UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 20-F

☐ **REGISTRATION STATEMENT PURSUANT TO SECTION 12(b) OR (g) OF THE SECURITIES EXCHANGE ACT OF 1934**

OR

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2001

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission File Number: 1-14614

Petroleum Geo-Services ASA

(Exact name of registrant as specified in its charter)

Kingdom of Norway
(Jurisdiction of incorporation or organization)

Strandveien 4, N-1366 Lysaker, Norway
(Address of principal executive offices)

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

Title of each class	Name of each exchange on which registered
American Depositary Shares, each representing one ordinary share of nominal value NOK 5 per share	New York Stock Exchange
PGS Trust I 9⅝% Trust Preferred Securities	New York Stock Exchange

Securities registered or to be registered pursuant to Section 12(g) of the Act: None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act: None

As of December 31, 2001, the number of ordinary shares, nominal value NOK 5 per share, outstanding was 103,345,987.

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

Yes ☑ No ☐

Indicate by check mark which financial statement item the registrant has elected to follow.

Item 17 ☐ Item 18 ☑

PETROLEUM GEO-SERVICES ASA

ANNUAL REPORT ON FORM 20-F FOR THE FISCAL YEAR ENDED DECEMBER 31, 2001

TABLE OF CONTENTS

		Page
US Dollar Presentations		2
Where You Can Find More Information		2
Forward-Looking Information		3
PART I		
ITEM 1.	Identity of Directors, Senior Management and Advisors	4
ITEM 2.	Offer Statistics and Expected Timetable	4
ITEM 3.	Key Information	4
ITEM 4.	Information on the Company	12
ITEM 5.	Operating and Financial Review and Prospects	35
ITEM 6.	Directors, Senior Management and Employees	51
ITEM 7.	Major Shareholders and Related Party Transactions	55
ITEM 8.	Financial Information	56
ITEM 9.	The Offer and Listing	57
ITEM 10.	Additional Information	58
ITEM 11.	Quantitative and Qualitative Disclosures About Market Risk	66
ITEM 12.	Description of Securities Other than Equity Securities	66
PART II		
ITEM 13.	Defaults, Dividend Arrearages and Delinquencies	67
ITEM 14.	Material Modifications to the Rights of Security Holders and Use of Proceeds	67
PART III		
ITEM 17.	Financial Statements	67
ITEM 18.	Financial Statements	67
ITEM 19.	Exhibits	67

US DOLLAR PRESENTATIONS

In this Form 20-F, references to “US dollars” and “$” are to United States dollars; references to “NOK” are to Norwegian kroner; and references to “British pounds” and “£” are to British pounds sterling.

WHERE YOU CAN FIND MORE INFORMATION

We have filed this annual report on Form 20-F with the Securities and Exchange Commission under the Securities Exchange Act of 1934. Statements made in this annual report as to the contents of any agreement or other document referred to are not necessarily complete. For each such agreement or other document filed as an exhibit to this annual report, we urge you to refer to the exhibit for a more complete description of the matter involved. We are subject to the informational requirements of the Exchange Act that apply to foreign private issuers and file reports and other information with the SEC. Reports and other information we file with the SEC, including this annual report on Form 20-F, may be inspected and copied at the public reference facilities of the SEC at 450 Fifth Street N.W., Washington D.C. 20549.

You can also obtain copies of this material by mail from the Public Reference Room of the SEC, 450 Fifth Street, N.W., Washington, D.C. 20549, at prescribed rates. The SEC’s telephone number is

1-800-SEC-0330. Additionally, information that we file electronically with the SEC may also be obtained from its Internet site at *http://www.sec.gov*.

FORWARD-LOOKING INFORMATION

Some of the statements contained in this annual report are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. They include such matters as:

- the repayment or refinancing of debt and the effects of possible credit rating downgrades
- liquidity and future cash flows
- future capital expenditures and investments in our geophysical and production assets, including Atlantis-related development costs, and future investments in our multi-client library
- market conditions, technological developments and other trends in the seismic data industry
- business strategies
- maintaining and obtaining contracts for our floating production, storage and offloading vessels
- acquisition of contract and multi-client seismic data
- licensing activities in Norway, West Africa and the Asia Pacific region
- amortization charges for our multi-client library
- expected future sales of seismic data
- utilization and upgrading of our seismic vessels and equipment, including the *Ramform Banff*
- future operating results and financial condition

These statements:

- address activities, events or developments that we expect, believe, anticipate or estimate will or may occur in the future
- are based on assumptions and analyses that we have made and that we believe were reasonable under the circumstances when made
- are based on many assumptions, uncertainties and other factors, many of which are beyond our control

Any one of these assumptions, uncertainties or other factors, or a combination of these assumptions, uncertainties or other factors, could materially affect our future results of operations, financial position, cash flows and whether the forward-looking statements ultimately prove to be accurate. These forward-looking statements are not guarantees of our future performance, and our actual results, financial position, cash flows and future developments may differ materially from those projected in the forward-looking statements. When considering these forward-looking statements, you should keep in mind the risk factors and other cautionary statements elsewhere in this annual report. We will not update these statements unless the securities laws require us to do so. Please read "Key Information — Risk Factors" in Item 3 of this annual report.

PART I

ITEM 1. ***Identity of Directors, Senior Management and Advisors***

Not applicable.

ITEM 2. ***Offer Statistics and Expected Timetable***

Not applicable.

ITEM 3. ***Key Information***

Selected Financial Data

We have presented below, on the basis of United States generally accepted accounting principles, our selected consolidated financial data for the five-year period ended December 31, 2001. Independent accountants have audited our financial statements for each of the five years in the period ended December 31, 2001. From these consolidated financial statements, we have derived the financial data presented below for such periods and as of such dates. You should read the financial data for the three-year period ended December 31, 2001 and as of December 31, 2001 and 2000 in conjunction with, and the financial data are qualified in their entirety by reference to, our financial statements and notes included in Item 18 of this annual report. Our financial statements and related notes as of and for the years ended December 31, 2000, 1999 and 1998 have previously been restated in our Form 20-F/A dated February 15, 2002 as described in note 24 to our financial statements included in Item 18 of this annual report to:

- reflect fair value accounting for tax equalization swap contracts entered into in 1998 and 1999 to hedge our exposure to Norwegian taxes arising out of the conversion, for Norwegian tax purposes, of our US dollar denominated debt into Norwegian kroner
- reflect the adoption of Staff Accounting Bulletin ("SAB") No. 101, "Revenue Recognition in Financial Statements", which became effective January 1, 2000, to our revenue recognition policy for some types of volume seismic data licensing arrangements

The financial data presented below and in our financial statements and related notes included in Item 18 of this annual report as of and for those years have been further restated as described in note 24 to:

- properly capitalize interest cost associated with the upgrade of floating production, storage and offloading vessels
- properly reflect property and equipment, multi-client library and depreciation and amortization related to two of our seismic vessels
- reflect uncertainties regarding the future utilization of deferred tax assets in the form of a valuation allowance against these tax assets
- properly amortize multi-client library in accordance with our minimum amortization policy
- properly amortize deferred assets over their useful lives and accrue defined benefit pension obligations, commission/royalty liabilities and lease liabilities as incurred

We have presented earnings before interest, taxes, depreciation and amortization and unusual items, or EBITDA, in the table to provide additional information about our financial performance. Our management uses EBITDA as a supplemental financial measurement in the evaluation of our business. You should not consider EBITDA as an alternative to net income, as an indicator of operating performance or as an alternative to cash flows as a measure of liquidity.

	2001	2000	1999	1998	1997
	Years ended December 31(1)				
	(In thousands, except for share data)				
		(As restated)	(As restated)	(As restated)	
STATEMENT OF OPERATIONS DATA					
Revenue	$ 1,052,628	$ 913,482	$ 788,160	$ 761,762	$ 539,381
Operating profit (loss)	205,978	(231,494)	39,072	143,968	126,356
Income (loss) before extraordinary charge and cumulative effect of accounting change(2)(3)	4,453	(204,960)	(13,839)	107,684	77,584
Extraordinary charge, net of tax(2)	—	—	—	—	(3,447)
Cumulative effect of accounting change, net of tax(3)	—	(6,555)	(19,977)	—	—
Net income (loss)	$ 4,453	$ (211,515)	$ (33,816)	$ 107,684	$ 74,137
Operating profit (loss) per share:					
Basic	$ 2.00	$ (2.27)	$ 0.41	$ 1.75	$ 1.96
Diluted	$ 2.00	$ (2.27)	$ 0.41	$ 1.70	$ 1.88
Income (loss) per share before extraordinary charge and cumulative effect of accounting change(2)(3):					
Basic	$ 0.04	$ (2.01)	$ (0.15)	$ 1.31	$ 1.20
Diluted	$ 0.04	$ (2.01)	$ (0.15)	$ 1.27	$ 1.15
Net income (loss) per share:					
Basic	$ 0.04	$ (2.07)	$ (0.36)	$ 1.31	$ 1.15
Diluted	$ 0.04	$ (2.07)	$ (0.36)	$ 1.27	$ 1.10
Basic shares outstanding	102,768,283	102,020,830	94,767,967	82,260,652	64,519,503
Diluted shares outstanding	102,788,055	102,020,830	94,767,967	84,794,836	67,358,004
BALANCE SHEET DATA (end of period)					
Total assets	$ 4,302,806	$ 4,278,706	$ 4,184,997	$ 3,426,627	$ 1,677,848
Multi-client library, net	918,072	848,720	816,423	553,415	325,181
Total long-term debt and capital lease obligations	1,945,254	2,171,981	1,998,530	1,421,670	550,450
Mandatorily redeemable preferred subsidiary securities	163,588	—	—	—	—
Guaranteed preferred beneficial interest in subordinated debt securities	141,000	140,050	139,164	—	—
Capital stock	1,296,204	1,286,426	1,278,999	1,058,811	580,991
Shareholders' equity	1,361,447	1,349,978	1,568,417	1,393,238	811,347
OTHER DATA					
EBITDA(4)	$ 434,572	$ 397,875	$ 367,503	$ 443,504	$ 318,049
Cash flows from operating activities	211,702	158,157	200,678	274,656	228,686
Capital expenditures	239,623	115,217	667,869	521,630	468,872
Investment in multi-client library	230,166	264,541	338,718	388,228	203,267

(1) We have made some reclassifications to conform prior year amounts with the current year presentation. We restated our fiscal 2000, 1999 and 1998 financial statements as described in note 24 of the notes to our financial statements. The effects of the restatements for the years ended December 31, 2000, 1999 and 1998 were net, non-cash charges of $23.9 million, $17.5 million and $3.9 million, respectively.

(2) During March 1997, we prepaid our $30 million 7.12% senior notes due February 2004 and our $95 million 7.33% senior notes due February 2006. As a result, we incurred an extraordinary charge of $3.4 million, net of tax benefits of $1.3 million. The extraordinary charge consisted of a write-off of the associated debt issuance costs and the prepayment premium.

(3) Effective January 1, 2000, we adopted SAB No. 101. Application of this SAB required that we defer revenue recognition on some types of volume seismic data licensing arrangements until we have entered into a license agreement for specific data with the customer. Accordingly, we recognized a charge to income of $6.6 million, net of tax benefits of $2.5 million, as the cumulative effect of the change in accounting principle. Effective January 1, 1999, we adopted Statement of Position ("SOP") 98-5, "Reporting on the Costs of Start-up Activities." This SOP requires that the initial, one-time costs related to introducing new products and services, conducting business in new territories or commencing new operations be expensed as incurred. Accordingly, we have recognized a charge to income of $20.0 million, net of tax benefits of $8.1 million, for the year ended December 31, 1999 as the cumulative effect of the change in accounting principle.

(4) We define EBITDA for this purpose as operating profit before depreciation and amortization and unusual items.

Risk Factors

You should carefully consider the risks described below. The risks and uncertainties described below are not the only ones facing our company. Additional risks and uncertainties not presently known to us or that we currently do not believe are material may also impair our financial condition or our business operations. If any of the following risks actually occur, our business, financial condition or results of operations could be materially adversely affected and the trading price of our shares could decline significantly.

Risk Factor Relating to Our Pending Transactions Involving Veritas DGC Inc. and Our Atlantis Subsidiary

We may not be able to complete our pending combination transaction with Veritas or the pending sale of our Atlantis subsidiary.

Both of these transactions include conditions to closing that depend on the actions of third parties and are therefore outside of our control. In addition, the Veritas transaction is itself conditioned on closing the Atlantis sale. As a result, we may not be able to complete these transactions or the transactions could be delayed. If we fail to complete the sale of Atlantis, we could suffer adverse consequences, including a downgrade of our debt and trust preferred securities credit ratings by one or more credit rating agencies. If we fail to complete the transaction with Veritas, we could suffer similar adverse consequences. Please read "Information on the Company — Recent Developments — Combination with Veritas" and "— Sale of Atlantis" in Item 4, "Operating and Financial Review and Prospects — Financial Condition — Capital Resources and Liquidity" in Item 5 and note 3 of the notes to our financial statements in Item 18 of this annual report.

Risk Factors Relating to Our Financial Condition

Our debt could be downgraded by one or more rating agencies.

As of May 3, 2002, Moody's Investors Service, Inc. had rated our senior unsecured debt at Baa3, its lowest investment grade credit rating, and had placed that credit rating under review for possible downgrade. At that date, Standard & Poor's Ratings Services, a division of The McGraw-Hill Companies, Inc., had rated our senior unsecured debt at BBB-, its lowest investment grade credit rating, and had placed that credit rating on creditwatch with negative implications, and Fitch IBCA, Duff & Phelps had rated our senior unsecured debt at BBB-. If one or more rating agencies downgrades our debt or trust preferred securities, we may have difficulty obtaining financing and our cost of obtaining additional financing or refinancing existing debt may be increased significantly. A credit rating downgrade would cause the interest rate on our $250.0 million short-term bank facility to increase by up to 3.5% and would most likely require us to seek refinancing alternatives for the facility that would not otherwise be required. In addition, credit rating downgrades to below BB+ or Ba1 by Standard & Poor's or Moody's, respectively, would require us to increase by 30% the quarterly redemption of the mandatorily redeemable cumulative preferred securities of a subsidiary which owns a portion of our multi-client library. If those credit ratings remain for a certain period of time or deteriorate below BB- or Ba3, respectively, we must increase the quarterly redemption of the preferred securities to an amount equal to 100% of the actual revenue recognized from the licensing of the data held by that subsidiary. In the event of a credit rating downgrade by both Standard & Poor's and Moody's, we may be required to provide collateral or other credit support to one or more lessors or other parties under UK leasing arrangements, which could adversely affect our liquidity.

We are highly leveraged.

As of December 31, 2001, we had approximately $2.8 billion of outstanding debt, lease and preferred securities obligations. We estimate our total cash obligations for these commitments to be $454.2 million, $723.1 million and $94.7 million for the years ended December 31, 2002, 2003 and 2004, respectively.

Because of the level of our debt and other contractual cash obligations:

- a substantial portion of our cash flow from operations must be dedicated to debt service and payments of such obligations and, to the extent so used, will not be available for operational purposes
- our ability to obtain additional financing in the future may be limited and
- our flexibility in reacting to changes in the operating environment and economic conditions, including possible future downturns in our business, may be limited

We are highly dependent on external sources of financing, improved cash flow and proceeds from asset sales to meet our obligations and reduce our indebtedness in the future.

In the short-term, we expect a substantial portion of our liquidity to be provided by our committed $430.0 million revolving credit facility and several uncommitted bank lines. As of March 31, 2002, we had $70.0 million of borrowing capacity under our committed revolving credit facility and approximately $40.0 million available under other uncommitted facilities. Additional borrowings under our committed revolving credit facility are subject to a material adverse change clause regarding our financial condition and to other conditions to borrowing that are customary for such types of facilities. If either or both of these sources of liquidity were not to be available, we would be substantially dependent on operating cash flow, asset sales and external sources of financing other than bank lines for our liquidity needs.

In the longer term, our ability to pay debt service and other contractual obligations will depend on improving our future performance and cash flow generation, which in turn will be affected by prevailing economic and industry conditions and financial, business and other factors, many of which are beyond our control. If we have difficulty paying debt service or other contractual obligations in the future, we will be forced to take actions such as reducing or delaying capital expenditures, reducing costs, selling assets, refinancing or restructuring our debt or other obligations and seeking additional equity capital. We may not be able to take any of these actions on satisfactory terms or at all.

Our debt agreements may limit our flexibility in responding to changing market conditions or in pursuing business opportunities.

Our debt agreements contain restrictions and requirements relating to, among other things:

- the issuance of additional indebtedness
- the maintenance of credit ratings
- the maintenance of financial ratios
- the encumbrance or sale of assets
- the payment of dividends
- capital expenditures

- mergers
- sale/leaseback transactions

These restrictions and requirements may limit our flexibility in responding to changing market conditions or in pursuing opportunities that we believe would have a positive effect on our business.

Risk Factors Relating to Our Business Operations

Our business could be adversely affected if low oil and gas prices decrease demand for our services.

Our business and operations depend upon exploration, development and production spending by oil and gas companies. Low oil and gas prices, and concerns about possible low oil and gas prices in the future, may reduce the level of that spending. As overall conditions in the oil and gas industry deteriorate, demand for our services and products may decrease and our business may be adversely affected. Furthermore, recoveries in oil and gas prices do not immediately increase exploration, development and production spending, so improved demand for our services and products will generally lag oil and gas price increases. In December 2000, we recognized impairment charges, including multi-client library impairment charges, totaling $365.8 million, primarily due to weakness in our geophysical services business. We also recognized $13.2 million in multi-client library impairment charges in 2001.

We could incur operating losses if we cannot keep our vessels and other equipment utilized at high levels.

Our businesses are capital intensive and generally require significant investments in multi-client data, vessels and processing, seismic and other equipment. As a result, we incur relatively high fixed costs in our operations. If we cannot keep our vessels and other equipment utilized at high levels, we could incur significant operating losses.

In 2000 and 1999, we incurred net losses of $211.5 million and $33.8 million, respectively. In 2001, we had net income of $4.5 million on revenue of $1.1 billion. We may incur losses in the future.

We invest significant amounts of money in acquiring and processing seismic data for our data library without knowing how much of the data we will be able to sell or at what price we will be able to sell the data.

We invest significant amounts in acquiring and processing seismic data that we own, which we call multi-client data. By making such investments, we assume the risk that:

- we may not fully recover the costs of the data through future sales
- the value of our multi-client data could be adversely affected if any material adverse change occurred in the general prospects for oil and gas exploration, development and production activities in the areas where we acquire multi-client data

Our future sales are uncertain and depend on a variety of factors, many of which are beyond our control. In addition, the timing of these sales can vary greatly from period to period. Technological or regulatory changes or other developments also could adversely affect the value of the data.

During 2001 and 2000, we recognized impairment charges of $13.2 million and $166.5 million, respectively, against our multi-client library.

The amounts we amortize from our data library each period may fluctuate significantly, and these fluctuations can have a significant effect on our reported results of operations.

How we account for our data library has a significant effect on our reported results of operations. We amortize the cost of our multi-client data library based in part on our estimates of future sales of data. These estimates:

- are inherently imprecise
- may vary from period to period depending upon market developments and our expectations
- may result in periodic determinations of permanent value impairment

Substantial changes in amortization rates can have a significant effect on our reported results of operations.

In addition, our accounting policy requires that we reduce the book value of our individual seismic surveys to a specified percentage of gross cost at the end of each year regardless of sales. In December 2001 and 2000, we recognized $39.1 million and $2.2 million, respectively, in such minimum amortization charges. We recognize minimum amortization charges quarterly beginning in the second quarter of each year, when we evaluate on a survey-by-survey basis the minimum amortization requirements against the remaining sales estimates for that year.

Unpredictable changes in governmental regulations could increase our operating costs and reduce demand for our services.

Our operations are affected by a variety of laws and regulations, including those relating to:

- the protection of the environment
- exports and imports
- occupational health and safety
- permitting or licensing requirements for seismic activities and for oil and gas exploration, development and production activities

We and our customers are required to invest financial and managerial resources to comply with these laws and regulations. Because these laws and regulations and our business change from time to time, we cannot predict the future costs of complying with these laws and regulations, and our expenditures could be material in the future. Modification of existing laws or regulations or adoption of new laws or regulations limiting exploration or production activities by oil and gas companies or imposing more stringent restrictions on seismic or hydrocarbon production-related operations could adversely affect us by increasing our operating costs and/or reducing the demand for our services.

Our results of operations could suffer as a result of risks arising from our floating production, storage and offloading contracts.

Our floating production, storage and offloading contracts involve various risks, including risks of:

- failure to commence production from floating production, storage and offloading vessels in a timely manner
- failure to operate at high uptime performance levels on a sustained basis for technical reasons, including operational difficulties that require reworking of vessels
- termination
- redeployment of vessels following expiration or termination of long-term contracts
- failure to produce expected amounts of oil and gas under contracts where our compensation depends on the amount of oil and gas produced

Our FPSO vessel *Ramform Banff* is producing under contract at levels substantially below its capacity and, as a result, is currently operating at a loss.

We have received notice of termination of the contract for the Varg field, which is being produced by the FPSO vessel *Petrojarl Varg.* The contract is scheduled to terminate in July 2002. If and when we complete our acquisition of the 70% interest in Production License 038, which includes the Varg field, we expect to extend the terms of the contract on terms similar to the existing terms. Please read "Information on the Company — FPSO Operations — Varg Field Contract" in Item 4 of this annual report.

Because we conduct a substantial amount of international operations, we have exposure to those risks inherent in doing business abroad.

A significant portion of our revenue is derived from operations outside the United States and Norway and is subject in varying degrees to risks inherent in doing business abroad. These risks include:

- war and terrorist activities
- the possibility of unfavorable changes in tax or other laws
- partial or total expropriation
- restrictions on currency repatriation
- the disruption of operations from labor and political disturbances
- the imposition of new laws or regulations that have the effect of restricting operations or increasing the cost of operations
- the disruption or delay of licensing or leasing activities
- the requirements of partial local ownership of operations

We are subject both to hazards customary for marine operations and to those more specific to our seismic and floating production, storage and offloading operations.

Substantially all of our operations are subject to perils that are customary for marine operations, including capsizing, grounding, collision, interruption and damage from severe weather conditions, fire, explosions and environmental contamination from spillage. Any of these risks could result in damage to or destruction of vessels or equipment, personal injury and property damage, suspension of operations or environmental damage. In addition, our operations involve risks of a technical and operational nature due to the complex systems that we utilize.

Because we do not have insurance to cover some operating risks, our results of operations could be adversely affected if one or more of those risks occurred.

We cannot always obtain full insurance for all of our operating risks. We carry insurance against the destruction of or damage to our seismic and floating production, storage and offloading vessels and equipment in amounts that we consider adequate. However, as a result of market conditions following the events of September 11, 2001, premiums and deductibles for some of our insurance policies are expected to increase substantially, and coverages may be decreased, when we next seek to renew our coverages. For example, insurance carriers are now requiring broad exclusions for losses due to war risk and terrorist acts. In addition, some types of insurance coverage could become unavailable or available only at very expensive premiums or for reduced amounts of coverage.

Because we generate revenue and incur expenses in various currencies, exchange rate fluctuations and devaluations could have a material impact on our results of operations.

Currency exchange rate fluctuations and currency devaluations could have a material impact on our results of operations from time to time. Although we periodically undertake hedging activities in an attempt to reduce certain currency fluctuation risks, these activities do not provide complete protection from currency-related losses. In recent periods, we have been required to recognize charges relating to the fair value of tax equalization swap agreements due to changes in the exchange rate between the Norwegian kroner and the United States dollar. Additionally, in some circumstances our hedging activities can require us to make cash outlays.

Other Risk Factors

We could become liable for substantial taxes if we fail to qualify for the Norwegian shipping tax regime.

A significant portion of our operations are subject to the Norwegian shipping tax regime and are therefore taxed at a zero rate. Qualification under the Norwegian shipping tax regime is subject to special qualifications and requirements, many of which are continuing and require strict compliance by us. The Norwegian government could change or add to such qualifications and requirements. If we fail to comply with the requirements of the regime or if we are determined not to be entitled to the benefits under the regime, we could become liable for substantial taxes, which could have a material adverse effect on our financial position and results of operations.

Because we are a foreign company and many of our directors and executive officers are not residents of the United States, you may have difficulty suing us and obtaining or enforcing judgments against us.

We are incorporated in the Kingdom of Norway, and many of our current directors and executive officers do not reside in the United States. All or a substantial portion of the assets of these persons and of PGS are/is located outside the United States. As a result, you may have difficulty:

- suing us or our directors and executive officers in the United States
- obtaining a judgment in Norway in an original action based solely on United States federal securities laws
- enforcing in Norway judgments obtained in the United States courts that are based upon the civil liability provisions of the United States federal securities laws

ITEM 4. *Information on the Company*

Overview of Who We Are

We are a public limited liability company established under the laws of the Kingdom of Norway in 1991. We are organized as a holding company that owns subsidiary companies. Our subsidiary companies conduct substantially all of our business. Unless we inform you otherwise or the context indicates otherwise, references to us in this annual report are to Petroleum Geo-Services ASA, its predecessors and its majority-owned subsidiaries. We maintain executive offices in both Lysaker, Norway (Strandveien 4, N-1366, 011-47-67-52-6600) and Houston, Texas (16010 Barker's Point Lane, 77079, 281-589-7935, Attention: Chief Financial Officer).

We are a technologically focused oilfield service company. Our business includes:

- acquiring, processing and marketing seismic data. Oil and gas companies use the data to explore for new oil and gas reserves, to develop existing oil and gas reservoirs and to manage producing oil and gas fields.
- providing floating production, storage and offloading, or FPSO, vessels. These vessels permit oil and gas companies to produce oil and gas from offshore fields and to process, store and offload the oil and gas for transport to refineries, distribution companies and end-users. We also provide various production management services related to these operations.
- providing geophysical and other services that help oil and gas companies monitor producing oil and gas reservoirs to increase ultimate recoveries

Business Strategies

Our principal business strategies include:

- using, developing and investing in advanced technologies for the acquisition, processing, interpretation and marketing of seismic data
- increasing the returns from our geophysical business by using our advanced geophysical technologies and reservoir expertise and by increasing our current market share
- increasing the returns from our production business by maintaining a high level of operational performance, actively pursuing various redeployment opportunities and using our geophysical knowledge and technology to maximize opportunities
- using the capabilities of our Ramform seismic vessels to capitalize on market opportunities for high-definition seismic data
- increasing our emphasis on the international seismic contract market
- reducing costs and maximizing cash flow from operations

Recent Developments

Combination with Veritas

In November 2001, we entered into an agreement with Veritas DGC Inc., a geophysical services company, to combine the businesses of the two companies under a new Cayman Islands holding company, which we refer to as "Caymanco." Under the agreement, Caymanco will make an exchange offer to issue its ordinary shares in exchange for our outstanding shares and American Depositary Shares representing our shares, or ADSs. Following the closing of the exchange offer, Veritas will merge with a wholly owned subsidiary of Caymanco. Upon closing of the exchange offer and the merger, PGS and Veritas will become subsidiaries of Caymanco. The closing of the transaction is subject to a number of conditions, including:

- the tender in the exchange offer of PGS shares and ADSs representing more than 90% of the PGS shares outstanding as of the expiration of the exchange offer, which percentage may be reduced in limited circumstances described in the agreement
- the approval of the merger by the stockholders of Veritas
- the receipt of applicable regulatory clearances
- PGS' having in effect definitive credit agreements or binding commitments providing for credit capacity of $430 million
- Veritas' having in effect definitive credit agreements or binding commitments providing for credit capacity of $235 million
- the authorization of the ordinary shares of Caymanco for listing on the New York Stock Exchange
- PGS' having completed the previously announced sale of its Atlantis subsidiary
- PGS' having entered into replacement employment agreements with some of its active employees
- other customary conditions, including the absence of any events or series of events that has had or would have a material adverse effect on Veritas or PGS

Under the agreement, a material adverse effect will be deemed to have occurred and either party may terminate the agreement if, among other things:

- the settlement price for the NYMEX natural gas futures contract for delivery 12 months following the month in which the relevant date of determination occurs falls below $2.25 per MMBtu for 20 consecutive trading days or
- the settlement price for the NYMEX light sweet crude oil futures contract for delivery 12 months following the month in which the relevant date of determination occurs falls below $12.50 per barrel for 20 consecutive trading days

A number of the conditions to the transaction have been satisfied, including expiration of the applicable waiting periods under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, receipt of appropriate clearance under UK competition law and our receipt of waivers under our $430 million credit facility sufficient to satisfy the related condition under the agreement.

We have had discussions with Veritas about amending the terms of the agreement in various respects. Although no definitive amendment has been reached, we expect any such amendment to include the following key terms:

- our shareholders would receive 0.40 shares (previously 0.47 shares) of Caymanco for each of our shares or ADSs, and Veritas shareholders would receive one share of Caymanco for each Veritas share, resulting in Veritas shareholders owning approximately 44% of the Caymanco shares and our shareholders owning approximately 56% of the Caymanco shares upon completion of the transaction (assuming all our shares and ADSs are tendered and accepted in the exchange offer)
- Veritas would be entitled to nominate six of the proposed ten directors of Caymanco while we would be entitled to nominate four directors
- David B. Robson, the Chief Executive Officer of Veritas, would be the Chief Executive Officer of Caymanco and Reidar Michaelsen, our Chairman and Chief Executive Officer, would be the Chairman of the Board
- Matthew D. Fitzgerald, the Chief Financial Officer of Veritas, would be the Chief Financial Officer of Caymanco

- the transaction would be conditioned upon Veritas being treated as the acquiring company for accounting purposes

In April 2002, Veritas reported that the SEC staff would not object to Veritas being treated as the accounting acquiror. Any amendment to our agreement with Veritas would be subject to final approval of the boards of directors of each company.

If we and Veritas amend the original agreement along the lines described above and assuming all conditions precedent were satisfied or waived, we would expect the transaction to close during the third quarter of 2002. However, we or Veritas may not be able to satisfy all the conditions to closing, including the sale of our Atlantis subsidiary, and there is no assurance that any conditions that are not satisfied will be waived. In addition, the original agreement, which is still in effect, provides that either party may terminate the agreement if the transaction has not been effected by June 30, 2002. Accordingly, the transaction may not close by the third quarter of 2002 or at all. Please read "Key Information — Risk Factors — Risk Factor Relating to Our Pending Transactions Involving Veritas DGC Inc. and Our Atlantis Subsidiary" in Item 3 of this annual report.

Sale of Atlantis

In January 2002, we entered into an agreement with China National Chemicals Import and Export Corporation, or "Sinochem," for the sale of our Atlantis subsidiary. We expect proceeds from the sale to be approximately $200 million plus certain qualifying capital expenditures incurred during 2002. Sinochem also has agreed to assume $20.5 million of Atlantis' short-term debt. Consummation of the sale is subject to a number of conditions, including the receipt of various consents and waivers from governmental authorities and partners.

In April 2002, we agreed with Sinochem to extend the period to close the sale through June 28, 2002, although Sinochem has the right under the extension to terminate the agreement after May 27, 2002. Under the extension agreement, if the required closing conditions are satisfied or are waived by Sinochem after May 20, 2002, then the sale proceeds will be reduced by $100,000 per day from May 13, 2002 through the date that the closing conditions are so satisfied or waived. If we terminate the agreement after June 28, 2002, we may be required to pay a $1.4 million termination fee to Sinochem. If the sale is not consummated and the agreement is terminated, we will continue to develop Atlantis' oil and gas properties and may seek to dispose of Atlantis to either Sinochem under a new agreement or to another buyer. We are continuing to pursue fulfillment of the conditions to closing of the sale of our Atlantis subsidiary. However, as several of the conditions are beyond our control, we may not be able to satisfy all conditions, and the transaction may not close. Please read "Key Information — Risk Factors — Risk Factor Relating to Our Pending Transactions Involving Veritas DGC Inc. and Our Atlantis Subsidiary" in Item 3 of this annual report.

Seismic Background

Overview

Oil and gas companies use geophysical or seismic surveys to help them find oil and gas and to determine the size and structure of known oil and gas reservoirs. Seismic projects generally consist of planning a seismic survey and acquiring, processing and interpreting seismic data. Such data are then used to produce computer-generated graphic two-dimensional, or 2D, cross-sections or three-dimensional, or 3D, images of the subsurface. Oil and gas companies use these seismic images in evaluating whether to acquire new leases or licenses in areas with potential accumulations of oil and gas, in selecting drilling locations and in managing producing reservoirs.

We refer to the repetition of identical 3D surveys over the same area at different time intervals as 4D data or surveys. Oil and gas companies use these surveys to gain an understanding of subsurface geophysical conditions that change over time due to the depletion and production of the reservoir fluids.

Contract and Multi-Client Data

We acquire seismic data both on an exclusive contract basis for our customers and on our own behalf as multi-client data for licensing on a non-exclusive basis to others. We acquire contract data for the specific client that requests the data. We acquire and retain ownership of multi-client data for licensing from time to time to multiple customers on a non-exclusive basis. In some of our projects, we share interests in the revenue from the sales of the multi-client data with third parties.

Demand for Seismic Data and Services

Various factors influence the demand for seismic data and services, including:

- the demand for and prices of oil and gas and expectations about future prices
- the level of exploration and production spending by oil and gas companies
- developments in technology that affect the cost, quality and reliability of seismic data

Where We Acquire Seismic Data

We conduct the majority of our seismic data acquisition business in the North Sea and offshore Brazil and West Africa. We also acquire seismic data in other active oil and gas exploration and/or production areas around the world from time to time, including:

- the Gulf of Mexico
- offshore China and Korea
- offshore and onshore India and Pakistan
- the Sakhalin area of Russia
- offshore Australia, Indonesia and other countries in the Asia Pacific region
- offshore Canada
- offshore and onshore in the Middle East
- the Caspian Sea area
- offshore and onshore Mexico and Latin America
- the US mid-continent, Rocky Mountain and Alaskan North Slope regions

How We Acquire Seismic Data

To acquire marine seismic data through conventional streamer operations, we discharge a wave of acoustic energy just below the water's surface from one or more energy sources towed behind one or more survey vessels. As the wave travels through the water and subsurface earth, portions of the wave are reflected back at rock layer boundaries. The reflections are detected by hydrophones contained in streamers towed behind the survey vessels. The streamers convert the reflected waves into digital data that are then transmitted to a recording unit onboard the survey vessel. We then analyze the acquired data for quality control purposes before inputting the data into a processing system to produce images of the subsurface. In addition to conventional streamer operations, we also acquire marine seismic data through seafloor seismic operations in which we place recording cables on the ocean floor and retrieve them as data are acquired.

A 2D marine seismic survey typically is produced by a single survey vessel towing a single streamer and one energy source. The seismic data acquired generally represent a vertical cross-section beneath the line tracked by the streamer, which we refer to as a "seismic line." We acquire 3D data by combining parallel 2D seismic lines that can be processed to produce a three-dimensional image of subsurface strata. When we perform a 3D seismic survey, we acquire a dense grid of seismic data using multiple streamer configurations over a precisely defined area. Such data acquisition requires the use of sophisticated navigation equipment that permits the constant and precise determination of the positions of streamers and energy sources during the acquisition process. This determination of position is essential to producing accurate subsurface images. When we perform a 4D seismic survey, we repeat a series of 3D seismic surveys over the same survey area at different time intervals. This series of surveys shows the changing subsurface geophysical conditions over time and provides information about the fluid movements in the area.

In acquiring 3D marine seismic data, we may use multiple vessels and multiple streamers and energy sources to acquire more rapidly, and at lower unit cost, the large number of seismic lines needed to produce a 3D data volume. By increasing the number of streamers and energy sources used, we can perform large surveys more rapidly and cost-effectively. Dual vessel operations, with one vessel acting as a source/recording vessel and the other as a recording vessel, permit us to acquire data in areas where production platforms or other obstructions interfere with seismic operations. Dual vessel operations also generally allow us to use shorter streamers, which improves efficiency and reduces the chance of collision or entanglement with obstructions. In addition, we use multiple vessel and streamer configuration operations to acquire data for imaging deep targets.

To image complex geophysical and geological areas more accurately, we deploy a dense configuration of streamers using a single energy source to enhance seismic data quality and resolution. This technology is known as HD3D™ seismic technology, and has become cost effective due to the utilization of vessels, like our Ramform seismic vessels, that have the capability to tow in excess of 12 streamers at a time. We believe that useful 4D seismic information requires HD3D™ or similar seismic technology and increased computing capacity to reflect the subtle changes in geophysical conditions that occur over time. We believe that oil and gas companies find 4D seismic surveys and related reservoir monitoring services to be particularly useful in their efforts to increase recoveries from producing petroleum reservoirs. Please read "— Reservoir Monitoring."

To acquire land seismic data, we use an explosive or mechanical vibrating unit to produce an acoustical impulse that is reflected back at rock layer boundaries. A recording unit synchronizes the shooting and captures the reflected signals via geophones placed on or planted in the ground that produce an electrical current when the ground moves. On a typical land survey, several thousand geophones are laid out in multiple lines to record the acoustical impulse. The data are then processed to produce a 3D image that enables geoscientists to visualize prospective drilling areas and producing oil and gas reservoirs.

FPSO Background

Overview

In the remainder of this annual report, we will use the acronym "FPSO" to refer to floating production, storage and offloading.

An FPSO system is a type of mobile production unit that produces, processes, stores and offloads oil and gas from offshore fields with widely differing production characteristics, sizes and water depths. The selection of a particular mobile production unit from among the several types of readily movable offshore production systems depends on an overall technical and financial evaluation of the field to be developed. FPSO systems typically perform the same function as fixed offshore platforms in the offshore production of oil and gas, with the exceptions of drilling and heavy well maintenance. However, FPSO systems provide a number of advantages over fixed platforms including:

- being suitable for a wide range of field sizes and water depths
- being reusable on more than one developed reservoir
- generally costing less and being easier to install and remove than fixed platforms
- reducing the time from the discovery of oil and gas to production

An FPSO vessel may be either a newly constructed vessel specifically designed to function in an FPSO system or an existing tanker or other marine vessel converted to function in an FPSO system. A typical FPSO life-of-field system consists of wells completed using subsea wellheads that are connected to the FPSO vessel by flexible tubing, or risers. Risers carry the oil and gas from the ocean floor to the vessel. The oil and gas are processed onboard the FPSO vessel and the resulting oil is exported, either by a subsea pipeline or an off-take system using shuttle tankers. Natural gas may be exported by subsea pipeline, reinjected into the reservoir or, in some circumstances, flared.

Demand for FPSO Services

How the FPSO Market Differs from the Seismic Market. The market for FPSO services differs fundamentally from the seismic market. Offshore production, either for test purposes or for full exploitation, generally takes place a relatively long time after exploration drilling has been completed. Oil and gas companies typically make production-related decisions based on different financial parameters and with different views about changes in oil and gas prices than are used for decisions relating to seismic or drilling activities. Oil and gas companies in a number of oil producing areas have increasingly focused on the development of smaller fields with relatively smaller or uncertain reservoir estimates and/or shorter expected producing lives. For development of these smaller fields to be profitable, the oil and gas companies must reduce cost levels and financial exposure. As a result, producers have focused increasingly on subsea installations and FPSO systems instead of the more traditional fixed steel and concrete platforms.

The FPSO Market. The market for FPSO systems can generally be divided into three segments:

- extended well tests or production testing
- early production
- life-of-field development

In production testing, the oil and gas company produces oil and gas from one or more producing formations or zones, and from one or more wells, to confirm various characteristics of a reservoir. The oil and gas company then uses this information, among other things, to make better estimates of the productivity and extent of the reservoir and to position production facilities. From the perspective of an FPSO operator, use of FPSO systems for production testing, which is relatively short-term in nature, involves a greater risk that the FPSO system will not maintain high utilization rates due to downtime between contracts.

The early production phase of development follows the decision to develop a tested field into full production. During this phase, production facilities are engineered, built and installed. By increasing production during this phase, the overall financial performance of the field can be enhanced by reducing the need for or level of financing and by providing income and cash flow at an earlier stage than would otherwise be the case.

In life-of-field development, the FPSO system is designed for production for the life of the field and the operator generally attempts to adapt either the production facility to the reservoir requirements or the reservoir strategy to the production facility.

Property, Plant and Equipment Information

We incorporate by reference in response to this item the information in "Operating and Financial Review and Prospects — Financial Condition — Capital Requirements" in Item 5 and note 20 of the notes to our financial statements in Item 18 of this annual report, which, among other things, provide information on the nature and geographic distribution of our capital expenditures.

Leased Premises

Our principal offices are in Lysaker, Norway and in Houston, Texas, in leased premises. We also maintain leased premises in other cities in Norway and the United States, the United Kingdom, Egypt, Venezuela, Singapore, Australia, Brazil, the United Arab Emirates, Russia, Angola and China. We believe that all leased properties are well maintained and are suitable and adequate for our present activities.

Our Seismic Vessel Fleet and Crews

We believe that we operate one of the most advanced marine seismic data acquisition fleets in the world. To improve crew productivity and efficiency, we emphasize a high ratio of streamers towed to vessels in operation. As of December 31, 2001, we had a total of ten 3D marine seismic streamer crews operating 17 seismic vessels, and one 2D marine seismic streamer crew operating one seismic vessel. In addition, as of December 31, 2001, we had two seafloor seismic crews operating a total of nine vessels. Our seafloor seismic crews perform our ocean bottom seismic operations, as well as other forms of multi-component operations.

We acquire marine seismic data using seismic crews on both owned and chartered vessels that have been constructed or modified to our specifications and outfitted with a full complement of data acquisition, recording, navigation and communications equipment. Our crews direct the positioning of a vessel using sophisticated navigation equipment, deploy and retrieve streamers, cables, receivers and energy sources, and operate all of the seismic systems. Our seismic crews do not operate the vessels. The vessel maritime crews are employees of either the owner of the chartered vessels or a contract operator for our vessels.

Equipment Used on Our Seismic Vessels. Most of our seismic vessels, other than those used in seafloor seismic operations, have an equipment complement consisting of the following:

- recording instrumentation
- digital recording streamers
- streamer and seismic data location systems
- supercomputer systems for data processing
- multiple navigation systems
- except for vessels that record only, a source control system that controls the synchronization of the energy sources and a firing system that generates acoustic energy

For seafloor seismic operations, the *Ocean Explorer,* the *Carlson Tide,* the *Bergen Surveyor,* the *Jonathan Chouest* and the *Dickerson Tide* each have a dynamic positioning system and recording instrumentation that permits the recording of data from up to 48 kilometers of ocean bottom cables. These vessels also have equipment to deploy and recover cables automatically.

Vessel Information. We provide in the following table information as of December 31, 2001 about our marine seismic data acquisition vessels.

Vessel name	Year rigged/ converted	Total length (feet)	Total beam (feet)	Long-length streamer capability	Maximum streamers deployed (through December 31, 2001)	Owned or charter expiration
3D Seismic Vessels:						
Ramform Challenger	1996	284	130	16	12	Owned
Ramform Explorer	1995	270	130	12	8	Owned
Ramform Valiant	1998	284	130	20	10	2023(1)
Ramform Viking	1998	284	130	20	10	2023(1)
Ramform Victory	1999	284	130	20	16	2024(1)
Ramform Vanguard	1999	284	130	20	10	2024(1)
Atlantic Explorer	1994	300	58	6	6	Owned
American Explorer	1994	306	59	8	8	Owned
Nordic Explorer	1993	209	54	6	6	Owned
Orient Explorer(2)	1995/96	246	49	4	4	2004
Geo Explorer(2) (3)	1991	215	46	3	3	2002
Walther Hervig(2) (3) (4)	1997	254	56	5	4	2002
Falcon Explorer(2)	1997	266	53	1	1	2002
Seafloor Seismic Vessels(2):						
Carlson Tide	1995	194	40	N/A	N/A	2002
Dickerson Tide	1995	194	40	N/A	N/A	2002
Beulah Chouest	1996	195	40	N/A	N/A	2002
Jonathan Chouest	1996	180	34	N/A	N/A	2002
Kondor Explorer(2)	1997	197	43	N/A	N/A	2002
Bergen Surveyor	1997	217	48	N/A	N/A	2004
Ocean Explorer	1993/95	269	59	6	6	Owned

(1) We have UK lease arrangements for each of the *Ramform Valiant*, the *Ramform Viking*, the *Ramform Victory* and the *Ramform Vanguard*. Under the leases, we lease the vessels from UK financial institutions under long-term charters that give us the option to purchase the vessels for a *de minimis* amount at the end of the charter periods. We used a substantial portion of the proceeds from these arrangements to legally defease the present value of our future charter obligations for the vessels.

(2) These vessels operate in a multi-vessel configuration.

(3) Chartered from a limited partnership owned 50% by us.

(4) Currently stacked and not operating.

Several of our 3D seismic vessels and substantially all of our seafloor seismic vessels operate under charter agreements expiring in 2002. These charter agreements typically are renewed on an annual or other relatively short-term basis. We believe that maintaining a number of short-term vessel charters provides more flexibility to adjust the size of our fleet according to market demands.

Our Ramform Seismic Vessels

As of December 31, 2001, we operated six Ramform design vessels in our marine seismic data acquisition operations. Each of the Ramform seismic vessels is a state-of-the-art vessel that is capable of pulling a relatively large number of streamers and is built according to a design in which we own proprietary rights. Our four Ramform seismic vessels delivered in 1998 and 1999 are designed to deploy up to 20 streamers.

We believe that our Ramform design seismic vessels represent the most advanced seismic vessels currently in operation in the world. Because of their size and unique design, including their extreme width in relation to their overall length, Ramform design seismic vessels have an increased streamer towing capacity as compared to conventional seismic vessels. In addition, the Ramform vessels have increased stability and improved motion characteristics over conventional seismic vessels. Among other things, these characteristics allow these vessels to leave seismic equipment deployed during more severe weather conditions than is possible for conventional seismic vessels. As a result, these vessels can resume production more quickly once conditions have stabilized and thereby acquire seismic data for more sustained periods of time. The size and unique design of the Ramform seismic vessels, together with our advanced techniques for rapid deployment and retrieval of seismic streamers, allow us to acquire marine seismic data more efficiently. The Ramform design seismic vessels are also well-suited for acquiring high-definition surveys, which require the use of multiple streamer configurations with narrower distances between streamers in order to generate the necessary density of seismic data for enhanced resolution. The Ramform design seismic vessel has recently completed seismic surveys using HD3D™ seismic technology. We have experienced an increase in demand for data acquired in this manner.

FPSO Vessels

As of December 31, 2001, we owned and operated four FPSO systems and provided operations and maintenance services, on a contract basis, to 17 additional offshore production facilities for oil and gas companies.

We provide in the following table information as of December 31, 2001 about our owned FPSO vessels(1).

FPSO Vessel Name	Year delivered	Approximate total length (feet)	Approximate total width (feet)	Production capacity (barrels per day)	2001 average production (barrels per day) (3)	Displacement (metric tons)	Storage capacity (barrels)
Ramform Banff(2)	1998	395	175	95,000	22,700	32,100	120,000
Petrojarl I	1986	686	105	50,000	37,300	51,000	190,000
Petrojarl Foinaven	1996	820	112	180,000	81,300	72,000	280,000
Petrojarl Varg	1999	702	125	56,000	20,300	100,000	420,000

(1) Additionally, in our FPSO operations we utilize six FPSO shuttle tanker/storage tanker vessels from third-party contractors under operating leases (some of which are in turn subleased) expiring at various dates from 2003 through 2004.

(2) We have a UK lease arrangement for the vessel's topside production equipment. Under the lease, we lease the equipment from a UK financial institution under a long-term charter that gives us the option to purchase the equipment for a *de minimis* amount at the end of the charter period. We used a substantial portion of the proceeds from the arrangement to legally defease the present value of our future charter obligations for the equipment.

(3) Average production is computed by dividing total production by the number of days of operation of the relevant vessel.

Estimated Future Capital Expenditures

We do not have any material commitments for future capital expenditures. However, during 2002 we expect to spend approximately $45.0 million on upgrades of our geophysical assets and $15.0 million on our production assets (approximately $10.0 million of which represents the final payment on the *Petrojarl I* upgrade). We anticipate that we will spend additional capital on Atlantis-related development costs, which costs will be terminated if we are successful in selling Atlantis. We expect that a substantial portion of the Atlantis-related capital expenditures that we incur will be reimbursed if and when the sale of Atlantis closes. Please read "— Recent Developments — Sale of Atlantis."

Seismic Data Acquisition

Contract Operations

Overview. When we acquire seismic data on a contract basis, our customer directs the scope and extent of the survey and retains ownership of the data obtained. Contracts for seismic data acquisition, which are generally awarded on a competitive bid basis, typically are turnkey contracts. Under this turnkey method, our customers pay us based upon the number of seismic lines or kilometers of seismic data collected and bear most of the risk of business interruption, except in winter months when we assume greater responsibility for weather-related interruption. We generally require progress payments unless we expect to complete the survey in a brief period of time.

Geographic Mix of Operations. We expect in the near term to focus on contract revenue in the North Sea, in the Asia Pacific and Middle East regions and offshore West Africa and South America. However, we also intend to seek opportunities for contract revenue in other areas of the world where offshore oil and natural gas operations exist. During 2001, we performed or secured contract work in the North Sea; Mexico; offshore West Africa, Australia, China and other countries in the Asia Pacific region; offshore and onshore Canada; the US mid-continent, Rocky Mountain and Alaskan North Slope regions and the Middle East region. For more information regarding the geographic mix of our operations for the last three fiscal years, please read note 20 of the notes to our financial statements in Item 18 of this annual report.

Multi-Client Operations

Overview. We continue to build and market our seismic data library, including seafloor seismic data, with a particular emphasis in the North Sea, offshore Brazil and West Africa and in the Gulf of Mexico. We expect to continue this geographic focus in the future, but also intend to acquire multi-client seismic data in additional geographic areas from time to time, including offshore Australia and other countries in the Asia Pacific region and in the US mid-continent and Rocky Mountain regions.

From the perspective of an oil and gas company, purchasing multi-client seismic data is less expensive on a per unit basis than contracting to have seismic data acquired on an exclusive basis. From our perspective, multi-client seismic data are more cost effective to acquire and may be sold a number of times to different customers over a period of years. As a result, multi-client seismic data may be more profitable than contract data, but when we acquire multi-client seismic data we assume the risk that future sales may not cover the cost of acquiring and processing such seismic data. We reduce this risk by obtaining prefunding for a portion of such costs. The level of prefunding obtained for each multi-client seismic survey is determined, in part, by evaluating various factors affecting the sales potential of each survey. These factors include:

- the existence, quality and age of any seismic data that may already exist in the area
- the amount of leased acreage in the area
- the existing infrastructure in the region to transport oil and gas to market
- the historical turnover of the leased acreage
- the level of interest from oil and gas companies in the area

We attempt to protect our multi-client seismic data from misuse by customers primarily through contractual provisions that permit use of the data only by that particular customer on a nontransferable basis. Such provisions can be effective only if we can detect misuse of our data by customers or third parties and enforce our rights through legal actions.

Geographic Areas Covered by Multi-Client Seismic Data. A substantial portion of our Gulf of Mexico marine seismic data library has been acquired offshore Louisiana and Texas, including deepwater areas. We have also acquired significant data in the deepwater areas in the North Sea and offshore Brazil and West Africa. We believe that the deepwater areas in the Gulf of Mexico, the North Sea and offshore

Brazil and West Africa will be among the most active offshore exploration and development areas in the near future. We also believe that the relatively high cost of locating and producing deepwater oil and gas reservoirs will contribute to increased demand for high density marine seismic data and other specialized geophysical services which allow oil and gas companies to better define oil and gas reservoir potential. For more information regarding the geographic mix of our operations for the last three fiscal years, please read note 20 of the notes to our financial statements in Item 18 of this annual report.

Marketing Arrangements. We market multi-client data through our own organization and through various arrangements with third parties. Under arrangements relating to some of our multi-client seismic data programs in the Gulf of Mexico, we work with a third-party marketing company that presents to us seismic survey projects for our consideration. We acquire and process, or have a designee process, the data for the surveys that we choose to undertake. We then retain ownership of the data acquired, with the marketing company earning a commission or other compensation on the data it sells. We may grant an ownership interest in the data to the marketing company under a risk-sharing arrangement in limited circumstances.

Seafloor Seismic Operations

As of December 31, 2001, we had two seafloor seismic crews. One crew was outfitted with conventional ocean bottom cable technology, capable of recording multi-component seismic data in relatively shallow water. The second crew was outfitted with our proprietary FOURcE™ seafloor seismic acquisition technology, capable of recording multi-component seismic data in deeper water depths.

Seafloor seismic acquisition is used in areas where conventional streamer acquisition operations are not possible or economically feasible due to access limitations from shallow water or obstructions. Seafloor seismic acquisition is also used in areas where conventional streamer acquisition would not meet the desired geophysical objectives.

In multi-component seafloor seismic operations, both hydrophone and three-component geophone data are recorded simultaneously for a reservoir. Processing the data with our proprietary software allows for enhanced reservoir imaging and characterization, which improves:

- chances of discovery success at the exploration stage
- information relating to the size of and reserve estimates for reservoirs at the appraisal and development stages
- decision-making regarding production strategy and maximizing total reserve recovery at the production stage

Land Operations

As of December 31, 2001, we had eight 3D land seismic acquisition crews operating in various areas, including Mexico, the Middle East and the US mid-continent, Rocky Mountain and Alaskan North Slope regions. We are also developing a multi-client data library of gas basins in the United States.

We believe that our land seismic acquisition business offers the technical, and administrative support for successful growth into new land markets. We are able to field well-equipped crews on a timely basis through established volume purchase agreements that provide us with technologically-advanced recording, positioning, drilling and camp equipment.

Seismic Data Processing Operations

We provide seismic data processing services for our own seismic data acquisition operations and for third parties. We generally compete for data processing contracts on a competitive bid basis. These contracts generally provide for the customer to pay a flat fee per mile or kilometer processed for a prescribed set of processing procedures. Additional procedures may be quoted separately and are frequently added during the course of the project.

We operate four land-based seismic data processing centers, located in Houston, Texas, USA.; Cairo, Egypt; London, England; and Perth, Australia. Each of these centers is equipped with supercomputers for data processing. We also have a processing center in Oslo, Norway that is linked to our other centers' supercomputers. We use a proprietary operating system for our supercomputers, which is designed to take advantage of supercomputer architecture and can be converted to operate on a variety of supercomputers. These supercomputers offer processing capacities for the large data volumes and computer-intensive algorithms requiring numerous simultaneous calculations that are inherent in seismic data processing. Through our seismic data processing operations we provide:

- 3D data processing of land and marine seismic surveys
- onboard (vessel) seismic data processing for reduced delivery times and enhanced real-time quality control for data
- multi-component and 4D seismic data processing for reservoir characterization and monitoring
- imaging of subsurface structures in deepwater and under salt formations

We have deployed the onboard supercomputer processing systems for most of our marine seismic data acquisition crews and have stationed processing personnel onboard these vessels to process and provide quality control of the seismic data as they are acquired. We believe that onboard processing and quality control provide a competitive advantage because we can process the large volume of data associated with seismic surveys concurrently with data acquisition. This concurrent process allows us to shorten the period of time required to deliver high-quality finished data to the customer. In addition, onboard processing and quality control allow us to decide whether we should resurvey particular areas to fill gaps in the original data while the vessel and crew are on the prospect areas. As a result, we can resurvey more quickly and less expensively.

Reservoir Monitoring

We believe that the high-resolution 4D seismic data used in connection with reservoir monitoring will help oil and gas companies maximize production and increase the ultimate recoveries from producing hydrocarbon reservoirs, particularly as the level of production from such reservoirs begins to decline. In addition to the equipment and technology required for a 3D seismic survey, a 4D seismic survey may require or use:

- streamer technology
- vertical cable technology
- dual sensor or multi-component seafloor technology
- permanent installations of seismic receivers

4D seismic information requires a higher density of 3D data and increased computing capacity to reflect the subtle changes in geophysical conditions that occur over time. With our advanced vessel fleet, the large streamer capacity of our Ramform design seismic vessels, our expertise in acquiring, processing and interpreting 4D seismic data and our processing capacity, we believe that we are well positioned to meet future demand for 4D seismic surveys.

Data Management

In March 2001, we sold our global Petrobank data management business and related software for $165.7 million in net cash to Landmark Graphics Corporation, a Halliburton Company subsidiary. We also entered into an agreement with Landmark to provide data management and distribution services to us. This agreement has an initial term of three years, but may be extended on similar terms by mutual agreement of the parties for up to two additional one-year periods. During the term of the agreement, Landmark will be our exclusive provider of data storage and distribution services, except where otherwise agreed. The cost of these services for the ten month period ended December 31, 2001 was $8.0 million. The financial position and results of operations of our Petrobank data management business were not material to our consolidated financial position and results of operations for any year presented in this annual report.

FPSO Operations

We believe that our advanced geophysical technologies and reservoir expertise allow our FPSO customers to increase the amounts of oil and gas produced from the reservoirs served by our FPSO systems and assist in the identification of satellite fields that can be economically produced or "tied back" through the same systems. We believe that we can increase our revenue and operating profit from any incremental production through our FPSO systems through the use of contracts with a variable compensation component based on the amount of oil produced. As a result of these factors, we believe that we have a competitive advantage over other FPSO operators.

As of December 31, 2001, we owned and operated four FPSO systems, the *Ramform Banff*, the *Petrojarl Foinaven*, the *Petrojarl Varg* and the *Petrojarl I*. The contracts under which these FPSO systems operated are described below.

Banff Field Contract

In February 1997, Conoco awarded us a long-term contract to provide an FPSO system, the *Ramform Banff*, to produce the hydrocarbon reserves of the Banff field in the UK sector of the North Sea. Oil production from the field commenced in late January 1999. At that time, we began receiving a fixed day rate designed to cover operating expenses and a fixed tariff per barrel of stabilized crude oil produced.

If actual production averages less than 8,000 barrels per day for a period of 90 days, and continues to average less than that volume for at least two years after the commencement of the initial 90-day period, Conoco has the right to terminate the contract at the end of those two years. Conoco also may terminate the contract without paying a cancellation fee with twelve months written notice or if:

- the *Ramform Banff* becomes a total loss
- there is a breach of the FPSO contract by us that is not remedied within agreed deadlines
- we enter into debt negotiations with creditors or go into liquidation or are placed under administration
- force majeure events occur that are expected to continue for more than six months

During the fourth quarter of 2000, the *Ramform Banff* discontinued production on the Banff field and demobilized to Germany, where an upgrade to reduce vessel roll motion and improve uptime performance commenced. The upgrade was completed during the first quarter of 2001, and production on the Banff field recommenced in March 2001. From that time, the *Ramform Banff* operated with greater than 99% uptime performance over the remainder of the year.

The financial performance of the vessel continues to suffer due to relatively low levels of production resulting from underperformance of the reservoir itself. Additionally, the operating costs of the *Ramform Banff* are higher than originally expected. We have hired a storage vessel at a rate of $47,000 per day under a long-term charter arrangement relating to the operations of the *Ramform Banff*. Because of the higher than expected cost of operating the field, the additional cost associated with the storage tanker and the low level of oil production from the field, we have incurred losses on the contract. For additional information relating to the financial performance of the *Ramform Banff*, please read "Operating and Financial Review and Prospects — Results of Operations — Fiscal 2001 Compared with Fiscal 2000" and "Outlook; Factors Affecting Our Future Operating Results" in Item 5 of this annual report.

While we believe that Conoco has plans to drill one or two new wells during the second half of 2002 to increase field production, we cannot estimate the incremental production that might be provided by such additional wells, if any. Therefore, we cannot reasonably estimate whether losses will continue and, if so, at what level.

Based on a longer term assessment, we believe that the *Ramform Banff* should be removed from the Banff field and deployed on a field better suited for its production capacity. As a result, we are evaluating an alternative production solution for the Banff field and actively seeking to redeploy the vessel elsewhere.

If we succeed in obtaining a new contract for the *Ramform Banff*, it is possible that additional capital may be needed to prepare the vessel for the new contract. Additionally, we have invested $64.6 million in subsea equipment on the Banff field as of December 31, 2001, and a premature exit from the field could result in an impairment of the equipment unless the owners of the field pay a value equal to or greater than its book value at the time of exit.

Foinaven Field Contract

The *Petrojarl Foinaven* is under contract with Britoil PLC, a subsidiary of BP Amoco Plc, for production of the Foinaven field to the west of the Shetlands. Commercial production on the field commenced in November 1997. The Foinaven contract is not limited as to time. Britoil may terminate the contract in November 2002 or later, with a minimum of two years' notice. We have not received any notice of termination from Britoil, and we currently expect that the vessel will remain on the field for a substantial period. In the event of cancellation at the end of the fifth anniversary, the contract provides that Britoil must pay a cancellation fee of $60 million, which fee reduces by $12 million per year so that no cancellation fee is payable after November 2007. Britoil may also terminate the contract without paying a cancellation fee if, among other things:

- the *Petrojarl Foinaven* becomes a total loss
- there is a breach of the FPSO contracts by the FPSO contractor that is not remedied within agreed deadlines
- the FPSO contractor or its guarantors enter into debt negotiations with creditors or go into liquidation, are placed under administration or change ownership to the detriment of Britoil
- force majeure events occur that are expected to continue for more than 365 days

In addition, the contract may be terminated:

- by us with a minimum of two years' notice, if the production-dependent tariff falls to less than the equivalent of $102,250 per day
- from November 26, 2003 with one year's notice if the production-dependent tariff falls below $35,000 per day
- under additional circumstances, including war

The contract provides for compensation consisting of a fixed day rate and a production-dependent tariff. The current day rate is approximately $66,000 per day and is subject to adjustment according to agreed indices. The production-dependent tariff:

- is not subject to adjustment based on any index
- is equal to $3.50 per barrel for the first 25,000 barrels of production per day and $2.95 per barrel for production in excess of 25,000 barrels per day
- may depend upon a guaranteed minimum production volume equal to 95% of the predetermined production profile during the first five years of the contract

As long as the *Petrojarl Foinaven* is fully operational, Britoil will be required, in periods during the first five-year period where the actual production falls below the guaranteed minimum production, to make payments based on the guaranteed minimum production less credits for rate payments already made for volumes in excess of the guaranteed minimum production. If actual production is greater than the guaranteed minimum production in periods during the first five-year period, Britoil will make payments based on actual production less credits for rate payments already made for volumes below the guaranteed minimum production. During periods after the first five-year period in which the *Petrojarl Foinaven* is fully operational, the day rate will be approximately $66,000 per day, subject to adjustment according to agreed indices, and the production-dependent tariff will be based on the greatest of:

- actual production
- 90% of the highest of two expected annual oil production rates reported by Britoil and the planned production profile for the year in question or
- 10,000 barrels per day

The guaranteed minimum production amounts under the contract was 80,750 barrels per day in year 4, which ended in November 2001, and is 70,775 barrels per day in year 5. In periods when the *Petrojarl Foinaven* is not fully operational, the day rate payable is to be based on actual production. A reduction in production volume during the first five years that is due to matters for which we are responsible triggers a day rate equal to $60,000, as adjusted to reflect indexation, plus an additional $52,500 until production is resumed. After five years, the day rate under such circumstances will be $66,000, as adjusted to reflect indexation.

In periods of production stoppage covered by the contract's repair and start-up quota, we will be entitled to receive the day rate. We can accumulate credits under the quota at a rate of 24 hours per month, up to an annual maximum of 14 days, to be offset by any downtime taken. In periods when production is prevented or reduced due to force majeure, we will receive reduced income for 60 days, and the full production rate thereafter.

Britoil has the right to add production from a satellite field, the Foinaven East field, to the contract and exercised that right during the 2001 fourth quarter. To the extent that production from the Foinaven East field, when aggregated with Foinaven field production, is within the guaranteed minimum production level, the normal rate structure under the contract will apply. Foinaven East production in excess of the guaranteed minimum production amount will be paid at an incremental rate of at least $0.75 per barrel. We are currently receiving $0.75 per barrel of oil produced from the Foinaven East field. From commencement of production in the fourth quarter of 2001 through April 2002, Foinaven East production has averaged 8,800 barrels per day.

We have additional obligations that may arise under the contract relating to the Foinaven project, including obligations to:

- compensate Britoil up to a maximum of $10 million for breaches of contract due to deficiencies that provide Britoil a right to terminate the production contract
- contribute up to 80% of the payments expected to be made by Britoil under the contract for the year following the discovery of hidden defects toward the correction of those defects, where such correction involves extraordinary expense
- pay for pollution damage caused by diesel or lubricants used on the *Petrojarl Foinaven* during production

Varg Field Contract

We charter the *Petrojarl Varg* to Saga Petroleum ASA, with Saga acting on behalf of the owners of the production license relating to the Varg field offshore Norway. We operate the vessel on behalf of the license owners. The *Petrojarl Varg* currently operates in the Varg field, where production began in December 1998. The charter agreement provides for:

- a lease term for at least the full productive life of the Varg field, with a minimum term through July 22, 2002, subject to termination by the license owners either with or without cause. If termination is without cause, we are entitled to receive the applicable charter hire rate indicated below for the minimum term.
- a day rate of:
  - $177,000 through July 22, 2002
  - $162,000 after that date

The owners of the production license may terminate the contract for cause if:

- there is a substantial breach of the FPSO contract by us
- we become insolvent, make an arrangement with our creditors or otherwise become incapable of performing the required services under the contract
- force majeure events occur that continue or are expected to continue for more than 90 days

In addition, the contract will terminate if the *Petrojarl Varg* becomes a total loss.

The operating agreement provides:

- that we will perform various operating services for the license owners relating to the *Petrojarl Varg* and be compensated for those services in NOK at a day rate of approximately NOK 360,000, subject to escalation based on various price indices
- for a minimum term through July 22, 2002, subject to termination by the license owners either for breaches by us or without cause. If termination is without cause, we are entitled to receive the applicable contractual compensation, less savings we realize from not being obligated to perform the agreement

On April 29, 2002, we received notice of termination from the license owners, and the charter and operating agreements will terminate in late July 2002. However, if we complete our purchase of the 70% interest in the license described below, we intend to extend the charter and operating agreements on terms similar to the existing terms.

During the 2002 first quarter, we entered into agreements to purchase a 70% interest in Production License (PL) 038 on the Norwegian Continental Shelf of the North Sea. PL 038 includes the Varg license. If we consummate the purchase, the interests in PL 038 will be purchased from Statoil (which holds a 28% interest) and Norsk Hydro (which holds a 42% interest). As consideration for our 70% interest, we will assume a portion of the abandonment liabilities associated with the fields on the license and any future environmental liabilities that may be generated by production on the fields. We estimate these abandonment liabilities to range up to $32.0 million in gross costs, or $12.0 million in after-tax costs. The purchases are contingent on the approval of Norwegian authorities and expected to close during the 2002 third quarter. Upon completion of the purchases, our 30% partner will be the Norwegian government's State Direct Financial Interest. We intend to continue operating on the field once the purchase is complete. We have acquired 3D seismic data over some areas of the license in order to enhance our understanding of the geology and prospectivity of these areas and are evaluating several development options.

Glitne Field Contract

In September 2000, we entered into an agreement with Statoil to produce the Glitne field in the Norwegian sector of the North Sea. We began production of the field with the *Petrojarl I* in the 2001 third quarter. Production under the contract is expected to last between 26 and 30 months from the production commencement date, with the first 18 months of production effectively guaranteed by Statoil.

The contract provides for the following compensation structure (subject to annual adjustment according to agreed indices):

- a day rate of $121,250 plus a per barrel tariff for a period of 36 months from commencement of commercial production. The basic per barrel tariff, which is based on a contractual production profile, escalates from $0.50 per barrel for the first 12 months of production, to $0.70 per barrel for the following 12 months of production, to $1.50 per barrel for the following 12 months of production. For production in excess of the contractual production profile, the tariff rates are $3.50 per barrel, $3.30 per barrel and $2.50 per barrel for the respective 12 month periods.
- a maximum compensation of $145,000 per day from the 19th month of production through the 36th month of production (inclusive of tariff elements)
- a flat day rate of $127,500 beginning 36 months after the commencement of commercial production
- an additional $12,750 per day (to the $127,500 flat rate) from the 36th month of production through the 60th month of production
- an additional $6,200 per day (to the $127,500 flat rate) from the 60th month of production through the 120th month of production

Under certain force majeure and standby situations, we will receive a day rate generally equal to $85,000. If production is shut down for a period cumulatively exceeding 144 hours during any six-month period, except for any period where such production shut down has been caused by Statoil, there will be no compensation. The first six-month measurement period began on August 28, 2001, the date of commencement of commercial production. We have the right to accumulate unutilized downtime during the six months in which it is accrued; unutilized downtime can be forwarded to the next six-month period.

Statoil may temporarily suspend production by giving notice that specifies the effective date of the suspension and the expected date for the resumption of production, as well as any mobilization plan and support functions to be maintained during the suspension period.

Statoil may terminate the contract with immediate effect and without penalties in the event that:

- a force majeure situation lasts for more than 90 days
- we become insolvent, file for bankruptcy or demonstrate through similar or related actions that we are not capable of performing the work or
- we are in substantial breach of the contract

Cancellation of the contract by Statoil entitles us to a day rate of $85,000 per day for any remaining part of the 18-month period immediately following the date of commencement of commercial production, as well as to reimbursement of any unpaid monies due for production services performed and a modification reimbursement of $12,750 per day for any remaining part of the 24-month period immediately following the date of commencement of commercial production. Cancellation after the date of commencement of commercial production requires a 12-month notice period.

If either we or Statoil secure alternative work for the *Petrojarl I* in the 18-month period following any cancellation by Statoil without cause, then 80% of the total compensation achieved, less actual modification and mobilization costs for the alternative work, will be credited directly to Statoil's cancellation liability on a half year basis.

In the event that production is less than 50 percent of the volumes described in the contractual production profile for more than five consecutive days due to circumstances which are not the responsibility of Statoil, Statoil will have the option to instruct us to stop production and perform rectification work, during which work compensation will be treated as if the stop in production was our responsibility.

Production Services Operations

We provide complete project management, operations and maintenance services for every phase in the production of an oil or gas field through our production services operations, which are headquartered in Aberdeen, Scotland. Through these operations we provide:

- process facilities and asset management services, with an emphasis on logistics management and cost control
- facilities maintenance and materials management services
- facilities engineering services, from the design phase through commissioning
- information management systems services, including procurement, project management and personnel management systems
- mature asset management services, where we attempt to extend asset life and reduce operating costs for oil and gas field owners through our engineering expertise

Other Business Opportunities

We pursue various oil and gas business opportunities, typically in conjunction with utilization of our geophysical expertise. We intend to continue to pursue such opportunities and, in connection therewith, to provide technical consulting services, reservoir studies, enhanced recovery services, prospect identification, seismic data interpretation, seismic data reprocessing services or other geophysical services in exchange for cash or other forms of compensation. In this manner, we have acquired and may continue to acquire various interests in exploration and production companies and in oil and gas properties or concessions. The revenue from and value of these interests depend upon the operations of the entities or properties acquired.

In December 1996, we received, in exchange for interests in some of our seismic data, shares in Spinnaker Exploration Company, an independent energy company engaged in the exploration, development and production of natural gas and oil in the Gulf of Mexico. In December 2000, we sold our entire equity interest in Spinnaker for net proceeds of $150.5 million.

We also consider from time to time acquisitions in areas that complement our existing portfolio of services to the oil and gas industry.

Research and Product Development

We desire to be an industry leader in those oilfield service markets in which our advanced technologies and services may be used by customers to discover and produce oil and gas in demanding environments. We are committed to providing our customers with innovative services that help to lower the costs of finding and producing oil and gas. As a result, we incur research and development costs in an attempt to keep our key assets and services at the forefront of engineering and technical advances. For information regarding our research and development expenditures, please see our financial statements in Item 18 of this annual report.

Competition

The seismic data acquisition and processing businesses are very competitive worldwide for both the contract market and the multi-client market. We compete for available seismic surveys based on a number of factors, including technology, price, performance, dependability and crew availability. In addition, the first company to acquire multi-client seismic data in an area generally has a competitive advantage in that area. Our largest competitor on a global basis is WesternGeco, a joint venture between Schlumberger Limited and Baker Hughes Incorporated.

All of our major competitors in seismic data acquisition both acquire and process 3D seismic data. Our processing operations compete primarily with Compagnie Generale de Geophysique, S.A., WesternGeco and Veritas for time processing contracts. We compete for time processing contracts based primarily on price, but processing capacity and turnaround time, technology and processing center location are also important factors.

Our FPSO operations will generally compete from time to time with other FPSO operators, with fixed installations and tension leg platforms, with subsea production installations and with semi-submersible and jack-up platforms. Competition between FPSO systems and other offshore production systems is based on a number of factors including water depth, the availability or proximity of transportation infrastructure, the size of the producing field and time considerations. In addition to the FPSO operations and other offshore production systems of the major oil and gas companies, our FPSO competitors include numerous companies that own a small number of FPSO vessels.

Customers

Our major customers include multi-national oil and gas companies, foreign national oil and gas companies, major independent oil and gas companies and seismic marketing companies. For the years ended December 31, 2001 and 2000, two customers accounted for 14% and 11% (2001) of our revenue and 16% and 11% (2000) of our revenue; both customers utilized both geophysical and production services. For the year ended December 31, 1999, one customer accounted for approximately 16% of our revenue, all of which was production services revenue. Due to the nature of our operations, significant portions of future revenue may, from time to time, be attributable to a few customers.

Seasonality

Please read "Operating and Financial Review and Prospects — Overview of Our Business — Seasonality" in Item 5 of this annual report for a description of how seasonality and weather affect our business.

Operating Conditions and Insurance

Our operations often are conducted under extreme weather and other hazardous conditions. These operations are subject to risks of injury to personnel and loss of equipment. We have safety compliance programs staffed by full-time professional employees. We also carry insurance against the destruction of or damage to our vessels and equipment in amounts, generally equal to replacement value, that we consider adequate. From time to time, however, we may not be able to obtain insurance against all risks or for equipment located in all geographic areas. Under the terms of our vessel charters, we are not generally responsible for damage to chartered vessels.

We have established our own captive insurance company to provide insurance for our seismic equipment, some of our production equipment and limited business interruption. As noted below, this insurance is subject to deductibles and limits on coverage and is supplemented by commercial reinsurance arrangements.

We obtain a substantial portion of our casualty insurance through this wholly-owned captive insurance company. This company retains risk of $2.5 million for each accident, with a maximum risk retention of $5.4 million per year. Our various operating companies also retain levels of risk when obtaining this casualty insurance from the captive company, ranging from $1 million to $2 million per accident for our FPSOs and up to $200,000 per accident for our streamers.

We have filed approximately $50.0 million in insurance claims for the *Ramform Banff* related to weather-related damage incurred in 2000. During 2001, we recovered $35.0 million on these claims, with the remainder expected to be resolved over the course of 2002. These insurance recoveries offset certain capital expenditures that we incurred on the *Ramform Banff* to repair the weather-related damage.

International Operations

We are conducting the majority of our operations in the North Sea and offshore South America and West Africa. We also conduct significant business operations in other areas of the world from time to time, including:

- the Gulf of Mexico
- offshore Australia, Indonesia and other countries in the Asia Pacific region
- offshore and onshore in the Middle East
- the Caspian Sea area
- offshore China and Korea
- offshore and onshore India and Pakistan
- the Sakhalin area of Russia
- offshore Canada
- offshore and onshore Mexico and Latin America
- the US mid-continent, Rocky Mountain and Alaskan North Slope regions

Please read "— Seismic Background," "— Seismic Data Acquisition," "— Seismic Data Processing Operations" and "— FPSO Operations" above and "Key Information — Risk Factors — Risk Factors Relating to Our Business Operations — Because we conduct a substantial amount of international operations, we have exposure to those risks inherent in doing business abroad" in Item 3 of this annual report. Please read note 20 of the notes to our financial statements in Item 18 of this annual report for information regarding the geographic mix of our operations.

Governmental Regulation

In the North Sea, we are required to obtain licenses to acquire multi-client seismic data. We currently have licenses to conduct such activities in portions of the Norwegian, UK and Irish territorial waters. In other areas of the world, licensing requirements vary widely. There are no such licensing requirements in the Gulf of Mexico, offshore Brazil or in the onshore areas where we operate, although we are required to obtain permits for our operations. We believe that our relations with the licensing and permitting authorities are good.

In addition, our operations are affected by the licensing activities of various governmental authorities. The timing and extent of licensing of areas for exploration and production activities influence the level of seismic activity within a particular country. Prospective licensees often purchase multi-client seismic data prior to the award of licenses. Following a license award, license holders will generally acquire seismic data from the newly licensed areas. In the North Sea, the governments of Norway and the United Kingdom generally hold licensing rounds for exploration and production every two years. In the Gulf of Mexico, licensing of blocks for exploration and production are held twice each year, once offshore Texas and once offshore Louisiana. In other areas, the timing and extent of these licensing rounds tend to be irregular. The length of the actual license to explore for oil and gas varies from region to region and is subject to governmental regulation.

We have acquired multi-client seismic data offshore Norway covering areas that could be awarded in the 17th licensing round that is expected to occur during the second half of 2002. Additionally, we are awaiting consummation of production sharing arrangements between certain customers and the government of Brunei. Each of these events, if and when they occur, could generate significant revenue for us.

Our operations are affected by a variety of other laws and regulations, including laws and regulations relating to:

- the protection of the environment
- exports and imports
- occupational health and safety
- permitting or licensing agreements for oil and gas exploration, development and production activities

We believe that we are currently in compliance in all material respects with the requirements of environmental, export/import and occupational health and safety laws and regulations. Please read "Key Information — Risk Factors — Risk Factors Relating to Our Business Operations — Unpredictable changes in governmental regulations could increase our operating costs and reduce demand for our services" in Item 3 of this annual report.

Subsidiaries and Affiliated Companies

We provide in the following table a list of our subsidiaries and affiliated companies as of April 30, 2002.

Name	Jurisdiction	Ownership
PGS Shipping AS	Norway	100%
Oslo Seismic Services Ltd.	Isle of Man	100%
PGS Geophysical AS	Norway	100%
PGS Production AS	Norway	100%
PGS Reservoir Consultants AS	Norway	100%
Multiklient Invest AS	Norway	100%
Pertra AS	Norway	100%
Petroleum Geo-Services, Inc.	United States	100%
Petroleum Geo-Services, Ltd.	United Kingdom	100%
Seahouse Insurance Ltd.	Bermuda	100%
PGS Multiclient Seismic Ltd.	Jersey	100%
PGS Mexicana SA de CV	Mexico	100%
PGS Rio Bonito	Brazil	99%
Dalmorneftegeofizika PGS AS	Norway	49%
Walther Hervig AS	Norway	50%
Geo Explorer AS	Norway	50%
Shanghai Tensor CNOOC Geophysical Ltd.	United Kingdom	50%
Baro Mekaniske Verksted AS	Norway	10%
Calibre Seismic Company	United States	50%
PGS Reservoir Consultants, Inc.	United States	100%
PGS Capital, Inc.	United States	100%
Diamond Geophysical Services Company	United States	100%
PGS Exploration Ltd.	Nigeria	100%
Atlantis Holding Norway AS	Norway	100%
PGS Offshore Technology AS	Norway	100%
PGS Tensor Middle East SAE	Egypt	100%
PGS Data Processing Inc.	United States	100%
PGS Intervention AS	Norway	100%
PGS Asia Pacific Pte. Ltd.	Singapore	100%
PGS Australia Pty. Ltd.	Australia	100%
Atlantis Isis Ltd.	United Kingdom	100%
PGS Consulting AS	Norway	100%
UNACO AB	Sweden	100%

Name	Jurisdiction	Ownership
Hara Skip AS	Norway	100%
PGS Tensor Geofisica de Venezuela CA	Venezuela	100%
Atlantic Explorer AS	Norway	100%
PGS Exploration SDN BHD	Malaysia	100%
PGS Exploration, Inc.	United States	100%
PGS Ocean Bottom Seismic, Inc.	United States	100%
PGS Exploration Ltd.	United Kingdom	100%
PGS Floating Production Ltd.	United Kingdom	100%
PGS Pension Trustee Ltd.	United Kingdom	100%
PGS Tigress Ltd.	United Kingdom	100%
PGS Reservoir Consulting Ltd.	United Kingdom	100%
Atlantis Technology Services Ltd.	United Kingdom	100%
Atlantic Explorer Ltd.	Isle of Man	50%
Atlantis Technology Services Tunisia AS	Norway	100%
Atlantis Technology Services Ajman AS	Norway	100%
Atlantis Ras Al Khaimah AS	Norway	100%
Oslo Seismic Services Inc.	United States	100%
Oslo Explorer Plc	Isle of Man	100%
Oslo Challenger Plc	Isle of Man	100%
PGS Shipping Ltd.	Isle of Man	100%
PGS Onshore, Inc.	United States	100%
PGS Production, Inc.	United States	100%
PGS Americas, Inc.	United States	100%
Seismic Energy Holding, Inc.	United States	100%
PGS Caspian AS	Norway	100%
PGS Multiclient Services, Inc.	United States	100%
Atlantis Ltd.	United Kingdom	100%
PGS Marine Services Ltd.	Isle of Man	100%
Atlantis Argyll AS	Norway	100%
Golar-Nor Offshore AS	Norway	100%
Golar-Nor Offshore Ltd.	United Kingdom	100%
K/S Petrojarl I AS	Norway	98.5%
Golar-Nor Ltd.	United Kingdom	100%
Deep Gulf LLC	United States	50.1%
PGS Nopec Ltd.	United Kingdom	100%
PGS Production Group Ltd.	United Kingdom	100%
Atlantic Power & Gas Engineering Ltd.	United Kingdom	100%
PGS Nominees Ltd.	United Kingdom	100%
PGS Production Ltd.	United Kingdom	100%
PGS Production Ltd.	Jersey	100%
Atlantic Resourcing Ltd.	United Kingdom	60%
J.V. I Ltd.	United Kingdom	100%
Atlantic Power International Ltd.	United Kingdom	100%
Petrojarl 4 DA	Norway	99.25%
SOH, Inc.	United States	100%
JV O'Hare Ltd.	United Kingdom	50%
PGS Trust I	United States	100%
PGS Trust II	United States	100%
PGS Trust III	United States	100%
MJIVI	Brunei	50%
Atlantic Power de Venezuela SA	Venezuela	85%
OGIS	Malaysia	50%

Name	Jurisdiction	Ownership
ASJV Venezuela SA	Venezuela	100%
PGS Nusantara PT	Indonesia	100%
Triumph Petroleum	United States	37.59%
FW Oil Exploration, LLC	United States	63%
PGS Processing Ltd.	Angola	100%
Seismic Exploration Ltd.	Canada	100%
Monsoon Ship Management	Cyprus	100%
Sakhalin Petroleum Plc	Cyprus	100%
Ikdam Production, SA	France	40%
PGS Investigacào Petrolifera Limitada	Brazil	99%

ITEM 5. *Operating and Financial Review and Prospects*

You should read the discussion under this caption in combination with our financial statements and the related notes in Item 18 of this annual report and "Key Information — Selected Financial Data" in Item 3 of this annual report. This discussion is based upon, and the financial statements have been prepared in accordance with, United States generally accepted accounting principles.

The following information contains forward-looking statements. You should refer to the section in this annual report captioned "Forward-Looking Information" for cautionary statements relating to forward-looking statements.

Overview of Our Business

How We Categorize Our Business

The services we provide may be divided into two general categories consisting of:

- geophysical services, which includes:
  - seismic data acquisition and processing, and
  - reservoir characterization, monitoring and consulting services
- production services, which includes:
  - floating production, storage and offloading, or FPSO, operations, and
  - production management services

Key Factors Impacting 2001 Results

You should consider the following unusual or significant items and the following events, developments and factors in considering our results for 2001:

- an increased focus by our geophysical services operations on the contract seismic market, consistent with our goal of increasing cash flow
- our completion during 2001 of significant construction or upgrade projects for our FPSO vessels *Ramform Banff, Petrojarl I* and *Petrojarl Foinaven,* resulting in all of those FPSO vessels being operational at the end of 2001
- unusual items aggregating $105.9 million, including a $138.5 million gain from the sale of our data management business, $13.2 million of multi-client library impairment charges and $19.4 million in litigation costs and reorganization costs
- $65.9 million in valuation allowance charges related to deferred tax assets
- $18.0 million of charges relating to the fair value of tax equalization swap contracts
- $14.4 million in net gains associated with the resolution of various tax contingencies
- the deferral of revenue associated with the adoption of SAB No. 101 and its application to our volume seismic data licensing arrangements

During November 2001, we entered into an agreement with Veritas DGC Inc. to combine our businesses under a new holding company. This proposed transaction is described in more detail under "Information on the Company — Recent Developments — Combination with Veritas" in Item 4 and note 3 of the notes to our financial statements in Item 18 of this annual report.

During January 2002, we entered into a definitive agreement to sell our Atlantis subsidiary. Please read "Information on the Company — Recent Developments — Sale of Atlantis" in Item 4 and note 3 of the notes to our financial statements in Item 18 of this annual report for additional information relating to this proposed transaction.

Seasonality

Our geophysical services business experiences seasonality as a result of weather-related factors. Our first and fourth quarters, in particular, are generally negatively affected by adverse weather conditions in the North Sea, which prevent the full operation of seismic crews and vessels. During these periods, we generally repair our seismic vessels and relocate them to areas with more favorable weather conditions to conduct seismic activities. On the other hand, our fourth quarter revenue has historically been positively affected by end-of-year sales of multi-client data to oil and gas companies. In addition, licensing activities and oil and gas lease sales may affect quarterly operating results. Our FPSO and production services business generally does not experience material seasonality.

Critical Accounting Policies

Overview

The preparation of our consolidated financial statements and the application of our accounting policies requires us to make difficult, subjective and sometimes complex estimates, assumptions and judgments about matters that are inherently uncertain. These estimates, assumptions and judgments affect the amounts of assets and liabilities that we report and our related disclosure of contingent assets and liabilities. In addition, these estimates, assumptions and judgments can have a material effect on the amount of revenue and expenses that we report during a particular period. We base our estimates, assumptions and judgments on historical experience and on various other assumptions that we believe to be reasonable under the circumstances. We evaluate our estimates on a periodic basis, and our estimates, assumptions and judgments may change as new events occur, as more experience is acquired, as additional information is obtained and as our operating environment changes. Actual amounts may differ from these estimates, assumptions and judgments under different assumptions or conditions.

We believe the following accounting policies, which are summarized below, are among the most critical in the preparation and evaluation of our financial statements:

- accounting for our multi-client data sales and amortization

- accounting for our revenue transactions other than multi-client transactions

- accounting for our derivative financial instruments

- accounting for our income taxes

- accounting for our long-lived assets

For a description of our significant accounting policies, please read note 2 of the notes to our financial statements included in Item 18 of this annual report.

Accounting for Our Multi-Client Data Sales and Amortization

The accounting for our multi-client data sales and our multi-client data library is probably the most significant of our accounting policies. We derive a substantial portion of our revenue from sales of multi-client seismic data. Revenue from sales of multi-client data is:

- in the form of prefunding, defined as amounts funded by customers prior to or during the acquisition phase, recognized as revenue on a percentage-of-completion basis by evaluating the progress to date

- in the form of licenses of data from our multi-client library that are recognized as revenue when we enter into a license agreement for specific data with the customer, the customer has been granted access to the licensed data and collection is reasonably assured
- in the form of volume sales agreements related to portions of our multi-client library within a defined geographical area that are recognized as revenue, based on a ratable portion of the total volume sales agreement revenue, when we enter into a license agreement with the customer for specific data covered by the agreement, the customer has been granted access to the licensed data and collection is reasonably assured

For multi-client surveys, we typically obtain prefunding that covers only a portion of the costs of the surveys from a small number of oil and gas companies that desire to obtain seismic data in the areas to be covered by the surveys. As a result, we assume the risk that future sales of such data may not ultimately cover the remaining costs. We capitalize as an asset on our balance sheet the direct and indirect costs of acquiring and processing multi-client data, which we refer to as our multi-client library, and we charge such costs to operating expense periodically based on a percentage of current period multi-client revenue to total estimated multi-client revenue, which estimates are updated at least annually. Under our accounting policies, we also amortize these costs at minimum rates based on a 5 to 8 year life and periodically evaluate our multi-client library for impairment.

In determining the ordinary amortization rates applied to and the fair value of surveys in our multi-client library, we consider expected future multi-client sales and market developments as well as past experience. Our sales expectations include consideration of geographic location, prospectivity, political risk, exploration license periods and general economic conditions. These sales expectations are highly subjective, cover extended periods of time and are dependent on a number of factors outside our control. Accordingly, these expectations could differ significantly from year to year. To the extent that these sales expectations prove to be higher than actual sales, our future operations will reflect lower profitability due to increased amortization rates applied to the multi-client library in later years. Our ability to recover costs included in the multi-client library through sales of the data depends upon continued demand for the data and an absence of technological changes or other developments that would render the multi-client data obsolete or less valuable.

The financial impact for 2001 of our policies regarding amortization, including minimum amortization, and testing our multi-client library for impairment are discussed below under "— Results of Operations — Fiscal 2001 Compared with Fiscal 2000."

The following table presents our multi-client library as of December 31, 2001, allocated by the year in which the components were completed:

	Net book value (In thousands)
Completed surveys:	
Completed before 1996	$ 4,297
Completed during 1996	20,954
Completed during 1997	22,835
Completed during 1998	69,730
Completed during 1999	188,373
Completed during 2000	234,824
Completed during 2001	300,095
Completed surveys	841,108
Surveys in progress	76,964
Multi-client library	$918,072

The table below presents the application of our minimum amortization requirements to our multi-client library as of December 31, 2001. These minimum amortization requirements are calculated as if there will be no future sales from this multi-client library. We believe the likelihood of recording these precise minimum amortization amounts is remote because we expect that amortization generated by multi-client sales in the ordinary course of business will substantially reduce the book value of our multi-client library. We have incurred minimum amortization charges in the past and may incur additional minimum amortization charges in the future, depending on the timing and geographic mix of our multi-client sales.

	Minimum future amortization
	(In thousands)
During 2002	$100,234
During 2003	171,092
During 2004	187,120
During 2005	145,589
During 2006	130,335
During 2007	98,516
During 2008	73,898
During 2009	11,288
Future amortization	$918,072

Because our minimum amortization requirements apply to the multi-client library on a component basis rather than in the aggregate, we may incur minimum amortization charges in a year even if the aggregate amount of ordinary amortization charges that we recognize exceeds the aggregate minimum amortization charges.

We monitor our minimum amortization requirements on a quarterly basis. During the second quarter of each year, we begin to record minimum amortization charges, using revenue estimates for the remainder of the current year to project the maximum book value of each multi-client library component. However, the majority of our minimum amortization charges are recorded during the fourth quarter of each year due to the inherent imprecision in estimating current year revenue.

Accounting for Our Revenue Transactions Other Than Multi-Client

We recognize revenue on proprietary, or contract, sales of data and on our other geophysical services as we perform the services and are able to charge these services to the customer. We generally recognize revenue from our floating production services in two components: tariff-based revenue, based on the number of barrels that we produce, is recognized as the production occurs; and day-rate revenue is recognized over the passage of time. We recognize revenue from our production management services as we perform the services; any performance-based incentive fees are recognized as revenue when objective evidence indicates that the performance criteria have been met.

Accounting for Our Derivative Financial Instruments

The primary form of derivative financial instrument that we utilize is the forward foreign exchange contract. We do not engage in derivative financial instrument transactions for speculative purposes. Although our derivative financial instruments are economic hedges, we do not have any derivative financial instruments that qualify for hedge accounting treatment. Accordingly, we recognize periodic adjustments necessary to reflect the fair value of these instruments in our financial position. We recognize these adjustments through our results of operations as the fair value changes occur. We base the fair value estimates used to recognize these instruments on valuations that are performed by a third party and, at defined period-ends, on the settlements called for by the terms of the derivative financial instruments.

Accounting for Our Income Taxes

We evaluate the need for valuation allowances for our deferred tax assets by considering the evidence regarding the ultimate realization of those recorded assets. We record any required valuation allowances through charges that are classified as provision for income taxes. Currently, we are recording valuation allowances for 100% of net deferred tax assets in jurisdictions other than Norway due to cumulative losses in recent years in those jurisdictions. Because of these cumulative losses, we have concluded that it is not more likely than not that the net deferred tax assets in those jurisdictions will be realized, and are recognizing the valuation allowances accordingly. However, we believe that we have valid tax planning strategies that may ultimately be successful in using those net deferred tax assets. To the extent that we continue to generate non-Norwegian deferred tax assets, we will continue to provide 100% valuation allowances on those assets. With regard to our Norwegian net deferred tax assets, we have concluded that a valuation allowance is not required based on management's expectations about the generation of taxable income in Norway from contracts that are currently in effect. We intend to monitor the Norwegian deferred tax assets closely to determine whether taxable income will be sufficient to realize these assets. If we determine that it is more likely than not that the Norwegian deferred tax assets will not be realized, we will provide a valuation allowance on the excess of the deferred tax assets over taxable income.

Accounting for Our Long-lived Assets

We evaluate the seismic surveys in our multi-client library for impairment on an annual basis by comparing the total expected future sales (less selling expenses) to the remaining survey book value. During the years ended December 31, 2001 and 2000, we recorded $13.2 million and $166.5 million, respectively, in multi-client library impairment charges. We evaluate our property and equipment, goodwill and other long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be appropriate. We base these evaluations on a comparison of the assets' fair values, which are generally based on forecasts of cash flows associated with the assets, to the carrying amounts of the assets. Any impairment is recorded as the difference between the carrying amounts and the fair values. During the years ended December 31, 2000 and 1999, we recorded $148.8 million and $38.4 million, respectively, in impairment charges related to property and equipment and other long-lived assets. We have not recognized any impairment charges related to our goodwill. Our expectations regarding future sales and undiscounted cash flows are highly subjective, cover extended periods of time, and are dependent on a number of factors outside our control, such as changes in general economic conditions, laws and regulations. Accordingly, these expectations could differ significantly from year to year.

Restatements

As more fully described in note 24 of the notes to our financial statements included in Item 18 of this annual report, our financial statements and related disclosures as of and for the years ended December 31, 2000 and 1999 have previously been restated to:

- reflect fair value accounting for tax equalization swap contracts entered into in 1998 and 1999 to hedge our exposure to Norwegian taxes arising out of the conversion, for Norwegian tax purposes, of our US dollar denominated debt into Norwegian kroner
- reflect the adoption of SAB No. 101, which became effective January 1, 2000, to our revenue recognition policy for some types of volume seismic data licensing arrangements

Our financial statements and related disclosures as of and for those years included in this annual report have been further restated as described in note 24 to:

- properly capitalize interest cost associated with the upgrade of FPSO vessels
- properly reflect property and equipment, multi-client library and depreciation and amortization related to two of our seismic vessels

• reflect uncertainties regarding the future utilization of deferred tax assets in the form of a valuation allowance against these tax assets

• properly amortize multi-client library in accordance with our minimum amortization policy

• properly amortize deferred assets over their useful lives and accrue defined benefit pension obligations, commission/royalty liabilities and lease liabilities as incurred

We initially filed our financial statements and related disclosures as of and for the years ended December 31, 2000 and 1999 in June 2001 as part of our annual report on Form 20-F for the year ended December 31, 2000. In February 2002, we filed a Form 20-F/A that restated those previously issued financial statements for the tax equalization swap contract and SAB No. 101 issues described above. In March 2002, we announced the remaining restatement items, but did not file an additional Form 20-F/A for these items. We summarize in the table below the effects of all the restatements on our initially reported results of operations included in our financial statements for the indicated periods:

	Years ended December 31,			
	2000		1999	
	As restated	As initially reported	As restated	As initially reported
	(In thousands, except per share data)			
Revenue	$ 913,482	$ 906,233	$788,160	$788,160
Cost of sales	432,457	423,121	333,060	333,060
Depreciation and amortization	263,589	258,484	238,576	238,576
Selling, general and administrative costs	76,473	75,938	71,738	71,738
Total operating expenses	1,144,976	1,130,000	749,088	749,088
Operating profit (loss)	(231,494)	(223,767)	39,072	39,072
Financial expense, net	(134,599)	(122,933)	(95,969)	(95,969)
Other income (expense), net	(32,774)	28,583	(9,144)	23,650
Loss before income taxes	(337,716)	(256,966)	(70,976)	(38,182)
Income tax benefit	(132,756)	(69,392)	(57,137)	(41,890)
Income (loss) before cumulative effect of accounting change	(204,960)	(187,574)	(13,839)	3,708
Cumulative effect of accounting change, net of tax	(6,555)	—	(19,977)	(19,977)
Net loss	(211,515)	(187,574)	(33,816)	(16,269)
Basic loss per share before cumulative effect of accounting change	(2.01)	(1.84)	(0.15)	0.04
Cumulative effect of accounting change per share	(0.06)	—	(0.21)	(0.21)
Basic loss per share	(2.07)	(1.84)	(0.36)	(0.17)
Diluted loss per share before cumulative effect of accounting change	(2.01)	(1.84)	(0.15)	0.04
Cumulative effect of accounting change per share	(0.06)	—	(0.21)	(0.21)
Diluted loss per share	(2.07)	(1.84)	(0.36)	(0.17)

The discussion below of results of operations for the years 2001, 2000 and 1999 gives effect to these restatements.

Results of Operations

Fiscal 2001 Compared with Fiscal 2000

Revenue for 2001 of $1,052.6 million was 15% greater than revenue for 2000. The revenue mix between geophysical services and production services was 56% and 44%, respectively, compared to a prior year revenue mix of 51% and 49% for geophysical services and production services, respectively. The change in our revenue mix for 2001 primarily resulted from an improved contract seismic market.

Geophysical services revenue for 2001 totaled $594.5 million, which was 29% greater than revenue for 2000. Excluding data management revenue from the prior year, geophysical services revenue for 2001 was 35% greater than the prior year revenue. The increase in 2001 geophysical services revenue was attributable to a higher level of contract seismic activity due to our increased emphasis on this part of our business — contract seismic revenue for 2001 was 93% greater than comparable 2000 revenue. Multi-client seismic revenue for 2001 was $239.4 million, which was 4% less than the prior year revenue and reflected a reduction in multi-client investment levels and associated prefunding revenue. Multi-client prefunding revenue for 2001 was 26% lower than the prior year revenue. Multi-client late sales for 2001 were 11% greater than late sales for 2000, with sales from the Asia Pacific, UK and Norway regions contributing the greatest increases. The results of geophysical services for 2001 do not include $26.0 million in volume data licensing arrangements that will be recognized as revenue after December 31, 2001 due to the application of our revenue recognition policy.

Production services revenue for 2001 totaled $458.1 million, which was 2% greater than the prior year revenue. The revenue figures reflected the completion in 2001 of significant construction and upgrade projects related to *Ramform Banff, Petrojarl I* and *Petrojarl Foinaven* and the resumption of production from all of those FPSO vessels back into production.

Beginning in the 2000 fourth quarter, *Ramform Banff* undertook a performance upgrade to correct vessel roll motion problems. This upgrade project was completed during the 2001 first quarter, and *Ramform Banff* operated with greater than 99% uptime performance over the remainder of the year. However, the financial performance of the vessel continues to suffer due to relatively low levels of production. For the period of 2001 in which it operated, the *Ramform Banff* produced at roughly 15% of its capacity due to low oil production from the Banff field. We are evaluating an alternative production solution for the Banff field and are seeking to redeploy the *Ramform Banff* elsewhere. We may incur future operating losses from the *Ramform Banff.* We will re-evaluate the need for loss contract accruals for the *Ramform Banff* in future periods.

Also beginning in the 2000 fourth quarter, the processing facilities of the *Petrojarl I* were upgraded (a) to enable gas injection capabilities, (b) to improve the vessel's water injection capabilities, and (c) to maintain regular class certification to qualify the vessel for a lifetime extension of 15-20 years under Norwegian Shelf conditions. This upgrade project was completed during the 2001 second quarter and *Petrojarl I* began production on the Glitne field during the 2001 third quarter.

During portions of the 2001 second and third quarters, *Petrojarl Foinaven* undertook a production capacity upgrade that increased its maximum throughput capacity from 144,000 to 180,000 barrels of liquids per day.

Cost of sales, including research and technology costs, for 2001 was $100.6 million, or 23%, greater than cost of sales for the prior year. Cost of sales as a percentage of revenue was 51% for 2001, compared to 48% for 2000. The increase in cost of sales reflected both a decrease in costs capitalized into the multi-client library and oil and gas assets and an increase in operating cost of sales, due primarily to an increase in the acquisition of seismic data on a contract basis during 2001 rather than on a multi-client basis. Capitalized costs decreased by $24.0 million, or 6%. Operating cost of sales, including research and technology costs, increased by $76.7 million, or 9%, between 2001 and 2000. Excluding cost of sales associated with our data management business from both 2001 and 2000, capitalized costs decreased by $17.6 million, or 5%, and operating cost of sales, including research and technology costs, increased by $104.8 million, or 13%.

Geophysical services cost of sales increased by $84.2 million during 2001. This increase included a $52.1 million, or 15%, decrease in costs capitalized into the multi-client library and a $32.1 million, or 6%, increase in operating cost of sales, reflecting our decreased emphasis on multi-client seismic activity and our increased emphasis on contract seismic activity during 2001. Excluding cost of sales associated with our data management business, which prior to its sale in early 2001 was included as part of the geophysical services segment, from both 2001 and 2000, capitalized costs decreased by 13% and operating cost of sales increased by 12%.

Production services cost of sales increased by $16.4 million during 2001. This $16.4 million increase included a $28.1 million, or 90%, increase in costs capitalized into oil and gas assets and a $44.5 million, or 16%, increase in operating cost of sales. The increase in capitalized costs reflected the progress of our Atlantis subsidiary toward active production on several fields. The increase in operating cost of sales partly reflected gain items recognized during 2000: an approximate $12.0 million change in interest gain related to our investment in Spinnaker Exploration Company and recognized prior to the sale of this investment and an approximate $10.0 million gain related to the resolution of contingencies associated with our 1998 purchase of the *Petrojarl Foinaven* and *Petrojarl I.* Excluding the effect of these 2000 gain items, production services operating cost of sales increased by $22.5 million, or 7%, during 2001, reflecting the increased production from our upgraded FPSO vessels.

Depreciation and amortization for 2001 increased by $70.9 million, or 27%, compared to the prior year. Depreciation and amortization represented 32% and 29% of 2001 and 2000 revenue, respectively. Amortization of the multi-client library increased by $52.8 million, or 37%, during 2001. This increase included $39.1 million in minimum amortization for 2001, compared to $2.2 million in minimum amortization for 2000. A portion of the minimum amortization charges should be viewed in relation to our revenue recognition policy for volume seismic data licensing arrangements. Under volume seismic data licensing arrangements generally, the customer selects data to be licensed over a defined period of time. Under some of these arrangements, the customer commits to license the data and pays the license fee before actually selecting the seismic data to be licensed. However, under our revenue recognition policy we do not recognize revenue under the arrangement until the customer actually selects the specific data, the license period begins and collection is reasonably assured. As of December 31, 2001, we had approximately $26.0 million of these types of committed volume seismic data licensing arrangements that will be recognized in revenue after December 31, 2001, but were required to calculate our 2001 minimum amortization without taking into account the future licensing commitment — effectively accelerating the amortization ahead of the revenue that has been committed for future periods.

Excluding the effects of minimum amortization, amortization of the multi-client library increased by $15.9 million, or 11%. The average multi-client amortization rate during 2001 was 82%, compared to 57% for 2000. Excluding the effects of minimum amortization, the average multi-client amortization rate for 2001 was 65%, compared to 57% for 2000. Depreciation increased by $18.1 million, or 15%, between 2001 and 2000, with geophysical services depreciation increasing by $6.3 million (10%) and production services depreciation increasing by $11.8 million (21%). The increase in geophysical services depreciation reflected the increased emphasis on contract seismic work during 2001, with less depreciation capitalized into the multi-client library, and the increase in production services depreciation reflected the increased production from our upgraded FPSO vessels.

Selling, general and administrative costs for 2001 were $1.8 million, or 2%, greater than the prior year costs. As a percentage of revenue, these costs were 7% and 8% for 2001 and 2000, respectively. The comparability of our selling, general and administrative costs as a percentage of revenue for 2001 and 2000 reflected our efforts to hold these types of costs constant.

Unusual items, net, for 2001 included $13.2 million in multi-client library impairment charges, $19.4 million in litigation costs and reorganization costs including severance for former members of senior management and a $138.5 million gain on the sale of our data management business.

Operating profit, before unusual items and minimum amortization, for 2001 was $139.2 million, 2% higher than the comparable 2000 operating profit. Operating profit margin before unusual items and minimum amortization for 2001 decreased slightly to 13% from the comparable 2000 margin of 15%. Including the effects of minimum amortization, operating profit before unusual items was $100.1 million for 2001, which was 25% less than the comparable 2000 operating profit. The associated operating profit margin was 10% for 2001, compared to 15% for 2000.

Geophysical services operating profit before unusual items and minimum amortization of $47.3 million for 2001 was $14.0 million, or 42%, greater than the comparable 2000 operating profit, reflecting the increase in contract seismic activity during 2001. Operating profit margin before unusual items and minimum amortization increased slightly from 7% for 2000 to 8% for 2001. Including the effects of minimum amortization, geophysical services operating profit, before unusual items, was $8.2 million for 2001, which was 74% less than the comparable 2000 operating profit. The associated operating profit margin was 1% for 2001, compared to 7% for 2000.

Production services operating profit before unusual items of $91.9 million for 2001 was $11.3 million, or 11%, less than the comparable 2000 operating profit. Operating profit margin before unusual items decreased from 23% for 2000 to 20% for 2001. This decrease in production services operating profit includes the effect of the $22 million in non-recurring gain items recorded during 2000 and discussed above. Excluding the effects of these non-recurring gain items, production services operating profit for 2001 was $10.7 million, or 13%, greater than the comparable 2000 operating profit and the associated 2001 operating profit margin was 20%, compared to 18% for 2000. This improvement in the 2001 operating profit reflected the completion of our FPSO upgrade projects and the resumption of production from all of our FPSO vessels during 2001.

Net financial expense for 2001 was $8.6 million, or 6%, greater than net financial expense for the prior year. The increase in financial expense during 2001 was primarily due to $6.0 million in charges related to our multi-client library securitization transaction that was executed during the 2001 second quarter.

Other expense, net, of $22.1 million for 2001 included $18.0 million in fair value expense associated with our tax equalization swap contracts, compared to $61.4 million in fair value expense for 2000.

The $35.8 million in tax expense provided for 2001 consisted of:

- a benefit of $40.8 million on the results of continuing operations
- a net expense of $30.8 million associated with the $105.9 million in unusual items
- net gains of $14.4 million associated with the resolution of various tax contingencies
- a net benefit of $5.7 million related to tax equalization swap contracts
- a $65.9 million valuation allowance charge related to deferred tax assets

Fiscal 2000 Compared with Fiscal 1999

Revenue for 2000 totaled $913.5 million, an increase of approximately 16% over revenue for 1999. The production services segment contributed $450.9 million of 2000 revenue compared to $368.3 million for 1999. This 22% increase in production services revenue in 2000 reflected seven additional production months from the *Petrojarl Varg,* which we acquired in July 1999, and an increase in the level of third-party platform services provided by our Atlantic Power group. These increases were partially offset by suspended production operations on the *Petrojarl I* and *Ramform Banff* as these FPSO systems underwent significant upgrades during the fourth quarter of 2000. Geophysical services revenue for 2000 totaled $462.6 million and reflected an increase of 10%, or $42.8 million, from 1999 revenue. This increase was attributable to the higher level of contract seismic activity during the 2000 summer season. Multi-client seismic revenue for 2000 totaled $248.2 million, an increase of 2%, or $6.0 million, from comparable 1999 revenue.

Cost of sales, including research and technology costs, for 2000 increased by $90.2 million, or 26%, as compared to the prior year. Cost of sales as a percentage of revenue was 48% for 2000 as compared to 44% for 1999. The increase in cost of sales reflected the full year of production services from the *Petrojarl*

Varg and the increase in platform services and geophysical contract seismic activity over the year. The increase in cost of sales as a percentage of revenue primarily reflected continued low pricing for geophysical services and an increase in the lower margin platform services.

Depreciation and amortization for 2000 increased by $25.0 million, or 10%, as compared to the prior year. Depreciation and amortization represented 29% and 30% of 2000 and 1999 revenue, respectively. The increase in depreciation and amortization reflected the full year of production services from the *Petrojarl Varg* and the higher level of geophysical contract seismic services. The average multi-client amortization rate during 2000 was 57%, which was the same as the 1999 rate.

Selling, general and administrative costs for 2000 increased by $4.7 million, or 7%, as compared to the prior year. This increase was due in part to a gain for the year ended December 31, 1999 from our production services group related to resolution of a legal contingency. As a percentage of revenue, these costs were relatively consistent at 8% and 9% for 2000 and 1999, respectively.

Operating profit before unusual items for 2000 was $134.3 million, representing an increase of 4% compared to 1999. Operating profit margin before unusual items for 2000 decreased slightly to 15% from the comparable 1999 margin of 16%.

Production services operating profit before unusual items for 2000 increased by 48%, or $33.6 million, over operating profit for 1999. Operating profit margin before unusual items improved from 19% for 1999 to 23% for 2000. The improved production services operating profit resulted primarily from the additional seven production months in 2000 from the *Petrojarl Varg* and greater production in 2000 from the *Petrojarl Foinaven.*

Geophysical services operating profit before unusual items for 2000 decreased by 48%, or $28.3 million, from operating profit for 1999. Operating profit margin before unusual items declined from 14% for 1999 to 7% for 2000. Operating profit from the geophysical services segment did not reflect the significant, sustained rebound in oil and gas prices that occurred during 2000, as exploration and development spending by oil and gas companies did not increase in tandem with the oil and gas price increases. Additionally, the depressed oil and gas company spending level resulted in lower prices for geophysical services, and this reduced pricing also adversely affected our operating profit. As a result of these market conditions, we reviewed the carrying amounts of our assets and long-term contract performance and recorded $365.8 million in unusual items for 2000 as follows:

- $166.5 million in impairment charges against our multi-client library
- $148.8 million in impairment charges against property, equipment and other assets
- $50.5 million in losses for long-term contracts

Although primarily related to the geophysical services segment, these charges included $77.2 million related to the *Ramform Banff* and other production assets. We believe that the upgrade of the *Ramform Banff,* which commenced in the fourth quarter of 2000 and was completed in the first quarter of 2001, will significantly improve uptime performance from this asset.

Income from equity investments for 2000 included a $54.7 million gain associated with the sale of our share holdings in Spinnaker Exploration Company.

Net financial expense for 2000 increased by 40%, or $38.6 million, over net financial expense for 1999. The increase in financial expense for 2000 was due to (a) the issuance in March 2000 of $225.0 million in senior unsecured notes, (b) five additional months of expense relating to our trust preferred securities that were issued in June 1999 and (c) a higher average level of indebtedness outstanding under our revolving bank credit facility.

Other expense, net for 2000 included a $28.6 million increase in fair value expense associated with our tax equalization swap contracts and $26.0 million in gains associated with UK leases. For 1999, other expense, net included $19.1 million in gains associated with UK leases. We do not expect to recognize any significant income or cash flows related to UK leases in future periods.

The $132.8 million income tax benefit provided for 2000 consisted of (a) a benefit of $14.0 million on the results of continuing operations, (b) a net benefit of $72.3 million associated with the $365.8 million in unusual charges, the $26.0 million UK lease gain and the $54.7 million gain on the sale of our shares in Spinnaker, (c) a net benefit of $50.3 million related to tax equalization swap contracts, and (d) a $3.8 million valuation allowance against deferred tax assets.

The cumulative effect of accounting change, net of tax, was recorded as of January 1, 2000 and reflected our adoption of the provisions of SAB No. 101. This accounting change related to our accounting for some types of volume seismic data licensing arrangements and included adjustments to revenue ($22.8 million), amortization ($11.4 million) and commissions expense ($2.3 million). The aggregate $9.1 million cumulative effect charge was reduced by a $2.5 million tax benefit.

Outlook; Factors Affecting Our Future Operating Results

Our future operating results will depend on numerous factors, including those described under "Key Information — Risk Factors" in Item 3 of this annual report. Factors that will impact our future operating results include in particular the following:

- the results of the *Ramform Banff*. Based on available information including information about the reservoir, we expect the vessel to continue to produce at low levels and to continue to generate losses through at least the third quarter of 2002. We expect one or two new wells to be drilled on the Banff field during 2002, and any incremental production from such wells will help reduce losses under the existing Banff contract. In order to improve the results of the *Ramform Banff,* we are evaluating moving the vessel to another location and providing an alternative production solution for the Banff field. Depending on whether and when the *Ramform Banff* is redeployed, we may need to provide for future losses on the Banff contract.

- the benefits provided by the capacity upgrade of the *Petrojarl Foinaven*. In addition, we expect to realize additional revenue on the Foinaven contract since the field's reserve estimates were significantly increased during the 2001 fourth quarter. With the completion of several successful development drilling programs and 4D seismic surveys, we believe that *Petrojarl Foinaven* will remain in production on the Foinaven field for a substantial period of time. We anticipate that production services revenue for 2002 will be significantly higher than 2001 revenue, as the performance capability of the FPSO vessels as a group has been improved and there is no significant downtime planned for any of the vessels.

- the increased demand for contract seismic operations that we experienced during 2001, including demand for high-density, single-source 3D surveys. We believe that the demand for such surveys — supported by our Ramform HD3D™ seismic technology — will continue to increase during 2002, as the industry realizes the level of operational efficiency and data sophistication that can be achieved through the use of HD3D™ seismic technology. The expected increase in contract seismic operations in 2002 will likely yield lower operating profit margins than would multi-client operations, but we expect the contract operations to yield increased cash flow in the near term.

- our substantial geophysical services backlog. In addition to a substantial backlog of traditional marine acquisition work at December 31, 2001, our 2002 geophysical services backlog includes more than $100 million in onshore and transition zone contract acquisition work, a substantial portion of which will be performed using our HD3D™ seismic technology, and approximately $33 million in four-component contract acquisition work.

- future licensing activities in Norway (17th licensing round) and by host countries in West Africa and the Asia Pacific region. We expect to benefit from this licensing activity through uplift fees due under previously executed multi-client sales contracts and from the recognition in periods after December 31, 2001 of $26.0 million of revenue related to volume seismic data licensing arrangements that were committed as of such date.

- whether the closing of the sale of Atlantis occurs

- whether we are successful in reducing our outstanding debt levels and operating costs and improving our cash flow
- the amount of minimum amortization charges we incur for our multi-client data library
- the impact of adoption of SFAS No. 142
- the impact of foreign currency exchange rate fluctuations and the resulting fair value effects on our tax equalization swap contracts and the related income tax expense or benefit

Financial Condition

Capital Resources and Liquidity

Material Factors.

In March 2002, we entered into a $250.0 million short-term credit facility, which was amended and restated in May 2002. The facility will mature at the earlier of August 31, 2003 or June 16, 2003 if the Veritas transaction has been terminated prior to that date. We must make a mandatory prepayment of $175.0 million from the future proceeds of any Atlantis sale. The credit facility carries an initial interest rate equal to LIBOR plus a margin of 0.65%, which margin escalates to 1.0% on June 1, 2002, to 1.5% on August 1, 2002, and to 4.5% on October 1, 2002 until maturity. In the event that either Standard & Poor's or Moody's downgrades our credit rating below BBB- or Baa3, respectively, prior to October 1, 2002, the margin will escalate to 4.5% at the time that the downgrade is issued. If any amounts are outstanding under this credit facility at July 31, 2002 (or earlier in the event of termination of the Veritas transaction prior to July 31, 2002), we are obligated to use our best endeavors to arrange financing in order to repay such amounts prior to maturity. Additionally, if the facility remains outstanding at July 1, 2002, we will be required to limit any additional cumulative capital expenditures and multi-client investments to a maximum of $280.0 million for the period from July 1, 2002 through the maturity date of the facility.

We believe that our cash on hand ($86.0 million as of March 31, 2002), operating cash flows, available bank credit facilities and the proceeds from the sale of non-core assets, including our Atlantis subsidiary, will be sufficient to meet the existing contractual cash obligations, anticipated multi-client investments, anticipated capital expenditures, working capital and other operational needs of our business for the next 12 months. Our future operating cash flows will be affected by our future performance and will be subject to, among others, the factors discussed under "Key Information — Risk Factors" in Item 3 of this annual report. If cash generated from operations and these other expected sources is not sufficient to satisfy our liquidity requirements, we may seek to sell either debt or equity securities, to obtain additional credit facilities or other long-term financings or to sell assets. We cannot assure you that such sources of funds will be available in the future or be available at costs acceptable to us.

Credit Ratings.

Our senior unsecured debt credit ratings as of May 2, 2002 were as follows:

Rating agency	Rating
Moody's	Baa3
Standard & Poor's	BBB-
Fitch	BBB-

We cannot assure you that these credit ratings will remain in effect for any given period of time or that one or more of these credit ratings will not be lowered or withdrawn entirely by the credit rating agencies. Our credit ratings with Moody's and Standard & Poor's are currently under review and on creditwatch with negative implications, respectively. If we do not complete the Atlantis sale or if we do not complete the Veritas transaction, our credit ratings may be downgraded. We note that these credit ratings are not recommendations to buy, sell or hold our securities and may be revised or withdrawn at any time by the credit rating agencies. Each credit rating should be evaluated independently of any other credit rating. Any future reduction or withdrawal of one or more of our credit ratings could have a material adverse impact on our ability to access capital on acceptable terms.

Additionally, if our credit rating declines below BBB- (Standard & Poor's) and Baa3 (Moody's), we estimate that we could be obligated to provide up to £35.7 million (approximately $52.0 million) in collateral or other credit support to one or more lessors or other parties under UK leasing arrangements. In the event that our credit ratings are downgraded to below BB+ or Ba1 by Standard & Poor's or Moody's, respectively, we will be required to increase by 30% the quarterly redemption of the mandatorily redeemable cumulative preferred securities of a subsidiary which owns a portion of our multi-client library. If those credit ratings remain for a certain period of time, or deteriorate below BB- or Ba3, respectively, we will be required to increase the quarterly redemption of the preferred securities to an amount equal to 100% of the actual revenue recognized from the licensing of the data held by that subsidiary.

Credit Facilities.

The following table summarizes the amounts owed and amounts available under our various committed credit facilities (in millions) as of March 31, 2002. The following table does not include approximately $40.0 million in available, uncommitted credit lines at March 31, 2002:

	Total committed credit	Drawn amount	Unused amount	Maturing before December 31, 2002
Revolving bank credit facility	$430.0	$360.0	$70.0	$ —
Short-term bank facility	250.0	250.0	—	—
Other bank facilities	21.0	20.5	0.5	—
Total	$701.0	$630.5	$70.5	$ —

Significant Sources of Capital During 2001.

In March 2001, we sold our global Petrobank data management business and related software to a subsidiary of Halliburton for $165.7 million in cash, representing gross sale proceeds of $175.0 million less a $9.3 million working capital adjustment. The net proceeds received were used, in part, to repay indebtedness outstanding under our revolving bank credit facility.

In April 2001, we entered into a securitization transaction related to our multi-client marine seismic data library. In consideration for $234.3 million in net proceeds, we sold the ownership of a portion of this data library to a subsidiary, which then issued $240.0 million in cumulative preferred stock to a third-party investor. The preferred stock will be redeemed, and the preferred dividends will be paid, solely through the proceeds received on future data sales from the sold data. During 2001, redemption payments of $77.3 million were made from such sales proceeds. Once the $240.0 million of preferred stock is redeemed and the cumulative preferred dividends are paid, we will retain the full proceeds of any remaining data sales. We used the net proceeds from the securitization primarily to repay indebtedness outstanding under our revolving bank credit facility.

At December 31, 2001, we had $90.0 million available to be utilized under our primary committed revolving bank credit facility. This unsecured $430.0 million revolving bank credit facility matures in 2003 and bears interest at LIBOR plus a margin of either 0.35% per annum or 0.40% per annum, depending upon the level of our indebtedness. Borrowings under this revolving bank credit facility are subject to a material adverse change condition regarding our financial condition and to other conditions to borrowing that are customary for such types of facilities.

During 2001, we also borrowed under a $75.0 million unsecured revolving credit facility with a syndicate of banks. The facility bore interest at LIBOR, plus a margin that escalated from 0.4% to 0.6% by maturity. This facility matured in December 2001 and was repaid. During 2001, we borrowed under a $21.0 million unsecured bank credit facility to fund some of our oil and gas activities. This facility bears interest at LIBOR plus a margin that ranges from 0.63% to 1.4%, and is payable in installments through 2003, with the payment installments tied to future production from oil and gas assets. At December 31, 2001, $20.5 million in short-term debt was outstanding under this credit facility.

Capital Requirements

Our capital requirements are affected primarily by our results of operations, capital expenditures, investments in multi-client library, debt service requirements, lease obligations, payments on preferred securities of subsidiaries and working capital needs. The majority of our capital requirements, other than debt service, lease obligations and payments on preferred securities, consist of

- capital expenditures on seismic vessels and equipment
- capital expenditures on FPSO vessels and equipment
- investments in our multi-client library
- capital expenditures on computer processing and reservoir monitoring equipment
- working capital related to the growth and seasonal nature of our business

In prior years, our capital expenditures have related not only to normal ongoing equipment replacement and refurbishment needs, but also to increases in capacity in our seismic data acquisition operations and our FPSO operations. Additional capital expenditures, some of which could be substantial, depend to a large extent upon the nature and extent of future commitments that are discretionary.

The following table sets forth our consolidated capital requirements for 2001 and estimates of our consolidated capital requirements for 2002, in each case excluding the debt service and other contractual cash obligations that are shown in the table included later in this section (in millions):

	2001	2002 (estimated)
Capital expenditures — Geophysical	$ 26.1	$ 45.0
Capital expenditures — Production Services(1)	213.5	15.0
Investment in multi-client library	230.2	190.0
Total	$469.8	$250.0

(1) Excludes Atlantis-related development costs. We expect that a substantial portion of these costs will be reimbursed if and when the sale of Atlantis closes.

A substantial amount of our capital expenditures and investments in our multi-client library is discretionary. We expect to substantially decrease our capital expenditures in 2002, since there are no planned major capital projects for our FPSO systems. We expect to reduce investments in our multi-client library in 2002.

Capital expenditures of $239.6 million for 2001 related primarily to the upgrade of the *Ramform Banff, Petrojarl I* and *Petrojarl Foinaven* FPSO systems and to oil and gas assets. Capital expenditures of $115.2 million for 2000 related primarily to ongoing maintenance capital expenditures and the upgrade of both the *Ramform Banff* and *Petrojarl I* FPSO systems. Capital expenditures of $667.9 million for 1999 related primarily to the acquisition of the *Petrojarl Varg* in July 1999 and to final payments on the *Ramform Victory,* which was delivered in January 1999, the *Ramform Vanguard,* which was delivered in April 1999, and the *Ramform Banff,* which commenced production in the first quarter of 1999.

During 2001, our investment in multi-client library primarily related to seismic surveys in the North Sea, offshore Brazil and West Africa and in the Asia Pacific region. During 2000, we invested $264.5 million in our multi-client library, primarily in strategic, deepwater seismic surveys in the North Sea, offshore Brazil and West Africa and in the Asia Pacific region. During 1999, we invested

$338.7 million in our multi-client library, primarily in seismic surveys in the North Sea, the Gulf of Mexico, offshore West Africa and in the Asia Pacific region.

In the following table we estimate our consolidated contractual obligations as of December 31, 2001 to make future payments for 2002 through 2004 and thereafter (in millions). The following table does not include interest or dividend payments on our debt and preferred securities obligations:

	Payments due by period				
Contractual cash obligations	Total	2002	2003	2004	2005 and thereafter
Short-term and long-term debt, including current portion	$2,161.3	$ 257.7(1)	$ 599.0	$ 10.2	$1,294.4
Capital lease obligations(2)	60.9	13.1	11.2	9.2	27.4
Operating lease obligations	297.5	111.4	66.8	42.7	76.6
Guaranteed preferred beneficial interest in junior subordinated debt securities	141.0	—	—	—	141.0
Mandatorily redeemable cumulative preferred securities(3)	169.3	72.0	46.1	32.6	18.6
Total contractual cash obligations	$2,830.0	$ 454.2	$ 723.1	$ 94.7	$1,558.0

(1) Includes $225.0 million of floating rate notes that matured and were refinanced with a $250.0 million bank credit facility in March 2002. Such facility will mature in 2003.

(2) Reflects gross contractual commitments under capital leases.

(3) Assumes that our credit ratings remain at or above BB+ or Ba1 by Standard & Poor's or Moody's, respectively.

Currency Fluctuations

While we do not experience any significant effects from inflation, we can experience significant currency fluctuations. The primary currencies for our operations are the US dollar, the Norwegian kroner and the British pound. A strengthening or weakening of the Norwegian kroner or the British pound against the US dollar will generally have an impact on operating profit. We typically hedge a portion of our exposure to foreign currency exchange rate fluctuations by attempting to balance our asset and liability positions and, to a lesser extent, by purchasing foreign currency exchange contracts and other foreign currency exchange instruments from time to time.

In 1998 and 1999, we entered into tax equalization swap contracts to hedge the cash-flow risk associated with the Norwegian statutory tax effect of unrealized foreign currency exchange rate fluctuations between the Norwegian kroner and US dollar on our non-kroner denominated financial instruments (primarily US dollar denominated debt and trust preferred securities). These fluctuations are taxable/deductible on a mark-to-market basis for Norwegian statutory tax purposes, and therefore create current tax liability/benefit positions for us in our tax filings. The aggregate settlement for the year ended December 31, 2001 on these contracts created an $11.4 million liability to be paid to our counterparty during 2002. In addition to this settlement liability, we recorded $6.6 million to other expense during 2001 to properly reflect the fair value of these contracts. The aggregate settlement for 2000 created a $65.2 million liability which was paid during 2001. We also recorded a $3.8 million benefit to other expense during 2000 to properly reflect the fair value of these contracts. The aggregate settlement for 1999 created an $8.4 million liability, which was paid during 2000. We recorded $24.4 million in additional other expense for 1999 to properly reflect the fair value of these tax equalization swap contracts.

For 2001, we recorded to other expense, net, $1.7 million in net foreign exchange losses exclusive of the effect of our tax equalization swap contracts as the US dollar weakened against the Norwegian kroner. For 2000 and 1999, we recorded to other expense, net, $2.9 million and $4.1 million, respectively, in net foreign exchange gains exclusive of the effect of our tax equalization swap contracts as the US dollar continued to strengthen against the Norwegian kroner.

To the extent our level of international operations and the revenue and expenses that we generate in other currencies increases, our exposure to foreign currency exchange rate fluctuations will also increase. These fluctuations could have a material impact on our results of operations.

Under Norwegian foreign exchange controls currently in effect, transfers of capital to and from Norway are not subject to prior government approval, except that the physical transfer of payments in currency is restricted to licensed banks.

Income Taxes

Statement of Financial Accounting Standard ("SFAS") No. 109, "Accounting for Income Taxes," requires that our provision for income taxes be determined based upon the liability method, in which we recognize deferred tax assets and liabilities based on differences between the financial statement and tax bases of assets. The liability method requires us to evaluate our deferred tax assets for realization based on a "more likely than not" standard, and to provide a valuation allowance where realization is not determined to be "more likely than not." For 2001 and 2000, we provided $65.9 million and $3.8 million, respectively, in valuation allowances against our deferred tax assets because of uncertainties about our future ability to fully utilize net operating losses in the US and UK.

New Accounting Standards

During 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 141, "Business Combinations," and SFAS No. 142, "Goodwill and Other Intangible Assets." SFAS No. 141 requires that the purchase method of accounting be used for all business combinations initiated after June 30, 2001. Effective beginning January 1, 2002, SFAS No. 142 suspends amortization of goodwill and intangible assets with indefinite lives and, instead, requires an annual impairment review based on a comparison of fair value to carrying value. SFAS No. 142 requires the fair value determination to be completed by June 30, 2002, with any resulting transitional impairment to be recorded by December 31, 2002 as the cumulative effect of an accounting change. Any impairments other than transitional impairment will be recognized in continuing operations. We are developing our fair value calculations and have not yet determined the impact of adopting SFAS No. 142.

During 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations". SFAS No. 143 establishes accounting and reporting standards for the retirement of long-lived assets requiring the fair value of an asset retirement obligation to be recognized as a liability in the period in which it is incurred, with the associated costs capitalized as part of the carrying amount of the long-lived asset. SFAS No. 143 is effective for us beginning January 1, 2003, and any effects on adoption will be reflected as a cumulative effect of an accounting change. We have not yet determined the impact on us of SFAS No. 143.

Also during 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." SFAS No. 144 addresses, in part, issues related to implementation of SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of." SFAS No. 144 is effective for us as of January 1, 2002. We do not expect to recognize any material effects on the prospective implementation of SFAS No. 144.

ITEM 6. *Directors, Senior Management and Employees*

Board of Directors

The table below provides information about our directors as of May 17, 2002:

Name (Age)	Position	Director since	Term expires	Share Ownership
Reidar Michaelsen (58)	Chairman	1993	2003	*
Michael S. Mathews (61)	Vice Chairman	1993	2003	*
Jens Gerhard Heiberg (63)	Director	1993	2003	*
Mark G. Frantz (55)	Director	1994	2002	*
Jan Aage Strand (48)	Director	1996	2002	*
Endre Ording Sund (52)	Director	1998	2002	*

* Less than 1% of our outstanding shares as of December 31, 2001.

Mr. Michaelsen has been chairman of the board and chief executive officer since 1993. He was president of PGS from 1991 to 1993. Mr. Michaelsen served as managing director of Norsk Vekst AS during the period 1989 to 1991. He headed the Selmer Sande Group from 1986 to 1989 and was with Geco Geophysical Company, Inc., Houston ("Geco") from 1982 to 1986, reaching the position of managing director. Mr. Michaelsen received a degree in business economics from the Norwegian School of Management in 1968 and an M.B.A. from the University of Wisconsin in 1975.

Mr. Mathews is managing director of Westgate Capital Co., a private New York-based investment firm. From 1989 to 1992, Mr. Mathews served as managing director of Bradford Ventures Ltd., a private investment firm involved in equity investments, including acquisitions. Prior to 1989, he was president of DNC Capital Corporation and senior vice president and director of its parent, DNC America Banking Corp., the US subsidiary of Den Norske Credit Bank Group, where he directed merchant banking and investment activity in North America and founded and acted as senior advisor to Nordic Investors Limited, N.V., a private venture capital fund. Mr. Mathews has been a director of numerous companies and is currently chairman of Telecomputing ASA and Apptix ASA, both listed on the Oslo Stock Exchange. Mr. Mathews received an A.B. from Princeton University in 1962 and received a J.D. from the University of Michigan Law School in 1965.

Mr. Heiberg is a partner of Norscan Partners AS. From 1989 to 1994, he was chairman of the Lillehammer Olympic Organizing Committee, responsible for the 1994 Winter Olympic Games in Lillehammer, Norway. From 1973 to 1989, he was managing director of Aker Norcem A/S, and from 1989 to 1996, he was chairman of its successor company, Aker ASA. Mr. Heiberg serves on the boards of several companies, both inside and outside of Norway. Mr. Heiberg holds a degree from the College of Commerce in Oslo and received a master's degree in business administration from the Copenhagen Graduate School of Economics and Business Administration.

Mr. Frantz is chairman, chief executive officer and president of Frantz Medical Development Ltd., Frantz Imaging Inc., FrantzTech Ltd. and Frantz Tool & Design, Inc., a group of affiliated companies headquartered in New York specializing in the research, development and manufacturing of medical electronic devices and related disposables. Mr. Frantz founded Frantz Medical Development Ltd. in 1980 and the remainder of the group companies in the late 1980s. From 1976 to 1979, Mr. Frantz was employed as the vice president of operations of Med-Tek Ltd., a supplier of highly sophisticated medical electronics equipment. Mr. Frantz was also employed by Pfizer Pharmaceuticals from 1973 to 1975 in strategic planning and product management positions. Mr. Frantz received a B.S. degree from Georgetown University in 1969 and an M.B.A. from Columbia University in 1972.

Mr. Strand is the founder and, since 1991, has served as managing director of Tobine AS, a privately owned group of companies headquartered in Oslo involved in the shipping, construction, real estate and salmon production businesses. Mr. Strand served as senior vice president of Norsk Vekst AS during the period 1989 to 1991, and was Senior Vice President — Finance of Selmer Sande Group from 1987 to 1989. Prior to that time, Mr. Strand served as controller of Geco AS in Oslo and worked for Peat Marwick, Mitchell & Co. Mr. Strand received a master's degree in business administration from Bedriftsøkonomisk Institutt in Oslo.

Mr. Sund served as chairman of Golar-Nor Offshore until its acquisition by PGS from Awilco ASA in 1998. Mr. Sund also served as chairman of the board of Awilco ASA from 1992 through 2000 and served as president of Awilco ASA from 1989 to 1992. Mr. Sund served as the managing director of Anders Wilhelmsen & Co. AS from 1992 through 2000 and is a director of Kenor ASA and chairman of Marine Provider AS and the Norwegian Shareholder Association. Mr. Sund is the chairman and chief operating officer of Acta AS. Mr. Sund holds various other board positions. Mr. Sund graduated from the Norwegian Naval Academy, holds a Master Mariner's degree, studied at the Norwegian School of Management and obtained a PMD from Harvard Business School.

Audit and Compensation Committees of the Board

Our audit committee consists of Messrs. Mathews, Frantz and Strand; our compensation committee consists of Messrs. Mathews, Frantz and Heiberg. The audit committee reviews, acts on and reports to the board of directors with respect to various auditing and accounting matters. With respect to auditing matters, the committee's activities include the selection of our auditors for shareholder approval, the scope of the annual audit, fees to be paid to the auditors, the performance of our independent auditors and our accounting practices. With respect to accounting matters, the committee's activities include reviewing our interim and year-end financial condition and results of operations and considering the adequacy of our internal accounting and control procedures. The compensation committee establishes and reviews overall policy and structure with respect to compensation matters, including the determination of compensation arrangements for directors, executive officers and key employees and the administration of our share option plans.

Executive Officers

The table below provides information about our executive officers as of May 17, 2002:

Name (Age)	Position	Executive officer since	Share Ownership
Reidar Michaelsen (58)	Chief Executive Officer	1991	*
J. Christopher Boswell (41)	Senior Vice President and Chief Financial Officer	1995	*
Sam R. Morrow (53)	Senior Vice President — Finance and Treasurer	1996	*
Anthony Ross Mackewn (54) ..	President — PGS Geophysical	1999	*
Kaare Gisvold (59)	President — PGS Production	1998	*
Karl Andreas Berteussen (57) ..	Senior Vice President — Reservoir Technology	1999	*
William E. Harlan (43)	Vice President — Chief Accounting and Administrative Officer	1996	*
Knut Haavardsen (59)	General Counsel	1992	*

* Less than 1% of our outstanding shares as of December 31, 2001.

Mr. Boswell was appointed Senior Vice President and Chief Financial Officer in June 1996, and since the fourth quarter of 1995 had served as Senior Vice President — Control and Chief Accounting Officer. Mr. Boswell joined PGS in October 1994 as Vice President — Finance of PGS Exploration (US), Inc. Prior to joining PGS, Mr. Boswell was employed by Price Waterhouse from 1989 to 1994 and by Arthur Andersen from 1984 to 1989. Mr. Boswell received a bachelor's degree in business administration with an emphasis on accounting from the University of Texas at Austin in 1984.

Mr. Morrow joined PGS in June 1996 as Senior Vice President — Finance and Treasurer. Prior to joining PGS, Mr. Morrow served as Chief Financial Officer of SeaMar Inc., a supply vessel and marine management company, from 1995 to 1996. From 1993 to 1994, Mr. Morrow served as Senior Vice President and Chief Financial Officer of Total Energy Services, Inc., an oilfield services and products company. From 1985 until 1993, Mr. Morrow was Chief Financial Officer of The Western Company of North America, an oilfield services company. Mr. Morrow received his bachelor's degree in economics from De Pauw University in 1971 and his MBA from the University of Michigan in 1973.

Mr. Mackewn joined PGS as Technology Director of PGS Nopec in 1993, transferred to PGS Exploration in 1996 as Managing Director of PGS Exploration UK Ltd., was named President — Exploration EAME in November 1999 and was named President — PGS Geophysical Services in May 2001. Mr. Mackewn graduated with an honors degree in physics from the University of Southampton in 1969.

Mr. Gisvold joined PGS in December 1997 as part of PGS' acquisition of the FPSO operations (Golar-Nor Offshore) of Awilco ASA. He was appointed President — PGS Production in June 2000, prior to which time he served as a Senior Vice President responsible for strategic development of FPSO activities. From 1983 through December 1997, Mr. Gisvold was Chief Executive Officer of the NFDS drilling company Golar-Nor Offshore, where he was responsible for the technical and commercial development of the FPSO group. From 1981 to 1983, Mr. Gisvold worked with Volvo of Sweden. From 1971 through 1981, Mr. Gisvold was responsible for developing and running the MARINTEK laboratories in Trondheim, Norway. Mr. Gisvold received both an MSc and a PhD in naval architecture and marine engineering from the Technical University of Norway in 1967 and 1971, respectively.

Mr. Berteussen was appointed Senior Vice President — Reservoir Technology in November 1999, having served as President of PGS Reservoir AS since 1995. From 1987 to 1995, Mr. Berteussen was President of Read Well Services. From 1982 to 1987, Mr. Berteussen worked at Saga Petroleum, ultimately reaching the position of Senior Manager, Geophysics. From 1971 to 1981, Mr. Berteussen was an assistant professor at Oslo University and, beginning in 1985, has served as an adjunct professor at the University of Tromso in Norway. From 1972 to 1976, Mr. Berteussen was a research scientist with Norwegian Seismic Array (NORSAR). Mr. Berteussen received a PhD in seismology from the University of Oslo in 1976 and an MS in geophysics from Bergen University in 1972.

Mr. Harlan joined PGS in August 1996 as the Vice President — Chief Accounting and Administrative Officer. Prior to joining PGS, Mr. Harlan was the Controller of Air Liquide America Corporation, the US subsidiary of L'Air Liquide, from 1995 to 1996. From 1991 to 1994, Mr. Harlan served in Jakarta, Indonesia as the Chief Financial Officer of the Indonesian Operations of Huffco, a Houston-based oil and gas exploration and production company. Prior to joining Huffco, Mr. Harlan, a certified public accountant, was employed by KPMG Peat Marwick from 1988 to 1991 and by Arthur Andersen from 1983 to 1988. Mr. Harlan received his bachelor's and master's degrees of accountancy from the University of Mississippi in 1981 and 1983, respectively.

Mr. Haavardsen has been general counsel and secretary of PGS since 1992. Mr. Haavardsen served as senior vice president of Foinco Invest A.S. from 1989 to 1991, as general counsel and vice president of Geco from 1987 to 1989 and as legal director of Aspelin-Stormbull AS from 1975 to 1986. Mr. Haavardsen received a law degree from Oslo University in 1967, and an AMP from Harvard Business School in 1983.

Share Ownership of Directors and Executive Officers

As of December 31, 2001, the total number of our shares and ADSs, beneficially held by our directors and executive officers as a group (13 persons) was 1,597,540, representing approximately 2% of our outstanding shares. This amount includes 1,254,000 shares that could be acquired upon the exercise of options vested as of March 1, 2002.

Compensation of Directors and Executive Officers

For the year ended December 31, 2001, the aggregate amount we paid for compensation to our directors and executive officers as a group (13 persons) for services in all capacities was approximately $3.8 million (exclusive of any compensation attributable to any exercises of stock options). Mr. Michaelsen, our chief executive officer, received compensation for services to us during 2001 (exclusive of any compensation attributable to any exercises of stock options) of approximately $1.2 million. The aggregate benefits that had accrued to our executive officers as a group (8 persons) under our various defined benefit plans for the year ended December 31, 2001 was $1.1 million.

As of January 1, 2000, we entered into a deferred compensation agreement with one of our directors providing for director benefits upon termination of his directorship. The benefits accrue in the amount of $100,000 for each year of service, plus interest. As of December 31, 2001, approximately $200,000 in benefits had ratably accrued under this program. In the event of a change of control of our company or the director's death, the director or his beneficiaries will receive a lump sum payment of all unpaid amounts credited to his deferred compensation account.

We have established a discretionary incentive bonus plan designed primarily to compensate designated members of our senior management when we achieve specified annual performance-related goals. Participants in the plan are designated by the compensation committee of our board of directors. Performance goals and related award schedules for award periods may be established under the plan periodically and generally cannot be changed once established. Awards that accrue for each year are contingent until paid, unless earlier vested due to a change in control of our company, plan termination or a participant's involuntary termination of employment without cause, including by reason of death or disability. Unless earlier vested, any awards that accrue during an award period are forfeited by a participant who is no longer employed by us or our subsidiaries on the date award payments are made. Payment of accrued awards is deferred until after the end of the award period and is made in a cash lump sum. The maximum individual award potentially payable with respect to any year is 100% of a participant's base salary (for 2001, $950,000 for Mr. Michaelsen). The compensation committee has established a base award period for the plan covering the three years from 1996 to 1999 with a granted extension period through 2001, with annual awards during such periods accruing based in part (75%) on targeted operating profit levels and increases in our earnings per share. The remaining 25% of any annual award is granted at the discretion of the compensation committee.

As of December 31, 2001, our directors and executive officers as a group (13 persons) held options for 2,941,000 shares. As of that date, Mr. Michaelsen individually held options as shown in the table below. No other directors or executive officers individually held options equivalent to (or greater than) 1% of our outstanding shares at December 31, 2001; their aggregate holdings are shown in the table below. We have translated the NOK amounts in the table solely for convenience into US dollars at the noon buying rate on December 31, 2001 ($1.00 = NOK 8.97).

Name	Exercise dates	Number of outstanding options	Exercise price	
			NOK	$
Reidar Michaelsen	July 1, 2000 - July 1, 2002	720,000	162.0	18.06
	July 1, 2003 - July 1, 2006	900,000	133.0	14.83
Remaining directors and executive officers	July 1, 2000 - July 1, 2002	226,000	162.0	18.06
	July 1, 2000 - July 1, 2002	135,000	137.5	15.33
	July 1, 2001 - July 1, 2003	40,000	229.5	25.59
	July 1, 2001 - July 1, 2003	133,000	111.0	12.37
	July 1, 2002 - July 1, 2004	40,000	128.5	14.33
	July 1, 2002 - July 1, 2004	55,000	131.5	14.66
	July 1, 2003 - July 1, 2006	100,000	160.0	17.84
	July 1, 2003 - July 1, 2006	492,000	150.0	16.72
	July 1, 2004 - July 1, 2007	100,000	103.0	11.48

Please read notes 16 and 18 of the notes to our financial statements in Item 18 of this annual report for additional information regarding our share option and retirement plans.

Employees

At December 31, 2001, 2000 and 1999, we employed approximately 5,100, 4,200 and 4,100 full-time personnel, respectively. The mix between full-time personnel employed solely in our geophysical services group and our production services group for the year ended December 31, 2001 was 48% and 48%, respectively, which was consistent with the prior year mix. Our remaining employees provide services across the two segments of our organization. We have not experienced any material work stoppages related to union activities and consider our relations with our employees to be good.

ITEM 7. *Major Shareholders and Related Party Transactions*

Based on an amendment to Schedule 13G filed with the Securities and Exchange Commission on January 23, 2002 by Mellon Financial Corporation, on behalf of itself and a number of its subsidiaries, Mellon, through various subsidiaries, beneficially owns 11,645,410 shares, or 11.3% of the outstanding shares. Mellon does not have voting rights different from those of any other shareholders of PGS. To our knowledge, no other person or group beneficially owns 5% or more of our outstanding shares.

At December 31, 2001, we were party to a definitive agreement to combine with Veritas. For additional information about this transaction, please read "Information on the Company — Recent Developments — Combination with Veritas" in Item 4 and note 3 of the notes to our financial statements in Item 18 of this annual report.

As of December 31, 2001, there were 133 record holders of ADSs representing 46,762,867 shares, 116 of which had registered addresses in the United States. These 116 United States record holders held ADSs representing 46,750,453 shares, which represented approximately 45% of the total number of our shares outstanding as of that date.

Based upon information available from Verdipapirsentralen, the Norwegian centralized registry of securities, as of December 31, 2001, there were 103,345,987 shares outstanding (including shares represented by ADSs) held by 5,905 record holders, of which 76 had registered addresses in the United States and 5,484 had registered addresses in Norway. The United States holdings represented 56,810,791 shares, or approximately 55% of the total number of our shares outstanding as of that date. For this purpose, Citibank, in its capacity as the depositary for our ADSs, represents one record holder of shares. The above numbers may not be representative of the actual number of United States beneficial holders or of shares beneficially held by United States persons. The Norwegian holdings represented 30,951,046 shares, or approximately 30% of the total number of our shares outstanding as of that date.

Please read note 19 of the notes to our financial statements in Item 18 of this annual report for information regarding our related party transactions.

ITEM 8. *Financial Information*

Financial Statements

Please read Item 18 of this annual report.

Legal Proceedings

From time to time, we are involved in or threatened with various legal proceedings arising in the ordinary course of business. Our management does not believe that we are engaged in, or have recently been engaged in, any legal or arbitration proceedings which could have, or have had, a significant effect on our financial position or results of operations. We are not engaged in any material proceeding that involves any director, member of senior management or affiliate as an adverse party to us.

Dividend Restrictions

Our ability to meet parent company-level payment obligations depends upon dividends, distributions, advances and other intercompany transfers from our subsidiaries. Under Norwegian law, dividends in cash or in-kind as a distribution of our profit and the profits of our Norwegian subsidiaries are only payable annually, and any proposal by the board of directors to pay a dividend must be recommended by the directors and approved by the shareholders at a general meeting. The shareholders may vote to reduce, but not to increase, the dividends proposed. Dividends in cash or in-kind are payable only out of:

- the annual profit according to the income statement for the last financial year
- retained profit from previous years
- other unrestricted equity, after deduction of:
    - accumulated losses
    - the book value of research and development, goodwill and net deferred tax assets recorded on the balance sheet
    - the aggregate nominal value of treasury shares held by or pledged to us
    - the value of such credit or security in favor of our shareholders, directors or management that can be granted only out of our unrestricted equity
    - any part of the annual profit that, according to law or our articles of association and the articles of each of our Norwegian subsidiaries, must be allocated to restricted funds

Neither we nor our Norwegian subsidiaries can declare dividends if the equity, according to the balance sheet, amounts to less than 10% of the balance sheet, or dividends in excess of an amount that is compatible with good and careful business practice with due regard to any losses that may have occurred after the last balance sheet date or that may be expected to occur. Additionally, the terms of our debt agreements impose limitations on the payment of dividends. We do not currently intend to declare or pay dividends, but intend to reinvest any profit.

Significant Changes

Except as disclosed in "Information on the Company — Recent Developments — Combination with Veritas" and "— Sale of Atlantis" in Item 4, "Operating and Financial Review and Prospects — Financial Condition — Capital Resources and Liquidity" in Item 5, and notes 3 and 10 of the notes to our financial statements in Item 18 of this annual report, no significant changes have occurred since the date of our annual financial statements.

ITEM 9. *The Offer and Listing*

Listing Details

Our shares are listed on the Oslo Stock Exchange and trade on that exchange under the symbol "PGS." These shares are not listed on any other stock exchange and have not been publicly traded outside Norway. Each ADS represents one share. Citibank, N.A. serves as the depositary for the ADSs. Our ADSs are listed on the New York Stock Exchange and trade on that exchange under the symbol "PGO."

American Depositary Shares

We have presented in the table below, for the periods indicated, the reported high and low closing prices for our ADSs on the New York Stock Exchange.

	Price per ADS	
Calendar Period	High	Low
1997	$38.41	$19.00
1998	37.38	11.81
1999	24.19	11.19
2000	19.56	10.00
2001	14.63	5.00
2000		
First Quarter	19.56	13.69
Second Quarter	19.56	14.88
Third Quarter	19.31	16.00
Fourth Quarter	17.13	10.00
2001		
First Quarter	14.63	8.05
Second Quarter	12.89	8.20
Third Quarter	10.95	5.49
Fourth Quarter	8.11	5.00
2002		
First Quarter	7.89	4.81
Last Six Months		
April	6.89	6.11
March	6.51	4.81
February	6.95	5.43
January	7.89	6.44
December	8.11	6.50
November	6.71	5.00

Shares

We have presented in the table below, for the periods indicated, the reported high and low closing prices for our shares on the Oslo Stock Exchange.

Calendar Period	Price per share High	Price per share Low
1997	NOK268.5	NOK124.5
1998	282.0	91.5
1999	185.5	84.0
2000	174.0	91.5
2001	124.5	44.0
2000		
First Quarter	160.0	109.5
Second Quarter	172.0	127.0
Third Quarter	174.0	141.5
Fourth Quarter	159.0	91.5
2001		
First Quarter	124.5	73.0
Second Quarter	116.0	76.0
Third Quarter	97.5	44.0
Fourth Quarter	69.5	44.0
2002		
First Quarter	70.0	41.0
Last Six Months		
April	59.0	53.5
March	53.5	41.0
February	65.0	49.5
January	70.0	57.0
December	69.5	57.5
November	57.0	44.5

ITEM 10. *Additional Information*

Description of Share Capital

We have summarized below material information about our share capital, our articles of association and provisions of Norwegian law that apply to our share capital. This summary is not complete. For more information about our share capital, we encourage you to read our articles of association, which we have filed as an exhibit to this annual report.

Organization, Register and Purpose

We are a public limited liability company organized under the laws of the Kingdom of Norway. Our registration number with the Norwegian Company Registry is 916235291. As set forth in Section 2 of our articles of association, our business is to provide services to and participate and invest in energy related businesses.

Voting Rights

As a general rule, our shareholders can take action under Norwegian law or our articles of association by a simple majority of votes cast at a general meeting of shareholders. Each ordinary share carries one vote. Amendments to our articles of association, however, including any amendment increasing our share capital or altering the rights and preferences of any share or class of shares, require the approval of at least two-thirds of the votes cast and at least two-thirds of the share capital represented at a shareholders' meeting, whether or not holders of the share capital are entitled to vote. In some cases, a stricter voting requirement may apply.

The election of a new director as a replacement for an incumbent director prior to the expiration of the term of the incumbent director must be approved at a shareholders' meeting by either:

- a majority of our total outstanding voting shares or
- more than two-thirds of the votes cast and more than two-thirds of the share capital represented at the meeting

To vote at an annual or extraordinary general meeting, a shareholder must be registered as a holder of title to the shares to be voted in our share register maintained at Verdipapirsentralen ("VPS"), the Norwegian centralized registry of securities, not later than at the date of the general meeting. Shareholders who intend to participate in a general meeting in person or by proxy must notify us by the date stated in the notice convening the meeting. This date may not be more than two business days before the date of the meeting.

Under our articles of association, the beneficial owner of shares registered in VPS through a custodian approved by the Norwegian authorities may vote the shares covered by the custodial arrangement if:

- the beneficial owner provides us, no later than two business days prior to the meeting, with its name, address and a confirmation from the custodian that the holder is the beneficial owner of the shares held in custody and
- our board of directors does not disapprove the beneficial ownership after receipt of notification as described below under "— VPS and Transfer of Shares"

As an alternative to the voting procedure for beneficial owners described above, under Norwegian law, owners of ADSs representing shares can vote by surrendering their American Depositary Receipts or ADRs, evidencing ADSs to the custodian and having title to the related shares registered in our share register maintained at the VPS prior to the meeting.

Our annual general meeting of shareholders is held each year before the end of June. Under our articles of association, we may call ordinary general meetings on four weeks' written notice and extraordinary general meetings on two weeks' written notice. A shareholder may vote by proxy. Although Norwegian law does not require us to send proxy forms to our shareholders for general meetings, we normally include a proxy form with the notice of meetings.

Extraordinary general meetings of shareholders may be held:

- whenever our board of directors considers it necessary
- at the request of our auditor or
- at the request of shareholders representing at least 5% of our share capital

The request must name the matters to be considered. The extraordinary general meeting must be convened within one month of the date of the request. Other than approval of the annual accounts and distribution of cash dividends out of our annual profit, any matter that may be raised at an annual general meeting may also be raised at an extraordinary general meeting.

Restrictions on Ownership of Shares

At present, there is no limitation on ownership of shares by persons who are not Norwegian. The Norwegian 1994 Act on Control of Business Acquisitions requires any holder of shares or group of holders acting in concert, regardless of nationality, to notify the Norwegian government upon the acquisition of shares that would cause that holder's or group's aggregate holdings either:

- to exceed a threshold of 33⅓% of the total outstanding shares or
- to reach a threshold of 50% or 66⅔% of the total outstanding shares

For purposes of these determinations, shares include ADSs.

Any acquisition of shares or ADSs exceeding or reaching the thresholds described in the previous paragraph would be subject to a waiting period. During the waiting period, Norwegian governmental authorities could request further information, disapprove the acquisition or impose conditions aimed at safeguarding the public interest. During the waiting period, the acquiror is restricted from exercising its rights as a shareholder other than receiving dividends and exercising preemptive rights. If the waiting period expires and no official action occurs, the acquisition could go forward without condition.

VPS and Transfer of Shares

Norway has a paperless, centralized registry of shares and other securities, VPS. We and all other Norwegian public companies are obligated to register our shares in VPS. Share certificates are not used. VPS is a computerized bookkeeping system operated by an independent body in which the ownership of and all transactions relating to Norwegian listed shares must be recorded. Our share register is operated through VPS under VPS number 000-4225004.

All transactions relating to securities registered with VPS are made through computerized book entries. VPS confirms each entry by sending a transcript to the registered shareholder irrespective of any beneficial ownership. To effect an entry, the individual shareholder must establish a share account with a Norwegian account agent. Norwegian banks, the Bank of Norway and authorized securities brokers in Norway are allowed to act as agents. If the shareholder does not establish an account, the issuing company will appoint an agent on the shareholder's behalf.

A VPS entry represents prima facie evidence in determining the legal rights of a registered holder of a security against the issuing company or a third party claiming an interest in the security.

VPS is strictly liable for any loss resulting from an error in connection with registering, altering or canceling a right, except in the event of contributory negligence.

Under Norwegian law, a transferor must register immediately with VPS any acquisition or other transfer of shares. A person to whom shares have been transferred or assigned may exercise the rights of a shareholder for those shares only if:

- the transfer or assignment has been registered or that person has reported and shown evidence to us of the share acquisition and
- the acquisition is not prevented by law, our articles of association or otherwise

Our articles of association provide that a transfer of shares is subject to approval by our board of directors. The approval cannot be withheld without reasonable grounds. This provision could operate to prevent or impede a change in control of PGS.

Disclosure Obligations

Under Norwegian law, a person, entity or group acting in concert must notify the Oslo Stock Exchange immediately of an acquisition or disposition of shares and/or rights to shares and of its aggregate holdings of shares and/or rights to shares following the acquisition or disposition if the acquisition or disposition results in its aggregate beneficial ownership of shares and/or rights to shares reaching, exceeding or falling below thresholds of 1/10, 1/5, 1/3, 1/2, 2/3 or 9/10 of the total number of shares outstanding or of the outstanding voting rights. A corresponding disclosure obligation applies to any holder of ADRs.

Additional Issuances and Preemptive Rights

To issue additional shares, including bonus issues (share dividends), we must amend our articles of association. This amendment requires the same shareholder vote as other amendments to our articles of association. Our shareholders also must approve by the same vote the issuance of loans convertible into shares or warrants to purchase shares. At a general meeting, the shareholders may by the same majority authorize our board of directors to issue:

- an aggregate number of shares not exceeding 50% of the number of shares outstanding at the time of the general meeting
- loans convertible into an aggregate number of shares not exceeding 50% of the number of shares outstanding at the time of the general meeting

The duration of these authorizations cannot exceed two years.

Under Norwegian law, shareholders have a preemptive right to subscribe for and be allotted new shares that we issue. Shareholders may waive those preemptive rights in a general meeting by the same vote required to approve amendments to our articles of association. A waiver of the shareholders' preemptive rights for bonus issues (share dividends) must be approved by the holders of all shares outstanding.

If we issue shares upon the exercise of preemptive rights to holders who are citizens or residents of the United States, we may be required to file a registration statement in the United States under United States securities laws. If we decide not to file a registration statement, those US holders will not be able to exercise their preemptive rights and would be required to sell them to Norwegian persons or other non-US holders to realize the value of the rights.

Under Norwegian law and with shareholder approval, we may distribute bonus issues (share dividends) of our shares from amounts:

- that we could otherwise distribute as dividends
- that we may create by transferring funds from our share premium reserve discussed below under "— Dividends and Legal Reserves" to share capital

We can implement bonus issues (share dividends) either by issuing shares or by increasing the par value of the shares outstanding.

Dividends and Legal Reserves

Under Norwegian law, we can pay dividends only once a year in cash or in kind as a distribution of our annual profit and the annual profits of our Norwegian subsidiaries. Any proposal by the board of directors to pay a dividend must be recommended by the directors and approved by the shareholders at a general meeting. The shareholders may vote to reduce, but not to increase, the dividends proposed. Dividends in cash or in kind are payable only out of:

- the annual profit according to the income statement for the last financial year
- retained profit from previous years
- other unrestricted equity, after deduction of:
  - accumulated losses
  - the book value of research and development, goodwill and net deferred tax assets recorded on the balance sheet
  - the aggregate nominal value of treasury shares held by or pledged to us
  - the value of such credit or security in favor of our shareholders, directors or management that can be granted only out of our unrestricted equity
  - any part of the annual profit that, according to law or our articles of association and the articles of our Norwegian subsidiaries, must be allocated to restricted funds

Neither we nor our Norwegian subsidiaries can declare dividends if the equity, according to the balance sheet, amounts to less than 10% of the balance sheet. In addition, neither we nor they can declare dividends in excess of an amount that is compatible with good and careful business practice with due regard to any losses that may have occurred after the last balance sheet date or that may be expected to occur.

Under Norwegian law, we are required to maintain reserves that are adequate in light of our activities and related risks. We must allocate to the share premium (restricted) reserve any premium paid to us for the subscription of new shares.

Rights upon Winding-Up

A Norwegian company may be wound up by a resolution of the company in a general meeting passed by a two-thirds majority of the aggregate votes cast by its voting shares and by two-thirds of the aggregate share capital represented at the meeting irrespective of class.

Interested Director Transactions

Under Norwegian law, a director may not participate in the discussion or decision of any matter in which the director or any related person of the director has a significant personal or financial special interest. In addition, under Norwegian law, a director may not participate in a matter concerning a loan or other credit to the director or the pledging of security for the director's debt.

Other Provisions Relating to Directors

Under Norwegian law, any compensation payable to a director must be determined by the shareholders in a general meeting. There is no mandatory retirement provision under Norwegian law or our articles of association, nor is there a requirement that our directors own our shares or ADSs.

Mandatory Bid Requirement

Norwegian statutory law requires any person, entity, family group or other group acting in concert that acquires shares or ADSs representing more than 40% of the voting rights of a Norwegian company listed on the Oslo Stock Exchange to notify the Oslo Stock Exchange immediately and to make a general offer to acquire all the outstanding share capital of that company. The offer may not be conditional and is subject to approval by the Oslo Stock Exchange before submission to the shareholders. The offering price per share must be the greater of:

- the highest price paid by the offeror for the shares in the six-month period prior to the date the 40% threshold was exceeded or
- the recorded market price at that date

If the acquiror acquires additional shares at a higher price after exceeding the 40% threshold but prior to the expiration of the bid period, the acquiror must restate its bid at that higher price. If a shareholder who is required to make a mandatory bid fails to do so, the shareholder must within four weeks dispose of sufficient shares so that the obligation ceases to apply. Otherwise, the Oslo Stock Exchange may cause the shares exceeding the 40% limit to be sold by public auction.

During the time the mandatory bid requirement is in force, a shareholder failing to make the required offer may not vote or exercise any rights of share ownership other than the right to receive dividends and preferential rights relating to a share capital increase. In addition, the Oslo Stock Exchange may impose a daily fine upon a shareholder who fails to make the required offer.

In addition to these mandatory bid requirements under Norwegian statutory law, our articles of association require an acquiror of shares and/or ADSs representing more than one-third of the outstanding voting rights, but less than the 40% threshold for a mandatory bid requirement, to offer to purchase the remaining outstanding shares. Subject to the requirement that our board notify the acquiror, our board of directors may withhold approval of the acquisition of shares and/or ADSs to determine that the acquiror has complied with the mandatory bid requirements of the articles of association.

If an acquiror has not complied with these requirements, our board of directors may disapprove the acquisition of shares and/or ADSs. If the board of directors reasonably determines that, for any particular acquisition of shares and/or ADSs by an acquiror, the mandatory bid requirements in our articles of association are not in our interest or the interest of our shareholders, the board may exempt that acquiror from such requirements. Except as we have described above, the rules generally regarding mandatory bids under applicable Norwegian law at the relevant time will apply to the application of the mandatory bid requirements of our articles of association.

Citibank, N.A., the depositary, has qualified and been recognized as a custodian of the shares in Norway. As a result, it is exempt from the mandatory bid requirement.

Exchange Controls and Other Limitations Affecting Security Holders

Under Norwegian foreign currency exchange controls currently in effect, transfers of capital to and from Norway are not subject to prior governmental approval except for the physical transfer of payments in currency, which is restricted to licensed banks. As a result, a non-Norwegian resident may receive dividend, principal and interest payments on our securities without a Norwegian exchange control consent, but the payments must be made through a licensed bank.

There are no limitations imposed by Norwegian law or our articles of association on the right to hold or vote shares that apply differently to non-Norwegian owners than to Norwegian owners.

Taxation

General

The following discussion generally summarizes the principal Norwegian and United States federal income tax consequences of the ownership and disposition of our ADRs, which evidence our ADSs, and our shares to holders of ADRs and shares who are residents of the United States or otherwise subject to United States federal income taxation on a net income basis for ADRs and shares and who are not residents of Norway ("US Holders"). The summary applies only to holders who will hold ADRs or shares as capital assets and does not address certain classes of holders, such as holders who own, directly or indirectly, at least 10% of our outstanding shares, that may be subject to special rules. Because it is a general summary, prospective purchasers of ADRs or shares who would be US Holders are advised to consult their own tax advisors about the United States federal, state and local tax consequences and the Norwegian tax consequences of the ownership and disposition of ADRs and shares that are applicable in their particular tax situations, including the effects of recent and possible future changes in the applicable tax laws.

The summaries of United States and Norwegian tax laws provided below are based on the tax laws of the United States and Norway, the income tax convention between the United States and Norway (the "Convention") and interpretations by the relevant tax authorities that are in effect as of the date of this annual report and are subject to any changes that may occur after that date (possibly with retroactive effect).

For United States and Norwegian tax purposes, US Holders of ADRs will be treated as the owners of the shares represented by the ADRs. Unless we have otherwise stated below, the Norwegian tax consequences and the United States federal income tax consequences discussed below apply equally to US Holders of ADRs and US Holders of shares.

Taxation of Dividends

Under Norwegian tax law, dividends paid to foreign shareholders of Norwegian corporations are, unless otherwise provided for in an applicable tax treaty, subject to a withholding tax in Norway of 25%. Under the Convention, the maximum rate of withholding tax on dividends paid by a Norwegian corporation to a "resident of the United States," as defined in the Convention, is 15%. The 15% withholding rate will apply to any dividends paid on our shares held directly by US Holders who properly demonstrate to us and to the Norwegian tax authorities that they are entitled to the benefits of the Convention. Dividends paid to Citibank, as depositary, will be subject to withholding at the 25% rate. US Holders of ADRs who believe they are entitled to the benefits of the Convention may apply to the Norwegian tax authorities for a refund of amounts withheld in excess of 15%. The application is to be filed with the Norwegian Tax Directorate. There is some uncertainty, however, as to whether and when such a refund may be obtained.

We intend to file any reports with the Norwegian authorities or agencies necessary to obtain the benefits of the Convention for those entitled to them. We will exercise our right under the deposit agreement to reasonably request from Citibank such information from its records that will enable us to file the reports.

If, however, the recipient of a dividend is determined to be engaged in a business activity taxable in Norway and our shares or ADSs with respect to which the dividend is paid are effectively connected with that activity, then the amount distributed to the US Holder will be treated as taxable domestic dividend income in Norway, subject to the provisions of the Convention, where applicable.

To the extent paid out of our current or accumulated earnings and profits, distributions made on our shares or ADSs, other than certain distributions of our capital stock or rights to subscribe for shares of our capital stock, will be includible in the income of a US Holder for United States federal income tax purposes as ordinary dividend income. In the case of a US Holder of an ADR, such dividend income will be recognized on the date Citibank receives the distribution. Dividends we pay will not be eligible for the dividends-received deduction generally allowed to corporations under the US Internal Revenue Code of 1986, as amended (the "Code"). The amount of dividend distribution for tax purposes will equal the US dollar value of the amount of the distribution in Norwegian kroner (including the amount of Norwegian taxes withheld from the distribution), calculated by reference to the exchange rate in effect on the date of the distribution. Upon the ultimate conversion by Citibank into US dollars of the Norwegian kroner received in a distribution, US Holders of ADRs generally will recognize gain or loss for United States federal income tax purposes equal to the difference, if any, between such US dollars and the US dollar value of such Norwegian kroner on the date of the distribution. Such gain or loss will be treated as ordinary income or loss.

Norwegian taxes imposed on dividend distributions on our shares or ADSs generally will be eligible for credit against the US Holder's United States federal income taxes. The amount of the Norwegian taxes eligible for this foreign tax credit will be equal to the amount of such taxes withheld from the dividend distributions, reduced by the amount of any refunds of such taxes subsequently received, translated into US dollars at the exchange rate in effect on the date the taxes originally were paid. Under the foreign tax credit limitations of the Code, the foreign tax credit can offset United States federal income taxes imposed on foreign-source income but not on United States-source income. In addition, foreign taxes imposed on income in certain categories specified in the Code may only be used to offset United States taxes on income in the same category. Subject to the special rule we describe below, dividends we pay will generally be foreign-source income within either the "passive income" category or the "financial services income" category, depending on the particular US Holder's circumstances.

The Code contains a provision that could, in certain circumstances, cause a portion of the dividends we pay to be treated as United States-source income. Even if that provision applied to dividends we pay to a US Holder, because of the source rules contained in the Convention, no portion of such a dividend would be recharacterized as United States-source income if the US Holder includes the dividend as a separate category of income for purposes of the foreign tax credit limitation.

Taxation of Dispositions

A US Holder normally is not taxed in Norway on gains from the sale or other disposal of our shares or ADSs. Such a holder may be subject to taxation if the shareholding is effectively connected with a business carried out by the shareholder through a permanent establishment in Norway. In addition, a shareholder may be subject to taxation on gains if the shareholder is an individual who has been a resident of Norway for income tax purposes and the disposal takes place within five years after the calendar year in which the shareholder ceased to be a resident of Norway. The same rules apply to gains realized upon complete liquidation of us or upon redemption of our shares or ADSs. Repayment in connection with a reduction of our share capital by reducing the nominal value of the shares is, however, subject to withholding tax as a dividend distribution, if exceeding paid-in capital.

A US Holder will recognize capital gain or loss for United States federal income tax purposes on a sale or other disposition of our shares or ADSs (or rights to subscribe for our shares), including a sale or other disposition by Citibank of shares (or rights to subscribe for shares) received as dividends on the ADSs, in the same manner as on the sale or other disposition of any other shares held as capital assets (or rights to acquire such shares). Any such gain or loss will generally be United States-source income or loss.

Deposits and withdrawals of our shares in exchange for ADRs will not result in taxable gain or loss for United States or Norwegian tax purposes.

US Backup Withholding

Certain payments, including certain dividends and proceeds from sales of stock, may be subject to United States "backup withholding" at the current 30% rate if the recipient of such a payment fails to furnish to the payor certain information, including the recipient's taxpayer identification number, or otherwise fails to establish an exemption from withholding. Any amounts so withheld would be allowed as a credit against the recipient's United States federal income tax liability for the year. Dividends we pay to a US Holder generally would be subject to these backup withholding rules.

Norwegian Transfer Tax

There is no Norwegian stock transfer tax or capital tax upon the acquisition or subsequent disposition of our shares or ADSs.

Norwegian Inheritance Tax

There is no Norwegian inheritance tax or gift tax on our shares or ADSs if the deceased, at the time of death, or the donor at the time the gift is made, is neither a resident nor a national of Norway. If the deceased, at the time of death, is not a resident of Norway, but is a national of Norway, Norwegian inheritance tax will be levied unless inheritance tax or similar tax is levied in the country of residence and the shares are not effectively connected to a permanent establishment in Norway. Under all circumstances, a transfer of shares or ADSs will be subject to gift tax in Norway if the donor at the time of the gift is a Norwegian national.

Norwegian Property Taxes or Similar Taxes

US Holders of our shares or ADSs are not subject to Norwegian property tax or similar taxes (*e.g.*, wealth taxes) with respect to those shares or ADSs, unless the shareholding is effectively connected with a business carried out by the shareholder through a permanent establishment in Norway.

Documents on Display

Please read "Where You Can Find More Information" for information about where you may read and copy documents referred to in this annual report that we have filed with the SEC.

ITEM 11. *Quantitative and Qualitative Disclosures About Market Risk*

Our earnings and cash flows are subject to fluctuations due to changes in foreign currency exchange rates. We periodically enter into forward foreign currency exchange contracts and option contracts to hedge firm commitments but not for speculative or trading purposes. Our business contracts generally provide for payment in US dollars, and we do not maintain significant foreign currency cash balances. Our tax equalization swap contracts carried weighted average exchange rate floors of 7.7 NOK to the US dollar and 7.4 NOK to the US dollar, respectively at December 31, 2001 and 2000. Under each tax equalization swap contract, if the NOK to US dollar exchange rate at any settlement date is less than the contract's exchange rate floor, we will neither incur a liability nor accrue a benefit for the exchange rate differential below the floor. At December 31, 2001, after the determination of the December 2001 interim settlement, the outstanding aggregate notional value of the tax equalization swap contracts was $492.8 million and the base exchange rate on the contracts was reset to approximately 9.0 NOK to the US dollar. The December 2002 interim settlement will be measured as the difference between this base exchange rate and the then current exchange rate, subject to the exchange rate floor, applied to the outstanding aggregate notional value of the tax equalization swap contracts. Accordingly, we will incur a liability (payable in NOK) if the NOK to US dollar exchange rate exceeds the base exchange rate of 9.0 NOK to the US dollar, or we will accrue a benefit (receivable in NOK) if such exchange rate is less than this base exchange rate (subject to the exchange rate floor). Please read notes 2 and 17 of the notes to our financial statements in Item 18 of this annual report and "Operating and Financial Review and Prospects — Currency Fluctuations" in Item 5 of this annual report for additional information regarding our tax equalization swaps.

In April 2002, we terminated three tax equalization swap contracts with aggregate notional values of $160.0 million. We did not recognize any significant impact in our results of operations as a result of the termination.

Our earnings and cash flows are also exposed to changes in interest rates on our long-term debt obligations. Please read notes 10 and 11 of the notes to our financial statements in Item 18 of this annual report for additional information regarding the level and maturity profiles of our borrowings and the types of financial instruments used. We present below the weighted average interest rate for the scheduled maturities of our fixed rate long-term debt obligations as of December 31, 2001 and 2000 (in thousands of dollars):

	2001	2002	2003	2004	2005	2006	Thereafter	Total	Estimated fair value
As of December 31, 2000									
Fixed Rate Debt:									
Amount Due	$11,090	$11,595	$258,737	$10,200	$10,990	$11,920	$1,271,112	$1,585,644	$1,501,953
Weighted Average Interest Rate	8.3%	8.3%	6.3%	8.3%	8.3%	8.3%	7.4%	7.2%	—
As of December 31, 2001									
Fixed Rate Debt:									
Amount Due	$ —	$12,240	$258,959	$10,200	$10,990	$11,920	$1,271,503	$1,575,812	$1,356,350
Weighted Average Interest Rate	—%	8.5%	6.3%	8.3%	8.3%	8.3%	7.4%	7.2%	—

Our fixed rate debt includes Norwegian kroner-denominated debt totaling $0.7 million and $5.8 million at December 31, 2001 and 2000, respectively.

Our $141.0 million of trust preferred securities carried a 9.6% interest rate and a $136.5 million fair value at December 31, 2001.

Our $225.0 million unsecured floating-rate senior notes matured in March 2002; at December 31, 2001 these notes carried a 3.6% interest rate and had a fair value of $224.8 million. During 2001, we utilized our unsecured five-year $430.0 million revolving bank credit facility that bears interest at a LIBOR-based rate; at December 31, 2001, our outstanding balance on this facility of $340.0 million carried a 2.7% weighted average interest rate and a fair value approximately equal to its carrying value.

ITEM 12. *Description of Securities Other Than Equity Securities*

Not applicable.

PART II

ITEM 13. ***Defaults, Dividend Arrearages and Delinquencies***

None.

ITEM 14. ***Material Modifications to the Rights of Security Holders and Use of Proceeds***

None.

PART III

ITEM 17. ***Financial Statements***

Not applicable.

ITEM 18. ***Financial Statements***

Index to Consolidated Financial Statements

	Page
Consolidated Financial Statements of Petroleum Geo-Services ASA and Subsidiaries	
Report of Independent Public Accountants — Arthur Andersen LLP	F-1
Report of Independent Accountants — PricewaterhouseCoopers LLP	F-2
Consolidated Balance Sheets as of December 31, 2001 and 2000	F-3
Consolidated Statements of Operations for the years ended December 31, 2001, 2000 and 1999	F-4
Consolidated Statements of Cash Flows for the years ended December 31, 2001, 2000 and 1999	F-5
Consolidated Statements of Changes in Shareholders' Equity for the years ended December 31, 2001, 2000 and 1999	F-6
Notes to Consolidated Financial Statements	F-7

We specifically incorporate by reference in response to this item the auditors' reports, the consolidated financial statements and the notes to the consolidated financial statements appearing on pages F-1 through F-41.

ITEM 19. ***Exhibits***

Number	
1.1	— Articles of Association, as amended (English translation)
2.1	— Deposit Agreement, dated as of May 25, 1993, among Petroleum Geo-Services ASA (the "Company"), Citibank, N.A., as depositary (the "Depositary"), and all holders from time to time of American Depositary Receipts issued thereunder (incorporated by reference to Exhibit (a)(1) of Post-Effective Amendment No. 1 to the Company's Registration Statement on Form F-6 (Registration No. 33-61500))
2.2	— First Amendment to Deposit Agreement, dated as of April 24, 1997, among the Company, the Depositary and all holders from time to time of American Depositary Receipts issued thereunder (incorporated by reference to Exhibit (a)(2) of the Company's Registration Statement on Form F-6 (Registration No. 333-10856))
2.3	— Form of American Depositary Receipt (included in Exhibit 2.2)

Number	
2.4	— Certificate of Trust of PGS Trust I (the "Trust") (incorporated by reference to Exhibit 4.10.1 of the Registration Statement of the Company and the Trust on Form F-3 (Registration Nos. 333-10348 and 333-10348-01))
2.5	— Amended and Restated Declaration of Trust of the Trust, dated as of June 22, 1999, among the trustees of the Trust named therein, the Company, as Sponsor, and the holders from time to time of preferred undivided beneficial interests in the assets of the Trust (incorporated by reference to Exhibit 1 of the Company's Report on Form 6-K dated July 12, 1999 (SEC File No. 1-14614))
2.6	— Indenture, dated as of June 22, 1999, between the Company and Chase Bank of Texas, National Association, as Trustee, in respect of junior subordinated debentures of the Company (incorporated by reference to Exhibit 2 of the Company's Report on Form 6-K dated July 12, 1999 (SEC File No. 1-14614))
2.7	— First Supplemental Indenture, dated as of June 22, 1999, between the Company and Chase Bank of Texas, National Association, as Trustee, in respect of 9⅝% Junior Subordinated Debentures due 2039 of the Company (incorporated by reference to Exhibit 3 of the Company's Report on Form 6-K dated July 12, 1999 (SEC File No. 1-14614))
2.8	— Form of 9⅝% Junior Subordinated Debenture due 2039 (included in Exhibit 2.7)
2.9	— Guarantee Agreement, dated as of June 22, 1999, between the Company and Chase Bank of Texas, National Association, as Guarantee Trustee (incorporated by reference to Exhibit 4 of the Company's Report on Form 6-K dated July 12, 1999 (SEC File No. 1-14614))
2.10	— Form of Preferred Security (included in Exhibit 2.5)
2.11	— Indenture, dated as of April 1, 1998, between the Company and Chase Bank of Texas, National Association, as trustee, in respect of senior debt securities (incorporated by reference to exhibit 2.12 of the Company's Annual Report on Form 20-F for the year ended December 31, 1997 (SEC File No. 1-14614))
2.12	— First Supplemental Indenture, dated as of April 1, 1998, between the Company and Chase Bank of Texas, National Association, as trustee, in respect of 6⅝% Senior Notes due 2008 and 7⅛% Senior Notes due 2028 (incorporated by reference to exhibit 2.13 of the Company's Annual Report on Form 20-F for the year ended December 31, 1997 (SEC File No. 1-14614))
2.13	— Revolving Credit Agreement dated as of September 4, 1998 among the Company, Chase Manhattan PLC, as arranger, Chase Manhattan International Limited, as agent, and the financial institutions listed therein (incorporated by reference to exhibit 2.5 of the Company's Annual Report on Form 20-F for the year ended December 31, 1998 (SEC File No. 1-14614))
	The Company and its consolidated subsidiaries are party to several debt instruments under which the total amount of securities authorized does not exceed 10% of the total assets of the Company and its subsidiaries on a consolidated basis. Pursuant to paragraph 2(b)(i) of the instructions to the exhibits to Form 20-F, the Company agrees to furnish a copy of such instruments to the SEC upon request.
4.1	— Employment agreement dated April 27, 2000 between the Company and Michael Mathews (incorporated by reference to Exhibit 4.1 of the Company's Annual Report on Form 20-F for the year ended December 31, 2000 (File No. 1-14614) (the "Form 20-F"))

Number	
4.2	— Employment agreement dated July 31, 1997 between the Company and Reidar Michaelsen (incorporated by reference to Exhibit 4.2 of the Form 20-F)
4.3	— Petroleum Geo-Services ASA Executive Pension Scheme dated August 29, 1996 (incorporated by reference to Exhibit 4.13 of the Form 20-F)
4.4	— Petroleum Geo-Services ASA 2000 — Incentive Share Option Plan dated June 23, 2000 (incorporated by reference to Exhibit 4.14 of the Form 20-F)
4.5	— Petroleum Geo-Services ASA Non-Employee Director Stock Option Plan dated January 1, 2000 (incorporated by reference to Exhibit 4.15 of the Form 20-F)
4.6	— Framework Agreement, dated as of April 26, 2001, among Multi-Klient Invest AS, the Company, PGS Multi-Client Seismic Limited, Compass Finrec P Limited, Westdeutsche Landesbank Girozentrale and Compass Holdings Limited (incorporated by reference to Exhibit 4.16 of the Form 20-F)
4.7	— Servicing Agreement, dated as of April 26, 2001, among Multi-Klient Invest AS, the Company, PGS Multi-Client Seismic Limited, Compass Finrec P Limited, Westdeutsche Landesbank Girozentrale and Compass Holdings Limited (incorporated by reference to Exhibit 4.17 of the Form 20-F)
4.8	— Jersey License Agreement, dated as of April 26, 2001, among Multi-Klient Invest AS, the Company, PGS Multi-Client Seismic Limited, Compass Finrec P Limited, Westdeutsche Landesbank Girozentrale and Compass Holdings Limited (incorporated by reference to Exhibit 4.18 of the Form 20-F)
8	— Subsidiaries (included in Item 4 of the annual report)
10.1	— Consent of Arthur Andersen LLP
10.2	— Consent of PricewaterhouseCoopers LLP
99.1	— Letter to the Securities and Exchange Commission regarding Arthur Andersen LLP

SIGNATURES

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorized the undersigned to sign this annual report on its behalf.

PETROLEUM GEO-SERVICES ASA

Date: May 22, 2002

By: /s/ REIDAR MICHAELSEN

Reidar Michaelsen
Chairman and Chief Executive Officer

By: /s/ J. CHRISTOPHER BOSWELL

J. Christopher Boswell
Senior Vice President and Chief Financial Officer

By: /s/ WILLIAM E. HARLAN

William E. Harlan
Vice President, Chief Accounting and Administrative Officer

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Board of Directors and Shareholders of
PETROLEUM GEO-SERVICES ASA:

We have audited the accompanying consolidated balance sheet of Petroleum Geo-Services ASA and subsidiaries (the "Company") as of December 31, 2001 and the related statements of operations, cash flows and shareholders' equity for the year ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2001 and the results of their operations and their cash flows for the year ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

ARTHUR ANDERSEN LLP

Houston, Texas
May 2, 2002 (except with respect
to the matter discussed in Note 10,
as to which the date is May 16, 2002)

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and Shareholders of
Petroleum Geo-Services ASA

In our opinion, the accompanying consolidated balance sheet and the related consolidated statements of operations, of cash flows and of changes in shareholders' equity present fairly, in all material respects, the financial position of Petroleum Geo-Services ASA and its subsidiaries at December 31, 2000 and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2000 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Notes 1 and 24, the Company restated its 1999 and 2000 financial statements.

PricewaterhouseCoopers LLP

Houston, Texas
March 12, 2001, except as to the last five
paragraphs of Note 11, which are as of
April 30, 2001, and as to the third paragraph
of Note 1 and Note 24, which are as of
May 10, 2002

CONSOLIDATED BALANCE SHEETS

	December 31, 2001	December 31, 2000
	(In thousands of dollars, except for share data)	(As restated, Note 24)
ASSETS		
Cash and cash equivalents	$ 110,909	$ 145,215
Accounts receivable, net	254,177	242,751
Oil and gas assets	171,041	113,890
Other current assets, net	99,959	88,995
Total current assets	636,086	590,851
Multi-client library, net	918,072	848,720
Property and equipment, net	2,282,241	2,251,943
Goodwill, net	215,291	253,861
Other long-term assets, net	251,116	333,331
Total assets	$4,302,806	$4,278,706
LIABILITIES AND SHAREHOLDERS' EQUITY		
Short-term debt and current portion of long-term debt and capital lease obligations	$ 267,657	$ 23,892
Accounts payable	76,859	105,614
Accrued expenses	226,127	297,607
Income taxes payable	16,944	12,263
Total current liabilities	587,587	439,376
Long-term debt	1,903,571	2,159,421
Long-term capital lease obligations	41,683	12,560
Other long-term liabilities	25,355	81,061
Deferred tax liabilities	78,575	96,260
Total liabilities	2,636,771	2,788,678
Commitments and contingencies (Note 12)		
Guaranteed preferred beneficial interest in PGS junior subordinated debt securities (Note 11)	141,000	140,050
Mandatorily redeemable cumulative preferred subsidiary securities related to multi-client library securitization (Note 11)	163,588	—
Shareholders' equity		
Common stock, par value NOK 5; authorized 135,400,587 shares; issued and outstanding 103,345,987 shares at December 31, 2001 and 102,347,987 shares at December 31, 2000	71,089	70,542
Additional paid-in capital	1,225,115	1,215,884
Retained earnings	98,863	94,410
Accumulated other comprehensive loss	(33,620)	(30,858)
Total shareholders' equity	1,361,447	1,349,978
Total liabilities and shareholders' equity	$4,302,806	$4,278,706

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

CONSOLIDATED STATEMENTS OF OPERATIONS

	Years ended December 31,		
	2001	2000	1999
	(In thousands of dollars, except for share data)	(As restated, Note 24)	(As restated, Note 24)
Revenue	$ 1,052,628	$ 913,482	$ 788,160
Cost of sales	535,999	432,457	333,060
Depreciation and amortization	334,506	263,589	238,576
Research and technology costs	3,752	6,677	15,859
Selling, general and administrative costs	78,305	76,473	71,738
Unusual items (Note 23)	(105,912)	365,780	89,855
Total operating expenses	846,650	1,144,976	749,088
Operating profit (loss)	205,978	(231,494)	39,072
Income (loss) from equity investments	(491)	61,151	(4,935)
Financial expense, net	(143,179)	(134,599)	(95,969)
Other expense, net	(22,052)	(32,774)	(9,144)
Income (loss) before income taxes	40,256	(337,716)	(70,976)
Provision (benefit) for income taxes	35,803	(132,756)	(57,137)
Income (loss) before cumulative effect of accounting change	4,453	(204,960)	(13,839)
Cumulative effect of accounting change, net of tax	—	(6,555)	(19,977)
Net income (loss)	$ 4,453	$ (211,515)	$ (33,816)
Basic income (loss) per share before cumulative effect of accounting change	$ 0.04	$ (2.01)	$ (0.15)
Cumulative effect of accounting change, net of tax	—	(0.06)	(0.21)
Basic income (loss) per share	$ 0.04	$ (2.07)	$ (0.36)
Diluted income (loss) per share before cumulative effect of accounting change	$ 0.04	$ (2.01)	$ (0.15)
Cumulative effect of accounting change, net of tax	—	(0.06)	(0.21)
Diluted net income (loss) per share	$ 0.04	$ (2.07)	$ (0.36)
Basic shares outstanding	102,768,283	102,020,830	94,767,967
Diluted shares outstanding	102,788,055	102,020,830	94,767,967

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years ended December 31,		
	2001	2000	1999
	(In thousands of dollars)		
		(As restated, Note 24)	(As restated, Note 24)
Cash Flows From Operating Activities:			
Net income (loss)	$ 4,453	$(211,515)	$ (33,816)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization charged to expense	334,506	263,589	238,576
Non-cash charges	(97,027)	321,070	83,805
Provision (benefit) for deferred income taxes	22,114	(141,000)	(68,717)
Changes in current assets and current liabilities	(74,721)	(72,636)	(313)
Loss on sale of assets	294	199	3,256
Other items	22,083	(1,550)	(22,113)
Net cash provided by operating activities	211,702	158,157	200,678
Cash Flows From Investing Activities:			
Investment in multi-client library	(230,166)	(264,541)	(338,718)
Capital expenditures	(239,623)	(115,217)	(667,869)
Sale of subsidiary/investment in affiliated company	175,000	150,508	—
Other items, including net proceeds from UK leases	(19,485)	(12,086)	5,496
Net cash used in investing activities	(314,274)	(241,336)	(1,001,091)
Cash Flows From Financing Activities:			
Net proceeds from issuance of long-term debt	—	223,845	195,712
Net proceeds from issuance of guaranteed preferred beneficial interest in PGS junior subordinated debt securities (Note 11)	—	—	138,914
Net proceeds from issuance of subsidiary preferred stock (Note 11)	234,285	—	—
Net proceeds from issuance of common stock, including stock option exercises	816	7,425	220,024
Repayment of long-term debt	(11,414)	(15,447)	(29,924)
Repayment of subsidiary preferred stock (Note 11)	(77,280)	—	—
Net increase (decrease) in revolving and short-term debt	(5,667)	(34,409)	283,334
Principal payments under capital lease obligations	(7,806)	(7,775)	(13,437)
Net payments under tax equalization swap contracts (Note 17)	(64,575)	(8,068)	—
Other	—	—	15,512
Net cash provided by financing activities	68,359	165,571	810,135
Effect of exchange rate changes in cash and cash equivalents	(93)	(221)	49
Net increase (decrease) in cash and cash equivalents	(34,306)	82,171	9,771
Cash and cash equivalents at beginning of year	145,215	63,044	53,273
Cash and cash equivalents at end of year	$ 110,909	$ 145,215	$ 63,044

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

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

	Common Stock				Accumulated other comprehensive income (loss)			
	Number	Par value	Additional paid-in capital	Retained earnings	Foreign currency translation adjustments	Long-term intercompany currency losses	Total other comprehensive loss	Shareholders' equity
	(In thousands of dollars, except for share data) (As restated, Note 24)							
Balance at December 31, 1998	89,540,537	$62,312	$ 996,499	$ 339,741	$ 7,577	$(12,891)	$ (5,314)	$1,393,238
Comprehensive loss:								
Net loss				(33,816)				(33,816)
Other comprehensive loss					(5,387)	(5,806)	(11,193)	(11,193)
Issuance of common stock	11,159,500	7,232	205,674					212,906
Exercise of stock options	909,550	582	6,700					7,282
Balance at December 31, 1999	101,609,587	70,126	1,208,873	305,925	2,190	(18,697)	(16,507)	1,568,417
Comprehensive loss:								
Net loss				(211,515)				(211,515)
Other comprehensive loss					(256)	(14,095)	(14,351)	(14,351)
Exercise of stock options	738,400	416	7,011					7,427
Balance at December 31, 2000	102,347,987	70,542	1,215,884	94,410	1,934	(32,792)	(30,858)	1,349,978
Comprehensive income:								
Net income				4,453				4,453
Other comprehensive loss					(1,927)	(835)	(2,762)	(2,762)
Issuance of common stock	900,000	493	8,558					9,051
Exercise of stock options	98,000	54	673					727
Balance at December 31, 2001	103,345,987	$71,089	$1,225,115	$ 98,863	$ 7	$(33,627)	$(33,620)	$1,361,447

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 — Basis of Presentation, Restatement of Previously Issued Financial Statements and Liquidity

Petroleum Geo-Services ASA (the "Company") provides geophysical services and oil and gas production services. See further discussion of the Company's services in Note 20.

The Company is a Norwegian limited liability company and has prepared its consolidated financial statements in accordance with accounting principles generally accepted ("GAAP") in the United States of America ("US"). The Company's consolidated financial statements include all accounts of Petroleum Geo-Services ASA, its wholly owned subsidiaries and subsidiaries which it controls. Investments in associated entities (companies and joint ventures) in which the Company's ownership interests equal or exceed 20% and over which the Company exercises significant, but not controlling, influence are accounted for under the equity method. Other investments are accounted for at cost. All significant intercompany accounts and transactions are eliminated in consolidation. The Company did not have any significant transactions with acquired companies in the periods prior to acquisition.

As more fully described in Note 24, the accompanying financial statements as of and for the years ended December 31, 2000 and 1999 have been restated (1) to reflect fair value accounting for tax equalization swap contracts entered into in 1998 and 1999 to hedge the Company's exposure to Norwegian taxes arising out of the conversion, for Norwegian tax purposes, of the Company's US dollar-denominated debt into Norwegian kroner (Note 17); (2) to reflect the adoption of the US Securities and Exchange Commission's Staff Accounting Bulletin ("SAB") No. 101, "Revenue Recognition in Financial Statements", which became effective January 1, 2000, to our revenue recognition policy for some types of volume seismic data licensing arrangements; (3) to adjust property and equipment, multi-client library and depreciation and amortization to properly reflect capitalized interest and depreciation and amortization amounts related to two of the Company's seismic vessels and the upgrade of floating production, storage and offloading ("FPSO") vessels; (4) to provide a valuation allowance against certain deferred tax assets that properly reflects uncertainties about the future utilization of these tax assets; (5) to amortize the multi-client library in accordance with the Company's minimum amortization policy; and (6) to properly amortize deferred assets over their useful lives and accrue defined benefit pension obligations, commission/royalty liabilities and lease liabilities as incurred.

In addition, certain reclassifications have been made to prior year amounts to conform to the current year's presentation. In 2001, the Company reversed a previously recorded $56.8 million contingent liability related to the Foinaven field against goodwill recorded as part of the 1998 acquisition of the FPSO operations of Awilco ASA.

The accompanying financial statements have been prepared on the basis of accounting principles that presume the realization of assets and the settlement of liabilities in the ordinary course of business. Accordingly, the financial statements do not purport to present the realizable values of all assets or the settlement amounts of all liabilities.

Because of the level of the Company's debt and other contractual cash obligations, (1) a substantial portion of the Company's cash flow from operations must be dedicated to debt service and payments of such obligations and, to the extent so used, will not be available for operational purposes, (2) the Company's ability to obtain additional financing in the future may be limited, and (3) the Company's flexibility in reacting to changes in the operating environment and economic conditions may be limited. If the Company encounters difficulty in paying debt service or other obligations in the future, it will be forced to take actions such as reducing or delaying capital expenditures, reducing costs, selling assets, refinancing or restructuring its debt or other obligations and seeking additional equity capital. The Company may not be able to take any of these actions on satisfactory terms or at all.

As of December 31, 2001, the Company had approximately $2.8 billion of outstanding debt, lease and preferred securities obligations, with aggregate contractual cash obligations summarized as follows (in millions):

		Payments due by period			
Contractual cash obligations	Total	2002	2003	2004	2005 and thereafter
Debt obligations (Note 10)	$2,161.3	$257.7(1)	$599.0	$10.2	$1,294.4
Capital lease obligations (Note 12)(2)	60.9	13.1	11.2	9.2	27.4
Operating lease obligations (Note 12)	297.5	111.4	66.8	42.7	76.6
Guaranteed preferred beneficial interest in junior subordinated debt securities (Note 11)	141.0	—	—	—	141.0
Mandatorily redeemable cumulative preferred securities (Note 11)(3)	169.3	72.0	46.1	32.6	18.6
Total contractual cash obligations	$2,830.0	$454.2	$723.1	$94.7	$1,558.0

(1) Includes $225.0 million of floating rate notes that matured and were refinanced with a $250.0 million bank credit facility in March 2002. Such facility will mature in 2003.

(2) Reflects gross contractual commitments under capital leases.

(3) Assumes the Company's credit ratings remain at or above BB+ or Ba1 by Standard & Poor's Ratings Services ("Standard & Poor's"), a division of The McGraw-Hill Companies, Inc., or Moody's Investors Service, Inc. ("Moody's"), respectively.

As of May 3, 2002, Moody's had rated the Company's senior unsecured debt at Baa3, its lowest investment grade credit rating, and placed that credit rating under review for possible downgrade. At that date, Standard & Poor's had rated the Company's senior unsecured debt at BBB-, it lowest investment grade credit rating, and had placed that credit rating on creditwatch with negative implications, and Fitch IBCA, Duff & Phelps had rated our senior unsecured debt at BBB-. In the event of a credit rating downgrade, the Company may have difficulty obtaining financing and its cost of obtaining additional financing or refinancing existing debt may be increased significantly. A credit rating downgrade would cause the interest rate on the Company's $250.0 million short-term bank facility (Note 10) to increase by up to 3.5% and would most likely require the Company to seek refinancing alternatives for this facility that would not otherwise be required. In the event that the Company's credit ratings are downgraded to below BB+ or Ba1 by Standard & Poor's or Moody's, respectively, the Company will be required to increase by 30% the quarterly redemption of the mandatorily redeemable cumulative preferred securities of a subsidiary which owns a portion of the multi-client library (Note 11). If those credit ratings remain for a certain period of time, or deteriorate below BB- or Ba3, respectively, the Company will be required to increase the quarterly redemption of the preferred securities to an amount equal to 100% of the actual revenue recognized from the licensing of the data held by that subsidiary. In the event of a credit rating downgrade by both Standard & Poor's and Moody's, the Company may be required to provide up to £35.7 million (approximately $52.0 million) in collateral or other credit support to one or more lessors or other parties under UK leasing arrangements (Note 9), which could adversely impact liquidity.

The Company has entered into an agreement with Veritas DGC Inc. ("Veritas"), a geophysical services company, to combine the businesses of the two companies (Note 3). The Company has also signed a definitive agreement to sell its Atlantis subsidiary (Note 3). Both of these transactions include conditions to closing that depend on the actions of third parties and are therefore outside of the Company's control. If the Company fails to complete either transaction, it could suffer adverse consequences including a downgrade of its debt and trust preferred securities credit ratings by one or more rating agencies, which would in turn cause the Company to incur increased interest costs. In the event that the Atlantis sale is not completed, the Company will be required to seek refinancing alternatives that would not otherwise be required (Note 10). The Veritas transaction is itself conditioned on closing the Atlantis sale.

Note 2 — Summary of Significant Accounting Policies

Foreign Currency Translation.

Although the Company's activities span the globe, its transactions are primarily denominated in US dollars; therefore, the Company has adopted the US dollar ("$") as its reporting currency. The Company uses the US dollar as the functional currency for it and certain of its Norwegian subsidiaries.

The financial statements of non-US subsidiaries using the US dollar as their functional currency are translated as follows: non-monetary assets, share par value and paid-in capital are translated at historical exchange rates; revenue and expenses are translated at the average rates of exchange during the period, except for depreciation and amortization, which are translated at historical exchange rates; and all other financial statement accounts are translated at the rate of exchange at period end. Remeasurement adjustments are credited or charged directly to income, except for adjustments relating to long-term intercompany borrowings, which are accumulated as a separate component of shareholders' equity.

The financial statements of non-US subsidiaries using their local currency as their functional currency are translated using the current rate method. Assets and liabilities are translated at the rate of exchange in effect at period end; share par value and paid-in capital are translated at historical exchange rates; and revenue and expenses are translated at the average rates of exchange in effect during the period. Translation adjustments are recorded as a separate component of shareholders' equity.

The Company's exchange rate between the Norwegian kroner and US dollar at December 31, 2001 and 2000 was NOK 9.09 and NOK 8.84, respectively. The Company recorded ($1.7) million, $2.9 million and $4.1 million in net foreign exchange (losses) and gains, exclusive of the effects of the tax equalization swap contracts (Note 17), for 2001, 2000 and 1999, respectively.

Cash And Cash Equivalents.

The carrying amounts of cash and cash equivalents approximate fair value. Cash and cash equivalents include demand deposits and all highly liquid financial instruments purchased with maturities of three months or less. As of December 31, 2001 and 2000, $8.0 million and $4.0 million, respectively, in cash balances related to payroll, taxes, insurance and our multi-client library securitization (Note 11) were restricted.

UK Leases.

The Company has periodically executed leasing arrangements in the United Kingdom ("UK leases") relating to certain seismic and FPSO vessels and/or equipment. Under the leases, the Company sells the applicable assets to UK financial institutions and leases the assets from the institutions under long-term charters that give the Company the option to purchase the assets for a *de minimis* amount at the end of the charter periods. Due to the nature of the charters, the Company capitalizes the assets. The Company uses a substantial portion of the proceeds from the arrangements to legally defease the present value of the Company's future charter obligations for the assets. These UK leases provide the financial institutions with the tax depreciation rights to the assets and, therefore, the ability to utilize the related tax benefits. Under its UK leases, the Company has indemnified the financial institutions against certain future events that could reduce their expected after-tax returns on the UK leases. These events include potential changes in UK tax laws and interpretations, depreciation rates or interest rates. At the date that the Company executes any UK lease, the Company treats the excess of the sales proceeds received over the amount required to legally defease the charter obligations as a deferred gain, due to the indemnification contingencies. The deferred gain is recognizable as other income once the Company has determined that the possibility of the indemnification contingencies occurring is remote.

Accounting Estimates.

The preparation of financial statements in conformity with US GAAP requires management to make various estimates, assumptions and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities. In addition, such estimates, assumptions and judgments can have a material effect on the amount of reported revenue and expenses during a particular period. The Company reviews significant estimates, assumptions and judgments no less frequently than annually. In many circumstances, the ultimate outcomes related to the estimates, assumptions and judgments may not be known for several years after the preparation of the financial statements. Actual amounts may differ materially from these estimates due to changes in general economic conditions, laws and regulations, changes in future operating plans and the inherent imprecision associated with estimates.

Receivables Credit Risk.

The Company extends credit to various companies in the oil and gas industry worldwide, which may be affected by changes in economic or other external conditions. At December 31, 2001 and 2000, accounts receivable (both current and long-term) were primarily from multinational integrated oil companies and independent oil and gas companies, including companies owned in whole or in part by foreign governments. The Company manages its exposure to credit risk through ongoing credit evaluations of its customers and has provided for potential credit losses through an allowance for doubtful accounts. Management does not believe that the Company is exposed to concentrations of credit risk that are likely to have a material adverse impact on the Company's financial position or results of operations.

Multi-Client Library.

The multi-client library consists of seismic surveys that are to be licensed to customers on a non-exclusive basis. All costs directly or indirectly incurred in acquiring, processing and otherwise completing seismic surveys are capitalized into the multi-client library, including the applicable portion of the Company's interest costs. The multi-client library is stated at the lower of survey costs less accumulated amortization or fair value.

The Company records its investment in the multi-client library in a manner consistent with its capital investment and operating decision analysis, which generally results in each component of the multi-client library being recorded and evaluated on a survey-by-survey basis, except for the multi-client library in the Gulf of Mexico. Due to the density of the oil and gas prospectivity in the Gulf of Mexico, the multi-client library is recorded and evaluated by regions within the Gulf of Mexico and by year of completion.

Amortization of the multi-client library is generally recorded in proportion to revenue recognized to date as a percentage of the total expected revenue. In determining the annual amortization rates applied to the multi-client library, management considers expected future sales and market developments as well as past experience. These expectations include consideration of geographic location, prospectivity, political risk, exploration license periods and general economic conditions. Because of the inherent difficulty in estimating future sales and market developments, it is possible that the amortization rates could deviate significantly from year to year.

The Company's process for preparing expected revenue estimates begins with local management input, but is reviewed and approved by the Company's senior management. Beginning in 2002, changes to expected revenue estimates will require approval from the Company's executive committee, with approved changes effective in the following fiscal quarter. To the extent that such revenue estimates, or the assumptions used to make those estimates, prove to be higher than actual revenue, the Company's future operations will reflect lower profitability due to increased amortization rates applied to the multi-client library in later years, and the multi-client library may also become subject to minimum amortization and/or impairment.

The estimates of total expected revenue over the economic life of the multi-client library are highly subjective, cover extended periods of time, and are dependent on a number of factors outside the control of the Company (including, among others, general economic conditions, prospectivity within specific geographic regions and political and regulatory developments). The Company's local sales and operating management estimate, at least annually, the total expected revenue for each component of the multi-client library for their respective region, as described above. On reorganizing its geophysical operations in April 2001, the Company structured a sales team to focus on developing volume sales arrangements covering the multi-client library on a global basis. By the 2001 third quarter, the Company had a functional sales team and business plan devoted to this new global sales strategy. In the 2001 fourth quarter, the Company had sufficient evidence to make revenue estimates related to this global sales strategy and, accordingly, included global volume sales arrangement estimates in its total expected revenue estimates. Excluding the effect of the revenue estimates for these global volume sales arrangements, amortization of the multi-client library would have been approximately $3.0 million higher and an additional impairment of $1.3 million would have been recorded for the year ended December 31, 2001.

Although it is the Company's general policy to amortize the multi-client library based on the proportion of the recognized revenue to the total expected revenue, an integral element of the Company's amortization is the minimum amortization policy. Under this policy, the Company requires that the book value of each component of the multi-client library be reduced to a specified percentage by year-end, based on the age of the component in relation to its year of completion. This requirement is applied regardless of future-year revenue estimates for the multi-client library component. The specified percentage generates the maximum book value for each multi-client library component as the product of the percentage multiplied by the original book value of the multi-client library component. Any minimum amortization charges required are then determined through a comparison of the remaining book value to the maximum book value allowed for each component of the multi-client library.

The specified percentages the Company uses to determine the maximum book value of its multi-client library components are summarized as follows:

	Maximum book value from completion year		
Year from Completion	**Marine components (excluding Brazil)**	**Marine components (Brazil)**	**Land components**
Year 1	100%	100%	100%
Year 2	70%	92%	60%
Year 3	55%	76%	40%
Year 4	40%	50%	20%
Year 5	30%	43%	0%
Year 6	20%	34%	
Year 7	10%	20%	
Year 8	0%	0%	

The Company monitors its minimum amortization requirements on a quarterly basis. During the second quarter of each year, the Company begins to record minimum amortization charges, using revenue estimates for the remainder of the current year to project the maximum book value of each multi-client library component. However, the majority of the Company's minimum amortization charges are recorded during the fourth quarter of each year due to the inherent imprecision in estimating current year revenue. In the fourth quarters of 2001 and 2000, the Company recorded minimum amortization charges of $39.1 million and $2.2 million, respectively. No minimum amortization charges were recorded for the year ended December 31, 1999.

Property And Equipment.

Property and equipment are stated at cost less accumulated depreciation. Depreciation is calculated using a modified units-of-production method for certain FPSO vessels and equipment and the straight-line method for all other property and equipment, after allowing for residual values. The modified units-of-production depreciation method used for certain of the Company's FPSO vessels is based on an estimate of the total barrels of oil to be produced over the useful life of the vessel. Because the actual number of barrels of oil produced may ultimately differ from these estimates, it is possible that the depreciation rates could deviate significantly over time. The estimated useful lives for the Company's property and equipment are as follows:

	Years
Seismic vessels and FPSO vessels and equipment	20-30
Seismic and operations computer equipment	3-10
Leasehold improvements — seismic vessels	1-30
Buildings and related leasehold improvements	1-30
Fixtures, furniture and fittings	3-5

Expenditures for major property and equipment additions and improvements are capitalized. The Company defers the non-capitalizable costs associated with planned major maintenance activities and amortizes these costs over subsequent periods, generally twelve to eighteen months. Expenditures for minor replacement, maintenance and repair projects are charged to expense. The Company capitalizes the applicable portion of its interest costs to major capital projects that require a period of time to complete. When property and equipment are retired or otherwise disposed of, the related cost and accumulated depreciation are removed from the accounts, and any resulting gain or loss is included in the results of operations.

Oil and Gas Properties.

The Company follows the full-cost method of accounting for oil and gas properties, where all costs incurred in connection with the acquisition, exploration and development of oil and gas reserves are capitalized. Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs, interest capitalized on unevaluated leases and other costs incidental to exploration and development activities. Overhead costs capitalized include salary and benefits paid to employees directly engaged in the acquisition, exploration and/or development of oil and gas properties as well as other costs directly attributable to such activities. The Company captures and accounts for such costs in separate cost centers on a country-by-country basis.

Capitalized costs are amortized using the unit-of-production method on a country-by-country basis, using actual production quantities and estimates of proved reserve quantities. Unevaluated properties are excluded from the amortizable base. Costs associated with unevaluated properties are transferred to evaluated property costs at such time as wells are completed, the properties are sold, or management determines that the costs have been impaired. Future development costs and dismantlement, restoration, and abandonment costs, net of estimated salvage values, are added to the amortizable base.

The Company limits, on a country-by-country basis, the costs of proved oil and gas properties, net of accumulated depletion, depreciation and amortization ("DD&A"), to the estimated future net cash flows from proved oil and gas reserves, generally using prices in effect at the end of the period held flat for the life of production, discounted at 10%, net of related taxes. If the capitalized cost of proved oil and gas properties exceeds this limit, the excess is charged to expense in the period and reflected as additional DD&A.

Proved oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate and natural gas liquids that geological and engineering data demonstrate with reasonable certainty can be recovered in future years from known reservoirs under existing economic and operating conditions.

Reserves are considered proved if they can be produced economically, as demonstrated by either actual production or conclusive formation tests. The Company emphasizes that the volumes of reserves are estimates which, by their nature, are subject to revision. The estimates are made using all available geological and reservoir data, as well as production performance data. These estimates, made by the Company's engineers, are reviewed and revised, either upward or downward, as warranted by additional data. Revisions are necessary due to changes in assumptions based on, among other things, reservoir performance, prices, economic conditions and governmental restrictions. Decreases in prices, for example, may cause a reduction in some proved reserves due to uneconomic conditions.

The Company's oil and gas assets at December 31, 2001 are owned by its Atlantis subsidiary. On January 22, 2002, the Company entered into definitive agreement with China National Chemicals Import and Export Corporation ("Sinochem") for the sale of its Atlantis subsidiary (Note 3).

Goodwill and Other Long-Term Assets.

Goodwill is stated at cost less accumulated amortization. Goodwill amortization is calculated on a straight-line basis over the estimated life, with a maximum life of 40 years.

Other long-term assets consist of investments in associated entities, long-term receivables, deferred tax assets, direct costs of software product development, patents, royalties and licenses. Other long-term assets which are amortizable are stated at cost less accumulated amortization. Amortization is calculated on a straight-line basis over the estimated useful lives of the related assets, with a maximum life of 10 years.

Amortization of goodwill and other long-term assets was $15.4 million, $15.2 million and $14.3 million for the years ended December 31, 2001, 2000 and 1999, respectively.

Asset Recoverability.

The Company's management evaluates the recorded balances of its property and equipment, goodwill and other long-term assets for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be appropriate. This evaluation is based on a comparison of the assets' fair values, which are generally based on forecasts of cash flows associated with the assets, to the assets' carrying amounts. Any impairment loss is recorded as the difference between the assets' carrying amounts and fair values. As discussed in Note 23, during the three-year period ended December 31, 2001 certain events and circumstances warranted revision to the remaining useful lives and affected the recoverability of the Company's assets.

Loss Contracts.

The Company reviews its revenue-producing contracts in the ordinary course of business to determine if estimated costs to service the contract exceed the estimated contract revenue. Any resulting net loss indicated for the contract is expensed at the time the loss is determined. If the Company estimates intermittent periods of profitability over the life of a loss contract, this profitability is deferred against the future loss.

Derivative Financial Instruments.

Derivative financial instruments are used periodically by the Company in the management of its foreign currency exchange rate exposure. The Company does not engage in derivative financial instrument transactions for speculative purposes. The derivative contracts are entered into with major international financial institutions. The likelihood of non-performance by the Company's counterparties under these contracts is considered to be remote.

Gains and losses attributable to forward foreign exchange contracts and option contracts that do not qualify for hedge accounting, including tax equalization swap contracts (Note 17), are recognized in income as they arise. As of December 31, 2001 and 2000, the Company did not have outstanding any derivative financial instruments which qualified for hedge accounting.

Revenue Recognition.

Beginning January 1, 2000, the Company recognizes revenue in accordance with SAB No. 101. The Company's specific revenue recognition policies are as follows:

Geophysical Services

Sales of Multi-Client Library Data

Late sales — The Company grants a license to a customer which entitles the customer to have access to a specifically defined portion of the Company's multi-client data library. In each case, the portion of the multi-client library for which an access license is being granted is complete and ready for use. The customer's license payment is fixed and determinable, and typically is required at the time that the license is granted. The Company recognizes revenue for late sales at the point that the customer has executed a valid license agreement, the customer has been granted access to the licensed portion of the multi-client library and collection is reasonably assured.

Volume sales agreements — The Company enters into a customer arrangement in which the Company agrees to grant licenses to the customer for access to a specified number of blocks of the multi-client library within a defined geographical area. These arrangements typically enable the customer to select and access the specific blocks over a period of time. Although the license fee is fixed and determinable in all cases, the payment terms of individual volume sales agreements vary, ranging from payment of the entire fee at the commencement of the volume sales agreement, to installment payments over a multi-year period, to payment of the license fee as the specific blocks are selected.

The Company recognizes revenue for volume sales agreements, based on a ratable portion of the total volume sales agreement revenue, as the customer executes a license for specific blocks, the customer has been granted access to the data included in the agreement and collection is reasonably assured.

Pre-funding arrangements — The Company obtains funding from a limited number of customers before a seismic project commences from time to time. In return for the prefunding, the customer typically gains the ability to direct/influence the project specifications, advance access to data as it is being acquired and discounted pricing.

The Company recognizes prefunding revenue as the services are performed on a percentage-of-completion basis. The Company evaluates the progress to date, in a manner generally consistent with the physical progress off the project, and recognizes revenue based on the ratio of the project's progress to date to the total project.

Proprietary Sales/Contract Sales

The Company performs seismic services for a specific customer, in which case the seismic data is the exclusive property of that customer. The scope and terms of these proprietary sales vary substantially. The Company recognizes proprietary/contract revenue as the services are performed and become chargeable to the customer.

Other Geophysical Services

Revenue from the Company's other geophysical services is recognized as the services are performed.

Production Services

Tariff-based revenue from the Company's floating production services is recognized as production occurs, while day-rate revenue is recognized over the passage of time. Production management services revenue is recognized as the services are performed. Performance-based incentive fees are accrued when there is objective evidence that the performance criteria have been met.

Income Taxes.

The Company provides for all current taxes payable and for deferred taxes arising from temporary differences between the tax bases of assets and liabilities and their reported amounts in the financial statements, based on enacted tax rates and laws in effect for the years in which differences are expected to reverse. Income tax benefits and liabilities arising from tax-deductible share issue costs are recorded directly to shareholders' equity. Except where required by law, Norwegian income taxes are not accrued for unremitted earnings of international operations that have been, or are intended to be, reinvested indefinitely. Valuation allowances are provided against deferred tax assets when management determines that it is more likely than not that a future tax benefit will not be realized.

New Accounting Standards.

During 2001, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 141, "Business Combinations," and SFAS No. 142, "Goodwill and Other Intangible Assets." SFAS No. 141 requires that the purchase method of accounting be used for all business combinations initiated after June 30, 2001. Effective January 1, 2002, SFAS No. 142 suspends amortization of goodwill and intangible assets with indefinite lives and, instead, requires an annual impairment review based on a comparison of fair value to carrying value. SFAS No. 142 requires that the fair value determination be completed by June 30, 2002, with any resulting transitional impairment to be recorded by December 31, 2002 and reflected retroactively as of January 1, 2002 as the cumulative effect of an accounting change. Any impairments other than transitional impairment will be recognized in continuing operations. The Company is developing its fair value calculations and has not yet determined the impact of adopting SFAS No. 142.

During 2001, the FASB also issued SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 establishes accounting and reporting standards for the retirement of long-lived assets requiring the fair value of an asset retirement obligation to be recognized as a liability in the period in which it is incurred, with the associated costs capitalized as part of the carrying amount of the long-lived asset. SFAS No. 143 is effective for the Company beginning January 1, 2003, and any effects on adoption will be reflected as a cumulative effect of an accounting change. The Company has not yet determined the impact of SFAS No. 143.

Also during 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." SFAS No. 144 addresses, in part, issues related to implementation of SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of." SFAS No. 144 is effective for the Company as of January 1, 2002. The Company does not expect to recognize any material effects on the prospective implementation of SFAS No. 144.

Effective January 1, 2001, the Company adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 establishes accounting and reporting standards requiring that every derivative financial instrument be recorded in the balance sheet as either an asset or a liability measured at its fair value, with certain changes in fair value recognized currently in earnings. Under SFAS No. 133, the Company's derivative financial instruments are recognized at fair value (including any interim settlement value determined by the counterparty) in each reporting period, with any periodic adjustments to fair value recognized in the results of operations. The Company did not recognize any material effects on adoption of SFAS No. 133. However, see Notes 17 and 24 for further discussion of the Company's derivative financial instruments and the restatement related to these instruments.

The Company's financial statements and related disclosures reflect the January 1, 2000 adoption of SAB No. 101, "Revenue Recognition in Financial Statements." Application of this SAB required the deferral of revenue recognition on certain types of volume seismic data licensing arrangements until the time that customer enters into a license agreement for specific data. Accordingly, the Company adjusted revenue ($22.8 million), amortization ($11.4 million) and commission expense ($2.3 million) and recognized an aggregate charge to income of $6.6 million, net of tax benefits of $2.5 million, as of

January 1, 2000 as the cumulative effect of the change in accounting principle. See Note 23 for further discussion of these adjustments. As a result of the application of SAB No. 101, the Company has deferred $26.0 million and $15.6 million of revenue relating to certain volume sales agreements in effect as of December 31, 2001 and 2000, respectively.

Effective January 1, 1999, the Company adopted Statement of Position ("SOP") 98-5, "Reporting on the Costs of Start-up Activities." Accordingly, the Company expensed as a cumulative effect of an accounting change all previously capitalized start-up costs. The $20.0 million in expensed costs, net of income tax benefits of $8.1 million, included costs related to the start-up of the Company's floating production business, the reservoir monitoring business and the multi-component, vertical cable and land seismic businesses, as well as costs related to the opening of various worldwide offices. Subsequent to adoption, all start-up costs are expensed as incurred.

NOTE 3 — Acquisitions and Dispositions

On November 26, 2001, the Company entered into a definitive agreement with Veritas to combine the businesses of the two companies under a new Cayman Islands holding company, referred to as "Caymanco." Under the agreement, Caymanco will make an exchange offer to issue its ordinary shares in exchange for the Company's outstanding shares and American Depositary Shares ("ADSs"). Following the closing of the exchange offer, Veritas will merge with a wholly owned subsidiary of Caymanco. Upon closing of the exchange offer and the merger, the Company and Veritas will become subsidiaries of Caymanco. The closing of the transaction is subject to a number of conditions, including: (1) the tender in the exchange offer of Company shares and ADSs representing more than 90% of the shares outstanding as of the expiration of the exchange offer, which percentage may be reduced in limited circumstances described in the agreement; (2) the approval of the merger by the stockholders of Veritas; (3) the receipt of applicable regulatory clearances; (4) the Company having in effect definitive credit agreements or binding commitments providing for credit capacity of $430 million; (5) Veritas' having in effect definitive credit agreements or binding commitments providing for credit capacity of $235 million; (6) the authorization of the ordinary shares of Caymanco for listing on the New York Stock Exchange; (7) the Company having completed the sale of its Atlantis subsidiary (discussed further below); (8) the Company having entered into replacement employment agreements with some of its active employees; and (9) other customary conditions, including the absence of any events or series of events that has had or would have a material adverse effect on Veritas or the Company.

Under the agreement, a material adverse effect will be deemed to have occurred and either party may terminate the agreement if, among other things: (1) the settlement price for the NYMEX natural gas futures contract for delivery 12 months following the month in which the relevant date of determination occurs falls below $2.25 per MMBtu for 20 consecutive trading days; or (2) the settlement price for the NYMEX light sweet crude oil futures contract for delivery 12 months following the month in which the relevant date of determination occurs falls below $12.50 per barrel for 20 consecutive trading days.

During 2002, the Company has had discussions with Veritas about amending the terms of the agreement in various respects. Although no definitive amendment has been reached, the Company expects any such amendment to include the following key terms: (1) Company shareholders would receive 0.40 shares (previously 0.47 shares) of Caymanco for each Company share and ADS, and Veritas shareholders would receive one share of Caymanco for each Veritas share, resulting in Veritas shareholders owning approximately 44% of the Caymanco shares and Company shareholders owning approximately 56% of the Caymanco shares upon completion of the transaction (assuming all Company shares and ADSs are tendered and accepted in the exchange offer); (2) Veritas would be entitled to nominate six of the proposed ten directors of Caymanco while the Company would be entitled to nominate four directors; (3) David B. Robson, the Chief Executive Officer of Veritas, would be the Chief Executive Officer of Caymanco and Reidar Michaelsen, the Company's Chairman and Chief Executive Officer, would be the Chairman of the Board; (4) Matthew D. Fitzgerald, the Chief Financial Officer of Veritas, would be the Chief Financial Officer of Caymanco; and (5) the transaction would be conditioned upon Veritas being treated as the acquiring company for accounting purposes.

In April 2002, Veritas reported that the staff of the US Securities and Exchange Commission would not object to Veritas being treated as the accounting acquiror. Any amendment to the agreement with Veritas would be subject to final approval of the boards of directors of each company.

If the Company and Veritas amend the original agreement along the lines described above and assuming all conditions precedent were satisfied or waived, the transaction is expected to close during the third quarter of 2002. However, the Company or Veritas may not be able to satisfy all the conditions to closing, including the sale of Atlantis, and there is no assurance that any conditions that are not satisfied will be waived. In addition, the original agreement, which is still in effect, provides that either party may terminate the agreement if the transaction has not been effected by June 30, 2002. The transaction is expected to be a taxable transaction to the Company's Norwegian shareholders unless a specific exemption is granted by the Norwegian ministry of finance and a taxable transaction to the Company's US shareholders.

The transaction will be accounted for using the purchase method of accounting. The Company and Veritas have not had any significant intercompany transactions. On completion of the transaction, certain members of the Company's management could be entitled to receive compensation of up to $22.1 million due to the change in control of the Company. Such compensation amounts are not accruable until the transaction is consummated, and are therefore not reflected in the Company's statement of operations or financial position.

In July 2001, the Company consummated the acquisition of Diamond Geophysical Services Corporation ("Diamond"), a company specializing in the design and marketing of 3D multi-client seismic surveys. Consideration paid for the net assets acquired consisted of $1.0 million in cash paid and approximately $9.1 million in equity issued (in the form of 900,000 shares) to the former owners, as well as the assumption by the Company of approximately $1.4 million in assets and $1.0 million in liabilities. The transaction was treated as a purchase for accounting purposes, with the assets acquired and the liabilities assumed recorded at their fair values, including $9.7 million in goodwill. Prior to the acquisition (beginning in 1994), Diamond was the exclusive broker of a significant portion of the Company's Gulf of Mexico multi-client library, and received sales commissions and a monthly retainer for services from the Company.

In March 2001, the Company sold its global Petrobank data management business and related software to Landmark Graphics Corporation, a subsidiary of Halliburton Company, for $165.7 million in net cash proceeds ($175.0 in gross sale proceeds less $9.3 million in working capital adjustments). The Company recognized a $138.5 million gain on the sale, excluding taxes of $40.4 million, which was classified as an unusual item in the Company's results of operations. The Company's results of operations for the 2001 period (prior to consummation of the sale), 2000 and 1999 included pretax (loss)/income of ($3.7) million, $0.9 million and $0.6 million, respectively, related to the data management business. The financial position of the data management business was not material to the Company's consolidated financial position for any year presented.

In December 2000, the Company sold all of its holdings (5.4 million shares) in Spinnaker Exploration Company for net proceeds of $150.5 million. At December 31, 2000, $70.0 million of the proceeds had been used to repay indebtedness outstanding under the Company's revolving bank credit facility. A $54.7 million pretax gain on this transactions was recognized as income from equity investments.

Subsequent Events.

On January 22, 2002, the Company entered into a definitive agreement with Sinochem for the sale of the Company's Atlantis subsidiary, which is a part of the Company's production operations segment. Under the terms of the definitive agreement, total proceeds from the sale of Atlantis are expected to approximate $200 million in cash, plus certain qualifying capital expenditures incurred during 2002. Sinochem also has agreed to assume $20.5 million of Atlantis' short-term debt. The Company is required to use $175.0 of the net proceeds received from the Atlantis sale to repay a portion of the Company's $250.0 million short-term bank facility (Note 10).

As of December 31, 2001, Atlantis' assets and liabilities to be sold included the following: $3.6 million in cash, $0.5 million in other current assets, $0.2 million in property and equipment, $171.1 million in oil and gas assets, $4.0 million in net deferred tax assets, $20.5 million in short-term debt and $9.2 million in current liabilities. The Company did not record any impairment charges related to the Atlantis net assets since the carrying value did not exceed the fair value (less estimated costs to sell). Atlantis' pretax (loss) of ($4.0) million, ($2.3) million and $(11.4) million for the years ended December 31, 2001, 2000 and 1999, respectively, are included in the Company's results of operations for those periods. Interest capitalized into oil and gas assets was $6.7 million, $7.9 million and $4.2 million for the years ended December 31, 2001, 2000 and 1999, respectively.

Consummation of the sale is subject to certain conditions, including the receipt of certain consents and waivers from governmental authorities and partners. On April 22, 2002, the Company agreed with Sinochem to extend the period to close the sale through June 28, 2002, although Sinochem has the right under the extension to terminate the agreement after May 27, 2002. Under the extension agreement, if the required closing conditions are satisfied or are waived by Sinochem after May 20, 2002, then the sale proceeds will be reduced by $100,000 per day from the period May 13, 2002 through the date that the closing conditions are so satisfied or waived. In the event that the Company terminates the definitive agreement after June 28, 2002, the Company may be required to pay a $1.4 million termination fee to Sinochem.

During the 2002 first quarter, the Company entered into purchase commitments for an aggregate 70% interest in Production License (PL) 038 on the Norwegian Continental Shelf of the North Sea. The interests are to be purchased from Statoil (which holds a 28% interest in PL 038) and Norsk Hydro (which holds a 42% interest in PL 038). As consideration for its 70% interest, the Company will assume a portion of the abandonment liabilities associated with the fields on the license as well as any future environmental liabilities that may be generated by production on the fields. The estimates for these liabilities range up to $32.0 million in gross costs, or $12.0 million in after-tax costs. The license purchases are contingent on the approval of Norwegian authorities and expected to close during the 2002 third quarter. Upon completion of the purchases, the Company's 30% partner will be the Norwegian government's State Direct Financial Interest.

NOTE 4 — Accounts Receivable

The Company has recorded allowances for doubtful accounts of $3.6 million and $4.2 million at December 31, 2001 and 2000, respectively. The Company has recorded $83.7 million and $117.2 million of unbilled receivables at December 31, 2001 and 2000, respectively; these receivables relate to revenue that has been recognized but is not yet billable under the specific broker or customer agreements. Of these unbilled receivables, $11.1 million and $23.3 million were net long-term receivables at December 31, 2001 and 2000, respectively.

NOTE 5 — Multi-Client Library

The components of the multi-client library, net of accumulated amortization, are summarized as follows:

	December 31, 2001	December 31, 2000
	(In thousands of dollars)	
Multi-client seismic surveys, completed	$841,108	$628,909
Multi-client seismic surveys, work in progress	76,964	219,811
Total	$918,072	$848,720

The multi-client library as of December 31, 2001 allocated by the year in which the components were completed are summarized as follows:

	Net book value (In thousands of dollars)
Completed surveys:	
Completed before 1996	$ 4,297
Completed during 1996	20,954
Completed during 1997	22,835
Completed during 1998	69,730
Completed during 1999	188,373
Completed during 2000	234,824
Completed during 2001	300,095
Completed surveys	841,108
Surveys in progress	76,964
Multi-client library	$918,072

Amortization expense was $195.4 million, $142.6 million and $137.5 million for the years ended December 31, 2001, 2000 and 1999, respectively. Amortization expense for the years ended December 31, 2001 and 2000 included $39.1 million and $2.2 million, respectively in charges required under the Company's minimum amortization policy for the multi-client library (Note 1).

The application of the Company's minimum amortization requirements to the components of the multi-client library as of December 31, 2001 are summarized as follows:

	Minimum future amortization (In thousands of dollars)
During 2002	$100,234
During 2003	171,092
During 2004	187,120
During 2005	145,589
During 2006	130,335
During 2007	98,516
During 2008	73,898
During 2009	11,288
Future amortization	$918,072

These minimum amortization requirements are calculated as if there will be no future sales of these components. The Company believes that the likelihood of recognizing these precise minimum amortization amounts is remote, because amortization generated by multi-client sales in the ordinary course of business is expected to substantially reduce the book value of the multi-client library.

Because the minimum amortization requirements apply to the multi-client library on a component basis rather than in the aggregate, the Company may incur minimum amortization charges in a year even if the aggregate amount of ordinary amortization charges recognized exceeds the aggregate minimum amortization charges.

Interest capitalized into the multi-client library was $15.9 million, $21.7 million and $26.6 million for the years ended December 31, 2001, 2000 and 1999, respectively.

NOTE 6 — Other Current Assets, Net And Accrued Expenses

Other current assets, net at December 31, 2001 include $28.0 million in prepaid operating expenses; other current assets, net at December 31, 2000 include $27.9 million in prepaid operating expenses. Accrued expenses at December 31, 2001 include a $44.6 million liability related to the fair value of tax equalization swap contracts (Note 17) and $29.4 million in customer advances and deferred revenue. Accrued expenses at December 31, 2000 include a $91.2 million liability related to the fair value of tax equalization swap contracts (Note 17), $27.7 million in customer advances and deferred revenue, $21.2 million in accrued interest, $63.3 million in accrued loss contracts (customer contracts and vessel contracts), $22.1 million in accrued upgrade costs related to the *Petrojarl I* and *Ramform Banff* and $23.2 million in accrued vessel operating costs.

NOTE 7 — Property And Equipment

The components of property and equipment are summarized as follows:

	December 31, 2001	December 31, 2000
	(In thousands of dollars)	
FPSO vessels and equipment	$1,818,609	$1,698,522
Seismic vessels, including leasehold improvements	486,105	493,263
Seismic and operations computer equipment	537,742	483,340
Buildings, including leasehold improvements, and other	20,507	22,450
Fixtures, furniture and fittings	56,800	67,983
	2,919,763	2,765,558
Accumulated depreciation	(637,522)	(513,615)
Total	$2,282,241	$2,251,943

The gross cost of property and equipment includes $68.1 million and $54.9 million (primarily seismic and computer equipment) relating to capital leases (Note 12) as of December 31, 2001 and 2000, respectively, and reflected $30.2 million and $44.6 million of depreciation capitalized into the multi-client library for the years then ended, respectively. Accumulated depreciation of property and equipment includes $24.2 million and $36.2 million relating to capital leases as of December 31, 2001 and 2000, respectively. Net depreciation expense was $123.7 million, $105.8 million and $86.8 million for the years ended December 31, 2001, 2000 and 1999, respectively. Interest capitalized into property and equipment was $3.9 million, $5.4 million and $9.3 million for the years ended December 31, 2001, 2000 and 1999, respectively. Property and equipment balances at December 31, 2000 reflect the significant impairment charges and restructuring activities undertaken by the Company in 2000 (Note 23).

The property and equipment balances related to FPSO vessels and equipment included significant capital additions recorded as part of FPSO upgrade projects completed during 2001 on *Ramform Banff, Petrojarl Foinaven* and *Petrojarl I*. On completion of the *Petrojarl I* FPSO upgrade during the 2001 third quarter, the Company extended the remaining useful life of the FPSO system from 17 years to 27 years. As a result of this change in estimate, future annual depreciation for the *Petrojarl I* FPSO system will be reduced by approximately $5.0 million.

NOTE 8 — Loss Contracts

The Company had $8.2 million in accrued losses related to the *Ramform Banff's* Banff field contract as of December 31, 2001. The Company and its customer under the contract are evaluating alternatives to the current field production scenario, and the Company is unable to reasonably estimate whether and at what level contract losses will be incurred in the future. The Company will re-evaluate the need for loss contract accruals for *Ramform Banff* in future periods, and may be required to accrue additional loss contract accruals. Additionally, the Company has invested $64.6 million in subsea equipment on the Banff field as of December 31, 2001; in the event that the *Ramform Banff* exits the Banff field prior to the contract expiration date (one alternative currently being evaluated), the Company may be required to impair the value of this equipment.

NOTE 9 — UK Leases

The Company has periodically executed UK leases relating to certain seismic and FPSO vessels and/or equipment. Under the leases, the Company sells the applicable assets to UK financial institutions and leases the assets from the institutions under long-term charters that give the Company the option to purchase the assets for a *de minimis* amount at the end of the charter periods. Due to the nature of the charters, the Company capitalizes the assets. The Company uses a substantial portion of the proceeds from the arrangements to legally defease the present value of the Company's future charter obligations for the assets.

The Company had $1.4 billion and $1.5 billion in property and equipment under UK leases at December 31, 2001 and 2000, respectively. In the event of a downgrade of the Company's credit rating to below BBB− and Baa3 by Standard & Poor's and Moody's, respectively, the Company may be required to provide up to £35.7 million (approximately $52.0 million) in collateral or credit support to one or more lessors or other parties under outstanding UK leases.

As of the date of the Awilco acquisition (Note 3), Awilco had $51.0 million in indemnification contingencies recorded for a UK lease on the *Petrojarl Foinaven*, $25.0 million of which was reversed against goodwill in the year of acquisition. During the year ended December 31, 2000, the Company removed the remaining indemnification contingencies and, as a result, recognized the remaining $26.0 million deferred UK lease gain in income.

During 1999, the Company recognized $19.1 million in UK lease gains on delivery of two seismic vessels.

NOTE 10 — Debt

Long-Term Debt, Excluding Revolving Bank Credit Facilities.

Long-term debt, excluding revolving bank credit facilities, consists of the following:

	Year-end weighted average interest rate	December 31, 2001	Year-end weighted average interest rate	December 31, 2000
		(In thousands of dollars)		
Bank loans/public notes:				
Secured	8.3%	$ 119,884	8.3%	$ 130,965
Unsecured	6.7%	1,680,088	7.2%	1,679,360
Other loans:				
Secured	7.5%	97	7.5%	186
Unsecured	13.0%	726	—	—
		1,800,795		1,810,511
Current portion		(237,224)		(11,090)
Long-term portion		$1,563,571		$1,799,421

In March 2000, the Company issued $225.0 million of senior unsecured notes. The notes carried a floating interest rate equal to 0.65% over three-month LIBOR, subject to quarterly adjustment, with interest payable quarterly. The notes matured in March 2002. See "— *Subsequent Event*" below. The net proceeds from this issuance were primarily used to repay indebtedness outstanding under the Company's revolving bank credit facility.

In July 1999, the Company entered into a $350.0 million unsecured bridge facility in order to finance the acquisition of the *Petrojarl Varg* FPSO. The Company then issued $200.0 million of senior unsecured notes for net proceeds of $195.7 million. The net proceeds on these notes, together with the net proceeds from the Company's ADS/share offering (Note 15), were used to repay a $350.0 million bank bridge loan facility as well as indebtedness outstanding under the Company's revolving bank credit facility. The notes carry an interest rate of 8.2%, with interest payable semi-annually, and mature in July 2029. These notes can be redeemed at the Company's option, in whole or in part, at any time, subject to an early redemption premium.

In November 1998, the Company issued $250.0 million of senior unsecured notes. The notes carry an interest rate of 6.3%, with interest payable semi-annually, and mature in November 2003. These notes can be redeemed at the Company's option, in whole or in part, at any time, subject to an early redemption premium. The net proceeds from this issuance were used to repay indebtedness outstanding under the Company's revolving bank credit facilities. In April 1998, the Company issued $450.0 million and $200.0 million of senior unsecured notes. The notes carry interest rates of 7.1% and 6.6%, respectively, with interest payable semi-annually, and mature in March 2028 and March 2008, respectively. These notes can be redeemed at the Company's option, in whole or in part, at any time, subject to an early redemption premium. The net proceeds from this issuance were primarily used to repay indebtedness and certain other obligations that were assumed in the Awilco acquisition as well as indebtedness outstanding under the Company's revolving bank credit facilities.

In April 1997, the Company purchased all of the capital stock of a company that indirectly owns the *Ramform Explorer* and the *Ramform Challenger* seismic vessels. This company has outstanding mortgage notes, in an original principal amount of $165.7 million, secured by the *Ramform Explorer* and the *Ramform Challenger*. The notes carry an interest rate of 8.3%, with interest payable semi-annually, and mature in June 2011. The notes are subject to mandatory redemption through semi-annual sinking fund payments through June 2011. The notes can be redeemed at the holder's option on any sinking fund payment date on or after June 2006, in whole but not in part, subject to an early redemption premium. In March 1997, the Company issued $360.0 million of senior unsecured notes. The notes carry an interest rate of 7.5%, with interest payable semi-annually, and mature in March 2007. These notes can be redeemed at the Company's option, in whole or in part, at any time, subject to an early redemption premium. The net proceeds from this issuance were used, in part, to redeem $125.0 million of senior notes which were scheduled to begin amortizing in 2001.

Revolving Bank Credit Facilities.

In September 1998, the Company entered into an unsecured five-year $430.0 million revolving bank credit facility. The facility matures in 2003 and bears interest at LIBOR, plus a margin of either 0.35% or 0.40% depending on the Company's level of indebtedness, and carries quarterly commitment fees on any unused portion of the facility of 0.18%. The facility is subject to a material adverse change clause regarding the Company's financial condition and to other conditions to borrowing that are customary for such types of facilities.

During the year ended December 31, 2001, the Company borrowed an aggregate of $180.0 million under the $430.0 million revolving bank credit facility, with a weighted average interest rate of 3.1%. The average and maximum borrowings outstanding were $260.8 million and $360.0 million, respectively, and the weighted average interest rate was 2.7% on outstanding balances at December 31, 2001. At December 31, 2001, the Company had $90.0 million available for borrowing under this facility. During the year ended December 31, 2000, the Company borrowed an aggregate of $240.0 million under the revolving facility, with a weighted average interest rate of 7.0%. The average and maximum borrowings outstanding for the year ended December 31, 2000 were $328.3 million and $430.0 million, respectively. At December 31, 2000, the Company had $70.0 million available for borrowing under this facility, with the outstanding balance of $360.0 million carrying a weighted average interest rate of 7.1%.

Short-Term Debt.

During December 2000, the Company entered into a $75.0 million unsecured credit facility with a syndicate of banks. The facility was drawn to $30.0 million, with $27.5 million in average outstanding borrowings, and repaid in full by December 31, 2001. The facility bore interest at LIBOR, plus a margin that escalated from 0.4% to 0.6%; the average interest rate for the year was 4.5%. The facility matured in December 2001 and was fully repaid by this date. At December 31, 2000, there was no indebtedness outstanding under this credit facility.

Additionally during December 2000, the Company entered into a $21.0 million unsecured bank credit facility. The facility bears interest at a LIBOR-based rate plus a margin which can range from 0.63% to 1.4%; the interest rate averaged 4.4% during 2001 and was 2.8% at December 31, 2001 (7.2% for 2000). This facility is payable in installments through 2003, with the payment installments tied to future production from certain oil and gas assets. At December 31, 2001 and 2000, respectively, $20.5 million and $3.3 million was outstanding under this credit facility. This debt will be assumed by Sinochem in the sale of Atlantis (Note 3).

The Company also draws short-term debt with various international banks based on working capital requirements. Short-term debt (excluding the Atlantis facility) was $3.0 million at December 31, 2000. There was no such short-term debt at December 31, 2001. Average and maximum short-term debt balances for the year ended December 31, 2001 were $19.2 million and $40.0 million, respectively, and for 2000 were $18.3 million and $46.8 million, respectively. The associated weighted average interest rate for the year ended December 31, 2001 was 4.4%. The associated weighted average interest rates as of and for the year ended December 31, 2000 were 8.3% and 7.1%, respectively.

Maturities.

Aggregate maturities of the Company's debt, as of December 31, 2001 are as follows:

December 31,	(In thousands of dollars)
2002	$ 257,724
2003	598,958
2004	10,200
2005	10,990
2006	11,920
Thereafter	1,271,503
Total	$2,161,295

Covenants.

In addition to customary representations and warranties, certain of the Company's debt agreements and UK lease agreements (Note 9) include covenants relating to the maintenance of minimum net worth levels, interest coverage ratios and debt leverage ratios. Additionally, certain covenants restrict certain types of indebtedness, such as subsidiary indebtedness, liens on assets, cash dividends and sale/leaseback transactions. The Company was in compliance with all such covenants at December 31, 2001.

Pledged Assets.

Seismic vessels and related equipment carrying a book value of $128.5 million and $153.9 million at December 31, 2001 and 2000, respectively, are pledged as security on certain of the Company's indebtedness, as described above.

Letters Of Credit And Guarantees.

The Company had aggregate outstanding letters of credit and related types of guarantees, not reflected in the accompanying consolidated financial statements, of $62.1 million and $59.7 million at December 31, 2001 and 2000, respectively.

Subsequent Event.

In March 2002, the Company entered into a $250.0 million short-term credit facility, which was amended and restated in May 2002. The facility will mature at the earlier of August 31, 2003, or June 16, 2003 if the Veritas transaction (Note 3) has been terminated prior to that date. The Company must make a mandatory prepayment of $175.0 million from the future proceeds of any Atlantis sale (Note 3). The credit facility carries an initial interest rate equal to LIBOR plus a margin of 0.65%, which margin escalates to 1.0% on June 1, 2002, to 1.5% on August 1, 2002, and to 4.5% on October 1, 2002 until maturity. In the event that either Standard & Poor's or Moody's downgrades the Company's credit rating below BBB– or Baa3, respectively, prior to October 1, 2002, the margin will escalate to 4.5% at the time such downgrade is issued. If any amounts are outstanding under the credit facility at July 31, 2002 (or earlier in the event of termination of the Veritas transaction prior to July 31, 2002), the Company is obligated to use its best endeavors to arrange financing in order to repay such amounts prior to maturity. Additionally, if the credit facility remains outstanding at July 1, 2002, the Company will be required to limit any additional cumulative capital expenditures and multi-client investments to a maximum of $280.0 million for the period from July 1, 2002 through the maturity date of the credit facility. The net proceeds from this credit facility were used to repay the $225.0 million of senior unsecured notes which matured in March 2002 and for general corporate purposes.

NOTE 11 — Preferred Securities

Guaranteed Preferred Beneficial Interest in Junior Subordinated Debt Securities.

In June 1999, the Company entered into a transaction with PGS Trust I (the "Trust"), a newly formed Delaware statutory business trust and wholly owned finance subsidiary of the Company, whereby the Trust issued $4.4 million of common securities to a US subsidiary of the Company, issued $143.8 million of trust preferred securities to the public and used the proceeds to purchase $148.2 million of junior subordinated debt securities (the "junior debt securities") from the Company. The Company used the $138.9 million in net proceeds received to repay indebtedness outstanding under its revolving bank credit facility.

The trust preferred securities consist of 5,750,000 securities which carry a $25 per security liquidation value and mature on June 30, 2039. The trust preferred securities represent undivided beneficial interests in the assets of the Trust, but do not carry general voting rights. The trust preferred securities carry a 9.625% distribution rate, payable quarterly. The Company's junior debt securities bear an interest rate of 9.625%, payable quarterly, and mature on June 30, 2039. Absent any event of default, the Company can defer interest payments throughout the life of the junior debt securities for up to 20 consecutive quarterly periods, subject to the maturity date and limitations on certain other transactions during any interest deferral period. In the event that the Company defers its interest payments on the junior debt securities, the Trust will defer its distributions on the trust preferred securities.

The Company may redeem the junior debt securities, in whole or in part, at any time on or after June 2004. Prior to this time, the Company may redeem all junior debt securities in the event of certain changes in tax or investment company law. In the event that the Company redeems any of its junior debt securities prior to maturity, the Trust must use the redemption proceeds to redeem, on a pro rata basis, an equivalent amount of its trust preferred securities and common securities.

The Company has guaranteed, on a subordinated basis, the trust preferred securities' distributions to the extent that the Trust has cash available for those distributions. In the event that the Trust does not have such cash, holders of the trust preferred securities may directly sue the Company or seek other remedies against the Company. When considered together, the declaration of trust of the Trust, the junior debt securities, the indenture under which the junior debt securities were issued and the Company's guarantee related to the trust preferred securities constitute a full and unconditional guarantee by the Company of the Trust's obligations under the trust preferred securities.

Since a US subsidiary of the Company holds all of the Trust's common securities, the Company consolidates the Trust. The Trust serves solely as a finance subsidiary, having no independent assets or operations. The sole assets of the Trust are the junior debt securities issued by the Company, which have an aggregate principal amount equal to the aggregate liquidation amount of the trust preferred securities and the common securities issued by the Trust. The Trust held the full $148.2 million issue of the junior debt securities at December 31, 2001 and 2000. The $141.0 million carrying value of the trust preferred securities at December 31, 2001 reflects issuance costs; the carrying value will accrete to the $143.8 million redemption value by the first date at which the Company can redeem the trust preferred securities. During the years ended December 31, 2001, 2000 and 1999, the Company recorded $14.9 million, $14.8 million and $7.7 million in financial expense for the minority interest in income of subsidiaries due on the trust preferred securities.

Mandatorily Redeemable Cumulative Preferred Subsidiary Securities.

In April 2001, the Company entered into a securitization transaction related to a portion of its multi-client marine seismic library. Pursuant to this transaction, the Company sold the portion of its multi-client marine seismic library to a bankruptcy remote, special purpose subsidiary incorporated in Jersey, in exchange for net proceeds of $234.3 million and 100% of the common securities of the Jersey subsidiary. The Jersey subsidiary funded the $234.3 million in proceeds through the issuance of $240.0 million in mandatorily redeemable preferred securities to a third party investor (a commercial paper conduit). The Company used the net proceeds primarily to repay indebtedness outstanding under its revolving bank credit facility.

The preferred securities issued by the special purpose subsidiary are redeemed as applicable multi-client library sales occur, from a portion of the sales proceeds. The preferred securities carry a floating preferred dividend rate based on commercial paper rates plus a margin approximating 0.60%. Dividends are cumulative and payable quarterly. During the year ended December 31, 2001, $77.3 million of the preferred securities were redeemed and the Company recognized $6.0 million in minority interest expense on the preferred securities. The preferred shares may be redeemed at any time for an amount equal to the outstanding preferred securities, accrued preferred dividends and related expenses. The preferred securities will be redeemed, and the preferred dividends will be paid, solely through the proceeds received on future sales from the portion of the multi-client library sold to the Jersey subsidiary. The Company also has the ability, under certain circumstances, to repurchase portions of such multi-client library. Upon the occurrence of certain events, the preferred securities holder has the right to require full and immediate redemption of the preferred securities. Additionally, under certain circumstances that the Company believes are remote, the preferred securities holder has the ability to gain voting control of the Jersey subsidiary. However, the Company has various means to prevent such a change of control including, but not limited to, redemption of the preferred securities, preferred securities call options and options to purchase the data.

In the event that the Company's credit ratings are downgraded to below BB+ or Ba1 by Standard & Poor's or Moody's, respectively, the Company will be required to increase by 30% its quarterly redemption of the preferred securities. If those credit ratings remain for a certain period of time or deteriorate below BB- or Ba3, respectively, the Company must increase the quarterly redemption of the preferred securities to an amount equal to 100% of the actual revenue recognized from the licensing of the data held by the subsidiary.

The preferred securities do not entitle the holder to any substantive participation rights. Since the Company holds all of the Jersey entity's common securities, the Company consolidates the Jersey entity and reflects the preferred securities at the minimum redemption value less issuance costs.

The minimum required redemptions (exclusive of the effects of issuance costs) on the preferred securities are summarized as follows:

December 31,	(In thousands of dollars)
2002	$ 72,000
2003	46,080
2004	32,640
2005	17,880
2006	720
	$169,320

NOTE 12 — Commitments And Contingencies

Leases.

The Company has operating lease commitments expiring at various dates through 2014. The Company also has capital lease commitments for seismic vessels and equipment expiring at various dates through 2008. Future minimum payments related to non-cancelable operating and capital leases, with lease terms in excess of one year, existing at December 31, 2001 are as follows:

December 31,	Operating leases	Capital leases
	(In thousands of dollars)	
2002	$111,442	$13,141
2003	66,753	11,171
2004	42,726	9,187
2005	33,498	8,824
2006	21,227	3,269
Thereafter	21,881	15,274
Total	$297,527	60,866
Imputed interest		(9,250)
Net present value		51,616
Current portion		(9,933)
Long-term portion		$41,683

Future minimum payments related to non-cancelable operating leases reflect $21.4 million and $12.0 million in sub-lease income for 2002 and 2003, respectively, related to a time-charter of two FPSO shuttle tankers to a third party.

The future minimum payments under the Company's operating leases relate to the Company's operations as follows:

	December 31, (In thousands of dollars)
Marine seismic and support vessels	$ 46,630
FPSO shuttle tankers	58,105
Land seismic equipment	63,546
Operations computer equipment	51,287
Buildings	67,745
Fixtures, furniture and fittings	10,214
Total	$297,527

Rental expense for operating leases, including leases with terms of less than one year, was $123.1 million, $137.7 million and $133.3 million for the years ended December 31, 2001, 2000 and 1999, respectively. Rental expense for operating leases for the year ended December 31, 2001 reflected $13.8 million in sub-lease income related to a time charter of two FPSO shuttle tankers to a third party.

Certain operating leases for land seismic equipment contain extension options that the Company may exercise in 2002. If these options are exercised, the leases will be classified as capital leases at that time.

Other.

The Company has contingent liabilities resulting from litigation, other claims and commitments incidental to the ordinary course of business. Management believes that the probable resolution of such contingencies will not materially affect the financial position, results of operations or cash flows of the Company.

NOTE 13 — Income Taxes

The provision (benefit) for income taxes consists of the following:

	Years ended December 31,		
	2001	2000	1999
	(In thousands of dollars)		
Current taxes:			
Norwegian	$ 4,179	$ 1,077	$ —
Foreign	9,510	4,588	3,492
Deferred taxes:			
Norwegian	(11,031)	(122,847)	(38,792)
Foreign	33,145	(18,153)	(29,925)
Total	$ 35,803	$(135,335)	$(65,225)

The net expense (benefit) for the years ended December 31, 2001 and 2000 includes $65.9 million and $3.8 million, respectively, in valuation allowance charges related to deferred tax assets.

The Company has evaluated the need for valuation allowances for its deferred tax assets by considering the evidence regarding the ultimate realization of those recorded assets. The Company has recorded valuation allowances for 100% of net deferred tax assets in jurisdictions other than Norway due to cumulative losses in recent years in those jurisdictions. Because of these cumulative losses, the Company has concluded that it was not more likely than not that the net deferred tax assets in those jurisdictions would be realized and has recognized the valuation allowances accordingly. However, the Company believes that it has valid tax planning strategies that may ultimately be successful in utilizing those net deferred tax assets. To the extent that the Company continues to generate non-Norwegian deferred tax assets, the Company will continue to provide 100% valuation allowances on those assets. With regard to Norwegian net deferred tax assets, the Company has concluded that a valuation allowance is not required based on management's expectations about the generation of taxable income in Norway from contracts that are currently in effect. The Company intends to monitor deferred tax assets generated in Norway to determine whether taxable income will be sufficient to realize the assets. If the Company determines that it is more likely than not that the Norwegian deferred tax assets will not be realized, a valuation allowance will be provided on the excess of the deferred tax assets over taxable income.

The net expense (benefit) for the years ended December 31, 2001 and 1999 includes $14.4 million and $15.3 million, respectively, related to the resolution of uncertainties regarding outstanding tax issues.

The net benefit for the years ended December 31, 2000 and 1999 includes ($2.6) million and ($8.1) million, respectively, in benefit related to the cumulative effect of accounting changes.

The provision (benefit) for income taxes differs from the amounts computed when applying the Norwegian statutory tax rate to income (loss) before income taxes (inclusive of gross cumulative effect of accounting change) as a result of the following:

	Years ended December 31,		
	2001	2000	1999
	(In thousands of dollars)		
Income (loss) before income taxes:			
Norwegian	$(47,570)	$(337,706)	$(52,487)
Foreign	87,826	(9,110)	(46,554)
Total	40,256	(346,816))	(99,041)
Norwegian statutory rate	28%	28%	28%
Provision (benefit) for income taxes at the statutory rate	11,272	(97,108)	(27,731)
Increase (reduction) in income taxes from:			
Foreign earnings taxed at other than statutory rate	(40,695)	(11,733)	(34,503)
Prior year tax assessment	(696)	(1,177)	—
Unrealized exchange losses	(700)	(33,147)	(8,068)
Permanent items	1,590	2,010	6,166
Deferred tax assets valuation allowance	65,912	3,792	—
Other	(880)	2,028	(1,089)
Provision (benefit) for income taxes	$ 35,803	$(135,335)	$(65,225)

The temporary differences which generate the Company's deferred tax assets and liabilities are summarized as follows:

	December 31,	
	2001	2000
	(In thousands of dollars)	
Property and equipment and long-term assets	$ 76,408	$ 92,979
Tax losses carried forward	(215,817)	(143,502)
Deferred gains	2,167	3,281
Tax and book revenue and cost of sales	(16,974)	(75,582)
Tax credits	(3,657)	(3,839)
Expenses deductible when paid	(14,159)	(18,412)
Other temporary differences	(2,689)	(1,179)
Total before valuation allowance	(174,721)	(146,254)
Deferred tax assets valuation allowance	69,704	3,792
Total	(105,017)	(142,462)
Deferred tax (asset) — Norwegian	(110,284)	(96,175)
Deferred tax (asset) liability — Foreign	5,267	(46,287)
Total	$(105,017)	$(142,462)

Norwegian tax losses of $576.1 million expire at various dates from 2003 through 2011. Tax losses in the UK, Singapore and Australia totaling $141.6 million carry forward indefinitely. US tax losses of $27.2 million and $10.2 million expire in 2019 and 2021, respectively. US minimum tax credits of $4.0 million carry forward indefinitely.

It is the Company's current policy that unremitted earnings of certain international operations, which reflect full provision for non-Norwegian income taxes, have no provision for Norwegian taxes, as these earnings are expected to be reinvested indefinitely. The Company has not calculated the tax effect associated with these unremitted earnings as it is not practicable to so do.

The $15.9 million tax effect related to the reversal of $56.8 million in contingent liability and goodwill recorded in the acquisition of the FPSO operations of Awilco ASA was credited directly against deferred tax assets during the year ended December 31, 2001.

The tax effect of deductible share issue costs, which have been credited directly to shareholders' equity, was approximately $0.7 million for the year ended December 31, 1999. There were no such effects for the years ended December 31, 2001 and 2000.

NOTE 14 — Earnings Per Share

Basic earnings per share and diluted earnings per share for the years ended December 31, 2000 and 1999 were equal, since both basic and diluted earnings per share were calculated using the weighted average shares outstanding for the periods due to the Company's losses. The difference between the Company's 2001 basic earnings per share and diluted earnings per share calculations is reconciled as follows:

	Year ended December 31, 2001		
	Income available to shareholders	Weighted average shares	Per share amount
	(In thousands of dollars, except for share data)		
Basic earnings per share	$4,453	102,768,283	$0.04
Share equivalents — options		19,772	
Diluted earnings per share	$4,453	102,788,055	$0.04

Certain options that would have been anti-dilutive to earnings per share have been excluded from share equivalents.

NOTE 15 — Shareholders' Equity

The retained earnings of the Company, together with additional paid-in capital, constitute the restricted portion of shareholders' equity and are only distributable with shareholder approval. Additionally, the terms of certain of the Company's debt agreements restrict dividend payments. Dividends, if declared, are payable in Norwegian kroner.

In July and early August 1999, the Company issued an aggregate of 11,159,500 shares and ADSs in an international public offering. Net proceeds of $214.1 million were used, together with the net proceeds from $200.0 million in senior notes, to repay the bank bridge loan facility drawn to finance the *Petrojarl Varg* acquisition as well as to repay indebtedness outstanding under the Company's revolving bank credit facility (Note 10).

NOTE 16 — Share-Based Compensation

At December 31, 2001, the Company had share-based compensation plans for key employees and directors. The employee and director plans authorize the Company to award options to purchase shares prior to the year 2002. As of December 31, 2001, options to purchase 9,664,100 and 500,000 shares, respectively, remained under these authorizations (as defined under Norwegian law). Options granted from the plans' inceptions to December 31, 2001 totaled 16,462,404 and 816,800 shares, respectively, some of which have been exercised or were otherwise no longer outstanding at December 31, 2001.

Under the plans, the exercise price of each award equals the market price of the Company's shares on the date of grant. The vesting period for the granted options ranges from approximately three years to approximately three and one-half years, provided that the recipient is still employed by the Company on the vesting date. Once vested, the recipient generally has two years within which to exercise the options; for options granted in June 2000 and forward, the exercise period is generally three years. Certain option awards are exercisable only on a specific date. The exercise prices for options granted and outstanding at

December 31, 2001 under both the employee and director option plans ranged from NOK160 to NOK230 for 2,630,000 options and from NOK103 to NOK150 for 6,005,404 options, with weighted average exercise prices of NOK163 and NOK133 for these respective ranges. The weighted average remaining contractual lives of outstanding options approximated eight months and 37 months, respectively, for the option ranges described above.

Awards made under the plans become immediately exercisable upon the occurrence of a change in control of the Company, generally defined to include certain changes in the board of directors, the acquisition of a certain percentage of outstanding shares, certain merger transactions and certain dispositions of all or substantially all of the assets of the Company. Under the terms of the Company's pending transaction with Veritas (Note 3), each Company optionee will be offered an option to acquire Caymanco shares in exchange for the Company options. For each option so exchanged, the options will be exercisable under the same terms and conditions as the Company's current terms and conditions, except that each option will be exercisable for a whole number of Caymanco shares equal to the number of Company shares originally subject to the option multiplied by the exchange ratio, and the option price will be equal to the Company's original option price divided by the exchange ratio.

The Company applies Accounting Principles Board Opinion 25, "Accounting for Stock Issued to Employees," in accounting for its share-based compensation plans and has adopted the disclosure-only provisions of SFAS No. 123, "Accounting for Stock-Based Compensation." Accordingly, no compensation cost has been recognized under these plans. Had the compensation cost for the Company's share-based compensation plans been determined based on the fair values of the options awarded at the grant dates, consistent with the provisions of SFAS No. 123, the Company's net income (loss) and earnings (loss) per share would have been reduced to the pro forma amounts indicated below:

	Years ended December 31,		
	2001	2000	1999
	(In thousands of dollars, except for share data)		
Net income (loss):			
As reported	$ 4,453	$(211,515)	$(33,816)
Pro forma	(6,177)	(224,677)	(47,396)
Basic earnings (loss) per share:			
As reported	$ 0.04	$ (2.07)	$ (0.36)
Pro forma	(0.06)	(2.20)	(0.50)
Diluted earnings (loss) per share:			
As reported	$ 0.04	$ (2.07)	$ (0.36)
Pro forma	(0.06)	(2.20)	(0.50)

The fair value of each option award on the grant date is estimated using the Black-Scholes option-pricing model with the following weighted average assumptions used for grants in 2001, 2000 and 1999, respectively: expected volatility of 55%, 53% and 52%; risk-free interest rates of 4.23%, 6.52% and 5.8%; and expected lives of 3.4, 4.1 and 3.4 years. (Dividend yield is assumed to be zero for all plan grants.)

The effects of applying the fair market value method of accounting in the above pro forma disclosure may not be indicative of future amounts since additional awards in future years are anticipated.

A summary of the status of the Company's share-based compensation plans as of December 31, 2001, 2000 and 1999, and changes during the years then ended, is summarized as follows:

	December 31,					
	2001		2000		1999	
	Options	Weighted average exercise price	Options	Weighted average exercise price	Options	Weighted average exercise price
	(In thousands of options)					
Outstanding at beginning of year	10,690.8	NOK135	7,691.2	NOK127	8,388.0	NOK120
Granted	120.0	NOK103	3,926.0	NOK143	335.8	NOK130
Exercised	(98.0)	NOK 75	(738.4)	NOK 90	(909.6)	NOK 68
Forfeited	(2,077.4)	NOK108	(188.0)	NOK140	(123.0)	NOK126
Outstanding at end of year	8,635.4	NOK142	10,690.8	NOK135	7,691.2	NOK127
Weighted average fair value of options granted during year		NOK 44		NOK 69		NOK 56

As of December 31, 2001, 4,611,404 of the outstanding options were vested with a weighted average exercise price of NOK143. Exercisable options at December 31, 2000 and 1999 were 4,762,000 options at a weighted average exercise price of NOK136 and 2,308,000 options at a weighted average exercise price of NOK93, respectively.

NOTE 17 — Derivative Financial Instruments And Risk Management

Notional Amounts And Credit Exposure Of Derivative Financial Instruments.

The notional amounts of the derivative financial instruments summarized below do not reflect the values exchanged by the parties and, thus, are not a measure of the Company's exposure. The amounts ultimately exchanged are calculated on the basis of the notional amounts and the other terms of the respective derivative financial instruments.

Foreign Currency Exchange Risk Management.

The Company periodically enters into forward exchange contracts and option contracts to hedge against foreign currency exchange risks associated with certain firm commitments and transactions related to property and equipment. The Company is most sensitive to changes in the Norwegian kroner to US dollar exchange rates. At December 31, 2001, the Company had approximately $15.0 million of notional forward foreign currency exchange contracts outstanding to hedge short-term Norwegian kroner and US dollar transactions; these contracts had a *de minimis* aggregate fair value. Also at December 31, 2001, the Company had approximately $17.2 million of notional forward foreign currency exchange contracts outstanding to hedge US dollar and Brunei dollar transactions during 2002; these contracts had an aggregate fair value of approximately $0.9 million. There were no such foreign currency exchange contracts outstanding at December 31, 2000.

During 1998, the Company entered into forward foreign currency exchange contracts known as tax equalization swaps ("TES") related to its $360.0 million of senior unsecured notes and its mortgage notes (Note 9). During 1999, the Company entered into additional TES contracts related to its remaining $1.1 billion in unsecured senior notes (Note 8) and its trust preferred securities (Note 9). These contracts effectively hedge the risk related to the cash tax effect of unrealized exchange rate fluctuations between the Norwegian kroner and the US dollar related to the Company's US dollar-denominated debt and trust preferred securities, where such foreign currency exchange gains and losses are taxable and deductible, respectively, in each period on a mark-to-market basis for Norwegian statutory tax purposes. Although these contracts are economic hedges, they do not qualify for hedge accounting treatment. As a result, the periodic adjustments necessary to reflect the fair value of these instruments in the Company's balance sheet are recognized immediately in the Company's results of operations. The contracts' aggregate notional values at December 31, 2001 and 2000 were $492.8 million and $682.8 million, respectively. The TES contracts terminate at various dates through December 2003 and provide for interim settlements between the Company and the counterparty each December 30. At December 31, 2001, the Company's interim settlement position was an $11.4 million liability, and the Company carried an additional liability of $32.5 million to reflect the fair value of the contracts. At December 31, 2000, the Company's interim settlement position was a $65.2 million liability (which was paid during 2001), and the Company carried an additional liability of $26.0 million to reflect the fair value of the contracts. Results of operations for the years ended December 31, 2001, 2000 and 1999 included $18.0 million, $61.4 million and $32.8 million, respectively, of fair value expense (in other expense, net) for these contracts, and tax benefits of $5.7, $50.3 million and $14.8 million, respectively.

In April, 2002, the Company terminated three TES contracts with aggregate notional values of $160.0 million. The Company did not recognize any significant impact in its results of operations as a result of the termination.

Fair Values Of Financial Instruments.

The carrying amounts of cash and cash equivalents, accounts receivable, other current assets, accounts payable and accrued expenses and other current liabilities approximate their respective fair values because of the short maturities of those instruments. It is not practicable to estimate the value for the Company's mandatorily redeemable cumulative preferred subsidiary securities (Note 4), as the future redemptions do not have determinable dates. The carrying amounts and the estimated fair values of the Company's other financial instruments are summarized as follows:

	December 31,			
	2001		2000	
	Carrying amounts	Fair values	Carrying amounts	Fair values
	(In thousands of dollars)			
Long-term debt, including current portion	$2,161,310	$1,944,438	$2,170,511	$2,084,703
Trust preferred securities	141,000	136,505	140,050	120,750
TES contracts	43,909	43,909	91,163	91,163

The following methods and assumptions were used to estimate the fair values of each class of financial instrument:

Long-term Debt and Trust Preferred Securities — The carrying amounts of the Company's revolving bank credit facility approximate their fair values. The fair values of the Company's other long-term debt instruments and trust preferred securities are estimated using quotes obtained from dealers in such financial instruments.

TES Contracts — The fair values of the Company's TES contracts are estimated based on periodic valuations which are performed by a third party and, at year-end, the annual settlement.

NOTE 18 — Retirement Plans

The Company sponsors defined benefit pension plans for substantially all of its Norwegian and UK employees, with eligibility determined by certain period-of-service requirements. These plans are generally funded through contributions to insurance companies. It is the Company's general practice to fund amounts to these defined benefit plans which are sufficient to meet the applicable statutory requirements.

Reconciliations of the plans' aggregate projected benefit obligations and fair values of assets are summarized as follows:

	December 31, 2001	December 31, 2000
	(in thousands of dollars)	
Change in projected benefit obligations:		
Projected benefit obligations at beginning of year	$40,304	$33,886
Service cost	7,818	6,641
Interest cost	2,693	2,042
Employee contributions	1,118	1,018
Amendments	4,395	1,061
Actuarial (gain)/loss, net	(7,279)	505
Benefits paid	(1,760)	(1,385)
Exchange rate effects	(1,178)	(3,464)
Projected benefit obligations at end of year	$46,111	$40,304
Change in plan assets:		
Fair value of plan assets at beginning of year	$29,419	$25,149
Return on plan assets	(2,052)	1,515
Employer contributions	6,143	4,037
Employee contributions	1,118	1,018
Amendments	2,559	1,639
Benefits paid	(1,760)	(1,385)
Exchange rate effects	(856)	(2,554)
Fair value of plan assets at end of year	$34,571	$29,419

Plans with accumulated benefit obligations in excess of assets had aggregate accumulated benefit obligations of $24.7 million and $2.7 million and aggregate assets of $22.8 million and $2.2 million at December 31, 2001 and 2000, respectively.

The aggregate funded status of the plans and amounts recognized in the Company's balance sheets are summarized as follows:

	December 31, 2001	December 31, 2000
	(in thousands of dollars)	
Funded status	$(11,606)	$(10,885)
Unrecognized actuarial loss	302	2,442
Unrecognized prior service cost	22	25
Unrecognized transition obligation	132	138
Additional minimum liability	(58)	—
Net amount recognized as accrued pension cost	$(11,208)	$ (8,280)

The projected benefit obligations have been calculated using the projected unit credit method. The weighted average discount rate used was 6% for the years ended December 31, 2001 and 2000 and 7% for the year ended December 31, 1999. The weighted average expected return on plan assets was 8% for each of the three years in the period ended December 31, 2001. The weighted average rate of benefits increase was 4% for the year ended December 31, 2001 and 5% for each of the years ended December 31, 2000 and 1999.

The aggregate net periodic pension cost for the Company's defined benefit pension plans is summarized as follows:

	Years ended December 31,		
	2001	2000	1999
	(in thousands of dollars)		
Components of net periodic pension cost:			
Service cost	$ 7,818	$ 6,641	$6,602
Interest cost	2,693	2,042	1,674
Expected return on plan assets	(2,591)	(2,039)	(1,547)
Amortization of actuarial loss	26	17	176
Amortization of prior service cost	3	2	3
Amortization of transition obligation	14	14	17
Net periodic pension cost	$ 7,963	$ 6,677	$6,925

Substantially all employees not eligible for coverage under the defined benefit plans are eligible to participate in pension plans in accordance with local industrial, tax and social regulations. All of these plans are considered defined contribution plans. Under the Company's US defined contribution plan, essentially all US employees are eligible to participate upon completion of certain period-of-service requirements. The plan allows eligible employees to contribute up to 15% of compensation, subject to IRS and plan limitations, on a pre-tax basis. Employee pre-tax contributions are matched by the Company up to 6% of compensation, with a 2001 statutory employee contribution cap of $10,500. All contributions vest as made. The annual employer matching contribution recognized by the Company related to the plan was $1.2 million, $1.2 million and $0.7 million for the years ended December 31, 2001, 2000 and 1999, respectively. Contributions to the plan by employees for these periods were $3.7 million, $3.8 million and $2.3 million, respectively. Aggregate employer and employee contributions under the Company's other plans for the years ended December 31, 2001, 2000 and 1999 totaled $4.4 million and $2.7 million (2001), $5.4 million and $2.6 million (2000) and $5.9 million and $2.5 million (1999).

NOTE 19 — Related Party Transactions

At December 31, 2001, 2000 and 1999, the Company owned 50% of the shares in Geo Explorer AS and had chartered a vessel from that company during these years. The Company also held 50% of the shares in Walther Hervig AS and chartered three vessels from that company in 2001, 2000 and 1999. Total lease expense recognized by the Company for 2001, 2000 and 1999 on these vessels was $9.2 million, $8.5 million and $13.9 million, respectively. Remaining lease commitments to these investees are reflected in the Company's consolidated lease commitments (Note 12).

At December 31, 2001 and 2000, the Company held 50% of the shares in Calibre Seismic Company ("CSC"), one of the companies through which the Company markets its seismic data. The Company had $6.7 million and $11.9 million in investment in CSC at December 31, 2001 and 2000, respectively, representing Company-funded costs of seismic data acquisition projects performed for CSC from 1991 to 1995.

Two members of the Company's senior management each have been granted options on 50,000 shares in an oil and gas company in exchange for their services as directors. The Company contributed access to its multi-client library and a commitment for future geophysical services in exchange for an equity interest in this oil and gas company. The Company accounts for its investment in this venture under the equity method of accounting.

NOTE 20 — Segment and Geographic Information

The Company's services are provided by various separately managed business units. These business units have been aggregated into two reportable segments, geophysical services and production services, based on shared economic characteristics and similar long-term performance. The Company believes that the business units within each reportable segment are strategically and/or operationally interrelated and provide similar services to the same customer base. The Company's senior management regularly reviews the operating results of these two reportable segments in resource allocation decisions and performance assessment. The geophysical services segment primarily acquires, processes and markets 3D, 4D and multi-component marine and onshore seismic data and provides 4D and multi-component reservoir interpretation, characterization and monitoring services. The production services segment owns and/or operates FPSOs and other offshore production facilities and provides production management services for oil and gas companies. The principal markets for the Company's production services segment are the UK and Norway, while the geophysical services segment serves a worldwide market. Customers for both segments are primarily composed of major multi-national, independent and national or state-owned oil companies. The accounting policies for the segments are the same as those described in Note 2. The Company's corporate overhead has been allocated to the segments based on percentage of revenue. Affiliated sales are made at prices that approximate market value.

Information by segment is summarized as follows:

Years ended December 31,	Geophysical Services	Production Services	Elimination of affiliated sales	Total
		(In thousands of dollars)		
Revenue, unaffiliated companies:				
2001	$ 594,507	$ 458,121	—	$1,052,628
2000	462,604	450,878	—	913,482
1999	419,854	368,306	—	788,160
Revenue, includes affiliates:				
2001	$ 596,053	$ 458,121	$ (1,546)	$1,052,628
2000	472,570	452,095	(11,183)	913,482
1999	426,363	369,166	(7,369)	788,160
Operating profit (loss):				
2001	$ 121,670	$ 84,308	—	$ 205,978
2000	(257,415)	25,921	—	(231,494)
1999	(23,396)	62,468	—	39,072
Assets:				
2001	$2,115,647	$2,187,159	—	$4,302,806
2000	2,275,565	2,003,141	—	4,278,706
Depreciation and amortization:				
2001	$ 267,600	$ 66,906	—	$ 334,506
2000	208,433	55,156	—	263,589
1999	189,335	49,241	—	238,576
Unusual items:				
2001	$ (113,445)	$ 7,533	—	$ (105,912)
2000	288,595	77,185	—	365,780
1999	82,855	7,000	—	89,855
Interest expense, net:				
2001	$ 54,174	$ 68,070	—	$ 122,244
2000	57,191	62,591	—	119,782
1999	40,622	47,636	—	88,258
Additions to long-lived tangible assets:				
2001	$ 256,280	$ 213,509	—	$ 469,789
2000	285,750	94,008	—	379,758
1999	554,972	451,615	—	1,006,587

Years ended December 31,	Geophysical Services	Production Services	Elimination of affiliated sales	Total
		(In thousands of dollars)		
Investment in equity method investees:				
2001	$ 14,590	$ 6,783	—	$ 21,373
2000	16,566	2,902	—	19,468

Since the Company provides services to the oil and gas industry worldwide, a substantial portion of the Company's property and equipment is mobile, and the respective locations at the end of the period (as listed in the table below, together with multi-client library and oil and gas assets) are not necessarily indicative of the earnings of the related property and equipment during the period. The geographic classification of income statement amounts listed below is based upon location of performance or, in the case of multi-client seismic data sales, the area where the survey was physically located.

Information by geographic region is summarized as follows:

Years ended December 31,	Americas	UK	Norway	Asia/Pacific	Africa	Middle East/ Other	Elimination of affiliated sales	Total
				(In thousands of dollars)				
Revenue, unaffiliated companies:								
2001	$ 172,780	$ 384,742	$189,939	$148,345	$ 75,553	$ 81,269	—	$1,052,628
2000	144,124	402,735	155,561	115,130	39,029	56,903	—	913,482
1999	152,088	381,452	118,788	69,718	61,535	4,579	—	788,160
Revenue, includes affiliates:								
2001	$ 174,088	$ 387,113	$192,116	$148,562	$ 75,553	$ 81,269	$ (6,073)	$1,052,628
2000	150,688	411,417	166,764	117,716	39,029	68,134	(40,266)	913,482
1999	168,237	389,407	138,081	70,942	61,535	8,670	(48,712)	788,160
Operating profit (loss):								
2001	$ (9,402)	$ 50,781	$154,446	$ 5,778	$ 8,480	$ (4,105)	—	$ 205,978
2000	(161,179)	(6,782)	(2,410)	(39,020)	(8,241)	(13,862)	—	(231,494)
1999	(33,707)	96,098	2,843	(30,053)	4,549	(658)	—	39,072
Long-lived tangible assets:								
2001	$ 628,662	$1,647,819	$777,995	$139,618	$103,885	$ 73,375	—	$3,371,354
2000	538,900	2,208,465	180,923	120,823	100,177	65,266	—	3,214,554
Depreciation and amortization:								
2001	$ 95,630	$ 111,733	$ 60,326	$ 33,696	$ 29,588	$ 3,533	—	$ 334,506
2000	77,005	98,448	39,319	27,903	16,266	4,648	—	263,589
1999	68,530	93,579	30,489	26,331	17,552	2,095	—	238,576
Capital expenditures:								
2001	$ 5,258	$ 84,760	$148,915	$ 208	$ 312	$ 170	—	$ 239,623
2000	7,111	46,443	46,824	360	155	14,324	—	115,217
1999	4,812	608,054	31,320	82	282	23,319	—	667,869

Export sales from Norway to unaffiliated customers did not exceed 10% of gross revenue for the years ended December 31, 2001, 2000 and 1999.

For the years ended December 31, 2001 and 2000, two customers accounted for 14% and 11% of our revenue (2001) and 16% and 11% of our revenue (2000); both customers utilized both geophysical and production services. For the year ended December 31, 1999, the Company's largest customer accounted for approximately 16% of the Company's revenue, all of which was production services revenue.

NOTE 21 — Supplemental Cash Flow Information

Cash paid during the year includes payments for:

	Years ended December 31,		
	2001	2000	1999
	(In thousands of dollars)		
Interest, net of capitalized interest	$126,705	$120,076	$83,957
Minority interest on trust preferred securities (Note 11) / multi-client library securitization (Note 11)	19,310	13,835	7,225
Income taxes	1,257	4,505	7,790

The Company entered into capital lease agreements for new equipment aggregating $41.8 million, $8.5 million and $3.5 million during the years ended December 31, 2001, 2000 and 1999, respectively.

NOTE 22 — Financial Expense, Net

Financial expense, net, includes the following:

	Years ended December 31,		
	2001	2000	1999
	(In thousands of dollars)		
Interest income	$ 5,817	$ 5,076	$ 4,494
Interest expense	(128,061)	(124,858)	(92,752)
Minority interest on trust preferred securities (Note 11)	(14,935)	(14,817)	(7,711)
Minority interest on multi-client library securitization securities (Note 11)	(6,000)	—	—
Financial expense, net	$(143,179)	$(134,599)	$ (95,969)

NOTE 23 — Unusual Items

Unusual items for the year ended December 31, 2001 include a $138.5 million gain on the sale of the Company's data management business (Note 3). Additionally, unusual items include $13.2 million in multi-client library impairment charges, primarily related to onshore surveys in natural gas prone areas of the US, and $19.4 million in litigation costs and reorganization costs (including severance for former members of senior management).

During the year ended December 31, 2000, the Company's geophysical services did not recover as expected, despite the significant, sustained improvement in oil and gas prices. As a result of these market conditions, the Company recorded $166.5 million in impairment charges against its multi-client library; $148.8 million in impairment charges against property, equipment and other assets; and $50.5 million in contract losses. These charges included $77.2 million related to the *Ramform Banff* and certain other production assets.

During the year ended December 31, 1999, the Company experienced a significant decrease in the demand for its geophysical services due to the low price of oil during 1998 and the first half of 1999. As a result of these reduced activity levels, the Company implemented certain restructuring efforts and recorded charges during the first and third quarters related to these efforts as summarized below:

	Total charge	Amounts paid in 1999	Accrued balance at December 31, 1999	Amounts paid in 2000	Accrued balance at December 31, 2000
		(In thousands of dollars)			
Cash charges:					
Severance for approximately 500 employees	$12,685	$ 6,063	$ 6,622	$ 6,622	$ —
Lease termination, derigging and other obligations	38,734	28,036	10,698	10,698	—
Cash charges	51,419	34,099	17,320	17,320	—
Non-cash charges — write-off and write-down of property and equipment	22,535				
Total cash and non-cash charges	$73,954				

The employees whose employment was terminated were primarily field and support personnel associated with marine, transition zone and land seismic operations that were removed from service, and employees within the Company's data processing operations. The Company terminated the employment of approximately 400 employees as of December 31, 1999 and approximately 100 additional employees during 2000. The amount accrued was based upon the positions eliminated, length of service and any statutory or legal requirements applicable within the country where the terminations occurred. The Company paid all of the costs accrued at December 31, 1999 during 2000.

The Company accrued $38.7 million for costs to (1) derig marine vessels removed from operations, (2) settle contractual obligations associated with leased vessels and equipment removed from service, and (3) accrue for certain other incremental costs associated with the Company's restructuring efforts.

The impairment of property and equipment primarily consisted of the write-off or write-down of geophysical assets that were scrapped, disposed of or were not expected to benefit future operations, and the write-off of leasehold improvements associated with leased vessels and equipment removed from service. The Company also recognized $15.9 million in impairment charges for certain software, equity investment and other assets.

NOTE 24 — Restatement of Previously Issued Financial Statements

The restatements made to the Company's financial statements and related disclosures are summarized below.

The Company determined that the value of TES contracts (Note 17) was incorrectly recorded and presented in its previously issued financial statements, as only the year-end net settlement value of these instruments was recognized in the Company's statements of financial position and results of operations, rather than the fair value of the entire contracts in each reporting period. The financial statements and related disclosures have been restated to properly reflect the fair value of these TES contracts as of December 31, 2000 and for the years ended December 31, 2000 and 1999. The restatement also included a reclassification of the TES contract effects in the Company's statements of financial position and results of operations. Since the previously reported settlement values of the tax equalization swap contracts were treated as an accounting hedge and presented as a net of tax amount within the provision (benefit) for income taxes, the financial statement effects of these contracts were reclassified to accrued expenses and other income (expense). The effect of this restatement was non-cash, net adjustments to previously reported net income for the years ended December 31, 2000 and 1999 of $2.8 million and ($17.5) million, respectively.

The Company determined that its financial position and results of operations as of and for the year ended December 31, 2000 required restatement to reflect the adoption of SAB No. 101 to the Company's revenue recognition policy for some types of volume seismic data licensing arrangements and to defer revenue recognition until the Company has entered into a license agreement for specific data. The effect of this restatement was a non-cash, net adjustment to previously reported net income for the year ended December 31, 2000 of ($4.6) million, including ($6.6) million as the cumulative effect of the change in accounting principle.

The Company restated its statements of financial position and results of operations for fiscal year 2000 related to property and equipment. First, the Company determined that interest capitalization on its FPSO upgrade projects was incorrectly calculated and presented in its previously issued financial statements, as the full value of the capital assets, rather than the incremental expenditures incurred for the FPSO upgrade projects, was used as the qualifying asset. The effect of this restatement was a non-cash, net adjustment to previously reported net income for the year ended December 31, 2000 of ($10.7) million. Second, the Company determined that the value of two seismic vessels was incorrectly calculated, which resulted in the miscalculation of the associated depreciation expense as well as misstatements related to the Company's multi-client library and amortization, since a portion of the depreciation recorded for the seismic vessels was capitalized to multi-client seismic projects. The effect of this restatement was a non-cash, net adjustment to previously reported net income for the year ended December 31, 2000 of ($3.6) million.

The Company determined that a defined benefit plan for UK employees was incorrectly accounted for on a cash basis, rather than on the proper accrual basis. The effect of this restatement was a non-cash, net adjustment to previously reported net income and other comprehensive income for the year ended December 31, 2000 of ($1.9) million and $0.1 million, respectively.

The Company determined that it misapplied its minimum amortization policy for the multi-client library (Note 2). Under this minimum amortization accounting policy, the Company annually compares the cumulative sales for a survey to its sales forecast and records a minimum amortization amount if the survey's cumulative sales are lower than the cumulative forecast through that date. The Company incorrectly included customer commitments for volume seismic data licensing arrangements as realized transactions in its analysis of survey performance, rather than excluding the commitments from cumulative survey sales until the applicable license periods begin. The effect of this restatement was a non-cash, net adjustment to previously reported net income for the year ended December 31, 2000 of ($1.6) million.

Finally, the Company determined that certain deferred assets were incorrectly amortized and certain commission/royalty and lease liabilities were incorrectly accrued. The effects of these restatements were non-cash, net adjustments to previously reported net income for the year ended December 31, 2000 of ($0.5) million.

Relative to the tax benefits associated with the restatement adjustments for the year ended December 31, 2000, the Company determined that a valuation allowance against deferred tax assets was required due to uncertainties about its future ability to fully utilize net operating losses in the US and UK. The effect was a non-cash adjustment of ($3.8) million.

The effects of the restatements on the accompanying financial statements are included below:

	As of and for the years ended December 31,			
	2000		1999	
	As restated	As initially reported	As restated	As initially reported
	(In thousands of dollars, except per share data)			
Revenue	$ 913,482	$ 906,233	$ 788,160	$ 788,160
Cost of sales	432,457	423,121	333,060	333,060
Depreciation and amortization	263,589	258,484	238,576	238,576
Total operating expenses	1,144,976	1,130,000	749,088	749,088
Operating profit (loss)	(231,494)	(223,767)	39,072	39,072
Other income (loss), net	(32,774)	28,583	(9,144)	23,650
Loss before income taxes	(337,716)	(256,966)	(70,976)	(38,182)
Benefit for income taxes	(132,756)	(69,392)	(57,137)	(41,890)
Income (loss) before cumulative effect of accounting change	(204,960)	(187,574)	(13,839)	3,708
Cumulative effect of accounting change, net of tax	(6,555)	—	(19,977)	(19,997)
Net loss	(211,515)	(187,574)	(33,816)	(16,269)
Basic income (loss) per share before cumulative effect of accounting change	(2.01)	(1.84)	(0.15)	0.04
Cumulative effect of accounting change	(0.06)	—	(0.21)	(0.21)
Basic loss per share	(2.07)	(1.84)	(0.36)	(0.17)
Diluted income (loss) per share before cumulative effect of accounting change	(2.01)	(1.84)	(0.15)	0.04
Cumulative effect of accounting change	(0.06)	—	(0.21)	(0.21)
Diluted loss per share	(2.07)	(1.84)	(0.36)	(0.17)
Accounts receivable, net	242,751	253,410	240,634	240,634
Total current assets	476,961	488,655	398,604	398,604
Multi-client library, net	848,720	847,102	816,423	816,423
Other long-term assets, net	333,331	324,273	275,768	267,422
Total assets	4,278,706	4,292,391	4,184,997	4,176,651
Accrued expenses	297,607	203,368	182,441	144,212
Income taxes payable	12,263	77,464	9,805	9,805
Total current liabilities	439,376	410,338	302,720	264,491
Deferred tax liabilities	96,260	96,260	71,429	79,852
Total liabilities	2,788,678	2,757,050	2,477,416	2,447,610
Retained earnings	94,410	139,811	305,925	327,385
Total shareholders' equity	1,349,978	1,395,291	1,568,417	1,589,877
Total liabilities and shareholders' equity	4,278,706	4,292,391	4,184,997	4,176,651

The effects of these restatements on the beginning balance of retained earnings as presented in the consolidated statements of changes in shareholders' equity was a non-cash, net adjustment of ($3.8) million; this effect was reflected in the year ended December 31, 1998.

The pro forma effects of the adoption of SAB No. 101 (discussed above) as if the adoption had been reflected in fiscal year 1999, rather than as the cumulative effect of a change in accounting principle as of January 1, 2000, are presented below:

	Year ended December 31, 1999
Loss before cumulative effect of accounting change	$ (8,558)
Cumulative effect of accounting change, net of tax	(19,977)
Net loss	(28,535)
Basic loss per share before cumulative effect of accounting change	(0.09)
Cumulative effect of accounting change, net of tax	(0.21)
Basic loss per share	(0.30)
Diluted loss per share before cumulative effect of accounting change	(0.09)
Cumulative effect of accounting change, net of tax	(0.21)
Diluted loss per share	(0.30)

NOTE 25 — Summarized Financial Information

PGS Geophysical AS.

PGS Geophysical AS ("PEXAS"), a Norwegian corporation, is a wholly owned subsidiary of the Company. PEXAS is the largest geophysical services company within the PGS group of companies. PEXAS is also the charterer of the *Ramform Explorer* and the *Ramform Challenger*. The Company has fully and unconditionally guaranteed PEXAS charter obligations in connection with certain debt securities issued to finance the purchase of these vessels. Summarized financial information for PEXAS and its consolidated subsidiaries is presented below. This information was derived from the financial statements prepared on a stand-alone basis in conformity with US GAAP. Separate financial statements and other disclosures with respect to PEXAS are omitted because the information contained therein, in light of the information contained in the consolidated financial statements of the Company, would not be material.

	Years ended December 31,		
	2001	2000	1999
	(In thousands of dollars)		
INCOME STATEMENT DATA			
Revenue	$235,495	$ 200,560	$210,459
Operating loss	(90,505)	(110,983)	(10,924)
Net loss	(75,146)	(89,640)	(13,151)
BALANCE SHEET DATA			
Current assets	$147,679	$ 199,197	$100,165
Noncurrent assets	174,825	209,784	490,663
Current liabilities	92,568	102,389	61,116
Noncurrent liabilities	308,002	285,144	425,704
Equity (deficit)	(78,066)	21,448	104,008

Oslo Explorer PLC and Oslo Challenger PLC.

Both Oslo Explorer PLC ("Explorer") and Oslo Challenger PLC ("Challenger"), Isle of Man public limited companies, are wholly owned subsidiaries of the Company, purchased on April 4, 1997 (Note 10). Explorer and Challenger own the *Ramform Explorer* and the *Ramform Challenger*, respectively, and lease these vessels to PEXAS pursuant to long-term bareboat charters. Explorer and Challenger are jointly and severally liable under mortgage notes, in an original principal amount of $165.7 million, which were issued to finance the purchase of the *Ramform Explorer* and the *Ramform Challenger*. Summarized financial information for each of Explorer and Challenger is presented below. This information was derived from the financial statements prepared on a stand-alone basis in conformity with US GAAP. Separate financial statements and other disclosures with respect to Explorer and Challenger are omitted because the information, in light of the information contained in the consolidated financial statements of the Company, would not be material.

	Years ended December 31,			
	2001		2000	
	Explorer	Challenger	Explorer	Challenger
	(In thousands of dollars)			
INCOME STATEMENT DATA				
Revenue	$ 7,182	$ 7,144	$ 7,380	$ 7,341
Net income	1,609	1,570	1,787	1,749
BALANCE SHEET DATA				
Current assets	$ —	$ —	$ —	$ —
Noncurrent assets	74,099	73,906	76,482	76,328
Current liabilities	5,534	5,533	5,231	5,231
Noncurrent liabilities	59,373	59,372	63,668	63,666
Equity	9,192	9,001	7,583	7,431

INDEX TO EXHIBITS

Number	
1.1	— Articles of Association, as amended (English translation)
2.1	— Deposit Agreement, dated as of May 25, 1993, among Petroleum Geo-Services ASA (the "Company"), Citibank, N.A., as depositary (the "Depositary"), and all holders from time to time of American Depositary Receipts issued thereunder (incorporated by reference to Exhibit (a)(1) of Post-Effective Amendment No. 1 to the Company's Registration Statement on Form F-6 (Registration No. 33-61500))
2.2	— First Amendment to Deposit Agreement, dated as of April 24, 1997, among the Company, the Depositary and all holders from time to time of American Depositary Receipts issued thereunder (incorporated by reference to Exhibit (a)(2) of the Company's Registration Statement on Form F-6 (Registration No. 333-10856))
2.3	— Form of American Depositary Receipt (included in Exhibit 2.2)
2.4	— Certificate of Trust of PGS Trust I (the "Trust") (incorporated by reference to Exhibit 4.10.1 of the Registration Statement of the Company and the Trust on Form F-3 (Registration Nos. 333-10348 and 333-10348-01))
2.5	— Amended and Restated Declaration of Trust of the Trust, dated as of June 22, 1999, among the trustees of the Trust named therein, the Company, as Sponsor, and the holders from time to time of preferred undivided beneficial interests in the assets of the Trust (incorporated by reference to Exhibit 1 of the Company's Report on Form 6-K dated July 12, 1999 (SEC File No. 1-14614))
2.6	— Indenture, dated as of June 22, 1999, between the Company and Chase Bank of Texas, National Association, as Trustee, in respect of junior subordinated debentures of the Company (incorporated by reference to Exhibit 2 of the Company's Report on Form 6-K dated July 12, 1999 (SEC File No. 1-14614))
2.7	— First Supplemental Indenture, dated as of June 22, 1999, between the Company and Chase Bank of Texas, National Association, as Trustee, in respect of 9⅝% Junior Subordinated Debentures due 2039 of the Company (incorporated by reference to Exhibit 3 of the Company's Report on Form 6-K dated July 12, 1999 (SEC File No. 1-14614))
2.8	— Form of 9⅝% Junior Subordinated Debenture due 2039 (included in Exhibit 2.7)
2.9	— Guarantee Agreement, dated as of June 22, 1999, between the Company and Chase Bank of Texas, National Association, as Guarantee Trustee (incorporated by reference to Exhibit 4 of the Company's Report on Form 6-K dated July 12, 1999 (SEC File No. 1-14614))
2.10	— Form of Preferred Security (included in Exhibit 2.5)
2.11	— Indenture, dated as of April 1, 1998, between the Company and Chase Bank of Texas, National Association, as trustee, in respect of senior debt securities (incorporated by reference to exhibit 2.12 of the Company's Annual Report on Form 20-F for the year ended December 31, 1997 (SEC File No. 1-14614))
2.12	— First Supplemental Indenture, dated as of April 1, 1998, between the Company and Chase Bank of Texas, National Association, as trustee, in respect of 6⅝% Senior Notes due 2008 and 7⅛% Senior Notes due 2028 (incorporated by reference to exhibit 2.13 of the Company's Annual Report on Form 20-F for the year ended December 31, 1997 (SEC File No. 1-14614))

Number	
2.13	— Revolving Credit Agreement dated as of September 4, 1998 among the Company, Chase Manhattan PLC, as arranger, Chase Manhattan International Limited, as agent, and the financial institutions listed therein (incorporated by reference to exhibit 2.5 of the Company's Annual Report on Form 20-F for the year ended December 31, 1998 (SEC File No. 1-14614))
	The Company and its consolidated subsidiaries are party to several debt instruments under which the total amount of securities authorized does not exceed 10% of the total assets of the Company and its subsidiaries on a consolidated basis. Pursuant to paragraph 2(b)(i) of the instructions to the exhibits to Form 20-F, the Company agrees to furnish a copy of such instruments to the SEC upon request.
4.1	— Employment agreement dated April 27, 2000 between the Company and Michael Mathews (incorporated by reference to Exhibit 4.1 of the Company's Annual Report on Form 20-F for the year ended December 31, 2000 (File No. 1-14614) (the "Form 20-F"))
4.2	— Employment agreement dated July 31, 1997 between the Company and Reidar Michaelsen (incorporated by reference to Exhibit 4.2 of the Form 20-F)
4.3	— Petroleum Geo-Services ASA Executive Pension Scheme dated August 29, 1996 (incorporated by reference to Exhibit 4.13 of the Form 20-F)
4.4	— Petroleum Geo-Services ASA 2000 — Incentive Share Option Plan dated June 23, 2000 (incorporated by reference to Exhibit 4.14 of the Form 20-F)
4.5	— Petroleum Geo-Services ASA Non-Employee Director Stock Option Plan dated January 1, 2000 (incorporated by reference to Exhibit 4.15 of the Form 20-F)
4.6	— Framework Agreement, dated as of April 26, 2001, among Multi-Klient Invest AS, the Company, PGS Multi-Client Seismic Limited, Compass Finrec P Limited, Westdeutsche Landesbank Girozentrale and Compass Holdings Limited (incorporated by reference to Exhibit 4.16 of the Form 20-F)
4.7	— Servicing Agreement, dated as of April 26, 2001, among Multi-Klient Invest AS, the Company, PGS Multi-Client Seismic Limited, Compass Finrec P Limited, Westdeutsche Landesbank Girozentrale and Compass Holdings Limited (incorporated by reference to Exhibit 4.17 of the Form 20-F)
4.8	— Jersey License Agreement, dated as of April 26, 2001, among Multi-Klient Invest AS, the Company, PGS Multi-Client Seismic Limited, Compass Finrec P Limited, Westdeutsche Landesbank Girozentrale and Compass Holdings Limited (incorporated by reference to Exhibit 4.18 of the Form 20-F)
8	— Subsidiaries (included in Item 4 of the annual report)
10.1	— Consent of Arthur Andersen LLP
10.2	— Consent of PricewaterhouseCoopers LLP
99.1	— Letter to the Securities and Exchange Commission regarding Arthur Andersen LLP