SPINNAKER EXPLORATION CO
Form 10-K
March 26, 2003

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SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

[X] Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal year ended December 31, 2002.

[_] 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 001-16009

SPINNAKER EXPLORATION COMPANY
(Exact name of registrant as specified in its charter)

Delaware	76-0560101
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1200 Smith Street, Suite 800 Houston, Texas	77002
(Address of principal executive offices)	(Zip Code)

(713) 759-1770
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Securities Exchange Act of 1934:

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.01 per share	New York Stock Exchange

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes [X] No [_]

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. [X]

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 on June 30, 2002 was approximately $943.6 million.

The number of shares outstanding of the registrant's Common Stock, par value $0.01 per share, on March 25, 2003 was 33,193,944.

Parts of the registrant's Definitive Proxy Statement for its 2003 Annual Meeting of Stockholders are incorporated by reference into Part III of this annual report on Form 10-K.

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Spinnaker Exploration Company ("Spinnaker" or the "Company") has provided definitions for some of the natural gas and oil industry terms used in this report in the "Glossary of Natural Gas and Oil Terms" on page 12.

Cautionary Statement About Forward-Looking Statements

Some of the information in this annual report on Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 (the "Exchange Act"). The forward-looking statements speak only as of the date made, and the Company undertakes no obligation to update such forward-looking statements. These forward-looking statements may be identified by the use of the words "believe," "expect," "anticipate," "will," "contemplate," "would" and similar expressions that contemplate future events. These future events include the following matters:

- financial position;
- business strategy;
- budgets;
- amount, nature and timing of capital expenditures, including future development costs;
- drilling of wells;
- natural gas and oil reserves;
- timing and amount of future production of natural gas and oil;
- operating costs and other expenses;
- cash flow and anticipated liquidity;
- prospect development and property acquisitions; and
- marketing of natural gas and oil.

Numerous important factors, risks and uncertainties may affect the Company's operating results, including:

- the risks associated with exploration;
- delays in anticipated start-up dates;
- the ability to find, acquire, market, develop and produce new properties;
- natural gas and oil price volatility;
- uncertainties in the estimation of proved reserves and in the projection of future rates of production and timing of development expenditures;
- downward revisions of proved reserves and the related negative impact on the depreciation, depletion and amortization rate;
- production and reserves concentrated in a small number of properties;
- operating hazards attendant to the natural gas and oil business;
- drilling and completion risks, which costs are generally not recoverable from third parties or insurance;
- potential mechanical failure or under-performance of significant wells;
- impact of weather conditions on timing and costs of operations;
- availability and cost of material and equipment;
- actions or inactions of third-party operators of the Company's properties;
- the ability to find and retain skilled personnel;
- availability of capital;
- the strength and financial resources of competitors;
- regulatory developments;
- environmental risks; and
- general economic conditions.

Any of the factors listed above and other factors contained in this annual report could cause the Company's actual results to differ materially from the results implied by these or any other forward-looking statements made by the Company or on its behalf. The Company cannot provide assurance that future results will meet its expectations. You should pay particular attention to the risk factors and cautionary statements described under "Risk Factors" in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

PART I

Item 1. Business

General

Spinnaker Exploration Company, a Delaware corporation, is an independent energy company engaged in the exploration, development and production of natural gas and oil in the U.S. Gulf of Mexico ("Gulf of Mexico"). Spinnaker's Chief Executive Officer, Warburg, Pincus Ventures, L.P. ("Warburg") and Petroleum Geo-Services ASA ("PGS") formed Spinnaker in December 1996.

At December 31, 2002, the Company had license rights to approximately 14,000 blocks of mostly contiguous 3-D seismic data in the Gulf of Mexico. This database covers an area of approximately 40 million acres, which the Company believes is one of the largest 3-D seismic databases of any independent exploration and production company in the Gulf of Mexico. As of December 31, 2002, the Company had 293 leasehold interests located in federal and Texas state waters of the Gulf of Mexico covering approximately 1,293,000 gross and 742,000 net acres. Within its current inventory of leasehold interests, the Company has identified and captured approximately 125 exploratory prospects. Based on 3-D seismic analysis on blocks where it currently has no leasehold interest, the Company also has identified over 200 leads that may result in additional prospects. The Company believes its regional 3-D seismic approach allows it to create and maintain a large inventory of high-quality prospects and provides the opportunity to enhance its exploration success and efficiently deploy its capital resources. The Company also believes its license rights to large quantities of high-quality seismic data and its management and technical staff are important factors for its current and future success.

From inception through December 31, 2002, the Company participated in drilling 120 wells in the Gulf of Mexico resulting in 70 discoveries. As of December 31, 2002, Ryder Scott Company, L.P. estimated the Company's net proved reserves at approximately 323.6 Bcfe. Spinnaker's current capital expenditure budget for 2003 is $250.0 million, including approximately $94.0 million for exploration activities, $114.0 million for development activities, $38.0 million for leasehold acquisitions and geological and geophysical expenditures and $4.0 million for other property and equipment. The Company currently plans to drill 18 wells on the shelf and 14 wells in the deep water in 2003. Exploration and development in deep water requires significant capital commitments. If the Company is successful in its deepwater exploration efforts in 2003, currently budgeted capital requirements for development activities in 2003 will increase.

Spinnaker has a 25% non-operator working interest in a significant deepwater oil discovery on Green Canyon Blocks 338/339 ("Front Runner"). The Company participated in six consecutive successful wells and sidetracks to test the reservoirs on these blocks through December 31, 2002. Of the Company's total proved reserves as of December 31, 2002, 70% were proved undeveloped reserves. Front Runner represented more than 60% of total proved undeveloped reserves. Spinnaker has incurred capital expenditures associated with Front Runner of $70.2 million through December 31, 2002 and expects to incur an aggregate of approximately $67.0 million in future development costs during 2003 and 2004. First production is anticipated during the summer of 2004.

On April 3, 2002, the Company completed a public offering of 5,750,000 shares of common stock, par value $0.01 per share ("Common Stock"), at $41.50 per share, including the over-allotment option consisting of 750,000 shares. After payment of underwriting discounts and commissions, the Company received net proceeds of $227.9 million. On April 3, 2002, the Company used a portion of the proceeds from the offering to repay outstanding borrowings of $37.0 million. The remaining net proceeds were invested in short-term high quality investments and used to fund a portion of the costs to develop Front Runner, to fund a portion of exploration and other development activities and for general corporate purposes.

Spinnaker files reports with the Securities and Exchange Commission ("Commission") on Forms 10-K, 10-Q and 8-K. The public may read and copy any materials that the Company files with the Commission at the

Commission's public reference room. The public may also access Spinnaker's annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished to the Commission pursuant to Section 13(a) or 15(d) of the Exchange Act on its internet website at www.spinnakerexploration.com, free of charge, as soon as reasonably practicable after Spinnaker electronically files or furnishes such material with or to the Commission.

Business Strategy

Spinnaker's goals are to expand its reserve base, increase cash flow and net income and to generate an attractive return on capital. The Company emphasizes the following elements in its strategy to achieve these goals:

- Focus on the Gulf of Mexico
- Maintain a large database of 3-D seismic data
- Employ a rigorous prospect selection process
- Emphasize technical expertise
- Sustain a balanced, diversified exploration effort while maintaining a conservative balance sheet.

Focus on the Gulf of Mexico. Spinnaker has assembled a large 3-D seismic database and focuses its exploration activities exclusively in the Gulf of Mexico because it believes this area represents one of the most attractive exploration regions in North America. The Gulf of Mexico has the following characteristics that make it attractive to exploration and production companies:

- Prolific exploration and production history
- Access to acreage
- Existing oilfield service infrastructure
- Attractive taxation and royalty rates
- Relatively high-productivity wells
- Transportation infrastructure with geographic proximity to well-developed markets for natural gas and oil
- Geologic diversity that offers a variety of exploration opportunities.

The Company also believes its geographic focus provides an excellent opportunity to develop and maintain competitive advantages through the combination of its 3-D seismic database and regional exploration and operating expertise.

Maintain a large database of 3-D seismic data. Spinnaker believes its large database of original and reprocessed 3-D seismic data allows it to generate and maintain a large inventory of high-quality exploratory prospects. The Company's 3-D seismic database serves as the foundation for its exploration program. The Company will continue to supplement this database with 3-D seismic data acquisitions from various seismic data vendors and upgrade and improve the existing 3-D seismic data through reprocessing.

Employ a rigorous prospect selection process. Spinnaker uses its large inventory of contiguous areas of 3-D seismic data to select prospects by tying regional 3-D seismic analysis to existing well control. Through this process, the Company enhances its understanding of the geology before selecting prospects and increases the probability of accurately identifying hydrocarbon-bearing zones.

Emphasize technical expertise. Spinnaker's 15 explorationists have an average of over 20 years experience in exploration in the Gulf of Mexico. Spinnaker also has a team of six technical specialists with significant experience in reprocessing seismic data, petrophysics and geologic modeling and inversion. In its efforts to attract and retain explorationists and technical specialists, the Company offers an entrepreneurial culture, an extensive 3-D seismic database, state-of-the-art computer-aided exploration technology and other technical tools.

Spinnaker generally retains larger working interests in prospects located in water depths of less than 2,000 feet. The combination of larger working interests and its technical expertise has allowed the Company to act as the operator for a majority of these prospects, providing more control of costs, the timing and amount of capital expenditures and the selection of technology.

Sustain a balanced, diversified exploration effort while maintaining a conservative balance sheet. Spinnaker believes that its exploration approach results in portfolio balance and diversity among:

- shallow water, or water depths of less than 600 feet, and deepwater prospects;
- shallow drilling depth prospects and deep drilling depth prospects; and
- lower-risk, lower-potential prospects and higher-risk, higher-potential prospects.

The broad coverage of the Gulf of Mexico by the Company's 3-D seismic data allows it to participate in a variety of geologically diverse exploration opportunities and to create a diversified prospect portfolio. The Company intends to manage its exposure in deepwater exploration activities by focusing on prospects where commercial feasibility of the prospect can be evaluated with a small number of wells and where it believes 3-D seismic analysis provides attractive risk/reward benefits. The Company also strives to diversify its exploration efforts by seeking to limit the budgeted amount of the leasehold acquisition and drilling costs of the first exploratory well on any one prospect to less than 10% of the annual capital budget.

The Company believes that maintaining continuity in its exploration activity during all phases of the commodity price cycles is an important element to balance and diversification. By positioning the Company to have a continuous exploration program, it can potentially take advantage of reduced competition for prospects and lower drilling and other oilfield service costs during periods of low natural gas and oil prices. Drilling deep depth prospects and drilling in deep water is inherently more risky than drilling shallow depth prospects and drilling in shallow water. Spinnaker's emphasis on maintaining a lower debt-to-capitalization ratio than many of its peers has enhanced its ability to pursue this strategy.

Seismic Data Agreements

Data Covered by Seismic Data Agreements

The initial data agreement with PGS provided Spinnaker with a minimum of approximately 3,700 blocks of 3-D seismic data. The Company has acquired an additional 10,300 blocks of standard and enhanced 3-D seismic data from various seismic contractors, including approximately 3,900 blocks from PGS. The Company's 3-D seismic database included a total of approximately 8,300 blocks of standard data and 5,700 blocks of enhanced data as of December 31, 2002.

Seismic contractors acquire both proprietary and multi-client marine seismic data. When a seismic contractor acquires proprietary data, it does so on an exclusive contractual basis for its customers. When a seismic contractor acquires multi-client data, it owns the data itself and licenses the possession and use of copies of the data to the industry at large for a fee. Most of the standard data that Spinnaker is entitled to use is multi-client seismic data. Some of Spinnaker's enhanced data is proprietary, internally-reprocessed seismic data.

Standard data is the basic 3-D, post-stack time-migrated seismic data provided as the standard product to customers by seismic contractors. Enhanced data is created through additional computer processing of standard data and includes processed data referred to as pre-stack depth-migrated data, 3-D amplitude versus offset

processing, refined pre-stack time-migrated data and several seismic attributes used for geologic delineation, rock property analysis and pore pressure prediction.

Rights to Use the Data

In general, the Company may use the multi-client data from its seismic contractors as follows:

- for its internal needs, including using the data in connection with the drilling of wells or the acquiring of interests in natural gas or oil properties;

- to make maps and other work products from the data;

- to make the data and work product available to the Company's consultants and contractors for interpretation, analysis, evaluation, mapping and additional processing, provided that the data and work product are held in confidence by those individuals; and

- to show data and work products to prospective and existing investors and participants in farm-outs and exploration or development groups for the sole purpose of evaluating their participation in such ventures, provided that the data and work product are held in confidence by those individuals.

The data agreements provide that the Company's rights to use the seismic data continue for at least 25 years from the date of purchase subject to certain termination provisions discussed below. The data the Company receives under any data agreement remains the property of that seismic contractor subject to the rights granted to the Company in the data agreement.

Restrictions on Transfer and Assignment

The various seismic data agreements provide provisions for transfer of data licenses in the event the Company merges with or is acquired by another company. In some cases, the Company will incur fees for the transfer of these licenses.

Termination Events

In general, a seismic contractor may terminate substantially all of the Company's rights under a data agreement by giving Spinnaker notice after the occurrence of certain events, such as:

- the Company transfers data or its rights under the data agreement in violation of the data agreement;
- a competitor of the seismic contractor acquires control of the Company;
- a second major customer of the seismic contractor acquires control of the Company after an initial major customer of the seismic contractor has previously acquired control of the Company;
- the Company knowingly breaches one of the provisions of the data agreement relating to the use, transfer or disclosure of the data;
- the Company unknowingly breaches one of the previously mentioned provisions of the data agreement and the Company fails to diligently prevent a subsequent breach after it receives notice of the first breach;
- the Company commits a material breach of one of the other provisions of the data agreement and fails to remedy the breach after notice to the Company; or
- the Company commences a voluntary bankruptcy or similar proceeding or an involuntary bankruptcy or similar proceeding is commenced against the Company and remains un-dismissed for 30 days.

Use of Computer-Aided Exploration Technology

Computer-aided exploration is the process of using a computer workstation and common database to accumulate and analyze seismic, production and other data regarding a geographic area. In general, computer-aided exploration involves accumulating 3-D seismic data, as well as 2-D data in some cases, with respect to a potential drilling location and correlating that data with historical well control and production data from similar properties. The available data is then analyzed using computer software and modeling techniques to project the likely geologic setting of a potential drilling location and potential locations of undiscovered natural gas and oil reserves. This process relies on a comparison of actual data for the potential drilling location and historical data for the density and sonic characteristics of different types of rock formations, hydrocarbons and other subsurface minerals, resulting in a projected 3-D image of the subsurface. This modeling is performed through the use of advanced interactive computer workstations and various combinations of available computer software developed solely for this application.

The Company has invested extensively in the advanced computer hardware and software necessary for 3-D seismic exploration. The Company's explorationists can access a diverse software tool kit including modeling, mapping, well path description, time slice analysis, pre- and post-stack seismic processing, synthetic generation, fluid replacement studies and seismic attribute analyses.

Marketing

The Company sells its natural gas and oil production under fixed or floating market price contracts. Revenues, profitability, cash flow and future growth depend substantially on prevailing prices for natural gas and oil. The prices received by the Company for its natural gas and oil production fluctuates widely. For example, natural gas prices increased significantly in the second half of 2002 after a sharp decline in 2001 from levels reached in the second half of 2000 and early 2001. Oil prices have also increased recently as compared to prior years. Among the factors that can cause this fluctuation are the level of consumer product demand, weather conditions, domestic and foreign governmental regulations, the price and availability of alternative fuels, political conditions and actual or threatened acts of war, terrorism or hostilities in oil producing regions, the domestic and foreign supply of natural gas and oil, the price of foreign imports and overall economic conditions.

Decreases in the prices of natural gas and oil could adversely affect the carrying value of proved reserves and revenues, profitability and cash flow. Although the Company is not currently experiencing any significant involuntary curtailment of natural gas or oil production, market, economic and regulatory factors may in the future materially affect its ability to sell natural gas or oil production. For the year ended December 31, 2002, sales to Duke Energy Trade and Marketing LLC, Cinergy Marketing & Trading LP, Equiva Trading Company and Kinder Morgan Ship Channel Pipeline LP accounted for approximately 52%, 13%, 11% and 11%, respectively, of the Company's natural gas and oil revenues, excluding the effects of hedging activities. For the year ended December 31, 2001, sales to Enron North America Corp., Tejas Gas Marketing, LLC, Reliant Energy Services, Inc. and Bridgeline Gas Marketing LLC accounted for approximately 32%, 23%, 21% and 17%, respectively, of the Company's natural gas and oil revenues, excluding the effects of hedging activities. For the year ended December 31, 2000, sales to Enron North America Corp., Coral Energy Resources, L.P. and Reliant Energy Services, Inc. accounted for approximately 61%, 11% and 11%, respectively, of the Company's natural gas and oil revenues, excluding the effects of hedging activities. Spinnaker no longer sells its natural gas and oil production to Enron North America Corp. Spinnaker believes the loss of this customer has not materially affected its ability to market its natural gas and oil production.

Customers purchase all of the Company's natural gas production at current market prices. The terms of the arrangements require the customers to pay the Company within 60 days after delivery of the production. As a result, if the customers were to default on their payment obligations to the Company, near-term earnings and cash flows would be adversely affected. However, due to the availability of other markets and pipeline connections, the Company does not believe that the loss of these customers or any other single customer would adversely affect its ability to market production.

Spinnaker enters into hedging arrangements from time to time to reduce its exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flow. However, these contracts also limit the benefits the Company would realize if prices increase. These financial arrangements take the form of swap contracts or cashless collars and are placed with major trading counterparties the Company believes represent minimal credit risks. Spinnaker cannot provide assurance that these trading counterparties will not become credit risks in the future. For further information concerning Spinnaker's hedging transactions, see "Item 7A. Quantitative and Qualitative Disclosures about Market Risk." Under its current hedging policy, the Company generally does not hedge more than 66 2/3% of its estimated twelve-month production quantities without the prior approval of the risk management committee of the board of directors.

Competition

The Company competes with major and independent natural gas and oil companies for leasehold acquisitions. Spinnaker also competes for the equipment and labor required to operate and develop these properties. Most of the Company's competitors have substantially greater financial and other resources. As a result, in the deep water where exploration is more expensive, competitors may be better able to withstand sustained periods of unsuccessful drilling. In addition, larger competitors may be able to absorb the burden of any changes in federal, state and local laws and regulations more easily than Spinnaker can, which would adversely affect Spinnaker's competitive position. These competitors may be able to pay more for exploratory prospects and productive natural gas and oil properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than the Company can. The Company's ability to explore for natural gas and oil prospects and to acquire additional properties in the future will depend upon its ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. In addition, most of the Company's competitors have been operating in the Gulf of Mexico for a much longer time than the Company has and have demonstrated the ability to operate through industry cycles.

Regulation

Federal Regulation of Sales and Transportation of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and the regulations promulgated thereunder by the Federal Energy Regulatory Commission ("FERC"). In the past, the federal government has regulated the prices at which natural gas could be sold. Deregulation of natural gas sales by producers began with the enactment of the Natural Gas Policy Act of 1978. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining Natural Gas Act of 1938 and Natural Gas Policy Act of 1978 price and non-price controls affecting producer sales of natural gas effective January 1, 1993. Congress could, however, re-enact price controls in the future.

The Company's sales of natural gas are affected by the availability, terms and cost of pipeline transportation. The price and terms for access to pipeline transportation remain subject to extensive federal regulation. Commencing in April 1992, the FERC issued Order No. 636 and a series of related orders that required interstate pipelines to provide open-access transportation on a basis that is equal for all natural gas suppliers. The FERC has stated that it intends for Order No. 636 and its future restructuring activities to foster increased competition within all phases of the natural gas industry. Although Order No. 636 does not directly regulate the Company's production and marketing activities, it does affect how buyers and sellers gain access to the necessary transportation facilities and how the Company and its competitors sell natural gas in the marketplace. The courts have largely affirmed the significant features of Order No. 636 and the numerous related orders pertaining to individual pipelines. The FERC continues to review and modify its regulations regarding the transportation of natural gas. In 2000, the FERC issued Order No. 637 and subsequent orders, which Spinnaker refers to collectively as "Order No. 637." Order No. 637 imposes a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 revised the FERC pricing policy

by waiving price ceilings for short-term released capacity for a two-year period ending September 30, 2002, and effected changes in the FERC regulations relating to scheduling procedures, capacity segmentation, pipeline penalties, rights of first refusal and information reporting. Several parties subsequently filed appeals in the Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") seeking court review of various aspects of Order 637, particularly (i) the right of customers to segment their contractual capacity in a manner that allows a forwardhaul/backhaul to a single point and (ii) the rights of first refusal granted to existing customers to extend contracts beyond the end of the contract's term. On April 5, 2002, the D.C. Circuit generally affirmed Order No. 637 but remanded certain issues to the FERC, including the forwardhaul/backhaul and the rights of first refusal issues. The FERC on remand affirmed its position on the forwardhaul/backhaul issue but reversed itself on the rights of first refusal issue. Requests for rehearing of this order are currently pending at the FERC.

Order No. 637 also required interstate natural gas pipelines to implement the policies mandated by the order through individual compliance filings. The FERC has now ruled on a number of the individual compliance filings, although its decisions in such proceedings remain subject to the outcome of pending rehearing requests and possible court appeals.

In addition, the FERC implemented new regulations governing the procedure for obtaining authorization to construct new pipeline facilities and has issued a policy statement, which it largely affirmed in recent orders on rehearing, establishing a presumption in favor of requiring owners of new pipeline facilities to charge rates based solely on the costs associated with such new pipeline facilities. The Company cannot predict what further action the FERC will take on these matters, nor can it accurately predict whether the FERC's actions will achieve the goal of increasing competition in markets in which natural gas is sold. However, the Company does not believe that any action taken will affect it in a way that materially differs from the way it affects other natural gas producers, gatherers and marketers.

The Outer Continental Shelf Lands Act ("OCSLA") requires that all pipelines operating on or across the Outer Continental Shelf provide open-access, non-discriminatory service. Although the FERC has opted not to impose the regulations of Order No. 509, in which the FERC implemented the OCSLA, on gatherers and other non-jurisdictional entities, the FERC has retained the authority to exercise jurisdiction over those entities if necessary to permit non-discriminatory access to service on the Outer Continental Shelf. The FERC recently issued Order No. 639, requiring that virtually all non-proprietary pipeline transporters of natural gas on the Outer Continental Shelf report information on their affiliations, rates and conditions of service. Among the FERC's stated purposes in issuing such rules was the desire to provide shippers on the Outer Continental Shelf with greater assurance of open-access services on pipelines located on the Outer Continental Shelf and non-discriminatory rates and conditions of service on such pipelines. A federal district court determined that the FERC has exceeded its statutory authority in promulgating Order Nos. 639 and 639-A, and the court permanently enjoined the FERC from enforcing the orders. The FERC's appeal of the district court's decision is currently pending at the D.C. Circuit.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC and the courts. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue.

Federal Leases

A substantial portion of the Company's operations is located on federal natural gas and oil leases, which are administered by the Minerals Management Service ("MMS"). Such leases are issued through competitive bidding, contain relatively standardized terms and require compliance with detailed MMS regulations and orders pursuant to the OCSLA that are subject to interpretation and change by the MMS. For offshore operations, lessees must obtain MMS approval for exploration plans and development and production plans prior to the commencement of such operations. In addition to permits required from other agencies such as the Coast Guard,

the Army Corps of Engineers and the Environmental Protection Agency, lessees must obtain a permit from the MMS prior to the commencement of drilling. The MMS has promulgated regulations requiring offshore production facilities located on the Outer Continental Shelf to meet stringent engineering and construction specifications. The MMS also has regulations restricting the flaring or venting of natural gas. Similarly, the MMS has promulgated other regulations governing the plugging and abandonment of wells located offshore and the installation and removal of all production facilities. To cover the various obligations of lessees on the Outer Continental Shelf, the MMS generally requires that lessees have substantial net worth or post bonds or other acceptable assurances that such obligations will be met. The cost of these bonds or other surety can be substantial, and there is no assurance that bonds or other surety can be obtained in all cases. The Company is currently in compliance with the bonding requirements of the MMS. Under some circumstances, the MMS may require any of the Company's operations on federal leases to be suspended or terminated. Any such suspension or termination could materially adversely affect the Company's financial condition and results of operations.

The MMS has issued a final rule that governs the calculation of royalties and the valuation of crude oil produced from federal leases. This rule amends the way that the MMS values crude oil produced from federal leases for determining royalties by eliminating posted prices as a measure of value and relying instead on arm's-length sales prices and spot market prices as indicators of value. The lawfulness of the new rule has been challenged at the D.C. Circuit. The Company cannot predict whether this new rule will be upheld in federal court, nor can the Company predict whether the MMS will take further action on this matter. The Company believes this rule will not have a material impact on its financial condition, liquidity or results of operations.

State and Local Regulation of Drilling and Production

The Company owns interests in properties located in the state waters of the

Gulf of Mexico offshore Texas and occasionally may conduct operations in the state waters offshore Louisiana and Mississippi. These states regulate drilling and operating activities by requiring, among other things, drilling permits and bonds and reports concerning operations. The laws of these states also govern a number of environmental and conservation matters, including the handling and disposal of waste materials, unitization and pooling of natural gas and oil properties and establishment of maximum rates of production from natural gas and oil wells. Some states prorate production to the market demand for natural gas and oil.

Oil Price Controls and Transportation Rates

Sales of crude oil, condensate and natural gas liquids by the Company are not currently regulated and are made at market prices. The price the Company receives from the sale of these products may be affected by the cost of transporting the products to market. Effective as of January 1, 1995, the FERC implemented regulations generally grandfathering all previously unchallenged interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. As required by its own regulations, in July 2000, the FERC issued a Notice of Inquiry seeking comment on whether to retain or to change the existing methodology underlying its then current indexing system, which was based on the Producer Price Index for Finished Goods ("PPI-FG") minus one percent. In December of 2000, the FERC issued an order concluding that the PPI-FG minus one percent methodology reasonably estimated the actual cost changes in the pipeline industry and should be continued for another five-year period, subject to review in July 2005. In February 2003, on remand of its December 2000 order from the D.C. Circuit, the FERC changed the rate indexing methodology to the PPI-FG, but without the subtraction of 1% as had been done previously. The FERC made the change prospective only, but did allow oil pipelines to recalculate their maximum ceiling rates as though the new rate indexing methodology had been in effect since July 1, 2001. The FERC's regulation of oil transportation rates may tend to increase the cost of transporting oil and natural gas liquids by interstate pipeline, although the annual adjustments may result in decreased rates in a given year. The Company is unable at this time to predict the effects of these regulations, if any, on the transportation costs associated with oil production from its properties. However, the Company does not believe that these regulations affect it any differently than other producers.

Environmental Regulations

The Company's operations are subject to numerous stringent and complex laws and regulations at the federal, state and local levels governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may:

- require acquisition of a permit before drilling commences;
- restrict the types, quantities and concentrations of various materials that can be released into the environment in connection with drilling and production activities;
- limit or prohibit construction or drilling activities in certain ecologically sensitive and other protected areas;
- require remedial action to prevent pollution from former operations; and

. impose substantial liabilities for pollution resulting from the Company's operations.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of remedial requirements and the imposition of injunctions to force future compliance. Moreover, public interest in the protection of the environment has increased dramatically in recent years. Offshore drilling in some areas has been opposed by environmental groups and, in some areas, has been restricted. To the extent laws are enacted or other governmental action is taken that prohibits or restricts offshore drilling or imposes environmental protection requirements that result in increased costs to the natural gas and oil industry in general and the offshore drilling industry in particular, the Company's business and prospects could be adversely affected.

The Oil Pollution Act of 1990 ("OPA") and regulations thereunder impose a variety of regulations on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in United States waters. A "responsible party" includes the owner or operator of a facility or vessel, or the lessee or permittee of the area in which an offshore facility is located. The OPA imposes strict, joint and several liability on responsible parties for oil removal costs and a variety of public and private damages, including natural resource damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Even if applicable, the liability limits for offshore facilities require the responsible party to pay all removal costs, plus up to $75.0 million in other damages. Few defenses exist to the liability imposed by the OPA.

The OPA also requires a responsible party to submit proof of its financial ability to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill. As amended by the Coast Guard Authorization Act of 1996, the OPA requires parties responsible for offshore facilities to provide financial assurance in the amount of $35.0 million to cover potential OPA liabilities. This amount can be increased up to $150.0 million in certain limited circumstances where the MMS believes such an amount is justified based on the operational, environmental, human health and other risks posed by the quantity or quality of oil that is explored for, drilled for or produced by the responsible party. The Company is in compliance with its financial assurance obligations.

The OPA also imposes other requirements, such as the preparation of oil spill response plans. The Company has such plans in place. The Company is also regulated by the Clean Water Act and similar state laws. The Clean Water Act prohibits any discharge into waters of the United States except in strict conformance with permits issued by federal and state agencies. Failure to comply with the ongoing requirements of these laws or inadequate cooperation during a spill event may subject a responsible party to administrative, civil or criminal enforcement actions.

In addition, the OCSLA authorizes regulations relating to safety and environmental protection applicable to lessees and permittees operating on the Outer Continental Shelf. Specific design and operational standards may apply to Outer Continental Shelf vessels, rigs, platforms, vehicles and structures. Violations of lease conditions or regulations issued pursuant to the OCSLA can result in substantial civil and criminal penalties, as well as potential court injunctions curtailing operations and the cancellation of leases.

The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), also known as the "Superfund" law, and analogous state laws impose liability, without regard to fault or the legality of the original conduct, on some classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under the CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources. Additionally, it is not uncommon for neighboring landowners and other third parties to file tort claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

The Company's operations are also subject to regulation of air emissions under the Clean Air Act, comparable state and local requirements and the OCSLA. Future regulations under these laws could lead to the gradual imposition of new air pollution control requirements on the Company's operations. The Company does not believe that its operations would be materially affected by any such requirements, nor does it expect such requirements to be any more burdensome to it than to other companies of its size involved in natural gas and oil exploration and production activities.

In addition, legislation has been proposed in Congress from time to time that would reclassify some natural gas and oil exploration and production wastes as "hazardous wastes," which would make the reclassified wastes subject to more stringent handling, disposal and clean-up requirements. If Congress were to enact this legislation, it could increase the Company's operating costs, as well as those of the natural gas and oil industry in general.

Management believes that the Company is in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on its results of operations.

Operating Hazards and Insurance

The natural gas and oil business involves a variety of operating risks, including fires, explosions, blow-outs and surface cratering, uncontrollable flows of underground natural gas, oil and formation water, natural disasters, pipe or cement failures, casing collapses, embedded oilfield drilling and service tools, abnormally pressured formations and environmental hazards such as natural gas leaks, oil spills, pipeline ruptures and discharges of toxic gases. If any of these events occur, the Company could incur substantial losses as a result of injury or loss of life, severe damage to and destruction of property, natural resources and equipment, pollution and other environmental damage, clean-up responsibilities, regulatory investigation and penalties, suspension of the Company's operations and repairs to resume operations. If the Company experiences any of these problems, it could affect well bores, platforms, gathering systems and processing facilities, which could adversely affect its ability to conduct operations.

As part of its strategy, the Company explores for natural gas and oil in the deep waters of the Gulf of Mexico where operations are more difficult than in shallower waters. The Company's deepwater drilling and operations require the application of recently developed technologies that involve a higher risk of mechanical failure. Furthermore, the deep waters of the Gulf of Mexico lack the physical and oilfield service infrastructure present in the shallower waters.

As a result, deepwater operations may require a significant amount of time between a discovery and the time that the Company can market the natural gas or oil, increasing the risks involved with these operations.

Offshore operations are also subject to a variety of operating risks specific to the marine environment, such as capsizing, collisions and damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, the Company could incur substantial liabilities that could reduce or eliminate the funds available for exploration, development or leasehold acquisitions, or result in loss of properties.

In accordance with industry practice, the Company maintains insurance against some, but not all, potential risks and losses. Management reviews Spinnaker's coverage at least annually. For some risks, the Company may not obtain insurance if it believes the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could adversely affect the Company.

Employees

At December 31, 2002, the Company had 65 full-time employees. The Company believes that it maintains excellent relationships with its employees. None of the Company's employees is covered by a collective bargaining agreement. From time to time, the Company uses the services of independent consultants and contractors to perform various professional services, particularly in the areas of construction, design, well-site surveillance, permitting and environmental assessment. Independent contractors usually perform field and on-site production operation services for the Company, including pumping, maintenance, dispatching, inspection and testing.

GLOSSARY OF NATURAL GAS AND OIL TERMS

The following is a description of the meanings of some of the natural gas and oil industry terms used in this annual report.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, of crude oil or other liquid hydrocarbons.

Bcf. Billion cubic feet of natural gas.

Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Block. A block depicted on the Outer Continental Shelf Leasing and Official Protraction Diagrams issued by the U.S. Minerals Management Service or a similar depiction on official protraction or similar diagrams issued by a state bordering on the Gulf of Mexico.

Btu or British Thermal Unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Completion. The installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Development well. A well drilled into a proved natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Exploratory well. A well drilled to find and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend a known reservoir.

Farm-in or farm-out. An agreement under which the owner of a working interest in a natural gas and oil lease assigns the working interest or a portion of the working interest to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a "farm-in" while the interest transferred by the assignor is a "farm-out."

Field. An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Lead. A specific geographic area which, based on supporting geological, geophysical or other data, is deemed to have potential for the discovery of commercial hydrocarbons.

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MBbls. Thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. Thousand cubic feet of natural gas.

Mcfe. Thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MMBls. Million barrels of crude oil or other liquid hydrocarbons.

MMBtu. Million British Thermal Units.

MMcf. Million cubic feet of natural gas.

MMcfe. Million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or wells, as the case may be.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved developed non-producing reserves. Proved developed reserves expected to be recovered from zones behind casing in existing wells.

Proved developed producing reserves. Proved developed reserves that are expected to be recovered from completion intervals currently open in existing wells and capable of production to market.

Proved developed reserves. Proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.

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

Proved undeveloped reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether or not such acreage contains proved reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production.

Item 2. Properties

Since inception, the Company has concentrated on the exploration for natural gas and oil exclusively in the Gulf of Mexico. As of December 31, 2002, proved reserves associated with Spinnaker's discoveries were located on 30 different blocks, including one property in which the Company has only a royalty interest, with production established from 26 blocks. Spinnaker operates 41 of its 70 discoveries, and the Company's working interests in these wells range from 12.5% to 100%. Six blocks account for approximately 73% of the Company's total proved reserves.

As of December 31, 2002, the Company had license rights to approximately 14,000 blocks of mostly contiguous 3-D seismic data in the Gulf of Mexico. This database covers an area of approximately 40 million acres, which the Company believes is one of the largest 3-D seismic databases of any independent exploration and production company in the Gulf of Mexico. As of December 31, 2002, the Company had 293 leasehold interests located in federal and Texas state waters of the Gulf of Mexico covering approximately 1,293,000 gross and 742,000 net acres.

Natural Gas and Oil Reserves

Spinnaker has a 25% non-operator working interest in its significant deepwater oil discovery at Front Runner. The Company participated in six consecutive successful wells and sidetracks in testing the reservoirs on these blocks through December 31, 2002. Of the Company's total proved reserves as of December 31, 2002, 70% were proved undeveloped reserves. Front Runner represented more than 60% of total proved undeveloped reserves.

The following table presents estimated net proved natural gas and oil reserves and the related net present value of the reserves at December 31, 2002 as prepared by Ryder Scott Company, L.P. The present value of future net cash flows (before income taxes) discounted at 10% and the standardized measure of discounted future net cash flows shown in the table are not intended to represent the current market value of the estimated natural gas and oil reserves Spinnaker owns. For further information concerning the present value of future net cash flows associated with these proved reserves, see Note 14 of the Notes to Consolidated Financial Statements.

The present value of future net cash flows and the standardized measure of discounted future net cash flows as of December 31, 2002 was determined by using prices of $4.91 per Mcf of natural gas and $30.50 per barrel of oil as of December 31, 2002.

	Proved Reserves		
	Developed	Undeveloped	Total
Natural gas (MMcf)..	84,139	59,392	143,531
Oil and condensate (MBbls)................................	2,219	27,789	30,008
Total proved reserves (MMcfe).............................	97,456	226,121	323,577
Present value of future net cash flows (before income taxes) discounted at 10% (in thousands)(1)......................	$323,426	$523,847	$847,273
Standardized measure of discounted future net cash flows (in thousands)(1)..	$259,878	$420,920	$680,798

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(1) Excludes pre-tax unrealized losses of $19.9 million for the effects of hedging activities using natural gas and oil prices in effect at December 31, 2002.

The process of estimating natural gas and oil reserves is complex. It requires various assumptions, including natural gas and oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The Company must project production rates and timing of development expenditures. The Company analyzes available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. Therefore, estimates of natural gas and oil reserves are inherently imprecise.

Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves most likely will vary from estimates. Any significant variance could materially affect the estimated quantities and net present value of reserves. In addition, the Company may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond the Company's control. At December 31, 2002, approximately 82% of the Company's proved reserves were either undeveloped or non-producing. Because most of the reserve estimates are not based on a lengthy production history and are calculated using volumetric analysis, these estimates are less reliable than estimates based on a lengthy production history.

At December 31, 2002, approximately 70% of the Company's proved reserves were undeveloped and primarily related to Front Runner. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling operations. The reserve data assumes that the Company will make these expenditures. Although the Company estimates its reserves and the costs associated with developing them in accordance with industry standards, the estimated costs may be inaccurate, development may not occur as scheduled and results may not be as estimated.

It should not be assumed that the present value of future net cash flows is the current market value of the Company's estimated natural gas and oil reserves. In accordance with requirements of the Commission, the Company bases the estimated discounted future net cash flows from 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 present value estimate.

Volumes, Prices and Operating Expenses

The following table presents information regarding the production volumes of, average sales prices received for and average production costs associated with Spinnaker's sales of natural gas and oil and condensate for the periods indicated:

	Year Ended December 31,		
	2002	2001	2000
Production:			
Natural gas (MMcf)	45,180	51,234	28,845
Oil and condensate (MBbls)	1,040	310	225
Total (MMcfe)	51,419	53,094	30,194
Average sales price per unit:			
Natural gas revenues from production (per Mcf)	$ 3.46	$ 4.14	$ 4.62
Effects of hedging activities (per Mcf)	0.10	(0.18)	(0.59)
Average price (per Mcf)	$ 3.56	$ 3.96	$ 4.03
Oil and condensate revenues from production (per Bbl)	$ 26.39	$ 24.90	$ 30.14
Effects of hedging activities (per Bbl)	--	--	(7.16)
Average price (per Bbl)	$ 26.39	$ 24.90	$ 22.98
Total revenues from production (per Mcfe)	$ 3.57	$ 4.14	$ 4.64
Effects of hedging activities (per Mcfe)	0.09	(0.18)	(0.62)
Total average price (per Mcfe)	$ 3.66	$ 3.96	$ 4.02

Expenses (per Mcfe):			
Lease operating expenses(1)	$ 0.35	$ 0.23	$ 0.30
Depreciation, depletion and amortization--natural gas and oil properties	$ 2.12	$ 1.60	$ 1.57

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(1) The lease operating expense rate includes $0.03 per Mcfe associated with workovers in 2002, $0.04 per Mcfe associated with workovers in 2001 and $0.03 per Mcfe associated with workovers in 2000.

Development, Exploration and Acquisition Capital Expenditures

The following table presents information regarding Spinnaker's net costs incurred in acquisition, exploration and development activities. Acquisition costs include costs incurred to purchase, lease or otherwise acquire property. Exploration costs include the costs of drilling exploratory wells, including those in progress, geological and geophysical service costs and depreciation of support equipment used in exploration activities. Development costs include the costs of drilling development wells and costs of completions, platforms, facilities and pipelines.

	Year Ended December 31,		
	2002	2001	2000
Acquisition costs:			
Unproved	$ 39,789	$ 34,524	$ 21,421
Proved	--	--	--
Exploration costs	163,322	187,720	121,451
Development costs	139,368	80,276	51,144
Total costs incurred	$342,479	$302,520	$194,016

Drilling Activity

The following table shows Spinnaker's drilling activity. In the table, "gross" refers to the total wells in which the Company has a working interest and "net" refers to gross wells multiplied by the Company's working interest in such wells.

	Year Ended December 31,					
	2002		2001		2000	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive	11	5.1	17	8.2	16	10.4
Nonproductive	11	6.2	16	9.4	12	4.7

Total	22	11.3	33	17.6	28	15.1
Development Wells:						
Productive	3	2.0	2	0.5	--	--
Nonproductive	1	0.4	--	--	--	--
Total	4	2.4	2	0.5	--	--

In 1999, the Company drilled an exploratory well that was preliminarily determined to be unsuccessful and was temporarily abandoned. Upon reprocessing of the seismic data, further analysis of the well and related sidetrack and examination of proved category reserves, the Company determined that the development would be commercial, and the well was reclassified as a discovery in 2000. This well commenced production in 2002.

Since December 31, 2002 and through March 25, 2003, the Company has drilled two gross (1.3 net) productive exploratory wells, one gross (0.3 net) productive development well and one gross (0.5 net) nonproductive exploratory well. As of March 25, 2003, the Company was drilling four gross (1.1 net) exploratory wells and one gross (0.4 net) development well.

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Productive Wells

The following table sets forth the number of productive natural gas and oil wells in which Spinnaker owned an interest as of December 31, 2002:

	Total Productive Wells	
	Gross	Net
Natural gas	60	32.1
Oil	10	3.1
Total	70	35.2

Productive wells consist of producing wells and wells capable of production, including wells awaiting pipeline connections to commence deliveries and wells awaiting connection to production facilities.

Acreage Data

The following table presents information regarding developed and undeveloped lease acreage. Developed acreage is considered to be those lease acres that are allocated or assignable to productive wells or wells capable of production. Undeveloped acreage is considered to be those lease acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether or not such acreage contains proved reserves. Spinnaker's developed and undeveloped lease acreage as of December 31, 2002 was as follows (in thousands):

	Developed Acreage		Undeveloped Acreage		Total	
	Gross	Net	Gross	Net	Gross	Net
Federal Waters Offshore Louisiana	60	34	730	370	790	404
Federal Waters Offshore Texas....	58	38	405	284	463	322
Texas State Waters..............	15	5	25	11	40	16
Total........................	133	77	1,160	665	1,293	742

The Company's lease agreements generally terminate if wells have not been drilled on the acreage within a period of five years from the date of the lease if located on the shelf in less than 200 meters of water or ten years if located in the deep waters of the Gulf of Mexico. Excluding lease acreage held by production, average remaining lease terms were 6.3 years, 4.4 years and 1.5 years for leases in federal waters offshore Louisiana, federal waters offshore Texas and Texas state waters, respectively.

Item 3. Legal Proceedings

From time to time, the Company may be a party to various legal proceedings. The Company currently is not a party to any material litigation.

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

The Company did not hold a meeting of stockholders or otherwise submit any matter to a vote of stockholders in the fourth quarter of 2002.

PART II

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

Spinnaker's Common Stock trades on the New York Stock Exchange under the symbol "SKE." The following table sets forth the range of high and low sales prices per share of Common Stock for each quarter by period.

	Sales Price	
	High	Low
2001:		
First Quarter.........................	$44.50	$33.00
Second Quarter........................	$48.00	$36.60
Third Quarter.........................	$43.96	$30.00
Fourth Quarter........................	$45.55	$33.30
2002:		
First Quarter.........................	$44.64	$34.45

Second Quarter	$44.89	$35.77
Third Quarter	$36.90	$24.46
Fourth Quarter	$29.71	$18.45
2003:		
First Quarter (through March 25, 2003)	$22.70	$17.15

On March 25, 2003, the closing sale price of Spinnaker's Common Stock, as reported by the New York Stock Exchange, was $18.52 per share. On that date, there were 39 holders of record.

The Company has never declared or paid any dividends on its Common Stock. The Company currently intends to retain future earnings, if any, for the operation and development of its business and does not anticipate paying any dividends on its Common Stock in the foreseeable future. In addition, the Company's $200.0 million credit agreement ("Credit Facility") contains restrictions and limitations on paying cash dividends on its Common Stock. For a description of the covenants and restrictive provisions in the Credit Facility, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations--Liquidity and Capital Resources--Financing Activities" and Note 4 of the Notes to Consolidated Financial Statements.

The table of "Securities Authorized for Issuance Under Equity Compensation Plans" is set forth under "Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters" and is incorporated by reference herein.

Item 6. Selected Financial Data

The following table sets forth some of the Company's historical consolidated financial data. The following data should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and the Consolidated Financial Statements and Notes thereto included elsewhere herein. The selected consolidated financial data provided below are not necessarily indicative of the future results of operations or financial performance of the Company.

	Year Ended Dece		
	2002	2001	2000
	(In thousands, except		
Statement of Operations Data:			
Revenues	$188,326	$210,376	$121,383
Expenses:			
Lease operating expenses	18,212	12,132	9,009
Depreciation, depletion and amortization--natural gas and oil properties	108,998	85,059	47,451
Depreciation and amortization--other	914	398	309
Write-down of natural gas and oil properties(1)	--	--	--
General and administrative	10,984	9,443	7,350
Charges related to Enron bankruptcy(2)	128	3,059	--
Stock appreciation rights expense(3)	--	--	--

Total expenses	139,236	110,091	64,119
Income (loss) from operations	49,090	100,285	57,264
Other income (expense):			
Interest income	1,014	3,574	2,908
Interest expense, net	(762)	(381)	(748
Total other income (expense)	252	3,193	2,160
Income (loss) before income taxes	49,342	103,478	59,424
Income tax expense	17,763	37,252	20,858
Income (loss) before cumulative effect of change in accounting principle	31,579	66,226	38,566
Cumulative effect of change in accounting principle(4)	--	--	--
Net income (loss)	31,579	66,226	38,566
Accrual of dividends on preferred stock	--	--	--
Net income (loss) available to common stockholders	$ 31,579	$ 66,226	$ 38,566
Basic income (loss) per common share(5)(6):			
Income (loss) before cumulative effect of change in accounting principle	$ 1.00	$ 2.45	$ 1.70
Cumulative effect of change in accounting principle(4)	--	--	--
Net income (loss) per common share	$ 1.00	$ 2.45	$ 1.70
Diluted income (loss) per common share(5)(6):			
Income (loss) before cumulative effect of change in accounting principle	$ 0.97	$ 2.34	$ 1.61
Cumulative effect of change in accounting principle(4)	--	--	--
Net income (loss) per common share	$ 0.97	$ 2.34	$ 1.61
Weighted average number of common shares outstanding(5)(6):			
Basic	31,695	27,079	22,679
Diluted	32,653	28,360	24,011
Summary Balance Sheet Data:			
Working capital (deficit)	$ (6,359)	$(20,654)	$ 74,005
Property and equipment, net	760,854	522,573	304,381
Total assets	842,715	587,316	442,704
Short-term debt	--	--	--
Accrued preferred dividends payable(6)	--	--	--
Total equity(6)	692,977	458,492	361,259

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(1) At December 31, 1998, the Company recognized a non-cash write-down of natural gas and oil properties in the amount of approximately $2.6 million in connection with the ceiling limitation required by the full cost method of accounting for natural gas and oil properties. The write-down was primarily the result of the decline in natural gas prices experienced in 1998 and through April 9, 1999. As permitted by applicable Commission rules, in calculating the amount of the write-down, the Company used post year-end natural gas and oil price increases of $0.26 per MMBtu of natural

gas and $4.52 per barrel of oil from December 31, 1998 to April 9, 1999. If the Company had used only December 31, 1998 natural gas and oil prices, it would have recognized a total non-cash write-down of natural gas and oil properties of approximately $13.0 million.

(2) The Company had in place both financial hedge and physical contracts with Enron North America Corp. at the time Enron Corp. and its subsidiaries filed for bankruptcy in December 2001. Spinnaker did not receive payment for fixed price swap contracts totaling $2.1 million which were intended to hedge December 2001 natural gas sales, and $1.4 million related to November 2001 natural gas production sold to Enron entities. The Company has recorded a net reserve of $3.2 million against these receivables.

(3) Prior to July 1999, the stock option agreements of two of the Company's officers provided that they could elect to have Spinnaker deliver shares equal to the appreciation in the value of the stock over the option price in lieu of purchasing the amount of shares under option. Based on management's estimate of the share value of Spinnaker, the Company recorded compensation expense of approximately $1.7 million in 1999 related to the stock appreciation rights of the stock option agreements. In July 1999, these two officers agreed to eliminate the stock appreciation rights feature of their stock option agreements.

(4) The cumulative effect of change in accounting principle represents the adoption of Statement of Position 98-5 "Reporting on the Costs of Start-Up Activities."

(5) Spinnaker was originally formed as a limited liability company, and the Company issued common units and preferred units. In connection with its conversion to a corporation in January 1998, the Company exchanged Common Stock for all then outstanding common units and Preferred Stock for all then outstanding preferred units. The Company expresses all historical unit data in shares of Common Stock.

(6) On April 3, 2002, the Company completed a public offering of 5,750,000 shares of Common Stock. On August 16, 2000, the Company completed a public offering of 5,600,000 shares of Common Stock. In connection with its initial public offering in 1999, the Company issued 8,000,000 shares of Common Stock, converted all then outstanding shares of Preferred Stock into 6,061,840 shares of Common Stock and issued 1,200,248 shares of Common Stock to certain holders of the previously outstanding Preferred Stock in lieu of payment of accrued cash dividends.

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

Overview

Financial and operating results in 2002 compared to 2001 included:

- Revenues of $188.3 million, down 10%.
- Income from operations of $49.1 million, down 51%.
- Net income of $31.6 million, or $0.97 per diluted share, down 52%.
- Production of 51.4 Bcfe, down 3%.
- Proved reserves of 323.6 Bcfe, reserve replacement was 101% of production in 2002.

Spinnaker's results of operations and financial position were significantly impacted by lower commodity prices and production in 2002. Of the $22.1 million net decrease in revenues, $29.4 million was due to a lower average commodity price on an equivalent basis and $6.9 million related to decreased production, offset in part by an increase in net hedging income of $14.2 million. The Company had $32.5 million in cash and cash equivalents and no debt at

December 31, 2002.

Risk Factors

In addition to the other information set forth elsewhere in this annual report, the following factors should be carefully considered when evaluating Spinnaker.

Exploration is a high-risk activity, and the 3-D seismic data and other advanced technologies the Company uses cannot eliminate exploration risk and require experienced technical personnel whom the Company may be unable to attract or retain.

The Company's future success will depend on the success of its exploratory drilling program. Exploration activities involve numerous risks, including the risk that no commercially productive natural gas or oil reservoirs will be discovered. In addition, the Company often is uncertain as to the future cost or timing of drilling, completing and producing wells. Furthermore, drilling operations may be curtailed, delayed or canceled as a result of the additional exploration time and expense associated with a variety of factors, including unexpected drilling conditions, pressure or irregularities in formations, equipment failures or accidents, adverse weather conditions, compliance with governmental requirements and shortages or delays in the availability of drilling rigs or equipment.

Even when used and properly interpreted, 3-D seismic data and visualization techniques only assist geoscientists in identifying subsurface structures and hydrocarbon indicators. They do not allow the interpreter to know conclusively if hydrocarbons are present or economically producible. The Company could incur losses as a result of expenditures on unsuccessful wells. Poor results from exploration activities could materially and adversely affect future cash flows and results of operations.

The Company's exploratory drilling success will depend, in part, on its ability to attract and retain experienced explorationists and other professional personnel. Competition for explorationists and engineers with experience in the Gulf of Mexico is extremely intense. If the Company cannot retain its current personnel or attract additional experienced personnel, its ability to compete in the Gulf of Mexico could be adversely affected.

A substantial portion of Spinnaker's proved reserves are associated with its deepwater oil discovery at Front Runner. The development of Front Runner will require significant financial resources before initial production and remains subject to other uncertainties that could have a material impact on the development of this discovery.

Spinnaker's deepwater oil discovery at Front Runner, in which the Company has a 25% non-operator working interest, has required and will continue to require significant financial resources in advance of the expected initial production date in the summer of 2004. The Company has incurred $70.2 million in capital expenditures for Front Runner through December 31, 2002 and expects to incur an aggregate of approximately $67.0 million in future development costs during 2003 and 2004. Because another oil and gas exploration and production company operates Front Runner, the Company has a limited ability to influence the operations and costs associated with this property.

Front Runner is located in approximately 3,500 feet of water and wells have been drilled in the Front Runner area to total depths in excess of 20,000 feet.

The Company has limited experience with large deepwater and deep drilling depth discoveries similar to Front Runner as most of its prior discoveries have occurred in shallower waters and at shallower drilling depths. As a result of these uncertainties and risks, the Company may encounter difficulties and delays that could cause actual expenditures to exceed anticipated amounts.

J. Ray McDermott Inc. ("McDermott"), the contractor responsible for construction, delivery and installation of the Front Runner spar production facility, has announced that it is experiencing liquidity concerns. If McDermott experiences additional significant unanticipated costs in the future, it may be unable to fund all of its

anticipated operating and capital needs, which may delay the expected delivery date of the spar production facility as well as the initial production date and actual expenditures may exceed anticipated amounts.

The hull of the spar production facility is being constructed in Dubai, U.A.E. Due to the current military conflict in the Middle East, the delivery date of the hull to the Gulf of Mexico may be delayed. Additionally, weather and other conditions may delay the installation of the spar production facility on location. Any delays in the delivery or installation dates would cause a delay in the initial production date.

Front Runner accounted for more than 60% of Spinnaker's proved undeveloped reserves at December 31, 2002. If the actual reserves associated with Front Runner are substantially less than the estimated reserves, the Company's results of operations and financial condition could be adversely affected.

When production ultimately commences for this discovery, it may produce substantially less oil and natural gas than currently projected. Additionally, the Company cannot predict commodity prices when production commences. If production is substantially less than currently projected or commodity prices are low, the Company's results of operations and financial condition could be adversely affected.

These uncertainties and other risks described in this "Risk Factors" section and elsewhere in this annual report make it difficult to predict whether Front Runner can be successfully or economically developed. If Front Runner cannot be successfully and economically developed, the Company's future business, financial condition and operating results will be materially and adversely affected.

The natural gas and oil business involves many operating risks that can cause substantial losses.

The natural gas and oil business involves a variety of operating risks, including fires, explosions, blow-outs and surface cratering, uncontrollable flows of underground natural gas, oil and formation water, natural disasters, pipe or cement failures, casing collapses, embedded oilfield drilling and service tools, abnormally pressured formations and environmental hazards such as natural gas leaks, oil spills, pipeline ruptures and discharges of toxic gases. If any of these events occur, the Company could incur substantial losses as a result of injury or loss of life, severe damage to and destruction of property, natural resources and equipment, pollution and other environmental damage, clean-up responsibilities, regulatory investigation and penalties, suspension of the Company's operations and repairs to resume operations. If the Company experiences any of these problems, it could affect well bores, platforms, gathering systems and processing facilities, which could adversely affect its ability to conduct operations.

Offshore operations are also subject to a variety of operating risks specific to the marine environment, such as capsizing, collisions and damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, the Company could incur substantial liabilities that could reduce or eliminate the funds available for exploration, development or leasehold acquisitions, or result in loss of equipment and properties.

For some risks, the Company may not obtain insurance if it believes the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could adversely affect the Company's operations.

Exploration for natural gas and oil at deeper drilling depths and in the deep waters of the Gulf of Mexico involves greater operational and financial risks than exploration at shallower depths and in shallower waters. These risks could result in substantial losses.

The Company explores for natural gas and oil at deeper drilling depths and in the deep waters of the Gulf of Mexico where operations are more difficult and costly than at shallower depths and in shallower waters. Deep depth and deepwater drilling and operations require the application of recently developed technologies that

involve a higher risk of mechanical failure. The Company has experienced and will continue to experience significantly higher drilling costs for its deep depth and deepwater prospects.

At December 31, 2002, approximately 92% of the Company's proved undeveloped reserves were located in deep water. The deep water lacks the physical and oilfield service infrastructure present in the shallower waters. As a result, deepwater projects require long-term commitments of significant financial resources. Deepwater operations may also require a significant amount of time between the discovery date and the initial production date when the Company can market the natural gas or oil, increasing both the financial and operational risk involved with these operations.

The Company is vulnerable to operational, regulatory and other risks associated with the Gulf of Mexico because it currently explores and produces exclusively in that area.

The Company's operations and revenues are impacted acutely by conditions in the Gulf of Mexico because it currently explores and produces exclusively in that area. This concentration of activity makes the Company more vulnerable than many of its competitors to the risks associated with the Gulf of Mexico, including delays and increased costs relating to adverse weather conditions, drilling rig and other oilfield services and compliance with environmental and other laws and regulations.

A significant part of the value of the Company's production and reserves is concentrated in a small number of offshore properties. Because of this concentration, any production problems or inaccuracies in reserve estimates related to those properties are more likely to adversely impact the Company's business.

During 2002, approximately 44% of the Company's production came from three of its properties in the Gulf of Mexico. If mechanical problems, storms or other events curtailed a substantial portion of this production, the Company's cash flow would be adversely affected. In addition, at December 31, 2002, the Company's proved reserves were located on 26 different blocks in the Gulf of Mexico, with approximately 73% of the proved reserves attributable to six of these properties. One property, Front Runner, accounted for more than 60% of total proved undeveloped reserves and more than 40% of total proved reserves. If the actual reserves associated with any one of these six properties are substantially less than the estimated reserves, the Company's results of operations and financial condition could be adversely affected.

The Commission is currently reviewing information from Spinnaker and other oil and gas companies operating in the Gulf of Mexico to assess how the industry is determining proved reserves related to new discoveries. Rules and regulations of the Commission allow companies to recognize proved reserves if economic producibility is supported by either actual production or a conclusive formation test. The Commission believes that a production flow test of reserves satisfies the requirements of a conclusive formation test. In the absence of a production flow test, compelling technical data must exist to recognize proved reserves. The industry has increasingly depended on advanced technical testing to support economic producibility. Spinnaker has recorded most of its proved reserves in deep water based on various advanced technical tests rather than production flow tests. The Company expects initial production from the majority of its proved undeveloped reserves in deep water to commence no later than the summer of 2004. The Company believes these proved reserves are properly recorded and classified. Spinnaker has furnished the information requested by the Commission and is unable to predict the outcome of the Commission's review of Spinnaker's and the industry's practices.

If any seismic contractor terminates its data agreement with Spinnaker, the Company's ability to find additional reserves could be impaired.

The Company's success depends heavily on its access to 3-D seismic data. If any seismic contractor terminates its data agreement with Spinnaker, the Company would lose access to a portion of its 3-D seismic

data, which loss could have an adverse effect on its ability to find additional reserves. A seismic contractor may terminate its data agreement with Spinnaker on several grounds, including if a competitor of the seismic contractor acquires control of Spinnaker or if the Company breaches the data agreement with that seismic contractor, subject to certain exceptions. See "Item 1. Business--Seismic Data Agreements--Termination Events" for a description of these exceptions.

Competitors may use superior technology which the Company may be unable to afford or which would require costly investments in order to compete.

The industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, the Company may be placed at a competitive disadvantage, and competitive pressures may force it to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before the Company can. The Company cannot be certain that it will be able to implement technologies on a timely basis or at a cost that is acceptable to it. One or more of the technologies that the Company currently uses or that it may implement in the future may become obsolete, which may adversely affect the Company's results of operations and financial condition. For example, marine seismic acquisition technology has undergone rapid technological advancements in recent years and further significant technological developments could substantially impair the value of Spinnaker's 3-D seismic data.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or their underlying assumptions will materially affect the quantities and net present value of the Company's reserves.

The process of estimating natural gas and oil reserves is complex. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and net present value of reserves. See "Item 2. Properties--Natural Gas and Oil Reserves."

In order to prepare these estimates, the Company must project production rates and the timing of development expenditures. The Company must also analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also requires economic assumptions such as natural gas and oil prices, drilling and operating expenses, capital expenditures, taxes and the availability of funds. Therefore, estimates of natural gas and oil reserves are inherently imprecise.

Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves most likely will vary from the Company's estimates. Any significant variance could materially affect the estimated quantities and net present value of reserves. In addition, the Company may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond the Company's control. Moreover, some of the producing wells included in the reserve report had produced for only a relatively short period of time as of December 31, 2002. Because most of the reserve estimates are not based on a lengthy production history and are calculated using volumetric analysis, these estimates are less reliable than estimates based on a lengthy production history.

It should not be assumed that the present value of future net cash flows from the Company's proved reserves is the current market value of its estimated natural gas and oil reserves. In accordance with Commission requirements, the Company bases the estimated discounted future net cash flows from its 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.

The failure to replace reserves would adversely affect production and cash flows.

The Company's future natural gas and oil production depends on its success in finding or acquiring additional reserves. If the Company fails to replace reserves, its level of production and cash flows would be adversely impacted. In general, production from natural gas and oil properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics and mechanical issues. The Company's total proved reserves decline as reserves are produced unless it conducts other successful exploration and development activities or acquires properties containing proved reserves, or both. The Company's ability to make the necessary capital investment to maintain or expand its asset base of natural gas and oil reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. The Company may not be successful in exploring for, developing or acquiring additional reserves. If the Company is not successful, its future production and revenues will be adversely affected.

Relatively short production periods for Gulf of Mexico properties subject the Company to higher reserve replacement needs, require the Company to incur capital expenditures more frequently to replace production and may impair its ability to slow or shut-in production during periods of low prices for natural gas and oil.

Reservoirs in the Gulf of Mexico are generally sandstone reservoirs characterized by high porosity, permeability, pressure and temperature. Production of these reservoirs is generally constant for a relatively shorter period of time with a rapid decline in production at the end of the reservoir life compared to production of reservoirs in many other producing regions of the world. As a result, reserve replacement needs from new prospects in the Gulf of Mexico are greater and require the Company to incur capital expenditures more frequently to replace production than would typically be required in many other producing regions of the world. The Company expects a decline in production during the first quarter of 2003 due to the rapid production decline of certain producing wells and a shut-in for pipeline repairs.

Also, revenues and return on capital will depend significantly on prices prevailing during these relatively short production periods. The Company's potential need to generate revenues to fund ongoing capital commitments or reduce future indebtedness may limit its ability to slow or shut-in production from producing wells in the future during periods of low prices for natural gas and oil.

Natural gas and oil prices fluctuate widely, and low prices could have a material adverse impact on the Company's business and financial results.

The Company's revenues, profitability and future growth depend substantially on prevailing prices for natural gas and oil. Prices also affect the amount of cash flow available for capital expenditures and the Company's ability to borrow and raise additional capital. The amount the Company can borrow under the Credit Facility is subject to periodic re-determination based in part on changing expectations of future prices. Lower prices may also reduce the amount of natural gas and oil that the Company can economically produce.

Prices for natural gas and oil fluctuate widely. Among the factors that can cause this fluctuation are the level of consumer product demand, weather conditions, domestic and foreign governmental regulations, the price and availability of alternative fuels, political conditions in natural gas and oil producing regions, the domestic and foreign supply of natural gas and oil, the price of foreign imports and overall economic conditions. If natural gas and oil prices decline, even if for only a short period of time, it is possible that write-downs of natural gas and oil properties could occur in the future.

Hedging production has limited and may continue to limit potential gains from increases in commodity prices or result in losses.

The Company enters into hedging arrangements from time to time to reduce its exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flow. These financial arrangements take the form of swap contracts or cashless collars and are placed with major trading counterparties the Company believes represent minimum credit risks. The Company cannot provide assurance that these trading counterparties will not

become credit risks in the future. Hedging arrangements expose the Company to risks in some circumstances, including situations when the other party to the hedging contract defaults on its contract obligations or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received. These hedging arrangements have limited and may continue to limit the benefit the Company could receive from increases in the prices for natural gas and oil. The Company cannot provide assurance that the hedging transactions it has entered into, or will enter into, will adequately protect it from fluctuations in natural gas and oil prices. The Company may choose not to engage in hedging transactions in the future. As a result, the Company may be adversely affected during periods of declining natural gas and oil prices.

Natural gas prices have fluctuated widely in early 2003. The Company will recognize net hedging losses of $17.7 million in the first quarter of 2003 based on natural gas price settlements. If natural gas prices remain at current levels, Spinnaker will incur significant hedging losses in the remainder of 2003.

The Company's success depends on its Chief Executive Officer and other key personnel, the loss of whom could disrupt business operations.

The Company depends to a large extent on the efforts and continued employment of the Company's President and Chief Executive Officer, Roger L. Jarvis, and other key personnel, including the Company's Vice President--Exploration who will retire in early 2004. If Mr. Jarvis or other key personnel resign or become unable to continue in their present role and if they are not adequately replaced, the Company's business operations could be adversely affected.

The Company is subject to complex laws and regulations, including environmental regulations, that can adversely affect the cost, manner or feasibility of doing business.

Exploration for and development, production and sale of natural gas and oil in the U.S. and especially in the Gulf of Mexico are subject to extensive federal, state and local laws and regulations, including environmental laws and regulations. The Company may be required to make large expenditures to comply with environmental and other governmental regulations. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, reports concerning operations and taxation.

Under these laws and regulations, the Company could be liable for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. The Company does not believe that full insurance coverage for all potential environmental damages is available at a reasonable cost. Failure to comply with these laws and regulations also may result in the suspension or termination of its operations and subject the Company to administrative, civil and criminal penalties. Moreover, these laws and regulations could change in ways that substantially increase costs. For example, Congress or the MMS could decide to limit exploratory drilling or natural gas production in additional areas of the Gulf of Mexico. Accordingly, any of these liabilities, penalties, suspensions, terminations or regulatory changes could materially and adversely affect the Company's financial condition and results of operations.

Competition in the industry is intense, and the Company is smaller and has a more limited operating history than most of its competitors in the Gulf of Mexico.

The Company competes with major and independent natural gas and oil companies for property acquisitions. It also competes for the equipment and labor required to operate and develop properties. Most of the competitors have substantially greater financial and other resources than the Company. As a result, in the deep water where exploration is more expensive, competitors may be better able to withstand sustained periods of unsuccessful drilling. In addition, larger competitors may be able to absorb the burden of any changes in federal, state and local laws and regulations more easily than the Company can, which would adversely affect its competitive position. These competitors may be able to pay more for exploratory prospects and productive natural gas and oil properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than the Company can. The Company's ability to explore for natural gas and oil

prospects and to acquire additional properties in the future will depend on its ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. In addition, most of the competitors have been operating in the Gulf of Mexico for a much longer time than the Company has and have demonstrated the ability to operate through industry cycles.

The Company cannot control the activities on properties it does not operate.

Other companies operate some of the properties in which the Company has an interest, including Front Runner. As a result, the Company has a limited ability to exercise influence over operations for these properties or their associated costs. The Company's dependence on the operator and other working interest owners for these projects and its limited ability to influence operations and associated costs could materially and adversely affect the realization of its targeted returns on capital in drilling or acquisition activities. The success and timing of drilling and development activities on properties operated by others therefore depend upon a number of factors that are outside of the Company's control, including timing and amount of capital expenditures, the operator's expertise and financial resources, approval of other participants in drilling wells and selection of technology.

The Company may have difficulty financing its planned growth.

The Company has experienced and expects to continue to experience substantial capital expenditure and working capital needs, particularly as a result of its drilling program. In the future, the Company expects it will require additional financing, in addition to cash generated from its operations, to fund its planned growth. The Company cannot be certain that additional financing will be available on acceptable terms or at all. In the event additional capital resources are unavailable, the Company may curtail its drilling, development and other activities or be forced to sell some of its assets on an untimely or unfavorable basis.

Warburg owns a significant number of shares of Common Stock, giving it influence in corporate transactions and other matters, and the interests of Warburg could differ from those of other stockholders.

At December 31, 2002, Warburg owned approximately 20% of the outstanding shares of Common Stock. As a result, Warburg is in a position to significantly influence the outcome of matters requiring a stockholder vote, including the election of directors, the adoption of an amendment to the certificate of incorporation or bylaws and the approval of mergers and other significant corporate transactions. Its influence over Spinnaker may delay or prevent a change of control of the Company and may adversely affect the voting and other rights of other stockholders.

Furthermore, conflicts of interest could arise in the future between the Company and Warburg concerning, among other things, potential competitive business activities or business opportunities. Warburg is not restricted from competitive natural gas and oil exploration and production activities or investments. Warburg currently has significant equity interests in other public and private natural gas and oil companies. The interests of Warburg could differ from those of other stockholders.

A portion of the Company's outstanding shares owned by Warburg or other significant stockholders may be sold into the market in the near future. This could cause the market price of the Common Stock to drop significantly, even if the Company's business is doing well.

The market price of the Common Stock could drop due to sales of a large number of shares of Common Stock in the market or the perception that such sales could occur. This could make it more difficult to raise funds through any future offering of Common Stock.

The certificate of incorporation and bylaws contain provisions that could discourage an acquisition or change of control of the Company.

The certificate of incorporation authorizes the board of directors to issue Preferred Stock without stockholder approval. If the board of directors elects to issue Preferred Stock, it could be more difficult for a third

party to acquire control of the Company, even if that change of control might be beneficial to stockholders. In addition, provisions of the certificate of incorporation and bylaws, such as no stockholder action by written consent and limitations on stockholder proposals at meetings of stockholders, could also make it more difficult for a third party to acquire control of the Company.

Terrorist attacks on natural gas and oil production facilities, transportation systems and storage facilities could have a material adverse impact on the Company's business.

Natural gas and oil production facilities, transportation systems and storage facilities could be targets of terrorist attacks. These attacks could have a material adverse impact if certain natural gas and oil infrastructure integral to the Company's operations were destroyed or damaged.

Critical Accounting Policies

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant estimates include depreciation, depletion and amortization ("DD&A") of proved natural gas and oil properties. Natural gas and oil reserve estimates, which are the basis for unit-of-production DD&A and the full cost ceiling test, are inherently imprecise and are expected to change as future information becomes available. In addition, alternatives may exist among various accounting methods. In such cases, the choice of accounting method may also have a significant impact on reported amounts. The Company's critical accounting policies are as follows:

Full Cost Method of Accounting

The Company uses the full cost method of accounting for its investments in natural gas and oil properties. Under this method, all acquisition, exploration and development costs, including certain related employee costs, incurred for the purpose of exploring for and developing natural gas and oil are capitalized. Acquisition costs include costs incurred to purchase, lease or otherwise acquire property. Exploration costs include the costs of drilling exploratory wells, including those in progress, geological and geophysical service costs and depreciation of support equipment used in exploration activities. Development costs include the costs of drilling development wells and costs of completions, platforms, facilities and pipelines. Costs associated with production and general corporate activities are expensed in the period incurred. Sales of natural gas and oil properties, whether or not being amortized currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of natural gas and oil. Application of the full cost method of accounting for oil and gas properties generally results in higher capitalized costs, no exploration costs and higher DD&A rates than the application of the successful efforts method of accounting.

DD&A

The Company computes the provision for DD&A of natural gas and oil properties using the unit-of-production method based upon production and estimates of proved reserve quantities. Unevaluated costs and related carrying costs are excluded from the amortization base until the properties associated with these costs are evaluated. In addition to costs associated with evaluated properties, the amortization base includes estimated future development costs and dismantlement, restoration and abandonment costs, net of estimated salvage values.

Certain future development costs may be excluded from amortization when incurred in connection with major development projects expected to entail significant costs to ascertain the quantities of proved reserves

attributable to the properties under development. The amounts that may be excluded are portions of the costs that relate to the major development project and have not previously been included in the amortization base and the estimated future expenditures associated with the development project. Such costs may be excluded from costs to be amortized until the earlier determination of whether additional reserves are proved or impairment occurs.

As of December 31, 2002, the Company excluded from the amortization base estimated future expenditures of $29.4 million associated with common development costs for its deepwater discovery at Front Runner. This estimate of future expenditures associated with common development costs is based on existing proved reserves to total proved reserves expected to be established upon completion of the Front Runner project.

If the $29.4 million had been included in the amortization base as of December 31, 2002, and no additional reserves were assigned to the Front Runner project, the DD&A rate in 2002 would have been $2.21 per Mcfe, or an increase of $0.09 over the actual DD&A rate of $2.12 per Mcfe. All future development costs associated with the deepwater discovery at Front Runner are included in the determination of estimated future net cash flows from proved natural gas and oil reserves used in the full cost ceiling calculation, as discussed below.

Full Cost Ceiling

Capitalized costs of natural gas and oil properties, net of accumulated DD&A and related deferred taxes, are limited to the estimated future net cash flows from proved natural gas and oil reserves, including the effects of hedging activities in place as of December 31, 2002, discounted at 10%, plus the lower of cost or fair value of unproved properties, as adjusted for related income tax effects (full cost ceiling). If capitalized costs of the full cost pool exceed the ceiling limitation, the excess is charged to expense.

As of December 31, 2002, the Company's full cost ceiling, including estimated future net cash flows calculated using commodity prices of $4.91 per Mcf of natural gas and $30.50 per barrel of oil and condensate, exceeded capitalized costs of natural gas and oil properties, net of accumulated DD&A and related deferred taxes, by approximately $139.9 million. Considering the volatility of natural gas and oil prices, it is probable that the Company's estimate of discounted future net cash flows from proved natural gas and oil reserves will change in the near term. If natural gas or oil prices decline, even if for only a short period of time, or if the Company has downward revisions to its estimated proved reserves, it is possible that write-downs of natural gas and oil properties could occur in the future.

Capitalized Employee and Other General and Administrative Costs

Under the full cost method of accounting, certain costs are capitalized that are directly identified with acquisition, exploration and development activities. These capitalized costs include salaries, employee benefits, costs of consulting services and other related costs and do not include costs related to production, general corporate overhead or similar activities. Spinnaker capitalized employee and other general and administrative costs of $5.9 million, $5.1 million and $3.8 million in 2002, 2001 and 2000, respectively.

Unproved Properties

The costs associated with unproved properties and properties under development are not initially included in the amortization base and relate to unevaluated leasehold acreage and delay rentals, seismic data, wells in-progress and wells pending determination. Unevaluated leasehold costs and delay rentals are either transferred to the amortization base with the costs of drilling the related well or are assessed quarterly for possible impairment or reduction in value. Unevaluated leasehold costs and delay rentals are transferred to the amortization base if a reduction in value has occurred. The costs of seismic data are transferred to the amortization base using the sum-of-the-year's-digits method over a period of six years. The costs associated with wells in-progress and wells pending determination are transferred to the amortization base once a determination is made whether or not proved reserves can be assigned to the property. The costs of drilling exploratory dry holes and associated

leasehold costs are included in the amortization base immediately upon determination that the well is unsuccessful.

Natural Gas and Oil Reserves

The process of estimating natural gas and oil reserves is complex. It requires various assumptions, including natural gas and oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The Company must project production rates and timing of development expenditures. The Company analyzes available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. Therefore, estimates of natural gas and oil reserves are inherently imprecise.

Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves most likely will vary from estimates. Any significant variance could materially affect the estimated quantities and net present value of reserves. In addition, the Company may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond the Company's control. At December 31, 2002, approximately 82% of the Company's proved reserves were either undeveloped or non-producing. Because most of the reserve estimates are not based on a lengthy production history and are calculated using volumetric analysis, these estimates are less reliable than estimates based on a lengthy production history.

At December 31, 2002, approximately 70% of the Company's proved reserves were undeveloped and primarily related to Front Runner. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling operations. The reserve data assumes that the Company will make these expenditures. Although the Company estimates its reserves and the costs associated with developing them in accordance with industry standards, the estimated costs may be inaccurate, development may not occur as scheduled and results may not be as estimated.

Other Property and Equipment

The costs associated with seismic hardware and software are included in other property and equipment. These costs are amortized into the full cost pool using the straight-line method over three years. Amortization was $1.5 million, $0.5 million and $1.2 million in 2002, 2001 and 2000, respectively.

Commodity Price Risk Management Activities

On January 1, 2001, the Company adopted Statement of Financial Accounting Standards ("SFAS") No. 133, as amended, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 established accounting and reporting standards requiring that all derivative instruments be recorded in the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in a derivative's fair value be realized currently in earnings unless specific hedge accounting criteria are met. Accounting for qualifying hedges allows derivative gains and losses to offset related results on the hedged items in the statement of operations and requires a company to formally document, designate and assess the effectiveness of transactions that qualify for hedge accounting. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

Stock-Based Compensation

SFAS No. 148, "Accounting for Stock-Based Compensation--Transition and Disclosure," amends SFAS No. 123 to provide alternative methods of transition for an entity that voluntarily changes to the fair value based method of accounting for stock-based employee compensation and to require prominent disclosure about the effects on reported net income of an entity's accounting policy decisions with respect to stock-based employee compensation. SFAS No. 148 amends Accounting Principles Board ("APB") Opinion No. 28, "Interim Financial Reporting," to require disclosure about those effects in interim financial information.

SFAS No. 123, "Accounting for Stock-Based Compensation," encourages, but does not require, companies to record compensation cost for stock-based employee compensation plans at fair value. The Company has chosen to account for stock-based compensation using the intrinsic value method prescribed in APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. Accordingly, compensation cost for stock options is measured as the excess, if any, of the fair value of the Common Stock at the date of the grant over the amount an employee must pay to acquire the Common Stock.

Related Parties

The Company purchases oilfield goods, equipment and services from Baker Hughes Incorporated ("Baker Hughes"), Cooper Cameron Corporation ("Cooper Cameron") and other oilfield services companies in the ordinary course of business. The Company incurred charges of approximately $16.1 million and $16.3 million in 2002 and 2001, respectively, from affiliates of Baker Hughes, of which Mr. Michael E. Wiley, a director of Spinnaker since March 2001, serves as Chairman of the Board, Chief Executive Officer and President. The Company incurred charges of approximately $0.1 million, $0.1 million and $0.5 million in 2002, 2001 and 2000, respectively, from Cooper Cameron, of which Mr. Sheldon R. Erikson, a director of Spinnaker, serves as Chairman of the Board, Chief Executive Officer and President. Spinnaker believes that these transactions are at arm's-length and the charges it pays for such goods, equipment and services are competitive with the charges and fees of other companies providing oilfield goods, equipment and services to the oil and gas exploration and production industry. Both of these companies are leaders in their respective segments of the oilfield services sector. The Company could be at a disadvantage if it were to discontinue using either company as vendors.

Results of Operations

The following table sets forth certain operating information with respect to the natural gas and oil operations of the Company:

	Year Ended December 31,		
	2002	2001	2000
Production:			
Natural gas (MMcf)	45,180	51,234	28,845
Oil and condensate (MBbls)	1,040	310	225
Total (MMcfe)	51,419	53,094	30,194
Revenues (in thousands):			
Natural gas	$156,214	$212,238	$133,264
Oil and condensate	27,448	7,718	6,775
Net hedging income (loss)	4,664	(9,580)	(18,656)
Total	$188,326	$210,376	$121,383

Average sales price per unit:			
Natural gas revenues from production (per Mcf)	$ 3.46	$ 4.14	$ 4.62
Effects of hedging activities (per Mcf)	0.10	(0.18)	(0.59)
Average price (per Mcf)	$ 3.56	$ 3.96	$ 4.03
Oil and condensate revenues from production (per Bbl)	$ 26.39	$ 24.90	$ 30.14
Effects of hedging activities (per Bbl)	--	--	(7.16)
Average price (per Bbl)	$ 26.39	$ 24.90	$ 22.98
Total revenues from production (per Mcfe)	$ 3.57	$ 4.14	$ 4.64
Effects of hedging activities (per Mcfe)	0.09	(0.18)	(0.62)
Total average price (per Mcfe)	$ 3.66	$ 3.96	$ 4.02
Expenses (per Mcfe):			
Lease operating expenses	$ 0.35	$ 0.23	$ 0.30
Depreciation, depletion and amortization--natural gas and oil properties	$ 2.12	$ 1.60	$ 1.57
Income from operations (in thousands)	$ 49,090	$100,285	$ 57,264

Year Ended December 31, 2002 as Compared to the Year Ended December 31, 2001

Revenues, including the effects of hedging activities, decreased $22.1 million in 2002 compared to 2001. Natural gas revenues decreased $56.0 million, oil and condensate revenues increased $19.7 million and revenues from natural gas hedging activities improved $14.2 million in 2002 compared to 2001.

Production decreased approximately 1.7 Bcfe in 2002 compared to 2001. Average daily production in 2002 was 141 MMcfe compared to 145 MMcfe in 2001. Natural gas revenues decreased $56.0 million due to lower volumes of 6.1 Bcf and a lower average price in 2002 compared to 2001. The production declines of certain producing wells, particularly in the High Island 202 area, resulted in lower natural gas production in 2002. Oil and condensate revenues increased $19.7 million primarily due to higher production volumes of 730 MBbls. The Company expects a decline in production during the first quarter of 2003 due to the rapid production decline of certain producing wells and shut-ins for pipeline repairs.

Lease operating expenses increased $6.1 million in 2002 compared to 2001. Of the total increase in lease operating expenses, approximately $7.3 million was attributable to wells on ten new blocks that commenced production in 2002, offset in part by a decrease of $0.9 million in operating expenses associated with existing wells and a decrease of $0.3 million in workovers. The overall increase in the lease operating expense rate per Mcfe in 2002 compared to 2001 was primarily due to the production declines of certain wells in the High Island 202 area where the lease operating rate in 2001 was significantly lower compared to other producing areas operated by the Company. Additionally, the Company is experiencing higher lease operating rates associated with new wells compared to historical average lease operating rates due to well locations, transportation and gathering agreements and processing requirements.

DD&A increased $23.9 million in 2002 compared to 2001. Of the total increase in DD&A, $26.6 million related to an increase in the DD&A rate, offset in part by $2.7 million related to lower production volumes of 1.7 Bcfe in 2002 compared to 2001. The increase in the DD&A rate in 2002 was primarily due to costs of $72.6 million associated with 12 unsuccessful wells and higher finding costs associated with new discoveries in 2002.

General and administrative expenses increased $1.5 million in 2002 compared to 2001. The increase in general and administrative expenses was primarily due to higher employment-related costs resulting from the Company's recent growth and increased professional services fees.

Interest income decreased $2.6 million in 2002 compared to 2001 primarily due to lower average cash and short-term investment balances and significantly lower interest rates in 2002. Interest expense increased $0.3 million in 2002 compared to 2001 primarily due to interest on borrowings of $37.0 million in the first quarter of 2002 and higher commitment fees. On April 3, 2002, the Company repaid all of its outstanding borrowings of $37.0 million under the Credit Facility.

Income tax expense decreased $19.5 million in 2002 compared to 2001 due to lower earnings in 2002. Income taxes were accrued at a 36% effective tax rate in 2002 and 2001.

The Company recognized net income of $31.6 million, or $1.00 per basic share and $0.97 per diluted share, in 2002 compared to net income of $66.2 million, or $2.45 per basic share and $2.34 per diluted share, in 2001.

Year Ended December 31, 2001 as Compared to the Year Ended December 31, 2000

Revenues increased $89.0 million in 2001 compared to 2000. Excluding the effects of hedging activities, natural gas revenues increased $79.0 million and oil and condensate revenues increased $0.9 million. Losses resulting from hedging activities decreased by $9.1 million in 2001 compared to 2000, thereby improving revenues.

Production increased approximately 22.9 Bcfe in 2001 compared to 2000. Average daily production in 2001 was 145 MMcfe compared to 82 MMcfe in 2000. Natural gas production volumes increased 22.4 Bcf,

contributing $123.9 million of the increase in natural gas revenues, excluding the effects of hedging activities, offset in part by $44.9 million related to lower average natural gas prices in 2001 compared to 2000. Oil and condensate production volumes increased 85 MBbls, contributing $2.8 million of the increase in oil and condensate revenues, offset in part by $1.9 million related to decreases in average oil and condensate prices. The rapid production declines of certain producing wells, combined with pipeline-mandated curtailments of certain facilities, shut-ins related to facility upgrades and less than anticipated results from workovers resulted in lower production in the fourth quarter of 2001 compared to the prior quarter.

Lease operating expenses increased $3.1 million in 2001 compared to 2000. Of the total increase in lease operating expenses, $1.0 million was primarily related to workover activities in 2001 and $0.4 million was attributable to wells on new blocks that commenced production subsequent to December 31, 2000. The lease operating expense rate decreased 23% to $0.23 per Mcfe in 2001 compared to 2000 primarily due to increased production coupled with continued efficiencies gained in core operating areas, including the High Island 202 area.

DD&A increased $37.7 million in 2001 compared to 2000. The change in DD&A was attributable to an increase in production of 22.9 Bcfe and a slightly higher DD&A rate, which impacted DD&A by $36.0 million and $1.7 million, respectively.

General and administrative expenses increased $2.1 million in 2001 compared to 2000. The increase in general and administrative expenses was primarily due to higher employment-related costs resulting from the Company's recent growth.

The Company had in place both financial hedge and physical contracts with Enron North America Corp. at the time Enron Corp. and its subsidiaries filed for bankruptcy in December 2001. Spinnaker did not receive payment for fixed price swap contracts totaling $2.1 million which were intended to hedge December 2001 natural gas sales, and $1.4 million related to November 2001 natural gas production sold to Enron entities. The Company has recorded a net reserve of $3.2 million related to these receivables.

Interest income increased $0.7 million in 2001 compared to 2000 primarily due to investment income associated with proceeds from the Company's public offering of Common Stock completed on August 16, 2000. Interest expense decreased $0.4 million in 2001 compared to 2000. The Company had no outstanding borrowings in 2001 compared to 2000.

Income tax expense increased $16.4 million in 2001 compared to 2000 and primarily relates to deferred income taxes accrued at a 36% effective tax rate in 2001 and a 35% effective tax rate in 2000.

The Company recognized net income of $66.2 million, or $2.45 per basic share and $2.34 per diluted share, in 2001 compared to net income of $38.6 million, or $1.70 per basic share and $1.61 per diluted share, in 2000.

Liquidity and Capital Resources

The Company has experienced and expects to continue to experience substantial capital requirements, primarily due to its active exploration and development programs in the Gulf of Mexico. Spinnaker has capital expenditure plans for 2003 totaling approximately $250.0 million. Spinnaker has participated in a significant deepwater oil discovery, Front Runner, with a 25% non-operator working interest. Spinnaker incurred capital expenditures associated with Front Runner of $40.8 million in 2002 and $70.2 million from inception through December 31, 2002. The Company expects to incur approximately $86.0 million in future development costs related to Front Runner, including approximately $46.0 million in 2003, $21.0 million in 2004 and $19.0 million thereafter.

Natural gas and oil prices have a significant impact on the Company's cash flows available for capital expenditures and its ability to borrow and raise additional capital. The amount the Company can borrow under its

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Credit Facility is subject to periodic re-determination based in part on changing expectations of future prices. Lower prices may also reduce the amount of natural gas and oil that the Company can economically produce. Additionally, the rapid production declines of certain producing wells resulted in lower production in 2002. The Company expects a decline in production during the first quarter of 2003 from the 16.3 Bcfe reported in the fourth quarter of 2002 due to the rapid production decline of certain producing wells and shut-ins for pipeline repairs. Lower prices and/or lower production may decrease revenues, cash flows and the borrowing base under the Credit Facility, thus reducing the amount of financial resources available to meet the Company's capital requirements. The Company believes that working capital, cash flows from operations and proceeds from available borrowings under its Credit Facility will be sufficient to meet its capital requirements in the next twelve months. However, additional debt or equity financing may be required in the future to fund growth and exploration and development programs. In the event additional capital resources are unavailable, the Company may curtail its drilling, development and other activities or be forced to sell some of its assets on an untimely or unfavorable basis.

On April 3, 2002, the Company completed a public offering of 5,750,000 shares of Common Stock at $41.50 per share, including the over-allotment option consisting of 750,000 shares. After payment of underwriting discounts and commissions, the Company received net proceeds of $227.9 million. On April 3, 2002, the Company used a portion of the proceeds from the offering to repay outstanding borrowings of $37.0 million. The remaining net proceeds were invested in short-term high quality investments and are being used to fund a portion of the costs to develop the Company's deepwater oil discovery at Front Runner, to fund a portion of exploration and other development activities and for general corporate purposes, including possible acquisitions of properties or seismic data.

Spinnaker has an effective shelf registration statement relating to the potential public offer and sale by the Company or certain of its affiliates of up to $500.0 million of any combination of debt securities, preferred stock, common stock, warrants, stock purchase contracts and trust preferred securities from time to time or when financing needs arise. The registration statement does not provide assurance that the Company will or could sell any such securities.

Cash and cash equivalents increased $18.5 million to $32.5 million at December 31, 2002. The components of the increase in cash and cash equivalents include $154.0 million provided by operating activities, $363.8 million used in investing activities and $228.3 million provided by financing activities.

Operating Activities

Net cash provided by operating activities in 2002 decreased 26% to $154.0 million primarily due to lower commodity prices and production. Cash flow from operations is dependent upon the Company's ability to increase production through its exploration and development programs and the prices of natural gas and oil. The Company has made significant investments to expand its operations in the Gulf of Mexico. These investments increased the Company's average daily production in the fourth quarter of 2002 as compared to prior quarters; however, the Company expects a decline in production during the first quarter of 2003 from the 16.3 Bcfe reported in the fourth quarter of 2002.

The Company sells its natural gas and oil production under fixed or floating market price contracts. Spinnaker enters into hedging arrangements from time to time to reduce its exposure to fluctuations in natural gas and oil prices and achieve more predictable cash flow. However, these contracts also limit the benefits the Company would realize if prices increase. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

The Company's cash flow from operations also depends on its ability to manage working capital, including accounts receivable, accounts payable and accrued liabilities. The net increase of $13.4 million in accounts receivable was primarily related to an increase in the natural gas and oil revenue accrual due to higher production and commodity prices in December 2002 compared to December 2001. The net decrease of $15.1 million in

accounts payable and accrued liabilities was primarily due to the reversal of current deferred taxes of $7.2 million related to the fair value of open derivative contracts at December 31, 2001. In connection with the fair value of open derivative contracts at December 31, 2002, the Company recorded a net deferred tax asset of $7.2 million in other current assets.

Investing Activities

Net cash used in investing activities in 2002 increased 37% to $363.8 million compared to 2001. Net oil and gas property capital expenditures were $356.6 million and other property and equipment capital expenditures were $7.2 million.

As part of its strategy, the Company explores for natural gas and oil at deeper drilling depths and in the deep waters of the Gulf of Mexico, where operations are more difficult and costly than at shallower drilling depths and in shallower waters. Along with higher risks and costs associated with these areas, greater opportunity exists for reserve additions. The Company has experienced and will continue to experience significantly higher drilling costs for its deep shelf and deepwater projects relative to the drilling costs on shallower depth shelf projects in the Gulf of Mexico. The Company drilled 26 wells in 2002, 14 of which were successful. In 2001, the Company drilled 35 wells, 19 of which were successful. Since inception and through December 31, 2002, the Company has drilled 120 wells, 70 of which were successful, representing a success rate of 58%. Dry hole costs, including associated leasehold costs, were $72.6 million in 2002.

Purchases of other property and equipment increased to $7.2 million in 2002 primarily due to expenditures for seismic hardware and software of $4.1 million, leasehold improvements of $1.4 million and other hardware and software upgrades and other equipment of $1.7 million.

The Company has capital expenditure plans for 2003 totaling approximately $250.0 million, primarily for costs related to exploration and development programs. The Company does not anticipate any significant abandonment or dismantlement costs in 2003. Actual levels of capital expenditures may vary due to many factors, including drilling results, natural gas and oil prices, the availability of capital, industry conditions, acquisitions, decisions of operators and other prospect owners and the prices of drilling rig dayrates and other oilfield goods and services. In 2002, the Company incurred acquisition, exploration and development costs of $39.8 million, $163.3 million and $139.4 million, respectively. The costs associated with unproved properties and properties under development not included in the amortization base were $141.3 million and $102.9 million as of December 31, 2002 and 2001, respectively, and included the following (in thousands):

	As of December 31,	
	2002	2001
Leasehold, delay rentals and seismic data	$122,409	$ 92,150
Wells in-progress	17,639	10,112
Other	1,278	619
Total	$141,326	$102,881

Financing Activities

Net cash provided by financing activities of $228.3 million in 2002 included proceeds from the public offering of Common Stock and $37.0 million in proceeds from and subsequent payments on borrowings. The Company received net proceeds of $227.9 million from the Common Stock offering on April 3, 2002, and used a portion of the proceeds from the offering to repay outstanding borrowings of $37.0 million.

On December 28, 2001, the Company replaced its $75.0 million credit facility with an unsecured $200.0 million Credit Facility with a group of seven banks. The borrowing base of the three-year Credit Facility is

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re-determined on or about April 30 and September 30 each year. The banks and Spinnaker also have the option to request one additional re-determination each year. The banks determine the borrowing base at their sole discretion and in their usual and customary manner. The amount of the borrowing base is a function of the banks' view of the Company's reserve profile as well as commodity prices. The current borrowing base is $100.0 million. The Company has the option to elect to use a base interest rate as described below or the LIBOR rate plus, for each such rate, a spread based on the percentage of the borrowing base used at that time. The base interest rate under the Credit Facility is a fluctuating rate of interest equal to the higher of either Toronto-Dominion Bank's base rate for dollar advances made in the United States or the Federal Funds Rate plus 0.5% per annum. The commitment fee rate ranges from 0.3% to 0.5%, depending on the borrowing base usage.

The Credit Facility contains various covenants and restrictive provisions, including the following limitations, subject to some exceptions, where the Company:

- may not incur any other indebtedness from borrowings, except for indebtedness arising under hedging agreements, indebtedness incurred in the ordinary course of business not to exceed $1.0 million, unsecured vendor indebtedness of the Company related to purchases of 2-D and 3-D seismic data made in the ordinary course of business in an amount not to exceed $25.0 million, other unsecured indebtedness in an amount not to exceed $10.0 million in the aggregate;

- may not incur any liens upon properties or assets other than permitted liens securing indebtedness of up to $1.0 million, liens on the 2-D and 3-D seismic data securing the indebtedness permitted to acquire such data, pledges or deposits to secure hedging agreements up to $15.0 million, liens on property required as a condition to enter into a synthetic lease transaction in the ordinary course of business and other liens in the ordinary course of business;

- may not dispose of any assets or properties except obsolete equipment, inventory sold in the ordinary course of business, reserves in non-proved categories, a second license in certain seismic data, or interests in natural gas and oil properties included in the borrowing base in an aggregate amount not to exceed $25.0 million in any fiscal year;

- may not make or pay any dividend, distribution or payment in respect of capital stock nor purchase, redeem, acquire, retire or permit any reduction or retirement of capital stock in excess of $10.0 million in any fiscal year;

- must maintain the ratio of consolidated current assets to consolidated current liabilities as of the end of each fiscal quarter so that it is not less than 1.00 to 1.00. For purposes of the calculation, availability under the Credit Facility is included as current assets, any payments of principal owing under the Credit Facility required to be repaid within one year from the time of the calculation are excluded from current liabilities and mark-to-market hedging exposure is excluded from both current assets and current liabilities;

- must maintain a tangible net worth so that it is not less than the sum of 80% of the tangible net worth as of September 30, 2001, plus 50% of the adjusted consolidated net income for each fiscal quarter since the closing of the Credit Facility, plus 75% of the proceeds from the sale of any security, including without limitation, common equity, preferred equity or other equity interests or equity securities including warrants, options and the like issued after the closing of the Credit Facility; and

- may not enter into any hedging agreement unless the percent of volumes to be hedged to estimated production volumes for such month from total internally-projected proved reserves does not exceed: 100% for the period one to three months from and after the hedging agreement transaction date, 66 2/3% for the period four to 18 months from and after the hedging agreement transaction date and 33 1/3% for the period 19 to 36 months from and after the hedging agreement transaction date. Additionally, at no time will any hedging agreement of any nature have a counterparty with a minimum long-term senior unsecured indebtedness rating less than "BBB+" by Standard & Poor's or "Baa1" by Moody's Investors Services, Inc. at the time that such counterparty entered into the relevant transaction under such hedging

agreement and at no time will exposure to any single counterparty exceed 25% of the estimated twelve-month production volumes from total proved reserves.

At December 31, 2002, the Company was in compliance with the covenants and restrictive provisions and had no outstanding borrowings under the Credit Facility. The Company expects to borrow under the Credit Facility in 2003 and be in compliance with the covenants and restrictive provisions for the next twelve months.

Contractual Obligations

The Company leases administrative offices, office equipment and oil and gas equipment under non-cancelable operating leases. The Company had no long-term debt, capital lease or purchase obligations or other contractual long-term liabilities as of December 31, 2002. The Company has incurred obligations in the ordinary course of business under purchase and service agreements that are not included in the table below, including obligations of approximately $35.4 million and $6.7 million in 2003 and 2004, respectively, for construction of the Front Runner spar production facility. Operating lease obligations as of December 31, 2002 are as follows (in thousands):

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Operating leases............	$6,032	$1,708	$3,800	$524	$--
Other contractual obligations	--	--	--	--	--

Total	$6,032	$1,708	$3,800	$524	$--

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Interest Rate Risk

The Company is exposed to changes in interest rates. Changes in interest rates affect the interest earned on cash and cash equivalents and the interest rate paid on borrowings under the Credit Facility. The Company does not currently use interest rate derivative instruments to manage exposure to interest rate changes, but may do so in the future.

Commodity Price Risk

The Company's revenues, profitability and future growth depend substantially on prevailing prices for natural gas and oil. Prices also affect the amount of cash flow available for capital expenditures and the Company's ability to borrow and raise additional capital. Lower prices may also reduce the amount of natural gas and oil that the Company can economically produce. The Company sells its natural gas and oil production under fixed or floating market price contracts. Spinnaker enters into hedging arrangements from time to time to reduce its exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flow. Spinnaker does not enter into such hedging arrangements for trading purposes. However, these contracts also limit the benefits the Company would realize if prices increase. These financial arrangements are fixed price swap contracts and cashless collar arrangements and are placed with major trading counterparties the Company believes represent minimum credit risks. Spinnaker cannot provide assurance that these trading counterparties will not become credit risks in the future. Under its current hedging practice, the Company generally does not hedge more than 66 2/3% of its estimated twelve-month production quantities without the prior approval of the risk management committee of the board of directors.

On January 1, 2001, the Company adopted SFAS No. 133, as amended, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 established accounting and reporting standards requiring that all derivative instruments be recorded in the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in a derivative's fair value be realized currently in earnings unless

specific hedge accounting criteria are met. Accounting for qualifying hedges allows derivative gains and losses to offset related results on the hedged items in the statement of operations and requires a company to formally document, designate and assess the effectiveness of transactions that qualify for hedge accounting.

The Company enters into New York Mercantile Exchange ("NYMEX") related swap contracts and collar arrangements from time to time. The Company's swap contracts and collar arrangements will settle based on the reported settlement price on the NYMEX for the last trading day of each month for natural gas.

In a swap transaction, the counterparty is required to make a payment to the Company for the difference between the fixed price and the settlement price if the settlement price is below the fixed price. The Company is required to make a payment to the counterparty for the difference between the fixed price and the settlement price if the settlement price is above the fixed price. As of December 31, 2002, Spinnaker's commodity price risk management positions in fixed price natural gas swap contracts and related fair value were as follows:

Period	Average Daily Volume (MMBtus)	Weighted Average Price (Per MMBtu)	Fair Value (in thousands)
First Quarter 2003.	60,000	$3.71	$ (5,979)
Second Quarter 2003	53,297	3.55	(4,411)
Third Quarter 2003.	50,000	3.55	(4,068)
Fourth Quarter 2003	50,000	3.63	(4,340)
Year 2003..........	53,288	$3.61	$(18,798)

In a collar arrangement, the counterparty is required to make a payment to the Company for the difference between the fixed floor price and the settlement price if the settlement price is below the fixed floor price. The Company is required to make a payment to the counterparty for the difference between the fixed ceiling price and the settlement price if the settlement price is above the fixed ceiling price. Neither party is required to make a payment if the settlement price falls between the fixed floor price and the fixed ceiling price. As of December 31, 2002, Spinnaker's commodity price risk management positions in natural gas collar arrangements and related fair value were as follows:

Period	Average Daily Volume (MMBtus)	Weighted Average Floor Price (Per MMBtu)	Weighted Average Ceiling Price (Per MMBtu)	Fair Value (in thousands)
First Quarter 2003.	15,000	$3.25	$5.21	$ (228)
Second Quarter 2003	15,000	3.25	5.21	(262)
Third Quarter 2003.	15,000	3.25	5.21	(287)
Fourth Quarter 2003	15,000	3.25	5.21	(342)
Year 2003..........	15,000	$3.25	$5.21	$(1,119)

The Company reported a net liability of $19.9 million and a net asset of $22.3 million related to its derivative contracts at December 31, 2002 and 2001, respectively. Amounts related to hedging activities as of December 31, 2002 and 2001 were as follows (in thousands):

As of December 31,

	2002	2001
Current assets:		
Hedging asset..	$ --	$20,593
Deferred tax asset related to hedging activities......	7,170	--
Non-current assets:		
Hedging asset..	$ --	$ 1,726
Current liabilities:		
Hedging liability....................................	$ 19,917	$ --
Deferred tax liability related to hedging activities..	--	7,208
Non-current liabilities:		
Deferred tax liability related to hedging activities..	$ --	$ 604
Accumulated other comprehensive income (loss):		
Accumulated other comprehensive income (loss).........	$(19,917)	$22,319
Income taxes...	7,170	(7,812)
Accumulated other comprehensive income (loss).....	$(12,747)	$14,507

The Company recognized a net hedging gain of $4.7 million and net hedging losses of $9.6 million and $18.7 million in revenues in 2002, 2001 and 2000, respectively. There was no ineffective component of the derivatives recognized in earnings in 2002 and 2001. Based on future natural gas prices as of December 31, 2002, the Company would reclassify a net loss of $12.7 million from accumulated other comprehensive income (loss) to earnings within the next twelve months. The amounts ultimately reclassified into earnings will vary due to changes in the fair value of the open derivative contracts prior to settlement.

Subsequent to December 31, 2002, Spinnaker has not entered into additional hedging arrangements. Natural gas prices have fluctuated widely in early 2003. The Company will recognize net hedging losses of $17.7 million in the first quarter of 2003 based on natural gas price settlements. If natural gas prices remain at current levels, Spinnaker will incur significant hedging losses in the remainder of 2003.

To calculate the potential effect of the derivative contracts on future revenues, the Company applied NYMEX natural gas forward prices as of December 31, 2002 to the quantity of the Company's natural gas production covered by those derivative contracts as of that date. The following table shows the estimated potential effects of the derivative financial instruments on future revenues (in thousands):

Derivative Instrument	Estimated Decrease in Revenues at Current Prices	Estimated Decrease in Revenues with 10% Decrease in Prices	Estimated Decrease in Revenues with 10% Increase in Prices
Fixed price swap transactions	$(18,798)	$(10,926)	$(26,912)
Collar arrangements..........	$ (1,119)	$ (289)	$ (2,216)

Item 8. Financial Statements and Supplementary Data

The consolidated financial statements and supplementary data of the Company appear on pages 46 through 71 hereof and are incorporated by reference into this Item 8. Selected quarterly financial data is set forth in Note 13 of the Notes to Consolidated Financial Statements, which is incorporated herein by reference.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

There have been no disagreements with the Company's accountants or any reportable events regarding accounting principles or practices or financial statement disclosures.

PART III

Item 10. Directors and Executive Officers of the Registrant

The Company's Definitive Proxy Statement for its 2003 Annual Meeting of Stockholders, when filed pursuant to Regulation 14A under the Securities Exchange Act of 1934, will be incorporated by reference into this annual report on Form 10-K pursuant to General Instruction G(3) of Form 10-K and will provide the information required under Part III, Item 10.

Item 11. Executive Compensation

The Company's Definitive Proxy Statement for its 2003 Annual Meeting of Stockholders, when filed pursuant to Regulation 14A under the Securities Exchange Act of 1934, will be incorporated by reference into this annual report on Form 10-K pursuant to General Instruction G(3) of Form 10-K and will provide the information required under Part III, Item 11.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The Company's Definitive Proxy Statement for its 2003 Annual Meeting of Stockholders, when filed pursuant to Regulation 14A under the Securities Exchange Act of 1934, will be incorporated by reference into this annual report on Form 10-K pursuant to General Instruction G(3) of Form 10-K and will provide the information required under Part III, Item 12.

At December 31, 2002, officers, directors and employees had been granted options to purchase Common Stock under stock plans adopted in 1998, 1999, 2000 and 2001. The following table provides "Securities Authorized for Issuance Under Equity Compensation Plans":

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Nu sec re avai futur unde comp
Equity compensation plans approved by security holders....	3,954,002	$23.00	1
Equity compensation plans not approved by security holders	432,531	$31.81	
	---------		-

Total...	4,386,533	$23.87	2
	=========		=

The Spinnaker Exploration Company 2000 Stock Option Plan (the "2000 Plan") was adopted by the board of directors of Spinnaker without the approval of the stockholders of the Company in order for Spinnaker to grant options to purchase Common Stock as a material inducement to certain persons who were not previously employed by the Company to enter into an employment contract with the Company. The number of shares of Common Stock that may be issued under the 2000 Plan may not exceed 500,000 shares. The purchase price of any Common Stock pursuant to any options granted under the 2000 Plan may not be less than 80% of the fair market value of the Common Stock on the date the option is granted, subject to certain limited exceptions. The Company has not granted nor does it intend to grant any options under the 2000 Plan at a price below the fair market value of the Common Stock on the date of grant.

Item 13. Certain Relationships and Related Transactions

The Company's Definitive Proxy Statement for its 2003 Annual Meeting of Stockholders, when filed pursuant to Regulation 14A under the Securities Exchange Act of 1934, will be incorporated by reference into this annual report on Form 10-K pursuant to General Instruction G(3) of Form 10-K and will provide the information required under Part III, Item 13.

Item 14. Controls and Procedures

(a) Evaluation of disclosure controls and procedures. Within 90 days before the filing of this annual report on Form 10-K, the Company's principal executive officer and principal financial officer evaluated the effectiveness of the Company's disclosure controls and procedures. Based on the evaluation, the Company's principal executive officer and principal financial officer believe that:

- the Company's disclosure controls and procedures are designed to ensure that information required to be disclosed by the Company in the reports it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms; and

- the Company's disclosure controls and procedures were effective to ensure that material information was accumulated and communicated to the Company's management, including the Company's principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

(b) Changes in internal controls. There have been no significant changes in the Company's internal controls or in other factors that could significantly affect the Company's internal controls subsequent to their evaluation, nor have there been any corrective actions with regard to significant deficiencies or material weaknesses.

PART IV

Item 15. Exhibits, Financial Statement Schedules, and Reports on Form 8-K

(a) Financial Statements

(1) and (2) Financial Statements and Schedules

See "Index to Consolidated Financial Statements" on page 46.

(3) Exhibits

See "Exhibit Index" on page 72.

The management contracts and compensatory plans or arrangements required to be filed as exhibits to this report are as follows:

Exhibit Number	Description
10.2	--Amended and Restated 1998 Spinnaker Stock Option Plan (incorporated by reference to Exh 10.2 to Spinnaker's Registration Statement on Form S-1 (Commission File No. 333-83093))
10.6	--Employment Agreement between Spinnaker and Roger L. Jarvis dated December 20, 1996, as amended (incorporated by reference to Exhibit 10.6 to Spinnaker's Registration Statemen Form S-1 (Commission File No. 333-83093))
10.7	--Employment Agreement between Spinnaker and William D. Hubbard dated February 24, 1997, amended (incorporated by reference to Exhibit 10.8 to Spinnaker's Registration Statemen Form S-1 (Commission File No. 333-83093))
10.8	--Employment Agreement between Spinnaker and Kelly M. Barnes dated February 24, 1997, as amended (incorporated by reference to Exhibit 10.9 to Spinnaker's Registration Statemen Form S-1 (Commission File No. 333-83093))
10.9	--1999 Spinnaker Stock Incentive Plan (incorporated by reference to Exhibit 10.10 to Spin Registration Statement on Form S-1 (Commission File No. 333-83093))
10.10	--1999 Spinnaker Employee Stock Purchase Plan (incorporated by reference to Exhibit 10.11 Spinnaker's Registration Statement on Form S-1 (Commission File No. 333-83093))
10.12	--Adjunct Stock Option Plan (incorporated by reference to Exhibit 4.3 to Spinnaker's Regi Statement on Form S-8 (Commission File No. 333-36592))
10.13	--Spinnaker Exploration Company 2000 Stock Option Plan (incorporated by reference to Exhi 10.13 to Spinnaker's Annual Report on Form 10-K for the year ended December 31, 2000)
10.14	--Spinnaker Exploration Company 2001 Stock Incentive Plan, as amended (incorporated by reference to Exhibit 10.2 to Spinnaker's Registration Statement on Form S-8 (Commission No. 333-61888))

(b) Reports on Form 8-K

A Current Report on Form 8-K dated November 12, 2002 and filed on November 13, 2002 furnished under "Item 9. Regulation FD Disclosure" the certifications by each of the Chief Executive Officer and the Chief Financial Officer that accompanied the Company's Quarterly Report on Form 10-Q for the period ended September 30, 2002 in accordance with 18 U.S.C. Section 1350. No financial statements were filed therewith.

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.

March 25, 2003

SPINNAKER EXPLORATION COMPANY

By: /s/ ROGER L. JARVIS

Roger L. Jarvis
Chairman, President, Chief Executive Officer and Director

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

Signature	Title	Date
/s/ ROGER L. JARVIS Roger L. Jarvis	Chairman, President, Chief Executive Officer and Director	March 25, 2003
/s/ ROBERT M. SNELL Robert M. Snell	Vice President, Chief Financial Officer and Secretary (Principal Financial Officer)	March 25, 2003
/s/ JEFFREY C. ZARUBA Jeffrey C. Zaruba	Vice President, Treasurer and Assistant Secretary (Principal Accounting Officer)	March 25, 2003
/s/ SHELDON R. ERIKSON Sheldon R. Erikson	Director	March 25, 2003
/s/ JEFFREY A. HARRIS Jeffrey A. Harris	Director	March 25, 2003
/s/ MICHAEL E. MCMAHON Michael E. McMahon	Director	March 25, 2003
/s/ MICHAEL G. MORRIS Michael G. Morris	Director	March 25, 2003
/s/ HOWARD H. NEWMAN Howard H. Newman	Director	March 25, 2003
/s/ MICHAEL E. WILEY	Director	March 25, 2003

Michael E. Wiley

CERTIFICATION OF
PRINCIPAL EXECUTIVE OFFICER
OF SPINNAKER EXPLORATION COMPANY
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT

I, Roger L. Jarvis, certify that:

1. I have reviewed this annual report on Form 10-K of Spinnaker Exploration Company;
2. Based on my knowledge, this annual 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 annual report;
3. Based on my knowledge, the financial statements, and other financial information included in this annual 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 annual report;
4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

   a) designed such disclosure controls and procedures 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 annual report is being prepared;
   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and
   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; 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; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 25, 2003

/s/ ROGER L. JARVIS

Name: Roger L. Jarvis
Title: Chief Executive Officer

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CERTIFICATION OF
PRINCIPAL FINANCIAL OFFICER
OF SPINNAKER EXPLORATION COMPANY
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT

I, Robert M. Snell, certify that:

1. I have reviewed this annual report on Form 10-K of Spinnaker Exploration Company;
2. Based on my knowledge, this annual 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 annual report;
3. Based on my knowledge, the financial statements, and other financial information included in this annual 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 annual report;
4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

   a) designed such disclosure controls and procedures 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 annual report is being prepared;
   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and
   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; 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; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls

subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 25, 2003

/s/ ROBERT M. SNELL

Name: Robert M. Snell
Title: Chief Financial Officer

SPINNAKER EXPLORATION COMPANY

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Stockholders of
Spinnaker Exploration Company:

We have audited the accompanying consolidated balance sheets of Spinnaker Exploration Company and subsidiaries, as of December 31, 2002 and 2001, and the related consolidated statements of operations, equity and cash flows for each of the years in the three-year period ended December 31, 2002. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. 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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of Spinnaker Exploration Company and subsidiaries as of December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America.

As explained in Note 2 to the consolidated financial statements, effective January 1, 2001, the Company changed its method of accounting for its derivative instruments.

KPMG LLP

Houston, Texas
February 7, 2003

SPINNAKER EXPLORATION COMPANY

CONSOLIDATED BALANCE SHEETS

(In thousands, except share and per share data)

	As of Dece
	2002
ASSETS	
CURRENT ASSETS:	
Cash and cash equivalents	$ 32,543
Accounts receivable, net of allowance for doubtful accounts of $3,232 and $3,059 at December 31, 2002 and 2001, respectively	37,572
Hedging assets	--
Other	11,438
Total current assets	81,553
PROPERTY AND EQUIPMENT:	
Oil and gas, on the basis of full-cost accounting:	
Proved properties	879,840
Unproved properties and properties under development, not being amortized	141,326
Other	14,461
	1,035,627
Less--Accumulated depreciation, depletion and amortization	(274,773)
Total property and equipment	760,854
OTHER ASSETS	308
Total assets	$ 842,715
LIABILITIES AND EQUITY	
CURRENT LIABILITIES:	
Accounts payable	$ 29,453

Accrued liabilities and other	38,542
Hedging liabilities	19,917
Total current liabilities	87,912
DEFERRED INCOME TAXES	61,826
COMMITMENTS AND CONTINGENCIES (Note 11)	
EQUITY:	
Preferred stock, $0.01 par value; 10,000,000 shares authorized; no shares issued and outstanding at December 31, 2002 and 2001, respectively	--
Common stock, $0.01 par value; 50,000,000 shares authorized; 33,184,463 shares issued and 33,171,759 shares outstanding at December 31, 2002 and 27,308,912 shares issued and 27,293,264 shares outstanding at December 31, 2001	332
Additional paid-in capital	596,087
Retained earnings	109,337
Less: Treasury stock, at cost, 12,704 and 15,648 shares at December 31, 2002 and 2001, respectively	(32)
Accumulated other comprehensive income (loss)	(12,747)
Total equity	692,977
Total liabilities and equity	$ 842,715

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

SPINNAKER EXPLORATION COMPANY

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share data)

	Year Ended December 31,		
	2002	2001	2000
REVENUES	$188,326	$210,376	$121,383
EXPENSES:			
Lease operating expenses	18,212	12,132	9,009
Depreciation, depletion and amortization--natural gas and oil properties	108,998	85,059	47,451
Depreciation and amortization--other	914	398	309
General and administrative	10,984	9,443	7,350
Charges related to Enron bankruptcy	128	3,059	--
Total expenses	139,236	110,091	64,119
INCOME FROM OPERATIONS	49,090	100,285	57,264
OTHER INCOME (EXPENSE):			
Interest income	1,014	3,574	2,908
Interest expense, net	(762)	(381)	(748)
Total other income (expense)	252	3,193	2,160

INCOME BEFORE INCOME TAXES	49,342	103,478	59,424
Income tax expense	17,763	37,252	20,858
NET INCOME	$ 31,579	$ 66,226	$ 38,566
NET INCOME PER COMMON SHARE:			
Basic	$ 1.00	$ 2.45	$ 1.70
Diluted	$ 0.97	$ 2.34	$ 1.61
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING:			
Basic	31,695	27,079	22,679
Diluted	32,653	28,360	24,011

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

SPINNAKER EXPLORATION COMPANY

CONSOLIDATED STATEMENTS OF EQUITY

(In thousands, except share data)

	Shares Issued		Par Value		Additional Paid-In Capital	Retained Earnings (Accumulated Deficit)	Trea Sto
	Preferred	Common	Preferred	Common			
Balance, December 31, 1999....	--	20,426,192	$--	$204	$203,987	$(27,034)	$(
Net income..................	--	--	--	--	--	38,566	
Comprehensive income........							
Common stock issuance, net of issuance costs..........	--	5,600,000	--	56	138,342	--	
Exercise of stock options...	--	462,478	--	5	3,195	--	
Employer contributions to 401(k) Plan................	--	5,923	--	--	148	--	
Stock compensation costs....	--	--	--	--	158	--	
Tax benefit associated with exercise of non-qualified stock options.............	--	--	--	--	3,676	--	
Balance, December 31, 2000....	--	26,494,593	$ --	$265	$349,506	$ 11,532	$(
Net income..................	--	--	--	--	--	66,226	
Other comprehensive income, net of tax:							
Cumulative effect of accounting change for							

derivative financial instruments................	--	--	--	--	--	--	
Net change in fair value of derivative financial instruments................	--	--	--	--	--	--	
Financial derivative settlements reclassed to income.....................	--	--	--	--	--	--	
Comprehensive income........							
Exercise of stock options...	--	808,863	--	8	7,142	--	
Employer contributions to 401(k) Plan................	--	5,456	--	--	216	--	
Stock compensation costs....	--	--	--	--	114	--	
Tax benefit associated with exercise of non-qualified stock options.............	--	--	--	--	9,015	--	
Balance, December 31, 2001....	--	27,308,912	$ --	$273	$365,993	$ 77,758	$(
Net income..................	--	--	--	--	--	31,579	
Other comprehensive income, net of tax:							
Net change in fair value of derivative financial instruments................	--	--	--	--	--	--	
Financial derivative settlements reclassed to income.....................	--	--	--	--	--	--	
Comprehensive income........							
Common stock issuance, net of issuance costs..........	--	5,750,000	--	58	227,326	--	
Exercise of stock options...	--	116,489	--	1	948	--	
Employer contributions to 401(k) Plan................	--	9,062	--	--	287	--	
Stock compensation costs....	--	--	--	--	177	--	
Tax benefit associated with exercise of non-qualified stock options.............	--	--	--	--	1,356	--	
Balance, December 31, 2002....	--	33,184,463	$ --	$332	$596,087	$109,337	$(

	Comprehensive Income (Loss)
Balance, December 31, 1999....	
Net income..................	$ 38,566
Comprehensive income........	$ 38,566
Common stock issuance, net of issuance costs..........	
Exercise of stock options...	
Employer contributions to	

401(k) Plan................	
Stock compensation costs....	
Tax benefit associated with exercise of non-qualified stock options.............	
Balance, December 31, 2000....	
Net income..................	$ 66,226
Other comprehensive income, net of tax:	
Cumulative effect of accounting change for derivative financial instruments................	(27,126)
Net change in fair value of derivative financial instruments................	35,502
Financial derivative settlements reclassed to income.....................	6,131
Comprehensive income........	$ 80,733
Exercise of stock options...	
Employer contributions to 401(k) Plan................	
Stock compensation costs....	
Tax benefit associated with exercise of non-qualified stock options.............	
Balance, December 31, 2001....	
Net income..................	$ 31,579
Other comprehensive income, net of tax:	
Net change in fair value of derivative financial instruments................	(24,269)
Financial derivative settlements reclassed to income.....................	(2,985)
Comprehensive income........	$ 4,325
Common stock issuance, net of issuance costs..........	
Exercise of stock options...	
Employer contributions to 401(k) Plan................	
Stock compensation costs....	
Tax benefit associated with exercise of non-qualified stock options.............	
Balance, December 31, 2002....	

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

SPINNAKER EXPLORATION COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Year Ended December 31		
	2002	2001	2
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 31,579	$ 66,226	$ 3
Adjustments to reconcile net income to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	109,912	85,457	4
Deferred income tax expense	18,063	36,977	2
Other	881	549	
Change in operating assets and liabilities:			
Accounts receivable	(13,443)	21,465	(3
Accounts payable and accrued liabilities	7,726	(3,216)	1
Other assets	(759)	1,979	(
Net cash provided by operating activities	153,959	209,437	8
CASH FLOWS FROM INVESTING ACTIVITIES:			
Oil and gas properties	(356,601)	(287,225)	(16
Proceeds from sale of natural gas and oil assets	--	--	
Purchases of other property and equipment	(7,216)	(1,603)	(
Purchases of short-term investments	--	(29,627)	(2
Sales of short-term investments	--	52,014	
Net cash used in investing activities	(363,817)	(266,441)	(18
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowings	37,000	--	1
Payments on borrowings	(37,000)	--	(1
Proceeds from issuance of common stock	227,873	--	13
Common stock issuance costs	(489)	--	
Proceeds from exercise of stock options	956	7,155	
Net cash provided by financing activities	228,340	7,155	14
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	18,482	(49,849)	4
CASH AND CASH EQUIVALENTS, beginning of year	14,061	63,910	2
CASH AND CASH EQUIVALENTS, end of year	$ 32,543	$ 14,061	$ 6
SUPPLEMENTAL CASH FLOW DISCLOSURES:			
Cash paid for interest, net of amounts capitalized	$ 468	$ 190	$
Cash paid (received) for income taxes, net	$ (300)	$ 275	$

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

SPINNAKER EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization:

Spinnaker Exploration Company ("Spinnaker" or the "Company") was formed in 1996 and engages in the exploration, development and production of natural gas and oil properties in the U.S. Gulf of Mexico.

On September 28, 1999, the Company priced its initial public offering of 8,000,000 shares of common stock, par value $0.01 per share ("Common Stock"), and commenced trading the following day. After payment of underwriting discounts and commissions, the Company received net proceeds of $108.7 million on October 4, 1999. With a portion of the proceeds, the Company retired all outstanding debt of $72.0 million. In connection with the initial public offering, the Company converted all outstanding Series A Convertible Preferred Stock, par value $0.01 per share ("Preferred Stock"), into shares of Common Stock, and certain shareholders reinvested preferred dividends payable of $16.3 million into shares of Common Stock.

2. Summary of Significant Accounting Policies:

A summary of significant accounting policies followed in the preparation of the accompanying consolidated financial statements is set forth below:

General

The accompanying consolidated financial statements of the Company have been prepared in accordance with accounting principles generally accepted in the United States and pursuant to the rules and regulations of the Securities and Exchange Commission (the "Commission").

Principles of Consolidation

The accompanying consolidated financial statements include the activities and accounts of the Company and its subsidiaries, all of which are wholly owned. All significant intercompany transactions and balances are eliminated in consolidation.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant estimates include depreciation, depletion and amortization ("DD&A") of proved natural gas and oil properties. Natural gas and oil reserve estimates, which are the basis for unit-of-production DD&A and the full cost ceiling test, are inherently imprecise and are expected to change as future information becomes available.

Cash Equivalents

The Company considers all highly liquid investments with a maturity of three months or less when purchased to be cash equivalents.

Other Current Assets

Other current assets include unamortized debt financing costs of $0.3 million and $0.3 million at December 31, 2002 and 2001, respectively. Other non-current assets include unamortized debt financing costs of $0.3 million and $0.6 million at December 31, 2002 and 2001, respectively. These costs are amortized to interest

expense over the three-year term of the related credit facility. Amortization of these and other debt financing costs included in interest expense was $0.3 million, $0.2 million and $0.4 million for the years ended December 31, 2002, 2001 and 2000, respectively.

Full Cost Method of Accounting

The Company uses the full cost method of accounting for its investments in natural gas and oil properties. Under this method, all acquisition, exploration and development costs, including certain related employee costs, incurred for the purpose of exploring for and developing natural gas and oil are capitalized. Acquisition costs include costs incurred to purchase, lease or otherwise acquire property. Exploration costs include the costs of drilling exploratory wells, including those in progress, geological and geophysical service costs and depreciation of support equipment used in exploration activities. Development costs include the costs of drilling development wells and costs of completions, platforms, facilities and pipelines. Costs associated with production and general corporate activities are expensed in the period incurred. Sales of natural gas and oil properties, whether or not being amortized currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of natural gas and oil. Substantially all the Company's exploration activities are conducted jointly with others and, accordingly, the natural gas and oil property balances reflect only its proportionate interest in such activities.

DD&A

The Company computes the provision for DD&A of natural gas and oil properties using the unit-of-production method based upon production and estimates of proved reserve quantities. Unevaluated costs and related carrying costs are excluded from the amortization base until the properties associated with these costs are evaluated. In addition to costs associated with evaluated properties, the amortization base includes estimated future development costs and dismantlement, restoration and abandonment costs, net of estimated salvage values.

Certain future development costs may be excluded from amortization when incurred in connection with major development projects expected to entail significant costs to ascertain the quantities of proved reserves attributable to the properties under development. The amounts that may be excluded are portions of the costs that relate to the major development project and have not previously been included in the amortization base and the estimated future expenditures associated with the development project. Such costs may be excluded from costs to be amortized until the earlier determination of whether additional reserves are proved or impairment occurs.

As of December 31, 2002, the Company excluded from the amortization base estimated future expenditures of $29.4 million associated with common development costs for its deepwater discovery at Front Runner. This estimate of future expenditures associated with common development costs is based on existing proved reserves to total proved reserves expected to be established upon completion of the Front Runner project.

Full Cost Ceiling

Capitalized costs of natural gas and oil properties, net of accumulated DD&A and related deferred taxes, are limited to the estimated future net cash flows from proved natural gas and oil reserves, including the effects of hedging activities in place as of December 31, 2002, discounted at 10%, plus the lower of cost or fair value of unproved properties, as adjusted for related income tax effects (the full cost ceiling). If capitalized costs of the full cost pool exceed the ceiling limitation, the excess is charged to expense.

Capitalized Employee and Other General and Administrative Costs

Under the full cost method of accounting, certain costs are capitalized that are directly identified with acquisition, exploration and development activities. These capitalized costs include salaries, employee benefits, costs of consulting services and other related costs and do not include costs related to production, general corporate overhead or similar activities. Spinnaker capitalized employee and other general and administrative costs of $5.9 million, $5.1 million and $3.8 million in 2002, 2001 and 2000, respectively.

Unproved Properties

The costs associated with unproved properties and properties under development are not initially included in the amortization base and relate to unevaluated leasehold acreage and delay rentals, seismic data, wells in-progress and wells pending determination. Unevaluated leasehold costs and delay rentals are either transferred to the amortization base with the costs of drilling the related well or are assessed quarterly for possible impairment or reduction in value. Unevaluated leasehold costs and delay rentals are transferred to the amortization base if a reduction in value has occurred. The costs of seismic data are transferred to the amortization base using the sum-of-the-year's-digits method over a period of six years. The costs associated with wells in-progress and wells pending determination are transferred to the amortization base once a determination is made whether or not proved reserves can be assigned to the property. The costs of drilling exploratory dry holes and associated leasehold costs are included in the amortization base immediately upon determination that the well is unsuccessful.

Of the $141.3 million of net unproved property costs at December 31, 2002 excluded from the amortizable base, net costs of $38.4 million, $19.7 million and $42.5 million were incurred in 2002, 2001 and 2000, respectively, and $40.7 million was incurred prior to 2000. The majority of the costs will be evaluated over the next five years.

Other Property and Equipment

Other property and equipment consists of computer hardware and software, office furniture and leasehold improvements. The Company is depreciating these assets using the straight-line method based upon estimated useful lives ranging from three to five years.

The costs associated with seismic hardware and software are included in other property and equipment. These costs are amortized into the full cost pool using the straight-line method over three years. Amortization was $1.5 million, $0.5 million and $1.2 million in 2002, 2001 and 2000, respectively.

Revenue Recognition Policy

The Company records as revenue only that portion of production sold and delivered and allocable to its ownership interest in the related property. Imbalances arise when a purchaser takes delivery of more or less volume from a property than the Company's actual interest in the production from that property. Such imbalances are reduced either by subsequent recoupment of over-and-under deliveries or by cash settlement, as required by applicable contracts. Under-imbalances included in accounts receivable were $0.6 million and $0.7 million at December 31, 2002 and 2001, respectively. Over-imbalances included in accrued liabilities were $2.5 million and $0.7 million at December 31, 2002 and 2001, respectively.

Income Taxes

Under Statement of Financial Accounting Standards ("SFAS") No. 109, "Accounting for Income Taxes," deferred income taxes are recognized at each year-end for the future tax consequences of differences between the

tax bases of assets and liabilities and their financial reporting amounts based on enacted tax laws and statutory tax rates applicable to the periods in which the differences are expected to affect taxable income. Valuation allowances are established when necessary to reduce deferred tax assets to the amount expected to be realized.

Stock-Based Compensation

SFAS No. 148, "Accounting for Stock-Based Compensation--Transition and Disclosure," amends SFAS No. 123 to provide alternative methods of transition for an entity that voluntarily changes to the fair value based method of accounting for stock-based employee compensation and to require prominent disclosure about the effects on reported net income of an entity's accounting policy decisions with respect to stock-based employee compensation. SFAS No. 148 amends Accounting Principles Board ("APB") Opinion No. 28, "Interim Financial Reporting," to require disclosure about those effects in interim financial information.

SFAS No. 123, "Accounting for Stock-Based Compensation," encourages, but does not require, companies to record compensation cost for stock-based employee compensation plans at fair value. The Company has chosen to account for stock-based compensation using the intrinsic value method prescribed in APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. Accordingly, compensation cost for stock options is measured as the excess, if any, of the fair value of the Common Stock at the date of the grant over the amount an employee must pay to acquire the Common Stock. In accordance with APB Opinion No. 25, compensation expense related to stock-based compensation was $0.2 million, $0.1 million and $0.2 million in 2002, 2001 and 2000, respectively. Had compensation cost for the Company's stock option compensation plans been determined based on the fair value at the grant dates for awards under these plans consistent with the method of SFAS No. 123, the Company's pro forma net income and pro forma net income per common share would have been as follows (in thousands, except per share amounts):

	Year Ended December 31,		
	2002	2001	2000
Net income, as reported	$31,579	$66,226	$38,56
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	114	73	10
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(8,902)	(8,920)	(3,12
Pro forma net income	$22,791	$57,379	$35,54
Net income per common share:			
Basic, as reported	$ 1.00	$ 2.45	$ 1.7
Basic, pro forma	$ 0.72	$ 2.12	$ 1.5
Diluted, as reported	$ 0.97	$ 2.34	$ 1.6
Diluted, pro forma	$ 0.70	$ 2.02	$ 1.4

For purposes of the SFAS No. 123 disclosure, the fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model with assumptions for grants in 2002, 2001 and 2000 as follows:

	Year Ended December 31,		
	2002	2001	2000
Risk-free interest rate	3.98%-5.28%	4.85%-5.57%	5.14%-6.82%
Volatility factor	62.2%	43.0%	42.5%
Dividend yield	0%	0%	0%
Expected life of the options (years)	4	4	4

Financial Instruments and Price Risk Management Activities

At December 31, 2002, the Company's financial instruments consisted of cash and cash equivalents, receivables, payables and derivative instruments. The carrying amounts of cash and cash equivalents, receivables and payables approximate fair value because of the short-term nature of these items. The Company enters into hedging arrangements from time to time to reduce its exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flow. These hedging arrangements take the form of swap contracts or cashless collars and are placed with major trading counterparties.

On January 1, 2001, the Company adopted SFAS No. 133, as amended, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 established accounting and reporting standards requiring that all derivative instruments be recorded in the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in a derivative's fair value be realized currently in earnings unless specific hedge accounting criteria are met. Accounting for qualifying hedges allows derivative gains and losses to offset related results on the hedged items in the statement of operations and requires a company to formally document, designate and assess the effectiveness of transactions that qualify for hedge accounting. Upon adoption of SFAS No. 133 on January 1, 2001, the Company designated its open derivative contracts as cash flow hedges and recorded (i) a net current liability of $41.7 million, representing the fair market value of all derivatives on that date and (ii) a reduction of equity through accumulated other comprehensive income (loss) of $27.1 million, representing the fair market value of the derivatives as of January 1, 2001, net of deferred income taxes of $14.6 million.

Concentration of Credit Risk

Financial instruments that potentially subject the Company to concentration of credit risk consist principally of cash equivalents and trade accounts receivable. Derivative contracts also subject the Company to concentration of credit risk. Management believes that the credit risk posed by this concentration is mitigated by its hedging policy. The hedging policy requires that (i) at no time will any hedging agreement of any nature have a counterparty with a minimum long-term senior unsecured indebtedness rating less than "BBB+" by Standard & Poor's or "Baa1" by Moody's Investors Services, Inc. at the time that such counterparty entered into the relevant transaction under such hedging agreement and (ii) at no time will exposure to any single counterparty exceed 25% of the estimated twelve-month production volumes from total proved reserves.

The Company had in place both financial hedge and physical contracts with Enron North America Corp. at the time Enron Corp. and its subsidiaries filed for bankruptcy in December 2001. Spinnaker did not receive payment for fixed price swap contracts totaling $2.1 million which were intended to hedge December 2001 natural gas sales, and $1.4 million related to November 2001 natural gas production sold to Enron entities. The Company has recorded a net reserve of $3.2 million related to these receivables.

New Accounting Pronouncements

SFAS No. 143, "Accounting for Asset Retirement Obligations," requires entities to record a liability for asset retirement obligations at fair value in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. SFAS No. 143 is effective for financial statements issued for fiscal years beginning after June 30, 2002 using a cumulative effect approach to recognize transition amounts for asset retirement obligations, asset retirement costs and accumulated depreciation, depletion and amortization. The Company will adopt SFAS No. 143 effective January 1, 2003. The Company expects the adoption of this statement to result in the recognition of a liability for asset retirement obligations of approximately $22-$26 million, approximately $2-$4 million of which will be included in current liabilities and approximately $20-$22

million of which will be included in non-current liabilities, an increase in property and equipment of approximately $18-$22 million in the Company's balance sheets, and a cumulative accounting adjustment of approximately $2-$4 million recorded as expense, net of taxes of $1-$2 million, as the effect of the change in accounting principle.

SFAS No. 148, "Accounting for Stock-Based Compensation--Transition and Disclosure," amends SFAS No. 123 to provide alternative methods of transition for an entity that voluntarily changes to the fair value based method of accounting for stock-based employee compensation and to require prominent disclosure about the effects on reported net income of an entity's accounting policy decisions with respect to stock-based employee compensation. SFAS No. 148 amends APB Opinion No. 28, "Interim Financial Reporting," to require disclosure about those effects in interim financial information. SFAS No. 148 is effective for financial statements for fiscal years ending after December 15, 2002.

3. Accounts Receivable, Other Current Assets and Accrued Liabilities and Other:

Supplemental disclosures related to accounts receivable, other current assets and accrued liabilities and other are as follows (in thousands):

	As of December 31,	
	2002	2001
Accounts receivable:		
Natural gas and oil sales	$24,434	$10,679
Hedging receivable	2,093	2,093
Joint interest billings	10,430	8,735
Insurance claims receivable	3,127	4,593
Other receivables	720	1,088
Allowance for doubtful accounts	(3,232)	(3,059)
Total accounts receivable	$37,572	$24,129
Other current assets:		
Deferred tax assets associated with hedging activities	$ 7,170	$ 115
Drilling advances	2,060	710
Prepaid insurance	648	1,664
Prepaid debt financing costs	301	328
Other	1,259	847

Total other current assets	$11,438	$ 3,664
Accrued liabilities and other:		
Accrued liabilities	$38,542	$43,510
Deferred income taxes associated with hedging activities.	--	7,208
Total accrued liabilities and other	$38,542	$50,718

4. Debt:

In October 1999, the Company, Bank of Montreal and Credit Suisse First Boston entered into the $25.0 million Amended and Restated 364-Day Credit Agreement ("First Amended Credit Agreement"). The First Amended Credit Agreement was amended on July 20, 2000. The Second Amended and Restated Credit Agreement provided a $75.0 million credit facility ("Second Amended Credit Agreement") with an initial borrowing base of $40.0 million and an original term of 364 days. The borrowing base as of December 31, 2000

was $30.0 million. The Second Amended Credit Agreement was renewed for an additional 364-day term on July 18, 2001 before being terminated on December 28, 2001.

On December 28, 2001, the Company replaced its $75.0 million credit facility with an unsecured $200.0 million credit facility ("Credit Facility") with a group of seven banks. The borrowing base of the three-year Credit Facility is re-determined on or about April 30 and September 30 each year. The banks and Spinnaker also have the option to request one additional re-determination each year. The banks determine the borrowing base at their sole discretion and in their usual and customary manner. The amount of the borrowing base is a function of the banks' view of the Company's reserve profile as well as commodity prices. The current borrowing base is $100.0 million. The Company has the option to elect to use a base interest rate as described below or the LIBOR rate plus, for each such rate, a spread based on the percentage of the borrowing base used at that time. The base interest rate under the Credit Facility is a fluctuating rate of interest equal to the higher of either Toronto-Dominion Bank's base rate for dollar advances made in the United States or the Federal Funds Rate plus 0.5% per annum. The commitment fee rate ranges from 0.3% to 0.5%, depending on the borrowing base usage.

The Credit Facility contains various covenants and restrictive provisions, including the following limitations, subject to some exceptions, where the Company:

- may not incur any other indebtedness from borrowings, except for indebtedness arising under hedging agreements, indebtedness incurred in the ordinary course of business not to exceed $1.0 million, unsecured vendor indebtedness of the Company related to purchases of 2-D and 3-D seismic data made in the ordinary course of business in an amount not to exceed $25.0 million, other unsecured indebtedness in an amount not to exceed $10.0 million in the aggregate;

- may not incur any liens upon properties or assets other than permitted liens securing indebtedness of up to $1.0 million, liens on the 2-D and 3-D seismic data securing the indebtedness permitted to acquire such data, pledges or deposits to secure hedging agreements up to $15.0 million, liens on property required as a condition to enter into a synthetic lease transaction in the ordinary course of business and other liens in the ordinary course of business;

- may not dispose of any assets or properties except obsolete equipment, inventory sold in the ordinary course of business, reserves in non-proved categories, a second license in certain seismic data, or interests in natural gas and oil properties included in the borrowing base in an aggregate amount not to exceed $25.0 million in any fiscal year;

- may not make or pay any dividend, distribution or payment in respect of capital stock nor purchase, redeem, acquire, retire or permit any reduction or retirement of capital stock in excess of $10.0 million in any fiscal year;

- must maintain the ratio of consolidated current assets to consolidated current liabilities as of the end of each fiscal quarter so that it is not less than 1.00 to 1.00. For purposes of the calculation, availability under the Credit Facility is included as current assets, any payments of principal owing under the Credit Facility required to be repaid within one year from the time of the calculation are excluded from current liabilities and mark-to-market hedging exposure is excluded from both current assets and current liabilities;

- must maintain a tangible net worth so that it is not less than the sum of 80% of the tangible net worth as of September 30, 2001, plus 50% of the adjusted consolidated net income for each fiscal quarter since the closing of the Credit Facility, plus 75% of the proceeds from the sale of any security, including without limitation, common equity, preferred equity or other equity interests or equity securities including warrants, options and the like issued after the closing of the Credit Facility; and

- may not enter into any hedging agreement unless the percent of volumes to be hedged to estimated production volumes for such month from total internally-projected proved reserves does not exceed: 100% for the period one to three months from and after the hedging agreement transaction date, 66 2/3% for the period four to 18 months from and after the hedging agreement transaction date and 33 1/3% for the period 19 to 36 months from and after the hedging agreement transaction date. Additionally, at no time will any hedging agreement of any nature have a counterparty with a minimum long-term senior unsecured indebtedness rating less than "BBB+" by Standard & Poor's or "Baa1" by Moody's Investors Services, Inc. at the time that such counterparty entered into the relevant transaction under such hedging agreement and at no time will exposure to any single counterparty exceed 25% of the estimated twelve-month production volumes from total proved reserves.

At December 31, 2002, the Company was in compliance with the covenants and restrictive provisions and had no outstanding borrowings under the Credit Facility.

5. Equity:

Prior to Spinnaker's initial public offering in September 1999, the Company sold Preferred Stock to various investors. On September 28, 1999, the Company priced its initial public offering of 8,000,000 shares of Common Stock and commenced trading the following day. In connection with the initial public offering, the Company converted all outstanding Preferred Stock into 6,061,840 shares of Common Stock, and certain shareholders reinvested preferred dividends payable of $16.3 million into 1,200,248 shares of Common Stock. On August 16, 2000, the Company completed a public offering of 5,600,000 shares of Common Stock at $26.25 per share. After payment of underwriting discounts and commissions, the Company received net proceeds of $138.9 million. On December 20, 2000, PGS sold its 5,388,743 shares of Common Stock at $29.25 per share. Spinnaker received no proceeds from this sale. On April 3, 2002, the Company completed a public offering of 5,750,000 shares of Common Stock at $41.50 per share, including the over-allotment option consisting of 750,000 shares. After payment of underwriting discounts and commissions, the Company received net proceeds of $227.9 million.

Spinnaker has an effective shelf registration statement relating to the potential public offer and sale by the Company or certain of its affiliates of up to $500.0 million of any combination of debt securities, preferred stock, common stock, warrants, stock purchase contracts and trust preferred securities from time to time or when financing needs arise. The registration statement does not provide assurance that the Company will or could sell any such securities.

6. Stock Plans:

At December 31, 2002, officers, directors and employees had been granted options to purchase Common Stock under stock plans adopted in 1998, 1999, 2000 and 2001. The exercise price of each option equals the market price of Spinnaker's Common Stock on the date of grant. Stock option grants generally vest ratably over four years, with 20% vesting on the date of grant and 20% vesting in each of the succeeding four years, and expire after ten years. In the event of certain significant changes in control of the Company, all options then outstanding generally will become immediately exercisable in full.

In January 1998, the stockholders approved the 1998 Stock Option Plan ("1998 Plan"). The 1998 Plan was amended and restated in September 1999 and authorized the issuance of 2,673,242 shares of Common Stock. In September 1999, the stockholders approved the 1999 Stock Incentive Plan ("1999 Plan"). The number of shares of Common Stock that may be issued under the 1999 Plan may not exceed 1,300,000 shares. The maximum number of shares of Common Stock that may be subject to awards granted under the 1999 Plan to any one individual during any calendar year may not exceed 300,000 shares. In connection with the 1999 Plan, the

stockholders approved the Adjunct Stock Option Plan ("Adjunct Plan"). The number of shares of Common Stock that may be issued under the Adjunct Plan may not exceed 21,920 shares. In November 2000, the board of directors adopted the 2000 Stock Option Plan ("2000 Plan"). Stockholder approval was not required for the 2000 Plan. The number of shares of Common Stock that may be issued under the 2000 Plan may not exceed 500,000 shares. In May 2001, the stockholders approved the 2001 Stock Incentive Plan ("2001 Plan"). The number of shares of Common Stock that may be issued under the 2001 Plan may not exceed 1,500,000 shares. The maximum number of shares of Common Stock that may be subject to awards granted under the 2001 Plan to any one individual during any calendar year may not exceed 300,000 shares.

Presented below is a summary of stock option activity.

	2002		2001		2000	
	Shares Under Option	Weighted Average Exercise Price	Shares Under Option	Weighted Average Exercise Price	Shares Under Option	Weig Aver Exer Pri
Outstanding, beginning of year........	4,062,556	$22.08	3,718,886	$13.80	3,382,974	$10
Granted...........................	450,000	35.82	1,242,800	37.90	802,470	23
Exercised.........................	(119,433)	8.01	(810,991)	8.82	(466,558)	6
Forfeited.........................	(6,590)	27.64	(88,139)	17.57	--	
Outstanding, end of year.............	4,386,533	$23.87	4,062,556	$22.08	3,718,886	$13
Exercisable, end of year.............	2,845,250	$19.30	2,273,548	$16.16	2,364,270	$11
Available for grant, end of year......	204,535		648,545		303,206	
Weighted average fair value of options granted during the year............	$ 26.83		$ 23.76		$ 15.17	

The Company transferred treasury shares to certain employees in connection with their exercises of 2,944, 2,128 and 4,080 options in 2002, 2001 and 2000, respectively. Options to purchase 1,240 shares of Common Stock were forfeited during 2002 and 1999 and are not currently available for future grants due to exercise price restrictions under the 1998 Plan.

At December 31, 2002, the following options were outstanding and exercisable and had the indicated weighted average remaining contractual lives:

	Outstanding		Exercisable		
Range of Exercise Prices Per Share	Number of Options	Weighted Average Exercise Price Per Share	Number of Options	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Life (Years)
$2.50-$5.00	541,004	$ 4.94	541,004	$ 4.94	4.2
$14.50-$16.13	1,749,699	15.36	1,462,164	15.36	5.7
$21.58-$26.88	322,700	26.05	172,200	26.41	8.2
$31.33-$36.81	173,220	32.74	60,932	32.23	8.8
$37.35-$38.63	1,407,210	37.84	529,530	37.86	8.4
$39.35-$42.06	192,700	40.50	79,420	40.80	8.6

4,386,533	2,845,250
=========	=========

SPINNAKER EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS--(Continued)

7. Earnings Per Share:

Basic and diluted net income per common share is computed based on the following information (in thousands, except per share amounts):

	Year Ended December 31,		
	2002	2001	2000
Numerator:			
Net income available to common stockholders	$31,579	$66,226	$38,566
Denominator:			
Basic weighted average number of shares	31,695	27,079	22,679
Dilutive securities:			
Stock options	958	1,281	1,332
Diluted adjusted weighted average number of shares and assumed conversions	32,653	28,360	24,011
Net income per common share:			
Basic	$ 1.00	$ 2.45	$ 1.70
Diluted	$ 0.97	$ 2.34	$ 1.61

For the years ended December 31, 2002, 2001 and 2000, 1,680,640, 113,200 and 399,920 stock options that could potentially dilute earnings per share are excluded from the calculations as they were anti-dilutive.

8. Major Customers:

The Company had natural gas and oil sales to four customers accounting for approximately 52%, 13%, 11% and 11%, respectively, of total natural gas and oil revenues, excluding the effects of hedging activities, for the year ended December 31, 2002. The Company had natural gas and oil sales to four customers accounting for approximately 32%, 23%, 21% and 17%, respectively, of total natural gas and oil revenues, excluding the effects of hedging activities, for the year ended December 31, 2001. The Company had natural gas and oil sales to three customers accounting for approximately 61%, 11% and 11%, respectively, of total natural gas and oil revenues, excluding the effects of hedging activities, for the year ended December 31, 2000. One of the customers in 2001 and 2000 was Enron North America Corp. Spinnaker no longer sells its natural gas and oil production to this customer.

9. Related-Party Transactions:

The Company incurred charges of approximately $16.1 million and $16.3 million in 2002 and 2001, respectively, from affiliates of Baker Hughes Incorporated, an oilfield services company of which Mr. Michael E. Wiley, a director of Spinnaker since March 2001, serves as Chairman of the Board, Chief Executive Officer and President. The Company incurred charges of approximately $0.1 million, $0.1 million and $0.5 million in 2002, 2001 and 2000, respectively, from Cooper Cameron Corporation, an oilfield services company of which Mr. Sheldon R. Erikson, a director of Spinnaker, serves as Chairman of the Board, Chief Executive Officer and President.

10. Income Taxes:

The significant items giving rise to the deferred income tax assets and liabilities are as follows (in thousands):

	As of December 31,	
	2002	2001
Deferred income tax liabilities:		
Basis differences in natural gas and oil properties.	$156,588	$104,141
Hedging activities................................	--	7,812
Total deferred income tax liabilities..........	156,588	111,953
Deferred income tax assets:		
Net operating losses..............................	$ 92,650	$ 58,400
Hedging activities................................	7,170	--
Other...	2,112	622
Total deferred income tax assets...............	101,932	59,022
Net deferred income tax liabilities...................	$ 54,656	$ 52,931

Tax benefits of $1.4 million and $9.0 million associated with the exercise of non-qualified stock options during the years ended December 31, 2002 and 2001 are reflected as a component of equity. The net deferred income tax liabilities include a deferred tax asset of $7.2 million and a deferred tax liability of $7.8 million related to the tax effect of the fair market value of derivatives at December 31, 2002 and 2001, respectively, as required by SFAS No. 133, as amended.

As of December 31, 2002, the Company had approximately $257.4 million of net operating loss carryforwards ("NOLs") that will begin expiring in 2018. For federal income tax purposes, certain limitations are imposed on an entity's ability to utilize its NOLs in future periods if a change of control, as defined for federal income tax purposes, has occurred. In general terms, the limitation on utilization of NOLs and other tax attributes during any one year is determined by the value of an entity at the date of the change of control multiplied by the then-existing long-term, tax-exempt interest rate. The Internal Revenue Service has not yet addressed the manner of determining an entity's value. The Company has determined that, for federal income tax purposes, a change of control occurred during 2000. However, the Company does not believe such limitations will significantly impact its ability to utilize the NOLs.

Significant components of the provision for income taxes are as follows (in thousands):

	Year Ended December 31,		
	2002	2001	2000
Current	$ (300)	$ 275	$ 25
Deferred	18,063	36,977	20,833
Income tax expense	$17,763	$37,252	$20,858

The differences between income tax expense and the amount that would be determined by applying the statutory federal income tax rate of 35% to the income before income taxes are as follows (in thousands):

	Year Ended December 31,		
	2002	2001	2000
Federal income tax expense at statutory rates	$17,270	$36,217	$20,798
Non-deductible expenses and other	493	1,035	659
Valuation allowance	--	--	(599)
Income tax expense	$17,763	$37,252	$20,858

During 2000, the Company expected that it would realize all of its deferred tax assets and therefore decreased the valuation allowance to $0.

11. Commitments and Contingencies:

The Company is, from time to time, party to certain legal actions and claims arising in the ordinary course of business. While the outcome of these events cannot be predicted with certainty, management does not expect these matters to have a materially adverse effect on the financial position, results of operations or cash flows of the Company.

Employment Contracts

The Company has employment contracts with certain of its executive officers. These contracts provide for annual base salaries, bonus compensation, various benefits and the continuation of salary and benefits for the respective terms of the agreements in the event of termination of employment for various reasons, and whether by the Company or the employee. These agreements are subject to automatic annual extensions unless terminated.

Employee 401(k) Retirement Plan

In July 1998, the Company instituted a 401(k) retirement savings plan ("401(k) Plan") for its employees. The 401(k) Plan provides that all qualified employees may defer the maximum income allowed under current tax law. The 401(k) Plan covers all employees at least 21 years of age.

Effective January 1, 2000, the Company began matching employee contributions to the 401(k) Plan. The Company matches 100% of each participant's contributions up to 6% of the participant's annual base salary. In connection with the employer match, the Company issued 9,062 shares of Common Stock valued at $0.3 million in 2002, 5,456 shares of Common Stock valued at $0.2 million in 2001 and 5,923 shares of Common Stock valued at $0.1 million in 2000.

Leases

The Company leases administrative offices under a non-cancelable operating lease expiring in 2007. The lease agreement requires the Company pay for utilities, maintenance and other operational expenses of the building. Additionally, the lease contains escalation clauses. The Company also leases office equipment and oil and gas equipment under non-cancelable operating leases. Rental expense was $1.6 million, $0.7 million and $0.5 million in 2002, 2001 and 2000, respectively. Minimum future obligations under non-cancelable operating

leases at December 31, 2002 for the following five years are $1.7 million, $1.3 million, $1.3 million, $1.2 million and $0.5 million, respectively.

Summary of Contractual Obligations

The Company had no long-term debt, capital lease or purchase obligations or other contractual long-term liabilities as of December 31, 2002. The Company has incurred obligations in the ordinary course of business under purchase and service agreements that are not included in the table below, including obligations of approximately $35.4 million and $6.7 million in 2003 and 2004, respectively, for construction of the Green Canyon Blocks 338/339 ("Front Runner") spar production facility. Contractual obligations as of December 31, 2002 are as follows:

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Operating leases.............	$6,032	$1,708	$3,800	$524	$--
Other contractual obligations	--	--	--	--	--
Total.....................	$6,032	$1,708	$3,800	$524	$--

12. Commodity Price Risk Management Activities:

The Company enters into New York Mercantile Exchange ("NYMEX") related swap contracts and collar arrangements from time to time. The Company's swap contracts and collar arrangements will settle based on the reported settlement price on the NYMEX for the last trading day of each month for natural gas.

In a swap transaction, the counterparty is required to make a payment to the Company for the difference between the fixed price and the settlement price if the settlement price is below the fixed price. The Company is required to make a payment to the counterparty for the difference between the fixed price and the settlement price if the settlement price is above the fixed price. As of December 31, 2002, Spinnaker's commodity price risk management positions in fixed price natural gas swap contracts and related fair value were as follows:

Period	Average Daily Volume (MMBtus)	Weighted Average Price (Per MMBtu)	Fair Value (in thousands)
First Quarter 2003.	60,000	$3.71	$ (5,979)
Second Quarter 2003	53,297	3.55	(4,411)
Third Quarter 2003.	50,000	3.55	(4,068)
Fourth Quarter 2003	50,000	3.63	(4,340)
Year 2003..........	53,288	$3.61	$(18,798)

In a collar arrangement, the counterparty is required to make a payment to the Company for the difference between the fixed floor price and the settlement price if the settlement price is below the fixed floor price. The Company is required to make a payment to the counterparty for the difference between the fixed ceiling price and the settlement price if the settlement price is above the fixed ceiling price. Neither party is required to make a payment if the settlement price falls between the fixed floor price and the fixed ceiling price. As of December 31, 2002, Spinnaker's commodity price risk management positions in natural gas collar arrangements and related fair value were as follows:

Period	Average Daily Volume (MMBtus)	Weighted Average Floor Price (Per MMBtu)	Weighted Average Ceiling Price (Per MMBtu)	Fair Value (in thousands)
First Quarter 2003.	15,000	$3.25	$5.21	$ (228)
Second Quarter 2003	15,000	3.25	5.21	(262)
Third Quarter 2003.	15,000	3.25	5.21	(287)
Fourth Quarter 2003	15,000	3.25	5.21	(342)
Year 2003..........	15,000	$3.25	$5.21	$(1,119)

The Company reported a net liability of $19.9 million and a net asset of $22.3 million related to its derivative contracts at December 31, 2002 and 2001, respectively. Amounts related to hedging activities as of December 31, 2002 and 2001 were as follows (in thousands):

	As of December 31, 2002	2001
Current assets:		
Hedging asset..	$ --	$20,593
Deferred income tax asset related to hedging activities.....	7,170	--
Non-current assets:		
Hedging asset..	$ --	$ 1,726
Current liabilities:		
Hedging liability..	$ 19,917	$ --
Deferred income tax liability related to hedging activities.	--	7,208
Non-current liabilities:		
Deferred income tax liability related to hedging activities.	$ --	$ 604
Accumulated other comprehensive income (loss):		
Accumulated other comprehensive income (loss)...............	$(19,917)	$22,319
Income taxes...	7,170	(7,812)
Accumulated other comprehensive income (loss)...........	$(12,747)	$14,507

The Company recognized a net hedging gain of $4.7 million and net hedging losses of $9.6 million and $18.7 million in revenues in 2002, 2001 and 2000, respectively. There was no ineffective component of the derivatives recognized in earnings in 2002 and 2001. Based on future natural gas prices as of December 31, 2002, the Company would reclassify a net loss of $12.7 million from accumulated other comprehensive income (loss) to earnings within the next twelve months. The amounts ultimately reclassified into earnings will vary due to changes in the fair value of the open derivative contracts prior to settlement.

SPINNAKER EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS--(Continued)

13. Quarterly Financial Data (Unaudited):

Quarterly operating results for the years ended December 31, 2002 and 2001 are summarized as follows (in thousands, except per share amounts):

	(Unaudited) Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
2002:				
Revenues....................	$32,600	$37,164	$51,558	$67,004
Income from operations......	8,963	9,256	11,042	19,829
Net income..................	5,576	6,222	7,146	12,635
Net income per common share:				
Basic....................	$ 0.20	$ 0.19	$ 0.22	$ 0.38
Diluted..................	$ 0.20	$ 0.18	$ 0.21	$ 0.37
2001:				
Revenues....................	$67,453	$59,500	$44,818	$38,605
Income from operations......	42,792	32,886	16,150	8,457
Net income..................	28,148	21,781	10,803	5,494
Net income per common share:				
Basic....................	$ 1.05	$ 0.80	$ 0.40	$ 0.20
Diluted..................	$ 1.00	$ 0.77	$ 0.38	$ 0.19

14. Supplementary Financial Information on Oil and Gas Exploration, Development and Production Activities (Unaudited):

Capitalized Costs Related to Oil and Gas Producing Activities
(In thousands)

	As of December 31,	
	2002	2001
Capitalized costs:		
Proved properties..................................	$ 879,840	$ 575,806
Unproved properties not being amortized............	141,326	102,881
Total..	1,021,166	678,687
Accumulated depreciation, depletion and amortization(1)	(267,744)	(158,746)
Net capitalized costs..........................	$ 753,422	$ 519,941

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(1) Depreciation, depletion and amortization per Mcfe was $2.12, $1.60 and $1.57 in 2002, 2001 and 2000, respectively.

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities
(In thousands)

	Year Ended December 31,		
	2002	2001	2000
Acquisition costs:			
Unproved	$ 39,789	$ 34,524	$ 21,421
Proved	--	--	--
Exploration costs	163,322	187,720	121,451
Development costs	139,368	80,276	51,144
Total costs incurred	$342,479	$302,520	$194,016

SPINNAKER EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS--(Continued)

Acquisition costs include costs incurred to purchase, lease or otherwise acquire property. Exploration costs include the costs of drilling exploratory wells, including those in progress, geological and geophysical service costs and depreciation of support equipment used in exploration activities. Development costs include the costs of drilling development wells and costs of completions, platforms, facilities and pipelines.

Costs being excluded from amortization consist of the following (in thousands):

	Year Ended December 31,				
	Total	2002	2001	2000	1999 and Prior
Unproved property costs	$ 89,837	$28,635	$22,362	$ 4,910	$33,930
Exploration costs	49,751	11,306	(5,880)	37,559	6,766
Development costs	1,738	(1,496)	3,234	--	--
Total	$141,326	$38,445	$19,716	$42,469	$40,696

Results of Operations for Oil and Gas Producing Activities
(In thousands)

Year Ended December 31,

	2002	2001	2000
Revenues	$188,326	$210,376	$121,383
Operating expenses(1)	18,212	12,132	9,009
Depreciation, depletion and amortization	108,998	85,059	47,451
Charges related to Enron bankruptcy	128	3,059	--
Income tax expense(2)	21,956	39,645	23,372
Results of operations	$ 39,032	$ 70,481	$ 41,551

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(1) Operating expenses represent costs incurred to operate and maintain wells and related equipment and facilities. These costs include, among other things, workover expenses, labor, materials, supplies, property taxes, insurance, severance taxes and transportation expenses.

(2) Income tax expense is calculated by applying the statutory tax rate to operating profit, then adjusting for any applicable permanent tax differences or tax credits and allowances.

Proved natural gas and oil reserve quantities and the related discounted future net cash flows before income taxes are based on estimates prepared by Ryder Scott Company, L.P., independent petroleum consultants. Such estimates have been prepared in accordance with guidelines established by the Commission.

Proved reserves are estimated quantities of natural gas and oil that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are proved reserves that can reasonably be expected to be recovered through existing wells with existing equipment and operating methods.

Reserve Quantity Information

	Natural Gas (MMcf)	Oil and Condensate (MBbls)	Natural Gas Equivalents (MMcfe)
Proved reserves as of December 31, 1999	90,030	2,412	104,501
Extensions, discoveries and other additions	97,665	1,027	103,829
Revisions of previous estimates	5,248	(116)	4,552
Production	(28,845)	(225)	(30,194)
Proved reserves as of December 31, 2000	164,098	3,098	182,688
Extensions, discoveries and other additions	74,531	18,921	188,057
Revisions of previous estimates	(11,414)	2,829	5,556
Production	(51,234)	(310)	(53,094)

Proved reserves as of December 31, 2001(1).....	175,981	24,538	323,207
Extensions, discoveries and other additions.	24,666	7,678	70,733
Revisions of previous estimates(2)..........	(11,936)	(1,168)	(18,944)
Production.................................	(45,180)	(1,040)	(51,419)
Proved reserves as of December 31, 2002(1).....	143,531	30,008	323,577
Proved developed reserves:			
December 31, 2002(1).......................	84,139	2,219	97,456
December 31, 2001(1).......................	82,221	748	86,711
December 31, 2000..........................	112,315	1,042	118,568
December 31, 1999..........................	50,756	384	53,062

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(1) Spinnaker has a 25% non-operator working interest in a significant deepwater oil discovery at Front Runner. This significant oil discovery changed Spinnaker's reserve profile. Proved oil and condensate reserves were 56% and 46% of total proved reserves at December 31, 2002 and 2001, respectively, compared to 10% at December 31, 2000. Of the Company's total proved reserves as of December 31, 2002, 70% were proved undeveloped reserves. Front Runner represented more than 60% of total proved undeveloped reserves.

(2) Front Runner area reserves are subject to royalty relief on the first 87.5 million equivalent barrels of oil produced. As new reserves are added in the Front Runner area, changes in future production assumptions result in a reallocation of reserves subject to royalty relief. These reallocations resulted in downward revisions to previous estimates of approximately 671 MMcf and 1,002 MBbls, or natural gas equivalents of 6,681 MMcfe. No downward revision on any individual property exceeded 1% of proved reserves as of December 31, 2001.

The standardized measure of discounted future net cash flows from production of proved reserves was developed as follows:

- Estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on year-end economic conditions.

- The estimated future gross revenues of proved reserves are priced on the basis of year-end market prices.

- The future gross revenue streams are reduced by estimated future costs to develop and to produce the proved reserves, as well as certain abandonment costs based on year-end cost estimates and the estimated effect of future income taxes.

- Future income taxes are computed by applying the statutory tax rate to future net cash flows reduced by the tax basis of the properties, the estimated permanent differences applicable to future natural gas and oil producing activities and tax carryforwards.

The standardized measure of discounted future net cash flows is not intended to present the fair market value of the Company's natural gas and oil reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves in excess of proved reserves, anticipated future changes in prices and costs, an allowance for return on investment and the risks inherent in reserve estimates. Given the volatility of natural gas and oil prices, it is reasonably possible that the Company's estimate of discounted future net cash flows from proved natural gas and oil reserves will change in the near term. If natural gas and oil prices decline, even if for only a short period of time, or if the Company has significant downward revisions to its estimated proved reserves, it is possible that write-downs of natural gas and oil properties could occur in the future.

Standardized Measure of Discounted Future Net Cash Flows
(In thousands)

	Year Ended December 31,		
	2002	2001	2000
Future cash inflows(1)	$1,613,724	$ 944,861	$1,730,754
Future operating expenses	(185,782)	(164,105)	(60,259)
Future development costs	(184,441)	(191,711)	(68,929)
Future net cash flows before income taxes	1,243,501	589,045	1,601,566
Future income taxes	(259,436)	(120,489)	(516,488)
Future net cash flows	984,065	468,556	1,085,078
10% annual discount	(303,267)	(139,000)	(185,941)
Standardized measure of discounted future net cash flows	$ 680,798	$ 329,556	$ 899,137

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(1) Prices for natural gas and oil used to calculate future cash inflows were $4.91, $2.71 and $9.99 per Mcf of natural gas and $30.50, $19.23 and $30.41 per barrel of oil as of December 31, 2002, 2001 and 2000, respectively.

Principal Sources of Change in the Standardized Measure of Discounted Future Net Cash Flows
(In thousands)

	Year Ended December 31,		
	2002	2001	200
Standardized measure, beginning of year	$ 329,556	$ 899,137	$ 151,
Extensions and discoveries, net of related costs	215,800	198,709	719,
Sales of natural gas and oil produced, net of production costs	(165,450)	(207,824)	(131,
Net changes in prices and production costs	403,728	(958,755)	486,
Change in future development costs	(26,795)	(18,959)	(3,
Development costs incurred during the period that reduced future development costs	56,831	47,463	37,

Revisions of quantity estimates	(57,991)	6,092	34,
Accretion of discount	(640)	132,067	15,
Net change in income taxes	(80,892)	335,952	(421,
Change in production rates and other	6,651	(104,326)	9,
Standardized measure, end of year	$ 680,798	$ 329,556	$ 899,

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INDEPENDENT AUDITORS' REPORT ON CONSOLIDATED
FINANCIAL STATEMENT SCHEDULE

To the Board of Directors and Stockholders of
Spinnaker Exploration Company:

Under date of February 7, 2003, we reported on the consolidated balance sheets of Spinnaker Exploration Company and subsidiaries, as of December 31, 2002 and 2001, and the related consolidated statements of operations, equity and cash flows for each of the years in the three-year period ended December 31, 2002. In connection with our audits of the aforementioned consolidated financial statements, we also audited the related consolidated financial statement schedule. This consolidated financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statement schedule based on our audits.

In our opinion, the consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

KPMG LLP

Houston, Texas
February 7, 2003

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Schedule II

SPINNAKER EXPLORATION COMPANY

VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

For the Years Ended December 31, 2002, 2001 and 2000
(In thousands)

	Balance at Beginning of Year	Charged to Costs and Expenses	Deductions and Other	Balance at End of Year
Year ended December 31, 2002:				
Allowance for doubtful accounts.	$3,059	$ 128	$45	$3,232
Year ended December 31, 2001:				
Allowance for doubtful accounts.	$ --	$3,059	$--	$3,059

Year ended December 31, 2000:				
Allowance for doubtful accounts.	$ --	$ --	$--	$ --

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EXHIBIT INDEX

Exhibit Number	Description
3.1	--Certificate of Incorporation of Spinnaker, as amended (incorporated by reference to Exh Spinnaker's Registration Statement on Form S-1 (Commission File No. 333-83093))
3.2	--Restated Bylaws of Spinnaker (incorporated by reference to Exhibit 3.2 to Spinnaker's Registration Statement on Form S-1 (Commission File No. 333-83093))
4.1	--Specimen Common Stock certificate (incorporated by reference to Exhibit 4.1 to Spinnake Registration Statement on Form S-3 (Commission File No. 333-72238))
10.1	--Second Amended and Restated Data Contribution Agreement between Petroleum Geo-Services ASA, Seismic Energy Holdings, Inc., Spinnaker Exploration Company, L.L.C. and Spinnaker dated June 30, 1999 (incorporated by reference to Exhibit 10.1 to Spinnaker's Registrat Statement on Form S-1 (Commission File No. 333-83093))
10.2	--Amended and Restated 1998 Spinnaker Stock Option Plan (incorporated by reference to Exh 10.2 to Spinnaker's Registration Statement on Form S-1 (Commission File No. 333-83093))
10.3	--Amended and Restated Stockholders Agreement by and among Spinnaker, Warburg, Pincus Ventures, Petroleum Geo-Services, Roger L. Jarvis, James M. Alexander, William D. Hubba Kelly M. Barnes and certain other stockholders of Spinnaker (including the Registration Agreement as Exhibit A to the Stockholders Agreement) (incorporated by reference to Exh 10.3 to Spinnaker's Registration Statement on Form S-1 (Commission File No. 333-83093))
10.3.1	--First Amendment to the Amended and Restated Stockholders Agreement by and among Spinnak Warburg, Pincus Ventures, Petroleum Geo-Services, Roger L. Jarvis, James M. Alexander, William D. Hubbard, Kelly M. Barnes and certain other stockholders of Spinnaker (incorp by reference to Exhibit 10.3.1 to Spinnaker's Quarterly Report on Form 10-Q for the qua June 30, 2000)
10.5	--Credit Agreement for a $200 million credit facility dated as of December 28, 2001 (inco by reference to Exhibit 10.5 to Spinnaker's Annual Report on Form 10-K for the year end December 31, 2001)
10.6	--Employment Agreement between Spinnaker and Roger L. Jarvis dated December 20, 1996, as amended (incorporated by reference to Exhibit 10.6 to Spinnaker's Registration Statemen Form S-1 (Commission File No. 333-83093))
10.7	--Employment Agreement between Spinnaker and William D. Hubbard dated February 24, 1997, amended (incorporated by reference to Exhibit 10.8 to Spinnaker's Registration Statemen Form S-1 (Commission File No. 333-83093))
10.8	--Employment Agreement between Spinnaker and Kelly M. Barnes dated February 24, 1997, as amended (incorporated by reference to Exhibit 10.9 to Spinnaker's Registration Statemen Form S-1 (Commission File No. 333-83093))
10.9	--1999 Spinnaker Stock Incentive Plan (incorporated by reference to Exhibit 10.10 to Spin Registration Statement on Form S-1 (Commission File No. 333-83093))
10.10	--1999 Spinnaker Employee Stock Purchase Plan (incorporated by reference to Exhibit 10.11 Spinnaker's Registration Statement on Form S-1 (Commission File No. 333-83093))
10.11	--Form of Indemnification Agreement (incorporated by reference to Exhibit 10.12 to Spinna Registration Statement on Form S-1 (Commission File No. 333-83093))
10.12	--Adjunct Stock Option Plan (incorporated by reference to Exhibit 4.3 to Spinnaker's Regi Statement on Form S-8 (Commission File No. 333-36592))
10.13	--Spinnaker Exploration Company 2000 Stock Option Plan (incorporated by reference to Exhibit 10.13 to Spinnaker's Annual Report on Form 10-K for the year ended December 31,

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Exhibit Number	Description
10.14	--Spinnaker Exploration Company 2001 Stock Incentive Plan, as amended (incorporated by reference to Exhibit 10.2 to Spinnaker's Registration Statement on Form S-8 (Commission No. 333-61888))
12.1*	--Calculation of Ratios of Earnings to Fixed Charges and Combined Fixed Charges and Prefe Dividends
21.1	--Subsidiaries of Spinnaker Exploration Company (incorporated by reference to Exhibit 21. Spinnaker's Registration Statement on Form S-1 (Commission File No. 333-83093))
23.1*	--Consent of KPMG LLP
23.2*	--Consent of Ryder Scott Company, L.P.
99.1*	--Certification of Chief Executive Officer of Spinnaker Exploration Company pursuant to 1 U.S.C. Section 1350
99.2*	--Certification of Chief Financial Officer of Spinnaker Exploration Company pursuant to 1 U.S.C. Section 1350

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* Filed herewith.

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ss purchase price over the estimated fair value of net assets acquired (dollars in thousands):

Estimated purchase price	$265,465
Less: Estimated fair value of net assets acquired (see table below)	(69,719)
Excess purchase price over estimated fair value of net assets acquired	$195,746

The preliminary purchase accounting related to the FacilitySource Acquisition has been recorded in the accompanying consolidated financial statements. The excess purchase price over the estimated fair value of net assets acquired has been recorded to goodwill. The goodwill arising from the FacilitySource Acquisition consists largely of the synergies and economies of scale expected from combining the operations acquired from FacilitySource with ours. We are currently assessing if any portion of the goodwill recorded in connection with the FacilitySource Acquisition will be deductible for tax purposes. Given the complexity of the transaction, the calculation of the fair value of certain assets and liabilities acquired, primarily intangible assets, computer software and income tax items, is still preliminary. The purchase price allocation is expected to be completed as soon as practicable, but no later than one year from the acquisition date. The following table summarizes the aggregate estimated fair values of the assets acquired and the liabilities assumed in the FacilitySource Acquisition (dollars in thousands):

Assets Acquired:	
Cash and cash equivalents	$2,627

Receivables, net	37,902
Prepaid expenses	477
Property and equipment	60,530
Other intangible assets	89,000
Other assets	114
Total assets acquired	190,650
Liabilities Assumed:	
Accounts payable and accrued expenses	47,663
Compensation and employee benefits payable	1,800
Accrued bonus and profit sharing	5,036
Line of credit and term loan	26,295
Deferred tax liability	39,009
Other liabilities	1,128
Total liabilities assumed	120,931
Estimated Fair Value of Net Assets Acquired	$69,719

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CBRE GROUP, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

The following is a summary of the preliminary estimate of the amortizable intangible assets and depreciable computer software acquired in connection with the FacilitySource Acquisition (dollars in thousands):

			At June 30, 2018	
Asset Class	Weighted Average Amortization/ Depreciation Period	Amount Assigned at Acquisition Date	Accumulated Amortization and Depreciation	Net Carrying Value
Intangibles:				
Trade names	20 years	$ 50,400	$ 105	$ 50,295
Customer relationships	6.67 years	38,600	241	38,359
Total amortizable intangible assets acquired	14.22 years	$ 89,000	$ 346	$ 88,654
Property and Equipment:				
Computer software	10 years	$ 57,650	$ 240	$ 57,410

Upon close of the FacilitySource Acquisition, we immediately repaid the line of credit and term loan assumed from FacilitySource.

The accompanying consolidated statement of operations for the three and six months ended June 30, 2018 include revenue, an operating loss and a net loss of $12.6 million, ($0.2) million and ($0.2) million, respectively, attributable to the FacilitySource Acquisition. This does not include direct transaction and integration costs of $0.2 million and depreciation and amortization expense of $0.6 million related to computer software and intangible assets acquired, all of which were incurred during both the three and six months ended June 30, 2018 in connection with the FacilitySource Acquisition.

Unaudited pro forma results, assuming the FacilitySource Acquisition had occurred as of January 1, 2017 for purposes of the pro forma disclosures for the three and six months ended June 30, 2018 and 2017, are presented below. They include certain adjustments for increased depreciation and amortization expense related to acquired computer software and intangible assets as well as increased interest expense associated with borrowings under our revolving credit facility used to fund the acquisition, as follows (dollars in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Depreciation expense	$ 1,201	$ 1,235	$ 2,642	$ 2,469
Amortization expense	1,731	2,078	3,809	4,155
Interest expense	1,224	1,525	2,748	3,049

Pro forma adjustments also include the removal of $0.2 million of direct costs incurred by us during the three and six months ended June 30, 2018 as well as the tax impact of all pro forma adjustments for all periods presented. These unaudited pro forma results have been prepared for comparative purposes only and do not purport to be indicative of what operating results would have been had the FacilitySource Acquisition occurred on January 1, 2017 and may not be indicative of future operating results (dollars in thousands, except share data):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Revenue	$5,141,339	$4,476,952	$9,852,160	$8,565,300
Operating income	218,988	220,565	424,689	418,015
Net income attributable to CBRE Group, Inc.	222,941	195,874	366,083	326,993
Basic income per share:				
Net income per share attributable to CBRE Group, Inc.	$0.66	$0.58	$1.08	$0.97
Weighted average shares outstanding for basic income per share	339,081,556	336,975,149	338,986,354	336,941,681
Diluted income per share:				
Net income per share attributable to CBRE Group, Inc.	$0.65	$0.57	$1.07	$0.96
Weighted average shares outstanding for diluted income per share	343,471,513	340,882,603	343,031,189	340,214,246

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CBRE GROUP, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

5. Warehouse Receivables & Warehouse Lines of Credit

Our wholly-owned subsidiary CBRE Capital Markets, Inc. (CBRE Capital Markets) is a Federal Home Loan Mortgage Corporation (Freddie Mac) approved Multifamily Program Plus Seller/Servicer and an approved Federal National Mortgage Association (Fannie Mae) Aggregation and Negotiated Transaction Seller/Servicer. In addition, CBRE Capital Markets' wholly-owned subsidiary CBRE Multifamily Capital, Inc. (CBRE MCI) is an approved Fannie Mae Delegated Underwriting and Servicing (DUS) Seller/Servicer and CBRE Capital Markets' wholly-owned subsidiary CBRE HMF, Inc. (CBRE HMF) is a U.S. Department of Housing and Urban Development (HUD) approved Non-Supervised Federal Housing Authority (FHA) Title II Mortgagee, an approved Multifamily Accelerated Processing (MAP) lender and an approved Government National Mortgage Association (Ginnie Mae) issuer of mortgage-backed securities (MBS). Under these arrangements, before loans are originated through proceeds from warehouse lines of credit, we obtain either a contractual loan purchase commitment from either Freddie Mac or Fannie Mae or a confirmed forward trade commitment for the issuance and purchase of a Fannie Mae or Ginnie Mae MBS that will be secured by the loans. The warehouse lines of credit are generally repaid within a one-month period when Freddie Mac or Fannie Mae buys the loans or upon settlement of the Fannie Mae or Ginnie Mae MBS, while we retain the servicing rights. Loans are funded at the prevailing market rates. We elect the fair value option for all warehouse receivables. At June 30, 2018 and December 31, 2017, all of the warehouse receivables included in the accompanying consolidated balance sheets were either under commitment to be purchased by Freddie Mac or had confirmed forward trade commitments for the issuance and purchase of Fannie Mae or Ginnie Mae mortgage-backed securities that will be secured by the underlying loans.

A rollforward of our warehouse receivables is as follows (dollars in thousands):

Beginning balance at December 31, 2017	$928,038
Origination of mortgage loans	7,552,229
Gains (premiums on loan sales)	25,890
Proceeds from sale of mortgage loans:	
Sale of mortgage loans	(6,993,724)
Cash collections of premiums on loan sales	(25,890)
Proceeds from sale of mortgage loans	(7,019,614)
Net increase in mortgage servicing rights included in warehouse receivables	1,781
Ending balance at June 30, 2018	$1,488,324

The following table is a summary of our warehouse lines of credit in place as of June 30, 2018 and December 31, 2017 (dollars in thousands):

	June 30, 2018	December 31, 2017

Lender	Current Maturity	Pricing	Maximum Facility Size	Carrying Value	Maximum Facility Size	Carrying Value
JP Morgan Chase Bank, N.A. (JP Morgan)	10/23/2018	daily one-month LIBOR plus 1.45%	$1,000,000	$725,150	$1,000,000	$192,180
JP Morgan	10/23/2018	daily one-month LIBOR plus 2.75%	25,000	—	25,000	5,800
Fannie Mae Multifamily As Soon As Pooled Plus Agreement and Multifamily As Soon As Pooled Sale Agreement (ASAP) Program	Cancelable anytime	daily one-month LIBOR plus 1.35%, with a LIBOR floor of 0.35%	450,000	15,338	450,000	205,827
TD Bank, N.A. (TD Bank) (1)	6/30/2019	daily one-month LIBOR plus 1.20%	400,000	366,043	800,000	225,416
Bank of America, N.A. (BofA) (2)	9/4/2018	daily one-month LIBOR plus 1.40%	225,000	225,303	337,500	130,443
Capital One, N.A. (Capital One) (3)	7/27/2018	daily one-month LIBOR plus 1.40%	200,000	139,757	387,500	151,100
			$2,300,000	$1,471,591	$3,000,000	$910,766

(1) Line was temporarily increased from $400.0 million to $800.0 million to accommodate year-end volume. Maximum facility reverted back to $400.0 million on February 1, 2018. During July 2018, to accommodate increased volume, line was increased to $800.0 million, which

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CBRE GROUP, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

will continue until maturity date unless we elect to adjust. Our arrangement with TD Bank allows us to increase or decrease the line with two-week notice.

(2) Line was temporarily increased from $225.0 million to $337.5 million to accommodate year-end volume. Maximum facility reverted back to $225.0 million on January 27, 2018. Effective July 2, 2018, line was temporarily increased from $225.0 million to $337.5 million to accommodate projected volume in July. Maximum facility will revert back to $225.0 million on August 18, 2018.

(3) Line was temporarily increased from $200.0 million to $387.5 million to accommodate year-end volume. Maximum facility reverted back to $200.0 million on January 9, 2018. During July 2018, to accommodate increased volume, the line was temporarily increased from $200.0 million to $375.0 million and will revert back to $200.0 million on October 1, 2018. Additionally, in July 2018 the maturity date of the warehouse line with Capital One was extended for one year.

During the six months ended June 30, 2018, we had a maximum of $1.5 billion of warehouse lines of credit principal outstanding.

6. Variable Interest Entities (VIEs)

We hold variable interests in certain VIEs in our Global Investment Management and Development Services segments which are not consolidated as it was determined that we are not the primary beneficiary. Our involvement with these entities is in the form of equity co-investments and fee arrangements.

As of June 30, 2018 and December 31, 2017, our maximum exposure to loss related to the VIEs which are not consolidated was as follows (dollars in thousands):

	June 30, 2018	December 31, 2017
Investments in unconsolidated subsidiaries	$25,160	$ 26,273
Co-investment commitments	4,266	2,364
Other current assets	3,475	3,401
Maximum exposure to loss	$32,901	$ 32,038

7. Fair Value Measurements

Topic 820 of the FASB Accounting Standards Codification defines fair value as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants at the measurement date. Topic 820 also establishes a three-level fair value hierarchy that prioritizes the inputs used to measure fair value. This hierarchy requires entities to maximize the use of observable inputs and minimize the use of unobservable inputs. The three levels of inputs used to measure fair value are as follows:

- Level 1 – Quoted prices in active markets for identical assets or liabilities.
- Level 2 – Observable inputs other than quoted prices included in Level 1, such as quoted prices for similar assets and liabilities in active markets; quoted prices for identical or similar assets and liabilities in markets that are not active; or other inputs that are observable or can be corroborated by observable market data.
- Level 3 – Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities. This includes certain pricing models, discounted cash flow methodologies and similar techniques that use significant unobservable inputs.

There were no significant transfers in or out of Level 1 and Level 2 during the three and six months ended June 30, 2018 and 2017. There have been no significant changes to the valuation techniques and inputs used to develop the recurring fair value measurements from those disclosed in our 2017 Annual Report.

CBRE GROUP, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

The following tables present the fair value of assets and liabilities measured at fair value on a recurring basis as of June 30, 2018 and December 31, 2017 (dollars in thousands):

	As of June 30, 2018 Fair Value Measured and Recorded Using			
	Level 1	Level 2	Level 3	Total
Assets				
Available for sale debt securities:				
U.S. treasury securities	$3,626	$—	$ —	$3,626
Debt securities issued by U.S. federal agencies	—	10,134	—	10,134
Corporate debt securities	—	27,845	—	27,845
Asset-backed securities	—	3,965	—	3,965
Collateralized mortgage obligations	—	2,288	—	2,288
Total available for sale debt securities	3,626	44,232	—	47,858
Equity securities	140,035	—	—	140,035
Warehouse receivables	—	1,488,324	—	1,488,324
Total assets at fair value	$143,661	$1,532,556	$ —	$1,676,217
Liabilities				
Interest rate swaps	$—	$2,091	$ —	$2,091
Securities sold, not yet purchased	3,556	—	—	3,556
Total liabilities at fair value	$3,556	$2,091	$ —	$5,647

	As of December 31, 2017 Fair Value Measured and Recorded Using			
	Level 1	Level 2	Level 3	Total
Assets				
Available for sale debt securities:				
U.S. treasury securities	$3,820	$—	$ —	$3,820
Debt securities issued by U.S. federal agencies	—	4,901	—	4,901
Corporate debt securities	—	20,023	—	20,023
Asset-backed securities	—	3,577	—	3,577
Collateralized mortgage obligations	—	2,366	—	2,366
Total available for sale debt securities	3,820	30,867	—	34,687
Equity securities	133,595	—	—	133,595
Warehouse receivables	—	928,038	—	928,038
Total assets at fair value	$137,415	$958,905	$ —	$1,096,320
Liabilities				
Interest rate swaps	$—	$4,766	$ —	$4,766

Securities sold, not yet purchased	3,431	—	—	3,431
Foreign currency exchange forward contracts	—	55	—	55
Total liabilities at fair value	$ 3,431	$ 4,821	$ —	$ 8,252

There were no significant non-recurring fair value measurements recorded during the three and six months ended June 30, 2018 and 2017.

FASB ASC Topic 825, "Financial Instruments" requires disclosure of fair value information about financial instruments, whether or not recognized in the accompanying consolidated balance sheets. Our financial instruments are as follows:

- Cash and Cash Equivalents and Restricted Cash – These balances include cash and cash equivalents as well as restricted cash with maturities of less than three months. The carrying amount approximates fair value due to the short-term maturities of these instruments.
- Receivables, less Allowance for Doubtful Accounts – Due to their short-term nature, fair value approximates carrying value.
- Warehouse Receivables – These balances are carried at fair value based on market prices at the balance sheet date.
- Debt & Equity Securities – These investments are carried at their fair value.

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CBRE GROUP, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

- Foreign Currency Exchange Forward Contracts – These assets and liabilities are carried at their fair value as calculated by using widely accepted valuation techniques including discounted cash flow analysis on the expected cash flows of each derivative.
- Securities Sold, not yet Purchased – These liabilities are carried at their fair value.
- Short-Term Borrowings – The majority of this balance represents outstanding amounts under our warehouse lines of credit of our wholly-owned subsidiary, CBRE Capital Markets, and our revolving credit facility. Due to the short-term nature and variable interest rates of these instruments, fair value approximates carrying value (see Notes 5 and 9).
- Senior Term Loans – Based upon information from third-party banks (which falls within Level 2 of the fair value hierarchy), the estimated fair value of our senior term loans was approximately $742.5 million at June 30, 2018 and $199.9 million at December 31, 2017. Their actual carrying value, net of unamortized debt issuance costs, totaled $743.7 million and $193.5 million at June 30, 2018 and December 31, 2017, respectively (see Note 9).
- Interest Rate Swaps – These liabilities are carried at their fair value as calculated by using widely-accepted valuation techniques including discounted cash flow analysis on the expected cash flows of each derivative.
- Senior Notes – Based on dealers' quotes (which falls within Level 2 of the fair value hierarchy), the estimated fair values of our 4.875% senior notes and 5.25% senior notes were $622.5 million and $447.0 million, respectively, at June 30, 2018 and $645.7 million and $468.0 million, respectively, at December 31, 2017. The actual carrying value of our 4.875% senior notes and 5.25% senior notes, net of unamortized debt issuance costs as well as unamortized discount or premium, if applicable, totaled $592.4 million and $422.6 million, respectively, at June 30, 2018 and $592.0 million and $422.4 million, respectively, at December 31, 2017. In March 2018, we redeemed our 5.00% senior notes in full (see Note 9). At December 31, 2017, the estimated fair value (based on dealers' quotes) and actual carrying value (net of unamortized debt issuance costs) of our 5.00% senior notes was $823.8 million and $791.7 million, respectively.

8. Investments in Unconsolidated Subsidiaries

Investments in unconsolidated subsidiaries are accounted for under the equity method of accounting. Our investment ownership percentages in equity method investments vary, generally ranging up to 5.0% in our Global Investment Management segment, up to 10.0% in our Development Services segment, and up to 50.0% in our other business segments.

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Combined condensed financial information for the entities accounted for using the equity method is as follows (dollars in thousands):

	Three Months Ended June 30, 2018	2017	Six Months Ended June 30, 2018	2017
Global Investment Management				
Revenue	$361,317	$237,907	$625,287	$505,058
Operating income	206,206	76,410	277,362	91,888
Net income	138,954	60,307	173,291	64,397
Development Services				
Revenue	$31,329	$27,477	$54,005	$49,003
Operating income	24,560	157,296	83,137	177,857
Net income	17,117	150,055	70,313	166,152
Other				
Revenue	$52,384	$44,145	$108,937	$70,003
Operating income	5,415	8,800	11,890	10,979
Net income	5,757	11,510	12,220	13,658
Total				
Revenue	$445,030	$309,529	$788,229	$624,064
Operating income	236,181	242,506	372,389	280,724
Net income	161,828	221,872	255,824	244,207

9. Long-Term Debt and Short-Term Borrowings

Long-Term Debt

Long-term debt consists of the following (dollars in thousands):

	June 30, 2018	December 31, 2017
Senior term loans, with interest ranging from 2.51% to 3.07%, due quarterly through 2022	$750,000	$ 200,000
4.875% senior notes due in 2026, net of unamortized discount	596,460	596,273
5.25% senior notes due in 2025, net of unamortized premium	426,226	426,317
5.00% senior notes, redeemed in full in March 2018	—	800,000
Other	5,711	8
Total long-term debt	1,778,397	2,022,598
Less: current maturities of long-term debt	(1,466)	(8)

Less: unamortized debt issuance costs	(14,046)	(22,987)
Total long-term debt, net of current maturities	$ 1,762,885	$ 1,999,603

We maintain credit facilities with third-party lenders, which we use for a variety of purposes. On October 31, 2017, CBRE Services, Inc. (CBRE Services), our wholly-owned subsidiary, entered into a Credit Agreement (the 2017 Credit Agreement), which refinanced and replaced our prior credit agreement (the 2015 Credit Agreement). We used $200.0 million of borrowings from the tranche A term loan facility and $83.0 million of revolving credit facility borrowings under the 2017 Credit Agreement, in addition to cash on hand, to repay all amounts outstanding under the 2015 Credit Agreement.

The 2017 Credit Agreement is a senior unsecured credit facility that is jointly and severally guaranteed by us and certain of our subsidiaries. As of June 30, 2018, the 2017 Credit Agreement provided for the following: (1) a $2.8 billion revolving credit facility, which includes the capacity to obtain letters of credit and swingline loans and matures on October 31, 2022 and (2) a $750.0 million delayed draw tranche A term loan facility, requiring quarterly principal payments, which began on March 5, 2018 and continue through maturity on October 31, 2022, provided that in the event that our leverage ratio (as defined in the 2017 Credit Agreement) is less than or equal to 2.50 to 1.00 on the last day of the fiscal quarter immediately preceding any such payment date, no such quarterly principal payment shall be required on such date.

On March 14, 2013, CBRE Services issued $800.0 million in aggregate principal amount of 5.00% senior notes due March 15, 2023. The 5.00% senior notes were unsecured obligations of CBRE Services, senior to all of its

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current and future subordinated indebtedness, but effectively subordinated to all of its current and future secured indebtedness. The 5.00% senior notes were jointly and severally guaranteed on a senior basis by us and each domestic subsidiary of CBRE Services that guaranteed our 2017 Credit Agreement. Interest accrued at a rate of 5.00% per year and was payable semi-annually in arrears on March 15 and September 15. The 5.00% senior notes were redeemable at our option, in whole or in part, on March 15, 2018 at a redemption price of 102.5% of the principal amount on that date. We redeemed these notes in full on March 15, 2018 and incurred charges of $28.0 million, including a premium of $20.0 million and the write-off of $8.0 million of unamortized deferred financing costs. We funded this redemption with $550.0 million of borrowings from our tranche A term loan facility and borrowings from our revolving credit facility under our 2017 Credit Agreement. The amount of the 5.00% senior notes, net of unamortized debt issuance costs, included in the accompanying consolidated balance sheets was $791.7 million at December 31, 2017.

The indentures governing our 4.875% senior notes and 5.25% senior notes contain restrictive covenants that, among other things, limit our ability to create or permit liens on assets securing indebtedness, enter into sale/leaseback transactions and enter into consolidations or mergers. In addition, our 2017 Credit Agreement also requires us to maintain a minimum coverage ratio of consolidated EBITDA (as defined in the 2017 Credit Agreement) to consolidated interest expense of 2.00x and a maximum leverage ratio of total debt less available cash to consolidated EBITDA (as defined in the 2017 Credit Agreement) of 4.25x (and in the case of the first four full fiscal quarters following consummation of a qualified acquisition (as defined in the 2017 Credit Agreement), 4.75x) as of the end of each fiscal quarter. On this basis, our coverage ratio of consolidated EBITDA to consolidated interest expense was 16.97x for the trailing twelve months ended June 30, 2018, and our leverage ratio of total debt less available cash to consolidated EBITDA was 1.05x as of June 30, 2018.

Short-Term Borrowings

Revolving Credit Facility

As of June 30, 2018, letters of credit totaling $2.0 million were outstanding under our revolving credit facility under our 2017 Credit Agreement. These letters of credit, which reduce the amount we may borrow under the revolving credit facility, were primarily issued in the ordinary course of business. As of June 30, 2018, $598.0 million was outstanding under the revolving credit facility. As of December 31, 2017, no amounts were outstanding under the revolving credit facility other than letters of credit totaling $2.0 million.

Warehouse Lines of Credit

CBRE Capital Markets has warehouse lines of credit with third-party lenders for the purpose of funding mortgage loans that will be resold, and a funding arrangement with Fannie Mae for the purpose of selling a percentage of certain closed multifamily loans to Fannie Mae. These warehouse lines are recourse only to CBRE Capital Markets and are secured by our related warehouse receivables. See Note 5 for additional information.

10. Commitments and Contingencies

We are a party to a number of pending or threatened lawsuits arising out of, or incident to, our ordinary course of business. We believe that any losses in excess of the amounts accrued therefor as liabilities on our financial statements are unlikely to be significant, but litigation is inherently uncertain and there is the potential for a material adverse effect on our financial statements if one or more matters are resolved in a particular period in an amount materially in excess of what we anticipated.

In January 2008, CBRE MCI, a wholly-owned subsidiary of CBRE Capital Markets, entered into an agreement with Fannie Mae under Fannie Mae's Delegated Underwriting and Servicing Lender Program (DUS Program), to provide financing for multifamily housing with five or more units. Under the DUS Program, CBRE MCI originates, underwrites, closes and services loans without prior approval by Fannie Mae, and typically, is subject to sharing up to one-third of any losses on loans originated under the DUS Program. CBRE MCI has funded loans subject to such loss sharing arrangements with unpaid principal balances of $21.3 billion at June 30,

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2018. CBRE MCI, under its agreement with Fannie Mae, must post cash reserves or other acceptable collateral under formulas established by Fannie Mae to provide for sufficient capital in the event losses occur. As of June 30, 2018 and December 31, 2017, CBRE MCI had a $60.0 million and a $58.0 million, respectively, letter of credit under this reserve arrangement, and had recorded a liability of approximately $33.9 million and $32.9 million, respectively, for its loan loss guarantee obligation under such arrangement. Fannie Mae's recourse under the DUS Program is limited to the assets of CBRE MCI, which assets totaled approximately $734.0 million (including $491.1 million of warehouse receivables, a substantial majority of which are pledged against warehouse lines of credit and are therefore not available to Fannie Mae) at June 30, 2018.

CBRE Capital Markets participates in Freddie Mac's Multifamily Small Balance Loan (SBL) Program. Under the SBL program, CBRE Capital Markets has certain repurchase and loss reimbursement obligations. These obligations are for the period from origination of the loan to the securitization date. CBRE Capital Markets must post a cash reserve or other acceptable collateral to provide for sufficient capital in the event the obligations are triggered. As of June 30, 2018 and December 31, 2017, CBRE Capital Markets had posted a $5.0 million letter of credit under this reserve arrangement.

We had outstanding letters of credit totaling $71.2 million as of June 30, 2018, excluding letters of credit for which we have outstanding liabilities already accrued on our consolidated balance sheet related to our subsidiaries' outstanding reserves for claims under certain insurance programs as well as letters of credit related to operating leases. The CBRE Capital Markets letters of credit totaling $65.0 million as of June 30, 2018 referred to in the preceding paragraphs represented the majority of the $71.2 million outstanding letters of credit as of such date. The remaining letters of credit are primarily executed by us in the ordinary course of business and expire at varying dates through June 2019.

We had guarantees totaling $56.3 million as of June 30, 2018, excluding guarantees related to pension liabilities, consolidated indebtedness and other obligations for which we have outstanding liabilities already accrued on our consolidated balance sheet, and excluding guarantees related to operating leases. The $56.3 million primarily represents guarantees executed by us in the ordinary course of business, including various guarantees of management and vendor contracts in our operations overseas, which expire at the end of each of the respective agreements.

In addition, as of June 30, 2018, we had issued numerous non-recourse carveout, completion and budget guarantees relating to development projects for the benefit of third parties. These guarantees are commonplace in our industry and are made by us in the ordinary course of our Development Services business. Non-recourse carveout guarantees generally require that our project-entity borrower not commit specified improper acts, with us potentially liable for all or a portion of such entity's indebtedness or other damages suffered by the lender if those acts occur. Completion and budget guarantees generally require us to complete construction of the relevant project within a specified timeframe and/or within a specified budget, with us potentially being liable for costs to complete in excess of such timeframe or budget. However, we generally use "guaranteed maximum price" contracts with reputable, bondable general contractors with respect to projects for which we provide these guarantees. These contracts are intended to pass the risk to such contractors. While there can be no assurance, we do not expect to incur any material losses under these guarantees.

An important part of the strategy for our Global Investment Management business involves investing our capital in certain real estate investments with our clients. These co-investments generally total up to 2.0% of the equity in a particular fund. As of June 30, 2018, we had aggregate commitments of $36.5 million to fund future co-investments.

Additionally, an important part of our Development Services business strategy is to invest in unconsolidated real estate subsidiaries as a principal (in most cases co-investing with our clients). As of June 30, 2018, we had committed to fund $23.5 million of additional capital to these unconsolidated subsidiaries.

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11. Income Per Share Information

The calculations of basic and diluted income per share attributable to CBRE Group, Inc. shareholders are as follows (dollars in thousands, except share data):

	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017 (As Adjusted) (1)	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017 (As Adjusted) (1)
Basic Income Per Share				
Net income attributable to CBRE Group, Inc. shareholders	$228,667	$ 201,777	$378,955	$ 338,797
Weighted average shares outstanding for basic income per share	339,081,556	336,975,149	338,986,354	336,941,681
Basic income per share attributable to CBRE Group, Inc. shareholders	$0.67	$ 0.60	$1.12	$ 1.01
Diluted Income Per Share				
Net income attributable to CBRE Group, Inc. shareholders	$228,667	$ 201,777	$378,955	$ 338,797
Weighted average shares outstanding for diluted income per share:				
Weighted average shares outstanding for basic income per share	339,081,556	336,975,149	338,986,354	336,941,681
Dilutive effect of contingently issuable shares	4,389,957	3,905,498	4,044,050	3,267,556
Dilutive effect of stock options	—	1,956	785	5,009
Weighted average shares outstanding for diluted income per share	343,471,513	340,882,603	343,031,189	340,214,246
Diluted income per share attributable to CBRE Group, Inc. shareholders	$0.67	$ 0.59	$1.10	$ 1.00

(1)

We adopted new revenue recognition guidance in the first quarter of 2018. Certain restatements have been made to the 2017 financial statements to conform with the 2018 presentation. See Notes 2 and 3 for more information.

For the three and six months ended June 30, 2018, 75,851 and 51,946, respectively, of contingently issuable shares were excluded from the computation of diluted income per share because their inclusion would have had an anti-dilutive effect.

For the three and six months ended June 30, 2017, 1,317,651 and 2,037,886, respectively, of contingently issuable shares were excluded from the computation of diluted income per share because their inclusion would have had an anti-dilutive effect.

12. Revenue from Contracts with Customers

Disaggregated Revenue

The following tables represent a disaggregation of revenue from contracts with customers for the three and six months ended June 30, 2018 and 2017 by type of service and/or region (dollars in thousands):

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

	Three Months Ended June 30, 2018					
	Americas	EMEA	APAC	Global Investment Management	Development Services	Consolidated
Topic 606 Revenue:						
Occupier outsourcing	$1,923,585	$995,265	$264,717	$ —	$ —	$3,183,567
Leasing	536,660	106,295	100,186	—	839	743,980
Sales	269,636	98,081	68,883	—	—	436,600
Property management	172,343	60,706	69,466	—	2,106	304,621
Valuation	64,346	43,256	30,765	—	—	138,367
Commercial mortgage origination (1)	27,090	1,214	343	—	—	28,647
Investment management	—	—	—	98,947	—	98,947
Development services	—	—	—	—	15,463	15,463
Topic 606 Revenue	2,993,660	1,304,817	534,360	98,947	18,408	4,950,192
Out of Scope of Topic 606 Revenue:						
Commercial mortgage origination	91,167	—	—	—	—	91,167
Loan servicing	41,327	2,360	221	—	—	43,908
Other revenue	14,273	8,275	3,619	—	—	26,167
Total Out of Scope of Topic 606 Revenue	146,767	10,635	3,840	—	—	161,242
Total revenue	$3,140,427	$1,315,452	$538,200	$ 98,947	$ 18,408	$5,111,434

	Three Months Ended June 30, 2017 (As Adjusted) (2)					
	Americas	EMEA	APAC	Global Investment Management	Development Services	Consolidated
Topic 606 Revenue:						
Occupier outsourcing	$1,742,122	$726,890	$236,274	$ —	$ —	$2,705,286
Leasing	450,208	88,076	81,606	—	26	619,916
Sales	261,710	94,055	78,303	—	165	434,233
Property management	161,116	59,249	56,560	—	3,098	280,023
Valuation	61,599	37,229	30,940	—	—	129,768
Commercial mortgage origination (1)	29,883	1,985	915	—	—	32,783
Investment management	—	—	—	92,763	—	92,763
Development services	—	—	—	—	13,677	13,677
Topic 606 Revenue	2,706,638	1,007,484	484,598	92,763	16,966	4,308,449
Out of Scope of Topic 606 Revenue:						
Commercial mortgage origination	71,727	—	—	—	—	71,727

Loan servicing	37,190	2,682	—	—	—	39,872
Other revenue	11,368	5,854	2,301	—	—	19,523
Total Out of Scope of Topic 606 Revenue	120,285	8,536	2,301	—	—	131,122
Total revenue	$2,826,923	$1,016,020	$486,899	$ 92,763	$ 16,966	$4,439,571

(1) We earn fees for arranging financing for borrowers with third-party lender contacts. Such fees are in scope of Topic 606.

(2) We adopted new revenue recognition guidance in the first quarter of 2018. Certain restatements have been made to the 2017 financial statements to conform with the 2018 presentation. See Notes 2 and 3 for more information.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

	Six Months Ended June 30, 2018					
	Americas	EMEA	APAC	Global Investment Management	Development Services	Consolidated
Topic 606 Revenue:						
Occupier outsourcing	$3,717,732	$1,889,082	$530,832	$ —	$ —	$6,137,646
Leasing	936,858	206,884	171,765	—	959	1,316,466
Sales	537,311	176,321	128,118	—	418	842,168
Property management	346,171	118,917	139,496	—	3,661	608,245
Valuation	123,412	84,319	56,854	—	—	264,585
Commercial mortgage origination (1)	48,917	2,437	394	—	—	51,748
Investment management	—	—	—	222,637	—	222,637
Development services	—	—	—	—	36,695	36,695
Topic 606 Revenue	5,710,401	2,477,960	1,027,459	222,637	41,733	9,480,190
Out of Scope of Topic 606 Revenue:						
Commercial mortgage origination	175,360	—	—	—	—	175,360
Loan servicing	80,853	4,648	221	—	—	85,722
Other revenue	24,037	14,098	5,979	—	—	44,114
Total Out of Scope of Topic 606 Revenue	280,250	18,746	6,200	—	—	305,196
Total revenue	$5,990,651	$2,496,706	$1,033,659	$ 222,637	$ 41,733	$9,785,386

	Six Months Ended June 30, 2017 (As Adjusted) (2)					
	Americas	EMEA	APAC	Global Investment Management	Development Services	Consolidated
Topic 606 Revenue:						
Occupier outsourcing	$3,406,476	$1,393,584	$442,699	$ —	$ —	$5,242,759
Leasing	844,073	163,007	142,134	—	180	1,149,394
Sales	495,506	161,355	130,471	—	695	788,027
Property management	322,513	113,989	111,239	—	5,008	552,749
Valuation	118,780	69,738	57,705	—	—	246,223
Commercial mortgage origination (1)	49,701	3,805	1,454	—	—	54,960
Investment management	—	—	—	182,329	—	182,329
Development services	—	—	—	—	25,300	25,300

Topic 606 Revenue	5,237,049	1,905,478	885,702	182,329	31,183	8,241,741
Out of Scope of Topic 606 Revenue:						
Commercial mortgage origination	134,274	—	—	—	—	134,274
Loan servicing	70,724	5,558	—	—	—	76,282
Other revenue	24,082	9,615	4,543	—	—	38,240
Total Out of Scope of Topic 606 Revenue	229,080	15,173	4,543	—	—	248,796
Total revenue	$5,466,129	$1,920,651	$890,245	$ 182,329	$ 31,183	$8,490,537

(1) We earn fees for arranging financing for borrowers with third-party lender contacts. Such fees are in scope of Topic 606.
(2) We adopted new revenue recognition guidance in the first quarter of 2018. Certain restatements have been made to the 2017 financial statements to conform with the 2018 presentation. See Notes 2 and 3 for more information.

Contract Assets and Liabilities

We had contract assets totaling $169.3 million ($109.3 million of which was current) and $330.9 million ($273.1 million of which was current) as of June 30, 2018 and December 31, 2017, respectively. During the six months ended June 30, 2018, our contract assets decreased by $161.7 million, primarily due to contract assets moving to accounts receivable in our occupier outsourcing business (due to at-risk and incentive fees becoming billable per the contract terms) and in our leasing business (billing of commissions).

We had contract liabilities totaling $86.8 million ($76.2 million of which was current) and $100.6 million (all of which was current) as of June 30, 2018 and December 31, 2017, respectively. During the six months ended June 30, 2018, we recognized revenue of $64.1 million that was included in the contract liability balance at December 31, 2017.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Contract Costs

Within our Occupier Outsourcing business line, we incur transition costs to fulfil contracts prior to services being rendered. We capitalized $13.4 million and $23.0 million, respectively, of transition costs during the three and six months ended June 30, 2018, and $5.8 million and $14.7 million, respectively, of transition costs during the three and six months ended June 30, 2017. We recorded amortization of transition costs of $6.2 million and $12.2 million, respectively, during the three and six months ended June 30, 2018 and $3.6 million and $7.2 million, respectively, during the three and six months ended June 30, 2017. No impairment loss in relation to the costs capitalized was recorded during the three and six months ended June 30, 2018 or 2017.

13. Segments

We report our operations through the following segments: (1) Americas; (2) Europe, Middle East and Africa (EMEA); (3) Asia Pacific; (4) Global Investment Management; and (5) Development Services.

Summarized financial information by segment is as follows (dollars in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017 (As Adjusted) (1)	2018	2017 (As Adjusted) (1)
Revenue				
Americas	$3,140,427	$ 2,826,923	$5,990,651	$ 5,466,129
EMEA	1,315,452	1,016,020	2,496,706	1,920,651
Asia Pacific	538,200	486,899	1,033,659	890,245
Global Investment Management	98,947	92,763	222,637	182,329
Development Services	18,408	16,966	41,733	31,183
Total revenue	$5,111,434	$ 4,439,571	$9,785,386	$ 8,490,537
Adjusted EBITDA				
Americas	$258,353	$ 233,711	$484,196	$ 458,936
EMEA	66,519	70,293	103,465	105,748
Asia Pacific	42,861	44,556	76,741	67,832
Global Investment Management	15,901	23,910	45,593	49,769
Development Services	55,673	46,216	77,119	49,578
Total Adjusted EBITDA	$439,307	$ 418,686	$787,114	$ 731,863

(1) We adopted new revenue recognition guidance in the first quarter of 2018. Certain restatements have been made to the 2017 financial statements to conform with the 2018 presentation. See Notes 2 and 3 for more information.

Adjusted EBITDA is the measure reported to the chief operating decision maker for purposes of making decisions about allocating resources to each segment and assessing performance of each segment. EBITDA represents earnings before net interest expense, write-off of financing costs on extinguished debt, income taxes, depreciation and amortization. Amounts shown for adjusted EBITDA further remove (from EBITDA) the impact of certain cash and non-cash charges related to acquisitions and certain carried interest incentive compensation reversal to align with the timing of associated revenue.

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(Unaudited)

Adjusted EBITDA is calculated as follows (dollars in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017 (As Adjusted) (1)	2018	2017 (As Adjusted) (1)
Net income attributable to CBRE Group, Inc.	$228,667	$ 201,777	$378,955	$ 338,797
Add:				
Depreciation and amortization	113,399	100,386	221,564	194,423
Interest expense	26,885	35,430	55,743	69,440
Write-off of financing costs on extinguished debt	—	—	27,982	—
Provision for income taxes	70,319	69,887	116,483	123,706
Less:				
Interest income	1,489	1,427	5,110	3,838
EBITDA	437,781	406,053	795,617	722,528
Adjustments:				
Carried interest incentive compensation expense (reversal) to align with the timing of associated revenue	1,526	(2,775)	(8,503)	(18,016)
Integration and other costs related to acquisitions	—	15,408	—	27,351
Adjusted EBITDA	$439,307	$ 418,686	$787,114	$ 731,863

(1) We adopted new revenue recognition guidance in the first quarter of 2018. Certain restatements have been made to the 2017 financial statements to conform with the 2018 presentation. See Notes 2 and 3 for more information.

Geographic Information

Revenue in the table below is allocated based upon the country in which services are performed (dollars in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017 (As Adjusted) (1)	2018	2017 (As Adjusted) (1)
Revenue				
United States	$2,908,185	$ 2,644,445	$5,582,402	$ 5,116,851
United Kingdom	634,264	518,988	1,214,781	991,143

All other countries	1,568,985	1,276,138	2,988,203	2,382,543
Total revenue	$5,111,434	$ 4,439,571	$9,785,386	$ 8,490,537

(1) We adopted new revenue recognition guidance in the first quarter of 2018. Certain restatements have been made to the 2017 financial statements to conform with the 2018 presentation. See Notes 2 and 3 for more information.

14. Guarantor and Nonguarantor Financial Statements

The following condensed consolidating financial information (dollars in thousands) includes condensed consolidating balance sheets as of June 30, 2018 and December 31, 2017 and condensed consolidating statements of operations and condensed consolidating statements of comprehensive income (loss) for the three and six months ended June 30, 2018 and 2017 and condensed consolidating statements of cash flows for the six months ended June 30, 2018 and 2017 of:

- CBRE Group, Inc., as the parent; CBRE Services, as the subsidiary issuer; the guarantor subsidiaries; the nonguarantor subsidiaries;
- Elimination entries necessary to consolidate CBRE Group, Inc., as the parent, with CBRE Services and its guarantor and nonguarantor subsidiaries; and
- CBRE Group, Inc., on a consolidated basis.

Investments in consolidated subsidiaries are presented using the equity method of accounting. The principal elimination entries eliminate investments in consolidated subsidiaries and intercompany balances and transactions.

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CBRE GROUP, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Condensed Consolidating Balance Sheets

As of June 30, 2018	Parent	CBRE Services	Guarantor Subsidiaries	Nonguarantor Subsidiaries	Eliminations	Consolidated Total
ASSETS						
Current Assets:						
Cash and cash equivalents	$7	$8,404	$78,760	$444,310	$—	$531,481
Restricted cash	—	—	2,034	69,831	—	71,865
Receivables, net	—	—	1,361,023	1,963,499	—	3,324,522
Warehouse receivables (1)	—	—	964,915	523,409	—	1,488,324
Prepaid expenses	—	—	119,201	149,025	—	268,226
Contract assets	—	—	69,537	39,735	—	109,272
Income taxes receivable	3,173	3,744	6,635	41,116	(6,916)	47,752
Other current assets	—	—	67,968	197,300	—	265,268
Total Current Assets	3,180	12,148	2,670,073	3,428,225	(6,916)	6,106,710
Property and equipment, net	—	—	508,976	196,493	—	705,469
Goodwill	—	—	1,958,448	1,448,721	—	3,407,169
Other intangible assets, net	—	—	821,779	626,505	—	1,448,284
Investments in unconsolidated subsidiaries	—	—	192,203	41,686	—	233,889
Investments in consolidated subsidiaries	5,972,519	5,585,138	3,126,655	—	(14,684,312)	—
Intercompany loan receivable	—	2,732,714	700,000	—	(3,432,714)	—
Deferred tax assets, net	—	—	5,300	101,859	(9,269)	97,890
Other assets, net	—	20,639	415,638	99,769	—	536,046
Total Assets	$5,975,699	$8,350,639	$10,399,072	$5,943,258	$(18,133,211)	$12,535,457
LIABILITIES AND EQUITY						
Current Liabilities:						
Accounts payable and accrued expenses	$—	$18,763	$524,878	$1,098,389	$—	$1,642,030
Compensation and employee benefits payable	—	626	504,909	365,091	—	870,626
Accrued bonus and profit sharing	—	—	353,632	275,412	—	629,044
Contract liabilities	—	—	35,149	41,067	—	76,216
Income taxes payable	—	—	12,327	16,507	(6,916)	21,918
Short-term borrowings:					—	
Warehouse lines of credit (which fund	—	—	955,246	516,345	—	1,471,591

loans that U.S. Government Sponsored Enterprises have committed to purchase) (1)						
Revolving credit facility	—	598,000	—	—	—	598,000
Other	—	—	16	—	—	16
Total short-term borrowings	—	598,000	955,262	516,345	—	2,069,607
Current maturities of long-term debt	—	—	59	1,407	—	1,466
Other current liabilities	—	—	55,886	14,342	—	70,228
Total Current Liabilities	—	617,389	2,442,102	2,328,560	(6,916)	5,381,135
Long-Term Debt, net:						
Long-term debt, net	—	1,758,640	29	4,216	—	1,762,885
Intercompany loan payable	1,522,122	—	1,849,837	60,755	(3,432,714)	—
Total Long-Term Debt, net	1,522,122	1,758,640	1,849,866	64,971	(3,432,714)	1,762,885
Deferred tax liabilities, net	—	—	70,996	125,335	(9,269)	187,062
Non-current tax liabilities	—	—	136,320	3,730	—	140,050
Other liabilities	—	2,091	314,650	230,713	—	547,454
Total Liabilities	1,522,122	2,378,120	4,813,934	2,753,309	(3,448,899)	8,018,586
Commitments and contingencies	—	—	—	—	—	—
Equity:						
CBRE Group, Inc. Stockholders' Equity	4,453,577	5,972,519	5,585,138	3,126,655	(14,684,312)	4,453,577
Non-controlling interests	—	—	—	63,294	—	63,294
Total Equity	4,453,577	5,972,519	5,585,138	3,189,949	(14,684,312)	4,516,871
Total Liabilities and Equity	$5,975,699	$8,350,639	$10,399,072	$5,943,258	$(18,133,211)	$12,535,457

(1) Although CBRE Capital Markets is included among our domestic subsidiaries that jointly and severally guarantee our 4.875% senior notes, 5.25% senior notes and our 2017 Credit Agreement, a substantial majority of warehouse receivables funded under JP Morgan, TD Bank, BofA, Capital One and Fannie Mae ASAP lines of credit are pledged to JP Morgan, TD Bank, BofA, Capital One and Fannie Mae.

CBRE GROUP, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Condensed Consolidating Balance Sheets

	As of December 31, 2017 (As Adjusted) (1)					
	Parent	CBRE Services	Guarantor Subsidiaries	Nonguarantor Subsidiaries	Eliminations	Consolidated Total
ASSETS						
Current Assets:						
Cash and cash equivalents	$7	$15,604	$112,048	$624,115	$—	$751,774
Restricted cash	—	—	2,095	70,950	—	73,045
Receivables, net	—	—	990,923	2,121,366	—	3,112,289
Warehouse receivables (2)	—	—	479,628	448,410	—	928,038
Prepaid expenses	—	—	81,106	134,230	—	215,336
Contract assets	—	—	263,756	9,297	—	273,053
Income taxes receivable	2,162	—	—	49,628	(2,162)	49,628
Other current assets	—	—	50,556	176,865	—	227,421
Total Current Assets	2,169	15,604	1,980,112	3,634,861	(2,162)	5,630,584
Property and equipment, net	—	—	431,755	185,984	—	617,739
Goodwill	—	—	1,774,529	1,480,211	—	3,254,740
Other intangible assets, net	—	—	751,930	647,182	—	1,399,112
Investments in unconsolidated subsidiaries	—	—	197,395	40,606	—	238,001
Investments in consolidated subsidiaries	5,551,781	4,930,109	3,066,303	—	(13,548,193)	—
Intercompany loan receivable	—	2,621,330	700,000	—	(3,321,330)	—
Deferred tax assets, net	—	—	5,300	98,746	(5,300)	98,746
Other assets, net	—	22,810	348,191	108,473	—	479,474
Total Assets	$5,553,950	$7,589,853	$9,255,515	$6,196,063	$(16,876,985)	$11,718,396
LIABILITIES AND EQUITY						
Current Liabilities:						
Accounts payable and accrued expenses	$—	$29,708	$404,367	$1,139,597	$—	$1,573,672
Compensation and employee benefits payable	—	626	479,306	424,502	—	904,434
Accrued bonus and profit sharing	—	—	590,534	487,811	—	1,078,345
Contract liabilities	—	—	42,994	57,621	—	100,615
Income taxes payable	—	3,314	13,704	55,778	(2,162)	70,634
Short-term borrowings:					—	
Warehouse lines of credit (which fund	—	—	474,195	436,571	—	910,766

loans that U.S. Government Sponsored Enterprises have committed to purchase) (2)						
Other	—	—	16	—	—	16
Total short-term borrowings	—	—	474,211	436,571	—	910,782
Current maturities of long-term debt	—	—	—	8	—	8
Other current liabilities	—	55	56,260	18,139	—	74,454
Total Current Liabilities	—	33,703	2,061,376	2,620,027	(2,162)	4,712,944
Long-Term Debt, net:						
Long-term debt, net	—	1,999,603	—	—	—	1,999,603
Intercompany loan payable	1,439,454	—	1,798,550	83,326	(3,321,330)	—
Total Long-Term Debt, net	1,439,454	1,999,603	1,798,550	83,326	(3,321,330)	1,999,603
Deferred tax liabilities, net	—	—	29,785	122,733	(5,300)	147,218
Non-current tax liabilities	—	—	135,396	5,396	—	140,792
Other liabilities	—	4,766	300,299	238,160	—	543,225
Total Liabilities	1,439,454	2,038,072	4,325,406	3,069,642	(3,328,792)	7,543,782
Commitments and contingencies	—	—	—	—	—	—
Equity:						
CBRE Group, Inc. Stockholders' Equity	4,114,496	5,551,781	4,930,109	3,066,303	(13,548,193)	4,114,496
Non-controlling interests	—	—	—	60,118	—	60,118
Total Equity	4,114,496	5,551,781	4,930,109	3,126,421	(13,548,193)	4,174,614
Total Liabilities and Equity	$5,553,950	$7,589,853	$9,255,515	$6,196,063	$(16,876,985)	$11,718,396

(1) We adopted new revenue recognition guidance in the first quarter of 2018. Certain restatements have been made to the 2017 financial statements to conform with the 2018 presentation. See Notes 2 and 3 for more information.

(2) Although CBRE Capital Markets is included among our domestic subsidiaries that jointly and severally guarantee our 5.00% senior notes, 4.875% senior notes, 5.25% senior notes and our 2017 Credit Agreement, a substantial majority of warehouse receivables funded under TD Bank, Fannie Mae ASAP, JP Morgan, Capital One and BofA lines of credit are pledged to TD Bank, Fannie Mae, JP Morgan, Capital One and BofA, and accordingly, are not included as collateral for these notes or our other outstanding debt.

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CBRE GROUP, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Condensed Consolidating Statements of Operations

	Three Months Ended June 30, 2018					
	Parent	CBRE Services	Guarantor Subsidiaries	Nonguarantor Subsidiaries	Eliminations	Consolidated Total
Revenue	$—	$—	$2,848,854	$2,262,580	$—	$5,111,434
Costs and expenses:						
Cost of services	—	—	2,265,206	1,693,542	—	3,958,748
Operating, administrative and other	7,039	246	430,122	388,875	—	826,282
Depreciation and amortization	—	—	68,334	45,065	—	113,399
Total costs and expenses	7,039	246	2,763,662	2,127,482	—	4,898,429
Gain on disposition of real estate	—	—	11,212	1,099	—	12,311
Operating (loss) income	(7,039)	(246)	96,404	136,197	—	225,316
Equity income from unconsolidated subsidiaries	—	—	94,755	1,266	—	96,021
Other income	—	—	1,189	2,820	—	4,009
Interest income	—	34,946	1,336	153	(34,946)	1,489
Interest expense	—	26,078	32,260	3,493	(34,946)	26,885
Royalty and management service (income) expense	—	—	(2,370)	2,370	—	—
Income from consolidated subsidiaries	233,952	227,472	98,642	—	(560,066)	—
Income before (benefit of) provision for income taxes	226,913	236,094	262,436	134,573	(560,066)	299,950
(Benefit of) provision for income taxes	(1,754)	2,142	34,964	34,967	—	70,319
Net income	228,667	233,952	227,472	99,606	(560,066)	229,631
Less: Net income attributable to non-controlling interests	—	—	—	964	—	964
Net income attributable to CBRE Group, Inc.	$228,667	$233,952	$227,472	$98,642	$(560,066)	$228,667

Three Months Ended June 30, 2017 (As Adjusted) (1)

	Parent	CBRE Services	Guarantor Subsidiaries	Nonguarantor Subsidiaries	Eliminations	Consolidated Total
Revenue	$—	$—	$2,590,186	$1,849,385	$—	$4,439,571
Costs and expenses:						
Cost of services	—	—	2,054,829	1,354,711	—	3,409,540
Operating, administrative and other	1,046	538	387,951	323,080	—	712,615
Depreciation and amortization	—	—	58,695	41,691	—	100,386
Total costs and expenses	1,046	538	2,501,475	1,719,482	—	4,222,541
Gain on disposition of real estate	—	—	2	11,296	—	11,298
Operating (loss) income	(1,046)	(538)	88,713	141,199	—	228,328
Equity income from unconsolidated subsidiaries	—	—	74,960	424	—	75,384
Other income	—	1	612	2,573	—	3,186
Interest income	—	30,698	892	535	(30,698)	1,427
Interest expense	—	34,364	22,468	9,296	(30,698)	35,430
Royalty and management service (income) expense	—	—	(897)	897	—	—
Income from consolidated subsidiaries	202,422	205,012	88,198	—	(495,632)	—
Income before (benefit of) provision for income taxes	201,376	200,809	231,804	134,538	(495,632)	272,895
(Benefit of) provision for income taxes	(401)	(1,613)	26,792	45,109	—	69,887
Net income	201,777	202,422	205,012	89,429	(495,632)	203,008
Less: Net income attributable to non-controlling interests	—	—	—	1,231	—	1,231
Net income attributable to CBRE Group, Inc.	$201,777	$202,422	$205,012	$88,198	$(495,632)	$201,777

(1) We adopted new revenue recognition guidance in the first quarter of 2018. Certain restatements have been made to the 2017 financial statements to conform with the 2018 presentation. See Notes 2 and 3 for more information.

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CBRE GROUP, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Condensed Consolidating Statements of Operations

	Six Months Ended June 30, 2018					
	Parent	CBRE Services	Guarantor Subsidiaries	Nonguarantor Subsidiaries	Eliminations	Consolidated Total
Revenue	$—	$—	$5,466,548	$4,318,838	$—	$9,785,386
Costs and expenses:						
Cost of services	—	—	4,322,819	3,255,890	—	7,578,709
Operating, administrative and other	12,743	731	802,467	742,576	—	1,558,517
Depreciation and amortization	—	—	132,643	88,921	—	221,564
Total costs and expenses	12,743	731	5,257,929	4,087,387	—	9,358,790
Gain on disposition of real estate	—	—	11,230	1,099	—	12,329
Operating (loss) income	(12,743)	(731)	219,849	232,550	—	438,925
Equity income from unconsolidated subsidiaries	—	—	134,047	2,153	—	136,200
Other income (loss)	—	—	2,899	(3,170)	—	(271)
Interest income	—	67,632	3,788	1,322	(67,632)	5,110
Interest expense	—	53,953	59,291	10,131	(67,632)	55,743
Write-off of financing costs on extinguished debt	—	27,982	—	—	—	27,982
Royalty and management service (income) expense	—	—	(1,672)	1,672	—	—
Income from consolidated subsidiaries	388,525	399,815	159,054	—	(947,394)	—
Income before (benefit of) provision for income taxes	375,782	384,781	462,018	221,052	(947,394)	496,239
(Benefit of) provision for income taxes	(3,173)	(3,744)	62,203	61,197	—	116,483
Net income	378,955	388,525	399,815	159,855	(947,394)	379,756
Less: Net income attributable to non-controlling interests	—	—	—	801	—	801
Net income attributable to CBRE Group, Inc.	$378,955	$388,525	$399,815	$159,054	$(947,394)	$378,955

	Six Months Ended June 30, 2017 (As Adjusted) (1)					
	Parent	CBRE Services	Guarantor Subsidiaries	Nonguarantor Subsidiaries	Eliminations	Consolidated Total
Revenue	$—	$—	$ 5,008,786	$ 3,481,751	$ —	$ 8,490,537
Costs and expenses:						
Cost of services	—	—	3,975,517	2,580,500	—	6,556,017
Operating, administrative and other	762	887	703,760	613,832	—	1,319,241
Depreciation and amortization	—	—	115,425	78,998	—	194,423
Total costs and expenses	762	887	4,794,702	3,273,330	—	8,069,681
Gain on disposition of real estate	—	—	228	12,455	—	12,683
Operating (loss) income	(762)	(887)	214,312	220,876	—	433,539
Equity income from unconsolidated subsidiaries	—	—	89,330	1,072	—	90,402
Other income	—	1	1,026	6,274	—	7,301
Interest income	—	60,599	2,539	1,299	(60,599)	3,838
Interest expense	—	67,510	44,616	17,913	(60,599)	69,440
Royalty and management service (income) expense	—	—	(6,699)	6,699	—	—
Income from consolidated subsidiaries	339,267	344,076	133,717	—	(817,060)	—
Income before (benefit of) provision for income taxes	338,505	336,279	403,007	204,909	(817,060)	465,640
(Benefit of) provision for income taxes	(292)	(2,988)	58,931	68,055	—	123,706
Net income	338,797	339,267	344,076	136,854	(817,060)	341,934
Less: Net income attributable to non-controlling interests	—	—	—	3,137	—	3,137
Net income attributable to CBRE Group, Inc.	$ 338,797	$ 339,267	$ 344,076	$ 133,717	$ (817,060)	$ 338,797

(1) We adopted new revenue recognition guidance in the first quarter of 2018. Certain restatements have been made to the 2017 financial statements to conform with the 2018 presentation. See Notes 2 and 3 for more information.

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CBRE GROUP, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Condensed Consolidating Statements of Comprehensive Income (Loss)

	Three Months Ended June 30, 2018					
	Parent	CBRE Services	Guarantor Subsidiaries	Nonguarantor Subsidiaries	Eliminations	Consolidated Total
Net income	$228,667	$233,952	$227,472	$99,606	$(560,066)	$229,631
Other comprehensive income (loss):						
Foreign currency translation loss	—	—	—	(165,926)	—	(165,926)
Amounts reclassified from accumulated other comprehensive loss to interest expense, net	—	628	—	—	—	628
Unrealized gains on interest rate swaps, net	—	214	—	—	—	214
Unrealized holding losses on available for sale debt securities, net	—	—	(122)	—	—	(122)
Total other comprehensive income (loss)	—	842	(122)	(165,926)	—	(165,206)
Comprehensive income (loss)	228,667	234,794	227,350	(66,320)	(560,066)	64,425
Less: Comprehensive income attributable to non-controlling interests	—	—	—	480	—	480
Comprehensive income (loss) attributable to CBRE Group, Inc.	$228,667	$234,794	$227,350	$(66,800)	$(560,066)	$63,945

	Three Months Ended June 30, 2017 (As Adjusted) (1)					
	Parent	CBRE	Guarantor	Nonguarantor	Eliminations	Consolidated

		Services	Subsidiaries	Subsidiaries		Total
Net income	$201,777	$202,422	$205,012	$89,429	$(495,632)	$203,008
Other comprehensive income:						
Foreign currency translation gain	—	—	—	88,649	—	88,649
Amounts reclassified from accumulated other comprehensive loss to interest expense, net	—	1,380	—	—	—	1,380
Unrealized losses on interest rate swaps, net	—	(217)	—	—	—	(217)
Unrealized holding gains on available for sale debt securities, net	—	—	896	81	—	977
Other, net	3	—	(13)	—	—	(10)
Total other comprehensive income	3	1,163	883	88,730	—	90,779
Comprehensive income	201,780	203,585	205,895	178,159	(495,632)	293,787
Less: Comprehensive income attributable to non-controlling interests	—	—	—	1,390	—	1,390
Comprehensive income attributable to CBRE Group, Inc.	$201,780	$203,585	$205,895	$176,769	$(495,632)	$292,397

(1) We adopted new revenue recognition guidance in the first quarter of 2018. Certain restatements have been made to the 2017 financial statements to conform with the 2018 presentation. See Notes 2 and 3 for more information.

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CBRE GROUP, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Condensed Consolidating Statements of Comprehensive Income (Loss)

	Six Months Ended June 30, 2018					
		CBRE	Guarantor	Nonguarantor		Consolidated
	Parent	Services	Subsidiaries	Subsidiaries	Eliminations	Total
Net income	$378,955	$388,525	$ 399,815	$ 159,855	$ (947,394)	$ 379,756
Other comprehensive income (loss):						
Foreign currency translation loss	—	—	—	(99,894)	—	(99,894)
Adoption of Accounting Standards Update 2016-01, net	—	—	(3,964)	—	—	(3,964)
Amounts reclassified from accumulated other comprehensive loss to interest expense, net	—	1,383	—	—	—	1,383
Unrealized gains on interest rate swaps, net	—	817	—	—	—	817
Unrealized holding losses on available for sale debt securities, net	—	—	(627)	—	—	(627)
Other, net	—	—	20	5,508	—	5,528
Total other comprehensive income (loss)	—	2,200	(4,571)	(94,386)	—	(96,757)
Comprehensive income	378,955	390,725	395,244	65,469	(947,394)	282,999
Less: Comprehensive income attributable to non-controlling interests	—	—	—	122	—	122
Comprehensive income attributable to CBRE Group, Inc.	$378,955	$390,725	$ 395,244	$ 65,347	$ (947,394)	$ 282,877

	Six Months Ended June 30, 2017 (As Adjusted) (1)					
	Parent	CBRE Services	Guarantor Subsidiaries	Nonguarantor Subsidiaries	Eliminations	Consolidated Total
Net income	$338,797	$339,267	$ 344,076	$ 136,854	$ (817,060)	$ 341,934
Other comprehensive (loss) income:						
Foreign currency translation gain	—	—	—	139,837	—	139,837
Amounts reclassified from accumulated other comprehensive loss to interest expense, net	—	2,888	—	—	—	2,888
Unrealized gains on interest rate swaps, net	—	77	—	—	—	77
Unrealized holding gains on available for sale debt securities, net	—	—	1,725	175	—	1,900
Other, net	(2)	—	(14)	—	—	(16)
Total other comprehensive (loss) income	(2)	2,965	1,711	140,012	—	144,686
Comprehensive income	338,795	342,232	345,787	276,866	(817,060)	486,620
Less: Comprehensive income attributable to non-controlling interests	—	—	—	3,317	—	3,317
Comprehensive income attributable to CBRE Group, Inc.	$338,795	$342,232	$ 345,787	$ 273,549	$ (817,060)	$ 483,303

(1) We adopted new revenue recognition guidance in the first quarter of 2018. Certain restatements have been made to the 2017 financial statements to conform with the 2018 presentation. See Notes 2 and 3 for more information.

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CBRE GROUP, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Condensed Consolidating Statements of Cash Flows

	Six Months Ended June 30, 2018				
	Parent	CBRE Services	Guarantor Subsidiaries	Nonguarantor Subsidiaries	Consolidated Total
CASH FLOWS PROVIDED BY (USED IN) OPERATING ACTIVITIES:	$51,094	$2,234	$(56,141)	$(89,249)	$(92,062)
CASH FLOWS FROM INVESTING ACTIVITIES:					
Capital expenditures	—	—	(65,676)	(41,806)	(107,482)
Acquisition of businesses, including net assets acquired, intangibles and goodwill, net of cash acquired	—	—	(259,338)	(5,364)	(264,702)
Contributions to unconsolidated subsidiaries	—	—	(17,030)	(4,012)	(21,042)
Distributions from unconsolidated subsidiaries	—	—	24,986	3,249	28,235
Net proceeds from disposition of real estate held for investment	—	—	–	14,174	14,174
Purchase of equity securities	—	—	(13,718)	—	(13,718)
Proceeds from sale of equity securities	—	—	8,889	—	8,889
Purchase of available for sale debt securities	—	—	(18,723)	—	(18,723)
Proceeds from the sale of available for sale debt securities	—	—	4,121	—	4,121
Other investing activities, net	—	—	(6,454)	70	(6,384)
Net cash used in investing activities	—	—	(342,943)	(33,689)	(376,632)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from senior term loans	—	550,000	—	—	550,000
Proceeds from revolving credit facility	—	2,000,000	—	—	2,000,000
Repayment of revolving credit facility	—	(1,402,000)	—	—	(1,402,000)
Repayment of 5.00% senior notes (including premium)	—	(820,000)	—	—	(820,000)
Proceeds from notes payable on real estate held for investment	—	—	—	52	52
Repayment of notes payable on real estate held for investment	—	—	—	(13,028)	(13,028)
Proceeds from notes payable on real estate held for sale and	—	—	—	1,101	1,101

under development					
Repayment of notes payable on real estate held for sale and under development	—	—	—	(2,991)	(2,991)
Acquisition of businesses (cash (paid) received for acquisitions more than three months after purchase date)	—	—	(13,166)	1,983	(11,183)
Repayment of debt assumed in acquisition of FacilitySource	—	—	(26,295)	—	(26,295)
Units repurchased for payment of taxes on equity awards	(4,630)	—	—	—	(4,630)
Non-controlling interest contributions	—	—	—	2,744	2,744
Non-controlling interest distributions	—	—	—	(7,652)	(7,652)
(Increase) decrease in intercompany receivables, net	(46,622)	(337,235)	405,196	(21,339)	—
Other financing activities, net	158	(199)	—	(35)	(76)
Net cash (used in) provided by financing activities	(51,094)	(9,434)	365,735	(39,165)	266,042
Effect of currency exchange rate changes on cash and cash equivalents and restricted cash	—	—	—	(18,821)	(18,821)
NET DECREASE IN CASH AND CASH EQUIVALENTS AND RESTRICTED CASH	—	(7,200)	(33,349)	(180,924)	(221,473)
CASH AND CASH EQUIVALENTS AND RESTRICTED CASH, AT BEGINNING OF PERIOD	7	15,604	114,143	695,065	824,819
CASH AND CASH EQUIVALENTS AND RESTRICTED CASH, AT END OF PERIOD	$7	$8,404	$80,794	$514,141	$603,346
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:					
Cash paid during the period for:					
Interest	$—	$58,814	$—	$523	$59,337
Income taxes, net	$—	$—	$77,076	$82,757	$159,833

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CBRE GROUP, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Condensed Consolidating Statements of Cash Flows

	Six Months Ended June 30, 2017 (As Adjusted) (1)				
	Parent	CBRE Services	Guarantor Subsidiaries	Nonguarantor Subsidiaries	Consolidated Total
CASH FLOWS PROVIDED BY (USED IN) OPERATING ACTIVITIES:	$49,436	$16,131	$(162,159)	$(20,845)	$(117,437)
CASH FLOWS FROM INVESTING ACTIVITIES:					
Capital expenditures	—	—	(39,925)	(19,938)	(59,863)
Acquisition of businesses, including net assets acquired, intangibles and goodwill, net of cash acquired	—	—	(20,584)	(4,742)	(25,326)
Contributions to unconsolidated subsidiaries	—	—	(23,752)	(8,908)	(32,660)
Distributions from unconsolidated subsidiaries	—	—	19,333	4,637	23,970
Purchase of equity securities	—	—	(9,280)	—	(9,280)
Proceeds from sale of equity securities	—	—	9,428	—	9,428
Purchase of available for sale debt securities	—	—	(10,454)	—	(10,454)
Proceeds from the sale of available for sale debt securities	—	—	7,849	—	7,849
Other investing activities, net	—	—	2,486	(207)	2,279
Net cash used in investing activities	—	—	(64,899)	(29,158)	(94,057)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from revolving credit facility	—	911,000	—	—	911,000
Repayment of revolving credit facility	—	(911,000)	—	—	(911,000)
Proceeds from notes payable on real estate held for sale and under development	—	—	—	2,137	2,137
Repayment of notes payable on real estate held for sale and under development	—	—	—	(9,189)	(9,189)
Acquisition of businesses (cash paid for acquisitions more than	—	—	(11,196)	(3,930)	(15,126)

three months after purchase date)					
Units repurchased for payment of taxes on equity awards	(1,900)	—	—	—	(1,900)
Non-controlling interest contributions	—	—	—	1,941	1,941
Non-controlling interest distributions	—	—	—	(3,904)	(3,904)
(Increase) decrease in intercompany receivables, net	(47,896)	(20,114)	46,854	21,156	—
Other financing activities, net	360	—	(3,145)	(881)	(3,666)
Net cash (used in) provided by financing activities	(49,436)	(20,114)	32,513	7,330	(29,707)
Effect of currency exchange rate changes on cash and cash equivalents and restricted cash	—	—	—	20,190	20,190
NET DECREASE IN CASH AND CASH EQUIVALENTS AND RESTRICTED CASH	—	(3,983)	(194,545)	(22,483)	(221,011)
CASH AND CASH EQUIVALENTS AND RESTRICTED CASH, AT BEGINNING OF PERIOD	7	16,889	271,088	543,428	831,412
CASH AND CASH EQUIVALENTS AND RESTRICTED CASH, AT END OF PERIOD	$7	$12,906	$76,543	$ 520,945	$ 610,401
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:					
Cash paid during the period for:					
Interest	$—	$59,446	$—	$ 44	$ 59,490
Income taxes, net	$—	$—	$82,017	$ 81,868	$ 163,885

(1) We adopted new revenue recognition guidance in the first quarter of 2018. Certain restatements have been made to the 2017 financial statements to conform with the 2018 presentation. See Notes 2 and 3 for more information.

CBRE GROUP, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

15. Subsequent Event

In June 2016, CBRE was named as a defendant in a class action lawsuit relating to its role as property manager of certain real estate investment properties owned by the plaintiffs in Florida. CBRE started managing these various properties between July 2005 and March 2007, and CBRE ceased managing these properties in January 2011. The third-party sponsors of such investment properties inappropriately managed funds for the plaintiffs which resulted in losses, used some of these funds for personal purposes, and were imprisoned for their conduct. Since the third-party sponsors could not answer financially for the resulting losses to the plaintiffs, the plaintiffs made claims against CBRE generally alleging that CBRE should have prevented the fraud perpetuated by the third-party sponsors with respect to the properties managed by CBRE. On August 3, 2018, we reached a tentative settlement agreement regarding this proceeding, which agreement is subject to negotiation of definitive settlement documentation and court approval, including the payment of $100 million to the plaintiffs. We expect that such settlement payment will be funded principally by insurance coverage.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations
This Quarterly Report on Form 10-Q (Quarterly Report) for CBRE Group, Inc. for the three months ended June 30, 2018 represents an update to the more detailed and comprehensive disclosures included in our Annual Report on Form 10 K for the year ended December 31, 2017. Accordingly, you should read the following discussion in conjunction with the information included in our Annual Report on Form 10-K for the year ended December 31, 2017 as well as the unaudited financial statements included elsewhere in this Quarterly Report.

In addition, the statements and assumptions in this Quarterly Report that are not statements of historical fact are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 or Section 21E of the Securities Exchange Act of 1934, each as amended, including, in particular, statements about our plans, strategies and prospects as well as estimates of industry growth for the next quarter and beyond. For important information regarding these forward-looking statements, please see the discussion below under the caption "Cautionary Note on Forward-Looking Statements."

Overview

CBRE Group, Inc. is a Delaware corporation. References to "the company," "we," "us" and "our" refer to CBRE Group, Inc. and include all of its consolidated subsidiaries, unless otherwise indicated or the context requires otherwise.

We are the world's largest commercial real estate services and investment firm, based on 2017 revenue, with leading global market positions in our leasing, property sales, occupier outsourcing and valuation businesses. As of December 31, 2017, we operated in more than 450 offices worldwide with over 80,000 employees, excluding independent affiliates.

Our business is focused on providing services to both occupiers of and investors in real estate. For occupiers, we provide facilities management, project management, transaction (both property sales and tenant leasing) and consulting services, among others. For investors, we provide capital markets (property sales, commercial mortgage brokerage, loan origination and servicing), leasing, investment management, property management, valuation and development services, among others. We provide commercial real estate services under the "CBRE" brand name, investment management services under the "CBRE Global Investors" brand name and development services under the "Trammell Crow Company" brand name.

Our revenue mix has shifted in recent years toward more contractual revenue as occupiers and investors increasingly prefer to purchase integrated, account-based services from firms that meet the full spectrum of their needs nationally and globally. We believe we are well-positioned to capture a growing share of this business. We generate revenue from both management fees (large multi-year portfolio and per-project contracts) and commissions on transactions. Our contractual, fee-for-services businesses generally involve occupier outsourcing (including facilities and project management), property management, investment management, appraisal/valuation and loan servicing). In addition, our leasing services business line is largely recurring in nature over time.

In 2017, we generated revenue from a highly diversified base of clients, including more than 90 of the Fortune 100 companies. We have been an S&P 500 company since 2006 and in 2017 we were ranked #214 on the Fortune 500. We have been voted the most recognized commercial real estate brand in a Lipsey Company survey for 17 years in a row (including 2018). We have also been rated a World's Most Ethical Company by the Ethisphere Institute for five consecutive years.

Critical Accounting Policies

Our consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States, or GAAP, which require us to make estimates and assumptions that affect reported amounts. The estimates and assumptions are based on historical experience and on other factors that we believe to be reasonable. Actual results may differ from those estimates. Critical accounting policies represent the areas where more significant judgments and estimates are used in the preparation of our consolidated financial statements. A discussion of such critical accounting policies, which include revenue recognition, goodwill and other intangible assets, and income taxes can be found in our Annual Report on Form 10-K for the year ended December 31, 2017. There have been no material changes to these policies as of June 30, 2018, except for the adoption of new revenue recognition guidance in the first quarter of 2018 and an update to our estimate of the U.S. federal and state tax impact of the transition tax related to the Tax Cuts and Jobs Act (the Tax Act). For a detailed discussion of our new revenue recognition policies and updates to income taxes, see Note 2 of the Notes to Consolidated Financial Statements (Unaudited) set forth in Item 1 of this Quarterly Report.

New Accounting Pronouncements

See Note 3 of the Notes to Consolidated Financial Statements (Unaudited) set forth in Item 1 of this Quarterly Report.

Seasonality

A significant portion of our revenue is seasonal, which an investor should keep in mind when comparing our financial condition and results of operations on a quarter-by-quarter basis. Historically, our revenue, operating income, net income and cash flow from operating activities tend to be lowest in the first quarter, and highest in the fourth quarter of each year. Revenue, earnings and cash flow have generally been concentrated in the fourth calendar quarter due to the focus on completing sales, financing and leasing transactions prior to year-end.

Inflation

Our commissions and other variable costs related to revenue are primarily affected by commercial real estate market supply and demand, which may be affected by inflation. However, to date, we do not believe that general inflation has had a material impact upon our operations.

Items Affecting Comparability

When you read our financial statements and the information included in this Quarterly Report, you should consider that we have experienced, and continue to experience, several material trends and uncertainties that have affected our financial condition and results of operations that make it challenging to predict our future performance based on our historical results. We believe that the following material trends and uncertainties are crucial to an understanding of the variability in our historical earnings and cash flows and the potential for continued variability in the future.

Macroeconomic Conditions

Economic trends and government policies affect global and regional commercial real estate markets as well as our operations directly. These include: overall economic activity and employment growth; interest rate levels and changes in interest rates; the cost and availability of credit; and the impact of tax and regulatory policies. Periods of economic weakness or recession, significantly rising interest rates, fiscal uncertainty, declining employment levels, decreasing demand for commercial real estate, falling real estate values, disruption to the global capital or credit markets, or the public perception that any of these events may occur, will negatively affect the performance of our business.

Compensation is our largest expense and our sales and leasing professionals generally are paid on a commission and/or bonus basis that correlates with their revenue production. As a result, the negative effect of difficult market conditions on our operating margins is partially mitigated by the inherent variability of our compensation cost structure. In addition, when negative economic conditions have been particularly severe, we have moved decisively to lower operating expenses to improve financial performance, and then have restored certain expenses as economic conditions improved. Nevertheless, adverse global and regional economic trends could pose significant risks to the performance of our operations and our financial condition.

Commercial real estate markets in the United States have generally been marked by increased demand for space, falling vacancies and higher rents since 2010. During this time, healthy U.S. property sales activity has been sustained by gradually improving market fundamentals, including higher occupancy rates and rents, broad, low-cost credit availability and increased institutional capital allocations to commercial real estate. Following years of strong growth, U.S. property sales volumes slowed in 2016 and 2017, but edged up modestly in the first half of 2018 as significant capital continues to target commercial real estate. Commercial mortgage markets also have remained highly active, driven by relatively low interest rates, a favorable lending environment and improved market fundamentals. The U.S. Government Sponsored Enterprises continue to be a significant source of debt capital for multi-family properties.

European countries began to emerge from recession in 2013, with economic growth accelerating in 2017. Sales and leasing activity has improved steadily across most of continental Europe for more than three years, though market volumes dipped slightly in the first half of 2018. Since the United Kingdom’s June 2016 referendum to leave the European Union (EU), sentiment in that country has improved. While steady progress continues to be made regarding the United Kingdom’s long-term relationship with the EU, the absence of an agreement as the March 2019 deadline draws closer has contributed to uncertainty more recently.

In Asia Pacific, real estate leasing and investment markets have remained highly active since late 2016. Asia Pacific investors also continue to be a significant source of real estate investment both in the region and across other parts of the world.

Real estate investment management and property development markets have been generally favorable with abundant debt and equity capital flows into commercial real estate. Actively managed real estate equity strategies have been pressured by a shift in investor preferences from active to passive portfolio strategies and concerns about potentially higher interest rates.

The performance of our global real estate services and real estate investment businesses depends on sustained economic growth and job creation; stable, healthy global credit markets; and continued positive business and investor sentiment.

Effects of Acquisitions

We historically have made significant use of strategic acquisitions to add and enhance service competencies around the world. On June 12, 2018, CBRE Jason Acquisition LLC (Merger Sub), our wholly-owned subsidiary, and FacilitySource Holdings, LLC (FacilitySource), WP X Finance, LP and Warburg Pincus X Partners, LP (collectively, the Stockholders) entered into a stock purchase agreement and plan of merger (the Merger Agreement). As part of the Merger Agreement, (i) we purchased from the Stockholders all the outstanding shares of capital stock of FS WP Holdco, Inc (Blocker Corp), which owned 1,686,013 Class A units (the Blocker Units) and (ii) immediately following the acquisition of Blocker Corp, Merger Sub merged with FacilitySource, with FacilitySource continuing as the surviving company and our wholly-owned subsidiary within our Americas segment (the FacilitySource Acquisition), with the remaining Blocker Units not held by Blocker Corp. cancelled and converted into the right to receive cash consideration as set forth in the Merger Agreement. The estimated net initial purchase price was approximately $265.5 million, with $262.0 million paid in cash, plus adjustments for working capital and other items. We financed the transaction with cash on hand and borrowings under our revolving credit facility. We completed the FacilitySource Acquisition to help us (i) build a tech-enabled supply chain capability that is unique for the occupier outsourcing industry and (ii) drive meaningfully differentiated outcomes for leading occupiers of real estate.

Strategic in-fill acquisitions have also played a key role in strengthening our service offerings. The companies we acquired have generally been regional or specialty firms that complement our existing platform, or independent affiliates in which, in some cases, we held a small equity interest. During 2017, we completed 11 in-fill acquisitions, including two leading Software as a Service (SaaS) platforms – one that produces scalable interactive visualization technologies for commercial real estate and one that provides technology solutions for facilities management operations, a healthcare-focused project manager in Australia, a full-service brokerage and management boutique in South Florida, a technology-enabled national boutique commercial real estate finance and consulting firm in the United States, a retail consultancy in France, a majority interest in a Toronto-based investment management business specializing in private infrastructure and private equity investments, a San Francisco-based technology-focused boutique real estate brokerage firm, a project management and design engineering firm operating across the United States, a Washington, D.C.-based retail brokerage operation and a leading technical engineering services provider in Italy. During the six months ended June 30, 2018, we acquired a retail leasing and property management firm in Australia and our affiliate in Israel. In addition, in July 2018, we completed the acquisition of a local facilities management provider in Israel.

We believe that strategic acquisitions can significantly decrease the cost, time and commitment of management resources necessary to attain a meaningful competitive position within targeted markets or to expand our presence within our current markets. In general, however, most acquisitions will initially have an adverse impact on our operating and net income as a result of transaction-related expenditures. These include severance, lease termination, transaction and deferred financing costs, among others, and the charges and costs of integrating the acquired business and its financial and accounting systems into our own.

Our acquisition structures often include deferred and/or contingent purchase price payments in future periods that are subject to the passage of time or achievement of certain performance metrics and other conditions. As of June 30, 2018, we have accrued deferred consideration totaling $88.2 million, which is included in accounts payable and accrued expenses and in other long-term liabilities in the accompanying consolidated balance sheets set forth in Item 1 of this Quarterly Report.

International Operations

We are monitoring the economic and political developments related to the United Kingdom’s referendum to leave the European Union and the potential impact on our businesses in the United Kingdom and the rest of Europe, including, in particular, sales and leasing activity in the United Kingdom, as well as any associated currency volatility impact on our results of operations.

As we continue to increase our international operations through either acquisitions or organic growth, fluctuations in the value of the U.S. dollar relative to the other currencies in which we may generate earnings could adversely affect our business, financial condition and operating results. Our Global Investment Management business has a significant amount of euro-denominated assets under management, or AUM, as well as associated revenue and earnings in Europe. In addition, our Global Workplace Solutions business also has a significant amount of its revenue and earnings denominated in foreign currencies, such as the euro and the British pound sterling. Fluctuations in foreign currency exchange rates have resulted and may continue to result in corresponding fluctuations in our AUM, revenue and earnings.

During the six months ended June 30, 2018, approximately 43% of our business was transacted in non-U.S. dollar currencies, the majority of which included the Australian dollar, Brazilian real, British pound sterling, Canadian dollar, Chinese yuan, Danish krone, euro, Hong Kong dollar, Indian rupee, Japanese yen, Korean won, Mexican peso, Polish zloty, Singapore dollar, Swedish krona, Swiss franc and Thai baht. The following table sets forth our revenue derived from our most significant currencies (U.S. dollars in thousands):

	Three Months Ended June 30, 2018		2017 (As Adjusted) (1)		Six Months Ended June 30, 2018		2017 (As Adjusted) (1)	
United States dollar	$2,908,185	56.9 %	$2,644,445	59.5 %	$5,582,402	57.0 %	$5,116,851	60.3 %
British pound sterling	634,264	12.4 %	518,988	11.7 %	1,214,781	12.4 %	991,143	11.7 %
Euro	560,352	11.0 %	405,563	9.1 %	1,056,298	10.8 %	754,835	8.9 %
Canadian dollar	181,075	3.5 %	139,683	3.1 %	341,957	3.5 %	270,254	3.2 %
Australian dollar	128,376	2.5 %	119,025	2.7 %	229,933	2.3 %	211,877	2.5 %
Indian rupee	103,651	2.0 %	94,347	2.1 %	207,245	2.1 %	172,166	2.0 %
Chinese yuan	69,284	1.4 %	57,691	1.3 %	131,659	1.3 %	108,126	1.3 %
Singapore dollar	68,273	1.3 %	64,792	1.5 %	128,506	1.3 %	121,970	1.4 %
Japanese yen	62,491	1.2 %	66,457	1.5 %	127,659	1.3 %	113,845	1.3 %
Brazilian real	44,455	0.9 %	33,909	0.8 %	85,151	0.9 %	69,216	0.8 %
Swiss franc	44,066	0.9 %	34,503	0.8 %	87,314	0.9 %	71,584	0.8 %
Hong Kong dollar	39,169	0.8 %	34,226	0.8 %	74,355	0.8 %	65,497	0.8 %
Mexican peso	34,387	0.7 %	29,369	0.7 %	66,998	0.7 %	49,455	0.6 %
Polish zloty	21,509	0.4 %	14,555	0.3 %	38,947	0.4 %	27,119	0.3 %
Danish krone	18,608	0.4 %	18,705	0.4 %	41,931	0.4 %	37,165	0.4 %
Thai baht	18,438	0.4 %	14,533	0.3 %	38,363	0.4 %	28,066	0.3 %
Swedish krona	16,674	0.3 %	16,195	0.4 %	36,094	0.4 %	31,108	0.4 %
Korean won	12,559	0.2 %	12,719	0.3 %	26,085	0.3 %	22,628	0.3 %
Other currencies	145,618	2.8 %	119,866	2.7 %	269,708	2.8 %	227,632	2.7 %
Total revenue	$5,111,434	100.0%	$4,439,571	100.0%	$9,785,386	100.0%	$8,490,537	100.0%

(1) We adopted new revenue recognition guidance in the first quarter of 2018. Certain restatements have been made to the 2017 financial statements to conform with the 2018 presentation. See Notes 2 and 3 of the Notes to Consolidated Financial Statements (Unaudited) set forth in Item 1 of this Quarterly Report for more information.

Although we operate globally, we report our results in U.S. dollars. As a result, the strengthening or weakening of the U.S. dollar may positively or negatively impact our reported results. For example, we estimate that had the British pound sterling-to-U.S. dollar exchange rates been 10% higher during the six months ended June 30, 2018, the net impact would have been an increase in pre-tax income of $1.7 million. Had the euro-to-U.S. dollar exchange rates been 10% higher during the six months ended June 30, 2018, the net impact would have been an increase in pre-tax income of $5.3 million. These hypothetical calculations estimate the impact of translating results into U.S. dollars and do not include an estimate of the impact that a 10% change in the U.S. dollar against other currencies would have had on our foreign operations.

Due to the constantly changing currency exposures to which we are subject and the volatility of currency exchange rates, we cannot predict the effect of exchange rate fluctuations upon future operating results. In addition, fluctuations in currencies relative to the U.S. dollar may make it more difficult to perform period-to-period comparisons of our reported results of operations. Our international operations also are subject to, among other things, political instability and changing regulatory environments, which affects the currency markets and which as a result may adversely affect our future financial condition and results of operations. We routinely monitor these risks and related costs and evaluate the appropriate amount of oversight to allocate towards business activities in foreign countries where such risks and costs are particularly significant.

Results of Operations

The following table sets forth items derived from our consolidated statements of operations for the three and six months ended June 30, 2018 and 2017 (dollars in thousands):

	Three Months Ended June 30,				Six Months Ended June 30,			
	2018		2017 (As Adjusted) (1)		2018		2017 (As Adjusted) (1)	
Revenue:								
Fee revenue:								
Occupier outsourcing	$762,173	14.9 %	$613,372	13.8 %	$1,474,694	15.1 %	$1,180,712	13.9 %
Property management	150,181	2.9 %	133,315	3.0 %	298,310	3.0 %	259,062	3.1 %
Valuation	138,367	2.7 %	129,768	2.9 %	264,585	2.7 %	246,223	2.9 %
Loan servicing	43,908	0.9 %	39,872	0.9 %	85,722	0.9 %	76,282	0.9 %
Investment management	98,947	1.9 %	92,763	2.1 %	222,637	2.3 %	182,329	2.1 %
Leasing	743,980	14.6 %	619,916	14.0 %	1,316,466	13.5 %	1,149,394	13.5 %
Capital Markets:								
Sales	436,600	8.5 %	434,233	9.8 %	842,168	8.6 %	788,027	9.3 %
Commercial mortgage origination	119,814	2.3 %	104,510	2.4 %	227,108	2.3 %	189,234	2.2 %
Other:								
Development services	15,463	0.3 %	13,677	0.3 %	36,695	0.4 %	25,300	0.3 %
Other	26,167	0.6 %	19,523	0.4 %	44,114	0.4 %	38,240	0.5 %
Total fee revenue	2,535,600	49.6 %	2,200,949	49.6 %	4,812,499	49.2 %	4,134,803	48.7 %
Pass through costs also recognized as revenue	2,575,834	50.4 %	2,238,622	50.4 %	4,972,887	50.8 %	4,355,734	51.3 %
Total revenue	5,111,434	100.0%	4,439,571	100.0%	9,785,386	100.0%	8,490,537	100.0%
Costs and expenses:								
Cost of services	3,958,748	77.4 %	3,409,540	76.8 %	7,578,709	77.4 %	6,556,017	77.2 %
Operating, administrative and other	826,282	16.2 %	712,615	16.1 %	1,558,517	15.9 %	1,319,241	15.5 %
Depreciation and amortization	113,399	2.2 %	100,386	2.2 %	221,564	2.3 %	194,423	2.3 %
Total costs and expenses	4,898,429	95.8 %	4,222,541	95.1 %	9,358,790	95.6 %	8,069,681	95.0 %
Gain on disposition of real estate	12,311	0.2 %	11,298	0.2 %	12,329	0.1 %	12,683	0.1 %
Operating income	225,316	4.4 %	228,328	5.1 %	438,925	4.5 %	433,539	5.1 %
Equity income from unconsolidated subsidiaries	96,021	1.9 %	75,384	1.7 %	136,200	1.4 %	90,402	1.1 %
Other income (loss)	4,009	0.1 %	3,186	0.1 %	(271)	0.0 %	7,301	0.1 %
Interest income	1,489	0.0 %	1,427	0.0 %	5,110	0.1 %	3,838	0.0 %
Interest expense	26,885	0.5 %	35,430	0.8 %	55,743	0.6 %	69,440	0.8 %
Write-off of financing costs on extinguished debt	—	0.0 %	—	0.0 %	27,982	0.3 %	—	0.0 %
	299,950	5.9 %	272,895	6.1 %	496,239	5.1 %	465,640	5.5 %

Income before provision for income taxes												
Provision for income taxes	70,319	1.4	%	69,887	1.5	%	116,483	1.2	%	123,706	1.5	%
Net income	229,631	4.5	%	203,008	4.6	%	379,756	3.9	%	341,934	4.0	%
Less: Net income attributable to non-controlling interests	964	0.0	%	1,231	0.1	%	801	0.0	%	3,137	0.0	%
Net income attributable to CBRE Group, Inc.	$228,667	4.5	%	$201,777	4.5	%	$378,955	3.9	%	$338,797	4.0	%
EBITDA	$437,781	8.6	%	$406,053	9.1	%	$795,617	8.1	%	$722,528	8.5	%
Adjusted EBITDA	$439,307	8.6	%	$418,686	9.4	%	$787,114	8.0	%	$731,863	8.6	%

(1) We adopted new revenue recognition guidance in the first quarter of 2018. Certain restatements have been made to the 2017 financial statements to conform with the 2018 presentation. See Notes 2 and 3 of the Notes to Consolidated Financial Statements (Unaudited) set forth in Item 1 of this Quarterly Report for more information.

Fee revenue, EBITDA and adjusted EBITDA are not recognized measurements under GAAP. When analyzing our operating performance, investors should use these measures in addition to, and not as an alternative for, their most directly comparable financial measure calculated and presented in accordance with GAAP. We generally use these non-GAAP financial measures to evaluate operating performance and for other discretionary purposes. We believe these measures provide a more complete understanding of ongoing operations, enhance comparability of current results to prior periods and may be useful for investors to analyze our financial performance because they eliminate the impact of selected charges that may obscure trends in the underlying performance of our business. Because not all companies use identical calculations, our presentation of fee revenue, EBITDA and adjusted EBITDA may not be comparable to similarly titled measures of other companies.

Fee revenue is gross revenue less both client reimbursed costs largely associated with employees that are dedicated to client facilities and subcontracted vendor work performed for clients. We believe that investors may find this measure useful to analyze the company's overall financial performance because it excludes costs reimbursable by clients, and as such provides greater visibility into the underlying performance of our business.

EBITDA represents earnings before net interest expense, write-off of financing costs on extinguished debt, income taxes, depreciation and amortization. Amounts shown for adjusted EBITDA further remove (from EBITDA) the impact of certain cash and non-cash charges related to acquisitions and certain carried interest incentive compensation reversal to align with the timing of associated revenue. We believe that investors may find these measures useful in evaluating our operating performance compared to that of other companies in our industry because their calculations generally eliminate the effects of acquisitions, which would include impairment charges of goodwill and intangibles created from acquisitions, the effects of financings and income taxes and the accounting effects of capital spending.

EBITDA and adjusted EBITDA are not intended to be measures of free cash flow for our discretionary use because they do not consider certain cash requirements such as tax and debt service payments. These measures may also differ from the amounts calculated under similarly titled definitions in our debt instruments, which amounts are further adjusted to reflect certain other cash and non-cash charges and are used by us to determine compliance with financial covenants therein and our ability to engage in certain activities, such as incurring additional debt and making certain restricted payments. We also use adjusted EBITDA as a significant component when measuring our operating performance under our employee incentive compensation programs.

EBITDA and adjusted EBITDA are calculated as follows (dollars in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017 (As Adjusted) (1)	2018	2017 (As Adjusted) (1)
Net income attributable to CBRE Group, Inc.	$228,667	$ 201,777	$378,955	$ 338,797
Add:				
Depreciation and amortization	113,399	100,386	221,564	194,423
Interest expense	26,885	35,430	55,743	69,440
Write-off of financing costs on extinguished debt	—	—	27,982	—
Provision for income taxes	70,319	69,887	116,483	123,706
Less:				
Interest income	1,489	1,427	5,110	3,838
EBITDA	437,781	406,053	795,617	722,528
Adjustments:				
Carried interest incentive compensation expense (reversal) to align with the timing of associated revenue	1,526	(2,775)	(8,503)	(18,016)
Integration and other costs related to acquisitions	—	15,408	—	27,351
Adjusted EBITDA	$439,307	$ 418,686	$787,114	$ 731,863

(1) We adopted new revenue recognition guidance in the first quarter of 2018. Certain restatements have been made to the 2017 financial statements to conform with the 2018 presentation. See Notes 2 and 3 of the Notes to

Consolidated Financial Statements (Unaudited) set forth in Item 1 of this Quarterly Report for more information.
Three Months Ended June 30, 2018 Compared to the Three Months Ended June 30, 2017

We reported consolidated net income of $228.7 million for the three months ended June 30, 2018 on revenue of $5.1 billion as compared to consolidated net income of $201.8 million on revenue of $4.4 billion for the three months ended June 30, 2017.

Our revenue on a consolidated basis for the three months ended June 30, 2018 increased by $671.9 million, or 15.1%, as compared to the three months ended June 30, 2017. The revenue increase reflects strong organic growth fueled by higher occupier outsourcing revenue (up 14.9%) and property management revenue (up 6.5%) as well as increased leasing (up 18.4%) and commercial mortgage origination activity (up 14.6%). In addition, foreign currency translation had a $110.4 million positive impact on total revenue during the three months ended June 30, 2018, primarily driven by strength in the British pound sterling and euro.

Our cost of services on a consolidated basis increased by $549.2 million, or 16.1%, during the three months ended June 30, 2018 as compared to the same period in 2017. This increase was primarily due to higher costs associated with our occupier outsourcing business. In addition, our sales professionals generally are paid on a commission basis, which substantially correlates with our leasing revenue performance. Lastly, foreign currency translation had a $83.8 million negative impact on total cost of services during the three months ended June 30, 2018. Cost of services as a percentage of revenue increased to 77.4% for the three months ended June 30, 2018 versus 76.8% for the three months ended June 30, 2017. This increase was primarily driven by outsourcing revenue, which has a lower margin than sales and lease transaction revenue, comprising a higher percentage of our consolidated revenue during the three months ended June 30, 2018 as compared to the second quarter of 2017.

Our operating, administrative and other expenses on a consolidated basis increased by $113.7 million, or 16.0%, during the three months ended June 30, 2018 as compared to the same period in 2017. The increase was mostly driven by higher payroll-related costs (including increases in bonus and stock compensation expense) as well as increases in consulting, marketing and occupancy costs. Foreign currency translation also had a $19.5 million negative impact on total operating expenses during the three months ended June 30, 2018. Operating expenses as a percentage of revenue was consistent at 16.2% for the three months ended June 30, 2018 and 16.1% for the three months ended June 30, 2017.

Our depreciation and amortization expense on a consolidated basis increased by $13.0 million, or 13.0%, during the three months ended June 30, 2018 as compared to the same period in 2017. This increase was primarily attributable to a rise in depreciation expense of $7.0 million during the three months ended June 30, 2018 driven by technology-related capital expenditures. Higher amortization expense associated with mortgage servicing rights and intangibles acquired in acquisitions also contributed to the increase.

Our equity income from unconsolidated subsidiaries on a consolidated basis increased by $20.6 million, or 27.4%, during the three months ended June 30, 2018 as compared to the same period in 2017, primarily driven by higher equity earnings associated with gains on property sales reported in our Development Services segment.

Our consolidated interest expense decreased by $8.5 million, or 24.1%, for the three months ended June 30, 2018 as compared to the three months ended June 30, 2017. This decrease was primarily driven by the early redemption, in full, of the $800.0 million aggregate outstanding principal amount of our 5.00% senior notes in the first quarter of 2018.

Our provision for income taxes on a consolidated basis was $70.3 million for the three months ended June 30, 2018 as compared to $69.9 million for the same period in 2017. Our effective tax rate, after adjusting pre-tax income to remove the portion attributable to non-controlling interests, decreased to 23.5% for the three months ended June 30, 2018 compared to 25.7% for the three months ended June 30, 2017. We benefited from a lower U.S. corporate tax rate, with such rate being 35% in 2017 versus 21% in 2018. The effect of the decrease in the U.S. corporate tax rate was partially offset by discrete tax benefits for the three months ended June 30, 2017 from the re-measurement of income tax exposures relating to prior periods with no similar items for the three months ended June 30, 2018.

Six Months Ended June 30, 2018 Compared to the Six Months Ended June 30, 2017

We reported consolidated net income of $379.0 million for the six months ended June 30, 2018 on revenue of $9.8 billion as compared to consolidated net income of $338.8 million on revenue of $8.5 billion for the six months ended June 30, 2017.

Our revenue on a consolidated basis for the six months ended June 30, 2018 increased by $1.3 billion, or 15.3%, as compared to the six months ended June 30, 2017. The revenue increase reflects strong organic growth fueled by higher occupier outsourcing revenue (up 13.4%) and property management revenue (up 6.8%), increased leasing (up 12.3%), sales (up 4.0%) and commercial mortgage origination activity (up 19.9%) and higher revenue from our Global Investment Management segment (up 15.5%). In addition, foreign currency translation had a $281.2 million positive impact on total revenue during the six months ended June 30, 2018, primarily driven by strength in the British pound sterling and euro.

Our cost of services on a consolidated basis increased by $1.0 billion, or 15.6%, during the six months ended June 30, 2018 as compared to the same period in 2017. This increase was primarily due to higher costs associated with our occupier outsourcing business. In addition, our sales professionals generally are paid on a commission basis, which substantially correlates with our transaction revenue performance. Lastly, foreign currency translation had a $215.3 million negative impact on total cost of services during the six months ended June 30, 2018. Cost of services as a percentage of revenue was relatively consistent at 77.4% for the six months ended June 30, 2018 versus 77.2% for the six months ended June 30, 2017.

Our operating, administrative and other expenses on a consolidated basis increased by $239.3 million, or 18.1%, during the six months ended June 30, 2018 as compared to the same period in 2017. The increase was mostly driven by higher payroll-related costs (including increases in bonus and stock compensation expense), higher carried interest expense and increases in consulting, marketing and occupancy costs. Foreign currency translation also had a $50.8 million negative impact on total operating expenses during the six months ended June 30, 2018. These items contributed to operating expenses as a percentage of revenue increasing from 15.5% for the six months ended June 30, 2017 to 15.9% for the six months ended June 30, 2018.

Our depreciation and amortization expense on a consolidated basis increased by $27.1 million, or 14.0%, during the six months ended June 30, 2018 as compared to the same period in 2017. This increase was primarily attributable to higher amortization expense associated with mortgage servicing rights and intangibles acquired in acquisitions. A rise in depreciation expense of $12.4 million during the six months ended June 30, 2018 driven by technology-related capital expenditures also contributed to the increase.

Our equity income from unconsolidated subsidiaries on a consolidated basis increased by $45.8 million, or 50.7%, during the six months ended June 30, 2018 as compared to the same period in 2017, primarily driven by higher equity earnings associated with gains on property sales reported in our Development Services segment.

Our consolidated interest expense decreased by $13.7 million, or 19.7%, for the six months ended June 30, 2018 as compared to the six months ended June 30, 2017. This decrease was primarily driven by the early redemption, in full, of the $800.0 million aggregate outstanding principal amount of our 5.00% senior notes in the first quarter of 2018.

Our write-off of financing costs on extinguished debt on a consolidated basis was $28.0 million for the six months ended June 30, 2018. These costs included a $20.0 million premium paid and the write-off of $8.0 million of unamortized deferred financing costs in connection with the early redemption, in full, of the $800.0 million aggregate outstanding principal amount of our 5.00% senior notes.

Our provision for income taxes on a consolidated basis was $116.5 million for the six months ended June 30, 2018 as compared to $123.7 million for the same period in 2017. Our effective tax rate, after adjusting pre-tax income to remove the portion attributable to non-controlling interests, decreased to 23.5% for the six months ended June 30, 2018 compared to 26.7% for the six months ended June 30, 2017. We benefited from a lower U.S. corporate tax rate, with such rate being 35% in 2017 versus 21% in 2018. The effect of the decrease in the U.S. corporate tax rate was partially offset by discrete tax benefits for the six months ended June 30, 2017 from the re-measurement of income tax exposures relating to prior periods with no similar items for the six months ended June 30, 2018.

Segment Operations

We report our operations through the following segments: (1) Americas; (2) Europe, Middle East and Africa (EMEA); (3) Asia Pacific; (4) Global Investment Management; and (5) Development Services. The Americas consists of operations located in the United States, Canada and key markets in Latin America. EMEA mainly consists of operations in Europe, while Asia Pacific includes operations in Asia, Australia and New Zealand. The Global

Investment Management business consists of investment management operations in North America, Europe and Asia Pacific. The Development Services business consists of real estate development and investment activities primarily in the United States.

Americas

The following table summarizes our results of operations for our Americas operating segment for the three and six months ended June 30, 2018 and 2017 (dollars in thousands):

	Three Months Ended June 30,				Six Months Ended June 30,			
	2018		2017 (As Adjusted) (1)		2018		2017 (As Adjusted) (1)	
Revenue:								
Fee revenue:								
Occupier outsourcing	$310,901	9.9 %	$273,044	9.7 %	$619,286	10.3 %	$524,660	9.6 %
Property management	77,433	2.5 %	69,310	2.5 %	155,533	2.6 %	137,450	2.5 %
Valuation	64,346	2.0 %	61,599	2.2 %	123,412	2.1 %	118,780	2.2 %
Loan servicing	41,327	1.3 %	37,190	1.3 %	80,853	1.3 %	70,724	1.3 %
Leasing	536,660	17.1 %	450,208	15.9 %	936,858	15.6 %	844,073	15.4 %
Capital Markets:								
Sales	269,636	8.6 %	261,710	9.3 %	537,311	9.0 %	495,506	9.1 %
Commercial mortgage origination	118,257	3.8 %	101,610	3.6 %	224,277	3.7 %	183,975	3.4 %
Other	14,273	0.4 %	11,368	0.3 %	24,037	0.5 %	24,082	0.4 %
Total fee revenue	1,432,833	45.6 %	1,266,039	44.8 %	2,701,567	45.1 %	2,399,250	43.9 %
Pass through costs also recognized as revenue	1,707,594	54.4 %	1,560,884	55.2 %	3,289,084	54.9 %	3,066,879	56.1 %
Total revenue	3,140,427	100.0%	2,826,923	100.0%	5,990,651	100.0%	5,466,129	100.0%
Costs and expenses:								
Cost of services	2,506,171	79.8 %	2,255,569	79.8 %	4,781,022	79.8 %	4,361,928	79.8 %
Operating, administrative and other	384,626	12.2 %	350,937	12.4 %	739,897	12.4 %	673,305	12.3 %
Depreciation and amortization	80,693	2.6 %	71,724	2.5 %	158,674	2.6 %	140,293	2.6 %
Operating income	168,937	5.4 %	148,693	5.3 %	311,058	5.2 %	290,603	5.3 %
Equity income from unconsolidated subsidiaries	7,534	0.2 %	5,222	0.2 %	11,533	0.2 %	9,862	0.2 %
Other income	1,189	0.0 %	612	0.0 %	2,931	0.1 %	1,039	0.0 %
Less: Net income attributable to non-controlling interests	—	0.0 %	1	0.0 %	—	0.0 %	—	0.0 %
Add-back: Depreciation and amortization	80,693	2.6 %	71,724	2.5 %	158,674	2.6 %	140,293	2.6 %
EBITDA	$258,353	8.2 %	$226,250	8.0 %	$484,196	8.1 %	$441,797	8.1 %
Adjusted EBITDA	$258,353	8.2 %	$233,711	8.3 %	$484,196	8.1 %	$458,936	8.4 %

(1)

We adopted new revenue recognition guidance in the first quarter of 2018. Certain restatements have been made to the 2017 financial statements to conform with the 2018 presentation. See Notes 2 and 3 of the Notes to Consolidated Financial Statements (Unaudited) set forth in Item 1 of this Quarterly Report for more information.

Three Months Ended June 30, 2018 Compared to the Three Months Ended June 30, 2017

Revenue increased by $313.5 million, or 11.1%, for the three months ended June 30, 2018 compared to the three months ended June 30, 2017. The revenue increase reflects strong organic growth fueled by higher occupier outsourcing and property management revenue as well as improved sales, leasing and commercial mortgage origination activity. Foreign currency translation also had a $0.4 million positive impact on total revenue during the three months ended June 30, 2018, primarily driven by strength in the Canadian dollar largely offset by weakness in the Argentine peso and Brazilian real.

Cost of services increased by $250.6 million, or 11.1%, for the three months ended June 30, 2018 as compared to the same period in 2017, primarily due to higher costs associated with our occupier outsourcing business. Also contributing to the variance was higher commission expense resulting from improved sales and lease transaction revenue. Foreign currency translation had a $0.1 million positive impact on total cost of services during the three months ended June 30, 2018. Cost of services as a percentage of revenue was consistent at 79.8% for both the three months ended June 30, 2018 and 2017.

Operating, administrative and other expenses increased by $33.7 million, or 9.6%, for the three months ended June 30, 2018 as compared to the three months ended June 30, 2017. The increase was partly driven by higher payroll-related costs (including an increase in stock compensation expense) as well as increases in consulting, marketing and occupancy costs. Foreign currency translation also had a $0.3 million positive impact on total operating expenses during the three months ended June 30, 2018.

We earn fees from the origination and sale of commercial mortgage loans for which the company retains the servicing rights. Upon origination of a mortgage loan held for sale, the fair value of the mortgage servicing rights (MSR) to be retained is included in the forecasted proceeds from the anticipated loan sale and results in a net gain (which is reflected in revenue). Upon sale, we record a servicing asset or liability based on the fair value of the retained MSR associated with the transferred loan. Subsequent to the initial recording, MSRs are amortized (within amortization expense) and carried at the lower of amortized cost or fair value in other intangible assets in the accompanying consolidated balance sheets. They are amortized in proportion to and over the estimated period that the servicing income is expected to be received. For the three months ended June 30, 2018, MSRs contributed to operating income $39.2 million of gains recognized in conjunction with the origination and sale of mortgage loans, offset by $26.6 million of amortization of related intangible assets. For the three months ended June 30, 2017, MSRs contributed to operating income $32.6 million of gains recognized in conjunction with the origination and sale of mortgage loans, offset by $24.4 million of amortization of related intangible assets.

Six Months Ended June 30, 2018 Compared to the Six Months Ended June 30, 2017

Revenue increased by $524.5 million, or 9.6%, for the six months ended June 30, 2018 compared to the six months ended June 30, 2017. The revenue increase reflects strong organic growth fueled by higher occupier outsourcing and property management revenue as well as improved sales, leasing and commercial mortgage origination activity. Foreign currency translation also had an $8.2 million positive impact on total revenue during the six months ended June 30, 2018, primarily driven by strength in the Canadian dollar partially offset by weakness in the Argentine peso and Brazilian real.

Cost of services increased by $419.1 million, or 9.6%, for the six months ended June 30, 2018 as compared to the same period in 2017, primarily due to higher costs associated with our occupier outsourcing business. Also contributing to the variance was higher commission expense resulting from improved sales and lease transaction revenue. Foreign currency translation had a $6.0 million negative impact on total cost of services during the six months ended June 30, 2018. Cost of services as a percentage of revenue was consistent at 79.8% for both the six months ended June 30, 2018 and 2017.

Operating, administrative and other expenses increased by $66.6 million, or 9.9%, for the six months ended June 30, 2018 as compared to the six months ended June 30, 2017. The increase was partly driven by higher payroll-related costs (including an increase in stock compensation expense) as well as increases in consulting, marketing and occupancy costs. Foreign currency translation also had a $0.7 million negative impact on total operating expenses during the six months ended June 30, 2018.

For the six months ended June 30, 2018, MSRs contributed to operating income $71.4 million of gains recognized in conjunction with the origination and sale of mortgage loans, offset by $53.5 million of amortization of related intangible assets. For the six months ended June 30, 2017, MSRs contributed to operating income $60.6 million of gains recognized in conjunction with the origination and sale of mortgage loans, offset by $46.7 million of amortization of related intangible assets.

EMEA

The following table summarizes our results of operations for our EMEA operating segment for the three and six months ended June 30, 2018 and 2017 (dollars in thousands):

	Three Months Ended June 30,				Six Months Ended June 30,			
	2018		2017 (As Adjusted) (1)		2018		2017 (As Adjusted) (1)	
Revenue:								
Fee revenue:								
Occupier outsourcing	$377,527	28.7 %	$280,665	27.6 %	$712,465	28.5 %	$539,997	28.1 %
Property management	47,612	3.6 %	40,920	4.0 %	92,815	3.7 %	76,823	4.0 %
Valuation	43,256	3.3 %	37,229	3.7 %	84,319	3.4 %	69,738	3.6 %
Loan servicing	2,360	0.2 %	2,682	0.3 %	4,648	0.2 %	5,558	0.3 %
Leasing	106,295	8.1 %	88,076	8.7 %	206,884	8.3 %	163,007	8.5 %
Capital Markets:								
Sales	98,081	7.5 %	94,055	9.3 %	176,321	7.1 %	161,355	8.4 %
Commercial mortgage origination	1,214	0.1 %	1,985	0.2 %	2,437	0.1 %	3,805	0.2 %
Other	8,275	0.5 %	5,854	0.5 %	14,098	0.5 %	9,615	0.5 %
Total fee revenue	684,620	52.0 %	551,466	54.3 %	1,293,987	51.8 %	1,029,898	53.6 %
Pass through costs also recognized as revenue	630,832	48.0 %	464,554	45.7 %	1,202,719	48.2 %	890,753	46.4 %
Total revenue	1,315,452	100.0%	1,016,020	100.0%	2,496,706	100.0%	1,920,651	100.0%
Costs and expenses:								
Cost of services	1,048,971	79.7 %	789,693	77.7 %	2,009,618	80.5 %	1,518,217	79.0 %
Operating, administrative and other	200,728	15.3 %	164,540	16.2 %	384,975	15.4 %	307,482	16.0 %
Depreciation and amortization	20,277	1.5 %	18,845	1.9 %	39,123	1.6 %	34,415	1.8 %
Operating income	45,476	3.5 %	42,942	4.2 %	62,990	2.5 %	60,537	3.2 %
Equity income from unconsolidated subsidiaries	238	0.1 %	318	0.1 %	476	0.0 %	819	0.0 %
Other (loss) income	(27)	0.0 %	24	0.0 %	62	0.0 %	23	0.0 %
Less: Net loss attributable to non-controlling interests	(555)	0.0 %	(503)	0.0 %	(814)	0.0 %	(160)	0.0 %
Add-back: Depreciation and amortization	20,277	1.5 %	18,845	1.9 %	39,123	1.6 %	34,415	1.8 %
EBITDA	$66,519	5.1 %	$62,632	6.2 %	$103,465	4.1 %	$95,954	5.0 %
Adjusted EBITDA	$66,519	5.1 %	$70,293	6.9 %	$103,465	4.1 %	$105,748	5.5 %

(1) We adopted new revenue recognition guidance in the first quarter of 2018. Certain restatements have been made to the 2017 financial statements to conform with the 2018 presentation. See Notes 2 and 3 of the Notes to Consolidated Financial Statements (Unaudited) set forth in Item 1 of this Quarterly Report for more information.

Three Months Ended June 30, 2018 Compared to the Three Months Ended June 30, 2017

Revenue increased by $299.4 million, or 29.5%, for the three months ended June 30, 2018 as compared to the same period in 2017. We achieved strong organic growth fueled by higher occupier outsourcing revenue as well as higher leasing activity. Foreign currency translation also had a $93.7 million positive impact on total revenue during the three months ended June 30, 2018, primarily driven by strength in the British pound sterling and euro.

Cost of services increased by $259.3 million, or 32.8%, for the three months ended June 30, 2018 as compared to the same period in 2017, primarily due to higher costs associated with our occupier outsourcing business. In addition, foreign currency translation had a $75.2 million negative impact on total cost of services during the three months ended June 30, 2018. Cost of services as a percentage of revenue increased from 77.7% for the three months ended June 30, 2017 to 79.7% for the three months ended June 30, 2018, primarily driven by our revenue mix, with outsourcing revenue, which has a lower margin than sales and lease revenue, comprising a higher percentage of revenue than in the prior year.

Operating, administrative and other expenses increased by $36.2 million, or 22.0%, for the three months ended June 30, 2018 as compared to the same period in 2017. This increase was primarily driven by higher payroll-related costs (including increases in bonus and stock compensation expense) as well as increases in consulting, marketing and occupancy costs. Foreign currency translation also had a $14.0 million negative impact on total operating expenses during the three months ended June 30, 2018.

Six Months Ended June 30, 2018 Compared to the Six Months Ended June 30, 2017

Revenue increased by $576.1 million, or 30.0%, for the six months ended June 30, 2018 as compared to the same period in 2017. We achieved strong organic growth fueled by higher occupier outsourcing revenue as well as higher leasing activity. Foreign currency translation also had a $224.4 million positive impact on total revenue during the six months ended June 30, 2018, primarily driven by strength in the British pound sterling and euro.

Cost of services increased by $491.4 million, or 32.4%, for the six months ended June 30, 2018 as compared to the same period in 2017, primarily due to higher costs associated with our occupier outsourcing business. In addition, foreign currency translation had a $180.6 million negative impact on total cost of services during the six months ended June 30, 2018. Cost of services as a percentage of revenue increased from 79.0% for the six months ended June 30, 2017 to 80.5% for the six months ended June 30, 2018, primarily driven by our revenue mix, with outsourcing revenue, which has a lower margin than sales and lease revenue, comprising a higher percentage of revenue than in the prior year.

Operating, administrative and other expenses increased by $77.5 million, or 25.2%, for the six months ended June 30, 2018 as compared to the same period in 2017. This increase was primarily driven by higher payroll-related costs (including increases in bonus and stock compensation expense) and increases in consulting, marketing and occupancy costs. Foreign currency translation also had a $34.9 million negative impact on total operating expenses during the six months ended June 30, 2018.

Asia Pacific

The following table summarizes our results of operations for our Asia Pacific operating segment for the three and six months ended June 30, 2018 and 2017 (dollars in thousands):

	Three Months Ended June 30,				Six Months Ended June 30,			
	2018		2017 (As Adjusted) (1)		2018		2017 (As Adjusted) (1)	
Revenue:								
Fee revenue:								
Occupier outsourcing	$73,745	13.7 %	$59,663	12.3 %	$142,943	13.8 %	$116,055	13.0 %
Property management	23,030	4.3 %	19,987	4.1 %	46,301	4.5 %	39,781	4.5 %
Valuation	30,765	5.7 %	30,940	6.4 %	56,854	5.5 %	57,705	6.5 %
Loan servicing	221	0.0 %	—	0.0 %	221	0.0 %	—	0.0 %
Leasing	100,186	18.6 %	81,606	16.8 %	171,765	16.6 %	142,134	16.0 %
Capital Markets:								
Sales	68,883	12.8 %	78,303	16.1 %	128,118	12.4 %	130,471	14.7 %
Commercial mortgage origination	343	0.1 %	915	0.2 %	394	0.0 %	1,454	0.2 %
Other	3,619	0.7 %	2,301	0.3 %	5,979	0.7 %	4,543	0.4 %
Total fee revenue	300,792	55.9 %	273,715	56.2 %	552,575	53.5 %	492,143	55.3 %
Pass through costs also recognized as revenue	237,408	44.1 %	213,184	43.8 %	481,084	46.5 %	398,102	44.7 %
Total revenue	538,200	100.0%	486,899	100.0%	1,033,659	100.0%	890,245	100.0%
Costs and expenses:								
Cost of services	403,606	75.0 %	364,278	74.8 %	788,069	76.2 %	675,872	75.9 %
	91,768	17.1 %	78,332	16.1 %	169,078	16.4 %	147,009	16.5 %

Operating, administrative and other											
Depreciation and amortization	4,989	0.9	%	4,389	0.8	%	9,670	0.9	%	8,703	0.9 %
Operating income	37,837	7.0	%	39,900	8.3	%	66,842	6.5	%	58,661	6.7 %
Equity income (loss) from unconsolidated subsidiaries	35	0.1	%	(19)	0.0	%	229	0.0	%	50	0.0 %
Add-back: Depreciation and amortization	4,989	0.9	%	4,389	0.8	%	9,670	0.9	%	8,703	0.9 %
EBITDA	$42,861	8.0	%	$44,270	9.1	%	$76,741	7.4	%	$67,414	7.6 %
Adjusted EBITDA	$42,861	8.0	%	$44,556	9.2	%	$76,741	7.4	%	$67,832	7.6 %

(1) We adopted new revenue recognition guidance in the first quarter of 2018. Certain restatements have been made to the 2017 financial statements to conform with the 2018 presentation. See Notes 2 and 3 of the Notes to Consolidated Financial Statements (Unaudited) set forth in Item 1 of this Quarterly Report for more information.

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Three Months Ended June 30, 2018 Compared to the Three Months Ended June 30, 2017

Revenue increased by $51.3 million, or 10.5%, for the three months ended June 30, 2018 as compared to the three months ended June 30, 2017. The revenue increase reflects strong organic growth, fueled by higher occupier outsourcing and property management revenue as well as improved leasing activity. In addition, foreign currency translation had an $11.6 million positive impact on total revenue during the three months ended June 30, 2018, primarily driven by strength in the Chinese yuan and Singapore dollar.

Cost of services increased by $39.3 million, or 10.8%, for the three months ended June 30, 2018 as compared to the same period in 2017, driven by higher costs associated with our occupier outsourcing business. In addition, foreign currency translation had a $8.7 million negative impact on total cost of services during the three months ended June 30, 2018. Cost of services as a percentage of revenue was relatively consistent at 75.0% for the three months ended June 30, 2018 versus 74.8% for the three months ended June 30, 2017.

Operating, administrative and other expenses increased by $13.4 million, or 17.2%, for the three months ended June 30, 2018 as compared to the same period in 2017. We incurred higher payroll-related costs (including increased stock compensation and bonus expense) as well as increases in marketing, occupancy and travel costs during the three months ended June 30, 2018. Foreign currency translation also had a $2.0 million negative impact on total operating expenses for the three months ended June 30, 2018.

Six Months Ended June 30, 2018 Compared to the Six Months Ended June 30, 2017

Revenue increased by $143.4 million, or 16.1%, for the six months ended June 30, 2018 as compared to the six months ended June 30, 2017. The revenue increase reflects strong organic growth, fueled by higher occupier outsourcing and property management revenue as well as improved leasing activity. In addition, foreign currency translation had a $36.5 million positive impact on total revenue during the six months ended June 30, 2018, primarily driven by strength in the Australian dollar, Chinese yuan, Japanese yen and Singapore dollar.

Cost of services increased by $112.2 million, or 16.6%, for the six months ended June 30, 2018 as compared to the same period in 2017, driven by higher costs associated with our occupier outsourcing business. In addition, foreign currency translation had a $28.7 million negative impact on total cost of services during the six months ended June 30, 2018. Cost of services as a percentage of revenue increased from 75.9% for the six months ended June 30, 2017 to 76.2% for the six months ended June 30, 2018, primarily driven by our revenue mix, with outsourcing revenue, which has a lower margin than sales and lease revenue, comprising a higher percentage of revenue than in the prior year.

Operating, administrative and other expenses increased by $22.1 million, or 15.0%, for the six months ended June 30, 2018 as compared to the same period in 2017. We incurred higher payroll-related costs (including increased stock compensation and bonus expense) as well as increases in marketing, occupancy and travel costs during the six months ended June 30, 2018. Foreign currency translation also had a $5.8 million negative impact on total operating expenses for the six months ended June 30, 2018.

Global Investment Management

The following table summarizes our results of operations for our Global Investment Management operating segment for the three and six months ended June 30, 2018 and 2017 (dollars in thousands):

	Three Months Ended June 30,				Six Months Ended June 30,			
	2018		2017 (As Adjusted) (1)		2018		2017 (As Adjusted) (1)	
Revenue	$98,947	100.0%	$92,763	100.0 %	$222,637	100.0%	$182,329	100.0%
Costs and expenses:								
Operating, administrative and other	88,891	89.8 %	71,309	76.9 %	167,206	75.1 %	122,831	67.4 %
Depreciation and amortization	7,257	7.4 %	4,885	5.2 %	13,484	6.1 %	9,924	5.4 %
Operating income	2,799	2.8 %	16,569	17.9 %	41,947	18.8 %	49,574	27.2 %
Equity income from unconsolidated subsidiaries	2,461	2.4 %	4,419	4.9 %	3,336	1.5 %	5,292	3.0 %
Other income (loss)	2,847	2.9 %	2,550	2.7 %	(3,264)	(1.5 %)	6,239	3.4 %
Less: Net income attributable to non-controlling interests	989	1.0 %	1,738	1.9 %	1,407	0.6 %	3,244	1.8 %
Add-back: Depreciation and amortization	7,257	7.4 %	4,885	5.2 %	13,484	6.1 %	9,924	5.4 %
EBITDA	$14,375	14.5 %	$26,685	28.8 %	$54,096	24.3 %	$67,785	37.2 %
Adjusted EBITDA	$15,901	16.1 %	$23,910	25.8 %	$45,593	20.5 %	$49,769	27.3 %

(1) We adopted new revenue recognition guidance in the first quarter of 2018. Certain restatements have been made to the 2017 financial statements to conform with the 2018 presentation. See Notes 2 and 3 of the Notes to Consolidated Financial Statements (Unaudited) set forth in Item 1 of this Quarterly Report for more information.

Three Months Ended June 30, 2018 Compared to the Three Months Ended June 30, 2017

Revenue increased by $6.2 million, or 6.7%, for the three months ended June 30, 2018 as compared to the three months ended June 30, 2017, primarily driven by higher asset management fees, partially offset by lower carried interest revenue. Foreign currency translation also had a $4.7 million positive impact on total revenue during the three months ended June 30, 2018, primarily driven by strength in the British pound sterling and euro.

Operating, administrative and other expenses increased by $17.6 million, or 24.7%, for the three months ended June 30, 2018 as compared to the same period in 2017, primarily driven by higher payroll-related costs (including bonuses). Foreign currency translation also had a $3.8 million negative impact on total operating expenses during the three months ended June 30, 2018.

A roll forward of our AUM by product type for the three months ended June 30, 2018 is as follows (dollars in billions):

	Funds	Separate Accounts	Securities	Total

Balance at March 31, 2018	$33.8	$ 57.1	$ 13.3	$104.2
Inflows	0.9	1.1	0.6	2.6
Outflows	(1.3)	(0.6)	(1.5)	(3.4)
Market (depreciation) appreciation	(0.2)	(2.0)	0.5	(1.7)
Balance at June 30, 2018	$33.2	$ 55.6	$ 12.9	$101.7

AUM generally refers to the properties and other assets with respect to which we provide (or participate in) oversight, investment management services and other advice, and which generally consist of real estate properties or loans, securities portfolios and investments in operating companies and joint ventures. Our AUM is intended principally to reflect the extent of our presence in the real estate market, not the basis for determining our management fees. Our assets under management consist of:

- the total fair market value of the real estate properties and other assets either wholly-owned or held by joint ventures and other entities in which our sponsored funds or investment vehicles and client accounts have invested or to which they have provided financing. Committed (but unfunded) capital from investors in our sponsored funds is not included in this component of our AUM. The value of development properties is included at estimated completion cost. In the case of real estate operating companies, the total value of real properties controlled by the companies, generally through joint ventures, is included in AUM; and
- the net asset value of our managed securities portfolios, including investments (which may be comprised of committed but uncalled capital) in private real estate funds under our fund of funds investments.

Our calculation of AUM may differ from the calculations of other asset managers, and as a result, this measure may not be comparable to similar measures presented by other asset managers.

Six Months Ended June 30, 2018 Compared to the Six Months Ended June 30, 2017

Revenue increased by $40.3 million, or 22.1%, for the six months ended June 30, 2018 as compared to the six months ended June 30, 2017, primarily driven by higher asset management fees as well as higher carried interest revenue. Foreign currency translation also had a $12.1 million positive impact on total revenue during the six months ended June 30, 2018, primarily driven by strength in the British pound sterling and euro.

Operating, administrative and other expenses increased by $44.4 million, or 36.1%, for the six months ended June 30, 2018 as compared to the same period in 2017, primarily driven by higher carried interest expense as well as higher payroll-related costs (including bonuses). Foreign currency translation also had a $9.4 million negative impact on total operating expenses during the six months ended June 30, 2018.

A roll forward of our AUM by product type for the six months ended June 30, 2018 is as follows (dollars in billions):

	Funds	Separate Accounts	Securities	Total
Balance at December 31, 2017	$31.7	$ 56.7	$ 14.8	$103.2
Inflows	2.6	2.1	1.0	5.7
Outflows	(2.0)	(2.6)	(2.5)	(7.1)
Market appreciation (depreciation)	0.9	(0.6)	(0.4)	(0.1)
Balance at June 30, 2018	$33.2	$ 55.6	$ 12.9	$101.7

We describe above how we calculate AUM. Also, as noted above, our calculation of AUM may differ from the calculations of other asset managers, and as a result, this measure may not be comparable to similar measures presented by other asset managers.

Development Services

The following table summarizes our results of operations for our Development Services operating segment for the three and six months ended June 30, 2018 and 2017 (dollars in thousands):

	Three Months Ended June 30,						Six Months Ended June 30,					
	2018			2017 (As Adjusted) (1)			2018			2017 (As Adjusted) (1)		
Revenue:												
Property management	$2,106	11.4	%	$3,098	18.3	%	$3,661	8.8	%	$5,008	16.1	%
Leasing	839	4.6	%	26	0.1	%	959	2.3	%	180	0.6	%
Capital Markets:												
Sales	—	0.0	%	165	1.0	%	418	1.0	%	695	2.2	%
Other:												
Development services	15,463	84.0	%	13,677	80.6	%	36,695	87.9	%	25,300	81.1	%

Total revenue	18,408	100.0 %	16,966	100.0 %	41,733	100.0 %	31,183	100.0%
Costs and expenses:								
Operating, administrative and other	60,269	327.4 %	47,497	280.0 %	97,361	233.3 %	68,614	220.0%
Depreciation and amortization	183	1.0 %	543	3.2 %	613	1.5 %	1,088	3.5 %
Gain on disposition of real estate	12,311	66.9 %	11,298	66.6 %	12,329	29.6 %	12,683	40.6 %
Operating loss	(29,733)	(161.5%)	(19,776)	(116.6%)	(43,912)	(105.2%)	(25,836)	(82.9 %)
Equity income from unconsolidated subsidiaries	85,753	465.8 %	65,444	385.8 %	120,626	289.0 %	74,379	238.6%
Less: Net income (loss) attributable to non-controlling interests	530	2.9 %	(5)	0.0 %	208	0.5 %	53	0.2 %
Add-back: Depreciation and amortization	183	1.0 %	543	3.2 %	613	1.5 %	1,088	3.5 %
EBITDA and Adjusted EBITDA	$55,673	302.4 %	$46,216	272.4 %	$77,119	184.8 %	$49,578	159.0%

(1) We adopted new revenue recognition guidance in the first quarter of 2018. Certain restatements have been made to the 2017 financial statements to conform with the 2018 presentation. See Notes 2 and 3 of the Notes to Consolidated Financial Statements (Unaudited) set forth in Item 1 of this Quarterly Report for more information.

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Three Months Ended June 30, 2018 Compared to the Three Months Ended June 30, 2017

Revenue increased by $1.4 million, or 8.5%, for the three months ended June 30, 2018 as compared to the three months ended June 30, 2017, primarily driven by higher development fees during the three months ended June 30, 2018.

Operating, administrative and other expenses increased by $12.8 million, or 26.9%, for the three months ended June 30, 2018 as compared to the same period in 2017. This increase was primarily driven by higher payroll-related costs, particularly increased bonus expense during the three months ended June 30, 2018 due to improved performance (property sales reflected in equity income from unconsolidated subsidiaries were significantly higher during the three months ended June 30, 2018).

As of June 30, 2018, development projects in process totaled $8.0 billion, up $0.3 billion from first quarter 2018. The pipeline decreased by $0.2 billion during the second quarter of 2018.

Six Months Ended June 30, 2018 Compared to the Six Months Ended June 30, 2017

Revenue increased by $10.6 million, or 33.8%, for the six months ended June 30, 2018 as compared to the six months ended June 30, 2017, primarily driven by higher development and incentive fees during the six months ended June 30, 2018.

Operating, administrative and other expenses increased by $28.7 million, or 41.9%, for the six months ended June 30, 2018 as compared to the same period in 2017. This increase was primarily driven by higher payroll-related costs, particularly increased bonus expense during the six months ended June 30, 2018 due to improved performance (property sales reflected in equity income from unconsolidated subsidiaries were significantly higher during the six months ended June 30, 2018).

Liquidity and Capital Resources

We believe that we can satisfy our working capital and funding requirements with internally generated cash flow and, as necessary, borrowings under our revolving credit facility. Our expected capital requirements for 2018 include up to approximately $190 million of anticipated capital expenditures, net of tenant concessions. During the six months ended June 30, 2018, we incurred $91.4 million of capital expenditures, net of tenant concessions received. As of June 30, 2018, we had aggregate commitments of $36.5 million to fund future co-investments in our Global Investment Management business, $14.2 million of which is expected to be funded in 2018. Additionally, as of June 30, 2018, we are committed to fund $23.5 million of additional capital to unconsolidated subsidiaries within our Development Services business, which we may be required to fund at any time. As of June 30, 2018, we had $2.2 billion of borrowings available under our $2.8 billion revolving credit facility.

We have historically relied on our internally generated cash flow and our revolving credit facility to fund our working capital, capital expenditure and general investment requirements (including strategic in-fill acquisitions) and have not sought other external sources of financing to help fund these requirements. In the absence of extraordinary events or a large strategic acquisition, we anticipate that our cash flow from operations and our revolving credit facility would be sufficient to meet our anticipated cash requirements for the foreseeable future, and at a minimum for the next 12 months. We may seek to take advantage of market opportunities to refinance existing debt instruments, as we have done in the past, with new debt instruments at interest rates, maturities and terms we deem attractive. We may also, from time to time in our sole discretion, purchase, redeem, or retire our existing senior notes, through tender offers, in privately negotiated or open market transactions, or otherwise.

In March 2018, we redeemed the $800.0 million aggregate outstanding principal amount of our 5.00% senior notes in full. We funded this redemption with $550.0 million of borrowings from our tranche A term loan facility and borrowings from our revolving credit facility under our credit agreement.

As noted above, we believe that any future significant acquisitions that we may make could require us to obtain additional debt or equity financing. In the past, we have been able to obtain such financing for material transactions on terms that we believed to be reasonable. However, it is possible that we may not be able to obtain acquisition financing on favorable terms, or at all, in the future if we decide to make any further significant acquisitions.

Our long-term liquidity needs, other than those related to ordinary course obligations and commitments such as operating leases, are generally comprised of two elements. The first is the repayment of the outstanding and anticipated principal amounts of our long-term indebtedness. We are unable to project with certainty whether our long-term cash flow from operations will be sufficient to repay our long-term debt when it comes due. If our cash flow is insufficient, then we expect that we would need to refinance such indebtedness or otherwise amend its terms to extend the maturity dates. We cannot make any assurances that such refinancing or amendments would be available on attractive terms, if at all.

The second long-term liquidity need is the payment of obligations related to acquisitions. Our acquisition structures often include deferred and/or contingent purchase price payments in future periods that are subject to the passage of time or achievement of certain performance metrics and other conditions. As of June 30, 2018 and December 31, 2017, we had accrued $88.2 million ($49.5 million of which was a current liability) and $83.6 million ($23.2 million of which was a current liability), respectively, of deferred purchase consideration, which was included in accounts payable and accrued expenses and in other long-term liabilities in the accompanying consolidated balance sheets set forth in Item 1 of this Quarterly Report.

In addition, on October 27, 2016, we announced that our board of directors had authorized the company to repurchase up to an aggregate of $250.0 million of our Class A common stock over three years. The timing of the repurchase and the actual amount repurchased will depend on a variety of factors, including the market price of our common stock, general market and economic conditions and other factors. We intend to fund the repurchases, if any, with cash on hand or borrowings under our revolving credit facility. As of June 30, 2018, the authorization remained unused.

Historical Cash Flows

Operating Activities

Net cash used in operating activities totaled $92.1 million for the six months ended June 30, 2018, a decrease of $25.4 million as compared to the six months ended June 30, 2017. The decrease in net cash used in operating activities was primarily due to improved operating performance as well as a higher distribution of earnings from unconsolidated subsidiaries in the current year.

Investing Activities

Net cash used in investing activities totaled $376.6 million for the six months ended June 30, 2018, an increase of $282.6 million as compared to the six months ended June 30, 2017. The increase in cash used in investing activities was primarily driven by higher amounts paid for acquisitions driven by the FacilitySource Acquisition in the six months ended June 30, 2018.

Financing Activities

Net cash provided by financing activities totaled $266.0 million for the six months ended June 30, 2018, as compared to net cash used in financing activities of $29.7 million for the six months ended June 30, 2017. This variance was primarily due to $550.0 million of borrowings from our tranche A term loan facility as well as higher net borrowings under our revolving credit facility during the six months ended June 30, 2018. These items were largely offset by the full redemption of the $800.0 million aggregate outstanding principal amount of our 5.00% senior notes (including premium) as well as the repayment of $26.3 million of debt assumed in the FacilitySource Acquisition in the current year.

Indebtedness

Our level of indebtedness increases the possibility that we may be unable to pay the principal amount of our indebtedness and other obligations when due. In addition, we may incur additional debt from time to time to finance strategic acquisitions, investments, joint ventures or for other purposes, subject to the restrictions contained in the documents governing our indebtedness. If we incur additional debt, the risks associated with our leverage, including our ability to service our debt, would increase.

Long-Term Debt

We maintain credit facilities with third-party lenders, which we use for a variety of purposes. On October 31, 2017, CBRE Services, Inc. entered into a Credit Agreement (the 2017 Credit Agreement), which refinanced and replaced our prior credit agreement (the 2015 Credit Agreement). We used $200.0 million of borrowings from the tranche A term loan facility and $83.0 million of revolving credit facility borrowings under the 2017 Credit Agreement, in addition to cash on hand, to repay all amounts outstanding under the 2015 Credit Agreement.

The 2017 Credit Agreement is a senior unsecured credit facility that is jointly and severally guaranteed by us and certain of our subsidiaries. The 2017 Credit Agreement currently provides for the following: (1) a $2.8 billion revolving credit facility, which includes the capacity to obtain letters of credit and swingline loans and matures on October 31, 2022 and (2) a $750.0 million delayed draw tranche A term loan facility, requiring quarterly principal payments, which began on March 5, 2018 and continue through maturity on October 31, 2022, provided that in the event that our leverage ratio (as defined in the 2017 Credit Agreement) is less than or equal to 2.50 to 1.00 on the last day of the fiscal quarter immediately preceding any such payment date, no such quarterly principal payment shall be required on such date.

As previously mentioned, in March 2018, we redeemed the $800.0 million aggregate outstanding principal amount of our 5.00% senior notes in full. In connection with this early redemption, we incurred charges of $28.0 million, including a premium of $20.0 million and the write-off of $8.0 million of unamortized deferred financing costs.

In prior years, we also issued 4.875% and 5.25% senior notes that are due in 2026 and 2025, respectively. For additional information on all of our long-term debt, see Note 11 of the Notes to Consolidated Financial Statements set forth in Item 8 included in our Annual Report on Form 10 K for the year ended December 31, 2017 and Note 9 of the Notes to Consolidated Financial Statements (Unaudited) set forth in Item 1 of this Quarterly Report.

Short-Term Borrowings

We maintain a $2.8 billion revolving credit facility under the 2017 Credit Agreement and warehouse lines of credit with certain third-party lenders. For additional information on all of our short-term borrowings, see Note 11 of the Notes to Consolidated Financial Statements set forth in Item 8 included in our Annual Report on Form 10 K for the year ended December 31, 2017 and Notes 5 and 9 of the Notes to Consolidated Financial Statements (Unaudited) set forth in Item 1 of this Quarterly Report.

Interest Rate Swap Agreements

In March 2011, we entered into five interest rate swap agreements, all with effective dates in October 2011, and immediately designated them as cash flow hedges in accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Topic 815, “Derivatives and Hedging.” The purpose of these interest rate swap agreements is to attempt to hedge potential changes to our cash flows due to the variable interest nature of our senior term loan facilities. A notional amount of $200.0 million of these interest rate swap agreements expired in

October 2017. The remaining total notional amount of these interest rate swap agreements at June 30, 2018 was $200.0 million, which expire in September 2019. As of June 30, 2018 and December 31, 2017, the fair values of such interest rate swap agreements were reflected as a $2.1 million liability and a $4.8 million liability, respectively, and were included in other long-term liabilities in the accompanying consolidated balance sheets set forth in Item 1 of this Quarterly Report.

In July 2015, we entered into three interest rate swap agreements with an aggregate notional amount of $300.0 million, all with effective dates in August 2015, and designated them as cash flow hedges in accordance with FASB ASC Topic 815. In August 2015, we elected to terminate these agreements and paid a $6.2 million cash settlement, which has been recorded to accumulated other comprehensive loss in the accompanying consolidated balance sheets set forth in Item 1 of this Quarterly Report. This settlement fee is being amortized to interest expense throughout the remaining term of the terminated hedge transaction until August 2025.

Off –Balance Sheet Arrangements

Our off-balance sheet arrangements are described in Note 10 of the Notes to Consolidated Financial Statements (Unaudited) set forth in Item 1 of this Quarterly Report and are incorporated by reference herein.

Cautionary Note on Forward-Looking Statements

This Quarterly Report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act. The words “anticipate,” “believe,” “could,” “should,” “propose,” “continue,” “estimate,” “expect,” “intend,” “m “predict,” “project,” “will” and similar terms and phrases are used in this Quarterly Report to identify forward-looking statements. Except for historical information contained herein, the matters addressed in this Quarterly Report are forward-looking statements. These statements relate to analyses and other information based on forecasts of future results and estimates of amounts not yet determinable. These statements also relate to our future prospects, developments and business strategies.

These forward-looking statements are made based on our management’s expectations and beliefs concerning future events affecting us and are subject to uncertainties and factors relating to our operations and business environment, all of which are difficult to predict and many of which are beyond our control. These uncertainties and factors could cause our actual results to differ materially from those matters expressed in or implied by these forward-looking statements.

The following factors are among those, but are not only those, that may cause actual results to differ materially from the forward-looking statements:

- disruptions in general economic and business conditions, particularly in geographies where our business may be concentrated;
- volatility and disruption of the securities, capital and credit markets, interest rate increases, the cost and availability of capital for investment in real estate, clients’ willingness to make real estate or long-term contractual commitments and other factors affecting the value of real estate assets, inside and outside the United States;
- increases in unemployment and general slowdowns in commercial activity;
- trends in pricing and risk assumption for commercial real estate services;
- the effect of significant movements in average cap rates across different property types;
  - a reduction by companies in their reliance on outsourcing for their commercial real estate needs, which would affect our revenues and operating performance;
- client actions to restrain project spending and reduce outsourced staffing levels;
- declines in lending activity of U.S. Government Sponsored Enterprises, regulatory oversight of such activity and our mortgage servicing revenue from the commercial real estate mortgage market;
- our ability to diversify our revenue model to offset cyclical economic trends in the commercial real estate industry;
- our ability to attract new user and investor clients;
- our ability to retain major clients and renew related contracts;

- our ability to leverage our global services platform to maximize and sustain long-term cash flow;
- our ability to maintain EBITDA and adjusted EBITDA margins that enable us to continue investing in our platform and client service offerings;
- our ability to control costs relative to revenue growth;
- economic volatility and market uncertainty globally related to uncertainty surrounding the implementation and effect of the United Kingdom's referendum to leave the European Union, including uncertainty in relation to the legal and regulatory framework that would apply to the United Kingdom and its relationship with the remaining members of the European Union;
- foreign currency fluctuations;
- our ability to retain and incentivize key personnel;
- our ability to compete globally, or in specific geographic markets or business segments that are material to us;
- our ability to identify, acquire and integrate synergistic and accretive businesses;
- costs and potential future capital requirements relating to businesses we may acquire;
- integration challenges arising out of companies we may acquire;
- the ability of our Global Investment Management business to maintain and grow assets under management and achieve desired investment returns for our investors, and any potential related litigation, liabilities or reputational harm possible if we fail to do so;
- our ability to manage fluctuations in net earnings and cash flow, which could result from poor performance in our investment programs, including our participation as a principal in real estate investments;
- our leverage under our debt instruments as well as the limited restrictions therein on our ability to incur additional debt, and the potential increased borrowing costs to us from a credit-ratings downgrade;
- the ability of CBRE Capital Markets to periodically amend, or replace, on satisfactory terms, the agreements for its warehouse lines of credit;
- variations in historically customary seasonal patterns that cause our business not to perform as expected;
- litigation and its financial and reputational risks to us;
- our exposure to liabilities in connection with real estate advisory and property management activities and our ability to procure sufficient insurance coverage on acceptable terms;
- liabilities under guarantees, or for construction defects, that we incur in our Development Services business;
- our and our employees' ability to execute on, and adapt to, information technology strategies and trends;
- cybersecurity threats, including the potential misappropriation of assets or sensitive information, corruption of data or operational disruption;
- changes in domestic and international law and regulatory environments (including relating to anti-corruption, anti-money laundering, trade sanctions, tariffs, currency controls and other trade control laws), particularly in Russia, Eastern Europe and the Middle East, due to the level of political instability in those regions;
- our ability to comply with laws and regulations related to our global operations, including real estate licensure, tax, labor and employment laws and regulations, as well as the anti-corruption laws and trade sanctions of the U.S. and other countries;
- our ability to maintain our effective tax rate, including during 2018 as we continue to assess the provisional amount recorded based upon our best estimate of the tax impact of the Tax Act (which was

enacted into law on December 22, 2017) in accordance with our understanding of the Tax Act and the related guidance available;

- changes in applicable tax or accounting requirements, including the impact of any subsequent additional regulation or guidance associated with the Tax Act;
- the effect of implementation of new accounting rules and standards (including new lease accounting guidance which will be effective in the first quarter of 2019); and
- the other factors described elsewhere in this Quarterly Report on Form 10-Q, included under the headings "Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies," "Quantitative and Qualitative Disclosures About Market Risk" and Part II, Item 1A, "Risk Factors" or as described in our Annual Report on Form 10-K for the year ended December 31, 2017, in particular in Part II, Item 1A "Risk Factors", or as described in the other documents and reports we file with the Securities and Exchange Commission (SEC).

Forward-looking statements speak only as of the date the statements are made. You should not put undue reliance on any forward-looking statements. We assume no obligation to update forward-looking statements to reflect actual results, changes in assumptions or changes in other factors affecting forward-looking information, except to the extent required by applicable securities laws. If we do update one or more forward-looking statements, no inference should be drawn that we will make additional updates with respect to those or other forward-looking statements. Additional information concerning these and other risks and uncertainties is contained in our other periodic filings with the SEC.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The information in this section should be read in connection with the information on market risk related to changes in interest rates and non-U.S. currency exchange rates in Part II, Item 7A, "Quantitative and Qualitative Disclosures About Market Risk" in our Annual Report on Form 10-K for the year ended December 31, 2017.

Our exposure to market risk primarily consists of foreign currency exchange rate fluctuations related to our international operations and changes in interest rates on debt obligations. We manage such risk primarily by managing the amount, sources, and duration of our debt funding and by using derivative financial instruments. We apply Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Topic 815, "Derivatives and Hedging," when accounting for derivative financial instruments. In all cases, we view derivative financial instruments as a risk management tool and, accordingly, do not use derivatives for trading or speculative purposes.

Exchange Rates

Our foreign operations expose us to fluctuations in foreign exchange rates. These fluctuations may impact the value of our cash receipts and payments in terms of our functional (reporting) currency, which is U.S. dollars. See the discussion of international operations, which is included in Item 2. "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Items Affecting Comparability—International Operations" and is incorporated by reference herein.

Interest Rates

We manage our interest expense by using a combination of fixed and variable rate debt. We enter into interest rate swap agreements to attempt to hedge the variability of future interest payments due to changes in interest rates. See discussion of our interest rate swap agreements, which is included in Item 2. "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Liquidity and Capital Resources—Indebtedness—Interest Rate Swap Agreements" and is incorporated by reference herein.

The estimated fair value of our senior term loans was approximately $742.5 million at June 30, 2018. Based on dealers' quotes, the estimated fair values of our 4.875% senior notes and 5.25% senior notes were $622.5 million and

$447.0 million, respectively, at June 30, 2018.

We utilize sensitivity analyses to assess the potential effect of our variable rate debt. If interest rates were to increase 100 basis points on our outstanding variable rate debt at June 30, 2018, excluding notes payable on real estate, the net impact of the additional interest cost would be a decrease of $5.7 million on pre-tax income and an increase of $5.7 million in cash used in operating activities for the six months ended June 30, 2018.

Item 4. Controls and Procedures
Disclosure Controls and Procedures

Rule 13a-15 of the Securities and Exchange Act of 1934, as amended, requires that we conduct an evaluation of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this Quarterly Report, and we have a disclosure policy in furtherance of the same. This evaluation is designed to ensure that all corporate disclosure is complete and accurate in all material respects. The evaluation is further designed to ensure that all information required to be disclosed in our SEC reports is accumulated and communicated to management to allow timely decisions regarding required disclosures and recorded, processed, summarized and reported within the time periods and in the manner specified in the SEC's rules and forms. Any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives. Our Chief Executive Officer and Chief Financial Officer supervise and participate in this evaluation, and they are assisted by our Chief Accounting Officer and other members of our Disclosure Committee. In addition to our Chief Accounting Officer, our Disclosure Committee consists of our General Counsel, our Chief Digital and Technology Officer, our chief communication officer, our corporate controller, our head of Global SOX Assurance, our senior officers of significant business lines and other select employees.

We conducted the required evaluation, and our Chief Executive Officer and Chief Financial Officer have concluded that our disclosure controls and procedures (as defined by Securities Exchange Act Rule 13a-15(e)) were effective as of June 30, 2018 to accomplish their objectives at the reasonable assurance level.

Changes in Internal Control Over Financial Reporting

No changes in our internal control over financial reporting occurred during the fiscal quarter ended June 30, 2018 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings
There have been no material changes to our legal proceedings as previously disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2017.

Item 1A. Risk Factors
There have been no material changes to our risk factors as previously disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2017.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds
As permitted by our director compensation policy, two of our non-employee directors elected to receive shares of our Class A common stock as consideration for their service as directors in lieu of cash payments during the three months ended June 30, 2018. Director fees are allocated in quarterly installments, and the non-employee directors participating in the "stock in lieu of cash" program were issued 64 shares on May 7, 2018 in lieu of $3,000 in accrued director fees. The number of shares issued was based on the closing price on the NYSE of our Class A common stock on the date of issuance. The issuance of these securities qualified for an exemption from registration under the Securities Act of 1933, as amended, or the Securities Act, pursuant to Section 4(a)(2) of the Securities Act because the

issuance did not involve a public offering.

Item 6. Exhibits

Exhibit No.	Exhibit Description	Incorporated by Reference Form	SEC File No.	Exhibit	Filing Date	Filed Herewith
3.1	Amended and Restated Certificate of Incorporation of CBRE Group, Inc.	8-K	001-32205	3.1	05/23/2018	
3.2	Amended and Restated By-Laws of CBRE Group, Inc.	8-K	001-32205	3.2	05/23/2018	
11	Statement concerning Computation of Per Share Earnings (filed as Note 11 of the Consolidated Financial Statements)					X
31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, as adopted pursuant to §302 of the Sarbanes-Oxley Act of 2002					X
31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, as adopted pursuant to §302 of the Sarbanes-Oxley Act of 2002					X
32	Certifications of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002					X
101.INS	XBRL Instance Document					X
101.SCH	XBRL Taxonomy Extension Schema Document					X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document					X
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document					X
101.LAB	XBRL Taxonomy Extension Label Linkbase Document					X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document					X

[Remainder of this page intentionally left blank.]

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

		CBRE GROUP, INC.
Date:	August 9, 2018	/s/ James R. Groch James R. Groch Chief Financial Officer (Principal Financial Officer)
Date:	August 9, 2018	/s/ Dara A. Bazzano Dara A. Bazzano Chief Accounting Officer (Principal Accounting Officer)