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, 2004

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 30 per share	New York Stock Exchange, Inc.
Ordinary shares of nominal value NOK 30 per share*	New York Stock Exchange, Inc.

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

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report: 20,000,000 ordinary shares, nominal value NOK 30 per share.

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 the registrant has elected to follow. Item 17 ☐ Item 18 ☑

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Sections 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes ☑ No ☐

* The ordinary shares were registered for technical purposes only, not involving trading privileges, in accordance with the requirements of the Securities and Exchange Commission.

PETROLEUM GEO-SERVICES ASA

ANNUAL REPORT ON FORM 20-F FOR THE YEAR ENDED DECEMBER 31, 2004

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PETROLEUM GEO-SERVICES ASA

As used in this annual report, we refer to Petroleum Geo-Services ASA, its predecessors and its majority-owned subsidiaries as "PGS," "we," "us" or "our," unless the context clearly indicates otherwise.

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 or furnish reports and other information with the SEC. Reports and other information we file with or furnish to the SEC, including this annual report, may be inspected and copied at the public reference facilities of the SEC at 450 Fifth Street N.W., Washington D.C. 20549. Additionally, information that we file electronically with the SEC may also be obtained from its Internet site at *http://www.sec.gov* and our Internet site at *http://www.pgs.com*. Information contained on or connected to our website is not incorporated by reference into this annual report on Form 20-F and should not be considered part of this report or any other filing that we make with the SEC.

FORWARD-LOOKING STATEMENTS

In order to utilize the "Safe Harbor" provisions of the United States Private Securities Litigation Reform Act of 1995, we are providing the following cautionary statement. This annual report, particularly in "Our Business Priorities," "Our Geophysical Services" and "Our Production Segment" in Item 4 and "Outlook; Factors Affecting Our Future Operating Results" and "Liquidity and Capital Resources" in Item 5, contains forward-looking statements about our financial condition, results of operations, businesses and prospects. These forward-looking statements address matters such as:

- market conditions, anticipated demand and prices for our services and multi-client data that we license, productive capacity in the markets in which we operate, other competitive factors, possible expansion, technological developments and other trends in the businesses in which we operate;
- business strategies, including geographic areas in which we may operate from time to time and potential acquisitions and/or dispositions;
- maintaining and obtaining contracts for our floating production, storage and offloading vessels, the estimated productive lives of the fields served by such vessels and the periods we expect such vessels to continue to produce such fields;
- operating regularity and levels of production for our floating production, storage and offloading vessels;
- the extent to which our seismic vessels and equipment will be utilized, including utilization of such vessels to acquire contract or multi-client seismic data;
- acquisition of contract and multi-client seismic data, governmental licensing activity relating to such acquisition and expected future sales of multi-client seismic data;
- future capital expenditures, investments in our businesses and dividends;
- investments in, and amortization charges for, our multi-client library;
- governmental and tax regulations and enforcement;
- future exposure to currency devaluations or exchange rate fluctuations, including in particular fluctuations in the value of the U.S. dollar as compared to the Norwegian kroner and the British pound; and
- interest rates.

These forward-looking statements:

- address activities, events or developments that we expect, believe, anticipate or estimate will or may occur in the future;
- are based at least in part on assumptions and analyses that we have made and that we believe were reasonable under the circumstances when made; and
- can be impacted by 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 disclosed elsewhere in this annual report, including those described under "Key Information — Risk Factors" in Item 3.

CURRENCY PRESENTATIONS

In this annual report, references to "U.S. dollars," "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.

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 U.S. GAAP, our selected consolidated financial data as of December 31, 2004 and 2003 (Successor Company) and as of December 31, 2002 and 2001 (Predecessor Company), for the year ended December 31, 2004 and for the two-month period ended December 31, 2003 (Successor Company) and for the ten-month period ended October 31, 2003 and the years ended December 31, 2002 and 2001 (Predecessor Company). We have derived the financial data presented below for such periods and as of such dates from our consolidated financial statements included in Item 18 of this annual report. The financial data presented below excludes our Production Services subsidiary, Atlantis oil and natural gas subsidiary and PGS Tigress software subsidiary, which were sold in 2002 and 2003 and are presented as discontinued operations in our financial statements for all periods. You should read the financial data in conjunction with "Operating and Financial Review and Prospects" in Item 5 of this annual report and our consolidated financial statements and related notes included in Item 18 of this annual report. The financial data presented below are qualified in their entirety by reference to those consolidated financial statements and related notes.

We operated our business as a debtor-in-possession under Chapter 11 of the U.S. Bankruptcy Code from July 29, 2003 until November 5, 2003, when our reorganization plan became effective and was substantially consummated. Under the plan, our then-existing bank debt and outstanding senior notes were cancelled in exchange for a combination of new senior notes, a new term loan, new ordinary shares and the right to receive cash. For additional information about our Chapter 11 reorganization, please read "Operating and Financial Review and Prospects — 2003 Financial Restructuring" in Item 5 of this annual report and notes 3 and 15 of the consolidated financial statements included in Item 18 of this annual report.

We have prepared our post-reorganization consolidated financial statements in accordance with the American Institute of Certified Public Accountants Statement of Position 90-7, *"Financial Reporting by Entities in Reorganization Under the Bankruptcy Code,"* or SOP 90-7. For financial reporting purposes, the effects of the completion of the reorganization plan and adjustments for fresh-start reporting have been recorded as of October 31, 2003. Under fresh-start reporting, a new entity was deemed created for financial reporting purposes, and the carrying values of our assets were adjusted to their reorganization values, which are equivalent to their estimated fair values. The carrying values of our liabilities were also adjusted to their present values. The terms "Predecessor" and "Predecessor Company" refer to PGS and its subsidiaries for periods prior to and including October 31, 2003. The terms "Successor" and "Successor Company" refer to PGS and its subsidiaries for periods from and after November 1, 2003. The effects of the completion of the reorganization plan and adjustments for fresh-start reporting recorded as of October 31, 2003 are Predecessor Company transactions. All other results of operations on November 1, 2003 are Successor Company transactions.

We restated the financial data presented below as of and for the year ended December 31, 2001 when we issued our U.S. GAAP consolidated financial statements for the fiscal year ended December 31, 2003. The restatements also affected periods prior to 2001. The impact of the restatement on such prior periods was reflected as an adjustment to retained earnings as of January 1, 2001.

Pursuant to Item 3.A.1 of Form 20-F, selected financial data as of and for the year ended December 31, 2000 have been omitted because such information cannot be provided on an audited or unaudited restated basis without unreasonable effort or expense. We believe that providing such information would involve unreasonable effort or expense because (1) the benefits of providing such information are diminished by the fact that we adopted fresh start reporting for financial statement purposes, effective November 1, 2003, as described above, (2) the preparation of such restated consolidated financial statements would be extremely time consuming and burdensome since our current independent registered public accounting firm, Ernst & Young AS, was not our independent auditors during that period, and (3) we identified significant adjustments to the beginning balances as of January 1, 2001 that would be burdensome and expensive to allocate and to apply consistently and with reasonable precision to the year 2000.

	Successor Company		Predecessor Company		
	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Years Ended December 31, 2002	2001
	(In thousands of dollars, except for share data)				
STATEMENT OF OPERATIONS DATA:					
Revenues	$ 1,129,468	$ 172,371	$ 961,864	$ 1,043,231	$ 893,230
Operating profit (loss)	35,683	10,702	9,825	(488,609)	46,798
Reorganization items:					
Gain on debt discharge	—	—	1,253,851	—	—
Fresh-start adoption	—	—	(532,268)	—	—
Cost of reorganization	(3,498)	(3,325)	(52,334)	(3,616)	—
Income (loss) from continuing operations before cumulative effect of change in accounting principles	(137,778)	(9,818)	556,938	(809,903)	(140,125)
Net income (loss)	(134,730)	(9,953)	557,045	(1,174,678)	(172,479)
Basic and diluted income (loss) per share from continuing operations	$ (6.89)	$ (0.49)	$ 5.39	$ (7.84)	$ (1.36)
Basic and diluted net income (loss) per share	(6.74)	(0.50)	5.39	(11.37)	(1.68)
Basic and diluted weighted average shares outstanding	20,000,000	20,000,000	103,345,987	103,345,987	102,768,283
CASH FLOW DATA:					
Cash flows provided by operating activities	$ 282,372	$ 62,170	$ 164,948	$ 294,609	$ 110,581
Cash flows used in investing activities	(183,446)	(25,089)	(69,732)	(274,497)	(220,516)
Cash flows provided by (used in) financing activities	(71,283)	(25,807)	(92,896)	(7,636)	64,349
Capital expenditures	148,372	15,985	42,065	56,735	147,536
Investment in multi-client library	41,140	9,461	81,142	151,590	174,028

	Successor Company		Predecessor Company	
	December 31,		December 31,	
	2004	2003	2002	2001
	(In thousands of dollars)			
BALANCE SHEET DATA:				
Total assets	$1,852,153	$1,997,360	$2,839,757	$3,962,129
Multi-client library, net	244,689	408,005	583,859	799,062
Total long-term debt and capital lease obligations	1,118,346	1,172,147	1,409,134	1,964,888
Guaranteed preferred beneficial interest in PGS junior subordinated debt securities	—	—	142,322	141,000
Common stock	85,714	85,714	71,089	71,089
Shareholders' equity (deficit)	222,907	353,634	(192,254)	979,896

Risk Factors

You should carefully consider the risks described below. 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 securities could decline significantly.

Risk Factors Relating to Financial Reporting Matters

We have continuing issues regarding our internal control over financial reporting. Failure to achieve and maintain effective internal controls could adversely affect both our ability to provide timely and accurate financial statements and the trading prices of our securities.

We have continuing issues regarding our internal control over financial reporting. In September 2003 our independent registered public accounting firm communicated to us material weaknesses regarding broad elements of our system of internal controls. Although we have worked to address those material weaknesses, our assessment of the progress made in addressing the material weaknesses indicates that for the period relevant for the preparation of our 2004 financial statements and at December 31, 2004, material weaknesses continued to exist in certain areas. In connection with their audit of our 2004 financial statements under U.S. GAAP, our independent registered public accounting firm delivered to us a letter dated May 3, 2005 that also confirmed the continuation of some matters that, in the aggregate, were considered to constitute material weaknesses.

The Public Company Accounting Oversight Board has defined a material weakness as "a significant deficiency, or combination of significant deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim statements will not be prevented or detected." Material weaknesses increase the risk that the financial information we report in the future could contain material errors. The existence of the material weaknesses also means that we must make still further improvements to our internal controls before our management will be able to conclude and our independent registered public accounting firm will be able to attest that we have effective internal control over financial reporting in accordance with the rules under Section 404 of the Sarbanes-Oxley Act of 2002. Those rules will apply to us beginning with our annual report on Form 20-F for the year ending December 31, 2006.

Even aside from Section 404 of Sarbanes-Oxley, effective internal controls are important for producing timely and reliable financial reports and preventing financial fraud. If we do not effectively address the material weaknesses or otherwise maintain effective internal control over financial reporting, we may be unable to process key components of our results of operations and financial condition timely and accurately, investors and rating agencies could lose confidence in our reported financial information and the trading prices of our securities could be adversely affected.

Our adoption of "fresh start" reporting may make future financial statements difficult to compare.

As a result of the November 2003 consummation of our reorganization plan, we are operating our business under a new capital structure. In addition, we adopted, as of November 1, 2003, fresh start reporting in accordance with SOP 90-7. Because SOP 90-7 required us to reset our assets and liabilities to then current fair values, our financial condition and results of operations after our reorganization will not be comparable to the financial condition and results of operations reflected in our historical financial statements for periods prior to November 2003. This may make it difficult to assess our performance after the reorganization compared with our historical performance prior to the reorganization.

Risk Factors Relating to Our Indebtedness and Other Obligations

We have significant indebtedness and other obligations.

We have a relatively high level of indebtedness in relation to our capital structure. As of December 31, 2004, we had approximately $1,164 million of indebtedness and capital leases outstanding, including indebtedness and leases with maturities in 2005 ($45 million), 2006 ($284 million), 2007 to 2009 ($55 million) and after 2009 ($780 million). The amount for 2006 includes $175 million of 8% senior notes due 2006 that we redeemed in April 2005. Because of the high level of our debt and other contractual obligations,

- we must dedicate a substantial portion of our cash flow from operations to debt service and other contractual obligations, which reduces the amount we have available for capital investment, working capital or other general corporate purposes;
- we are more vulnerable to adverse developments in general economic and industry conditions;
- we are less flexible in responding to changing market conditions or in pursuing favorable business opportunities;
- we are limited in our ability to borrow additional funds; and
- we may be at a competitive disadvantage compared to our competitors that have less debt.

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

Our debt agreements contain provisions that restrict our ability, among other things, to:

- pay dividends or make other restricted payments;
- incur debt above specified amounts;
- create or permit to exist liens on our assets;
- consolidate, merge or transfer all or substantially all of our assets;
- sell assets for consideration other than cash or cash equivalents or without using the proceeds to reinvest in our businesses or to repay debt;
- undergo a change of control without having an obligation to purchase all of our senior notes; and
- engage in certain sale and leaseback transactions.

In addition, our debt agreements and other contractual obligations require us to provide audited and unaudited financial statements prepared under U.S. GAAP or international accounting standards within a specified period of time after each fiscal year and each of the first three fiscal quarters of each year. A breach of any of the covenants or restrictions in our debt agreements could result in an event of default. Such default could allow our debt holders to accelerate the related debt as well as any other debt to which a cross-acceleration or cross-default provision applies and declare all borrowings outstanding thereunder to be due and payable. If our debt is accelerated, our assets may not be sufficient to repay such debt and we may not be able to borrow sufficient funds to do so. See "Our ability to obtain additional financing or to refinance our indebtedness could be restricted" below.

Our ability to obtain additional financing or to refinance our indebtedness could be restricted.

As of April 30, 2005, our long-term unsecured indebtedness carried a non-investment grade rating (Ba3) from Moody's Investors Service, Inc. rating agency. As of that date, our debt was not rated by Standard & Poor's Ratings Services, a division of The McGraw-Hill Companies, Inc. As long as we have a non-investment grade credit rating, our access to the debt capital markets will be restricted to the non-investment grade sector. Such a situation could increase our borrowing costs or restrict our ability to obtain additional financing or to refinance our existing indebtedness, or to do so on satisfactory terms.

The continued existence of material weaknesses as described above under "Risk Factors — Risk Factors Relating to Financial Reporting Matters — We have continuing issues regarding our internal control over financial reporting. Failure to achieve and maintain effective internal controls could adversely affect both our ability to provide timely and accurate financial statements and the trading prices of our securities" could similarly restrict our ability to obtain financing, or to do so on satisfactory terms.

Risk Factors Relating to Our Business Operations Generally

We have experienced substantial losses in the past and may continue to do so in the future.

For the year ended December 31, 2004, we suffered a net loss of $135 million. We also reported operating losses and net losses for 2002 and a small operating profit for 2003 (both for Predecessor Company and Successor Company). We may incur operating losses and net losses in the future.

Our business could be adversely affected if demand for our services from oil and natural gas companies decreases.

Our geophysical and offshore production businesses depend substantially upon exploration, development and production spending by oil and natural gas companies. Capital expenditures, and in particular exploration and development expenditures, by oil and natural gas companies have tended in the past to follow the prices of oil and natural gas, which have fluctuated widely in recent years. Lower oil and natural gas prices, actual or projected, and other factors including mergers of oil and natural gas companies may reduce the level of those expenditures, which could adversely affect our businesses.

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

Our businesses are capital intensive, and we make significant investments in vessels and in processing, seismic and other equipment. We also incur relatively high fixed costs in our operations. As a result, if we cannot keep our vessels and other equipment utilized at relatively high levels, due to reduced demand, weather interruptions, equipment failure, technical difficulties, labor unrest or other causes, we could incur significant operating losses.

Our future revenues may fluctuate significantly from period to period.

Our future revenues may fluctuate significantly from quarter to quarter and from year to year as a result of various factors including the following:

- fluctuating oil and natural gas prices, which may impact customer demand for our services;
- different levels of activity planned by our customers;
- the timing of offshore lease sales and the effect of such timing on the demand for seismic data and geophysical services;
- the timing of award and commencement of significant contracts for offshore production services and geophysical data acquisition services;

- weather and other seasonal factors; and
- seasonality in the sales of geophysical data from our multi-client data library.

Our technology could be rendered obsolete since technological changes and new products and services are regularly introduced to our markets and we may not be able to develop and produce competitive products and services on a cost-effective and timely basis.

We will be required to invest substantial capital to maintain competitive technologies. Technology changes rapidly, and new and enhanced products and services are frequently introduced in our markets, particularly in the geophysical services and seismic data processing business. Our success depends to a significant extent on our ability to develop and produce new and enhanced products and services on a cost-effective and timely basis in accordance with industry demands. While we commit resources to research and development, we may encounter resource constraints or technical or other difficulties that could delay introduction of new and enhanced products and services in the future. In addition, continuing development of new products and services inherently carries the risk of obsolescence of older products and services. New and enhanced products and services, if introduced, may not gain market acceptance or may be adversely affected by technological changes.

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:

- permit or license requirements for geophysical activities and for oil and natural gas exploration, development and production activities;
- exports and imports;
- taxes;
- occupational health and safety; and
- the protection of the environment.

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 increase materially in the future. Modification of existing laws or regulations or adoption of new laws or regulations limiting exploration or production activities by oil and natural gas companies or imposing more stringent restrictions on geophysical or hydrocarbon production-related operations could adversely affect us by increasing our operating costs and/or reducing the demand for our services.

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. These operations are subject in varying degrees to risks inherent in doing business abroad including risks of war, terrorist activities, political, civil or labor disturbances, border disputes and embargoes. Our operations are also subject to various risks related to government activities, including:

- the disruption of operations from labor and political disturbances;
- the possibility of unfavorable changes in tax or other laws;
- partial or total expropriation;
- restrictions on currency repatriation or the imposition of new laws or regulations that preclude or restrict the conversion and free flow of currencies;

- the imposition of new laws or regulations that have the effect of restricting operations or increasing the cost of operations; and

- the disruption or delay of licensing or leasing activities.

We are subject to hazards relating to our geophysical and production services businesses.

Our seismic data acquisition and offshore production services often take place under extreme weather and other hazardous conditions. In particular, a substantial portion of our operations are subject to perils that are customary for marine operations, including capsizing, grounding, collision, interruption and damage or loss from severe weather conditions, fire, explosions and environmental contamination from spillage. Any of these risks, whether in our marine or onshore operations, 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. If any of these events occur, our business could be interrupted and we could incur significant liabilities. In addition, many similar risks may result in curtailment or cancellation of, or delays in, exploration and production activities of our customers, which could in turn adversely impact our operations.

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

We do not carry full insurance for all of our operating risks. Although we generally attempt to 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, such insurance coverage is subject to various exclusions. In addition, we may not be able to maintain adequate insurance for our vessels and equipment in the future or do so at rates that we consider reasonable. We do not maintain insurance to protect against loss of revenues caused by business interruptions.

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. Historically, most of our revenue and operating expenses have been generated in U.S. dollars, NOK and British pounds, but we predominantly sell our products and services in U.S. dollars while some portion of our operating expenses are incurred in NOK and British pounds. A depreciation in the U.S. dollar compared to these other currencies, as has been the case in recent periods, adversely affects our reported results of operations since expenses denominated in NOK or British pounds are converted into U.S. dollars, our reporting currency, at an increased value. Although we periodically undertake limited hedging activities in an attempt to reduce some currency fluctuation risks, these activities do not provide complete protection from currency-related losses. In addition, in some circumstances our hedging activities can require us to make cash outlays. Finally, the amount of currency hedging transactions we are able to enter into may be limited because of our having a non-investment grade credit rating.

We are subject to intense competition that could limit our ability to maintain or increase our market share and to maintain our prices at profitable levels.

Most of our geophysical and offshore production contracts are obtained through a competitive bidding process. While no single company competes with us in all of our business segments, we are subject to intense competition from large, international companies and smaller, local companies in each of our businesses. Some of our competitors may have greater financial and other resources than us and may be better positioned to withstand and adjust more quickly to volatile market conditions and changes in government regulations. We also face competition from new low-cost competitors in various geographic areas, particularly in the onshore seismic market.

Our strategy of pursuing selective growth opportunities may be unsuccessful if we incorrectly predict operating results for acquired assets or businesses, are unable to identify and complete future acquisitions and integrate acquired assets or businesses or are unable to raise financing for acquisitions on acceptable terms.

The acquisition of assets or businesses on a selective basis or the making of strategic investments on a selective basis in companies or ventures that are complementary to our geophysical business or our production business is a component of our business strategy. We believe that attractive acquisition and strategic investment opportunities may arise from time to time, and any such acquisition or investment could be significant. At any given time, discussions with one or more potential sellers or possible business partners may be at different stages. However, we cannot provide any assurance that any such discussions will result in the consummation of an acquisition transaction or strategic investment or that we will be able to identify or complete any acquisitions or investments. Furthermore, we cannot predict the effect, if any, that any announcement or consummation of an acquisition or strategic investment transaction would have on the trading prices of our securities.

Any future acquisition or investment could present a number of risks to our company, including:

- the risk of incorrect assumptions regarding the future results of acquired operations or assets or investments or any cost reductions or other synergies expected to be realized as a result of the acquisition or investment;
- the risk of failing to integrate successfully and timely the operations and/or management of any acquired operations or assets;
- the risk of diversion of our management's attention from existing operations or other priorities; and
- the risk of undisclosed or contingent liabilities associated with the acquired operations or assets.

In addition, we may not be able to raise, on terms we find acceptable, any debt or equity financing that may be required for any such acquisition or investment.

Our results of operations depend in part upon our ability to establish and protect our proprietary technology.

We rely on a combination of patents, trademarks, copyrights and trade secret laws to establish and protect our proprietary technology. We endeavor to obtain patents on our technology in Norway, the United States and the United Kingdom and in other jurisdictions that we consider important to our business. In addition, we enter into confidentiality and license agreements with our employees, and with consultants and companies from whom we acquire technology, and with others who have access to our proprietary technology. However, we do not patent all of our proprietary technology, and enforcement of proprietary technology rights may be difficult in some jurisdictions. Accordingly, the procedures we have taken to protect our proprietary rights may not be adequate to deter the misappropriation of our proprietary technology in all situations.

Risk Factors Relating Primarily to Our Geophysical Business, Both Marine Geophysical and Onshore

We invest significant amounts of money in acquiring and processing seismic data for our multi-client data library without being certain about how much of the data we will be able to sell or when and 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. Because our future multi-client data sales, including the timing of such sales, are uncertain and depend on a variety of factors, many of which are beyond our control, by making such investments we assume the risk that:

- we may not fully recover the costs of the data through future sales; and
- the value of our multi-client data could be adversely affected by, among other things, any material adverse change in the general prospects for oil and natural gas exploration, development and

production activities in the areas where we acquire multi-client data and by technological or regulatory changes.

In particular, we own a significant amount of multi-client data offshore Brazil. As of December 31, 2004, the carrying value of our multi-client data offshore Brazil was $133.7 million. A further delay of sales in this region could have an adverse impact on our multi-client data sales.

In the past, we have incurred substantial impairment charges related to our multi-client data.

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

The manner in which we account for our multi-client data library has a significant effect on our results of operations. We amortize the capitalized cost of our multi-client data library based principally on the relationship of actual data sales for the relevant data to our estimates of total, including future, sales of data. Our sales estimates are inherently imprecise and may vary from period to period depending upon market developments and our expectations. Changes in the amounts and timing of data sales may result in impairment charges or changes in our amortization expense, which will affect our results of operations.

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

We perform a substantial portion of our contract seismic work under turnkey arrangements. If we bid too low on these contracts, we could incur losses on projects and experience reduced profitability.

Many of our contracts for seismic data acquisition are turnkey contracts where our work is delivered at a predetermined and fixed price. In submitting a bid on a turnkey contract, we estimate our costs associated with the project. However, our actual costs can vary from our estimated costs because of changes in assumed operating conditions (including weather, fishing activity, interference from other seismic vessels and other operating disturbances), exchange rates and equipment productivity, among others. As a result, we may experience reduced profitability or losses on projects if our bids on turnkey contracts are too low and/or actual costs exceed estimated costs.

Risk Factors Relating Primarily to Our Production Business

Our operating results 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 operate at high levels on a sustained basis for technical reasons, including operational difficulties that require modification of vessels or equipment, or due to strikes, employee lockouts or other labor unrest;
- contract termination prior to the scheduled or anticipated expiration date for the contracts;
- failure to redeploy vessels following expiration or termination of long-term contracts; and
- failure of the underlying reservoir and/or the prevailing market prices for oil and natural gas to allow production of the expected amounts of oil and natural gas under contracts where our compensation depends to a significant degree on the amount of oil and natural gas produced.

Other Risk Factors

We are a multinational organization faced with increasingly complex tax issues in many jurisdictions, and we could be obligated to pay additional taxes in various jurisdictions.

As a multinational organization, we are subject to taxation in many jurisdictions around the world with increasingly complex tax laws. The amounts of taxes we pay in these jurisdictions could increase substantially as a result of changes in these laws or their interpretations by the relevant taxing authorities, which could have a material adverse effect on our liquidity and results of operations. In addition, those authorities could review our tax returns and impose additional taxes and penalties, which could be material. We have an issue pending with the Norwegian Central Tax Office ("CTO") for 2002 relating to two of our subsidiaries that withdrew from the Norwegian tonnage tax regime. If the CTO position is upheld, we estimate that taxes payable for 2002, without considering mitigating actions, could increase by up to $24 million. We also have tax issues in several other jurisdictions that could eventually make us liable to pay material amounts in taxes relating to prior years.

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 substantially all of our current directors and executive officers reside outside the United States. All or a substantial portion of the assets of these persons and our company are 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 the Kingdom of Norway in an original action based solely on United States federal securities laws; and
- enforcing in the Kingdom of Norway judgments obtained in the United States courts that are based upon the civil liability provisions of the United States federal securities laws.

We could be adversely affected by violations of applicable anti-corruption laws.

We and our affiliated entities conduct business in countries known to experience government corruption. We are committed to doing business in accordance with our code of conduct, but there is a risk that we, our affiliated entities or our or their respective officers, directors, employees and agents may take action in violation of applicable anti-corruption laws, including the U.S. Foreign Corrupt Practices Act of 1977. Any such violations could result in substantial civil and/or criminal penalties and might adversely affect our business, results of operations or financial condition.

ITEM 4. *Information on the Company*

History and Development of the Company

Organization

Petroleum Geo-Services ASA is 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 our headquarters and executive offices at Lysaker, Norway (Strandveien 4, N-1366, telephone: +47-67-52-6400). Our registration number in the Norwegian Company Registry is 916235291. Our agent in the United States is CT Corporation System, 1633 Broadway, New York, New York 10019.

Who We Are

We are a technologically focused oilfield service company principally involved in providing geophysical services worldwide and providing floating production services in the North Sea. Globally, we provide a broad range of geophysical and reservoir services, including seismic data acquisition, processing and interpretation and field evaluation. In the North Sea, we own and operate four harsh environment floating production, storage and offloading ("FPSO") units.

In 2004 we managed our business in four segments as follows:

- *Marine Geophysical,* which consists of both streamer and seafloor seismic data acquisition, marine multi-client library and data processing;

- *Onshore,* which consists of all seismic operations on land and in very shallow water and transition zones, including our onshore multi-client library;
- *Production,* which owns and operates four harsh environment FPSO units in the North Sea; and
- *Pertra,* a small oil and natural gas company that owned 70% of and was operator for Production License 038 ("PL038") on the Norwegian Continental Shelf ("NCS") and also owned participating interests in six additional NCS licenses without production.

We sold Pertra to Talisman Energy (UK) Ltd. ("Talisman") in March 2005 as described in more detail below, and we will report Pertra as discontinued operation starting with our consolidated financial statements for 2005.

Following the sale of Pertra, we will focus on our remaining three business segments in the oilfield service sector. We manage our Marine Geophysical segment from Lysaker, Norway, our Onshore segment from Houston, Texas, and our Production segment from Trondheim, Norway.

Historical Development

The primary milestones in our historical development include the following:

- *January 1991:* Company established with the merger of Geoteam a.s. and Nopec a.s.
- *August 1992:* Company ordinary shares listed on Oslo Stock Exchange
- *May 1993:* Initial public offering and listing in U.S. on NASDAQ
- *1995-1999:* Construction and deployment of six Ramform design 3D seismic vessels
- *April 1997:* Listing of our ADSs on the New York Stock Exchange
- *May 1998:* Acquisition of Golar-Nor (*Petrojarl I* and *Petrojarl Foinaven*)
- *October 1998:* Delivery of *Ramform Banff*
- *July 1999:* Acquisition of FPSO *Varg* (renamed *Petrojarl Varg*)
- *March 2001:* Sale of data management business and related software to Landmark Graphics Corporation, a subsidiary of Halliburton, and resumption of oil production by the re-tooled *Ramform Banff*
- *November 2001:* Announcement of business combination transaction with Veritas DGC (terminated in July 2002)
- *August 2002:* Acquisition of 70% ownership in, and operatorship of, PL 038 on NCS of the North Sea (including Varg field)
- *August-November 2002:* Replacement of various members of senior management, including the Chairman of the Board and Chief Executive Officer and the Chief Financial Officer, with a new non-executive Chairman of the Board, a new Chief Executive Officer and a new Chief Financial Officer
- *December 2002:* Sale of Production Services subsidiary to Petrofac Ltd.
- *February 2003:* Sale of Atlantis subsidiary to Sinochem
- *February 2003:* Delisting of ADSs from the New York Stock Exchange and quotations for ADSs available through Pink Sheets
- *July 2003:* Filing under Chapter 11 of U.S. Bankruptcy Code
- *November 2003:* Emergence from Chapter 11 proceedings, reorganization plan becomes effective and new Board of Directors takes office

- *December 2004:* Re-listing of our ADSs on the New York Stock Exchange following filing of Form 20-F for 2003 fiscal year

- *March 2005:* Sale of oil and natural gas subsidiary Pertra to Talisman

2004 Developments

Our primary business achievements in 2004 include:

- continuing our strong safety performance;

- operating at relatively high utilization levels and regularity in all business segments, with the exception of the impact of (a) a strike on the NCS in the fall 2004 affecting two of our FPSOs and (b) damage to a riser relating to operations in the Varg field;

- continuing our successful development of Pertra;

- realizing strong multi-client late sales and improved marine seismic contract performance in the second half of 2004;

- improving our financial flexibility through increased cash flow from operations;

- reducing our net interest bearing debt from $1,077 million at year end 2003 to $995 million at year end 2004; and

- completing the re-audit of our 2001 U.S. GAAP financial statements, completing and filing our 2003 Annual Report on Form 20-F and re-listing our ADSs on the New York Stock Exchange.

In addition, during the first four months of 2005 we have

- realized the substantial value enhancement of Pertra by selling it in March 2005;

- improved our financial flexibility with the significant cash proceeds realized from the sale of Pertra; and

- redeemed in April 2005 $175 million of our 8% Senior Notes due 2006.

Sale of Our Oil and Natural Gas Subsidiary Pertra

On March 1, 2005, we sold our wholly-owned subsidiary Pertra AS to Talisman for a sales price of approximately $155 million. We expect to recognize a gain from the sale for financial reporting purposes in excess of $140 million. We do not expect to incur any taxes from the transaction.

As part of the transaction, Talisman has agreed to share with us (on a post petroleum tax basis), on a 50/50 basis for each of 2005 and 2006, its revenues from production from its interest in the Varg Field in excess of $240 million.

In addition, we entered into an agreement with Talisman under which the PL038 license holders have an option, at their discretion, to extend the term of the charter and operating agreement for the *Petrojarl Varg* until 2010. The option is exercisable until February 1, 2006, and if exercised the license owners will be obligated to pay us $22.5 million and to guarantee a minimum of $190,000 per day as compensation for the use of *Petrojarl Varg*. We received $2.5 million at closing of the Pertra sale for granting this option. Under our existing contract with the PL038 license holders relating to the *Petrojarl Varg*, our compensation consists of a fixed base day rate of $90,000 and a tariff of $6.30 per barrel produced. Subject to the option, we currently have the right to terminate the agreement if production from the Varg field falls below 15,700 barrels of oil per day.

For additional information about our acquisitions and dispositions, please read note 23 of the notes to our consolidated financial statements in Item 18 of this annual report.

Our Business Priorities

Following our financial reorganization in 2003 and the sale of Pertra, we intend to create value for our shareholders by being a more focused oil-services group, building on increased cash flow from and returns on our present assets and pursuing selective growth opportunities.

We intend to continue our focus on our health, safety and environment ("HSE") performance and strengthening internal controls, corporate governance and human resource capabilities.

Within Marine Geophysical, we intend to maintain our emphasis on high acquisition productivity and regularity in our operations and in customer delivery. We will seek to expand our market share in the data processing business and invest prudently in technology, equipment and multi-client seismic data.

Within Onshore, we will seek to expand our business by fully utilizing our present equipment, while selectively broadening our geographical market exposure.

Within our Production segment, we intend to maintain our position as a leader in harsh environment operations, while seeking growth opportunities in and outside the North Sea.

Our Geophysical Services

Overview

We manage our geophysical services through two segments:

- *Marine Geophysical,* which consists of both streamer and seafloor seismic data acquisition, marine multi-client library and data processing; and
- *Onshore,* which consists of all seismic operations on land and in very shallow water and transition zones, including our onshore multi-client library.

Our geophysical services business is one of the major global participants in the acquisition of marine three-dimensional (3D) seismic data. This business acquires, processes, interprets, markets and sells seismic data worldwide that is used by oil and natural gas companies to help them find oil and natural gas and to determine the size and structure of known oil and natural gas reservoirs. In our seismic projects, we are involved in planning the seismic surveys and acquiring and processing the seismic data. Oil and natural gas companies use this information in evaluating whether to acquire new leases or licenses in areas with potential accumulations of oil and natural gas, in selecting drilling locations, in modeling oil and natural gas reservoir areas and in managing producing reservoirs. Oil and natural gas companies use 4D or time lapse surveys, which are surveys produced by the repetition of identical 3D surveys over time, to assist in their evaluation of subsurface geophysical conditions that change over time due to the depletion and production of reservoir fluids. This evaluation provides for more efficient production of the reservoir and the possible extension of the reservoir's useful life. We use our High Density 3D — HD3D℠ — technology to acquire 3D data with higher trace densities, giving improved resolution of the subsurface and higher quality images of the reservoirs.

We acquire seismic data both on an exclusive contract basis for our customers and on our own behalf as 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. During 2004, we continued our deliberate shift in the utilization of our data acquisition capacity from multi-client to the contract market such that we used a substantial majority of our capacity in the contract market.

During 2004, we:

- continued our strong HSE performance;
- continued our focus on contract seismic, although this part of our business was negatively affected by a weak market and by external operational disturbances in the first half of the year;
- further reduced our investments in multi-client seismic while at the same time achieved higher levels of pre-funding;

- increased significantly our late-sales of multi-client data; and
- increased significantly our contract order backlog in Marine Geophysical.

Our Strategies for Geophysical Services

Our principal strategies for our geophysical services include:

- capitalizing on our strong cost position and operating performance;
- increasing utilization and productivity of, and operating margins on, our acquisition capacity by
  - reducing steaming and down-time in Marine Geophysical,
  - entering selected new geographic areas in Onshore, and
  - positioning ourselves to benefit from improved contract market conditions;
- regaining growth and profitability in data processing by
  - capturing the full potential of our data processing Mega-Centers,
  - commercializing new technology, and
  - increasing our market share, especially in high-end processing, including depth migration;
- rebuilding a profitable multi-client data acquisition business by
  - prudently increasing activity from very low 2004 levels,
  - strengthening our emphasis on the target selection process and assessment of prospectivity,
  - revitalizing our existing library through reprocessing, and
  - reducing risk through high levels of pre-funding;
- investing selectively in new technology and equipment, including new streamers, to increase productivity of our unique Ramform seismic vessels and our HD3D℠ seismic solution; and
- identifying and pursuing through selective acquisitions attractive growth opportunities.

In the past, we have invested heavily in our multi-client seismic data library and in high technology acquisition equipment, including:

- our Ramform seismic vessels and deep water seafloor FOURcE℠ acquisition systems;
- our high capacity computing facilities, together with the development of specialized proprietary software for seismic imaging, multi-component processing, signal enhancement and visualization technology; and
- state-of-the-art technology in our onshore seismic data acquisition equipment to enable efficient acquisition of high quality seismic data in varied terrain.

We believe that our main competitive strengths within our geophysical services businesses include:

- high operational reliability, safety and customer satisfaction;
- our ability to tow more streamers and our superior streamer retrievability, control and stability, which yield better cost effectiveness on large surveys and in adverse weather conditions, respectively;
- our high technology Ramform seismic vessels and deep water seafloor FOURcE℠ acquisition systems;
- the high channel count for our onshore operations; and
- our highly experienced work force.

Geographic Areas of Operation

We have divided our Marine Geophysical business into three primary areas of operations:

- North and South America;
- Europe, Africa and the Middle East; and
- Asia Pacific.

We have divided our Onshore geophysical business into three primary areas of operations:

- North America (U.S. and Canada);
- Latin America (Mexico and South America); and
- Eastern Hemisphere.

We acquire seismic data in most of the active oil and natural gas exploration or production areas around the world, including:

- offshore and onshore Canada;
- the Gulf of Mexico;
- onshore in the U.S. mid continent, Rocky Mountains and Alaskan North Slope regions;
- offshore and onshore Mexico and other parts of Latin America;
- offshore Brazil;
- the North Sea;
- the Mediterranean and Black Seas;
- offshore West Africa;
- the Middle East and North Africa;
- the Caspian Sea area;
- offshore China and Korea;
- offshore India and onshore Bangladesh;
- offshore in the Sakhalin area of Russia; and
- offshore Australia, Indonesia and other countries in the Asia Pacific region.

Contract and Multi-Client Operations

Contract Operations. When we acquire seismic data on a contract basis, our customers direct the scope and extent of the survey and retain ownership of the data obtained. Contracts for seismic data acquisition, which are generally awarded on a competitive bid basis, may include both a day-rate and a production rate element. Under these contracts, the customer assumes primary responsibility for interruption of acquisition operations due to factors that are beyond our control, including weather and permitting. Contracts are also awarded on a turnkey basis. With turnkey contracts, the customers pay based upon the number of seismic lines or square kilometers of seismic data collected and we often bear some or all of the risk of interruption of operations due to factors that may be beyond our control.

During 2004, we further increased our emphasis on acquiring seismic data on a contract basis. We performed contract operations during 2004 in the North Sea; offshore and onshore Mexico; offshore West Africa, Australia, India and other countries in the Asia Pacific region; offshore Brazil and onshore Latin America; offshore and onshore Canada; onshore in the U.S. mid-continent, Rocky Mountains, Gulf Coast and Alaska, offshore the Middle East and offshore and onshore Central Asia.

Multi-Client Operations. From the perspective of an oil and natural gas company, licensing multi-client seismic data on a non-exclusive basis is typically less expensive on a per unit basis than acquiring the seismic data on an exclusive basis. From our perspective, multi-client seismic data can be 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 has the potential to be more profitable than contract data. However, 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. Obtaining prefunding for a portion of these costs reduces this risk, and increasingly we require a relatively high level of prefunding before beginning a project. We determine the level of prefunding that we will require before initiating a multi-client seismic survey 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 prospectivity of the area in question for hydrocarbons and for future licenses of multi-client data;
- the existing infrastructure in the region to transport oil and natural gas to market;
- the historical turnover of the leased acreage;
- the political and economic stability of the countries where the data are to be acquired; and
- the level of interest from oil and natural gas companies in the area.

We own a significant library of marine multi-client data in most of the major oil and natural gas basins of the world, including the Gulf of Mexico, the North Sea, offshore West Africa, offshore Brazil and the Asia Pacific region. Our onshore library is entirely in North America. We continue to build and market our multi-client data library, including seafloor and onshore data, but we also intend to acquire multi-client data in additional geographic areas from time to time. During both 2004 and 2003, we substantially reduced the amount we invested in new multi-client data, as compared to earlier years, and devoted a higher portion of our capacity to the contract market.

In our multi-client operations, we make initial sales of the data prior to project completion, which we refer to as prefunding sales, and we refer to all further sales as late sales. We make a substantial portion of these late sales in connection with acreage license round activity in those regions where we have a data library. Typically, customers are required to pay an amount for access to the data and additional amounts, or uplift fees, upon award of a concession or sometimes upon execution of a production sharing or similar contract. The timing and regularity of such license round activity varies considerably depending upon a number of factors, including in particular the geopolitical stability of the region in question. As a result, both the total amount and the timing of late sales can be difficult to forecast accurately, with potentially significant revenue swings from quarter to quarter and from year to year.

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

Our multi-client data is marketed primarily through our own sales organization.

Data Processing

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

We reorganized our data processing division during 2003 to be part of our regional Marine Geophysical business unit. Technical support, research and development and computer operations continue to be provided on a global basis. As of March 31, 2005, we operated twelve land-based seismic data processing centers, with the largest centers being located in Houston, Texas, U.S.; London, England; Lysaker, Norway; Cairo, Egypt; Rio de Janeiro, Brazil; and Perth, Australia. The largest seismic processing centers utilize computer resources organized in a global computer resource organization (Mega-Center) consisting of three major computer centers located in Houston, London and Perth. These three centers are inter-connected through high capacity network links. In addition, most of our marine seismic crews have the capability to perform data processing on board the vessel.

Through our seismic data processing operations we provide:

- 2D and 3D data processing of onshore and marine seismic surveys;
- onboard (vessel) seismic data processing for reduced delivery times and enhanced real-time quality control for data that we acquire;
- multi-component and 4D seismic data processing for reservoir characterization and monitoring;
- special process design to exploit the dense sampling of our HD3D℠ data acquisition;
- specialized depth imaging of subsurface structures; and
- other specialized signal enhancement techniques.

Our Marine Geophysical Segment

Marine Acquisition. We believe that we operate one of the most advanced marine seismic data acquisition fleets in the world. As of March 31, 2005, we had a total of ten 3D marine seismic streamer crews operating seismic vessels, and we had one seafloor seismic crew.

Streamer Seismic Acquisition. Our conventional streamer operations represent the largest part of our marine seismic data acquisition business. In our streamer operations, we use our seismic vessel fleet to acquire 3D, 4D and HD3D℠ seismic data as described above under "Our Geophysical Services — Overview." For information relating to our fleet of vessels used to acquire marine seismic data, see "Vessel Fleet and Crews" below.

Seafloor Seismic Acquisition. We use seafloor seismic acquisition 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. As of March 31, 2005, we had one seafloor seismic crew that utilized a recording vessel, a source vessel and a cable laying vessel.

In our multi-component seafloor seismic operations, we record both hydrophone and three component geophone data simultaneously. 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 the chances of maximizing total reserve recovery at the production stage.

Vessel Fleet and Crews. 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 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.

Most of our seismic vessels have an equipment complement consisting of the following:

- recording instrumentation;
- digital recording streamers;
- acoustic positioning systems for source and streamer locations;
- multiple navigation systems for vessel positioning; and
- except for vessels that record only, a source control system that controls the synchronization of the energy sources and an airgun array firing system that activates the acoustic energy source.

For seafloor seismic operations, the *Ocean Explorer* and the *Bergen Surveyor* each has 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.

We provide in the following table information as of March 31, 2005 about our marine seismic data acquisition vessels.

Vessel Name	Year Rigged/ Converted	Total Length (Feet)	Total Beam (Feet)	Maximum Streamer Capability	Maximum Streamers Deployed (through December 31, 2004)	Owned or Charter Expiration
3D Seismic Vessels:						
Ramform Explorer	1995	270	130	12	8	Owned
Ramform Challenger	1996	284	130	16	12	Owned (1)
Ramform Valiant	1998	284	130	20	12	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	300	72	8	8	Owned
Nordic Explorer	1993	266	54	6	6	Owned
Orient Explorer	1995/96	246	49	4	4	2005 (2)
Seafloor Seismic Vessels:						
Falcon Explorer	1997	266	53	N/A	N/A	Owned
Bergen Surveyor	1997	217	48	N/A	N/A	2005 (3)
Ocean Explorer	1993/95	269	59	N/A	N/A	Owned
Support Vessels:						
Remus	1998	136	32	N/A	N/A	Owned
Romulus	1997	118	34	N/A	N/A	Owned

(1) We have UK lease arrangements for each of the *Ramform Valiant*, the *Ramform Viking*, the *Ramform Victory*, the *Ramform Vanguard* and the *Ramform Challenger*. Under the leases, we lease the vessels 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. The leases are legally defeased because we have made payments to banks in consideration for which the banks have assumed liability to the lessors equal to basic rentals and termination sum obligations. Please read notes 2 and 19 of the notes to our consolidated financial statements included in Item 18 of this annual report.

(2) The charter agreement for Orient Explorer has a one year term and will be extended annually for another year until 2011, unless we terminate the charter by giving three months' notice.

(3) The charter for *Bergen Surveyor* continues until terminated by us on four months' notice.

Competition in Our Marine Geophysical Segment. 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, crew availability, turnaround time and processing capacity availability. Our largest competitors on a global basis are WesternGeco, a joint venture between the seismic units of Schlumberger Limited and Baker Hughes Incorporated, Compagnie Generale de Geophysique, S.A. and Veritas DGC Inc.

All of our major competitors in the seismic business both acquire and process 3D seismic data. Our processing operations compete primarily with WesternGeco, Compagnie Generale de Geophysique and Veritas DGC for time processing contracts. For depth imaging and other advanced processing applications, we also compete with several smaller processing companies. We compete for time processing contracts based primarily on price and technology, but processing capacity, turnaround time and processing center location are also important factors.

Our Onshore Segment

Our Onshore segment consists of all our seismic acquisition operations on land and in very shallow water and transition zones, including the onshore multi-client library. We conduct contract onshore seismic acquisition throughout the world. Our onshore multi-client library is entirely in the United States. During 2004, we conducted seismic acquisition operations in the United States (Gulf Coast, mid-continent, Rocky Mountains and Alaska), Canada, Mexico, Ecuador, Bolivia, Venezuela and Bangladesh. During 2004, active crew counts have ranged from five to seven. As of March 31, 2005, we had six crews conducting activities in the United States, Canada, Mexico and Venezuela. We also have environmental specific operating equipment in Alaska and in the Middle East. We are pursuing additional contract opportunities in Mexico, South America, Africa, Central Asia, the United States, Canada and the Middle East and are expanding our multi-client onshore library in the U.S. mid-continent.

In the market for onshore seismic services, we are a medium-sized operator among a large number of regional and global competitors. Competition in the onshore segment is intense and varies from region to region. In particular, we have seen increased competition from Chinese operators who have aggressively expanded their global presence. We believe that we can remain competitive by capitalizing on our project execution and management skills and by continuing to provide a high quality technical product. The majority of our recording equipment pool is relatively uniform, facilitating changing crew counts and channel counts on any specific crew as the market dictates.

Our Production Segment

Overview

We are one of the largest operators of FPSO vessels in the North Sea, measured by production capacity and number of vessels. Through our Production segment, we own and operate four FPSO vessels with a combined production capacity of 339,000 barrels of oil per day and a crude oil storage capacity of one million barrels. All four of our FPSOs, the *Ramform Banff, Petrojarl I, Petrojarl Foinaven* and *Petrojarl Varg*, are double hulled, rated for harsh environments and capable of working in deepwater fields.

We believe that our fleet of FPSO vessels is one of the most technologically advanced in the industry. We have experience operating in some of the industry's most demanding environments in the North Sea and the continental shelf of the Atlantic Ocean.

An FPSO system is a ship-based type of mobile production unit that produces, processes, stores and offloads oil and processes, reinjects or exports 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 several factors, including overall reservoir and environmental characteristics of the field to be developed, availability of transportation infrastructure and financial and schedule constraints. FPSO systems typically perform the same function as fixed offshore platforms in the offshore production of oil and natural gas, with the exceptions of drilling and heavy well maintenance. However, FPSO systems generally provide a number of advantages over fixed platforms, including:

- capable of storing and offloading oil;
- 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; and
- reducing the time from the discovery of oil and natural gas to production.

Our FPSO Strategy

Our strategy for production services includes:

- capitalizing on our strong North Sea floating production operations;
- maximizing the value of our existing contracts through maintaining a high level of operational performance, through incentive structures and through pursuing opportunities to extend the contracts;
- seeking and supporting NCS small-field development projects suitable for our FPSO fleet; and
- seeking opportunities to expand our vessel fleet and to broaden our competence and geographical business scope.

We believe a number of opportunities exist in the North Sea, particularly on the Norwegian Continental Shelf where we currently operate two vessels, to redeploy our FPSO vessels when our existing FPSO contracts terminate. We also intend to continue to evaluate redeployment opportunities in other regions.

The FPSO Market

The market for production services differs fundamentally from the geophysical market. Offshore production generally takes place a relatively long time after exploration drilling has been completed. As a result, oil and natural gas companies typically make production-related decisions based on different financial parameters than those used for decisions relating to seismic or drilling activities. As offshore hydrocarbon basins around the world in general have matured, oil and natural 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 natural gas companies must reduce development cost levels and financial exposure. As a result, producers have focused increasingly on subsea installations and reusable FPSO systems instead of the more traditional fixed steel and concrete platforms, which generally are not reusable.

Our FPSO Systems

We provide in the following table information as of March 31, 2005 about our four FPSO vessels. In addition to these four vessels, as of March 31, 2005 we used three FPSO shuttle tankers (one of which was subleased) and one storage tanker from third-party contractors under operating leases expiring at various dates through 2013. In addition, as of March 31, 2005 we owned a 40% interest in a French company that owns the FPSO *Ikdam*, which is producing the Isis field located offshore Tunisia on a fixed day rate contract. As of that date, production from this vessel was approximately 3,000 barrels per day with a maximum processing capacity of 30,000 barrels per day.

FPSO Vessel Name	Year Delivered	Approximate Total Length (Feet)	Approximate Total Width (Feet)	Production Capacity (Barrels of Oil per Day)	Displacement (Metric Tons)	Storage Capacity (Barrels)
Ramform Banff(1)	1998	395	175	95,000	32,100	120,000
Petrojarl I	1986	683	105	47,000	51,000	180,000
Petrojarl Foinaven(1)	1996	827	116	140,000	72,000	280,000
Petrojarl Varg	1999	702	125	57,000	100,000	420,000

(1) We have UK lease arrangements for the *Petrojarl Foinaven* and for the *Ramform Banff* topside production equipment. Under the leases, we lease the vessel and equipment under long-term charters that give us the option to purchase the vessel and equipment for a *de minimis* amount at the end of the charter periods. The leases are legally defeased because we have made payments to banks in consideration for which the banks have assumed liability to the lessors equal to basic rentals and termination sum obligations. Please read notes 2 and 19 of the notes to our consolidated financial statements included in Item 18 of this annual report.

Ramform Banff

The *Ramform Banff* operates on the Banff field, located in the UK sector of the North Sea about 120 miles east of Aberdeen, Scotland. Our contract for this work dates to 1997, and oil production from the field commenced in January 1999.

Under the existing contract with the field operator, which became effective January 1, 2004, we will continue to produce the Banff field with the *Ramform Banff* until the end of the life of the field. The new contract contains a two-tier production-dependent tariff that varies at different production levels. We receive $5 per barrel of oil produced per day up to 15,400 barrels and $3 per barrel of oil produced per day in excess of 15,400 barrels. We also receive a fixed day rate of £40,000 (approximately $76,000) per day, with a minimum total rate of $125,000 per day ($126,800 per day from January 1, 2005). These rates are applicable for production through 2014, with provisions for cost index adjustments. If field production extends beyond 2014, we will be entitled to an increased day rate. Under the amended contract, the field operator has the right to terminate the contract at its sole discretion on six months' notice. Upon termination of the contract, the field operator has the option to acquire the subsea facilities of the *Ramform Banff* free of charge or cost. In the event that the field operator does not exercise its option, we are obligated to remove the subsea facilities at our cost and, upon completion of our obligations under the contract, the operator will owe us five million British pounds.

In October 2004, one well from the nearby Kyle field commenced production through the *Ramform Banff*. We expect more wells from the Kyle field to be tied in to *Ramform Banff* during 2005.

Petrojarl I

We operate the *Petrojarl I* under contract to 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 August 2001. Based on production estimates filed by the operator, we expect production under the contract to continue into 2007.

The contract provides for compensation consisting of a tariff-based element of $3.50 per barrel and a fixed day rate of $12,750 plus up to $5,000 per day for water injection, subject to a minimum of $58,500 and a maximum of $108,500. In addition, we are entitled to receive an additional amount of NOK 455,088 (approximately $74,000) per day for operating expenses. Statoil may cancel the contract on six months' notice. In addition, Statoil may terminate the contract upon specified force majeure events; the insolvency or bankruptcy of our subsidiary K/S Petrojarl I A/S or demonstration by that subsidiary that it is not capable of performing the work; or our substantial breach of the contract. We may cancel the contract on three months' notice if the minimum variable rate has been received for 90 days in a 120 day period, subject, however, to Statoil's right to continue the contract by increasing the tariff element.

Petrojarl Foinaven

The *Petrojarl Foinaven* is under contract to a consortium of field co-operators led by Britoil PLC, a subsidiary of BP plc, for production of the Foinaven field west of the Shetlands. The Foinaven contract is not limited as to time. Britoil may terminate the contract with a minimum of two years' notice. We currently expect that the vessel will remain on the field for a substantial period. In the event of cancellation by Britoil taking effect before November 2007, the contract provides that Britoil will pay a cancellation fee of $12 million. No cancellation fee will be payable by Britoil with respect to a cancellation after November 2007. Britoil may also terminate the contract without paying a cancellation fee upon the total loss of the vessel, a breach of the contract that is not remedied within agreed deadlines, specified insolvency and bankruptcy related events or specified force majeure events. In addition, we may terminate the contract with prior notice if production-dependent tariff revenue falls below specified levels.

The contract provides for compensation consisting of a fixed day rate of $67,308 and a two-tier production-dependent tariff that varies at different production levels. We receive $3.50 per barrel of oil produced per day up to 25,000 barrels and $2.95 per barrel of oil produced per day in excess of 25,000 barrels, and we receive $0.75 per barrel of oil produced per day from East Foinaven. The contract provides for guaranteed minimum production amounts of 51,000 barrels per day for the twelve month period that ended in November 2003, 35,500 barrels per day for the twelve month period ending in November 2004 and 24,000 barrels per day for the twelve month period ending in November 2005.

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 some breaches of contract; and
- pay for pollution damage caused by diesel or lubricants.

Petrojarl Varg

The *Petrojarl Varg* produces the Varg field on the Norwegian Continental Shelf of the North Sea under a contract with the license owners of Production License ("PL") 038, where production began in December 1998. Pertra, which was our subsidiary until March 1, 2005 and has been renamed Talisman Production Norge AS, has a 70% interest in PL 038, which includes the Varg field. The remaining 30% is held by Petoro, manager of the Norwegian State's Direct Financial Interests.

Under the existing charter and operating agreement with the PL 038 license owners, our compensation consists of a fixed base day rate of $90,000 and a tariff of $6.30 per barrel produced per day. The charter and operating agreement may be terminated with 90 days' written notice, but we are not entitled to terminate the agreements as long as the mean weekly production during normal operation on the license exceeds approximately 15,700 barrels of oil per day.

In connection with our sale of Pertra in March 2005, we entered into an agreement under which the PL038 license holders have an option, at their discretion, to extend the term of the charter and operating agreement for the *Petrojarl Varg* until 2010. The option is exercisable until February 1, 2006, and if exercised the license owners will be obligated to pay us $22.5 million and to guarantee a minimum of $190,000 per day as compensation for the use of *Petrojarl Varg*.

As a result of development work on the Varg field during 2004, underlying field output levels increased substantially during 2004. However, in the fourth quarter of 2004 production from the field was negatively affected by two events: a shut down for approximately two weeks in October caused by a labor conflict on the NCS and damage of the main production riser on November 5. As a result of the riser damage, production was limited to a daily maximum of approximately 15,000 barrels, approximately one half of the production run rate at the time of the incident. The field returned to normal production after a successful installation of a new riser in early March 2005.

Employee Lockout and Strike in September/October 2004

Petrojarl I was selected by the Norwegian Shipowners Association to be included in a general employee lockout affecting several NCS installations. Production from the *Petrojarl I* was shut down from September 12 through October 27, 2004. For approximately two weeks in October 2004, production on the *Petrojarl Varg* was shut down as a result of the same labor conflict. The labor conflict ended in late October 2004 after intervention by Norwegian authorities. Because of *force majeure* and other payments we received for operations during these periods, this labor conflict did not have a material adverse effect on our Production segment. However, our oil and natural gas subsidiary lost approximately two weeks of oil production from the Varg field.

Competition in Our Production Operations

Our production operations generally compete with oil companies deciding to operate FPSOs themselves, with other FPSO operators, with fixed installations and tension leg platforms, with subsea production installations tied back to existing infrastructure, with semi-submersible and jack-up platforms and with other floating or land-based production systems. 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, estimated reserves, the cost and schedule for modifications, as well as local regulatory framework. Competition tends to be limited within segments of processing plant sophistication, operating conditions and regulatory regimes, as FPSO systems having different specifications cannot be redeployed easily or cost effectively between these segments. Our fleet of FPSOs is designed specifically for harsh weather operations, limited shuttling distances and demanding regulatory regimes, such as typically found in the North Sea and the Atlantic Continental Shelf. The limited shuttling distances required for our FPSOs results in relatively low need for storage capacity. In addition to the FPSO operations and other offshore production systems of the major oil and natural gas companies, our FPSO competitors include numerous companies that own a small number of FPSO vessels.

FPSOs perform similar tasks as fixed installations, with the exception of drilling and heavy well maintenance. To combine drilling and heavy well maintenance with production, some oil companies have opted for semi-submersible platforms. The choice of development system between an FPSO and either a fixed installation or another floating system is dependent on an overall technical and financial evaluation of the individual field to be developed.

Oil and Natural Gas Production Segment (Pertra)

We sold Pertra to Talisman in March 2005 as described in more detail under "Operating and Financial Review and Prospects — Sale of Our Oil and Natural Gas Subsidiary Pertra" in Item 5 of this annual report. The operations of Pertra will be reported as discontinued operations starting with our 2005 consolidated financial statements. At the time of releasing such financial statements, the operations of Pertra will also be reclassified to discontinued operations in our consolidated financial statements for prior periods that accompany our 2005 financial statements. Since the decision to sell Pertra was made after December 31, 2004, Pertra is included our 2004 consolidated financial statements as ongoing operations. Following our sale of Pertra, we do not have any continuing direct economic interest in the activities of Pertra except for certain additional contingent sales proceeds as described under "Operating and Financial Review and Prospects — Sale of Our Oil and Natural Gas Subsidiary Pertra" in Item 5 of this annual report and our continued production of the Varg field using *Petrojarl Varg* as described in more detail under "Information on the Company — Our Production Segment — Petrojarl Varg" in Item 4 of this annual report.

We formed Pertra AS in late 2001 to secure continued employment of the *Petrojarl Varg*, to pursue small field opportunities on the NCS and to act as a facilitator for FPSO opportunities. Pertra was formally approved in February 2002 as a license holder and operator on the NCS of the North Sea.

In August 2002, Pertra acquired a 70% interest in, and achieved operatorship of, the Varg field and PL 038. PL 038 is located approximately 140 miles southwest of Stavanger in the Norwegian Sector of the North Sea and includes the Varg oil field and the Varg South discovery.

For approximately two weeks in October 2004, production on the Varg field was shut down as a result of a labor conflict involving a number of service providers on the NCS. Production from the Varg field was further reduced to a daily maximum of approximately 15,000 barrels per day as a result of damage to the main production riser going from the wellhead platform to *Petrojarl Varg* that occurred on November 5, 2004. The field returned to normal production after a successful installation of a new riser in March 2005.

Pertra continued significant development work on the Varg field in 2004, with a drilling rig working throughout the entire year. In total, five development wells were completed on the Varg field during 2004. In addition, one dry exploration well was drilled on the "Villmink" prospect in PL 038.

Pertra was awarded participation in two new licenses in the 18th round licensing awards offshore Norway in June 2004. Pertra was further awarded participation in an additional four licenses in the 2004 Predefined Areas Round in December 2004.

The following table presents our estimated net proved oil and natural gas reserves as of December 31, 2004, 2003 and 2002. The December 31, 2004 and 2003 reserve estimates were prepared by our engineers and were reviewed by an independent reservoir engineering consultant. The process of estimating natural gas and oil reserves is complex and inherently imprecise and requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. In the reserve calculation we did not include any reserves related to the expected 2005 drilling program since a finally approved budget for this program was not concluded at December 31, 2004. As a result, the reserves included in the below table do not include any undeveloped reserves. In addition, the quantities of developed reserves are affected by the exclusion of reserves expected to be developed by the 2005 drilling program since the exclusion affects economic cut-off in the computations.

	December 31,		
	2004	**2003**	**2002**
Proved Crude Oil Reserves (in thousands of barrels):			
Developed	5,477	2,114	3,272
Undeveloped	—	5,704	865
Total	5,477	7,818	4,137

By October 15 of each year, we report oil and natural gas reserves estimated as of the upcoming year end to the Norwegian government for inclusion in the Revised National Budget. These reserves include all categories (proved, probable and possible) and are not limited by economic cut-off. As a result, such reserves reported to the Norwegian government are not comparable to the proved reserves included in this annual report.

We had net oil production of 5,317,134 barrels, 4,056,083 barrels and 1,297,767 barrels for the years ended December 31, 2004, 2003 and 2002, respectively. Please refer to other information regarding our oil and natural gas production in note 29 of the notes to our consolidated financial statements included in Item 18 of this annual report.

Other Factors Related to Our Business

Our 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 natural 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 natural 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 consolidated statements of operations in Item 18 of this annual report.

Our research and development activities carried out in 2004 include development of:

- a complete deep water handling system, installed on our seismic sea floor crew and successfully deployed in water depth of more than 1,800 meters;
- a new generation of solid streamers (in collaboration with Teledyne), which streamers were installed on the Atlantic Explorer;
- a new methodology for determining how much "infill" is needed during seismic acquisition operations;
- the high-end visualization tool holoSeis and the implementation of this tool onboard our seismic vessels to improve the quality control process of seismic data during acquisition;
- a portfolio of pre-stack depth migration software; and
- advanced data processing technology, including imaging for true 3D multiple attenuation.

Seasonality

We incorporate by reference in response to this item the information in "Operating and Financial Review and Prospects — Seasonality" in Item 5 of this annual report.

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 and a program for developing, implementing and managing our responsibility for the health and safety of our employees and the environments in which we operate. Systems for reporting and tracking the occupational health of our employees are in place in our business units. Company-wide initiatives focus on the further development of our environmental management systems. All our FPSO units and associated shuttle tankers are ISO 14001 certified (environmental certification). We consider each employee to be a vital contributor to health, safety and environment in our company, and we are fully committed to our health, safety and environment program.

In 1994, we established our own captive re-insurance company that provides insurance for our seismic equipment, including marine acquisition vessels and equipment, onshore equipment, data processing and information technology hardware and software, and some of our production equipment including FPSOs and shuttle tankers. As part of this insurance, all of our seismic vessels, shuttle tankers and FPSOs have a level of coverage against war and terrorism risks that is customary for our industry. We do not generally maintain such insurance for our land-based assets because we do not believe such insurance is cost effective. As noted below, this insurance is subject to deductibles and limits of coverage and is supplemented by commercial reinsurance arrangements with creditworthy reinsurers.

We obtain a substantial portion of our casualty insurance through this wholly-owned captive re-insurance company. This company retains risk of $4.5 million for each accident, with a maximum risk retention of $9.4 million per year, in excess of underlying deductibles. Our various operating companies also retain levels of risk when obtaining this casualty insurance from the captive company, ranging from $150,000 per accident for our seismic vessels, up to $200,000 per accident for our streamers and $750,000 per accident for our FPSOs.

Governmental Regulation

In various areas of the world, we are required to obtain and we have acquired licenses to acquire multi-client seismic data. Licensing and permitting requirements vary widely. We believe that we have complied in all material respects with the licensing and permitting requirements relating to our acquisition of multi-client data.

Our operations are also affected by the exploration and production licensing requirements 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 for the newly licensed areas if they have not previously obtained multi-client data. 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, including Brazil and Brunei, the timing and extent of these licensing rounds tend to be irregular, and the licenses awarded may be subject to resolution of border disputes. The length of the actual license to explore for oil and natural gas varies from region to region and is subject to governmental regulation.

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

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

Our operations are subject to a variety of laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous governmental departments issue rules and regulations to implement and enforce such laws that are often complex and costly to comply with and that can carry substantial penalties or fines for failure to comply. Under these laws and regulations, we may be liable for remediation or removal costs, damages and other costs associated with releases of hazardous materials including oil into the environment.

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 Generally — Unpredictable changes in governmental regulations could increase our operating costs and reduce demand for our services" in Item 3 of this annual report.

Capital Expenditures

We incorporate by reference in response to this item the information in "Operating and Financial Review and Prospects — Liquidity and Capital Resources — Capital Requirements and Commitments" in Item 5 and note 26 of the notes to our consolidated 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.

Geographic Mix of Operations and Segment Information

We incorporate by reference in response to this item the information regarding the geographic mix of our operations and segments, including revenue breakdowns, in note 26 of the notes to our consolidated financial statements in Item 18 of this annual report.

Organizational Structure

We provide in the following table a list of our subsidiaries and affiliated companies as of March 31, 2005.

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 AS	Norway	100%
Multiklient Invest AS	Norway	100%
Petroleum Geo-Services, Inc.	United States	100%
Petroleum Geo-Services (UK) Ltd.	United Kingdom	100%
Seahouse Insurance Ltd.	Bermuda	100%
PGS Mexicana SA de CV	Mexico	100%
PGS Rio Bonito SA	Brazil	99%
Dalmorneftegeofizika PGS AS	Norway	49%
Walther Herwig AS	Norway	100%
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 Capital, Inc.	United States	100%
Diamond Geophysical Services Company	United States	100%
PGS Exploration (Nigeria) Ltd.	Nigeria	100%
PGS Data Processing Middle East SAE	Egypt	100%
PGS Data Processing, Inc.	United States	100%
Petroleum Geo-Services Asia Pacific Pte. Ltd.	Singapore	100%
PGS Australia Pty. Ltd.	Australia	100%
Atlantis (UK) Ltd.	United Kingdom	100%
PGS Egypt for Petroleum Services	Egypt	100%
Hara Skip AS	Norway	100%
PGS Exploration, SDN BHD	Malaysia	100%
PGS Exploration, Inc.	United States	100%
PGS Exploration Pty. Ltd.	Australia	100%
PGS Ocean Bottom Seismic, Inc.	United States	100%
PGS Exploration (UK) Ltd.	United Kingdom	100%
PGS Floating Production (UK) Ltd.	United Kingdom	100%
PGS Pension Trustee Ltd.	United Kingdom	100%
PGS Reservoir (UK) Ltd.	United Kingdom	100%
Atlantic Explorer Ltd.	Isle of Man	50%
Oslo Seismic Services Inc.	United States	100%

Name	Jurisdiction	Ownership
Oslo Explorer Plc	Isle of Man	100%
Oslo Challenger Plc	Isle of Man	100%
PGS Shipping (Isle of Man) Ltd.	Isle of Man	100%
PGS Onshore, Inc.	United States	100%
PGS Onshore (Canada), Inc.	Canada	100%
PGS Americas, Inc.	United States	100%
Seismic Energy Holding, Inc.	United States	100%
PGS Caspian AS	Norway	100%
PGS Multi-Client Seismic Ltd.	Jersey	100%
PGS Marine Services (Isle of Man) Ltd.	Isle of Man	100%
Golar-Nor Offshore AS	Norway	100%
Golar-Nor Offshore (UK) Ltd.	United Kingdom	100%
K/S Petrojarl I AS	Norway	98.5%
Golar-Nor (UK) Ltd.	United Kingdom	100%
Deep Gulf LLC	United States	50.1%
PGS Nopec (UK) Ltd.	United Kingdom	100%
PGS Nominees Ltd.	United Kingdom	100%
Petrojarl 4 DA	Norway	99.25%
SOH, Inc.	United States	100%
PT PGS Nusantara	Indonesia	100%
PGS Processing (Angola) Ltd.	United Kingdom	100%
Seismic Exploration (Canada) Ltd.	United Kingdom	100%
PGS Ikdam Ltd.	United Kingdom	100%
Sakhalin Petroleum Plc	Cyprus	100%
Ikdam Production, SA	France	40%
PGS Investigacào Petrolifera Limitada	Brazil	99%
Sea Lion Exploration Ltd.	Bahamas	100%
PGS Administración y Servicios S.A. de C.V.	Mexico	100%
PGS Servicios C.A.	Venezuela	100%
PGS Venezuela de C.A.	Venezuela	100%

Leased Premises

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

ITEM 5. *Operating and Financial Review and Prospects*

You should read the discussion under this caption in combination with consolidated 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 consolidated financial statements included in Item 18 of this annual report 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 Statements" for cautionary statements relating to forward-looking statements.

Overview

We are a technologically focused oilfield service company principally involved in providing geophysical services worldwide and providing floating production services in the North Sea. Globally, we provide a broad range of geophysical and reservoir services, including seismic data acquisition, processing and interpretation and field evaluation. In the North Sea, we own and operate four harsh environment FPSO units. During 2004, we owned a small oil and natural gas company with offshore operations on the NCS.

In 2004 we managed our business in four segments as follows:

- *Marine Geophysical,* which consists of both streamer and seafloor seismic data acquisition, marine multi-client library and data processing;
- *Onshore,* which consists of all seismic operations on land and in very shallow water and transition zones, including our onshore multi-client library;
- *Production,* which owns and operates four harsh environment FPSO units in the North Sea; and
- *Pertra,* a small oil and natural gas company that owned 70% of and was operator for Production License 038 ("PL038") on the NCS and also owned participating interests in additional NCS licenses without production.

We discuss below our results of operations based on these four business segments. For a more comprehensive discussion of our history and development, including our four business segments and our strategic focus, please read "Information on the Company" in Item 4 of this annual report.

We sold Pertra to Talisman in March 2005 as described in more detail below. In our 2004 financial statements, the results of Pertra are included in our consolidated statement of operations. In our 2005 financial statements, we will report the gain on the sale of Pertra and the operating results for Pertra for the first two months of 2005 as discontinued operations and we will reclassify all historical financial statements to report Pertra as discontinued operations. In addition, we will reclassify to external revenue the revenues from the *Petrojarl Varg* FPSO related to Pertra's 70% interest in the Varg field instead of being eliminated as inter-segment revenues, thereby increasing significantly the revenues of Production included in our consolidated statement of operations.

Following the sale of Pertra, we will focus on our remaining three business segments in the oilfield service sector. We manage our Marine Geophysical segment from Lysaker, Norway, our Onshore segment from Houston, Texas, and our Production segment from Trondheim, Norway.

Sale of Our Oil and Natural Gas Subsidiary Pertra

On March 1, 2005, we sold our wholly-owned subsidiary Pertra AS to Talisman for a sales price of approximately $155 million. We expect to recognize a gain from the sale for financial reporting purposes of approximately $140 million. We do not expect to incur any taxes from the transaction.

As part of the transaction, Talisman has agreed to share with us (on a post petroleum tax basis), on a 50/50 basis for each of 2005 and 2006, their revenues from production from their interest in the Varg Field in excess of $240 million.

In addition, we entered into an agreement with Talisman under which the PL038 license holders have an option, at their discretion, to extend the term of the charter and operating agreement for the *Petrojarl Varg* until 2010. The option is exercisable until February 1, 2006, and if exercised the license owners will be obligated to pay us $22.5 million and to guarantee a minimum of $190,000 per day as compensation for the use of *Petrojarl Varg.* We received $2.5 million at closing of the Pertra sale for granting this option. Under our existing contract with the PL038 license holders relating to the *Petrojarl Varg*, our compensation consists of a fixed base day rate of $90,000 and a tariff of $6.30 per barrel produced. Subject to the option, we currently have the right to terminate the agreement if production from the Varg field falls below 15,700 barrels of oil per day.

2003 Financial Restructuring

In 2003, we implemented a financial restructuring that was accomplished through a reorganization, which involved only our parent company and not any operating subsidiaries, under Chapter 11 of the U.S. Bankruptcy Code. The reorganization plan became effective and was substantially consummated on November 5, 2003, at which time we emerged from Chapter 11 reorganization. Under the reorganization plan, $2,140 million of our senior unsecured debt was cancelled, and the associated creditors received the following:

- $746 million of unsecured 10% Senior Notes due 2010;
- $250 million of unsecured 8% Senior Notes due 2006;
- $4.8 million of an eight-year unsecured senior term loan facility;
- 91% of our new ordinary shares as constituted immediately post restructuring, with an immediate reduction of this shareholding to 61% in a rights offering of 30% of the new ordinary shares to the pre-restructuring shareholders for $85 million, or $14.17 per share; and
- $40.6 million of cash, of which $17.9 million was distributed in December 2003 and the remainder in May 2004.

Under the reorganization plan,

- our pre-restructuring share capital was cancelled and 20,000,000 new ordinary shares, par value NOK 30 per share, were issued;
- the pre-restructuring shareholders received 4%, or 800,000, of the new ordinary shares and the right to acquire 30%, or 6,000,000, of the new ordinary shares for $85 million ($14.17 per share) in the rights offering;
- pre-restructuring owners of $144 million of trust preferred securities received 5%, or 1,000,000, of the new ordinary shares; and
- the principal amount of our interest-bearing debt and capital lease obligations was reduced by approximately $1,283 million to approximately $1,210 million immediately after the restructuring.

2003 Fresh Start Reporting and Changes in Accounting Policies

In connection with our emergence from Chapter 11 reorganization, we adopted "fresh start" reporting for financial statement purposes, effective November 1, 2003, in accordance with SOP 90-7. Under SOP 90-7, we adjusted the recorded value of our assets and liabilities to reflect their fair market value as of the date we emerged from Chapter 11 reorganization.

In connection with our adoption of fresh start accounting, we reviewed our accounting policies with a view toward creating new policies that are less complex, more transparent and better reflect current operations. The most significant changes in our accounting policies were:

- Expenditures incurred in connection with steaming and mobilization are expensed as incurred. Onsite project costs such as positioning, deploying and retrieving equipment at the beginning and end of a project are considered mobilization or demobilization costs and are expensed as incurred, unless the project relates to the building of the multi-client data library, in which case such costs are included in the costs of the multi-client survey. Such expenses were previously recognized as part of contract costs or multi-client project costs as appropriate, and as such would not have been fully expensed immediately.
- The successful efforts method of accounting for oil and natural gas assets was adopted.
- We made certain changes to our amortization policy for our multi-client library, including an increase in minimum amortization by reducing the maximum amortization period from eight to five years after completion of a survey.

- Depreciable lives of Ramform seismic acquisition vessels and FPSOs, other than the *Petrojarl I*, were reduced from 30 to 25 years.

Please refer to note 2 of our consolidated financial statements included in Item 18 of this annual report for disclosure of our significant accounting policies, including those policies that changed under fresh-start. Please refer to note 3 for disclosure of the fresh-start adjustments.

Internal Controls over Financial Reporting

For information relating to material weaknesses in our internal controls over financial reporting, please read "Controls and Procedures" in Item 15 of this annual report.

Critical Accounting Policies and Estimates

We discuss below our operating results and financial condition based on our consolidated financial statements, which are prepared in accordance with U.S. GAAP. In order to prepare these financial statements, we must make estimates and assumptions that affect the reported amount of assets and liabilities, our disclosure of contingent assets and liabilities and the amounts of reported revenues and expenses. We evaluate our estimates and assumptions from time to time and may employ outside experts to assist in our evaluations. We believe that our estimates and assumptions are reasonable, but we acknowledge that actual results may vary from what we have estimated or assumed. Our significant accounting policies are described in note 2 to the consolidated financial statements included in Item 18 of this annual report.

We list and summarize in greater detail below those accounting policies that we believe to be the most critical in the preparation and evaluation of our financial statements and that involve the use of assumptions and estimates that require a higher degree of judgment and complexity. As a result, our reported assets, liabilities, revenues and expenses could be materially affected if the assumptions and estimates we make were changed significantly, and our actual financial position, results of operations, cash flows and future developments may differ materially from the assumptions and estimates we have made. Our critical accounting policies and related estimates for the periods discussed below relate to:

- revenue recognition;
- multi-client data library, including cost capitalization, sales and amortization;
- oil and natural gas accounting, including capitalization, amortization and impairment;
- long-lived assets, particularly impairment and depreciation, depletion and amortization;
- deferred tax assets; and
- fresh start reporting.

Revenue Recognition

We recognize revenue on our contract sales of data and on our other geophysical services as we perform the services and are able to charge the customer for these services. Because of the nature of the geophysical services business, we incur and recognize costs from time to time prior to the time revenues can be recognized. As a result, a non-symmetrical matching of revenues and expenses may result in variability of results of operations between accounting periods. We generally recognize revenue from our floating production services in two components. First, we recognize tariff based revenues, based on the number of barrels produced, as production occurs. Second, we recognize day rate revenues over the passage of time. We recognize oil and natural gas production revenue when the production is delivered and ownership has passed to the customer.

Sales of data from our multi-client library generally fall into one of three categories.

- Late sales — we grant a license to the customer to a specified portion of the library.
- Volume sales agreements — we grant a license or licenses to a specified number of blocks in a defined geographical area so that the customer can select and access the specific blocks over a period of time.

- Pre-funding arrangements — we obtain funding from a limited number of customers before a seismic acquisition project commences. In return for the pre-funding, the customer typically gains the ability to direct or influence the project specifications, to access data as it is being acquired and to pay discounted prices.

We recognize revenue

- from late sales when the customer executes a valid license agreement and has been granted access to the library and collection is reasonably assured;
- from volume sales agreements ratably based on the total revenue and volume of data specified in the agreement as the customer executes licenses for specific blocks and has been granted access to the data; and
- from pre-funding arrangements as the data is acquired, generally based on physical progress, on a proportionate performance basis.

Multi-Client Data Library

We discuss revenue recognition relating to our multi-client library above under "— Revenue Recognition."

We capitalize as an asset the costs associated with acquiring and processing multi-client data. We base our amortization of the multi-client data library on the sales forecast method. Under this method, we amortize the cost of a particular survey contained in the library based on the ratio between the cost of the survey and the total forecasted sales of data for such survey. In applying this method following our adoption of fresh start reporting, we categorize surveys into three amortization categories with amortization rates of 90%, 75% or 60% of sales amounts. Each category will include surveys where the remaining unamortized cost as a percentage of remaining forecasted sales is less than or equal to the amortization rate applicable to each category. We have also established maximum book value criteria for the library projects based on a five-year life for marine and onshore projects and a three-year life for all derivative processed projects. The maximum book value for each project at year end is the total cost of the project less accumulated straight line minimum amortization. Prior to our adoption of fresh start reporting, we amortized our multi-client data library based on the ratio of actual sales to expected sales with a minimum amortization based on five to eight year lives.

We periodically evaluate the projects in the multi-client library for impairment. Effective January 1, 2004, we classify as amortization expense in our consolidated statements of operations write-downs of individual multi-client surveys that are based on changes in project specific expectations and that are not individually material. We expect this additional, non sales related, amortization expense to occur regularly because we evaluate projects on a project by project basis. We classify as impairment in our consolidated statements of operations write-downs related to significant changes in estimates affecting a larger part of our multi-client library and that are material. Prior to 2004 we classified as impairment expense all write-downs of multi-client library.

In determining the ordinary amortization rates applied to, and fair value of, our multi-client data library, we consider expected future multi-client sales, market developments and past experience. Our sales expectations include consideration of geographic locations, prospects, 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 that we do not control. Accordingly, these expectations could differ significantly from year to year. Our ability to recover costs included in the multi-client data library through sales of the data depends upon continued demand for the data and the absence of technological or regulatory changes or other developments that would render the data obsolete or reduce its value.

Through 2003, the sales expectations for our multi-client library declined significantly, reflecting a weakening of the market for multi-client data. As a result, our multi-client library amortization rates increased over time and we recognized an impairment of the multi-client data library of $90 million for the Predecessor for the ten months ended October 31, 2003 and $200.4 million for 2002.

Oil and Natural Gas Accounting

Following our adoption of fresh-start reporting, we used the successful efforts method of accounting for oil and natural gas properties. Under this method, all costs of acquiring unproved oil and natural gas properties and drilling and equipping exploration wells are capitalized pending determination of whether the properties have proved reserves. If an exploration well is determined not to have commercial quantities of reserves, the drilling and equipment costs for the well are expensed and classified as exploration costs at that time. All development drilling and equipment costs are capitalized. Capitalized costs of proved properties are amortized on a property-by-property basis using the unit-of-production method whereby the ratio of annual production to beginning of period proved oil and natural gas reserves is applied to the remaining net book value of such properties. Geological and geophysical costs are expensed as incurred and presented as exploration costs.

The estimates of proved oil and natural gas reserves as of December 31, 2004, 2003 and 2002 were prepared by our engineers in accordance with guidelines established by the SEC and the Financial Accounting Standards Board, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations except by contractual arrangements. The estimates were reviewed by an independent reservoir engineering consultant. Oil and natural gas reserve quantity estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment.

Prior to our adoption of fresh start reporting, we used the full cost method of accounting for oil and natural gas properties. Under this method, all costs associated with the acquisition, exploration and development of oil and natural gas properties are capitalized. Costs are accumulated on a country-by-country basis. Under this method, capitalized costs are amortized using the unit-of-production method on a country-by-country basis. Unevaluated properties are excluded from the amortization base. Future development costs and dismantlement and abandonment costs are included in the amortizable cost base. In accordance with SEC guidelines, the cost bases of proved oil and natural gas properties accounted for under the full cost method are limited, on a country-by-country basis, to the estimated future net cash flows from proved oil and natural gas reserves using prices and other economic conditions in effect at the end of the reporting period, discounted at 10%, net of related taxes. If the capitalized cost of proved oil and natural gas properties exceeds this limit, the excess is charged to expense as additional depletion, depreciation and amortization.

We sold our oil and natural gas subsidiary Pertra to Talisman in March 2005 as described in "Sale of our Oil and Natural Gas Subsidiary Pertra" above. For additional information about our oil and natural gas accounting, please read note 2 of the consolidated financial statements included in Item 18 of this annual report.

Accounting for Long-Lived Assets

We review long-lived assets or groups of assets for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If the total of the undiscounted future cash flows is less than the carrying amount of the asset or group of assets, an impairment loss is recognized for the difference between the estimated fair value and the carrying value of the asset or group of assets. We assess for possible impairment long-lived assets, such as multi-client data library, property and equipment, and proved oil and natural gas assets accounted for under the successful efforts method, upon the occurrence of a triggering event. Events that can trigger assessments for possible impairments include, but are not limited to (a) significant decreases in the market value of an asset, (b) significant changes in the extent or manner of use of an asset, (c) a physical change in the asset, (d) a reduction of proved oil and natural gas reserves based on field performance and (e) a significant decrease in the price of oil or natural gas. We assess for impairment unproved oil and gas properties in accordance with the guidelines of SFAS No. 19. Prior to the adoption of fresh-start reporting, we assessed for impairment oil and natural gas assets in accordance with the full cost accounting guidelines as described under "Oil and Natural Gas Accounting" above.

Estimating undiscounted future cash flows requires us to make judgments about long-term forecasts of future revenues and costs related to the assets subject to review. These forecasts are uncertain as they require assumptions about demand for our products and services, future market conditions and future technological developments. Significant and unanticipated changes in these assumptions could require a provision for impairment in a future period. Given the nature of these evaluations and their application to specific assets and specific times, it is not possible to reasonably quantify the impact of changes in these assumptions.

Deferred Tax Assets

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 have recorded valuation allowances for 100% of deferred tax assets due to cumulative losses in recent years and management's expectations about the generation of taxable income from contracts that are currently in effect. Because of these cumulative losses and future expectations, we concluded that it was more likely than not that the deferred tax assets would not be realized and have recognized the valuation allowances accordingly. To the extent that we continue to generate deferred tax assets, we will continue to assess the need for valuation allowances on those assets.

When we adopted fresh start reporting effective November 1, 2003, we established valuation allowances for deferred tax assets. If such deferred tax assets, for which a valuation allowance is established, are realized in subsequent periods, the tax benefit will be recorded as a reduction of the carrying value of long-term intangible assets and certain favorable lease contracts existing at adoption of fresh-start accounting until the value of such assets is reduced to zero. Any recognition of fresh start deferred tax assets after intangible assets are reduced to zero will be credited to shareholders' equity. Of the total valuation allowance as of December 31, 2004, $358.1 million relates to pre-reorganization amounts and will only affect net income with the reduction of amortization expense for intangible assets.

Fresh Start Reporting

We adopted fresh start reporting upon our emergence from Chapter 11 in accordance with SOP 90-7. Accordingly, all assets and liabilities were adjusted to reflect their reorganization value as of November 1, 2003, which approximates fair value at the date of reorganization. We engaged independent financial advisors to assist in the determination of the reorganization value of the combined entity and for most of the individual assets and liabilities. Assets and liabilities were valued based on a combination of the cost, income and market approach. We also considered technical, functional and economic obsolescence. Please see "2003 Fresh Start Reporting and Changes in Accounting Policy" above.

Similar to the estimates made for long-lived assets as described above, the estimates of fair value made for purposes of fresh start reporting required judgments regarding long-term forecasts of future revenues and costs related to all significant assets and liabilities. These forecasts are uncertain in that they require assumptions about demand for our products and services, future market conditions and technological developments. Significant and unanticipated changes to these assumptions could require a provision for impairment in a future period.

Seasonality

Our Marine Geophysical segment experiences seasonality as a result of weather-related factors. Adverse weather conditions in the North Sea, which can prevent the full operation of seismic crews and vessels, generally adversely impact our first and fourth quarter results. Storm seasons in the tropics can also affect our operations when we have crews in the Gulf of Mexico or tropical Asia. During these periods, we generally relocate our seismic vessels to areas with more favorable weather conditions to conduct seismic activities, or we conduct repairs and maintenance. 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 natural gas companies. In addition, timing of licensing activities and oil and natural gas lease sales may significantly affect quarterly operating results.

Our Onshore segment can also be affected by weather and seasons, depending on where we deploy our crews at a particular time. Our Production segment generally does not experience material seasonal effects, other than normal maintenance and refurbishment activities for our FPSO vessels in our Production segment that typically take place during the summer months.

Our results of operations fluctuate from quarter to quarter due to a number of other factors. Oil and natural gas industry capital expenditure budgets and spending patterns influence our results. These budgets are not necessarily spent in equal or progressive increments during the year, with spending patterns affected by individual customer requirements and industry-wide conditions. In addition, under our revenue recognition policy, revenue recognition from data licensing contracts depends, among other things, upon when the customer selects the data. In addition, many of our contract projects are relatively short term. The timing of start-up and completion and crew or vessel movement can significantly affect our results of operations from period to period. As a result, our seismic data revenue does not necessarily flow evenly or progressively during a year or from year to year.

Results of Operations

Overview

Our results of operations for the years 2004, 2003 (Successor and Predecessor) and 2002 are presented below in an expanded format that shows the primary components of and key drivers affecting our results of operations. Our consolidated statements of operations show separately the ten month period ended October 31, 2003 (Predecessor) and the two month period ended December 31, 2003 (Successor) as we emerged from Chapter 11 bankruptcy proceedings on November 5, 2003 and adopted fresh start reporting effective as of November 1, 2003. As indicated in the discussion of our results for 2003 below, Successor and Predecessor are in some areas combined for purposes of the discussion. Successor financial statements are prepared on the basis of fresh start reporting from November 1, 2003 and include changes in the carrying value of assets and liabilities and changes to certain accounting policies.

In addition, the results of operations discussed below exclude the results from our Production Services subsidiary (formerly Atlantic Power Group), our Atlantis oil and natural gas subsidiary and our Tigress software subsidiary, all of which were sold in 2002 or 2003 and are presented as discontinued operations in our consolidated financial statements included in Item 18 of this annual report. The results of operations discussed below includes the results for Pertra, our oil and natural gas subsidiary that we sold in March 2005, because we decided to sell Pertra after December 31, 2004. In our 2005 financial statements, we will report the gain on the sale of Pertra and the operating results for Pertra for the first two months of 2005 as discontinued operations and we will reclassify all historical financial statements to report Pertra as discontinued operations. The *Petrojarl Varg* (Production segment) has provided production services to the Varg field in which Pertra owns a 70% interest. Accordingly, 70% of the associated revenues from the *Petrojarl Varg* have been eliminated as inter-segment revenues. Following Pertra's reclassification to discontinued operations, this portion of the revenues from the *Petrojarl Varg* will be reclassified to external revenues. This will significantly increase the revenues of Production included in our consolidated statement of operations.

We present operating results below based on our four business segments in 2004 — Marine Geophysical, Onshore, Production and Pertra. We operate our Marine Geophysical and Onshore businesses globally and generate revenues primarily through contract acquisition sales and multi-client sales (pre-funding and late sales). Our Production segment generates revenues from contract production activities in the Norwegian and U.K. sectors of the North Sea. Pertra generated oil production revenues from its 70% interest in PL 038 in the Norwegian Sector of the North Sea.

Revenues

The table below presents our mix of revenues for each of the three years by business segment.

	Successor Company	Successor Company	Predecessor Company	Combined	Predecessor Company
	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Twelve Months Ended December 31, 2003	Year Ended December 31, 2002
	(In thousands of dollars)				
Marine Geophysical					
Contract	$ 297,749	$ 48,273	$302,451	$ 350,724	$ 282,234
Multi-client pre-funding	30,535	6,510	43,187	49,697	100,326
Multi-client late sales	203,397	36,786	123,435	160,221	178,128
Other	39,124	7,813	31,040	38,853	31,952
	570,805	99,382	500,113	599,495	592,640
Onshore					
Contract	110,288	18,442	106,324	124,766	102,868
Multi-client pre-funding	12,761	1,807	14,636	16,443	14,104
Multi-client late sales	10,112	1,210	8,005	9,215	1,726
	133,161	21,459	128,965	150,424	118,698
Production					
Petrojarl I	61,303	11,086	58,529	69,615	62,631
Petrojarl Foinaven	96,595	18,726	93,373	112,099	133,364
Ramform Banff	51,509	6,572	38,616	45,188	37,886
Petrojarl Varg	87,133	8,604	59,191	67,795	69,455
Other	1,662	241	349	590	3,309
	298,202	45,229	250,058	295,287	306,645
Other/elimination	(56,834)	(3,243)	(29,369)	(32,612)	(7,449)
Total revenues (services)	945,334	162,827	849,767	1,012,594	1,010,534
Revenues (products) — Pertra	184,134	9,544	112,097	121,641	32,697
Total revenues	$1,129,468	$172,371	$961,864	$1,134,235	$1,043,231

Our revenues for 2004 decreased $4.8 million as compared with combined 2003 revenues for Predecessor and Successor. Pertra revenues increased by $62.5 million, but this increase was more than offset by a decrease of revenues in Marine Geophysical ($28.7 million) and Onshore ($17.3 million) and higher elimination of inter-segment revenues as described below. Combined 2003 revenues for Predecessor and Successor were $91.0 million (9%) greater than 2002 revenues primarily due to increased revenues in Marine Geophysical ($6.9 million), Onshore ($31.7 million) and Pertra ($88.9 million), partially offset by decreased revenues in Production ($11.4 million).

Marine Geophysical — 2004 vs. 2003. Marine Geophysical 2004 revenues decreased by $28.7 million (5%) as compared with 2003 (combined). Revenues from contract seismic acquisition decreased by $53.0 million (15%), primarily due to a close down of our ocean bottom 2C crew in late 2003. Revenues from this crew amounted to $40.5 million in 2003 (combined). In addition, contract revenues were negatively impacted by a weak contract market in the first half of 2004 and significant operating disturbances during completion of a large turnkey project offshore India in the second quarter. Revenues from multi-client late sales increased by $43.2 million (27%), reflecting overall high demand in the second half of 2004. In 2004, we reduced further our acquisition of multi-client data, and revenues from multi-client pre-funding decreased by $19.2 million (39%). Pre-funding as a percentage of cash investments in multi-client data increased to 99% in

2004 compared to 72% in 2003. In 2004, we allocated the active vessel time for our seismic fleet between contract and multi-client data acquisition approximately 89% and 11%, respectively, as compared to approximately 81% and 19%, respectively, in 2003.

Marine Geophysical — 2003 vs. 2002. Marine Geophysical 2003 (combined) revenues increased by $6.9 million (1%) as compared with 2002. Revenues from contract seismic acquisition increased by $68.5 million (24%) as a result of our strategy to increase our focus on the contract market. Revenues from multi-client pre-funding decreased $50.6 million (50%). Our acquisition of multi-client data was reduced significantly, while the pre-funding achieved as a percentage of cash investments in multi-client data was 72% in 2003 (combined) compared to 76% in 2002. Multi-client late sales decreased $17.9 million (10%) from 2002 to 2003. In 2003, we allocated a substantially larger percentage of the active vessel time for our seismic vessel fleet to contract acquisition rather than multi-client acquisition as compared to 2002.

Onshore — 2004 vs. 2003. Onshore revenues for 2004 decreased by $17.3 million (11%) as compared with 2003 (combined). Onshore had significant activity in Alaska, Mexico and Saudi Arabia in 2003, but in 2004 Onshore had no activity in Saudi Arabia or Alaska. In addition, activity in Mexico declined at the end of 2004 as we completed one of our two large projects in that region in the third quarter.

Onshore — 2003 vs. 2002. Onshore revenues for 2003 (combined) increased by $31.7 million (27%) as compared with 2002. Onshore realized a significant increase both in contract and multi-client revenues due to major new contracts in Mexico and stronger multi-client late sales in North America.

Production — 2004 vs. 2003. Production revenues for 2004 increased $2.9 million (1%) as compared to 2003 (combined). *Petrojarl Foinaven* revenues declined $15.5 million (14%) primarily due to a natural field production decline. *Petrojarl I* revenues declined $8.3 million (12%) primarily for the same reason. Further, the production on *Petrojarl I* was shut down from September 12 to October 29 due to a labor conflict on the NCS, but the revenue impact was limited as we received force majeure compensation during the period. Revenues from *Ramform Banff* increased by $6.3 million (14%), primarily due to a $3.7 million lump sum modification job for Canadian Natural Resources and a new production contract effective January 1, 2004 with a minimum day-rate of $125,000. Production levels on *Ramform Banff* improved in the latter part of 2004 due to the tie in of one well from the Kyle field and development work on Banff field wells. Revenues from *Petrojarl Varg* increased by $19.3 million (29%), including inter segment revenues from Pertra (approximately 70% of *Petrojarl Varg* revenues). The increase is due primarily to increased production, despite a shut down for approximately two weeks in October related to a labor conflict on the NCS and damage to the main production riser on the Varg field that reduced production to approximately 50% of the field's potential from November 5, 2004 through the end of the year. The compensation structure in the *Petrojarl Varg* production contract was amended, effective May 29, 2004, to a combination of a fixed day rate and a production tariff (as compared to a pure production tariff previously).

Production — 2003 vs. 2002. Production revenues for 2003 (combined) decreased by $11.4 million (4%) as compared with 2002. This decrease was primarily attributable to a $21.3 million decline in revenues for *Petrojarl Foinaven,* reflecting both a general decline in the production level of the field and a temporary reduction in production due to problems with one of the compressors from late June through October 2003. *Petrojarl I* revenues increased in 2003 due to improvements in the production contract for the Glitne field. Revenues from *Ramform Banff* increased as a result of a temporary increase in production resulting from an additional production well drilled early in 2003. Revenues from *Petrojarl Varg* decreased in 2003 due to a reduction in the day rate mid-2002 and conversion from a fixed day rate to a pure production tariff in August 2002 when we acquired 70% of PL 038, which includes the Varg field.

Elimination of Inter-Segment Amounts. In 2004, elimination of inter-segment revenues and costs (which reduces consolidated revenues and operating costs), increased by $23.9 million and $22.3 million, respectively, as compared to 2003 (combined) primarily due to increased payments from Pertra to Production for the use of *Petrojarl Varg*. Since August 2002, 70% of *Petrojarl Varg* revenues related to Pertra's interest in the Varg field have been eliminated in the consolidated financial statements. These inter-segment revenues, which aggregated $60.4 million, $45.1 million and $14.9 million in 2004, 2003 (combined) and 2002, respectively, are eliminated in our consolidated statement of operations.

Pertra. Pertra revenues for 2004 increased $62.5 million (51%) as compared with 2003 (combined) primarily due to increased production of oil. Pertra revenues for 2003 (combined) increased by $88.9 million (272%) compared to 2002, as Pertra became the 70% owner and operator of PL 038 in August 2002. As a result, 2002 revenues reflect only the last five months of the year. Pertra's net oil production in 2004 was 5.3 million barrels compared to 4.1 million barrels in 2003 and 1.3 million barrels in 2002 (five months).

Cost of Sales

The following table shows our cost of sales (products and services) by segment and each segment's cost of sales as a percentage of revenues generated by that segment:

	Successor Company	Successor Company	Predecessor Company	Combined	Predecessor Company
	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Twelve Months Ended December 31, 2003	Year Ended December 31, 2002
	(In thousands of dollars, except percentage data)				
Marine Geophysical	$342,460	$55,903	$248,965	$304,868	$286,324
% of revenue	60.0%	56.3%	49.8%	50.9%	48.3%
Onshore	$ 92,290	$13,043	$ 76,634	$ 89,677	$ 98,769
% of revenue	69.3%	60.8%	59.4%	59.6%	83.2%
Production	$167,764	$21,208	$133,114	$154,322	$144,261
% of revenue	56.3%	46.9%	53.2%	52.3%	47.0%
Other	$ 9,558	$ 900	$ 6,776	$ 7,676	$ 4,286
Transfer of cost(1)	(24,160)	3,990	(11,093)	(7,103)	(3,254)
Total cost of sales (services)	$587,912	$95,044	$454,396	$549,440	$530,386
% of revenue	62.2%	58.4%	53.5%	54.3%	52.5%
Cost of sales (products)					
Pertra	$ 93,035	$ 7,040	$ 61,910	$ 68,950	$ 27,430
Elimination(1)	(48,197)	(5,130)	(28,528)	(33,658)	(16,629)
Total cost of sales (products)	$ 44,838	$ 1,910	$ 33,382	$ 35,292	$ 10,801
% of revenue	24.3%	20.0%	29.8%	29.0%	33.0%
Total cost of sales	$632,750	$96,954	$487,778	$584,732	$541,187
% of revenue	56.0%	56.2%	50.7%	51.6%	51.9%

(1) Elimination of inter-segment charter hire related to *Petrojarl Varg* and inter-segment transfers of costs.

Cost of sales services — 2004 vs. 2003. Cost of sales (services) increased by $38.5 million in 2004 as compared with 2003 (combined) primarily due to reduced multi-client activity in our Marine Geophysical business as we increased our focus in 2004 on contract marine seismic acquisition as compared to 2003. As a result, we reduced costs capitalized as investment in multi-client library by $49.5 million. In addition, cost of sales increased due to general cost increases driven by a weakening of the U.S. dollar against the British pound and the Norwegian kroner (which increases the reported U.S. dollar cost of expenses incurred in those currencies) and increased fuel prices, partially offset by the effect of closing down our ocean bottom 2C crew in late 2003. Production's cost of sales increased by $13.4 million, primarily due to increased materials purchases reimbursed by a customer, a weakening of the U.S. dollar exchange rate (which increases the reported U.S. dollar cost for Production since a significant part of these costs are incurred in British pounds and Norwegian kroner) and increased maintenance expense. Production's cost of sales includes all of the operating costs for *Petrojarl Varg* while 70% of these costs are eliminated from cost of sales (services) and included in cost of sales (products) and 70% of *Petrojarl Varg* revenues are eliminated from cost of sales (products) representing the 70% interest Pertra had in the Varg field.

Cost of sales products — 2004 vs. 2003. Cost of sales products increased by $9.5 million in 2004 as compared with 2003 (combined) as a result of increased Pertra operating costs due primarily to a significant increase in production and increased well intervention costs.

Eliminations. Total elimination of inter-segment cost (which reduces consolidated operating costs) in 2004 increased by $22.3 million compared to 2003 (combined) primarily due to increased payments from Pertra to Production for the use of *Petrojarl Varg.*

Cost of sales services — 2003 vs. 2002. Cost of sales services in 2003 (combined) increased by $19.1 million as compared with 2002 primarily due to reduced multi-client activity in our Marine Geophysical business. This had the effect of reducing the amount of costs capitalized as multi-client investment by $63.8 million. Excluding the effect of costs capitalized as multi-client investment, Marine Geophysical, Onshore and Production realized cost improvements in 2003, after having also reduced costs significantly in 2002.

Cost of sales products — 2003 vs. 2002. Cost of sales products in 2003 (combined) increased by $24.5 million as compared with 2002 as a result of an increase in Pertra operating costs due to a full year of operation in 2003 compared with only five months in 2002.

Exploration Costs

Exploration costs were $16.3 million in 2004. Exploration costs in 2004 include $11.4 million for the drilling of a dry exploration well in PL038. We incurred exploration costs in our oil and natural gas subsidiary Pertra. Such costs include costs to drill exploration wells and other costs related to exploration for oil and natural gas, including geological and geophysical services.

Prior to adopting fresh start reporting we accounted for oil and natural gas assets using the full cost method and all exploration costs were capitalized.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization ("DD&A") expenses result primarily from the allocation of capitalized costs over the estimated useful lives of our geophysical seismic equipment (including seismic vessels), our FPSO vessels, our seismic and operations computer equipment, leasehold improvements, buildings and other fixtures, and depletion of our oil and gas exploration and production assets (consisting of licenses, tangible and intangible costs of drilling wells and production equipment) that are depleted using a units of production method based on proved oil and gas reserves. DD&A expenses also include the amortization of our multi-client data library, which we refer to as MCDL Amortization, and the amortization of certain intangible assets recognized upon our adoption of fresh start reporting effective as of November 1, 2003.

The following table shows our total DD&A expenses by segment. For our Marine Geophysical and Onshore segments, we have provided separately (1) DD&A expenses excluding MCDL Amortization, or Adjusted DD&A, and (2) MCDL Amortization because we believe that separately disclosing MCDL Amortization provides users useful information about a key component impacting the results of our geophysical operations.

	Successor Company	Successor Company	Predecessor Company	Combined	Predecessor Company
	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Twelve Months Ended December 31, 2003	Year Ended December 31, 2002
	(In thousands of dollars)				
Marine Geophysical:					
Adjusted DD&A	$ 55,277	$ 9,565	$ 59,730	$ 69,295	$ 64,616
MCDL amortization	186,435	29,786	131,485	161,271	183,317
DD&A	241,712	39,351	191,215	230,566	247,933
Onshore:					
Adjusted DD&A	18,677	3,571	14,292	17,863	17,077
MCDL amortization	21,208	2,653	15,133	17,786	11,331
DD&A	39,885	6,224	29,425	35,649	28,408
Production:					
DD&A	44,561	8,112	43,418	51,530	70,958
Pertra:					
DD&A	38,965	743	30,826	31,569	12,695
Corporate and other:					
Adjusted DD&A	2,414	361	4,911	5,272	6,203
MCDL amortization	825	908	1,781	2,689	1,306
DD&A	3,239	1,269	6,692	7,961	7,509
Total:					
Adjusted DD&A	159,894	22,352	153,177	175,529	171,549
MCDL amortization	208,468	33,347	148,399	181,746	195,954
DD&A	$368,362	$55,699	$301,576	$357,275	$367,503

2004 vs. 2003. Adjusted DD&A for 2004 decreased by $15.6 million (9%) compared with 2003 (combined) primarily due to reduced depreciation in Marine Geophysical ($14.0 million) and Production ($7.0 million). Reductions in those two segments was partly offset by increased depreciation and depletion of oil and gas assets in Pertra, reflecting increased production. Depreciation in Marine Geophysical and Production generally decreased due to the significant reduction in carrying values of fixed assets as a result of our adoption of fresh start reporting effective as of November 1, 2003, partly offset by a reduction of the estimates of the useful depreciable lives for several of the assets in our seismic and FPSO fleet. Additionally, depreciation capitalized as part of the cost of multi-client library was reduced by $9.1 million to $4.0 million in 2004.

MCDL Amortization for 2004 increased by $26.7 million (15%) as compared with 2003 (combined). The increase relates primarily to charges for minimum amortization that amounted to $28.9 million and additional amortization of $19.9 million to write certain surveys down to fair value compared to minimum amortization of $36.6 million in 2003. Please read note 2 of the consolidated financial statements included in Item 18 of this annual report for a description of our policy related to amortization of multi-client library. In total, MCDL Amortization as a percentage of multi-client revenues was 81% in 2004 compared to 76% in 2003.

2003 vs. 2002. Adjusted DD&A for 2003 (combined) increased by $4.0 million (2%) compared with 2002 primarily due to increased depletion of oil and gas assets in Pertra, which was consolidated for a full year in 2003 compared to only five months in 2002. This increase was partly offset by the reduced depreciation in 2003 resulting from the impairment of *Ramform Banff* in 2002. Adjusted DD&A of the Predecessor was $153.2 million for the first ten months of 2003. Adjusted DD&A of the Successor was $22.4 million in the last two months of 2003 and was affected by the significant reduction in carrying values and changes in depreciable lives after adoption of fresh start reporting as described above.

MCDL Amortization for 2003 (combined) was reduced by $14.2 million (7%) as compared with 2002. The reduction relates primarily to lower pre-funding and late-sales revenues, partially offset by a higher average amortization rate as a consequence of reduced sales forecasts and library impairments recorded in 2002 and 2003, and adoption of fresh start reporting as of November 1, 2003.

Selling, General and Administrative Costs

Selling, general and administrative costs in 2004 increased $13.1 million as compared with 2003 (combined). The increase was caused by various factors. We increased substantially our effort in several areas including internal audit, internal control and compliance; business development and business improvement projects; and human resources. Our selling costs increased because our multi-client late sales increased substantially. We incurred increased bonus expenses to a broad category of employees due to achievement of key performance indicators under the bonus program that we established for 2004. Finally, because we incur most of our selling, general and administrative costs in Norwegian kroner and other currencies other than the U.S. dollar, the weakening of the U.S. dollar against these currencies increased our reported cost.

Selling, general and administrative costs decreased $1.7 million in 2003 (combined) as compared with 2002 primarily as a result of our cost reduction efforts in this area.

Impairments and other operating expense, net

Since we generally evaluate our multi-client library on a survey by survey basis at the end of each year, we expect to write down the value of some surveys each year due to survey specific factors. In 2004, we reported no impairments since we classified as amortization, rather than impairments, $19.9 million in write downs of individual surveys that related to individual survey-specific factors and that were not individually material.

In the first ten months (Predecessor) of 2003, we had impairments of $95.0 million, which included $90.0 million of impairment of multi-client library and $5.0 million of impairments related to other assets and equipment. In 2002 we had impairments totaling $558.5 million, which included impairment of multi-client library of $200.4 million and impairment of seismic equipment and geophysical assets of $16.7 million. In 2002 we also recorded an impairment of $332.0 million on *Ramform Banff* as a result of negative development of the field and decreased prospects for redeployment alternatives.

We recorded other operating expense, net, of $8.1 million in 2004, primarily relating to costs to complete the 2002 U.S. GAAP consolidated financial statements and the re-audit of our U.S. GAAP financial statements for the year ended December 31, 2001. In 2003 (combined) we recorded other operating expense, net, of $22.4 million, primarily relating to severance payments that aggregated $19.8 million. We had other operating expense, net, of $8.5 million in 2002.

Interest expense and other financial items

Interest expense for 2004 totaled $110.8 million compared to $99.0 million for the first ten months (Predecessor) and $16.9 million for the last two months (Successor) of 2003. Our average interest bearing debt was significantly lower in 2004 compared to 2003, but in 2003 most of our debt did not accrue interest for approximately 100 days while we were in Chapter 11 proceedings. Interest expense in 2002 was $153.3 million as our interest bearing debt was significantly higher in 2002 than in subsequent years.

Income from associated companies totaled $0.7 million in 2004 compared to $1.0 million in 2003 (combined) and a loss of $11.5 million in 2002.

Other financial items, net, amounted to an expense of $10.9 million in 2004 compared to an expense of $5.7 million in 2003 (combined). The increase in expense primarily relates to the cost to obtain from our bondholders waivers of certain requirements to report financial statements on a U.S. GAAP basis. Other financial items, net, for 2002 was a gain of $33.8 million and included a gain of $45.3 million from tax equalization contracts that were terminated in 2002.

Reorganization items

In connection with our Chapter 11 reorganization, which we completed in 2003, we recorded reorganization items in our consolidated statement of operations totaling $3.5 million in expenses for 2004 and the following items in 2003:

- for the first ten months (Predecessor) we recorded a gain on debt discharge of $1,253.9 million and costs of reorganization of $52.3 million;
- for the last two months (Successor) we recorded $3.3 million in costs of reorganization;
- for the first ten months (Predecessor) we recorded the net effect at November 1, 2003, of adopting fresh start reporting of $532.3 million. This amount represents the net effect of differences between the fair value of our assets and liabilities as measured at November 1, 2003 and the carrying value of those assets and liabilities immediately before adoption of fresh start reporting.

We describe our financial restructuring in more detail under "2003 Financial Restructuring" above and in note 3 of the notes to our consolidated financial statements included in Item 18 of this annual report. We describe our adoption of fresh start reporting in more detail under "2003 Fresh Start Reporting and Changes in Accounting Policies" above and in note 3 of the notes to our consolidated financial statements included in Item 18 of this annual report.

Income tax expense

Income tax expense was $48.0 million in 2004 compared with $18.1 million in 2003 (combined) and $185.9 million in 2002, excluding tax relating to discontinued operations and the adoption of fresh start reporting. Tax expense in 2004 included current taxes of $20.8 million and net deferred tax expense of $27.2 million. Taxes payable related primarily to foreign taxes in regions where we are subject to withholding taxes or deemed to have a permanent establishment and where we had no carryover losses. Current taxes included a $9.5 million charge related to tax contingencies. Deferred tax expense related primarily to Pertra where we make a full deduction of capital expenditures for tax purposes in the year these are incurred. Pertra is subject to petroleum taxation rules in Norway at a nominal tax rate of 78%, and Pertra cannot offset its income against losses from other operations. For information about how we evaluate the need for valuation allowances related to deferred tax assets, please read note 20 of the consolidated financial statements included in Item 8 of this annual report.

Tax expense in 2003 included current taxes of $24.0 million and net deferred tax benefits of $5.9 million. Income tax expense in 2002 included taxes payable of $23.8 million and net deferred taxes of $162.1 million, which reflects a substantial change in deferred taxes in connection with exit from the shipping tax regime in Norway in 2002 and a valuation allowance related to deferred tax asset of $61.1 million.

Discontinued Operations

In 2004, we recognized income from discontinued operations, net of tax, of $3.0 million relating to certain contingent proceeds from the sale of our Production Services subsidiary in 2002. In 2003, loss from discontinued operations, net of tax, amounted to $2.3 million for the first ten months (Predecessor) and

$0.1 million for the last two months (Successor). In 2002, we had $201.1 million in loss from discontinued operations, net of tax, including a loss of $174.5 million related to the investment in our Atlantis subsidiary (sale completed February 2003) and a loss of $22.6 million related to the investment in our Production Services subsidiary (sale completed December 2002).

Operating profit (loss) and net income (loss)

Operating profit for 2004 was $35.7 million, compared to a profit of $9.8 million for the first ten months (Predecessor) of 2003, which included impairment charges of $95.0 million, and a profit of $10.7 million for the last two months (Successor) of 2003. In 2002 we reported an operating loss of $488.6 million, after impairment charges of $558.5 million.

We reported a net loss of $134.7 million for 2004. For 2003 we reported net income of $557.0 million for the first ten months (Predecessor) and a net loss of $10.0 million for the last two months (Successor). As described above, net income for the first ten months of 2003 is significantly impacted by the effects of our financial reorganization, including gain on debt discharge of $1,253.9 million, adoption of fresh start reporting ($532.3 million), and impairment charges ($95.0 million). We reported a net loss for 2002 of $1,174.7 million.

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, but are not limited to, the following:

- the development of our main market drivers, which includes prices and price expectations for oil and natural gas. Such prices and price expectations affect the demand for exploration and production related seismic services and the economics in developing and producing small and medium sized oil and natural gas fields;
- our ability to optimize performance of our FPSO vessels and profitably expand the Production segment, including, among others:
  - sustaining high regularity and uptime;
  - maximizing volumes and revenues under current contracts, including further extension of contract duration where appropriate; and
  - capturing new profitable contract opportunities and achieving timely redeployment of vessels on terms and at volumes reflecting their production capacities;
- the business performance of our Onshore and Marine Geophysical segments, including, among others:
  - the demand for contract seismic services, coupled with (a) our ability to benefit from our strong HD3D℠ position and high productivity and vessel performance, (b) our ability to reduce steaming and other unproductive vessel time, and (c) the prices for our services;
  - demand for multi-client seismic data in various geographic regions, including future licensing rounds and demand for data offshore Brazil;
  - our ability to profitably rebuild new multi-client seismic survey activity to complement our contract work; and
  - implementation of our streamer replacement program for our seismic vessels;
- foreign currency exchange rate fluctuations between the U.S. dollar, our functional currency, and the Norwegian kroner or the British pound, which will generally have an impact on our operating profit because we have significant operating expenses in Norwegian kroner and British pounds;

- the extent to which we participate in strategic acquisitions or dispositions of assets or businesses or in one or more joint ventures involving such assets or businesses; and
- our ability to continue to develop or acquire competitive technological solutions for our different business units.

The markets in which we operate improved during 2004. Oil prices varied significantly through 2004, but generally at relatively high levels. We understand that market analysts generally expect high price levels for oil and natural gas to continue. In the medium to long-term, high oil price levels should positively impact our core markets.

Over the past few years, oil and natural gas exploration and production companies have made relatively low investments in exploration. We believe that as companies continue to focus on replacing oil and natural gas reserves in the coming years, such companies will be gradually more active in exploration.

We also believe that, after a number of years of overcapacity in the marine seismic market, the market has improved and industry order backlog and margins have increased. Within our Production segment, we believe that increased industry focus on smaller fields and tail-end field optimization forms a basis for growth in outsourcing where our Production segment is well positioned in the North Sea and has the potential to expand into selected international markets.

In 2005, after the sale of our oil and natural gas subsidiary Pertra, we operate from a more focused oil services base seeking to build our competitive advantage and market position. At the same time, we intend to continue to manage our business in a financially disciplined manner, focusing on improvement in return on capital employed, cash generation and prudent risk management.

In 2005, we expect the following factors to influence our performance:

Marine Geophysical

- Increased contract prices driven by relatively high industry capacity utilization;
- Continued focus on contract acquisition, with a moderate increase in multi-client activity;
- Lower multi-client late sales as compared with 2004 due to limited reinvestment over the past three years and expected delay of Brazilian 7th Licensing Round sales into 2006; and
- Increased costs due to increased fuel prices and a weaker U.S. dollar compared to 2004.

Onshore

- Continued focus on markets where we can compete most effectively; and
- Full year activity level similar to that in 2004, building on expected start-up of a significant transition zone project in Nigeria and contract awards for crews in South America.

Production

- Continued production by our FPSOs on existing assignments;
- Total oil production from the four FPSOs in line with 2004 levels; and
- Increased operating costs due to (a) increased maintenance costs on FPSO vessels as the time since deployment of the FPSOs on their respective fields is increasing and (b) a weakened U.S. dollar as compared to 2004.

Liquidity and Capital Resources

Liquidity — General

We believe that our cash balances and our available borrowing capacity under our revolving credit facility will be adequate to meet our working capital and liquidity needs for the remainder of 2005 and 2006. While we believe that we have adequate sources of funds to meet our liquidity needs for the 2005-2006 period, our ability to meet our obligations in the longer term depends on our future performance, which, in turn, is subject to many factors beyond our control. See "Key Information — Risk Factors" in Item 3 of this annual report.

While we have made some progress since we completed our financial restructuring in late 2003 in strengthening our balance sheet and increasing our financial flexibility, we remain committed to strengthen further our financial flexibility. As a result, we intend to use our available cash flow to develop our core businesses and to maintain or improve financial ratios.

Sources of Liquidity — Capital Resources

Our internal sources of liquidity are cash and cash equivalents and cash flow from operations. Cash and cash equivalents totaled $132.9 million at December 31, 2004, an increase from $105.2 million at December 31, 2003. In addition, in March 2005 we sold our oil and natural gas subsidiary Pertra and thereby realized a net cash proceeds of approximately $150 million. In April 2005, we redeemed $175 million of our 8% Senior Notes due 2006.

Net cash provided by operating activities totaled $282.4 million in 2004, representing an increase of $55.3 million compared with 2003 (combined). In 2004, our restructuring costs were significantly less than in 2003. In 2004, our accounts receivables, net, increased $33.6 million, but the cash flow effect was offset by a $25.6 million increase in accounts payable and a $15.6 net release of restricted cash.

Our external sources of liquidity include our secured revolving credit facility, equipment financing and trade credit. Subject to market conditions and other factors, we might also seek to raise debt or equity in the capital markets.

We have a secured $110 million credit facility consisting of a $70 million revolving credit facility and a $40 million letter of credit facility. We can borrow U.S. dollars under the revolving credit facility for working capital and general corporate purposes, and the letter of credit facility can be utilized in multiple currencies to obtain letters of credit to secure, among other things, performance and bid bonds required in our ongoing business. The credit facility matures in March 2006 and is secured by various assets. Borrowings under the facility bear interest at LIBOR plus 2%. At December 31, 2004, approximately $15 million of letters of credit were outstanding under this facility. No borrowings were outstanding under the revolving credit portion of the facility at December 31, 2004. We will seek to establish a similar facility when this one matures in March 2006.

In February 2005 we established an overdraft facility of NOK 50 million as part of our Norwegian cash pooling arrangement.

The book value of our debt, including capital leases, was approximately $1,164 million as of December 31, 2004 compared to approximately $1,211 million at December 31, 2003.

Our debt consisted of the following primary components at December 31, 2004 (in millions):

10% Senior Notes, due 2010	$ 746
8% Senior Notes, due 2006	250
8.28% First Preferred Mortgage Notes, due 2011	99
Other loans, due 2005 — 2006	10
Total debt	$1,105
Capital leases	59
Total	$1,164

Net interest bearing debt (interest bearing debt, including capital leases, less cash and cash equivalents and restricted cash) was approximately $995 million as of December 31, 2004 compared to $1,077 million (adjusted for the final excess cash distribution of $22.7 million that was included in accrued expenses) at December 31, 2003.

In April 2005, we redeemed $175 million of our $250 million 8% Senior Notes due 2006 at a redemption price of 102% of the principal amount of the notes redeemed. The remaining balance of the 8% notes may be redeemed at a redemption price of 101% of the outstanding principal amount starting in November 2005.

Certain of our loan and lease agreements and our senior note indenture require us to provide audited U.S. GAAP financial statements by June 30 of each year and to provide unaudited U.S. GAAP quarterly financial statements within a specified period (typically 60 days) after the end of each of the first three quarters. We have received waivers from the various lenders allowing us to report under those agreements and the indenture under Norwegian GAAP in lieu of U.S. GAAP until June 30, 2005.

In addition to customary representations and warranties, certain of our debt agreements restrict us from incurring debt unless specified coverage ratios are met and limit our financial indebtedness, excluding project debt, to $1.5 billion. These agreements also contain other restrictions as described in note 15 to the consolidated financial statements included in Item 18 of this annual report. See "Key Information — Risk Factors — Risk Factors Relating to Our Indebtedness and Other Obligations — Our debt agreements may limit our flexibility in responding to changing market conditions or in pursuing business opportunities" in Item 3 of this annual report.

For a description of limitations on the ability of our Norwegian subsidiaries to pay dividends to us, please read "Financial Information — Dividend Restrictions" in Item 8 of this annual report. We do not expect these limitations to affect in a material way our ability to meet our cash obligations.

For further information relating to our outstanding indebtedness as of December 31, 2004 and the maturities of such indebtedness, please read note 15 of the notes to our consolidated financial statements in Item 18 of this annual report.

Net Cash Used in Investing and Financing Activities

Net cash used in investing activities totaled $183.4 million in 2004, an increase of $88.6 million compared with 2003 (combined). This increase was primarily due to (a) a $90.3 million increase in capital expenditures, and (b) a $48.1 million reduction in cash inflow from the sale of subsidiaries, offset in part by (c) a $49.5 million reduction in cash investment in multi-client library reflecting our continued focus on the contract market. Our capital expenditures increased primarily due to (x) increased capital expenditures in our oil and natural gas subsidiary, Pertra, relating to an extensive drilling program, (y) increased capital expenditures on the streamer replacement program in Marine Geophysical, and (z) increased investments in data processing equipment and normal equipment replacement after unusually low levels during 2003, the year of our financial restructuring.

Net cash used in financing activities totaled $71.3 million in 2004, representing a decrease of $47.4 million compared to 2003. In 2004, we made net repayments of long-term debt and principal payments under capital leases totaling $47.1 million, a reduction of $53.6 million compared to 2003. We also made in 2004 a $22.7 million distribution of excess cash to creditors under the debt restructuring agreement compared to a similar distribution of $17.9 million in 2003.

Capital Requirements and Commitments

Our capital requirements are affected primarily by our results of operations, capital expenditures, investments in multi-client library, debt service requirements, lease obligations, working capital needs and outcome of significant contingencies. The majority of our ongoing capital requirements, other than debt service, lease obligations and contingencies, consists of:

- capital expenditures on seismic vessels and equipment, including data processing equipment and streamers;
- capital expenditures on FPSO vessels and equipment;
- investments in our multi-client library; and
- working capital related to growth, seasonality and specific project requirements.

Since we sold our oil and natural gas subsidiary Pertra in March 2005, we do not have any ongoing capital requirements related to these operations. We made substantial capital expenditures in Pertra in 2004.

In prior years, our capital expenditures have related not only to normal ongoing equipment replacement and refurbishment needs, but also to increases in our seismic data acquisition capacity and in our FPSO operations. Such expenditures, which can be substantial from time to time, depend to a large extent upon the nature and extent of future commitments that are largely discretionary. In 2004, with the exception of expenditures in Pertra to explore and develop the Varg field, we did not make significant capital expenditures to increase capacity.

The following table sets forth our consolidated capital expenditures (which does not include our investment in multi-client library) for continuing operations in 2004 (in thousands):

Segment	Amount
Marine Geophysical	$ 56,946
Onshore	1,372
Production	988
Pertra	84,991
Other	4,075
Total	$148,372

For 2005, we expect:

- to prudently increase our investment in multi-client library as compared to 2004 as we start rebuilding our multi-client business;
- capital expenditures in Marine Geophysical to be largely in line with 2004 as we continue our streamer replacement program and otherwise continue to invest in upgrading our seismic vessels and data processing equipment;
- capital expenditures in Onshore to increase to above $10 million as we expect to make investments in specialized equipment within certain areas, including transition zone recording equipment; and
- capital expenditures in Production on our existing vessels to continue at a low level because our FPSO vessels are not expected to have substantial replacement needs through 2005 and we expense maintenance expenditures.

As of March 31, 2005, we did not have any material commitments for future capital expenditures in our Marine Geophysical, Onshore or Production segments, except for equipment orders consistent with the descriptions above.

We expect to spend approximately $25 million per year through 2008 to upgrade our marine seismic streamers. Since this program is discretionary, however, we may in the future change the scope and annual capital expenditure related to the program. We also intend to make maintenance and refurbishment expenditures as required so as to maintain our fleet of marine seismic and FPSO vessels in good working order. We intend to make other capital expenditures in our business segments as conditions dictate and financial resources permit. Finally, we may also incur capital expenditures significantly above the amounts described above to pursue new business opportunities for any of our business segments.

Long-Term Contractual Obligations

The following table presents our long-term contractual obligations related to our loan and lease agreements and other long-term liabilities and related payments due in total and by period as of December 31, 2004:

	Payments Due by Period				
Contractual Obligations	Total	2005	2006 - 2007	2008 - 2009	Thereafter
	(In millions of dollars)				
Long term debt obligations	$1,103.0	$17.8	$276.1(1)	$ 29.2	$779.8
Operating lease obligations	163.6	36.4	45.4	43.9	37.8
Capital lease obligations	62.1	27.4	28.1	6.6	—
Other long-term liabilities(2)	158.2	16.2	33.7	76.7	31.6
Totals	$1,486.9	$97.8	$383.3	$156.4	$849.2

(1) This amount includes the maturity of $250 million of our 8% Senior Notes due 2006. We redeemed $175 million of these notes in April 2005.

(2) Excluding other long-term liabilities that are contingent or that have uncertain future cash flows.

For additional information about the components of our long-term debt and lease obligations, please refer to notes 15 and 19 to the consolidated financial statements included in Item 18 of this annual report.

The table below is provided to illustrate the expected timing of future payments related to other long-term liabilities reported in our consolidated balance sheet as of December 31, 2004. Determining the expected future cash flows presented in the table requires us to make estimates and assumptions since the timing of any payments related to these long-term liabilities generally is not fixed and determinable but rather depends on future events. We believe that our estimates and assumptions are reasonable, but actual results may vary from what we have estimated or assumed. As a result, our reported liabilities and expenses could be materially affected if the assumptions and estimates we have made were changed significantly.

Contractual Obligations	Total	2005	2006 - 2007	2008 - 2009	Thereafter	Not determinable
			Payments Due by Period (In millions of dollars)			
Pension liability(1)	$ 52.5	$ 7.9	$16.2	$17.0	$11.4	$ —
Asset removal obligations(2)	58.5	0.3	—	39.9	18.3	—
Accrued liabilities related to our UK leases:						
— related to interest rate differential(3)	47.2	8.0	17.5	19.8	1.9	—
— related to tax indemnifications	32.1	—	—	—	—	32.1
Tax contingencies	25.5	—	—	—	—	25.5
Other	3.8	—	—	—	—	3.8
Totals	$219.6	$16.2	$33.7	$76.7	$31.6	$61.4

(1) Pension liability represents the aggregate shortfall of pension plan assets compared to projected benefit obligations for our plans. We will pay this obligation over time, as adjusted for changes in estimates relating to obligations and assets, in accordance with the funding requirements of the life insurance companies through which we fund our plans. Such requirements are subject to change over time, but we expect these payments to be made over several years. We have used the premiums expected to be paid in future periods as an estimate of future cash outflows related to this liability. These premiums would generally relate both to payments of the pension obligations as of December 31, 2004 and service cost for future years.

(2) Asset removal obligations as of December 31, 2004 include $39.9 million relating to our Pertra oil and natural gas subsidiary that is included in amounts expected to be due for payments in the period 2008 — 2009. We sold Pertra in March 2005 to Talisman, and the buyer assumed this obligation as part of the transaction.

(3) The estimated net present value of future payments related to interest rate differential on our UK leases as of December 31, 2004 is $56.9 million based on forward interest rate curves, which is $9.7 million higher than the amount included in accrued liabilities. Payments through the year 2009 reflect estimated total payment based on forward interest rate curves as of December 31, 2004. The amount presented for periods after 2009 is the residual amount.

UK Leases

We have entered into vessel lease arrangements for five of our Ramform design seismic vessels, our FPSO vessel *Petrojarl Foinaven* and the topsides of our FPSO vessel *Ramform Banff*. In general, under the leases, UK financial institutions acquired the assets from third parties, and we leased the assets from the lessors under long-term charters that give us the option to purchase the assets for a bargain purchase price at the end of the charter periods. The lessors claim tax depreciation (capital allowances) on the capital expenditures that were incurred for the acquisition of the leased assets. Under these leases, we indemnified the lessors against specified future events that could reduce their expected after-tax returns, including potential changes in and interpretations of UK tax laws and changes in interest rates, as the leases are based on assumed interest rates.

The leases are legally defeased because we have made payments to independent third-party banks in consideration for which these banks have assumed liability to the lessors equal to basic rentals and termination sum obligations. The defeased rental payments are based on assumed Sterling LIBOR rates between 8% and 9%. If actual interest rates are greater than the assumed interest rates, we receive rental rebates. If, on the other hand, actual interest rates are less than the assumed interest rates, we are required to pay rentals in excess of the defeased rental payments. During 2004, 2003 and 2002, actual interest rates were below the assumed interest rates, and we made additional required rental payments of approximately $6.3 million, $6.4 million (combined for Predecessor and Successor) and $3.9 million, respectively, for those years.

The lessors claim tax depreciation (capital allowances) on the capital expenditures that were incurred for the acquisition of the leased assets. We understand that the UK Inland Revenue has generally deferred agreeing to the capital allowances claimed under such leases pending the outcome of a case that was appealed to the UK House of Lords, the highest UK court of appeal. In that case, the Inland Revenue was challenging capital allowances associated with a defeased lease. In November 2004, the House of Lords ruled in favor of the taxpayer and rejected the position of the UK Inland Revenue. We have been informed that in 2005, the Inland Revenue has accepted the lessor's claims to capital allowances for three of our UK leases. As a result of the November 2004 decision by the UK House of Lords, we believe it is unlikely that our UK leases will be successfully challenged by the Inland Revenue. Nevertheless, in connection with our adoption of fresh start reporting and before the House of Lords ruling, we recorded a liability of $28.3 million as of October 31, 2003 for this specific contingency in accordance with the requirements of SOP 90-7. At December 31, 2004 and 2003, this liability amounted to $32.1 million and $29.5 million, respectively. We expect to release appropriate portions of this liability if and when the UK Inland Revenue accepts the lessor's claims for capital allowances under each lease.

In addition, the Inland Revenue has raised a separate issue about the accelerated rate at which tax depreciation is available under the UK lease related to the *Petrojarl Foinaven.* If the Inland Revenue were successful in challenging that rate, the lessor would be liable for increased taxes on *Petrojarl Foinaven* in early periods (and decreased taxes in later years), and our rentals would correspondingly increase (and then decrease).

For additional information regarding our UK leases, please see notes 2 and 19 of the notes to our consolidated financial statements included in Item 18 of this annual report.

Research and Development

We incurred research and development costs of $3.4 million, $2.6 million and $2.8 million during the years ended December 31, 2004, 2003 and 2002, respectively. For additional information regarding our research and development policies and expenditures, please see "Information on the Company — Other Factors Related to Our Business — Our Research and Product Development" in Item 4 and our consolidated statements of operations in Item 18 of this annual report.

ITEM 6. *Directors, Senior Management and Employees*

Board of Directors

The table below provides information about our directors as of April 30, 2005:

Name (Age)	Position	Director Since	Term Expires (1)	Share Ownership
Jens Ulltveit-Moe (62)	Chairman	2002	2005	5.1% (2)
Francis Gugen (56)	Director	2003	2005	*
Keith Henry (60)	Director	2003	2005	*
Harald Norvik (59)	Director	2003	2005	*
Rolf Erik Rolfsen (64)	Director	2002	2005	*
Clare Spottiswoode (52)	Director	2003	2005	*
Anthony Tripodo (52)	Director	2003	2005	*

(1) In each case, in November 2005.

(2) Controlled through Umoe Invest AS

* Less than 1% of our outstanding shares as of March 31, 2005.

Mr. Ulltveit-Moe has been our chairman of the Board of Directors since September 2002. He is the founder and has been president and chief executive officer of Umoe AS, a shipping and industry company, since 1984. From 2000 to 2004, he was the president of the Confederation of Norwegian Business and

Industry. From 1980 to 1984, Mr. Ulltveit-Moe served as managing director of Knutsen OAS. From 1972 to 1980, he was managing director of the tanker division of SHV Corporation. From 1968 to 1972, Mr. Ulltveit-Moe was an associate with McKinsey & Company, Inc. in New York and London. He is chairman of the board of directors of Unitor ASA and Kverneland ASA. Mr. Ulltveit-Moe holds a master's degree in business administration from the Norwegian School of Economics and Business Administration and a master's degree in international affairs from the School of International Affairs, Columbia University, New York.

Mr. Gugen is currently active as a consultant and an investor in the energy industry. He served with Amerada Hess Corporation for eighteen years, from 1982 to 2000, holding various positions including chief executive of Amerada Hess UK from 1995 to 2000 and chief executive of northwestern Europe from 1998 to 2000. Mr. Gugen acts as chairman and non-executive director for various other companies, including CH4 Energy Limited, Island Gas Limited and The Britannia Building Society, where he also sits on the audit committee. Mr. Gugen has earlier worked for Arthur Andersen and is a UK chartered accountant.

Mr. Henry served as group executive vice president for the Kvaerner Engineering and Construction Group from March 2000 until June 2003. Mr. Henry was chief executive of National Power Plc from 1995 to 1999 and was chief executive of Brown & Root Ltd from 1990 to 1995. He acts as a non-executive director and as an advisor to a number of energy, construction and energy related organizations. He holds BSc and MSc degrees, and is a Fellow of the Royal Academy of Engineering.

Mr. Norvik is chairman and a partner of Econ Management. He served as chief executive officer of Statoil from 1988 to 1999. He was finance director and a member of the executive board of the Aker Group from 1981 to 1988. He served as personal secretary to the Prime Minister of Norway and as Deputy Minister in The Ministry of Petroleum and Energy from 1979 to 1981. Mr. Norvik has a Master of Science Degree in Business from The Norwegian School of Economics and Business Administration.

Mr. Rolfsen holds several board positions. He is a member of the board of directors of Technip S.A., Paris and Gaz de France Norge A.S. He is also chairman of the executive council of the Industrial Development Fund at NTNU in Trondheim. From 1987 to 2000, he was managing director of TOTAL Norge A.S. and from 1999 to 2000 he was also managing director of Fina Exploration Norway. From 1980 to 1986, he was executive vice president of Kongsberg Vapenfabrikk A.S. He was educated at the College of Commerce in Oslo.

Ms. Spottiswoode has been deputy chairman and senior non-executive director at British Energy since June 2002, acts as chair of British Energy's remuneration committee and has served as an independent director of that company since 2001. She currently acts as non-executive chair of the boards of Busybees and Economatters Ltd. and is a non-executive director of Advanced Technology (UK) plc, and Tullow Oil plc. She has previously held several non-executive director positions including Booker plc. She was director general of Ofgas, the UK Gas Regulation Organization, from 1993 to 1998. In 1993 she served as a member of the UK Deregulation Task Force, and from 1998 to 2002 sat on the UK Public Services Productivity Panel. Her career started as an economist with the HM Treasury before establishing her own software company. In 1999 she was made a Commander of the Order of the British Empire for services to industry, and holds degrees in economics from Cambridge and Yale University.

Mr. Tripodo has been managing director of Arch Creek Advisors LLC, an investment banking firm, since 2003. He also serves as a non-executive director for Cal Dive International and Vetco International Limited, both oilfield service companies, based in Houston, Texas and London, England, respectively. From 1997 to April 2003, Mr. Tripodo served at Veritas DGC in various capacities, including executive vice president and chief financial officer. He also has held various senior executive and financial roles at Baker Hughes and PricewaterhouseCoopers. Mr. Tripodo has a B.A. degree from St. Thomas University.

Currently there are two alternate directors, Marianne Elisabeth Johnsen and John Reynolds. As alternate directors they are available to fill in as needed on a meeting to meeting basis if a regular director is unable to attend and are also eligible to fill a vacancy on the board caused by a departure of a regular board member.

Ms. Johnsen is partner and founder of X-lence Group, a management consultancy and business strategy company. Until the end of 2002 she was Vice President Strategy and Business Development Elkem Shared

Services Division at Elkem ASA. From 1993 to 1997, she was Head of the Legal Section and Administration Department at Ullevaal University Hospital. She has also had positions in Norwegian Ministry of Foreign Affairs and Norwegian Ministry of Justice. She serves on the boards of several companies: Fjord Seafood ASA, Handicare ASA, Odin Fund Management AS and Norwegian Refugee Council. She has previously served on boards for Ementor ASA and Aker University Hospital. She holds a law degree from the University of Oslo and received a master's degree with honors in business administration (MBA) from the Solvay Business School in Brussels, Belgium.

Mr. Reynolds is managing director of Houlihan Lokey Howard & Zukin (Europe) Ltd., an investment bank. He has a master's degree in theology and religious studies from Cambridge University, and is a fellow of the Institution of Electrical Engineers and a fellow of the Energy Institute.

Board Committees

Under Norwegian law, decision-making authority may not be delegated by the Board of Directors to its committees or subcommittees. The Board may, however, establish committees to assist it in discharging its responsibilities. Our Board of Directors has appointed two such committees, the audit committee and the remuneration committee.

Our audit committee currently consists of three members, Messrs. Gugen (chairman), Norvik and Tripodo. The Board of Directors has determined that the members of the audit committee are independent under applicable provisions of the Securities Exchange Act of 1934 and New York Stock Exchange listing standards. Our audit committee has adopted a written charter, a copy of which we have filed as an exhibit to this annual report.

The audit committee acts to support the Board of Directors in the administration and exercise of the Board's responsibility for supervisory oversight under applicable Norwegian and other laws and stock exchange listing standards in connection with our financial statements and various audit, accounting and regulatory requirements. The audit committee is responsible for proposing to the full Board, for presentation and election at our annual general meeting of shareholders, the independent registered public accounting firm of our company. The audit committee is also responsible for supporting the Board in the administration and exercise of the Board's responsibility for supervisory oversight in relation to, among other items:

- financial statement and disclosure matters, including our quarterly and annual financial statements and related disclosures;
- reviewing the quarterly and annual financial statements, including reviewing major issues regarding accounting principles and financial statement presentations, the adequacy of our internal controls and discussing significant financial reporting issues and judgments made in connection with preparation of the financial statements;
- provision by the auditor of audit services and permitted non-audit services;
- audits of our financial statements, including reviewing our critical accounting policies and practices;
- our relationship with our independent registered public accounting firm, including the qualifications, performance and independence of the auditors;
- our internal audit function; and
- responsibilities to comply with various legal and regulatory requirements that could affect our financial statements.

The U.S. Securities Exchange Act of 1934 and the listing standards of the New York Stock Exchange require the audit committee of a listed company in the United States, such as PGS, to be directly responsible for the appointment, compensation, retention and oversight of the work of that company's independent registered public accounting firm. Because under Norwegian law the power to appoint, retain and compensate the auditors is held by the shareholders, our audit committee is directly responsible only for the oversight of the work of the auditors and the audit committee and the full Board recommend the appointment, retention and compensation of the auditors to its shareholders for approval. In addition, as a foreign private issuer in the United States, we are not required to publish the audit committee report required by applicable regulations of the SEC for U.S. domestic issuers.

Our remuneration committee consists of Messrs. Henry (chairman) and Rolfsen. The Board of Directors has determined that the members of the remuneration committee are independent under applicable New York Stock Exchange listing standards. The remuneration committee supports the Board of Directors in the administration and exercise of the Board's responsibility for supervisory oversight of overall policy and structure with respect to compensation and incentive matters, including compensation and incentive arrangements for our chief executive officer and other senior executive officers. Our remuneration committee has adopted a written charter, a copy of which we have filed as an exhibit to this annual report. As a foreign private issuer in the United States, we are not required to publish the compensation committee report required by applicable regulations of the SEC for U.S. domestic issuers.

The listing standards of the New York Stock Exchange require U.S. listed companies to have a nominating and corporate governance committee (1) to identify individuals qualified to become board members and to select, or to recommend that the board select, the director nominees for the next annual general meeting; (2) to develop and recommend to the board a set of corporate governance guidelines applicable to the listed company; and (3) to oversee the evaluation of the board and management. In accordance with Norwegian law and customary practice, our Board of Directors, which is composed entirely of non-management directors, fulfills those responsibilities.

Corporate Governance

We are committed to maintaining high standards of corporate governance and believe that effective corporate governance establishes the framework by which we conduct ourselves in delivering services to our customers and value to our shareholders. Although we are registered in Norway as a public limited company and our governance model is built on Norwegian corporate law, we are subject to the requirements applicable to foreign private issuers in the United States, including those established by the SEC and the NYSE.

Our corporate governance principles are adopted and reviewed periodically by the Board of Directors. The Corporate Governance Principles, together with our Core Values and our Code of Conduct, Audit Committee Charter, Remuneration Committee Charter and our Rules of Procedure for the Board of Directors, are available under the "About PGS" section of our internet website at *www.pgs.com* and in print to any shareholder who requests a copy. Requests should be directed to our investor relations department at ir@pgs.com.

Director Independence

At its meeting held in May 2005, our Board of Directors affirmatively determined that each of Francis Gugen, Keith Henry, Harald Norvik, Rolf Erik Rolfsen, Clare Spottiswoode and Anthony Tripodo has no material relationship with us (either directly or as a partner, shareholder or officer of an organization that has a relationship with us) and that each is therefore an "independent" director under applicable NYSE listing standards. These determinations were made by our Board of Directors based on representations made by each of those directors to us, a review of applicable NYSE rules and listing standards and a review of our Rules of Procedures for the Board of Directors. In confirming Mr. Gugen's status as an independent director, our Board of Directors reviewed and considered Mr. Gugen's service as a director of the CH4 group of companies and prior transactions, which amounted to $119,000 in 2004, between the CH4 group of companies and us.

Shareholders and other interested parties may communicate directly with our independent directors by sending a written communication in an envelope addressed to "Board of Directors (Independent Members)" in care of our General Counsel at the address indicated on the cover of this annual report.

Meetings of Non-management Directors

Our Board of Directors consist of only non-management directors. As such, every meeting of our Board of Directors is a meeting of non-management directors. In addition, if the group of non-management directors includes a director who is not independent under NYSE listing standards, the independent directors will meet in executive session at least once annually. Currently, the director who presides at meetings of the non-management directors is the Chairman of the Board. Further, the director currently presiding at meetings of the independent directors is the Vice-Chairman of the Board.

Certifications

We have filed the required certifications of our chief executive officer and our chief financial officer under Section 302 of the Sarbanes-Oxley Act of 2002 as exhibits 12.1 and 12.2 to this annual report, and we expect to file with the NYSE the chief executive officer certification without exceptions within 30 days following our annual general meeting, as required by Section 303A.12(a) of the NYSE Listed Company Manual.

Supermajority Voting Provision Relating to Our Board

Under our Amended Articles of Association, any change to our Board of Directors prior to October 16, 2005 will require approval by the holders of more than two-thirds of the votes cast as well as of the shares represented at the shareholders meeting. In addition, as part of our 2003 restructuring, our shareholders resolved that board decisions on certain specified major transactions, during the same two-year period, must be approved by the board members nominated by the pre-restructuring shareholders or their successors. These major transactions include:

- any single sale of assets or series of sales of assets, in any calendar year, in excess of $100 million and not otherwise requiring approval by two-thirds of the shareholders in a general meeting;
- changes to our key executive management;
- new financings or borrowings over $25 million;
- application of "major proceeds," which means the proceeds from the sale of any of our assets in excess of $100 million;
- material acquisitions, which includes any single acquisition of assets or series of acquisition of assets, in any calendar year, in excess of $100 million and not otherwise requiring approval by two-thirds of the shareholders present and voting in a general meeting;
- proposals to change our Articles of Association; and
- proposals for issuance of new equity or equity-like securities.

Any changes to these instructions require approval by the holders of at least two-thirds of the votes cast and of the shares represented at the shareholders meeting.

Executive Officers

The table below provides information about our executive officers as of April 30, 2005:

Name (Age)	Position	Executive Officer Since	Share Ownership
Svein Rennemo (57)	President and Chief Executive Officer	2002	*
Gottfred Langseth (38)	Senior Vice President and Chief Financial Officer	2004	*
Rune Eng (43)	President — Marine Geophysical	2004	*
Eric Wersich (42)	President — Onshore	2003	*
Sverre Skogen (48)	President — Production	2003	*
Anthony Ross Mackewn (57)	Senior Vice President — Geophysical	1999	*

* Less than 1% of our outstanding shares as of March 31, 2005.

Mr. Rennemo joined PGS in November 2002 as president and chief executive officer. Prior to joining PGS, he was a partner in ECON Management. From 1997 to March 2001, Mr. Rennemo was chief executive officer of Borealis, one of the world's largest producers of polyolefin plastics, headquartered in Copenhagen, Denmark, having previously served as chief financial officer and deputy chief executive officer since 1994. From 1982 to 1994, he filled various senior management positions within Statoil, among them group chief financial officer and president of Statoil Petrochemicals. From 1972 to 1982, he served as a policy analyst and advisor with the Central Bank and the Ministry of Finance in the kingdom of Norway and the OECD Secretariat in Paris. Mr. Rennemo earned a master's degree in economics at the University of Oslo in 1971. He is a non-executive board member of Dynea of Finland and Nutreco of the Netherlands.

Mr. Langseth joined PGS as senior vice president and chief financial officer in January 2004. He was chief financial officer at Ementor ASA (Merkantildata) from 2000 to August 2003. Mr. Langseth was senior vice president of finance and control for Aker Maritime from 1997 to 2000. He served with Arthur Andersen Norway from 1991 to 1997, qualifying as a Norwegian state authorized public accountant in 1991. Mr. Langseth has a master's degree in business administration from the Norwegian School of Economics and Business Administration.

Mr. Eng was appointed president of Marine Geophysical in August 2004. Since joining PGS in 1997, he has held the position of area manager Scandinavia and from 2000 has served as president for the EAME region (Europe, Africa and Middle East). Prior to joining PGS, Mr. Eng held different positions in Fugro-Geoteam, including a board position in Sevoteam, a Russian-Norwegian joint operating company. Mr. Eng has a bachelor's degree in applied geophysics from the University of Oslo and a master of science degree from Chalmers University of Technology (Sweden).

Mr. Wersich joined Onshore in January 2000 as vice president of western hemisphere and was appointed president of Onshore in June 2003. Mr. Wersich worked with Western Geophysical from 1984 to 2000, employed in various operational and management positions in North America, Latin America, Europe and the Middle East. He is a graduate of the Colorado School of Mines, where he earned a bachelor of engineering degree in geophysics.

Mr. Skogen was appointed president of Production in January 2004. He previously served as independent advisor for various projects from January 2003 to January 2004. He was president and chief executive officer of Aker Kvaerner AS Oil & Gas from March 2002 to January 2003, president and chief executive officer of Aker Maritime ASA from May 1997 to March 2002 and executive vice president of Aker RGI from January 1997 to May 1997. Mr. Skogen was the founding partner of TerraMar Prosjektledelse and helped establish TerraMar Informasjonssystemer in 1993, which he headed until 1997. During the 1980s, he held various positions in Norwegian Petroleum Consultants, the engineering contractor for a number of large developments on the Norwegian shelf. Mr. Skogen has a master's of science degree in construction management, a master's degree in business administration and a bachelor of science degree in civil engineering from the University of Colorado.

Mr. Mackewn joined PGS as the technology director of PGS Nopec in 1993 and transferred to PGS Exploration in 1996 as managing director of PGS Exploration UK Ltd. He was appointed president of Exploration EAME in November 1999, president of PGS Geophysical Services in May 2001, president of PGS Marine Geophysical in February 2003 and group senior vice president of Geophysical in August 2004. Prior to joining PGS, Mr. Mackewn held a number of senior positions within the seismic services division of Schlumberger. Mr. Mackewn graduated with an honors degree in physics from the University of Southampton in 1969.

In addition, Espen Klitzing will join PGS as senior vice president of business development and support in May 2005. From January to April 2005, Mr. Klitzing was a special advisor to the private investment company Kistefos. From 1999 to 2004, he was CEO of Storebrand Livsforsikring (Life Insurance), a company with a premium income of NOK 9.7 billion and 675 employees. Prior to joining Storebrand, Mr. Klitzing held positions with the consulting firm McKinsey & Company Inc. Mr. Klitzing also has served on numerous boards of directors. Mr. Klitzing has a degree in business administration from the Norwegian School of Economics and Business Administration.

Share Ownership of Directors and Executive Officers

As of April 30, 2005, the total number of our shares and ADSs beneficially held by directors (7 persons) and executive officers (6 persons) as a group was 1,016,520 representing approximately 5.1% of our outstanding shares. Mr. Ulltveit-Moe, chairman of our Board of Directors, is the founder, chief executive officer and president of Umoe Group, the parent company of Umoe Invest AS, which as of March 31, 2005 owned 1,012,444 shares, or 5.1% of our outstanding shares.

On consummation of our reorganization plan, all outstanding options for shares were cancelled without compensation to the holders, and as of April 30, 2005 we do not have board or shareholder authorization to issue shares under any share option plan. The establishment of any management incentive plan that includes the issuance of share options or other equity rights will require 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.

Compensation of Directors and Executive Officers

For the year ended December 31, 2004, the aggregate amount we paid for compensation to our directors and executive officers as a group for services in all capacities during 2004 was $3.6 million. This amount includes compensation paid to all persons who served as directors and executive officers during any period of 2004. Mr. Rennemo, our president and chief executive officer, received compensation for services to us during 2004 of $0.7 million. The aggregate benefits that had accrued to our directors and executive officers as a group (including all persons who served as such during any period of 2004) under our various defined benefit plans for the year ended December 31, 2004 was $0.1 million. Please read note 21 of the notes to our consolidated financial statements in Item 18 of this annual report for additional information relating to our defined benefit plans. None of our directors has a contract with us providing benefits upon termination of service.

For the year ended December 31, 2004, our executive officers listed above who were employed by us during 2004 and remain employed as of March 1, 2005 were eligible to receive in 2005 cash and share purchase bonuses under our 2004 Bonus Incentive Plan. Under this plan, our chief executive officer may receive a cash bonus of up to 50% of base salary and an additional cash bonus (the net amount of which must be used to purchase shares as described below) of up to 30% of base salary. Other executive officers may receive a cash bonus of up to 40% of base salary and an additional cash bonus (with a similar requirement to purchase shares) of up to 20% of base salary. Within these limits, bonuses are determined on the basis of achievement of financial and non-financial performance targets. Under our share purchase bonus plan, which is subject to final documentation and satisfaction of applicable legal requirements, any amount received as a share purchase bonus, net of withholding taxes, is required to be used to buy our shares in the open market at the prevailing market price, and such shares generally are required to be held for a minimum of three years. The aggregate amount of share purchase bonuses for 2004 for these executive officers is approximately $170,000, which amount was recognized as an expense in 2004. For the year ended December 31, 2004, we also had a cash bonus and share purchase bonus plan for another group of approximately 60 key employees that is similar to the plan described above for our executive officers, except that the bonus amounts and percentages for each employee are generally smaller. We have established bonus plans for 2005 with the same principles as the 2004 bonus plans, covering our executive officers and additionally approximately 130 key employees. We currently are not authorized to issue any stock options or other stock-based awards under any stock option plan or similar plan or arrangement for involving employees in the capital of our company.

Employees

The following table presents information about the number of our employees as of the end of each of the last three years:

	December 31,		
	2004	2003	2002
Marine Geophysical	1,115	1,143	1,356
Onshore	1,011	1,479	1,828
Production	501	515	520
Pertra	16	5	6
Global Services/Corporate	256	235	252
Discontinued Operations	—	—	41
Total	2,899	3,377	4,003

Except for the employee lockout affecting the *Petrojarl I* and the strike affecting *Petrojarl Varg* as described under "Information on the Company — Our Production Segment — Employee Lockout and Strike in September/October 2004" in Item 4 of this annual report, 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 amended Schedule 13G filed with the Securities and Exchange Commission on December 15, 2004, Umoe Invest AS beneficially owns 1,012,444 shares, or 5.1% of our outstanding shares. Mr. Jens Ulltveit-Moe, founder, chief executive officer and president of Umoe Group, the parent company of Umoe Invest AS, serves as chairman of our Board of Directors. Please read Item 6 of this annual report for additional information regarding Mr. Ulltveit-Moe.

Based on a Schedule 13G filed with Securities and Exchange Commission on July 29, 2004, John A. Griffin beneficially owns 1,468,093 shares, or 7.3% of our outstanding shares. Mr. Griffin is the Managing Member of JAG Holdings LLC and JAG Offshore Holdings LLC, and in that capacity directs their operations. JAG Holdings LLC is the general partner of Blue Ridge Limited Partnership, and JAG Offshore Holdings LLC is the general partner of Blue Ridge Offshore Master Limited Partnership. Based on the Schedule 13G, Blue Ridge Limited Partnership and JAG Holdings LLC beneficially own 976,329 shares, or 4.9% of our outstanding shares; and Blue Ridge Offshore Master Limited Partnership and JAG Offshore Holdings LLC beneficially own 491,764 shares, or 2.5% of our outstanding shares.

Our shareholders that are the beneficial owners of 5% or more of our ordinary shares do not have different voting rights than our other shareholders.

As of December 31, 2004, there were 31 record holders of ADSs representing 6,487,126 shares, of which 25 had registered addresses in the United States. These 25 United States record holders held ADSs representing 6,487,072 shares, which represented approximately 32% 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, 2004, there were 20,000,000 ordinary shares outstanding (including shares represented by ADSs) held by 2,952 record holders, of which 80 had registered addresses in the United States and 2,621 had registered addresses in Norway. The United States holdings represented 8,076,234 shares, or approximately 40% of the total number of our shares outstanding as of that date. For this purpose, Citibank, N.A., 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 4,696,752 shares, or approximately 24% of the total number of our shares outstanding as of that date.

In the late 1990s, bank loans were extended to various of our Norwegian employees, including some key management personnel and at least one director, in connection with the grant of options by us during that period. These loans were guaranteed by us, generally bore interest at 4% or 5% per annum and were intended to provide the individuals involved with funds required to pay Norwegian taxes that were triggered by option grants. Most of these loans were settled during 2003. The largest amount of outstanding loans from us to these employees during 2004 aggregated $0.3 million. As of December 31, 2004, the amount of these loans outstanding aggregated $0.1 million, with none of such outstanding loans being with any executive officers, directors or key management personnel.

Please read note 24 of the notes to our consolidated financial statements included in Item 18 of this annual report for additional 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. See "Key Information — Risk Factors — Other Risk Factors — We are a multinational organization faced with increasingly complex tax issues in many jurisdictions, and we could be obligated to pay additional taxes in various jurisdictions" in Item 3 of this annual report concerning the potential dispute with the Norwegian Central Tax Office relating to tonnage taxation. We do not believe that we are engaged in, or have recently been engaged in, any additional legal or arbitration proceedings that 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 following items, as computed for PGS in accordance with Norwegian GAAP:

- 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; and
  - 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 our unconsolidated Norwegian GAAP balance sheets, 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. In addition, we are not allowed to pay dividends or make similar distributions until the $250 million 8% Senior Notes due 2006, described in note 15 of the notes to our consolidated financial statements in Item 18 of this annual report, are repaid.

In addition, we are committed to strengthen our financial flexibility and intend to use our available cash flow to develop our core businesses and to maintain or improve financial ratios as described under "Liquidity and Capital Resources — Liquidity — General" in Item 5 of this annual report. As a result, we do not currently expect to pay ordinary dividends to shareholders in the next two to three years. Any future dividends will be subject to determination based upon our results of operations and financial condition, our future business prospects, any applicable legal or contractual restrictions and other factors that the Board of Directors considers relevant.

Significant Changes

Except as disclosed in this annual report, no significant changes have occurred since the date of our 2004 annual financial statements.

ITEM 9. *The Offer and Listing*

Listing Details

Our ordinary shares are listed on the Oslo Stock Exchange and trade on that exchange under the symbol "PGS." These shares are not publicly traded outside Norway.

Each ADS represents one share. Citibank, N.A. serves as the depositary for the ADSs. Prior to February 2003, the ADSs were traded on the New York Stock Exchange. On February 26, 2003, the NYSE informed us that our ADSs were suspended from the NYSE and that it would commence proceedings with the U.S. Securities and Exchange Commission to delist the securities. Our ADSs were then traded over-the-counter ("OTC") and were quoted on the Pink Sheets under the ticker symbol "PGOGY."

In November 2003, subsequent to our emergence from Chapter 11, our new ordinary shares began trading on the Oslo Stock Exchange and our new ADSs began trading on the OTC Pink Sheets under the symbol "PGEOY."

On December 17, 2004, our ADSs were relisted on the NYSE and began trading under the symbol "PGS."

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. Upon emergence from Chapter 11 proceedings and consummation of our financial restructuring, the pre-restructuring shareholders received one post-restructuring share per 129 old shares held in addition to the right to subscribe for new shares in a rights offering.

	Price per ADS	
Calendar Period	**High**	**Low**
2000	$19.56	$10.00
2001	14.63	5.00
2002	7.89	0.35
2003 (through February 26)	0.48	0.31
2004 (from December 17)	62.06	58.00
2005		
First Quarter	74.75	59.50
Last Five Months		
April	71.09	60.50
March	74.28	63.61
February	74.75	71.27
January	70.10	59.50
December (from December 17, 2004)	62.06	58.00

We have presented in the table below, for the periods indicated, the reported high and low closing prices for our ADSs on the Pink Sheets from February 26, 2003 to December 16, 2004.

	Price per ADS	
Calendar Period	**High**	**Low**
2003 (February 26, 2003 — November 5, 2003)	$ 1.49	$ 0.10
2003 (from November 6, 2003)	43.00	32.80
2003 (from February 26, 2003)	43.00	0.10
First Quarter	0.20	0.10
Second Quarter	0.66	0.15
Third Quarter	1.03	0.58
Fourth Quarter (through November 5, 2003)	1.49	0.34
Fourth Quarter (from November 6, 2003)	43.00	32.80
2004		
First Quarter	51.20	38.05
Second Quarter	48.00	33.50
Third Quarter	48.50	36.75
Fourth Quarter (through December 16, 2004)	62.25	37.50
Last Two Months of 2004		
December (through December 16, 2004)	62.25	55.00
November	55.61	37.50

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. Upon emergence from Chapter 11 proceedings and consummation of our financial restructuring, the pre-restructuring shareholders received one post-restructuring share per 129 old shares held in addition to the right to subscribe for new shares in a rights offering.

	Price per Share	
Calendar Period	High	Low
2000	NOK174.0	NOK 91.5
2001	124.5	44.0
2002	70.0	2.6
2003 (through November 5, 2003)	10.9	1.1
2003 (from November 6, 2003)	315.0	213.0
2003		
First Quarter	3.1	1.1
Second Quarter	5.1	1.1
Third Quarter	7.0	4.4
Fourth Quarter (through November 5, 2003)	10.9	6.9
Fourth Quarter (from November 6, 2003)	315.0	213.0
2004		
First Quarter	365.0	262.0
Second Quarter	337.0	245.0
Third Quarter	333.0	248.5
Fourth Quarter	385.0	289.0
2005		
First Quarter	485.0	373.0
Last Six Months		
April	451.0	380.0
March	459.0	405.0
February	485.0	445.0
January	446.0	373.0
December	385.0	340.0
November	339.0	289.0

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.

Before October 16, 2005, 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 more than two-thirds of the votes cast and more than two-thirds of the share capital represented at the meeting. After October 16, 2005, a simple majority will be sufficient to elect a new director, both before and after the expiration of an incumbent's term of office.

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. Norwegian law requires that written notice of general meetings be sent to shareholders whose addresses are known at least two weeks prior to the date of the meeting. 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. Any shareholder may demand that a specific issue be placed as an item on the agenda for any general meeting provided that we are notified in time for such item to be included in the meeting notice.

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, any matter that may be raised at an annual general meeting may also be raised at an extraordinary general meeting.

Norwegian law prohibits the general meeting or the Board of Directors of any other person representing us from taking any action that may give a shareholder an unreasonable benefit at the expense of other shareholders or us.

Restrictions on Ownership of Shares

At present, there is no limitation on ownership of shares by persons who are not Norwegian.

Share Register

Under Norwegian law, shares are registered in the name of the owner of the shares. As a general rule, there are no arrangements for nominee registration. However, shares may be registered in the VPS, described further below, by a fund manager (bank or other nominee) approved by the Norwegian Ministry of Finance, as the nominee of foreign shareholders. An approved and registered nominee has a duty to provide information on demand about beneficial shareholders to the company and to the Norwegian authorities. In the case of registration by nominees, registration with the VPS must show that the registered owner is a nominee. Registration must include the nominee's name, address and number of shares, which are the subject of the nomination agreement. A registered nominee has the right to receive dividends and other distributions but cannot vote at general meetings on behalf of the beneficial owners. Beneficial owners must register with the VPS or provide other proof of their acquisition of the shares in order to vote at general meetings.

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, authorized securities brokers in Norway and Norwegian branches of credit institutions established within the European Economic Area 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, in which event compensation owed by the VPS may be reduced or withdrawn.

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 our company.

ADSs and Transfer and Voting

Our shareholders may choose to hold our shares as ADSs, in which case the shares are represented by ADRs. ADSs may be transferred, at the option of the holder, by transferring the related ADRs, or by requesting the underlying shares to be issued to the holder, who transfers them to the transferee. Holders of ADSs may vote their shares by:

- requesting to be certificated by having the underlying shares transferred to a VPS account in the name of the holder;
- presenting themselves as a shareholder, providing name and address, and a confirmation from Citibank N.A. as depositary for the ADSs to the effect that they are the beneficial owner of the underlying shares; or
- authorizing Citibank N.A. to vote the ADSs on their behalf.

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 $^1/_{20}$, $^1/_{10}$, $^1/_5$, $^1/_3$, $^1/_2$, $^2/_3$ 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, which is at least two-thirds of the votes cast and at least two-thirds of the share capital represented at the meeting. 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; and
- 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 U.S. holders will not be able to exercise their preemptive rights and would be required to sell them to Norwegian persons or other non-U.S. 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; or
- 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

Please read "Financial Information — Dividend Restrictions" in Item 8 of this annual report for information regarding our ability to pay dividends and whether we intend to pay dividends. We hereby incorporate information called for by this Item 10 by reference to the information under that caption.

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.

Examination of PGS and its Accounts

Under Norwegian law, any shareholder may request the Norwegian courts to order an examination of our company and accounts if such request is approved by 10% or more of the aggregate share capital represented at any general meeting.

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. The shares rank pari passu in the event of a return of capital by the company on a winding-up or otherwise.

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 (including 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. Such offer must be made no later than four weeks after the obligation is triggered and in the form of an offer document to all shareholders. The offer may not be conditional and is subject to approval by the Oslo Stock Exchange before submission to the shareholders. The offer must be in cash or contain a cash alternative at least equivalent to any other consideration offered. 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, or agrees to acquire, additional shares at a higher price after exceeding the 40% threshold but prior to the expiration of the four-week 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, unless a majority of the remaining shareholders approve. In addition, the Oslo Stock Exchange may impose a daily fine upon a shareholder who fails to make the required offer.

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.

Sale of All or Substantial Part of Our Property or Assets

There is no general requirement under Norwegian law that the sale, lease or exchange of all or substantially all of the property or assets of a Norwegian company requires shareholder approval in addition to the approval of the Board of Directors, unless such a transaction would imply that the business and purpose of the company as described in its articles of association would be amended, in which event the approval of at least two-thirds of the votes cast and at least two-thirds of the share capital represented at the meeting is required.

Compulsory Acquisition (Squeeze Out/Sell Out Right)

Under Norwegian law, if a shareholder, directly or indirectly, acquires shares of a Norwegian company representing more than 90% of the total number of shares outstanding or of the outstanding voting rights, then such majority shareholder has the right (and each remaining minority shareholder of the company has the right to require such majority shareholder) to effect a compulsory acquisition for cash of any shares not already owned by such majority shareholder. Such compulsory acquisition would imply that the majority shareholder has become the owner of the acquired shares with immediate effect. On effecting the compulsory acquisition, the majority shareholder would have to offer the minority shareholders a specific price per share, the determination of which price would be at the discretion of the majority shareholder. If any minority shareholder does not accept the offered price, such minority shareholder may, within a specified deadline not less than two months, request that the price be set by the Norwegian courts. Generally, the cost of any such court procedure would be borne by the majority shareholder, and the courts would have full discretion in respect of the valuation of the shares for the compulsory acquisition. In the absence of such a request or other objection to the price being offered by the majority shareholder, the minority shareholders would be deemed to have accepted the offered price after the expiration of a two-month period.

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 U.S. 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 U.S. federal income taxation on a net income basis for ADRs and shares and who are not residents of Norway ("U.S. 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 U.S. Holders are advised to consult their own tax advisors about the U.S. 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 U.S. 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). Several amendments to Norwegian tax law were enacted in the national budget in Norway for 2005. The amendments include, among others, an exemption from taxation for dividends and gains from disposal of shares for corporate shareholders, although individual shareholders would continue to be subject to taxation of such dividends and gains. The amendments have some retroactive effect for 2004.

For U.S. and Norwegian tax purposes, U.S. 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 U.S. federal income tax consequences discussed below apply equally to U.S. Holders of ADRs and U.S. Holders of shares.

We believe, and this discussion assumes, that we are not and have never been a foreign personal holding company, a foreign investment company, or a passive foreign investment company as those terms are defined in the U.S. Internal Revenue Code of 1986, as amended (the "Code").

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 U.S. 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. U.S. 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 Central Office — Foreign Tax Affairs. There is some uncertainty, however, as to whether and when such a refund may be obtained. The amendments to the Norwegian tax law do not affect the withholding tax on dividends distributed to residents of the United States.

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 U.S. Holder will be treated as taxable domestic dividend income in Norway, subject to the provisions of the Convention, where applicable. After the amendments to the Norwegian tax law, the dividend could potentially be exempted from taxation in Norway if the business activity in Norway is owned by a corporate entity in the United States, but the legal situation is unclear. Such U.S. Holders should seek further tax advice regarding their tax situation in Norway.

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 U.S. Holder for U.S. federal income tax purposes as ordinary dividend income. In the case of a U.S. 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 Code. The amount of a dividend distribution for tax purposes will equal the U.S. 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 U.S. dollars of the Norwegian kroner received in a distribution, U.S. Holders of ADRs generally will recognize gain or loss for U.S. federal income tax purposes equal to the difference, if any, between such U.S. dollars and the U.S. dollar value of such Norwegian kroner on the date of the distribution. Such gain or loss will be treated as ordinary income or loss.

For tax years beginning after December 31, 2002 through tax years beginning on or before December 31, 2008, dividend income received by an individual, estate, or trust from a corporation organized in the U.S. or from a "qualified foreign corporation" generally is taxed at the lower rates imposed on long-term capital gains recognized by individuals. The maximum rate of tax for such dividends is 15%.

A non-U.S. corporation is a "qualified foreign corporation" if either (i) its stock with respect to which the dividend is paid is readily tradable on an established securities market in the U.S. or (ii) the corporation is eligible for the benefits of a comprehensive tax treaty with the U.S. that the Internal Revenue Service ("IRS") determines is satisfactory for purposes of the provision reducing the rate of tax on dividends, and that includes an exchange of information program. Our ADSs are readily tradable on an established securities market in the U.S. because they are listed on the NYSE. Moreover, we are eligible for benefits under the Convention, and the IRS has identified the Convention as satisfactory for purposes of the provision reducing the rate of tax on dividends and as including an exchange of information program. Accordingly, U.S. Holders that are individuals, estates, or trusts generally will be eligible for the lower long-term capital gains rates with respect to dividends paid on our shares or ADSs.

A U.S. Holder will not be allowed to benefit from the lower long-term capital gains rates unless the U.S. Holder (i) holds our shares or ADSs for more than 60 days during the 121-day period beginning on the date that is 60 days before the date on which the shares or ADSs become ex-dividend (disregarding any period during which the U.S. Holder has a diminished risk of loss with respect to such shares or ADSs), and (ii) is not under an obligation to make related payments with respect to positions in substantially similar or related property.

Norwegian taxes imposed on dividend distributions on our shares or ADSs generally will be eligible for credit against the U.S. Holder's U.S. federal income taxes. The amount of the Norwegian taxes eligible for this foreign tax credit generally 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. U.S. Holders that are eligible for benefits under the Convention will not be entitled to a foreign tax credit for the amount of any Norwegian taxes withheld in excess of the 15% maximum rate, and with respect to which the holder can obtain a refund from the Norwegian taxing authorities. U.S. Holders that are accrual basis taxpayers generally must translate Norwegian taxes into U.S. dollars at a rate equal to the average exchange rate for the taxable year in which the taxes accrue (except that, for taxable years beginning after December 31, 2004, such a U.S. Holder may elect to translate Norwegian taxes using the exchange rate at the time the taxes are paid if the U.S. Holder's functional currency for tax purposes is not the Norwegian kroner). All U.S. Holders must translate taxable dividend income into U.S. dollars at the spot rate on the date received. This difference in exchange rates may reduce the U.S. dollar value of the credits for Norwegian taxes relative to the U.S. Holder's U.S. federal income tax liability attributable to the dividend.

Under the foreign tax credit limitations of the Code, the foreign tax credit can offset U.S. federal income taxes imposed on foreign-source income but not on U.S.-source income. In addition, foreign taxes imposed on income in certain categories specified in the Code may only be used to offset U.S. taxes on income in the same category. Subject to special rules 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 U.S. Holder's circumstances. For taxable years beginning after December 31, 2006, dividends that previously would have been "passive income" will generally be "passive category income" and dividends that previously would have been "financial services income" will generally be "general category income."

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

If a U.S. Holder that is an individual, estate, or trust is taxed at the lower long-term capital gains rates on dividends we pay, the Code contains a provision that will cause a portion of any dividend eligible for this lower rate to be treated as U.S.-source income. This provision is intended to limit the amount of the Norwegian taxes eligible for the foreign tax credit to the amount of U.S. tax paid by the U.S. Holder at the lower long-term capital gains rates. U.S. Holders are advised to consult their own tax advisors when determining the portion of any dividend that will be treated as U.S.-source income under this provision.

A U.S. Holder will not be allowed to claim foreign tax credits (but would instead be allowed deductions) for Norwegian taxes withheld on a dividend unless the U.S. Holder (i) has held the shares or ADSs for at least 16 days in the 31-day period beginning 15 days before the date on which the shares or ADSs become ex-dividend with respect to such dividend (disregarding any period during which the U.S. Holder has a diminished risk of loss with respect to such shares or ADSs) and (ii) is not under an obligation to make related payments with respect to positions in substantially similar or related property.

Taxation of Ordinary Dispositions

A U.S. 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.

Under Norwegian tax law, gains from the sale or other disposal of our shares or ADSs by a U.S. Holder is taxable in Norway if the U.S. Holder is engaged in a business activity taxable in Norway and our shares or ADSs are effectively connected with that activity. After the amendments to the Norwegian tax law, such gains could potentially be exempted from taxation when the U.S. Holder with the business activity in Norway is a corporate entity, but the legal situation is unclear. We recommend that such U.S. Holders seek further tax advice regarding their tax situation in Norway. Losses are deductible if the gains are taxable. Gains from disposal of shares will be taxable if the shares are owned by a U.S. Holder who is an individual with business activity in Norway, and our shares or ADSs are effectively connected with that activity. Under the current legislation the gain for the individual shareholder will be calculated as the difference between the consideration received and the tax basis of the shares. The tax basis of the shares is determined as the acquisition cost, adjusted for annual changes in our taxed equity during the shareholders' ownership period. From 2006 the gain for the individual shareholder will still be taxable as general income at a flat rate of 28%. Losses are deductible against general income. However, the calculation of the taxable gain for the individual is amended such that the gain is calculated as the difference between the consideration received and the acquisition cost, adjusted for a "protected yield" (equal to average interest rate on five-year bonds). The tax liability and deductibility apply irrespective of how long the shares have been owned and the number of shares that is sold. If the shares disposed of have been acquired at different times, the shares that were first acquired will be deemed as first sold. Costs incurred in connection with the purchase and sale of shares are deductible in the year of sale, provided that the gain is not exempted from taxation.

A U.S. Holder will recognize capital gain or loss for U.S. 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). Such capital gain or loss will be an amount equal to the difference between the U.S. dollar value of the amount realized and the U.S. Holder's tax basis in the shares. Such capital gain or loss will be long-term if the shares have been held for more than one year. Long-term capital gains recognized by individuals, estates, and trusts are eligible for taxation at rates not in excess of 15%. Any such gain or loss will generally be U.S.-source income or loss.

Regardless of the holding period of the shares or ADSs disposed, if an individual U.S. Holder receives a dividend from us qualifying for the long-term capital gains rates and such dividend constitutes an "extraordinary dividend," and the U.S. Holder subsequently recognizes a loss on the sale or exchange of our shares or ADSs, then the loss will be long-term capital loss to the extent of such "extraordinary dividend." An "extraordinary dividend" for this purpose is a dividend in an amount (i) greater than or equal to 10% of the taxpayer's tax basis (or fair market value as of the day before the ex-dividend date) of the underlying shares or ADSs, aggregating dividends with ex-dividend dates within an 85-day period, or (ii) in excess of 20% of such tax basis (or fair market value as of the day before the ex-dividend date), aggregating dividends with ex-dividend dates within a period of 365 days.

A U.S. Holder will not be allowed to claim foreign tax credits (but would instead be allowed deductions) for foreign taxes imposed on a gross basis on gain with respect to the disposition of our shares or ADSs unless the U.S. Holder (i) holds such shares or ADSs for more than 15 days during the 31-day period beginning on the date that is 15 days before the right to receive payment arises (disregarding any period during which the U.S. Holder has a diminished risk of loss with respect to such shares or ADSs) and (ii) is not under an obligation to make related payments with respect to positions in substantially similar or related property.

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

U.S. Backup Withholding

Certain payments, including certain dividends and proceeds from sales of stock, may be subject to U.S. "backup withholding" at the current 28% rate if the recipient of such a payment fails to provide an accurate taxpayer identification number or certification of U.S. status or fails to report all interest and dividends required to be shown on its U.S. federal income tax returns, or otherwise fails to establish an exemption from withholding. Any amounts so withheld would be allowed as a credit against the recipient's U.S. federal income tax liability for the year. Dividends we pay to a U.S. Holder generally would be subject to these backup withholding rules.

Gift and Estate Tax

An individual U.S. Holder will be subject to U.S. gift and estate taxes with respect to our shares in the same manner and to the same extent as with respect to other types of personal property.

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

U.S. 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 report that we have filed with the SEC.

Subsidiary Information

Please read "Information on the Company — Organizational Structure" in Item 4 of this annual report for information regarding our subsidiaries.

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

We are exposed to certain market risks, including adverse changes in interest rates, foreign currency exchange rates and crude oil prices, as discussed below.

Interest Rate Risk

We enter into from time to time various financial instruments, such as interest rate swaps, to manage the impact of possible changes in interest rates. As of December 31, 2004, we had one open interest rate swap with the notional amount of $10.3 million and no interest rate lock agreements. Our exposure to changes in interest rates results primarily from our short-term and long-term debt with both fixed and floating interest rates, from our capital lease obligations and from our UK leases. The following table presents principal amounts and related average interest rates by year of maturity for our debt obligations as of December 31, 2004:

	2005	2006	2007	2008	2009	Thereafter
			(Dollar amounts in thousands)			
Debt:						
Fixed Rate	$10,990	$261,920(1)	$12,900	$14,040	$15,160	$779,860
Average Interest Rate	8.28%	8.01%	8.28%	8.28%	8.28%	9.93%
Variable Rate	$ 8,799	$ 1,312	—	—	—	—
Average Interest Rate	4.47%	4.22%	—	—	—	—

(1) The amount includes our $250 million 8% Senior Notes due 2006. We redeemed $175 million of these notes on April 7, 2005.

As of December 31, 2004, we had capital lease obligations of $62.1 million payable through 2008. Interest associated with these capital lease obligations is based on U.S. dollar LIBOR plus a margin. Accordingly, for every one percentage point change in LIBOR, our interest expense will increase approximately $0.6 million per year.

As described under "Operating and Financial Review and Prospects — Liquidity and Capital Resources — UK Leases" in Item 5 of this annual report, we have entered into certain capital leases in the United Kingdom. The leases are legally defeased because we have made payments to independent third-party banks in consideration for which these banks have assumed liability to the lessors equal to basic rentals and termination sum obligations. The defeased rental payments are based on assumed Sterling LIBOR rates between 8% and 9% per annum. If actual interest rates are greater than the assumed interest rates, we receive rental rebates. If, on the other hand, actual interest rates are less than the assumed interest rates, we are required to pay rentals in excess of the defeased rental payments. As of December 31, 2004, our balance sheet reflected a liability of $47.3 million for this interest rate exposure. This liability was recorded upon our adoption of fresh start reporting in November 2003 and is amortized based on rental payments after such adoption. During 2004, 2003 and 2002, actual interest rates were below the assumed interest rates, and we made additional required rental payments of approximately $6.3 million, $6.4 million (combined for Predecessor and Successor) and $3.9 million in the years 2004, 2003 and 2002, respectively. The estimated net present value of future payments related to interest differential on our UK leases as of December 31, 2004 is $56.9 million based on forward interest rate curves. For additional information with respect to our UK leases, please read "Operating and Financial Review and Prospects — Liquidity and Capital Resources — UK Leases" in Item 5 and notes 2 and 19 of the notes to our consolidated financial statements in Item 18 of this annual report.

Foreign Currency Exchange Rate Risk

We conduct business in various currencies including the Brazilian real, Mexican peso, Bolivian boliviano, Dubi dirham, Bangladesh taka, Kazakhstan tenge, Indian rupee, Saudi Arabian riyal, British pound, the Norwegian kroner, the Egyptian pound, the Singaporian dollar and the Australian dollar. We are subject to foreign currency exchange rate risk on cash flows related to sales, expenses, financing and investing transactions in currencies other than the U.S. dollar. As of December 31, 2004 and 2003, we did not have any open forward exchange contracts to manage the exposure related to these risks.

Our cash flows from operations are primarily denominated in U.S. dollars, British pounds and Norwegian kroner. We predominantly sell our products and services in U.S. dollars while some portion of our operating expenses are incurred in British pounds and Norwegian kroner. We therefore typically have higher expenses than revenue denominated in British pounds and Norwegian kroner.

Substantially all of our debt is denominated in U.S. dollars.

Commodity Risk

We operate in the worldwide crude oil markets and are exposed to fluctuations in hydrocarbon prices, which historically have fluctuated widely in response to changing market forces. Pertra's net production in 2004 (combined) was 5,317,134 barrels, with an average realized price of $35.11 per barrel. In 2003 the average realized price was $29.37 per barrel.

As of December 31, 2003 and 2004, we did not have any outstanding derivative commodity instruments. In the first half of 2004, we sold forward 950,000 barrels of our second half production at an estimated average of $30.50 per barrel. Of the total amount sold forward, 250,000 barrels sold forward at an average price of $29.91 per barrel remained undelivered at December 31, 2004 and were delivered in early January 2005.

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

Not applicable.

PART II

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

Not applicable.

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

Not applicable.

ITEM 15. ***Controls and Procedures***

In September 2003 our independent registered public accounting firm, Ernst & Young AS ("EY"), communicated to management and our Audit Committee material weaknesses regarding various elements of our system of internal controls over financial reporting. A material weakness is a significant control deficiency, or a combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected.

Material weaknesses were identified relating to:

- insufficient documentation of policies and procedures, or adherence thereto, relating to significant financial statement accounts;
- inadequate U.S. GAAP expertise within our corporate finance and accounting organization;
- insufficient quality of support for accounting books and records to support our financial statements; and
- insufficient supervision and review control activities within the finance and accounting organization.

At the time of receiving the September 2003 communication from our independent registered public accounting firm, we were in the process of re-auditing our 2001 U.S. GAAP financial statements and finalizing the audit of our U.S. GAAP financial statements for 2002. As a result of the material weaknesses and other factors, including our 2003 financial reorganization and Chapter 11 proceeding, we were unable to prepare audited consolidated financial statements under U.S. GAAP for 2001, 2002 and 2003 until November 2004. Further, in connection with the re-audit for 2001 and the audit of our financial statements for 2002 and 2003, we identified various accounting errors requiring restatement of our historical U.S. GAAP financial statements for 2001.

Acting under the supervision and guidance of our Audit Committee and Board of Directors, our management has worked, with assistance from various consultants and contractors, to address these material weaknesses, including implementing our Sarbanes-Oxley Section 404 readiness project. We have made and continue to make significant changes to improve our internal control over financial reporting and to eliminate material weaknesses.

We believe that the actions taken to date have significantly improved our internal controls. We believe that these and the additional improvements identified and in progress will remediate the weaknesses. However, our assessment of the progress made in addressing the material weaknesses identified in September 2003 indicates that for the period relevant for the preparation of our 2004 financial statements and at December 31, 2004, certain matters, which we believe in aggregate constitute material weaknesses continued to exist relating to:

- the U.S. GAAP competency and procedures for timely and complete identification of developments and transactions of a non-routine nature that require specific accounting consideration;
- the sufficiency of supervisory review control activities in parts of our company;
- the sufficiency of procedures to capture and timely and precisely accrue expenses for our Production operations and the vessel operations of Marine Geophysical; and
- the sufficiency of supervisory review and certain other procedures related to income tax provision.

In connection with the audit of our 2004 financial statements under U.S. GAAP, our independent registered public accounting firm delivered to us a letter dated May 3, 2005 that also confirmed the continuation of these matters that, in the aggregate, they considered to constitute material weaknesses.

As required by SEC Rule 13a-15(b), we have carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of December 31, 2004, the end of the period covered by this annual report. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that in light of the material weaknesses described above, our disclosure controls and procedures were not effective to ensure that information required to be disclosed by us in the reports we file or submit under the U.S. Securities Exchange Act of 1934 was timely recorded, processed, summarized and reported as of December 31, 2004. However, we have instituted a number of actions and performed additional analysis and other procedures to ensure the financial statements and other disclosures included in this report were complete and accurate in all material aspects.

Our management, with the oversight of our Audit Committee and Board of Directors, is committed to the remediation of remaining control deficiencies in our internal control over financial reporting as expeditiously as possible. We believe that the actions that we have already taken will continue to improve our internal controls over financial reporting since many of these controls and remedial actions relate to people and processes that require time before they are fully effective. To remediate fully the deficiency related to our accounting for unusual or non-routine transactions, we are placing increased focus on timely review, documentation and evaluation of account balances and agreements. We will continue to assess the need for additional resources in our review and control activities. We also are recruiting additional GAAP expertise to oversee our GAAP compliance and controls and to strengthen the procedures for capturing operating expenses and accruals related to our Production operations and vessel operations in Marine Geophysical. To address the deficiency related to reporting of income taxes, we have reviewed our control policies for income tax accounting and allocation of responsibilities and strengthened the review procedures. In addition, management has developed remediation plans to address certain other control deficiencies.

Beginning with the year ending December 31, 2006, Section 404 of the Sarbanes-Oxley Act will require us to include an internal control report of management with our annual report on Form 20-F. We expect to continue to make changes in our internal control over financial reporting during our documentation and control evaluation in preparation for compliance with Section 404 of the Sarbanes-Oxley Act. As we implement remaining changes in our internal controls and as we address requirements under the Sarbanes-Oxley Act, we may identify additional deficiencies in our system of internal control over financial reporting that will require additional remedial efforts.

Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that any and all control issues and instances of fraud will be or have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. The design of any system of controls also is based in part upon assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Over time, controls may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitation in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

ITEM 16A. *Audit Committee Financial Expert*

Our Board of Directors has determined that each of Francis Gugen, Anthony Tripodo and Harald Norvik meets the definition of an audit committee financial expert, as that term is defined for purposes of Item 16A of Form 20-F, and that each is independent under applicable provisions of the Securities Exchange Act of 1934 and New York Stock Exchange listing standards.

ITEM 16B. *Code of Ethics*

We have adopted a Code of Conduct that applies to, among others, our principal executive officer, principal financial officer, principal accounting officer and persons performing similar functions. We have filed the code as an exhibit to this annual report and posted it under the "About PGS" section of our internet website at *www.pgs.com*.

ITEM 16C. *Principal Accountant Fees and Services*

Under our Audit Committee Charter, the Audit Committee is responsible (subject to approval by the Board of Directors) for:

- pre-approving all auditing services and permitted non-audit services to be provided by our independent registered public accounting firm and for observing applicable limitations on engaging the independent registered public accounting firm to perform the specific non-audit services restricted by law or regulations; and
- to the extent it deems necessary or appropriate, to retain and compensate independent legal, accounting or other advisors.

Under our pre-approval policy, the Audit Committee is required to preapprove all audit, review or attest engagements and permissible non-audit services to be performed by our independent registered public accounting firm, subject to, and in compliance with, the *de minimis* exception for non-audit services described in applicable provisions of the Securities Exchange Act of 1934 and applicable SEC rules. All services provided by Ernst & Young (EY) in 2004 were pre-approved by the Audit Committee.

Aggregate fees through March 31, 2005 for professional services rendered by EY, including reimbursement of out-of-pocket expenses, related to 2004, 2003 and 2002 were as follows:

	2004	2003	2002
		(In thousands)	
Audit fees(1)	$4,097	$5,845	$2,609
Audit-related fees(2)	42	114	455
Fees for tax services(3)	134	182	51
All other fees(4)	—	541	540
Total	$4,273	$6,682	$3,655

(1) Audit fees consisted of fees for audit services, which related to the consolidated audit, statutory audits, accounting consultations, subsidiary audits and related matters, and fees for audit of fresh start reporting. Fees for 2004 are based on estimates as of May 3, 2005. Fees for 2003 and 2002 have been updated to reflect fees incurred after October 31, 2004 related to the 2003 and 2002 audits and the 2001 re-audit.

(2) Audit-related fees consisted of fees for agreed upon procedures and other attestation services.

(3) Fees for tax services consisted of fees for tax services, tax filing and compliance and reorganization.

(4) Other fees consisted of fees for assistance in connection with restructuring, refinancing and due diligence performed by banks in connection with our financial restructuring in 2003.

ITEM 16D. ***Exemptions from the Listing Standards for Audit Committees***

Not applicable.

ITEM 16E. ***Purchases of Equity Securities by the Issuer and Affiliated Purchasers***

None.

PART III

ITEM 17. ***Financial Statements***

Not applicable.

ITEM 18. *Financial Statements*

Index to Consolidated Financial Statements

We specifically incorporate by reference in response to this item the auditor's report, the consolidated financial statements and the notes to the consolidated financial statements appearing on pages F-2 through F-59.

ITEM 19. *Exhibits*

Exhibit Number	Description
1.1	— Articles of Association, as amended (unofficial English translation) (incorporated by reference to Exhibit 1.1 of the annual report of Petroleum Geo-Services ASA (the "Company") on Form 20-F for the year ended December 31, 2003 (SEC File No. 1-14614 (the "2003 Form 20-F"))).
2.1	— Deposit Agreement, dated as of May 25, 1993, among 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 (incorporated by reference to filing under Rule 424(b)(3) relating to the Company's Registration Statements on Form F-6 (Registration Nos. 33-61500 and 333-10856))
2.4	— Indenture dated as of November 5, 2003, among the Company, each of the guarantors named therein and Law Debenture Trust Company of New York, as trustee (the "Trustee") (incorporated by reference to Exhibit 2.4 of the 2003 Form 20-F)
2.5	— First Supplemental Indenture, dated as of November 5, 2003, among the Company, each of the guarantors named therein and the Trustee (incorporated by reference to Exhibit 2.5 of the 2003 Form 20-F)
2.6	— Second Supplemental Indenture, dated as of June 4, 2004, among the Company, each of the guarantors named therein and the Trustee (incorporated by reference to Exhibit 2.6 of the 2003 Form 20-F)
2.7	— Supplemental Indenture, dated as of August 31, 2004, among Pertra AS, the Company, each of the other guarantors named therein and the Trustee

Exhibit Number		Description
2.8	—	Supplemental Indenture, dated as of August 31, 2004, among P.G.S. Mexicana S.A. de C.V., the Company, each of the other guarantors named therein and the Trustee

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 November 4, 2002 between the Company and Svein Rennemo (the "Employment Agreement") (incorporated by reference to Exhibit 4.1 of the 2003 Form 20-F)
4.2	—	Addendum to the Employment Agreement dated June 8, 2004 between the Company and Svein Rennemo (incorporated by reference to Exhibit 4.2 of the 2003 Form 20-F)
4.3	—	2004 CEO Bonus Scheme (incorporated by reference to Exhibit 4.3 of the 2003 Form 20-F)
8.1	—	Subsidiaries (included in Item 4 of the annual report)
11.1	—	Code of Conduct
12.1	—	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 and Rule 13a-14(a) of the Securities Exchange Act of 1934
12.2	—	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 and Rule 13a-14(a) of the Securities Exchange Act of 1934
13.1	—	Certification of the Chief Executive Officer and the Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and Rule 13a-14(b) of the Securities Exchange Act of 1934
15.1	—	Audit Committee Charter
15.2	—	Remuneration Committee Charter

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

BY: /s/ GOTTFRED LANGSETH

GOTTFRED LANGSETH
Chief Financial Officer

Date: May 9, 2005

EXHIBIT INDEX

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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.

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INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Petroleum Geo-Services ASA and subsidiaries as of December 31, 2004 and 2003, and the related consolidated statements of operations, changes in shareholders' equity (deficit), and cash flows for the year ended December 31, 2004 and the two months ended December 31, 2003 (Successor), and for the ten months ended October 31, 2003 and the year ended December 31, 2002 (Predecessor). These financial statements are the responsibility of the Company's Board of Directors and management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (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. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly we express no such opinion. An audit also 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, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Petroleum Geo-Services ASA and subsidiaries as of December 31, 2004 and 2003, and the consolidated results of their operations and their cash flows for the year ended December 31, 2004 and the two months ended December 31, 2003 (Successor), and for the ten months ended October 31, 2003 and the year ended December 31, 2002 (Predecessor) in conformity with U.S. generally accepted accounting principles.

As discussed in Note 3 to the consolidated financial statements, the Company emerged from bankruptcy and, effective November 1, 2003, adopted fresh-start reporting pursuant to American Institute of Certified Public Accountants Statement of Position 90-7, *"Financial Reporting by Entities in Reorganization Under the Bankruptcy Code"*. As a result, the consolidated financial statements of the Successor are presented on a different basis than those of the Predecessor and, therefore, are not comparable.

As discussed in Note 2 of the consolidated financial statements, the Predecessor changed its accounting principles to adopt, as of January 1, 2002, the provisions of Statement of Financial Accounting Standards No. 142, *"Goodwill and Other Intangible Assets"* and Statement of Financial Accounting Standards No. 144 *"Accounting for the Impairment or Disposal of Long-Lived Assets"*, and, as of January 1, 2003, the provisions of Statement of Financial Accounting Standards No. 143, *"Accounting for Asset Retirement Obligations."*

/s/ ERNST & YOUNG AS

Oslo, Norway
May 3, 2005

PETROLEUM GEO-SERVICES ASA AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2004	December 31, 2003
	(In thousands of dollars, except share data)	
ASSETS		
Cash and cash equivalents	$ 132,942	$ 105,225
Restricted cash	25,477	41,123
Shares available for sale	9,689	—
Accounts receivable, net	161,283	127,706
Unbilled and other receivables	40,561	47,864
Other current assets	60,506	62,610
Total current assets	430,458	384,528
Multi-client library, net	244,689	408,005
Property and equipment, net	1,009,008	1,060,183
Oil and natural gas assets, net	71,491	36,426
Restricted cash	10,014	10,014
Investments in associated companies	5,720	8,070
Intangible assets, net	36,114	52,609
Other long-lived assets	44,659	37,525
Total assets	$1,852,153	$1,997,360
LIABILITIES AND SHAREHOLDERS' EQUITY		
Short-term debt and current portion of long-term debt	$ 19,790	$ 18,512
Current portion of capital lease obligations	25,583	19,963
Accounts payable	81,910	56,318
Accrued expenses	115,256	147,336
Deferred tax liabilities	761	2,166
Income taxes payable	11,870	17,946
Total current liabilities	255,170	262,241
Long-term debt	1,085,190	1,108,674
Long-term capital lease obligations	33,156	63,473
Other long-term liabilities	219,650	197,663
Deferred tax liabilities	35,118	10,738
Total liabilities	1,628,284	1,642,789
Minority interest in consolidated subsidiaries	962	937
Shareholders' equity:		
Common stock; 20,000,000 shares authorized, issued and outstanding, par value NOK 30, at December 31, 2004 and 2003	85,714	85,714
Additional paid-in capital	277,427	277,427
Accumulated deficit	(144,683)	(9,953)
Accumulated other comprehensive income	4,449	446
Total shareholders' equity	222,907	353,634
Total liabilities and shareholders' equity	$1,852,153	$1,997,360

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

PETROLEUM GEO-SERVICES ASA AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Successor Company		Predecessor Company	
	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
	(In thousands of dollars, except share data)			
Revenues services	$ 945,334	$ 162,827	$ 849,767	$ 1,010,534
Revenues products	184,134	9,544	112,097	32,697
Total revenues	1,129,468	172,371	961,864	1,043,231
Cost of sales services	587,912	95,044	454,396	530,386
Cost of sales products	44,838	1,910	33,382	10,801
Exploration costs	16,326	—	—	—
Depreciation and amortization	368,362	55,699	301,576	367,503
Research and development costs	3,419	598	2,024	2,766
Selling, general and administrative costs	64,816	7,366	44,326	53,426
Impairment of long-lived assets	—	—	95,011	558,471
Other operating expense, net	8,112	1,052	21,324	8,487
Total operating expenses	1,093,785	161,669	952,039	1,531,840
Operating profit (loss)	35,683	10,702	9,825	(488,609)
Other income (expense):				
Income (loss) from associated companies	668	200	774	(11,501)
Interest expense	(110,811)	(16,870)	(98,957)	(153,301)
Other financial items, net	(10,861)	(4,264)	(1,472)	33,792
	(85,321)	(10,232)	(89,830)	(619,619)
Reorganization items:				
Gain on debt discharge	—	—	1,253,851	—
Fresh-start adoption	—	—	(532,268)	—
Cost of reorganization	(3,498)	(3,325)	(52,334)	(3,616)
Minority expense	940	110	570	778
Income tax expense (benefit)	48,019	(3,849)	21,911	185,890
Income (loss) from continuing operations before cumulative effect of change in accounting principles	(137,778)	(9,818)	556,938	(809,903)
Income (loss) from discontinued operations, net of tax	3,048	(135)	(2,282)	(201,137)
Income (loss) before cumulative effect of change in accounting principles	(134,730)	(9,953)	554,656	(1,011,040)
Cumulative effect of change in accounting principles, net of tax	—	—	2,389	(163,638)
Net income (loss)	$ (134,730)	$ (9,953)	$ 557,045	$ (1,174,678)
Basic and diluted income (loss) per share from continuing operations	$ (6.89)	$ (0.49)	$ 5.39	$ (7.84)
Income (loss) from discontinued operations, net of tax	0.15	(0.01)	(0.02)	(1.95)
Cumulative effect of change in accounting principle, net of tax	—	—	0.02	(1.58)
Basic and diluted net income (loss) per share	$ (6.74)	$ (0.50)	$ 5.39	$ (11.37)
Weighted average basic and diluted shares outstanding	20,000,000	20,000,000	103,345,987	103,345,987

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

PETROLEUM GEO-SERVICES ASA AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Successor Company		Predecessor Company	
	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
	(In thousands of dollars)			
Cash flows (used in) provided by operating activities:				
Net income (loss)	$ (134,730)	$ (9,953)	$ 557,045	$(1,174,678)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Depreciation and amortization charged to expense	368,362	55,699	301,576	367,503
Exploration costs (dry well expensed)	11,438	—	—	—
Non-cash impairments, loss (gain) on sale of subsidiaries and change in accounting principles, net	—	32	92,622	935,244
Non-cash effect of fresh start adoption	—	—	534,085	—
Non-cash effect of restructuring	—	—	(1,253,851)	—
Non-cash write-off of deferred debt costs and issue discounts	—	—	13,152	—
Cash effects related to discontinued operations	—	157	3,185	5,540
Provision for deferred income taxes	27,263	(5,801)	(1,918)	171,771
(Increase) decrease in accounts receivable, net	(33,577)	34,582	6,848	(22,628)
Increase (decrease) in accounts payable	25,592	19,391	(18,587)	(10,814)
Loss on sale of assets	4,128	—	6,193	11,750
Net (increase) decrease in restricted cash	15,646	3,824	(23,728)	1,602
Other items	(1,750)	(35,761)	(51,674)	9,319
Net cash provided by operating activities	282,372	62,170	164,948	294,609
Cash flows (used in) provided by investing activities:				
Investment in multi-client library	(41,140)	(9,461)	(81,142)	(151,590)
Capital expenditures	(148,372)	(15,985)	(42,065)	(56,735)
Capital expenditures on discontinued operations	—	—	(118)	(77,364)
Sale of subsidiaries	2,035	—	50,115	20,222
Other items, net	4,031	357	3,478	(9,030)
Net cash used in investing activities	(183,446)	(25,089)	(69,732)	(274,497)
Cash flows (used in) provided by financing activities:				
Repayment of long-term debt	(24,167)	(4,850)	(70,496)	(340,809)
Principal payments under capital leases	(22,930)	(3,025)	(22,352)	(19,839)
Net increase (decrease) in bank facility and short-term debt	1,962	—	(48)	335,348
Net receipts under tax equalization swap contracts	—	—	—	9,566
Distribution to creditors under the restructuring agreement	(22,660)	(17,932)	—	—
Other items, net	(3,488)	—	—	8,098
Net cash used in financing activities	(71,283)	(25,807)	(92,896)	(7,636)
Effect of exchange rate changes on cash	74	—	14	537
Net increase in cash and cash equivalents	27,717	11,274	2,334	13,013
Cash and cash equivalents at beginning of period	105,225	93,951	91,617	78,604
Cash and cash equivalents at end of period	$ 132,942	$105,225	$ 93,951	$ 91,617

The accompanying notes are an integral part of these consolidated financial statements.
Supplementary cash flow information is included in note 27.

PETROLEUM GEO-SERVICES ASA AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

	Common Stock		Additional Paid-In Capital	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)				Shareholders' Equity
	Number	Par Value			Foreign Currency Translation Adjustments	Unrealized Gain (Loss) Investments	Pension Minimum Liability	Accumulated Other Comprehensive Income (Loss)	
	(In thousands of dollars, except for share data)								
Predecessor Company:									
Balance at December 31, 2001	103,345,987	$ 71,089	$ 1,225,115	$ (282,342)	$(33,620)	$ —	$ (346)	$(33,966)	$ 979,896
Comprehensive income (loss):									
Net loss				(1,174,678)	—	—	—	—	(1,174,678)
Other comprehensive income (loss)				—	7,195	—	(3,668)	3,527	3,527
Total comprehensive income (loss)				(1,174,678)	7,195	—	(3,668)	3,527	(1,171,151)
Dividends to minority interest				(1,077)	78	—	—	78	(999)
Balance at December 31, 2002	103,345,987	71,089	1,225,115	(1,458,097)	(26,347)	—	(4,014)	(30,361)	(192,254)
Comprehensive income (loss):									
Net income				557,045	—	—	—	—	557,045
Other comprehensive income (loss)				—	1,580	—	(3,230)	(1,650)	(1,650)
Total comprehensive income (loss)				557,045	1,580	—	(3,230)	(1,650)	555,395
Reorganization items	(103,345,987)	(71,089)	(1,225,115)	901,052	24,767		7,244	32,011	(363,141)
Balance at October 31, 2003	—	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Successor Company:									
Issuance of common stock	20,000,000	$ 85,714	$ 277,427	$ —	$ —	$ —	$ —	$ —	$ 363,141
Comprehensive income (loss):									
Net loss				(9,953)	—	—	—	—	(9,953)
Other comprehensive income				—	446	—	—	446	446
Total comprehensive income (loss)				(9,953)	446	—	—	446	(9,507)
Balance at December 31, 2003	20,000,000	85,714	277,427	(9,953)	446	—	—	446	353,634
Comprehensive income (loss):									
Net loss				(134,730)	—	—	—	—	(134,730)
Other comprehensive income (loss)				—	(1,667)	5,889	(219)	4,003	4,003
Total comprehensive income (loss)				(134,730)	(1,667)	5,889	(219)	4,003	(130,727)
Balance at December 31, 2004	20,000,000	$ 85,714	$ 277,427	$ (144,683)	$ (1,221)	$5,889	$ (219)	$ 4,449	$ 222,907

The Company's ability to pay dividends is limited to free equity as defined in Norwegian corporate law and measured on the basis of the unconsolidated financial statements of the parent company, PGS ASA, as prepared in accordance with generally accepted accounting principles in Norway. At December 31, 2004, the Company had no free equity available for payment of dividends to shareholders.

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

NOTE 1 — General Information about the Company and Basis of Presentation

Petroleum Geo-Services ASA ("PGS ASA") is a public limited liability company established under the laws of the Kingdom of Norway in 1991. Unless stated otherwise, references herein to the "Company" and "PGS" refer to Petroleum Geo-Services ASA and its majority-owned subsidiaries and affiliates, companies in which it has and controls a majority voting interest.

PGS is a technologically focused oilfield service company principally involved in providing geophysical services worldwide and floating production services in the North Sea. Globally, it provides a broad range of geophysical and reservoir services, including seismic data acquisition, processing and interpretation and field evaluation. In the North Sea, the Company owns and operates four floating production, storage and offloading ("FPSO") vessels. Through 2004, the Company also owned a small oil and natural gas company that produces oil and natural gas from a license on the Norwegian Continental Shelf. The Company sold this oil and natural gas subsidiary in March 2005. The Company's headquarters are at Lysaker, Norway. See further discussion of the Company's services in Note 26.

The Company considers its primary basis of accounting to be US generally accepted accounting principles ("US GAAP"), and has prepared these consolidated financial statements in accordance with those principles. PGS is also required to prepare and publish statutory accounts in Norway using Norwegian generally accepted accounting principles ("Norwegian GAAP"). Norwegian GAAP differs materially from US GAAP.

As more fully described in Note 23, the Company sold its wholly owned software company PGS Tigress (UK) Ltd. in December 2003. The Company sold its Production Services subsidiary in December 2002 and its Atlantis subsidiary in February 2003. Accordingly, the financial position and results of operations and cash flows for these subsidiaries have been presented as discontinued operations as of December 31, 2003 and 2002 and for the years then ended. The results of operations and cash flows for the year ended December 31, 2004 includes contingent proceeds from discontinued operations sold in 2002.

The accompanying financial statements have been prepared on the basis of accounting principles that assume 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, and therefore, do not reflect any adjustments in the carrying values of our assets, liabilities, income statement items and balance sheet classifications that would be necessary if our financial statements were not prepared on a going concern basis.

In 2003 the Company, as more fully described in Note 15, successfully completed a financial restructuring that involved cancellation of all pre-restructuring share capital and a reduction of interest bearing debt of $1,283 million from $2,472 million to $1,189 million. Costs relating to this restructuring totalled $3.5 million for the year ended December 31, 2004, $3.3 million for the two months ended December 31, 2003 and $52.3 million for the ten months ended October 31, 2003 (including $13.2 million in write-off of deferred debt costs and issue discounts).

Upon emergence from Chapter 11, the Company, adopted "fresh-start" reporting as required under the provisions of AICPA Statement of Position ("SOP") 90-7, *"Financial Reporting by Entities in Reorganization under the Bankruptcy Code,"* effective November 1, 2003. Adoption of fresh-start reporting results in companies reflecting the fair value of the business emerging from bankruptcy (the "reorganization value") in the post fresh start financial statements, and is required when the holders of the voting common shares immediately before the filing and confirmation of the reorganization plan received less than 50% of the voting shares of the emerging company and when the company's reorganization value is less than its post-petition liabilities and allowed claims. Since these conditions were met, the Company adopted fresh-start reporting, and as a result, in these consolidated financial statements, the terms "Successor" and "Successor Company" refer to PGS' financial statements subsequent to the emergence from Chapter 11 and the terms "Predecessor" and "Predecessor Company" refer to PGS' financial statements for periods up to the emergence from Chapter 11 including the effect of the reorganization plan. The adoption of fresh-start reporting reflects the Company's reorganization value as its new basis in accounting, new accounting pronouncements it was required to adopt with fresh start reporting and changes in certain of its accounting policies. The Company's financial information in Successor Company periods should not be compared to financial information from Predecessor Company periods as they are not comparable.

NOTE 2 — Summary of Significant Accounting Policies

Fresh Start Reporting.

In connection with the adoption of fresh start reporting effective November 1, 2003, the Company adopted new accounting policies for certain transactions and activities, as further described in the individual descriptions of these policies below. The most significant of these are:

- The successful efforts method of accounting for oil and natural gas exploration and development activities was adopted.
- The Company made certain changes to cost capitalization and amortization policies for the multi-client library, including an increase in minimum amortization by reducing the maximum amortization period from eight to five years after completion of a survey. Further, expenditures incurred in connection with yard stay and steaming of vessels are expensed as incurred. Such expenses were previously recognized as part of multi-client project costs.

In addition, the Company revised certain accounting estimates, including a reduction of depreciable lives of Ramform seismic acquisition vessels and FPSOs, other than the *Petrojarl I,* from 30 to 25 years.

Use of Estimates.

The preparation of financial statements in accordance with U.S. GAAP requires management to make estimates, assumptions and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent liabilities. In many circumstances, the ultimate outcome 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, changes in laws and regulations, changes in future operating plans and the inherent imprecision associated with estimates.

Consolidation and Equity Investments.

The Company's consolidated financial statements include all transactions of PGS ASA, its wholly-owned and majority-owned subsidiaries that it controls. Subsidiaries are consolidated in the accounts from the point of time when the Company gains control. Subsidiaries are valued using the purchase method of accounting. Acquisition prices are assigned to the assets and liabilities of the subsidiaries, using their fair value at the date of acquisition. Any excess of purchase cost over fair value of assets and liabilities is recorded as goodwill. All inter-company transactions and balances have been eliminated in consolidation. In those cases where the subsidiaries are not wholly-owned, the minority interests are separately presented in the consolidated statements of operations and consolidated balance sheets.

Investments in associated companies in which the Company has an ownership interest equal to or greater than 20% but equal to or less than 50%, and where the Company has the ability to exercise significant influence are accounted for using the equity method.

The Company periodically reviews its investments to determine if a loss in value has occurred that is other-than-temporary. PGS considers all available information, including the recoverability of its investment, the earnings and near-term prospects of the investee company, factors related to the industry, conditions of the investee company and the ability, if any, to influence the management of the investee company.

Shares available for sale with an available market value are carried at fair value at each balance sheet date, with unrealized holding gains and losses reported in other comprehensive income until realized.

In January 2003, the Financial Accounting Standards Board ("FASB") issued FASB Interpretation No. 46 ("FIN 46") *"Consolidation of Variable Interest Entities,"* and in December 2003, the FASB issued a revised FIN 46 ("FIN 46R"), which address when a company should include in its financial statements the assets, liabilities and activities of another entity. FIN 46R requires consolidation of a variable interest entity ("VIE") if the reporting entity is subject to a majority of the risk of loss from the VIE's activities or is entitled to receive a majority of the VIE's residual returns or both. The consolidation requirements of FIN 46R apply immediately to VIEs created after January 31, 2003, and to all other existing structures commonly referred to as special purpose entities. The consolidation requirements applied to VIEs were created prior to January 31, 2003 and apply to the Company upon the adoption of fresh-start reporting.

The Company has concluded that it is the primary beneficiary of two VIEs, DMNG PGS AS and Walter Herwig AS. Accordingly, these entities are consolidated in the Successor's financial statements. By December 31, 2003 Walter Herwig AS had become a 100% owned subsidiary of the Company. The operations, assets and liabilities of DMNG PGS AS are not material to the Company's financial statements.

In addition, the Company has considered its UK leases (see Note 19) in relation to FIN 46R. As part of the evaluation process, the Company has requested further information about the lessor entities, including information related to their other assets and contractual arrangements. However, the Company has no rights under its agreements with the lessor entities to request or receive such information, and the lessor entities (or their owners) have denied the Company access to any such information. Accordingly, the Company has not been able to affirmatively determine if any of the lessor entities are VIEs, and if any are VIEs, who the primary beneficiary would be.

However, based on information received from the lessor entities, which all have multiple lessees, the debt issued to finance the activities of the entities is full recourse to all assets of each entity. Based on publicly available information and confirmations from the lessor entities, the Company has determined that its relative portions of the fair value of the assets of the lessor entities are less than 50% of the assets of each entity. Accordingly, the Company has determined that it is not the primary beneficiary of these lessor entities and that the UK leases are not separate silos within the lessor entities (separate VIEs).

Discontinued Operations.

Subsidiaries that are either held-for-sale or discontinued are reported as discontinued operations. Revenues and expenses are excluded from revenue and expenses of the Company and reported separately as a one line item in the consolidated statement of operations, net of tax. Assets and liabilities are presented as separate line items in the balance sheet. For further details about subsidiaries that we have sold or operations that we have discontinued, see Note 23.

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.

Cash and cash equivalents that are restricted from the Company's use are disclosed separately in the consolidated balance sheets and are classified as current or long-term depending on the nature of the restrictions. Such restrictions primarily relate to cash collateral for bid or performance bonds, employee tax withholdings, restricted deposits under contracts, and cash in our wholly owned captive insurance company. Restricted cash related to bid or performance bonds amounted to $11.7 million at December 31, 2004 and $27.3 million at December 31, 2003.

Foreign Currency Translation.

The Company's reporting currency is the U.S. dollar as it is the functional currency for substantially all of its operations throughout the world.

The financial statements of non-US subsidiaries using their respective local currency as their functional currency are translated using the current exchange rate method. Under the current exchange 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, net of tax, are recorded as a separate component of shareholders' equity.

The Company's exchange rate between the Norwegian kroner and U.S. dollar at December 31, 2004 and 2003 was NOK 6.13 and 6.79, respectively.

Operating and Capital Leases.

The Company has significant operating lease arrangements in all of its operating segments and also has some capital lease arrangements for land seismic equipment and UK leases for vessels (see below). Capital leases are lease arrangements in which the substantial financial risk and control, but not ownership, of the assets is transferred from the lessor to the Company.

The Company accounts for capital lease arrangements as if the Company had acquired the assets, and the present value of the future lease payments is accounted for as liabilities. The assets are depreciated over the expected useful lives or the related lease terms, whichever is shorter.

UK Leases.

The Company has entered into vessel lease arrangements in the United Kingdom ("UK leases") relating to five of our Ramform design seismic vessels, our FPSO vessel *Petrojarl Foinaven* and the topsides of our FPSO vessel *Ramform Banff* (Note 19). Under the leases, generally, UK financial institutions ("Lessors") acquired the assets from third parties and the Company leased the assets from the Lessors under long-term charters that give the Company the option to purchase the assets for a bargain purchase price at the end of the charter periods. The Lessors claims tax depreciation (capital allowances) on the capital expenditures that were incurred for the acquisition of the leased assets. Under these UK leases, the Company indemnified the Lessors against certain future events that could reduce their expected after-tax returns. These events include potential changes in UK tax laws and interpretations thereof (including interpretations relating to depreciation rates) and changes in interest rates as the leases are based on assumed interest rates.

Due to the nature of the charters, the Company accounts for these leases as capital leases. The Company legally defeased its future charter obligations for the assets by making up-front, lump sum payments to unrelated large institutional banks ("Payment Banks"), which then assumed the Company's liability for making the periodic payments due under the long-term charters (the "Defeased Rental Payments") equal to the basic rentals and termination sum obligations, as defined in the agreements. The Company has no rights to the amounts paid to Payment Banks. Due to the assumption of the charter payment obligations by the Payment Banks, the Lessors legally released the Company as the primary obligor under the charters. Accordingly, the Company accounted for the release as a derecognition of the capital lease obligations with respect to these UK leases.

At the date that the Company executed any UK lease, the Company treated the excess of the capitalized asset value over the amount required to legally defease the charter obligations as a deferred gain. The deferred gain related to indemnification for tax contingencies and for changes in future interest rates. The portion of the deferred gain relating to changes in interest rates was amortized over the term of the respective leases up to the date of adoption of fresh start reporting. The portion of the deferred gain relating to tax contingencies was recognized in income in accordance with Emerging Issues Task Force ("EITF") Issue 89-20, *"Accounting for Cross Border Tax Benefit Leases,"* when the Company determined that the likelihood of the indemnifications becoming effective was remote.

The Defeased Rental Payments are based on assumed Sterling LIBOR rates between 8% and 9% (the "Assumed Interest Rates"). If actual interest rates are greater than the Assumed Interest Rates, the Company receives rental rebates. Conversely, if actual interest rates are less than the Assumed Interest Rates, the Company is required to pay rentals in excess of the Defeased Rental Payments (the "Additional Required Rental Payments"). Such payments are made annually or bi-annually and are recorded on a straight line basis as other financial items, net.

Effective November 1, 2003, the Company adopted fresh start reporting and recorded a liability equal to the fair value of the future Additional Required Rental Payments. Such fair value was estimated at the net present value of the Additional Required Rental Payments based on forward market rates for Sterling LIBOR and an 8% discount rate. This liability amounted to 30.5 million British pounds (approximately $51.6 million) at November 1, 2003, and was amortized to 27.4 million British pounds ($48.6 million) at December 31, 2003. At December 31, 2004, the liability was amortized to 24.6 million British pounds (approximately $47.2 million).

For fresh start reporting purposes, the Company estimated and recorded the fair value of the specific tax exposure related to defeased UK leases noted above using a probability-weighted analysis and a range of possible outcomes. The Company recorded a 16.7 million British pounds ($28.3 million) liability as of November 1, 2003 in accordance with the requirements of SOP 90-7. At December 31, 2004 and 2003 this liability amounted to $32.1 million and $29.5 million, respectively.

Receivables Credit Risk.

The Company's trade receivables are primarily from multinational integrated oil companies and independent oil and natural 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 customers and has provided for potential credit losses through an allowance for doubtful accounts. The allowance for doubtful accounts reflects management's best estimate of probable losses inherent in accounts receivable from trade customers and is based on a number of factors consisting mainly of aging of accounts, historical experience, customer concentration, customer creditworthiness and current industry and economic trends. The Company does not believe that exposure to concentrations of credit risk is likely to have a material adverse impact on its financial position or results of operations.

Multi-Client Library.

The multi-client library consists of seismic data surveys to be licensed to customers on a nonexclusive basis. Costs directly incurred in acquiring, processing and otherwise completing seismic surveys are capitalized into the multi-client library, including the applicable portion of interest costs. Prior to its adoption of fresh start reporting, the Company also capitalized certain indirect costs and other associated costs that could be attributed to the projects, including cost of relocating crews (steaming) between surveys and the cost of yard stays. Subsequent to the adoption of fresh start reporting, the Company no longer capitalizes such indirect costs.

The Company records its investment in 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 separately. Projects that are in the same political regime, with similar geological traits and that are marketed collectively are recorded and evaluated as a group by year of completion (currently applies to certain surveys in Brazil and the Gulf of Mexico).

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 and past experience. These expectations include consideration of geographic location, prospects, political risk, exploration license periods and general economic conditions. The local sales and operating management update, at least annually, the total expected revenue for each survey or group of surveys of the multi-client library. 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. 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. Subsequent to the adoption of fresh start reporting, for purposes of streamlining the accounting method of amortization, the Company has categorized its multi-client surveys into three amortization categories with amortization rates of 90%, 75% or 60% of sales amounts. Classification of a project into a rate category is based on the ratio of its remaining net book value to its remaining sales estimates. Each category therefore includes surveys as to which the remaining book value as a percentage of remaining estimated sales is less than or equal to the amortization rate applicable to that category.

An integral component of amortization of the multi-client library is the minimum amortization policy. Under this policy, the book value of each survey or group of surveys of the multi-client library is reduced to a specified percentage by year-end, based on the age of each survey or group of surveys in relation to their year of completion. This requirement is applied each year-end regardless of future revenue estimates for the multi-client library survey or group of surveys. The specified percentage generates the maximum book value for each multi-client library survey or group of surveys as the product of the percentage multiplied by the original cost of the multi-client library survey or group of surveys at the respective period end. Any additional or "minimum" amortization charges required are then determined through a comparison of the remaining book value to the maximum book value allowed for each survey or group of surveys in the multi-client library.

Subsequent to the adoption of fresh start reporting, the Company revised the minimum amortization period from eight years for marine surveys and five years for onshore surveys to five years for both marine and onshore projects from the end of the year of completion (the year when the project is completed and processed data is ready and available for use) and three years for derivative processed projects (processing or reprocessing that creates data that can be marketed and sold as an addition to the existing library) from the end of the year of completion. With the adoption of fresh start reporting, existing marine surveys were accorded a transition profile based on sales forecasts used to compute their fair value.

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

	Successor Company % of Total Cost		Predecessor Company % of Total Cost		
Calendar Year	5-Year Profile	3-Year Profile	Marine Components (Excluding Brazil)	Marine Components (Brazil)	Land Components
Year 1	80%	66%	100%	100%	100%
Year 2	60%	33%	70%	92%	60%
Year 3	40%	0%	55%	76%	40%
Year 4	20%		40%	50%	20%
Year 5	0%		30%	43%	0%
Year 6			20%	34%	
Year 7			10%	20%	
Year 8			0%	0%	

In addition, effective January 1, 2004, the Company classifies as amortization expense in its consolidated statements of operations write-downs of individual multi-client surveys that are based on changes in project specific expectations and that are not individually material. The Company expects this additional, non-sales related, amortization expense to occur regularly because the Company evaluates projects on a project by project basis. The Company classifies as impairment in its consolidated statements of operations write-downs related to fundamental changes in estimates affecting a larger part of the Company's multi-client library that are material. Prior to 2004 the Company classified as impairment expense all write-downs of multi-client library.

Property and Equipment.

Property and equipment are stated at cost less accumulated depreciation, amortization and impairment charges. Depreciation and amortization are calculated based on cost less estimated salvage values using the straight-line method for all property and equipment, excluding leasehold improvements, which are amortized over the asset life or lease term, whichever is shorter.

The estimated useful lives for property and equipment for the Predecessor and Successor are as follows:

	Successor Company Years	Predecessor Company Years
Seismic vessels	20-25	20-30
Seismic and operations computer equipment	3-15	3-10
FPSO vessels and equipment	25-30	20-30
Buildings and related leasehold improvements	1-30	1-30
Fixture, furniture, fittings and office computers	3-5	3-5

Expenditures for major property and equipment that have an economic useful life of at least one year are capitalized as individual assets and depreciated over their useful lives. Maintenance and repairs, including periodic maintenance and class surveys for FPSOs and seismic vessels, are expensed as incurred. The Company capitalizes the applicable portion of interest costs to major capital projects. 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 Natural Gas Assets.

Following its adoption of fresh-start reporting, the Company uses the successful efforts method of accounting for oil and natural gas properties. Under this method, all costs of acquiring unproved oil and natural gas properties and drilling and equipping exploratory wells are capitalized pending determination of whether the properties have proved reserves. If an exploratory well is determined not to have commercial quantities of reserves, the drilling and equipment costs for the well are expensed and classified as exploration costs at that time. Such expenses aggregated $11.4 million for the year ended December 31, 2004. All development drilling and equipment costs are capitalized. Capitalized costs of proved properties are amortized on a property-by-property basis using the unit-of-production method whereby the ratio of annual production to beginning of period proved oil and natural gas reserves is applied to the remaining net book value of such properties. Oil and natural gas reserve quantities represent estimates only and there are numerous uncertainties inherent in the estimation process. Actual future production may be materially different from amounts estimated, and such differences could materially affect future amortization of proved properties. Geological and geophysical costs are expensed as incurred and presented as exploration costs. Such costs aggregated $8.6 million for the year ended December 31, 2004.

Long-lived assets to be held and used, including proved oil and natural gas properties accounted for under the successful efforts method of accounting, are assessed for impairment whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. An impairment loss is indicated if the sum of the expected future cash flows, undiscounted, is less than the carrying amount of the assets. In this circumstance, an impairment loss is recognized for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset.

Unproved properties are periodically assessed for impairment and a loss is recognized at the time of impairment. Unproved oil and natural gas properties that are individually significant are periodically assessed for impairment by comparing their cost to their estimated value on a project-by-project basis. The remaining unproved oil and natural gas properties, if any, are aggregated and an overall impairment allowance is provided based on historical experience.

Prior to its adoption of fresh start reporting, the Company used the SEC full cost method of accounting for oil and natural gas properties. Under this method, all costs associated with the acquisition, exploration and development of oil and natural gas properties are capitalized. Such costs include lease acquisition, geological, geophysical, drilling, equipment, interest and overhead. Capitalized overhead costs are limited to salaries and benefits for employees directly involved in the acquisition, exploration and development of the properties as well as other costs directly associated with such activities. Costs are accumulated on a country-by-country basis.

Under the full cost method, capitalized costs are amortized using the unit-of-production method on a country-by-country basis. Unevaluated properties are excluded from the amortization base. Costs associated with unevaluated properties are transferred into the amortization base at such time as the wells are completed, the properties are sold or the costs have been impaired. Future development costs and dismantlement and abandonment costs are included in the amortizable cost base.

In accordance with the SEC guidelines for the full cost method, the cost bases of proved oil and natural gas properties are limited, on a country-by-country basis, to the estimated future net cash flows from proved oil and natural gas reserves using prices and other economic conditions in effect at the end of the reporting period, discounted at 10%, net of related taxes (ceiling test). If the capitalized cost of proved oil and natural gas properties exceeds this limit, the excess is charged to expense as additional depreciation and amortization.

Goodwill.

Following its adoption of fresh start reporting, the Company has no goodwill balances.

The Company adopted the provisions of Statement of Financial Accounting Standards No. 142, *"Goodwill and Other Intangible Assets"* ("SFAS 142") as of January 1, 2002. Under SFAS 142, goodwill and intangible assets acquired in a purchase business combination and determined to have an indefinite useful life are not amortized, but instead tested for impairment at least annually in accordance with the provisions of SFAS 142. SFAS 142 also requires that intangible assets with finite useful lives be amortized over their respective estimated useful lives to their estimated residual values and be reviewed for impairment in accordance with Statement of Financial Accounting Standards No. 144, *"Accounting for the Impairment or Disposal of Long-Lived Assets"* ("SFAS 144").

In connection with SFAS 142's transitional goodwill impairment evaluation, the Company was required to perform an assessment of whether there was an indication that goodwill was impaired as of the date of adoption. To accomplish this, the Company identified its reporting units and determined the carrying value of each reporting unit by assigning the assets and liabilities, including the existing goodwill and intangible assets, to those reporting units as of January 1, 2002, which included Marine Geophysical, Onshore, Production, Atlantic Power (Production Services) and the reservoir activities. The Company was required to determine the fair value of each reporting unit and compare it to the carrying amount of the reporting unit. To the extent the carrying amount of a reporting unit exceeded the fair value of the reporting unit, the Company would be required to perform the second step of the transitional impairment test, which is to compare the implied fair value of the reporting unit goodwill with the carrying amount of the reporting unit goodwill. As of January 1, 2002, the second step was required to be performed for the Company's Production and reservoir units as the implied fair value of the Company's reporting units exceeded their respective carrying amounts. This resulted in a goodwill impairment charge of $163.6 million upon adoption of SFAS 142 of which $161.1 million and $2.5 million related to the production and reservoir reporting units, respectively.

In September 2002, the Company performed a similar test to that described above, for its Marine Geophysical reporting unit due to identified impairment factors, which included a significant reduction in the market value of the Company. This resulted in a goodwill impairment charge of $9.4 million (see Note 4).

Intangible Assets.

Intangible assets relate to direct costs of software product for internal use, patents, royalties and licenses. Substantially all of the Company's intangible assets were recognized as a consequence of the Company's adoption of fresh start reporting. Such intangible assets include favorable contracts, order backlog and the value of various existing technologies used in the Company's operations. Intangible assets are stated at cost less accumulated amortization and any impairment charges. Amortization is calculated on a straight-line basis over estimated period of benefit, ranging from one to 10 years.

Other Long-Lived Assets.

Other long-lived assets consist of costs related to entering into long-term loan facilities (deferred debt issue costs) and long-term receivables. The Company capitalizes debt issue costs relating to long-term debt, and such costs are charged to interest expense using the effective interest method over the period the associated debt is outstanding. Other long-term receivable includes accounts receivable expected to be collected more than twelve months after the balance sheet date including government grants and contractual receivables related to asset removal obligations.

Impairment of Long-Lived Assets.

Long-lived assets, which consist primarily of multi-client library, property, plant and equipment and oil and gas assets (or the group of assets, including the asset in question, that represents the lowest level of separately identifiable cash flows), are assessed for possible impairment when indications of impairments exist in accordance with Statement of Financial Accounting Standards No. 144, *"Accounting for the Impairment or Disposal of Long-Lived Assets" ("SFAS 144")*. If the total of the undiscounted future cash flows is less than the carrying amount of the asset or group of assets, an impairment loss is recognized for the difference between the estimated fair value and the carrying value of the asset or groups of assets. Long-lived assets (multi-client library, property and equipment and oil and natural gas assets accounted for under the successful efforts method) are also assessed for possible impairment upon the occurrence of a triggering event. Events that can trigger assessments for possible impairments include, but are not limited to (i) significant decreases in the market value of an asset, (ii) significant changes in the extent or manner of use of an asset, (iii) a physical change in the asset, (iv) a reduction of proved oil and natural gas reserves based on field performance and (v) a significant decrease in the price of oil or natural gas.

Steaming and Mobilization.

Subsequent to the adoption of fresh start reporting, costs incurred while moving or "steaming" a vessel or crew from one location to another are expensed as incurred. Onsite project costs such as positioning, deploying and retrieval of equipment at the beginning and end of a project are considered mobilization or demobilization costs and are included in the cost of the multi-client survey or exclusive contract with which the costs are associated. Prior to fresh start, the Predecessor capitalized a proportionate share of cost incurred while moving or "steaming" a seismic vessel or crew as part of the cost of multi-client surveys.

Derivative Financial Instruments.

Derivative instruments are recognized in the balance sheet at their fair values while realized and unrealized gains and losses attributable to derivative instruments that do not qualify for hedge accounting are recognized as other financial items, net as they arise. To qualify for hedge accounting, the details of the hedging relationship must be formally documented at inception of the arrangement, including the risk management objective, hedging strategy, hedged items, specific risks that are being hedged, the derivative instrument and how effectiveness is being assessed. There are three types of hedges: cash flow hedges, which are hedges that use derivatives to offset the variability of expected future cash flow, fair value hedges, which are hedges that eliminate the risk of changes in the fair value of assets, liabilities and certain firm commitments, and net investment hedges, which hedge foreign currency exposure of a net investment in a foreign operation.

The Company uses derivative financial instruments periodically to manage exposure to changes in foreign currency exchange rates, changes in interest rates on variable rate debt, and firm commitments or expected future cash flows associated with the purchases of property, plant and equipment. The Company may also use derivatives to manage exposure to commodity price fluctuations for oil and natural gas. The Company does not engage in derivative financial instrument transactions for speculative purposes. As of December 31, 2004 and 2003, the Company did not have outstanding any derivative financial instruments that qualified for hedge accounting.

The Company operates in the worldwide crude oil markets and are exposed to fluctuations in hydrocarbon prices, which historically have fluctuated widely in response to changing market forces (see Note 18).

Share Based Compensation Plans.

The Company applies the intrinsic value method in accordance with Accounting Principles Board ("APB") Opinion 25, *"Accounting for Stock Issued to Employees,"* in accounting for its share-based compensation plans and has adopted the disclosure-only provisions of Statement of Financial Accounting Standards No. 123, *"Accounting for Stock-Based Compensation"* ("SFAS 123"), as amended by SFAS No. 148, *"Accounting for Stock-Based Compensation — Transition and Disclosure".* No compensation cost is recognized under the Company's plans since the option exercise price is above or equal to market value of the stock at the measurement date. The Company discloses the amount the compensation cost would have been had the share-based compensation been determined and recognized based on fair values of options awarded.

Revenue Recognition.

The Company recognizes revenue when persuasive evidence of a sale arrangement exists, delivery has occurred or services have been rendered, the sales price is fixed or determinable and collectibility is reasonably assured. The Company defers the unearned component of payments received from customers for which the revenue recognition requirements have not been met. For contracts after July 1, 2003, the provisions of EITF 00-21, *"Revenue Arrangement with Multiple Deliverables"* apply. As a result, consideration is allocated among the separate units of accounting based on their relative fair values. The Company's revenue recognition policy is described in more detail below.

Revenue Services.

1. Geophysical Services (Marine, Onshore and Other).

(a) 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 multi-client data library. 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 when the customer executes a valid license agreement and has access to the licensed portion of the multi-client library and collection is reasonably assured.

Volume sales agreements — The Company grants licenses to customers for access to a specified number of blocks of multi-client library within a defined geographical area. These licenses 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.

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

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

Pre-funding revenue is recognized as the services are performed on a proportional performance basis. Progress is measured in a manner generally consistent with the physical progress on the project, and revenue is recognized based on the ratio of the project's progress to date to the total project revenues, provided that all other revenue recognition criteria are satisfied.

(b) 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 Company recognizes proprietary/contract revenue as the services are performed and become chargeable to the customer on a proportionate performance basis over the term of each contract. Progress is measured in a manner generally consistent with the physical progress of the project, and revenue is recognized based on the ratio of the project's progress to date to the total project revenues, provided that all other revenue recognition criteria are satisfied.

(c) Other Geophysical Services.

Revenue from other geophysical services is recognized as the services are performed, provided all other recognition criteria are satisfied.

2. Production Services.

Tariff-based revenue from Production services from operation of FPSO vessels is recognized as production occurs, while day-rate revenue is recognized over the passage of time, provided all other recognition criteria are satisfied.

Revenue Products (Pertra).

Revenue from production and sale of oil produced under production licenses is recognized as produced barrels are lifted and ownership passes to the customer, provided all other recognition criteria are satisfied.

Deferred costs associated with a revenue contract are limited to the amount of deferred revenue related to the contract.

Reimbursements received for expenses incurred under a contract are characterized as revenue in accordance with EITF 01-14 *"Income Statement Characterization of Reimbursements Received for 'Out-of-Pocket' Expenses Incurred"*.

Income Taxes.

Deferred tax assets and liabilities are recognized for the expected future tax consequences of transactions and events. Under this method, deferred tax assets and liabilities are determined based on the difference between the financial statement and tax bases of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse. Deferred tax assets are reduced by a valuation allowance to record the deferred tax assets at an amount expected to be more likely than not recoverable. Deferred tax assets and liabilities are adjusted for the effects of changes in tax laws and rates on the date of enactment. In accordance with Accounting Principles Board Opinion No. 23, *"Accounting for Income Taxes — Special Areas,"* the Company does not recognize any deferred tax liability on unremitted earnings of foreign subsidiaries when remittance is indefinite.

When the Company adopted fresh start reporting, effective November 1, 2003, the Company established valuation allowances for deferred tax assets. If such deferred tax assets, for which a valuation allowance is established, are realized in subsequent periods, the tax benefit will be recorded as a reduction of the carrying value of long-term intangible assets existing at adoption of fresh-start accounting until the value of such assets is reduced to zero. Any recognition of fresh start deferred tax assets after intangible assets are reduced to zero will be credited to shareholders' equity.

Asset Retirement Obligations.

On January 1, 2003, the Company adopted Statement of Financial Accounting Standards No. 143, *"Accounting for Asset Retirement Obligations"* ("SFAS 143"). SFAS 143 requires entities to record the fair value of an asset retirement obligation as a liability in the period when it is incurred (typically when the asset is installed at the production location). When the liability is recorded, the entity capitalizes the cost by increasing the carrying amount of the related properties, plant and equipment. Over time, the liability is increased for the change in its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Also, revisions to a previously recorded asset retirement obligation may result from changes in the assumptions used to estimate the cash flows required to settle the asset retirement obligation. The effect of such changes is recorded as an adjustment to the related asset.

The Company has asset retirement obligations associated with its oil and gas producing activities in the Norwegian North Sea and with the sub-sea production facility associated with its *Ramform Banff* FPSO also operating in the North Sea. These obligations generally relate to restoration of the environment surrounding the facility and removal and disposal of all the production equipment. For oil and natural gas production facilities, the obligations are generally statutory as well as contractual. The asset retirement obligations will be covered in part by grants from the Norwegian government and in part with contractual payments from FPSO contract counterparties (see Note 11). These receivables have been included in the balance sheet under long-term receivables.

If the accounting change we implemented during 2003 for asset retirement obligations had been effective in 2002, the impact on income before cumulative effect of changes in accounting principles and earnings per share would have been immaterial. Computed on a pro forma basis as if SFAS 143 had been applied during all periods presented, the asset retirement obligation would have been $59.0 million as of January 1, 2003.

Upon adoption of SFAS 143 on January 1, 2003, the Company recorded $2.4 million (net of taxes) as income from cumulative effect of changes in accounting principles. Application of this new accounting principle resulted in an increase in property, plant and equipment of $6.5 million, an increase in the recorded asset retirement obligation liability of $1.5 million and a decrease in the recorded long-term receivables of $2.6 million.

Commitments and Contingencies.

The Company accrues for loss contingencies when it is probable that a loss will result from a contingency, and the amount of the loss can be reasonably estimated.

Pro forma information.

As described above, the Company adopted the provisions of SFAS 142, effective January 1, 2002 and SFAS 143, effective January 1, 2003. The pro forma effects of these changes in accounting for the year ended December 31, 2002 are shown in the table below:

	Loss from Continuing Operations Before Cumulative Effect of Change in Accounting Principle	Loss Before Cumulative Effect of Change in Accounting Principle	Net loss
	(In thousands of dollars, except per share data)		
Reported income (loss)	$(809,903)	$(1,011,040)	$(1,174,678)
Asset removal obligation pro forma effect	362	362	362
Reverse cumulative effect of change in accounting principle	—	—	163,638
Pro forma income (loss)	$(809,541)	$(1,010,678)	$(1,010,678)
Pro forma income (loss) per share (basic and diluted)	$ (7.83)	$ (9.78)	$ (9.78)

NOTE 3 — Financial Restructuring and Fresh Start Reporting

Background of Restructuring.

The Company had approximately $1.1 billion of debt and other contractual obligations maturing during 2003, of which $930 million were bank and senior note obligations of PGS ASA. Based on the Company's existing business plan and forecast at that time, it became clear that the Company was over leveraged and that a comprehensive financial restructuring was crucial to the long-term viability of the Company. As a result, on July 29, 2003, the Company filed a voluntary petition for protection under Chapter 11 of the United States Bankruptcy Code. The filing was based on a financial restructuring plan that was pre-approved by a majority of banks and bondholders and a group of the Company's largest shareholders. The Company emerged from Chapter 11 on November 5, 2003.

The financial restructuring involved only the parent company and did not involve operating subsidiaries, which continued full operations, leaving customers, lessors, vendors, employees and subsidiary creditors unaffected.

Financial Restructuring.

In accordance with the plan of reorganization, $2,140 million of the Company's senior unsecured debt was canceled and the associated creditors received the following:

- $746 million of unsecured 10% Senior Notes due 2010;
- $250 million of unsecured 8% Senior Notes due 2006;
- $4.8 million of an eight-year unsecured senior term loan facility (which the Company fully repaid in May 2004);
- 91% of new ordinary shares of PGS as constituted immediately post restructuring, with an immediate reduction of this shareholding to 61% through a rights offering of 30% of the new ordinary shares to the pre-restructuring shareholders for $85 million, or $14.17 per share; and

- $40.6 million in cash distributed by PGS, of which $17.9 million was distributed in December 2003 and $22.7 million in May 2004.

In accordance with the plan, the share capital outstanding immediately prior to the effectiveness of the restructuring, consisting of 103,345,987 shares, par value NOK 5, was cancelled and 20,000,000 new ordinary shares, par value NOK 30, were issued. The pre-restructuring shareholders received 4%, or 800,000, of the new ordinary shares (one new share per 129 old shares), and the right to acquire 30%, or 6,000,000, of the new ordinary shares (1,500,000 of which were committed to shareholders underwriting the rights offering and 4,500,000 of which were available to all pre-restructuring shareholders on a basis of one new share per 23 old shares), for $85 million ($14.17 per share) in the rights offering.

Owners of $144 million of trust preferred securities received 5%, or 1,000,000, of the new ordinary shares. The principal amount of the Company's interest bearing debt and capital lease obligations immediately after the restructuring was approximately $1,210 million, a reduction of approximately $1,283 million.

Reorganization Value.

The Company adopted fresh start reporting upon its emergence from Chapter 11 in accordance with SOP 90-7. Accordingly, all assets and liabilities were adjusted to reflect their reorganization value as of November 1, 2003, which approximates fair value at the date of reorganization. The Company engaged independent financial advisors to assist in the determination of its reorganization value as defined in SOP 90-7. In the disclosure statement dated September 10, 2003 prepared in the bankruptcy proceeding, the Company, together with financial advisors, determined through various analyses a reorganization value as an enterprise value in the range of $1.3 and $1.7 billion. On this basis, the Company determined that the reorganization value for the Company as defined by SOP 90-7 should be close to the mid-range of $1.5 billion.

These analyses are necessarily based on a variety of estimates and assumptions which, though considered reasonable by management, may not be realized and are inherently subject to significant business, economic and competitive uncertainties and contingencies, many of which are beyond the Company's control. These estimates and assumptions had a significant effect on the determination of the reorganization value. Accordingly, there can be no assurance that the estimates, assumptions and values reflected in the valuations will be realized, and actual results could vary materially.

Fresh Start Reporting.

The consolidated balance sheets as of December 31, 2004 and 2003 and the consolidated statements of operations and cash flows for the year ending December 31, 2004 and the two months ended December 31, 2003 are for the Successor and give effect to adjustments to the carrying value of assets or amounts and classifications of liabilities that were necessary upon adoption of fresh start reporting as of November 1, 2003. The consolidated statements of operations and cash flows for the year ended December 31, 2002 and for the ten months ended October 31, 2003 are for the Predecessor and reflect the assets and liabilities of PGS on a historical cost basis including the effect at October 31, 2003 of the fresh start adjustments. The adoption of fresh start reporting had a material effect on the consolidated balance sheets as of December 31, 2004 and 2003 and on the consolidated statements of operations for the year ending December 31, 2004 and the two-month period ending December 31, 2003 and will have a material impact on consolidated statements of operations for subsequent periods. Consequently, the financial information for the Successor and Predecessor companies are not comparable.

In connection with the adoption of fresh start reporting on November 1, 2003, the Company also adopted new accounting policies for certain transactions and activities related to the multi-client library, steaming and mobilization costs, certain other property and equipment, and oil and natural gas exploration, development and production activities. All new accounting policies under fresh start reporting are described in Note 2.

The following table summarizes the adjustments required to record the reorganization and the issuance of the various securities in connection with the implementation of the plan of reorganization:

PGS ASA Plan of Reorganization Recovery Analysis	Predecessor Company	Elimination of Debt and Equity	Recovery								
			Surviving Debt	Cash	2010 Note	2006 Note	Term Loan Facility	Common Stock %	Common Stock Value	Total Recovery %	Total Recovery Value
	(In thousands of dollars, except percentages)										
Other liabilities — not affected	$ 338,536	$ —	$ —	$ —	$ —	$ —	$ —		$ —		$ —
Unsecured Debt	2,140,000	(2,140,000)	—	40,592	745,949	250,000	4,810	91.0%	330,458	64%	1,371,809
Trust Preferred Securities (incl. accrued interest)	155,203	(155,203)	—	—	—	—	—	5.0%	18,157	12%	18,157
Capital lease obligations	89,913	—	89,913	—	—	—	—	—	—	100%	89,913
Senior Secured Debt	113,970	—	113,970	—	—	—	—	—	—	100%	113,970
Debt of Subsidiaries — not affected	5,295	—	5,295	—	—	—	—	—	—	100%	5,295
Common Stockholders	71,089	(71,089)	—	—	—	—	—	4.0%	14,526	20%	14,526
Deficit	(429,531)	429,531	—	—	—	—	—	—	—		—
Total	$2,484,475	$(1,936,761)	$209,178	$40,592	$745,949	$250,000	$4,810	100.0%	$363,141	65%	$1,613,670
Adjusted for fair value adjustment of interest rate variation on UK leases											$ 51,642
Adjusted for cash											(148,912)
Reorganization value											$1,516,400

Fresh start adjustments reflect the allocation of fair value to current and long-lived assets and the present value of liabilities to be paid as calculated with the assistance of independent third party valuation specialists. Current and long-lived assets were valued based on a combination of the cost, income and market approach. Also considered was technical, functional and economic obsolescence.

In applying fresh start reporting, the Company followed these principles:

- The reorganization value of the Company was allocated to the Company's assets in conformity with the procedures specified by Statement of Financial Accounting Standards No. 141, *"Business Combinations."* The sum of the amounts assigned to assets and liabilities was within the range of the estimated reorganization value and close to the mid-range of the valuation. Therefore, there was no excess or deficit value to be allocated to goodwill or long-term assets.

- Each liability and contingency existing as of the fresh start reporting date, other than deferred taxes, has been stated at the present value of the amounts to be paid, determined at appropriate then current interest rates.

- Deferred taxes were recorded in conformity with applicable income tax accounting standards, principally Statement of Financial Accounting Standards No. 109, *"Accounting for Income Taxes"*. Deferred tax assets and liabilities have been recognized for differences between the assigned values and the tax basis of the recognized assets and liabilities (see Note 20). Valuation allowances have been provided for deferred tax assets.

- Changes in existing accounting principles that otherwise would have been required in the consolidated financial statements of the emerging entity within the twelve months following the adoption of fresh start reporting were adopted at the time fresh start reporting was adopted.
- Resetting the multi-client library, the property and equipment and oil and natural gas assets to fair value and eliminating all of the accumulated depreciation.

The following table summarizes the reconciliation of the Predecessor Company's consolidated balance sheet, as of October 31, 2003 (prior to fresh start adjustments), to that of the Successor Company's opening balance sheet as of November 1, 2003, giving effect to the emergence from Chapter 11 reorganization and the adoption of fresh-start reporting:

	October 31, 2003	November 1, 2003		
	Predecessor Company	Effects of Plan	Fresh Start Valuation	Successor Company
		(In thousands of dollars)		
ASSETS				
Cash and cash equivalents	$ 93,951	$ —	$ —	$ 93,951
Restricted cash	44,947	—	—	44,947
Accountants receivable, net	162,288	—	2,000	164,288
Unbilled and other receivables	30,771	—	—	30,771
Other current assets	57,625	—	(2,405)	55,220
Assets of discontinued operations	2,753	—	—	2,753
Total current assets	392,335		(405)	391,930
Multi-client library, net	437,732	—	(7,151)	430,581
Property and equipment, net	1,577,065	—	(507,968)	1,069,097
Oil and natural gas assets, net	23,345	—	574	23,919
Restricted cash	10,014	—	—	10,014
Investments in associated companies	9,246	—	(205)	9,041
Intangible assets, net	3,636	—	52,383	56,019
Other long-lived assets	31,102	—	7,601	38,703
Total assets	$2,484,475	$ —	$(455,171)	$2,029,304
LIABILITIES AND SHAREHOLDERS' EQUITY				
Short-term debt and current portion of long-term debt	$2,294,995	$(2,283,395)	$ —	$ 11,600
Current portion of capital lease obligations	19,561	—	—	19,561
Debt and other liabilities of discontinued operations	1,252	—	—	1,252
Accounts payable	36,927	—	—	36,927
Accrued expenses	152,228	29,139	(4,818)	176,549
Income taxes payable	22,570	—	—	22,570
Total current liabilities	2,527,533	(2,254,256)	(4,818)	268,459
Long-term debt	108,015	1,000,405	—	1,108,420
Capital lease obligations	70,352	—	—	70,352
Other long-term liabilities	115,095	—	83,732	198,827
Deferred tax liabilities	21,095	—	(1,817)	19,278
Total liabilities	2,842,090	(1,253,851)	77,097	1,665,336
Minority interest in consolidated subsidiaries	827	—	—	827
Shareholders' equity:				
Common stock	71,089	14,625	—	85,714
Additional paid-in capital	—	809,695	(532,268)	277,427
Retained earnings (deficit)	(397,520)	397,520	—	—
Accumulated other comprehensive income (loss)	(32,011)	32,011	—	—
Total shareholders' equity (deficit)	(358,442)	1,253,851	(532,268)	363,141
Total liabilities and shareholders' equity	$2,484,475	$ —	$(455,171)	$2,029,304

NOTE 4 — Impairment of Long-Lived Assets and Other Operating Expense, Net

Impairments of long-lived assets consist of the following:

	Successor Company		Predecessor Company	
	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
	(In thousands of dollars)			
Multi-client library	$ —	$ —	$90,053	$200,393
Production assets and equipment	—	—	328	331,971
Seismic assets and equipment	—	—	3,539	16,706
Other long-lived assets	—	—	1,091	9,401
Total	$ —	$ —	$95,011	$558,471

During 2002 and 2003, the Company's sales estimates for several of its multi-client surveys were revised downward significantly, resulting in impairments of such surveys in 2002 and 2003. In 2002 the Company recorded an impairment charge of $332.0 million relating to the *Ramform Banff* as a result of negative development of the Banff field and decreased prospects for the redeployment of the vessel to more profitable projects. Also in 2002, the Company recorded $9.4 million (included in other long-lived assets above) of impairment of goodwill in relation to its Marine Geophysical segment.

Other operating expense, net consists of the following:

	Successor Company		Predecessor Company	
	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
	(In thousands of dollars)			
Termination of employees and reorganization	$ 665	$ 582	$19,235	$ 9,570
Cost relating to completion of 2002 U.S. GAAP accounts and re-audit 2001	7,447	470	2,089	—
Net gain related to canceled merger with Veritas DGC Inc.	—	—	—	(2,864)
Other	—	—	—	1,781
Total	$8,112	$1,052	$21,324	$ 8,487

NOTE 5 — Shares Available for Sale

Shares available for sale relates to the Company's investment in Endeavour International Corp. originally acquired through contribution of licenses to use PGS seismic data in the North Sea. The Company owns approximately 3.3% of Endeavour's shares, which had an original cost of $3.8 million. Under the terms of an agreement with Endeavour, the Company may not sell any of its shares for the first twelve months from the conversion date (February 2004); from twelve to twenty-four months, the Company may sell up to one-third of the equity per quarter. In adjusting the shares to fair value an unrealized holding gain of $5.9 million in 2004 has been recorded directly to other comprehensive income (see consolidated statements of changes in shareholders' equity).

NOTE 6 — Accounts Receivable, Net

Accounts receivable, net, consists of the following:

	December 31, 2004	December 31, 2003
	(In thousands of dollars)	
Accounts receivable — trade	$162,775	$130,821
Allowance for doubtful accounts	(1,492)	(3,115)
Total	$161,283	$127,706

Development of allowance for doubtful accounts is as follows:

	Successor Company		Predecessor Company	
	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
	(In thousands of dollars)			
Beginning balance	$ 3,444	$ 2,913	$ 4,648	$ 2,321
New and additional allowances	1,001	837	2,615	5,955
Write-offs and reversals	(2,953)	(179)	(4,350)	(3,616)
Disposal of subsidiary	—	(127)	—	(12)
Ending balance	$ 1,492	$ 3,444	$ 2,913	$ 4,648
Related to:				
Accounts receivable, net	$ 1,492	$ 3,115	$ 2,472	$ 4,608
Unbilled and other receivables	—	329	314	—
Assets of discontinued operations	—	—	127	40
Total	$ 1,492	$ 3,444	$ 2,913	$ 4,648

NOTE 7 — Other Current Assets

Other current assets consist of the following:

	December 31, 2004	December 31, 2003
	(In thousands of dollars)	
Prepaid operating expenses	$13,053	$19,186
Spare parts, consumables and supplies	12,840	11,348
Prepaid taxes	15,821	11,017
Produced oil, not lifted	5,037	4,569
Advances to agents	723	5,123
Other	13,032	11,367
Total	$60,506	$62,610

NOTE 8 — Property and Equipment, Net

The components of property and equipment, including property and equipment under capitalized leases, are summarized as follows:

	December 31, 2004	December 31, 2003
	(In thousands of dollars)	
Seismic vessels and equipment	$ 435,622	$ 384,294
Production vessels and equipment	680,737	679,748
Fixtures, furniture and fittings	18,383	11,786
Buildings and other	4,412	3,890
	1,139,154	1,079,718
Accumulated depreciation	(130,146)	(19,535)
Total	$1,009,008	$1,060,183

The Company had $616.5 million and $639.5 million in property and equipment under UK leases at December 31, 2004 and 2003, respectively (see Note 19).

When calculating impairments, the carrying values of assets or cash generating units are compared to their recoverable amounts, defined as the higher of estimated selling price and value in use. See Note 2 for further description of the accounting policy for impairments of long-lived assets. As seismic vessels and equipment are not separate cash-generating units, such assets are presented combined. Vessels and equipment subject to capital leases that are part of a cash-generating unit are presented on a combined basis.

The following table summarizes depreciation expense:

	Successor Company		Predecessor Company	
	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
	(In thousands of dollars)			
Depreciation expense, net of amounts capitalized into multi-client library	$106,629	$18,206	$121,485	$154,204
Depreciation expense capitalized into multi-client library	3,982	1,329	11,766	31,528

Significant impairment charges were recorded in the ten months ended October 31, 2003 and the year ended December 31, 2002 related to property and equipment. See Note 4.

NOTE 9 — Multi-Client Library, Net

The net carrying value of the multi-client library, by the year in which the components were completed, is summarized as follows:

	December 31, 2004	December 31, 2003
	(In thousands of dollars)	
Completed surveys:		
Completed during 1998, and prior years	$ 6,614	$ 37,424
Completed during 1999	20,158	40,402
Completed during 2000	21,976	40,140
Completed during 2001	106,876	139,154
Completed during 2002	35,393	54,520
Completed during 2003	33,296	74,686
Completed during 2004	11,620	—
Completed surveys	235,933	386,326
Surveys in progress	8,756	21,679
Multi-client library	$244,689	$408,005

The following table summarizes impairment charges, amortization expense and capitalization of interest and depreciation related to the multi-client library:

	Successor Company		Predecessor Company	
	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
	(In thousands of dollars)			
Impairment charges (Note 4)	$ —	$ —	$ 90,053	$200,393
Amortization and impairment (from 2004) expense	208,468	33,347	148,399	195,954
Interest capitalized into multi-client library	1,461	375	2,083	4,841
Depreciation capitalized into multi-client library	$ 3,982	$ 1,329	$ 11,766	$ 31,528

Amortization expense for the year ended December 31, 2004, includes $48.8 million of additional non-sales related amortization. This amount includes $28.9 million in minimum amortization and $19.9 million of non-sales related amortization (impairment) to reflect reduced fair value of future sales on certain individual surveys. For the two months ended December 31, 2003, the ten months ended October 31, 2003 and the year ended December 31, 2002, the Company recognized $0.0 million, $36.6 million and $37.4 million, respectively, in minimum amortization.

For informational purposes, the following shows the hypothetical application of the Company's minimum amortization requirements to the components of the existing multi-client library. These minimum amortization requirements are calculated as if there will be no future sales of these components.

	Minimum Future Amortizations
	(In thousands of dollars)
During 2005	$ 53,509
During 2006	61,863
During 2007	64,254
During 2008	51,794
During 2009	9,844
During 2010	3,425
Future minimum amortization	$244,689

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

NOTE 10 — Intangible Assets, Net

The components of intangible assets, net, are summarized as follows:

	December 31,	
	2004	2003
	(In thousands of dollars)	
Existing technology	$ 30,548	$33,011
Existing contracts	16,772	17,600
Order backlog	5,401	5,401
Patents, royalties and licenses	659	85
Total cost	53,380	56,097
Accumulated amortization	(17,266)	(3,488)
Total	$ 36,114	$52,609

Intangible assets existing at December 31, 2004 and 2003 were primarily recognized in conjunction with the adoption of fresh start reporting, effective November 1, 2003. Total amortization expense related to these intangible assets was $13.8 million for the year ended December 31, 2004, $3.5 million for the two months ended December 31, 2003, $1.5 million for the ten months ended October 31, 2003 and $4.9 million for the year ended December 31, 2002. The weighted remaining amortization period for intangible assets as of December 31, 2004 is 5.2 years, and the amortization expense related to these assets, under existing amortization plans, for the next five years is $11.0 million (2005), $6.3 million (2006), $4.1 million (2007), $3.5 million (2008) and $2.3 million (2009).

At the Company's adoption of fresh start reporting, effective November 1, 2003, the Company established valuation allowances for deferred tax assets. If such deferred tax assets, for which a valuation allowance is established, are realized in subsequent periods, the tax benefit will be recorded as a reduction of the carrying value of long-term intangible assets and certain favorable lease contracts existing at adoption of fresh-start accounting until the value of such assets is reduced to zero. At December 31, 2004, the Company realized such deferred tax assets and accordingly recorded $3.3 million in reduction of the carrying amounts of intangible assets, which are reflected in the table above as reduction in gross costs (see Note 20).

NOTE 11 — Other Long-Lived Assets

Other long-lived assets consist of the following:

	December 31,	
	2004	2003
	(In thousands of dollars)	
Governmental grants and contractual receivables	$17,204	$16,772
Long-term receivables	14,945	6,947
Favorable lease contracts	10,444	13,806
Deferred debt issue costs	2,066	—
Total	$44,659	$37,525

Governmental grants and contractual receivables relate to grants from the Norwegian Government and contractual payments from FPSO contract counterparties that the Company is entitled to receive to cover parts of its asset removal obligations (Notes 2 and 13).

The fair values of certain favorable lease contracts were recognized in the Company's balance sheet in connection with the adoption of fresh start reporting, effective November 1, 2003. The amortization of this asset over the remaining lease period (which averages approximately 5 years) is recorded as an increase of lease expense as part of cost of sales.

At the Company's adoption of fresh start reporting, effective November 1, 2003, the Company established valuation allowances for deferred tax assets. If such deferred tax assets, for which a valuation allowance is established, are realized in subsequent periods, the tax benefit will be recorded as a reduction of the carrying value of long-term intangible assets and certain favorable lease contracts assets existing at adoption of fresh-start accounting until the value of such assets is reduced to zero. At December 31, 2004, the Company realized such deferred tax assets and accordingly recorded $1.0 million in reduction of the carrying amounts of favorable lease contracts (see Note 20).

NOTE 12 — Accrued Expenses

Accrued expenses consist of the following:

	December 31,	
	2004	2003
	(In thousands of dollars)	
Accrued employee benefits	$ 37,659	$ 30,199
Accrued vessel operating expenses	17,080	25,126
Customer advances and deferred revenue	12,070	12,614
Accrued commissions	9,683	5,088
Accrued interest expenses	3,394	2,658
Accrued severance and restructuring expenses	290	5,061
Accrued debt restructuring expenses	—	25,218
Other	35,080	41,372
Total	$115,256	$147,336

Accrued debt restructuring costs as of December 31, 2003 includes $22.7 million of excess cash payable to creditors of the Company under the restructuring agreement. The amount was paid in May 2004.

Changes in accrued severance and restructuring are as follows:

	Successor Company		Predecessor Company	
	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
	(In thousands of dollars)			
Beginning balance	$ 5,061	$ 8,367	$ 1,215	$ —
Additional and adjustment of allowances	(632)	1,764	18,469	1,215
Severance and restructuring costs paid	(4,139)	(5,070)	(11,317)	—
Ending balance	$ 290	$ 5,061	$ 8,367	$1,215

NOTE 13 — Other Long-Term Liabilities

Other long-term liabilities consist of the following:

	December 31, 2004	December 31, 2003
	(In thousands of dollars)	
Accrued liabilities UK leases (Note 19)	$ 79,344	$ 78,120
Pension liability (Note 21)	52,472	45,185
Asset retirement obligations (“ARO”) (Note 2)	58,518	50,016
Tax contingencies	25,522	16,124
Other	3,794	8,218
Total	$219,650	$197,663

The following table presents changes in asset retirement obligations for the year ending December 31, 2004, the two months ended December 31, 2003 and the ten months ended October 31, 2003:

	Successor Company		Predecessor Company
	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003
	(In thousands of dollars)		
Balance at beginning of period	$50,016	$49,847	$ 59,767
Accretion expense	4,005	599	3,793
Liabilities settled in the period	—	(430)	—
Revision in estimated cash flow/fair value	4,497	—	(13,713)
Balance at end of period	$58,518	$50,016	$ 49,847

ARO liability as of December 31, 2004, includes $39.9 million relating to our Pertra oil and natural gas activity. When we sold Pertra to Talisman in March 2005, the buyer assumed this liability as part of the transaction. The remaining ARO liability relates mainly to the Banff field and will be settled at the end of the contract, currently expected to be not later than 2015.

NOTE 14 — Short-Term Debt and Current Portion of Long-Term Debt

Short-term debt and current portion of long-term debt consist of the following:

	December 31, 2004	December 31, 2003
	(In thousands of dollars)	
Short-term debt	$ 1,962	$ —
Current portion of long-term debt (Note 15)	17,828	18,512
Total	$19,790	$18,512

NOTE 15 — Financial Restructuring and Long-Term Debt

Financial restructuring completed in 2003:

On July 29, 2003, the Company voluntarily filed a petition for protection under Chapter 11 of the United States Bankruptcy Code ("Chapter 11"). The filing was based on a financial restructuring plan that was pre-approved by a majority of banks and bondholders as well as a group of PGS' largest shareholders. PGS emerged from Chapter 11 November 5, 2003, just 100 days after filing. (See Note 3.)

Long-Term Debt.

Long-term debt consists of the following:

	December 31, 2004	December 31, 2003
	(In thousands of dollars)	
Unsecured:		
10% Senior Notes, due 2010	$ 745,949	$ 745,950
8% Senior Notes, due 2006	250,000	250,000
Libor + 1.15% Unsecured senior term loan	—	4,811
Secured:		
8.28% First Preferred Mortgage Notes, due 2011	98,920	109,119
Other loans, due 2005 — 2006	8,149	17,306
Total debt	1,103,018	1,127,186
Less current portion	(17,828)	(18,512)
Total long-term debt	$1,085,190	$1,108,674

Aggregate maturities of long-term debt as of December 31, 2004 are as follows:

	December 31, 2004
	(In thousands of dollars)
Year of repayment:	
2005	$ 17,828
2006	263,231
2007	12,900
2008	14,040
2009	15,160
Thereafter	779,859
Total	$1,103,018

The 10% Senior Notes, due 2010 ("10% Notes") bear interest at 10% per annum payable semi-annually and mature in November 2010 with no required principal payments until maturity. The 10% Notes are callable beginning in November 2007 and are callable thereafter at par plus a premium of 5% declining linearly until maturity. The 8% Senior Notes, due 2006 ("8% Notes") bear interest at 8% payable semi-annually and mature in November 2006 with no required principal payment until maturity. The 8% Notes are callable from November 2003 at par plus a premium of 3% declining linearly until maturity. Both the 10% Notes and 8% Notes are unsecured obligations of PGS ASA and are guaranteed by certain material subsidiaries.

The 8.28% First Preferred Mortgage Notes, due 2011 ("8.28% Notes") bear interest at 8.28% payable semi-annually to the bondholders along with scheduled principal payments. The Company is required to make monthly sinking fund payments to the indenture trustee in the amount of $50,000 per day. These monthly payments are designed to meet semi-annual interest and principal payments and are held in trust by the indenture trustee until the semi-annual payments are made. The 8.28% Notes are secured by, among other things, two seismic vessels. In addition the indenture trustee has an irrevocable deposit of $10 million as security for future interest and principal payments. This deposit is presented as long-term restricted cash in the consolidated balance sheets because the monies will be used to make final debt service payment when the 8.28% Notes are retired. The 8.28% Notes are callable beginning in June 2006 and are callable thereafter at par plus a make whole premium based on U.S. treasury rates plus 0.375%

In May 2004, the Company repaid its 8-year, unsecured senior term loan of $4.8 million, which had an original maturity date in 2011.

Bank Credit Facilities.

In March 2004, the Company entered into a secured $110.0 million credit facility consisting of a $70.0 million revolving credit facility and a $40.0 million letter of credit facility. The Company may borrow U.S. dollars under the revolving credit facility for working capital and general corporate purposes, and the letter of credit facility can be utilized in various currencies to obtain letters of credit to secure, among other things, performance and bid bonds required in the Company's ongoing business. The credit facility matures in March 2006 and is secured by certain assets. The interest rate for borrowing under the credit facility is LIBOR plus 2%. The credit facility is an obligation of PGS ASA and is guaranteed by certain material subsidiaries. The aggregate amount drawn on this letter of credit facility at December 31, 2004 was $15.0 million.

Short-Term Debt.

Net short-term debt was $2.0 million as of December 31, 2004 of which $1.8 million relate to the purchase of the seismic vessel *Falcon Explorer.*

Covenants.

In addition to customary representations and warranties, the Company's loan and lease agreements include various covenants. Certain of the Company's debt agreements contain covenants restricting it from incurring debt unless certain coverage ratios are met and limiting financial indebtedness, excluding project debt, to $1.5 billion. These debt agreements also include restrictions on: payment of dividends; ability to place liens on Company assets; the amount of subsidiary financial indebtedness; certain sale/leaseback transactions; certain transactions with affiliates; investments in project companies; investment in multi-client library; and asset dispositions. Specifically, the Company is not allowed to pay dividends or make similar distribution until the 8% Notes are repaid.

Certain of the loan and lease agreements and the senior note indenture contain requirements to provide audited U.S. GAAP financial statements by June 30 of each year and to provide unaudited U.S. GAAP quarterly financial statements within a specified period (typically 60 days) after the end of each of the first three quarters. The Company has received waivers and amendments allowing it to report under Norwegian GAAP in lieu of U.S. GAAP until June 30, 2005.

The Company is in compliance with the covenants in its loan and lease agreements and senior note indenture as of December 31, 2004, after giving effect to the waivers and amendments described above.

Pledged Assets.

Certain seismic vessels and seismic equipment with a net book value of $55.2 million and $59.8 million at December 31, 2004 and 2003, respectively, are pledged as security on the Company's short-term and long-term debt. In addition *Petrojarl Varg* and the shares of KS Petrojarl 1 AS and Golar-Nor Offshore AS, 98.5% owners of *Petrojarl 1*, are pledged as security for the $110 million bank credit facility. The book value of *Petrojarl Varg* and shares in KS Petrojarl 1 AS and Golar-Nor Offshore AS totals $166.9 million at December 31, 2004.

Letter 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 $30.1 million and $31.0 million at December 31, 2004 and 2003, respectively.

Subsequent Events.

In February 2005 the Company established an additional overdraft facility of NOK 50 million as part of its Norwegian cash pooling system.

On March 8, 2005 the Company sent a notice of redemption relating to $175 million of its $250 million 8% Senior Notes due 2006. On April 7, 2005, 8% Senior Notes in the amount of $175 million were redeemed at a redemption price equal to 102.00% of the principal amount of such notes, plus accrued and unpaid interest to the redemption date.

NOTE 16 — Interest Expense

Interest expense consists of the following:

	Successor Company		Predecessor Company	
	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
	(In thousands of dollars)			
Interest expense, gross	$(112,272)	$(17,245)	$(92,504)	$(143,168)
Interest on trust preferred securities	—	—	(8,536)	(14,974)
Interest capitalized	1,461	375	2,083	4,841
Total interest expense	$(110,811)	$(16,870)	$(98,957)	$(153,301)

NOTE 17 — Other Financial Items, Net

Other financial items, net, consist of the following:

	Successor Company		Predecessor Company	
	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
	(In thousands of dollars)			
Interest income	$ 4,840	$ 1,050	$ 4,467	$ 4,214
Foreign currency loss	(8,024)	(5,208)	(4,286)	(10,915)
Sale of shares in Aqua Exploration Ltd.	1,500	—	—	—
Gain on TES	—	—	—	45,264
Other	(9,177)	(106)	(1,653)	(4,771)
Financial expense, net	$(10,861)	$(4,264)	$(1,472)	$ 33,792

During 1998 and 1999, the Company entered into forward foreign currency exchange contracts known as tax equalization swaps ("TES") related to its senior unsecured notes, its 8.28% First Preferred Mortgage Notes and its trust preferred securities. In 2002, all outstanding TES contracts were settled.

Other includes additional rental paid relating to UK leases of $6.3 million for the year ended December 31, 2004, $4.9 million for the two months ended December 31, 2003, $1.5 million for the ten months ended October 31, 2003 and $3.9 million for the year ended December 31, 2002 (see Note 19).

NOTE 18 — Financial Instruments

Fair Values of Financial Instruments.

The carrying amounts of cash and cash equivalents, restricted cash, accounts receivable, unbilled and other receivables, other current assets, accounts payable and accrued expenses approximate their respective fair values because of the short maturities of those instruments. The carrying amounts and the estimated fair values of debt instruments are summarized as follows:

	December 31, 2004		December 31, 2003	
	Carrying Amounts	Fair Values	Carrying Amounts	Fair Values
	(In thousands of dollars)			
Long-term debt	$1,103,018	$1,218,386	$1,127,186	$1,185,313

The fair values of the long-term debt instruments are estimated using quotes obtained from dealers in such financial instruments.

Interest Rate Exposure.

The Company engages from time-to-time in interest rate derivatives. As at December 31, 2004, the Company had outstanding interest swap agreements in the aggregate notional amount of $10.3 million that do not qualify for hedge accounting. The aggregate market value of these agreements at December 31, 2004 was approximately ($0.5) million.

Commodity Derivative.

The Company operates in the worldwide crude oil markets and are exposed to fluctuations in hydrocarbon prices, which historically have fluctuated widely in response to changing market forces. Pertra's net production in 2004 (combined) was 5,317,134 barrels, with an average realized price of $35.11 per barrel. In 2003 the average realized price was $29.37 per barrel.

As of December 31, 2004 and 2003, we did not have any outstanding derivative commodity instruments. In the first half of 2004, we sold forward 950,000 barrels of our second half production at an estimated average of $30.50 per barrel. Of the total amount sold forward, 250,000 barrels sold forward at an average price of $29.91 per barrel was not yet delivered at December 31, 2004 and was delivered in early January 2005. Estimated fair value of the contract at December 31, 2004 was a net liability of $2.6 million, which is included as accrued expenses in the consolidated balance sheets and revenues products in the consolidated statements of operations, based on marked to market rates.

NOTE 19 — Commitments and Contingencies

Leases.

The Company has operating lease commitments expiring at various dates through 2015. The Company also has capital lease commitments, primarily for onshore-based seismic 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, at December 31, 2004 are as follows:

	December 31, 2004	
	Operating Leases	Capital Leases
	(In thousands of dollars)	
2005	$ 36,436	$ 27,364
2006	22,818	21,224
2007	22,612	6,904
2008	22,609	6,632
2009	21,283	—
Thereafter	37,875	—
Total	$163,633	62,124
Imputed interest		(3,385)
Net present value of capital lease obligations		58,739
Current portion of capital lease obligations		(25,583)
Long-term portion of capital lease obligations		$ 33,156

Future minimum payments related to non-cancelable operating leases reflect $7.1 million in sublease income for 2005, related to a time-charter of one FPSO shuttle tanker to a third party.

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

	December 31, 2004
	(In thousands of dollars)
Marine seismic and support vessels	$ 7,135
Onshore seismic equipment	213
FPSO shuttle and storage tankers	60,000
Operations computer equipment	63
Buildings	95,714
Fixtures, furniture and fittings	508
Total	$163,633

Included in the minimum lease commitment for FPSO shuttle and storage tankers as presented in the table above, is the six month cancellation period for a storage tanker operating on the Banff field in the North Sea. The Company is required to charter the vessel for as long as *Ramform Banff* produces the Banff field, which could extend to 2015 depending on the customer/field operator. The maximum payment for the charter through 2015 is $119.4 million of which only the next six months charter is included in the table above.

Rental expense for operating leases, including leases with terms of less than one year, was $59.4 million for the year ended December 31, 2004, $12.2 million for the two months ended December 31, 2003, $76.3 million for the ten months ended December 31, 2003 and $105.4 million for the year ended December 31, 2002. Rental expense for operating leases are net of sub-lease income related to time charter of FPSO shuttle tankers to a third party amounting to $10.3 million for the year ended December 31, 2004, $1.4 million for the two months ended December 31, 2003, $16.6 million for the ten months ended October 31, 2003 and $21.7 million for the year ended December 31, 2002.

Other.

The Company has contingencies 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.

UK Leases.

The Company entered into capital leases from 1996 to 1998 relating to *Ramforms Challenger, Valiant, Viking, Victory* and *Vanguard*; the *Petrojarl Foinaven*; and the production equipment for the *Ramform Banff* for terms ranging from 20-25 years. The Company has indemnified the Lessors for the tax consequences resulting from changes in tax laws or interpretations thereof or adverse rulings by the tax authorities ("Tax Indemnities") and for variations in actual interest rates from those assumed in the leases ("Interest Rate Differential"). There are no limits on either of these indemnities. Reference is also made to the description in Note 2 — UK Leases.

The lessors claim tax depreciation (capital allowances) on the capital expenditures that were incurred for the acquisition of the leased assets. The Company understands that the UK Inland Revenue ("Inland Revenue") has generally deferred agreeing to the capital allowances claimed under such leases pending the outcome of a case that was appealed to the UK House of Lords, the highest UK court of appeal. In that case, the Inland Revenue was challenging capital allowances associated with a defeased lease. In November 2004, the House of Lords ruled in favor of the taxpayer and rejected the position of the Inland Revenue. The Company has been informed that in 2005 the Inland Revenue has accepted the lessors' claims to capital allowances for three of the Company's UK leases.

As a result of the November 2004 decision by the House of Lords, the Company believes it is unlikely that its leases will be successfully challenged by the Inland Revenue. However, the Company cannot predict what, if any, liability it may incur relating to the Tax Indemnities because it is not possible to know what, if any, events will happen in the future that might result in tax consequences for which the Lessors are indemnified.

For fresh start reporting purposes, the Company estimated and recorded the fair value of the specific tax exposure related to defeased UK leases noted above using a probability-weighted analysis and a range of possible outcomes. The Company recorded a 16.7 million British pounds ($28.3 million) liability as of November 1, 2003 in accordance with the requirements of SOP 90-7. At December 31, 2004 and 2003 this liability amounted to $32.1 million and $29.5 million, respectively. As noted above, the House of Lords rejected the appeal by the Inland Revenue in a similar case. As a result, the Company expects to reduce this liability as the Inland Revenue accepts the lessors' claims for capital allowances associated with the Company's defeased UK leases.

In addition, the Inland Revenue has raised a separate issue about the accelerated rate at which tax depreciation is available under the UK lease related to the *Petrojarl Foinaven.* If the Inland Revenue were successful in challenging that rate, the Lessor would be liable for increased taxes on *Petrojarl Foinaven* in early periods (and decreased taxes in later years), and the Company's rentals would correspondingly increase (and then decrease).

The Defeased Rental Payments are based on assumed Sterling LIBOR rates between 8% and 9% (the "Assumed Interest Rates"). If actual interest rates are greater than the Assumed Interest Rates, the Company receives rental rebates. Conversely, if actual interest rates are less than the Assumed Interest Rates, the Company pays rentals in excess of the Defeased Rental Payments ("Additional Required Rental Payments"). Over the last several years, the actual interest rates have been below the Assumed Interest Rates. Prior to November 1, 2003, the Company had deferred a portion of a deferred gain (see Note 2 — UK leases) representing the net present value of Additional Required Rental Payments as of the inception of each lease. Such deferred gain was amortized over the terms of the leases. Effective November 1, 2003, the Company adopted fresh start reporting, and recorded a liability equal to the fair value of the future Additional Required Rental Payments based on forward market rates for Sterling LIBOR and an 8% discount rate. This liability, which is amortized based on future rental payments, amounted to 30.5 million British pounds (approximately $51.6 million) at November 1, 2003, 27.4 million British pounds (approximately $48.6 million) at December 31, 2003 and 24.6 million British pounds (approximately $47.2 million) at December 31, 2004.

Currently, interest rates are below the Assumed Interest Rates. Based on forward market rates for Sterling LIBOR the net present value, using an 8% discount rate, of the Additional Required Rental Payments aggregated 29.6 million British pounds (approximately $56.9 million) as of December 31, 2004. Of this amount, 1.0 million British pounds (approximately $2.0 million) was accrued at December 31, 2004, in addition to the remaining fresh start liability as described above.

Additional Required Rental Payments were $6.3 million for the year ended December 31, 2004, $4.9 million for the two months ended December 31, 2003, $1.5 million for the ten months ended October 31, 2003 and $3.9 million for the year ended December 31, 2002.

NOTE 20 — Income Taxes

The expense (benefit) for income taxes from continuing operations consists of the following:

	Successor Company		Predecessor Company	
	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
	(In thousands of dollars)			
Current taxes:				
Norwegian	$ (5)	$ 394	$ 6,639	$ —
Foreign	20,761	1,558	15,373	23,801
Deferred taxes:				
Norwegian	24,534	(1,575)	2,025	158,846
Foreign	2,729	(4,226)	(3,943)	3,243
Total	$48,019	$(3,849)	$20,094	$185,890
Classification in Consolidated Statements of Operations:				
Income tax expense (benefit)	48,019	(3,849)	21,911	185,890
Fresh start adoption	—	—	(1,817)	—
Total income tax expense (benefit)	$48,019	$(3,849)	$20,094	$185,890

The total income tax expense (benefit) for the year ended December 31, 2004, the two months ended December 31, 2003, the ten months ended October 31, 2003 and the year ended 2002 include $41.0 million, $3.1 million, $182.9 million and $61.1 million, respectively, in valuation allowances related to deferred tax assets (see table below).

The total income tax expense (benefit) for the year ended December 31, 2004, the ten months ended October 31, 2003 and the year ended December 31, 2002 include $9.5 million, $2.0 million and $15.0 million, respectively, of provisions related to uncertainties regarding outstanding tax issues. See Note 13 for long-term tax contingencies.

The total income tax expense (benefit) for the year ended December 31, 2002 excludes $9.6 million related to discontinued operations.

The Company evaluates the need for valuation allowances related to 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 due to cumulative losses in recent years and management's expectations about the generation of taxable income from contracts that are currently in effect. Because of these cumulative losses and future expectations, the Company has concluded that it was more likely than not that the net deferred tax assets would not be realized and have recognized the valuation allowances accordingly.

Changes in valuation allowance are as follows:

	Successor Company		Predecessor Company	
	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
	(In thousands of dollars)			
Balance at the beginning of the period	$368,550	$365,439	$182,581	$121,498
Current year additions	41,021	3,111	182,858	61,083
Decrease of valuation allowance related to utilization of pre-reorganization deferred tax assets(a)	(4,286)	—	—	—
Balance at the end of the period	$405,285	$368,550	$365,439	$182,581

(a) The decrease of valuation allowance related to the utilization of tax benefits from pre-reorganization temporary differences and losses carried forward (for which a valuation allowance was provided at the date of reorganization) resulted in a corresponding decrease of intangible assets (see Notes 10 and 11). Of the total valuation allowance as of December 31, 2004, $358.1 million relates to pre-reorganization amounts and will, if the related deferred tax assets are subsequently recognized, be allocated to reduce intangible assets and certain favorable lease contracts (included in other long-lived assets) or directly to contributed capital.

The expense (benefit) for income taxes from continuing operations differs from the amounts computed when applying the Norwegian statutory tax rate to income (loss) before income taxes as a result of the following:

	Successor Company		Predecessor Company	
	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
	(In thousands of dollars)			
Income (loss) from continuing operations before income taxes, minority interest and cumulative effect of change in accounting principles:				
Norwegian	$(125,179)	$(16,755)	$ 623,654	$(547,030)
Foreign	35,421	3,198	(46,052)	(76,205)
Total	(89,758)	(13,557)	577,602	(623,235)
Norwegian statutory rate	28%	28%	28%	28%
Expense (benefit) for income taxes at statutory rate	(25,132)	(3,796)	161,729	(174,506)
Increase (reduction) in income taxes from:				
Foreign earnings taxed at other than statutory rate	(7,612)	(440)	(2,057)	(8,023)
Petroleum surtax(a)	12,343	(1,619)	5,908	(2,503)
Non-taxable gain on debt discharge	—	—	(351,078)	—
Exit Norwegian shipping regime 2002	—	—	—	78,859
Prior year adjustment regarding exit Norwegian shipping regime 2001	—	—	—	82,141
Other prior year adjustments	3,047	—	—	—
Goodwill impairment	—	—	—	48,462
Gain (loss) from local currency other than reporting currency	(2,578)	(1,495)	372	91,020
Non-creditable foreign taxes and other permanent items	26,930	390	22,362	9,357
Deferred tax asset valuation allowance	41,021	3,111	182,858	61,083
Total income tax expense (benefit)	$ 48,019	$ (3,849)	$ 20,094	$ 185,890

(a) Pertra's income from oil activities on the Norwegian Continental Shelf is taxed according to the Norwegian Petroleum Tax Law, which includes a surtax of 50% in addition to the Norwegian corporate tax of 28%.

Deferred tax assets and liabilities are summarized as follows:

	December 31,			
	2004		2003	
	Asset	Liability	Asset	Liability
	(In thousands of dollars)			
Current assets	$ (3,036)	$ 1,038	$ (11,803)	$ 2,188
Property, equipment and other long-lived assets	(23,384)	37,002	(55,035)	120,585
Tax losses carried forward	(262,458)	—	(326,622)	—
Deferred gain (loss)	(57,721)	32,971	(63,419)	37,583
Tax credits	(2,893)	—	(3,855)	—
Expenses deductible when paid	(84,853)	—	(31,208)	—
Other temporary differences	(6,072)	—	(37,833)	13,773
Total deferred tax (asset) liability before valuation allowance	(440,417)	71,011	(529,775)	174,129
Deferred tax asset valuation allowance	405,285		368,550	
Deferred tax (asset) liability	$ (35,132)	$71,011	$(161,225)	$174,129
Net deferred tax liability — Norwegian		35,514		10,980
Net deferred tax liability — Foreign		365		1,924
Net deferred tax liability		$35,879		$ 12,904
Classification in Consolidated Balance Sheets:				
Short-term deferred tax liability		$ 761		$ 2,166
Long-term deferred tax liability		35,118		10,738
Net deferred tax liability		$35,879		$ 12,904

Norwegian tax loss carried forwards of $471.6 million expire at various dates from 2011 through 2014. Tax loss carried forwards in the UK, Singapore and other totaling $353.0 million do not expire. US tax loss carried forward of $72.5 million expire between 2019 and 2025. It is the Company's current policy not to provide Norwegian taxes on unremitted earnings of certain international operations, which reflect full provision for non-Norwegian income taxes, as these earnings are expected to be reinvested outside of Norway indefinitely. The Company has not calculated the tax effect associated with these unremitted earnings as it is not practicable to do so.

Until January 1, 2002 a foreign subsidiary was included in the Norwegian shipping tax regime. No deferred taxes were recognized on unremitted earnings in this subsidiary prior to the withdrawal from the regime as these earnings at that time were expected to be reinvested indefinitely within the regime. A subsequent decision in 2003 to exit with effect from 2002 resulted in recognition of deferred tax liabilities of $78.8 million. The Norwegian Central Tax Office (CTO) has not yet finalized the 2002 tax assessment in relation to withdrawal from the Norwegian shipping tax regime. The pending issue is related to fair value of the vessels involved. The Company based such exit values on third party valuations, while the CTO has raised the issue whether the Company's book values at December 31, 2001, would be more appropriate as basis for computing the tax effects of the exit. Any increase of exit values will result in an increase of taxable exit gain and a corresponding increase in basis for future tax depreciation. The Company estimates that if the CTO position is upheld, taxes payable for 2002, without considering mitigating actions, could increase by up to $24 million. The Company believes that its calculation basis for exit has been prepared using acceptable principles and will contest any adjustment to increase taxes payable.

NOTE 21 — Pension Obligations

The Company has 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 that are sufficient to meet the applicable statutory requirements. At December 31, 2004, 1,069 employees were participating in these plans.

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

Change in projected benefit obligations:

	December 31, 2004	December 31, 2003
	(In thousands of dollars)	
Projected benefit obligations at beginning of period(a)	$101,855	$ 90,478
Service cost	10,198	1,204
Interest cost	5,145	1,207
Employee contributions	968	—
Payroll tax	178	1,359
Actuarial (gain) loss, net	(9,532)	3,338
Benefits paid	(1,212)	—
Exchange rate effects	10,196	4,269
Projected benefit obligations at end of year	$117,796	$101,855

(a) Projected benefit obligations at beginning of period in the column for 2003 refers to fresh start reporting as of November 1, 2003.

Change in plan assets:

	December 31, 2004	December 31, 2003
	(In thousands of dollars)	
Fair value of plan assets at beginning of period(b)	$53,332	$50,134
Adjustment at beginning of year	(1,214)	—
Return on plan assets	4,130	819
Employer contributions	8,383	504
Employee contributions	968	—
Benefits paid	(1,212)	—
Exchange rate effects	7,178	1,875
Fair value of plan assets at end of year	$71,565	$53,332

(b) Fair value of plan assets at beginning of period in the column for 2003 refers to fresh start reporting as of November 1, 2003.

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

	December 31, 2004	December 31, 2003
	(In thousands of dollars)	
Funded status	$(46,232)	$(48,523)
Unrecognized actuarial (gain) loss	(6,021)	3,338
Additional minimum liability	(219)	—
Net amount recognized as accrued pension liability	$(52,472)	$(45,185)

The accumulated benefit obligation for all defined benefit pension plans was $104.3 million and $81.4 million as of December 31, 2004 and 2003, respectively.

Assumptions used to determine benefit obligations:

	2004		2003	
	Norway	UK	Norway	UK
Discount rate	5.3%	5.3%	6.0%	5.3%
Return on plan assets	6.3%	7.5%	7.0%	7.5%
Benefit increase	3.0%	3.0%	3.0%	4.7%
Annual adjustment to pensions	3.0%	3.0%	3.0%	3.0%

The measurement dates used to calculate the actuary measurements are approximately one month prior to balance sheet dates.

The aggregate net periodic pension costs for the Company's defined benefit pension plans are summarized as follows.

	Successor Company		Predecessor Company	
	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
	(In thousands of dollars)			
Service cost	$10,198	$ 1,204	$ 7,145	$ 7,928
Interest cost	5,145	1,207	3,247	3,108
Expected return on plan assets	(4,130)	(819)	(2,977)	(3,439)
Amortization of actuarial loss (gain)	16	(80)	403	1,908
Amortization of prior service cost	—	—	3	2
Amortization of transition obligation	—	—	17	15
Adjustment to minimum liability	198	—	—	—
Administration cost	99	—	—	—
Payroll tax	949	266	397	367
Net periodic pension cost	$12,475	$ 1,778	$ 8,235	$ 9,889

Information for pension plans with an accumulated benefit obligation in excess of plan assets are as follows:

	December 31, 2004	December 31, 2003
	(In thousands of dollars)	
Projected benefit obligation	$112,727	$89,819
Accumulated benefit obligation	100,167	72,151
Fair value of plan assets	67,147	45,074

The Company's pension plan asset allocation at December 31, 2004 and 2003, by asset category, are presented by major plan group as follows:

	December 31, 2004		December 31, 2003		
	Norway(1)	UK	Norway(1)		UK
	(In thousands of dollars)				
Fair value of plan assets	$40,111	$31,454	$15,280	$14,907	$23,145
Bonds	69%	—	62%	57%	—
Equity securities	16%	92%	13%	14%	74%
Real estate	12%	—	12%	13%	—
Other	3%	8%	13%	16%	26%
Total	100%	100%	100%	100%	100%

(1) Prior to 2004, the plans in Norway were with two separate companies. These companies merged in 2004.

For the Norwegian plans, the average target allocation for plan assets are 10-25% in equity securities, 50-70% in bonds, 10-15% in real estate and 3-10% in other.

The Company expects to contribute approximately $7.9 million to its pension plans in 2005. Total pension benefit payments expected to be paid to participants from the plans are as follows:

	(In thousands of dollars)
2005	$ 1,431
2006	1,500
2007	1,620
2008	1,777
2009	1,991
2010 through 2014	16,494

Substantially all employees not eligible for coverage under the defined benefit plans described above 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 U.S. defined contribution 401(k) plan, essentially all U.S. employees are eligible to participate upon completion of certain period-of-service requirements. The plan allows eligible employees to contribute up to 100% of compensation, subject to IRS and plan limitations, on a pre-tax basis, with a 2004 statutory cap of $13,000 ($16,000 for employees over 50 years). Employee pre-tax contributions are matched by the Company as follows: the first 3% are matched at 100% and the next 2% are matched at 50% of compensation. All contributions vest when made. The employer matching contribution recognized by the Company related to the plan was $1.2 million for the year ended December 31, 2004, $0.2 million for the two months ended December 31, 2003, $1.2 million for the ten months ended October 31, 2003 and $1.2 million for the year ended December 31, 2002. Contributions to the plan by employees for these periods were $3.1 million, $0.6 million, $2.7 million and $3.8 million, respectively. Aggregate employer and employee contributions under the Company's other plans for the year ended December 31, 2004, the two months ended December 31, 2003, the ten months ended October 31, 2003 and the year ended December 31, 2002, totalled $0.8 million and $0.4 million (2004), $0.1 million and $0.1 million (two months 2003), $2.1 million and $0.3 million (ten months 2003) and $7.4 million and $3.0 million (2002).

NOTE 22 — Share Based Compensation Plans

In connection with the restructuring of the Company in 2003, all shares in the Company were cancelled (see Notes 1 and 3 for additional information). Accordingly, all agreements relating to share options for the Company's key employees and directors were also cancelled. No new option agreements have been established since the restructuring. During the period in which the share-based compensation plan was active, the exercise price of each award equaled the market price of the Company's shares on the grant date. The vesting period for granted options ranged from approximately three years to approximately three and one-half years. Once vested, the exercisable life of the options was generally a two-year period, with certain options granted during 2000 and thereafter exercisable over a three-year period.

A summary of the status of the Company's share-based compensation plans as of December 31, 2003 and 2002, and changes during the years ended, is summarized as follows:

	December 31,			
	2003		2002	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
	(In thousands of options, except exercise prices)			
Outstanding at beginning of year	4,973.5	NOK135	8,635.4	NOK142
Granted	—	—	—	—
Exercised	—	—	—	—
Forfeited/cancelled	(4,973.5)	NOK135	(3,661.9)	NOK151
Outstanding at December 31	—	—	4,973.5	NOK135
Weighted average grant fair value of options granted during year		—		—

If the compensation cost for the share-based compensation plans had been determined based on the fair values of the options awarded at the grant dates, consistent with the provisions of SFAS 123, the net income (loss) and earnings (loss) per share would have been affected on a pro forma basis as indicated below:

	Successor Company		Predecessor Company	
	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
	(In thousands of dollars, except per share amounts)			
Net income (loss), as reported	$(134,730)	$(9,953)	$557,045	$(1,174,678)
Deduct: Total share-based compensation expense determined under the fair value based method for all awards, net of related tax effect	—	—	(5,105)	(9,804)
Pro forma, net income (loss)	$(134,730)	$(9,953)	$551,940	$(1,184,482)
Net income (loss) per share:				
Basic and diluted — as reported	$ (6.74)	$ (0.50)	$ 5.39	$ (11.37)
Basic and diluted — pro forma	$ (6.74)	$ (0.50)	$ 5.34	$ (11.46)

The Company did not grant any share options during the years ended December 31, 2004, 2003 or 2002.

NOTE 23 — Acquisitions and Dispositions

During August 2002, the Company purchased an aggregate 70% interest in PL 038 on the Norwegian Continental Shelf of the North Sea. The interest was purchased from Statoil (28%) and Norsk Hydro (42%). The Company's 30% partner is the Norwegian government's State Direct Financial Interest. The Company's FPSO vessel, *Petrojarl Varg*, has been in production on the Varg field since December 1998.

In December 2002, the Company sold its Production Services (formerly Atlantic Power Group) subsidiary to Petrofac Limited and recognized $26.8 million gross loss on disposal of this subsidiary in 2002, which included $35.4 million in goodwill impairment. The Company received proceeds of $20.2 million at the closing date and received an additional $3.8 million in 2003 upon settlement of the working capital adjustment. Furthermore, the Company recorded additional gains of $3.0 million and $1.5 million relating to contingent events for the years ended December 31, 2004 and 2003, respectively. In addition, the Company recorded fair value of $2.0 million related to such contingent events in connection with its adoption of fresh start reporting as of November 1, 2003. The Company is eligible to receive an additional $3.0 million upon the occurrence of certain contingent events through 2010.

In February 2003, the Company sold its Atlantis oil and gas activities to Sinochem and received proceeds of $48.6 million in addition to $10.6 million as reimbursements of outlays on behalf of Sinochem. The Company may receive up to $25.0 million in additional, contingent proceeds, which currently has not been recognized. During 2002, the Company recognized $174.1 million in impairment charges related to Atlantis, including the estimated loss on disposal.

In December 2003, the Company sold its wholly owned software company PGS Tigress (UK) Ltd. for a deferred compensation of approximately $1.8 million, payable during 2004 and 2007. The first payment was received in December 2004. The Company may also receive additional contingent proceeds based on performance of the company through 2006. As of December 31, 2004, the Company had not received any such contingent proceeds. The Company recognized no net gain or loss on the sale of Tigress.

The results of operations, net assets and cash flows for the above mentioned subsidiaries have been presented as discontinued operations for 2003 and 2002, and are summarized as follows:

	Successor Company	Predecessor Company			
	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002		
	Tigress	Tigress	Tigress	Atlantis	Production Services
	(In thousands of dollars)				
Revenue	$ 137	$ 1,107	$ 1,684	$ 23,452	$ 181,302
Operating expenses before depreciation, amortization, impairment and other operating income and expenses	(264)	(2,433)	(2,796)	(15,836)	(176,642)
Depreciation and amortization	—	(707)	(913)	—	(455)
Impairment of long-term assets	—	—	—	(169,284)	—
Other operating income and expenses	—	(512)	—	—	—
Total operating expenses	(264)	(3,652)	(3,709)	(185,120)	(177,097)
Operating profit (loss)	(127)	(2,545)	(2,025)	(161,668)	4,205
Financial expenses and other financial items, net	24	(1,237)	(1,278)	1,545	(74)
Income (loss) before income taxes and change in accounting principle	$(103)	$(3,782)	$(3,303)	$(160,123)	$ 4,131
Capital expenditures of discontinued operations	$ —	$ 118	$ 135	$ 77,126	$ 103

A reconciliation of income (loss) before income taxes, as reported above, and income (loss) from discontinued operations, net of tax, as presented in the Consolidated Statements of Operations, is as follows:

	Successor Company		Predecessor Company	
	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
	(In thousands of dollars)			
Income (loss) from discontinued operations before income taxes and change in accounting principles	$ —	$(103)	$(3,782)	$(159,295)
Loss on disposal	—	(32)	—	(31,580)
Additional proceeds	3,048	—	1,500	—
Income tax benefit (expense)	—	—	—	(9,588)
Goodwill impairments SFAS 142, net of tax	—	—	—	(674)
Loss from discontinued operations, net of tax	$3,048	$(135)	$(2,282)	$(201,137)

Operating expenses relating to discontinued operations includes corporate management fees based on actual charges to these entities. For continuing operations such fees are presented in the segment for Reservoir/Shared Services/Corporate (Note 26). Allocation of interest expense to discontinued operations is based on actual interest charged to the respective entities.

Subsequent Event:

On February 1, 2005, the Company signed an agreement to sell its wholly-owned subsidiary Pertra AS to Talisman Energy (UK) Ltd., and the transaction closed on March 1, 2005. The sales price was approximately $155 million with an estimated gain of approximately above $140 million, based on book-value of net assets as of December 31, 2004. We do not expect to incur any taxes from this transaction. The Pertra operations up to March 1, 2005 will be presented as discontinued operations in the consolidated financial statements for 2005. See Note 26 for selected financial information for Pertra for the years ended December 31, 2004, 2003 and 2002.

Assets and liabilities relating to Pertra as of December 31, 2004 and 2003 were as follows:

	December 31,	
	2004	2003
	(In thousands of dollars)	
Cash and cash equivalents	$ 13,423	$16,437
Accounts receivable, net	7,406	(6)
Other current assets	15,916	5,242
Property and equipment, net	937	44
Oil and natural gas assets, net	70,940	33,523
Other long-lived assets	12,024	11,828
Total assets	$120,646	$67,068
Accounts payable	$ 1,624	$ 3
Accrued expenses	8,720	11,702
Deferred tax liabilities, current	761	2,166
Income taxes payable	—	3,587
Other long-term liabilities	39,942	32,764
Deferred tax liabilities, long-term	34,752	8,813
Total liabilities	$ 85,799	$59,035

NOTE 24 — Related Party Transactions

At December 31, 2003 and 2002, 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 100% of the shares in Walther Herwig AS (until December 11, 2003, the Company held 50% of the shares, but increased its shares as Walter Herwig AS was de-merged) and chartered three vessels from that company in 2003 and 2002. Total lease expense recognized during the two months ended December 31, 2003, the ten months ended October 31, 2003 and the year ended December 31, 2002 on these vessels was $1.1 million, $6.4 million and $8.9 million, respectively, while there were no lease expense recognized during 2004.

As of December 31, 2004, the Chairman of the Board, Jens Ulltveit-Moe, through Umoe AS, controlled a total of 1,012,444 shares in Petroleum Geo-Services ASA. Jens Ulltveit-Moe became a major shareholder and took office as Chairman of the Board in 2002. Jens Ulltveit-Moe also has a 60% ownership interest in Knutsen OAS Shipping AS ("Knutsen"). Knutsen is chartering the MT *Nordic Svenita* and was also chartering the MT *Nordic Yukon* up to 2003, from PGS on a time charter contract and paid $10.3 million, $20.1 million and $20.5 million to PGS under these contracts in 2004, 2003 and 2002, respectively. PGS charters the vessels from an independent third party. The vessels were chartered by PGS to provide shuttle services for the Banff field, but in 2001 were chartered to Knutsen on terms approximating PGS's terms under the third-party lease, due to low production on the Banff field. The vessel MT *Nordic Yukon* was redelivered by PGS to the vessel owner in November 2003. In addition, PGS has a contract of affreightment with Knutsen for transporting crude oil relating to the Banff field and paid $0.7 million, $2.4 million and $1.8 million to Knutsen under this contract in 2004, 2003 and 2002, respectively. Mr. Ulltveit-Moe is also the Chairman of Unitor ASA, a company that from time to time provides the Company with equipment for its vessels.

NOTE 25 — Investments in Associated Companies

Income (loss) from associated companies accounted for using the equity method is as follows:

	Successor Company		Predecessor Company	
	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
	(In thousands of dollars)			
Corporations and limited partnerships:				
Geo Explorer AS	$ 26	$119	$1,425	$ 142
Atlantic Explorer (IoM) Ltd.	(80)	—	—	—
FW Oil Exploration LLC	—	—	—	(5,845)
Ikdam Production SA	722	81	162	(3,561)
Triumph Petroleum	—	—	(813)	(2,237)
Total	$668	$200	$ 774	$(11,501)

Investments and advances to associated companies accounted for using the equity method are as follows:

	Book Value December 31, 2003	Share of Income 2004	Paid-In Capital/ (Dividends) 2004	Equity Transactions 2004(a)	Book Value December 31, 2004	Ownership Percent as of December 31, 2004
	(In thousands of dollars)					
Corporations and limited partnerships:						
Geo Explorer AS	$3,174	$ 26	$(3,018)	$ —	$ 182	50.0%
Atlantic Explorer (IoM) Ltd.	112	(80)	—	—	32	50.0%
Ikdam Production, SA	4,690	722	—	(1)	5,411	40.0%
General partnerships	94	—	—	1	95	
Total	$8,070	$668	$(3,018)	$ —	$5,720	

(a) Includes foreign currency translation differences.

NOTE 26 — Segment and Geographic Information

In 2004 we managed our business in four segments as follows:

- *Marine Geophysical*, which consists of both streamer and seafloor seismic data acquisition, marine multi-client library and data processing;
- *Onshore*, which consists of all seismic operations on land and in very shallow water and transition zones, including onshore multi-client library;
- *Production*, which owns and operates four harsh environment FPSOs in the North Sea; and

- *Pertra,* a small oil and natural gas company that owns 70% of and was operator for PL 038 on the Norwegian Continental Shelf ("NCS") and also owns participating interests in six additional NCS licenses without current production.

Pertra was sold to Talisman in March 2005 and will be reported as discontinued operations in the 2005 financial statements.

The Company manages its Marine Geophysical segment from Lysaker, Norway, its Onshore segment from Houston, Texas, and its Production segment and Pertra from Trondheim, Norway.

The principal markets for the Production segment are the UK and Norway. Pertra produces its oil in Norwegian waters, but oil is sold as a commodity worldwide. The Varg field (PL 038), which is 70% owned and operated by Pertra, is producing using the *Petrojarl Varg,* which is owned and operated by the Company's Production segment. The Marine Geophysical and Onshore segments serve a worldwide market. Customers for all segments are primarily composed of major multi-national, independent and national or state-owned oil companies. Corporate overhead has been presented under Reservoir/Shared Services/Corporate. Significant charges, which do not relate specifically to the operations of any one segment, such as debt restructuring costs, are also presented as Reservoir/Shared Services/Corporate. Information related to discontinued operations during any period presented has been separately aggregated. Affiliated sales are made at prices that approximate market value. Interest and income tax expense is not included in the measure of segment performance.

Information by business segment is summarized as follows:

	Marine Geophysical	Onshore	Production	Pertra	Reservoir/ Shared Services/ Corporate	Elimination of Affiliated Sales	Total
	(In thousands of dollars)						
Revenue, unaffiliated companies:							
2004 (Successor)	$ 561,898	$133,161	$ 237,815	$ 184,134	$ 12,460	$ —	$1,129,468
2003 (Successor — two months)	99,283	21,459	39,745	9,544	2,340	—	172,371
2003 (Predecessor — ten months)	498,719	128,965	210,437	112,097	11,646	—	961,864
2002 (Predecessor)	587,229	118,698	291,762	32,697	12,845	—	1,043,231
Revenue, includes affiliates:							
2004 (Successor)	$ 570,805	$133,161	$ 298,202	$ 184,134	$ 20,852	$(77,686)	$1,129,468
2003 (Successor — two months)	99,382	21,459	45,229	9,544	4,957	(8,200)	172,371
2003 (Predecessor — ten months)	500,113	128,965	250,058	112,097	16,243	(45,612)	961,864
2002 (Predecessor)	592,640	118,698	306,645	32,697	16,022	(23,471)	1,043,231
Depreciation and amortization:							
2004 (Successor)	$ 241,712	$ 39,885	$ 44,561	$ 38,965	$ 3,239	$ —	$ 368,362
2003 (Successor — two months)	39,351	6,224	8,112	743	1,269	—	55,699
2003 (Predecessor — ten months)	191,215	29,425	43,418	30,826	6,692	—	301,576
2002 (Predecessor)	247,933	28,408	70,958	12,695	7,509	—	367,503
Impairment of long-lived assets:							
2004 (Successor)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
2003 (Successor — two months)	—	—	—	—	—	—	—
2003 (Predecessor — ten months)	89,598	5,085	328	—	—	—	95,011
2002 (Predecessor)	220,594	5,906	331,971	—	—	—	558,471

	Marine Geophysical	Onshore	Production	Pertra	Reservoir/ Shared Services/ Corporate	Elimination of Affiliated Sales	Total
	(In thousands of dollars)						
Other operating (income) expense, net:							
2004 (Successor)	$ (13)	$ 9	$ —	$ —	$ 8,116	$ —	$ 8,112
2003 (Successor — two months)	1,189	38	—	—	(175)	—	1,052
2003 (Predecessor — ten months)	8,107	266	—	—	12,951	—	21,324
2002 (Predecessor)	1,341	2,625	—	—	4,521	—	8,487
Operating profit (loss):							
2004 (Successor)	$ (34,967)	$ (4,544)	$ 77,769	$ 28,120	$(29,102)	$ (1,593)	$ 35,683
2003 (Successor — two months)	583	1,740	11,878	(3,198)	(301)	—	10,702
2003 (Predecessor — ten months)	(55,923)	14,390	66,548	17,236	(32,426)	—	9,825
2002 (Predecessor)	(188,532)	(21,791)	(246,601)	(4,204)	(22,481)	(5,000)	(488,609)
Loss from discontinued operations, net of tax:(a)							
2004 (Successor)	$ —	$ —	$ 3,048	$ —	$ —	$ —	$ 3,048
2003 (Successor — two months)	(135)	—	—	$ —	$ —	—	(135)
2003 (Predecessor — ten months)	(3,782)	—	1,500	—	—	—	(2,282)
2002 (Predecessor)	(3,977)	—	(22,660)	(174,500)	—	—	(201,137)
Cumulative effect of change in accounting principles, net of tax							
2004 (Successor)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
2003 (Successor — two months)	—	—	—	—	—	—	—
2003 (Predecessor — ten months)	(779)	—	3,168	—	—	—	2,389
2002 (Predecessor)	—	—	(161,106)	—	(2,532)	—	(163,638)
Investment in associated companies:							
December 31, 2004 (Successor)	$ 235	$ —	$ 5,411	$ —	$ 74	$ —	$ 5,720
December 31, 2003 (Successor)	3,308	—	4,687	—	75	—	8,070
Assets:							
December 31, 2004 (Successor)	$ 795,102	$ 90,451	$ 710,521	$ 120,646	$135,433	$ —	$1,852,153
December 31, 2003 (Successor)	959,261	117,383	790,316	67,068	63,332	—	1,997,360
Additions to long-lived tangible assets:(b)							
2004 (Successor)	$ 87,742	$ 10,817	$ 988	$ 84,991	$ 5,088	$ (114)	$ 189,512
2003 (Successor — two months)	13,715	5,182	1,662	4,424	463	—	25,446
2003 (Predecessor — ten months)	71,299	21,965	(1,147)	29,741	1,349	—	123,207
2002 (Predecessor)	167,400	24,981	3,828	10,913	1,203	—	208,325
Capital expenditures on discontinued operations:(a)							
2004 (Successor)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
2003 (Successor — two months)	—	—	—	—	—	—	—
2003 (Predecessor — ten months)	118	—	—	—	—	—	118
2002 (Predecessor)	135	—	103	77,126	—	—	77,364

(a) Loss from discontinued operations, net of tax, and capital expenditures on discontinued operations, included in segment data for Pertra, relates to Atlantis, which was a part of the Company's oil and natural gas operations prior to its disposition in early 2003. The discontinued operations for Tigress and Production Services are related to Marine Geophysical and Production, respectively.

(b) Consists of cash investments in multi-client library and capital expenditures.

Since the Company provides services worldwide to the oil and natural gas industry, a substantial portion of the 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 natural 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 conducted.

Information by geographic region is summarized as follows:

	Americas	UK	Norway	Asia/Pacific	Africa	Middle East/ Other	Elimination of Affiliated Sales	Total
				(In thousands of dollars)				
Revenue, unaffiliated companies:								
2004 (Successor)	$267,054	$191,745	$336,949	$191,703	$112,503	$29,514	$ —	$1,129,468
2003 (Successor — two months)	49,164	30,743	33,087	35,175	20,784	3,418	—	172,371
2003 (Predecessor — ten months)	270,095	181,595	235,663	82,980	124,601	66,930	—	961,864
2002 (Predecessor)	235,010	275,706	227,104	154,821	80,393	70,197	—	1,043,231
Revenue, includes affiliates:								
2004 (Successor)	$267,054	$194,712	$343,736	$191,703	$112,503	$29,514	$(9,754)	$1,129,468
2003 (Successor — two months)	49,164	31,067	35,429	35,175	20,784	3,418	(2,666)	172,371
2003 (Predecessor — ten months)	270,095	183,371	238,543	82,980	124,601	66,930	(4,656)	961,864
2002 (Predecessor)	235,610	278,611	230,022	154,851	80,393	70,197	(6,453)	1,043,231
Total assets:								
December 31, 2004 (Successor)	$343,484	$927,172	$469,675	$ 79,873	$ 21,211	$10,738	$ —	$1,852,153
December 31, 2003 (Successor)	430,972	870,941	539,935	111,484	20,567	23,461	—	1,997,360
Capital expenditures (cash):								
2004 (Successor)	$ 7,955	$ 40,812	$ 96,813	$ 1,975	$ —	$ 817	$ —	$ 148,372
2003 (Successor — two months)	5,464	1,005	9,294	222	—	—	—	15,985
2003 (Predecessor — ten months)	6,261	6,155	27,952	136	—	1,561	—	42,065
2002 (Predecessor)	10,776	17,073	28,415	192	—	279	—	56,735

Export sales from Norway to unaffiliated customers did not exceed 10% of gross revenue for the years ended December 31, 2004, 2003 and 2002.

For the years ended December 31, 2004, 2003 and 2002, customers exceeding 10% of the Company's total revenue were as follows (the table shows percentage of revenues accounted for by each of such customers, and the segments that had sales to the respective customers are marked with X):

	Years Ended December 31,						
	2004		2003			2002	
	25%	10%	19%	12%	10%	15%	11%
Segments serving customer (each % in each year represents a separate customer):							
Marine Geophysical	X	X	X	X	X	X	X
Onshore					X		
Production	X	X	X	X		X	X
Pertra	X		X				X
Reservoir/Shared Services/Corporate	X		X			X	X

In certain of the regions where the Company operates, a significant share of its employees is organized in labor unions. Similarly, the Company's operations in certain regions are members of employer unions. Therefore, the Company may be affected by labor conflicts involving such labor and employer unions.

NOTE 27 — Supplemental Cash Flow Information

Cash paid during the year includes payments for:

	Successor Company		Predecessor Company	
	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
	(In thousands of dollars)			
Interest, net of capitalized interest	$106,731	$19,619	$120,162	$112,543
Interest on trust preferred securities	—	—	—	10,377
Income taxes	29,751	4,951	8,145	15,938

The Company entered into capital lease agreements for new equipment aggregating $0.6 million for the ten months ended October 31, 2003 and $65.0 million for the year ended December 31, 2002. There were no new capital lease agreements during the two months ended December 31, 2003 or the year ended December 31, 2004.

NOTE 28 — Summarized Financial Information for Subsidiaries with Debt Securities

PGS Geophysical AS, a Norwegian corporation, is a wholly owned subsidiary of the Company. PGS Geophysical AS is the largest geophysical services company within the PGS group of companies. PGS Geophysical AS is also the lessee of the *Ramform Explorer* and the *Ramform Challenger* seismic vessels. PGS ASA has fully and unconditionally guaranteed PGS Geophysical AS charter obligations in connection with certain debt securities issued in order to finance the purchase of these vessels. Summarized financial information for PGS Geophysical AS and its consolidated subsidiaries is presented below. This information was derived from the financial statements prepared on a stand-alone basis in conformity with U.S. GAAP. Separate financial statements and other disclosures with respect to PGS Geophysical AS 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.

The PGS Geophysical AS summarized financial information consists of the following:

	Successor Company		Predecessor Company	
	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
	(In thousands of dollars)			
Income Statement Data:				
Revenue	$257,609	$ 17,610	$ 244,605	$ 286,261
Operating loss	(4,761)	(26,009)	(4,238)	(52,245)
Net loss	(22,868)	(12,671)	(6,752)	(47,887)
Balance Sheet Data:				
Current assets	$116,910	$ 99,453	$ 141,008	$ 146,061
Non-current assets	190,874	148,951	123,182	157,137
Current liabilities	56,573	84,523	82,555	112,941
Non-current liabilities	327,199	408,479	416,699	385,920
Equity (deficit)	(75,988)	(244,598)	(235,064)	(195,663)

Both Oslo Explorer PLC ("Explorer") and Oslo Challenger PLC ("Challenger"), Isle of Man public limited companies, are wholly-owned subsidiaries of the Company, purchased in April 1997. Explorer and Challenger own the *Ramform Explorer* and the *Ramform Challenger*, respectively, and lease these vessels to PGS Geophysical AS pursuant to long-term bareboat charters. *Explorer* and *Challenger* are jointly and severally liable under the 8.28% First Preferred Mortgage Notes (see note 15), 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 U.S. 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.

The Oslo Explorer PLC and Oslo Challenger PLC summarized financial information consists of the following:

	Successor Company				Predecessor Company			
	Year Ended December 31, 2004		Two Months Ended December 31, 2003		Ten Months Ended October 31, 2003		Year Ended December 31, 2002	
	Explorer	Challenger	Explorer	Challenger	Explorer	Challenger	Explorer	Challenger
	(In thousands of dollars)							
Income Statement Data:								
Revenue	$ 5,251	$ 5,258	$ 1,078	$ 1,084	$ 6,032	$ 6,003	$ 7,458	$ 7,421
Operating profit	5,090	5,098	(8,462)	(9,098)	5,885	5,857	7,295	7,259
Net income	1,042	1,048	(9,162)	(9,809)	1,738	1,708	2,094	2,058
Balance Sheet Data:								
Current assets	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Non-current assets	55,493	54,621	59,561	58,681	72,964	72,719	71,879	71,651
Current liabilities	6,625	6,624	6,252	6,252	7,616	7,616	5,864	5,864
Non-current liabilities	44,175	44,177	49,658	49,657	52,324	52,336	54,729	54,729
Equity	4,693	3,820	3,651	2,772	13,024	12,767	11,286	11,058

NOTE 29 — Supplemental Information — Oil and Gas Reserves and Costs (Unaudited)

Pertra has proved oil reserves associated with its 70% interest in PL 038 on the NCS. The Company, through its Marine Geophysical segment, also owns some small overriding royalty interests in oil and natural gas production offshore in the US Gulf of Mexico. Approximately 75% of these interests were sold in 2004 for $2.4 million. The supplemental financial and oil and natural gas reserve information and standardized measure of future cash flows from proved reserves are presented for Pertra only, The overriding royalties financial results and oil and natural reserves are not considered material for disclosure. In addition, Pertra employs a Company FPSO to produce oil from PL 038. The revenues and expenses from this FPSO are eliminated in consolidation, but the expenses are presented gross for this supplemental presentation. As a result, the oil and natural gas results in this supplemental disclosure will not match the results in the consolidated statements of operations. The Company meets the significant activities requirement for 2004 and 2003, but did not meet the requirement for 2002. As a result, no 2002 information is presented. In addition, it is not considered material to the disclosure to separately present the changes in reserves or the changes in Standardized Measure for the Predecessor and Successor periods during 2004 and 2003.

Financial Results Related to Oil and Natural Gas Activities.

The Successor results of operations, capitalized costs and costs incurred are based on the successful efforts method of accounting for oil and natural gas activities. The Predecessor results of operations and costs incurred are based on the SEC full cost method. See Note 2 for the description of each method. These methods may create significant differences in results, primarily because of the capitalization policies of each method. As a result, the Successor and Predecessor results of operations, capitalized costs and costs incurred information are not comparable.

Results of operations relating to oil and natural gas producing activities are as follows:

	Successor Company		Predecessor Company
	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003
	(In thousands of dollars)		
Oil revenues	$184,134	$ 9,544	$112,097
Production costs	93,036	6,354	62,296
Other operating costs	3,952	599	2,126
Accretion of asset retirement obligation	1,664	271	1,821
Exploration costs	20,062	4,344	—
Depletion, depreciation and amortization	38,965	743	30,826
Results of operations before tax	26,455	(2,767)	15,028
Income tax expense (benefit)	20,635	(2,159)	11,722
Results of operations	$ 5,820	$ (609)	$ 3,306

The above table does not include any amounts for allocated selling, general and administrative expense or finance income or expense.

Capitalized costs relating to oil and natural gas producing activities are set forth below:

	December 31, 2004	December 31, 2003
	(In thousands of dollars)	
Capitalized Costs:		
Proved properties	$106,604	$30,262
Unproved properties	4,000	4,000
Accumulated depreciation, depletion and amortization	(39,664)	(739)
Net	$ 70,940	$33,523

As a supplemental disclosure, under the full cost method the depletion, depreciation and amortization rate for the Predecessor for the ten months ended October 31, 2003 was $8.65 per barrel of oil produced.

Following is a summary of costs incurred in oil and natural gas exploration and development activities:

	Successor Company		Predecessor Company
	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003
	(In thousands of dollars)		
Exploration costs	$ 20,062	$13,262	$16,253
Development costs	76,342	4,375	10,318
Total costs incurred	$ 96,404	$17,637	$26,571

Proved Reserves and Standardized Measure.

The estimates of proved oil and natural gas reserves for Pertra as of December 31, 2004 and 2003 were prepared by the Company's engineers in accordance with guidelines established by the SEC and the FASB, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations except by contractual arrangements. The estimates were reviewed by an independent reservoir engineering consultant. All of Pertra's proved reserves are located in the Norwegian North Sea. The reserve estimates as of December 31, 2004 and 2003 utilize oil prices of $40.24 and $29.97, respectively, per barrel (reflecting adjustments for oil quality). The Company's actual average sale price for oil produced in 2004 was $35.11 per barrel, compared to $29.37 per barrel in 2003.

Oil and natural gas reserve quantity estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward or downward revision of previous estimates. Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. Reserve estimates are inherently imprecise, and estimates of new discoveries are more imprecise than those of currently producing oil and natural gas properties. Accordingly, these estimates are expected to change as additional information becomes available in the future.

The oil and natural gas proved reserve quantities and changes in reserve quantities, the Standardized Measure of Future Net Cash Flows from Proved Reserves (Standardized Measure) and the changes in Standardized Measure are presented for the years ended December 31, 2004 and 2003 and as of December 31, 2004 and 2003, respectively. A company is required to disclose this information when it has significant oil and natural gas exploration and production activities.

The following tables provide a roll-forward of total proved reserves for the years ended December 31, 2004 and 2003, as well as proved developed reserves at year end, as of the beginning and end of each respective year, the Standardized Measure as of December 31, 2004 and 2003 and the changes in Standardized Measure for the years ended December 31, 2004 and 2003:

Estimated Quantities of Reserves (Unaudited).

	December 31,	
	2004	2003
	(In thousand barrels)	
Crude Oil		
Proved Reserves:		
Beginning of the year	7,818	4,137
Extensions and discoveries	2,976	4,669
Revisions of previous estimates	—	3,067
Production	(5,317)	(4,056)
End of year	5,477	7,818
Proved Developed Reserves:		
Beginning of year	2,114	3,272
End of year	5,477	2,114

Standardized Measure of Future Net Cash Flows from Proved Reserves (Unaudited)

	December 31,	
	2004	2003
	(In thousands of dollars)	
Future cash inflows	$220,440	$234,300
Future production costs	108,253	109,010
Future development costs	—	12,900
Future abandonment costs	47,391	37,122
Future income taxes	51,762	59,906
Future net cash flows	13,034	15,362
Discount at 10% per annum	(2,288)	(369)
Standardized Measure	$ 15,322	$ 15,731

Changes in Standardized Measure (Unaudited)

	December 31, 2004	December 31, 2003
	(In thousands of dollars)	
Standardized Measure at beginning of year	$15,731	$ 944
Revisions of reserves proved in prior years	—	49,280
Changes in prices and production costs	10,636	333
Changes in estimates of future development and abandonment costs	(4,847)	(10,760)
Net change in income taxes	1,757	(59,090)
Accretion of discount	1,573	94
Other, primarily timing of production	10,454	695
Extensions, discoveries and other additions, net of future production and development cost	58,216	75,102
Sales of oil and natural gas produced, net of production costs	(91,098)	(48,667)
Previously estimated development and abandonment costs incurred during the period	12,900	7,800
Net changes in Standardized Measure	(409)	14,787
Standardized Measure at end of year	$15,322	$ 15,731

EXHIBIT INDEX

Exhibit Number		Description
1.1	—	Articles of Association, as amended (unofficial English translation) (incorporated by reference to Exhibit 1.1 of the annual report of Petroleum Geo-Services ASA (the "Company") on Form 20-F for the year ended December 31, 2003 (SEC File No. 1-14614 (the "2003 Form 20-F"))).
2.1	—	Deposit Agreement, dated as of May 25, 1993, among 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 (incorporated by reference to filing under Rule 424(b) (3) relating to the Company's Registration Statements on Form F-6 (Registration Nos. 33-61500 and 333-10856))
2.4	—	Indenture dated as of November 5, 2003, among the Company, each of the guarantors named therein and Law Debenture Trust Company of New York, as trustee (the "Trustee") (incorporated by reference to Exhibit 2.4 of the 2003 Form 20-F)
2.5	—	First Supplemental Indenture, dated as of November 5, 2003, among the Company, each of the guarantors named therein and the Trustee (incorporated by reference to Exhibit 2.5 of the 2003 Form 20-F)
2.6	—	Second Supplemental Indenture, dated as of June 4, 2004, among the Company, each of the guarantors named therein and the Trustee (incorporated by reference to Exhibit 2.6 of the 2003 Form 20-F)
2.7	—	Supplemental Indenture, dated as of August 31, 2004, among Pertra AS, the Company, each of the other guarantors named therein and the Trustee
2.8	—	Supplemental Indenture, dated as of August 31, 2004, among P.G.S. Mexicana S.A. de C.V., the Company, each of the other guarantors named therein and the Trustee

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 November 4, 2002 between the Company and Svein Rennemo (the "Employment Agreement") (incorporated by reference to Exhibit 4.1 of the 2003 Form 20-F)
4.2	—	Addendum to the Employment Agreement dated June 8, 2004 between the Company and Svein Rennemo (incorporated by reference to Exhibit 4.2 of the 2003 Form 20-F)
4.3	—	2004 CEO Bonus Scheme (incorporated by reference to Exhibit 4.3 of the 2003 Form 20-F)
8.1	—	Subsidiaries (included in Item 4 of the annual report)
11.1	—	Code of Conduct
12.1	—	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 and Rule 13a-14(a) of the Securities Exchange Act of 1934
12.2	—	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 and Rule 13a-14(a) of the Securities Exchange Act of 1934
13.1	—	Certification of the Chief Executive Officer and the Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and Rule 13a-14(b) of the Securities Exchange Act of 1934
15.1	—	Audit Committee Charter
15.2	—	Remuneration Committee Charter