrease)	%
Revenue				
Oil and gas production	**$12,074**	$ 6,436	$5,638	88
Petroleum and Gas Revenue Tax	**(599)**	(590)	(9)	2
Gas gathering and transmission	**3,779**	3,790	(11)	—
Other	**401**	426	(25)	(6)
	15,655	10,062	5,593	56
Expenses				
Oil and gas operating expenses	**3,158**	2,399	759	32
Gas purchases	**1,515**	1,831	(316)	(17)
General and administrative	**2,515**	2,516	(1)	—
Depreciation, depletion and amortization	**1,737**	1,183	554	47
Interest	**3,427**	3,163	264	8
Other	**255**	341	(86)	(25)
	12,607	11,433	1,174	10
Income (loss) before income taxes	**3,048**	(1,371)	4,419	322
Provision for taxes	**661**	(125)	786	629
Net income (loss)	**$ 2,387**	$ (1,246)	$3,633	291

Heavy oil sales increased 110% to $5,337,000 as a result of a 91% increase in the average price received to $24.60 and a 5% increase in sales volumes. By the end of the fourth quarter, 19 wells were producing from the Phase III expansion of the Ft. Kent heavy oil project. Total production during December 1982 averaged 1500 gross BOPD which represents a 35% increase over the same period in 1981. Through December 31, 1982, 47 successful wells, 10 marginal oil wells, and 10 dry holes had been drilled in the Phase III expansion. Drilling results in this expansion to date have indicated the presence of a channel sand formation in which the lateral extent of the formation is less than expected, but the pay zones of wells within the channel are thicker than expected. Management consequently believes that fewer than the previously planned 112 wells may be required in Phase III, but the overall anticipated production may remain unchanged.

Conventional oil sales increased approximately $234,000 reflecting a 36% increase in price to $20.47 as a result of price increases scheduled under the Energy Pricing and Taxation Agreement between Alberta and the Canadian Federal Government.

Total gas sales, net of purchases, rose to $7,864,000, reflecting percentage increases in daily volumes of Company-owned gas and pipeline throughput of 46% and 34%, respectively. Sales of Company-owned gas increased far greater than total pipeline throughput because the Company has been emphasizing the production and sales of its own gas. The total 1982 volume throughput reflects two sales of some magnitude compared to 1981. One of these was to Canadian Western Natural Gas Company Limited under an interim sales contract to supply 1,000,000 MCF of gas, completed in late October 1982. In addition, on November 11, the Company began delivering gas under a long-term contract to Celanese Canada Inc. to supply its petrochemical plant located near Edmonton. 626,000 MCF were delivered to Celanese in 1982. These delivery increases offset reduced demand by Northwestern Utilities Limited for the account of Esso, historically the system's largest purchaser, in connection with its experimental heavy oil project.

Depreciation, depletion and amortization increased proportionately with increased sales volumes. The Alberta Royalty Tax Credit increased $1,009,000 to $1,652,000 due to an increase in rates to 75% of Alberta Crown Royalties.

These positive factors were partially offset by a $759,000 increase in operating expenses.

Interest expense rose 8% to $3.4 million, primarily as a result of higher borrowing levels. Interest associated with the Phase III expansion of Ft. Kent prior to production is being capitalized and will be amortized as part of the depreciation, depletion and amortization calculation upon determination of proved reserves from Phase III.

1981 compared to 1980

The Company experienced a net loss for 1981 of $574,000 compared to net income of $3,250,000 in 1980. The following table compares results by country.

	1981	1980	Decrease
United Kingdom	$ (885,000)	$ (378,000)	$ (507,000)
United States	1,557,000	2,352,000	(795,000)
Canada	(1,246,000)	1,276,000	(2,522,000)
	$ (574,000)	$3,250,000	$(3,824,000)

United Kingdom

The 1981 loss associated with the United Kingdom reflects a $561,000 write-down of assets to zero because of continuing unprofitable operations of a tungsten mine and mill in Northern England. The Company and its joint venture partner have since sold the mine for a nominal amount.

United States (includes United Kingdom)

A comparison of the results of U.S. and United Kingdom operations for 1981 versus 1980 is as follows (amounts in thousands):

	1981	1980	Increase (Decrease)	%
Revenue				
Oil and gas production	$15,629	$11,401	$ 4,228	37
Windfall Profit Tax expense	(1,827)	(1,032)	(795)	77
Gas gathering and transmission	29,579	23,705	5,874	25
Interest and other income	1,031	405	626	155
	44,412	34,479	9,933	29
Expenses				
Oil and gas operating expenses	5,527	4,592	935	20
Gas purchases	24,227	19,924	4,303	22
General and administrative	3,853	2,163	1,690	78
Depreciation, depletion and amortization	5,096	3,242	1,854	57
Interest	4,034	1,861	2,173	117
Other	1,032	609	423	69
	43,769	32,391	11,378	35
Income before income taxes	643	2,088	(1,445)	(69)
Provision for income taxes	(29)	114	(143)	(125)
Net Income	$ 672	$ 1,974	$(1,302)	(66)

Sales from oil and gas production increased 37% due to a 26% increase in oil sales and a 107% increase in gas and liquids sales. Oil sales increased due to higher sales volumes from continued development of the Sunshine Field in Smith County, Texas, net of normal declines in more mature production in south Texas. Gas volumes increased 23%, primarily from the added Sunshine Field production. In addition, average gas prices rose 56% to $1.81 per MCF inasmuch as new production receives higher prices and because of price escalations provided for by the Natural Gas Policy Act of 1978. The percentage increase in Windfall Profit Tax was larger than the percentage increase in oil and gas sales because it was only in effect for ten months in 1980.

Gas gathering and transmission revenue growth and the somewhat smaller growth in the cost of purchases reflect the renegotiated sales contract with the Company's major purchaser. In addition, throughput volumes increased 15%.

Other revenue includes $834,000 associated with the sale of tax benefits. See Note 13 of Notes to Consolidated Financial Statements.

Operating expenses did not increase proportionately with the increase in oil and gas sales because the increased production resulting from the Sunshine Field is less costly to operate than the mature south Texas waterflood production. Depreciation, depletion and amortization grew more quickly than increased revenues because finding costs of oil and gas reserves have increased from prior years. General and administrative expenses increased 78% in 1981, reflecting expanded geology, land and engineering staffs to increase our prospecting capability and enhance our production efficiencies. In addition, the Company installed a computer-based financial and operational control system during 1981.

Interest expense more than doubled in 1981. Average interest rates increased from 16.8% to 19.5% while average debt outstanding increased 87% to $21 million. The higher level of borrowing was necessary to meet acquisition, exploration, development and gas gathering facility expenditures.

Canada

A comparison of the results of Canadian operations for 1981 versus 1980 is as follows (amounts in thousands):

	1981	1980	Increase (Decrease)	%
Revenue				
Oil and gas production	$ 6,436	$6,161	$ 275	4
Petroleum and Gas Revenue Tax	(590)	—	(590)	N/A
Gas gathering and transmission	3,790	2,607	1,183	45
Other	426	486	(60)	(12)
	10,062	9,254	808	9
Expenses				
Oil and gas operating expenses	2,399	1,691	708	42
Gas purchases	1,831	1,574	257	16
General and administrative	2,516	1,383	1,133	82
Depreciation, depletion and amortization	1,183	1,320	(137)	(10)
Interest	3,163	1,286	1,877	146
Other	341	37	303	797
	11,433	7,291	4,142	57
Income (loss) before income taxes	(1,371)	1,963	(3,334)	(170)
Provision for taxes	(125)	687	(812)	(118)
Net Income (loss)	$(1,246)	$1,276	$(2,522)	(198)

Canadian results were adversely affected because demand for gas delivered by its Cold Lake transmission system was 50% below expectations. In November 1980, the Company nominated to deliver an average of 11 MMCF of gas per day to its major customer which would have represented a substantial increase over prior deliveries. Because of the expected increased demand, the Company doubled the Cold Lake transmission system capacity which caused increased capital expenditures and borrowing levels resulting in increased interest costs. This, together with higher interest rates, caused interest expense to increase 146% to $3,163,000. In order to help minimize the impact of reduced Cold Lake gas throughput, the Company maximized the sale of its own gas in lieu of purchasing gas from others. In addition, the Company opened a fully operational office in Calgary to manage its increased activities causing a growth in general and administrative expenses. Also, the new Petroleum and Gas Revenue Tax amounting to $590,000 was incurred during the year. Because of the uncertainty and negative aspects associated with the Federal Government's efforts to tax and Canadianize the oil and gas industry, drilling activity in Canada slowed resulting in the Company's rig having substantial periods of inactivity and negative operating results included in other revenue and expense.

Liquidity and Capital Commitments

The primary sources of funding for the Company's 1982 and 1981 oil and gas leasehold acquisition, exploration and development programs and pipeline expansions were bank lines of credit and internally generated funds.

The Company's long-term debt has increased from $29.1 million in 1980 to $45.5 million in 1981 and to $64.5 million in 1982, with a resulting increase of interest expense for the corresponding years from $3.2 million to $7.2 million to $7.8 million (see "Consolidated Statements of Income"). As a result of the Company's increased debt, the ratio of long-term debt to shareholders' equity increased from 154% as of December 31, 1981 to 220% as of December 31, 1982. In an attempt to help reverse this unfavorable trend, subsequent to year-end, the Company issued new common stock through the exercise of warrants and registered for sale a portion of its ownership in Canadian Worldwide Energy Limited (Canadian Worldwide) together with preferred stock in Canadian Worldwide, as described more fully below.

United States

At December 31, 1982, the Company had borrowing bases amounting to $34.2 million, of which $34.0 million was borrowed or utilized, leaving approximately $200,000 in available credit. 200,000 shares of common stock of the Company were issued in January, 1983, pursuant to the exercise of previously issued warrants, yielding approximately $950,000 after expenses. During March 1983, the Company and Canadian Worldwide filed the final prospectus for a $16 million (Cdn.) offering in Canada. Upon completion of the offering, expected to occur early in April 1983, the Company's U.S. operations should receive approximately $5.3 million (Cdn.) from the sale of Canadian Worldwide stock owned by the Company (see Note 14 of Notes to Consolidated Financial Statements).

Generally, borrowing bases under both U.S. credit facilities are re-evaluated quarterly; to the extent reserves are increased or decreased relative to present levels, bank borrowing bases will be increased or decreased accordingly. The decline in oil prices and the uncertainty surrounding them has had a negative impact on the Company's borrowing base and may continue to cause significant changes in the future.

Upon completion of the Canadian offering, the Company will be required to pay down the U.S. credit facilities with the proceeds it receives in the U.S. from the Canadian offering and to reduce its borrowing base by the lesser of the amount of such proceeds or $6.4 million (see Note 3 to Notes to Consolidated Financial Statements). The banks waived a redetermination of the Company's borrowing base until April 30, 1983 in exchange for a pledge of 25% of the Company's Canadian Worldwide stock. Because of lower oil prices, reduced price escalation rates and higher discounting factors now applied by the banks, the Company anticipates that there could be a further reduction in its borrowing base at such time. The Company has agreed to pay down any borrowings in excess of the new borrowing base in three equal monthly installments, beginning April 30, 1983. The negative loan convenant concerning the current ratio was waived through March 31, 1983. Upon completing the Canadian offering, the negative loan convenants relating to financial statement ratios and net worth will be revised such that they will be based on U.S. financial statements treating the Canadian operations under the equity method of accounting. In addition, the loan covenants will be revised to (1) require a debt-to-equity ratio of 2-to-1, and (2) require a 1-to-1 working capital position. Substantial amounts under lines of credit are due in 1984 which would require refinancing with the banks, through subordinated debt or equity capital.

Funds generated from U.S. opeations in 1982 and 1981 were $5.2 million and $6.1 million, respectively. Because of reduced available credit and the uncertainty regarding oil prices and their potential impact on bank borrowing lines, the 1983 capital budget will be limited primarily to lower risk development drilling, a waterflood of the Company's Sunshine Field and high return expenditures on the gas gathering systems. Following is a summary of the U.S. capital budget:

Exploration and leasehold acquisition	$ 133,000
Development	2,433,000
Pipeline facilities	2,056,000
Other	1,572,000
	$6,194,000

Complete implementation of the budget will be dependent on the successful closing of the Canadian offering, no further reduction in the U.S. borrowing base and, depending upon 1983 funds generated from operations, a small amount of additional financing. In addition, because of the current economic environment in which drilling costs and the cost of purchasing producing properties has declined dramatically, Management is investigating sources of long-term capital with the intent of acquiring producing properties directly or through the acquisition of one or more companies.

Canada

At December 31, 1982, Canadian Worldwide and its subsidiaries had the following loan arrangements and available credit (in Canadian dollars):

	Borrowing Base	Utilized	Available
Oil & gas production loan	$25,000,000	$24,030,000	$970,000
Project loan - Ft. Kent	18,000,000	18,000,000	—
	$43,000,000	$42,030,000	$970,000

Subsequent to year end, the Ft. Kent expansion loan was increased to $30 million. In addition, during March 1983, Canadian Worldwide filed the final prospectus for an offering of 9.25% Cumulative Redeemable Preferred Shares included as part of a unit consisting of two shares of Canadian Worldwide preferred and one share of Canadian Worldwide common owned by the Company. Assuming the offering is closed in mid-April 1983 as planned, after utilizing a portion of the anticipated proceeds to repurchase 527,536 Canadian Worldwide Common Shares from a wholly-owned subsidiary of the Company, $9.5 million (Cdn.) will be available for Canadian operations to reduce, on a short-term basis, outstanding bank indebtedness. This will increase amounts available under bank credit facilities, which may from time to time, as required, be drawn down to continue the Phase III heavy oil development program at Ft. Kent, to use for other capital expenditures and to add to general working capital. See Note 14 to Consolidated Financial Statements.

Funds generated from operations amounted to approximately $5.8 million (Cdn.) and a $200,000 (Cdn.) deficit in 1982 and 1981, respectively. With gas deliveries under the new Celanese contract beginning in late 1982 and the addition of wells added from the Ft. Kent expansion, Management is forecasting 1983 cash flows from operations of $17.6 million (Cdn.). The capital budget for 1983 is as follows (in Canadian dollars):

Exploration and leasehold acquisition	$ 2,154,000
Ft. Kent Phase III expansion	16,541,000
Other heavy oil projects	3,025,000
Development	1,254,000
Pipeline facilities	3,008,000
Other	405,000
	$26,387,000

Impact of Inflation

Oil and Gas Production

Oil and gas price increases during prior years had more than offset increased operating costs resulting from inflation. However, the recent international oil glut created by reduced demand and increased supplies has caused world oil prices to decline. This, together with relatively high interest rates and finding costs and the imposition of the Windfall Profit Tax, has reduced the profitability of oil exploration, development and production activities. This has been particularly burdensome on United States operations where oil reserves are substantial. Consequently, the Company's U.S. earnings and borrowing bases have declined during the current year. In the future, U.S. earnings will be more dependent upon the movement of world oil prices.

Because gas prices escalate at a rate equal to or greater than inflation under the Natural Gas Policy Act of 1978, such price increases should be adequate to offset the effect of inflation on operating costs, assuming the demand for gas is not materially reduced by excess gas supplies. If gas prices are decontrolled, the price received will be dependent upon market conditions, the effect of which cannot be determined at this time.

In Canada, the September 1, 1981 energy pricing and taxation agreement between Alberta and Canada provides for scheduled increases in existing conventional oil and gas prices which should more than offset the impact of inflation. However, as part of this agreement, certain additional taxes have been imposed. In addition, all of the Company's heavy oil production began receiving the New Oil Reference Price effective April 1, 1982. In 1982, this resulted in an approximate doubling of the price received. Because the New Oil Reference Price and scheduled price increases for existing conventional oil are tied to the free market price, declines in the world oil price may have a negative impact on oil revenues (not a one-to-one correlation). However, since gas prices are regulated and sales contracts are based on a percentage of such prices, Management believes they should escalate at a rate at least equal to inflation.

Gas Gathering and Transmission

The major sales contract for the Company's gas gathering system in Kansas was re-negotiated in 1981 and provides for price escalations under the Natural Gas Policy Act of 1978 (NGPA) which, beginning in April 1982, provides for inflation as well as a growth factor of 4% per year. This should allow the Company's sales to outpace the inflation associated with operating costs during the effective period of the NGPA. However, gross profit after purchases will continue to be a function of Central States' ability to continue to purchase gas at less than its resale price.

Based on gas purchases and sales contracts, the gross profit on gas transmitted by the Company's Cold Lake system in Canada will increase commensurate with the Alberta Border Price which will increase as scheduled under the September 1, 1981 Canada-Alberta energy pricing and taxation agreement.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT CERTIFIED PUBLIC ACCOUNTANTS

To the Board of Directors and Shareholders
Worldwide Energy Corporation:

We have examined the consolidated financial statements and the financial statement schedules of Worldwide Energy Corporation and its subsidiaries as listed under Item 13 in this Form 10-K. Our examinations were made in accordance with generally accepted auditing standards and, accordingly, included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

In our opinion, the financial statements referred to above present fairly the consolidated financial position of Worldwide Energy Corporation and its subsidiaries as of December 31, 1982 and 1981, and the consolidated results of their operations and changes in their financial position for each of the three years in the period ended December 31, 1982, in conformity with generally accepted accounting principles which, except for the change, with which we concur, in the method of translating foreign currency as described in Note 1 of Notes to Consolidated Financial Statements, have been applied on a consistent basis. In addition, the financial statement schedules referred to above, when considered in relation to the basic financial statements taken as a whole, present fairly the information required to be included therein.

COOPERS & LYBRAND

Denver, Colorado
March 7, 1983

Worldwide Energy Corporation and Subsidiaries
Consolidated Statements of Income

	Years Ended December 31		
	1982	1981	1980
Revenue			
Oil and gas production	**$26,972,000**	$22,065,000	$17,562,000
Windfall Profit Tax and Canadian revenue tax expense	**(1,541,000)**	(2,417,000)	(1,032,000)
Gas gathering and transmission	**32,187,000**	33,369,000	26,312,000
Other income (Note 13)	**1,159,000**	1,457,000	891,000
	58,777,000	54,474,000	43,733,000
Expenses			
Oil and gas operating expenses	**9,199,000**	7,926,000	6,283,000
Gas purchases	**25,361,000**	26,058,000	21,499,000
General and administrative	**5,915,000**	6,369,000	3,546,000
Depreciation, depletion and amortization	**8,140,000**	6,279,000	4,562,000
Interest	**7,789,000**	7,197,000	3,148,000
Foreign exchange conversion (Note 1)	**7,000**	37,000	(225,000)
Equity in net loss of affiliate (Note 1)	**182,000**	—	—
Other (Note 12)	**747,000**	1,336,000	869,000
	57,340,000	55,202,000	39,682,000
Income (Loss) From Operations Before Provision for Income Taxes	**1,437,000**	(728,000)	4,051,000
Provision (Credit) for Income Taxes (Note 5)	**580,000**	(154,000)	801,000
Net Income (Loss)	**$ 857,000**	$ (574,000)	$ 3,250,000
Net Income (Loss) Per Share	**$.09**	$(.06)	$.35
Average Shares Outstanding	**9,202,900**	9,109,700	9,261,700

The accompanying notes are an integral part of the consolidated financial statements.

Worldwide Energy Corporation and Subsidiaries

Consolidated Balance Sheets - As of December 31, 1982 and 1981

Assets

	1982	1981
Current Assets		
Cash	$ 2,710,000	$ 188,000
Accounts receivable (Note 3)	11,875,000	12,273,000
Alberta Royalty Tax credits receivable	292,000	648,000
Inventory of supplies - at average cost	1,223,000	1,649,000
Prepaid expenses	82,000	107,000
	16,182,000	14,865,000
Property, Plant and Equipment, at Cost		
(Notes 2 and 3 and Schedules V and VI)		
Oil and gas properties - under full cost method	84,774,000	63,147,000
Gas gathering and transmission facilities	25,834,000	20,544,000
Gas purchase contracts	8,177,000	8,177,000
Other equipment and property	6,859,000	5,530,000
	125,644,000	97,398,000
Less - Accumulated depreciation, depletion and amortization	29,076,000	21,810,000
	96,568,000	75,588,000
Deferred Charges and Other Assets (Note 4)	517,000	332,000
	$113,267,000	$90,785,000

The accompanying notes are an integral part of the consolidated financial statements.

Worldwide Energy Corporation and Subsidiaries
Consolidated Balance Sheets - as of December 31, 1982 and 1981

Liabilities and Shareholders' Equity

	1982	1981
Current Liabilities		
Long-term debt due within one year (Note 3)	$ 2,969,000	$ 588,000
Accounts payable and accrued expenses	13,557,000	12,441,000
	16,526,000	13,029,000
Long-Term Debt (Note 3)	64,458,000	45,470,000
Deferred Compensation (Note 7)	220,000	225,000
Deferred Income Taxes (Note 5)	2,744,000	2,595,000
Total Liabilities	83,948,000	61,319,000
Commitments and Contingencies (Notes 2, 9 and 13)		
Shareholders' Equity (Note 6)		
Common stock, authorized 20,000,000 shares, par value $.20, issued 9,113,705 shares in 1982 and 1981	1,823,000	1,823,000
Capital in excess of par value	17,018,000	16,898,000
	18,841,000	18,721,000
Cumulative foreign currency translation adjustment (Note 1)	(1,117,000)	—
Retained earnings (Note 3)	11,645,000	10,788,000
	29,369,000	29,509,000
Treasury stock, 8,211 shares in 1982 and 6,499 shares in 1981, at cost	(50,000)	(43,000)
Total Shareholders' Equity	29,319,000	29,466,000
	$113,267,000	$90,785,000

The accompanying notes are an integral part of the consolidated financial statements.

Worldwide Energy Corporation and Subsidiaries

Consolidated Statements of Changes in Financial Position

	Years Ended December 31		
	1982	1981	1980
Funds Were Provided By:			
Operations			
Net income (loss)	$ 857,000	$ (574,000)	$ 3,250,000
Items not requiring outlay of working capital:			
Depreciation, depletion and amortization	8,140,000	6,279,000	4,562,000
Deferred income taxes	494,000	(194,000)	733,000
Other items	499,000	561,000	—
Working capital provided by operations	9,990,000	6,072,000	8,545,000
Issuance of common stock and equity transactions of affiliate, net	113,000	(21,000)	7,097,000
Banks loans, net	18,988,000	16,370,000	7,394,000
Decrease (increase) in deferred charges and other items	(185,000)	62,000	(659,000)
Total funds provided	28,906,000	22,483,000	22,377,000
Funds Were Used For:			
Additions to properties, net	32,010,000	19,815,000	25,346,000
Adjustments resulting from change in method of translating foreign currency:			
Properties, net	(2,391,000)	—	—
Deferred income tax	345,000	—	—
Cumulative translation adjustment	1,117,000	—	—
Other	5,000	—	56,000
Total funds used	31,086,000	19,815,000	25,402,000
Increase (Decrease) in Working Capital	(2,180,000)	2,668,000	(3,025,000)
Working Capital - Beginning of Year	1,836,000	(832,000)	2,193,000
Working Capital — End of Year	$ (344,000)	$ 1,836,000	$ (832,000)

Changes in Components of Working Capital			
Increase (Decrease) in Current Assets			
Cash	$ 2,522,000	$(1,647,000)	$ 246,000
Receivables	(754,000)	3,842,000	2,459,000
Inventory of supplies and prepaid expenses	(451,000)	263,000	406,000
	1,317,000	2,458,000	3,111,000
Less Increase (Decrease) in Current Liabilities			
Accounts payable and accrued expenses	1,116,000	(798,000)	6,730,000
Long-term debt due within one year	2,381,000	588,000	(594,000)
	3,497,000	(210,000)	6,136,000
Increase (Decrease) in Working Capital	$(2,180,000)	$2,668,000	$(3,025,000)

The accompanying notes are an integral part of the consolidated financial statements.

Worldwide Energy Corporation and Subsidiaries

Consolidated Statements of Shareholders' Equity

For the Years Ended December 31, 1982, 1981 and 1980

	Common Stock		Capital in Excess of Par Value	Treasury Stock	Cumulative Foreign Currency Translation Adj.	Retained Earnings
	Issued Shares	Amount				
Balances -						
December 31, 1979	5,788,833	$1,158,000	$10,447,000	$ (3,000)	$ —	$ 8,169,000
Issued on conversion of 8% debentures	1,048,853	210,000	6,898,000	—	—	—
Issued on the exercise of stock purchase option	200	—	3,000	—	—	—
Receipt of stock from employee for forgiveness of receivable	—	—	—	(14,000)	—	—
Four-for-three stock split effected in the form of a 33⅓% stock distribution	2,275,286	455,000	(455,000)	—	—	(57,000)
Net income for the year ended December 31, 1980	—	—	—	—	—	3,250,000
Balances -						
December 31, 1980	9,113,172	$1,823,000	$16,893,000	$(17,000)	—	$11,362,000
Issued on the exercise of stock purchase option	533	—	5,000	—	—	—
Receipt of stock from employees for forgiveness of receivable	—	—	—	(26,000)	—	—
Net loss for the year ended December 31, 1981	—	—	—	—	—	(574,000)
Balances -						
December 31, 1981	9,113,705	$1,823,000	$16,898,000	$(43,000)	$ —	$10,788,000

The accompanying notes are an integral part of the consolidated financial statements.

Worldwide Energy Corporation and Subsidiaries
Consolidated Statements of Shareholders' Equity
For the Years ended December 31, 1982, 1981 and 1980

	Common Stock		Capital in Excess of Par Value	Treasury Stock	Cumulative Foreign Currency Translation Adj.	Retained Earnings
	Issued Shares	Amount				
Balances - December 31, 1981	9,113,705	$1,823,000	$16,898,000	$(43,000)	$ —	$10,788,000
Receipt of stock from employees for forgiveness of receivable	—	—	—	(7,000)	—	—
Cumulative foreign currency translation adjustments as of January 1, 1982	—	—	—	—	(908,000)	—
Cumulative foreign currency translation adjustments for the year ended December 31, 1982	—	—	—	—	(209,000)	—
Share of equity transactions of affiliate	—	—	120,000	—	—	—
Net income for the year ended December 31, 1982	—	—	—	—	—	857,000
Balances - December 31, 1982	9,113,705	$1,823,000	$17,018,000	$(50,000)	$(1,117,000)	$11,645,000

The accompanying notes are an integral part of the consolidated financial statements.

Worldwide Energy Corporation and Subsidiaries
Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies

Basis of Consolidation

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries operating in the United States, Canada, Fiji, and the United Kingdom. The Company's 47% ownership interest in Worldwide One, Inc. is accounted for in accordance with the equity method. Significant intercompany balances and transactions have been eliminated.

Income Taxes

Investment tax credits are recognized as a reduction of income taxes in the year in which the credits are utilized.

Sale of Tax Benefits

Proceeds from sale of tax benefits are recorded as income in the period in which the sale occurs.

Currency Conversion

Prior to January 1, 1982, foreign subsidiary balance sheets were converted to United States dollars at the rates of exchange in effect at the end of the year, except for property, plant and equipment, deferred income taxes and shareholders' equity accounts which were converted at the historical rate of exchange. Revenue and expense accounts were converted monthly based upon the average rates of exchange in effect during the month, except for depreciation, depletion and amortization, which was translated at the rates of exchange prevailing when the assets were acquired. Gains or losses from foreign exchange were included in net income.

As of January 1, 1982, the Company adopted Statement of Financial Accounting Standards No. 52, Foreign Currency Translation. In accordance with the new FASB No. 52, all asset and liability accounts were translated at the rates of exchange in effect at the end of the year. Revenue and expense accounts are converted monthly based upon the average rates of exchange during the month. Unrealized gains or losses are recognized as an adjustment of shareholders' equity, and realized gains and losses are charged to operations. Had the Company not adopted the new standard, net income would have been increased by $742,000 or $.08 per share for 1982. Had the change in accounting principle been applied retroactively to prior years, net income (loss) for the years ended December 31, 1981 and 1980 would have been $(433,000) or $(.05) per share and $3,110,000 or $.34 per share, respectively.

Alberta Royalty Tax Credit

As of April 13, 1982 the Canadian Province of Alberta announced its Economic Resurgence Plan which included an increase in the Alberta Royalty Tax Credit to 75% of royalties paid to Alberta, effective September 1, 1981. Because the credit (1) is paid in cash irrespective of whether there is an income tax liability, (2) is not a function of taxable income and (3) reflects the intention of Alberta to increase cash flow to small producers, the Company has concluded that the credit more appropriately represents a reduction of the royalties paid to the government rather than a reduction of the provision for income taxes. Therefore, the credit has been reclassified to oil and gas revenues from the provision for income taxes. This reclassification has the effect of increasing oil and gas revenues by $1,652,000, $643,000 and $512,000 for the years ended December 31, 1982, 1981 and 1980, respectively. The retroactive benefits of the April 13, 1982 plan were recognized in the first quarter of 1982.

Reclassifications

Prior year amounts in the statements of income and in the segment information have been reclassified to conform to the current year's presentation. These reclassifications have no effect on net income.

Overdraft Bank Accounts

Bank accounts in an overdraft position amounting to $2,414,000 and $1,852,000 at December 31, 1982 and 1981, respectively, have been classified as accounts payable.

Oil and Gas Properties and Gas Gathering and Transmission Facilities

The Company records its oil and gas properties based on the "full cost" method of accounting under which all costs of acquiring, exploring for and developing oil and gas reserves are capitalized. Such costs include lease acquisition, geological and geophysical expenses, delay rentals and interest associated with non-producing properties not being amortized and exploration, development and overhead expenses related to the acquisition of properties and oil and gas reserves. Oil and gas property costs are amortized on a future gross revenue basis utilizing separate cost pools for the United States, Canada and the Fiji

Islands. Only proved reserves, as determined by in-house or independent engineers, are utilized in estimating future gross revenues. Future revenues are estimated using prices in effect at the end of the period, including consideration of changes in existing prices provided only by contractual arrangements. Canadian reserves include price escalations as defined in the September 1, 1981 Canada/Alberta Energy Pricing and Taxation Agreement. Costs capitalized are not in excess of their estimated net realizable value.

Gas gathering and transmission facilities are depreciated on a straight-line basis over their estimated useful lives or over the lives of reserves estimated to be available for transportation through the facilities if such reserve lives are less than the estimated useful lives of the assets. Gas contracts acquired with Central States Gas Company are amortized over the life of the gas reserves dedicated to the system.

Gains or losses resulting from dispositions of oil and gas properties and inventory are charged or credited to the cost pools. Gains or losses on the disposal of unusually significant properties are recognized at the time of disposition.

Depreciation of Other Equipment

Depreciation is provided at straight-line rates ranging from 3% to 33%. Gains and losses from disposals are included in income. Maintenance and repairs are charged to expense. Major improvements and replacements are capitalized.

Earnings Per Share

Earnings per share computations are based on the weighted average number of shares of common stock and common stock equivalents outstanding during the year. Computations giving effect to potential dilutive factors do not result in a significant dilutive effect on earnings per share.

2. Oil and Gas Producing Activities

Capitalized Costs

Details of capitalized costs and accumulated depreciation, depletion and amortization (DD&A) as of December 31, 1982, 1981 and 1980 relating to oil and gas producing activities are as follows:

(000's Omitted)

	1982		1981		1980	
	Cost	**Accum. DD&A**	**Cost**	**Accum. DD&A**	**Cost**	**Accum. DD&A**
Canada						
Heavy oil	**$19,341**	$ 1,880	$ 5,839	$ 1,417	$ 5,539	$ 1,117
Conventional oil and gas	**20,734**	3,770	19,215	3,519	16,386	2,959
Total Canada	**40,075**	5,650	25,054	4,936	21,925	4,076
United States	**41,968**	15,054	37,292	10,442	25,727	6,960
Fiji Islands	**2,731**	—	801	—	—	—
Total	**$84,774**	$20,704	$63,147	$15,378	$47,652	$11,036

Capitalized costs include lease acquisition, exploration and development activities including production equipment and related facilities. Excluding Fiji Islands, capitalized costs of unproved properties are not significant in relation to total capitalized costs. In the Fiji Islands, the Company has expended $2,557,000 on the 2,000,000 acre OEL-7 exploration license in which the two wells drilled have been plugged and abandoned. Management believes there are still several viable remaining prospects. Although the original operator of the joint venture had agreed that the Company earned and was entitled to the assignment of an approximate 11% working interest, the assignment has been delayed pending the outcome of the filing of a bankruptcy petition under Chapter 11 by the original operator. Once title is assigned, the Company and its partners plan to farmout the OEL-7 prospect. In addition, subsequent to drilling an unsuccessful well on the OEL-9 exploration license, the Company did not exercise its option to earn an interest in this license. Total costs incurred on OEL-9 amount to $174,000. Should (1) title to OEL-7 not be assigned, (2) the operating group not be able to successfully farmout the prospect, or (3) the prospect, once farmed out, proves unsuccessful, a direct charge to earnings for $2,731,000 and any future expenditures will be recognized.

Costs Incurred in Producing Activities

Details of costs incurred in the Company's oil and gas producing activities for the years ended December 31, 1982, 1981 and 1980 are as follows:

(000's Omitted)

	1982	1981	1980
Property Acquisition Costs			
Canada			
Heavy oil	$ —	$ 6	$ 19
Conventional oil and gas	172	1,095	3,566
Total Canada	172	1,101	3,585
United States	1,051	2,776	1,825
Fiji Islands	—	579	—
Total	$ 1,223	$4,456	$5,410
Exploration Costs			
Canada			
Heavy oil	$ 29	$ —	$ 59
Conventional oil and gas	344	173	2,024
Total Canada	373	173	2,083
United States	144	3,493	1,838
Fiji Islands	1,929	223	—
Total	$ 2,446	$3,889	$3,921
Development Costs			
Canada			
Heavy oil	$15,093	$ 294	$ 481
Conventional oil and gas	1,589	1,561	931
Total Canada	16,682	1,855	1,412
United States	4,109	5,296	7,033
Total	$20,791	$7,151	$8,445
Production Costs			
Canada			
Heavy oil	$ 1,607	$1,453	$1,073
Conventional oil and gas	900	370	619
Total Canada	2,507	1,823	1,692
United States	4,689	4,400	3,511
Total	$ 7,196	$6,223	$5,203
Depreciation, depletion and amortization			
Canada	$ 1,337	$ 860	$1,065
United States	4,611	3,482	1,851
Total	$ 5,948	$4,342	$2,916

Depreciation, Depletion and Amortization Expense Per Dollar of Gross Revenue

	1982	1981	1980
Canada	$ .12	$ .13	$ .17
United States	$ .33	$ .25	$ .18

Revenues from Producing Oil and Gas

Net revenue derived from oil and gas production for the years ended December 31, 1982, 1981 and 1980 is indicated below. Net revenue reflects the Company's share of oil and gas produced and sold after deducting costs of production.

(000's Omitted)	1982	1981	1980
Canada			
Heavy oil	**$ 3,498**	$ 889	$ 1,065
Conventional oil and gas	**5,471**	3,134	3,404
Total Canada	**8,969**	4,023	4,469
United States	**9,266**	9,402	6,858
Total	**$18,235**	$13,425	$11,327

Estimated Oil and Gas Reserves

A review of the Company's net proved reserves of crude oil and natural gas as of December 31, 1979, 1980, 1981 and 1982 determined by the Company's engineers (based in part upon reports of other consultants) are as follows:

		Proved Developed Reserves		
		Producing		Non-Producing
Oil Reserves (Bbls.) - United States (Unaudited)	**Total Proved Reserves**	**Working Interest**	**Royalty Interest**	
Reserves at December 31, 1979	2,540,804	2,013,448	476,254	51,102
Additions:				
Net revisions of previous estimates	(221,200)	(87,139)	(135,341)	1,280
Extensions and discoveries	628,284	259,417	—	38,270
	2,947,888	2,185,726	340,913	90,652
Deductions:				
Production	293,507	261,407	32,100	—
Reserves at December 31, 1980	2,654,381	1,924,319	308,813	90,652
Additions:				
Net revisions of previous estimates	(377,587)	(342,261)	90,237	120,555
Extensions and discoveries	268,293	120,607	—	—
	2,545,087	1,702,665	399,050	211,207
Deductions:				
Production	356,638	322,589	34,049	—
Reserves at December 31, 1981	2,188,449	1,380,076	365,001	211,207
Additions:				
Net revisions of previous estimates	(291,891)	65,791	(4,463)	(130,168)
Extensions and discoveries	48,036	4,163	—	2,598
	1,944,594	1,450,030	360,538	83,637
Deductions:				
Production	356,141	327,038	29,103	—
Reserves at December 31, 1982	1,588,453	1,122,992	331,435	83,637

	Total Proved Reserves	Proved Developed Reserves — Producing — Conventional	Heavy Oil
Oil Reserves (Bbls.) - Canada (Unaudited)			
Reserves at December 31, 1979	1,726,559	775,523	951,036
Additions:			
Net revisions of previous estimates due to royalty adjustments and additional production and engineering data	357,768	(23,394)	381,162
Extensions and discoveries	22,773	—	22,773
	2,107,100	752,129	1,354,971
Deductions:			
Production	238,677	48,865	189,812
Reserves at December 31, 1980	1,868,423	703,264	1,165,159
Additions:			
Net revisions of previous estimates due to royalty adjustments and additional production and engineering data	68,766	(286,358)	355,124
Extensions and discoveries	17,382	17,382	—
	1,954,571	434,288	1,520,283
Deductions:			
Production	243,878	48,132	195,746
Reserves at December 31, 1981	1,710,693	386,156	1,324,537
Additions:			
Net revisions of previous estimates due to royalty adjustments and additional production and engineering data	(311,758)	(80,639)	(231,119)
Extensions and discoveries	2,922,200	—	1,927,900
	4,321,135	305,517	3,021,318
Deductions:			
Production	246,018	47,517	198,501
Reserves at December 31, 1982	4,075,117	258,000	2,822,817

	Total Proved Reserves	Proved Developed Reserves — Producing — Working Interest	Proved Developed Reserves — Producing — Royalty Interest	Proved Developed Reserves — Non-Producing
Gas Reserves (Mmcf) - United States (Unaudited)				
Reserves at December 31, 1979	18,886	18,299	172	415
Additions:				
Revisions of previous estimates	(2,365)	(3,905)	1,250	290
Extensions and discoveries	1,696	538	—	436
	18,217	14,932	1,422	1,141
Deductions:				
Production	1,655	1,582	73	—
Reserves at December 31, 1980	16,562	13,350	1,349	1,141
Additions:				
Revisions of previous estimates	(608)	(629)	555	(57)
Extensions and discoveries	3,702	1,440	—	—
	19,656	14,161	1,904	1,084
Deductions:				
Production	2,042	1,987	55	—
Reserves at December 31, 1981	17,614	12,174	1,849	1,084
Additions:				
Revisions of previous estimates	(1,736)	1,091	(197)	(288)
Extensions and discoveries	4,925	24	—	520
	20,803	13,289	1,652	1,316
Deductions:				
Production	2,033	1,984	49	—
Reserves at December 31, 1982	18,770	11,305	1,603	1,316

	Total Proved Reserves	Proved Developed Reserves: Producing	Proved Developed Reserves: Non-Producing*
Gas Reserves (Mmcf) - Canada (Unaudited)			
Reserves at December 31, 1979	33,202	22,762	10,440
Additions:			
Net revisions of previous estimates and additional production and engineering data	13,807	18,429	(4,622)
Extensions and discoveries	11,659	950	10,709
	58,668	42,141	16,527
Deductions:			
Production	2,048	2,048	—
Reserves at December 31, 1980	56,620	40,093	16,527
Additions:			
Net revisions of previous estimates due to royalty adjustments and additional production and engineering data	8,067	6,977	1,090
Extensions and discoveries	9,151	1,165	7,986
	73,838	48,235	25,603
Deductions:			
Production	2,121	2,121	—
Reserves at December 31, 1981	71,717	46,114	25,603
Additions:			
Net revisions of previous estimates due to royalty adjustments and additional production and engineering data**	(28,439)	(11,396)	(17,043)
Extensions and discoveries	2,859	2,308	551
	46,137	37,026	9,111
Deductions:			
Production	3,103	3,103	—
Reserves at December 31, 1982	43,034	33,923	9,111

*Requires pipeline to market gas.

**Because of the Canadian offering (See Note 14), the Company was required to use the services of an outside engineering firm, which calculated the reserves utilizing volumetrics and other methods the Company has not historically used. The Company has used such firm's calculation for this year's reserve calculations.

Estimated Future Net Revenues and Present Value (Unaudited)

Estimated future net revenues from proved reserves of oil and gas as of December 31, 1982 are as follows:

	U.S.A.		Canada	
	Total Proved	Proved Developed	Total Proved	Proved Developed
1983	$ 7,517,000	$ 9,145,000	$ 14,107,000	$ 17,153,000
1984	8,659,000	6,936,000	21,762,000	19,309,000
1985	6,409,000	4,951,000	20,674,000	18,072,000
Thereafter	36,560,000	25,730,000	67,133,000	58,179,000
Total	$59,145,000	$46,762,000	$123,676,000	$112,713,000

The present value of estimated future net revenues from proved reserves of oil and gas as of December 31, 1982, 1981 and 1980, using a 10% discount factor, is as follows:

	U.S.A.		Canada	
	Total Proved	Proved Developed	Total Proved	Proved Developed
1982				
Present value of oil and gas reserves:				
Added in previous years	$28,149,000	$27,585,000	$56,462,000	$56,462,000
Added during current year	5,943,000	1,044,000	29,524,000	23,246,000
Total value	$34,092,000	$28,629,000	$85,986,000	$79,708,000
1981				
Present value of oil and gas reserves:				
Added in previous years	$33,785,000	$33,295,000	$54,961,000	$54,961,000
Added during current year.	5,923,000	3,070,000	7,806,000	7,806,000
Total value	$39,708,000	$36,365,000	$62,767,000	$62,767,000
1980				
Present value of oil and gas reserves:				
Added in previous years	$20,816,000	$20,816,000	$49,515,000	$49,515,000
Added during current year	12,232,000	7,949,000	11,803,000	11,803,000
Total value	$33,048,000	$28,765,000	$61,318,000	$61,318,000

In the United States, these economics were projected utilizing year-end oil and gas prices, Windfall Profit Tax, severance tax, operating expenses and capital costs.

Economics for Canadian reserves utilize price escalations as defined under the September 1, 1981 Canada/Alberta Energy Pricing and Taxation Agreement. The Alberta Royalty Tax Credit has been added to revenues and the Petroleum and Gas Revenue Tax and the Incremental Oil Revenue Tax as outlined in the agreement have been deducted from revenues as well as operating expenses and capital costs.

The economics do not include projections for the Company's gas gathering and transmission operations. In Canada production is generally subject to a sliding scale royalty that varies with price changes and production declines. Accordingly, evaluations of Canadian reserves usually entail escalating product prices over the life of the reserves to arrive at the appropriate royalty percentage on an annual basis. These two factors have the effect of decreasing net remaining volumes being offset by higher cash flows in future periods.

The application of constant unit values to the reserve volumes and the resulting estimated future net revenue fails to represent fairly the effects of increased royalties which will arise from future price increases or decreases.

Reserve Recognition Accounting (Unaudited)

Summary of Oil and Gas Producing Activities on the Basis of Reserve Recognition Accounting For the Years Ended December 31, 1982, 1981 and 1980

(000's Omitted)

	1982	1981	1980
Additions and Revisions to Estimated Proved Oil and Gas Reserves:			
Additions to estimated proved reserves, gross	**$66,023**	$22,385	$32,680
Revisions to estimates of reserves proved in prior years:			
Changes in prices	**1,288**	56,083	22,048
Royalty adjustments and other	**(13,442)**	(49,376)	(3,319)
Windfall Profit Tax and Canadian revenue taxes	**5,985**	(11,166)	(6,202)
Accretion of discount	**7,252**	7,790	5,461
	67,106	25,716	50,668
Evaluated Acquisition, Exploration, Development and Production Costs:			
Costs incurred this period and revisions of prior costs to develop	**(21,117)**	(7,907)	(23,287)
Present value of estimated future development and production costs	**(32,550)**	(8,571)	(9,157)
	(53,667)	(16,478)	(32,444)
Additions and Revisions to Proved Reserves Over Evaluated Costs	**13,439**	9,238	18,224
Provision for Income Taxes	**(3,274)**	2,169	457
Results of Oil and Gas Producing Activities on the Basis of Reserve Recognition Accounting	**$16,713**	$ 7,069	$17,767

Changes in Present Value of Estimated Future Net Revenue from Proved Oil and Gas Reserves For the Years Ended December 31, 1982, 1981 and 1980

(000's Omitted)

	1982	1981	1980
Increases:			
Additions and revisions	**$ 67,106**	$ 25,716	$ 50,668
Less related estimated future development and production costs	**32,550**	8,571	9,157
Net additions and revisions	**34,556**	17,145	41,511
Expenditures that reduced estimated future development costs	**1,281**	5,108	—
	35,837	22,253	41,511
Decreases:			
Sales of oil and gas and value of transfers, including gas processing fee and excluding the Alberta Royalty Tax credit, net of production costs of $7,196 in 1982, $6,223 in 1981 and $4,926 in 1980	**18,235**	14,143	11,264
Net Increase	**17,602**	8,110	30,247
Beginning of Year	**102,476**	94,366	64,119
End of Year	**$120,078**	$102,476	$ 94,366

Acquisition and exploration costs of $4,017,000 and $2,536,000 for 1982 and 1981 respectively have been deferred pending determination of proved reserves.

3. Long-Term Debt

	December 31 1982	December 31 1981
U.S. Banks -		
½% over prime rate or 1½% over LIBOR (11.0% to 12.0% at December 31, 1982), due July 1984, collateralized by U.S. producing oil and gas properties (a)	**$24,050,000**	$22,070,000
½% over prime rate or 1½% over LIBOR (10.9% to 12.0% at December 31, 1982), due January 1986, collateralized by gas purchase contracts and gas gathering facilities located in Kansas (b)	**7,950,000**	4,450,000
Canadian Banks -		
½% over prime rate (13.0% at December 31, 1982), collateralized by (1) substantially all Canadian gas producing properties, (2) accounts receivable in Alberta and (3) the gas sales contracts involving the major purchasers of gas from the Company's pipeline facilities (c)	**19,546,000**	19,538,000
¾% over prime rate (13.25% at December 31, 1982), due in substantially equal monthly installments over six years beginning May 1984, collateralized by the Fort Kent Heavy Oil Project (d)	**14,641,000**	—
Other indebtedness (e)	**1,240,000**	—
	67,427,000	46,058,000
Less current maturities	**2,969,000**	588,000
Total long-term debt	**$64,458,000**	$45,470,000

(a) At December 31, 1982 the Company's available borrowing base under its revolving line of credit was $24,200,000 leaving $150,000 in unused line of credit. The banks waived redetermining the Company's borrowing base until April 1983 in exchange for a pledge of 25% of the Company's Canadian Worldwide Energy Limited (Canadian Worldwide) stock. However, the banks required the proceeds of the Canadian offering (Note 14) to be paid down on the loan and the borrowing base to be reduced by the lesser of such amount or $6.4 million. Because of lower oil prices, reduced price escalation rates and higher discounting factors now applied by the banks, the Company anticipates that there will be a reduction in borrowing base. The Company has agreed to pay down any borrowings in excess of the new borrowing base in three equal monthly installments beginning April 30, 1983.

(b) The revolving line of credit available at December 31, 1982 was $10,000,000. Approximately $2,000,000 was allocated to letters of credit provided in conjunction with tax lease transactions (see Note 13), leaving virtually no unused line of credit at year end.

(c) The Company's available revolving line of credit at December 31, 1982 was $25,000,000 (Cdn.), leaving an unused line amounting to $970,000 (Cdn.). Although this production loan is due on demand, the Company has been advised that, provided its loan remains in good standing, the bank will not request principal repayment in excess of approximately $3.6 million (Cdn.) during 1983.

(d) This term credit facility, to finance a portion of the Phase III expansion of the Fort Kent Heavy Oil Project, was fully utilized in the amount of $18,000,000 (Cdn.) at December 31, 1982. This facility was subsequently increased to $30,000,000 (Cdn.) in January 1983.

(e) Other indebtedness represents outstanding amounts at December 31, 1982 due under the Phase III Fort Kent expansion which will be covered by the term loan.

Certain loan covenants include maintaining a .7-to-1 working capital position, maintaining a 1-to-1 working capital position if available borrowing base is considered as a current asset, restriction of dividend payments to 50% of net earnings during the preceding four fiscal quarters, and not allowing liabilities to exceed 275% of shareholders' equity. The working capital restrictions have been waived through March 31, 1983. Upon successful completion of the Canadian offering (Note 14), the financial ratios will be based on a consolidated balance sheet, except that the Canadian subsidiary will be accounted for under the equity method, and the ratios will be revised to (1) include a debt-to-equity ratio of 2-to-1, and (2) eliminate the requirement of the ratio of the .7-to-1 working capital position.

At December 31, 1982, the aggregate minimum annual principal reduction of long-term debt for each of the next five years is as follows:

1983	$ 2,969,000
1984	28,518,000
1985	5,568,000
1986	13,518,000
1987	5,568,000
Subsequent	11,286,000
	$67,427,000

The Company has incurred $8,528,000, $7,222,000 and $3,148,000 of interest in 1982, 1981 and 1980, respectively, of which $739,000 and $25,000 has been capitalized in 1982 and 1981, respectively.

4. Deferred Charges and Other Assets

Prior to 1980, the Company made non-recourse 4% loans to key employees, including officers of the Company, for the purpose of purchasing common shares of the Company at current market prices. Balances outstanding at December 31, 1982 and 1981 amount to $54,795 and $63,567 respectively.

5. Income Taxes

The Company files United States Income Tax returns on a consolidated basis with its United States subsidiaries. Canadian subsidiaries file separate income tax returns.

Income before income taxes and income tax expense consisted of the following:

	1982	1981	1980
Income before income taxes:			
United States	**$(1,610,000)**	$ 643,000	$1,971,000
Foreign	**3,047,000**	(1,371,000)	2,080,000
	$ 1,437,000	$(728,000)	$4,051,000

Income tax expense:

	1982	1981	1980
Canadian income taxes			
Current	**$ 86,000**	$ 23,000	$ 45,000
Deferred	**575,000**	(148,000)	642,000
Total Canada	**661,000**	(125,000)	687,000
United States federal and state income taxes			
Current	—	—	4,000
Deferred	**(81,000)**	(29,000)	110,000
Total United States	**(81,000)**	(29,000)	114,000
	$ 580,000	$(154,000)	$ 801,000

A reconciliation between the Company's provision for income taxes computed at the statutory United States Federal Income Tax rate (46%) and the provision for income taxes as reported is set forth below.

	1982	1981	1980
Provision on Income Before Income Taxes Computed at Statutory Rate	**$ 661,000**	$ (335,000)	$ 1,863,000
Operating losses with no tax benefit	**566,000**	—	—
Investment tax credits	—	40,000	(449,000)
Statutory depletion in excess of basis	—	—	(741,000)
Canadian tax law differences	**(741,000)**	504,000	2,000
United States tax preference items	—	—	7,000
Write-off of investment of foreign subsidiary	—	(523,000)	—
Loss from foreign subsidiary	—	149,000	174,000
Equity in loss of affiliate	**84,000**	—	—
Other	**10,000**	11,000	(55,000)
	$ 580,000	$ (154,000)	$ 801,000
Effective Rate	**40%**	21%	20%

The Company provides for deferred income taxes on all amounts which are reported in different time periods for income tax and financial reporting purposes, as follows:

	1982	1981	1980
U. S. oil and gas exploration and development costs which are capitalized for financial reporting purposes but are deducted for income tax purposes	**$ 2,012,000**	$ 2,761,000	$ 2,474,000
Depreciation, depletion and amortization	**(969,000)**	(864,000)	(1,003,000)
Investment tax credits	—	40,000	(449,000)
Tax net operating loss	**(1,039,000)**	(2,729,000)	(1,023,000)
Canadian oil and gas exploration and development expenditures utilized to reduce Canadian income taxes	**222,000**	264,000	784,000
Sale of tax benefits	**231,000**	386,000	—
Other	**37,000**	(35,000)	(31,000)
Total provision for deferred income taxes	**$ 494,000**	$ (177,000)	$ 752,000

The Company has differing carryover amounts for financial reporting and income tax reporting purposes because certain items of income and expense are recognized in different taxable years for income tax reporting purposes than for financial reporting purposes. At December 31, 1982, the Company has the following carryforwards available to offset future taxable income for both income tax reporting and financial reporting purposes together with the year of expiration:

Income Tax Reporting Purposes:

	Carryforward	
	Amount	Year
U.S.		
Net Operating Loss		Various through
	$ 6,000	1993
	4,261,000	1995
	7,366,000	1996
	3,490,000	1997
	$15,123,000	
Investment Tax Credit		Various through
	$ 376,000	1994
	500,000	1995
	110,000	1996
	250,000	1997
	$ 1,236,000	
Jobs Tax Credit	$ 27,000	1985
Statutory Depletion	$ 8,256,000	No expiration

Income Tax Reporting Purposes:

	Carryforward Amount	Carryforward Year
Canada		
Drilling exploration, lease acquisition, research and development costs	$15,144,000	No expiration
Capital Cost Allowances	$16,815,000	No expiration
Earned Depletion Allowance	$ 5,951,000	No expiration
Investment Tax Credit	$ 68,000	1983
	168,000	1984
	52,000	1985
	53,000	1986
	383,000	1987
	$ 724,000	
Loss Carryforward	$ 48,000	1986

Financial Reporting Purposes:

	Carryforward Amount
U.S.	
Investment Tax Credit	$ 777,000
Statutory Depletion	$4,852,000
Canada	
Earned Depletion Allowance	$3,184,000
Investment Tax Credit	$ 53,000

6. Reserved Shares

Of the authorized but unissued common shares, 653,333 and 665,856 shares were reserved for issuance upon exercise of available options and warrants at December 31, 1982 and 1981, respectively. As of December 31, 1982, such shares were reserved for issuance upon the exercise of 371,562 stock options outstanding and warrants for the purchase of 200,000 shares of common stock of the Company at $4.84 per share. The warrants were exercised during January 1983 for $967,500.

During 1982, the Company's shareholders approved the 1982 Non-qualified Stock Option Plan and the 1982 Incentive Stock Option Plan, which replaced the Company's prior plans. The following table summarizes the activity in all of the various plans combined from inception to December 31, 1982:

			Outstanding Options		
			Option Price		
	Available For Grant	Outstanding	Per Share $	Total $	Shares Exercisable
Outstanding at					
December 31, 1979	—	—	—	—	
Authorized	266,589	—	—	—	
Granted	(265,923)	265,923	$7.13-17.16	$2,492,000	
Exercised	—	(200)	13.50	(3,000)	
Outstanding at					
December 31, 1980	666	265,723	7.13-17.16	2,489,000	240,125
Authorized	200,000	—	—	—	
Granted	(113,000)	113,000	9.88-14.63	1,625,000	
Exercised	—	(533)	10.04	(5,000)	
Cancelled	34,796	(34,796)	10.13-17.06	(368,000)	
Outstanding at					
December 31, 1981	122,462	343,394	7.13-17.16	3,741,000	236,594
Authorized	453,333	—	—	—	
Granted	(394,894)	394,894	4.75-5.125	1,997,000	
Cancelled	(99,130)	(366,726)	5.00-17.16	(3,860,000)	
Outstanding at					
December 31, 1982	81,771	371,562	$4.75-$5.125	$1,878,000	264,294

Subject to shareholder approval, the Company has granted an additional 20,000 shares exercisable at $5.125 under the 1982 Non-Qualified Stock Option Plan, together with a 20,000 share reduction in shares available for grant under the 1982 Incentive Stock Option Plan.

7. Employee Benefit Plans

The Company's non-qualified, non-funded Deferred Compensation Plan for key employees, including officers of the Company, provides for qualified employees to be credited with amounts determined annually by the Board of Directors. At the end of each Plan year, each participating employee will be paid 20% of the balance of the credit in his account. The Company accrued $69,000, $142,000 and $105,000 in 1982, 1981 and 1980, respectively, to the credit of the Plan. Amounts are charged to expense when accrued.

During 1982, 1981 and 1980 the Company contributed $275,000, $243,000 and $154,000, respectively, to the Employee Stock Ownership Plan consisting of cash and stock.

The Company made contributions to the Deferred Profit Sharing Plan for employees of Canadian subsidiary companies amounting to $109,000, $46,000 and $23,000 in 1982, 1981 and 1980, respectively.

8. Related Party Transactions

The directors have approved a policy of allowing key employees, officers and directors of the Company to participate in exploration joint ventures with the Company on the same terms as those offered to industry partners but limited to an aggregate working interest of 5%. As of December 31, 1982, 1981, and 1980, there were 29, 29 and 21 participants in various programs, respectively.

In addition, the Directors have authorized a $100,000 (Cdn.) loan to an officer, in the form of a promissory note.

9. Commitments and Contingencies

Litigation

On March 29, 1983 the Oklahoma Court of Appeals, Fourth Division, on assignment from the Oklahoma Supreme Court, upheld the decision of the Beaver County District Court in favor of the Company. The Company expects this decision to be appealed. If the decision of the Court of Appeals is reversed, the Company will be denied the right to participate in and receive its share of the proceeds from the well. Revenue from this well reflected in the Company's accounts and statements of income for the periods prior to 1979 is approximately $311,000, less the Company's share of estimated drilling costs of $65,000 which amount has been paid to the District Court. Revenue of approximately $446,000, net of the Company's share of royalties, for 1979 through 1982 has not been reflected for financial reporting purposes.

Altacan Investment Limited has filed a Statement of Claim in the Court of the Queen's Bench, Judicial District of Edmonton, Alberta, Canada, on June 5, 1981, in which the Company's subsidiary, Canadian Worldwide, and one of its employees are defendants. Altacan alleges that Canadian Worldwide commited to lease 10,000 square feet of space in a building in Bonnyville, Alberta, that Canadian Worldwide breached that commitment, and that as a result, plaintiff has incurred damages of $2.5 million (Cdn.) plus ongoing damages as proved at trial. The building in question was constructed by a third party, also a defendant in this action, who had purchased the land from Canadian Worldwide and resold it to Altacan. Canadian Worldwide believes that it has met all of its obligations with respect to this building and intends to counterclaim against Altacan as successor to the original purchase for breach of its agreement with Canadian Worldwide.

Office Leases

At December 31, 1982, future minimum lease payments due under noncancellable leases for office space, were as follows:

1983	$1,031,000
1984	1,503,000
1985	1,475,000
1986	1,455,000
1987	1,391,000
Thereafter	1,478,000
	$8,333,000

Substantially all of the office space rentals may be increased annually for the Company's proportionate share of real estate taxes and operating costs. Automobile and equipment leases are insignificant.

Rent expense was $786,000, $755,000, and $488,000 for 1982, 1981 and 1980, respectively.

10. Supplementary Income Statement Information

Item	1982	1981	1980
Maintenance and repairs	$2,213,000	$2,523,000	$2,220,000
Taxes, other than income and payroll	$ 610,000	$ 523,000	$ 421,000

11. Segment Information

Segment information for the year ended December 31, 1982 is as follows:

(000's Omitted)

	Total	Other	Oil & Gas Production	Gathering and Transmission
Revenue	$ 58,777	$1,159	$25,431	$32,187
Operating Profit	$ 15,604	$ 11	$10,625	$ 4,968
Interest Expense	7,789			
General and Administrative Expense	5,915			
Other, Net	463			
Pre-Tax Earnings	$ 1,437			
Depreciation, Depletion and Amortization	$ 8,140	$ 646	$ 5,948	$ 1,546
Capital Expenditures	$ 32,215	$ 999	$24,460	$ 6,756
Identifiable assets related to the above segments as of December 31, 1982 are:	$113,267	$4,184	$72,979	$36,104

Intercompany purchases of gas amounting to approximately $4.7 million in 1982 have been eliminated from gas gathering and transmission revenues. Therefore only the gross profit on such transactions is included in gas gathering and transmission revenues.

Similar information for the year ended December 31, 1981 is as follows:

(000's Omitted)

	Total	Other	Oil & Gas Production	Gathering and Transmission
Revenue	$54,474	$1,457	$19,648	$33,369
Operating Profit	$12,565	$ (189)	$ 8,401	$ 4,353
Interest Expense	7,197			
General and Administrative Expense	6,369			
Other, Net	(273)			
Pre-Tax Earnings (loss)	$ (728)			
Depreciation, Depletion and Amortization	$ 6,279	$ 638	$ 4,343	$ 1,298
Capital Expenditures	$20,840	$1,376	$16,054	$ 3,410
Identifiable assets related to the above segments as of December 31, 1981 are:	$90,785	$4,171	$57,168	$29,446

Intercompany purchases of gas amounting to approximately $3.8 million in 1981 have been eliminated from gas gathering and transmission revenues. Therefore only the gross profit on such transactions is included in gas gathering and transmission revenues.

Similar information for 1980 is as follows:

(000's Omitted)

	Total	Other	Oil & Gas Production	Gathering and Transmission
Revenue	$43,733	$ 891	$16,530	$26,312
Operating Profit	$10,745	$ 247	$ 8,150	$ 2,348
Interest Expense	3,148			
General and Administrative Expense	3,546			
Pre-Tax Earnings	$ 4,051			
Depreciation, Depletion and Amortization	$ 4,562	$ 321	$ 2,917	$ 1,324
Capital Expenditures	$ 25,735	$2,314	$17,777	$ 5,644
Identifiable assets related to the above segments as of December 31, 1980 are:	$75,376	$4,367	$43,685	$27,324

Intercompany purchases of gas amounting to approximately $3.4 million in 1980 have been eliminated from gas gathering and transmission revenues. Therefore only the gross profit on such transactions is included in gas gathering and transmission revenues.

Information regarding the Company's assets, liabilities, and operations by country for 1982 is as follows:

(000's Omitted)

	Canada	U.S.	Fiji	Total
Assets	$50,988	$59,548	$2,731	$113,267
Liabilities	$42,575	$41,373	$ —	$ 83,948
Gross Revenues	$15,655	$43,122	$ —	$ 58,777
Net Income	$ 2,386	$ (1,529)	$ —	$ 857

During 1982 the Company had gas transmission sales to one customer which exceeded 10% of its total consolidated revenues for the year. The amount of such sales was $22,498,000, representing 38% of the Company's consolidated revenues.

Similar information for 1981 is as follows:

(000's Omitted)

	Canada	U.S.	Fiji	Total
Assets	$32,711	$57,273	$801	$90,785
Liabilities	$25,658	$35,661	$ —	$61,319
Gross Revenues	$10,062	$44,412	$ —	$54,474
Net Income	$ (1,246)	$ 672	$ —	$ (574)

During 1981 the Company had gas transmission sales to one customer which exceeded 10% of its total consolidated revenues for the year. The amount of such sales was $23,968,000, representing 44% of the Company's consolidated revenues.

Similar information for 1980 is as follows:

(000's Omitted)

	Canada	U.S.	Total
Assets	$29,099	$46,277	$75,376
Liabilities	$20,254	$25,060	$45,314
Gross Revenues	$ 9,254	$34,479	$43,733
Net Income	$ 1,276	$ 1,974	$ 3,250

During 1980 the Company had gas transmission sales to one customer which exceeded 10% of its total consolidated revenues for the year. The amount of such sales was $20,878,000, representing 48% of the Company's consolidated revenues.

12. Mineral Property Write-Offs

Tungsten Mine

As of October 1981, the operations of the Company's tungsten mining joint venture in Northern England were discontinued. As a result of this action, the 1981 Statement of Income reflects a $561,000 write-off which reduces the book value of this investment to zero. Net losses from the operation of this mine were $324,000 and $378,000 in 1981 and 1980 respectively. The mine was sold during 1982 for a nominal amount.

Uranium and Gold Properties

During 1982, the Company allowed its mining claims and leases to expire resulting in a write-off of $464,000 in 1982. There were no material costs included in results of operations for the periods presented.

13. Income From Sale of Tax Benefits

The safe-harbor leasing provisions of the Economic Recovery Tax Act of 1981 allow corporations to transfer certain tax benefits such as investment tax credits and deductions under the Accelerated Cost Recovery System. During 1982 and 1981, the Company entered into sale-leaseback arrangements to transfer tax benefits of certain U.S. equipment additions. These leases are solely for the purpose of transferring tax benefits and do not represent leases for financial reporting purposes.

The cash proceeds of $441,000 and $834,000 for 1982 and 1981, respectively, were recorded as income and a provision for deferred taxes was recorded (see Note 5). In connection with its sale of tax benefits the Company obtained letters of credit totaling approximately $2 million for the benefit of the purchasers if the Company does not make payment in accordance with the agreements for partial terminating events. To date, no material terminating events have occurred (see Note 3).

14. Subsequent Events

Canadian Offering

The Company and Canadian Worldwide filed the final prospectus for a $16,000,000 (Cdn.) offering during March 1983. The offering consists of $40 (Cdn.) units, each unit consisting of two 9.25% Cumulative Redeemable Convertible Preferred Shares and one share of common stock (presently owned by the Company) of Canadian Worldwide. The offering is expected to close in mid-April 1983, but could be withdrawn by the underwriters in certain events. In addition, the Company is selling 527,536 shares of Canadian Worldwide common stock to a newly formed wholly-owned subsidiary in exchange for a $3,130,000 note. Canadian Worldwide, in turn, will purchase the shares from the new subsidiary upon completion of the public offering, which will provide the funds necesary to pay off the note. Upon completion of the public offering, in accordance with the terms of the prospectus and the payment of the note, the Company will receive approximately $5.3 million (Cdn.), net of costs, and Canadian Worldwide will receive approximately $9.5 million (Cdn.), net of costs. The Company will own 95% of Canadian Worldwide initially and 76% upon full conversion of the preferred shares.

Item 8. Supplementary Financial Data

(a) Selected Quarterly Financial Data (Unaudited)

	1982			
	4th Qtr	3rd Qtr	2nd Qtr	1st Qtr
Revenue	$17,367,000	$15,040,000	$12,225,000	$14,145,000
Operating expenses	10,061,000	8,962,000	7,311,000	8,973,000
General and administrative	1,555,000	1,072,000	1,603,000	1,692,000
Depreciation, depletion and amortization	2,355,000	2,141,000	1,801,000	1,843,000
Interest	1,644,000	2,091,000	2,115,000	1,939,000
Equity in net loss of affiliate	26,000	46,000	88,000	22,000
Total expenses	15,641,000	14,312,000	12,918,000	14,469,000
Income (Loss) Before Income Taxes	1,726,000	728,000	(693,000)	(324,000)
Provision (Credit) For Income Taxes	464,000	119,000	177,000	(180,000)
Net Income (Loss)	$ 1,262,000	$ 609,000	$ (870,000)	$ (144,000)
Net Income (Loss) Per Share	$.14	$.07	$(.10)	$(.02)

Quarterly data for the first two quarters has been restated for the retroactive implementation of FASB No. 52 (see Note 1 to Consolidated Financial Statements) to January 1, 1982 and to account for the Company's investment in Worldwide One, Inc. on the equity method. In addition, certain reclassifications have been made between expense categories.

	1981			
	4th Qtr	3rd Qtr	2nd Qtr	1st Qtr
Revenue	$16,338,000	$12,475,000	$13,031,000	$12,630,000
Operating expenses	10,171,000	8,561,000	8,101,000	8,488,000
General and administrative	2,122,000	1,707,000	1,444,000	1,134,000
Depreciation, depletion and amortization	1,674,000	1,605,000	1,594,000	1,406,000
Interest	1,909,000	1,991,000	1,793,000	1,502,000
Total expenses	15,876,000	13,864,000	12,932,000	12,530,000
Income (Loss) Before Income Taxes	462,000	(1,389,000)	99,000	100,000
Provision (Credit) For Income Taxes	(106,000)	187,000	(269,000)	34,000
Net Income (Loss)	$ 568,000	$ (1,576,000)	$ 368,000	$ 66,000
Net Income (Loss) Per Share	$.06	$(.17)	$.04	$.01

Revenue in the fourth quarter includes the sale of tax benefits for $834,000 and the recognition of $457,000 of deferred income relating to the "take or pay" provision of a gas sales contract in which the time period for taking gas expired.

Item 9. Disagreements on Accounting and Financial Disclosure Matters

The Company had no disagreements on accounting or financial disclosure matters with its accountants, nor did it change accountants, during the three years ended December 31, 1982.

PART III

As provided in General Instruction G(3), the information called for by Item 10. "Directors and Executive Officers of the Registrant", Item 11. "Management Remuneration" and Item 12. "Security Ownership of Certain Beneficial Owners and Management" is incorporated by reference to the Company's definitive proxy statement to be filed pursuant to SEC Regulation 14A with respect to the upcoming Annual Meeting of Shareholders to be held June 10, 1983 in Toronto, Ontario, Canada. Certain information called for by Item 10., as it pertains to executive officers, is included at the end of Part I of this Form 10-K.

PART IV

Item 13. Exhibits, Financial Statement Schedules, and Reports on Form 8-K

(a)(1) The following Financial Statements are filed as a part of this report:

		Page(s)
(i)	Report of Independent Certified Public Accountants	44
(ii)	Consolidated Statements of Income for the years ended December 31, 1982, 1981 and 1980	45
(iii)	Consolidated Balance Sheets as of December 31, 1982 and 1981	46-47
(iv)	Consolidated Statements of Changes in Financial Position for the years ended December 31, 1982, 1981 and 1980	48
(v)	Consolidated Statements of Shareholders' Equity for the years ended December 31, 1982, 1981 and 1980	49-50
(vi)	Notes to Consolidated Financial Statements	51-70

(a)(2) The following Financial Statement Schedules for years ended December 31, 1982, 1981 and 1980 are filed as a part of this report:

(i)	Schedule II - Amounts Receivable from Related Parties and Underwriters, Promoters, and Employees other than Related Parties	77
(ii)	Schedule V - Property, Plant and Equipment	77-78
(iii)	Schedule VI - Accumulated Depreciation and Depletion of Property, Plant and Equipment	78-79

Schedules IX, XIII, XIV, and XVI are omitted because the required information is set forth in the Financial Statements, or notes thereto. Schedules I, III, IV, VII, VIII, X, XI, XII, XV, XVII, XVIII, and XIX are omitted because the information called for is not present or is not required.

(a)(3) The Exhibits set forth in the following index of Exhibits are filed as a part of this report:

Exhibit No.	Description
(3)	Articles of Incorporation and By-laws:
	(a) Certificate of Incorporation (as amended) is incorporated by reference to the Company's Annual Report on Form 10-K filed for the year ended December 31, 1981, as amended on Form 8 dated October 22, 1982 at pages 75-90.
	(b) By-laws as amended, are incorporated by reference to the Company's Annual Report on Form 10-K filed for the year ended December 31, 1980 at pages 86-100.

Exhibit No.	Description
(4)	Instruments defining the rights of securityholders:
	(a) Letter (loan agreement) dated March 31, 1981 from Canadian Imperial Bank of Commerce is incorporated by reference to the Company's Quarterly Report on Form 10-Q filed for the quarter ended March 31, 1981 at page 9; restated in letter of July 17, 1981 from Canadian Imperial Bank of Commerce filed as an Exhibit to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 1982 at page 9.
	(b) Loan Agreement dated June 17, 1981 between the Company and Republic National Bank of Dallas and United Bank of Denver National Association, is incorporated by reference to the Company's Quarterly Report on Form 10-Q filed for the quarter ended June 30, 1981 at page 9.
	(c) As amended by First Amendment to Loan Agreement dated December 13, 1982, among the Company, RepublicBank Dallas, National Association and United Bank of Denver N.A. ....
	(d) And as further amended in Letter Agreement dated March 4, 1983, among the Company, RepublicBank Dallas, National Association and United Bank of Denver N.A. ....
	(e) Further amended in Letter Agreement dated March 21, 1983, among the Company, RepublicBank Dallas, National Association and United Bank of Denver N.A..................................
	(f) Sixth Amendatory Agreement dated December 13, 1982 between the Company and RepublicBank Dallas, National Association ....
	(g) Loan Agreement dated March 5, 1982 between the Company and The Royal Bank of Canada is incorporated by reference to the Company's Annual Report on Form 10-K filed for the year ended December 31, 1981 as amended on Form 8 dated October 22, 1982 at pages 113-119.
	(h) As amended by Agreement dated December 31, 1982 between the Company and The Royal Bank of Canada ....
	(i) Further amended by Agreement dated January 20, 1983 between the Company and The Royal Bank of Canada ....
(9)	Voting Trust Agreement ....

Exhibit No.	Description
(10)	Material Contracts:

(a) Incorporated herein by Reference:

Deferred Compensation Plan for Key Employees dated July 1, 1977, filed as an Exhibit to the Company's Annual Report on Form 10-K for the period ended December 31, 1978.

Pooling and Farmin Agreement with Pacific Petroleums Ltd. filed as an Exhibit to the Company's Annual Report on Form 10-K for the period ended December 31, 1978.

Agreement with Sun Oil Company Limited (now Suncor Inc.) dated June 22, 1978 filed as an Exhibit to the Company's Annual Report on Form 10-K for the period ended December 31, 1979 at pages 101-151.

Lease Agreement with Gerald D. Hines dated June 23, 1980 filed as an Exhibit to the Company's Annual Report on Form 10-K for the period ended December 31, 1980 at pages 101-129.

Letter Agreement with James B. Owen dated July 25, 1979 and Amendment thereto dated August 3, 1979 filed as an Exhibit to the Company's Annual Report on Form 10-K for the period ended December 31, 1980 at pages 130-140.

July 30, 1981 letter amendment to Gas Purchase and Sales Agreement dated September 19, 1975 between Kansas Power & Light Company and Registrant's predecessor, Central States Gas Company filed as an Exhibit to the Company's Annual Report on Form 10-K for the period ended December 31, 1981, as amended on Form 8 dated October 22, 1982 at pages 154-159.

Gas Purchase Contract dated August 15, 1981 between Worldwide Energy Company Ltd. and Celanese Canada Inc. filed as an Exhibit to the Company's Annual Report on Form 10-K for the period ended December 31, 1981, as amended on Form 8 dated October 22, 1982 at pages 160-217.

Agreement dated September 24, 1981 between the Company and Bennett Petroleum Corporation filed as an Exhibit to the Company's Annual Report on Form 10-K for the period ended December 31, 1981, as amended on Form 8 dated October 22, 1982 at pages 218-226.

Agreement dated November 13, 1981 relating to the sale of tax benefits filed as an Exhibit to the Company's Annual Report on Form 10-K for the period ended December 31, 1981, as amended on Form 8 dated October 22, 1982 at pages 227-260.

(b) Underwriting Agreement dated March 23, 1983, among the Company, Canadian Worldwide Energy Limited, McLeod Young Weir Limited and Pitfield McKay Ross Limited ....

Exhibit No.	Description
	(c) Agreement dated December 29, 1981 relating to the sale of tax benefits . . . .
	(d) Agreement dated February 19, 1982 relating to the sale of tax benefits. . . . .
	(e) Agreement dated April 16, 1982 relating to the sale of tax benefits
	(f) Agreement dated June 29, 1982 relating to the sale of tax benefits
	(g) Letter Proposal dated August 26, 1982 of Bennett Petroleum Corporation and counter offer dated August 31, 1982 of working interest owners under the Agreement between the Company and Bennett Petroleum Corporation referenced under (a) above . . . .
	(h) Memorandum of Understanding dated September 14, 1982, among Worldwide Energy Company Ltd., Petro-Canada Exploration Inc. and Aberford Resources Ltd. . . . .
(11)	Statement regarding computation of per share earnings . . . .
(12)	Statement regarding computation of ratios . . . .
(13)	Annual Report to Securityholders, Form 10-Q or Quarterly Report to Securityholders . . . .
(18)	Letter regarding Change in Accounting Principles . . . .
(19)	Previously Unfiled Documents . . . .
(22)	Subsidiaries of the Registrant . . . .
	(b) The following Reports on Form 8-K were filed during the quarter ended December 31, 1982:
	Current Report on Form 8-K dated December 16, 1982, filed pursuant to Section 13 of the Securities Exchange Act of 1934, Commission File No. 1-7904.
	Current Report on Form 8-K dated December 23, 1982, filed pursuant to Section 13 of the Securities Exchange Act of 1934, Commission File No. 1-7904.
(23)	Published report regarding matters submitted to vote of Securityholders
(24)	Consents of Experts and Counsel . . . .
(25)	Powers of Attorney . . . .
(28)	Additional Exhibits . . . .

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Company has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

WORLDWIDE ENERGY CORPORATION

By/s/Robert B. Tenison

Robert B. Tenison, President, Chief Executive and Financial Officer and Director

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Company and in the capacities and on the dates indicated.

By/s/Mark A. Hellerstein

Mark A. Hellerstein, Treasurer

/s/Arthur R. Smith, by
By Robert B. Tenison, Attorney-In-Fact

Arthur R. Smith, Director by
Robert B. Tenison, Attorney-In-Fact

/s/J. Kenneth Boyles, by
By Robert B. Tenison, Attorney-In-Fact

J. Kenneth Boyles, Director by
Robert B. Tenison, Attorney-In-Fact

/s/Barron C. Housel, by
By Robert B. Tenison, Attorney-In-Fact

Barron C. Housel, Director by
Robert B. Tenison, Attorney-In-Fact

/s/William C. Jones III, by
By Robert B. Tenison, Attorney-In-Fact

William C. Jones, III, Director by
Robert B. Tenison, Attorney-In-Fact

/s/James B. Owen, by
By Robert B. Tenison, Attorney-In-Fact

James B. Owen, Director by
Robert B. Tenison, Attorney-In-Fact

Worldwide Energy Corporation and Subsidiaries
Schedule II - Amounts Receivable From Related Parties And Underwriters, Promoters, and Employees other than Related Parties

Name of Debtor	Balance at Dec. 31, 1981	Additions	Deductions		Balances at Dec. 31, 1982	
			Amounts Collected	Amounts Written Off	Current	Non-Current
Worldwide One, Inc.	$ —	$325,100	$ —	$ —	$325,100	$ —

Worldwide One, Inc. is 47% owned by the Company. The receivables are payable on demand and are non-interest bearing.

Worldwide Energy Corporation and Subsidiaries
Schedule V - Property, Plant and Equipment

Column A	Column B	Column C	Column D	Column E	Column F
	Balance January 1, 1982	Additions At Cost	Retirements Or Sales	Other Changes (1)	Balance December 31, 1982
Oil and Gas Properties	$47,208,000	$21,399,000	$ 378,000	$ (1,637,000)	$ 66,592,000
Gas Contracts	8,177,000	—	—	—	8,177,000
Production Equipment	15,940,000	3,061,000	250,000	(569,000)	18,182,000
Gas Pipeline, Plant Equipment and Rights-of-Way	20,544,000	6,756,000	70,000	(609,000)	26,621,000
Mineral Properties	407,000	—	—	(280,000)	127,000
Other Assets	5,122,000	999,000	55,000	(121,000)	5,945,000
	$97,398,000	$32,215,000	$ 753,000	$ (3,216,000)	$125,644,000

(1) Transfers, mineral property write-offs and impact of converting to FASB No. 52.

Worldwide Energy Corporation and Subsidiaries
Schedule V - Property, Plant and Equipment

Column A	Column B	Column C	Column D	Column E	Column F
	Balance January 1, 1981	Additions At Cost	Retirements Or Sales	Other Changes (1)	Balance December 31, 1981
Oil and Gas Properties	$34,314,000	$12,834,000	$ 298,000	$ 358,000	$47,208,000
Gas Contracts	8,177,000	—	—	—	8,177,000
Production Equipment	13,338,000	3,220,000	252,000	(366,000)	15,940,000
Gas Pipeline, Plant Equipment and Rights-of-Way	17,046,000	3,410,000	365,000	453,000	20,544,000
Mineral Properties	407,000	—	—	—	407,000
Other Assets	4,633,000	1,376,000	110,000	(777,000)(2)	5,122,000
	$77,915,000	$20,840,000	$ 1,025,000	$ (332,000)	$97,398,000

(1) Transfers and miscellaneous adjustments.
(2) Write-off of United Kingdom.

Worldwide Energy Corporation and Subsidiaries
Schedule V - Property, Plant and Equipment

Column A	Column B	Column C	Column D	Column E	Column F
	Balance January 1, 1980	Additions At Cost	Retirements Or Sales	Other Changes (1)	Balance December 31, 1980
Oil and Gas Properties	$19,873,000	$14,530,000	$ 88,000	$ (1,000)	$34,314,000
Gas Contracts	8,177,000	—	—	—	8,177,000
Production Equipment	10,262,000	3,247,000	172,000	1,000	13,338,000
Gas Pipeline, Plant Equipment and Rights-of-Way	11,508,000	5,644,000	10,000	(96,000)	17,046,000
Mineral Properties	298,000	109,000	—	—	407,000
Other Assets	2,451,000	2,205,000	119,000	96,000	4,633,000
	$52,569,000	$25,735,000	$389,000	$ —	$77,915,000

(1) Transfers and miscellaneous adjustments.

Worldwide Energy Corporation and Subsidiaries
Schedule VI - Accumulated Depreciation, Depletion and Amortization of Property, Plant and Equipment

Column A	Column B	Column C	Column D	Column E	Column F
	Balance January 1, 1982	Additions Charged To Costs And Expenses	Retirements	Other Changes (1)	Balance December 31, 1982
Oil and Gas Properties	$10,705,000	$4,521,000	$ —	$ (440,000)	$14,786,000
Gas Contracts	2,293,000	620,000	—	—	2,913,000
Production Equipment	4,673,000	1,427,000	—	(182,000)	5,918,000
Gas Pipeline, Plant Equipment and Rights-of-Way	2,758,000	926,000	—	(204,000)	3,479,000
Mineral Properties	5,000	—	—	—	5,000
Other Assets	1,376,000	646,000	49,000	1,000	1,975,000
	$21,810,000	$8,140,000	$ 49,000	$ (825,000)	$29,076,000

(1) Transfers, miscellaneous adjustments and impact of converting to FASB No. 52.

Worldwide Energy Corporation and Subsidiaries

Schedule VI - Accumulated Depreciation, Depletion and Amortization of Property, Plant and Equipment

Column A	Column B	Column C	Column D	Column E	Column F
	Balance January 1, 1981	Additions Charged To Costs And Expenses	Retirements	Other Changes (1)	Balance December 31, 1981
Oil and Gas Properties	$ 7,442,000	$3,201,000	$ —	$ 62,000	$10,705,000
Gas Contracts	1,658,000	595,000	—	40,000	2,293,000
Production Equipment	3,594,000	1,142,000	—	(63,000)	4,673,000
Gas Pipeline, Plant Equipment and Rights-of-Way	2,090,000	703,000	12,000	(23,000)	2,758,000
Mineral Properties	5,000	—	—	—	5,000
Other Assets	755,000	638,000	1,000	(16,000)	1,376,000
	$15,544,000	$6,279,000	$ 13,000	$ —	$21,810,000

(1) Transfers and miscellaneous adjustments.

Worldwide Energy Corporation and Subsidiaries

Schedule VI - Accumulated Depreciation, Depletion and Amortization of Property, Plant and Equipment

Column A	Column B	Column C	Column D	Column E	Column F
	Balance January 1, 1980	Additions Charged To Costs And Expenses	Retirements	Other Changes (1)	Balance December 31, 1980
Oil and Gas Properties	$ 5,522,000	$1,920,000	$ —	$ —	$ 7,442,000
Gas Contracts	961,000	697,000	—	—	1,658,000
Production Equipment	2,597,000	997,000	—	—	3,594,000
Gas Pipeline, Plant Equipment and Rights-of-Way	1,466,000	627,000	4,000	1,000	2,090,000
Mineral Properties	5,000	—	—	—	5,000
Other Assets	469,000	321,000	34,000	(1,000)	755,000
	$11,020,000	$4,562,000	$ 38,000	$ —	$15,544,000

(1) Transfers and miscellaneous adjustments.

Directors

Arthur R. Smith
Chairman *#
Robert B. Tenison
President #
J. Kenneth Boyles
Executive Vice-President
The National State Bank *
Barron C. Housel
Oil and gas consultant
Houston, Texas +#
William C. Jones, III
Attorney
Dallas, Texas *+
James B. Owen
Independent oil and gas operator
and cattleman
Tyler, Texas *+

+ Compensation Committee
* Audit Committee
# Executive Committee

Officers

Robert B. Tenison
President and Chief Executive Officer
Ronald J. Cargo
Senior Vice President and President
Canadian Worldwide Energy Limited
Blaine S. Day
Vice President, Exploration
A. H. Hurley, Jr.
Vice President, Operations
Walter V. Pelepchan
Vice President, Corporate Development
Larry D. Van Cleave
Vice President, Land
Mark A. Hellerstein
Treasurer
Eldon L. Hinds
Secretary
Mary E. Dickerson
Assistant Secretary

Corporate Information

Counsel
Roath & Brega, P.C., Denver, Colorado
Auditors
Coopers & Lybrand
Denver, Colorado
Transfer Agents
The National State Bank
Elizabeth, New Jersey
National Trust Company, Limited
Toronto, Ontario, Canada
Financial Public Relations
Louis Moore & Company, Inc.
Glen Head, New York

Executive Offices -
Suite 1600, 1700 Broadway
Denver, Colorado, 80290
(303) 861-8615

Operational Offices -
Freer, Texas
Pratt, Kansas

Subsidiaries, Affiliates, and Divisions
Canadian Worldwide Energy Limited - Calgary, Alberta
Central States Gas Company - Denver, Colorado
Semco Gas, Inc. - Denver, Colorado
Worldwide One, Inc. - Denver, Colorado

Dividends
Worldwide Energy Corporation has not paid any dividends on its Common Stock and does not expect to do so in the foreseeable future. The Company intends to follow a policy of retaining earnings to provide funds for the expansion of its buisness.

Stockholders
At March 1, 1983, the approximate number of holders of record of the Company's Common Stock was 8,669.

Market for Common Stock
The shares of Worldwide Energy Corporation are listed on the American Stock Exchange and the Toronto Stock Exchange under the symbol WWE. The following table sets forth the high and low sales prices for the Company's common stock for 1982, 1981, and 1980 and is adjusted for the January, 1981 four-for-three stock split.

Quarter Ended

	March 31		June 30		September 30		December 31	
	Low	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**
1982	4	7¼	4¾	6¼	4¼	5¾	4¾	9¼
1981	11⅛	17 23/32	9¾	12¾	5¼	12½	6¾	10¼
1980	7 1/32	18	9 15/32	14 7/16	11 23/32	18 3/32	14 5/32	20 13/16

Worldwide Energy Corporation
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(303) 861-8615