NOVA AN ALBERTA CORPORATION

ANNUAL REPORT 1982

Consolidated Financial Highlights

	1982	1981	% Increase (Decrease)
Operating revenue	$3,501,798,000	$2,669,551,000	31.18
Net operating income	$ 541,058,000	$ 395,036,000	36.96
Net income	$ 149,752,000	$ 129,862,000	15.32
Earnings per common share			
Basic	$ 0.80	$ 0.90	(11.11)
Fully diluted	$ 0.74	$ 0.80	(7.50)
Dividends paid per Class "A" common share	$ 0.40	$ 0.38666	3.45
Average number of common shares outstanding	114,340,585	107,582,894	6.28
Additions to plant, property and equipment	$1,221,953,000	$1,371,230,000	(10.89)
Investment in plant, property and equipment (cost)	$5,658,693,000	$4,338,575,000	30.43
Investment in plant, property and equipment (net)	$4,859,431,000	$3,745,700,000	29.73

Principal Companies in the NOVA Group

Natural Gas Transmission

Alberta Gas Transmission Division
Novacorp Engineering Services Ltd.
Foothills Pipe Lines (Yukon) Ltd.
Trans Québec & Maritimes Pipeline Inc.

Resource Development

Husky Oil Ltd.
Novalta Resources Ltd.
Pan-Alberta Gas Ltd.
Canstar Oil Sands Ltd.
Noval Technologies Ltd.
NOVA/Husky Research Corporation Ltd.
CanOcean Resources Ltd.

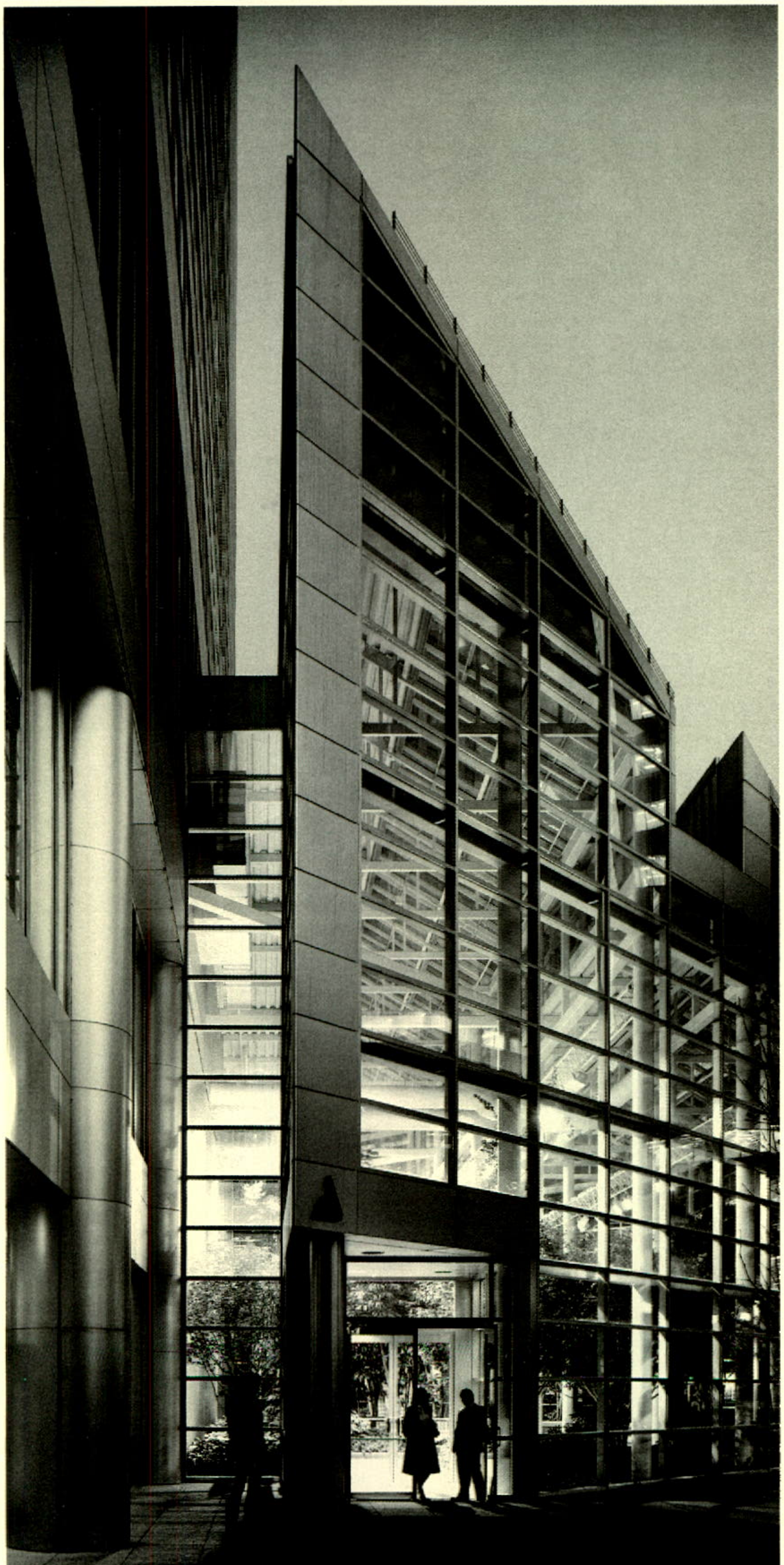
Petrochemicals

Novacor Chemicals Ltd.
The Alberta Gas Ethylene Company Ltd.
Alberta Gas Chemicals Ltd.
Diamond Shamrock Alberta Gas
A.G. Pipe Lines (Canada) Ltd.
A.G. Pipe Lines Inc.

Manufacturing

NOVA/AGT Joint Venture
Energy Equipment & Systems Inc.
Grove Valve and Regulator Company
WAGI International S.p.A.
Western Star Trucks Inc.

Contents



NOVA is a major Canadian energy company actively involved in natural gas transmission, resource development, petrochemicals and manufacturing.

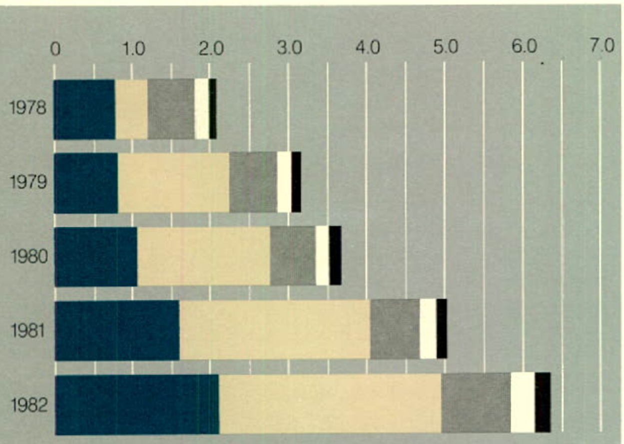
NOVA was established in 1954 to build, own and operate Alberta's natural gas gathering and transmission facilities. In the early 1970s, the Company began to broaden its base and pursue other opportunities. Today, NOVA's assets exceed $6.3 billion. Consolidated revenues for 1982 amounted to $3.5 billion, and consolidated net income was a record $149.8 million.

The NOVA companies employ more than 9,000 people in a wide range of activity related to:

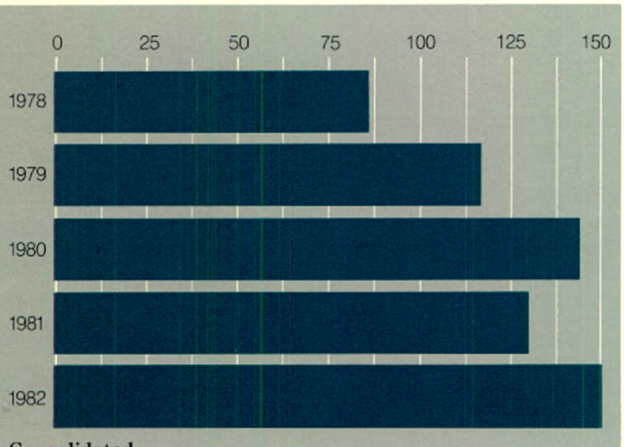
- The Alberta natural gas gathering and transmission system, now more than 7,800 miles in length and carrying 70 percent of the gas marketed annually in Canada.
- Half ownership in the Alaska Highway Gas Pipeline in Canada and the Trans Québec & Maritimes Pipeline.
- Majority ownership of Husky Oil Ltd., a large, fully integrated petroleum company operating in both Canada and the United States.
- Major holdings in Alberta's expanding petrochemical industry. Recently consolidated, those holdings are now directed by Novacor Chemicals Ltd.
- Ownership of energy-related manufacturing companies in the United States and Italy.

NOVA
AN ALBERTA
CORPORATION

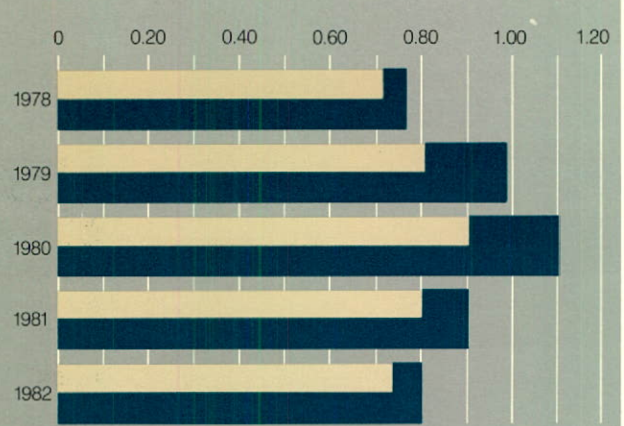
Report to Shareholders



Consolidated Assets
(in billions of dollars)



Consolidated Net Income
(in millions of dollars)



Earnings Per Common Share
(in dollars)

Financial Highlights

A large 1982 capital investment program raised our total consolidated assets to over $6.3 billion by year end. Consolidated net income for 1982 of $149.8 million represents a 15% increase over 1981 and exceeds the previous high reported for 1980.

The dilution in basic earnings per share (80¢ in 1982 as compared to 90¢ in 1981) was fully anticipated due to new share issues. During 1982, we successfully raised about $800 million in preferred share equity and fixed rate debt. These financings reduced variable rate debt and improved our overall financial position.

The NOVA group of companies has budgeted $1.2 billion in capital expenditures for 1983 to cover continuing activity in oil and gas exploration and development, petrochemical plant construction, and pipeline and related construction in Alberta.

Operations Highlights

Natural gas flowed through the Phase I eastern leg of the Alaska Highway Gas Pipeline for the first time on September 1, 1982. Foothills Pipe Lines, partially owned by NOVA, thereby became a major operating company with more than $1 billion in assets and contributed revenues of $60 million in 1982. NOVA's gas marketing affiliate, Pan-Alberta Gas Ltd., has also experienced larger sales volumes because of Phase I shipments. Pan-Alberta's revenues for 1982 were $841 million, up from $243 million in 1981.

The initial sales of Alberta natural gas to Canadian markets east of Montreal also began during 1982 through the first completed sections of the Trans Québec & Maritimes Pipeline, sponsored and partially owned by NOVA. Sales of about $25 million were recorded for the year. The line will be completed as far as Quebec City in the fall of 1983.

The Alberta Gas Transmission Division 1982 capital program was $233 million (including $9.0 million of interest during construction). The year's heavy construction activity culminated a major three-year program of about $677 million. The facilities are connecting additional reserves primarily to new export markets.

Total gas deliveries from Alberta by the Alberta Gas Transmission Division in 1982 were 1.6 tcf (45 $10^9 m^3$), up two percent from 1981. Although we started the two new sales operations mentioned above, natural gas market demand has remained relatively static in Canada and actually showed significant decline in the United States during late 1982 and early 1983. At the time of this report, gas market demand in the United States is so low that critical operations problems are occurring in the American gas transmission and distribution companies. This is leading to requests to Canadian suppliers to waive contracted quantity minimums and to petition governments for reduction of unit prices. Factors causing this situation include the business recession, energy conservation by customers, a mild winter in 1982/83, lower prices of heating and residual fuel oil and higher gas production deliverability rates in the United States. Anomalies in existing gas price regulation and policy in the United States and proposed changes are building pressures for a reduction in the unit price of gas imports.

NOVA and its affiliates are very active in endeavoring to keep the Alberta-produced gas export quantities flowing and providing attractive netbacks to the Alberta industry. Our own business risks in this sector are reasonably protected by the terms of contracts and of government regulations, but that does not lessen NOVA's preoccupation with helping to sustain a healthy natural gas industry.

Within the province of Alberta, gas deliveries from our Alberta Gas Transmission Division in 1982 were up 21% over 1981 to 286 bcf

($8.1\ 10^9m^3$). Much of this market was created by the gas feedstock upgrading investments that NOVA subsidiaries and petrochemical partners undertook in the 1970s.

Total volumes of gas handled by NOVA of 1.8 to 2.0 tcf (51 to 56 10^9m^3) per year for each of the last 10 years have at recent prices furnished a $6 billion annual gross sales level to Alberta producers and had a 1982 annual value on delivery to utility companies in Canada and the United States of about $10 billion. The natural gas industry is important now and can well take on a much increased role when immediate problems have been overcome.

In other parts of our business, the following developments occurred:

• Husky Oil Ltd. launched a major bi-provincial upgrader and heavy oil production proposal for western Saskatchewan and eastern Alberta. Land position off Canada's east coast and in the Beaufort region was increased, and there were significant oil discoveries in Alberta and the United States.

• Novacor Chemicals took on new marketing and manufacturing responsibilities. Novacor is now operating the polyvinyl chloride plant at Fort Saskatchewan and is in charge of constructing the linear low density polyethylene plant.

• In manufacturing, NOVA entered into a new joint venture to explore business opportunities in high technology, particularly telecommunications. The initial focus is on development, manufacture and international marketing of an advanced mobile radio telephone system.

• Novacorp Engineering Services Ltd. has been doing more work overseas, and it is expected that the company will be taking on additional international assignments. Other companies in the NOVA group, in particular Novacor Chemicals Ltd. and CanOcean Resources Ltd., are also expanding their activity worldwide.

Research and Development

The NOVA/Husky Research Corporation has been set up with a specific mandate to contribute to continuing research and development activities carried on throughout our companies. Designing, developing, testing and proving new technology is an integral part of operations in all our business areas.

During 1982, we spent almost $10 million on research and development, and this amount is expected to exceed $15 million in 1983. Cumulatively over the last five years, expenditures that qualify as research and development totalled almost $50 million.

If we include projects that are not necessarily categorized in this way — Husky's enhanced oil recovery projects are an example — the figure increases significantly.

Some examples of NOVA research and development activities are:

• Two first-of-a-kind improvements in ditching equipment pioneered by the Alberta Gas Transmission Division: an arctic ditcher and a topsoil stripper for use in conserving topsoil during winter construction.

• Highly productive mechanized welding processes for improving construction effectiveness on large compressor stations, developed during construction of the Alaska Highway Gas Pipeline's Phase I eastern leg.

• Novacor Chemicals' technical developments, including improved computer process control that yields much higher efficiency in ethylene production.

Employees

The country has experienced a difficult year but NOVA ended it in good shape for an energy company, thanks in large part to the commitment and dedication of our staff.

Early in 1982, we removed the third-Friday holiday that is customary in the oil industry, and our employees are now working a longer standard work week, as well as their usual extra hours. However, the added standard hours are not the sole cause of greater efficiency and better performance. We've also increased productivity — determined to work our way out of this difficult period.

Although employees were laid off by some companies in our group during 1982, a concerted and largely successful effort has been made to place those people elsewhere. We anticipate better economic times in Canada, but are also looking abroad for markets that can use our skills and products. We expect to be able to keep some of our people busy with assignments overseas while continuing to make a contribution to the Company.

Board Changes

At the 1982 annual meeting, J. E. (Ted) Baugh, formerly a senior operating executive in a major international energy company, was elected to the Board by our Class "B" shareholders. He was previously a NOVA director from 1968 to 1978. Harley N. Hotchkiss, who has represented Class "B" shareholders since 1979, is now a representative of our Class "A" shareholders.

Respectfully submitted on behalf of the Board of Directors:

H. J. S. Pearson, Chairman

S. R. Blair, President and Chief Executive Officer

Calgary, Alberta
March 11, 1983

Special Report – A New Home for Head Office Staff

In 1978, when work first began on NOVA's corporate headquarters, the designers were given a clear directive to create a building that would contribute significantly to the quality of life in Calgary's urban core. It had to be a "people" place. It had to be inviting to the general public and provide a comfortable, safe working environment for our employees.

Plans for the project were put before the City of Calgary planning department in early 1979, and the response was highly favorable. The design had clearly met our original directive, and city planners commented that it was special, particularly in its involvement with the public interest.

Those plans were realized in the 37-storey stainless steel tower now standing as a major landmark at the western end of the city's downtown business district.

From most points, the viewer's attention is caught by the tower's angular shape. The wedge was designed to allow sunlight into the adjoining park and the other pedestrian areas. The highly reflective stainless steel exterior adds to the play of light into the streets below.

The building site is also unusual, extending north and south across Seventh Avenue, Calgary's main public transit artery. A three-storey conference and training centre to the north is connected to the tower by Plus 15 and Plus 30 walkways.

South of the avenue, the main tower is flanked on its far side by the Garden Court, a transparent three-storey atrium with a glazed roof. Inside, tropical plants and seasonal flowers surround a tropical fish pond, while an open spiral stairway leads to the building's Plus 15 level and food fair.

Both the tower and the north site facility are recessed from the street at 45 degrees to allow additional space for landscaping and pedestrian circulation. The main entry into the tower is through a three-storey open foyer of Italian granite. Seventeen elevators service the public areas, the 33 office floors and the four levels of underground parking.

The building, which was recently cited by the steel industry for unique and innovative use of that metal, was brought to completion under the direction of Novalta Properties Ltd., a wholly owned subsidiary. Novalta Properties is currently managing the building and is also working on a number of other projects, including our new computer centre.

The move to our new building was a milestone in NOVA's history. It culminated over a quarter century of growth and service to the people of Alberta. The building represents the confidence of our shareholders and the dedicated work of NOVA employees over the years.

This year, we take pleasure in extending a special invitation to shareholders to attend our annual meeting, the first to be held on our own premises.

Consolidated Management Committee

The Consolidated Management Committee (CMC) has given guidance and direction to NOVA's rapid growth over the past 10 years. It is a policy setting group in the Company, and this feature is intended to introduce our readers both to the purpose and function of the committee and to the officers who serve on it.

At present, the CMC includes 11 senior corporate executives and operations officers representing key activities of the NOVA group of companies. It meets monthly, or more often if necessary, to discuss policy matters that affect our Company. The committee considers and approves all items brought before the Company's Board of Directors, both as to content and style.

Each year the CMC meets several times to review capital and operating budgets prior to their presentation to the Board. This process gives CMC members an opportunity to examine operations and projects critically and provides a basis for ongoing discussion of Company direction and objectives.

Nearly a third of the group's time is spent reviewing personnel policy matters. Such items as codes of conduct, compensation, employee benefits and hours of work appear frequently on the agenda. An effort is made to provide consistency in such policies across the NOVA group.

Other areas that received consideration during 1982 were proposals to create further employment, the introduction of electronic office equipment and administrative procedures to implement cost reductions. The decision to set up an occupational health and safety department with authority throughout NOVA came from the CMC.

The officers serving on the CMC are introduced briefly on these pages.

Robert Blair *Joan A. Dennis*

Robert L. Pierce *John P. Sutherland* *John E. Feick*

Robert Blair — Mr. Blair, 53, has been president and chief executive officer of NOVA since 1970, shortly after he joined the Company. He worked prior to that on pipelines and refineries as a field engineer and construction supervisor, then in operations management. He is chairman of Husky Oil Ltd. and a director of all principal companies in which NOVA holds an equity investment. A chemical engineering graduate, Mr. Blair has received several honorary doctorates and the 1982 Gold Medal Award of the Association of Professional Engineers of the Province of Ontario. He is an Officer of the Order of Canada.

Robert L. Pierce — Mr. Pierce, 53, is executive vice president and a director of NOVA, president of The Alberta Gas Ethylene Company Ltd. and president and chief executive officer of both Foothills Pipe Lines (Yukon) Ltd. and Novacor Chemicals Ltd. Admitted to the Saskatchewan Bar in 1954, Mr. Pierce practised law in Regina until 1973 when he joined NOVA as senior vice president and secretary. He is a director and/or officer of most NOVA companies.

John E. Feick — Mr. Feick, 40, is a senior vice president of NOVA. He joined the NOVA group in 1977 in the business development department of Alberta Gas Ethylene. In addition to his NOVA corporate responsibilities, he is now a senior vice president of AGEC and of Novacor Chemicals, in charge of business development and finance. Mr. Feick provides direction to our economic planning group, as well as executive leadership for NOVA in the Canstar Oil Sands joint venture. A native of northern Ontario, Mr. Feick holds a Ph.D. in chemical engineering from the University of Alberta.

Dianne I. Hall — Miss Hall, 40, is senior vice president in charge of NOVA's corporate administrative functions and secretary to the Company's Board of Directors. Originally from Saskatchewan, she joined NOVA in 1972 following several years of secretarial experience. She serves as an officer and director of Foothills Pipe Lines (Yukon) and Husky and is president of Novalta Properties Ltd. Miss Hall is a member of the Export Trade Development Board.

William C. Rankin — Mr. Rankin, 53, is a senior vice president and the controller of NOVA, as well as a vice president and director of Husky. He was recently appointed chairman of the board of the operating company for the NOVA/AGT Joint Venture in telecommunications. Prior to joining NOVA in 1978, he held executive positions in a major Canadian retail company and in two communications companies. A commerce graduate of the University of Toronto, Mr. Rankin is also a chartered accountant.

Bruce W. Simpson — Mr. Simpson, 38, is a senior vice president of NOVA responsible for pipeline investments and a senior vice president of Foothills Pipe Lines (Yukon). He joined the Company in 1971 and, over the years, has served as assistant to the executive vice president and as manager of financial planning. A native Calgarian, Mr. Simpson holds a commerce degree from the University of Alberta and is a member of the Institute of Chartered Accountants of Alberta.

William J. Deyell — Mr. Deyell, 60, joined the NOVA group in 1959. In 1966, he became the Company's chief engineer and was made vice president of operations in 1971, overseeing the rapid expansion and automation of NOVA's Alberta system. He went on to become a senior vice president and a member of the Board of Directors before being seconded to the Alaska Project Division of NOVA. In 1980, he was appointed executive vice president of Foothills Pipe Lines (Yukon) with responsibility for engineering and construction of the Alaska Highway Gas Pipeline. Mr. Deyell is vice chairman of Canada West Foundation and a member of the program advisory committee for the Banff Centre School of Management.

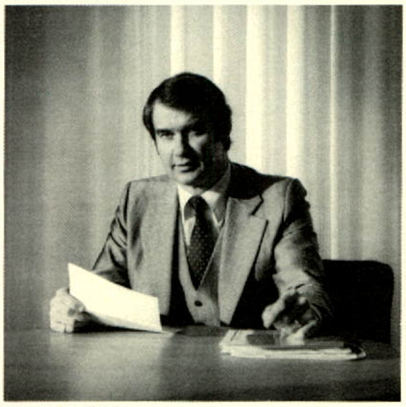
Ronald D. Dooley — Mr. Dooley, 44, is a corporate vice president of NOVA and president of Energy Equipment & Systems Inc., our holding company for valve manufacturing operations. He was formerly vice president and treasurer of NOVA and, before joining the Company in 1976, held various positions with a major Canadian bank in Canada and New York City. Mr. Dooley holds an engineering degree from the University of Alberta and an M.B.A. from the University of Western Ontario.

Donald G. Olafson — Mr. Olafson, 46, serves as division senior vice president of the Alberta Gas Transmission Division and is president of Novacorp Engineering Services Ltd. He joined NOVA in 1973 and, over the years, has served as manager of engineering development, director of contract administration, vice president, and division vice president and general manager. He is a mechanical engineering graduate of the University of Saskatchewan.

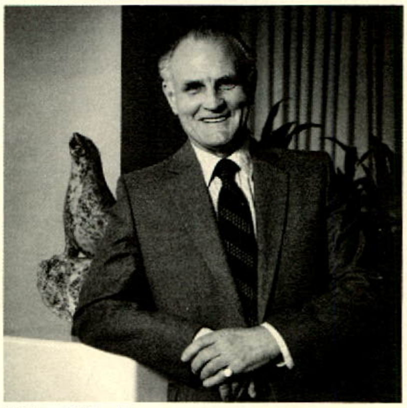
John P. Sutherland — Mr. Sutherland, 48, is executive vice president of Novacor Chemicals and executive vice president of Alberta Gas Ethylene. Prior to joining the NOVA group of companies in 1974, Mr. Sutherland served as director of business development, then as director of chemical operations for a large chemical and industrial product manufacturer. He holds a Ph. D. in chemical engineering.

Joan A. Dennis — Mrs. Dennis, 39, is assistant secretary for NOVA and is a director and secretary to the board of CanOcean Resources Ltd. She joined NOVA in 1975 as secretary to the president and was subsequently appointed assistant to the president. Prior to joining NOVA, she served as secretary to the chief executive officers in several oilwell drilling and oil and gas companies.

William C. Rankin *Dianne I. Hall*



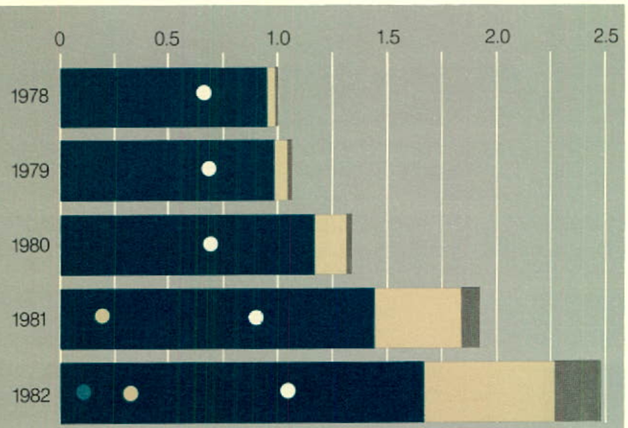
Ronald D. Dooley



William J. Deyell

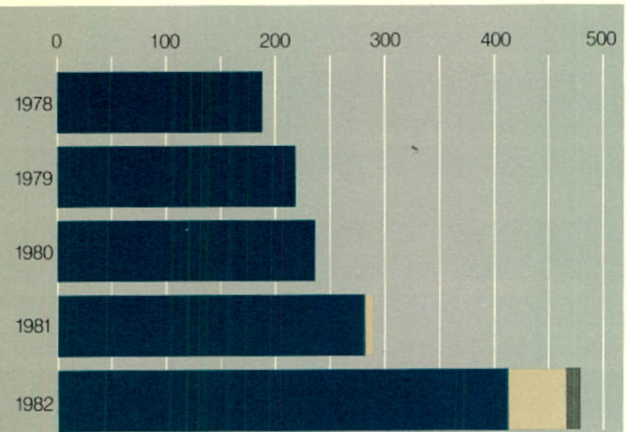
Donald G. Olafson *Bruce W. Simpson*

Natural Gas Transmission



Natural Gas Transmission Gross Assets*
(in billions of dollars)

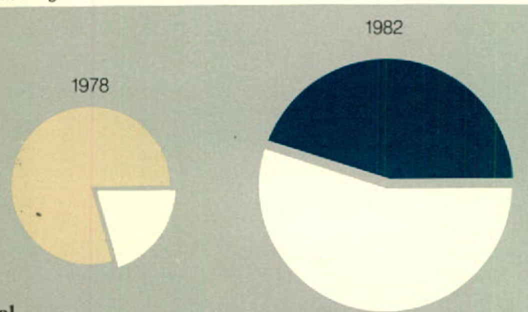
- Trans Québec & Maritimes Pipeline Inc.
- Foothills Pipe Lines (Yukon) Ltd.
- Alberta Gas Transmission Division
- Average Rate Base, TQM System
- Average Rate Base, Foothills System
- Average Rate Base, Alberta System



Natural Gas Transmission Gross Revenue*
(in millions of dollars)

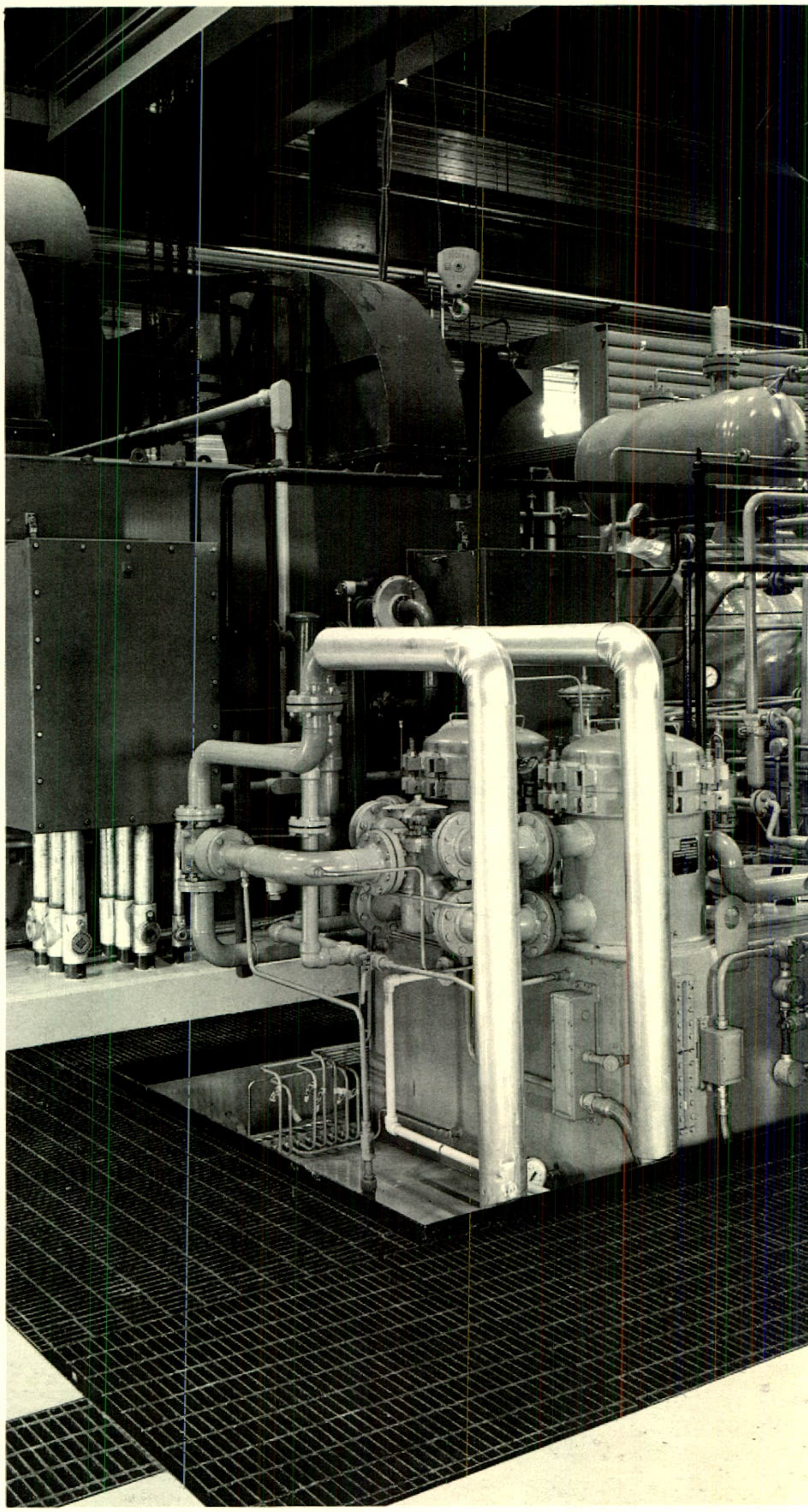
- Trans Québec & Maritimes Pipeline Inc.
- Foothills Pipe Lines (Yukon) Ltd.
- Alberta Gas Transmission Division

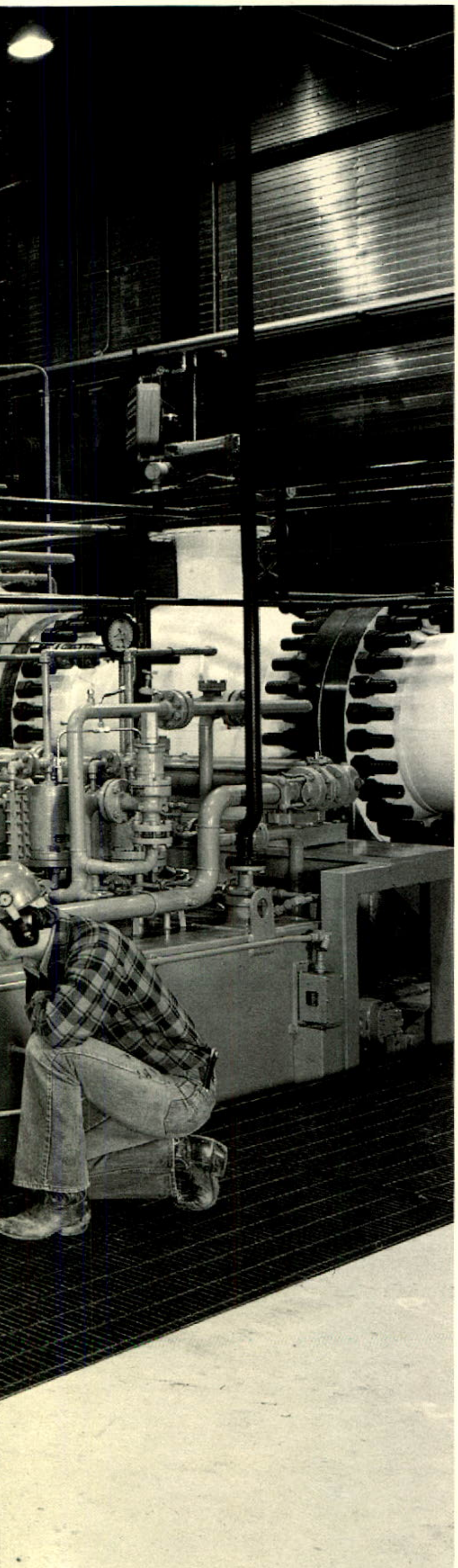
**These graphs depict assets, before depreciation and depletion, and revenue, before the elimination of intersegment revenue, of NOVA, its subsidiaries and affiliates. For the Company and its subsidiaries (where the Company has a controlling interest) 100% of gross assets and gross revenues are included. For affiliates only the Company's ownership share of gross assets and gross revenues is included.*



Natural Gas Transmission Net Operating Income Contribution

- 79% or $95 Million
- 45% or $246 Million





The Alberta Gas Transmission Division (100% owned) is included in this sector, along with Novacorp Engineering Services Ltd. (100% owned), Foothills Pipe Lines (Yukon) Ltd. (50% owned) and Trans Québec & Maritimes Pipeline Inc. (50% owned).

NOVA's natural gas transmission sector experienced a particularly rewarding year in 1982, marked by two major pipeline projects coming onstream. Foothills Pipe Lines started up the Phase I eastern leg of the Alaska Highway Gas Pipeline and is now an operating entity with significant assets and revenues. Initial sections of the Trans Québec & Maritimes Pipeline began operation, too, transporting Alberta natural gas to Canadian markets east of Montreal for the first time.

For the Alberta Gas Transmission Division, 1982 was a busy and challenging year. A heavy calendar of engineering and construction projects was completed, and the operations staff took on the added responsibility of operating, monitoring and maintaining new Foothills facilities.

NOVA's natural gas transmission sector has expanded rapidly in recent years and continues to be a solid business base for the Company. In addition to financial return, we are realizing another return on the years invested in building and operating one of the world's largest pipeline systems: other business opportunities are now being developed offshore for our pipeline engineering and operations expertise. It is anticipated that Novacorp Engineering will play an increasingly important role, as these opportunities abroad present additional challenges and growth for our people.

Energy efficient compressor facilities at Jenner, Alberta, on the Foothills eastern leg went into operation in September.

ALBERTA GAS TRANSMISSION DIVISION

The Alberta Gas Transmission Division (AGTD) — now numbering about 1,700 employees — underwent organizational changes this past year, including increased involvement in expanded international activity.

Executive Changes

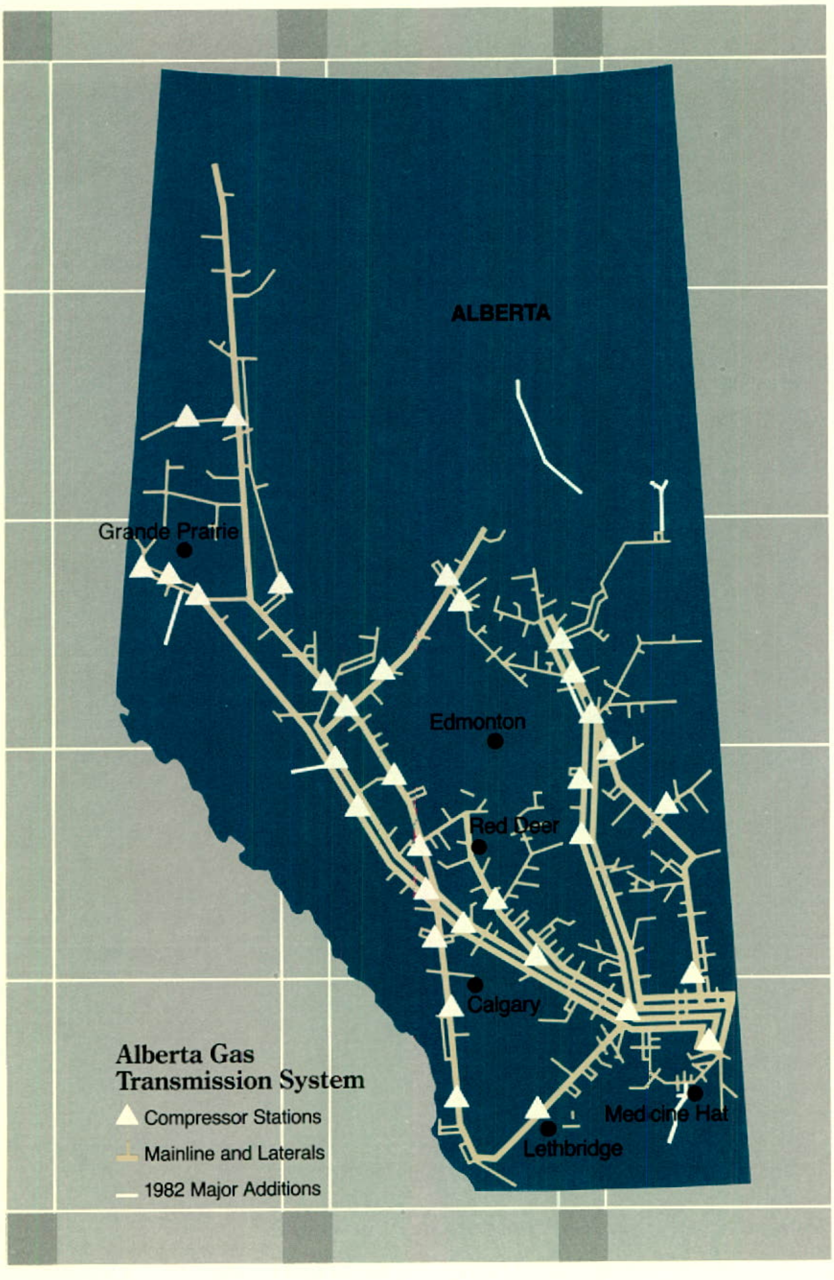
Donald Olafson, formerly division vice president and general manager, has been named division senior vice president responsible for the engineering, construction and system planning functions. Walter Litvinchuk has assumed responsibility for system planning, while Dale Richards continues with his duties in engineering and construction. Both are division vice presidents.

Robert Snyder, formerly senior vice president of Foothills Pipe Lines (Yukon) Ltd., was appointed division senior vice president to direct the operational activities of the AGTD from our Edmonton office. Reporting to him are division vice presidents Terence Befus, responsible for system operations; Ben Kromand, for field operations; and Robert Schmidt, for financial services.

Continuing in a specialized role is Eric Shelton, division vice president, who oversees quality assessment of materials being used in our pipeline activities.

Engineering and Construction Groups

During the year, more than 400 mi. (644 km) of pipeline were added to the Alberta gas transmission system, and numerous modifications were made to existing facilities to ensure continued safe and efficient operation. Purchase of the Etzikom lateral from South Alberta Pipelines Limited added capacity in southern Alberta. Statistics for the major AGTD 1982 pipeline additions are shown in the table on page 11, and their locations are highlighted in the system map on page 10.



A large project this past year was the consolidation and expansion of our meter stations at Empress in southeastern Alberta. Empress is the gateway through which Alberta natural gas is shipped to eastern Canada and the midwestern United States, and our original measurement facilities there were operating at near capacity.

System energy efficiency was increased with installation of a new compressor at Smoky Lake. This compressor, added to accommodate increased gas supply from the northeastern part of the province, is powered by a variable speed electric motor that responds to pressure requirements in the pipeline. This new unit and a similar one installed at Foothills' Jenner station are the first of their kind to be put into service in the natural gas transmission industry.

Two of the main construction projects scheduled for 1983 completion are the 80-mi. (127-km) Heart River lateral in the Peace River area and the 30-mi. (49-km) Hoole lateral northeast of Slave Lake. Engineering and construction activities for both these projects are currently underway. Compression capacity of 8,000 hp. (6.0 MW) will be added in the Peace region, and engineering design has begun on the three new facilities involved.

A second trailer-mounted mobile compressor, which will provide up to 5,230 hp. (3.9 MW) of power, is being built to supplement our original unit. These compressors are used when new pipelines are added to the system or when existing lines require maintenance. Previously, natural gas in the pipeline being serviced would have been vented to the atmosphere. Using the mobile compressors, the gas can be moved into an adjacent section and conserved. In two and a half years of operation, the original compressor unit, with a capacity of 4,020 hp. (3.0 MW), has made possible conservation of nearly 1.3 bcf ($38\ 10^6 m^3$) of gas, representing an estimated savings of $2.5 million.

Major 1982 Additions to NOVA's Alberta System					
		LINE LENGTH		PIPE SIZE	
	LOCATION	(mi.)	(km)	(in.)	(mm)
Constructed					
Graham-Chard Lateral	Northeastern Alberta	48.4	77.9	8 6	219.1 168.3
Leige Lateral	Northeastern Alberta	92.3	148.6	12 10	323.9 273.1
Cutbank Lateral	Northwestern Alberta (south of Grande Prairie)	45.5	73.2	20 16	508.0 406.4
Robb Lateral*	Central Alberta (southwest of Edson)	26.1	42.0	20	508.0
Flat Lake Loop	Smoky Lake area	23.6	38.0	20	508.0
Acquired by Purchase					
Etzikom Lateral	Southern Alberta	50.9	81.9	10 6 4	273.1 168.3 114.8

**Placed in service early 1983.*

Operations Groups

AGTD operations employees keep the Alberta system running at peak efficiency. Their activities include operating and maintaining the pipelines and meter and compressor stations, improving facilities, bringing newly completed projects into operation, and keeping track of and controlling the flow of natural gas through the system. Now they have additional responsibilities with respect to the Foothills system.

One of the most interesting roles this group plays is in developing and testing new technology. This is an area in which our Company has continued to show leadership over the years.

Some of the new technology introduced during 1982 includes:

• The first machine to remove and conserve frozen topsoil successfully during winter pipeline construction. This development has been long awaited by the industry, and the equipment has been proven over a complete working season. The topsoil stripper is leased to other companies when not in use by NOVA.

• A mechanical dry gas seal at our Hussar Compressor Station. This seal requires lower horsepower to operate and less maintenance than conventional compressor seals.

• A prototype valve controller to be used as an additional pressure monitor and safety device, particularly for mainline block valves. This device, developed in conjunction with Noval Technologies Ltd., is being tested at the Didsbury Compressor Station.

Other projects initiated by the AGTD operations group during the year included:

• Conversion of a small number of vehicles to use propane or compressed natural gas (CNG) as fuel. This pilot project is being carried out to assess the feasibility of using alternate fuels in more of our vehicles.

• Transport of pressurized natural gas by tanker truck in northeastern Alberta. When proven economically feasible, this procedure will provide a way of transporting new production before a pipeline is installed.

The AGTD, in conjunction with NOVA/Husky Research Corporation, is developing a computer simulation program to further improve the efficiency of pipeline operations.

Commissioning new facilities — that is, bringing them into service — has been another area of concentrated activity for operations staff. This year's projects included the Leige and Graham-Chard laterals, lines that traverse northeastern Alberta's muskeg terrain, and the new Foothills compressor station at Jenner, Alberta.

Several field offices and service sites saw additions and improvements during the year. A new district office and workshops were completed at Edson, as well as a sub-district office at Redcliff. The move of personnel to the Spruce Grove Service Centre near Edmonton was completed early in 1982.

Regulatory Activities

Over the past several years, we have been appealing decisions concerning treatment of the provisions for depreciation and income taxes included in cost of service charges for the Alberta system. These decisions were made by the Public Utilities Board (PUB) of Alberta during 1978 and 1979 and then suspended by the courts during the appeals process.

Following considerable discussion among all interested parties, the issue was resolved on June 17, 1982, when we implemented the final PUB decisions. As a result, we have refunded to our Alberta gas transmission customers the difference between the amount actually collected from them and the amount we would have collected had the decisions not been suspended. The effect of this refund has been a reduction of working capital for the year, with no material impact on net income.

Also during the year, we applied to the Alberta Energy Resources Conservation Board (ERCB) for 110 permits to construct facilities. These included 54 pipelines with a total length of approximately 485 mi. (781 km), 83 meter stations and three compressor stations. Only one public hearing was required during 1982 in the processing of these applications.

Operating Highlights	1982	1981	% INCREASE
NOVA Alberta System			
Average Rate Base ($000)	1,071,362	874,976	22.4
Average Rate of Return (%)	14.02	12.39	
Length of Pipeline in Service (mi.)	7,818	7,443	5.0
(km)	12 582	11 979	
Compression (hp.)	531,802	516,582	2.9
(kW)	396 566	385 216	
Receipts (mmcf)	1,943,743	1,858,416	4.6
(10^9m^3)	54.763	52.359	
Maximum Day Receipts (mmcf)	7,430	6,956	6.8
(10^3m^3)	209 338	195 992	
Average Day Receipts (mmcf)	5,325	5,092	4.6
(10^3m^3)	150 036	143 449	
Foothills Pipe Lines (Yukon) Ltd.*			
Average Rate Base ($000)	346,930		
Average Rate of Return (%)	15.74		
Length of Pipeline in Service (mi.)	527		
(km)	849		
Compression (hp.)	50,050		
(kW)	37 323		
Receipts (mmcf)	114,125		
(10^9m^3)	3233		
Maximum Day Receipts (mmcf)	999		
(10^3m^3)	28 288		
Western Leg Average Day Receipts (mmcf)	160**		
(10^3m^3)	4513		
Eastern Leg Average Day Receipts (mmcf)	458***		
(10^3m^3)	12 995		
Trans Québec & Maritimes Pipeline******			
Average Rate Base ($000)	116,802		
Average Rate of Return (%)	15.88		
Length of Pipeline in Service (mi.)	133		
(km)	214		
Compression	—		
Receipts (mmcf)	14,502		
(10^6m^3)	413.0		
Maximum Day Receipts (mmcf)	260.3		
(10^3m^3)	7374		
Average Day Receipts (mmcf)	45.5		
(10^3m^3)	1290		

* First year of operation of both western and eastern legs of Foothills System — Phase I
** The Phase I western leg was in service for the whole 12-month period in 1982.
*** The Phase I eastern leg was in service for only the last four months of 1982. Average day receipts for December 1982 were 822 mmcf (23 288.5 10^3m^3) per day.
**** Gas sales to Boisbriand began in February 1982; sales to the Trois-Rivières area began in November 1982.

Environmental Affairs

Our environmental affairs group is engaged in three key activities: applications, inspections, and research and development.

In support of new facility applications to government agencies, staff members prepared environmental and socio-economic impact assessments for 11 large-diameter pipeline projects and specified requirements for 35 additional laterals. Our environmental inspectors are placed on site to monitor relevant aspects of construction and provide reclamation expertise.

Techniques used in construction and reclamation are continually reviewed and evaluated by our environmental research and development staff, who consider both immediate and long-term impact. Investigation focuses on such areas as fish habitat, wildlife resources, air emissions and soil productivity.

In addition to its services to the AGTD, the environmental group's expertise is used by NOVA subsidiary and affiliate companies.

NOVACORP ENGINEERING SERVICES LTD.

With NOVA's added emphasis on international marketing of transmission expertise, Novacorp — formerly Algas Engineering Services Ltd. — has an increasingly important role to play abroad.

Drawing on NOVA staff, Novacorp provides engineering and project/construction management to pipeline projects involving transport of natural gas, crude oil and petroleum products. Because the NOVA group operates a wide range of facilities, including world-scale pipeline systems and petrochemical process plants, Novacorp is strongly positioned to offer comprehensive consulting services in the operation and maintenance of such facilities.

In Canada, most of Novacorp's 1982 assignments were carried out for other companies in the NOVA group.

Overseas ventures included projects in Asia and Europe.

In early 1983, Novacorp announced a successful joint venture with two Japanese companies to design and construct the Peninsular Gas Utilization Project's initial pipeline in Malaysia. The project is owned by Petroliam Nasional Berhad (Petronas), that country's state petroleum corporation.

Novacorp is responsible for the engineering design, construction inspection and commissioning of this system. In addition, Novacorp has offered Petronas the option of sending up to 20 employees to Alberta for training on the NOVA natural gas transmission system. Engineering on the Malaysian project is underway in Calgary, with construction to begin this summer and be completed in December 1984.

The project includes three pipeline components, with associated metering stations and regulating facilities. Novacorp's partners are Mitsui Engineering and Shipbuilding Co., Ltd., and Nichimen Corporation.

Other overseas projects include:

• Provision of on-site consulting services during 1982 to the Petroleum Authority of Thailand in operating and maintaining a new 106-mi. (170-km) natural gas pipeline.

• Assistance to the Swedish State Power Board as engineering consultants in a pipeline feasibility study. The proposal under review involves constructing and operating a 1,056-mi. (1700-km) pipeline to transport natural gas from offshore Norway to markets in Sweden and mainland Europe.

• Involvement in a joint venture bid which, if successful, will provide engineering, procurement and construction services for a short crude oil pipeline on India's east coast. The proposed line would connect tankers moored in Vizag Harbour to the Hindustan Petroleum Corporation's Vishaka refinery.

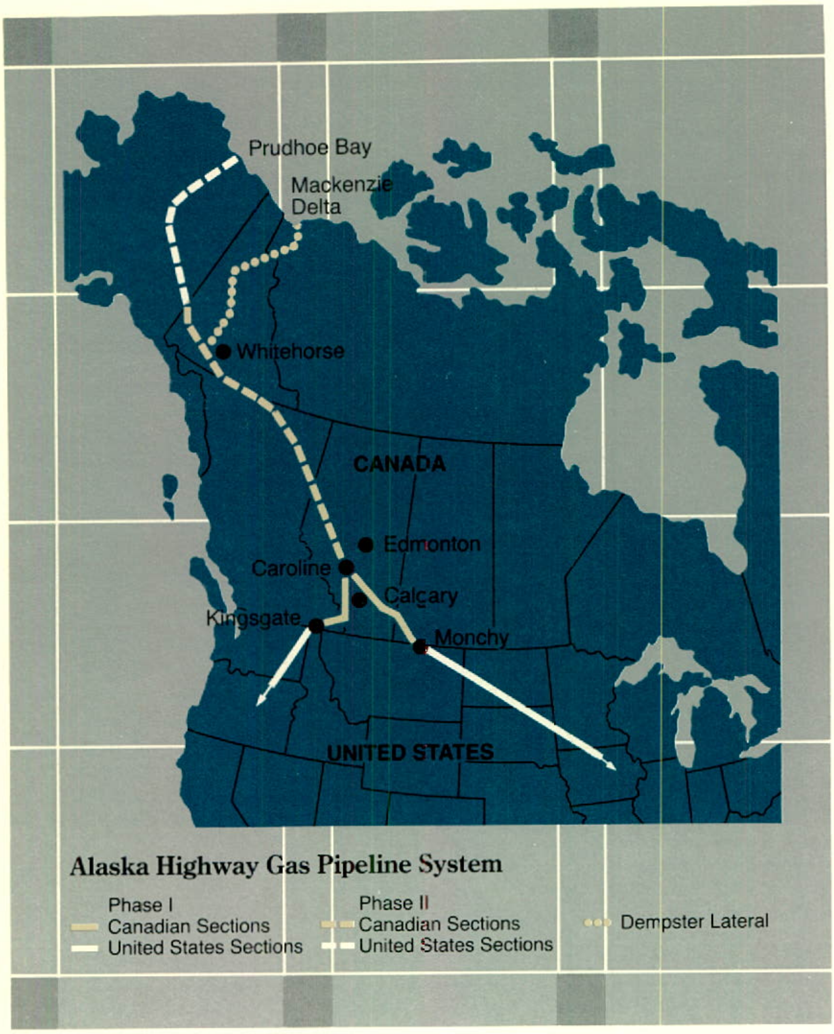
Conservation of topsoil during winter construction is now possible, using new NOVA-developed topsoil stripping equipment.

• Participation in discussions with government and industry authorities in the People's Republic of China for supply of expertise to help develop China's energy resources.

Novacorp is pursuing other opportunities in such areas as the Middle East, Southeast Asia, Europe and Latin America.

In addition to assisting during the planning, engineering, construction and operation of these projects, Novacorp is providing training for employees of the project sponsors. Developing countries usually seek this type of technology transfer as they expand their energy sectors. Novacorp's training programs are comprehensive, involving both classroom sessions and actual on-site work experience.

Novacorp has several new officers assisting in direction of its activities. Donald Olafson is the new president, and three additional vice presidents have been appointed: Walter



Alaska Highway Gas Pipeline System

Litvinchuk and Dale Richards, both also AGTD division vice presidents, and George Lipsett, a recent appointee formerly with Foothills Pipe Lines. Rick Hutchison and James Wong continue as vice presidents carrying out marketing and business development responsibilities.

FOOTHILLS PIPE LINES (YUKON) LTD.

Operation of the Phase I eastern leg of the Alaska Highway Gas Pipeline began on September 1, 1982. With this section in operation and the western leg transporting natural gas for well over a year, Foothills now has more than $1 billion in assets.

Phase I sections in Canada and the United States comprise nearly a third of the total Alaska Highway project, 1,510 mi. (2430 km) out of 4,802 mi. (7728 km). When complete, the pipeline will be capable of transporting 2.1 bcf (59.5 $10^6 m^3$) per day of natural gas from Alaska's North Slope to markets in the lower 48 states. Completion is expected to make it possible to bring Canadian gas from the Beaufort Sea to market.

Foothills, which NOVA owns jointly with Westcoast Transmission Company Limited, is responsible for engineering, procurement and construction management of the 2,041-mi. (3284-km) portion of the project in Canada. The Canadian portion has several components:

- The Phase I western leg, 132 mi. (213 km) of 36-in. (914-mm) pipe, looping parts of our Alberta system and that of the Alberta Natural Gas Company in British Columbia. This section began operation on October 1, 1981.
- The Phase I eastern leg, completed on schedule and under budget and operating as of September. It consists of 395 mi. (636 km) of 42-in. (1067-mm) pipeline.
- Phase II, the northern portion, 1,514 mi. (2435 km) of pipeline from the Alaska/Yukon border to the junction of the Phase I eastern and western legs at Caroline, Alberta. This phase is scheduled for completion in 1989.
- The Dempster Lateral (in the application stage), connecting the Mackenzie Delta area with the Alaska Highway pipeline just north of Whitehorse in the Yukon Territory. A date for hearing of this application by the National Energy Board (NEB) has not been set.

The Foothills compressor station near Jenner, Alberta, was completed on schedule and under budget, and the first of two units was commissioned in time to support initial gas flows through the eastern leg.

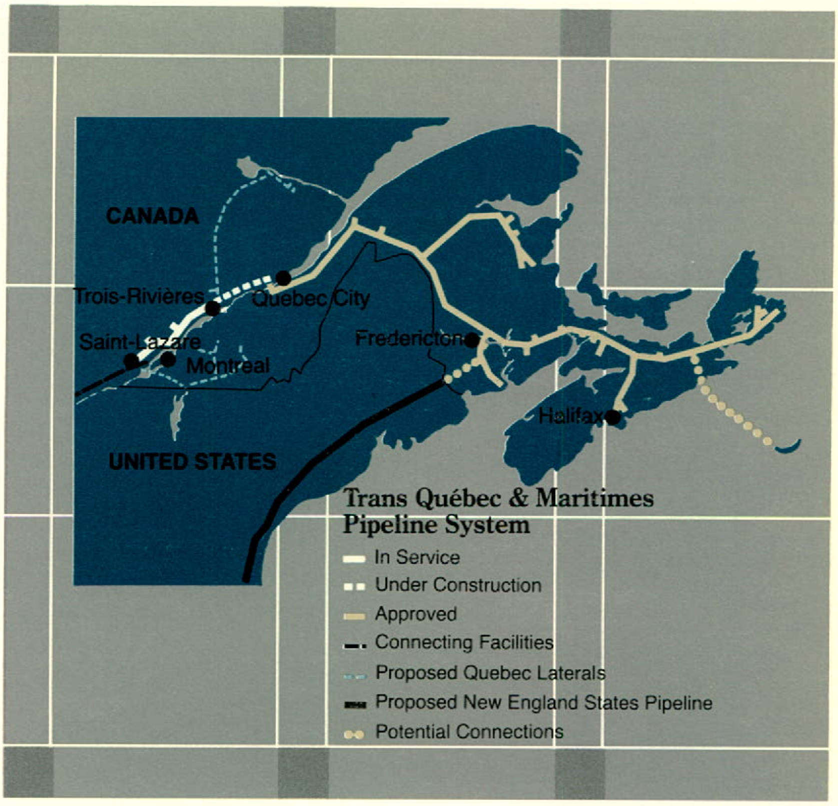
Construction of the three compressor stations in Saskatchewan was delayed by an extended labor dispute, but this did not interfere with operations. Those stations are nearing completion.

The National Energy Board held Foothills' rates and tariffs hearings in June and October. The board ruled that Foothills can include in its rate base actual eastern leg expenditures to the end of 1981 and estimated expenditures during 1982, with cost of service billings commencing September 1, 1982. In addition, the NEB permitted the recovery in the Phase I cost of service charges of a 16% return and a 4% amortization on a portion of the deferred costs incurred to the end of 1981. These charges are refundable with interest when Phase II of the pipeline is completed.

Also during 1982, the Federal Environmental Assessment Review

Panel concluded its hearings on the Yukon segment and issued its final report. In it, preliminary environmental planning on the project is judged to be generally adequate. A number of recommendations were made to the Northern Pipeline Agency for future consideration.

In April 1982, the project sponsors announced a two-year deferment in completion of Phase II. Both U.S. and Canadian sponsors are continuing with reduced engineering and pre-construction planning activities to meet the revised completion date of late 1989. As a result of the deferment and completion of Phase I construction, Foothills has decreased its staff considerably.



TRANS QUÉBEC & MARITIMES PIPELINE INC.

Boisbriand, Quebec, received its first Alberta natural gas on February 15, 1982, through the initial sections of the Trans Québec & Maritimes Pipeline. By November, the line was completed to Trois-Rivières. Work is currently progressing on the connecting section to Quebec City, and deliveries are expected to begin in the fall.

These sections, running from Saint Lazare to Quebec City, consist of 179 mi. (288 km) of mainline and 27 mi. (43 km) of laterals, of which approximately 133 mi. (214 km) were in service by the end of 1982. The initial average flow to Boisbriand was 45.3 mmcf (1.3 10^6m^3) per day, with an increase to 171 mmcf (4.8 10^6m^3) per day expected by 1987. The Trois-Rivières section commenced deliveries at 318 mcf (9.0 10^3m^3) per day and is expected to reach 33 mmcf (940.0 10^3m^3) per day by 1987.

TQM, owned jointly by NOVA and TransCanada PipeLines Limited, holds NEB certificates for mainline and lateral facilities in Quebec, as well as a conditional certificate for further facilities in New Brunswick and Nova Scotia.

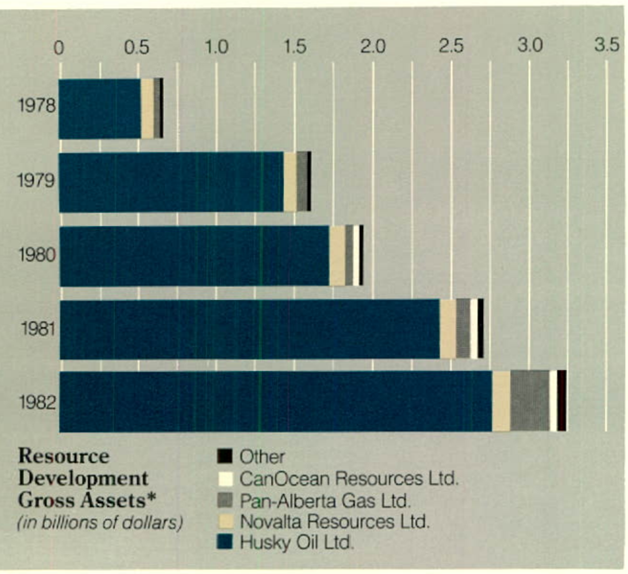
During 1982, a $500 million fund for the Quebec laterals was created as part of the Canadian government's National Energy Program (NEP) Update. Discussions were held among the federal and Quebec governments and two Quebec gas distributors, Gaz Metropolitain, inc., and Gaz Inter-Cité Québec Inc., and as a result, these companies now have responsibility for construction and operation of most of the Quebec laterals. A $100 million Gas Marketing Assistance Program has been created by the federal government to pay operating costs during the initial years, thereby assisting with gas penetration into these new markets.

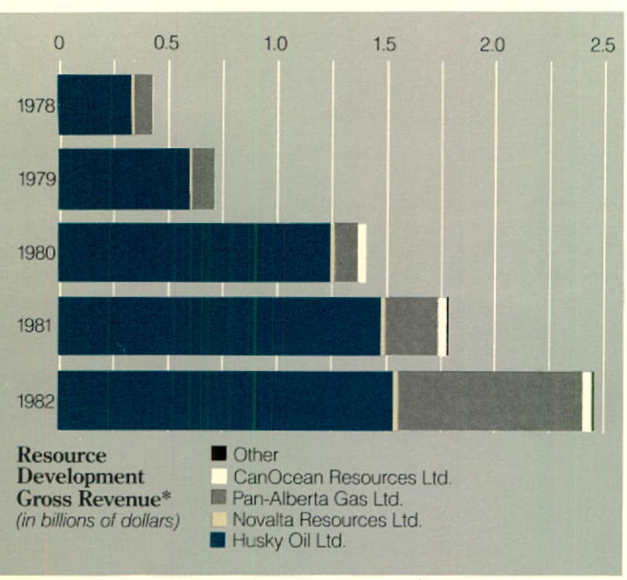
The NEP Update also provided for receipt of a non-interest-bearing loan by TQM. The loan is to be used to defray costs of initial design and engineering incurred until construction begins on the sections in New Brunswick and Nova Scotia. Terms and conditions of this arrangement are still under discussion.

Beginning in November, TQM appeared before the National Energy Board for its first rate hearing. The NEB will rule on matters related to rates, tolls and charges to TQM's customers, with a decision expected in mid-1983.

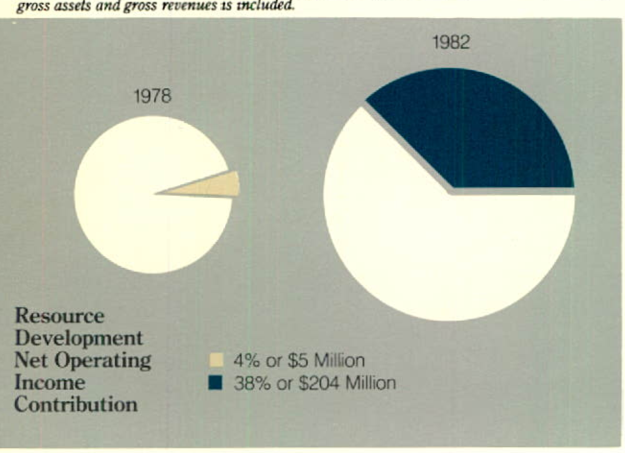
The New England States Pipeline Project is a proposal to transport surplus Canadian gas via an export pipeline link from the New Brunswick/Maine border to existing facilities in the northeast United States. Construction on the 360-mi. (579-km) pipeline could commence once the appropriate agreements are executed, regulatory approvals obtained in both countries, and suitable financing arranged.

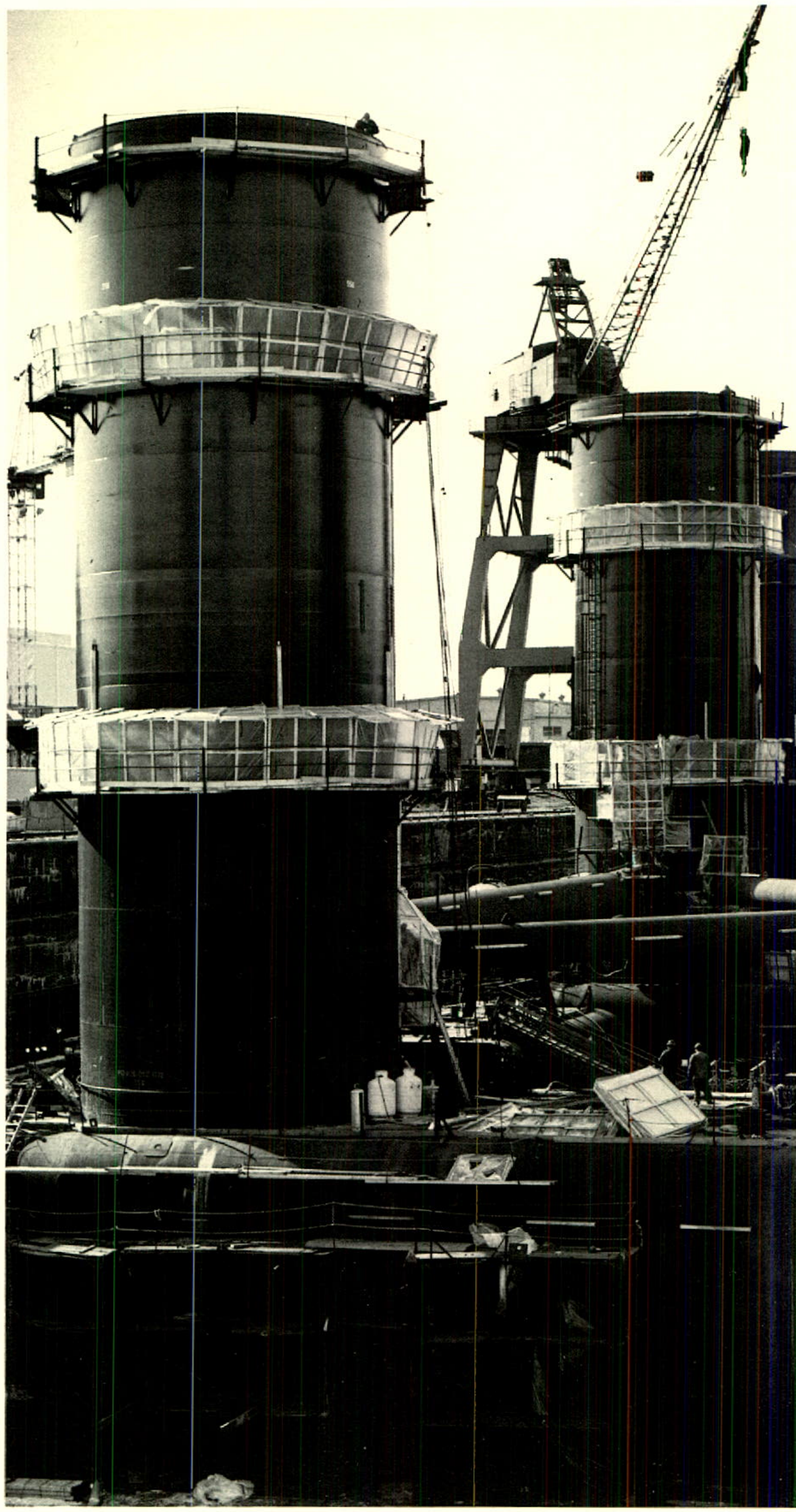
Resource Development





*These graphs depict assets, before depreciation and depletion, and revenue, before the elimination of intersegment revenue, of NOVA, its subsidiaries and affiliates. For the Company and its subsidiaries (where the Company has a controlling interest) 100% of gross assets and gross revenues are included. For affiliates only the Company's ownership share of gross assets and gross revenues is included.



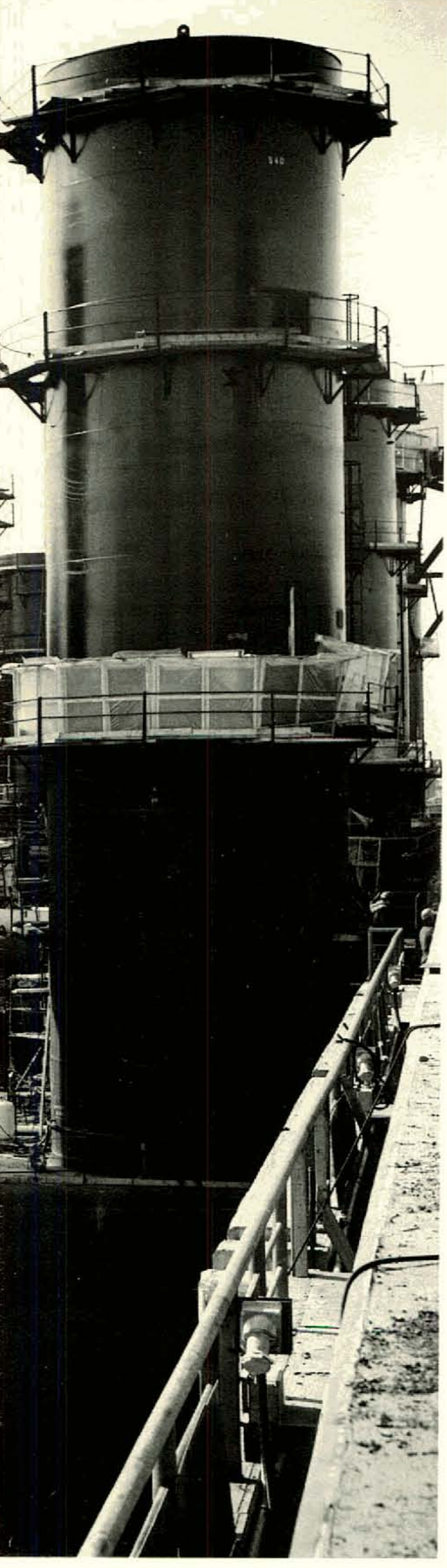


To our shareholders

Our annual and interim reports are produced to keep you in touch with the activities and financial performance of the Company. We would like to have your opinion as to how we can make these reports better serve your needs.

This reply card has been developed to help gather this information and includes additional space for your comments.

Please feel free to send it either unsigned, or complete with your name and address. Simply drop the card in the mail and postage will be paid by NOVA. We appreciate your cooperation and will let you know the results of the survey in our second quarter interim report.



The major operation reported in this sector is that of Husky Oil Ltd. (68% owned). Other companies reporting here are Pan-Alberta Gas Ltd. (50.005% owned) and Canstar Oil Sands Ltd. (50% owned), along with wholly owned Novalta Resources Ltd., CanOcean Resources Ltd. and Noval Technologies Ltd. and the jointly owned NOVA/Husky Research Corporation Ltd. The Arctic Pilot Project (25% share) is also included.

Through NOVA's majority ownership position in Husky Oil Ltd., resource development has become a major component of our business. Husky accounts for over a third of our assets and about 45% of revenues.

During 1982, it was mainly through Husky initiatives that we moved toward the goal of expanded investment in the Canada Lands and increased emphasis on conventional exploration and production and enhanced heavy oil recovery. We are continuing to aggressively pursue and build upon opportunities in these areas.

During the year, we made an important step toward accomplishing another of our basic corporate goals: the expansion of markets for Alberta natural gas. With Phase I facilities of the Alaska Highway Gas Pipeline in place, Pan-Alberta is currently shipping new volumes of Alberta's surplus gas to export markets in the United States.

Other NOVA companies in the resource development sector are carrying out research, development and marketing activities focused on a wide spectrum of energy-related projects.

At Saint John, New Brunswick, Husky and a partner are building a semi-submersible drilling rig for use primarily off Canada's east coast.

HUSKY OIL LTD.

Husky is one of the largest Canadian-owned, fully integrated oil companies. It engages in all aspects of petroleum activity — from exploration, development and production to distribution, refining and marketing.

As well as aggressive conventional and frontier exploration activity, Husky is very committed to ongoing production of heavy oil and investigation and work in enhanced oil recovery. Exploration opportunities outside of North America are pursued through subsidiary companies. Marketing facilities include the Husky car/truck stops, well known to drivers in the western provinces and the U.S. mountain states.

Among other recent major activities, Husky has committed to increased frontier activity off Canada's east coast, particularly on the Scotian Shelf, and in the Beaufort Sea. The company has also made two major discoveries in California, one offshore in the Santa Maria Basin, the other onshore in the Tulare Lake field.

A summary of Husky's operations follows and more comprehensive information is available in the 1982 Husky Oil Ltd. annual report, available upon request.

Canadian Petroleum Operations

Husky continues as a leader in enhanced oil recovery (EOR) research, seeking to establish technologies suitable for commercial application. Several of the more advanced EOR pilot projects in the Lloydminster area at the Alberta/Saskatchewan border are showing promise of recovering oil on a commercial scale. In comparison to others in the industry, Husky has the most extensive EOR program in the Lloydminster area, where six projects are currently in operation and four additional thermal projects are to begin operation in 1983. About $44.5 million was spent on the projects in 1982.

Heavy oil exploration in Lloydminster involved participation in drilling 28 gross (18.5 net) wells, resulting in nine oil wells and two gas wells.

Husky's capacity to process its Lloydminster production is now twice what it was a year ago. An expansion to the refinery there — representing a major construction effort in terms of time, manpower and capital — was completed during the year and will begin operation in May 1983. This efficient, modern facility can refine 25,000 bbls. (3970 m^3) a day. Located adjacent to the refinery is a new operations and control centre housing offices and a modern laboratory, along with pipeline control equipment. Staff moved into the centre in October.

The Lloydminster operations were given additional support in early September when Husky submitted a heavy oil development and upgrader proposal for consideration by the federal, Saskatchewan and Alberta governments. Discussions on the proposal are continuing.

The plan, which offers the potential of a wide range of employment and industrial benefits to most regions of the country, involves constructing a heavy oil upgrader in Saskatchewan and linking it to the expanded refinery, located on the Alberta side of the border. A capacity of 52,860 bbls. (8400 m^3) per day of heavy oil is projected, with production coming from the Lloydminster/Cold Lake area. This proposal was put forward in the expectation that the upgrader could be built expeditiously.

Bold pursuit of resource prospects in Canada's frontier regions is an integral part of Husky's long-term plan as a major Canadian explorer. The company's drilling expenditures in these areas qualify for the federal government's Petroleum Incentive Program (PIP) grants at the maximum 80% level.

During 1982, Husky was able to expand its involvement off the Canadian east coast considerably. Two farmin agreements were negotiated on the Scotian Shelf, which allow Husky to obtain a working share of lands on which other companies hold leases. In addition, Husky and its partners received four exploration agreements from the Canada Nova Scotia Offshore Oil and Gas Board.

A total of nine million acres (3.6 million ha) is involved, including:

• 2.3 million acres (940 000 ha) on which Husky and its Canadian partner, Bow Valley Industries Ltd., can earn an interest through an agreement with Onaping Resources and Scotia Energy Resources.

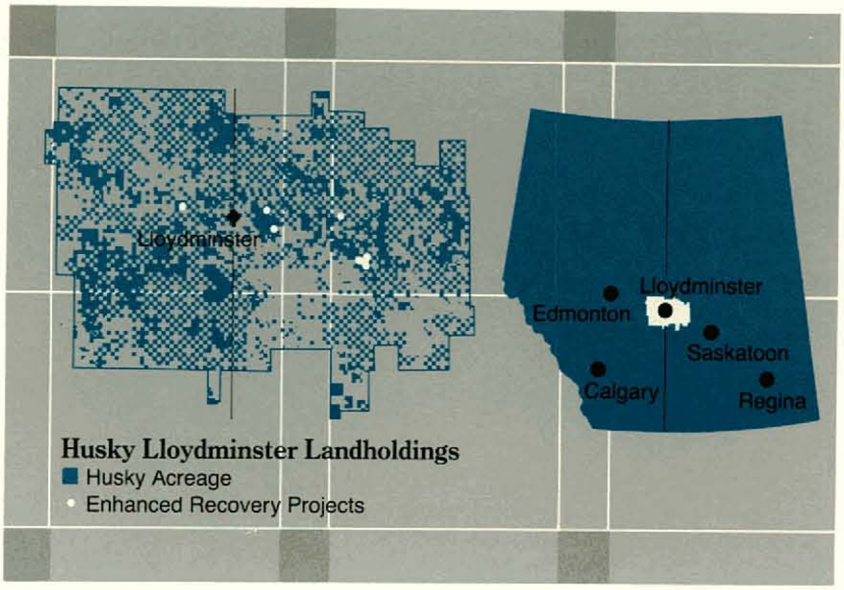
• 4.3 million acres (1.7 million ha) in the Erie/Abenaki area north of Sable Island, where Husky has a 25% interest in four exploration agreements.

• 2.4 million acres (984 000 ha) on the Scotian Shelf, where Husky and Bow Valley can earn 50% of Mobil Oil Canada Ltd.'s interest through two agreements made near the end of 1982.

Husky and Bow Valley Resource Services Ltd. have two semi-submersible drilling rigs and six supply vessels under construction. They are being built primarily for use in the east coast offshore area, adding significant Canadian content to drilling activity in the region. One of the rigs is being constructed in Saint John, New Brunswick, and two of the supply vessels are under construction in Vancouver.

The 1982 Scotian Shelf drilling program involved participation in two exploratory wells on the Banquereau acreage, 47 mi. (75 km) east of the Venture gas field. One of these wells, Banquereau C-21, had a final stabilized flow of 21 mmcf (600 10^3m^3) per day of gas with 100 bbls. (16 m^3) per day of condensate. Further exploration will need to be done to prove out the commercial viability of the area. Husky has a 29% interest in 366,000 acres (148 000 ha) in the Banquereau block.

Another frontier commitment was made in August, when Husky negotiated a farmin in the Beaufort Sea oil play. The company will participate in a four-well program over the next three years to earn 15% of Gulf Canada Resources Inc.'s interest in four blocks totalling 295,000 acres (119 000 ha).



Husky Lloydminster Landholdings

Traditionally, Husky is known for its heavy oil activities in western Canada. However, the company has also been building a stronger land position in Alberta's light oil areas. The largest portion of the 1982 exploratory drilling program was directed at evaluating landholdings acquired from Uno-Tex Petroleum Corporation that have the prospect of yielding light oil.

During the year, Husky was a participant in 30 gross (10.3 net)* conventional exploration wells in western Canada, resulting in 13 oil and three gas discoveries. The majority of these successful wells were located in the Peace River Arch region of north-central Alberta, where the Golden-Evi play is located. An oil discovery was also made in south-central Alberta, where Husky is a participant in the Fenn West play. These wells are eligible for the New Oil Reference Price (NORP) under the National Energy Program.

**Gross figures represent the actual number of wells in which a company participates; net figures, the number of wells expressed on a working interest basis.*

In its retail marketing operations, Husky is continuing to diversify and upgrade facilities as a service for motorists. Several foodstores were added during 1982, and customers at selected stations were offered a choice of two alternate fuels: propane and compressed natural gas (CNG).

The demand for light oil products in Canada declined from the past year, reflecting the general downturn in the economy. However, compared with the industry overall, Husky's light oil sales volumes were not as severely affected, but regional retail discounting and price wars did affect profit margins.

Husky's continued growth and development has meant a need for additional office space. The company is completing a new headquarters building in Calgary, with staff move-in expected to be completed by the end of October.

United States Petroleum Operations

Husky Oil Company, a U.S. subsidiary with executive offices in Denver, Colorado, once again achieved very positive results after a

Drilling crew members adjust the drill pipe on one of Husky's exploratory rigs in Alberta.

year of aggressive exploration and development.

During 1982, exploratory activities continued in the Rocky Mountain states, California and the Pacific Northwest and were expanded in Texas, Oklahoma and Louisiana.

The discovery in the Tulare Lake field of Kings County, California, appears to be one of the company's largest onshore finds in the United States in several years and has additional significance because Husky has large landholdings in the surrounding area. The well tested oil at approximately 1,000 bbls. (160 m^3) per day. Offshore in the state's Santa Maria Basin, another major discovery well tested at a daily rate of 1,550 bbls. (250 m^3) of oil.

Other discoveries were made in Colusa County, California, Menard County, Texas, and Eddy County, New Mexico, as well as in the Paradox Basin of southwest Colorado.

The 1982 development programs were concentrated primarily in California, Texas, Wyoming and New Mexico. Husky participated in a total of 207 gross (64 net) wells, yielding 130 oil and 42 gas wells. In addition to the successes in California, production was boosted by development drilling in Wyoming's Halfmoon field and by output from expanded secondary recovery operations near Cody, Wyoming, and Red Willow Creek, Nebraska.

In early 1982 and again in the first two months of 1983, a deterioration in retail profits occurred, primarily due to reduced margins. This decline is general for retail gasoline marketers in the United States and a recovery can be anticipated once crude oil prices stabilize and stocks of old high-cost inventory are depleted. A deliberate inventory reduction program was pursued in late 1982 so that the company is in a good position for a quick recovery.

In September 1982, Husky purchased from the Cheyenne Pipeline Company a product pipeline which runs from Wyoming to Nebraska. The acquisition allows

Husky to continue supplying customers in western Nebraska and enhances the opportunities for expanding markets in that area.

International Operations

Production from offshore fields in the Philippines and acquisitions in Indonesia and New Zealand were highlights of the year for Husky's international subsidiaries.

Production doubled in the Philippines with the Matinloc field off Palawan Island coming onstream. Husky's net oil production in the Philippines averaged 3,000 bbls. (475 m^3) per day for December 1982. Five exploratory wells were drilled and subsequently abandoned, although two of them showed significant gas flows.

The newly acquired Indonesia acreage, located in the Madura Straits region southeast of Java, will be the focus of geological field studies and a marine seismic survey during 1983. The lease consists of approximately 3.5 million acres (1.4 million ha). A similar survey was completed in January 1983 in the Banggai block offshore east Sulawesi where Husky has a 50% operating interest in 4.4 million acres (1.8 million ha).

A marine seismic program is also planned during 1983 on Husky's New Zealand property, situated offshore the southeast corner of the South Island. The company has an 80% interest in a licence covering 2.7 million acres (1.1 million ha).

Husky is also active in the North Sea and in Senegal. Exploratory drilling in the North Sea's German sector proved disappointing, and participation has been discontinued. Three exploration wells in the United Kingdom sector tested dry and were subsequently abandoned. In Senegal, a third marine seismic survey was conducted and data was obtained for evaluating drilling prospects for the 1983 exploration program.

NOVALTA RESOURCES LTD.

Novalta Resources, a wholly owned subsidiary, was NOVA's earliest entry into the oil and gas exploration and production industry. Novalta concentrates its efforts on conventional oil and gas exploration, primarily in Alberta. While its achievements may be somewhat overshadowed by Husky's, it has over the years performed as one of the industry's most successful junior companies. During 1982, Novalta had an overall net success ratio in excess of 75%, finding oil or gas in 24 out of 30 gross (17.3 out of 22.5 net) wells drilled.

Novalta has successfully constructed production facilities in the Caslan field (83% working interest) and the Kehiwin field (100% working interest), and sales commenced in early 1983. Significant economic benefit will be realized by the Kehiwin Indian Band through royalty payments. Novalta continues to work closely and cooperatively with the Band Council in developing industry-related employment opportunities.

Within its total operations, Novalta's share of gross sales before royalty during 1982 amounted to five bcf (140 10^6m^3) of gas (including gas equivalents of oil and natural gas liquids) as compared with 5.7 bcf (160 10^6m^3) in 1981. Reduced sales to the Alberta industrial market, in particular the petrochemicals sector, have resulted in a reduction to 1982 cash flow from operations. However, new gas sales to both the export and domestic markets should offset these declines and could contribute positively to profitability in 1983.

Novalta's strategy of placing more emphasis on the intermediate and deeper exploration prospects in the western Canadian basin has resulted in a strong land position, and preliminary exploration results continue to be encouraging.

During 1982, Novalta participated in extensive seismic surveys on 20 separate prospective areas and acquired exploratory acreage amounting to 52,000 acres (20 800 ha) gross, 46,500 acres (18 600 ha) net. Landholdings at year end were 1,253,000 acres (501 000 ha) gross, 544,000 acres (218 000 ha) net.

Total capital expenditures for petroleum and natural gas rights, geophysical surveys, exploration and development drilling, and surface facilities amounted to $16.5 million in 1982 as compared to $13.5 million in 1981.

PAN-ALBERTA GAS LTD.

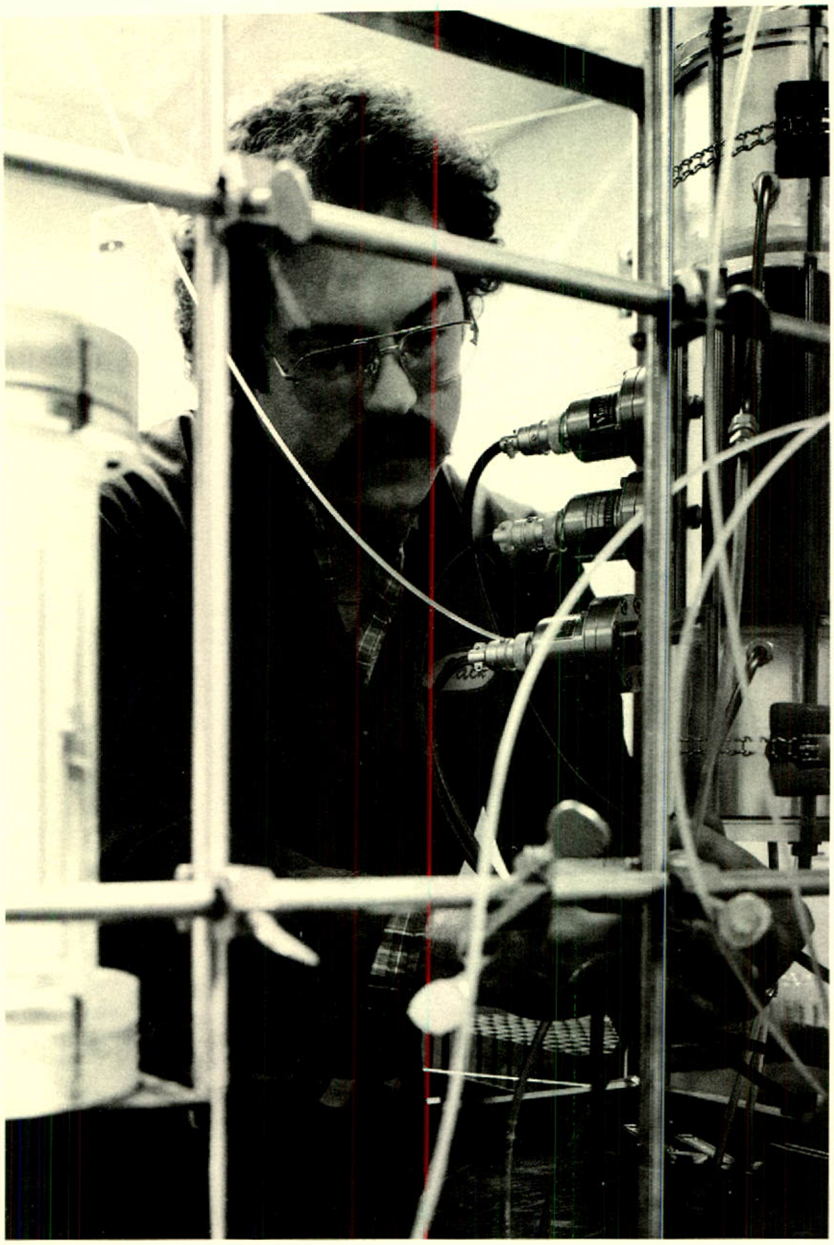
Pan-Alberta marked its tenth year of operation in 1982 with a large jump in export sales volumes, brought about by completion of the Alaska Highway Gas Pipeline's Phase I eastern leg. The line has an annual capacity of 292 bcf (8.3 10^9m^3), equivalent to maximum annual revenues of $1.7 billion and a maximum annual return to Alberta producers of $1.4 billion, when at full capacity.

Pan-Alberta, a natural gas marketing company owned jointly by NOVA and the Alberta Energy Company, is transporting gas through the eastern leg for sale to three major United States pipeline companies. Natural gas is delivered to the export point at Monchy, Saskatchewan, where it enters the Northern Border Pipeline Company system.

Pan-Alberta was granted permits for new exports and extensions to the terms of existing licences by the National Energy Board in its early 1983 gas export decision. The permits allow export of 0.6 tcf (16.6 10^9m^3) from Niagara Falls into the New England and eastern seaboard areas of the United States over 12 years beginning in 1984. An additional 1.6 tcf (46 10^9m^3) has been approved for export to the United States from Kingsgate, British Columbia, and Monchy.

Pan-Alberta is currently awaiting decisions from the Alberta Energy Resources Conservation Board to allow removal of the corresponding volumes from the province and from U.S. regulatory agencies to permit our customers to import the gas.

A new project involving exports to the United States was announced early in 1982 with the sale of 101 mmcf (2.9 10^6m^3) per day to Texas Gas Transmission. Producers in Alberta, British Columbia and the Yukon Territory can benefit from the



Scientists at the NOVA/Husky research centre use drilling cores to study techniques for enhanced oil recovery.

innovative arrangements of the agreement. These involve using Pan-Alberta's existing gas supply and spare capacity in the eastern leg in conjunction with unused export licence capacity of Westcoast Transmission Company Limited and Columbia Gas Development of Canada Ltd.

Sales to Gaz Metropolitain, inc., continued at a favorable level during 1982, but those to Westcoast decreased, primarily because of a decline in the United States markets served by that company.

Pan-Alberta collected total revenues in 1982 of $841 million, compared with $243 million in 1981. This increase reflects a full year's operations on the Phase I western leg and four months' service on the eastern leg. Sales volumes increased from 62 bcf (1.8 10^9m^3) in 1981 to 156 bcf (4.4 10^9m^3) in 1982.

In April 1982, the Alberta Petroleum Marketing Commission allowed an increase in rate of return on common equity from 11.25% to 17%.

CANSTAR OIL SANDS LTD.

This NOVA joint venture with Petro-Canada Exploration Inc. redirected its activity following the collapse of the Alsands project in April 1982. Plans for developing a similar oil sands project were reassessed and, because of limited prospects for early approval and the high costs associated with development, it was decided that studies would continue, but at a significantly reduced rate of expenditure.

Canstar is currently evaluating the economics of commercial production for a smaller scale plant, but no date has been set for seeking regulatory permission to proceed. We continue to believe that mineable oil sands can be an economical source of oil for Canada in the 1990s, and Canstar's activities will keep us well positioned to participate.

ARCTIC PILOT PROJECT

National Energy Board (NEB) hearings began on this project in February 1982, but were adjourned on August 31 so that sponsors could assess potential markets in Europe. The project envisages producing liquefied natural gas in the Arctic Islands and transporting it to market year round in ice-breaking tankers. While project expenditures have been greatly reduced, we continue to believe the Arctic Pilot Project is a valid prospect for the 1990s. Our partners in the joint venture are Petro-Canada Exploration Inc., Dome Petroleum Limited and Melville Shipping Limited.

NOVAL TECHNOLOGIES LTD.

Our Noval Technologies subsidiary carries out investigative, developmental and operations project work in the areas of new and alternate energy sources, waste heat utilization and new product development. It also manages NOVA's involvement in technology transfer and assessment of high technology activities.

Noval's two Prairie Sun greenhouse operations, totalling seven acres (2.8 ha), continue to market vegetables and potted flowers at several locations in Alberta, including a kiosk in our new corporate headquarters building. The greenhouses use waste heat from NOVA's Princess Compressor Station and the ethylene plant at Joffre.

Noval's work in alternate energy includes three projects in the Atlantic provinces. These are in the engineering design and demonstration stages, and no decisions have yet been taken for commercial implementation. The projects are:

• Mine methane drainage at Sydney, Nova Scotia. The methane gas in the Cape Breton mines is collected and brought to the surface. The process greatly increases mine safety and yields a product that can be used as a fuel.

• Virgin coal demethanation in the Pictou areas of Nova Scotia. Methane is collected from coal seams to increase safety in areas where mining is planned or to extract this resource from areas that may never be mined.

• Fuel peat production near Bishop's Falls, Newfoundland. Canada has the second largest peat deposits in the world. The peat reclaimed in Newfoundland is being used to produce steam for power generation and can be pressed into logs or briquets for stoves and furnaces.

A coal demethanation project is also underway in New Zealand.

Several of the initial electronic development projects undertaken at the new product development facility in Calgary on behalf of other NOVA companies were completed and turned over to the operating companies.

NOVA/HUSKY RESEARCH CORPORATION LTD.

In late 1982, the NOVA/Husky Research Corporation Ltd. moved into a facility which has laboratories for chemical, geological and biological research programs. Research objectives are focused on improving and developing technologies of benefit to operations of NOVA and Husky companies, principally in the areas of resource recovery.

A program in biotechnology, using microbes to enhance oil recovery, is being continued at University of Calgary laboratories through an arrangement with the university-based Arctic Institute of North America. Additional work in this field is being done under contract with B.C. Research, an independent, non-profit society in British Columbia.

Also during 1982, several new studies in the field of heavy oil production were undertaken. These are continuing in 1983, along with new programs in stratigraphy and geochemistry aimed at developing methods to better identify source rocks and thereby reducing drilling risk in new target areas. A biocorrosion program is also underway to determine possible causes of corrosion in pipelines.

CANOCEAN RESOURCES LTD.

CanOcean Resources, headquartered in New Westminster, British Columbia, develops, manufactures and services high technology production equipment for conventional and offshore applications in the oil and gas industry, as well as doing engineering consulting in a number of specialized fields.

The combination of uncertain world oil prices and the movement into deeper and more hostile waters is increasing the petroleum industry's interest in subsea systems. This is a positive trend for CanOcean.

During 1982, CanOcean continued to service a subsea oil production system offshore of Brazil for Petrobras, the Brazilian national oil company.

CanOcean is also working on:

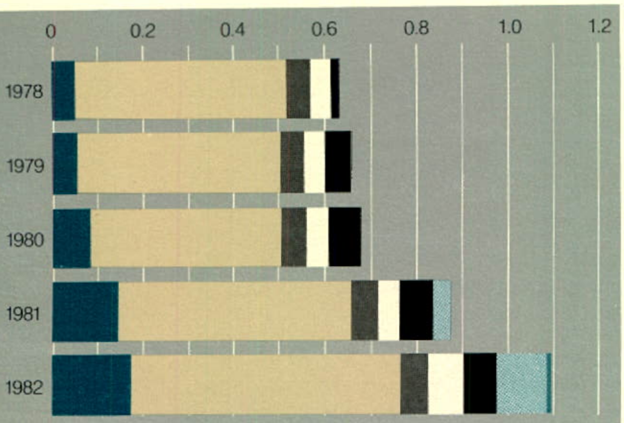
• Preliminary design and engineering of subsea production equipment for Norske Shell in the Norwegian sector of the North Sea, for 1,000 ft. (305 m) depths.

• Design and project management services for what will be the world's largest individual GOSP (Gas/Oil Separation Plant) facility for the Arabian American Oil Company.

• Engineering study of development alternatives for offshore fields in conjunction with engineers from the People's Republic of China.

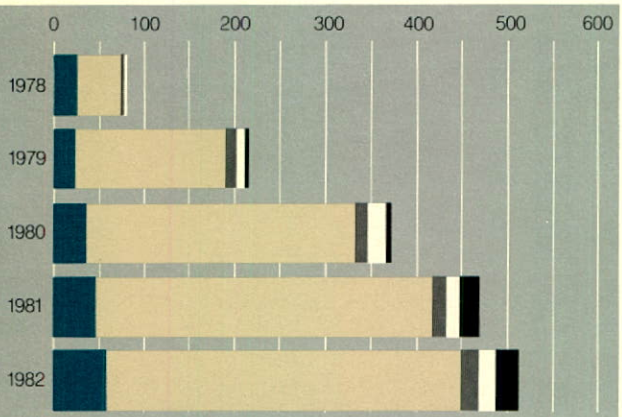
With its superior subsea engineering expertise, a stronger marketing effort and improved manufacturing capabilities, CanOcean is pursuing projects throughout the world.

Petrochemicals



Petrochemicals Gross Assets*
(in billions of dollars)

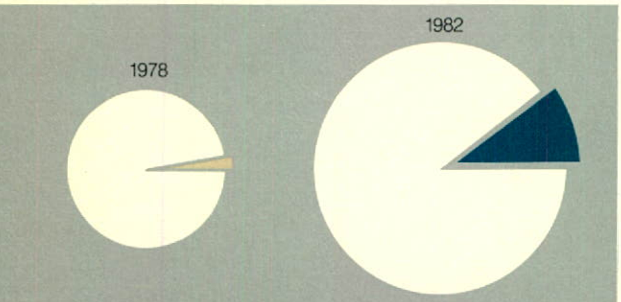
- Other
- Novacor Polyethylene Plant
- Diamond Shamrock Alberta Gas
- A. G. Pipe Lines (Canada) Ltd.
- A. G. Pipe Lines Inc.
- The Alberta Gas Ethylene Company Ltd.
- Alberta Gas Chemicals Ltd.



Petrochemicals Gross Revenue*
(in millions of dollars)

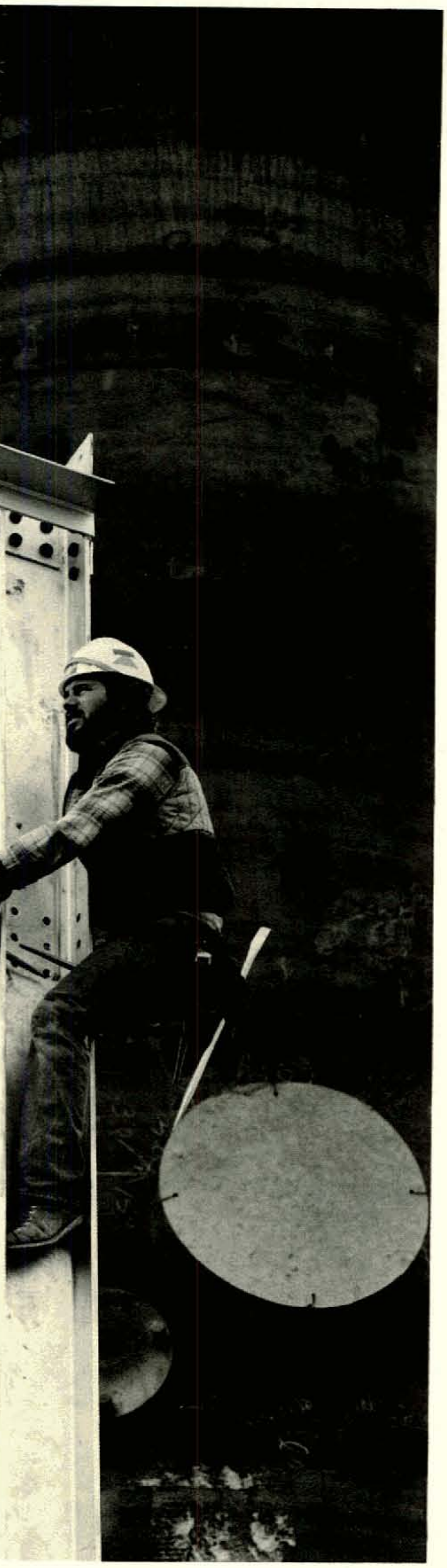
- Diamond Shamrock Alberta Gas
- A. G. Pipe Lines (Canada) Ltd.
- A. G. Pipe Lines Inc.
- The Alberta Gas Ethylene Company Ltd.
- Alberta Gas Chemicals Ltd.

**These graphs depict assets, before depreciation and depletion, and revenue, before the elimination of intersegment revenue, of NOVA, its subsidiaries and affiliates. For the Company and its subsidiaries (where the Company has a controlling interest) 100% of gross assets and gross revenues are included. For affiliates only the Company's ownership share of gross assets and gross revenues is included.*



Petrochemicals Net Operating Income Contribution

- 3% or $3 Million
- 10% or $55 Million



Operating in this sector under the direction of Novacor Chemicals Ltd. (100% owned) are: The Alberta Gas Ethylene Company Ltd. (100% owned), Alberta Gas Chemicals Ltd. (50% owned), Diamond Shamrock Alberta Gas (50% owned), A.G. Pipe Lines (Canada) Ltd. (100% owned) and A.G. Pipe Lines Inc. (100% owned).

NOVA continued to show a profit in this business sector despite a difficult year in the petrochemical industry. This is partly because our plants use feedstocks derived from abundant local supplies of natural gas, but primarily because our ethylene plant is a cost of service operation.

Worldwide, additions to supply capacity in combination with the current economic recession have resulted in extremely low operating rates, driving most companies into loss positions.

The Canadian industry has not escaped the problem and has seen its competitive market position at least temporarily eroded. The export markets on which the industry depends have been shrinking. This situation is coupled with the fact that petrochemical operators have been caught in a rigid system where domestic natural gas feedstock prices have continued to rise while declining in most other countries.

Although NOVA's operations overall achieved good results, individual segments of our business were adversely affected by this cost/price squeeze. However, we continue to believe in the long-term competitive position of a natural gas-based petrochemical industry and are pursuing an aggressive leadership role in Alberta.

A construction worker erects structural steel for a process piping rack at NOVA's polyethylene plant site. Polymerization of ethylene into polyethylene granules will take place in the reactors in the background.

During 1982, NOVA's petrochemicals group brought a third methanol plant into operation and continued construction of ethylene and polyethylene facilities. Efficiency of all operating plants was improved. Novacor Chemicals was reorganized to accommodate some of the operations of a petrochemicals joint venture in which we were involved and the assumption of operating management of Diamond Shamrock Alberta Gas (DSAG), our polyvinyl chloride operation.

NOVACOR CHEMICALS LTD.

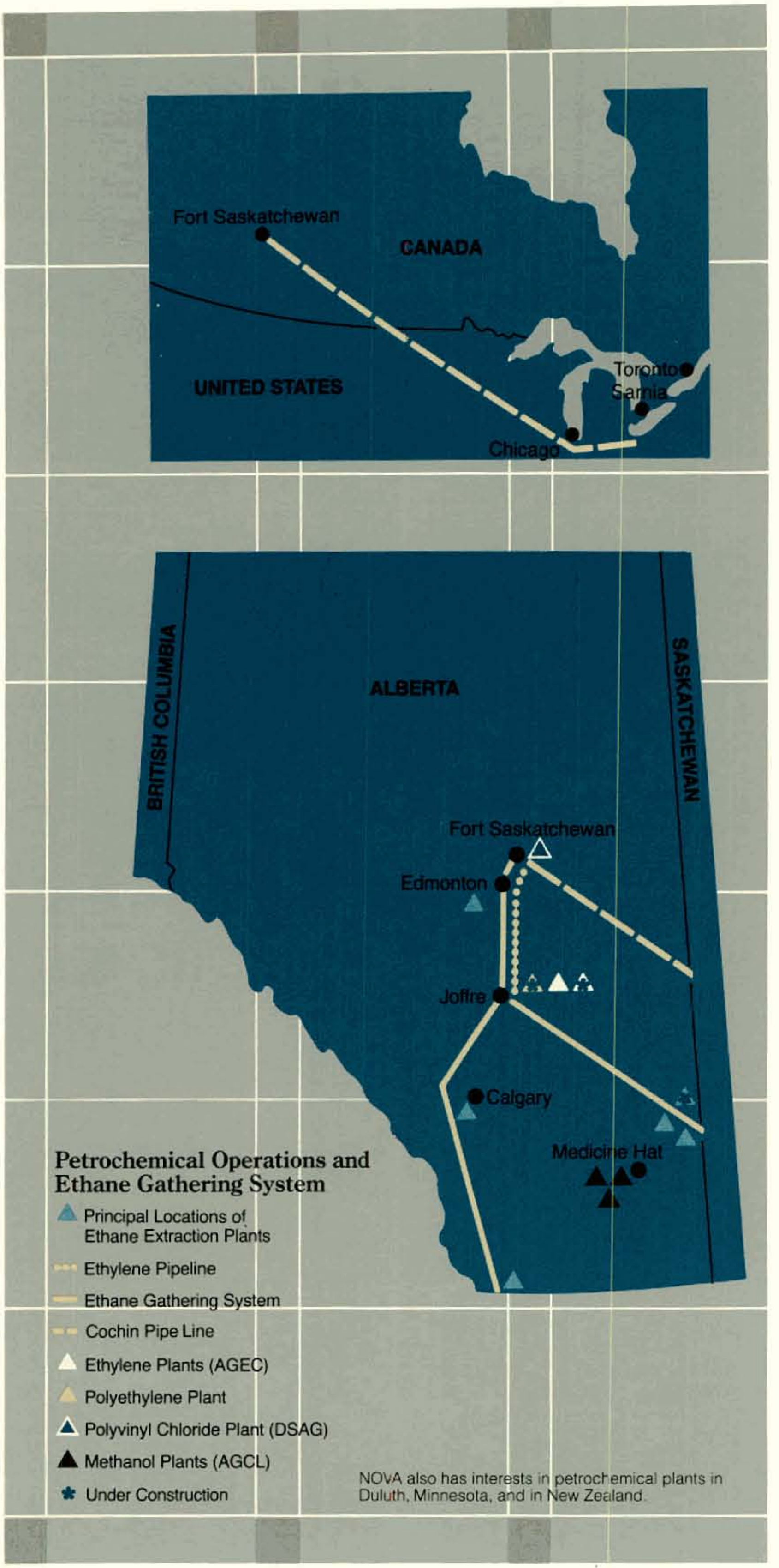
Novacor Chemicals was formed in 1981 to direct, control and, in due course, own the Company's petrochemical interests. During 1982, the company also took on the role of managing the plant operations.

In May 1982, after a mutual agreement to dissolve the ENESCO CHEM LTD. joint venture with Shell Canada Limited, Novacor assumed responsibility for the linear low density polyethylene project being constructed at Joffre, Alberta. Novacor Chemicals thereby became an operating as well as a managing company, with responsibility for marketing and manufacturing.

Rolland Frakes, formerly president of the joint venture, was appointed a senior vice president of Novacor, with specific responsibility for marketing. Manufacturing responsibility was assumed by Bud Clark, senior vice president.

In July 1982, it was agreed between ourselves and Diamond Shamrock Corporation that Novacor would take over operating responsibility for Diamond Shamrock Alberta Gas. DSAG employees were transferred to Novacor, and during the last half of the year, there was an improvement in the operation of this polyvinyl chloride business.

In November 1982, Novacor decided to transfer its petrochemical marketing and distribution functions from Edmonton to Calgary. The transfer should result in reduced costs, but more important, it will improve internal communication



which is vital to the ongoing operation of the business.

As of December 31, 1982, employees of Novacor (including those transferred from the other companies) numbered 225, a substantial increase from a year ago.

The polyethylene project at Joffre, Alberta, remains on schedule and within budget. As of December 31, engineering was over 60% complete and construction was well underway. The full feedstock requirement will be supplied by Alberta Gas Ethylene's second plant.

Novacor is continuing to explore the possibilities and timing of other projects within Alberta, including a linear higher olefins plant.

THE ALBERTA GAS ETHYLENE COMPANY LTD.

In 1982, the first Alberta Gas Ethylene plant operated at about 57% of its design capacity. This was because Dow Chemical Canada Inc., the company contracted to purchase the plant's production, experienced constraints on its ability to consume ethylene due to the continuing economic recession and the rigid feedstock pricing schedule imposed by the National Energy Program. This pricing schedule caused feedstock costs to increase in Alberta while they were decreasing elsewhere, particularly on the U.S. Gulf Coast. There has been some recent recovery of ethylene pricing in the United States that, we hope, will continue in 1983.

A concerted cost reduction and feedstock efficiency program at Joffre has significantly reduced our ethylene production costs. Alberta Gas Ethylene's income has been protected by a cost of service, take or pay contract; nevertheless, the situation cannot be described as satisfactory.

Construction of the second Alberta Gas Ethylene plant, scheduled to come onstream in mid-1984, is proceeding on schedule at costs lower than formerly budgeted. Originally projected at $650 million, the cost is now expected to be about

Production Capacities of Novacor Ventures				
		ANNUAL PLANT CAPACITY		
PRODUCT	LOCATION	(metric)	(imperial)	IN OPERATION
Ethylene	Joffre, Alberta			
Plant 1		544 kt	1.2 billion lbs.	1979
Plant 2		680 kt	1.5 billion lbs.	1984
Polyethylene	Joffre, Alberta	270 kt	600 million lbs.	1984
Polyvinyl Chloride	Fort Saskatchewan, Alberta	100 kt	220 million lbs.	1979
Methanol	Medicine Hat, Alberta (3 plants)	720 kt	240 million U.S. gal.	1974-81
	New Zealand	400 kt	133 million U.S. gal.	1984
Malic/ Fumaric Acid	Duluth, Minnesota	7.2 kt	15.8 million lbs.	1977

$576 million, inclusive of interest during construction and pre-startup expenses. Maximum Alberta and Canadian content is being used in the engineering, procurement and construction of this facility.

Production from the second plant has been committed to NOVA, Shell Canada Limited, Union Carbide Canada Ltd. and Dow Chemical Canada Inc. NOVA will repurchase a certain amount of the ethylene from Shell and Dow for use as feedstock to keep the polyethylene plant operating at full capacity.

Negotiations for the required ethane feedstock supply are at an advanced stage, having been completed with respect to extraction facilities located at Cochrane and Jumping Pound, Alberta. No difficulty is anticipated in securing adequate supplies. NOVA and two joint venture partners have an additional extraction plant under construction at Empress.

Engineering for the third ethylene plant has been suspended until an assured market for production is determined. A concerted effort will be made in 1983 to accomplish this so that work can proceed. We expect there will be a renewed interest in building additional Alberta-based petrochemical facilities when it is apparent that markets are available and that feedstock gas supply will be as competitively priced in the future as it has been in the past.

ALBERTA GAS CHEMICALS LTD.

All three methanol plants of Alberta Gas Chemicals Ltd. at Medicine Hat operated at near capacity rates throughout 1982. Profitability was heavily affected by the recession and the continuing increase in feedstock costs through the imposition of the new federal tax on natural gas liquids. Little improvement is seen for 1983, with increased competition from two recently completed plants in western Canada.

Construction continued in New Zealand on the Petralgas methanol plant, a 49% owned joint venture with the Petroleum Corporation of New Zealand, a Crown corporation. Completion is expected in the second half of 1983. Financing arrangements for this plant have been completed.

In May 1982, an explosion and fire destroyed the malic and fumaric acid plant in Duluth, Minnesota. The plant has been rebuilt and the insurance recovery is being processed. Meanwhile, operation resumed in December. During the plant shutdown, some customers were supplied with purchased material.

Throughout the year, AGCL continued its program of securing feedstock supplies by purchasing gas reserves and participating in gas exploration and supply agreements.

DIAMOND SHAMROCK ALBERTA GAS

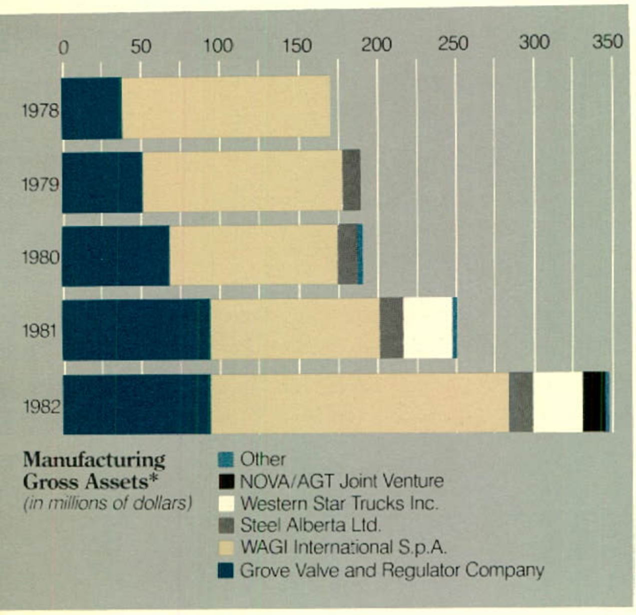
DSAG, a joint venture of NOVA and Diamond Shamrock Corporation for the manufacture and sale of polyvinyl chloride (PVC), continued to experience technical difficulties in 1982, but its performance was significantly better than in 1981. Markets were, however, adversely affected by the economic recession.

Better coordination into NOVA's overall petrochemical activities and improved operating performance are anticipated following Novacor Chemicals' assumption of operating responsibility. A capital program has been established which will lead to improved output in 1983.

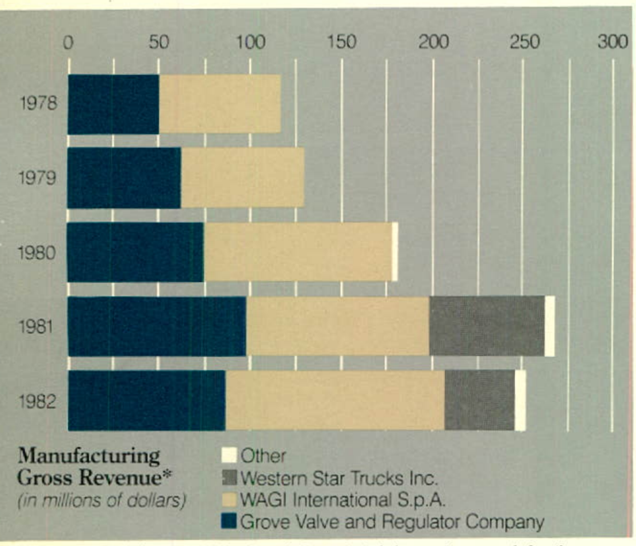
A.G. PIPE LINES

The A.G. Pipe Lines companies are the holding companies for our interest in the Alberta Ethane Gathering System (33⅓%), the Cochin Pipe Line (20%) and, as of September 30, in the Fort Saskatchewan Ethylene Storage Corporation (50%). This latter joint venture with Dow Chemical Canada will provide ethylene storage for AGEC's customers. The cost of the acquisition was $28 million. During 1982, both the gathering system and the Cochin system operated at satisfactory rates. The decline in interest rates during the latter half of the year improved overall profitability.

Manufacturing

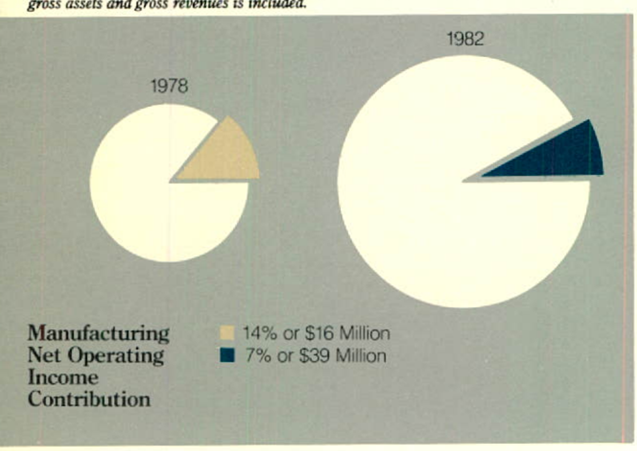


Manufacturing Gross Assets*
(in millions of dollars)

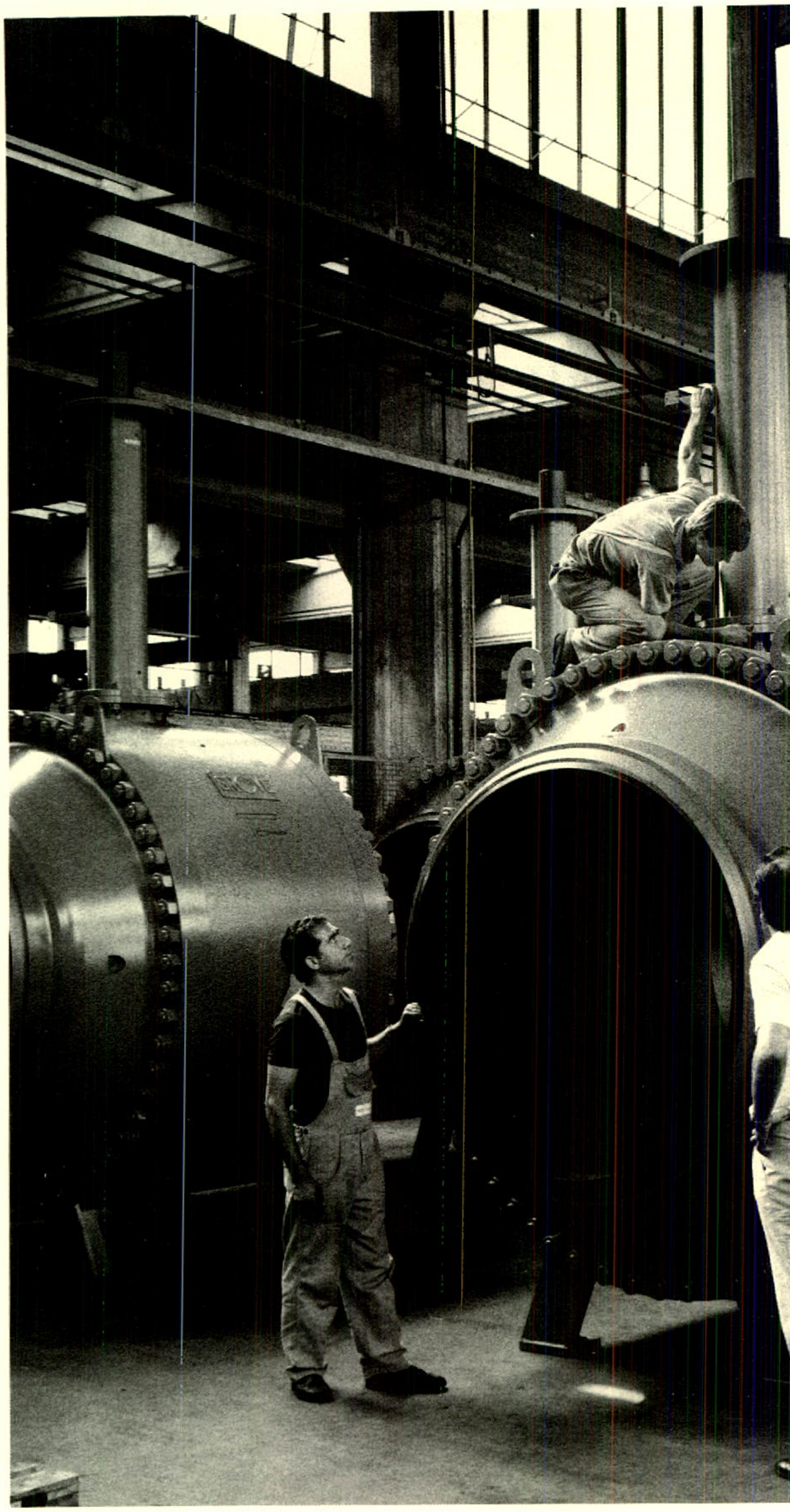


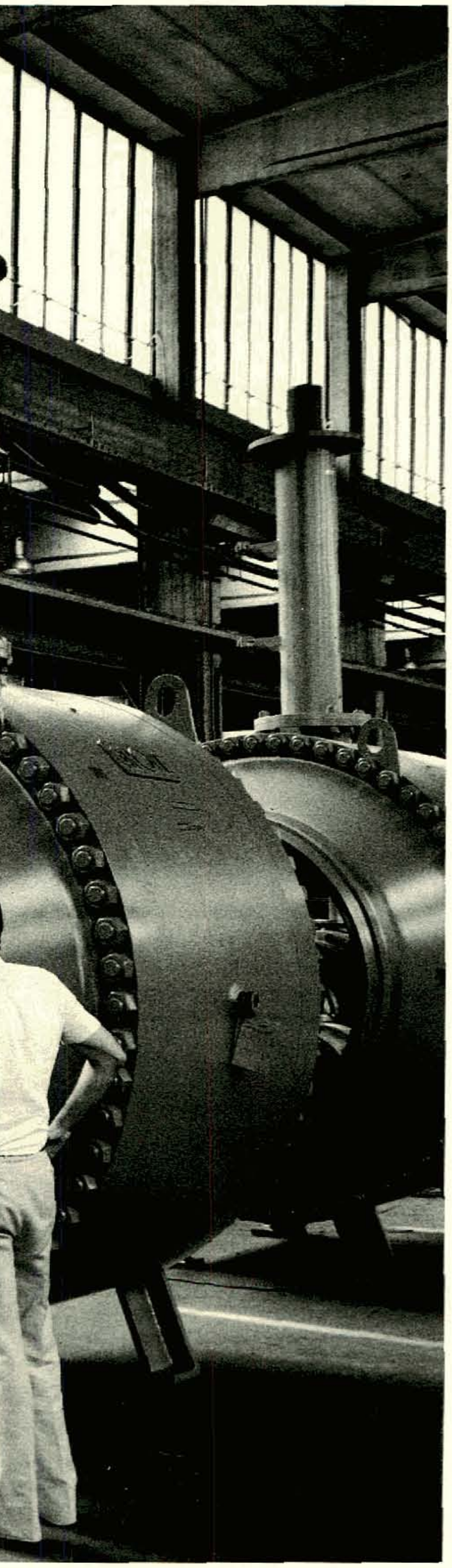
Manufacturing Gross Revenue*
(in millions of dollars)

**These graphs depict assets, before depreciation and depletion, and revenue, before the elimination of intersegment revenue, of NOVA, its subsidiaries and affiliates. For the Company and its subsidiaries (where the Company has a controlling interest) 100% of gross assets and gross revenues are included. For affiliates only the Company's ownership share of gross assets and gross revenues is included.*



Manufacturing Net Operating Income Contribution





Companies reporting in this sector are Energy Equipment & Systems Inc. (100% owned) and its wholly owned subsidiaries, Grove Valve and Regulator Company and WAGI International S.p.A., along with Western Star Trucks Inc. (50% owned) and Steel Alberta Ltd. (50% owned). Also included is our joint venture (50% owned) with Alberta Government Telephones.

Manufacturing has historically produced the best return on investment of any of NOVA's business sectors. During 1982, we entered the field of high technology as part of a joint venture that will initially produce and market a mobile radio telephone system.

NOVA/AGT JOINT VENTURE

Through the new joint venture initiated during 1982 with Alberta Government Telephones, NOVA intends to explore business opportunities in high technology, with an emphasis on telecommunications. The venture's initial undertaking is to develop, manufacture and market internationally a cellular mobile radio telephone system.

The use of mobile radio telephones is expected to expand dramatically over the next two decades. To date, the market has been constrained by technical limitations, but computer technology is now providing practical solutions and permitting features and conveniences not previously possible.

Momentum for this new technology is based on the cellular concept, with a metropolitan area served by a number of cells placed at distributed locations and individually served by low power stations. Each cell provides for more radio telephone channels than were available under the old mobile phone technology. As the mobile phone user moves between cells, a computer automatically switches the call from one cell to another, without interrupting the conversation in progress. This means that a given area can accommodate far heavier calling volumes than possible under the present system. The architecture of the cellular system developed by the joint venture provides significantly lower operating costs than competitive systems.

High quality ball valves manufactured in WAGI's Voghera, Italy, plant are used in energy projects around the world.

NOVA believes that it is important for an aggressive corporation to participate in the growth opportunities which high technology ventures will offer during the next decade. In selecting telecommunications as a product area in partnership with a major telephone company, NOVA believes it is well positioned to enter the high technology market.

ENERGY EQUIPMENT & SYSTEMS INC.

Through Energy Equipment & Systems Inc. (EESI) and other manufacturing subsidiary companies in the United States and Europe, NOVA is engaged in producing and marketing high quality valves, flow control equipment and systems for the energy industry worldwide.

This group achieved excellent results for 1982 in spite of the recessionary business conditions. Satisfactory business performance is expected in 1983 as well.

Final approval is expected shortly for a change of name from EESI to NOVA Energy Systems Inc.

United States Operations

In the United States, EESI, through its subsidiaries — Grove Valve and Regulator Company, Ledeen Flow Control Systems, Inc., and Pipeline Hydraulics Engineering Inc. — supplies valves, regulators, actuators, flow measurement systems, metering devices and engineering services. These products and services are provided primarily to the oil, gas and water pipeline industries and used in certain petrochemical and specialty defence applications.

The U.S. group operated at an acceptable profit level in 1982,

Public Contributions and Employee Programs

(Manufacturing continued)
although in mid-year it experienced the drastic reduction in business that is affecting all energy-related activities in the United States.

European Operations

European manufacturing operations are based in Italy and managed by WAGI International S.p.A. Five wholly owned subsidiaries — Grove Italia, Grove Valve Systems, Ledeen Italia, WAGI Italia and WAGI Fonderia — operate plants, producing valves and actuators for the pipeline and process industries.

In 1982, the WAGI group was highly profitable and expects a good year in 1983, even though its bookings are below its record 1982 levels.

WESTERN STAR TRUCKS INC.

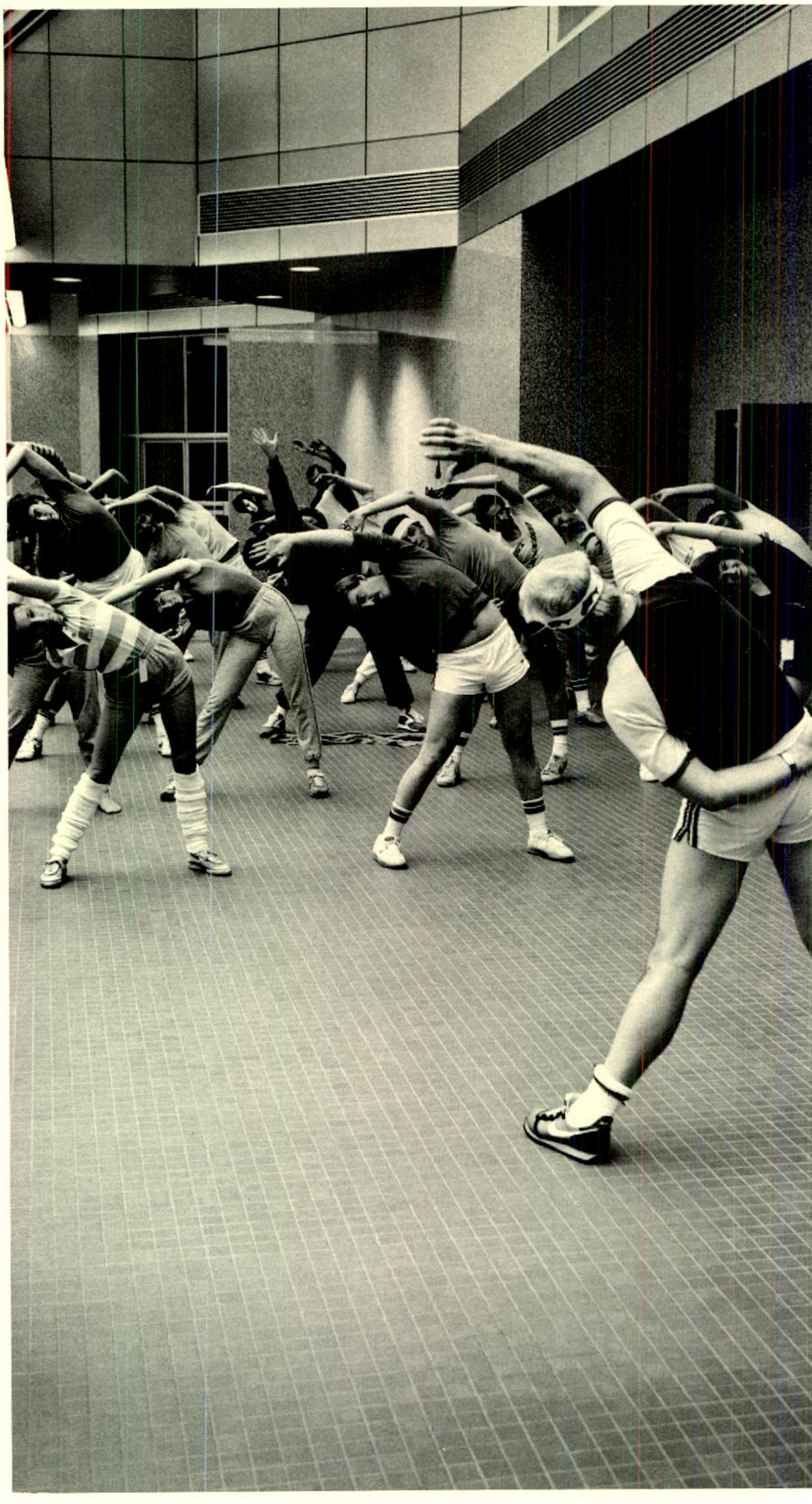
Western Star assembles large highway and off-highway trucks in Kelowna, British Columbia, and markets them throughout North America and in certain offshore areas. Production during 1982 was low reflecting high inventory and severely depressed sales for all North American heavy truck manufacturers.

A new U.S. subsidiary, Western Star Inc., has been headquartered in the state of Washington and is launching direct marketing activities in 1983. The company has also completed a licensing arrangement for the assembly in Australia of truck kits manufactured in Kelowna.

The company is in good position, through inventory reductions, for an economic recovery in 1983 and, based on present estimates for that recovery, is anticipating sales growth of 30-35%.

STEEL ALBERTA LTD.

Steel Alberta continues to own 20.2% of the shares of Interprovincial Steel and Pipe Corporation Ltd. (IPSCO) of Regina. IPSCO's net income for the fiscal year ended August 31, 1982, was slightly higher than for the previous year but sales and income during the last part of 1982 fell considerably because of low demand for steel products.



Corporate Contributions

In 1982, NOVA continued to support non-profit, voluntary organizations working at local, provincial and national levels. Over $870,000 was allotted to 237 organizations.

A large portion of the contributions budget is set aside for health and welfare, an area that is experiencing increased demand. Major corporate support was given to United Way campaigns in Alberta, supplemented by an in-house employee campaign. Our employees contributed or raised almost $34,000 through pledges, a bake sale, a fitness challenge, a dance and a luncheon.

In arts and culture, NOVA completed a total pledge of $150,000 to the Calgary Centre for Performing Arts, as well as contributing to provincial and national orchestral, dance and vocal groups. We also sponsored the Royal Winnipeg Ballet's western Canadian tour.

Contributions to education included major support to Canadian university campaigns, including completion of a pledge to Nova Scotia Technical University. Montreal's McGill Centre for the Study of Regulated Industries and the Institute for Intergovernmental Relations at Queen's University in Kingston, Ontario, were given grants. The University of Alberta at Edmonton received sponsorship from our Alberta Gas Transmission Division (AGTD) for a four-year professorship to benefit post-graduates in engineering welding, and we are also a major sponsor of a faculty chair in occupational health.

Educational groups such as the Youth Science Fairs, Junior Achievement and the Alberta Debate and Speech Association continued to receive support.

After-work exercise classes are offered through NOVACTION, a health enhancement program that is proving popular with employees.

Civic endeavors receiving funds included Ottawa's Terry Fox Canadian Youth Centre, where 3,200 students will spend a week of their school year in a cross-Canada exchange. This centre was established by the Council for Canadian Unity.

Through the AGTD, we provided support to many projects in communities throughout Alberta where we have facilities. Included were the 25th anniversary celebrations at Cavendish/Oyen, rescue units for the Fort Macleod and Vegreville fire departments, printing of a community history book by the Rumsey-Rowley Historical Society, and community centre campaigns in Worsley, Leslieville, Thorhild and Caroline.

In recreation, we continued as the corporate sponsor of the international Skate Canada championships. Canadian athletes competing in the 1982 Commonwealth Games in Brisbane, Australia, were assisted through a grant to the Canadian Commonwealth Games Association.

Occupational Health and Safety

In its first year of operation, the occupational health and safety department has been designing and implementing programs to protect the health and safety of our employees while at work. Leadership, support and service are provided in three major areas: occupational medicine; safety engineering; and toxicology, occupational and environmental health.

The occupational medicine group develops medical policy, procedures and standards, and provides medical examinations, treatment of injuries and illnesses, health counselling and education. The group also gives life saving training and first aid programs.

NOVACTION, the medical group's first program in Company health promotion, is proving that many NOVA employees are concerned about maintaining good health. Employee advisory committees provide ongoing support and advice for the programs and activities.

The safety group's main objective is to prevent injury in the workplace. It is providing support and services in safety training, use of personal protective equipment, accident investigation and workplace design. The Group Oriented Safety Award Program introduced in 1983 takes into account the risk involved in each given job and sets standards that allow groups experiencing similar degrees of risk to compete against each other for the award.

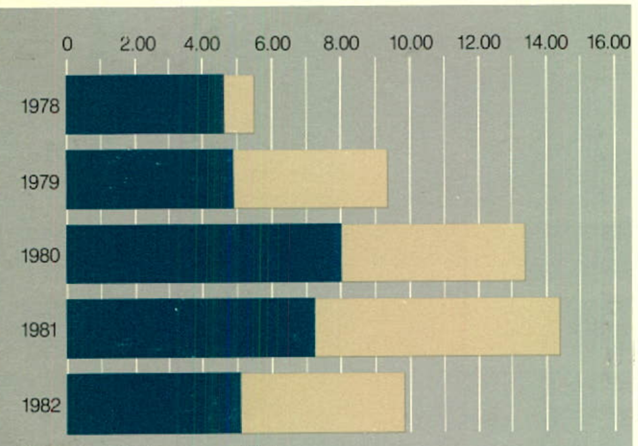
The toxicology, occupational and environmental health section was established to prevent occupational diseases. This group is developing measures to recognize, evaluate and control exposure of employees and the general public to hazardous agents.

Human Resources

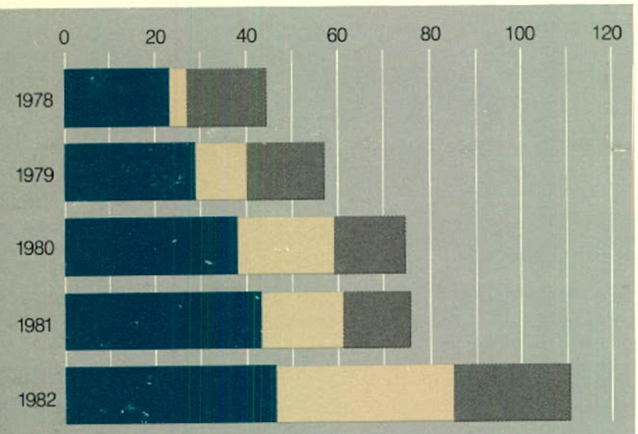
The major emphasis in the human resources department during 1982 was enhancing, consolidating, reviewing and upgrading existing programs. The training facilities in our new head office building have allowed us to increase the number of in-house programs, most of which are conducted by staff. A Technical Training Centre in Calgary offers simulated field conditions for the training of technical staff and helps us meet present and long-term technical manpower requirements.

The need for sound and effective employer/employee relations in the Company is regularly considered by our Employee Relations Council. The council provides an effective forum for management and employees to discuss issues affecting the whole organization, and Company support of this group continues to be a priority.

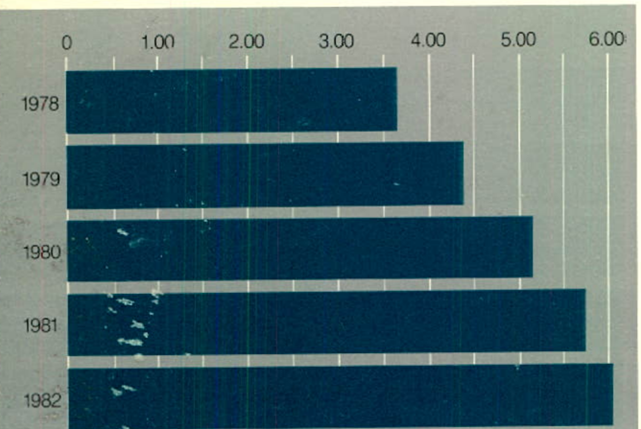
Shareholder Information



High-Low Price
(in dollars)
High
Low



Total Dividends
(in millions of dollars)
Other Preferred Shares
Convertible Preferred Shares
Common Shares



Shareholders' Equity Per Common "A" Share At Year End
(dollars)

Annual Meeting
The Annual Meeting of the shareholders of the Company will be held at the NOVA head office building, 801 Seventh Avenue S.W., Calgary, Alberta, on Friday, May 6, 1983, at 3:00 p.m.

Stock Exchange Listings
CLASS "A" COMMON SHARES
Alberta Stock Exchange
The Montreal Exchange
The Toronto Stock Exchange
PREFERRED SHARES
Alberta Stock Exchange
The Montreal Exchange for 7.60%, 6⅜%, 6½%, 15%, 12%, and 11.24% Preferred Shares only.
The Toronto Stock Exchange

Transfer Agents and Registrars
CLASS "A" COMMON SHARES
National Trust Company, Limited in Vancouver, Calgary, Edmonton, Winnipeg, Toronto and Montreal.
Canada Permanent Trust Company as agent for National Trust Company, Limited in Regina.
CLASS "B" COMMON SHARES
National Trust Company, Limited in Calgary.
PREFERRED SHARES
The Canada Trust Company in Vancouver, Calgary, Edmonton, Regina, Winnipeg, Toronto and Montreal for all share issues. The Canada Trust Company in Halifax for the 7.60%, 6⅜%, 6½%, 15%, 12% and 11.24% Preferred Shares only.

Solicitors
Howard, Mackie; Calgary, Alberta

Auditors
Clarkson Gordon; Calgary, Alberta

Rapports annuels en français
Les personnes désirant des exemplaires en français du présent rapport sont priées de s'adresser au secrétaire de la Compagnie.

Duplicate Annual Reports
Some holders of NOVA securities receive more than one copy of our annual report and other material. We make an effort to eliminate duplications; however, if securities of the same class or series are registered in different names and addresses, multiple copies will be received. In those instances, security holders should contact either the appropriate registrar or the Company to consolidate their holdings under one name.

Dividend Reinvestment and Share Purchase Plan
During the first quarter of 1982, the Company implemented a Dividend Reinvestment and Share Purchase Plan. The Plan provides shareholders with an opportunity to reinvest their cash dividends automatically in Class "A" common shares and to acquire additional Class "A" common shares without brokerage cost. To obtain further information about the Plan, contact: National Trust Company, Limited, Transfer Department, 1040 Seventh Avenue S.W., Calgary, Alberta T2P 1A7; (403) 263-9781.

The Dividend Reinvestment and Share Purchase Plan is not available to residents of the United States of America or any of the territories or possessions thereof.

Units of Measure

UNITS	IMPERIAL	METRIC (SI)	CONVERSION FACTORS
Volume	million cubic feet (mmcf)	cubic metres (m^3)	1 cu. ft. = 0.028 m^3 of gas*
	billion cubic feet (bcf)	thousand cubic metres (10^3m^3)	
	trillion cubic feet (tcf)	million cubic metres (10^6m^3)	
	barrels (bbls.)	billion cubic metres (10^9m^3)	1 bbl. = 0.159 m^3 of liquid
Weight	tons pounds (lbs.)	tonnes (t) kilotonnes (kt)	1 ton = 0.907 t
Distance	miles (mi.)	kilometres (km)	1 mile = 1.609 km
Length	inches (in.)	millimetres (mm)	1 in. = 25.4 mm
Area	acres	hectares (ha)	1 acre = 0.405 ha
Power	horsepower (hp.)	kilowatts (kW) megawatts (MW)	1 hp. = 0.746 kW

**One cubic metre of gas is approximately the volume an average-sized furnace at full capacity will burn in 20 minutes.*

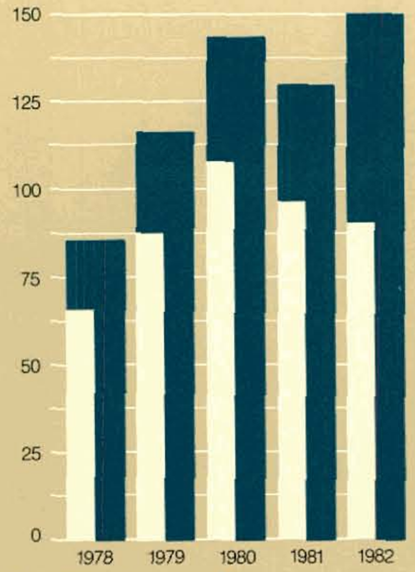
Financial Report

Contents

NOVA AN ALBERTA CORPORATION

Financial Review

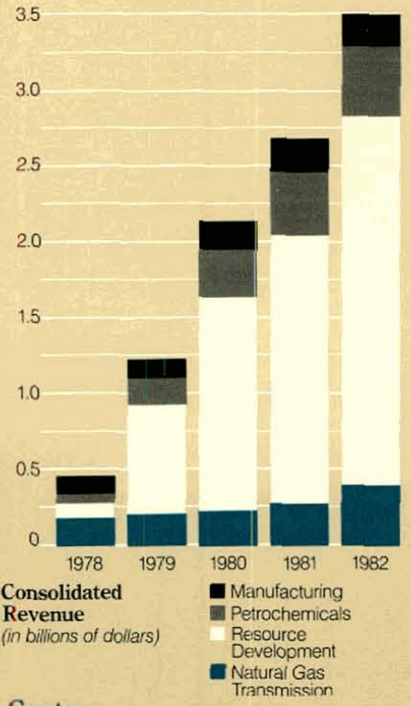
In 1982 the Company recorded annual consolidated net income of \$149.8 million. This figure represents a 15% increase over 1981 net income of \$129.9 million and exceeds the previous high of \$143.7 million reported for 1980. A decline in basic earnings per share occurred due to an increase in the average number of common shares outstanding and an increase in preferred share dividends. The increased preferred share dividends resulted from 1982 preferred share equity financings which were used to reduce variable rate debt and strengthen the financial position of the Company.



Consolidated Net Income And Net Income Available to Common Shareholders
(in millions of dollars)

Revenue

Total operating revenue was \$3.502 billion compared with \$2.670 billion in 1981, an increase of 31%. All segments achieved revenue growth with Resource Development up \$666 million and Natural Gas Transmission up \$122 million. Natural gas sales by Pan-Alberta marketed through Phase I of the Alaska Highway Gas Pipeline were the main reason for the revenue growth in Resource Development. Other highlights for 1982 included the commencement of natural gas transportation service through the eastern leg of the Alaska Highway Gas Pipeline — Phase I and through the Trans Québec & Maritimes Pipeline.



Consolidated Revenue
(in billions of dollars)

Costs

Total costs and expenses were \$2.961 billion compared with \$2.275 billion in 1981, an increase of 30%. The increase in operating expenses of \$643 million or 31% was mainly attributable to Resource Development (\$563 million) and Natural Gas Transmission (\$46 million).

An increase of \$63.4 million or 34% in depletion and depreciation reflects the significant increase in production over the past years and increase in natural gas transportation assets.

Loss on foreign currency translation of \$6.3 million compares to a loss of \$17.3 million in 1981. The 1982 loss results principally from the translation effect of U.S. dollar debt retirements and the weaker Italian lire at year end. After allowing for income taxes, minority interest and amounts billed under cost of service contracts, this item had an adverse effect of 4¢ per share on net income (7¢ in 1981).

Net Operating Income

Net operating income of \$541 million represents an increase of 37% over \$395 million in 1981. All segments showed improvement. The increase of \$121 million for Natural Gas Transmission was due to higher operating returns from the Alberta Gas Transmission Division and new gas delivery activities of the Alaska Highway Gas Pipeline — Phase I and the Trans Québec & Maritimes Pipeline. The higher operating returns result principally from the growth in assets for these cost of service operations.

Other Income Items

Equity in earnings of affiliated companies in the Petrochemicals and Manufacturing segments declined by \$9 million in 1982. Within Petrochemicals, the decline in equity earnings from Alberta Gas Chemicals was mainly due to reduced margins resulting from the continuing slump in the world methanol markets and higher costs of natural gas feedstock. Within the Manufacturing segment both Western Star Trucks and Steel Alberta (through its 20.2% investment in Interprovincial Steel and Pipe Corporation Ltd.) performed at levels below 1981.

For 1982 the allowance for funds capitalized during development and construction was up \$11.5 million over 1981 due primarily to construction work on the second ethylene plant. For its investment in the Alaska Highway Gas Pipeline Project — Phase II expenditures the Company, effective September 1, 1982, commenced capitalizing only an allowance for funds which approximates the Company's after tax carrying cost.

Interest

Net interest expense for 1982 was \$347.2 million compared to \$247.9 million for 1981, up \$99.3 million. This variance is due principally to the cost of increased borrowings to finance the significant capital expenditures. The average 1982 consolidated interest rate was approximately 14⅛% versus 14½% for 1981.

The Company is provided a degree of insulation from interest rate fluctuations due to the cost of service activities of Natural Gas Transmission and certain Petrochemicals operations. In the case of major construction activities for this group the interest costs are capitalized, while during the operating phase interest costs are reflected in the rates of return allowed on rate base.

Taxes

The petroleum gas and incremental oil revenue taxes increased by $22.6 million in 1982. This was due to an increase in the petroleum and gas revenue tax rate from 8% during 1981 to effective rates of 12% for the period January 1 to May 31, 1982 and 11% thereafter. In addition, the incremental oil revenue tax was levied between January 1 and May 31, 1982.

The 1982 provision for income taxes represents an increase of $14.2 million or 30% from 1981. This increase is due to the higher income taxes billed or provided under cost of service contracts, up $47.5 million, offset by a reduction of $33.3 million in income taxes on the consolidated income subject to normalized taxes, where Resource Development activities and earnings from foreign subsidiaries attract lower effective tax rates.

Minority Interest

Minority interest share of income of $35.4 million is down $7.5 million from $42.9 million in 1981. This decline was principally due to the lower Husky net income and the redemption of 10% of the principal amount of A.G. Investments' preferred shares.

Net Income

As outlined in the introduction, 1982 consolidated net income of $149.8 million represents an improvement of $19.9 million or 15% compared to net income of $129.9 million for 1981.

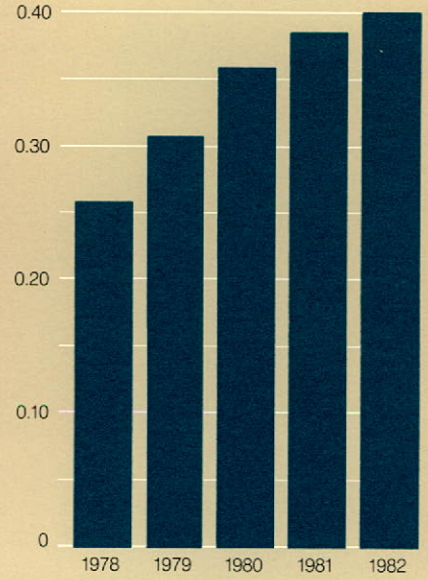
	1982	1981	**Variance**
Earnings per common share			
Basic	**$0.80**	$0.90	(11.1%)
Fully diluted	**$0.74**	$0.80	(7.5%)
Average common shares outstanding during the year (millions)	**114.3**	107.6	6.7

The above table displays earnings per common share, after providing for the dividend entitlement on preferred shares, and the average common shares outstanding for 1982 and 1981.

The decline in basic earnings per common share reflects the increase of 6.7 million in the average number of common shares outstanding and the increase of $25.7 million in the preferred share dividend entitlement resulting from preferred equity financing in 1982.

Assets

Total assets increased from $5.0 billion at December 31, 1981 to $6.3 billion at December 31, 1982, an increase of $1.3 billion. This 26% increase reflects asset growth in each of Natural Gas Transmission, Resource Development, Petrochemicals and Manufacturing.



Dividends Paid Per Class "A" Common Share
(in dollars)

Dividends

Dividends paid or payable for 1982 totalled $110.7 million compared to $75.7 million for 1981. Common share dividends were $46 million ($42.9 million in 1981); convertible preferred share dividends were $39.1 million ($17.9 million in 1981); and preferred share dividends were $25.6 million ($14.9 million in 1981). The 1982 Class "A" common shareholder received total dividends equal to 40¢ per common share compared to 38.666¢ in 1981. The quarterly dividend on common shares was increased from 9.33¢ to 10¢ with the August 1981 dividend.

New Funds

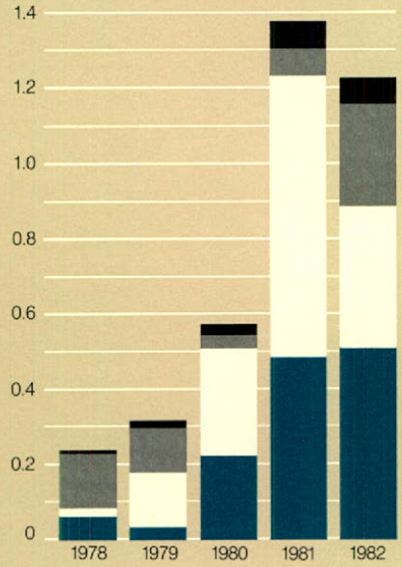
Total sources of funds for 1982 amounted to $2.047 billion compared to $1.620 billion in 1981. Operations provided $427 million, representing an increase of $76.4 million from $350.6 million in 1981. Long term debt of $1.088 billion compares to $1.256 billion obtained in 1981. In 1982 new preferred share equity issued by the Company amounted to $417.5 million and $91.3 million for Husky. A Dividend Reinvestment and Share Purchase Plan was introduced in 1982 to provide shareholders with the opportunity to reinvest their cash dividends in Class "A" common shares and to acquire additional Class "A" common shares without brokerage cost. In 1982 $4 million was invested by shareholders participating in the Plan.

Funds generated in 1982 were mainly utilized for capital expenditures and deferred costs ($1.276 billion), retirement of long term debt ($551.9 million) and payment of dividends to the shareholders of the Company ($110.7 million) and minority shareholders of subsidiaries

($34 million). Working capital increased by $7.2 million in 1982.

Capital Expenditures

Expenditures for capital assets and deferred projects amounted to $1.276 billion in 1982 compared to $1.428 billion in 1981. The 1982 capital expenditures were incurred principally for petroleum properties and refining and marketing facilities ($374.8 million), the expansion of the Alberta based petrochemical complex ($268.8 million), Alberta Gas Transmission Division facilities expansion ($223.7 million), and the Company's proportionate share of the Alaska Highway Gas Pipeline facilities ($165.2 million) and the TQM Pipeline ($119.5 million).



Expenditures On Plant, Property And Equipment
(in billions of dollars)

Financing

During 1982 the Company was successful in raising funds in the Canadian, American and European capital markets. The Company arranged fixed rate debt financing through the issue of U.S. $100 million (Cdn. $119 million) and Cdn. $125 million principal amount of unsecured debentures and from U.S. $110 million (Cdn. $138 million) arranged on a private placement basis. Equity financings were obtained in Canadian capital markets through the issue and sale of Cdn. $255 million principal amount of 12% Cumulative Redeemable Convertible Second Preferred Shares, Cdn. $62.5 million principal amount of 15% Cumulative Redeemable First Preferred Shares and Cdn. $100 million principal amount of 11.24% Cumulative Redeemable First Preferred Shares.

The Company anticipates additional financing of up to $400 million may be raised for the 1983 capital expenditure program.

Share Capital and Ownership

Class "A" common shares outstanding at December 31, 1982 totalled 116.2 million compared to 111 million a year previous. The increase in the number of Class "A" common shares occurred primarily as a result of conversions of 6⅜% Cumulative Redeemable Convertible Second Preferred Shares. The Class "A" shares are owned by 42,778 shareholders of whom 16,806 or 39% are registered in Alberta. In addition, the Company has received its Canadian Ownership Rating and Control Status certificate indicating a rating of 90% including a 5% bonus.

1983 Outlook

The 1983 consolidated capital program, amounting to about $1.2 billion, reflects continued growth in both production and Natural Gas Transmission assets. These programs principally cover continuing exploration and development activities of the Resource Development segment, petrochemical construction activities on the second ethylene and the linear low density polyethylene plants and capital programs for the Alberta Gas Transmission Division.

New Accounting Standards

The Canadian Institute of Chartered Accountants (CICA) issued its standard on "Reporting the Effects of Changing Prices" in December 1982. This standard recommends that, effective with 1983 annual reporting periods, large Canadian public companies should supplement their historical cost financial statements with financial information based on measurements of the current cost of inventory and plant, property and equipment and disclosure of the effects of changes in the general price level. The Company has reviewed the standard and is now in the process of determining how the recommendations may be applied to NOVA's many diverse activities, in particular the application to the Company's cost of service and Resource Development activities.

In June 1982 the CICA issued an exposure draft on "Foreign Currency Translation". It now appears that due to the many concerns expressed by industry, as well as public practitioners, the proposed standard will not be finalized until mid 1983. Until final recommendations have been issued, the Company does not feel it appropriate to change its existing accounting policy in this regard.

Supplementary Segment Information

Financial information relating to specific segments is included both in the narrative section of this Annual Report and in the Consolidated Financial Statements and Notes thereto. A summary of operations by segment is set out below:

(a) Natural Gas Transmission

The Natural Gas Transmission segment consists principally of the Company's interest (either directly or through subsidiaries) in the following:

(i) The facilities of the Alberta Gas Transmission Division are used for the transmission of gas owned by TransCanada PipeLines Limited, Alberta and Southern Gas Co. Ltd., Westcoast Transmission Company Limited, Westcoast Transmission Company (Alberta) Ltd., Consolidated Natural Gas Limited, Pan-Alberta Gas Ltd., Progas Limited and Many Islands Pipe Lines (Canada) Limited.

The natural gas transmission services are provided primarily under transportation contracts which provide for recovery of the cost of service. Cost of service includes reasonable and necessary operating expenses, depreciation, amortization, income and other taxes and a rate of return on net rate base. At December 31, 1982 the rate of return on rate base of 14.15% includes a return of 16.25% on a deemed common equity component of 32%. The Company continually monitors its rate of return to ensure that an appropriate equity return is earned under changing economic conditions and that coverage for the variable and fixed rate debt financing cost of the rate base is appropriate;

(ii) The Alaska Highway Gas Pipeline consists of the Company's proportionate interests in Foothills Pipe Lines (Yukon) Ltd. and its subsidiaries who together with others are the sponsors of the Alaska Highway Gas Pipeline Project which has as its ultimate objective the transportation of natural gas from Alaska through Canada to the United States.

Construction of the Canadian section has been divided into two separate phases. Phase I involves the construction of facilities in Canada south of Caroline, Alberta to provide transmission service for Canadian gas destined for sale in the United States. Phase II involves construction of the remaining Canadian facilities required for the transportation of Alaska gas to markets in the United States.

Initial transportation service on a cost of service basis commenced on the western leg with delivery of gas to California markets on October 1, 1981 and commenced on the eastern leg with delivery of gas to midwestern United States markets on September 1, 1982. An approved incentive rate of return is expected to result in an after tax return to Foothills Pipe Lines (Yukon) common equity of approximately 18% on Phase I;

(iii) The Company is an equal partner with TransCanada PipeLines Limited in a partnership to construct and operate a major gas transmission system to transport natural gas in the provinces of Quebec, New Brunswick and Nova Scotia.

Construction of the Quebec portion of the pipeline system commenced in the spring of 1981. The first sections of the pipeline to Trois Rivières, Quebec were placed into service in 1982. Further sections will be placed into service when completed, with final completion of facilities to Quebec City, Quebec expected in the fall of 1983. The National Energy Board has issued an interim order allowing a 15¾% return on a deemed 25% common equity component with final determination awaiting a decision from the formal hearings which commenced in late 1982.

Construction of the Maritimes portion of the pipeline system has been deferred pending resolution of proposed Federal funding for front-end design work.

(b) Petrochemicals

The table on the following page summarizes the petrochemical investments (either directly or through subsidiaries) which are consolidated in the financial statements. Cost estimates presented are in as spent dollars including inflation factors and capitalized interest based on financing assumptions and represent initial completion costs.

(i) All production from Ethylene Plant I is sold to Dow Chemical Canada Inc. on a take or pay basis. The ethylene is paid for by Dow Canada on a cost of service basis including cost of feedstock (ethane) and fuel, operating expenses, depreciation, amortization, income taxes, return on capital and foreign exchange gains or losses in respect of debt service. The return to capital includes a 20% after tax return to equity on a deemed 75:25 debt equity ratio.

Contracts have been signed with a number of purchasers for the sale of output from Ethylene Plant II on substantially the same terms as the contract respecting the output of the first plant. The Company will be responsible, directly or indirectly, for the purchase from Alberta Gas Ethylene of approximately 38% of the output of the second ethylene plant;

(ii) The Cochin Pipe Line transports ethane, ethylene and other products from Alberta to markets in eastern Canada and the United States;

(iii) 33⅓% interest is held in a joint venture formed to own and

Facilities In Service	Capacity Per Year	Effective Ownership	Total Cost	Company's Proportionate Share	
			(millions of dollars)		
Ethylene Plant I and related pipeline — Joffre, Alberta	1.2 billion lbs. (544 kt)	100%	$361.5	$361.5	
Cochin Pipe Line		20%	340.0	68.0	
Ethane Gathering System		33⅓%	50.0	16.7	
Polyvinyl Chloride Plant —Fort Saskatchewan, Alberta	220 million lbs. (100 kt)	50%	127.0	63.5	
Ethylene Storage Facility — Fort Saskatchewan, Alberta		50%	56.8	28.4	
Facilities Under Construction					**Estimated Completion Date**
Ethylene Plant II — Joffre, Alberta	1.5 billion lbs. (680 kt)	100%	576.0	576.0	mid 1984
Linear Low Density Polyethylene Plant — Joffre, Alberta	600 million lbs. (270 kt)	100%	477.0	477.0	mid 1984
Natural Gas Liquids Extraction Plant — Empress, Alberta		25%	200.0	50.0	late 1983

operate an ethane gathering pipeline and related storage facilities to transport ethane from the extraction plants to the Joffre ethylene plants and to the western terminus of the Cochin Pipe Line at a point near Edmonton. The ethane gathering system consists of approximately 550 mi. (885 km) of pipeline together with storage facilities of approximately 500,000 bbls. (79.0 $10^3 m^3$). Alberta Gas Ethylene has agreed to pay the joint venture on a cost of service basis for such transportation and storage;

(iv) The Company, as to 20%, and others have agreed to purchase on a take or pay basis ethane in excess of the requirements for the ethylene plants but not exceeding 44,000 bbls. (6950 m^3) per day. (See Note 13(a) to the Consolidated Financial Statements);

(v) The polyvinyl chloride manufacturing plant uses vinyl chloride monomer feedstock purchased from Dow Canada. Dow Canada manufactures vinyl chloride monomer from ethylene purchased from the first Joffre ethylene plant. The polyvinyl chloride is marketed in both Canada and export markets and is used in the manufacture of such items as plastic pipe, wire coating, floor tiles, records and footwear;

(vi) 50% interest is held in a joint venture formed, with Dow Canada, to own and operate an ethylene storage facility; the Company and Dow Canada have agreed to store ethylene in the facilities until June 30, 2004 on a cost of service, take or pay basis, which provides for a 20% after tax return on a deemed 75:25 debt equity ratio;

(vii) The polyethylene plant, utilizing ethylene as feedstock, will employ UNIPOL technology under licence from Union Carbide Corporation. Under agreement for a term of eight years Union Carbide Corporation will purchase up to 400 million lbs. (180 kt) per year of polyethylene resin. Linear low density polyethylene is marketed for use in packaging film, food containers, pipe, electrical wire coating and molded forms such as toys and sporting goods;

(viii) The Company, through an affiliate, has entered into an agreement with Dome Petroleum Limited for the construction and ownership of a natural gas liquids extraction plant.

Alberta Gas Ethylene has also received approval for a third ethylene plant to be located in Joffre, Alberta and having a capacity of 1.5 billion lbs. (680 kt) per year. Construction of the third plant has been deferred until suitable sales contracts for the output of the plant can be concluded. The Company is also developing a proposal to construct a higher olefins plant using feedstock from Alberta Gas Ethylene's proposed third ethylene plant.

The Company equity accounts for its 50% interest in Alberta Gas Chemicals Ltd. which operates three methanol plants at Medicine Hat, Alberta. Natural gas provides the feedstock for the production of methanol which is currently being produced at approximately the total name plate capacity of 2,400 short tons (2,178 t) per day. Methanol is sold either on the open market or under contracts for various periods. In addition, Alberta Gas Chemicals has a 49% interest in a joint venture to construct and operate a 1,320 short tons (1,200 t) per day methanol plant in New Zealand. The estimated cost of this facility is approximately U.S. $200,000,000 with completion expected in the second half of 1983. A subsidiary of Alberta Gas Chemicals owns and operates a malic and fumaric acid plant in Duluth, Minnesota.

(c) Resource Development

This segment consists of the Company's investments (either directly or through subsidiaries) in the following interests:

(i) 67.6% ownership of Husky Oil Ltd.; a fully integrated Canadian oil and gas company engaged in the exploration for, and the production and transportation of, crude oil and natural gas, the refining of crude oil and the wholesale and retail marketing of petroleum products as well as warehousing distribution and the marketing of charcoal briquets and industrial and activated carbons. For further details regarding the nature of Husky Oil Ltd. operations, refer to the Husky 1982 Annual Report;

(ii) 100% ownership of Novalta Resources Ltd.; a company engaged in the acquisition, development and production of crude oil and natural gas reserves;

(iii) 50.005% ownership of Pan-Alberta Gas Ltd.; a company which contracts for the purchase of natural gas at field delivery points throughout Alberta and for the sale of such gas to purchasers primarily outside Alberta;

(iv) 100% ownership of CanOcean Resources Ltd.; a company that develops, manufactures and services high technology production equipment for conventional and offshore applications in the oil and gas industry, as well as doing engineering consulting in a number of specialized fields;

(v) The Company and Petro-Canada Exploration Inc. are equal partners in a joint venture company, Canstar Oil Sands Ltd., formed to examine the feasibility of developing an oil sands mining complex in northern Alberta;

(vi) 25% interest in the Arctic Pilot Project, the objective of which is the production and liquefaction in the Arctic Islands of natural gas, and the year round transportation of the liquefied natural gas to potential markets in eastern Canada and western Europe;

(vii) Varying interests in other energy related projects including study and development of new energy sources that offer viable supplements to conventionally produced crude oil and natural gas.

	Canada		United States		International	
	Oil	**Gas**	**Oil**	**Gas**	**Oil**	**Gas**
Proved						
December 31, 1981	115,745	669,954	47,573	160,843	3,136	—
December 31, 1982	99,874	629,227	47,375	158,745	3,350	—
Probable						
December 31, 1981	58,168	185,555	8,165	13,742	—	—
December 31, 1982	58,899	151,272	10,768	11,849	—	—
Combined						
December 31, 1981	173,913	855,509	55,738	174,585	3,136	—
December 31, 1982	158,773	780,499	58,143	170,594	3,350	—

The above table presents the estimated gross proved and probable oil and gas reserves of Husky and Novalta Resources at December 31, 1982 and December 31, 1981.

Crude oil, including natural gas liquids, is expressed in thousands of barrels. A barrel represents a stock tank barrel equivalent to 42 U.S. gallons or 35 imperial gallons. Natural gas is expressed in millions of cubic feet measured at 60°F and 14.65 psia.

Volumes represent the reserves owned before deduction of royalties, reversionary interest, and net profit interest owned by others.

(d) Manufacturing

Manufacturing consists of the Company's investments (either directly or through subsidiaries) in the following interests:

(i) The Company, through indirect wholly-owned subsidiaries, is engaged in the design, manufacture, distribution and licensed production of flow control systems (high quality valves and other products) on a world-wide basis for use primarily in the oil and gas industry. This investment is primarily represented by the 100% ownership of both the Grove Valve and Regulator Company and WAGI International S.p.A.;

(ii) Steel Alberta Ltd. (50% owned) holds 20.2% of the issued common shares of Interprovincial Steel Pipe Corporation Ltd., an integrated steel company which manufactures pipe, casing, structural tubing and sheet steel;

(iii) On April 1, 1981 the Company and Bow Valley Resources Services Ltd. jointly purchased substantially all the assets and business of the truck division of White Motor Corporation of Canada, now operated as Western Star Trucks Inc. This operation assembles large highway and off-highway trucks in Kelowna, British Columbia, and markets them throughout North America and in certain offshore areas;

(iv) During 1982, the Company initiated a new joint venture with Alberta Government Telephones to explore business opportunities in high technology, with an emphasis on telecommunications. The venture's initial undertaking is the development, manufacture and international marketing of a cellular mobile radio telephone system and mobile radio telephones.

Supplemental Information on Cost of Service Activities

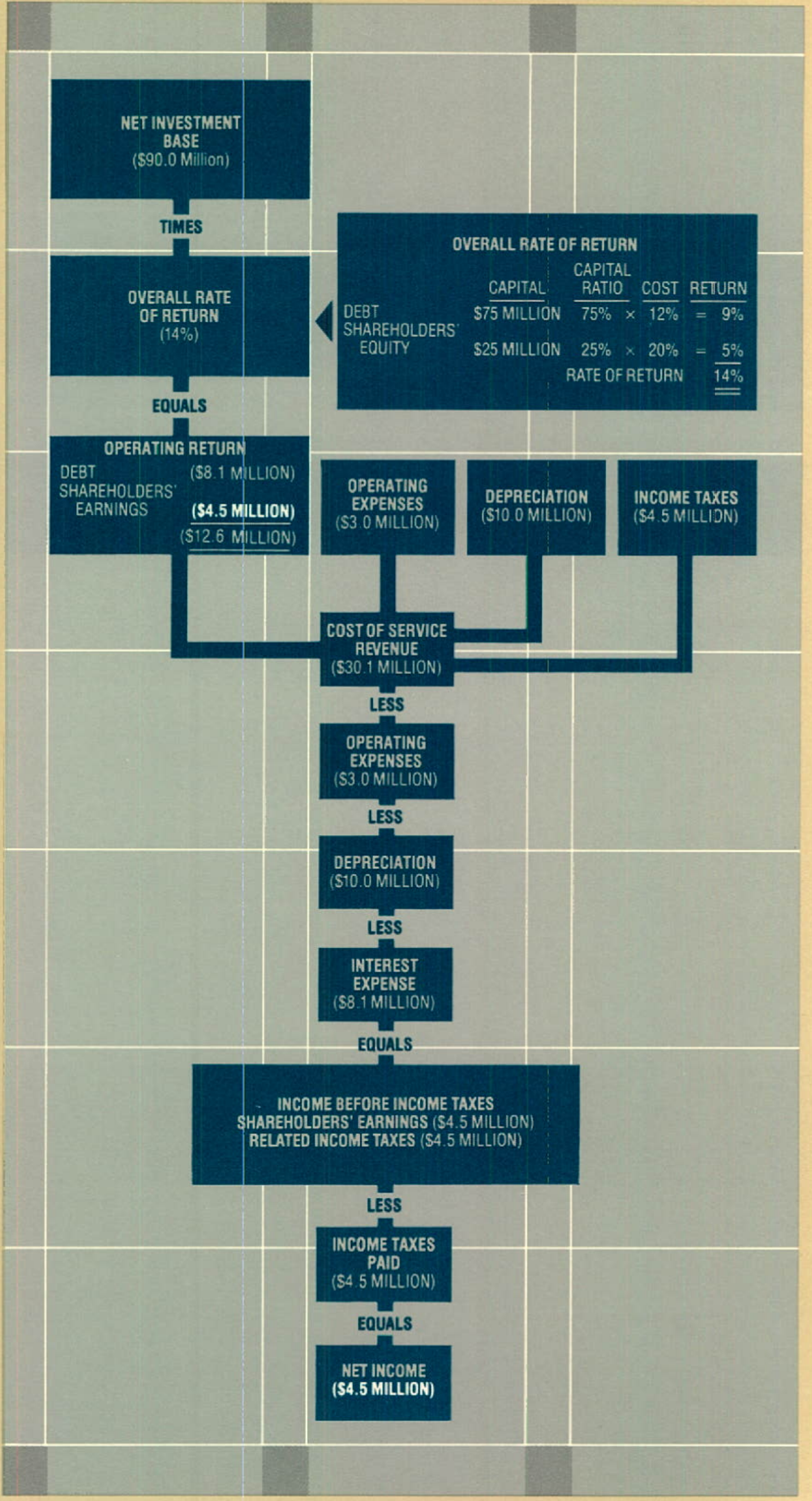
Cost of service activities through investments in Natural Gas Transmission and Petrochemicals are an important part of NOVA's diverse operations and make a significant contribution to the Company's overall financial picture.

As many readers of our Annual Report and Consolidated Financial Statements are not familiar with how these activities operate, we are providing an explanation below.

To summarize briefly, our example, based here on an after tax return to common shareholders of 20%, shows how the shareholders' equity component of the rate of return flows through to the "bottom line" of NOVA's income statement. In determining the cost of service connected with these activities, debt and shareholders' equity components are combined and the rate of return percentage determined. This percentage is then applied to the net investment base (similar to total net assets). The result — operating return — is combined with the operating expenses, depreciation and income taxes to yield cost of service revenue. The specified deductions are then made to determine net income.

How this works can be shown in a diagram. The numbers used here are hypothetical, and we are making the following assumptions:

1. Investment Base	$100 Million
2. Depreciation, based on a 10 year life	$ 10 Million
3. Net Investment Base	$ 90 Million
4. Capital Structure	
Debt	$ 75 Million
Common Shareholders	$ 25 Million
5. Cost of Debt	12%
6. Return to Common Shareholders (After tax)	20%
7. Operating Expenses	$ 3 Million
8. Income Taxes Paid	$4.5 Million



As the illustration shows, cost of service provides the necessary revenue to meet all operating expenses, to pay interest on debt, and recover, through depreciation, the original investment in assets. As well, it provides the common shareholders with an appropriate return on their investment.

Management's Statement of Financial Reporting

The December 31, 1982 consolidated financial statements of NOVA, AN ALBERTA CORPORATION presented in the Annual Report have been prepared by management on a consistent basis in accordance with accounting principles generally accepted in Canada and conform in all material respects with International Accounting Standards. The financial statements have, in management's opinion, been properly prepared within reasonable limits of materiality and within the framework of the accounting policies as outlined in the Summary of Accounting Policies which form an integral part of the financial statements.

The Company maintains systems of internal accounting controls, policies and procedures in order to provide, on a reasonable basis, assurance as to the reliability of the financial information and the safeguarding of assets.

Clarkson Gordon, the Company's external auditors, have examined the December 31, 1982 consolidated financial statements, and their report is set out below.

The audit committee of the Board of Directors has reviewed the consolidated financial statements, including the notes thereto, with management and both the internal and the external auditors. The financial statements have been approved by the Board on the recommendation of the audit committee.

Auditors' Report

To the Shareholders of
NOVA, AN ALBERTA CORPORATION

We have examined the consolidated balance sheet of NOVA, AN ALBERTA CORPORATION as at December 31, 1982 and the consolidated statements of income, reinvested earnings, contributed surplus and changes in financial position for the year then ended. Our examination was made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as we considered necessary in the circumstances.

In our opinion, these consolidated financial statements present fairly the financial position of the Company as at December 31, 1982 and the results of its operations and the changes in its financial position for the year then ended in accordance with generally accepted accounting principles applied on a basis consistent with that of the preceding year.

Clarkson Gordon

Calgary, Canada
March 8, 1983

Chartered Accountants

NOVA
AN ALBERTA
CORPORATION

Consolidated Statement of Income

(thousands of dollars except for per share data)

	Total	
Year ended December 31	**1982**	1981
Revenue		
Operating revenue	**$3,501,798**	$2,669,551
Intersegment revenue	**—**	—
	3,501,798	2,669,551
Costs and expenses		
Operating expenses	**2,702,220**	2,059,457
Intersegment expenses	**—**	—
Depreciation and depletion	**249,151**	185,795
Loss on foreign currency translation	**6,261**	17,347
Unallocated expenses	**3,108**	11,916
	2,960,740	2,274,515
Net operating income	**541,058**	395,036
Equity in earnings of affiliated companies	**5,038**	14,054
Allowance for funds used during development and construction	**85,928**	74,398
	90,966	88,452
Income before the undernoted items	**632,024**	483,488
Interest and expense on debt (net) (Note 6)	**347,207**	247,869
Income before taxes and minority interest	**284,817**	235,619
Taxes		
Petroleum gas and incremental oil revenue taxes	**38,673**	16,105
Income taxes (Note 7)		
Current	**11,269**	221
Deferred	**49,687**	46,516
	99,629	62,842
Income before minority interest	**185,188**	172,777
Minority interest	**35,436**	42,915
Net income	**149,752**	129,862
Less preferred share dividend entitlement	**58,571**	32,834
Net income available to common shareholders	**$ 91,181**	$ 97,028
Average common shares outstanding during the year (thousands)	**114,341**	107,583
Earnings per common share		
Basic	**$ 0.80**	$ 0.90
Fully diluted	**$ 0.74**	$ 0.80

See accompanying summary of accounting policies and notes

Natural Gas Transmission		Resource Development		Petrochemicals		Manufacturing	
1982	1981	**1982**	1981	**1982**	1981	**1982**	1981
$388,835	$266,624	**$2,441,512**	$1,775,462	**$459,893**	$424,046	**$211,558**	$203,419
88,216	22,577	**—**	—	**—**	—	**—**	—
477,051	289,201	**2,441,512**	1,775,462	**459,893**	424,046	**211,558**	203,419
167,869	121,568	**1,996,131**	1,433,233	**375,237**	348,523	**162,983**	156,133
—	—	**88,216**	22,577	**—**	—	**—**	—
63,598	43,380	**152,131**	110,338	**27,244**	25,310	**6,178**	6,767
—	—	**1,079**	7,202	**2,072**	2,921	**3,110**	7,224
—	—	**—**	—	**—**	—	**—**	—
231,467	164,948	**2,237,557**	1,573,350	**404,553**	376,754	**172,271**	170,124
245,584	124,253	**203,955**	202,112	**55,340**	47,292	**39,287**	33,295
—	—	**—**	—	**4,359**	10,071	**679**	3,983
69,002	71,645	**—**	—	**16,926**	2,753	**—**	—
69,002	71,645	**—**	—	**21,285**	12,824	**679**	3,983
$314,586	$195,898	**$ 203,955**	$ 202,112	**$ 76,625**	$ 60,116	**$ 39,966**	$ 37,278

NOVA
AN ALBERTA
CORPORATION

Consolidated Balance Sheet
(thousands of dollars)

Assets December 31	1982	1981
Current Assets		
Cash and short term deposits	**$ 90,798**	$ 42,581
Accounts receivable	**700,359**	489,047
Inventories (Note 2)	**406,402**	413,388
Prepaid expenses	**8,410**	9,500
	1,205,969	954,516
Investments and Advances (Note 3)	**113,205**	106,062
Plant, Property and Equipment (Note 4)	**5,658,693**	4,338,575
Less accumulated depreciation and depletion	**(799,262)**	(592,875)
	4,859,431	3,745,700
Deferred Costs (Note 5)	**143,332**	197,641
	$6,321,937	$5,003,919

On behalf of the Board:

, Director

, Director

See accompanying summary of accounting policies and notes

Liabilities and Shareholders' Equity December 31	**1982**	1981
Current Liabilities		
Bank loans (Note 6)	**$ 228,329**	$ 195,103
Accounts payable and accrued liabilities	**766,695**	545,011
Income taxes payable	**23,369**	6,866
Deferred income taxes	**37,354**	71,567
Dividends payable	**31,744**	19,057
Long term debt instalments due within one year	**72,731**	78,345
	1,160,222	915,949
Long Term Debt (Note 6)	**2,740,612**	2,206,283
Deferred Income Taxes (Note 7)	**399,336**	369,048
Minority Interest in Subsidiary Companies (Note 8)	**498,706**	438,326
Shareholders' Equity		
Capital stock (Note 9)		
Preferred shares	**826,122**	441,235
Common shares	**115,041**	85,345
Contributed surplus	**224,991**	229,874
Reinvested earnings	**356,907**	317,859
	1,523,061	1,074,313
Contingencies and Commitments (Note 13)		
	$6,321,937	$5,003,919

NOVA
AN ALBERTA
CORPORATION

Consolidated Statement of Contributed Surplus
(thousands of dollars)

Year ended December 31	1982	1981
Balance at beginning of year	**$229,874**	$223,368
Premium on issue of common shares	—	4,431
Gain on purchase of preferred shares for cancellation	2,777	2,075
Capital stock issue expenses	(7,660)	—
Balance at end of year	**$224,991**	$229,874

Consolidated Statement of Reinvested Earnings
(thousands of dollars)

Year ended December 31	1982	1981
Balance at beginning of year	**$317,859**	$263,668
Net income	149,752	129,862
	467,611	393,530
Less dividends paid or payable		
Preferred shares	64,701	32,834
Common shares	46,003	42,837
	110,704	75,671
Balance at end of year	**$356,907**	$317,859

See accompanying summary of accounting policies and notes

NOVA AN ALBERTA CORPORATION

Consolidated Statement of Changes in Financial Position

(thousands of dollars)

Year ended December 31	1982	1981
Source of funds		
Operations	$ 427,017	$ 350,627
Long term debt	1,088,244	1,255,835
Preferred shares	417,500	—
Common shares	29,696	46,706
Less common shares issued on conversion of —		
Preferred shares	(22,569)	(41,612)
Debentures	(2,022)	(213)
Preferred shares issued by subsidiary —		
Husky Oil Ltd.	91,250	—
Other	18,040	8,618
	$2,047,156	$1,619,961
Use of funds		
Plant, property and equipment —		
Alberta Gas Transmission Division	$ 223,744	$ 233,946
Alaska Highway Gas Pipeline	165,183	194,473
TQM Pipeline	119,481	56,278
Petrochemical facilities	268,801	64,288
Petroleum and mineral resource properties	287,727	660,718
Refining, marketing and other facilities	87,079	84,898
Manufacturing and corporate assets	69,938	76,629
	1,221,953	1,371,230
Other investments	20,217	19,490
Deferred costs	54,166	56,388
Reduction of long term debt	551,893	92,348
Purchase of minority interest	—	8,740
Dividends to —		
Shareholders	110,704	75,671
Minority shareholders of subsidiaries	33,999	31,481
Capital stock issue expenses	7,660	—
Purchase of preferred shares for cancellation	7,267	7,801
Redemption of preferred shares issued by subsidiaries	32,117	949
Working capital increase (decrease)	7,180	(44,137)
	$2,047,156	$1,619,961

See accompanying summary of accounting policies and notes

NOVA AN ALBERTA CORPORATION

Summary of Accounting Policies

December 31, 1982

The consolidated financial statements have been prepared on the historic cost basis in accordance with accounting principles generally accepted in Canada and conform in all material respects with International Accounting Standards. The accounting policies of significance to the Company are as follows:

Principles of consolidation — The consolidated financial statements include the accounts of the Company and all subsidiaries, principally:

100% Owned

The Alberta Gas Ethylene Company Ltd.
AGEC Security Corporation
A.G. Investments Ltd.
A.G. Pipe Lines Inc.
A.G. Pipe Lines (Canada) Ltd.
CanOcean Resources Ltd.
Energy Equipment & Systems Inc.
Grove Valve and Regulator Company
Novacor Chemicals Ltd.
Novacor Polyethylene (LLD) Ltd.
Novacorp Engineering Services Ltd.
(formerly Algas Engineering Services Ltd.)
Noval Technologies Ltd.
Novalta Properties Ltd.
Novalta Resources Ltd.
WAGI International S.p.A.

Partially Owned

Husky Oil Ltd.
(67.6% owned)
Pan-Alberta Gas Ltd.
(50.005% owned)

Companies acquired have been accounted for using the purchase method.

Substantially all of the companies' exploration and production activities related to oil and gas are conducted jointly with others and accordingly the accounts reflect only the companies' proportionate interest in such activities.

Investments in the Alaska Highway Gas Pipeline Project, the Trans Québec & Maritimes Pipeline Project (TQM Pipeline Project) and in unincorporated petrochemical joint ventures are accounted for by the proportionate consolidation method and, accordingly, the accounts reflect only the companies' proportionate interest in such activities. The Company's investment in the Alaska Highway Gas Pipeline Project is represented by its direct and indirect percentage ownership in Foothills Pipe Lines (Yukon) Ltd. and its subsidiaries. Costs for Phase I of the project (being essentially those portions in Canada south of Caroline, Alberta) are classified as plant, property and equipment.

The companies' proportionate share of aggregate assets, liabilities, revenue and operating expenses of these ventures is as follows:

	Assets		Liabilities		Revenue		Operating Expenses	
	1982	1981	**1982**	1981	**1982**	1981	**1982**	1981
	(thousands of dollars)							
Natural Gas Transmission								
Alaska Highway Gas Pipeline Project	**$ 596,508**	$385,331	**$362,759**	$210,907	**$ 60,530**	$ 9,351	**$ 3,902**	$ 429
TQM Pipeline Project	**211,701**	59,497	**162,161**	—	**12,723**	—	**3,941**	—
	808,209	444,828	**524,920**	210,907	**73,253**	9,351	**7,843**	429
Petrochemicals	**209,196**	158,647	**63,497**	49,182	**110,220**	88,688	**76,002**	67,577
Total	**$1,017,405**	$603,475	**$588,417**	$260,089	**$183,473**	$ 98,039	**$ 83,845**	$ 68,006

Foreign currency translation — Accounts in foreign currencies have been translated to Canadian dollars using current rates of exchange for current assets and current liabilities, historical rates of exchange for non-current assets and non-current liabilities and average rates for the year for revenue and expenses, except depreciation and depletion which are translated at the rate of exchange applicable to the related assets. Gains or losses resulting from exchange adjustments are included in income.

Inventories — Inventories are carried at the lower of cost, as determined on a first-in, first-out basis, and net realizable value. Other materials and supplies are carried at cost. Refined oil product inventory costs are determined by allocating costs to products on the basis of the relative market value of the product.

Investments and advances — The Company accounts for its investment in Alberta Gas Chemicals Ltd., Steel Alberta Ltd., Western Star Trucks Inc. and the NOVA/AGT Joint Venture (all 50% owned) by the equity method. Other investments are carried at cost.

Plant, property and equipment — Plant, property and equipment are carried at cost; maintenance and repair costs of a routine nature are expensed as incurred; renewals and betterments which extend the economic useful life of properties are capitalized.

An allowance for funds used during construction is capitalized when recoverable under cost of service contracts. For facilities subject to regulations the rate is the approved rate of capitalization and for petrochemical facilities the rate is the agreed cost of capital. For plant, property and equipment not subject to cost of service contracts, related interest incurred during construction is capitalized.

Plant, property and equipment (except for natural gas transmission and certain petroleum production equipment) are depreciated on a straight-line basis at annual rates varying from 3% to 50% which rates are designed to write these assets off over their estimated useful lives. Depreciation for the Alberta Gas Transmission Division plant approximated a composite rate of 3% on cost in 1982 (1981 — 3.5%). Depreciation for the Alaska Highway Gas Pipeline — Phase I facilities approximates a composite rate of 4% on costs. Depreciation for the TQM Pipeline approximated a composite rate of 2% in 1982. Certain petroleum production equipment is depreciated by the unit of production method. The new NOVA Head Office building is depreciated by the sinking fund method at an annual rate of 5%.

The companies employ the full cost method of accounting and capitalize all exploration and reserve acquisition and development costs into five cost centres: the Lloydminster heavy oil area of Canada, the Canadian Frontier regions, all other areas of Canada, the United States and the Philippines.

For Canadian cost centres, the companies have computed depletion by the revenue method. Under this method, the ratio of current year revenues to total future revenues from the production of proved reserves determines the proportion of depletable costs to be expensed. Revenue projections are determined by the companies' engineers and are confirmed by an independent petroleum engineering consultant in a manner consistent with the establishment of proved reserves. Depletion expense is not calculated relative to the Canadian Frontier regions until such time as economically recoverable reserves are established. In the United States and the Philippines the costs are depleted on a composite unit of production method based upon proved developed reserves, as estimated by the companies' engineers.

The cost of acquiring, exploring for and developing oil and gas interests outside of North America and the Philippines has been capitalized pending the outcome of exploration in each area of interest. These costs are being amortized on a straight-line method at an annual rate of 20% pending reserve development. Unamortized costs will be depleted on a composite unit of production method if sufficient reserves are developed. The unamortized costs of an abandoned area are charged against income at the time of abandonment.

Deferred costs — Costs relating to Phase II of the Alaska Highway Gas Pipeline Project and costs of other projects which may benefit future periods are being deferred. Deferred costs applicable to projects which have been terminated are expensed.

An allowance for funds on deferred expenditures incurred to date for the Alaska Highway Gas Pipeline Project — Phase II is capitalized. Effective September 1, 1982 the allowance approximates the Company's after tax carrying cost of its investment in Phase II expenditures (see Note 5).

Unamortized debt discount and expense are being amortized over the terms of the respective issues.

Long term debt — Short term borrowings which are expected to be repaid from the proceeds of long term financing are included in long term debt.

Capital lease obligations which relate to transactions which are similar in nature to a purchase have been capitalized and included in long term debt.

Income taxes — The companies follow the tax allocation basis of recording income taxes on all income except for the Natural Gas Transmission segment and certain Petrochemicals operations which are subject to cost of service contracts. Income taxes are provided on these sources of income only to the extent that they are included in allowable cost of service under such contracts.

Resource development incentives — Federal and provincial exploration incentives (principally, the Petroleum Incentives Programmes) are accounted for as a reduction of the related capital expenditures. Amounts received from the Saskatchewan provincial government relative to its oil and gas incentive regulations are credited against provincial royalties.

Pension and retirement plans — The Company and its subsidiaries maintain pension and retirement plans for substantially all employees. The past service liabilities of these plans are being charged to income over varying periods not exceeding ten years. Charges to income are determined from actuarial valuations of the pension plans.

Earnings per common share — Basic earnings per common share are calculated after deducting dividends on preferred shares and using the weighted average number of shares outstanding during the period. The calculation of earnings per common share on a fully diluted basis assumes conversion of all securities and exercise of all stock options which would have a dilutive effect on basic earnings per common share.

Net income for the calculation of earnings per common share is reduced by the amount of dividends to which the preferred shareholders are entitled as at the end of the fiscal year. The Company accrues against reinvested earnings the preferred share dividends normally declared near the year end but with a payment date following in the next year.

**NOVA
AN ALBERTA
CORPORATION**

Notes to Consolidated Financial Statements

December 31, 1982

1. Regulatory matters — Alberta Gas Transmission Division

Pursuant to a decision in June, 1982 by the Public Utilities Board of Alberta, the Company refunded certain amounts with respect to income taxes and depreciation collected during 1978 and 1979. The effect of the refunds has been a reduction in working capital of the Company with no material impact on net income.

2. Inventories

	December 31 1982	1981
	(thousands of dollars)	
Natural Gas Transmission	$ 22,603	$ 20,034
Petrochemicals	23,403	20,128
Resource Development	304,092	321,636
Manufacturing and other	56,304	51,590
	$406,402	$413,388

3. Investments and advances

	December 31 1982	1981
	(thousands of dollars)	
Alberta Gas Chemicals Ltd.	$ 38,545	$ 34,380
Steel Alberta Ltd.	15,826	15,050
Western Star Trucks Inc.	10,682	15,079
NOVA/AGT Joint Venture	14,250	—
Other	33,902	41,553
	$113,205	$106,062

4. Plant, property and equipment

	December 31 1982 Cost	Accumulated Depreciation and Depletion	Net	1981 Net
	(thousands of dollars)			
Natural Gas Transmission				
Alberta Gas Transmission Division				
Plant in service	$1,518,035	$353,651	$1,164,384	$ 970,398
Plant under construction	59,715	—	59,715	72,876
Alaska Highway Gas Pipeline				
Plant in service	494,654	18,469	476,185	87,583
Plant under construction	24,450	—	24,450	182,983
TQM Pipeline				
Plant in service	133,543	802	132,741	—
Plant under construction	75,907	—	75,907	59,497
Petrochemicals				
Plant in service	568,185	92,779	475,406	472,764
Plant under construction	319,522	—	319,522	61,950
Resource Development				
Petroleum and mineral resource properties	1,747,327	230,235	1,517,092	1,346,175
Refining and marketing facilities	417,520	54,901	362,619	316,137
Other facilities	67,689	18,455	49,234	35,778
Manufacturing	79,834	28,293	51,541	37,807
Corporate assets	152,312	1,677	150,635	101,752
	$5,658,693	$799,262	$4,859,431	$3,745,700

ALASKA HIGHWAY GAS PIPELINE PROJECT:

The Company, through its investment in Foothills Pipe Lines (Yukon) Ltd., is one of the principal sponsors of the Alaska Highway Gas Pipeline Project. This project has as its objective the transportation of natural gas from Alaska through Canada to the United States and would have the potential of facilitating the transportation of Canadian natural gas from the Mackenzie Delta and Beaufort Basin through a proposed pipeline — the Dempster Lateral.

Phase I involves the construction of portions of the pipeline system south of Caroline, Alberta for delivery of Canadian gas to the United States while Phase II involves the construction of the balance of the pipeline system north of Caroline, Alberta for delivery of Alaska gas through Canada to the United States. Initial transportation service on a cost of service basis commenced for the western leg of Phase I on October 1, 1981 and the eastern leg of Phase I on September 1, 1982. The total cost of Phase I is estimated at $1.0 billion (as spent, including capitalized interest) of which $100,000,000 will be provided as equity by the Company.

On August 26, 1982 and November 2, 1982 the National Energy Board released decisions related to rates and tolls to be charged on Phase I. Pursuant to these decisions the Company reclassified to plant, property and equipment $72,669,000 of preliminary expenditures which had previously been classified as deferred costs. These preliminary expenditures are being amortized on a straight-line basis at an annual rate of 4% and earn a 16% pre-tax rate of return on the unamortized portion. In this regard Foothills Pipe Lines (Yukon) Ltd. has undertaken to repay amounts collected, along with appropriate interest, when Phase II commences operation. The remaining Phase II preliminary expenditures are classified as deferred costs (see Note 5).

Upon commencement of construction of Phase II, the Company would incur, or be responsible for, large expenditures in respect of this phase of the project.

TQM PIPELINE PROJECT:

The Company is an equal partner with TransCanada PipeLines Limited in a partnership formed to construct and operate a major gas transmission system to transport natural gas in the provinces of Quebec, New Brunswick and Nova Scotia.

The National Energy Board has issued certificates of public convenience and necessity authorizing construction of a pipeline from St. Lazare to Lévis, Quebec and laterals to certain other Quebec communities, subject to certain conditions. The first sections of the pipeline to Trois Rivières, Quebec were placed into service during 1982 and are operating under an interim cost of service tariff pending a decision by the National Energy Board on tariff matters. Further sections and laterals will be placed into service when completed, with final completion expected to be in the fall of 1983. The total cost of the Quebec section of the project is estimated at $500,000,000 (as spent, including capitalized interest) of which approximately $50,000,000 will be provided through advances from the Company.

The National Energy Board has issued a certificate of public convenience, subject to certain conditions, for the construction of pipeline facilities in the province of Quebec east of Lévis and in the provinces of New Brunswick and Nova Scotia. Upon commencement of construction the Company would incur, or be responsible for, large expenditures in respect of this phase of the pipeline project.

PETROCHEMICAL PLANTS UNDER CONSTRUCTION:

Alberta Gas Ethylene has received approval for a second ethylene plant with a capacity of 1.5 billion pounds per year and construction has commenced. The cost of this second plant is estimated at $576,000,000 (as spent, including capitalized interest), based upon completion in mid 1984. In addition, Alberta Gas Ethylene has received the necessary approvals for a third ethylene plant having a capacity of 1.5 billion pounds per year. Construction of the third plant has been deferred until suitable sales contracts for the output of the plant can be concluded.

On April 22, 1982 the Company announced that it has taken responsibility for a 600 million pound per year linear low density polyethylene plant on which construction has commenced. The plant is estimated to cost $477,000,000 (as spent, including capitalized interest), based upon completion in mid 1984.

The Company, through an affiliate, has entered into an agreement with Dome Petroleum Limited for the construction and ownership of a natural gas liquids extraction plant. The cost of the plant is approximately $200,000,000 (as spent, including capitalized interest) of which the Company's indirect share is approximately $50,000,000, based upon completion in late 1983.

RESOURCE DEVELOPMENT:

Husky has committed to the joint construction, ownership and operation of two semi-submersible drilling vessels for use off the east coast of Canada. Husky's capital investment is estimated at U.S. $90,000,000 (as spent, including capitalized interest) for the project and delivery of the first vessel is projected for the second half of 1983.

In March 1982, Husky committed to the joint ownership and construction of six supply vessels which will be used to support the operation of the two semi-submersibles. Delivery of these vessels is scheduled to coincide with that of the semi-submersibles. It is estimated that Husky's total capital investment in the construction of these vessels will be $51,000,000 (as spent, including capitalized interest).

5. Deferred costs

	December 31 1982	1981
	(thousands of dollars)	
Alaska Highway Gas Pipeline Project — Phase II (Note 4)	**$ 67,090**	$114,765
TQM Pipeline Project	**—**	20,183
Oil Sands Mining Project	**23,879**	11,883
Arctic Pilot Project	**21,188**	16,396
Petrochemical Projects	**1,582**	14,660
Unamortized debt discount and expense	**8,804**	3,904
Other	**20,789**	15,850
	$143,332	$197,641

OIL SANDS MINING PROJECT:

The Company and Petro-Canada Exploration Inc. each own 50% of Canstar Oil Sands Ltd., a joint venture company formed to examine the feasibility of developing an oil sands mining complex in northern Alberta.

ARCTIC PILOT PROJECT:

The Company, as to 25%, is involved in a joint venture (Arctic Pilot Project) formed for the purpose of producing and processing natural gas in, and transporting liquefied natural gas by LNG tanker from, the Arctic Islands.

6. Long term debt
(thousands of dollars)

	Maturity	December 31 1982	1981
NOVA, AN ALBERTA CORPORATION			
First Mortgage Sinking Fund Bonds			
5½% Series C	1985	**$ 3,775**	$ 5,319
8¾% Series D (1982 – U.S. $33,400; 1981 – U.S. $36,900)	1989	**35,847**	39,603
Secured Debentures			
5¾% Series B	1985	**15,822**	16,903
Unsecured Debentures			
7½% Series 1	1990	**195**	2,217
9¾% Series 2	1990	**16,564**	16,872
9¼% Series 3	1990	**14,885**	15,263
8% Series 4	1991	**42,223**	43,189
8⅛% Series 5	1992	**30,305**	31,017
11⅜% Series 6	1995	**52,863**	54,715
17½% Series 7	1987	**75,000**	—
17¾% Series 8	1997	**50,000**	—
16¼% (1982 – U.S. $100,000)	1989	**118,982**	—
Unsecured Term Notes with interest rates averaging 16⅛% (1982 – U.S. $110,000)	1987	**137,996**	—
		594,457	225,098
Bank loans and notes (unsecured)		**73,173**	417,407
		667,630	642,505
Alberta Gas Ethylene			
Ethylene Plant I Financing			
8¼% Secured Notes (1982 – U.S. $228,251; 1981 – U.S. $242,517)	1998	**259,616**	275,842
5⅜% First Income Debentures (1982 – U.S. $228,251; 1981 – U.S. $242,517)	1987	**259,616**	275,842
Less certificates of deposit (1982 – U.S. $228,251; 1981 – U.S. $242,517) pledged as security against the First Income Debentures		**(259,616)**	(275,842)
		259,616	275,842
Ethylene Plant II Financing			
Unsecured bank loans		**125,000**	44,000
		384,616	319,842

	Maturity	December 31 1982	1981
Husky Oil Ltd. and Subsidiaries			
Sinking Fund Debentures, Series A, B and C with interest rates varying from 6% to 8½%	1984-1991	**27,817**	29,907
Notes payable and other loans — secured and unsecured with interest rates averaging 12½%			
Canadian	1986	**660,000**	601,652
United States (1982 – U.S. $203,543; 1981 – U.S. $180,638)	Various	**237,717**	203,921
Capital lease obligations (1982 – U.S. $12,564; 1981 – U.S. $11,014)	Various	**13,021**	11,409
		938,555	846,889
Novalta Resources			
Income Debentures (1982 – U.S. $43,760; 1981 – U.S. $47,778)	1986-1989	**49,585**	54,130
Cochin Pipe Line and Ethane Gathering System			
A.G. Pipe Lines (Canada) Ltd.	1998	**28,900**	30,700
A.G. Pipe Lines Inc. (1982 – U.S. $36,450; 1981 – U.S. $39,487)	2000	**42,533**	45,979
		71,433	76,679
Foothills (Yukon) — Phase I Financing	1987-1996	**335,920**	194,046
TQM Pipeline Financing		**150,500**	—
Polyvinyl Chloride Plant Financing (1982 and 1981 – U.S. $36,340)	1999	**42,095**	42,095
Novalta Properties — Head Office Building Financing	Various	**97,633**	56,108
Other Loans	Various	**75,376**	52,334
		2,813,343	2,284,628
Less instalments due within one year shown as current liability		**72,731**	78,345
		$2,740,612	$2,206,283

NOVA, AN ALBERTA CORPORATION:

The First Mortgage Sinking Fund Bonds are secured by a first fixed and specific mortgage, pledge and charge and a first floating charge on the assets of the Company. The Secured Debentures are secured in the same manner, subject to the prior charge of the First Mortgage Sinking Fund Bonds.

Foreign exchange gains or losses relative to the principal and interest on U.S. dollar borrowings are for the account of the Alberta Gas Transmission Division customers.

ETHYLENE PLANT I FINANCING:

The proceeds from the issuance of the 8¼% Secured Notes are invested in certificates of deposit which bear interest equivalent to that due on the Secured Notes. The Secured Notes are guaranteed by The Alberta Gas Ethylene Company Ltd. and are secured by a first fixed and floating charge on the first ethylene plant, the ethylene pipeline and related assets of Alberta Gas Ethylene and by the assignment of certain related contracts.

The First Income Debentures were issued simultaneously with the issuance of the Secured Notes and are secured by the certificates of deposit referred to in the previous paragraph.

Under the take or pay contract with Dow Chemical Canada Inc., all exchange gains and losses are for the account of Dow.

ETHYLENE PLANT II FINANCING:

The Alberta Gas Ethylene Company Ltd. has arranged a revolving credit facility of up to $250,000,000 with certain Canadian banks to provide interim financing for construction of the second ethylene plant. Such credit facility expires on the earlier of the drawdown of any financing for the construction of the second ethylene plant not provided for in the loan agreement with DCS Capital Partnership, discussed below, and April 30, 1983. The interest rate at December 31, 1982 was approximately 11¾% (16⅞% at December 31, 1981).

On March 1, 1983 Alberta Gas Ethylene entered into a loan agreement with DCS Capital Partnership, a Delaware partnership, in respect of financing construction costs and certain deferred start-up costs of the second ethylene plant. The partners of DCS Capital Partnership are affiliates of The Dow Chemical Company, Union Carbide Corporation and Shell Canada Limited. Pursuant to such loan agreement, DCS Capital Partnership has agreed to provide loans to Alberta Gas

Ethylene for up to the lesser of $535,000,000 and approximately 76% of the construction costs and certain deferred start-up costs of the second ethylene plant. The loans will be repayable in equal monthly instalments over the period commencing on the earlier of the start-up of the second ethylene plant and March 25, 1985 and ending July 25, 2004. The cost of such loans is tied to the cost of third party financing undertaken by DCS Capital Partnership, which financing at present is being conducted in the U.S. commercial paper market. The loans are secured, pursuant to a trust deed, by an assignment of the proceeds of the ethylene sales contracts for the second ethylene plant, the related performance guarantees and the construction agreement for the second ethylene plant and a first fixed charge on the second ethylene plant.

HUSKY OIL LTD. AND SUBSIDIARIES:

The Series A, B and C Sinking Fund Debentures are secured by the common shares of certain wholly-owned subsidiaries of Husky and a first floating charge on all other assets of Husky and certain of its subsidiaries. Certain notes payable and other loans of $44,639,000 at December 31, 1982 ($7,377,000 at December 31, 1981) are secured by certain assets and properties.

NOVALTA RESOURCES FINANCING:

Security for the Income Debentures includes natural gas properties and a general assignment of book debts. Interest on these Income Debentures varies with the London Inter Bank Offered Rate and was approximately 8% at December 31, 1982 (9⅛% at December 31, 1981). These Income Debentures mature on various dates between 1986 and 1989.

COCHIN PIPE LINE AND ETHANE GATHERING SYSTEM FINANCING:

A.G. Pipe Lines (Canada) Ltd., in connection with the long term financing of its share of the cost of the Canadian segment of the Cochin Pipe Line and of the Ethane Gathering System, has entered into a loan agreement with certain banks which provides for a term credit facility consisting of term loans and/or bankers' acceptances up to $28,900,000. The term credit facility expires on December 31, 1998 and is secured by a first floating charge upon a portion of the assets of A.G. Pipe Lines (Canada) Ltd., and a first fixed charge on certain agreements. The interest rate on the term credit facility was approximately 11⅝% at December 31, 1982 (17¼% at December 31, 1981).

A.G. Pipe Lines Inc., in connection with the long term financing of its share of the cost of the United States segment of the Cochin Pipe Line, pursuant to a loan agreement, has issued promissory notes of U.S. $36,450,000 at December 31, 1982 (U.S. $39,487,000 outstanding at December 31, 1981) which mature on various dates to December 31, 2000. These promissory notes are secured by an assignment of the interest of A.G. Pipe Lines Inc. in certain agreements (insofar as they relate to the United States segment of the Cochin Pipe Line), by the guarantee of A.G. Pipe Lines (Canada) Ltd., and by a pledge of the outstanding shares of A.G. Pipe Lines Inc. The interest rate varies with the London Inter Bank Offered Rate and was approximately 9¾% at December 31, 1982 (14¾% at December 31, 1981).

FOOTHILLS (YUKON) — PHASE I FINANCING:

In connection with the financing of Phase I of the Alaska Highway Gas Pipeline, Foothills Pipe Lines (Yukon) Ltd. has arranged long term financing with Canadian chartered banks for the issuance of term notes of up to $835,000,000 of which the major portion will be repaid on or before December 31, 1987, with the balance maturing on December 31, 1996. These term notes are secured by the assignment of the interest of Foothills (Yukon) and three of its subsidiaries in certain agreements and floating charges on their respective properties and assets.

At December 31, 1982 $656,483,000 ($399,298,000 at December 31, 1981) had been issued pursuant to the loan agreement of which the Company's proportionate share is $335,920,000 ($194,046,000 at December 31, 1981). The interest rate at December 31, 1982 was approximately 13⅛% (17⅞% at December 31, 1981).

TQM PIPELINE FINANCING:

The Trans Québec & Maritimes Pipeline partnership, Trans Québec & Maritimes Pipeline Inc., TransCanada PipeLines Limited and the Company have arranged with a Canadian chartered bank a bridge credit facility of $400,000,000 (repayable on June 30, 1983) to finance 75% of the capital costs of construction unconditionally approved by the National Energy Board for inclusion in the Quebec portion of the pipeline system's rate base. The partnership intends to arrange suitable long term financing to replace the bridge credit facility which is secured by an assignment of insurance and an assignment of the transportation service agreement relating to the project.

In the event of default under the bridge credit facility, an application would be made to the National Energy Board for inclusion in the partnership's rate base of any capital costs incurred to that time which have not previously been subject of such an application or in respect of which an application has been made for inclusion in the partnership's rate base but such costs were neither allowed nor disallowed. Any capital costs disallowed in the partnership's rate base would be paid by the partners, in amounts equal to their respective share, such that the bridge credit facility does not exceed 75% of the capital costs included in the approved rate base.

At December 31, 1982 $301,000,000 had been issued pursuant to the credit facility of which the Company's proportionate share is $150,500,000. The interest rate at December 31, 1982 was approximately 12¾%.

POLYVINYL CHLORIDE PLANT FINANCING:

The polyvinyl chloride plant is financed through the issuance of U.S. $72,680,000 8¾% secured notes Series A due December 15, 1999 of which the Company's proportionate share is U.S. $36,340,000. These notes are secured by a first fixed and floating charge upon the property and assets relating to the project and by an assignment of certain rights under related contracts. Repayment on the notes is required to commence in December 1983 at an annual rate of 5.88% of the principal amount outstanding.

NOVALTA PROPERTIES — HEAD OFFICE BUILDING FINANCING:

Novalta Properties Ltd., in connection with the financing of the Head Office building, has arranged a line of credit with a Canadian chartered bank of up to $100,000,000 of which $97,633,000 was outstanding at December 31, 1982 ($56,108,000 at December 31, 1981). This line of credit is secured by the hypothecation of the title to the property and is repayable in varying amounts commencing in 1986 with final maturity in 1998. The interest rate at December 31, 1982 was approximately 10⅞% (17% at December 31, 1981).

OTHER LOANS:

At December 31, 1982 other loans of $59,554,000 ($33,454,000 at December 31, 1981) are secured by certain assets and agreements. The effective interest rate on the other loans varies and approximated 11⅜% at December 31, 1982 (12¾% at December 31, 1981).

SINKING FUND AND REPAYMENT REQUIREMENTS:

Sinking fund and repayment requirements in respect of long term debt maturing within five years following December 31, 1982 are: 1983 – $72,731,000; 1984 – $164,493,000; 1985 – $173,930,000; 1986 – $173,705,000; 1987 – $378,266,000.

CURRENT BANK LOANS:

Current bank loans of $51,641,000 ($17,744,000 at December 31, 1981) are secured by accounts receivable and inventories.

INTEREST AND EXPENSE ON DEBT:

	Year ended December 31	
	1982	1981
	(thousands of dollars)	
Interest and expense on long term debt	**$349,293**	$224,025
Interest on short term debt	**52,125**	49,030
Interest capitalized during construction	**(24,844)**	(5,831)
Interest income	**(29,367)**	(19,355)
	$347,207	$247,869

7. Income taxes

For Natural Gas Transmission and certain of the Petrochemicals operations, charges to customers are on a cost of service basis. Because income taxes related to these operations are a component of the charges, the billing for such income taxes on either a taxes payable or tax allocation basis does not affect net income.

Income tax expense varies from the amounts that would be computed by applying the Canadian federal and provincial income tax rates to income before taxes and minority interest as shown in the following table:

	Year ended December 31	
	1982	1981
	(thousands of dollars)	
Income before taxes and minority interest	**$284,817**	$235,619
Less: Adjustments for income not subject to normalized income taxes —		
Cost of service activities		
Natural Gas Transmission	**144,723**	73,046
Petrochemicals	**17,930**	16,901
Equity component in allowance for funds used during development and construction	**46,812**	47,890
Equity in earnings of affiliated companies	**5,038**	14,054
Income subject to normalized income taxes	**$ 70,314**	$ 83,728
"Expected" income tax expense at 48.8%	**$ 34,313**	$ 40,859
Add (deduct) adjustments to income taxes resulting from —		
Resource Development activities		
Resource allowance on Canadian production income	**(31,869)**	(22,806)
Earned and supplementary depletion	**(6,688)**	(9,719)
Royalties, lease rentals and mineral taxes payable to the Crown	**39,072**	33,703
Investment tax credits	**(7,587)**	(9,038)
Incremental oil revenue tax	**(6,003)**	—
Alberta royalties tax credit	**(6,230)**	(2,572)
Other	**(353)**	5,062
Earnings from foreign subsidiaries with lower effective tax rates	**(7,964)**	(1,264)
Other	**(7,580)**	(1,859)
	(889)	32,366
Add income taxes billed or provided under cost of service contracts	**61,845**	14,371
Actual income tax expense	**$ 60,956**	$ 46,737

8. Minority interest in subsidiary companies

	December 31 1982	1981
	(thousands of dollars)	
A.G. Investments Ltd.	**$229,500**	$255,000
Husky Oil Ltd.	**259,802**	174,699
Other	**9,404**	8,627
	$498,706	$438,326

In connection with the acquisition of 41,716,500 shares of Husky, A.G. Investments Ltd. issued $255,000,000 of variable rate, cumulative, redeemable, senior preferred shares, of which $229,500,000 (or U.S. dollar equivalent) was outstanding at December 31, 1982. The preferred shares are redeemable at the option of A.G. Investments Ltd. between 1983 and 1989 and are required to be redeemed, as to 10% of the initially issued preferred shares, on September 30 of each of the years 1983 to 1988 inclusive and as to the balance thereof on September 30, 1989. These shares are redeemable at the option of the holder in certain events. The variable dividend rate approximated 8⅛% at December 31, 1982 (10½% at December 31, 1981). The Husky shares owned by A.G. Investments Ltd. have been pledged as collateral security.

Pursuant to an underwriting agreement dated July 13, 1982 Husky issued and sold $91,250,000 13% Cumulative Redeemable Convertible Retractable Junior Preferred Shares, Series A. The net proceeds of the issue of approximately $87,200,000 were used to reduce outstanding bank borrowings.

9. Capital stock

(a) Preferred shares

	December 31 1982	1981
	(thousands of dollars)	
(i) Preferred shares of a par value of $100 each		
Authorized — 2,000,000 shares		
Issued — Cumulative and Redeemable		
4¾% Series C – 97,867 shares (1981 – 107,541)	**$ 9,787**	$ 10,754
(ii) Preferred shares of a par value of $25 each		
Authorized — 16,500,000 shares (1981 – 10,000,000)		
Issued — Cumulative and Redeemable		
7¾% – 811,411 shares (1981 – 839,381)	**20,285**	20,997
9¾% – 1,118,192 shares (1981 – 1,200,681)	**27,955**	30,017
9.76% – 1,658,495 shares (1981 – 1,763,480)	**41,462**	44,087
7.60% – 2,665,500 shares (1981 – 2,756,650)	**66,638**	68,916
15% – 2,500,000 shares	**62,500**	—
11.24% – 4,000,000 shares	**100,000**	—
(iii) Second preferred shares of a par value of $25 each		
Authorized — 26,120,000 shares (1981 – 15,560,000)		
Issued — Cumulative and Redeemable		
6⅜% Convertible – 1,774,444 shares (1981 – 2,725,626)	**44,361**	68,141
6½% Convertible – 7,927,385 shares (1981 – 7,932,905)	**198,185**	198,323
12% Convertible – 10,197,970 shares	**254,949**	—
	$826,122	$441,235

On February 15, 1982 the Company increased the number of authorized First Preferred Shares of the par value of $25.00 each from 10,000,000 to 12,500,000 First Preferred Shares and designated 2,500,000 shares thereof as 15% Cumulative Redeemable First Preferred Shares which were sold for $62,500,000 cash, pursuant to an underwriting agreement dated February 15, 1982.

The 15% Preferred Shares are redeemable at the option of the Company on or after August 15, 1987 and on or before August 15, 1988 at $26.50 per share plus accrued and unpaid dividends and at reducing amounts thereafter. These 15% Preferred Shares are also retractable at the option of the holder by deposit of these shares on or before August 7, 1987 for redemption on August 15, 1987 at $25.00 per share plus accrued and unpaid dividends. In addition, the Company shall make all reasonable efforts to purchase for cancellation at a price not in excess of $25.00 per share plus accrued and unpaid dividends and costs of purchase, 100,000 15% Preferred Shares annually up to and including August 15, 1987 and annually 4% of the remaining 15% Preferred Shares outstanding on August 16, 1987 and thereafter.

On April 29, 1982 the Company increased the number of authorized Second Preferred Shares of the par value of $25.00 each from 15,560,000 to 26,120,000 Second Preferred Shares and designated 10,560,000 shares thereof as 12% Cumulative Redeemable Convertible Second Preferred Shares of which 10,200,000 shares were issued and sold for $255,000,000 cash, pursuant to an underwriting agreement dated April 29, 1982.

The 12% Preferred Shares are redeemable at the option of the Company on or after May 15, 1985 and prior to May 15, 1987 at $26.25 per share if the weighted average price at which the Class "A" common shares were traded was not less than 130% of the conversion price. These 12% Preferred Shares are also redeemable at the option of the Company on or after May 15, 1987 up to and including May 15, 1988 at $26.25 per share plus accrued and unpaid dividends and at reducing amounts thereafter. In addition, the Company shall make all reasonable efforts to purchase for cancellation, at a price not in excess of $25.00 per share plus accrued and unpaid dividends and costs of purchase, 204,000 12% Preferred Shares annually commencing May 16, 1986 up to and including May 15, 1990 and annually 4% of the remaining 12% Preferred Shares outstanding on May 16, 1990 and thereafter.

On November 4, 1982 the Company increased the number of authorized First Preferred Shares of the par value of $25.00 each from 12,500,000 to 16,500,000 First Preferred Shares and designated 4,000,000 shares thereof as 11.24% Cumulative Redeemable First Preferred Shares which were sold for $100,000,000 cash, pursuant to an underwriting agreement dated November 4, 1982.

The 11.24% Preferred Shares are redeemable at the option of the Company on or after May 15, 1988 and on or before May 15, 1989 at $26.25 per share plus accrued and unpaid dividends and at reducing amounts thereafter. These 11.24% Preferred Shares are also retractable at the option of the holder by deposit of these shares on or before May 6, 1988 for redemption on May 15, 1988 at $25.00 per share plus accrued and unpaid dividends. In addition, the Company shall make all reasonable efforts to purchase for cancellation at a price not in excess of $25.00 per share plus accrued and unpaid dividends and costs of purchase, 80,000 11.24% Preferred Shares annually commencing May 16, 1983 up to and including May 15, 1988 and annually 4% of the remaining 11.24% Preferred Shares outstanding on May 16, 1988 and thereafter.

The Company is required to set aside on its books as Purchase Funds $1,575,000 annually or such lesser amount as would increase the funds to $3,150,000 for the purchase for cancellation, if and when available in the open market or through invitation by the Company to tender, of its 4¾% Cumulative Redeemable Preferred Shares Series C at a price not in excess of $100.00 per share plus costs of purchase, and its 7¾% Cumulative Redeemable Preferred Shares, at a price not in excess of $25.00 per share plus accrued and unpaid dividends and costs of purchase.

The Company has the option of redeeming the 4¾% Preferred Shares Series C at $102.00 per share on or before May 15, 1985 and the 7¾% Preferred Shares at $26.50 per share on or before May 15, 1984 plus accrued and unpaid dividends and at reducing amounts after those dates.

The Company is required to call for redemption and redeem annually, through the operation of cumulative mandatory sinking funds, 64,000 9¾% Preferred Shares on May 15 of each year and 96,000 9.76% Preferred Shares on November 15 of each year, at par value plus accrued and unpaid dividends unless acquired otherwise and credited against the cumulative mandatory sinking funds. In addition, the Company may call for redemption and redeem annually, through the operation of non-cumulative optional sinking funds, 48,000 9¾% Preferred Shares on May 15 of each year and 72,000 9.76% Preferred Shares on November 15 of each year, at par value plus accrued and unpaid dividends. The Company also has the option of redeeming the 9¾% Preferred Shares at $26.50 per share on or before May 15, 1983 and the 9.76% Preferred Shares at $26.00 per share on or before November 15, 1983 plus accrued and unpaid dividends and at reducing amounts thereafter.

The 7.60% Preferred Shares are not redeemable until on or after February 15, 1983 at which time they are redeemable at the option of the Company to February 15, 1984 at $26.25 per share plus accrued and unpaid dividends and at reducing amounts thereafter. In addition, the Company shall annually use all reasonable efforts to purchase for cancellation 90,000 7.60% Preferred Shares at a price not in excess of $25.00 per share plus accrued and unpaid dividends and costs of purchase.

The 6⅜% Preferred Shares are redeemable at the option of the Company prior to November 15, 1983 at $26.25 per share if the weighted average price at which the Class "A" common shares were traded was not less than 125% of the conversion price. These 6⅜% Preferred Shares are also redeemable at the option of the Company from November 15, 1983 up to and including November 15, 1984 at $26.25 per share plus accrued and unpaid dividends and at reducing amounts thereafter. In addition, the Company shall annually use all reasonable efforts to purchase for cancellation 216,000 6⅜% Preferred Shares at a price not in excess of $25.00 per share plus accrued and unpaid dividends and costs of purchase.

The 6½% Preferred Shares are redeemable at the option of the Company on or after February 15, 1983 and prior to February 15, 1985 at $26.25 per share if the weighted average price at which the Class "A" common shares were traded was not less than 130% of the conversion price. These 6½% Preferred Shares are also redeemable at the option of the Company from February 15, 1985 up to and including February 15, 1986 at $26.25 per share plus accrued and unpaid dividends and at reducing amounts thereafter. In addition, the Company shall annually, commencing in 1983, use all reasonable efforts to purchase for cancellation 240,000 6½% Preferred Shares at a price not in excess of $25.00 per share plus accrued and unpaid dividends and costs of purchase.

During the year ended December 31, 1982 the Company purchased for cancellation 9,674 4¾% Preferred Shares, 28,470 7¾% Preferred Shares, 82,489 9¾% Preferred Shares, 104,985 9.76% Preferred Shares, 91,150 7.60% Preferred Shares and 56,000 6⅜% Preferred Shares at an aggregate discount of $2,777,000, which has been credited to contributed surplus. In addition, 895,182 6⅜% Preferred Shares were converted into 3,759,764 Class "A" common shares, 5,520 6½% Preferred Shares were converted into 14,275 Class "A" common shares and 2,030 12% Preferred Shares were converted into 6,861 Class "A" common shares.

(b) Common shares	December 31	
	1982	1981
(i) Class "A" common shares without par value non-voting except for the election of seven directors	(thousands of dollars)	
Authorized — 300,000,000 shares		
Issued — 116,187,195 shares (1981 – 110,959,389)	**$115,033**	$85,337
(ii) Class "B" common shares of the par value of $5.00 each		
Authorized — 2,004 shares		
Issued — 1,661 shares (1981 – 1,653)	**8**	8
	$115,041	$85,345

The Class "B" common shares are precluded upon the reduction or redemption of such shares or the winding-up of the Company from participating in assets of the Company to a greater extent than the amount paid up thereon. The Class "B" common shares are divided into four Groups which are allotted: Group I to utility companies, Group II to gas export companies, Group III to gas producers and Group IV to four directors appointed by the Lieutenant Governor in Council of the Province of Alberta. Holders of Class "B" common shares have full voting rights except for the election of the seven directors elected by the holders of Class "A" common shares. The holders of Class "B" common shares Group IV have full voting rights in all circumstances.

On February 13, 1981 the Company increased the number of authorized Class "A" common shares from 100,000,000 to 300,000,000 and Class "A" common shares of the par value of $1.25 per share were converted into Class "A" common shares without par value. In addition, February 13, 1981 was the date of record of the subdivision of the Class "A" common shares on a three-for-one basis.

Class "A" common shares were issued during the year ended December 31, 1982 as follows: (share capital in thousands of dollars)	Shares	Share Capital
On conversion of —		
6⅜% Preferred Shares	3,759,764	$22,380
6½% Preferred Shares	14,275	138
12% Preferred Shares	6,861	51
7½% Sinking Fund Debentures Series 1	606,600	2,022
On exercise of options granted to officers and employees	219,051	1,124
Under the Dividend Reinvestment and Share Purchase Plan	621,255	3,981
	5,227,806	$29,696

(iii) Reserved:

Class "A" common shares were reserved at December 31, 1982 as follows:	Shares
For conversion of the 6⅜% Cumulative Redeemable Convertible Second Preferred Shares until November 15, 1986 on a conversion basis of 4.2 common shares for each preferred share	7,452,665
For conversion of the 6½% Cumulative Redeemable Convertible Second Preferred Shares until February 15, 1990 on a conversion basis of 2.586 common shares for each preferred share	20,500,218
For conversion of the 12% Cumulative Redeemable Convertible Second Preferred Shares until May 15, 1990 on a conversion basis of 3.38 common shares for each preferred share	34,469,139
Under the incentive stock option plan, options are outstanding to officers and employees to purchase 422,600 common shares at prices ranging from $5.00 to $12.125 per share exercisable in annual instalments on a cumulative basis from 1983 to 1986	422,600
On September 10, 1982 the Company established the Incentive Stock Option Plan (1982) and the Board of Directors approved the acceptance by the Company of the surrender of certain options previously granted under the existing incentive stock option plan for Class "A" common shares at purchase prices in excess of $7.00 per share and the granting of replacement options pursuant to the Incentive Stock Option Plan (1982) to those employees who so surrender their options.	
Under the Incentive Stock Option Plan (1982) options are outstanding to officers and employees to purchase 981,000 common shares at prices ranging from $6.625 to $7.50 exercisable as to 25% annually on a cumulative basis from 1983 to 1985 and thereafter to 1987 and 921,700 common shares are reserved but unallocated	1,902,700
Under the executive share option plan, options are outstanding to officers to purchase 1,445,000 common shares at prices ranging from $6.625 to $8.417 per share (1,275,000 shares at December 31, 1981 at prices ranging from $8.147 to $12.125 per share) exercisable in annual instalments on a cumulative basis from 1983 to 1984 and thereafter over varying periods from 1989 to 1991 and 655,000 common shares are reserved but unallocated (345,000 shares at December 31, 1981)	2,100,000
Under the Dividend Reinvestment and Share Purchase Plan	4,378,745
	71,226,067

10. Remuneration of directors and senior officers
The aggregate remuneration including benefits paid during the year by the Company and its subsidiaries to directors of the Company, as such, was $345,000 (1981 – $311,000) and to senior officers of the Company, as such, was $3,208,000 (1981 – $2,466,000).

In 1982 the aggregate amount paid in respect of the year 1981 from the Company's Bonus Plan for the benefit of senior officers was $912,000. This plan replaced the Company's Profit Sharing Deferred Bonus Plan for which $892,000 was paid to the trustee in 1981.

11. Pension and retirement plans
The Company and its subsidiaries maintain pension and retirement plans for substantially all employees. At December 31, 1982 there were no significant unfunded liabilities with respect to any of these plans.

12. Acquisition of Uno-Tex Petroleum Corporation
In August 1981 Husky acquired Uno-Tex Petroleum Corporation for a total consideration of $371,247,000. This purchase was financed by existing lines of credit.

The excess of the purchase price over the book value of the assets acquired has been allocated to the carrying value of the petroleum resource properties. The assets acquired and total consideration, including fees and other costs relating to the acquisition, are summarized as follows:

	(thousands of dollars)
Petroleum resource properties	$382,674
Less net liabilities assumed	(11,427)
Total consideration	$371,247

13. Contingencies and commitments
Petrochemicals —

(a) The Company (to the extent of 20%), Dow Chemical Canada Inc., Dome Petroleum Limited, Petro-Canada Exploration Inc. and Shell Canada Resources Ltd. have agreed on a cost of service basis under take or pay contracts to purchase, for a term extending to December 31, 1998, ethane acquired by Alberta Gas Ethylene in excess of its requirements for its ethylene plants but not exceeding 44,000 barrels per day. Dome has agreed to act as agent for the sale of the Company's 20% share of the surplus ethane.

Contracts have been signed with a number of purchasers for the sale of the output of the second ethylene plant on substantially the same terms as the contract respecting output of the first plant. The Company will be responsible for the purchase directly or indirectly from Alberta Gas Ethylene of approximately 38% of the output of the second ethylene plant, which amount is sufficient to meet the requirements of the linear low density polyethylene plant presently under construction.

(b) The Company and PVC Plastics of Canada Limited (formerly Diamond Shamrock Canada Ltd.), as limited partners, and Diamond Shamrock Alberta Gas Ltd., as general partner, are parties to a limited partnership agreement. The limited partnership owns and operates a polyvinyl chloride plant near Fort Saskatchewan, Alberta, having an annual capacity of 220 million pounds of polyvinyl chloride. Under a product purchase agreement, the Company has agreed to purchase 50% of the output of the polyvinyl chloride plant and in certain events to make advance payments to the limited partnership in an amount equal to 50% of the limited partnership's cash requirements, such advances to be credited against future purchases of polyvinyl chloride.

14. Summarized quarterly financial data (unaudited)
(thousands of dollars except for per share data)

	Three Months Ended							
	March 31		June 30		September 30		December 31	
	1982	1981	**1982**	1981	**1982**	1981	**1982**	1981
Consolidated revenue	**$730,164**	599,666	**858,140**	629,615	**858,521**	641,595	**1,054,973**	798,675
Net operating income	**$109,403**	100,327	**119,513**	78,141	**148,601**	112,393	**163,541**	104,175
Net income	**$ 27,416**	35,670	**30,969**	33,508	**40,119**	32,381	**51,248**	28,303
Earnings per common share								
Basic	**$ 0.17**	0.26	**0.15**	0.24	**0.20**	0.22	**0.28**	0.18
Fully diluted	**$ 0.16**	0.22	**0.14**	0.21	**0.20**	0.20	**0.24**	0.17
Market price per common share								
High	**$ 9⅞**	14⅜	**6⅞**	12⅞	**7⅞**	12	**9**	10⅜
Low	**$ 6**	11⅝	**5⅛**	10½	**5⅛**	7¼	**6⅝**	8

15. Segmented information

(a) Natural Gas Transmission (thousands of dollars)

	Year Ended December 31							
	Total		Alberta Gas Transmission		Alaska Highway Gas Pipeline		TQM Pipeline	
	1982	1981	**1982**	1981	**1982**	1981	**1982**	1981
Revenue:								
Operating revenue	**$388,835**	$266,624	**$375,610**	$266,624	**$ 502**	$ —	**$12,723**	$ —
Intrasegment revenue	**—**	—	**—**	—	**6,810**	—	**—**	—
Intersegment revenue	**88,216**	22,577	**34,998**	13,226	**53,218**	9,351	**—**	—
	477,051	289,201	**410,608**	279,850	**60,530**	9,351	**12,723**	—
Costs and expenses:								
Operating expenses	**167,869**	121,568	**160,026**	121,139	**3,902**	429	**3,941**	—
Intrasegment expense	**—**	—	**6,810**	—	**—**	—	**—**	—
Depreciation	**63,598**	43,380	**47,762**	39,799	**15,035**	3,581	**801**	—
	231,467	164,948	**214,598**	160,938	**18,937**	4,010	**4,742**	—
Net operating income	**245,584**	124,253	**196,010**	118,912	**41,593**	5,341	**7,981**	—
Allowance for funds used during development and construction	**69,002**	71,645	**9,486**	9,508	**46,877**	53,677	**12,639**	8,460
	$314,586	$195,898	**$205,496**	$128,420	**$88,470**	$59,018	**$20,620**	$8,460

(b) Financial Information by Segment (thousands of dollars)

	1982	1981	1980
Revenue:			
Natural Gas Transmission	**$ 388,835** ***11.1%***	$ 266,624 *10.0%*	$ 219,324 *10.3%*
Resource Development	**$2,441,512** ***69.7%***	$1,775,462 *66.5%*	$1,404,564 *66.1%*
Petrochemicals	**$ 459,893** ***13.2%***	$ 424,046 *15.9%*	$ 321,147 *15.1%*
Manufacturing	**$ 211,558** ***6.0%***	$ 203,419 *7.6%*	$ 180,718 *8.5%*
Consolidated	**$3,501,798** ***100%***	$2,669,551 *100%*	$2,125,753 *100%*
Net operating income:			
Natural Gas Transmission	**$ 245,584** ***45.4%***	$ 124,253 *31.4%*	$ 110,175 *30.3%*
Resource Development	**$ 203,955** ***37.7%***	$ 202,112 *51.2%*	$ 192,984 *53.0%*
Petrochemicals	**$ 55,340** ***10.2%***	$ 47,292 *12.0%*	$ 48,320 *13.3%*
Manufacturing	**$ 39,287** ***7.3%***	$ 33,295 *8.4%*	$ 19,108 *5.2%*
Other	**$ (3,108)** ***(0.6%)***	$ (11,916) *(3.0%)*	$ (6,720) *(1.8%)*
Consolidated	**$ 541,058** ***100%***	$ 395,036 *100%*	$ 363,867 *100%*

	1982	1981	1980
Identifiable assets:			
Natural Gas Transmission	**$2,103,205**	$1,595,999	$1,066,724
	33.3%	*31.9%*	*29.1%*
Resource Development	**$2,833,495**	$2,423,045	$1,687,207
	44.8%	*48.4%*	*46.0%*
Petrochemicals	**$ 901,353**	$ 646,633	$ 585,763
	14.2%	*12.9%*	*16.0%*
Manufacturing	**$ 299,537**	$ 211,919	$ 171,513
	4.7%	*4.3%*	*4.7%*
Other	**$ 184,347**	$ 126,323	$ 152,338
	3.0%	*2.5%*	*4.2%*
Consolidated	**$6,321,937**	$5,003,919	$3,663,545
	100%	*100%*	*100%*

(c) Financial Information by Geographic Area (thousands of dollars)

	1982	1981	1980
Revenue:			
Canada	**$2,303,712**	$1,449,585	$ 996,969
	65.8%	*54.3%*	*46.9%*
United States	**$1,019,964**	$1,086,520	$ 988,796
	29.1%	*40.7%*	*46.6%*
Other	**$ 178,122**	$ 133,446	$ 139,988
	5.1%	*5.0%*	*6.5%*
Consolidated	**$3,501,798**	$2,669,551	$2,125,753
	100%	*100%*	*100%*
Net operating income:			
Canada	**$ 450,718**	$ 266,101	$ 230,830
	83.3%	*67.4%*	*63.4%*
United States	**$ 71,086**	$ 119,722	$ 118,841
	13.1%	*30.3%*	*32.7%*
Other	**$ 19,254**	$ 9,213	$ 14,196
	3.6%	*2.3%*	*3.9%*
Consolidated	**$ 541,058**	$ 395,036	$ 363,867
	100%	*100%*	*100%*
Identifiable assets:			
Canada	**$5,094,719**	$3,885,101	$2,617,833
	80.6%	*77.6%*	*71.5%*
United States	**$ 925,381**	$ 930,701	$ 917,399
	14.6%	*18.6%*	*25.0%*
Other	**$ 301,837**	$ 188,117	$ 128,313
	4.8%	*3.8%*	*3.5%*
Consolidated	**$6,321,937**	$5,003,919	$3,663,545
	100%	*100%*	*100%*

NOVA AN ALBERTA CORPORATION

Ten Year Review

Financial *(thousands of dollars except share data)*	1982	1981
Statement of Income		
Operating revenue	**$3,501,798**	2,669,551
Operating expenses	**$2,702,220**	2,059,457
Depreciation and depletion	**$ 249,151**	185,795
Loss (gain) on foreign currency translation	**$ 6,261**	17,347
Unallocated expenses	**$ 3,108**	11,916
Net operating income	**$ 541,058**	395,036
Equity in earnings of affiliated companies	**$ 5,038**	14,054
Allowance for funds used during development and construction	**$ 85,928**	74,398
Interest and expense on debt (net)	**$ 347,207**	247,869
Income before taxes and minority interest	**$ 284,817**	235,619
Petroleum gas and incremental oil revenue taxes	**$ 38,673**	16,105
Income taxes	**$ 60,956**	46,737
Minority interest	**$ 35,436**	42,915
Net income	**$ 149,752**	129,862
Assets		
Working capital (deficiency) at year end	**$ 45,747**	38,567
Additions to plant, property and equipment	**$1,221,953**	1,371,230
Investment in plant, property and equipment (cost)	**$5,658,693**	4,338,575
Investment in plant, property and equipment (net)	**$4,859,431**	3,745,700
Deferred costs (net)	**$ 143,332**	197,641
Total assets	**$6,321,937**	5,003,919
Capital Employed		
Long term debt (less due within one year)	**$2,740,612**	2,206,283
Deferred income taxes	**$ 399,336**	369,048
Minority interest	**$ 498,706**	438,326
Shareholders' equity		
Preferred shareholders	**$ 826,122**	441,235
Common shareholders	**$ 696,939**	633,078
Share Data[(1)]		
Earnings per common share		
Basic	**$ 0.80**	0.90
Fully diluted	**$ 0.74**	0.80
Dividends paid per Class "A" common share	**$ 0.40**	0.38666
Average common shares outstanding during year (thousands)	**114,341**	107,583
Number of common shares outstanding at year end (thousands)	**116,189**	110,961
Book value per common share	**$ 6.00**	5.71
Market value per common share		
High	**$ 9⅞**	14⅜
Low	**$ 5⅛**	7¼

Statistics

Shareholder Data		
Number of preferred shareholders	**41,414**	25,368
Number of common shareholders	**42,874**	40,657
Employee Data		
Number of employees of NOVA and its wholly-owned subsidiaries	**4,654**	4,573
Number of employees in other NOVA companies	**4,602**	5,400
Total number of employees in the NOVA group of companies	**9,256**	9,973

(1) *Share data has been restated, after giving effect to the 3-for-1 stock split on February 13, 1981.*

1980	1979[2]	1978[2]	1977	1976	1975	1974	1973
2,125,753	1,229,209	431,952	348,779	271,397	141,844	89,860	78,715
1,586,124	871,241	280,802	186,725	146,992	66,338	31,434	22,864
161,308	97,404	37,492	38,599	29,493	20,861	13,112	12,408
7,734	231	(6,168)	(2,184)	—	—	—	—
6,720	2,076	3,970	—	904	—	—	104
363,867	258,257	115,856	125,639	94,008	54,645	45,314	43,339
16,267	18,580	16,924	3,184	1,620	1,993	135	—
17,399	21,165	23,777	13,831	8,544	4,030	1,228	1,668
93,279	64,658	41,113	28,055	29,470	25,015	22,546	24,255
304,254	233,344	115,444	114,599	74,702	35,653	24,131	20,752
—	—	—	—	—	—	—	—
107,732	76,726	24,070	49,372	30,338	9,188	6,321	5,884
52,776	40,220	5,743	7,756	4,947	415	—	—
143,746	116,398	85,631	57,471	39,417	26,050	17,810	14,868
82,704	132,199	125,431	64,305	87,279	6,614	15,179	(4,463)
569,389	313,905	233,154	233,988	152,244	108,306	44,255	26,804
2,995,508	2,428,515	1,368,054	1,110,991	863,007	680,009	578,448	535,009
2,541,902	2,110,332	1,137,411	923,420	712,674	558,472	477,539	446,396
126,568	110,578	68,421	46,358	29,120	26,277	12,435	9,226
3,663,545	3,140,545	2,061,821	1,443,625	945,356	657,918	534,673	473,491
1,043,009	1,038,193	821,091	744,255	411,311	377,369	305,370	315,113
328,097	256,192	90,754	62,653	40,747	20,248	12,205	5,884
439,772	410,679	218,208	15,915	10,293	446	6	—
492,723	363,581	392,593	210,597	142,254	45,413	47,982	30,547
530,106	402,901	317,970	270,546	239,936	162,674	146,190	103,455
1.10	0.99	0.77	0.55	0.47	0.36	0.28	0.26
0.90	0.81	0.71	0.53	0.45	0.35	0.28	0.26
0.36	0.30833	0.25907	0.2448	0.20453	0.17333	0.14833	0.14
99,001	89,223	85,083	82,263	66,063	64,032	52,113	50,379
103,351	92,253	87,354	83,474	80,807	64,452	63,264	50,506
5.13	4.37	3.64	3.24	2.97	2.52	2.31	2.05
13⅜	9⅜	5½	5½	4⅞	4⅝	4⅝	6
8	4⅞	4⅝	4¼	3⅝	3⅜	3	3¼
28,776	22,534	25,564	12,111	12,524	6,894	7,195	7,977
33,073	31,974	31,798	29,555	26,405	23,508	23,184	22,148
2,984	2,566	2,198	2,086	1,202	1,036	907	762
5,790	5,529	5,002	1,718	2,270	993	229	142
8,774	8,095	7,200	3,804	3,472	2,029	1,136	904

(2) *The 1978 and 1979 operating revenues, depreciation and income taxes have been restated (see Note 1 to the Consolidated Financial Statements).*

Directors and Officers

Board of Directors

J. Edward Baugh – *President, Ted Baugh Resource Consultants Ltd., Calgary, Alberta (Resource Management)*

Robert Blair – *President and Chief Executive Officer of the Company*

Arthur J. E. Child – *President and Chief Executive Officer, Burns Foods Limited, Calgary, Alberta (Food Processor)*

Donald R. Getty – *President, D. Getty Investments Ltd., Edmonton, Alberta (Investments)*

J. Joseph Healy – *President, Healy Motors Limited, Edmonton, Alberta (Transportation)*

Harley N. Hotchkiss – *President, Harman Resources Ltd., Calgary, Alberta (Investments)*

William A. Howard – *Partner, Howard, Mackie, Calgary, Alberta (Barristers and Solicitors)*

Peter L. P. Macdonnell – *Partner, Milner & Steer, Edmonton, Alberta (Barristers and Solicitors)*

John R. McCaig – *Chairman and Chief Executive Officer, Trimac Limited, Calgary, Alberta (Transportation and Resource Services)*

Frederick A. McKinnon – *Retired, Calgary, Alberta*

A. Ernest Pallister – *President, Pallister Resource Management Ltd., Calgary, Alberta (Resource Management)*

H. J. Sanders Pearson – *Chairman and Chief Executive Officer, Century Sales & Service Limited, Edmonton, Alberta (Industrial Tools and Fasteners Distribution); Chairman of the Board of Directors of the Company*

Robert L. Pierce – *Executive Vice President of the Company*

Daryl K. Seaman – *Chairman, Bow Valley Industries Ltd., Calgary, Alberta (Natural Resource Services, Exploration and Development)*

Ronald D. Southern – *President and Chief Executive Officer, ATCO Ltd., Calgary, Alberta (Natural Resource Services, Property Development and Manufacturing)*

Company Officers

Senior Corporate Officers

Robert Blair – *President and Chief Executive Officer*

Robert L. Pierce – *Executive Vice President*

John E. Feick – *Senior Vice President*

Dianne I. Hall – *Senior Vice President and Secretary to the Board*

William C. Rankin – *Senior Vice President and Controller*

Bruce W. Simpson – *Senior Vice President*

Corporate Officers

George L. Bastin – *Vice President and Corporate Secretary*

William J. Beamer – *Vice President*

John W. F. Cowell, M.D. – *Vice President, Occupational Health and Safety*

Ronald D. Dooley – *Vice President*

Barry E. Harper – *Vice President*

Bruce G. Hartwick – *Vice President*

Edmond A. Lemieux – *Vice President*

Richard C. Milner – *Vice President and Treasurer*

Richard A. Molyneaux – *Vice President*

John Patterson – *Vice President and Assistant Controller*

Joan A. Dennis – *Assistant Secretary*

James D. Hinks – *Assistant Treasurer*

Alberta Gas Transmission Division

Donald G. Olafson – *Division Senior Vice President*

Robert B. Snyder – *Division Senior Vice President*

Terence N. Befus – *Division Vice President*

V. Ben Kromand – *Division Vice President*

Walter J. Litvinchuk – *Division Vice President*

C. Dale Richards – *Division Vice President*

Robert W. Schmidt – *Division Vice President*

Eric H. Shelton – *Division Vice President*

Principal Officers, Marketing Operations

CanOcean Resources Ltd.*

William A. Talley – *President (Vancouver)*

Kung Wong Chen – *Vice President (Calgary)*

Energy Equipment & Systems Inc.*

Louis K. Mihaly – *Chairman of the Board*

Ronald D. Dooley – *President (Calgary)*

Novacor Chemicals Ltd.*

Robert L. Pierce – *President and Chief Executive Officer*

John P. Sutherland – *Executive Vice President*

G. L. W. (Bud) Clark – *Senior Vice President*

John E. Feick – *Senior Vice President*

Rolland G. Frakes – *Senior Vice President (Marketing)*

Robert E. Bowser – *Vice President*

Peter C. Flynn – *Vice President*

John Kuziak – *Vice President*

William K. Stephenson – *Vice President*

Novacorp Engineering Services Ltd.*

Donald G. Olafson – *President*

Noval Technologies Ltd.*

William J. Beamer – *President*

*See facing page for addresses.

On assignment to affiliate:

William J. Deyell – *Executive Vice President, Foothills Pipe Lines (Yukon) Ltd.*

PRINTED IN CANADA

Principal Offices of NOVA Companies

CORPORATE HEADQUARTERS

NOVA, AN ALBERTA CORPORATION
801 Seventh Avenue S.W., P.O. Box 2535, Postal Station M, Calgary, Alberta, T2P 2N6; (403) 290-6000; Telex 038-21503

OFFICES IN CANADA

Offices of NOVA, AN ALBERTA CORPORATION:

ALBERTA GAS TRANSMISSION DIVISION – Edmonton Office: 9888 Jasper Avenue, P.O. Box 2330, Edmonton, Alberta, T5J 2R1; (403) 423-6111

Calgary Service Centre: 7210 Blackfoot Trail S., P.O. Box 2535, Postal Station M, Calgary, Alberta, T2P 2N6; (403) 252-8821

Edmonton Service Centre: 15810-114 Avenue, Edmonton, Alberta, T5M 2Z4; (403) 451-0531

Spruce Grove Service Centre: 425 Diamond Avenue, Spruce Grove, Alberta, P.O. Box 2330, Edmonton, Alberta, T5J 2R1; (403) 962-8807

District No. 1 Headquarters: 9615-52 Street S.E., P.O. Box 2535, Postal Station M, Calgary, Alberta, T2P 2N6; (403) 279-7201

District No. 2 Headquarters: P.O. Box 819, Brooks, Alberta, T0J 0J0; (403) 362-2838

District No. 3 Headquarters: P.O. Box 1808, Edson, Alberta, T0E 0P0; (403) 723-3371

District No. 4 Headquarters: P.O. Box 1650, Vegreville, Alberta, T0B 4L0; (403) 632-3336

Offices of Principal Subsidiaries and Certain Affiliate Companies:

ALBERTA GAS CHEMICALS LTD. – Third Floor, 11456 Jasper Avenue, Edmonton, Alberta, T5K 0M1; (403) 482-6361

THE ALBERTA GAS ETHYLENE COMPANY LTD. – Suite 1600, 734 Seventh Avenue S.W., Calgary, Alberta, T2P 3P9; (403) 290-8088

CANOCEAN RESOURCES LTD. – 610 Derwent Way, New Westminster, British Columbia, V3M 5P8; (604) 524-4451

DIAMOND SHAMROCK ALBERTA GAS – Suite 1600, 734 Seventh Avenue S.W., Calgary, Alberta, T2P 3P9; (403) 290-8977

ENERGY EQUIPMENT & SYSTEMS INC. – P.O. Box 2535, Postal Station M, Calgary, Alberta, T2P 2N6; (403) 290-6000

FOOTHILLS PIPE LINES (YUKON) LTD. – Suite 1600, 205 Fifth Avenue S.W., Calgary, Alberta, T2P 2V7; (403) 294-4111

HUSKY OIL LTD. – P.O. Box 6525, Postal Station D, Calgary, Alberta, T2P 3G7; (403) 267-6111

NOVACOR CHEMICALS LTD. – Suite 1600, 734 Seventh Avenue S.W., Calgary, Alberta, T2P 3P9; (403) 290-8977

NOVACORP ENGINEERING SERVICES LTD. – 801 Seventh Avenue S.W., P.O. Box 2535, Postal Station M, Calgary, Alberta, T2P 2N6; (403) 290-6000

NOVAL TECHNOLOGIES LTD. – Esso Plaza, Ninth Floor, East Tower, 425 First Street S.W., Calgary, Alberta, T2P 3L8; (403) 290-7752

NOVALTA PROPERTIES LTD. – Suite 1400, 801 Seventh Avenue S.W., P.O. Box 2535, Postal Station M, Calgary, Alberta, T2P 2N6; (403) 290-6260

NOVALTA RESOURCES LTD. – Suite 700, Home Oil Tower, 324 Eighth Avenue S.W., P.O. Box 2870, Calgary, Alberta, T2P 2M7; (403) 261-3630

NOVA/HUSKY RESEARCH CORPORATION – 1411-25 Avenue N.E., Calgary, Alberta, T2E 7L6; (403) 276-9844

PAN-ALBERTA GAS LTD. – Suite 350, 202 Sixth Avenue S.W., Calgary, Alberta, T2P 2R9; (403) 265-1763

TRANS QUÉBEC & MARITIMES PIPELINE INC. – Sixth Floor, 870 de Maisonneuve Blvd. East, Montreal, Quebec, H2L 1Y6; (514) 286-5000

WESTERN STAR TRUCKS INC. – 6205 Airport Road, Mississauga, Ontario, L4V 1E2; (416) 677-9800

MAIN OFFICES OUTSIDE CANADA

ALBERTA GAS CHEMICALS INC. – 7 Century Drive, Parsippany, New Jersey, U.S.A., 07054; (201) 267-1400

CANOCEAN RESOURCES LTD. – Suite 220, Two Greenbriar Place, 652 North Belt, Houston, Texas, U.S.A., 77060; (713) 931-1945

CanOcean House, 1 Francis Grove, Wimbledon, England, SW19 4DT; (01) 946-3910

ENERGY EQUIPMENT & SYSTEMS INC. – Suite 904, Spear Street Tower, One Market Plaza, San Francisco, California, U.S.A., 94105; (415) 777-1607

GROVE ITALIA – Strada Campoferro 15, 27058 – Voghera, Italy; (0383) 6911

GROVE VALVE AND REGULATOR COMPANY – 6529 Hollis Street, Oakland, California, U.S.A., 94608; (415) 655-7700

HUSKY OIL COMPANY – 600 South Cherry Street, Denver, Colorado, U.S.A., 80222; (303) 370-1300

1501 Stampede Avenue, P.O. Box 380, Cody, Wyoming, U.S.A., 82414; (307) 578-1000

LEDEEN FLOW CONTROL SYSTEMS, INC. – 9200 Glen Oaks Boulevard, Sun Valley, California, U.S.A., 91352; (213) 767-1800

NOVACORP ENGINEERING SERVICES LTD. – 1901 Hong Chong Building, 5 Queens Road Central, Hong Kong; 5-229-064/5

PIPELINE HYDRAULICS ENGINEERING INC. – Suite 110, 8800 Jameel Road, Houston, Texas, U.S.A., 77040; (713) 939-1260

WAGI INTERNATIONAL S.p.A. – Via Parigi 11, 00185-Rome, Italy; (06) 475-6896

Design
The Design Works
Photography
Dale Hannaford
Peter Leon
Hilda Onions
James Wilson
Printing
Mitchell Press Limited