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

FORM 10-K

(Mark One)
[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE FISCAL YEAR ENDED DECEMBER 31, 2004 [ ] 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 0-22739

CAL DIVE INTERNATIONAL, INC.
(Exact name of registrant as specified in its charter)

MINNESOTA	95-3409686
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
400 NORTH SAM HOUSTON PARKWAY EAST SUITE 400 HOUSTON, TEXAS	77060
(Address of principal executive offices)	(Zip Code)

REGISTRANT'S TELEPHONE NUMBER, INCLUDING AREA CODE:
(281) 618-0400

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

TITLE OF EACH CLASS NAME OF EACH EXCHANGE ON WHICH REGISTERED

- None
None

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:

COMMON STOCK (NO PAR VALUE)
(Title of Class)

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 Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes [X] No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2). Yes [X] No [ ]

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2004 was $1,080,978,797 based on the last reported sales price of the Common Stock on June 30, 2004, as reported on the NASDAQ/National Market System.

The number of shares of the registrant's Common Stock outstanding as of March 9, 2005 was 38,698,679.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive Proxy Statement for the Annual Meeting of Shareholders to be held on May 10, 2005, are incorporated by reference into Part III hereof.

CAL DIVE INTERNATIONAL, INC. ("CDI") INDEX -- FORM 10-K

FORWARD LOOKING STATEMENTS

This Annual Report on Form 10-K, or Annual Report, including "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7, contains forward-looking statements that involve risks, uncertainties and assumptions that could cause the results of Cal Dive International, Inc. and its consolidated subsidiaries ("CDI" or "Cal Dive") to differ materially from those expressed or implied by such forward-looking statements. All statements, other than statements of historical fact, are statements that could be deemed forward-looking statements, including, without limitation, any projections of revenue, gross margin, expenses, earnings or losses from operations, or other financial items; any statements of the plans, strategies and objectives of management for future operations; any statement concerning developments, performance or industry rankings relating to services; any statements regarding future economic conditions or performance; any statements of expectation or belief; and any statements of assumptions underlying any of the foregoing. The risks, uncertainties and assumptions referred to above include the performance of contracts by suppliers, customers and partners; employee management issues; complexities of global political and economic developments; and other risks that are described herein, including, but not limited to, the items discussed in "Factors Influencing Future Results and Accuracy of Forward-Looking Statements" set forth in Item 1 of this Annual Report, and that are otherwise described from time to time in CDI's reports filed with the Securities and Exchange Commission after this report. CDI assumes no obligation and does not intend to update these forward-looking statements.

PART I

ITEM 1. BUSINESS.

OVERVIEW

We are an energy services company, incorporated in the State of Minnesota, specializing in Marine Contracting development (including subsea construction and well operations) and providing oil and gas companies with alternatives to traditional approaches of equity or production sharing in offshore properties through our Oil & Gas Production and Production Facilities segments. Operations in the Production Facilities segment began in 2004. We operate primarily in the Gulf of Mexico, or Gulf, and, since 2002, in the North Sea and the Asia/Pacific regions with services that cover the lifecycle of an offshore oil and gas field. We believe we have a longstanding reputation for innovation in our subsea construction techniques, equipment design and methods of partnering with customers. Our diversified fleet of 22 vessels and 26 remotely operated vehicles (or ROVs) and trencher systems perform services that support drilling, well completion, intervention, construction and decommissioning projects involving pipelines, production platforms, risers and subsea production systems. We also have acquired significant interests in oil and gas properties; a Deepwater production facility at the Marco Polo field; and a planned facility, the Independence Hub, to be located in Mississippi Canyon Block 920. Our customers include major and independent oil and gas producers, pipeline transmission companies and offshore engineering and construction firms.

We have positioned ourselves for work in water depths greater than 1,000 feet, referred to as the Deepwater, by continuing to grow our technically advanced fleet of dynamically positioned, or DP, vessels, ROVs and the number of highly experienced support professionals we employ. These DP vessels serve as advanced work platforms for the subsea solutions that we provide with our alliance partners, a group of internationally recognized contractors and manufacturers. Most notably, the Q4000, our Deepwater semi-submersible multi-service vessel, or MSV, incorporates patented technologies that can improve Deepwater well completion, intervention and construction economics for our customers. Availability of the Q4000 and the Seawell, together with our other large vessels, the Eclipse, Mystic Viking and Intrepid, enable us to offer a diverse fleet of DP subsea construction and intervention vessels.

Our ROV subsidiary, Canyon Offshore, Inc., or Canyon, offers survey, engineering, repair, maintenance and international cable burial services in the Gulf, Europe/West Africa and Asia/Pacific regions. Our wholly owned subsidiaries, Wells Ops, Inc., and its Aberdeen, Scotland based sister company, Cal Dive International Limited (formerly known as Well Ops (U.K.) Limited), engineer, manage and conduct well construction, intervention and decommissioning operations in water depths from 200 to 10,000 feet in, the Gulf of Mexico and the North Sea, respectively. Cal Dive International Limited also performs saturation diving in the North Sea from its DP vessel, the Seawell.

On the Outer Continental Shelf, or OCS, of the Gulf of Mexico, in water depths up to 1,000 feet, we perform traditional subsea services, including air and saturation diving and salvage work. Our shallow water diving division provides a full complement of services in the shallow water market from the shore to a depth of 200 feet. We own and operate eleven vessels that are permanently dedicated to performing traditional diving services. Altogether we employ more than 300 full-time supervisors, divers, tenders and support staff who make us the market leader for all manned diving services in the Gulf. In depths from 200 feet to 1,000 feet, these services are provided by our two four-point saturation diving vessels, with another four DP vessels capable of providing such services on the OCS. We provide subsea construction services in the OCS "spot market" where projects are generally turnkey in nature, short in duration (two to thirty days), and require the availability of multiple vessels due to frequent rescheduling. The technical and operational experience of our personnel and the scheduling flexibility offered by our large fleet enable us to manage turnkey projects and to meet our customers' requirements. We have also established a presence in the salvage market by offering customers a number of options to address their decommissioning obligations in a cost-efficient manner, particularly the removal of smaller structures.

In our Oil & Gas Production business, our subsidiary Energy Resource Technology, Inc., or ERT, acquires and produces mature, non-core offshore property interests, offering customers a cost-effective alternative to the decommissioning process required by law (the "mature field strategy"). In 2000, ERT's reservoir engineering and geophysical expertise enabled us to acquire in partnership with the operator, Kerr McGee Oil & Gas Corp., a working interest in Gunnison, a Deepwater Gulf oil and natural gas exploration project, which began initial production in December 2003. In 2004, ERT continued to successfully pursue its strategy of acquiring (or partnering in) and developing proved undeveloped and high probability of success reserves, i.e., leases where reserves were judged by the current owner to be too marginal to justify development or they were seeking a partner. Also, in 2004, Cal Dive formed ERT (U.K.) Limited to explore exporting these strategies to the North Sea.

In our Production Facilities segment, we participate in the ownership of production facilities in hub locations where there is potential for significant subsea tieback activity. In addition to production from the Gunnison reservoir (which began in December 2003), Cal Dive will receive ongoing revenues from its 20% interest in the production facility as satellite prospects are drilled and tied back to the spar. Deepwater Gateway, L.L.C., our second such endeavor, involves a 50% ownership position in the tension-leg platform installed at Anadarko's Marco Polo field at Green Canyon block 608 (which began producing in July 2004). In 2004, we acquired a 20% interest in Independence Hub, LLC, an affiliate of Enterprise Products Partners L.P. Independence Hub, LLC will own the "Independence Hub" platform to be located in Mississippi Canyon block 920 in a water depth of 8,000 feet. Construction is ongoing and is expected to complete and come online in early 2007. At both Gunnison and Marco Polo, we participated in field development planning and performed subsea construction work.

Significant financial information relating to the Company's segments for the last three years is contained in footnote 14 of the Consolidated Financial Statements included herein, which financial statements are included in Item 8 hereof.

BUSINESS STRENGTHS AND STRATEGIES

Our overall corporate goal is to increase shareholder value by strengthening our market position to provide a return that leads our Peer Group. Our goal for Return on Invested Capital is 10% or greater. We attempt to achieve our return on capital objective by focusing on the following business strengths and strategies.

OUR STRENGTHS

Fleet of DP Vessels. We believe our fleet of DP construction vessels is one of the largest in the world, with one of the most diverse and technically advanced collections of subsea intervention and construction capabilities. The comprehensive services provided by our DP vessels are both complementary and overlapping, enabling us to provide customers with the redundancy essential for most projects, especially in the Deepwater. We also utilize these capabilities to develop our own, or partnering interest, in reservoirs.

Formation of Well Operations Subsidiary as a "First In" Advantage. Establishment of the Well Ops group followed the construction of the purpose-built Q4000 and the acquisition of the Subsea Well Operations Business Unit of Technip in Aberdeen, Scotland. The mission of these companies is to provide the industry with a single, comprehensive source for addressing current well operations needs and to engineer for future needs. We also use these capabilities to maintain, enhance and abandon our own reservoirs.

Experienced Personnel and Turnkey Contracting. A key element of our successful growth has been our ability to attract and retain experienced personnel who are among the best in the industry at providing turnkey contracting. We believe the recognized skill of our personnel and our successful operating history uniquely position us to capitalize on the trend in the oil and gas industry of increased outsourcing to contractors and suppliers. This is especially true on a broader scale with smaller, economically challenged reservoirs.

Major Provider of Marine Construction Services on the OCS. We believe that our shallow water diving division, and our position in the Gulf for saturation diving services make us one of the largest suppliers of subsea construction services on the Gulf of Mexico OCS. We expect the aging infrastructure will require increasing levels of inspection, maintenance and repair activities, or IMR.

Oil & Gas Production. The strategy of ERT's oil and gas production business differentiates us from our competitors and helps to offset the cyclical nature of our subsea construction operations. Each of ERT's oil and gas investments is designed to secure utilization of CDI construction vessels.

Production Facilities. At the Marco Polo field, our 50% ownership in the production facility allows us to realize a return on investment consisting of both a fixed monthly demand charge and a volumetric tariff charge. In addition, we assisted with the installation of the tension leg platform ("TLP") and the work to develop the surrounding acreage that can be tied back to the platform by our construction vessels. With the acquisition of a 20% interest in Independence Hub, LLC, we are in a good position to secure installation and tie-back work similar to what we achieved at the Marco Polo field. We also own a 20% interest in the spar at Gunnison. Our long-term goal is that 40% of all of our construction utilization is provided by ownership of offshore fields and production facilities. As our track record increases so does the demand for our model.

Decommissioning Operations. Over the last decade, we have established a presence in decommissioning offshore facilities, particularly in the removal of the smaller structures and caissons that make up approximately half of the structures in the Gulf. We expect demand for decommissioning services to increase due to the significant backlog of platforms and caissons that must be removed in accordance with government regulations.

OUR STRATEGIES

Focusing on the Gulf and Global Expansion. We will continue to focus on the Gulf of Mexico, where we have provided marine construction services since 1975, as well as the North Sea, Southeast Asia and other Deepwater basins worldwide. We expect oil and gas exploration and development activity in the Deepwater Gulf and other Deepwater basins of the world to increase over the next several years.

Capturing a Leading Presence in the Deepwater Market. Our fleet now includes eight world-class DP vessels, five of which are based in the Gulf of Mexico. In addition, through Canyon we operate 26 ROV and trencher systems, including a "T750" Super Trencher as well as three Triton XLS ROV systems to fulfill requirements under a Master Service Agreement entered into with Technip-Coflexip. In 2004, Canyon purchased an Olympian T1 trencher, which is currently being upgraded to a "T600" Trencher. Canyon represents an integration consistent with our strategy of providing key services along the critical path of Deepwater projects.

Developing Well Operations Niche. As major and independent oil and gas companies expand operations in the Deepwater basins of the world, development of these reserves will often require the installation of subsea trees. Historically, drilling rigs were usually necessary for subsea well operations to troubleshoot or enhance production, shift zones or perform recompletions. Three of our vessels serve as work platforms for well operations services at costs significantly less than drilling rigs. In the Gulf of Mexico, our multi-service semi-submersibles, the Q4000 and the Uncle John have set a series of well operations "firsts" in increasingly deep water without the use of a rig. In the North Sea, the Seawell has provided intervention and abandonment services for approximately 500 North Sea wells since her commissioning in 1987. Competitive advantages of the CDI vessels stem from their lower operating costs, together with an ability to mobilize quickly and to maximize productive time by performing a broad range of tasks for intervention, construction, inspection, repair and maintenance.

Acquiring Mature Oil and Gas Properties. Through ERT we have been acquiring mature or sunset properties since 1992, thereby providing customers a cost effective alternative to the decommissioning process. In the last twelve years, we have acquired interests in 90 leases and currently are the operator of 35 of 50 active offshore leases. ERT has been able to achieve a significant return on capital by efficiently developing acquired reserves, lowering lease operating expenses and adding new reserves through exploitation drilling and well work. Our customers consider ERT a preferred buyer as a result of ERT's reputation, Cal Dive's financial strength and our salvage expertise. As an industry leader in acquiring mature properties, ERT has a significant flow of potential acquisitions. At December 31, 2004, ERT's total proved reserves were 116.3 Bcfe, including 43.9 Bcfe of proved reserves assigned to our ownership position in Gunnison.

Expanding Ownership in Production Facilities. Along with Enterprise Products Partners L.P., Cal Dive owns 50% of the tension leg production platform installed at the Marco Polo field and 20% of the Independence Hub platform, a 105 foot deep draft, semi-submersible platform. We also own a 20% interest in the spar at Gunnison. Ownership of these production facilities provides a transmission type return that does not entail any reservoir or commodity price risk. The Company plans to seek additional opportunities to invest in such production facilities as well as evolved models.

Expanding the PUD Model. We successfully applied the ERT model to the Deepwater with our involvement in the Gunnison field. The Deepwater Gulf has seen a significant increase in oil and gas exploration, development, and production due, in part, to new technologies that reduce operational costs and risks; the discovery of new, larger oil and gas reservoirs with high production potential; government deepwater incentives; and increasing demand and prices. Along with these larger fields are prospects where the reserves are judged by the current owner to be too marginal to justify development. In 2005, ERT will continue to aggressively pursue its strategy of acquiring reserves and develop these reserves utilizing Cal Dive's assets. Development of these fields may require services and a combination of Cal Dive assets to enhance the economics. Through ERT (U.K.) Limited, we plan to expand the model to the North Sea, and eventually to the Asian Continent.

THE INDUSTRY

The offshore oilfield services industry originated in the early 1950s to assist companies as they began to explore and develop offshore fields. The industry has grown significantly since the early 1970s as the domestic oil and gas industry has increasingly relied upon these fields for new domestic production. Factors we believe will benefit the industry in the coming years include: (i) increasing world demand for oil and natural gas; (ii) a continued increase in exploration, development, and production in the Deepwater Gulf and other Deepwater basins of the world; and (iii) an increased demand for decommissioning services in compliance with MMS regulations as the OCS offshore oil and gas industry continues to mature.

In response to the oil and gas industry's ongoing migration to the Deepwater, equipment and vessel requirements have changed. Most vessels currently operating in the Deepwater Gulf were designed in the

1970s and 1980s for work in a maximum depth of approximately 1,000 feet. These vessels have been modified to take advantage of new technologies and now operate in depths up to 4,000 feet. We believe there is demand in the Gulf for new generation vessels, such as the Q4000 and Intrepid, that are specifically designed to work in water depths beyond 4,000 feet.

Defined below are certain terms helpful to understanding the services we perform in support of offshore development:

Bcfe: Billions of cubic feet equivalent, used to describe oil volumes converted to their energy equivalent in natural gas as measured in billions of cubic feet.

Deepwater: Water depths beyond 1,000 feet.

Dive Support Vessel (DSV): Specially equipped vessel that performs services and acts as an operational base for divers, ROVs and specialized equipment.

Dynamic Positioning (DP): Computer-directed thruster systems that use satellite-based positioning and other positioning technologies to ensure the proper counteraction to wind, current and wave forces enabling the vessel to maintain its position without the use of anchors. Two DP systems (DP-2) are necessary to provide the redundancy required to support safe deployment of divers, while only a single DP system is necessary to support ROV operations.

DP-2: Redundancy allows the vessel to maintain position even with failure of one DP system; required for vessels which support both manned diving and robotics and for those working in close proximity to platforms.

EHS: Environment, Health and Safety programs to protect the environment, safeguard employee health and eliminate injuries.

E&P: Oil and gas exploration and production activities.

IMR: Inspection, maintenance and repair activities.

Life of Field Services: Services performed on offshore facilities, trees and pipelines from the beginning to the economic end of the life of an oil field, including installation, inspection, maintenance, repair, contract operations, well intervention, recompletion and abandonment.

MBbl: When describing oil, refers to 1,000 barrels containing 42 gallons each.

Minerals Management Service (MMS): The federal regulatory body having responsibility for the mineral resources of the United States OCS.

MMcf: When describing natural gas, refers to 1 million cubic feet.

Moonpool: An opening in the center of a vessel through which a saturation diving system or ROV may be deployed, allowing safe deployment in adverse weather conditions.

Outer Continental Shelf (OCS): For purposes of our industry, areas in the Gulf from the shore to 1,000 feet of water depth.

Peer Group: Defined in this Annual Report as comprising Global Industries, Ltd. (Nasdaq: GLBL), Horizon Offshore, Inc. (Nasdaq: HOFF), McDermott International, Inc. (NYSE: MDR), Oceaneering International, Inc. (NYSE: OII), Stolt Offshore SA (Nasdaq: SOSA), Technip-Coflexip (NYSE: TKP) and Superior Energy Services, Inc. (NYSE: SPN).

Proved Undeveloped Reserve (PUD): Proved undeveloped oil and gas reserves that are expected to be recovered from a new well on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Remotely Operated Vehicle (ROV): Robotic vehicles used to complement, support and increase the efficiency of diving and subsea operations and for tasks beyond the capability of manned diving operations.

Saturation Diving: Saturation diving, required for work in water depths between 200 and 1,000 feet, involves divers working from special chambers for extended periods at a pressure equivalent to the pressure at the work site.

Spar: Floating production facility anchored to the sea bed with catenary mooring lines.

Spot Market: Prevalent market for subsea contracting in the Gulf, characterized by projects generally short in duration and often of a turnkey nature. These projects often require constant rescheduling and the availability or interchangeability of multiple vessels.

Stranded Field: Smaller PUD reservoir that standing alone may not justify the economics of a host production facility and/or infrastructure connections.

Subsea Construction Vessels: Subsea services are typically performed with the use of specialized construction vessels which provide an above-water platform that functions as an operational base for divers and ROVs. Distinguishing characteristics of subsea construction vessels include DP systems, saturation diving capabilities, deck space, deck load, craneage and moonpool launching. Deck space, deck load and craneage are important features of the vessel's ability to transport and fabricate hardware, supplies and equipment necessary to complete subsea projects.

Tension Leg Platform (TLP): A floating Deepwater compliant structure designed for offshore hydrocarbon production.

Trencher or Trencher System: A subsea robotics system capable of providing post lay trenching, inspection and burial (PLIB) and maintenance of submarine cables and flowlines in water depths of 30 to 7,200 feet across a range of seabed and environmental conditions.

Ultra-Deepwater: Water depths beyond 4,000 feet.

MARINE CONTRACTING

We and our alliance partners provide a full range of marine contracting services in both the shallow water and Deepwater including:

- Exploration. Pre-installation surveys; rig positioning and installation assistance; drilling inspection; subsea equipment maintenance; well completion; search and recovery operations.

- Development. Installation of production platforms; installation of subsea production systems; pipelay support including connecting pipelines to risers and subsea assemblies; pipeline stabilization, testing and inspection; cable and umbilical lay and connection.

- Production. Inspection, maintenance and repair of production structures, risers and pipelines and subsea equipment; well intervention; life of field support.

- Decommissioning. Decommissioning and remediation services; plugging and abandonment services; platform salvage and removal; pipeline abandonment; site inspections.

DEEPWATER CONTRACTING AND WELL OPERATIONS

In 1994, we began to assemble a fleet of DP vessels in order to deliver subsea services in the Deepwater and Ultra-Deepwater. Today, our fleet consists of two semi-submersible DP MSVs, the Q4000 and the Uncle John; a dedicated well operations vessel, the Seawell; an umbilical and rigid pipelay vessel, the Intrepid; three construction DP DSVs, the Witch Queen, the Mystic Viking, and the Eclipse; and an ROV support vessel the Northern Canyon.

Our subsidiary, Canyon Offshore, Inc., operates ROVs and trenchers designed for offshore construction, rather than supporting drilling rig operations. As marine construction support in the Gulf of Mexico and other areas of the world moves to deeper waters, ROV systems will play an increasingly important role. Our vessels add value by supporting deployment of Canyon's ROVs. We have positioned ourselves to provide our customers with vessel availability and schedule flexibility to meet the technological challenges of these Deepwater construction developments in the Gulf and internationally. Our ROVs operate in three regions: the Americas (7), Europe/West Africa (7) and Asia Pacific (7) regions. In addition to the ROVs, Canyon also has five trenchers that operate in the Americas (1), Asia Pacific (1) and the Europe/West Africa (3) regions, including a state of the art "T750" Super Trencher (Europe/West Africa) and the soon to be completed "T600" Trencher (Gulf of Mexico).

Utilization of our Deepwater Contracting vessels of 60.6% in 2004 declined from 2003's utilization of 77.4%; however, utilization of our Well Ops vessels (the Q4000 and the Seawell) improved to 80.2% in 2004 from 77.5% in 2003. Major projects for the Deepwater Contracting group in 2003 and 2004 included:

DEPTH END CLIENT
PROJECT NAME
SCOPE OF WORK
(FEET) ----------
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Allseas/Williams
Energy Devil's
Tower 16" Jumper
Installation
3,200 BP America
Mad Dog Flotel
(SPAR
Installation)
4,500 ENI
Petroleum K2
Horizontal Tree
Installations (3)
4,000 GulfTerra
Field Services
Green Canyon 237
Post-Crossings
and ROV
Inspections 2,700
GulfTerra/El Paso
Phoenix 16" SCR
Recovery and J-
Tube Pull-In
5,300 JPK/Kerr
McGee Garden
Banks 197
Flowline and
Umbilical
Installation
1,000 Kerr McGee
Triton Flowline
and Umbilical
Installation
2,024 Kerr-McGee
Triton Connector
Seal Change-Out
2,000 Kerr McGee
Boomvang
Pipeline/Umbilical
Installation
3,500 Kerr McGee
Triton Umbilical
Repair 1,800 Kerr
McGee Red Hawk
Change Out Pod on
SS Tree 5,400
Llano Subsea
Production Garden
Banks 385/386
Jumper and Flying
Lead Installation
2,700
Pinnacle/LLOG
Green Canyon
50/137 4" & 6"
Flowlines,
Umbilical, Riser
1,150 Exploration
and I-Tube

Installations Harrier 10" Tie-Ins & Jumpers 4,114	Pioneer Natural Resources

The mission of the Well Ops Group (Well Ops Inc. and Cal Dive International Limited) is to provide the industry with a single, comprehensive source for addressing current subsea well operations needs and to engineer for future needs. Our purpose-built vessels serve as work platforms for subsea well operations services at costs significantly less than drilling rigs. In the Gulf of Mexico, the Q4000 and the Uncle John have set a series of "firsts" in increasingly deep water without the use of a rig including: first "live subsea well" intervention; first through tubing subsea well decommission; first "live subsea well" intervention using wireline lubricator; first Deepwater full field decommission; first re-entry and decommission through horizontal tree; first removal and recovery of subsea well templates and horizontal trees; first use of test tree in open water as a lower riser package (LRP); first subsea transfer of tree from one well to another during decommissioning operations; first use of coil tubing drilling in subsea decommissioning; first installation of a "storm choke" as replacement for subsurface safety control valve; first transit between wells with intervention riser system deployed; first multiple tree installations and testing, all of which utilized a semi-submersible DP MSV instead of a drilling rig; as well as first to provide and apply a purpose-built 7 3/8" bore Intervention Riser System and the first interventions in 3,900 feet of salt water without use of a rig. The Seawell has provided intervention and abandonment services on approximately 500 North Sea wells since her commissioning in 1987, being the only consistent and continuous solution to light well intervention needs in the region, setting many records and "firsts" over the last 17 years. One additional advantage is that the Seawell can undertake saturation diving and construction tasks independently or simultaneously with the well intervention activities. We believe the Seawell sets the standard for the industry in subsea well intervention and continues to redefine the boundaries of the industry. In 2004, the Seawell performed the first live subsea well interventions from a monohull in the Norwegian Sector, undertaking work on five Statoil wells during the 2004 Campaign. According to Statoil, the Seawell operations saved 50% against the cost of a traditional semi-submersible offshore unit and gained additional value in improving their recoverable reserves and production rates. Competitive advantages of our vessels stem from their lower operating costs and the ability to mobilize quickly for multi-well campaigns of work and maximize productive time by performing a broad range of tasks for intervention, construction, inspection, repair and maintenance. Well Ops Inc. and Cal Dive International Limited also collaborate with leading downhole service providers to provide superior, comprehensive solutions to the well operations challenges faced by our customers.

SHELF CONTRACTING

On the OCS, in water depths up to 1,000 feet, we perform traditional subsea services including air and saturation diving in support of marine construction activities. Eleven of our vessels are permanently dedicated to performing traditional diving services, with another four DP vessels capable of providing such services, on the OCS. Six of these vessels support saturation diving. In addition, our highly qualified personnel have the technical and operational experience to manage turnkey projects to satisfy customers' requirements and achieve our targeted profitability.

We deliver our services in the shallow water market, from the shore to a depth of 200 feet, through our shallow water diving division. In addition, our saturation diving vessels can deliver services in depths up to 1,000 feet.

Since 1989, we have undertaken a wide variety of decommissioning assignments, mostly on a turnkey basis. We have established a leading position in the removal of smaller structures, such as caissons and well protectors, which represent approximately half of the structures in the Gulf.

OIL & GAS PRODUCTION

We formed ERT in 1992 to exploit a market opportunity to provide a more efficient solution to offshore abandonment, to expand our off-season salvage and decommissioning activity and to support full field production development projects. Through ERT we offer customers the option of selling mature offshore fields as an alternative to contracting and managing the many phases of the decommissioning process. The benefits of our strategy are fourfold. First, oil and gas revenues counteract the volatility in revenues we experience in offshore construction. Second, in periods of excess capacity, such as in 2002 and 2003, we have the flexibility to be less dependent on the competitive bid market and instead focus on negotiated contracts. Third, our oil and gas operations generate significant cash flow that has partially funded construction and/or modification of assets such as the Q4000, Intrepid and Eclipse, enabling us to add technical talent to support our expansion into the new Deepwater frontier. Finally, a major objective of our investments in oil and gas properties is to secure the associated marine construction work.

Within ERT we have assembled a team of personnel with experience in geology, geophysics, reservoir engineering, drilling, production engineering, facilities management, lease operations and petroleum land management. ERT generates income in three ways: lowering salvage costs by using our assets, operating the field more cost effectively and extending reservoir life through well exploitation operations. When a company sells an OCS property, they retain the financial responsibility for plugging and decommissioning if their purchaser becomes financially unable to do so. Thus, it becomes important that a property be sold to a purchaser who has the financial wherewithal to perform their contractual obligations. Although there is significant competition in this mature field market, ERT's reputation, supported by Cal Dive's financial strength, has made it the purchaser of choice of many major and independent oil and gas companies. In addition, ERT's reservoir engineering and geophysical expertise enabled us in 2000 to acquire in partnership with the operator, Kerr-McGee Oil & Gas Corp., a working interest in Gunnison, a Deepwater Gulf oil and natural gas exploration project, which began initial production in December 2003.

The Deepwater Gulf has seen a significant increase in oil and gas exploration, development and production due, in part, to new technologies that reduce operational costs and risks, the discovery of new, larger oil and gas reservoirs with high production potential, government deepwater incentives, and increasing demand and prices. Along with these larger fields are discoveries where the exploratory well has encountered smaller proven undeveloped reserves that are judged by the current owner to be too marginal to justify development. As an extension of ERT's well exploitation strategy, it is the Company's intent from time to time to participate in drilling of high probability of success wells which initially do not possess proven reserves, and thus would be considered exploratory wells. Depending upon the water depth, development of these fields may require state of the art equipment such as the Q4000, a more specialized asset such as the Intrepid for pipelay, or a combination of Cal Dive contracting assets.

The table below sets forth information, as of December 31, 2004, with respect to estimates of net proved reserves and the present value of estimated future net cash flows at such date, prepared in accordance with guidelines established by the Securities and Exchange Commission. The Company's estimates of reserves at December 31, 2004, have been audited by Huddleston & Co., Inc., independent petroleum engineers. All of the Company's reserves are located in the United States. Proved reserves cannot be measured exactly because the estimation of reserves involves numerous judgmental determinations. Accordingly, reserve estimates must be continually revised as a result of new information obtained from drilling and production history, new geological and geophysical data and changes in economic conditions.

	TOTAL PROVED
Estimated Proved Reserves:	
Natural gas (MMcf)...	53,204
Oil and condensate (MBbls).................................	10,517
Standardized measure of discounted future net cash flows (pre-tax)*..	$408,074,363

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* The standardized measure of discounted future net cash flows attributable to our reserves was prepared using constant prices as of the calculation date, discounted at 10% per annum. As of December 31, 2004, we owned an interest in 288 gross (252 net) oil wells and 145 gross (91 net) natural gas wells located in federal offshore waters in the Gulf of Mexico.

PRODUCTION FACILITIES

There are over 100 discoveries in the Deepwater Gulf yet to be brought into production. Many of these are smaller reservoirs that standing alone cannot justify the economics of a host production facility. As a result, we expect that the Deepwater Gulf will be developed in a hub and satellite field concept. We expect significant opportunities as this occurs. At the Marco Polo field, our 50% ownership in the production facility through Deepwater Gateway, L.L.C. will allow us to realize a return on investment consisting of both a fixed monthly demand charge and a volumetric tariff charge. In addition, we assisted with the installation of the TLP and will work to develop the surrounding acreage that can be tied back to the platform by our construction vessels. Our 20% interest in the Independence Hub platform, scheduled for installation in late 2006, should enable us to repeat the Marco Polo strategy. Through our 20% interest in the Gunnison field, we also own an interest in the Gunnison spar production facility.

CUSTOMERS

Our customers include major and independent oil and gas producers, pipeline transmission companies and offshore engineering and construction firms. The level of construction services required by any particular customer depends on the size of that customer's capital expenditure budget devoted to construction plans in a particular year. Consequently, customers that account for a significant portion of contract revenues in one fiscal year may represent an immaterial portion of contract revenues in subsequent fiscal years. The percent of consolidated revenue of major customers was as follows: 2004 -- Louis Dreyfus Energy Services (11%) and Shell Trading (US) Company (10%); 2003 -- Shell Trading (US) Company (10%) and Petrocom Energy Group Ltd. (10%); 2002 -- Horizon Offshore, Inc. (10%) and BP Trinidad & Tobago LLC (11%). Louis Dreyfus Energy Services, Shell Trading and Petrocom were purchasers of ERT's oil and gas production. We estimate in 2004 we provided subsea services to over 200 customers. Our projects are typically of short duration and are generally awarded shortly before mobilization. Accordingly, we believe backlog is not a meaningful indicator of future business results.

COMPETITION

The marine contracting industry is highly competitive. While price is a factor, the ability to acquire specialized vessels, attract and retain skilled personnel, and demonstrate a good safety record are also important. Our competitors on the OCS include Global Industries Ltd., Oceaneering International, Inc., Stolt Offshore S.A., Torch Offshore, Inc., and a number of smaller companies, some of which only operate a single vessel and often compete solely on price. For Deepwater projects, our principal competitors include Stolt Offshore S.A., Subsea 7, Technip-Coflexip and Torch.

ERT encounters significant competition for the acquisition of mature oil and gas properties. Our ability to acquire additional properties depends upon our ability to evaluate and select suitable properties and consummate transactions in a highly competitive environment. Competition includes TETRA Technologies, Inc. and Superior Energy Services, Inc. Many potential purchasers of oil and gas properties are well-established companies with substantially larger operating staffs and greater capital resources.

TRAINING, SAFETY AND QUALITY ASSURANCE

We have established a corporate culture in which safety is among the highest priorities. Our corporate goal, based on the belief that all accidents are preventable, is to provide an injury-free workplace by focusing on correct safety behavior. Our safety procedures and training programs were developed by management personnel who came into the industry as divers and who know first hand the physical challenges of the ocean work site. As a result, management believes that our safety programs are among the best in the industry. We have introduced a company-wide effort to enhance a behavioral safety process and training program that makes safety a constant focus of awareness through open communication with all offshore and yard employees. The process includes the documentation of all daily observations and the collection of this data. In addition, we initiated regular monthly visits by project managers to conduct "Hazard Hunts" on each vessel, providing a "safety audit" with a fresh perspective. Results from this program were evident as our safety performance improved significantly in 2003 and 2004.

GOVERNMENT REGULATION

Many aspects of the offshore marine construction industry are subject to extensive governmental regulations. We are subject to the jurisdiction of the U.S. Coast Guard, the U.S. Environmental Protection Agency, the MMS and the U.S. Customs Service, as well as private industry organizations such as the American Bureau of Shipping. In the North Sea, international regulations govern working hours and a specified working environment, as well as standards for diving procedures, equipment and diver health. These North Sea standards are some of the most stringent worldwide. In the absence of any specific regulation, our North Sea branch adheres to standards set by the International Marine Contractors Association and the International Maritime Organisation.

We support and voluntarily comply with standards of the Association of Diving Contractors International. The Coast Guard sets safety standards and is authorized to investigate vessel and diving accidents, and to recommend improved safety standards. The Coast Guard also is authorized to inspect vessels at will. We are required by various governmental and quasi-governmental agencies to obtain various permits, licenses and certificates with respect to our operations. We believe that we have obtained or can obtain all permits, licenses and certificates necessary for the conduct of our business.

In addition, we depend on the demand for our services from the oil and gas industry and, therefore, our business is affected by laws and regulations, as well as changing taxes and policies relating to the oil and gas industry generally. In particular, the development and operation of oil and gas properties located on the OCS of the United States is regulated primarily by the MMS.

The MMS requires lessees of OCS properties to post bonds or provide other adequate financial assurance in connection with the plugging and abandonment of wells located offshore and the removal of all production facilities. Operators on the OCS are currently required to post an area-wide bond of $3.0 million, or

$500,000 per producing lease. We have provided adequate financial assurance for our offshore leases as required by the MMS.

We acquire production rights to offshore mature oil and gas properties under federal oil and gas leases, which the MMS administers. These leases contain relatively standardized terms and require compliance with detailed MMS regulations and orders pursuant to the Outer Continental Shelf Lands Act, or OCSLA. These MMS directives are subject to change. The MMS has promulgated regulations requiring offshore production facilities located on the OCS to meet stringent engineering and construction specifications. The MMS also has issued regulations restricting the flaring or venting of natural gas and prohibiting the burning of liquid hydrocarbons without prior authorization. Similarly, the MMS has promulgated other regulations governing the plugging and abandonment of wells located offshore and the removal of all production facilities. Finally, under certain circumstances, the MMS may require any operations on federal leases to be suspended or terminated or may expel unsafe operators from existing OCS platforms and bar them from obtaining future leases. Suspension or termination of our operations or expulsion from operating on our leases and obtaining future leases could have a material adverse effect on our financial condition and results of operations.

Under OCSLA and the Federal Oil and Gas Royalty Management Act, MMS also administers oil and gas leases and establishes regulations that set the basis for royalties on oil and gas produced from the leases. The MMS's amendments to these regulations are subject to judicial review. In 2002, the D.C. Circuit reversed a 2000 district court decision and upheld a 1997 MMS gas valuation rule categorically denying allowances for post-production marketing costs such as long-term storage fees and marketer fees; however, the D.C. Circuit decision expressly allows firm demand charges to be deducted. Two trade associations had sought judicial review of the 1997 gas valuation rule and procured a favorable district court decision; however, the D.C. Circuit decision and denial of certorari by the Supreme Court ended the litigation in early 2003. In early 2005, the MMS is expected to publish a further revision to its gas valuation rule. The 2005 gas rule revision will clarify the deductibility of transportation costs and adopt the 2004 oil valuation rule's cost of capital approach described below. The revisions are not expected to reflect any major changes. We cannot predict what effect these changes will have on our operations but nothing significant is anticipated.

In 2004, the MMS further amended its royalty regulations governing the valuation of crude oil produced from federal leases. The MMS's 2000 oil valuation rule had replaced a set of valuation benchmarks based on posted prices and comparable sales with an indexing system based on spot prices at nearby market centers. Among other things, the 2000 oil valuation rule (like the 1997 gas valuation rule) also categorically disallowed deductions for post-production marketing costs. Two industry trade associations sought judicial review of the 2000 oil rule, but voluntarily dismissed their suit after late 2002 negotiations led the MMS to amend its oil valuation rule further in 2004. The amended rule retained indexing for valuation but replaced spot prices with NYMEX future prices, except in the Rocky Mountain Region and California. The 2004 oil valuation rule also liberalized allowances for non-arm's length transportation arrangements by increasing the multiplier used for calculating the cost of capital. While the 2000 oil valuation rule was likely to increase our royalty obligation somewhat, the 2004 oil valuation rule is likely to attenuate that increase.

Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated pursuant to the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978, or NGPA, and the regulations promulgated thereunder by the Federal Energy Regulatory Commission, or FERC. In the past, the federal government has regulated the prices at which oil and gas could be sold. While sales by producers of natural gas, and all sales of crude oil, condensate and natural gas liquids currently can be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead sales in the natural gas industry began with the enactment of the NGPA. In 1989, the Natural Gas Wellhead Decontrol Act was enacted. This act amended the NGPA to remove both price and non-price controls from natural gas sold in "first sales" no later than January 1, 1993.

Sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms for access to pipeline transportation remain subject to extensive federal and state regulation. Several major regulatory changes have been implemented by Congress and the FERC from 1985 to the present that affect the economics of natural gas production, transportation and sales. In addition, the FERC continues to promulgate revisions to various aspects of the rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to FERC jurisdiction. These initiatives may also affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry. The ultimate impact of the complex rules and regulations issued by the FERC since 1985 cannot be predicted.

We cannot predict what further action the FERC will take on these matters, but we do not believe any such action will materially affect us differently than other companies with which we compete.

Additional proposals and proceedings before various federal and state regulatory agencies and the courts could affect the oil and gas industry. We cannot predict when or whether any such proposals may become effective. In the past, the natural gas industry has been heavily regulated. There is no assurance that the regulatory approach currently pursued by the FERC will continue indefinitely. Notwithstanding the foregoing, we do not anticipate that compliance with existing federal, state and local laws, rules and regulations will have a material effect upon our capital expenditures, earnings or competitive position.

ENVIRONMENTAL REGULATION

Our operations are subject to a variety of national (including federal, state and local) and international 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 carry substantial administrative, civil and possibly criminal penalties 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, and such liability may be imposed on us even if the acts that resulted in the releases were in compliance with all applicable laws at the time such acts were performed. Some of the environmental laws and regulations that are applicable to our business operations are discussed in the following paragraphs, but the discussion does not cover all environmental laws and regulations that govern our operations.

The Oil Pollution Act of 1990, as amended, or OPA, imposes a variety of requirements on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in waters of the United States. A "Responsible Party" includes the owner or operator of an onshore facility, a vessel or a pipeline, and the lessee or permittee of the area in which an offshore facility is located. OPA imposes liability on each Responsible Party for oil spill removal costs and for other public and private damages from oil spills. Failure to comply with OPA may result in the assessment of civil and criminal penalties. OPA establishes liability limits of $350 million for onshore facilities, all removal costs plus $75 million for offshore facilities and the greater of $500,000 or $600 per gross ton for vessels other than tank vessels. The liability limits are not applicable, however, if the spill is caused by gross negligence or willful misconduct; if the spill results from violation of a federal safety, construction, or operating regulation; or if a party fails to report a spill or fails to cooperate fully in the cleanup. Few defenses exist to the liability imposed under OPA. Management is currently unaware of any oil spills for which we have been designated as a Responsible Party under OPA that will have a material adverse impact on us or our operations.

OPA also imposes ongoing requirements on a Responsible Party, including preparation of an oil spill contingency plan and maintaining proof of financial responsibility to cover a majority of the costs in a potential spill. We believe we have appropriate spill contingency plans in place. With respect to financial responsibility, OPA requires the Responsible Party for certain offshore facilities to demonstrate financial responsibility of not less than $35 million, with the financial responsibility requirement potentially increasing up to $150 million if the risk posed by the quantity or quality of oil that is explored for or produced indicates that a greater amount is required. The MMS has promulgated regulations implementing these financial responsibility requirements for covered offshore facilities. Under the MMS regulations, the amount of financial responsibility required for an offshore facility is increased above the minimum amounts if the "worst case" oil spill volume calculated for the facility exceeds certain limits established in the regulations. We believe that we currently have established adequate proof of financial responsibility for our onshore and offshore facilities and that we satisfy the MMS requirements for financial responsibility under OPA and applicable regulations.

OPA also requires owners and operators of vessels over 300 gross tons to provide the Coast Guard with evidence of financial responsibility to cover the cost of cleaning up oil spills from such vessels. We currently own and operate six vessels over 300 gross tons. Satisfactory evidence of financial responsibility has been provided to the Coast Guard for all of our vessels.

The Clean Water Act imposes strict controls on the discharge of pollutants into the navigable waters of the U.S. and imposes potential liability for the costs of remediating releases of petroleum and other substances. The controls and restrictions imposed under the Clean Water Act have become more stringent over time, and it is possible that additional restrictions will be imposed in the future. Permits must be obtained to discharge pollutants into state and federal waters. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the exploration for and production of oil and gas into certain coastal and offshore waters. The Clean Water Act provides for civil, criminal and administrative penalties for any unauthorized discharge of oil and other hazardous substances and imposes liability on responsible parties for the costs of cleaning up any environmental contamination caused by the release of a hazardous substance and for natural resource damages resulting from the release. Many states have laws that are analogous to the Clean Water Act and also require remediation of releases of petroleum and other hazardous substances in state waters. Our vessels routinely transport diesel fuel to offshore rigs and platforms and also carry diesel fuel for their own use. Our vessels transport bulk chemical materials used in drilling activities and also transport liquid mud which contains oil and oil by-products. Offshore facilities and vessels operated by us have facility and vessel response plans to deal with potential spills of oil or its derivatives. We believe that our operations comply in all material respects with the requirements of the Clean Water Act and state statutes enacted to control water pollution.

OCSLA provides the federal government with broad discretion in regulating the production of offshore resources of oil and gas, including authority to impose safety and environmental protection requirements applicable to lessees and permittees operating in the OCS. Specific design and operational standards may apply to OCS vessels, rigs, platforms, vehicles and structures. Violations of lease conditions or regulations issued pursuant to OCSLA can result in substantial civil and criminal penalties, as well as potential court injunctions curtailing operations and cancellation of leases. Because our operations rely on offshore oil and gas exploration and production, if the government were to exercise its authority under OCSLA to restrict the availability of offshore oil and gas leases, such action could have a material adverse effect on our financial condition and results of operations. As of this date, we believe we are not the subject of any civil or criminal enforcement actions under OCSLA.

The Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, contains provisions requiring the remediation of releases of hazardous substances into the environment and imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons including owners and operators of contaminated sites where the release occurred and those companies who transport, dispose of or who arrange for disposal of hazardous substances released at the sites. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. Third parties may also file claims for personal injury and property damage allegedly caused by the release of hazardous substances. Although we handle hazardous substances in the ordinary course of business, we are not aware of any hazardous substance contamination for which we may be liable.

We operate in foreign jurisdictions that have various types of governmental laws and regulations relating to the discharge of oil or hazardous substances and the protection of the environment. Pursuant to these laws and regulations, we could be held liable for remediation of some types of pollution, including the release of oil, hazardous substances and debris from production, refining or industrial facilities, as well as other assets we own or operate or which are owned or operated by either our customers or our sub-contractors.

Management believes that we are in compliance in all material respects with all applicable environmental laws and regulations to which we are subject. We do not anticipate that compliance with existing environmental laws and regulations will have a material effect upon our capital expenditures, earnings or competitive position. However, changes in the environmental laws and regulations, or claims for damages to persons, property, natural resources or the environment, could result in substantial costs and liabilities, and thus there can be no assurance that we will not incur significant environmental compliance costs in the future.

EMPLOYEES

We rely on the high quality of our workforce. As of December 31, 2004, we had approximately 900 employees, nearly 200 of which were salaried personnel. As of that date, we also utilized approximately 500 non-U.S. citizens to crew our foreign flag vessels under crewing contracts with C-MAR Services (UK), Ltd. of Aberdeen, Scotland and Well Ops PTE Limited. None of our employees belong to a union or are employed pursuant to any collective bargaining agreement or any similar arrangement. We believe our relationship with our employees and foreign crew members is good.

WEBSITE AND OTHER AVAILABLE INFORMATION

The Company maintains a website on the Internet with the address of www.caldive.com. Copies of this Annual Report on Form 10-K for the year ended December 31, 2004, and copies of the Company's Quarterly Reports on Form 10-Q for 2004 and 2005 and any Current Reports on Form 8-K for 2004 and 2005, and any amendments thereto, are or will be available free of charge at such website as soon as reasonably practicable after they are filed with, or furnished to, the SEC. Information contained on the Company's website is not part of this report.

The general public may read and copy any materials the Company files with the SEC at the SEC's Public Reference Room at 450 Fifth Street, N.W., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The Company is an electronic filer, and the SEC maintains an Internet website that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC, including the Company. The Internet address of the SEC's website is www.sec.gov.

FACTORS INFLUENCING FUTURE RESULTS AND ACCURACY OF FORWARD-LOOKING STATEMENTS

Shareholders should carefully consider the following risk factors in addition to the other information contained herein. This Annual Report on Form 10-K includes certain statements that may be deemed "forward-looking statements" within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. You can identify these statements by forward-looking words such as "anticipate," "believe," "budget," "could," "estimate," "expect," "forecast," "intend," "may," "plan," "potential," "should," "will" and "would" or similar words. You should read statements that contain these words carefully because they discuss our future expectations, contain projections of our future financial position or results of operations or state other forward-looking information. We believe that it is important to communicate our future expectations to our investors. However, there may be events in the future that we are not able to predict or control accurately. The factors listed below in this section, captioned "Factors Influencing Future Results and Accuracy of Forward-Looking Statements," as well as any cautionary language in this Annual Report, provide examples of risks, uncertainties and events that may cause our actual results to differ materially from the expectations we describe in our forward-looking statements. You should be aware that the occurrence of the events described in these risk factors and elsewhere in this Annual Report could have a material adverse effect on our business, results of operations and financial position.

OUR BUSINESS IS ADVERSELY AFFECTED BY LOW OIL AND GAS PRICES AND BY THE CYCLICALITY OF THE OIL AND GAS INDUSTRY.

Our business is substantially dependent upon the condition of the oil and gas industry and, in particular, the willingness of oil and gas companies to make capital expenditures for offshore exploration, drilling and production operations. The level of capital expenditures generally depends on the prevailing view of future oil and gas prices, which are influenced by numerous factors affecting the supply and demand for oil and gas, including, but not limited to:

- Worldwide economic activity,
- Economic and political conditions in the Middle East and other oil-producing regions,
- Coordination by the Organization of Petroleum Exporting Countries, or OPEC,
- The cost of exploring for and producing oil and gas,
- The sale and expiration dates of offshore leases in the United States and overseas,
- The discovery rate of new oil and gas reserves in offshore areas,
- Technological advances,
- Interest rates and the cost of capital,
- Environmental regulations, and
- Tax policies.

The level of offshore construction activity improved somewhat in 2004. We cannot assure you activity levels will remain the same or increase. A sustained period of low drilling and production activity or the return of lower commodity prices would likely have a material adverse effect on our financial position, cash flows and results of operations.

THE OPERATION OF MARINE VESSELS IS RISKY, AND WE DO NOT HAVE INSURANCE COVERAGE FOR ALL RISKS.

Marine construction involves a high degree of operational risk. Hazards, such as vessels sinking, grounding, colliding and sustaining damage from severe weather conditions, are inherent in marine operations. These hazards can cause personal injury or loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. Damage arising from such occurrences may result in lawsuits asserting large claims. We maintain such insurance protection as we deem prudent, including Jones Act employee coverage, which is the maritime equivalent of workers' compensation,

and hull insurance on our vessels. We cannot assure you that any such insurance will be sufficient or effective under all circumstances or against all hazards to which we may be subject. A successful claim for which we are not fully insured could have a material adverse effect on us. Moreover, we cannot assure you that we will be able to maintain adequate insurance in the future at rates that we consider reasonable. As a result of market conditions, premiums and deductibles for certain of our insurance policies have increased substantially and could escalate further. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. For example, insurance carriers are now requiring broad exclusions for losses due to war risk and terrorist acts. As construction activity expands into deeper water in the Gulf and other Deepwater basins of the world, a greater percentage of our revenues may be from Deepwater construction projects that are larger and more complex, and thus riskier, than shallow water projects. As a result, our revenues and profits are increasingly dependent on our larger vessels. The current insurance on our vessels, in some cases, is in amounts approximating book value, which could be less than replacement value. In the event of property loss due to a catastrophic marine disaster, mechanical failure or collision, insurance may not cover a substantial loss of revenues, increased costs and other liabilities, and could have a material adverse effect on our operating performance if we were to lose any of our large vessels.

OUR CONTRACTING BUSINESS DECLINES IN WINTER, AND BAD WEATHER IN THE GULF OR NORTH SEA CAN ADVERSELY AFFECT OUR OPERATIONS.

Marine operations conducted in the Gulf and North Sea are seasonal and depend, in part, on weather conditions. Historically, we have enjoyed our highest vessel utilization rates during the summer and fall when weather conditions are favorable for offshore exploration, development and construction activities. We typically have experienced our lowest utilization rates in the first quarter. As is common in the industry, we typically bear the risk of delays caused by some, but not all, adverse weather conditions. Accordingly, our results in any one quarter are not necessarily indicative of annual results or continuing trends.

IF WE BID TOO LOW ON A TURNKEY CONTRACT, WE SUFFER CONSEQUENCES.

A majority of our projects are performed on a qualified turnkey basis where described work is delivered for a fixed price and extra work, which is subject to customer approval, is billed separately. The revenue, cost and gross profit realized on a turnkey contract can vary from the estimated amount because of changes in offshore job conditions, variations in labor and equipment productivity from the original estimates, and the performance of others such as alliance partners. These variations and risks inherent in the marine construction industry may result in our experiencing reduced profitability or losses on projects.

ESTIMATES OF OUR OIL AND GAS RESERVES, FUTURE CASH FLOWS AND ABANDONMENT COSTS MAY BE SIGNIFICANTLY INCORRECT.

Our proved reserves at December 31, 2004, included the reserves assigned to our ownership position in the Gunnison project, a Deepwater Gulf of Mexico oil and gas field operated by Kerr-McGee Oil & Gas Corp. The Gunnison reserves constitute approximately 38% of our total proved reserves as of December 31, 2004. This Annual Report contains estimates of our proved oil and gas reserves and the estimated future net cash flows there from based upon reports for the year ended December 31, 2003 and 2004, audited by our independent petroleum engineers. These reports rely upon various assumptions, including assumptions required by the Securities and Exchange Commission, as to oil and gas prices, drilling and operating expenses, capital expenditures, abandonment costs, taxes and availability of funds. The process of estimating oil and gas reserves is complex, requiring significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. As a result, these estimates are inherently imprecise. Actual future production, cash flows, development expenditures, operating and abandonment expenses and quantities of recoverable oil and gas reserves may vary substantially from those estimated in these reports. Any significant variance in these assumptions could materially affect the estimated quantity and value of our proved reserves. You should not assume that the present value of future net cash flows from our proved reserves referred to in this Annual Report is the current market value of our estimated oil and gas reserves. In accordance with Securities and Exchange Commission requirements, we base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the net present value estimate. In addition, if costs of abandonment are materially greater than our estimates, they could have an adverse effect on financial position, cash flows and results of operations.

RESERVE REPLACEMENT MAY NOT OFFSET DEPLETION.

Oil and gas properties are depleting assets. We replace reserves through acquisitions and exploitation of current properties. If we are unable to acquire additional properties or if we are unable to find additional reserves through exploitation of our properties, our future cash flows from oil and gas operations could decrease.

OUR OIL AND GAS OPERATIONS INVOLVE SIGNIFICANT RISKS, AND WE DO NOT HAVE INSURANCE COVERAGE FOR ALL RISKS.

Our oil and gas operations are subject to risks incident to the operation of oil and gas wells, including, but not limited to, uncontrollable flows of oil, gas, brine or well fluids into the environment, blowouts, cratering, mechanical difficulties, fires, explosions, pollution and other risks, any of which could result in substantial losses to us. We maintain insurance against some, but not all, of the risks described above. Drilling for oil and gas involves numerous risks, including the risk that the Company will not encounter commercially productive oil or gas reservoirs. If certain exploration efforts are unsuccessful in establishing proved reserves and exploration activities cease, the amounts accumulated as unproved property costs would be charged against earnings as impairments.

WE MAY NOT BE ABLE TO COMPETE SUCCESSFULLY AGAINST CURRENT AND FUTURE COMPETITORS.

The business in which we operate is highly competitive. Several of our competitors are substantially larger and have greater financial and other resources than we have. If other companies relocate or acquire vessels for operations in the Gulf or the North Sea, levels of competition may increase and our business could be adversely affected.

THE LOSS OF THE SERVICES OF ONE OR MORE OF OUR KEY EMPLOYEES, OR OUR FAILURE TO ATTRACT AND RETAIN OTHER HIGHLY QUALIFIED PERSONNEL IN THE FUTURE, COULD DISRUPT OUR OPERATIONS AND ADVERSELY AFFECT OUR FINANCIAL RESULTS.

Our industry has lost a significant number of experienced subsea professionals over the years due to, among other reasons, the volatility in commodity prices. Our continued success depends on the active participation of our key employees. The loss of our key people could adversely affect our operations. We believe that our success and continued growth are also dependent upon our ability to attract and retain skilled personnel. We believe that our wage rates are competitive; however, unionization or a significant increase in the wages paid by other employers could result in a reduction in our workforce, increases in the wage rates we pay, or both. If either of these events occurs for any significant period of time, our revenues and profitability could be diminished and our growth potential could be impaired.

IF WE FAIL TO EFFECTIVELY MANAGE OUR GROWTH, OUR RESULTS OF OPERATIONS COULD BE HARMED.

We have a history of growing through acquisitions of large assets and acquisitions of companies. We must plan and manage our acquisitions effectively to achieve revenue growth and maintain profitability in our evolving market. If we fail to effectively manage current and future acquisitions, our results of operations could be adversely affected. Our growth has placed, and is expected to continue to place, significant demands on our personnel, management and other resources. We must continue to improve our operational, financial, management and legal/compliance information systems to keep pace with the growth of our business.

WE MAY NEED TO CHANGE THE MANNER IN WHICH WE CONDUCT OUR BUSINESS IN RESPONSE TO CHANGES IN GOVERNMENT REGULATIONS.

Our subsea construction, intervention, inspection, maintenance and decommissioning operations and our oil and gas production from offshore properties, including decommissioning of such properties, are subject to and affected by various types of government regulation, including numerous federal, state and local environmental protection laws and regulations. These laws and regulations are becoming increasingly complex, stringent and expensive to comply with, and significant fines and penalties may be imposed for noncompliance. We cannot assure you that continued compliance with existing or future laws or regulations will not adversely affect our operations.

CERTAIN PROVISIONS OF OUR CORPORATE DOCUMENTS AND MINNESOTA LAW MAY DISCOURAGE A THIRD PARTY FROM MAKING A TAKEOVER PROPOSAL.

In addition to the 55,000 shares of preferred stock issued to Fletcher International, Ltd. under the First Amended and Restated Agreement dated January 17, 2003, but effective as of December 31, 2002, by and between Cal Dive and Fletcher International, Ltd., our board of directors has the authority, without any action by our shareholders, to fix the rights and preferences on up to 4,945,000 shares of undesignated preferred stock, including dividend, liquidation and voting rights. In addition, our by-laws divide the board of directors into three classes. We are also subject to certain anti-takeover provisions of the Minnesota Business Corporation Act. We also have employment contracts with all of our senior officers that require cash payments in the event of a "change of control." Any or all of the provisions or factors described above may have the effect of discouraging a takeover proposal or tender offer not approved by management and the board of directors and could result in shareholders who may wish to participate in such a proposal or tender offer receiving less for their shares than otherwise might be available in the event of a takeover attempt.

ITEM 2. PROPERTIES

OUR VESSELS

We own a fleet of 21 vessels and 26 ROVs and trenchers. We also lease one vessel. We believe that the Gulf market requires specially designed and/or equipped vessels to competitively deliver subsea construction services. Nine of our vessels have DP capabilities specifically designed to respond to the Deepwater market requirements. Eight of our vessels (six of which are based in the Gulf) have the capability to provide saturation diving services. Recent developments in our fleet include:

Q4000: We began construction of our newest Ultra-Deepwater MSV, the Q4000in 1999, and accepted her delivery in early 2002. The vessel cost approximately $170 million and incorporates our latest semi-submersible technologies, including various patented elements such as the absence of lower hull cross bracing. A variable deck load of over 4,000 metric tons and upgraded well completions capability make the vessel particularly well suited for large offshore well intervention or construction projects in the Ultra-Deepwater. Its Huisman-Itrec multi-purpose tower has an open face which allows free access from three sides, an advantage for a construction and intervention vessel.

Intrepid: The Intrepid offers customers a pipelay/construction vessel capable of carrying an 8,000 metric ton deck load. She began work in June of 2002.

Eclipse: This large DP DSV is 370 feet long, 67 feet wide, and includes a saturation diving system and DP-2. The Eclipse began work in March 2002.

Merlin: Vessel is held for sale at December 31, 2004.

Cal Dive Barge I: Vessel expected to be retired in 2005.

Seawell: This purpose-build 364 foot mono-hull DP vessel, capable of supporting both manned diving and ROVs, was recently upgraded for coiled tubing deployment and well testing. The Seawell was purchased in July 2002.

ROVs: Canyon currently operates 21 ROVs and five trencher systems. In 2004, Canyon took delivery of an Olympian T1 trencher that is currently being upgraded to a "T600" Trencher.

LISTING OF VESSELS, BARGE AND ROVS

DATE MOONPOOL FOUR CAL DIVE CLEAR DECK DECK LAUNCH/ POINT CRANE PLACED IN LENGTH SPACE LOAD SAT ANCHOR CAPACITY SERVICE (FEET) (SQ. FEET) (TONS) BERTHS DIVING MOORED (TONS) CLASSIFICATION(1) --------- ------ ---------- ------ ------ -------- ------ ---- ---------- --------- -------- DP MSVS: Uncle John........... 11/96 254 11,834 460 102 X -- 2X100 DNV FLOWLINE LAY: Intrepid............. 8/97 381 17,728 4,000 50 -- -- 400 ABS WELL OPERATIONS: Seawell.............. 7/02 368 9,688 700 129 X -- 130 DNV Q4000................ 4/02 312 26,400 4,000 135 X -- 160 and 360 ABS Derrick - 600 DP DSVS: Eclipse.............. 3/02 367 8,611 2,436 109 X -- Forward - 5 DNV Mid - 4.3 Aft - 92/43 A-Frame 20.4 T Witch Queen.......... 11/95 278 5,600 500 60 X -- 50 DNV Mystic Viking........ 6/01 253 5,600 1,340 60 X -- 50 DNV DP ROV SUPPORT Vessels: Merlin (2)........... 12/97 198 2,900 268 32 -- -- A-Frame ABS Crane - 5 Northern Canyon(3)... 6/02 276 9,677 2,400 58 - - -- 50 DNV DSVS: Cal Diver I.......... 7/84 196 2,400 220 40 X X 30 ABS Cal Diver II......... 6/85 166 2,816 300 32 X X A-Frame ABS Cal Diver V.......... 9/91 168 2,324 490 34 -- X A-Frame ABS Cal Diver IV......... 3/01 120 1,440 60 24 -- -- -- ABS Mr. Fred............. 3/00 167 2,465 500 36 -- X 25 USCG Mr. Sonny(4)......... 3/01 175 3,480 409 28 -- X 35 ABS UTILITY VESSELS: Mr. Jim.............. 2/98 110 1,210 64 19

-- -- -- USCG Mr.
Jack.............
1/98 120 1,220 66 22
-- -- -- USCG Polo
Pony............
3/01 110 1,240 69 25
-- -- -- USCG
Sterling
Pony........ 3/01
110 1,240 64 25 -- -
- -- USCG White
Pony........... 3/01
116 1,230 64 25 -- -
- -- USCG OTHER: Cal
Dive Barge 1(5)..
8/90 150 N/A 200 30
-- X 200 ABS
Talisman.............
11/00 195 3,000 675
14 -- -- -- ABS 26
ROVs and
Trenchers(6).......
Various -- -- -- --
-- -- -- --

- ---------------

(1) Under government regulations and our insurance policies, we are required to maintain our vessels in accordance with standards of seaworthiness and safety set by government regulations and classification organizations. We maintain our fleet to the standards for seaworthiness, safety and health set by the American Bureau of Shipping, or ABS, Det Norske Veritas, or DNV, and the U.S. Coast Guard, or USCG. The ABS is one of several classification societies used by ship owners to certify that their vessels meet certain structural, mechanical and safety equipment standards, including Lloyd's Register, Bureau Veritas and DNV among others.

(2) Held for sale at December 31, 2004.

(3) Leased.

(4) Cold stacked.

(5) Expected to be retired in 2005.

(6) Average age of ROV fleet is approximately 4.25 years.

We incur routine drydock inspection, maintenance and repair costs pursuant to Coast Guard regulations and in order to maintain ABS or DNV classification for our vessels. In addition to complying with these requirements, we have our own vessel maintenance program that we believe permits us to continue to provide our customers with well maintained, reliable vessels. In the normal course of business, we charter other vessels on a short-term basis, such as tugboats, cargo barges, utility boats and dive support vessels. The Q4000 is subject to liens to secure the MARAD financing guarantees.

SUMMARY OF NATURAL GAS AND OIL RESERVE DATA

The table below sets forth information, as of December 31, 2004, with respect to estimates of net proved reserves and the present value of estimated future net cash flows at such date, prepared in accordance with guidelines established by the Securities and Exchange Commission. The Company's estimates of reserves at December 31, 2004, have been audited by Huddleston & Co., Inc., independent petroleum engineers. All of the Company's reserves are located in the United States. Proved reserves cannot be measured exactly because the estimation of reserves involves numerous judgmental determinations. Accordingly, reserve estimates must be continually revised as a result of new information obtained from drilling and production history, new geological and geophysical data and changes in economic conditions.

	TOTAL PROVED
Estimated Proved Reserves:	
Natural gas (MMcf)...	53,204
Oil and condensate (MBbls)................................	10,517
Standardized measure of discounted future net cash flows (pre-tax)..	$408,074,363

- ---------------

- - The standardized measure of discounted future net cash flows attributable to our reserves was prepared using constant prices as of the calculation date, discounted at 10% per annum. As of December 31, 2004, we owned an interest in 288 gross (252 net) oil wells and 145 gross (91 net) natural gas wells located in federal and state offshore waters in the Gulf of Mexico.

PRODUCTION FACILITIES

At Gunnison, we own a 20% interest in the Gunnison truss spar facility, together with the operator Kerr-McGee Oil & Gas Corporation, who owns a 50% interest, and Nexen, Inc., who owns the remaining 30% interest. The Gunnison spar, which is moored in 3,150 feet of water and located on Garden Banks Block 668, has daily production capacity of 40,000 barrels of oil and 200 MMCF of gas. This facility is designed with excess capacity to accommodate production from satellite prospects in the area.

Through our interest Deepwater Gateway, L.L.C., a 50/50 venture between us and Enterprise Products Partners L.P., we own a 50% interest in the Marco Polo TLP, which was installed on Green Canyon Block 608 in 4,300 feet of water. Deepwater Gateway, L.L.C. was formed to construct, install and own the Marco Polo TLP in order to process production from Anadarko Petroleum Corporation's Marco Polo field discovery at Green Canyon Block 608. Anadarko required 50,000 barrels of oil per day and 150 million feet per day of processing capacity for Marco Polo. The Marco Polo TLP was designed to process 120,000 barrels of oil per day and 300 million cubic feet per day and payload with space for up to six subsea tie backs.

We also own a 20% interest in Independence Hub, LLC, an affiliate of Enterprise Products Partners L.P., that will own the "Independence Hub" platform, a 105 foot deep draft, semi-submersible platform to be located in Mississippi Canyon block 920 in a water depth of 8,000 feet that will serve as a regional hub for natural gas production from multiple ultra-deepwater fields in the previously untapped eastern Gulf of Mexico. Installation of the platform is scheduled for late 2006 and first production is expected in 2007.

FACILITIES

Our corporate headquarters are located at 400 N. Sam Houston Parkway E., Suite 400, Houston, Texas. Our primary subsea and marine services operations are based in Morgan City, Louisiana. We own the Aberdeen, Scotland facility. All of our other facilities are leased.

PROPERTIES AND FACILITIES SUMMARY

FUNCTION SIZE
-------- ----
Houston,
Texas Cal
Dive
International,
Inc. (CDI)
60,000 square
feet
Corporate
Headquarters,
Project
Management,
and Sales
Office;
Energy
Resource
Technology,
Inc.; and
Well Ops Inc.
Canyon
Offshore,
Inc. (Canyon)
15,000 square
feet
Corporate
Headquarters,
Management
and Sales
Office
Aberdeen,
Scotland Cal
Dive
International
Ltd.
Operations
3.9 acres
(42,463
Canyon Sales
Office square
feet --
office)
Singapore
Canyon
Operations
10,000 square
feet Morgan
City,
Louisiana CDI
Operations
28.5 acres
CDI Warehouse
30,000 square
feet CDI
Offices 4,500
square feet
Lafayette,
Louisiana CDI
Operations 8
acres CDI
Warehouse
12,000 square
feet CDI
Offices 5,500

square feet
New Orleans, Louisiana CDI Sales Office 2,724 square feet

ITEM 3. LEGAL PROCEEDINGS

INSURANCE AND LITIGATION

Our operations are subject to the inherent risks of offshore marine activity, including accidents resulting in personal injury and the loss of life or property, environmental mishaps, mechanical failures, fires and collisions. We insure against these risks at levels consistent with industry standards. We also carry workers' compensation, maritime employer's liability, general liability and other insurance customary in our business. All insurance is carried at levels of coverage and deductibles we consider financially prudent. Our services are provided in hazardous environments where accidents involving catastrophic damage or loss of life could occur, and litigation arising from such an event may result in our being named a defendant in lawsuits asserting large claims. To date, we have been involved in only one such claim, where the cost of our vessel, the Balmoral Sea, was fully covered by insurance. Although there can be no assurance the amount of insurance we carry is sufficient to protect us fully in all events, or that such insurance will continue to be available at current levels of cost or coverage, we believe that our insurance protection is adequate for our business operations. A successful liability claim for which we are underinsured or uninsured could have a material adverse effect on our business.

We are involved in various legal proceedings, primarily involving claims for personal injury under the General Maritime Laws of the United States and the Jones Act as a result of alleged negligence. In addition, we from time to time incur other claims, such as contract disputes, in the normal course of business. In that regard, in 1998, one of our subsidiaries entered into a subcontract with Seacore Marine Contractors Limited ("Seacore") to provide a vessel to a Coflexip subsidiary in Canada ("Coflexip"). Due to difficulties with respect to the sea states and soil conditions the contract was terminated and an arbitration to recover damages was commenced. A preliminary liability finding has been made by the arbitrator against Seacore and in favor of the Coflexip subsidiary. We were not a party to this arbitration proceeding. Seacore and Coflexip settled this matter prior to the conclusion of the arbitration proceeding with Seacore paying Coflexip $6.95 million CDN. Seacore has initiated an arbitration proceeding against Cal Dive Offshore Ltd. ("CDO"), a subsidiary of Cal Dive, seeking contribution of one-half of this amount. Because only one of the grounds in the preliminary findings by the arbitrator is applicable to CDO, and because CDO holds substantial counterclaims against Seacore, it is anticipated our subsidiary's exposure, if any, should be less than $500,000.

During 2002, we engaged in a large construction project and in late September of that year, supports engineered by a subcontractor failed resulting in over a month of downtime for two of CDI's vessels. Management believes under the terms of the contract, we are entitled to indemnification for the contractual stand-by rate for the vessels during their downtime (the indemnification claim). The customer has disputed these invoices along with certain other change orders. Of the amounts billed by us for this project, approximately $6.8 million had not been collected as of December 31, 2004. This matter settled in March 2005 with no material effect on the Company's financial position or results of operations.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.

None.

EXECUTIVE OFFICERS OF THE COMPANY

The executive officers of Cal Dive are as follows:

NAME	AGE	POSITION
Owen Kratz	50	Chairman and Chief Executive Officer and Director
Martin R. Ferron	48	President and Chief Operating Officer and Director
James Lewis Connor, III	47	Senior Vice President, General Counsel and Corporate Secretary
A. Wade Pursell	40	Senior Vice President, Chief Financial Officer and Treasurer
Lloyd A. Hajdik	39	Vice President -- Corporate Controller and Chief Accounting Officer

Owen Kratz is Chairman and Chief Executive Officer of Cal Dive International, Inc. He was appointed Chairman in May 1998 and has served as our Chief Executive Officer since April 1997. Mr. Kratz served as President from 1993 until February 1999, and as a Director since 1990. He served as Chief Operating Officer from 1990 through 1997. Mr. Kratz joined Cal Dive in 1984 and has held various offshore positions, including saturation diving supervisor, and has had management responsibility for client relations, marketing and estimating. Mr. Kratz has a Bachelor of Science degree in Biology and Chemistry from State University of New York.

Martin R. Ferron has served on our Board of Directors since September 1998. Mr. Ferron became President in February 1999 and has served as Chief Operating Officer since January 1998. Mr. Ferron has 25 years of experience in the oilfield industry, including seven in senior management positions with the international operations of McDermott and Oceaneering. Mr. Ferron has a civil engineering degree, a master's degree in marine technology, an MBA and is a chartered civil engineer.

James Lewis Connor, III became Senior Vice President and General Counsel of Cal Dive in May 2002 and Corporate Secretary in July 2002. He had previously served as Deputy General Counsel since May 2000. Mr. Connor has been involved with the oil and gas industry for over 20 years, including nearly 14 years in his

capacity as legal counsel to both companies and individuals. Prior to joining Cal Dive, Mr. Connor was a Senior Counsel at El Paso Production Company (formerly Sonat Exploration Company) from 1997 to 2000 and previously from 1995 to 1997 was a senior associate in the oil, gas and energy law section of Hutcheson & Grundy, L.L.P. Mr. Connor received his Bachelor of Science degree from Texas A&M University in 1979 and his law degree, with honors, from the University of Houston in 1991.

A. Wade Pursell is Senior Vice President and Chief Financial Officer of Cal Dive International, Inc. In this capacity, which he was appointed to in October 2000, Mr. Pursell oversees the finance, treasury, accounting, tax, administration and corporate planning functions. He joined Cal Dive in May 1997, as Vice President -- Finance and Chief Accounting Officer. From 1988 through 1997 he was with Arthur Andersen LLP, lastly as an Experienced Manager specializing in the offshore services industry (which included servicing the Cal Dive account from 1990 to 1997). Mr. Pursell received an undergraduate degree (BS) from the University of Central Arkansas and is a Certified Public Accountant.

Lloyd A. Hajdik joined the Company in December 2003 as Vice President -- Corporate Controller. From January 2002 to November 2003 he was Assistant Corporate Controller for Houston-based NL Industries, Inc. Prior to NL, Mr. Hajdik served as Senior Manager of SEC Reporting and Accounting Services for Compaq Computer Corporation from 2000 to 2002, and as Controller for Halliburton's Baroid Drilling Fluids and Zonal Isolation product service lines from 1997 to 2000. Mr. Hajdik served as Controller for Engineering Services for Cliffs Drilling Company from 1995 to 1997 and was with Ernst & Young in the audit practice from 1989 to 1995. Mr. Hajdik graduated from Texas State University -- San Marcos (formerly Southwest Texas State University) receiving a Bachelor of Business Administration degree. Mr. Hajdik is a Certified Public Accountant and a member of the Texas Society of CPAs as well as the American Institute of Certified Public Accountants.

PART II

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY, AND RELATED SHAREHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is traded on the Nasdaq National Market under the symbol "CDIS." The following table sets forth, for the periods indicated, the high and low closing sale prices per share of our common stock:

COMMON STOCK PRICE	HIGH	LOW
Calendar Year 2003		
First quarter...	$24.46	$16.99
Second quarter..	$23.19	$15.95
Third quarter...	$22.74	$19.31
Fourth quarter..	$25.24	$19.88
Calendar Year 2004		
First quarter...	$28.00	$22.74
Second quarter..	$31.24	$25.01
Third quarter...	$36.27	$27.91
Fourth quarter..	$43.71	$33.89
Calendar Year 2005		
First quarter (through March 9, 2005)....................	$52.28	$38.22

On March 9, 2005, the closing sale price of our common stock on the Nasdaq National Market was $48.80 per share. As of March 9, 2005, there were an estimated 41 registered shareholders (approximately 4,700 beneficial owners) of our common stock.

We have never declared or paid cash dividends on our common stock and do not intend to pay cash dividends in the foreseeable future. We currently intend to retain earnings, if any, for the future operation and growth of our business. In addition, our financing arrangements prohibit the payment of cash dividends on our common stock. See "Management's Discussion and Analysis of Financial Condition and Results of Operations -- Liquidity and Capital Resources."

ITEM 6. SELECTED FINANCIAL DATA

The financial data presented below for each of the five years ended December 31, 2004, should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations and the Consolidated Financial Statements and Notes to Consolidated Financial Statements included elsewhere in this Form 10-K (in thousands, except per share amounts).

	2004	2003	2002	2001	2000
Net Revenues	$ 543,392	$396,269	$302,705	$227,141	$181,014
Gross Profit	171,912	92,083	53,792	66,911	55,369
Equity in Earnings (Losses) of Production Facilities Investments	7,927	(87)	--	--	--
Net Income Before Change in Accounting Principle	82,659	33,678	12,377	28,932	23,326
Cumulative Effect of Change in Accounting Principle, net	--	530	--	--	--
Net Income	82,659	34,208	12,377	28,932	23,326
Preferred Stock Dividends and Accretion	2,743	1,437	--	--	--
Net Income Applicable to Common Shareholders	79,916	32,771	12,377	28,932	23,326
Earnings per Common Share					
Basic:					
Earnings Per Share Before Change in Accounting Principle	2.09	0.86	0.35	0.89	0.74
Cumulative Effect of Change in Accounting Principle	--	0.01	--	--	--
Earnings Per Share	2.09	0.87	0.35	0.89	0.74
Diluted:					
Net Income Before Change in Accounting Principle	2.06	0.86	0.35	0.88	0.72
Cumulative Effect of Change in Accounting Principle	--	0.01	--	--	--
Earnings Per Share	2.06	0.87	0.35	0.88	0.72
Total Assets	1,038,758	882,842	840,010	494,296	347,488
Long-Term Debt	138,947	206,632	223,576	98,048	40,054
Convertible Preferred Stock(1)	55,000	24,538	--	--	--
Shareholders' Equity	485,292	381,141	337,517	226,349	194,725

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(1) See discussion at Item 7. Liquidity and Capital Resources -- Financing Activities.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

BUSINESS OVERVIEW

Oil and gas prices, the offshore mobile rig count, and Deepwater construction activity are three of the primary indicators we use to forecast the future performance of our Marine Contracting business. Our construction services generally follow successful drilling activities by six to eighteen months on the OCS and twelve months or longer in the Deepwater arena. The level of drilling activity is related to both short- and long-term trends in oil and gas prices. Oil and natural gas prices have been at robust levels for the last two years and offshore drilling activity has increased, but only recently in the Gulf of Mexico. Our primary leading indicator, the number of offshore mobile rigs contracted, is currently at approximately 131 rigs employed in the Gulf of Mexico, slightly higher than year ago levels of 115 and compared to 182 during the first quarter of 2001. The Deepwater Gulf is principally being developed for oil, with the complexity of developing these reservoirs resulting in significant lead times to first production. In the North Sea, the rig count is currently at 59 rigs employed, which compared to 48 during the first quarter of 2004.

Our business is substantially dependent upon the condition of the oil and gas industry and, in particular, the willingness of oil and gas companies to make capital expenditures for offshore exploration, drilling and production operations. The level of capital expenditures generally depends on the prevailing view of future oil and gas prices, which are influenced by numerous factors affecting the supply and demand for oil and gas, including, but not limited to:

- Worldwide economic activity,

- Economic and political conditions in the Middle East and other oil-producing regions,

- Coordination by the Organization of Petroleum Exporting Countries, or OPEC,

- The cost of exploring for and producing oil and gas,

- The sale and expiration dates of offshore leases in the United States and overseas,

- The discovery rate of new oil and gas reserves in offshore areas,

- Technological advances,

- Interest rates and the cost of capital,

- Environmental regulations, and

- Tax policies.

The level of offshore construction activity has increased only modestly despite higher commodity prices in 2003 and 2004. We cannot assure you that activity levels will continue to increase. A sustained period of low drilling and production activity or the return of lower commodity prices would likely have a material adverse effect on our financial position and results of operations.

Product prices impact our oil and gas operations in several respects. Historically, we sought to acquire producing oil and gas properties that were generally in the later stages of their economic life. The sellers' potential abandonment liabilities are a significant consideration with respect to the offshore properties we have purchased to date. Although higher natural gas prices tend to reduce the number of mature properties available for sale, these higher prices typically contribute to improved operating results for ERT. In contrast, lower natural gas prices typically contribute to lower operating results for ERT and a general increase in the number of mature properties available for sale. In 2000, we expanded the scope of our gas and oil operations by taking a working interest in Gunnison, a Deepwater Gulf development of Kerr-McGee Oil & Gas Corp. In 2004, ERT continued to successfully pursue its strategy of acquiring (or partnering in) and developing proved undeveloped, or high probability of success reserves, i.e., leases where reserves were judged by the current owner to be too marginal to justify development or they were seeking a partner. Each of ERT's oil and gas investments is designed to secure utilization of CDI construction vessels.

In our Production Facilities segment we participate in the ownership of production facilities in hub locations where there is potential for significant subsea tieback activity. We have a 50% interest in the TLP at Marco Polo, which began production in the second quarter of 2004, and a 20% interest in the Independence Hub semi-submersible which should be online in early 2007. See further discussion on the Independence Hub under Liquidity and Capital Resources -- Investing Activities.

Gunnison reserves constitute approximately 38% of our total proved reserves as of December 31, 2004. This Annual Report contains estimates of our proved oil and gas reserves based upon reports audited by our independent petroleum engineers. The process of estimating oil and gas reserves is complex, requiring significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. As a result, these estimates are inherently imprecise. Actual future production, cash flows, development expenditures, operating and abandonment expenses and quantities of recoverable oil and gas reserves may vary substantially from those estimated in these reports. Any significant variance in these assumptions could materially affect the estimated quantity and value of our proved reserves. Further, costs incurred relating to unsuccessful exploratory wells are expensed in the period the drilling is determined to be unsuccessful. As an extension of ERT's well exploitation and PUD strategies, ERT agreed to participate in the drilling of an exploratory well to be drilled in 2005 that targets reserves in deeper sands, within the same trapping fault system, of a currently producing well with estimated drilling costs of approximately $20 million, of which $1.1 million of equipment costs had been incurred through December 31, 2004. If the drilling is successful, ERT's share of the development cost is estimated to be an additional $15 million. Our Marine Contracting assets would participate in this development.

Regarding marine contracting, vessel utilization is historically lower during the first quarter due to winter weather conditions in the Gulf and the North Sea. Accordingly, we normally plan our drydock inspections and other routine and preventive maintenance programs during this period. During the first quarter, a substantial number of our customers finalize capital budgets and solicit bids for construction projects. The bid and award process during the first two quarters typically leads to the commencement of construction activities during the second and third quarters. As a result, we have historically generated up to 65% of our marine contracting revenues in the last six months of the year. Our operations can also be severely impacted by weather during the fourth quarter. Operation of oil and gas properties and production facilities tends to offset the impact of weather since the first and fourth quarters are typically periods of high demand and strong prices for natural gas. Due to this seasonality, full year results are not likely to be a direct multiple of any particular quarter or combination of quarters.

The following table sets forth for the periods presented average U.S. natural gas prices, our equivalent natural gas production, the average number of offshore rigs under contract in the Gulf, the number of platforms installed and removed in the Gulf and the vessel utilization rates for each of the major categories of our fleet.

	2004				2003				2002			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
U.S. natural gas prices(1)................	$ 5.61	$ 6.08	$5.44	$6.26	$6.25	$5.61	$4.87	$5.06	$2.54	$3.36	$3.20	$4.29
ERT oil and gas production (MMcfe)..................	10,020	10,043	9,959	9,792	6,780	6,722	7,175	7,241	2,910	3,487	3,967	6,230
Rigs under contract in the Gulf(2)..................	115	116	118	123	119	126	128	122	122	125	131	128
Rigs under contract in N. Sea(3)...................	48	49	56	57	51	58	54	53	55	68	65	58
Platform installations(4)...	26	28	26	10	7	21	12	13	14	19	14	11
Platform removals(4)........	23	47	67	22	3	11	34	18	11	37	26	4
Our average vessel utilization rate:(5)												
Shelf.....................	32%	48%	52%	68%	51%	49%	61%	43%	55%	68%	56%	72%
Deepwater.................												

70% 57% 52% 64% 79% 78%
79% 74% 85% 79% 75% 89%
Well
Operations........... 82%
73% 73% 92% 51% 90% 81%
89% NA 91% 69% 60%
ROVs......................
49% 46% 45% 61% 50% 54%
53% 47% 47% 51% 63% 50%

- ---------------

(1) Henry Hub Gas Daily Average (the midpoint index price per Mmbtu for deliveries into a specific pipeline for the applicable calendar day as reported by Platts Gas Daily in the "Daily Price Survey" table).

(2) Average monthly number of rigs contracted, as reported by Offshore Data Services.

(3) Derived from information obtained from Platts U.K. and the Baker-Hughes International Rotary Rig Count for Q1 2002.

(4) Source: Minerals Management Service (2004 and 2003) and Offshore Data Services (2002); installation and removal of platforms with two or more piles in the Gulf.

(5) Average vessel utilization rate is calculated by dividing the total number of days the vessels in this category generated revenues by the total number of days in each quarter.

CRITICAL ACCOUNTING POLICIES

Our results of operations and financial condition, as reflected in the accompanying financial statements and related footnotes, are subject to management's evaluation and interpretation of business conditions, changing capital market conditions and other factors which could affect the ongoing viability of our business segments and/or our customers. We believe the most critical accounting policies in this regard are those described below. While these issues require us to make judgments that are somewhat subjective, they are generally based on a significant amount of historical data and current market data.

ACCOUNTING FOR OIL AND GAS PROPERTIES

ERT acquisitions of producing offshore properties are recorded at the fair value exchanged at closing together with an estimate of its proportionate share of the decommissioning liability assumed in the purchase based upon its working interest ownership percentage. In estimating the decommissioning liability assumed in offshore property acquisitions, we perform detailed estimating procedures, including engineering studies and then reflect the liability at fair value on a discounted basis as discussed below. We follow the successful efforts method of accounting for our interests in oil and gas properties. Under the successful efforts method, the costs of successful wells and leases containing productive reserves are capitalized. Costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized. Costs incurred relating to unsuccessful exploratory wells are expensed in the period the drilling is determined to be unsuccessful.

GOODWILL

The Company tests for the impairment of goodwill on at least an annual basis. The Company's goodwill impairment test involves a comparison of the fair value of each of the Company's reporting units with its carrying amount. The fair value is determined using discounted cash flows and other market-related valuation models, such as earnings multiples and comparable asset market values. Prior to 2002 goodwill was amortized on a straight line basis over 25 years. In 2002 the Company discontinued the amortization of goodwill. The Company completed its annual goodwill impairment test as of November 1, 2004. The Company's goodwill impairment test involves a comparison of the fair value of each of the Company's reporting units with its carrying amount. All of the Company's goodwill as of December 31, 2004 and 2003 related to its Marine Contracting segment. None of the Company's goodwill was impaired based on the impairment test performed as of November 1, 2004. The Company will continue to test its goodwill annually on a consistent measurement date unless events occur or circumstances change between annual tests that would more likely than not reduce the fair value of a reporting unit below its carrying amount.

PROPERTY AND EQUIPMENT

Property and equipment, both owned and under capital leases, are recorded at cost. Depreciation is provided primarily on the straight-line method over the estimated useful lives of the assets described in footnote 2 to the Consolidated Financial Statements included herein.

For long-lived assets to be held and used, excluding goodwill, the Company bases its evaluation of recoverability on impairment indicators such as the nature of the assets, the future economic benefit of the assets, any historical or future profitability measurements and other external market conditions or factors that may be present. If such impairment indicators are present or other factors exist that indicate that the carrying amount of the asset may not be recoverable, the Company determines whether an impairment has occurred through the use of an undiscounted cash flows analysis of the asset at the lowest level for which identifiable cash flows exist. The Company's marine vessels are assessed on a vessel by vessel basis, while the Company's ROVs are grouped and assessed by asset class. If an impairment has occurred, the Company recognizes a loss for the difference between the carrying amount and the fair value of the asset. The fair value of the asset is measured using quoted market prices or, in the absence of quoted market prices, is based on management's estimate of discounted cash flows. The Company recorded an impairment charge of $1.9 million (included in Marine Contracting cost of sales in the accompanying consolidated statement of operations) in December 2004 on certain Marine Contracting vessels that met the impairment criteria. Assets are classified as held for sale when the Company has a plan for disposal of certain assets and those assets meet the held for sale criteria. During the fourth quarter of 2004, the Company classified a certain Marine Contracting vessel and other property and equipment intended to be disposed of within a twelve month period as assets held for sale totaling $5.0 million (included in other current assets in the accompanying consolidated balance sheet at December 31, 2004). The Company recorded an impairment charge of $2.0 million (included in Marine Contracting cost of sales), representing the amount by which their carrying value exceeds estimated fair value less cost to sell.

The Company evaluates the impairment of its oil and gas properties on a field-by-field basis whenever events or changes in circumstances indicate, but at least annually, an asset's carrying amount may not be recoverable. Unamortized capital costs are reduced to fair value (based upon discounted cash flows) if the expected undiscounted future cash flows are less than the asset's net book value. Cash flows are determined based upon proved reserves using prices and costs consistent with those used for internal decision making. Although prices used are likely to approximate market, they do not necessarily represent current market prices. Proved oil and gas reserve quantities are based on estimates prepared by Company engineers in accordance with guidelines established by the U.S. Securities and Exchange Commission. The Company's estimates of reserves at December 31, 2004, have been audited by Huddleston & Co., independent petroleum engineers. All of the Company's reserves are located in the United States. Proved reserves cannot be measured exactly because the estimation of reserves involves numerous judgmental determinations. Accordingly, reserve estimates must be continually revised as a result of new information obtained from drilling and production history, new geological and geophysical data and changes in economic conditions.

RECERTIFICATION COSTS AND DEFERRED DRYDOCK CHARGES

The Company's Marine Contracting vessels are required by regulation to be recertified after certain periods of time. These recertification costs are incurred while the vessel is in drydock where other routine repairs and maintenance are performed and, at times, major replacements and improvements are performed. The Company expenses routine repairs and maintenance as they are incurred. Recertification costs can be accounted for in one of three ways: (1) defer and amortize, (2) accrue in advance, or (3) expense as incurred. Companies in the industry use either the defer and amortize or the expense as incurred accounting method. The Company defers and amortizes recertification costs over the length of time in which the recertification is expected to last, which is generally 30 months. Major replacements and improvements, which extend the vessel's economic useful life or functional operating capability, are capitalized and depreciated over the vessel's remaining economic useful life. Inherent in this process are estimates the Company makes regarding the specific cost incurred and the period that the incurred cost will benefit.

The Company accounts for regulatory (U.S. Coast Guard, American Bureau of Shipping and Det Norske Veritas) related drydock inspection and certification expenditures by capitalizing the related costs and amortizing them over the 30-month period between regulatory mandated drydock inspections and certification. As of December 31, 2004 and 2003, capitalized deferred drydock charges (included in other assets, net) totaled $10.0 million and $7.3 million, respectively. During the years ended December 31, 2004, 2003 and 2002, drydock amortization expense was $4.9 million, $4.1 million and $4.9 million, respectively.

ACCOUNTING FOR DECOMMISSIONING LIABILITIES

Statement of Financial Accounting Standards ("SFAS") No. 143, Accounting for Asset Retirement Obligations, addresses the financial accounting and reporting obligations and retirement costs related to the retirement of tangible long-lived assets. Among other things, SFAS No. 143 requires oil and gas companies to reflect decommissioning liabilities on the face of the balance sheet at fair value on a discounted basis. ERT historically has purchased producing offshore oil and gas properties that are in the later stages of production. In conjunction with acquiring these properties, ERT assumes an obligation associated with decommissioning the property in accordance with the regulations set by government agencies. The abandonment liability related to the acquisitions of these properties is determined through a series of management estimates.

Prior to an acquisition and as part of evaluating the economics of an acquisition, ERT will estimate the plug and abandonment liability. ERT personnel prepare detailed cost estimates to plug and abandon wells and remove necessary equipment in accordance with regulatory guidelines. ERT currently calculates the discounted value of the abandonment liability (based on the estimated year the abandonment will occur) in accordance with SFAS No. 143 and capitalizes that portion as part of the basis acquired and records the related abandonment liability at fair value. Decommissioning liabilities were $82.0 million and $78.4 million at December 31, 2004 and 2003, respectively.

On an ongoing basis, ERT personnel monitor the status of wells on the properties, and as fields deplete and no longer produce, ERT will monitor the timing requirements set forth by the MMS for plugging and abandoning the wells and commence abandonment operations, when applicable. On an annual basis, ERT and Cal Dive management personnel review and update the abandonment estimates and assumptions for changes, among other things, in market conditions, interest rates and historical experience.

The adoption of SFAS No. 143 resulted in a cumulative effect adjustment as of January 1, 2003 to record (i) a $33.1 million decrease in the carrying values of proved properties, (ii) a $7.4 million decrease in accumulated depreciation, depletion and amortization of property and equipment, (iii) a $26.5 million decrease in decommissioning liabilities and (iv) a $0.3 million increase in deferred income tax liabilities. The net impact of items (i) through (iv) was to record a gain of $0.5 million, net of tax, as a cumulative effect adjustment of a change in accounting principle in the Company's consolidated statements of operations upon adoption on January 1, 2003. The Company has no material assets that are legally restricted for purposes of settling its decommissioning liabilities other than $15.1 million of restricted cash held in escrow included in Other Assets, net in the accompanying consolidated balance sheet (see Liquidity and Capital Resources -- Investing Activities).

REVENUE RECOGNITION

The Company earns the majority of marine contracting revenues during the summer and fall months. Revenues are derived from billings under contracts (which are typically of short duration) that provide for either lump-sum turnkey charges or specific time, material and equipment charges which are billed in accordance with the terms of such contracts. The Company recognizes revenue as it is earned at estimated collectible amounts. Revenues generated from specific time, materials and equipment charges contracts are generally earned on a dayrate basis and recognized as amounts are earned in accordance with contract terms. Revenues generated in the pre-operation mode before a contract commences are deferred and recognized on a straight line basis in accordance with contract terms. Direct and incremental costs associated with pre-operation activities are similarly deferred and recognized over the estimated contract period.

Revenue on significant turnkey contracts is recognized on the percentage-of-completion method based on the ratio of costs incurred to total estimated costs at completion, or achievement of certain contractual milestones if provided for in the contract. Contract price and cost estimates are reviewed periodically as work progresses and adjustments are reflected in the period in which such estimates are revised. Provisions for estimated losses on such contracts are made in the period such losses are determined. The Company recognizes additional contract revenue related to claims when the claim is probable and legally enforceable. Unbilled revenue represents revenue attributable to work completed prior to year-end which has not yet been invoiced. All amounts included in unbilled revenue at December 31, 2004 are expected to be billed and collected within one year.

The Company records revenues from the sales of crude oil and natural gas when delivery to the customer has occurred and title has transferred. This occurs when production has been delivered to a pipeline or a barge lifting has occurred. The Company may have an interest with other producers in certain properties. In this case the Company uses the entitlements method to account for sales of production. Under the entitlements method the Company may receive more or less than its entitled share of production. If the Company receives more than its entitled share of production, the imbalance is treated as a liability. If the Company receives less than its entitled share, the imbalance is recorded as an asset. As of December 31, 2004 the net imbalance was $3.2 million and was included in Other Current Assets in the accompanying consolidated balance sheet.

ACCOUNTS RECEIVABLE AND ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS

Accounts receivable are stated at the historical carrying amount net of write-offs and allowance for uncollectible accounts. The Company establishes an allowance for uncollectible accounts receivable based on historical experience and any specific customer collection issues that the Company has identified. Uncollectible accounts receivable are written off when a settlement is reached for an amount that is less that the outstanding historical balance or when the Company has determined the balance will not be collected.

FOREIGN CURRENCY

The functional currency for the Company's foreign subsidiary, Cal Dive International Limited (formerly known as Well Ops (U.K.) Limited), is the applicable local currency (British Pound). Results of operations for this subsidiary are translated into U.S. dollars using average exchange rates during the period. Assets and liabilities of this foreign subsidiary are translated into U.S. dollars using the exchange rate in effect at the balance sheet date and the resulting translation adjustment, which was a gain in 2004 and 2003 of $10.8 million and $5.0 million (net of taxes in 2003), respectively, is included as accumulated other comprehensive income, as a component of shareholders' equity. Beginning in 2004, deferred taxes have not been provided on foreign currency translation adjustments since the Company considers its undistributed earnings (when applicable) of its non-U.S. subsidiaries to be permanently reinvested. As a result, cumulative deferred taxes on translation adjustments totaling approximately $6.5 million were reclassified from noncurrent deferred income taxes and accumulated other comprehensive income. All foreign currency transaction gains and losses are recognized currently in the statements of operations.

Canyon Offshore, the Company's ROV subsidiary, has operations in the Europe/West Africa and Asia/ Pacific regions. Canyon conducts the majority of its affairs in these regions in U.S. dollars which it considers the functional currency. When currencies other than the U.S. dollar are to be paid or received the resulting gain or loss from translation is recognized in the statements of operations. These amounts for the years ended December 31, 2004 and 2003, respectively, were not material to the Company's results of operations or cash flows.

ACCOUNTING FOR PRICE RISK MANAGEMENT ACTIVITIES

The Company's price risk management activities involve the use of derivative financial instruments to hedge the impact of market price risk exposures primarily related to our oil and gas production. All derivatives are reflected in our balance sheet at their fair market value.

There are two types of hedging activities: hedges of cash flow exposure and hedges of fair value exposure. The Company engages primarily in cash flow hedges. Hedges of cash flow exposure are entered into to hedge a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability. Changes in the derivative fair values that are designated as cash flow hedges are deferred to the extent that they are effective and are recorded as a component of accumulated other comprehensive income until the hedged transactions occur and are recognized in earnings. The ineffective portion of a cash flow hedge's change in value is recognized immediately in earnings in oil and gas production revenues.

We formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives, strategies for undertaking various hedge transactions and our methods for assessing and testing correlation and hedge ineffectiveness. All hedging instruments are linked to the hedged asset, liability, firm commitment or forecasted transaction. We also assess, both at the inception of the hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows of the hedged items. We discontinue hedge accounting prospectively if we determine that a derivative is no longer highly effective as a hedge or it is probable that a hedged transaction will not occur. If hedge accounting is discontinued, deferred gains or losses on the hedging instruments are recognized in earnings immediately.

The fair value of hedging instruments reflects our best estimate and is based upon exchange or over-the-counter quotations whenever they are available. Quoted valuations may not be available due to location differences or terms that extend beyond the period for which quotations are available. Where quotes are not available, we utilize other valuation techniques or models to estimate market values. These modeling techniques require us to make estimations of future prices, price correlation and market volatility and liquidity. Our actual results may differ from our estimates, and these differences can be positive or negative.

During 2004 and 2003, the Company entered into various cash flow hedging swap and costless collar contracts to stabilize cash flows relating to a portion of the Company's oil and gas production. All of these qualified for hedge accounting and none extended beyond a year and a half. The aggregate fair value of the hedge instruments was a net liability of $876,000 and $2.2 million as of December 31, 2004 and 2003, respectively. For the years ended December 31, 2004 and 2003 the Company recorded unrealized gains of approximately $846,000 and $1.2 million, net of taxes of $456,000 and $654,000, respectively, in other comprehensive income, a component of shareholders' equity as these hedges were highly effective. The balance in the cash flow hedge adjustments account is recognized in earnings when the hedged item is sold. During 2004 and 2003, the Company reclassified approximately $11.1 million and $14.6 million, respectively, of losses from other comprehensive income to Oil and Gas Production revenues upon the sale of the related oil and gas production.

EQUITY INVESTMENTS

Our equity investments in unconsolidated subsidiaries include our investments in Deepwater Gateway, L.L.C. and Independence Hub, LLC. We review our equity investments for impairment and record an adjustment when we believe the decline in fair value is other than temporary. The fair value of the asset is measured using quoted market prices or, in the absence of quoted market prices, fair value is based on an estimate of discounted cash flows. In determining whether the decline is other than temporary, we consider the cyclical nature of the industry in which the investment operates, its historical performance, its performance in relation to its peers and the current economic environment. We will monitor the fair value of our investments for impairment and will record an adjustment if we believe a decline is other than temporary. During 2004 and 2003 no impairment indicators existed.

INCOME TAXES

Deferred income taxes are based on the difference between financial reporting and tax bases of assets and liabilities. The Company utilizes the liability method of computing deferred income taxes. The liability method is based on the amount of current and future taxes payable using tax rates and laws in effect at the balance sheet date. Income taxes have been provided based upon the tax laws and rates in the countries in which operations are conducted and income is earned. A valuation allowance for deferred tax assets is recorded when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized. The Company considers the undistributed earnings of its non-U.S. subsidiaries to be permanently reinvested. At December 31, 2004, the Company's non-U.S. subsidiaries had an accumulated deficit of $8.9 million in earnings and profits. These losses are primarily due to timing differences related to fixed assets. The Company has not provided deferred U.S. income tax on the losses. See footnote 9 to the Consolidated Financial Statements included herein for discussion of net operating loss carry forwards and deferred income taxes.

WORKER'S COMPENSATION CLAIMS

Our onshore employees are covered by Worker's Compensation. Offshore employees, including divers and tenders and marine crews, are covered by our Maritime Employers Liability insurance policy which covers Jones Act exposures. The Company incurs worker's compensation claims in the normal course of business, which management believes are substantially covered by insurance. The Company, its insurers and legal counsel analyze each claim for potential exposure and estimate the ultimate liability of each claim.

RECENTLY ISSUED ACCOUNTING PRINCIPLES

In December 2004, the FASB issued SFAS No. 123 (revised 2004), Share-Based Payment ("SFAS No. 123R"), which replaces SFAS No. 123, Accounting for Stock-Based Compensation, ("SFAS No. 123") and supercedes APB Opinion No. 25, Accounting for Stock Issued to Employees. SFAS No. 123R requires all share-based payments to employees, including grants of employee stock options, to be recognized in the financial statements based on their fair values beginning with the first interim or annual period after June 15, 2005, with early adoption encouraged. The pro forma disclosures previously permitted under SFAS No. 123 no longer will be an alternative to financial statement recognition. The Company is required to adopt SFAS No. 123R in the third quarter of fiscal 2005, beginning July 1, 2005. Under SFAS No. 123R, the Company must determine the appropriate fair value model to be used for valuing share-based payments, the amortization method for compensation cost and the transition method to be used at date of adoption. The transition methods include prospective and retroactive adoption options. Under the retroactive option, prior periods may be restated either as of the beginning of the year of adoption or for all periods presented. The prospective method requires that compensation expense be recorded for all unvested stock options and restricted stock at the beginning of the first quarter of adoption of SFAS No. 123R, while the retroactive methods would record compensation expense for all unvested stock options and restricted stock beginning with the first period restated. The Company has not yet determined the method of adoption of SFAS No. 123R. The Company is evaluating the requirements of SFAS No. 123R and expects that the adoption of SFAS No. 123R will not have a material impact on the Company's consolidated results of operations and earnings per share.

In December 2004, the FASB issued SFAS No. 153, Exchanges of Nonmonetary Assets, an Amendment of APB Opinion No. 29, which is effective for the Company for asset-exchange transactions beginning July 1, 2005. Under APB 29, assets received in certain types of nonmonetary exchanges were permitted to be recorded at the carrying value of the assets that were exchanged (i.e., recorded on a carryover basis). As amended by SFAS No. 153, assets received in some circumstances will have to be recorded instead at their fair values. In the past, the Company has not engaged in a large number of nonmonetary asset exchanges for significant amounts.

RESULTS OF OPERATIONS

We derive our revenues, earnings and cash flows from three primary business segments: Marine Contracting, Oil and Gas Production and Production Facilities. Within Marine Contracting, we operate primarily in the Gulf of Mexico (Gulf), and recently in the North Sea and Asia/Pacific regions, with services that cover the lifecycle of an offshore oil or gas field. Our current diversified fleet of 22 vessels and 26 remotely operated vehicles (ROVs) and trencher systems perform services that support drilling, well completion, intervention, construction and decommissioning projects involving pipelines, production platforms, risers and subsea production systems. We also have a significant investment in offshore oil and gas production as well as production facilities. Operations in the Production Facilities segment began in 2004 with Marco Polo coming online. Investments in our Production Facilities segment is currently accounted for under the equity method of accounting. Our customers include major and independent oil and gas producers, pipeline transmission companies and offshore engineering and construction firms.

COMPARISON OF YEARS ENDED 2004 AND 2003

Revenues. During the year ended December 31, 2004, the Company's revenues increased 37% to $543.4 million compared to $396.3 million for the year ended December 31, 2003. Of the overall $147.1 million increase, $106.0 million was generated by the Oil and Gas Production segment due to increased oil and gas production and higher commodity prices. Marine Contracting revenues increased $41.1 million from $259.0 million for 2003 to $300.1 million for 2004 due primarily to slightly increased utilization and improved contract pricing for the Company's Well Ops Group and improved performance from the Company's ROV division.

Oil and Gas Production revenue for the year ended December 31, 2004 increased $106.0 million, or 77%, to $243.3 million from $137.3 million during 2003. Production increased 43% (39.8 Bcfe for the year ended December 31, 2004 compared to 27.9 Bcfe in 2003) primarily as a result of our successful well exploitation program, bringing a subsea PUD development online late in 2003, and Gunnison wells coming online throughout 2004 and provided 21% of total production. The average realized natural gas price of $6.13 per Mcf, net of hedges in place, during 2004 was 23% higher than the $4.98 per Mcf realized in 2003 while average realized oil prices, net of hedges in place, increased 28% to $35.34 per barrel compared to $27.63 per barrel realized during 2003.

Gross Profit. Gross profit of $171.9 million for the year ended December 31, 2004 represented an 87% increase compared to the $92.1 million recorded in the prior year with the Oil and Gas Production segment contributing 87% of the increase. Marine Contracting gross profit increased to $36.5 million, for the year ended December 31, 2004, from $26.0 million in the prior year. The increase was primarily attributable to improved contract pricing for the Company's Well Ops Group and improved performance from the Company's ROV division, partially offset by asset impairments on certain Shelf and Deepwater division vessels totaling $3.9 million for conditions meeting the Company's asset impairment criteria. Oil and Gas Production gross profit increased $69.3 million, to $135.4 million, due to the aforementioned higher levels of production and commodity price increases.

Gross margins of 32% in 2004 were 9 points better than the 23% in 2003. Marine Contracting margins increased 2 points to 12% for the year ended December 31, 2004, from 10% in the prior year, due to the factors noted above. In addition, margins in the Oil and Gas Production segment increased 8 points to 56% for the year ended December 31, 2004, from 48% in 2003, due primarily to the higher oil and gas commodity prices.

Selling & Administrative Expenses. Selling and administrative expenses of $48.9 million for the year ended December 31, 2004 were $13.0 million higher than the $35.9 million incurred in 2003 due primarily to an increase in the 2004 Marine Contracting compensation program, which is based on certain individual performance criteria and the Company's profitability, and the ERT incentive compensation program, which is tied directly to the Oil and Gas Production segment profitability that was significantly higher in 2004 compared to 2003. Selling and administrative expenses at 9% of revenues for 2004 matched that of the prior year.

Equity in Earnings of Production Facilities Investments. Equity in earnings of the Company's 50% investment in Deepwater Gateway, L.L.C. increased to $7.9 million in 2004 compared with a loss of $87,000 in 2003. The increase was attributable to the demand fees which commenced following the March 2004 mechanical completion of the Marco Polo tension leg platform, owned by Deepwater Gateway, L.L.C., as well as production tariff charges which commenced in the third quarter of 2004 as Marco Polo began producing.

Other (Income) Expense. The Company reported other expense of $5.3 million for the year ended December 31, 2004 compared to other expense of $3.4 million for the year ended December 31, 2003. Net interest expense of $5.6 million in 2004 was higher than the $2.4 million incurred in 2003, due primarily to $243,000 of capitalized interest in 2004, compared with $3.4 million in 2003, which related to the Company's investment in Gunnison and construction of the Marco Polo tension leg platform, both of which were online at different times during 2004.

Income Taxes. Income taxes increased to $43.0 million for the year ended December 31, 2004 compared to $19.0 million in 2003, primarily due to increased profitability. The effective tax rate of 34.2% in 2004 is lower than the 36.1% effective tax rate for 2003 due to the benefit recognized by the Company for its research and development credits in the first quarter of 2004 as a result of the conclusion of the Internal Revenue Service ("IRS") examination of the Company's income tax returns for 2001 and 2002, and the tax cost or benefit of U.S. and U.K. branch operations.

Net Income. Net income of $79.9 million for 2004 was $47.1 million greater than 2003 as a result of the factors described above. Further, convertible preferred stock dividends and accretion increased from $1.4 million in 2003 to $2.7 million in 2004 as a result of the Series A-2 Tranche of convertible preferred stock issued in June 2004 to the existing holder. See Liquidity and Capital Resources -- Financing Activities.

COMPARISON OF YEARS ENDED 2003 AND 2002

Revenues. During the year ended December 31, 2003, revenues increased $93.6 million, or 31%, to $396.3 million compared to $302.7 million for the year ended December 31, 2002. The Marine Contracting segment contributed $19.1 million of the increase, primarily as a result of the acquisition of the Seawell during the third quarter of 2002. In addition, the Q4000, Intrepid and Eclipse worked a full year in 2003 as compared to nine months in the prior year, as these vessels were placed in service in the second quarter of 2002.

Oil and Gas Production revenue for the year ended December 31, 2003 increased $74.5 million, or 119%, to $137.3 million from $62.8 million during the prior year. The increase was due to a 33% increase in our average realized commodity prices to $4.82 per Mcfe, net of hedges in place ($4.98 per Mcfe of natural gas and $27.63 per barrel of oil) in 2003 from $3.63 per Mcfe ($3.49 per Mcfe of natural gas and $24.73 per barrel of oil) in 2002. Production increased 69% to 28 Bcfe during 2003 from 16.6 Bcfe during the prior year as a result of the property acquisitions during the third quarter of 2002 and Gunnison coming on line in December 2003.

Gross Profit. Gross profit of $92.1 million for 2003 was $38.3 million, or 71%, greater than the $53.8 million gross profit recorded in the prior year due entirely to the revenue increase in Oil and Gas Production mentioned above. Oil and Gas Production gross profit increased $39.4 million from $26.7 million in 2002 to $66.1 million for 2003, due to the increases in average realized commodity prices and production described above.

Gross margins improved to 23% for the year ended December 31, 2003 compared to 18% during 2002 due primarily to the aforementioned increases in average realized commodity prices. Marine Contracting margins decreased from 11% for 2002 to 10% during 2003 due mainly to the depressed markets for offshore construction in the GOM and the North Sea, increased competition in the OCS market and increased offshore insurance costs offset by the impact of charges recorded in the fourth quarter of 2002 related to a contract dispute.

Selling & Administrative Expenses. Selling and administrative expenses were $35.9 million in 2003, which is 10% more than the $32.8 million incurred in 2002, primarily due to the addition of business units acquired and higher ERT incentive accruals. Selling and administrative expenses were 9% of revenues for 2003, which was two points better than the 11% for 2002 due primarily to the EEX settlement charges in the fourth quarter of 2002.

Other (Income) Expense. The Company reported other expense of $3.5 million for the year ended December 31, 2003 in contrast to $2.0 million for 2002. Included in other expense for 2002 is a $1.1 million gain on our foreign currency derivative associated with the acquisition of Well Ops (U.K.) Limited recorded in other income in June 2002. Net interest expense of $2.4 million for 2003 is higher than the $2.2 million in the prior year as a result of our higher debt levels and the reduction of capitalized interest expense as the Q4000 and Intrepid were in service for only the last nine months of 2002.

Income Taxes. Income taxes increased to $19.0 million for 2003, compared to $6.7 million in the prior year period, due to increased profitability. The effective rate increased to 36.1% in 2003 compared to 35.0% in 2002 due primarily to provisions for foreign taxes. The IRS is in the process of examining our income tax return for years 2001 and 2002, and the 2001 pre-acquisition income tax return for Canyon Offshore Inc. We believe the ultimate resolution of these audits will not have a material adverse effect on our financial condition, liquidity or results of operations.

Net Income. Net income of $32.8 million for 2003 was $20.4 million, or 165%, greater than 2002, as a result of the factors described above.

ITEM 7. LIQUIDITY AND CAPITAL RESOURCES

LIQUIDITY AND CAPITAL RESOURCES

In August 2000, we closed the long-term MARAD financing for construction of the Q4000. This U.S. Government guaranteed financing is pursuant to Title XI of the Merchant Marine Act of 1936 which is administered by the Maritime Administration. We refer to this debt as MARAD Debt. At December 31, 2004, $136.4 million was outstanding on this debt. In August 2004 we closed a four year, $150 million revolving credit facility with a syndicate of banks. This facility was undrawn upon at December 31, 2004. In January 2002, we acquired Canyon Offshore, Inc.; in July 2002, we acquired the Well Operations Business Unit of Technip-Coflexip and, in August 2002, ERT made two significant property acquisitions. These acquisitions significantly increased our debt to total book capitalization ratio from 31% at December 31, 2001 to 40% at December 31, 2002. Cash flow from operations, along with the private placement of convertible preferred stock in January 2003 ($25 million, or $24.1 million net of transaction costs) and June 2004 ($30 million, or $29.3 million net of transaction costs), have enabled us to reduce this ratio to 22% as of December 31, 2004, as well as to build $91.1 million of unrestricted cash as of December 31, 2004.

Operating Activities. Net cash provided by operating activities was $226.8 million during 2004, an increase of $139.4 million over the $87.4 million generated during 2003 due primarily to an increase in profitability ($48.5 million), a $37.5 million increase in depreciation and amortization (including the non-cash asset impairment charge in 2004) resulting from the aforementioned increase in production levels (including the Gunnison wells that began producing in December 2003). Further an increase in trade payables and accrued liabilities of $53.1 million due primarily to higher accruals for ERT royalties as a result of increased production and higher accruals for ERT and Marine Contracting incentive compensation also contributed to the increase in operating cash flow. Cash flow from operations was negatively impacted by an increase in other current assets ($28.3 million) primarily for prepaid insurance and current deferred taxes.

In March 2004, the Company elected not to renew its alliance with Horizon Offshore, Inc. As part of the settlement of outstanding trade accounts receivable with Horizon, the Company obtained exclusive use of a Horizon spoolbase facility for a period of five years. Utilization of the spoolbase facility was valued at approximately $2.0 million with the Company offsetting a corresponding amount of trade accounts receivable in exchange for the utilization agreement. The value of the spoolbase facility is being amortized over the five year term of the agreement. Trade receivables from Horizon at December 31, 2004 and 2003 were approximately $3.3 million and $11.0 million, respectively.

Net cash provided by operating activities was $87.4 million during 2003, as compared to $66.9 million during 2002 due primarily to an increase in profitability and a $26.0 million increase in depreciation and amortization resulting from the aforementioned increase in production levels as well as depreciation on additional DP vessels placed in service. This increase was partially offset by funding from accounts receivable collections decreasing $20.3 million as receivables have grown primarily as a result of increased ERT production levels.

Investing Activities. Capital expenditures have consisted principally of strategic asset acquisitions related to the purchase or construction of DP vessels, acquisition of select businesses, improvements to existing vessels, acquisition of oil and gas properties and investments in our Production Facilities. We incurred $82.3 million of capital investments during 2004, $95.4 million during 2003 and $312.8 million in 2002.

We incurred $50.1 million of capital expenditures during 2004 compared to $93.2 million in 2003. Included in the capital expenditures during 2004 was $5.5 million for the purchase of an intervention riser system, $14.8 million for ERT well exploitation programs, $19.6 million for further Gunnison field development, $6.7 million for the purchase of an operations facility in Aberdeen, Scotland to serve as our UK headquarters and $3.5 million for the purchase and upgrade of a trencher system for our ROV division.

We incurred $93.2 million of capital expenditures during the year ended December 31, 2003 compared to $161.8 million during the prior year. Included in the capital expenditures during 2003 was $17.5 million for the purchase of ROV units to support the Canyon MSA agreement with Technip/Coflexip to provide robotic and trenching services, $39.6 million related to Gunnison development costs, including the spar, as well as $39.7 million relating to ERT's 2003 well exploitation program. Included in capital expenditures in 2002 was $29.1 million for the construction of the Q4000 and $20.8 million relating to the Intrepid DP conversion and Eclipse upgrade. Also included in 2002 was over $25 million in ERT offshore property acquisitions (see discussion below) as well as approximately $53 million related to Gunnison development costs, including the spar.

In 2004, we invested $32.2 million in our Production Facilities segment which consists of our equity method investments in Deepwater Gateway, L.L.C. and Independence Hub, LLC. In June 2002, CDI, along with Enterprise Products Partners L.P. ("Enterprise"), formed Deepwater Gateway, L.L.C. (a 50/50 venture accounted for by CDI under the equity method of accounting) to design, construct, install, own and operate TLP production hub primarily for Anadarko Petroleum Corporation's Marco Polo field discovery in the Deepwater Gulf of Mexico. In August 2002, the Company along with Enterprise, completed a non-recourse project financing for this venture, terms of which include a minimum equity investment in Deepwater Gateway, L.L.C. of $33 million, all of which had been paid as of December 31, 2004, and is recorded as Investments in Production Facilities in the accompanying consolidated balance sheet. The Company's investment in Deepwater Gateway, L.L.C. totaled $56.6 million as of December 31, 2004. Included in the investment account was capitalized interest and insurance paid by the Company totaling approximately $2.6 million. In June 2004, the Deepwater Gateway, L.L.C. construction loan, excluded from the Company's long-term debt, was converted to a term loan. The term loan is collateralized by substantially all of Deepwater Gateway, L.L.C.'s assets and is non-recourse to the Company except for the balloon payment due at the end of the term. In the event of default, the Company would be required to pay up to $22.5 million; however, the Company has not recorded any liability for this guarantee as management believes that it is unlikely the Company will be required to pay the $22.5 million. In December 2004, the Company received its first distribution from Deepwater Gateway, L.L.C. totaling $7.5 million. The $7.5 million distribution was recorded as restricted cash (included in other assets, net in the accompanying consolidated balance sheet) at December 31, 2004 as the Company is required to escrow distributions from Deepwater Gateway, L.L.C. up to the first $22.5 million. In accordance with terms of the term loan, Deepwater Gateway, L.L.C. has the right to repay the principal amount plus any accrued interest due under its term loan at any time without penalty. Deepwater Gateway, L.L.C. has decided to extinguish its term loan. The Company and Enterprise will make equal cash contributions (approximately $72 million each) to Deepwater Gateway, L.L.C. to fund the repayment. At March 9, 2005, the term loan principal amount owed by Deepwater Gateway, L.L.C. was $144 million.

In December 2004, CDI acquired a 20% interest (accounted for by CDI under the equity method of accounting) in Independence Hub, LLC ("Independence"), an affiliate of Enterprise. Independence will own the "Independence Hub" platform to be located in Mississippi Canyon block 920 in a water depth of 8,000 feet. Independence has previously executed agreements with the Atwater Valley Producers Group of five exploration and production companies for the dedication and processing of natural gas and condensate production from fields in the Atwater Valley, DeSoto Canyon and Lloyd Ridge areas of the deepwater Gulf of Mexico on the Independence Hub platform. As part of that transaction, the producers have also dedicated future production from a number of undeveloped blocks in the area for processing. The 105 foot deep draft, semi-submersible platform will serve as a regional hub for natural gas production from multiple ultra-deepwater fields in the previously untapped eastern Gulf of Mexico. The platform, which is estimated to cost approximately $385 million, will be capable of processing 850 million cubic feet of gas per day. It is designed to process production from six anchor fields and has excess payload capacity to tie back up to 10 additional fields. CDI's initial investment of $10.6 million has been paid as of December 31, 2004, and its total investment in Independence is expected to be approximately $77 million. Further, CDI is party to a guaranty agreement with Enterprise to the extent of CDI's ownership in Independence (20% at December 31, 2004). The agreement states, among other things, that CDI and Enterprise guarantee performance under the Independence Hub Agreement between Independence and the producers group of exploration and production companies up to $397.5 million, plus applicable attorneys' fees and related expenses. CDI has estimated the fair value of its share of the guarantee obligation to be immaterial at December 31, 2004 based upon the remote possibility of payments being made under the performance guarantee.

In March 2005, ERT acquired a 30% working interest in a proven undeveloped field in Atwater Valley Block 63 of the deepwater Gulf of Mexico for cash consideration and assumption of certain decommissioning liabilities. ERT's expected share of development costs for 2005 through 2007 are approximately $70 million to $100 million.

As of December 31, 2004, the Company had $22.6 million of restricted cash, included in other assets, net in the accompanying consolidated balance sheet, of which $15.1 million related to ERT's escrow funds for decommissioning liabilities associated with the SMI 130 field acquisitions in 2002 and $7.5 million related to the Investment in Deepwater Gateway, L.L.C. discussed previously. Under the purchase agreement, ERT is obligated to escrow 50% of production up to the first $20 million and 37.5% of production on the remaining balance up to $33 million in total escrow. Once the escrow reaches $10 million, ERT may use the restricted cash for decommissioning the related fields.

In March 2003, ERT acquired additional interests, ranging from 45% to 84%, in four fields acquired in 2002, enabling ERT to take over as operator of one field. ERT paid $858,000 in cash and assumed Exxon/ Mobil's pro-rata share of the abandonment obligation for the acquired interests.

On August 30, 2002, ERT acquired the 74.8% working interest of Shell Exploration & Production Company in the South Marsh Island 130 (SMI 130) field. ERT paid $10.3 million in cash and assumed Shell's pro-rata share of the related decommissioning liability. ERT also completed the purchase of interests in seven Gulf of Mexico fields from Amerada Hess including its 25% ownership position in SMI 130 for $9.3 million in cash and assumption of Amerada Hess' pro-rata share of the related decommissioning liability. As a result, ERT is the operator with an effective 100% working interest in that field.

In July 2002, CDI purchased the Subsea Well Operations Business Unit of CSO Ltd., a wholly owned subsidiary of Technip-Coflexip, for approximately $72.0 million ($68.6 million cash and $3.4 million deferred tax liability assumption).

In June 2002, ERT acquired a package of offshore properties from Williams Exploration and Production. ERT paid $4.9 million and assumed the pro-rata share of the abandonment obligation for the acquired interests. The blocks purchased represent an average 30% net working interest in 26 Gulf of Mexico leases. In April 2002, ERT acquired a 100% interest in East Cameron Block 374, including existing wells, equipment and improvements. The property, located in 425 feet of water, was jointly owned by Murphy Exploration & Production Company and Callon Petroleum Operating Company. Terms included a cash payment of approximately $3 million to reimburse the owners for the inception-to-date cost of the subsea wellhead and umbilical and an overriding royalty interest in future production. Cal Dive completed the temporarily abandoned number one well and performed a subsea tie-back to host platform. The cost of completion and tie-back was approximately $7 million with first production occurring in August 2002.

In January 2002, CDI purchased Canyon, a supplier of remotely operated vehicles (ROVs) and robotics to the offshore construction and telecommunications industries. CDI purchased Canyon for cash of $52.8 million, the assumption of $9.0 million of Canyon debt (offset by $3.1 million of cash acquired), 181,000 shares of our common stock (143,000 shares of which we purchased as treasury shares during the fourth quarter of 2001) and a commitment to purchase the redeemable stock in Canyon at a price to be determined by Canyon's performance during the years 2002 through 2004 from continuing employees at a minimum purchase price of $13.53 per share.

In April 2000, ERT acquired a 20% working interest in Gunnison, a Deepwater Gulf of Mexico prospect of Kerr-McGee Oil & Gas Corp. Financing for the exploratory costs of approximately $20 million was provided by an investment partnership (OKCD Investments, Ltd. or "OKCD"), the investors of which include current and former CDI senior management, in exchange for a revenue interest that is an overriding royalty interest of 25% of CDI's 20% working interest. Production began in December 2003. Payments to OKCD from ERT totaled $20.3 million in the year ended December 31, 2004. The Company's Chief Executive Officer, as a Class A limited partner of OKCD, personally owns approximately 57% of the partnership. Other executive officers of the Company own approximately 6% combined of the partnership. OKCD has also awarded Class B limited partnership interests to key CDI employees.

Financing Activities. We have financed seasonal operating requirements and capital expenditures with internally generated funds, borrowings under credit facilities, the sale of equity and project financings. Our largest debt financing has been the MARAD debt. No draws were made on this facility in 2004 and 2003. The MARAD debt is payable in equal semi-annual installments which began in August 2002 and matures 25 years from such date. We made two payments each during 2004 and 2003 totaling $2.9 million and $2.8 million, respectively. The MARAD Debt is collateralized by the Q4000, with Cal Dive guaranteeing 50% of the debt, and bears an interest rate which currently floats at a rate approximating AAA Commercial Paper yields plus 20 basis points (approximately 2.47% as of December 31, 2004). CDI has paid MARAD guarantee fees for this debt which adds approximately 50 basis points per annum of interest expense. For a period up to ten years from delivery of the vessel in April 2002, the Company has the ability to lock in a fixed rate. In accordance with the MARAD Debt agreements, we are required to comply with certain covenants and restrictions, including the maintenance of minimum net worth, working capital and debt-to-equity requirements. As of December 31, 2004, we were in compliance with these covenants.

The Company had a $70 million revolving credit facility originally due in February 2005. This facility was collateralized by accounts receivable and certain of the Company's Marine Contracting vessels. All outstanding borrowings under the facility were repaid during 2004 and the facility was cancelled and terminated in August 2004, and replaced by the new $150 million revolving credit facility described below.

In August 2004, the Company entered into a four year, $150 million revolving credit facility with a syndicate of banks, with Bank of America, N.A. as administrative agent and lead arranger. The amount available under the facility may be increased to $250 million at any time upon the agreement of the Company and the existing or additional lenders. The new credit facility is secured by the stock in certain Company subsidiaries and contains a negative pledge on assets. The new facility bears interest at LIBOR plus 75 -- 175 basis points depending on Company leverage and contains financial covenants relative to the Company's level of debt to EBITDA, as defined in the credit facility, fixed charge coverage and book value of assets coverage. As of December 31, 2004, the Company was in compliance with these covenants and there was no outstanding balance under this facility.

The Company had a $35 million term loan facility which was obtained to assist CDI in funding its portion of the construction costs of the spar for the Gunnison field. The loan was repaid in full in August 2004, and the loan agreement was subsequently cancelled and terminated.

In connection with borrowings under credit facilities and long-term debt financings, the Company has paid deferred financing costs totaling $4.6 million, $208,000 and $1.7 million in the years ended December 31, 2004, 2003 and 2002, respectively.

On January 8, 2003, CDI completed the private placement of $25 million of a newly designated class of cumulative convertible preferred stock (Series A-1 Cumulative Convertible Preferred Stock, par value $0.01 per share) that is convertible into 833,334 shares of Cal Dive common stock at $30 per share. The preferred stock was issued to a private investment firm. Subsequently in June 2004, the preferred stockholder exercised its existing right and purchased $30 million in additional cumulative convertible preferred stock (Series A-2 Cumulative Convertible Preferred Stock, par value $0.01 per share). In accordance with the January 8, 2003 agreement, the $30 million in additional preferred stock is convertible into 982,029 shares of Cal Dive common stock at $30.549 per share. In the event the holder of the convertible preferred stock elects to redeem into Cal Dive common stock and Cal Dive's common stock price is below the conversion prices, unless the Company has elected to settle in cash, the holder would receive additional shares above the 833,334 common shares (Series A-1 tranche) and 982,029 common shares (Series A-2 tranche). The incremental shares would be treated as a dividend and reduce net income applicable to common shareholders. The preferred stock has a minimum annual dividend rate of 4%, subject to adjustment, payable quarterly in cash or common shares at Cal Dive's option. CDI paid these dividends in 2004 and 2003 on the last day of the respective quarter in cash. After the second anniversary of the original issuance, the holder may redeem the value of its original and additional investment in the preferred shares to be settled in common stock at the then prevailing market price or cash at the discretion of the Company. In the event the Company is unable to deliver registered common shares, CDI could be required to redeem in cash.

In August 2003, Canyon Offshore, Ltd. (a U.K. subsidiary -- "COL") (with a parent guarantee from Cal Dive) completed a capital lease with a bank refinancing the construction costs of a newbuild 750 horsepower trenching unit and a ROV. COL received proceeds of $12 million for the assets and agreed to pay the bank sixty monthly installment payments of $217,174 (resulting in an implicit interest rate of 3.29%). No gain or loss resulted from this transaction. COL has an option to purchase the assets at the end of the lease term for $1. The proceeds were used to reduce the Company's revolving credit facility, which had initially funded the construction costs of the assets. This transaction was accounted for as a capital lease with the present value of the lease obligation (and corresponding asset) being reflected on the Company's consolidated balance sheet beginning in the third quarter of 2003.

In April 2004 and 2003, the Company purchased approximately one-third and one-third, respectively, of the redeemable stock in Canyon related to the Canyon purchase (see Investing Activities above and footnote 5 in the accompanying consolidated financial statements included herein for discussion of the Canyon acquisition) at the minimum purchase price of $13.53 per share ($2.5 million and $2.7 million).

In May 2002, CDI sold 3.4 million shares of primary common stock for $23.16 per share, along with 517,000 additional shares to cover over-allotments. Net proceeds to the Company of approximately $87.2 million were used for the Coflexip Well Operations acquisition, ERT acquisitions and to retire debt under the Company's revolving line of credit.

During 2004, 2003 and 2002, we made payments of $3.6 million, $2.4 million and $5.2 million separately on capital leases related to Canyon. The only other financing activity during 2004, 2003 and 2002 involved the exercise of employee stock options ($11.0 million, $3.6 million and $5.9 million, respectively).

The following table summarizes our contractual cash obligations as of December 31, 2004 and the scheduled years in which the obligation are contractually due:

	TOTAL(1)	LESS THAN 1 YEAR	1-3 YEARS	3-5 YEARS	MORE THAN 5 YEARS
MARAD debt.............	$136,412	$ 4,321	$ 9,037	$ 9,592	$113,462
Revolving debt.........	--	--	--	--	--
Capital leases and other................	12,148	5,292	5,353	1,503	--
Investments in Deepwater Gateway, L.L.C. (2)............	--	--	--	--	--
Investments in Independence Hub, LLC..................	66,415	45,000	21,415	--	--
Field development costs(3).............	14,500	14,500	--	--	--
Drilling costs(4)......	20,000	20,000	--	--	--
Operating leases.......	12,014	3,266	2,217	1,782	4,749
Property and equipment............	--	--	--	--	--
Total cash obligations.......	$261,489	$ 92,379	$38,022	$12,877	$118,211

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(1) Excludes CDI guarantee of payment due in 2009 on term loan related to Deepwater Gateway, L.L.C. (estimated to be $22.5 million), guarantee of performance related to the construction of the Independence Hub platform under Independence Hub, LLC (estimated to be immaterial at December 31, 2004) and unsecured letters of credit outstanding at December 31, 2004 totaling $3.7 million. These letters of credit primarily guarantee various contract bidding and insurance activities.

(2) In accordance with terms of the term loan, Deepwater Gateway, L.L.C. has the right to repay the principal amount plus any accrued interest due under its term loan at any time without penalty. Deepwater Gateway, L.L.C. has decided to extinguish its term loan. The Company and Enterprise will make equal cash contributions (approximately $72 million each) to Deepwater Gateway, L.L.C. to fund the repayment. At March 9, 2005, the term loan principal amount owed by Deepwater Gateway, L.L.C. was $144 million.

(3) In March 2005, ERT acquired a 30% working interest in a proven undeveloped field in Atwater Valley Block 63 of the deepwater Gulf of Mexico for cash consideration and assumption of certain decommissioning liabilities. ERT's expected share of development costs for 2005 through 2007 are approximately $70 million to $100 million.

(4) As an extension of ERT's well exploitation and PUD strategies, ERT agreed to participate in the drilling of an exploratory well to be drilled in 2005 that targets reserves in deeper sands, within the same trapping fault system, of a currently producing well. If the drilling is successful, ERT's share of the development cost is estimated to be an additional $15 million. CDI's Marine Contracting assets would participate in this development.

In addition, in connection with our business strategy, we regularly evaluate acquisition opportunities (including additional vessels as well as interest in offshore natural gas and oil properties). We believe internally generated cash flow, borrowings under existing credit facilities and use of project financings along with other debt and equity alternatives will provide the necessary capital to meet these obligations and achieve our planned growth.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company is currently exposed to market risk in three major areas: interest rates, commodity prices and foreign currency exchange rates.

Interest Rate Risk

Because the majority of the Company's debt at December 31, 2004 was based on floating rates, changes in interest would, assuming all other things equal, have a minimal impact on the fair value of the debt instruments, but every 100 basis points move in interest rates would result in approximately $1.4 million of annualized interest expense or savings, as the case may be, to the Company.

Commodity Price Risk

The Company has utilized derivative financial instruments with respect to a portion of 2004 and 2003 oil and gas production to achieve a more predictable cash flow by reducing its exposure to price fluctuations. The Company does not enter into derivative or other financial instruments for trading purposes.

As of December 31, 2004, the Company has the following volumes under derivative contracts related to its oil and gas producing activities:

PRODUCTION PERIOD	INSTRUMENT TYPE	AVERAGE MONTHLY VOLUMES	WEIGHTED AVERAGE PRICE
Crude Oil:			
January - June 2005...............	Swap	20 MBbl	$35.80
January - September 2005..........	Collar	40 MBbl	$37.00 - $47.48
Natural Gas:			
January - June 2005...............	Collar	300,000 MMBtu	$5.67 - $8.15

Changes in NYMEX oil and gas strip prices would, assuming all other things being equal, cause the fair value of these instruments to increase or decrease inversely to the change in NYMEX prices.

Subsequent to December 31, 2004, the Company entered into additional oil costless collars for the periods July through December 2005 and October through December 2005. The July contract covers 20 MBbl per month at a price of $37.00 to $50.50 and the October contract covers 20 MBbl per month at a price of $37.00 to $50.80. The Company also entered into additional natural gas costless collars for the period July through December 2005. The contracts cover 225,000 MMBtu per month at a weighted average price of $5.00 to $9.44.

Foreign Currency Exchange Rates

Because we operate in various oil and gas exploration and production regions in the world, we conduct a portion of our business in currencies other than the U.S. dollar (primarily with respect to Cal Dive International Limited). The functional currency for Cal Dive International Limited is the applicable local currency (British Pound). Although the revenues are denominated in the local currency, the effects of foreign currency fluctuations are partly mitigated because local expenses of such foreign operations also generally are denominated in the same currency. The impact of exchange rate fluctuations during the years ended December 31, 2004 and 2003, respectively, did not have a material effect on reported amounts of revenues or net income.

Assets and liabilities of Cal Dive International Limited are translated using the exchange rates in effect at the balance sheet date, resulting in translation adjustments that are reflected in accumulated other comprehensive income (loss) in the shareholders' equity section of our balance sheet. Approximately 14% of our assets are impacted by changes in foreign currencies in relation to the U.S. dollar. We recorded gains of $10.8 and $5.0 million (net of taxes in 2003) to our equity account in the years ended December 31, 2004 and 2003, respectively, to reflect the net impact of the decline of the U.S. dollar against the British Pound. Beginning in 2004, deferred taxes have not been provided on foreign currency translation adjustments since the Company considers its undistributed earnings (when applicable) of its non-U.S. subsidiaries to be permanently reinvested. As a result, cumulative deferred taxes on translation adjustments totaling approximately $6.5 million were reclassified from noncurrent deferred income taxes and accumulated other comprehensive income.

Canyon Offshore, the Company's ROV subsidiary, has operations in the Europe/West Africa and Asia/ Pacific regions. Canyon conducts the majority of its operations in these regions in U.S. dollars which it considers the functional currency. When currencies other than the U.S. dollar are to be paid or received, the resulting transaction gain or loss is recognized in the statements of operations. These amounts for the years ended December 31, 2004 and 2003, respectively, were not material to the Company's results of operations or cash flows.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO FINANCIAL STATEMENTS

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Cal Dive International, Inc., together with its consolidated subsidiaries (the "Company"), is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed under the supervision of the Company's principal executive and principal financial officers to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external reporting purposes in accordance with U.S. generally accepted accounting principles.

As of the end of the Company's 2004 fiscal year, management conducted an assessment of the effectiveness of the Company's internal control over financial reporting using the criteria set forth in the framework established in Internal Control -- Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management has determined that the Company's internal control over financial reporting as of December 31, 2004 is effective.

Our internal control over financial reporting includes policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets of the Company; provide reasonable assurances that transactions are recorded as necessary to permit preparation of financial statements in accordance with U.S. generally accepted accounting principles, and that receipts and expenditures are being made only in accordance with authorizations of management and the directors of the Company; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on our financial statements.

Management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2004 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report appearing on page 46, which expresses an unqualified opinion on management's assessment and on the effectiveness of Company's internal control over financial reporting as of December 31, 2004.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Cal Dive International, Inc.

We have audited the accompanying consolidated balance sheets of Cal Dive International, Inc. and Subsidiaries as of December 31, 2004 and 2003, and the related consolidated statements of operations, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our 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 Cal Dive International, Inc. and Subsidiaries at December 31, 2004 and 2003, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Cal Dive International, Inc.'s internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 11, 2005 expressed an unqualified opinion thereon.

As discussed in Note 2 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" in 2003.

/s/ ERNST & YOUNG LLP

Houston, Texas
March 11, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON INTERNAL CONTROL OVER FINANCIAL REPORTING

To the Board of Directors and Shareholders of
Cal Dive International, Inc.

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that Cal Dive International, Inc. maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control -- Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Cal Dive International, Inc.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the company's internal control over financial reporting based on our audit.

We conducted our audit 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that Cal Dive International, Inc. maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, Cal Dive International, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Cal Dive International, Inc. as of December 31, 2004 and 2003, and the related consolidated statements of operations, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2004 of Cal Dive International, Inc. and Subsidiaries and our report dated March 11, 2005 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
March 11, 2005

CAL DIVE INTERNATIONAL, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
DECEMBER 31, 2004 AND 2003

DECEMBER 31,	2004	2003
	(IN THOUSANDS)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 91,142	$ 6,378
Restricted cash	--	2,433
Accounts receivable -- Trade, net of allowance for uncollectible accounts of $7,768 and $7,462	95,732	78,733
Unbilled revenue	18,977	17,874
Deferred income taxes	12,992	5,398
Other current assets	35,118	19,834
Total current assets	253,961	130,650
Property and equipment	861,281	802,694
Less -- Accumulated depreciation	(276,864)	(183,891)
	584,417	618,803
Other assets:		
Equity investments in production facilities	67,192	34,517
Goodwill, net	84,193	81,877
Other assets, net	48,995	16,995
	$1,038,758	$ 882,842
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 56,047	$ 50,897
Accrued liabilities	75,502	36,850
Current maturities of long-term debt	9,613	16,199
Total current liabilities	141,162	103,946
Long-term debt	138,947	206,632
Deferred income taxes	133,777	89,274
Decommissioning liabilities	79,490	75,269
Other long term liabilities	5,090	2,042
Total liabilities	498,466	477,163
Convertible preferred stock	55,000	24,538
Commitments and contingencies		
Shareholders' equity:		
Common stock, no par, 120,000 shares authorized, 52,020 and 51,460 shares issued	212,608	199,999
Retained earnings	258,634	178,718
Treasury stock, 13,602 shares, at cost	(3,741)	(3,741)
Accumulated other comprehensive income	17,791	6,165
Total shareholders' equity	485,292	381,141
	$1,038,758	$ 882,842

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

CAL DIVE INTERNATIONAL, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED DECEMBER 31, 2004, 2003 AND 2002

	YEAR ENDED DECEMBER 31,		
	2004	2003	2002
	(IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)		
Net Revenues:			
Marine contracting	$300,082	$258,990	$239,916
Oil and gas production	243,310	137,279	62,789
	543,392	396,269	302,705
Cost of sales:			
Marine contracting	263,597	233,005	212,868
Oil and gas production	107,883	71,181	36,045
Gross profit	171,912	92,083	53,792
Selling and administrative expenses	48,881	35,922	32,783
Income from operations	123,031	56,161	21,009
Equity in earnings (losses) of production facilities investments	7,927	(87)	--
Net interest expense and other	5,265	3,403	1,968
Income before income taxes and change in accounting principle	125,693	52,671	19,041
Provision for income taxes	43,034	18,993	6,664
Income before change in accounting principle	82,659	33,678	12,377
Cumulative effect of change in accounting principle, net	--	530	--
Net Income	82,659	34,208	12,377
Preferred stock dividends and accretion	2,743	1,437	--
Net income applicable to common shareholders	$ 79,916	$ 32,771	$ 12,377
Earnings per common share			
Basic: Earnings per share before change in accounting principle	$ 2.09	$ 0.86	$ 0.35
Cumulative effect of change in accounting principle	--	0.01	--
Earnings per share	$ 2.09	$ 0.87	$ 0.35
Diluted: Earnings per share before change in accounting principle	$ 2.06	$ 0.86	$ 0.35
Cumulative effect of change in accounting principle	--	0.01	--
Earnings per share	$ 2.06	$ 0.87	$ 0.35
Weighted average common shares outstanding:			
Basic	38,204	37,740	35,504
Diluted	39,531	37,844	35,749

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

CAL DIVE INTERNATIONAL, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2004, 2003 AND 2002

ACCUMULATED OTHER COMMON
STOCK TREASURY STOCK
COMPREHENSIVE TOTAL ------
----------- RETAINED -----
------------ INCOME
SHAREHOLDERS' SHARES
AMOUNT EARNINGS SHARES
AMOUNT (LOSS) EQUITY -----
- -------- -------- ------
- ------- ------------ --
----------- (IN THOUSANDS)
Balance, December 31,
2001... 46,239 $ 99,105
$133,570 (13,783) $(6,326)
$ -- $226,349
Comprehensive income: Net
income................. --
-- 12,377 -- -- -- 12,377
Foreign currency
translation
adjustments.............
-- -- -- -- -- 2,548 2,548
Unrealized loss on
commodity hedges, net....
-- -- -- -- -- (2,642)
(2,642) --------
Comprehensive
income......... 12,283 ---
----- Sale of common
stock, net.... 3,961
87,219 -- -- -- -- 87,219
Activity in company stock
plans,
net................. 860
7,376 -- -- -- -- 7,376
Issuance of shares in
business
acquisition....... --
1,705 -- 181 2,585 --
4,290 ------ -------- ----
---- ------- ------- -----
-- -------- Balance,
December 31, 2002...
51,060 195,405 145,947
(13,602) (3,741) (94)
337,517 Comprehensive
income: Net
income................. --
-- 34,208 -- -- -- 34,208
Foreign currency
translations
adjustments.............
-- -- -- -- -- 5,044 5,044
Unrealized gain on
commodity hedges, net....
-- -- -- -- -- 1,215 1,215
-------- Comprehensive
income......... 40,467 ---
----- Convertible
preferred stock
dividends..................
-- -- (981) -- -- -- (981)
Accretion of preferred
stock
costs......................
-- -- (456) -- -- -- (456)
Activity in company stock
plans,
net................. 400
4,594 -- -- -- -- 4,594 --
---- -------- -------- ---
---- ------- ------- -----
--- Balance, December 31,

2003... 51,460 199,999
178,718 (13,602) (3,741)
6,165 381,141
Comprehensive income: Net
income................. --
-- 82,659 -- -- -- 82,659
Foreign currency
translations
adjustments.............
-- -- -- -- -- 10,780
10,780 Unrealized gain on
commodity hedges, net....
-- -- -- -- -- 846 846 ---
----- Comprehensive
income......... 94,285 ---
----- Convertible
preferred stock
dividends..................
-- -- (1,620) -- -- --
(1,620) Accretion of
preferred stock
costs......................
-- -- (1,123) -- -- --
(1,123) Activity in
company stock plans,
net................. 560
12,609 -- -- -- -- 12,609
------ -------- -------- -
------ ------- ------- ---
----- Balance, December
31, 2004... 52,020
$212,608 $258,634 (13,602)
$(3,741) $17,791 $485,292
====== ======== ========
======= ======= =======
========

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

CAL DIVE INTERNATIONAL, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2004, 2003 AND 2002

	YEAR ENDED DECEMBER 31,		
	2004	2003	2002
	(IN THOUSANDS)		
Cash flows from operating activities:			
Net income	$ 82,659	$ 34,208	$ 12,377
Adjustments to reconcile net income to net cash provided by operating activities --			
Cumulative effect of change in accounting principle	--	(530)	--
Depreciation and amortization	104,405	70,793	44,755
Asset impairment charge	3,900	--	--
Equity in (earnings) losses of production facilities investments	(469)	87	--
Deferred income taxes	42,046	18,493	6,130
Loss (gain) on sale of assets	100	45	(10)
Changes in operating assets and liabilities:			
Accounts receivable, net	(17,397)	(20,256)	(1,728)
Other current assets	(23,294)	5,038	(7,086)
Accounts payable and accrued liabilities	43,292	(9,808)	16,206
Other noncurrent, net	(8,435)	(10,654)	(3,749)
Net cash provided by operating activities	226,807	87,416	66,895
Cash flows from investing activities:			
Capital expenditures	(50,123)	(93,160)	(161,766)
Acquisition of businesses, net of cash acquired	--	(407)	(118,331)
Investments in production facilities	(32,206)	(1,917)	(32,688)
(Increase) decrease in restricted cash	(20,133)	73	(2,506)
Proceeds from (payments on) sales of property	(100)	200	483
Net cash used in investing activities	(102,562)	(95,211)	(314,808)
Cash flows from financing activities:			
Sale of common stock, net of transaction costs	--	--	87,219
Sale of convertible preferred stock, net of transaction costs	29,339	24,100	--
Borrowings under MARAD loan facility	--	--	43,899
Repayment of MARAD borrowings	(2,946)	(2,767)	(1,318)
Borrowings (repayments) on line of credit	(30,189)	(22,402)	52,591
Deferred financing costs	(4,550)	(208)	(1,694)
Borrowings on term loan	--	5,730	29,270
Repayments of term loan borrowings	(35,000)	--	--
Borrowings on capital leases	--	12,000	--
Capital lease payments	(3,647)	(2,430)	(5,183)
Preferred stock dividends paid	(1,620)	(981)	--
Redemption of stock in subsidiary	(2,462)	(2,676)	--
Exercise of stock options, net	11,038	3,570	5,900
Net cash (used in) provided by financing activities	(40,037)	13,936	210,684
Effect of exchange rate changes on cash and cash equivalents	556	237	106
Net increase (decrease) in cash and cash equivalents	84,764	6,378	(37,123)
Cash and cash equivalents:			
Balance, beginning of year	6,378	--	37,123
Balance, end of			

year...................................... $ 91,142 $ 6,378 $ -- ========= ======== =========

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION

Cal Dive International, Inc. (Cal Dive, CDI or the Company), headquartered in Houston, Texas, is an energy services company with operations in three primary business segments: Marine Contracting, Oil & Gas Production and Production Facilities. Within its Marine Contracting segment, CDI operates primarily in the Gulf of Mexico (Gulf), the North Sea and Asia/Pacific regions, with services that cover the lifecycle of an offshore oil or gas field. CDI's current diversified fleet of 22 vessels and 26 remotely operated vehicles (ROVs) and trencher systems perform services that support drilling, well completion, intervention, construction and decommissioning projects involving pipelines, production platforms, risers and subsea production systems. The Company also has a significant investment in offshore oil and gas production (through its wholly owned subsidiary Energy Resource Technology, Inc.) as well as production facilities. Operations in the Production Facilities segment began in 2004 with Marco Polo coming online. The Production Facilities segment is currently accounted for under the equity method of accounting and includes the Company's 50% investment in Deepwater Gateway, L.L.C. and its 20% investment in Independence Hub, LLC. CDI's customers include major and independent oil and gas producers, pipeline transmission companies and offshore engineering and construction firms.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

PRINCIPLES OF CONSOLIDATION

The accompanying consolidated financial statements include the accounts of the Company and its majority owned subsidiaries. All significant intercompany accounts and transactions have been eliminated. The Company accounts for its 50% interest in Deepwater Gateway, L.L.C. and its 20% interest in Independence Hub, LLC using the equity method of accounting as the Company does not have voting or operational control of either entity.

Certain reclassifications were made to previously reported amounts in the consolidated financial statements and notes thereto to make them consistent with the current presentation format.

USE OF ESTIMATES

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. On an ongoing basis the Company evaluates its estimates including those related to bad debts, investments, intangible assets and goodwill, property plant and equipment, decommissioning liabilities, income taxes, worker's compensation insurance and contingent liabilities. The Company bases its estimates on historical experience and on various other assumptions believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results could differ from those estimates.

GOODWILL

The Company tests for the impairment of goodwill on at least an annual basis. The Company's goodwill impairment test involves a comparison of the fair value of each of the Company's reporting units with its carrying amount. The fair value is determined using discounted cash flows and other market-related valuation models, such as earnings multiples and comparable asset market values. Prior to 2002 goodwill was amortized on a straight line basis over 25 years. In 2002 the Company discontinued the amortization of goodwill. The Company completed its annual goodwill impairment test as of November 1, 2004. The Company's goodwill impairment test involves a comparison of the fair value of each of the Company's reporting units with its carrying amount. All of the Company's goodwill as of December 31, 2004 and 2003 related to its Marine Contracting segment. None of the Company's goodwill was impaired based on the impairment test performed as of November 1, 2004. The Company will continue to test its goodwill annually on a consistent measurement date unless events occur or circumstances change between annual tests that would more likely than not reduce the fair value of a reporting unit below its carrying amount.

PROPERTY AND EQUIPMENT

Property and equipment, both owned and under capital leases, are recorded at cost. Depreciation is provided primarily on the straight-line method over the estimated useful lives of the assets.

All of the Company's interests in oil and gas properties are located offshore in United States waters. The Company follows the successful efforts method of accounting for its interests in oil and gas properties. Under the successful efforts method, the costs of successful wells and leases containing productive reserves are capitalized. Costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized. Costs incurred relating to unsuccessful exploratory wells are expensed in the period the drilling is determined to be unsuccessful.

Energy Resource Technology, Inc. ("ERT") acquisitions of producing offshore properties are recorded at the value exchanged at closing together with an estimate of its proportionate share of the discounted decommissioning liability assumed in the purchase based upon its working interest ownership percentage. In estimating the decommissioning liability assumed in offshore property acquisitions, the Company performs detailed estimating procedures, including engineering studies. The resulting decommissioning liability is reflected on the face of the balance sheet at fair value on a discounted basis. All capitalized costs are amortized on a unit-of-production basis (UOP) based on the estimated remaining oil and gas reserves. Properties are periodically assessed for impairment in value, with any impairment charged to expense.

The following is a summary of the components of property and equipment (dollars in thousands):

	ESTIMATED USEFUL LIFE	2004	2003
Vessels	15 to 30 years	506,262	$490,878
Offshore leases and equipment	UOP	328,071	292,858
Machinery, equipment, buildings and leasehold improvements	5 to 30 years	26,948	18,958
Total property and equipment		$861,281	$802,694

The Company capitalized interest totaling $243,000, $3.4 million and $4.4 million during the years ended December 31, 2004, 2003 and 2002, respectively.

The cost of repairs and maintenance of vessels and equipment is charged to operations as incurred, while the cost of improvements is capitalized. Total repair and maintenance charges were $17.0 million, $14.7 million and $11.5 million for the years ended December 31, 2004, 2003 and 2002, respectively.

For long-lived assets to be held and used, excluding goodwill, the Company bases its evaluation of recoverability on impairment indicators such as the nature of the assets, the future economic benefit of the assets, any historical or future profitability measurements and other external market conditions or factors that may be present. If such impairment indicators are present or other factors exist that indicate that the carrying amount of the asset may not be recoverable, the Company determines whether an impairment has occurred through the use of an undiscounted cash flows analysis of the asset at the lowest level for which identifiable cash flows exist. The Company's marine vessels are assessed on a vessel by vessel basis, while the Company's ROVs are grouped and assessed by asset class. If an impairment has occurred, the Company recognizes a loss for the difference between the carrying amount and the fair value of the asset. The fair value of the asset is measured using quoted market prices or, in the absence of quoted market prices, is based on an estimate of discounted cash flows. The Company recorded an impairment charge of $1.9 million (included in Marine Contracting cost of sales) in December 2004 on certain Marine Contracting vessels that met the impairment criteria. Assets are classified as held for sale when the Company has a plan for disposal of certain assets and those assets meet the held for sale criteria. During the fourth quarter of 2004, the Company classified a certain Marine Contracting vessel and other property and equipment intended to be disposed of within a twelve month period as assets held for sale totaling $5.0 million (included in other current assets at December 31, 2004). The Company recorded an impairment charge of $2.0 million (included in Marine Contracting cost of sales), representing the amount by which their carrying value exceeds estimated fair value less cost to sell.

RECERTIFICATION COSTS AND DEFERRED DRYDOCK CHARGES

The Company's Marine Contracting vessels are required by regulation to be recertified after certain periods of time. These recertification costs are incurred while the vessel is in drydock where other routine repairs and maintenance are performed and, at times, major replacements and improvements are performed. The Company expenses routine repairs and maintenance as they are incurred. Recertification costs can be accounted for in one of three ways: (1) defer and amortize, (2) accrue in advance, or (3) expense as incurred. Companies in the industry use either the defer and amortize or the expense as incurred accounting method. The Company defers and amortizes recertification costs over the length of time in which the recertification is expected to last, which is generally 30 months. Major replacements and improvements, which extend the vessel's economic useful life or functional operating capability, are capitalized and depreciated over the vessel's remaining economic useful life. Inherent in this process are estimates the Company makes regarding the specific cost incurred and the period that the incurred cost will benefit.

The Company accounts for regulatory (U.S. Coast Guard, American Bureau of Shipping and Det Norske Veritas) related drydock inspection and certification expenditures by capitalizing the related costs and amortizing them over the 30-month period between regulatory mandated drydock inspections and certification. As of December 31, 2004 and 2003, capitalized deferred drydock charges (included in other assets, net) totaled $10.0 million and $7.3 million, respectively. During the years ended December 31, 2004, 2003 and 2002, drydock amortization expense was $4.9 million, $4.1 million and $4.9 million, respectively.

ACCOUNTING FOR DECOMMISSIONING LIABILITIES

On January 1, 2003, the Company adopted Statement of Financial Accounting Standards ("SFAS") No. 143, Accounting for Asset Retirement Obligations, which addresses the financial accounting and reporting obligations and retirement costs related to the retirement of tangible long-lived assets. Among other things, SFAS No. 143 requires oil and gas companies to reflect decommissioning liabilities on the face of the balance sheet at fair value on a discounted basis. Prior to January 1, 2003, the Company reflected this liability on the balance sheet on an undiscounted basis.

The adoption of SFAS No. 143 resulted in a cumulative effect adjustment as of January 1, 2003 to record (i) a $33.1 million decrease in the carrying values of proved properties, (ii) a $7.4 million decrease in accumulated depreciation, depletion and amortization of property and equipment, (iii) a $26.5 million decrease in decommissioning liabilities and (iv) a $0.3 million increase in deferred income tax liabilities. The net impact of items (i) through (iv) was to record a gain of $0.5 million, net of tax, as a cumulative effect adjustment of a change in accounting principle in the Company's consolidated statements of operations upon adoption on January 1, 2003. The Company has no material assets that are legally restricted for purposes of settling its decommissioning liabilities other than the $15.1 million of restricted cash in escrow (see Statement of Cash Flow Information in this footnote).

The pro forma effects of the application of SFAS No. 143 as if the statement had been adopted on January 1, 2002 are presented below (in thousands, except per share amounts):

	YEARS ENDED DECEMBER 31,		
	2004	2003	2003
Net income applicable to common shareholders as reported	$79,916	$32,771	$12,377
Changes in accretion and depreciation expense	--	--	(649)
Cumulative effect of accounting change	--	(530)	--
Pro forma net income applicable to common shareholders	$79,916	$32,241	$11,728
Pro forma earnings per common share applicable to common shareholders:			
Basic	$ 2.09	$ 0.86	$ 0.33
Diluted	2.06	0.86	0.33
Earnings per common share applicable to common shareholders as reported:			
Basic	$ 2.09	$ 0.87	$ 0.35
Diluted	2.06	0.87	0.35

The following table describes the changes in the Company's asset retirement obligations for the year ended 2004 (in thousands):

Asset retirement obligation at December 31, 2003	$78,414
Liability incurred during the period	202
Liabilities settled during the period	(5,415)
Revision in estimated cash flows	3,953
Accretion expense (included in depreciation and amortization)	4,876
Asset retirement obligation at December 31, 2004	$82,030

FOREIGN CURRENCY

The functional currency for the Company's foreign subsidiary, Cal Dive International Limited, is the applicable local currency (British Pound). Results of operations for this subsidiary are translated into U.S. dollars using average exchange rates during the period. Assets and liabilities of this foreign subsidiary are translated into U.S. dollars using the exchange rate in effect at the balance sheet date and the resulting translation adjustment, which was a gain of $10.8 million and $5.0 million (net of taxes of $2.8 million in 2003), respectively, is included in accumulated other comprehensive income, a component of shareholders' equity. Beginning in 2004, deferred taxes have not been provided on foreign currency translation adjustments since the Company considers its undistributed earnings (when applicable) of its non-U.S. subsidiaries to be permanently reinvested. As a result, cumulative deferred taxes on translation adjustments totaling approximately $6.5 million were reclassified from noncurrent deferred income taxes and accumulated other comprehensive income. All foreign currency transaction gains and losses are recognized currently in the statements of operations. These amounts for the years ended December 31, 2004 and 2003 were not material to the Company's results of operations or cash flows.

Canyon Offshore, the Company's ROV subsidiary, has operations in the Europe/West Africa and Asia/ Pacific regions. Canyon conducts the majority of its affairs in these regions in U.S. dollars which it considers the functional currency. When currencies other than the U.S. dollar are to be paid or received, the resulting gain or loss from translation is recognized in the statements of operations. These amounts for the years ended December 31, 2004 and 2003 were not material to the Company's results of operations or cash flows.

ACCOUNTING FOR PRICE RISK MANAGEMENT ACTIVITIES

The Company's price risk management activities involve the use of derivative financial instruments to hedge the impact of market price risk exposures primarily related to its oil and gas production. All derivatives are reflected in the Company's balance sheet at fair market value.

There are two types of hedging activities: hedges of cash flow exposure and hedges of fair value exposure. The Company engages primarily in cash flow hedges. Hedges of cash flow exposure are entered into to hedge a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability. Changes in the derivative fair values that are designated as cash flow hedges are deferred to the extent that they are effective and are recorded as a component of accumulated other comprehensive income until the hedged transactions occur and are recognized in earnings. The ineffective portion of a cash flow hedge's change in value is recognized immediately in earnings in oil and gas production revenues.

The Company formally documents all relationships between hedging instruments and hedged items, as well as its risk management objectives, strategies for undertaking various hedge transactions and the methods for assessing and testing correlation and hedge ineffectiveness. All hedging instruments are linked to the hedged asset, liability, firm commitment or forecasted transaction. The Company also assesses, both at the inception of the hedge and on an on-going basis, whether the derivatives that are used in the hedging transactions are highly effective in offsetting changes in cash flows of its hedged items. The Company discontinues hedge accounting if it determines that a derivative is no longer highly effective as a hedge, or it is probable that a hedged transaction will not occur. If hedge accounting is discontinued, deferred gains or losses on the hedging instruments are recognized in earnings immediately.

The fair value of hedging instruments reflects the Company's best estimate and is based upon exchange or over-the-counter quotations whenever they are available. Quoted valuations may not be available due to location differences or terms that extend beyond the period for which quotations are available. Where quotes are not available, the Company utilizes other valuation techniques or models to estimate market values. These modeling techniques require the Company to make estimations of future prices, price correlation and market volatility and liquidity. The Company's actual results may differ from its estimates, and these differences can be positive or negative.

During 2004 and 2003, the Company entered into various cash flow hedging swap and costless collar contracts to stabilize cash flows relating to a portion of the Company's oil and gas production. All of these qualified for hedge accounting and none extended beyond a year and a half. The aggregate fair value of the hedge instruments was a net liability of $876,000 and $2.2 million as of December 31, 2004 and 2003, respectively. For the years ended December 31, 2004 and 2003 the Company recorded unrealized gains of approximately $846,000 and $1.2 million, net of taxes of $456,000 and $654,000, respectively, in other comprehensive income, a component of shareholders' equity as these hedges were highly effective. The balance in the cash flow hedge adjustments account is recognized in earnings when the hedged item is sold. During 2004 and 2003, the Company reclassified approximately $11.1 million and $14.6 million, respectively, of losses from other comprehensive income to Oil and Gas Production revenues upon the sale of the related oil and gas production.

As of December 31, 2004, the Company has the following volumes under derivative contracts related to its oil and gas producing activities:

PRODUCTION PERIOD	INSTRUMENT TYPE	AVERAGE MONTHLY VOLUMES	WEIGHTED AVERAGE PRICE
Crude Oil:			
January -- June 2005	Swap	20 MBbl	$35.80
January -- September 2005	Collar	40 MBbl	$37.00 -- $47.48
Natural Gas:			
January -- June 2005	Collar	300,000 MMBtu	$5.67 -- $8.15

Subsequent to December 31, 2004, the Company entered into additional oil costless collars for the periods July through December 2005 and October through December 2005. The July contract covers 20 MBbl per month at a price of $37.00 to $50.50 and the October contract covers 20 MBbl per month at a price of $37.00 to $50.80. The Company also entered into additional natural gas costless collars for the period July through December 2005. The contracts cover 225,000 MMBtu per month at a weighted average price of $5.00 to $9.44.

EQUITY INVESTMENTS

The Company periodically reviews its investments in Deepwater Gateway, L.L.C. and Independence Hub, LLC for impairment. Recognition of a loss would occur when the decline in an investment is other than temporary. In determining whether the decline is other than temporary, the Company considers the cyclical nature of the industry in which the investments operate, their historical performance, their performance in relation to their peers and the current economic environment. During 2004 and 2003 no impairment indicators existed.

EARNINGS PER SHARE

Basic earnings per share ("EPS") is computed by dividing the net income available to common shareholders by the weighted-average shares of outstanding common stock. The calculation of diluted EPS is similar to basic EPS except that the denominator includes dilutive common stock equivalents and the income included in the numerator excludes the effects of the impact of dilutive common stock equivalents, if any. The computation of the basic and diluted per share amounts for the Company was as follows (in thousands, except per share amounts):

	YEARS ENDED DECEMBER 31,		
	2004	2003	2002
Income before change in accounting principle	$82,659	$33,678	$12,377
Cumulative effect of change in accounting principle, net	--	530	--
Preferred stock dividends and accretion	(2,743)	(1,437)	--
Net income applicable to common shareholders	$79,916	$32,771	$12,377
Weighted-average common shares outstanding:			
Basic	38,204	37,740	35,504
Effect of dilutive stock options	305	104	245
Effect of convertible preferred stock	1,022	--	--

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Diluted... 39,531 37,844 35,749 ======= ======= =======

	YEARS ENDED DECEMBER 31,		
	2004	2003	2002
Basic Earnings Per Share:			
Income before change in accounting principle	$ 2.16	$ 0.90	$ 0.35
Cumulative effect of change in accounting principle, net	--	0.01	--
Preferred stock dividends and accretion	(0.07)	(0.04)	--
	$ 2.09	$ 0.87	$ 0.35
Diluted Earnings Per Share:			
Income before change in accounting principle	$ 2.09	$ 0.90	$ 0.35
Cumulative effect of change in accounting principle, net	--	0.01	--
Preferred stock dividends and accretion	(0.03)	(0.04)	--
	$ 2.06	$ 0.87	$ 0.35

Stock options to purchase approximately 1,027,000 shares and 260,000 shares for the years ended December 31, 2003 and 2002, respectively, were not dilutive and, therefore, were not included in the computations of diluted income per common share amounts. There were no antidilutive shares in 2004. In addition, approximately 510,000 shares attributable to the convertible preferred stock were excluded in the year ended December 31, 2004, calculation of diluted EPS, as the effect was antidilutive. Further, approximately 1,111,000 shares attributable to the convertible preferred stock were excluded in the year ended December 31, 2003, calculation of diluted EPS, as the effect was antidilutive. Net income for the diluted earnings per share calculation for the year ended December 31, 2004 was adjusted to add back the preferred stock dividends and accretion on the 1,022,000 shares.

STOCK BASED COMPENSATION PLANS

The Company uses the intrinsic value method of accounting to account for its stock-based compensation programs. Accordingly, no compensation expense is recognized when the exercise price of an employee stock option is equal to the common share market price on the grant date and all other provisions are fixed. The following table reflects the Company's pro forma results if the fair value method had been used for the accounting for these plans (in thousands, except per share amounts):

	YEARS ENDED DECEMBER 31,		
	2004	2003	2002
Net income applicable to common shareholders:			
As Reported	$79,916	$32,771	$12,377
Stock-based employee compensation cost, net of tax	(2,368)	(3,331)	(4,474)
Pro Forma	$77,548	$29,440	$ 7,903
Earnings per common share:			
Basic, as reported	$ 2.09	$ 0.87	$ 0.35
Stock-based employee compensation cost, net of tax	(0.06)	(0.09)	(0.13)
Basic, pro forma	$ 2.03	$ 0.78	$ 0.22
Diluted, as reported	$ 2.06	$ 0.87	$ 0.35
Stock-based employee compensation cost, net of tax	(0.06)	(0.09)	(0.13)
Diluted, pro forma	$ 2.00	$ 0.78	$ 0.22

For the purposes of pro forma disclosures, the fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions used: expected dividend yields of 0 percent; expected lives ranging from three to ten years, risk-free interest rate assumed to be 4.0 percent in 2004, 2003 and 2002, and expected volatility to be 56 percent in 2004 and 2003, and 59 percent in 2002. The fair value of shares issued under the Employee Stock Purchase Plan was based on the 15% discount received by the employees. The weighted average per share fair value of the options granted in 2004, 2003 and 2002 was $17.59, $12.74 and $15.20, respectively. The estimated fair value of the options is amortized to pro forma expense over the vesting period.

REVENUE RECOGNITION

The Company earns the majority of marine contracting revenues during the summer and fall months. Revenues are derived from billings under contracts (which are typically of short duration) that provide for either lump-sum turnkey charges or specific time, material and equipment charges which are billed in accordance with the terms of such contracts. The Company recognizes revenue as it is earned at estimated collectible amounts. Revenues generated from specific time, materials and equipment charges contracts are generally earned on a dayrate basis and recognized as amounts are earned in accordance with contract terms. Revenues generated in the pre-operation mode before a contract commences are deferred and recognized on a straight line basis in accordance with contract terms. Direct and incremental costs associated with pre-operation activities are similarly deferred and recognized over the estimated contract period.

Revenue on significant turnkey contracts is recognized on the percentage-of-completion method based on the ratio of costs incurred to total estimated costs at completion, or achievement of certain contractual milestones if provided for in the contract. Contract price and cost estimates are reviewed periodically as work progresses and adjustments are reflected in the period in which such estimates are revised. Provisions for estimated losses on such contracts are made in the period such losses are determined. The Company recognizes additional contract revenue related to claims when the claim is probable and legally enforceable. Unbilled revenue represents revenue attributable to work completed prior to year-end which has not yet been invoiced. All amounts included in unbilled revenue at December 31, 2004 are expected to be billed and collected within one year.

The Company records revenues from the sales of crude oil and natural gas when delivery to the customer has occurred and title has transferred. This occurs when production has been delivered to a pipeline or a barge lifting has occurred. The Company may have an interest with other producers in certain properties. In this case the Company uses the entitlements method to account for sales of production. Under the entitlements method the Company may receive more or less than its entitled share of production. If the Company receives more than its entitled share of production, the imbalance is treated as a liability. If the Company receives less than its entitled share, the imbalance is recorded as an asset.

ACCOUNTS RECEIVABLE AND ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS

Accounts receivable are stated at the historical carrying amount net of write-offs and allowance for uncollectible accounts. The Company establishes an allowance for uncollectible accounts receivable based on historical experience and any specific customer collection issues that the Company has identified. Uncollectible accounts receivable are written off when a settlement is reached for an amount that is less that the outstanding historical balance or when the Company has determined the balance will not be collected.

MAJOR CUSTOMERS AND CONCENTRATION OF CREDIT RISK

The market for the Company's products and services is primarily the offshore oil and gas industry. Oil and gas companies make capital expenditures on exploration, drilling and production operations offshore, the level of which is generally dependent on the prevailing view of the future oil and gas prices, which have been characterized by significant volatility. The Company's customers consist primarily of major, well-established oil and pipeline companies and independent oil and gas producers. The Company performs ongoing credit evaluations of its customers and provides allowances for probable credit losses when necessary. The percent of consolidated revenue of major customers was as follows: 2004 -- Louis Dreyfus Energy Services (11%) and Shell Trading (US) Company (10%); 2003 -- Shell Trading (US) Company (10%) and Petrocom Energy Group, Ltd. (10%); and 2002 -- Horizon Offshore, Inc. (10%) and BP Trinidad & Tobago LLC (11%). Louis Dreyfus Energy Services, Shell Trading (US) Company and Petrocom Energy Group, Ltd. were purchasers of ERT's oil and gas production. In March 2004, the Company elected not to renew its alliance with Horizon Offshore, Inc. As part of the settlement of outstanding trade accounts receivable with Horizon, the Company obtained exclusive use of a Horizon spoolbase facility for a period of five years. Utilization of the spoolbase facility was valued at approximately $2.0 million with the Company offsetting a corresponding amount of trade accounts receivable in exchange for the utilization agreement. The value of the spoolbase facility is being amortized over the five year term of the agreement. Trade receivables from Horizon at December 31, 2004 and 2003 were approximately $3.3 million and $11.0 million, respectively.

INCOME TAXES

Deferred income taxes are based on the differences between financial reporting and tax bases of assets and liabilities. The Company utilizes the liability method of computing deferred income taxes. The liability method is based on the amount of current and future taxes payable using tax rates and laws in effect at the balance sheet date. Income taxes have been provided based upon the tax laws and rates in the countries in which operations are conducted and income is earned. A valuation allowance for deferred tax assets is recorded when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized. The Company considers the undistributed earnings of its non-U.S. subsidiaries to be permanently reinvested. At December 31, 2004, the Company's non-U.S. subsidiaries had an accumulated deficit of $8.9 million in earnings and profits. These losses are primarily due to timing differences related to fixed assets. The Company has not provided deferred U.S. income tax on the losses.

STATEMENT OF CASH FLOW INFORMATION

The Company defines cash and cash equivalents as cash and all highly liquid financial instruments with original maturities of less than three months. The Company had $2.4 million of restricted cash as of December 31, 2003, of which $2.3 million represented amounts securing a performance bond which was released in March 2004. As of December 31, 2004, the Company had $22.6 million of restricted cash included in other assets, net, of which $15.1 million related to ERT's escrow funds for decommissioning liabilities associated with the South Marsh Island 130 ("SMI 130") field acquisitions in 2002. Under the purchase agreement, ERT is obligated to escrow 50% of production up to the first $20 million and 37.5% of production on the remaining balance up to $33 million in total escrow. Once the escrow reaches $10 million, ERT may use the restricted cash for decommissioning the related fields. Additionally, $7.5 million was included in restricted cash in other assets, net at December 31, 2004 related to the Company's investment in Deepwater Gateway, L.L.C. The Company is required to escrow up to $22.5 million related to its guarantee under the term loan agreement for Deepwater Gateway, L.L.C. See footnote 6.

During the years ended December 31, 2004, 2003 and 2002, the Company made cash payments for interest charges totaling $3.2 million, $2.7 million and $811,000, respectively, net of capitalized interest.

RECENTLY ISSUED ACCOUNTING PRINCIPLES

In December 2004, the FASB issued SFAS No. 123 (revised 2004), Share-Based Payment ("SFAS No. 123R"), which replaces SFAS No. 123, Accounting for Stock-Based Compensation, ("SFAS No. 123") and supercedes APB Opinion No. 25, Accounting for Stock Issued to Employees.

SFAS No. 123R requires all share-based payments to employees, including grants of employee stock options, to be recognized in the financial statements based on their fair values beginning with the first interim or annual period after June 15, 2005, with early adoption encouraged. The pro forma disclosures previously permitted under SFAS No. 123 no longer will be an alternative to financial statement recognition. The Company is required to adopt SFAS No. 123R in the third quarter of fiscal 2005, beginning July 1, 2005. Under SFAS No. 123R, the Company must determine the appropriate fair value model to be used for valuing share-based payments, the amortization method for compensation cost and the transition method to be used at date of adoption. The transition methods include prospective and retroactive adoption options. Under the retroactive option, prior periods may be restated either as of the beginning of the year of adoption or for all periods presented. The prospective method requires that compensation expense be recorded for all unvested stock options and restricted stock at the beginning of the first quarter of adoption of SFAS No. 123R, while the retroactive methods would record compensation expense for all unvested stock options and restricted stock beginning with the first period restated. The Company has not yet determined the method of adoption of SFAS No. 123R. The Company is evaluating the requirements of SFAS No. 123R and expects that the adoption of SFAS No. 123R will not have a material impact on the Company's consolidated results of operations and earnings per share.

SFAS No. 153, Exchanges of Nonmonetary Assets, an Amendment of APB Opinion No. 29. In December 2004, the FASB issued SFAS No. 153, which is effective for the Company for asset-exchange transactions beginning July 1, 2005. Under APB 29, assets received in certain types of nonmonetary exchanges were permitted to be recorded at the carrying value of the assets that were exchanged (i.e., recorded on a carryover basis). As amended by SFAS No. 153, assets received in some circumstances will have to be recorded instead at their fair values. In the past, the Company has not engaged in a large number of nonmonetary asset exchanges for significant amounts.

3. OFFSHORE PROPERTY TRANSACTIONS

As an extension of ERT's well exploitation and PUD strategies, ERT agreed to participate in the drilling of an exploratory well to be drilled in 2005 that targets reserves in deeper sands, within the same trapping fault system, of a currently producing well with estimated drilling costs of approximately $20 million, of which $1.1 million of equipment costs had been incurred through December 31, 2004. If the drilling is successful, ERT's share of the development cost is estimated to be an additional $15 million. CDI's Marine Contracting assets would participate in this development.

In March 2005, ERT acquired a 30% working interest in a proven undeveloped field in Atwater Valley Block 63 of the deepwater Gulf of Mexico for cash consideration and assumption of certain decommissioning liabilities. ERT's expected share of development costs for 2005 through 2007 are approximately $70 million to $100 million.

In March 2003, ERT acquired additional interests from Exxon/Mobil ranging from 45% to 84%, in four fields acquired in 2002, enabling ERT to take over as operator of one field. ERT paid $858,000 in cash and assumed Exxon/Mobil's pro-rata share of the abandonment obligation for the acquired interests.

In August 2002, ERT, acquired the 74.8% working interest of Shell Exploration & Production Company in the South Marsh Island 130 (SMI 130) field ("Shell acquisition"). ERT paid $10.3 million in cash and assumed Shell's pro-rata share of the related decommissioning liability. SMI 130 consists of two blocks, located in approximately 215 feet of water, with approximately 155 wells on five 8-pile platforms.

In August 2002, ERT also completed the purchase of seven Gulf of Mexico fields from Amerada Hess (including its 25% ownership position in SMI 130) for $9.3 million in cash and assumption of Amerada Hess's pro-rata share of the related decommissioning liability. As a result, ERT took over as operator with an effective 100% working interest in that field.

In June 2002, ERT acquired a package of offshore properties from Williams Exploration and Production. ERT paid $4.9 million and assumed the pro-rata share of the abandonment obligation for the acquired interests. The blocks purchased represent an average 30% net working interest in 26 Gulf of Mexico leases.

During the second quarter of 2003, the Company completed purchase price allocations relating to the Shell acquisition as well as Amerada Hess' interest in SMI 130 and six other fields, and the June 2002 acquisition of a package of properties from Williams Exploration and Production. The allocations were based on settlement agreements as well as additional information obtained relating to certain asset retirement obligation estimates. The result was a net decrease of $1.6 million in property and equipment and had no statement of operations impact.

In April 2002, ERT acquired a 100% interest in East Cameron Block 374, including existing wells, equipment and improvements. Terms included a cash payment of approximately $3 million to reimburse the owners for the inception-to-date cost of the subsea wellhead and umbilical, and an overriding royalty interest in future production. Cal Dive completed the temporarily abandoned number one well and performed a subsea tie-back to a host platform. The cost of completion and tie-back was approximately $7 million, with first production occurring in August 2002.

As a result of 2002 offshore property acquisitions, ERT assumed net abandonment liabilities estimated at approximately $63.6 million.

ERT production activities are regulated by the federal government and require significant third-party involvement, such as refinery processing and pipeline transportation. The Company records revenue from its offshore properties net of royalties paid to the Minerals Management Service (MMS). Royalty fees paid totaled approximately $26.7 million, $16.4 million and $9.2 million for the years ended December 31, 2004, 2003 and 2002 respectively. In accordance with federal regulations that require operators in the Gulf of Mexico to post an area wide bond of $3 million, the MMS has allowed the Company to fulfill such bonding requirements through an insurance policy.

4. RELATED PARTY TRANSACTIONS

In April 2000, ERT acquired a 20% working interest in Gunnison, a Deepwater Gulf of Mexico prospect of Kerr-McGee Oil & Gas Corp. Financing for the exploratory costs of approximately $20 million was provided by an investment partnership (OKCD Investments, Ltd. or "OKCD"), the investors of which include current and former CDI senior management, in exchange for a revenue interest that is an overriding royalty interest of 25% of CDI's 20% working interest. Production began in December 2003. Payments to OKCD from ERT totaled $20.3 million in the year ended December 31, 2004. The Company's Chief Executive Officer, as a Class A limited partner of OKCD, personally owns approximately 57% of the partnership. Other executive officers of the Company own approximately 6% combined of the partnership. OKCD has also awarded Class B limited partnership interests to key CDI employees.

During 2003, the Company was paid $2.2 million, by Ocean Energy, Inc. ("Ocean"), an oil and gas industry customer, for marine contracting services. A member of the Company's board of directors was a member of senior management of Ocean (now part of Devon Energy Corp.).

5. ACQUISITION OF BUSINESSES

CANYON OFFSHORE, INC.

In January 2002, CDI purchased Canyon, a supplier of remotely operated vehicles (ROVs) and robotics to the offshore construction and telecommunications industries. CDI purchased Canyon for cash of $52.8 million, the assumption of $9.0 million of Canyon debt (offset by $3.1 million of cash acquired), 181,000 shares of CDI common stock valued at $4.3 million (143,000 shares of which we purchased as treasury shares during the fourth quarter of 2001) and a commitment to purchase the redeemable stock in Canyon at a price to be determined by Canyon's performance during the years 2002 through 2004 from continuing employees at a minimum purchase price of $13.53 per share (or $7.5 million). The Company also agreed to make future payments relating to the tax impact on the date of redemption, whether employment continued or not. As they are employees, any share price paid in excess of the $13.53 per share will be recorded as compensation expense. These remaining shares have been classified as long-term debt in the accompanying balance sheet and will be adjusted to their estimated redemption value at each reporting period based on Canyon's performance. The acquisition was accounted for as a purchase with the acquisition price allocated to the assets acquired and liabilities assumed based upon their estimated fair values, with the excess being recorded as goodwill. The allocation of the $70.5 million purchase price was as follows: ROVs and equipment ($22.9 million); net working capital assumed ($4.0 million) and goodwill ($43.6 million). The results of Canyon are included in the accompanying statements of operations since the date of the purchase, January 2, 2002. In April 2004 and 2003, the Company purchased approximately one-third and one-third, respectively, of the redeemable shares at the minimum purchase price of $13.53 per share. Consideration included approximately $344,000 and $400,000 of contingent consideration relating to tax gross-up payments paid to the Canyon employees in accordance with the purchase agreement. These gross-up amounts were recorded as goodwill in the period paid (i.e., the second quarters of 2004 and 2003). As of December 31, 2004, goodwill related to the Canyon acquisition was approximately $44.8 million.

CAL DIVE INTERNATIONAL LIMITED (FORMERLY KNOWN AS WELL OPS (U.K.) LIMITED)

In July 2002, CDI purchased the subsea well operations business unit of CSO Ltd., a wholly owned subsidiary of Technip-Coflexip, for approximately $72.0 million ($68.6 million cash and $3.4 million deferred tax liability assumption). Cal Dive International Limited performs life of field well operations and marine construction tasks primarily in the North Sea. The assets purchased include the Seawell (a 368-foot DPDSV capable of supporting manned diving, ROVs and well operations). The acquisition was accounted for as a business purchase with the acquisition price allocated to the assets acquired and liabilities assumed based upon their estimated fair values, with the excess being recorded as goodwill. During the fourth quarter of 2002, the Company completed its purchase price allocation, including obtaining an appraisal of the Seawell, resulting in $50 million allocated to this vessel, $1.5 million allocated to patented technology (to be amortized over 20 years) and goodwill of approximately $20.6 million as of December 31, 2002 ($24.4 million as of December 31, 2004). The results of Cal Dive International Limited are included in the accompanying statements of operations since the date of the purchase, July 1, 2002.

6. INVESTMENTS IN PRODUCTION FACILITIES

In June 2002, CDI, along with Enterprise Products Partners L.P. ("Enterprise"), formed Deepwater Gateway, L.L.C. to design, construct, install, own and operate a tension leg platform ("TLP") production hub primarily for Anadarko Petroleum Corporation's Marco Polo field discovery in the Deepwater Gulf of Mexico. CDI's share of the construction costs was approximately $120 million, all of which had been incurred as of December 31, 2004. In August 2002, the Company along with Enterprise, completed a non-recourse project financing for this venture, terms of which include a minimum equity investment in Deepwater Gateway, L.L.C. of $33 million, all of which had been paid as of December 31, 2004, and is recorded as Investments in Production Facilities in the accompanying consolidated balance sheet. The Company's investment in Deepwater Gateway, L.L.C. totaled $56.6 million as of December 31, 2004. Included in the investment account was capitalized interest and insurance paid by the Company totaling approximately $2.6 million. In June 2004, the Deepwater Gateway, L.L.C. construction loan, excluded from the Company's long-term debt, was converted to a term loan. The term loan is collateralized by substantially all of Deepwater Gateway, L.L.C.'s assets and is non-recourse to the Company except for the balloon payment due at the end of the term. In the event of default, the Company would be required to pay up to $22.5 million; however, the Company has not recorded any liability for this guarantee as management believes that it is unlikely the Company will be required to pay the $22.5 million. In accordance with terms of the term loan, Deepwater Gateway, L.L.C. has the right to repay the principal amount plus any accrued interest due under its term loan at any time without penalty. Deepwater Gateway, L.L.C. has decided to extinguish its term loan. The Company and Enterprise will make equal cash contributions (approximately $72 million each) to Deepwater Gateway, L.L.C. to fund the repayment. At March 9, 2005, the term loan principal amount owed by Deepwater Gateway, L.L.C. was $144 million.

Summary balance sheets of Deepwater Gateway, L.L.C. as of December 31, 2004 and 2003 were as follows (in thousands):

	2004	2003
ASSETS		
Current assets	$ 5,047	$ 8,536
Noncurrent assets	250,508	230,826
	$255,555	$239,362
LIABILITIES AND MEMBERS' EQUITY		
Current liabilities	$ 25,164	$ 18,716
Noncurrent liabilities	122,397	155,000
Members' equity	107,994	65,646
	$255,555	$239,362

Summary statements of operations of Deepwater Gateway, L.L.C. for the years ended December 31, 2004, 2003 and 2002 were as follows (in thousands):

	2004	2003	2002
Revenues	$26,740	$ --	$ --
Operating expenses	247	187	234
Depreciation	6,018	--	--
Operating income (loss)	20,475	(187)	(234)
Interest expense	(4,475)	--	--
Interest income	118	47	20
Net Income (Loss)	$16,118	$(140)	$(214)

Deepwater Gateway, L.L.C. operated as a development stage enterprise for 2003 and 2002. In 2004, Deepwater Gateway, L.L.C. exited development stage.

In December 2004, CDI acquired a 20% interest in Independence Hub, LLC ("Independence"), an affiliate of Enterprise. Independence will own the "Independence Hub" platform to be located in Mississippi Canyon block 920 in a water depth of 8,000 feet. Independence has previously executed agreements with the Atwater Valley Producers Group of five exploration and production companies for the dedication and processing of natural gas and condensate production from fields in the Atwater Valley, DeSoto Canyon and Lloyd Ridge areas of the deepwater Gulf of Mexico on the Independence Hub platform. As part of that transaction, the producers have also dedicated future production from a number of undeveloped blocks in the area for processing. The 105 foot deep draft, semi-submersible platform will serve as a regional hub for natural gas production from multiple ultra-deepwater fields in the previously untapped eastern Gulf of Mexico. The platform, which is estimated to cost approximately $385 million, will be capable of processing 850 million cubic feet of gas per day. It is designed to process production from six anchor fields and has excess payload capacity to tie back up to 10 additional fields. CDI's initial investment of $10.6 million has been paid as of December 31, 2004, and its total investment in Independence is expected to be approximately $77 million. Further, CDI is party to a guaranty agreement with Enterprise to the extent of CDI's ownership in Independence (20% at December 31, 2004). The agreement states, among other things, that CDI and Enterprise guarantee performance under the Independence Hub Agreement between Independence and the producers group of exploration and production companies up to $397.5 million, plus applicable attorneys' fees and related expenses. CDI has estimated the fair value of its share of the guarantee obligation to be immaterial at December 31, 2004 based upon the extreme remote possibility of payments being made under the performance guarantee.

7. ACCRUED LIABILITIES

Accrued liabilities consisted of the following as of December 31, 2004 and 2003 (in thousands):

	2004	2003
Accrued payroll and related benefits	$20,195	$10,571
Workers' compensation claims	2,767	2,203
Insurance claims to be reimbursed	9,485	3,250
Royalties payable	26,196	6,589
Decommissioning liability	2,540	3,145
Hedging liability	876	2,194
Income taxes payable	797	--
Other	12,646	8,898
Total accrued liabilities	$75,502	$36,850

8. LONG-TERM DEBT

At December 31, 2004, $136.4 million was outstanding on the Company's long-term financing for construction of the Q4000. This U.S. Government guaranteed financing is pursuant to Title XI of the Merchant Marine Act of 1936 which is administered by the Maritime Administration ("MARAD Debt"). The MARAD Debt is payable in equal semi-annual installments which began in August 2002 and matures 25 years from such date. The MARAD Debt is collateralized by the Q4000, with CDI guaranteeing 50% of the debt, and bears interest at a rate which currently floats at a rate approximating AAA Commercial Paper yields plus 20 basis points (approximately 2.47% as of December 31, 2004). CDI has paid MARAD guarantee fees for this debt which adds approximately 50 basis points per annum of interest expenses. For a period up to ten years from delivery of the vessel in April 2002, CDI has the ability to lock in a fixed rate. In accordance with the MARAD Debt agreements, CDI is required to comply with certain covenants and restrictions, including the maintenance of minimum net worth, working capital and debt-to-equity requirements. As of December 31, 2004 the Company was in compliance with these covenants.

The Company had a $70 million revolving credit facility originally due in February 2005. This facility was collateralized by accounts receivable and certain of the Company's Marine Contracting vessels. All outstanding borrowings under the facility were repaid during 2004 and the facility was cancelled and terminated in August 2004 and replaced by the new $150 million revolving credit facility described below.

In August 2004, the Company entered into a four-year, $150 million revolving credit facility with a syndicate of banks, with Bank of America, N.A. as administrative agent and lead arranger. The amount available under the facility may be increased to $250 million at any time upon the agreement of the Company and the existing or additional lenders. The new credit facility is secured by the stock in certain Company subsidiaries and contains a negative pledge on assets. The new facility bears interest at LIBOR plus 75 -- 175 basis points depending on Company leverage and contains financial covenants relative to the Company's level of debt to EBITDA, as defined in the credit facility, fixed charge coverage and book value of assets coverage. As of December 31, 2004, the Company was in compliance with these covenants and there was no outstanding balance under this facility.

The Company had a $35 million term loan facility which was obtained to assist CDI in funding its portion of the construction costs of the spar for the Gunnison field. The loan was repaid in full in August 2004 and the loan agreement was subsequently cancelled and terminated.

In August 2003, Canyon Offshore, Ltd. (a U.K. subsidiary -- "COL") (with a parent guarantee from Cal Dive) completed a capital lease with a bank refinancing the construction costs of a newbuild 750 horsepower trenching unit and a ROV. COL received proceeds of $12 million for the assets and agreed to pay the bank sixty monthly installment payments of $217,174 (resulting in an implicit interest rate of 3.29%). No gain or loss resulted from this transaction. COL has an option to purchase the assets at the end of the lease term for $1. The proceeds were used to reduce the Company's revolving credit facility, which had initially funded the construction costs of the assets. This transaction was accounted for as a capital lease with the present value of the lease obligation (and corresponding asset) reflected on the Company's consolidated balance sheet.

Deferred financing costs of $11.6 million ($3.6 million of which was accrued at December 31, 2004 due upon the Company locking in a fixed rate of interest on the MARAD Debt) related to the MARAD Debt and the revolving credit facility, respectively, are being amortized over the life of the respective agreements and are included in Other Assets, net as of December 31, 2004.

The Company incurred interest expense, net of amounts capitalized, of $5.6 million, $2.6 million and $2.3 million for the years ended December 31, 2004, 2003 and 2002, respectively.

Scheduled maturities of Long-term Debt and Capital Lease Obligations outstanding as of December 31, 2004 were as follows (in thousands):

	MARAD DEBT	REVOLVER	CAPITAL LEASE & OTHER	TOTAL
2005	$ 4,321	$ --	$ 5,292	$ 9,613
2006	4,452	--	2,841	7,293
2007	4,585	--	2,512	7,097
2008	4,725	--	1,503	6,228
2009	4,867	--	--	4,867
Thereafter	113,462	--	--	113,462
Long-term debt	136,412	--	12,148	148,560
Current maturities	(4,321)	(-)	(5,292)	(9,613)
Long-term debt, less current maturities	$132,091	$ --	$ 6,856	$138,947

The Company had unsecured letters of credit outstanding at December 31, 2004 totaling approximately $3.7 million. These letters of credit primarily guarantee various contract bidding and insurance activities.

9. INCOME TAXES

CDI and its subsidiaries, including acquired companies from their respective dates of acquisition, file a consolidated U.S. federal income tax return. The Company conducts its international operations in a number of locations that have varying laws and regulations with regard to taxes. Management believes that adequate provisions have been made for all taxes that will ultimately be payable. Income taxes have been provided based on the US statutory rate of 35 percent adjusted for items which are allowed as deductions for federal income tax reporting purposes, but not for book purposes. The primary differences between the statutory rate and the Company's effective rate are as follows:

YEARS ENDED DECEMBER 31,	2004	2003	2002
Statutory rate	35.0%	35.0%	35.0%
Foreign provision	0.9	0.4	3.5
Foreign tax credit	--	--	(3.9)
Research and development tax credits	(1.3)	--	--
Other	(0.4)	0.7	0.4
Effective rate	34.2%	36.1%	35.0%

Components of the provision for income taxes reflected in the statements of operations consist of the following (in thousands):

YEARS ENDED DECEMBER 31,	2004	2003	2002
Current	$ 988	$ 500	$ 534
Deferred	42,046	18,493	6,130
	$43,034	$18,993	$6,664

	2004	2003	2002
Domestic	$41,260	$20,492	$5,996
Foreign	1,774	(1,499)	668
	$43,034	$18,993	$6,664

Deferred income taxes result from the effect of transactions that are recognized in different periods for financial and tax reporting purposes. The nature of these differences and the income tax effect of each as of December 31, 2004 and 2003, is as follows (in thousands):

	2004	2003
Deferred tax liabilities		
Depreciation	$136,328	$146,432
Equity investments in production facilities	23,152	--
Prepaid and other	6,657	13,055
Total deferred tax liabilities	$166,137	$159,487
Deferred tax assets		
Net operating loss carry forward	$ (3,706)	$(28,305)
Decommissioning liabilities	(28,711)	(31,546)
R&D credit carry forward	(4,455)	(18,335)
Reserves, accrued liabilities and other	(8,263)	(8,081)
Valuation allowance (R&D credit)	--	11,161
Total deferred tax assets	$(45,135)	$(75,106)
Net deferred tax liability	$121,002	$ 84,381

At December 31, 2004, the Company had $12.0 million of net operating losses, $4.5 million of research and development credits and $1.0 million of alternative minimum tax credits. $2.2 million of the net operating losses were incurred in the United States and $9.8 million were incurred in the United Kingdom. The credits were generated in the United States. The use of these net operating losses and the credits is subject to limitations imposed by the tax jurisdiction in which the loss or credit was generated and is also restricted to the taxable income of the entity generating the loss or credit. The U.S. losses if not utilized, will expire in 2022 and 2023. The U.K. losses have an indefinite carryforward period. The research and development credits will expire in the years 2018 through 2022. The alternative minimum tax credits have an indefinite carryforward period.

The examination of the Company's 2001 and 2002 income tax returns by the Internal Revenue Service ("IRS") was concluded in the first quarter of 2004. As a result, the Company recorded an income tax benefit of $1.7 million during the first quarter of 2004 primarily related to research and development credits offset by $430,000 of interest expense related to timing differences with respect to research and development deductions.

The IRS concluded its examination of the 2001 pre-acquisition income tax return for Canyon in the second quarter of 2004. The resolution of this audit did not have a material impact on the consolidated financial statements of the Company.

In 2004, the Company paid $282,000 in cash taxes for adjustments to Canyon Offshore Inc.'s 2001 U.S. Federal Income Tax return resulting from an IRS audit of that return. The Company paid no cash taxes in 2002 or 2003.

The Company plans to file for a change in its tax method of accounting for the timing differences that arise from the abandonment obligations assumed in certain offshore property acquisitions. The accompanying financial statements include an adjustment to account for the estimated amount of deferred tax liability related to this timing difference as required under the current tax accounting rules. At December 31, 2004 and 2003, the adjustment resulted in a decrease of $20.7 million and $16.4 million, respectively, in the deferred tax assets and liabilities for the timing differences related to abandonment obligations and fixed assets and a corresponding decrease of $20.7 million and $16.4 million, respectively, in the deferred tax asset related to net operating losses. This change has no impact on the net deferred tax liability of the Company.

The Company considers the undistributed earnings of its non-U.S. subsidiaries to be permanently reinvested. At December 31, 2004, the Company's non-U.S. subsidiaries had an accumulated deficit of $8.9 million in earnings and profits. These losses are primarily due to timing differences related to fixed assets. The Company has not provided deferred U.S. income tax on the losses.

10. CONVERTIBLE PREFERRED STOCK

On January 8, 2003, CDI completed the private placement of $25 million of a newly designated class of cumulative convertible preferred stock (Series A-1 Cumulative Convertible Preferred Stock, par value $0.01 per share) that is convertible into 833,334 shares of Cal Dive common stock at $30 per share. The preferred stock was issued to a private investment firm. Subsequently in June 2004, the preferred stockholder exercised its existing right and purchased $30 million in additional cumulative convertible preferred stock (Series A-2 Cumulative Convertible Preferred Stock, par value $0.01 per share). In accordance with the January 8, 2003 agreement, the $30 million in additional preferred stock is convertible into 982,029 shares of Cal Dive common stock at $30.549 per share. In the event the holder of the convertible preferred stock elects to redeem into Cal Dive common stock and Cal Dive's common stock price is below the conversion prices unless the Company has elected to settle in cash, the holder would receive additional shares above the 833,334 common shares (Series A-1 tranche) and 982,029 common shares (Series A-2 tranche). The incremental shares would be treated as a dividend and reduce net income applicable to common shareholders.

The preferred stock has a minimum annual dividend rate of 4%, subject to adjustment, payable quarterly in cash or common shares at Cal Dive's option. CDI paid these dividends in 2004 and 2003 on the last day of the respective quarter in cash. After the second anniversary of the original issuance, the holder may redeem the value of its original and additional investment in the preferred shares to be settled in common stock at the then prevailing market price or cash at the discretion of the Company. In the event the Company is unable to deliver registered common shares, CDI could be required to redeem in cash.

The proceeds received from the sales of this stock, net of transaction costs, have been classified outside of shareholders' equity on the balance sheet below total liabilities. The transaction costs have been deferred and accreted through the statement of operations through December 31, 2004. Prior to the conversion, common shares issuable will be assessed for inclusion in the weighted average shares outstanding for the Company's diluted earnings per share using the if converted method based on the Company's common share price at the beginning of the applicable period for the original $25 million issuance and on the date of issuance (June 25, 2004) for the additional $30 million. Beginning in 2005, both tranches of preferred stock will be based on the lower of the Company's share price at the beginning of the applicable period or the applicable conversion price ($30.00 and $30.549).

11. COMMITMENTS AND CONTINGENCIES

LEASE COMMITMENTS

The Company leases several facilities, ROVs and a vessel under noncancelable operating leases. Future minimum rentals under these leases are approximately $12.0 million at December 31, 2004 with $3.3 million due in 2005, $1.1 million in 2006, $1.1 million in 2007, $892,000 in 2008, $889,000 in 2009 and $4.7 million thereafter. Total rental expense under these operating leases was approximately $8.9 million, $8.1 million and $6.9 million for the years ended December 31, 2004, 2003 and 2002, respectively.

INSURANCE

The Company carries Hull and Increased Value insurance which provides coverage for physical damage to an agreed amount for each vessel. The deductibles are based on the value of the vessel with a maximum deductible of $500,000 on the Intrepid, Seawell and Q4000. Other vessels carry deductibles between $250,000 and $350,000. The Company also carries Protection and Indemnity insurance which covers liabilities arising from the operation of the vessel and General Liability insurance which covers liabilities arising from construction operations. The deductible on both the P&I and General Liability is $100,000 per occurrence. Onshore employees are covered by Workers' Compensation. Offshore employees, including divers and tenders and marine crews, are covered by Maritime Employers Liability insurance policy which covers Jones Act exposures and includes a deductible of $100,000 per occurrence plus a $1 million annual aggregate. In addition to the liability policies named above, the Company carries various layers of Umbrella Liability for total limits of $200,000,000 excess of primary limits. The Company's self insured retention on its medical and health benefits program for employees is $100,000 per claim.

The Company incurs workers' compensation and other insurance claims in the normal course of business, which management believes are covered by insurance. The Company, its insurers and legal counsel analyze each claim for potential exposure and estimate the ultimate liability of each claim. Amounts accrued and receivable from insurance companies, above the applicable deductible limits, are reflected in other current assets in the consolidated balance sheet. Such amounts were $9.5 million and $3.3 million as of December 31, 2004 and 2003, respectively. See related accrued liabilities at footnote 7. The Company has not incurred any significant losses as a result of claims denied by its insurance carriers.

LITIGATION AND CLAIMS

The Company is involved in various routine legal proceedings, primarily involving claims for personal injury under the General Maritime Laws of the United States and the Jones Act as a result of alleged negligence. In addition, the Company from time to time incurs other claims, such as contract disputes, in the normal course of business. In that regard, in 1998, one of the Company's subsidiaries entered into a subcontract with Seacore Marine Contractors Limited ("Seacore") to provide the Sea Sorceress to a Coflexip subsidiary in Canada ("Coflexip"). Due to difficulties with respect to the sea and soil conditions, the contract was terminated and an arbitration to recover damages was commenced. A preliminary liability finding has been made by the arbitrator against Seacore and in favor of the Coflexip subsidiary. The Company was not a party to this arbitration proceeding. Seacore and Coflexip settled this matter prior to the conclusion of the arbitration proceeding with Seacore paying Coflexip $6.95 million CDN. Seacore has initiated an arbitration proceeding against Cal Dive Offshore Ltd. ("CDO"), a subsidiary of Cal Dive, seeking contribution of one-half of this amount. One of the grounds in the preliminary findings by the arbitrator is applicable to CDO, and CDO holds substantial counterclaims against Seacore.

During 2002, the Company engaged in a large construction project offshore Trinidad and in late September of that year, supports engineered by a subcontractor failed resulting in over a month of downtime for two of CDI's vessels. Management believes under the terms of the contract the Company is entitled to indemnification for the contractual stand-by rate for the vessels during their downtime. The customer has disputed these invoices along with certain other change orders. In May 2004, the Company and its customer settled certain elements of the dispute. Of the amounts billed by CDI for this project, $6.8 million had not been collected as of December 31, 2004. This matter settled in March 2005 with no material effect on the Company's financial position or results of operations.

Although the above discussed matters have the potential of significant additional liability, the Company believes the outcome of all such matters and proceedings will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

12. EMPLOYEE BENEFIT PLANS

DEFINED CONTRIBUTION PLAN

The Company sponsors a defined contribution 401(k) retirement plan covering substantially all of its employees. The Company's contributions are in the form of cash and are determined annually as 50 percent of each employee's contribution up to 5 percent of the employee's salary. The Company's costs related to this plan totaled $691,000, $785,000 and $811,000 for the years ended December 31, 2004, 2003 and 2002, respectively.

STOCK-BASED COMPENSATION PLANS

During 2000, the Board of Directors approved a "Stock Option in Lieu of Salary Program" for the Company's Chief Executive Officer. Under the terms of the program, the participant may annually elect to receive non-qualified stock options (with an exercise price equal to the closing stock price on the date of grant) in lieu of cash compensation with respect to his base salary and any bonus earned under the annual incentive compensation program. The number of options granted is determined utilizing the Black-Scholes valuation model as of the date of grant with a risk premium included. The participant made such election for 2002 and 2001 resulting in a total of 105,000 and 180,000 options being granted during 2002 and 2001, respectively (which included bonuses earned under the annual incentive compensation program in 2001 and 2000).

During 1995, the Board of Directors and shareholders approved the 1995 Long-Term Incentive Plan, as amended (the Incentive Plan). Under the Incentive Plan, a maximum of 10% of the total shares of Common Stock issued and outstanding may be granted to key executives and selected employees who are likely to make a significant positive impact on the reported net income of the Company as well as non-employee members of the Board of Directors. The Incentive Plan is administered by a committee which determines, subject to approval of the Compensation Committee of the Board of Directors, the type of award to be made to each participant and sets forth in the related award agreement the terms, conditions and limitations applicable to each award. The committee may grant stock options, stock appreciation rights, or stock and cash awards. Options granted to employees under the Incentive Plan vest 20% per year for a five year period or 33% per year for a three year period, have a maximum exercise life of three, five or ten years and, subject to certain exceptions, are not transferable.

On January 3, 2005, the Company granted certain key executives and selected management employees 94,000 restricted shares under the Incentive Plan. The shares vest 20% per year for a five year period. The market value (based on the quoted price of the common stock on the date of grant) of the restricted shares was $39.12 per share, or $3.7 million, at the date of the grant and will be recorded as unearned compensation, a component of shareholders' equity. This amount will be charged to expense over the respective vesting period.

Effective May 12, 1998, the Company adopted a qualified, non-compensatory Employee Stock Purchase Plan ("ESPP"), which allows employees to acquire shares of common stock through payroll deductions over a six month period. The purchase price is equal to 85 percent of the fair market value of the common stock on either the first or last day of the subscription period, whichever is lower. Purchases under the plan are limited to 10 percent of an employee's base salary. Under this plan 46,790, 52,572 and 44,158 shares of common stock were purchased in the open market at a weighted average share price of $27.15, $21.74 and $21.86 during 2004, 2003 and 2002, respectively.

All of the options outstanding at December 31, 2004, have exercise prices as follows: 104,000 shares at $17.14, 118,000 shares at $19.63, 205,000 shares at $21.38, 131,035 shares at $21.83, 91,400 shares at $24.00, 124,500 shares at $24.36, 80,000 shares at $26.75 and 446,012 shares ranging from $16.45 to $27.82 and a weighted average remaining contractual life of 6.41 years.

Options outstanding are as follows:

	2004		2003		2002	
	SHARES	WEIGHTED AVERAGE EXERCISE PRICE	SHARES	WEIGHTED AVERAGE EXERCISE PRICE	SHARES	WEIGHTED AVERAGE EXERCISE PRICE
Options outstanding, Beginning of year....	1,723,102	$20.38	1,990,746	$19.52	2,179,246	$13.66
Granted................	168,500	25.26	183,990	17.90	732,670	21.88
Exercised.............	(559,909)	19.70	(315,757)	13.38	(862,241)	7.18
Terminated............	(31,746)	20.85	(135,877)	20.37	(58,929)	15.12
Options outstanding, December 31.......	1,299,947	$21.29	1,723,102	$20.38	1,990,746	$19.52
Options exercisable, December 31.......	714,174	$21.15	936,395	$20.69	704,191	$18.76

13. SHAREHOLDERS' EQUITY

The Company's amended and restated Articles of Incorporation provide for authorized Common Stock of 120,000,000 shares with no par value per share and 5,000,000 shares of preferred stock, $0.01 par value per share, in one or more series.

Included in accumulated other comprehensive income (loss) at December 31, 2004 was an unrealized loss on commodity hedges, net of $581,000 and an unrealized gain on foreign currency translation adjustments of $18.4 million.

In May 2002, CDI sold 3.4 million shares of primary common stock for $23.16 per share, along with 517,000 additional shares to cover over-allotments.

14. BUSINESS SEGMENT INFORMATION (IN THOUSANDS)

The Company's operations are conducted through three primary reportable segments, Marine Contracting, Oil and Gas Production and Production Facilities. The Company evaluates its performance based on income before income taxes of each segment. Segment assets are comprised of all assets attributable to the reportable segment The Company's Production Facilities segment (Deepwater Gateway, L.L.C. and Independence Hub, LLC) is accounted for under the equity method of accounting.

The following summarizes certain financial data by business segment:

	YEAR ENDED DECEMBER 31,		
	2004	2003	2002
Revenues -- Marine contracting	$ 300,082	$258,990	$239,916
Oil and gas production	243,310	137,279	62,789
Total	$ 543,392	$396,269	$302,705
Income from operations -- Marine contracting(1)	$ 5,694	$ 2,528	$ 742
Oil and gas production	117,337	53,633	20,267
Total	$ 123,031	$ 56,161	$ 21,009

	YEAR ENDED DECEMBER 31,		
	2004	2003	2002
Net interest expense and other --			
Marine contracting	$ 4,663	$ 2,786	$ 1,359
Oil and gas production	602	617	609
Total	$ 5,265	$ 3,403	$ 1,968
Equity in earnings (losses) of production facilities investments	$ 7,927	$ (87)	$ --
Provision (benefit) for income taxes --			
Marine contracting	$ (2,408)	$ 322	$ (798)
Oil and gas production	42,787	18,701	7,462
Production facilities equity investments	2,655	(30)	--
Total	$ 43,034	$ 18,993	$ 6,664
Identifiable assets --			
Marine contracting	$ 742,483	$623,095	$615,557
Oil and gas production	229,083	225,230	191,765
Production facilities equity investments	67,192	34,517	32,688
Total	$1,038,758	$882,842	$840,010
Capital expenditures --			
Marine contracting	$ 22,808	$ 21,569	$ 66,297
Oil and gas production	27,315	71,591	95,469
Production facilities equity investments	32,206	1,917	32,688
Total	$ 82,329	$ 95,077	$194,454
Depreciation and amortization --			
Marine contracting(1)	$ 39,259	$ 32,902	$ 27,220
Oil and gas production	69,046	37,891	17,535
Total	$ 108,305	$ 70,793	$ 44,755

- ---------------

(1) Included pre-tax $3.9 million of asset impairment charges in 2004.

During the years ended December 31, 2004 and 2003, the Company derived approximately $77.1 million and $48.4 million, respectively, of its revenues from the U.K. sector utilizing approximately $136.7 million and $117.1 million, respectively, of its total assets in this region. The majority of the remaining revenues were generated in the U.S. Gulf of Mexico.

15. SUPPLEMENTAL OIL AND GAS DISCLOSURES (UNAUDITED)

The following information regarding the Company's oil and gas producing activities is presented pursuant to SFAS No. 69, Disclosures About Oil and Gas Producing Activities (in thousands).

CAPITALIZED COSTS

Aggregate amounts of capitalized costs relating to the Company's oil and gas producing activities and the aggregate amount of related accumulated depletion, depreciation and amortization as of the dates indicated are presented below. The Company has no capitalized costs related to unproved properties.

	AS OF DECEMBER 31, 2004	2003	2002
Gunnison (net of accumulated depletion, depreciation and amortization	$ 107,335	$104,378	$ 63,294
Proved developed properties being amortized	201,392	188,113	180,256
Less -- Accumulated depletion, depreciation and amortization	(136,066)	(96,086)	(71,151)
Net capitalized costs	$ 172,661	$196,405	$172,399

Included in capitalized costs proved developed properties being amortized is the Company's estimate of its proportionate share of decommissioning liabilities assumed relating to these properties which are also reflected as decommissioning liabilities in the accompanying consolidated balance sheets at fair value on a discounted basis.

COSTS INCURRED IN OIL AND GAS PRODUCING ACTIVITIES

The following table reflects the costs incurred in oil and gas property acquisition and development activities, including estimated decommissioning liabilities assumed, during the years indicated:

	YEAR ENDED DECEMBER 31, 2004	2003	2002
Proved property acquisition costs	$ --	$ 2,687	$ 94,034
Development costs	38,373	79,289	67,241
Total costs incurred	$38,373	$81,976	$161,275

RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES

	YEAR ENDED DECEMBER 31, 2004	2003	2002
Revenues	$243,310	$137,279	$62,789
Production (lifting) costs	39,454	33,907	19,153
Depreciation, depletion and amortization	69,046	37,891	17,535
Selling and administrative	18,075	12,465	6,443
Pretax income from producing activities	116,735	53,016	19,658
Income tax expense	42,787	18,701	7,462
Results of oil and gas producing activities	$ 73,948	$ 34,315	$12,196

ESTIMATED QUANTITIES OF PROVED OIL AND GAS RESERVES

Proved oil and gas reserve quantities are based on estimates prepared by Company engineers in accordance with guidelines established by the U.S. Securities and Exchange Commission. The Company's estimates of reserves at December 31, 2004, have been audited by Huddleston & Co., independent petroleum engineers. All of the Company's reserves are located in the United States.

Proved reserves cannot be measured

exactly because the estimation of reserves involves numerous judgmental determinations. Accordingly, reserve estimates must be continually revised as a result of new information obtained from drilling and production history, new geological and geophysical data and changes in economic conditions.

As of December 31, 2002, 6,375,000 Bbls of oil and 51,807,000 Mcf of gas were undeveloped, 82% of which is attributable to Gunnison. As of December 31, 2003, 7,608,000 Bbls of oil and 28,888,000 Mcf of gas were undeveloped, 72% of which is attributable to Gunnison. As of December 31, 2004, 4,088,358 Bbls of oil and 16,842,700 MCf of gas were undeveloped, 41% of which is attributable to Gunnison.

RESERVE QUANTITY INFORMATION	OIL (MBBLS)	GAS (MMCF)	TOTAL (MMCFE)
Total proved reserves at December 31, 2001	7,858	53,936	101,084
Revision of previous estimates	(1,442)	11,049	2,397
Production	(922)	(11,062)	(16,594)
Purchases of reserves in place	6,543	31,302	70,560
Sales of reserves in place	--	--	--
Extensions and discoveries	--	--	--
Total proved reserves at December 31, 2002	12,037	85,225	157,447
Revision of previous estimates	1,942	(5,545)	6,107
Production	(1,952)	(16,208)	(27,920)
Purchases of reserves in place	6	2,657	2,693
Sales of reserves in place	--	--	--
Extensions and discoveries	488	8,531	11,459
Total proved reserves at December 31, 2003	12,521	74,660	149,786
Revision of previous estimates	(1,412)	(2,184)	(10,656)
Production	(2,593)	(25,957)	(41,515)
Purchases of reserves in place	--	--	--
Sales of reserves in place	(1)	(697)	(703)
Extensions and discoveries	2,002	7,382	19,394
Total proved reserves at December 31, 2004	10,517	53,204	116,306

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED OIL AND GAS RESERVES

The following table reflects the standardized measure of discounted future net cash flows relating to the Company's interest in proved oil and gas reserves as of December 31:

	2004	2003	2002
Future cash inflows	$ 756,668	$ 807,868	$ 693,023
Future costs -- Production	(125,350)	(127,530)	(129,375)
Development and abandonment	(146,131)	(145,268)	(176,094)
Future net cash flows before income taxes	485,187	535,070	387,554
Future income taxes	(144,263)	(154,046)	(106,258)
Future net cash flows	340,924	381,024	281,296
Discount at 10% annual rate	(54,185)	(71,586)	

(69,569) --------- --------- ---------
Standardized measure of discounted future net cash
Flows..
$ 286,739 $ 309,438 $ 211,727 =========
========= =========

CHANGES IN STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS

Principal changes in the standardized measure of discounted future net cash flows attributable to the Company's proved oil and gas reserves are as follows:

	2004	2003	2002
Standardized measure, beginning of year	$ 309,438	$ 211,727	$ 21,445
Sales, net of production costs	(203,856)	(103,372)	(43,729)
Net change in prices, net of production costs	92,395	102,319	69,085
Changes in future development costs	(17,474)	(3,339)	28,958
Development costs incurred	38,373	79,289	67,241
Accretion of discount	43,048	21,173	6,390
Net change in income taxes	3,770	(37,127)	(62,166)
Purchases of reserves in place	--	4,994	124,322
Extensions and discoveries	55,743	21,224	--
Sales of reserves in place	(3,077)	--	--
Net change due to revision in quantity estimates	(32,025)	11,312	899
Changes in production rates (timing) and other	404	1,238	(718)
Standardized measure, end of year	$ 286,739	$ 309,438	$211,727

16. ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS

The following table sets forth the activity in the Company's Allowance for Uncollectible Accounts for each of the three years in the period ended December 31, 2004 (in thousands):

	2004	2003	2002
Beginning balance	$ 7,462	$ 6,390	$ 2,889
Additions	2,745	2,688	8,678
Deductions	(2,439)	(1,616)	(5,177)
Ending balance	$ 7,768	$ 7,462	$ 6,390

See Note 2 for a detailed discussion regarding the Company's accounting policy on Accounts Receivable and Allowance for Uncollectible Accounts and Note 11 for a discussion of a large construction project in 2002.

17. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

The offshore marine construction industry in the Gulf of Mexico is highly seasonal as a result of weather conditions and the timing of capital expenditures by the oil and gas companies. Historically, a substantial portion of the Company's services has been performed during the summer and fall months. As a result, historically a disproportionate portion of the Company's revenues and net income is earned during such period. The following is a summary of consolidated quarterly financial information for 2004 and 2003.

	QUARTER ENDED			
	MARCH 31	JUNE 30	SEPTEMBER 30	DECEMBER 31

------- ---------- -------------- -----
--------- (IN THOUSANDS, EXCEPT PER
SHARE AMOUNTS) Fiscal 2004
Revenues...........................
$120,714 $127,701 $131,987 $162,990
Gross
profit.................................
31,741 41,415 45,726 53,030 Net
income....................................
14,009 18,592 23,787 26,271

	QUARTER ENDED			
	MARCH 31	JUNE 30	SEPTEMBER 30	DECEMBER 31
	(IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)			
Net income applicable to common shareholders	13,645	18,208	22,794	25,269
Earnings per common share:				
Basic	0.36	0.48	0.60	0.66
Diluted	0.36	0.47	0.59	0.65
Fiscal 2003				
Revenues	$ 88,900	$101,839	$103,855	$101,675
Gross profit	19,196	24,197	24,005	24,685
Income before change in accounting principle	5,851	9,275	9,299	9,253
Net income	6,381	9,275	9,299	9,253
Net income applicable to common shareholders	6,038	8,912	8,937	8,884
Earnings per common share:				
Basic:				
Earnings per share before change in accounting principle	0.15	0.24	0.24	0.23
Cumulative effect of change in accounting principle	0.01	--	--	--
Earnings per share	0.16	0.24	0.24	0.23
Diluted:				
Earnings per share before change in accounting principle	0.15	0.24	0.24	0.23
Cumulative effect of change in accounting principle	0.01	--	--	--
Earnings per share	0.16	0.24	0.24	0.23

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

The Company's management, with the participation of the Company's principal executive officer (CEO) and principal financial officer (CFO), evaluated the effectiveness of the Company's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of the end of the fiscal year ended December 31, 2004. Based on this evaluation, the CEO and CFO have concluded that the Company's disclosure controls and procedures were effective as of the end of the fiscal year ended December 31, 2004 to ensure that information that is required to be disclosed by the Company in the reports it files or submits under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms.

Management's Report on Internal Control Over Financial Reporting and the Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting thereon are set forth in Part II, Item 8 of the Annual Report on Form 10-K on page 44 and page 46, respectively. There were no changes in the Company's internal control over financial reporting that occurred during the fiscal quarter ended December 31, 2004 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Except as set forth below, the information required by this Item is incorporated by reference to the Company's definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection with the Company's 2005 Annual Meeting of Shareholders. See also "Executive Officers of the Registrant" appearing in Part I of this Report.

CODE OF ETHICS

The Company has adopted a Code of Business Conduct and Ethics for all directors, officers and employees as well as a Code of Ethics for Chief Executive Officer and Senior Financial Officers specific to those officers. Copies of these documents are available at the Company's Website www.caldive.com under Corporate Governance. Interested parties may also request a free copy of these documents from:

Cal Dive International, Inc.
ATTN: Corporate Secretary
400 N. Sam Houston Parkway E., Suite 400
Houston, Texas 77060

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference to the Company's definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection with the Company's 2005 Annual Meeting of Shareholders.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this Item is incorporated by reference to the Company's definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection with the Company's 2005 Annual Meeting of Shareholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required by this Item is incorporated by reference to the Company's definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection with the Company's 2005 Annual Meeting of Shareholders.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this Item is incorporated by reference to the Company's definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection with the Company's 2005 Annual Meeting of Shareholders.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(1) Financial Statements

The following financial statements included on pages 43 through 76 in this Annual Report are for the fiscal year ended December 31, 2004.

Management's Report on Internal Control Over Financial Reporting
Report of Independent Registered Public Accounting Firm
Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting
Consolidated Balance Sheets as of December 31, 2004 and 2003
Consolidated Statements of Operations for the Years Ended December 31, 2004, 2003 and 2002
Consolidated Statements of Shareholders' Equity for the Years Ended December 31, 2004, 2003 and 2002
Consolidated Statements of Cash Flows for the Years Ended December 31, 2004, 2003 and 2002
Notes to Consolidated Financial Statements.

All financial statement schedules are omitted because the information is not required or because the information required is in the financial statements or notes thereto.

(2) Exhibits.

Pursuant to Item 601(b)(4)(iii), the Registrant agrees to forward to the commission, upon request, a copy of any instrument with respect to long-term debt not exceeding 10% of the total assets of the Registrant and its consolidated subsidiaries.

The following exhibits are filed as part of this Annual Report:

EXHIBITS --- ----- 3.1 1997 Amended and Restated Articles of Incorporation of registrant, incorporated by reference to Exhibit 3.1 to the Form S-1 Registration Statement filed by registrant with the Securities and Exchange Commission

on May 1, 1997 (Reg. No. 333-26357) (the "Form S-1").
3.2 By-Laws of registrant, incorporated by reference to Exhibit 3.2 to the Form S-1.

EXHIBITS -------- 3.3 Articles of Correction, incorporated by reference to Exhibit 3.3 to the Form S-3 Registration Statement filed by registrant with the Securities and Exchange Commission on May 22, 2002 (Reg. No. 333- 87620) (the "Form S-3"). 3.4 Amendment to the 1997 Amended and Restated Articles of Incorporation of registrant, incorporated by reference to Exhibit 3.4 to the Form S-3. 3.5 Certificate of Rights and Preferences for Series A-1 Cumulative Convertible Preferred Stock, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed by registrant with the Securities and Exchange Commission on January 22, 2003 (the "2003 Form 8-K"). 3.6 Certificate of Rights and Preferences for Series A-2 Cumulative Convertible Preferred Stock, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed by registrant with the

Securities and Exchange Commission on June 28, 2004 (the "2004 Form 8-K"). 4.1 Credit Agreement by and among Bank of America, N.A., et al., as Lenders, and Cal Dive International, Inc., as Borrower, dated August 16, 2004, incorporated by reference to Exhibit 4.1 to the registrant's Annual Report on 10-Q for the fiscal quarter ended September 30, 2004, filed by the registrant with the Securities and Exchange Commission on November 5, 2004 (the "2004 Form 10-Q"). 4.2 Participation Agreement among ERT, Cal Dive International, Inc., Cal Dive/Gunnison Business Trust No. 2001-1 and Bank One, N.A., et. al., dated as of November 8, 2001, incorporated by reference to Exhibit 4.2 to Form 10-K for the fiscal year ended December 31, 2001, filed by the registrant with the Securities and Exchange Commission on March 28, 2002 (the "2001 Form 10-K"). 4.3 Form of Common Stock certificate, incorporated by reference to Exhibit 4.1 to the

Form S-1. 4.4 Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of August 16, 2000, incorporated by reference to Exhibit 4.4 to the 2001 Form 10-K. 4.5 Amendment No. 1 to Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of January 25, 2002, incorporated by reference to Exhibit 4.9 to the 2002 Form 10-K/A. 4.6 Amendment No. 2 to Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of November 15, 2002, incorporated by reference to Exhibit 4.4 to the 2003 Form S-3. 4.7 First Amended and Restated Agreement dated January 17, 2003, but effective as of December 31, 2002, by and between Cal Dive International, Inc. and Fletcher International, Ltd., incorporated by reference to Exhibit 10.1 to the 2003 Form 8-K. 4.8

Amended and Restated Credit Agreement among Cal Dive/Gunnison Business Trust No. 2001-1, Energy Resource Technology, Inc., Cal Dive International, Inc., Wilmington Trust Company, a Delaware banking corporation, the Lenders party thereto, and Bank One, NA, as Agent, dated July 26, 2002, incorporated by reference to Exhibit 4.12 to the 2002 Form 10-K/A. 4.9 First Amendment to Amended and Restated Credit Agreement among Cal Dive/Gunnison Business Trust No. 2001-1, Energy Resource Technology, Inc., Cal Dive International, Inc., Wilmington Trust Company, a Delaware banking corporation, the Lenders party thereto, and Bank One, NA, as Agent, dated January 7, 2003, incorporated by reference to Exhibit 4.13 to the 2002 Form 10-K/A. 4.10 Second Amendment to Amended and Restated Credit Agreement among Cal Dive/Gunnison Business

Trust No. 2001-1, Energy Resource Technology, Inc., Cal Dive International, Inc., Wilmington Trust Company, a Delaware banking corporation, the Lenders party thereto, and Bank One, NA, as Agent, dated February 14, 2003, incorporated by reference to Exhibit 4.14 to the 2002 Form 10-K/A. 4.11 Lease with Purchase Option Agreement between Banc of America Leasing & Capital, LLC and Canyon Offshore Ltd. dated July 31, 2003 incorporated by reference to Exhibit 10.1 to the Form 10-Q for the fiscal quarter ended September 30, 2003, filed by the registrant with the Securities and Exchange Commission on November 13, 2003.

EXHIBITS -------- 4.12* Amendment No. 3 Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of July 31, 2003. 4.13* Amendment No. 4 to Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of December 15, 2004. 10.1 1995 Long Term Incentive Plan, as amended, incorporated by reference to Exhibit 10.3 to the Form S-1. 10.2 Employment Agreement between Owen Kratz and Company dated February 28, 1999, incorporated by reference to Exhibit 10.5 to the registrant's Annual Report on Form 10-K for the fiscal year ended December 31, 1998, filed by the registrant with the Securities and Exchange Commission on March 31, 1999 (the "1998 Form 10-K"). 10.3 Employment Agreement between

Martin R. Ferron and Company dated February 28, 1999, incorporated by reference to Exhibit 10.6 of the 1998 Form 10-K. 10.4 Employment Agreement between A. Wade Pursell and Company dated January 1, 2002, incorporated by reference to Exhibit 10.7 of the 2001 Form 10-K. 10.5 Employment Agreement between James Lewis Connor, III and Company dated May 1, 2002, incorporated by reference to Exhibit 10.6 to the registrant's Annual Report on Form 10-K for the fiscal year ended December 31, 2003, filed by the registrant with the Securities and Exchange Commission on March 15, 2004 (the "2004 Form 10-K"). 10.6* First Amendment to Employment Agreement between James Lewis Connor, III and Company dated May 1, 2002. 21.1 Subsidiaries of registrant -- The registrant has thirteen subsidiaries: Energy Resource Technology, Inc.; Canyon Offshore, Inc.; Cal Dive ROV, Inc.; Cal Dive I-Title XI, Inc.; Cal Dive Offshore, Ltd.; Cal Dive International Limited; Well Ops Inc.; ERT (U.K.) Limited; Cal Dive HR Services Limited; Cal Dive Trinidad & Tobago Ltd.; Canyon Offshore Ltd.; Canyon Offshore International Corp.; and Well Ops PTE Limited.

23.1* Consent of Ernst & Young LLP.

23.2* Consent of Huddleston & Co., Inc.

31.1* Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Owen Kratz, Chief Executive Officer.

31.2* Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by A. Wade Pursell, Chief Financial Officer.

32.1* Section 1350 Certification by Owen Kratz, Chief Executive Officer.

32.2* Section 1350 Certification by A. Wade Pursell, Chief Financial Officer.

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* Filed herewith.

SIGNATURES

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

CAL DIVE INTERNATIONAL, INC.

By: /s/ A. WADE PURSELL

A. Wade Pursell
Senior Vice President,
Chief Financial Officer

March 15, 2005

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

SIGNATURE
TITLE DATE

----- ----
/s/ OWEN
KRATZ
Chairman,
Chief
Executive
Officer
March 15,
2005 - ---

----- and
Director
(principal
executive
Owen Kratz
officer)
/s/ MARTIN
R. FERRON
President,
Chief
Operating
Officer
March 15,
2005 - ---

----- and
Director
Martin R.
Ferron /s/
A. WADE
PURSELL
Senior
Vice
President
and Chief
March 15,
2005 - ---

Financial
Officer
(principal
A. Wade
Pursell
financial
officer)
/s/ LLOYD
A. HAJDIK
Vice

President -- Corporate March 15, 2005 - --- ---------- ---------- ---------- -----
Controller and Chief Accounting Lloyd A. Hajdik Officer (principal accounting officer)
/s/ GORDON F. AHALT Director March 15, 2005 - --- ---------- ---------- ---------- -----
Gordon F. Ahalt /s/ BERNARD J. DUROC-DANNER Director March 15, 2005 - --- ---------- ---------- ---------- -----
Bernard J. Duroc-Danner /s/ JOHN V. LOVOI Director March 15, 2005 - --- ---------- ---------- ---------- ----- John V. Lovoi
/s/ T. WILLIAM PORTER Director March 15, 2005 - --- ---------- ---------- ---------- ----- T. William Porter /s/ WILLIAM L. TRANSIER Director March 15, 2005 - --- ---------- ---------- ---------- -----
William L. Transier /s/ ANTHONY TRIPODO Director March 15, 2005 - ---

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Anthony
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INDEX TO EXHIBITS

EXHIBITS -------- 3.1 1997 Amended and Restated Articles of Incorporation of registrant, incorporated by reference to Exhibit 3.1 to the Form S-1 Registration Statement filed by registrant with the Securities and Exchange Commission on May 1, 1997 (Reg. No. 333-26357) (the "Form S-1"). 3.2 By-Laws of registrant, incorporated by reference to Exhibit 3.2 to the Form S-1. 3.3 Articles of Correction, incorporated by reference to Exhibit 3.3 to the Form S-3 Registration Statement filed by registrant with the Securities and Exchange Commission on May 22, 2002 (Reg. No. 333- 87620) (the "Form S-3"). 3.4 Amendment to the 1997 Amended and Restated Articles of Incorporation of registrant, incorporated by reference to Exhibit 3.4 to the Form S-3. 3.5 Certificate of Rights and Preferences for Series A-1 Cumulative Convertible Preferred Stock, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed by registrant with the Securities and Exchange Commission on January 22, 2003 (the "2003 Form 8-K"). 3.6 Certificate of Rights and Preferences for Series A-2 Cumulative Convertible Preferred Stock, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed by registrant with the Securities and Exchange Commission on June 28, 2004 (the "2004 Form 8-K"). 4.1 Credit Agreement by and among Bank of America, N.A., et al., as Lenders, and Cal Dive International, Inc., as Borrower, dated August 16, 2004, incorporated by reference to Exhibit 4.1 to the registrant's Annual Report on 10-Q for the fiscal quarter ended September 30, 2004, filed by the registrant with the Securities and Exchange Commission on November 5, 2004 (the "2004 Form 10-Q"). 4.2 Participation Agreement among ERT, Cal Dive International, Inc., Cal Dive/Gunnison Business

Trust No. 2001-1 and Bank One, N.A., et. al., dated as of November 8, 2001, incorporated by reference to Exhibit 4.2 to Form 10-K for the fiscal year ended December 31, 2001, filed by the registrant with the Securities and Exchange Commission on March 28, 2002 (the "2001 Form 10-K"). 4.3 Form of Common Stock certificate, incorporated by reference to Exhibit 4.1 to the Form S-1. 4.4 Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of August 16, 2000, incorporated by reference to Exhibit 4.4 to the 2001 Form 10-K. 4.5 Amendment No. 1 to Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of January 25, 2002, incorporated by reference to Exhibit 4.9 to the 2002 Form 10-K/A. 4.6 Amendment No. 2 to Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of November 15, 2002, incorporated by reference to Exhibit 4.4 to the 2003 Form S-3. 4.7 First Amended and Restated Agreement dated January 17, 2003, but effective as of December 31, 2002, by and between Cal Dive International, Inc. and Fletcher International, Ltd., incorporated by reference to Exhibit 10.1 to the 2003 Form 8-K. 4.8 Amended and Restated Credit Agreement among Cal Dive/Gunnison Business Trust No. 2001-1, Energy Resource Technology, Inc., Cal Dive International, Inc., Wilmington Trust Company, a Delaware banking corporation, the Lenders party thereto, and Bank One, NA, as Agent, dated July 26, 2002, incorporated by reference to Exhibit 4.12 to the 2002 Form 10-K/A. 4.9 First Amendment to Amended and Restated Credit Agreement among Cal Dive/Gunnison Business Trust No. 2001-1, Energy Resource

Technology, Inc., Cal Dive International, Inc., Wilmington Trust Company, a Delaware banking corporation, the Lenders party thereto, and Bank One, NA, as Agent, dated January 7, 2003, incorporated by reference to Exhibit 4.13 to the 2002 Form 10-K/A. 4.10 Second Amendment to Amended and Restated Credit Agreement among Cal Dive/Gunnison Business Trust No. 2001-1, Energy Resource Technology, Inc., Cal Dive International, Inc., Wilmington Trust Company, a Delaware banking corporation, the Lenders party thereto, and Bank One, NA, as Agent, dated February 14, 2003, incorporated by reference to Exhibit 4.14 to the 2002 Form 10-K/A.

EXHIBITS -------- 4.11 Lease with Purchase Option Agreement between Banc of America Leasing & Capital, LLC and Canyon Offshore Ltd. dated July 31, 2003 incorporated by reference to Exhibit 10.1 to the Form 10-Q for the fiscal quarter ended September 30, 2003, filed by the registrant with the Securities and Exchange Commission on November 13, 2003. 4.12* Amendment No. 3 Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of July 31, 2003. 4.13* Amendment No. 4 to Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of December 15, 2004. 10.1 1995 Long Term Incentive Plan, as amended, incorporated by reference to Exhibit 10.3 to the Form S-1. 10.2 Employment

Agreement between Owen Kratz and Company dated February 28, 1999, incorporated by reference to Exhibit 10.5 to the registrant's Annual Report on Form 10-K for the fiscal year ended December 31, 1998, filed by the registrant with the Securities and Exchange Commission on March 31, 1999 (the "1998 Form 10-K"). 10.3 Employment Agreement between Martin R. Ferron and Company dated February 28, 1999, incorporated by reference to Exhibit 10.6 of the 1998 Form 10-K. 10.4 Employment Agreement between A. Wade Pursell and Company dated January 1, 2002, incorporated by reference to Exhibit 10.7 of the 2001 Form 10-K. 10.5 Employment Agreement between James Lewis Connor, III and Company dated May 1, 2002, incorporated by reference to Exhibit 10.6 to the registrant's Annual Report on Form 10-K for the fiscal year ended December 31, 2003, filed by the registrant with the Securities and Exchange Commission on March 15, 2004 (the "2004 Form 10-K"). 10.6* First Amendment to Employment Agreement between James Lewis Connor, III and Company dated May 1, 2002. 21.1 Subsidiaries of registrant -- The registrant has thirteen subsidiaries: Energy Resource Technology, Inc.; Canyon Offshore, Inc.; Cal Dive ROV, Inc.; Cal Dive I-Title XI, Inc.; Cal Dive Offshore, Ltd.; Cal Dive International Limited; Well Ops Inc.; ERT (U.K.) Limited; Cal Dive HR Services Limited; Cal Dive Trinidad & Tobago Ltd.; Canyon Offshore Ltd.; Canyon Offshore International Corp.; and Well Ops PTE Limited. 23.1* Consent of Ernst & Young LLP. 23.2* Consent of Huddleston & Co., Inc. 31.1* Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Owen Kratz, Chief Executive Officer.

31.2* Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by A. Wade Pursell, Chief Financial Officer.

32.1* Section 1350 Certification by Owen Kratz, Chief Executive Officer.

32.2* Section 1350 Certification by A. Wade Pursell, Chief Financial Officer.

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* Filed herewith.

EXHIBIT 4.12

AMENDMENT NO. 3
TO
CREDIT AGREEMENT

THIS AMENDMENT NO. 3, dated as of July 31, 2003 (this "Amendment No. 3"), to that certain Credit Agreement, dated as of August 16, 2000, as amended by Amendment No. 1 thereto, dated as of January 25, 2002, and Amendment No. 2 thereto, dated as of November 15, 2002 (as amended, the "Credit Agreement"), is made by and among CAL DIVE I-TITLE XI, INC., a Texas corporation (the "Shipowner"), GOVCO INCORPORATED, a Delaware corporation (the "Primary Lender"), CITIBANK, N.A., a national banking association (the "Alternate Lender"), CITIBANK INTERNATIONAL PLC, a bank organized and existing under the laws of England, as facility agent for both the Primary Lender and the Alternate Lender (and their respective successors and assigns) with respect to the Floating Rate Note, and its permitted successors and assigns (in such capacity, the "Facility Agent"), and CITICORP NORTH AMERICA, INC., a Delaware corporation, as administrative agent for the Primary Lender and the commercial paper holders of the Primary Lender (and their respective successors and assigns) (in such capacity, together with its permitted successors and assigns, the "Administrative Agent," and together with the Facility Agent, the "Agents").

WHEREAS, pursuant to Title XI of the Merchant Marine Act, 1936, as amended, the United States of America, represented by the Secretary of Transportation, acting by and through the Maritime Administration (the "Secretary"), pursuant to the Guarantee Commitment, dated as of August 16, 2000, as amended by Amendment No. 1 thereto, dated as of January 25, 2002, agreed to a redetermination of the Actual Cost of the Q4000 (the "Vessel") of $183,065,667, and agreed to guarantee Obligations in an amount which will not exceed 87-1/2% of Actual Cost, or Depreciated Actual Cost, as the case may be, as he determined pursuant to Amendment No. 1 to Security Agreement, dated as of January 25, 2002, and as reflected in Table A thereto, as the same may be redetermined from time to time;

WHEREAS, the Shipowner entered into Supplement No. 1 to Trust Indenture, dated as of January 25, 2002, providing for the issuance of Obligations up to the aggregate principal amount of $160,182,000, and certain other revisions to the Indenture reflecting the revised Delivery Date and certain other technical amendments; and

WHEREAS, on November 15, 2002, the parties entered into Amendment No. 2 to Credit Agreement pursuant to which the Lenders agreed, inter alia, to reflect the actual Delivery Date, to change the Final Disbursement Date and to change the Stated Maturity of the Floating Rate Note.

WHEREAS, the parties wish to further amend the Credit Agreement for the purpose of (i) clarifying the cumulative amount of disbursements under the Credit Facility, and (ii) changing the Final Disbursement Date so that the Shipowner can coordinate disbursements to be made on that date with the final Actual Cost determination required to be made by the Secretary, and the procedures and conditions precedent to such determination by the Secretary.

NOW THEREFORE, in consideration of the mutual rights and obligations set forth herein and of other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties agree as follows:

SECTION 1.01. Exhibit 1 to the Credit Agreement is hereby further amended by adding thereto the following definitions:

> "Amendment No. 3 to Credit Agreement" means the Amendment No. 3 to Credit Agreement, dated as of July 31, 2003, among the Shipowner, the Lenders and the Agents."

SECTION 1.02. Section 2.01 of the Credit Agreement, as amended by Amendment No. 2 thereto, is hereby amended by adding the following proviso prior to the period at the end of said Section 2.01:

"; provided, however, that in no event shall disbursements under the Credit Facility exceed $160,182,000."

SECTION 1.03. The definition of "Final Disbursement Date" appearing in Section 2.02 of the Credit Agreement, as amended by Amendment No. 2 thereto, is hereby further amended by changing the date "August 1, 2003" to "November 15, 2003".

All capitalized terms used herein and not defined shall have the meanings set forth in Exhibit 1 to the Credit Agreement.

Except as amended, the provisions of the Credit Agreement shall apply to and govern this Amendment No. 3.

This Amendment No. 3 may be executed in several counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

(SIGNATURE PAGE FOLLOWS)

IN WITNESS WHEREOF, this Amendment No. 3 to Credit Agreement has been duly executed and delivered by the parties hereto as of the day and year first above written.

CAL DIVE I-TITLE XI, INC.,
as the Shipowner

By /s/ A. WADE PURSELL
Name: A. Wade Pursell
Title: Vice President

GOVCO INCORPORATED,
as the Primary Lender, by Citicorp North America, Inc., its attorney-in-fact

By /s/ PATRICK A. BOTTICELLI
Name: Patrick A. Botticelli
Title: Vice President

CITIBANK INTERNATIONAL PLC,
as the Facility Agent

By /s/ PATRICK A. BOTTICELLI
Name: Patrick A. Botticelli
Title: Vice President

CITIBANK, N.A.,
as the Alternate Lender

By /s/ AE KYONG CHUNG
Name: Ae Kyong Chung
Title: Vice President

CITICORP NORTH AMERICA, INC.,
as the Administrative Agent

By /s/ PATRICK A. BOTTICELLI
Name: Patrick A. Botticelli
Title: Vice President

CONSENT

Pursuant to Section 11.08 of the Credit Agreement, the Secretary hereby consents to this Amendment No. 3 to Credit Agreement.

UNITED STATES OF AMERICA,
SECRETARY OF TRANSPORTATION

BY: MARITIME ADMINISTRATOR

By /s/ JOEL C. RICHARD
Secretary
Maritime Administration

ATTEST:

By /s/ SARAH J. WASHINGTON
Assistant Secretary
Maritime Administration

EXHIBIT 4.13

AMENDMENT NO. 4
TO
CREDIT AGREEMENT

THIS AMENDMENT NO. 4, dated as of December 15, 2004 (this "Amendment No. 4"), to that certain Credit Agreement, dated as of August 16, 2000, as amended by Amendment No. 1 thereto, dated as of January 25, 2002 ("Amendment No. 1"); Amendment No. 2 thereto, dated as of November 15, 2002 ("Amendment No. 2"); and Amendment No. 3 thereto dated as of July 31, 2003 ("Amendment No. 3") (as so amended, the "Credit Agreement"), is made by and among CAL DIVE I-TITLE XI, INC., a Texas corporation (the "Shipowner"), GOVCO INCORPORATED, a Delaware corporation (the "Primary Lender"), CITIBANK, N.A., a national banking association (the "Alternate Lender"), CITIBANK INTERNATIONAL PLC, a bank organized and existing under the laws of England, as facility agent for both the Primary Lender and the Alternate Lender (and their respective successors and assigns) with respect to the Floating Rate Note, and its permitted successors and assigns (in such capacity, the "Facility Agent"), and CITICORP NORTH AMERICA, INC., a Delaware corporation, as administrative agent for the Primary Lender and the commercial paper holders of the Primary Lender (and their respective successors and assigns) (in such capacity, together with its permitted successors and assigns, the "Administrative Agent," and together with the Facility Agent, the "Agents").

WHEREAS, the Secretary has redetermined the estimated Actual Cost of the Vessel, and the Shipowner has received its final total disbursements under the Credit Agreement in the amount of $143,446,092 (which is not in excess of 87.5 percent (87.5%) of such redetermined estimated Actual Cost);

WHEREAS, the Shipowner is required to revise the mandatory sinking fund payments for the Floating Rate Note to take into account the changes referred to in the first WHEREAS clause hereof by substituting the Third Revised Amortization Schedule for the existing Second Revised Amortization Schedule, which Third Revised Amortization Schedule has been approved by the Secretary and is attached as Attachment 1 to Supplement No. 3 to Trust Indenture dated as of the date hereof; and

WHEREAS, the Parties wish to amend the Credit Agreement pursuant to which the Lenders will agree to revise the mandatory sinking fund payments for the Floating Rate Note.

NOW THEREFORE, in consideration of the mutual rights and obligations set forth herein and of other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties agree as follows:

SECTION 1.01. CONCERNING EXHIBIT 1 TO THE CREDIT AGREEMENT. Exhibit 1 to the Credit Agreement is hereby further amended by adding thereto the following definition:

> "Amendment No. 4 to Credit Agreement" means the Amendment No. 4 to Credit Agreement, dated as of December 15, 2004, among the Shipowner, the Lenders and the Agents."

SECTION 1.02. CONCERNING SECTION 4.01 TO THE CREDIT AGREEMENT. Section 4.01 of the Credit Agreement, as amended by Amendment No. 1 and Amendment No. 2 thereto, is further amended by deleting the Section in its entirety and substituting the following therefor:

> "4.01 Principal Repayment. The Shipowner shall repay the Outstanding Principal of the Floating Rate Note as follows:
>
> (1) In installments in the principal amounts set forth in the Third Revised Amortization Schedule, Attachment 1 to Supplement No. 3 to Trust Indenture (which replaces all prior changes to Attachment 1 to Trust Indenture in Supplements No. 1 and No. 2 to Trust Indenture), as the same may be further revised in accordance with the Indenture on each Payment Date commencing August 1, 2002, and continuing until February 1, 2012; and
>
> (2) The full amount of the remaining Outstanding Principal, on the earlier of (x) February 1, 2012, or (y) the date upon which the Trigger Event shall occur."

SECTION 1.03. MISCELLANEOUS.

(a) All capitalized terms used herein and not defined shall have the meanings set forth in Exhibit 1 to the Credit Agreement.

(b) Except as amended, the provisions of the Credit Agreement shall apply to and govern this Amendment No. 4.

(c) This Amendment No. 4 may be executed in several counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

(SIGNATURE PAGE FOLLOWS)

IN WITNESS WHEREOF, this Amendment No. 4 to Credit Agreement has been duly executed and delivered by the parties hereto as of the day and year first above written.

CAL DIVE I-TITLE XI, INC.,
as the Shipowner

By /s/ A. WADE PURSELL
Name: A. Wade Pursell
Title: Vice President

GOVCO INCORPORATED,
as the Primary Lender, by Citicorp North America, Inc., its attorney-in-fact

By /s/ PATRICK A. BOTTICELLI
Name: Patrick A. Botticelli
Title: Vice President

CITIBANK INTERNATIONAL PLC,
as the Facility Agent

By /s/ PATRICK A. BOTTICELLI
Name: Patrick A. Botticelli
Title: Vice President

CITIBANK, N.A.,
as the Alternate Lender

By /s/ AE KYONG CHUNG
Name: Ae Kyong Chung
Title: Vice President

CITICORP NORTH AMERICA, INC.,
as the Administrative Agent

By /s/ PATRICK A. BOTTICELLI
Name: Patrick A. Botticelli
Title: Vice President

CONSENT OF THE SECRETARY
TO
AMENDMENT NO. 4 TO CREDIT AGREEMENT

Pursuant to Section 11.08 of the Credit Agreement, the Secretary hereby consents to this Amendment No. 4 to Credit Agreement and confirms the continued Guarantee of the Obligation by the United States of America pursuant to Title XI of the Merchant Marine Act, 1936, as amended.

UNITED STATES OF AMERICA,
SECRETARY OF TRANSPORTATION

ATTEST:

By /s/ SARAH J. WASHINGTON
Assistant Secretary
Maritime Administration

BY: MARITIME ADMINISTRATOR

By /s/ JOEL C. RICHARD
Secretary
Maritime Administration

FIRST AMENDMENT TO AMENDED AND RESTATED EMPLOYMENT AGREEMENT

This First Amendment to Amended and Restated Employment Agreement ("First Amendment") is made effective as of the 1st day of January, 2004 (the "Effective Date"), between CAL DIVE INTERNATIONAL, INC., a Minnesota corporation, ("Company"), and JAMES LEWIS CONNOR, III ("Employee"), an individual residing at 50 Highland Circle, The Woodlands, Texas 77381.

WHEREAS, Company and Employee has previously entered into that certain Amended and Restated Employment Agreement (the "Agreement") is made effective as of the 1st day of May, 2002; and

WHEREAS, Company and Employee now wish to amend said Agreement to reflect a change in Employee's Incentive Bonus (as defined in said Agreement);

NOW, THEREFORE, in consideration of the premises and mutual covenants and agreements set forth herein, the parties hereto agree as follows:

1. Section 2(b) is deleted and substituted in lieu thereof the following new Section 2(b):

(b) Incentive Bonus. During the Employment Term, in addition to the Annual Salary payable to Employee pursuant to paragraph (a) above, Employee shall be entitled to an annual incentive bonus (the "Incentive Bonus") based on the achievement of personal, departmental and Company performance objectives, payable not later than three months after the close of each fiscal year of the Company, commencing with the fiscal year ending December 31, 2004, as established annually or from time to time by the Board of Directors.

2. Except as hereby amended by this First Amendment, said Agreement shall remain as originally written.

IN WITNESS, WHEREOF, the parties hereto have duly executed this First Amendment effective as of the date first above written.

CAL DIVE INTERNATIONAL, INC.		EMPLOYEE
By:	/s/ MARTIN R. FERRON	/s/ JAMES LEWIS CONNOR, III
Name:	Martin R. Ferron	James Lewis Connor, III
Title:	President and Chief Operating Officer	

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-103451) and Form S-8 (Nos. 333-58817, 333-50289 and, 333-50205) of Cal Dive International, Inc., of our reports dated March 11, 2005, with respect to the consolidated financial statements of Cal Dive International, Inc. and Subsidiaries, Cal Dive International, Inc. management's assessment of the effectiveness of internal control over financial reporting, and the effectiveness of internal control over financial reporting of Cal Dive International, Inc., included in this Annual Report (Form 10-K) for the year ended December 31, 2004.

/s/ ERNST & YOUNG LLP

Houston, Texas
March 11, 2005

EXHIBIT 23.2

[Letterhead of Huddleston & Co., Inc.]

March 8, 2005

Cal Dive International, Inc.
400 North Sam Houston Parkway East
Suite 400
Houston, TX 77060

Re: Cal Dive International, Inc.
Securities and Exchange Commission Form 10-K
Consent Letter

Gentlemen:

The firm of Huddleston & Co., Inc. consents to the naming of it as experts and to the incorporation by reference of its report letter dated February 10, 2005 concerning the proved reserves as of December 31, 2004 attributable to Energy Resource Technology, Inc. in the Annual Report of Cal Dive International, Inc. on Form 10-K to be filed with the Securities and Exchange Commission.

Huddleston & Co., Inc. has no interests in Cal Dive International, Inc. or in any of its affiliated companies or subsidiaries and is not to receive any such interest as payment for such report and has no director, officer, or employee employed or otherwise connected with Cal Dive International, Inc. We are not employed by Cal Dive International, Inc. on a contingent basis.

Very truly yours,

HUDDLESTON & CO., INC.

By: /s/ B.P. HUDDLESTON

B.P. Huddleston, P.E.
Chairman

EXHIBIT 31.1

SECTION 302 CERTIFICATION

I, Owen Kratz, the Principal Executive Officer of Cal Dive International, Inc., certify that:

1. I have reviewed this Annual Report on Form 10-K of Cal Dive International, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors:

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls.

Date: March 15, 2005

/s/ OWEN KRATZ

Owen Kratz
Chairman and Chief Executive Officer

EXHIBIT 31.2

SECTION 302 CERTIFICATION

I, A. Wade Pursell, the Principal Financial Officer of Cal Dive International, Inc., certify that:

1. I have reviewed this Annual Report on Form 10-K of Cal Dive International, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors:

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls.

Date: March 15, 2005

/s/ A. WADE PURSELL

A. Wade Pursell
Senior Vice President and
Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Annual Report of Cal Dive International, Inc. ("CDIS") on Form 10-K for the period ended December 31, 2004, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Owen Kratz, Chairman and Chief Executive Officer of CDIS, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) the Report fully complies with the requirements of section 13(a) of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of CDIS.

Date: March 15, 2005

/s/ OWEN KRATZ

Owen Kratz
Chairman and Chief Executive Officer

EXHIBIT 32.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Annual Report of Cal Dive International, Inc. ("CDIS") on Form 10-K for the period ended December 31, 2004, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, A. Wade Pursell, Senior Vice President and Chief Financial Officer of CDIS, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) the Report fully complies with the requirements of section 13(a) of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of CDIS.

Date: March 15, 2005

/s/ A. WADE PURSELL

A. Wade Pursell
Senior Vice President and
Chief Financial Officer