KEY ENERGY SERVICES INC
Form 10-KT/A
April 10, 2003

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# UNITED STATES
# SECURITIES AND EXCHANGE COMMISSION

**Washington, D.C. 20549**

# FORM 10-K/A
# Amendment No. 1

**(Mark One)**

o **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the fiscal year ended ______________**

**or**

ý **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the transition period from July 1, 2002 to December 31, 2002**
**Commission file number 1-8038**

# KEY ENERGY SERVICES, INC.

(Exact name of registrant as specified in its charter)

| | |
|---|---|
| **Maryland** | **04-2648081** |
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |
| **6 Desta Drive, Midland, Texas** | **79705** |
| (Address of principal executive offices) | (Zip Code) |

Registrant's telephone number, including area code: **(915) 620-0300**

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

| Title of Each Class | Name of Each Exchange on Which Registered |
|---|---|
| Common Stock, $.10 par value | New York Stock Exchange |

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

5% Convertible Subordinated Notes Due 2004

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the past 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 ý No o

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. ý

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

The aggregate market value of the Common Shares held by nonaffiliates of the Registrant as of April 9, 2003 was approximately $1,136,543,362.

Common Shares outstanding at April 9, 2003: 128,475,639

DOCUMENTS INCORPORATED BY REFERENCE: Portions of the Proxy Statement with respect to the Annual Meeting of Shareholders for the fiscal year ended June 30, 2002 and the six months ended December 31, 2002 are incorporated by reference in Part III of this report.

**Key Energy Services, Inc.**

**INDEX**

## SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

The statements in this document that relate to matters that are not historical facts are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. When used in this document and the documents incorporated by reference, words such as "anticipate," "believe," "expect," "plan," "intend," "estimate," "project," "will," "could," "may," "predict" and similar expressions are intended to identify forward-looking statements. Further events and actual results may differ materially from the results set forth in or implied in the forward-looking statements. Factors that might cause such a difference include:

- fluctuations in world-wide prices and demand for oil and natural gas;
- fluctuations in level of oil and natural gas exploration and development activities;
- fluctuations in the demand for well servicing, contract drilling and ancillary oilfield services;
- the existence of competitors, technological changes and developments in the industry;
- the existence of operating risks inherent in the well servicing, contract drilling and ancillary oilfield services; and
- general economic conditions, the existence of regulatory uncertainties, and the possibility of political instability in any of the countries in which Key does business, in addition to other matters discussed under "Part II Item 7 Management's Discussion and Analysis of Results of Operations and Financial Condition."

These forward looking-statements speak only as of the date of this report and Key disclaims any duty or obligation to update the forward looking statement in this report.

## PART I

### ITEM 1. BUSINESS.

### THE COMPANY

Based on the number of rigs owned and available industry data, Key Energy Services, Inc. (the "Company" or "Key"), is the largest onshore, rig-based well servicing contractor in the world, with approximately 1,489 well service rigs and 2,295 oilfield service vehicles as of December 31, 2002. Key provides a complete range of well services to major oil companies and independent oil and natural gas production companies, including: rig-based well maintenance, workover, completion, and recompletion services (reentering a well to complete the well in a new zone or formation) (including horizontal recompletions); well intervention services; oilfield trucking services; and ancillary oilfield services. Key conducts well servicing operations onshore the continental United States in the following regions: Gulf Coast (including South Texas, Central Gulf Coast of Texas and South Louisiana), Permian Basin of West Texas and Eastern New Mexico, Mid-Continent (including the Anadarko, Hugoton and Arkoma Basins, Fort Worth Basin and the ArkLaTex region), Four Corners (including the San Juan, Piceance, Uinta, and Paradox Basins), Eastern (including the Appalachian, Michigan and Illinois Basins), Rocky Mountains (including the Denver-Julesberg, Powder River, Wind River, Green River and Williston Basins), and California (the San Joaquin Basin), and internationally in Argentina, Egypt and Canada (Ontario). Based on the number of rigs owned and available industry data, Key is also a leading onshore drilling contractor, with approximately 79 land drilling rigs as of December 31, 2002. Key conducts land drilling operations in a number of major domestic producing basins, as well as in Argentina and in Canada (Ontario). Key also produces and develops oil and natural gas reserves in the Permian Basin region and Texas Panhandle.

Key's principal executive office is located at 6 Desta Drive, Midland, Texas 79705. Key's phone number is (915) 620-0300 and its website address is *www.keyenergy.com*. Key makes available free of charge



through its website its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with the Securities and Exchange Commission. Information on Key's website is not a part of this report.

## BUSINESS STRATEGY

Key has built its leadership position through the acquisition and consolidation of smaller, regional competitors. This consolidation of assets and employees, together with a continuing decline in the number of available domestic well service rigs due to attrition, cannibalization and transfers outside of the United States, has given Key the opportunity to strengthen its position within the industry during the year ended June 30, 2002 and the six-month period ended December 31, 2002. Key has focused on maximizing results by reducing debt, building strong customer alliances, refurbishing rigs and related equipment, and training personnel to maintain a qualified and safe employee base.

*Reducing Debt.* An important element of Key's long-term business strategy is to reduce its debt and strengthen its balance sheet by repaying debt using a portion of available operating cash flow and by restructuring its debt to minimize cash interest expense and restructure debt maturities. Since March 1999, Key has reduced its long-term funded debt net of cash ("net funded debt") and its net funded debt to capitalization ratio from approximately $839 million and 87.5%, respectively, to approximately $485 million and 41.0%, respectively, as of December 31, 2002. In addition, during the six-month period ended December 31, 2002, Key restructured its senior credit facility in order to increase its borrowing capacity with a minimal effect on interest expense. Key expects to to be able to continue to reduce debt and strengthen its balance sheet in the future.

*Building Strong Customer Alliances.* Key seeks to maximize customer satisfaction by offering a broad range of equipment and services combined with a highly trained and motivated labor force. As a result, Key is able to offer proactive solutions for most of its customer's wellsite needs. Key ensures consistent high standards of quality and customer satisfaction by continually evaluating its performance. Key maintains strong alliances with major oil companies as well as numerous independent oil and natural gas production companies and believes that such alliances improve the stability of demand for its oilfield services.

*Remanufacturing Rigs and Related Equipment.* Key intends to continue actively remanufacturing its rigs and related equipment to maximize the utilization of its rig fleet. The Company believes that it has adequate cash flow and resources necessary to continue to make the capital expenditures required to continue its remanufacturing program.

*Training and Developing Employees.* Key has, and will continue to, devote significant resources to the training and professional development of its employees with a special emphasis on safety. Key currently has two training centers in Texas, one training center in New Mexico and one training center in California to improve its employees' understanding of operating and safety procedures. Key recognizes the historically high turn-over rate in the industry and is committed to offering compensation, benefits and incentive programs for its employees that are attractive and competitive in its industry, in order to ensure a steady stream of qualified, safety-conscious personnel to provide quality service to its customers.

## DEVELOPMENTS DURING AND SUBSEQUENT TO THE SIX MONTHS ENDED DECEMBER 31, 2002

### CHANGE IN FISCAL YEAR END

In December 2002, the Company's Board of Directors approved the Company's change of its fiscal year end from June 30 to December 31 of each year. As a result, this report covers the transition period from July 1, 2002 through December 31, 2002 (referred to as "the six month period ended December 31, 2002" or the "Transition Period").

**INDUSTRY CONDITIONS**

During the Transition Period, operating conditions improved modestly; however, demand for services remained comparatively weak given the underlying strength of commodity prices and the historical relationship between commodity prices and activity levels. Although WTI Cushing prices for light sweet crude averaged approximately $28.49 per barrel during the Transition Period and Nymex Henry Hub natural gas prices averaged approximately $3.76 per MMbtu during the Transition Period, as compared to an average WTI Cushing price for light sweet crude of $23.81 per barrel and an average Nymex Henry Hub natural gas price of $2.77 per MMbtu during the fiscal year ended June 30, 2002, the Company did not experience a corresponding increase in its well servicing business. The Company believes the causes for this disparity include: (i) high natural gas inventories at the beginning of the Transition Period, which may have caused some of Key's customers to question the sustainability of the then current high natural gas price; (ii) negative impact on customers' hedging positions caused by the financial collapse of dominant counter-parties such as Enron and Dynegy; (iii) limited access to the capital markets for small to mid-size independents oil and natural gas production companies for development projects; (iv) focus by customers on use of cash flow for debt reduction or share repurchase programs; (iv) uncertainty over the war in Iraq and political instability in the Middle East; and (v) overall concern about the U.S. and world economies.

Management believes that the current natural gas supply and storage conditions combined with declining U.S. natural gas production will eventually lead to increased demand for natural gas drilling. Furthermore, the Company believes that oilfield service activity, including well servicing, oilfield trucking and land drilling, tends to lag its customers' cash flows by several quarters which would imply that activity could improve during the later part of 2003.

The level of Key's revenues, cash flows, losses and earnings are substantially dependent upon, and affected by, the level of domestic and international oil and gas exploration and development activity (See Part II Item 7 Management's Discussion and Analysis of Results of Operations and Financial Condition).

**ACQUISITIONS**

*Q Services, Inc.* On July 19, 2002, Key acquired QSI pursuant to an Agreement and Plan of Merger dated May 13, 2002, as amended, by and among Key, Key Merger Sub, Inc. and QSI. As consideration for the acquisition, the Company issued approximately 17.1 million shares of its common stock to the QSI shareholders and paid approximately $94.2 million in cash at the closing to retire debt and preferred stock of QSI and to satisfy certain other obligations of QSI. In addition to assuming the positive working capital of QSI, the Company incurred other direct acquisition costs and assumed certain other liabilities of QSI, resulting in the Company recording an aggregate purchase price of approximately $250 million. The value of the shares issued was based on the closing price of the Key common stock on the closing date of $8.75 per share. The results of QSI's operations have been included in the consolidated financial statements since the closing date. Prior to the acquisition, QSI was a privately held corporation conducting field production, pressure pumping and other service operations in Louisiana, New Mexico, Oklahoma, Texas and the Gulf of Mexico. The Company and QSI operated in adjacent and/or overlapping locations and expect to realize future cost savings and synergies in connection with the merger. The combination of the companies formed one of the largest oilfield trucking fleets in the United States complementing the Company's well service rig fleet, which based on the number of rigs owned and available industry data, is the largest in the world.

*Other Acquisitions.* During the Transition Period, the Company completed several small acquisitions for total consideration of $15,620,000, which consisted of a combination of cash, a deferred non-compete



payment and shares of the Company's common stock. Other than QSI, none of the other acquisitions completed in the Transition Period were material individually or in the aggregate, thus the pro forma effect of these acquisitions is not presented. Each of the acquisitions was accounted for using the purchase method and the results of the operations generated from the acquired assets are included in the Company's results of operations as of the completion date of each acquisition.

**NEW SENIOR CREDIT FACILITY**

On July 15, 2002, the Company entered into a Third Amended and Restated Credit Agreement, as amended by the First Amendment to the Third Amended and Restated Credit Agreement (the "Senior Credit Facility"). The Senior Credit Facility consists of a $150,000,000 revolving loan facility with a $75,000,000 sublimit for letters of credit. The loans are secured by most of the tangible and intangible assets of the Company. The revolving loan commitment will terminate on July 15, 2005 and all revolving loans must be paid on or before that date. The revolving loans bear interest based upon, at the Company's option, the prime rate plus a variable margin of 0.00% to 1.00% or a Eurodollar rate plus a variable margin of 1.75% to 3.00%. The Senior Credit Facility has customary affirmative and negative covenants including maximum leverage ratios, a minimum fixed charge coverage ratio and a minimum net worth, as well as limitations on liens and indebtedness and restrictions on dividends, acquisitions and dispositions.

## DESCRIPTION OF BUSINESS SEGMENTS

Key operates in two primary business segments, which are well servicing and contract drilling. Key's operations are conducted domestically and internationally in Argentina, Egypt and Canada. The following is a description of each of these business segments (for financial information regarding these business segments, see Note 13 to Consolidated Financial Statements Business Segment Information).

### WELL SERVICING

Key provides a full range of well services, including rig-based services, oilfield trucking services, well intervention services and other ancillary oilfield services necessary to maintain and workover oil and natural gas producing wells. Rig-based services include: maintenance of existing wells, workovers of existing wells, completion of newly drilled wells, recompletion of existing wells (including horizontal recompletions) and plugging and abandonment of wells at the end of their useful lives. Well intervention services include fishing and rental tool services and pressure pumping services.

#### Well Service Rigs

Key uses its well service rig fleet to perform four major categories of rig services for oil and natural gas producers.

*Maintenance Services.* Key provides the well service rigs, equipment and crews for maintenance services, which are performed on both oil and natural gas wells, but which are more commonly required on oil wells. While some oil wells in the United States flow oil to the surface without mechanical assistance, most require pumping or some other method of artificial lift. Oil wells that require pumping characteristically require more maintenance than flowing wells due to the operation of the mechanical pumping equipment. Few natural gas wells have mechanical pumping systems in the wellbore, and, as a result, maintenance work on natural gas wells is less frequent.

Maintenance services are required throughout the life of most producing oil and natural gas wells to ensure efficient and continuous operation. These services consist of routine mechanical repairs necessary to maintain production from the well, such as repairing inoperable pumping equipment in an oil well or replacing defective tubing in an oil or natural gas well, and removing debris such as sand and paraffin from the well. Other services include pulling the rods, tubing, pumps and other downhole equipment out of the wellbore to identify and repair a production problem.



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Maintenance services are often performed on a series of wells in proximity to each other and typically require less than 48 hours per well to complete. The general demand for maintenance services is closely related to the total number of producing oil and natural gas wells in a geographic market, and maintenance services are generally the most stable type of well service activity.

*Workover Services.* In addition to periodic maintenance, producing oil and natural gas wells occasionally require major repairs or modifications, called "workovers." Workover services are performed to enhance the production of existing wells. Such services include extensions of existing wells to drain new formations either through deepening wellbores to new zones or by drilling horizontal lateral wellbores to improve reservoir drainage patterns. In less extensive workovers, Key's rigs are used to seal off depleted zones in existing wellbores and access previously bypassed productive zones. Key's workover rigs are also used to convert former producing wells to injection wells through which water or carbon dioxide is pumped into the formation for enhanced recovery operations. Other workover services include: major subsurface repairs such as casing repair or replacement, recovery of tubing and removal of foreign objects in the wellbore, repairing downhole equipment failures, plugging back the bottom of a well to reduce the amount of water being produced with the oil and natural gas, cleaning out and recompleting a well if production has declined, and repairing leaks in the tubing and casing. These extensive workover operations are normally performed by a well service rig with a workover package, which may include rotary drilling equipment, mud pumps, mud tanks and blowout preventers depending upon the particular type of workover operation. Most of Key's well service rigs are designed for and can be equipped to perform complex workover operations.

Workover services are more complex and time consuming than routine maintenance operations and consequently may last from a few days to several weeks. These services are almost exclusively performed by well service rigs.

*Completion Services.* Key's completion services prepare a newly drilled oil or natural gas well for production. The completion process may involve selectively perforating the well casing to access producing zones, stimulating and testing these zones and installing downhole equipment. Key typically provides a well service rig and may also provide other equipment such as a workover package to assist in the completion process. Producers use well service rigs to complete their wells because the rigs have specialized equipment, properly trained employees and the experience necessary to perform these services. However, during periods of weak drilling rig demand, drilling contractors may compete with service rigs for completion work.

The completion process typically requires a few days to several weeks, depending on the nature and type of the completion, and generally requires additional auxiliary equipment that can be provided for an additional fee. The demand for well completion services is directly related to drilling activity levels, which are highly sensitive to expectations relating to, and changes in, oil and natural gas prices. As the number of newly drilled wells decreases, the number of completion jobs correspondingly decreases.

*Plugging and Abandonment Services.* Well service rigs and workover equipment are also used in the process of permanently closing oil and natural gas wells at the end of their productive lives. Plugging and abandonment work can be performed with a well servicing rig along with wireline and cementing equipment. The services generally include the sale or disposal of equipment salvaged from the well as part of the compensation received and require compliance with state regulatory requirements. The demand for oil and natural gas does not significantly affect the demand for plugging and abandonment services, as well operators are required by state regulations to plug a well that it is no longer productive. The need for these services is also driven by lease and/or operator policy requirements.

**Oilfield Trucking**

Upon completion of the acquisition of QSI, Key had substantially expanded its liquid/vacuum truck services and fluid transportation and disposal services for operators whose wells produce saltwater and



other fluids, in addition to oil and natural gas. Of the approximately 2,295 heavy oilfield service vehicles operated by the Company following the acquisition of QSI, the Company operates approximately 1,026 vacuum and transport trucks in the United States. In addition, Key owns approximately 2,968 frac tanks which are used in conjunction with its fluid hauling operations.

Fluid hauling trucks are utilized in connection with drilling and workover projects, which tend to produce and use large amounts of various oilfield fluids. Fluid hauling companies transport fresh water to the well site and provide temporary storage and disposal of produced salt water and drilling/workover fluids. These fluids are picked up at the well site and transported for disposal in a salt water disposal well of which Key owns approximately 130. In addition, Key provides haul/equipment trucks that are used to move large pieces of equipment from one wellsite to the next and operates a fleet of approximately 132 hot oilers, which are capable of heating pumped fluids that may be used to clear restrictions in a wellbore such as paraffin build-up. Demand and pricing for these services are generally related to demand for Key's well service and drilling rigs. Fluid hauling and equipment hauling services are typically priced on a per hour basis while frac tank rentals are typically billed on a per day basis.

**Well Intervention Services**

Through its acquisition of QSI in July 2002, Key significantly expanded its fishing and rental tool operations and added a pressure pumping business.

*Fishing and Rental Tool Services.* Founded in 1993, QSI's fishing and rental tool operation, Quality Tubular Services, Inc. ("QTS"), provides fishing and rental tool services to major and independent oil and natural gas production companies primarily in the Gulf Coast region of the United States. Fishing services involve recovering downhole equipment that has been lost or become trapped in the wellbore and a "fishing tool" is a tool specifically designed to recover that equipment lost or trapped in the well. QTS operates nine 24-hour service locations and four regional sales offices. The fishing tool supervisors have extensive experience with downhole problems. In addition, QTS offers a full line of services and equipment designed for the harsh elements from land to offshore. The rental tool inventory consists of tubulars, handling tools, pressure-control equipment and a fleet of power swivels. Key also provides fishing and rental tools through its Landmark Fishing and Rental Tools operation in the Mid-Continent region and at various other locations throughout the country.

*Pressure Pumping Services.* Key's pressure pumping business operates under the name American Energy Services ("AES"). AES provides stimulation services, cementing services, nitrogen services, hydro-testing and production chemistry services to oil and natural gas producers. Key offers a full complement of acidizing technology, fracturing technology, nitrogen technology and cementing technology services. AES was established in December 1996 and operates in the Permian Basin, the San Juan Basin, and the Mid-Continent Region.

**Ancillary Oilfield Services**

Key provides ancillary oilfield services, which includes: wireline operations (lowering mechanical and electrical tools in the well); well site construction (preparation of a wellsite for drilling activities); roustabout services (coordination of equipment and supplies from an offshore rig to the shore base); foam units (drilling technique using air or gas to which a foaming agent has been added); and air drilling services (drilling technique using compressed air). Demand and pricing for these services are generally related to demand for Key's well service and drilling rigs.

**CONTRACT DRILLING**

Key provides contract drilling services to major oil companies and independent oil and natural gas producers onshore the continental United States in the Permian Basin, the Four Corners region, Michigan, the Northeast, and the Rocky Mountains and internationally in Argentina and Canada (Ontario). Contract



drilling services are primarily provided under standard dayrate, and, to a lesser extent, footage or turnkey contracts. Drilling rigs vary in size and capability and may include specialized equipment. The majority of Key's drilling rigs are equipped with mechanical power systems and have depth ratings ranging from approximately 4,500 to 12,000 feet. Key has one drilling rig with a depth rating of approximately 18,000 feet. Like workover services, the demand for contract drilling is directly related to expectations relating to, and changes in, oil and natural gas prices which in turn, are driven by the supply of and demand for these commodities.

**FOREIGN OPERATIONS**

Key also operates each of its business segments discussed above in Argentina, Canada (Ontario) and Egypt. Key's foreign operations currently own approximately 25 well servicing rigs, 75 oilfield trucks and seven drilling rigs in Argentina, four well servicing rigs, four oilfield trucks and two drilling rigs in Ontario, Canada and five well servicing rigs and 10 oilfield trucks in the Arab Republic of Egypt.

**CUSTOMERS**

Key's customers include major oil companies, independent oil and natural gas production companies, and foreign national oil and natural gas production companies. One customer in the year ended June 30, 2002, Occidental Petroleum Corporation, accounted for approximately 10% of Key's consolidated revenues. No single customer in the six months ended December 31, 2002 accounted for 10% or more of Key's consolidated revenues.

**COMPETITION AND OTHER EXTERNAL FACTORS**

Despite the significant consolidation that has occurred in the domestic well servicing industry, there are numerous smaller companies that compete in Key's well servicing markets. Nonetheless, Key believes that its performance, equipment, safety, and availability of equipment to meet customer needs and availability of experienced, skilled personnel is superior to that of its competitors.

In the well servicing markets, an important competitive factor in establishing and maintaining long-term customer relationships is having an experienced, skilled and well-trained work force. In recent years, many of Key's larger customers have placed increased emphasis on the safety records and quality of the crews, equipment and services provided by their contractors. Key has, and will continue to devote substantial resources toward employee safety and training programs. Management believes that many of Key's competitors, particularly small contractors, have not undertaken similar training programs for their employees. Management believes that Key's safety record and reputation for quality equipment and service are among the best in the industry.

In the contract drilling market, Key competes with other regional and national oil and natural gas drilling contractors, some of which have larger rig fleets with greater average depth capabilities and a few that have better capital resources than Key. Management believes that the contract drilling industry is less consolidated than the well servicing industry, resulting in a contract drilling market that is more price competitive. Nonetheless, Key believes that it is competitive in terms of drilling performance, equipment, safety, pricing, availability of equipment to meet customer needs and availability of experienced, skilled personnel in those regions in which it operates.

The need for well servicing and contract drilling fluctuates, primarily, in relation to expectations relating to, and fluctuations in, the price of oil and natural gas which, in turn, is driven by the supply of and demand for oil and natural gas. As supply of those commodities decreases and demand increases, service and maintenance requirements tend to eventually increase as oil and natural gas producers attempt to maximize the producing efficiency of their wells in a higher priced environment.



**EMPLOYEES**

As of December 31, 2002, Key employed approximately 8,409 persons (approximately 8,287 employees in its well servicing and contract drilling businesses and approximately 122 employees on its corporate staff). Key's employees are not represented by a labor union and are not covered by collective bargaining agreements. Key has not experienced work stoppages associated with labor disputes or grievances and considers its relations with its employees to be satisfactory.

**ENVIRONMENTAL REGULATIONS**

Key's operations are subject to various local, state and federal laws and regulations intended to protect the environment. Key's operations routinely involve the handling of waste materials, some of which are classified as hazardous substances. Consequently, the regulations applicable to Key's operations include those with respect to containment, disposal and controlling the discharge of any hazardous oilfield waste and other non-hazardous waste material into the environment, requiring removal and cleanup under certain circumstances, or otherwise relating to the protection of the environment. Laws and regulations protecting the environment have become more stringent in recent years, and may in certain circumstances impose "strict liability," rendering a party liable for environmental damage without regard to negligence or fault on the part of such party. Such laws and regulations may expose Key to liability for the conduct of, or conditions caused by, others, or for Key's acts, which were in compliance with all applicable laws at the times such acts were performed. Cleanup costs and other damages arising as a result of environmental laws, and costs associated with changes in environmental laws and regulations could be substantial and could have a material adverse effect on Key's financial condition. From time to time, claims have been made and litigation has been brought against Key under such laws. However, the uninsured costs incurred in connection with such claims and other costs of environmental compliance have not had any material adverse effect on Key's operations or financial statements in the past, and management is not currently aware of any situation or condition that it believes is likely to have any such material adverse effect in the future. Management believes that it conducts Key's operations in substantial compliance with all material federal, state and local regulations as they relate to the environment. Although Key has incurred certain costs in complying with environmental laws and regulations, such amounts have not been material to Key's financial results during the past three and one half years.

**ITEM 2. PROPERTIES.**

Key's corporate headquarters are located in Midland, Texas. In addition to its corporate headquarters, the corporate division leases two administrative office locations in Houston, Texas and New Hope, Pennsylvania. Key leases these office spaces from independent third parties. The Company leases the office space in Midland, Texas for approximately $42,000 per month and the lease terminates on October 31, 2007. The lease in New Hope, Pennsylvania is for a term of 10 years beginning September 1, 2001 and the lease in Houston, Texas terminates on November 14, 2005. The Company pays an aggregate of approximately $37,000 per month for each of the other two leases.



**WELL SERVICING AND CONTRACT DRILLING**

The following table sets forth the type, number and location of the major equipment owned and operated by Key's operating divisions as of December 31, 2002:

| Operating Division | Well Service and Workover Rigs | Oilfield Trucks | Drilling Rigs |
|---|---|---|---|
| *Domestic:* | | | |
| Permian Basin (well servicing) | 470 | 533 | 0 |
| Gulf Coast | 249 | 553 | 0 |
| Mid-Continent | 211 | 150 | 0 |
| Four Corners | 45 | 90 | 15 |
| Eastern | 91 | 253 | 3 |
| Rocky Mountains | 133 | 62 | 14 |
| California | 140 | 38 | 0 |
| Ark-La-TX | 116 | 250 | 0 |
| North Texas | 0 | 111 | 0 |
| Quality Tubular Services | 0 | 2 | 0 |
| American Energy Services | 0 | 114 | 0 |
| Key Energy Drilling (Permian Basin) | 0 | 50 | 38 |
| **Domestic Subtotal** | **1,455** | **2,206** | **70** |
| *International:* | | | |
| Argentina | 25 | 75 | 7 |
| Canada | 4 | 4 | 2 |
| Egypt | 5 | 10 | 0 |
| **International Subtotal** | **34** | **89** | **9** |
| **Totals** | **1,489** | **2,295** | **79** |

The Permian Basin Well Servicing division owns 39 and leases seven office and yard locations. The Gulf Coast division owns 26 and leases ten office and yard locations. The Mid-Continent division owns 17 and leases 16 office and yard locations. The Four Corners division owns six and leases two office and yard locations. The Eastern division owns three and leases ten office and yard locations. The Rocky Mountain division owns 16 and leases two office and yard locations. The California division owns one and leases three office and yard locations. The Permian Basin Drilling division owns two and leases two office and yard locations. The North Texas division owns three and leases three office and yard locations. The American Energy Services division leases 10 office and yard locations. The Quality Tubular Services division owns one and leases 10 office and yard locations. The Ark-La-Tx division owns 12 and leases six office and yard locations. The Argentina division owns one and leases two office and yard locations. The Canadian operation leases one yard location. The Egypt operation leases one yard location. Odessa Exploration owns interests in 223 gross (172 proved developed) oil leases and 57 gross (50 proved developed) gas leases.

The operating facilities are one or two story office and/or shop buildings. The buildings are occupied and considered to be in satisfactory condition.

## ITEM 3. LEGAL PROCEEDINGS AND OTHER ACTIONS.

Various suits and claims arising in the ordinary course of business are pending against the Company. Management does not believe that the disposition of any of these items will result in a material adverse impact to the consolidated financial position, results of operations or cash flows of the Company.

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

None.

## PART II

**ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS.**

Key's common stock is currently traded on the New York Stock Exchange, under the symbol "KEG." As of December 31, 2002, there were 645 registered holders of 128,341,027 issued and outstanding shares of common stock, excluding 416,666 shares of common stock held in treasury.

The following table sets forth, for the periods indicated, the high and low sales prices of Key's common stock on the New York Stock Exchange for the six months ended December 31, 2002 and the years ended June 30, 2002 and 2001, as derived from published sources.

| | High | Low |
|---|---|---|
| Six months ended December 31, 2002: | | |
| Second Quarter | $ 9.88 | $ 6.90 |
| First Quarter | 10.45 | 7.05 |
| Year Ended June 30, 2002: | | |
| Fourth Quarter | $ 12.59 | $ 9.63 |
| Third Quarter | 11.45 | 7.20 |
| Second Quarter | 9.70 | 5.99 |
| First Quarter | 11.01 | 5.58 |
| Year Ended June 30, 2001: | | |
| Fourth Quarter | $ 15.33 | $ 9.55 |
| Third Quarter | 13.52 | 8.13 |
| Second Quarter | 10.50 | 6.81 |
| First Quarter | 11.44 | 7.06 |

There were no dividends paid on Key's common stock during the six months ended December 31, 2002 or during years ended June 30, 2002, 2001 or 2000. Key does not intend to consider paying dividends on its common stock until its net funded debt to capitalization ratio is less than 25%. In addition, Key is contractually restricted from paying dividends under the terms of its existing credit facilities.

### RECENT SALES OF UNREGISTERED SECURITIES

Key did not make any unregistered sales of its securities during the six months ended December 31, 2002 that were not previously reported in its Quarterly Reports filed for such period.

### EQUITY COMPENSATION PLAN INFORMATION

The following table summarizes information, as of December 31, 2002, about the Company's common stock that may be issued upon the exercise of options that have been granted (i) under equity compensation plans that have been approved by the Company's shareholders and (ii) outside such plans. The only equity compensation plan that has been approved by the Company's shareholders is the Key Energy Group, Inc. 1997 Incentive Plan (the "Incentive Plan"). For a description of the Incentive Plan, see Note 8 to Consolidated Financial Statements  Stockholders' Equity. All options not issued under the Incentive Plan (the "Non-Plan Options") were approved by the Board or the Compensation Committee under individual option grants (rather than under a separate equity compensation plan not approved by the Company's shareholders). The Non-Plan Options (i) expire in ten years, (ii) vest either on the grant date or ratably over a three-year period following the grant date, (iii) have exercise prices equal to or greater than the market price at the date of the grant and (iv) have other terms similar to those options granted under the Incentive Plan.

| **Plan Category** | **Number of securities to be issued upon exercise of outstanding options, warrants, and rights (in thousands) (a)** | | **Weighted-average exercise price of outstanding options, warrants, and rights (b)** | **Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (in thousands) (c)** |
|---|---|---|---|---|
| Equity compensation plans approved by the security holders | 6,316 | $ | 7.54 | 2,191(1) |
| Equity compensation plans not approved by the security holders | 3,710 | $ | 8.45 | (2) |
| Total | 10,026 | $ | 7.88 | 2,191 |

(1) The number of shares of the Company's common stock available for issuance under the Incentive Plan on any given date, subject to adjustment in certain circumstances, is equal to (i) 10% of the number of shares of the Company's common stock issued and outstanding on the last day of the calendar quarter immediately preceding such date (provided, however, that such number cannot decrease from one quarter to the next quarter), less (ii) the number of shares of the Company's common stock previously granted under the Incentive Plan through such date, plus (iii) the number of shares of the Company's common stock previously granted under the Incentive Plan that have been forfeited through such date.

(2) Because the Non-Plan Options are comprised of individual grants outside the Incentive Plan, all shares available for issuance under the Non-Plan Options are reflected in column (a).



**Item 6. Selected Financial Data.**

| | Six Months Ended December 31, 2002(1) | Year Ended June 30, 2002 | 2001 | 2000 | 1999(2) | 1998 |
|---|---|---|---|---|---|---|
| | (in thousands, except per share amounts) | | | | | |
| **OPERATING DATA:** | | | | | | |
| Revenues | $ 408,998 | $ 802,564 | $ 873,262 | $ 637,732 | $ 491,817 | $ 424,543 |
| Operating costs: | | | | | | |
| Direct costs | 288,945 | 554,773 | 582,154 | 471,169 | 374,308 | 296,328 |
| Depreciation, depletion and amortization | 51,111 | 78,265 | 75,147 | 70,972 | 62,074 | 31,001 |

| | | Year Ended June 30, | | | | |
|---|---|---|---|---|---|---|
| General and administrative | 48,239 | 59,494 | 60,118 | 51,637 | 56,156 | 36,933 |
| Interest | 22,743 | 43,332 | 56,560 | 71,930 | 67,401 | 21,476 |
| Foreign currency transaction loss, Argentina | | 1,443 | | | | |
| Debt issuance costs | | | | | 6,307 | |
| Restructuring charge | | | | | 4,504 | |
| (Gain) loss on retirement of debt | (18) | 4,812 | (684) | (2,191) | | |
| Income (loss) before income taxes, minority interest, and cumulative effect | (2,022) | 60,445 | 99,967 | (25,785) | (78,933) | 38,805 |
| Net income (loss) | (4,376) | 38,146 | 62,710 | (18,959) | (53,258) | 24,175 |
| *Income (loss) per common share:* | | | | | | |
| Basic | $ (0.03) | $ 0.36 | $ 0.64 | $ (0.23) | $ (1.94) | $ 1.41 |
| Diluted | $ (0.03) | $ 0.35 | $ 0.61 | $ (0.23) | $ (1.94) | $ 1.23 |
| Average common shares outstanding: | | | | | | |
| Basic | 125,367 | 105,766 | 98,195 | 83,815 | 27,501 | 17,153 |
| Assuming full dilution | 125,367 | 107,462 | 102,271 | 83,815 | 27,501 | 24,024 |
| Common shares issued at period end | 128,758 | 110,308 | 101,440 | 97,210 | 82,738 | 18,267 |
| Market price per common share at period end | $ 8.97 | $ 10.50 | $ 10.84 | $ 9.64 | $ 3.56 | $ 13.12 |
| Cash dividends paid on common shares | | | | | | |
| **BALANCE SHEET DATA:** | | | | | | |
| Cash | $ 9,044 | $ 54,147 | $ 2,098 | $ 109,873 | $ 23,478 | $ 25,265 |
| Current assets | 175,574 | 192,073 | 206,150 | 253,589 | 132,543 | 127,557 |
| Property and equipment | 1,291,853 | 1,093,104 | 1,014,675 | 920,437 | 871,940 | 547,537 |
| Property and equipment, net | 956,505 | 808,900 | 793,716 | 760,561 | 769,562 | 499,152 |
| Total assets | 1,502,002 | 1,242,995 | 1,228,284 | 1,246,265 | 1,148,138 | 698,640 |
| Current liabilities | 108,875 | 96,628 | 115,553 | 92,848 | 73,151 | 48,029 |
| Long-term debt, including current portion | 493,565 | 443,610 | 493,907 | 666,600 | 699,978 | 399,779 |
| Stockholders' equity | 696,368 | 536,866 | 476,878 | 382,887 | 288,094 | 154,928 |
| **OTHER DATA:** | | | | | | |
| Net cash provided by (used in): | | | | | | |
| Operating activities | 57,594 | 178,716 | 143,347 | 34,860 | (13,427) | 40,925 |
| Investing activities | (146,073) | (108,749) | (83,980) | (37,766) | (294,654) | (306,339) |
| Financing activities | 44,054 | (17,315) | (167,142) | 89,301 | 306,294 | 248,975 |
| Working capital | 66,699 | 95,445 | 90,597 | 160,741 | 59,392 | 79,528 |
| Book value per common share(3) | $ 5.41 | $ 4.87 | $ 4.70 | $ 3.94 | $ 3.47 | $ 8.48 |

(1) Financial data for the six months December 31, 2002 includes the allocated purchase price of Q Services, Inc. and the results of their operations, beginning July 19, 2002.

(2) Financial data for the year ended June 30, 1999 includes the allocated purchase price of Dawson Production Services, Inc. and the results of their operations, beginning September 15, 1998.

(3) Book value per common share is stockholders' equity at period end divided by the number of issued common shares at period end.

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

Special Note: Certain statements set forth below under this caption constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. See "Special Note Regarding Forward-Looking Statements" for additional factors relating to such statements.

The following discussion provides information to assist in the understanding of the Company's financial condition and results of operations. It should be read in conjunction with the consolidated financial statements and related notes appearing elsewhere in this report. Certain reclassifications have been made to the consolidated financial statements for the years ended June 30, 2001 and 2000 to conform to the six months ended December 31, 2002 and the year ended June 30, 2002 presentation. The reclassifications consist primarily of reclassifying certain items from general and administrative expense to direct expenses. In addition on July 1, 2002, the Company adopted the provisions of SFAS 145. See Note 19 to the consolidated financial statements. As used in this Item 7, references to composite well servicing rig rates means, for a given period, the total well servicing revenues for that period divided by the total well servicing hours for that period. As used in this Item 7, references to composite contract drilling rig rates means, for a given period, the total contract drilling revenues for that period divided by the total contract drilling hours for that period. As used in this Item 7, references to composite truck rates means, for a given period, the total trucking revenues for that period divided by the total trucking hours for that period.

**RESULTS OF OPERATIONS**

**SIX MONTHS ENDED DECEMBER 31, 2002 VERSUS SIX MONTHS DECEMBER 31, 2001**

The Company's results of operations for the six months ended December 31, 2002 reflect the general uncertainty about future oil and natural gas prices, including the customers' perception that commodity prices may decrease, which in turn caused a decline in demand for the Company's equipment and services partially offset by minimizing rate concessions (see Part I Item 1 Developments During and Subsequent to the Six Months Ended December 31, 2002).

**The Company**

The Company's revenue for the six months ended December 31, 2002 decreased $53,576,000, or 11.6%, to $408,998,000 from $462,574,000 for the six months ended December 31, 2001. For the six months ended December 31, 2002, the Company incurred a net loss of $4,376,000, representing a decrease of $53,011,000, or 109.0%, from net income of $48,635,000, for the six months ended December 31, 2001. The decrease in revenues and net income is principally due to lower levels of activity and lower pricing partially offset by the acquisition of QSI. Total rig hours for the six months ended December 31, 2002 declined approximately 20% compared to total rig hours for the six months ended December 31, 2001 coupled with a decrease in composite well servicing rig rates for the six months ended December 31, 2002 of approximately 7% and composite contract drilling rig rates for the six months ended December 31, 2002 of approximately 7% compared to composite well servicing rig rates and composite contract drilling rig rates for the six months ended December 31, 2001. While trucking hours for the six-month period ended December 31, 2002 increased approximately 29% compared to trucking hours for the six-month period ended December 31, 2001, the increase was principally due to the acquisition of QSI. Further, composite truck rates for the six-month period ended December 31, 2002 declined approximately 16% compared to the composite truck rates for six-month period ended December 31, 2001. The net loss in the six months ended December 31, 2002 was also affected by the cumulative effect of the Company's mandatory adoption of SFAS 143, costs associated with the integration of QSI, and unusually high general liability costs and start-up costs associated with the Company's new Egypt project.

**Operating Revenues**

*Well Servicing.* Well servicing revenues for the six months ended December 31, 2002 decreased $27,968,000, or 7.0%, to $370,871,000 from $398,839,000 for the six months ended December 31, 2001. The



decrease in revenues was primarily due to a decline in activity and oilfield service rates partially offset by the acquisition of QSI. Well servicing hours for the six months ended December 31, 2002 declined approximately 18% compared to well servicing hours for the six months ended December 31, 2001, which was exacerbated by a decline in composite well servicing rig rates for the six months ended December 31, 2002 of approximately 7% compared to composite well servicing rig rates for the six months ended December 31, 2001. Trucking hours for the six months ended December 31, 2002 increased approximately 28% compared to trucking hours for the six months ended December 31, 2001. The increase was principally due to the acquisition of QSI. Further, composite truck rates for the six months ended December 31, 2002 declined approximately 16% compared to composite truck rates for the six months ended December 31, 2001.

*Contract Drilling.* Contract drilling revenues for the six months ended December 31, 2002 decreased $25,658,000, or 43.3%, to $33,632,000 from $59,290,000 for the six months ended December 31, 2001. The decrease in revenues was primarily due to a decline in equipment utilization and pricing of contract drilling services. Contract drilling hours for the six months ended December 31, 2002 declined approximately 39% compared to contract drilling hours for the six months ended December 31, 2001. Composite contract drilling rig rates for the six months ended December 31, 2002 declined approximately 7% compared to composite contract drilling rig rates for the six months ended December 31, 2001.

**Operating Expenses**

*Well Servicing.* Well servicing expenses for the six months ended December 31, 2002 increased $7,695,000, or 3%, to $263,595,000 from $255,900,000 for the six months ended December 31, 2001. Although well servicing hours decreased, expenses increased due to the acquisition and integration costs associated with QSI, higher insurance costs primarily in workers' compensation and health care, and start-up costs for the Company's new Egypt project. Well servicing expenses as a percentage of well servicing revenues increased from 64.2% for the six months ended December 31, 2001 to 71.1% for the six months ended December 31, 2002.

*Contract Drilling.* Contract drilling expenses for the six months ended December 31, 2002 decreased $15,112,000, or 39.2%, to $23,416,000 from $38,528,000 for the six months ended December 31, 2001. The decrease is primarily due to lower activity levels, which was partially offset by higher insurance costs primarily in workers' compensation and health care. Contract drilling expenses as a percentage of contract drilling revenues increased from 65.0% for the six months ended December 31, 2001 to 69.6% for the six months ended December 31, 2002.

**Depreciation, Depletion and Amortization Expense**

The Company's depreciation, depletion and amortization expense for the six months ended December 31, 2002 increased $13,518,000, or 36.0%, to $51,111,000 from $37,593,000 for the six months ended December 31, 2001. The increase is primarily due to the acquisition of QSI, which added approximately $142,264,000 in net depreciable assets, and capital expenditures during the prior year as the Company continued remanufacturing well servicing and contract drilling equipment.

**General and Administrative Expenses**

The Company's general and administrative expenses for the six months ended December 31, 2002 increased $19,320,000, or 66.8%, to $48,239,000 from $28,919,000 for the six months ended December 31, 2001. The increase was primarily due to the acquisition of QSI and costs associated with the integration of QSI, higher general liability costs including settlement expenses, and additional personnel supporting the implementation of information technology. General and administrative expenses, as a percentage of revenues, increased from 6.3% for the six months ended December 31, 2001 to 11.8% for the six months ended December 31, 2002.



**Interest Expense**

The Company's interest expense for the six months ended December 31, 2002 decreased $303,000, or 1.3%, to $22,743,000 from $23,046,000 for the six months ended December 31, 2001. The restructuring of the Company's long-term debt resulted in a decline in the Company's incremental borrowing rate of approximately 1%. Included in the interest expense was the amortization of debt issuance costs of $2,103,000 and $1,393,000 for the six months ended December 31, 2002 and 2001, respectively.

**Gain on Retirement of Debt**

During the six months ended December 31, 2002, the Company repurchased an aggregate principal amount of $397,000 of its long-term debt at various discounts and premiums to par value and expensed related unamortized debt issuance costs, all of which resulted in a gain of $18,000. The repurchase of the long term debt was part of the Company's overall plan to reduce and restructure its long term debt and to restructure debt maturities.

**Cumulative Effect on Prior Years of a Change in Accounting Principle**

On July 1, 2002, the Company adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations ("SFAS 143"). Adoption of SFAS 143 is required for all companies with fiscal years beginning after June 15, 2002. The new standard requires the Company to recognize a liability for the present value of all legal obligations associated with the retirement of tangible long-lived assets and capitalize an equal amount as a cost of the asset depreciating the additional cost over the estimated useful life of the asset. On July 1, 2002, the Company recorded additional costs, net of accumulated depreciation, of approximately $3,347,000, a non-current liability of approximately $7,980,000 and an after-tax charge of approximately $2,873,000 for the cumulative effect on prior years for depreciation of the additional costs and accretion expense on the liability related to expected abandonment costs of its oil and natural gas producing properties and salt water disposal wells. At December 31, 2002, the asset retirement obligation was $9,231,000, and the increase in the balance from July 1, 2002 of $1,251,000 is due to accretion expense of $226,000 and asset retirement obligations of QSI of $1,025,000 assumed in the purchase transaction. The pro forma amounts of the asset retirement obligation as of June 30, 2002, 2001, 2000 and 1999, were approximately $7,980,000, $7,581,000, $7,182,000 and $6,783,000, respectively. The pro forma amounts of the asset retirement obligation were measured using information, assumptions and interest rates as of the adoption date of July 1, 2002. Pro forma net income (loss) and related per share amounts for the years ended June 30, 2002, 2001 and 2000, assuming SFAS 143 had been applied in each year are as follows:

| | Year Ended | | |
|---|---|---|---|
| | 2002 | 2001 | 2000 |
| | (Thousands, except per share amount) | | |
| Pro forma net income (loss) | $ 37,894 | $ 62,460 | $ (19,252) |
| Earnings (loss) per share | | | |
| Basic | $ 0.36 | $ 0.64 | $ (0.23) |
| Diluted | $ 0.35 | $ 0.61 | $ (0.23) |

**Income Taxes**

The Company's income tax expense for the six months ended December 31, 2002 decreased $29,938,000 from an income tax expense of $29,419,000 for the six months ended December 31, 2001 to an income tax benefit of $519,000. The decrease in income tax expense is due to decreased pre-tax income. The Company's effective tax rate for the six months ended December 31, 2002 and 2001 was 25.7% and 37.7%, respectively. The effective tax rates are different from the statutory rate of 35% primarily because of non-deductible expenses and the effects of state and local taxes.



**Cash Flow**

The Company's net cash provided by operating activities for the six months ended December 31, 2002 decreased $45,223,000 to $57,594,000 from $102,817,000 for the six months ended December 31, 2001. The decrease is primarily due to decreased net income.

The Company's net cash used in investing activities for the six months ended December 31, 2002 increased $96,125,000 to $146,073,000 from $49,948,000 for the six months ended December 31, 2001. The Company used cash of approximately $105,365,000 for the purchase of QSI and other smaller acquisitions, which principally accounts for the increase in net cash used in investing activities.

The Company's net cash provided by financing activities for the six months ended December 31, 2002 was $44,054,000, representing an increase of $90,863,000 from a use of $46,809,000 for the six months ended December 31, 2001. For the six months ended December 31, 2002, the Company increased net borrowings by $46,685,000 principally in connection with the purchase of QSI. For the six months ended December 31, 2001, the Company reduced net borrowings by $90,930,000 which was partially funded by net proceeds of $42,590,000 from an equity offering.

The effect of exchange rates on cash for the six months ended December 31, 2002 and 2001 was a use of $678,000 and $192,000, respectively. This was a result of the devaluation of the Argentine peso for the six months ended December 31, 2002 and 2001.

**YEAR ENDED JUNE 30, 2002 VERSUS YEAR ENDED JUNE 30, 2001**

The Company's results of operations for the year ended June 30, 2002 reflect the impact of a decline in industry conditions resulting from decreased commodity prices (and its customers' perception that commodity prices may decrease further) which in turn caused a decline in demand for the Company's equipment and services partially offset by minimizing rate concessions and lower interest charges during the year ended June 30, 2002.

**The Company**

Revenues for the year ended June 30, 2002 decreased $70,698,000, or 8.1%, to $802,564,000 from $873,262,000 for the year ended June 30, 2001, while net income for the year ended June 30, 2002 decreased $24,564,000, or 39.2%, to $38,146,000 from a net income of $62,710,000 for the year ended June 30, 2001. The decrease in revenues and net income is due to lower levels of activity partially offset by higher pricing, with lower interest expense from debt reduction also contributing to net income. Composite truck rates for the year ended June 30, 2002 increased approximately 23% compared to composite truck rates for the year ended June 30, 2001. Composite well servicing rig rates and composite contract drilling rig rates for the year ended June 30, 2002 increased approximately 13% and 11%, respectively, compared to composite well servicing rig rates and composite contract drilling rig rates for the year ended June 30, 2001. However, total rig and trucking hours for the year ended June 30, 2002 decreased approximately 14% and 5%, respectively, compared to total rig and trucking hours for the year ended June 30, 2001. In addition, well servicing rig rates and contract drilling rig rates experienced later in the year ended June 30, 2002 had declined significantly from those rates experienced earlier in the period.

**Operating Revenues**

*Well Servicing.* Well servicing revenues for the year ended June 30, 2002 decreased $51,644,000, or 6.8%, to $706,629,000 from $758,273,000 for the year ended June 30, 2001. The decrease was due to lower demand for the Company's well servicing equipment and services partially offset by higher pricing. Well servicing hours for the year ended June 30, 2002 decreased approximately 13% compared to well servicing hours for the year ended June 30, 2001, while composite well servicing rig rates for the year ended June 30, 2002 increased approximately 13% compared to composite well servicing rig rates for the year ended June 30, 2001.



*Contract Drilling.* Contract drilling revenues for the year ended June 30, 2002 decreased $20,562,000, or 19.1%, to $87,077,000 from $107,639,000 for the year ended June 30, 2001. The decrease was due to lower demand for the Company's contract drilling equipment and services partially offset by higher pricing. Contract drilling hours for the year ended June 30, 2002 declined approximately 27% compared to contract drilling hours for the year ended June 30, 2001, while composite contract drilling rig rates for the year ended June 30, 2002 increased approximately 11% compared to composite contract drilling rig rates for the year ended June 30, 2001.

**Operating Expenses**

*Well Servicing.* Well servicing expenses for the year ended June 30, 2002 decreased $10,643,000, or 2.1%, to $489,681,000 from $500,324,000 for the year ended June 30, 2001. The decrease in expenses is due to lower activity levels partially offset by higher insurance costs primarily in workers' compensation and health care. Despite the decreased costs, well servicing expenses as a percentage of well servicing revenues increased from 66.0% for the year ended June 30, 2001 to 69.3% for the year ended June 30, 2002 primarily due to the increase in insurance costs.

*Contract Drilling.* Contract drilling expenses for the year ended June 30, 2002 decreased $16,805,000, or 21.7%, to $60,561,000 from $77,366,000 for the year ended June 30, 2001. The decrease is due to lower activity levels partially offset by higher insurance costs primarily in workers' compensation and health care. Contract drilling expenses as a percentage of contract drilling revenues decreased from 71.9% for the year ended June 30, 2001 to 69.6% for the year ended June 30, 2002. The marginal improvement is due to improved operating efficiencies and the effects of higher pricing partially offset by the increase in insurance costs.

**Depreciation, Depletion and Amortization Expense**

The Company's depreciation, depletion and amortization expense for the year ended June 30, 2002 increased $3,118,000, or 4.1%, to $78,265,000 from $75,147,000 for the year ended June 30, 2001. The increase is due to recent acquisitions and increased capital expenditures during the past year as the Company continued remanufacturing well servicing and contract drilling equipment partially offset by discontinued amortization of goodwill, which amounted to $9,322,000 for the year ended June 30, 2001, because of the Company's adoption of SFAS 142.

**General and Administrative Expenses**

The Company's general and administrative expenses for the year ended June 30, 2002 decreased $624,000, or 1.0%, to $59,494,000 from $60,118,000 for the year ended June 30, 2001. The decrease was due to reductions in incentive payroll costs partially offset by additional expenses incurred as a result of moving the corporate headquarters to Midland, Texas from East Brunswick, New Jersey and increases in personnel supporting information technology functions. Despite the decreased costs, general and administrative expenses as a percentage of total revenues increased from 6.9% for the year ended June 30, 2001 to 7.4% for the year ended June 30, 2002.

**Interest Expense**

The Company's interest expense for the year ended June 30, 2002 decreased $13,228,000, or 23.4%, to $43,332,000 from $56,560,000 for the year ended June 30, 2001. The decrease was primarily due to a significant reduction in the Company's long-term debt using proceeds from an equity offering, a debt offering and operating cash flow, and to a lesser extent, lower interest rates. Included in the interest expense was the amortization of debt issuance costs of $2,581,000 and $3,578,000 for the years ended June 30, 2002 and 2001, respectively.



**Foreign Currency Transaction Loss**

During the year ended June 30, 2002, the Company recorded an Argentine foreign currency transaction loss of approximately $1,443,000 related to dollar-denominated receivables resulting from the recent devaluation of Argentina's currency.

**Loss on Retirement of Debt**

During the year ended June 30, 2002, the Company repurchased an aggregate principal amount of $150,908,000 of its long-term debt at various discounts and premiums to par value and expensed related unamortized debt issuance costs, all of which resulted in a loss of $4,812,000. The repurchase of the long-term debt was part of the Company's overall plan to reduce and restructure its long-term debt. The repurchase of the long-term debt was intended to reduce interest rates and restructure debt maturities.

**Income Taxes**

The Company's income tax expense for the year ended June 30, 2002 decreased $14,958,000 to $22,299,000 from $37,257,000 for the year ended June 30, 2001. The decrease in income tax expense is due to decreased pre-tax income. The Company's effective tax rate for the years ended June 30, 2002 and 2001 was 36.9% and 37.3%, respectively. The effective tax rates vary from the statutory federal rate of 35% principally because of the disallowance of certain goodwill amortization (for the year ended June 30, 2001), and other non-deductible expenses and the effects of state and local taxes.

**Cash Flow**

The Company's net cash provided by operating activities for the year ended June 30, 2002 increased $35,369,000 to $178,716,000 from $143,347,000 for the year ended June 30, 2001. The increase, despite lower net income for the year ended June 30, 2002 compared to the net income for the year ended June 30, 2001, is primarily due to a decrease in the components of working capital, specifically accounts receivable and accounts payable. The reduction in working capital is primarily due to lower levels of activity.

The Company's net cash used in investing activities for the year ended June 30, 2002 increased $24,769,000 to $108,749,000 from $83,980,000 for the year ended June 30, 2001. The increase for the year ended June 30, 2002 is due primarily to higher capital expenditures, approximately 13% higher than that incurred in the year ended June 30, 2001, and an increase in acquisitions of well servicing and contract drilling equipment.

The Company's net cash used in financing activities for the year ended June 30, 2002 decreased $149,827,000 to $17,315,000 from $167,142,000 for the year ended June 30, 2001. The decrease is primarily the result of higher proceeds from debt and equity offerings completed during the year ended June 30, 2002 compared to financing proceeds received in the year ended June 30, 2001. While the Company continued its debt reduction strategy during the year ended June 30, 2002, total debt reductions for the year ended June 30, 2002 decreased to approximately $51 million compared to the year ended June 30, 2001 of approximately $169 million.

The effect of exchange rates on cash for the year ended June 30, 2002 was a use of $603,000. This was a result of the devaluation of the Argentine peso for the year ended June 30, 2002.

**YEAR ENDED JUNE 30, 2001 VERSUS YEAR ENDED JUNE 30, 2000**

The Company's results of operations for the year ended June 30, 2001 reflect the impact of favorable industry conditions resulting from increased commodity prices which in turn caused increased demand for the Company's equipment and services during the year ended June 30, 2001. The positive impact of this increased demand on the Company's operating results was partially offset by increased operating expenses incurred as a result of the increase in the Company's business activity.



**The Company**

Revenues for the year ended June 30, 2001 increased $235,530,000, or 36.9%, to $873,262,000 from $637,732,000 for the year ended June 30, 2000, while net income for the year ended June 30, 2001 increased $81,669,000 to $62,710,000 from a net loss of $18,959,000 for the year ended June 30, 2000. The increase in revenues and net income is due to improved operating conditions, higher rig hours, and increased pricing, with lower interest expense from debt reduction also contributing to net income. Total rig and trucking rig hours for the year ended June 30, 2001 increased approximately 18% and 9%, respectively, compared to the total rig and trucking hours for the year ended June 30, 2000. Composite well servicing rig rates and composite contract drilling rig rates for the year ended June 30, 2001 improved approximately 19% and 17%, respectively, compared to composite well servicing rig rates and composite contract drilling rig rates for the year ended June 30, 2000, while composite truck rates for the year ended June 30, 2001 improved approximately 20% compared to composite truck rates for the year ended June 30, 2000.

**Operating Revenues**

*Well Servicing.* Well servicing revenues for the year ended June 30, 2001 increased $198,781,000, or 35.5%, to $758,273,000 from $559,492,000 for the year ended June 30, 2000. The increase was due to increased demand for the Company's well servicing equipment and services and higher pricing. Well servicing hours for the year ended June 30, 2001 increased approximately 16% compared to the well servicing hours for the year ended June 30, 2000, while composite well servicing rates for the year ended June 30, 2001 improved approximately 19% compared to the composite well servicing rates for the year ended June 30, 2000.

*Contract Drilling.* Contract drilling revenues for the year ended June 30, 2001 increased $39,211,000, or 57.3%, to $107,639,000 from $68,428,000 for the year ended June 30, 2000. The increase was due to increased demand for the Company's contract drilling equipment and services and higher pricing. Contract drilling hours for the year ended June 30, 2001 increased approximately 35% compared to the contract drilling hours for the year ended June 30, 2000, while composite contract drilling rates improved approximately 17% compared to the composite contract drilling rates for the year ended June 30, 2000.

**Operating Expenses**

*Well Servicing.* Well servicing expenses for the year ended June 30, 2001 increased $91,601,000, or 22.4%, to $500,324,000 from $408,723,000 for the year ended June 30, 2000. The increase in expenses is due to higher utilization of the Company's well servicing equipment, higher labor costs and the overall increase in the Company's well servicing business. Despite the increased costs, well servicing expenses as a percentage of well servicing revenues decreased from 73.1% for the year ended June 30, 2000 to 66.0% for the year ended June 30, 2001. The marginal improvement is due to improved operating efficiencies and the effects of higher pricing.

*Contract Drilling.* Contract drilling expenses for the year ended June 30, 2001 increased $19,067,000, or 32.7%, to $77,366,000 from $58,299,000 for the year ended June 30, 2000. The increase is due to higher utilization of the Company's contract drilling equipment, higher labor costs and the overall increase in the Company's contract drilling business. Despite the increased costs, contract drilling expenses as a percentage of contract drilling revenues decreased from 85.2% for the year ended June 30, 2000 to 71.9% for the year ended June 30, 2001. The marginal improvement is due to improved operating efficiencies and the effects of higher pricing.

**Depreciation, Depletion and Amortization Expense**

The Company's depreciation, depletion and amortization expense for the year ended June 30, 2001 increased $4,175,000, or 5.9%, to $75,147,000 from $70,972,000 for the year ended June 30, 2000. The increase is due to higher capital expenditures incurred during the year ended June 30, 2001 as the



Company remanufactured equipment and increased utilization of its contract drilling equipment (which it depreciates partially based on utilization).

**General and Administrative Expenses**

The Company's general and administrative expenses for the year ended June 30, 2001 increased $8,481,000, or 16.4%, to $60,118,000 from $51,637,000 for the year ended June 30, 2000. The increase was due to higher administrative costs resulting from the growth of the Company's operations as a result of improved industry conditions. Despite the increased costs, general and administrative expenses as a percentage of total revenues declined from 8.1% for the year ended June 30, 2000 to 6.9% for the year ended June 30, 2001.

**Interest Expense**

The Company's interest expense for the year ended June 30, 2001 decreased $15,370,000, or 21.4%, to $56,560,000 from $71,930,000 for the year ended June 30, 2000. The decrease was primarily due to the impact of the long-term debt reduction during the year ended June 30, 2001 and, to a lesser extent, lower short-term interest rates and borrowing margins on floating rate debt.

**Gain on Retirement of Debt**

During the year ended June 30, 2001, the Company repurchased $257,115,000 of its long-term debt at various discounts and premiums to par value and expensed related unamortized debt issue costs, all of which resulted in a gain of $684,000. The repurchase of the long-term debt was made in connection with the Company's overall strategy to reduce and restructure its long-term debt. The repurchase was intended to lower fixed interest rates and restructure debt maturities.

**Income Taxes**

The Company's income tax expense for the year ended June 30, 2001 increased $44,083,000 to $37,257,000 from a benefit of $6,826,000 for the year ended June 30, 2000. The increase in income tax expense is due to increased pre-tax income. The Company's effective tax rate for the years ended June 30, 2001 and 2000 was 37.3% and (26.5)%, respectively. The effective tax rates vary from the statutory federal rate of 35% principally because of certain non-deductible goodwill amortization, other non-deductible expenses and state and local taxes.

**Cash Flow**

The Company's net cash provided by operating activities for the year ended June 30, 2001 increased $108,487,000 to $143,347,000 from $34,860,000 for the year ended June 30, 2000. The increase is due to higher revenues resulting from increased demand for the Company's equipment and services and higher pricing, partially offset by higher operating and general and administrative expenses resulting from increased business activity.

The Company's net cash used in investing activities for the year ended June 30, 2001 increased $46,214,000 to $83,980,000 from $37,766,000 for the year ended June 30, 2000. The increase is due primarily to higher capital expenditures.

The Company's net cash used in financing activities for the year ended June 30, 2001 increased $256,443,000 to a use of $167,142,000 from cash provided of $89,301,000 for the year ended June 30, 2000. The increase is primarily the result of significant debt reduction during the year ended June 30, 2001, partially offset by proceeds from a debt offering and the exercise of stock options and warrants during the year ended June 30, 2001.

## LIQUIDITY AND CAPITAL RESOURCES

The Company has historically funded its operations, acquisitions, capital expenditures and working capital requirements from cash flow from operations, bank borrowings and the issuance of equity and



long-term debt. The Company believes that its current reserves of cash and cash equivalents, availability of its existing credit lines, access to capital markets and internally generated cash flow from operations are sufficient to finance the cash requirements of its current and future operations, acquisitions and capital expenditures.

The Company's cash and cash equivalents decreased $45,103,000 to $9,044,000 as of December 31, 2002 from $54,147,000 as of June 30, 2002. The Company used its available cash to partially fund the acquisition of QSI.

As of December 31, 2002 the Company had working capital (excluding the current portion of long-term debt of $7,008,000) of approximately $73,707,000, which includes cash and cash equivalents of approximately $9,044,000, as compared to working capital (excluding the current portion of long-term debt of $7,674,000) of approximately $103,119,000, which includes cash and cash equivalents of approximately $54,147,000 as of June 30, 2002. The decrease in working capital is primarily due to a decrease in cash and cash equivalents, which was used to partially fund the acquisition of QSI that was partially offset by an increase in accounts receivable and inventories from the QSI acquisition.

**LONG-TERM DEBT**

Other than capital lease obligations and miscellaneous notes payable, as of December 31, 2002, the Company's long-term debt was comprised of (i) a senior credit facility, (ii) a series of $8^3/_8$% Senior Notes Due 2008, (iii) a series of 14% Senior Subordinated Notes Due 2009, and (iv) a series of 5% Convertible Subordinated Notes Due 2004.

**Senior Credit Facility**

On July 15, 2002, the Company entered into a Third Amended and Restated Credit Agreement, as amended by the First Amendment to the Third Amended and Restated Credit Agreement (the "Senior Credit Facility"). The Senior Credit Facility consists of a $150,000,000 revolving loan facility with a $75,000,000 sublimit for letters of credit. The loans are secured by most of the tangible and intangible assets of the Company. The revolving loan commitment will terminate on July 15, 2005 and all revolving loans must be paid on or before that date. The revolving loans bear interest based upon, at the Company's option, the prime rate plus a variable margin of 0.00% to 1.00% or a Eurodollar rate plus a variable margin of 1.75% to 3.00%. The Senior Credit Facility has customary affirmative and negative covenants including a maximum leverage ratio, a minimum fixed charge coverage ratio and a minimum net worth, as well as limitations on liens and indebtedness and restrictions on dividends, acquisitions and dispositions. As of December 31, 2002, the Company was in compliance with all covenants contained in the Senior Credit Facility.

As of December 31, 2002, approximately $52,000,000 was outstanding under the revolving loan facility and approximately $34,963,000 of letters of credit related to workers' compensation insurance were outstanding. The Company drew down approximately $53 million on July 19, 2002 in connection with the acquisition of QSI.

**$8^3/_8$% Senior Notes**

On March 6, 2001, the Company completed a private placement of $175,000,000 of $8^3/_8$% Senior Notes due 2008 (the "$8^3/_8$% Senior Notes"). The net cash proceeds from the private placement were used to repay all of the remaining balance of the original term loans under the Company's then outstanding senior credit facility (the "Prior Senior Credit Facility"), and a portion of the revolving loan facility under the Prior Senior Credit Facility then outstanding. On March 1, 2002, the Company completed a public offering of an additional $100,000,000 of $8^3/_8$% Senior Notes due 2008. The net cash proceeds from the public offering were used to repay all of the remaining balance of the revolving loan facility under the Prior Senior Credit Facility. The $8^3/_8$% Senior Notes are senior unsecured obligations and are fully and unconditionally guaranteed by all of the Company's significant subsidiaries. The $8^3/_8$% Senior Notes are



effectively subordinated to Key's secured indebtedness, which includes borrowings under the Senior Credit Facility.

On and after March 1, 2005, the Company may redeem some or all of the $8^3/_8$% Senior Notes at any time at varying redemption prices in excess of par, plus accrued interest. In addition, before March 1, 2004, the Company may redeem up to 35% of the aggregate principal amount of the $8^3/_8$% Senior Notes with the proceeds of certain sales of equity at 108.375% of par plus accrued interest.

At December 31, 2002, $275,000,000 principal amount of the $8^3/_8$% Senior Notes remained outstanding. The $8^3/_8$% Senior Notes require semi-annual interest payments on March 1 and September 1 of each year. Interest of approximately $11,516,000 was paid on September 1, 2002. As of December 31, 2002, the Company was in compliance with all covenants contained in the $8^3/_8$% Senior Notes.

**14% Senior Subordinated Notes**

On January 22, 1999, the Company completed the private placement of 150,000 units (the "Units") consisting of $150,000,000 of 14% Senior Subordinated Notes due 2009 (the "14% Senior Subordinated Notes") and 150,000 warrants to purchase 2,173,433 shares of the Company's common stock at an exercise price of $4.88125 per share (the "Unit Warrants"). The net cash proceeds from the private placement were used to repay substantially all of the remaining $148,600,000 principal amount (plus accrued interest) owed under the Company's bridge loan facility arranged in connection with the acquisition of Dawson Production Services, Inc. ("Dawson").

On and after January 15, 2004, the Company may redeem some or all of the 14% Senior Subordinated Notes at any time at varying redemption prices in excess of par, plus accrued interest. In addition, before January 15, 2002, the Company was allowed to redeem up to 35%

of the aggregate principal amount of the 14% Senior Subordinated Notes at 114% of par plus accrued interest with the proceeds of certain sales of equity. During the year ended June 30, 2001, the Company exercised its right of redemption for $10,313,000 principal amount of the 14% Senior Subordinated Notes at a price of 114% of the principal amount plus accrued interest. This transaction resulted in a loss before taxes of approximately $2,561,000. On January 14, 2002, the Company exercised its right of redemption for $35,403,000 principal amount of the 14% Senior Subordinated Notes at a price of 114% of the principal amount plus accrued interest. This transaction resulted in a loss before taxes of approximately $8,468,000. Also, during the year ended June 30, 2002, the Company purchased and canceled $6,784,000 principal amount of the 14% Senior Subordinated Notes at a price of 116% of the principal amount plus accrued interest. These transactions resulted in a loss before taxes of approximately $1,821,000.

The Unit Warrants have separated from the 14% Senior Subordinated Notes and became exercisable on January 25, 2000. On the date of issuance, the value of the Unit Warrants was estimated at $7,434,000 and is classified as a discount to the 14% Senior Subordinated Notes on the Company's consolidated balance sheet. The discount is being amortized to interest expense over the term of the 14% Senior Subordinated Notes. The 14% Senior Subordinated Notes mature and the Unit Warrants expire on January 15, 2009. The 14% Senior Subordinated Notes are subordinate to the Company's senior indebtedness, which includes borrowings under the Senior Credit Facility and the $8^3/8$% Senior Notes. The Senior Subordinated Notes are fully and unconditionally guaranteed by the Company's significant subsidiaries.

At December 31, 2002, $97,500,000 principal amount of the 14% Senior Subordinated Notes remained outstanding. The 14% Senior Subordinated Notes pay interest semi-annually on January 15 and July 15 of each year. Interest of approximately $6,825,000 was paid on July 15, 2002. As of December 31, 2002, 63,500 Unit Warrants had been exercised, producing approximately $4,173,000 of proceeds to the Company and leaving 86,500 Unit Warrants outstanding. As of December 31, 2002, the Company was in compliance with all covenants contained in the 14% Senior Subordinated Notes.



**5% Convertible Subordinated Notes**

In 1997, the Company completed a private placement of $216,000,000 of 5% Convertible Subordinated Notes due 2004 (the "5% Convertible Subordinated Notes"). The 5% Convertible Subordinated Notes are subordinate to the Company's senior indebtedness which includes borrowings under the Senior Credit Facility, the 14% Senior Subordinated Notes and the $8^3/8$% Senior Notes. The 5% Convertible Subordinated Notes are convertible, at the holder's option, into shares of the Company's common stock at a conversion price of $38.50 per share, subject to certain adjustments. The 5% Convertible Subordinated Notes are redeemable, at the Company's option, on and after September 15, 2000, in whole or part, together with accrued and unpaid interest. The initial redemption price is 102.86% for the year beginning September 15, 2000 and declines ratably thereafter on an annual basis.

During the year ended June 30, 2001, the Company repurchased (and canceled) $47,384,000 principal amount of the 5% Convertible Subordinated Notes. These repurchases resulted in gains of approximately $4,564,000. During the year ended June 30, 2002, the Company repurchased (and canceled) $108,475,000 principal amount of the 5% Convertible Subordinated Notes, leaving $49,951,000 principal amount of the 5% Convertible Subordinated Notes outstanding at June 30, 2002. These repurchases resulted in gains of approximately $5,633,000. During the six months ended December 31, 2002, the Company has repurchased (and canceled) an additional $397,000 principal amount of the 5% Convertible Subordinated Notes, leaving $49,554,000 outstanding as of December 31, 2002. These repurchases resulted in a gain of approximately $18,000. Interest on the 5% Convertible Subordinated Notes is payable on March 15 and September 15 of each year. Interest of approximately $1,244,000 was paid on September 15, 2002. As of December 31, 2002, the Company was in compliance with all covenants contained in the 5% Convertible Subordinated Notes.

## CRITICAL ACCOUNTING POLICIES

The Company prepares its consolidated financial statements in accordance with accounting principles generally accepted in the U.S. and follows certain significant accounting policies when preparing its consolidated financial statements. A complete summary of these policies is included in Note 1 to the consolidated financial statements included herein.

Certain of the policies require management to make significant and subjective estimates, judgments and assumptions that it believes are reasonable based upon the information available. These estimates and assumptions affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods presented. In particular, management makes estimates regarding the fair value of the Company's reporting units in assessing potential impairment of goodwill. In addition, the Company makes estimates regarding future undiscounted cash flows from the future use of long-lived assets whenever events or changes in circumstances indicate that the carrying amount of a long-lived asset may not be recoverable.

In assessing impairment of goodwill, the Company has used estimates and assumptions in estimating the fair value of its reporting units. Actual future results could be different than the estimates and assumptions used. Events or circumstances which might lead to an indication of impairment of goodwill would include, but might not be limited to, prolonged decreases in expectations of long-term well servicing and/or drilling activity or rates brought about by prolonged decreases in oil or natural gas prices, changes in government regulation of the oil and natural gas industry or other events which could affect the level of activity of exploration and production companies.

In assessing impairment of long-lived assets other than goodwill where there has been a change in circumstances indicating that the carrying amount of a long-lived asset may not be recoverable, the Company has estimated future undiscounted net cash flows from use of the asset based on actual historical results and expectations about future economic circumstances including oil and natural gas prices and operating costs. The estimate of future net cash flows from use of the asset could change if actual prices and costs differ due to industry conditions or other factors affecting the Company's performance.



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**RECENTLY ISSUED FINANCIAL ACCOUNTING STANDARDS**

In June 2002, the FASB issued Statement of Financial Accounting Standards No. 146, Accounting for Costs Associated with Exit or Disposal Activities ("SFAS 146"). SFAS 146 establishes requirements for financial accounting and reporting for costs associated with exit or disposal activities. SFAS 146 is effective for exit or disposal activities initiated after June 30, 2002. The adoption of SFAS 146 did not have a material impact on the Company.



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In November 2002, the FASB issued Interpretation No. 45, Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness to Others, an interpretation of FASB Statements No. 5, 57 and 107 and a rescission of FASB Interpretation No. 34 ("FIN 45"). FIN 45 elaborates on the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under guarantees issued. FIN 45 also clarifies that a guarantor is required to recognize, at inception of a guarantee, a liability for the fair value of the obligation undertaken. The initial recognition and measurement provisions of the FIN 45 are applicable to guarantees issued or modified after December 31, 2002 and are not expected to have a material effect on the Company's financial statements. The disclosure requirements are effective for financial statements of interim or annual periods ending after December 15, 2002 and have been adopted.

In December 2002, the FASB issued Statement of Financial Accounting Standards No. 148, Accounting for Stock-Based Compensation Transition and Disclosure, an amendment of FASB Statement No. 123 ("SFAS 148"). SFAS 148 amends FASB Statement No. 123, Accounting for Stock-Based Compensation, to provide alternative methods of transition for a voluntary change to the fair value method of accounting for stock-based employee compensation. In addition, this Statement amends the disclosure requirements of Statement No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock based employee compensation and the effect of the method used on reported results. Certain of the disclosure modifications are required for fiscal years ending after December 15, 2002 and are included in the notes to these consolidated financial statements.

In January 2003, the FASB issued Interpretation No. 46, Consolidation of Variable Interest Entities, an interpretation of ARB No. 51 ("FIN 46"). FIN 46 addresses the consolidation by business enterprises of variable interest entities as defined in FIN 46. FIN 46 applies immediately to variable interests in variable interest entities created after January 31, 2003, and to variable interests in variable interest entities obtained after January 31, 2003. The application of FIN 46 is not expected to have a material effect on the Company's financial statements. FIN 46 requires certain disclosures in financial statements issued after January 31, 2003 if it is reasonably possible that the Company will consolidate or disclose information about variable interest entities when FIN 46 becomes effective.

**IMPACT OF INFLATION ON OPERATIONS**

Management is of the opinion that inflation has not had a significant impact on Key's business.

**ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.**

Special Note: Certain statements set forth below under this caption constitute "forward-looking statements". See "Special Note Regarding Forward-Looking Statements" for additional factors relating to such statements.

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about Key's potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in foreign currency exchange risk, interest rates and oil and natural gas prices. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how Key views and manages its ongoing market risk exposures.



## INTEREST RATE RISK

At December 31, 2002, Key had long-term debt outstanding of $493,565,000. Of this amount, $420,401,000 or 85.18%, bears interest at fixed rates as follows:

| | | Balance at December 31, 2002 |
|---|---|---|
| | | (thousands) |
| $8^{3}/_{8}$% Senior Notes Due 2008 | $ | 276,331 |
| 14% Senior Subordinated Notes Due 2009 | | 94,411 |
| 5% Convertible Subordinated Notes Due 2004 | | 49,554 |
| Other (at approximately 8%) | | 105 |
| | $ | 420,401 |

The remaining $73,164,000 debt outstanding as of December 31, 2002 bears interest at floating rates, which averaged approximately 4.57% at December 31, 2002. A 10% increase in short-term interest rates on the floating-rate debt outstanding at December 31, 2002 would equal approximately 46 basis points. Such an increase in interest rates would increase Key's annual interest expense by approximately $300,000 assuming borrowed amounts remain outstanding.

The above sensitivity analysis for interest rate risk excludes accounts receivable, accounts payable and accrued liabilities because of the short-term maturity of such instruments.

## FOREIGN CURRENCY RISK

During the year ended June 30, 2002, the Argentine government suspended the law tying the Argentine peso to the U.S. dollar at the conversion ratio of 1:1 and created a dual currency system in Argentina. Key's net assets of its Argentina subsidiaries are based on the U.S. dollar equivalent of such amounts measured in Argentine pesos as of December 31, 2002 and June 30, 2002. Assets and liabilities of the Argentine operations were translated to U.S. dollars at December 31, 2002 and June 30, 2002 using the applicable free market conversion ratio of 3.4:1 and 3.9:1, respectively, and will be translated at future dates using the applicable free market conversion ratio on such dates. Key's net earnings and cash flows from its Argentina subsidiaries were tied to the U.S. dollar for the six months ended December 31, 2001 and are based on the U.S. dollar equivalent of such amounts measured in Argentine pesos for periods after December 31, 2001. Revenues, expenses and cash flow will be translated using the average exchange rates during the periods after December 31, 2001. See Note 18 to the consolidated financial statements.

The change in the Argentine peso to the U.S. dollar exchange rate since December 31, 2001 has reduced stockholders' equity by $44,547,000, through a charge to other comprehensive loss through December 31, 2002.

Key's net assets, net earnings and cash flows from its Canadian subsidiary are based on the U.S. dollar equivalent of such amounts measured in Canadian dollars. Assets and liabilities of the Canadian operations are translated to U.S. dollars using the applicable exchange rate as of the end of a reporting period. Revenues and expenses are translated using the average exchange rate during the reporting period.

A 10% change in the Canadian-to-U.S. Dollar exchange rate would not be material to the net assets, net earnings or cash flows of the Company. See discussion regarding foreign operations in Note 13 to the consolidated financial statements.

**COMMODITY PRICE RISK**

Key's major market risk exposure for its oil and natural gas production operations is in the pricing applicable to its oil and natural gas sales. Realized pricing is primarily driven by the prevailing worldwide



price for crude oil and spot market prices for natural gas. Pricing for oil and natural gas production has been volatile and unpredictable for several years.

The Company periodically hedges a portion of its oil and natural gas production through collar and option agreements. The purpose of the hedges is to provide a measure of stability in the volatile environment of oil and natural gas prices and to manage exposure to commodity price risk under existing sales commitments. The Company's risk management objective is to lock in a range of pricing for expected production volumes. This allows the Company to forecast future earnings within a predictable range. The Company meets this objective by entering into collar and option arrangements which allow for acceptable cap and floor prices.

As of December 31, 2002, Key had oil and natural gas price collars and put options in place, as detailed in the following table. Hedged oil and natural gas volumes as a percentage of actual production were 43% and 51%, respectively, for the six months ended December 31, 2002. A 10% variation in the market price of oil or natural gas from their levels at December 31, 2002 would have no material impact on the Company's net assets, net earnings or cash flows (as derived from commodity option contracts).

The following table sets forth the future volumes hedged by year and the weighted-average strike price of the option contracts at December 31, 2002 and June 30, 2002 and 2001:

| | Monthly Income | | | Strike Price Per Bbl/MMbtu | | |
|---|---|---|---|---|---|---|
| | **Oil (Bbls)** | **Gas (MMbtu)** | **Term** | **Floor** | **Cap** | **Fair Value** |
| At December 31, 2002 | | | | | | |
| Oil Put | 5,000 | | Mar 2002-Feb 2003 | $ 22.00 | | $ |
| Oil Put | 4,000 | | Mar 2003-Feb 2004 | $ 21.00 | | $ 34,000 |
| Gas Put | | 75,000 | Mar 2002-Feb 2003 | $ 3.00 | | $ |
| At June 30, 2002 | | | | | | |
| Oil Put | 5,000 | | Mar 2002-Feb 2003 | $ 22.00 | | $ 24,000 |
| Oil Put | 4,000 | | Mar 2003-Feb 2004 | $ 21.00 | | $ 118,000 |
| Gas Put | | 75,000 | Mar 2002-Feb 2003 | $ 3.00 | | $ 104,000 |
| At June 30, 2001 | | | | | | |
| Oil Collar | 5,000 | | Mar 2001-Feb 2002 | $ 19.70 | $ 23.70 | $ (115,000) |
| Oil Put | 5,000 | | Mar 2002-Feb 2003 | $ 22.00 | | $ 141,000 |
| Gas Collar | | 40,000 | Mar 2001-Feb 2002 | $ 2.40 | $ 2.91 | $ (229,000) |
| Gas Put | | 75,000 | Mar 2002-Feb 2003 | $ 3.00 | | $ 894,000 |

(The strike prices for the oil collars and puts are based on the NYMEX spot price for West Texas Intermediate; the strike prices for the natural gas collars are based on the Inside FERC-West Texas Waha spot price; the strike price for the natural gas put is based on the Inside FERC-El Paso Permian spot price.)

## ITEM 8. CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

Presented herein are the consolidated financial statements of Key Energy Services, Inc. as of December 31, 2002, June 30, 2002 and 2001, the six months ended December 31, 2002, and the years ended June 30, 2002, 2001 and 2000.

Also included is the report of KPMG LLP, independent certified public accountants, on such consolidated financial statements as of December 31, 2002, June 30, 2002 and 2001, the six months ended December 31, 2002, and the years ended June 30, 2002, 2001 and 2000.

### INDEX TO CONSOLIDATED FINANCIAL STATEMENTS





### Key Energy Services, Inc.

### Consolidated Balance Sheets

| | December 31, 2002 | June 30, 2002 | June 30, 2001 |
|---|---|---|---|
| | (Thousands, except share data) | | |
| ***ASSETS*** | | | |
| Current assets: | | | |
| Cash and cash equivalents | $ 9,044 | $ 54,147 | $ 2,098 |
| Accounts receivable, net of allowance for doubtful accounts, $4,439, $3,969 and $4,082, at December 31, 2002 and June 30, 2002 and 2001, respectively | 141,958 | 117,907 | 177,016 |
| Inventories | 10,243 | 7,776 | 16,547 |
| Prepaid expenses and other current assets | 14,329 | 12,243 | 10,489 |
| Total current assets | 175,574 | 192,073 | 206,150 |
| Property and equipment: | | | |
| Well servicing equipment | 935,911 | 776,271 | 723,724 |
| Contract drilling equipment | 128,199 | 124,191 | 119,122 |
| Motor vehicles | 79,110 | 68,977 | 64,907 |
| Oil and gas properties and other related equipment, successful efforts method | 48,362 | 44,439 | 44,245 |
| Furniture and equipment | 51,349 | 38,979 | 24,865 |
| Buildings and land | 48,922 | 40,247 | 37,812 |

| | December 31, 2002 | June 30, 2002 | June 30, 2001 |
|---|---|---|---|
| Total property and equipment | 1,291,853 | 1,093,104 | 1,014,675 |
| Accumulated depreciation & depletion | (335,348) | (284,204) | (220,959) |
| Net property and equipment | 956,505 | 808,900 | 793,716 |
| Goodwill, net of accumulated amortization, $27,876, $27,856 and $28,168 at December 31, 2002 and June 30, 2002 and 2001, respectively | 322,270 | 201,069 | 189,875 |
| Deferred costs, net | 13,503 | 12,580 | 17,624 |
| Notes receivable related parties | 251 | 274 | 6,050 |
| Other assets | 33,899 | 28,099 | 14,869 |
| Total assets | $ 1,502,002 | $ 1,242,995 | $ 1,228,284 |
| ***LIABILITIES AND STOCKHOLDERS' EQUITY*** | | | |
| Current liabilities: | | | |
| Accounts payable | $ 28,818 | $ 24,625 | $ 42,544 |
| Other accrued liabilities | 57,823 | 49,465 | 48,923 |
| Accrued interest | 15,226 | 14,864 | 16,140 |
| Current portion of long-term debt | 7,008 | 7,674 | 7,946 |
| Total current liabilities | 108,875 | 96,628 | 115,553 |
| Long-term debt, less current portion | 472,336 | 420,717 | 470,578 |
| Capital lease obligations, less current portion | 14,221 | 15,219 | 15,383 |
| Deferred revenue | 8,460 | 10,001 | 14,104 |
| Non-current accrued expenses | 40,477 | 13,574 | 8,388 |
| Deferred tax liability | 161,265 | 149,990 | 127,400 |
| Commitments and contingencies | | | |
| Stockholders' equity: | | | |
| Common stock, $0.10 par value; 200,000,000 shares authorized, 128,757,693, 110,308,463 and 101,440,166 shares issued, at December 31, 2002 and June 30, 2002 and 2001, respectively | 12,876 | 11,031 | 10,144 |
| Additional paid-in capital | 673,249 | 514,752 | 444,768 |
| Treasury stock, at cost; 416,666 shares at December 31, 2002 and June 30, 2002 and 2001 | (9,682) | (9,682) | (9,682) |
| Accumulated other comprehensive income (loss) | (45,431) | (48,967) | 62 |
| Retained earnings | 65,356 | 69,732 | 31,586 |
| Total stockholders' equity | 696,368 | 536,866 | 476,878 |
| Total liabilities and stockholders' equity | $ 1,502,002 | $ 1,242,995 | $ 1,228,284 |

*See the accompanying notes which are an integral part of these consolidated financial statements.*



**Key Energy Services, Inc.**

**Consolidated Statements of Operations**

**Year Ended June 30,**

| | Six Months Ended December 31, 2002 | Year Ended June 30, 2002 | 2001 | 2000 |
|---|---|---|---|---|
| | (Thousands, except per share data) | | | |
| ***REVENUES:*** | | | | |
| Well servicing | $ 370,871 | $ 706,629 | $ 758,273 | $ 559,492 |
| Contract drilling | 33,632 | 87,077 | 107,639 | 68,428 |
| Other | 4,495 | 8,858 | 7,350 | 9,812 |
| Total revenues | 408,998 | 802,564 | 873,262 | 637,732 |
| ***COSTS AND EXPENSES:*** | | | | |
| Well servicing | 263,595 | 489,681 | 500,324 | 408,723 |
| Contract drilling | 23,416 | 60,561 | 77,366 | 58,299 |
| Depreciation, depletion and amortization | 51,111 | 78,265 | 75,147 | 70,972 |
| General and administrative | 48,239 | 59,494 | 60,118 | 51,637 |
| Interest | 22,743 | 43,332 | 56,560 | 71,930 |
| Other expenses | 1,934 | 4,531 | 4,464 | 4,147 |
| Foreign currency transaction loss, Argentina | | 1,443 | | |
| (Gain) loss on retirement of debt | (18) | 4,812 | (684) | (2,191) |
| Total costs and expenses | 411,020 | 742,119 | 773,295 | 663,517 |
| Income (loss) before income taxes | (2,022) | 60,445 | 99,967 | (25,785) |
| Income tax benefit (expense) | 519 | (22,299) | (37,257) | 6,826 |
| ***INCOME (LOSS) before cumulative effect*** | (1,503) | 38,146 | 62,710 | (18,959) |
| Cumulative effect on prior years of change in accounting principle, net of tax (See Note 1) | (2,873) | | | |
| ***NET INCOME (LOSS)*** | $ (4,376) | $ 38,146 | $ 62,710 | $ (18,959) |
| ***EARNINGS (LOSS) PER SHARE:*** | | | | |
| Basic before cumulative effect | $ (0.01) | $ 0.36 | $ 0.64 | $ (0.23) |
| Cumulative effect, net of tax | (0.02) | | | |
| Basic after cumulative effect | $ (0.03) | $ 0.36 | $ 0.64 | $ (0.23) |
| Diluted before cumulative effect | $ (0.01) | $ 0.35 | $ 0.61 | $ (0.23) |
| Cumulative effect, net of tax | (0.02) | | | |
| Diluted after cumulative effect | $ (0.03) | $ 0.35 | $ 0.61 | $ (0.23) |

| | | Year Ended June 30, | | |
|---|---|---|---|---|
| WEIGHTED AVERAGE SHARES OUTSTANDING: | | | | |
| Basic | 125,367 | 105,766 | 98,195 | 83,815 |
| Diluted | 125,367 | 107,462 | 102,271 | 83,815 |

*See the accompanying notes which are an integral part of these consolidated financial statements.*



**Key Energy Services, Inc.**

**Consolidated Statements of Comprehensive Income**

| | Six Months Ended December 31, 2002 | Year Ended June 30, 2002 | 2001 | 2000 |
|---|---|---|---|---|
| | | (Thousands) | | |
| ***NET INCOME (LOSS)*** | $ (4,376) | $ 38,146 | $ 62,710 | $ (18,959) |
| ***OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX:*** | | | | |
| Derivative transition adjustment | | | (778) | |
| Oil and natural gas derivatives adjustment | (775) | (279) | 306 | |
| Amortization of oil and natural gas derivatives | 609 | (367) | 558 | |
| Currency translation gain (loss) | 3,702 | (48,383) | (32) | (1) |
| ***COMPREHENSIVE INCOME (LOSS), NET OF TAX*** | $ (840) | $ (10,883) | $ 62,764 | $ (18,960) |

*See the accompanying notes which are an integral part of these consolidated financial statements.*



**Key Energy Services, Inc.**

**Consolidated Statements of Cash Flows**

| | Six Months Ended December 31, 2002 | Year Ended June 30, 2002 | 2001 | 2000 |
|---|---|---|---|---|
| | | (Thousands) | | |
| ***CASH FLOWS FROM OPERATING ACTIVITIES:*** | | | | |
| Net income (loss) | $ (4,376) | $ 38,146 | $ 62,710 | $ (18,959) |
| *Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:* | | | | |
| Depreciation, depletion and amortization | 51,111 | 78,265 | 75,147 | 70,972 |

| | Year Ended June 30, | | | |
|---|---|---|---|---|
| Amortization of deferred debt issuance costs, discount and premium | 2,154 | 3,005 | 4,947 | 5,919 |
| Deferred income taxes | (552) | 21,385 | 34,953 | (1,238) |
| (Gain) loss on sale of assets | 477 | (668) | 173 | 25 |
| Foreign currency transaction loss, Argentina | | 1,443 | | |
| (Gain) loss on retirement of debt | (18) | 4,812 | (684) | (2,191) |
| Cumulative effect of a change in accounting principle, net of tax | 2,873 | | | |
| *Change in assets and liabilities net of effects from the acquisitions:* | | | | |
| (Increase) decrease in accounts receivable | (4,951) | 48,907 | (53,813) | (31,205) |
| (Increase) decrease in other current assets | 7,655 | (4,410) | (4,485) | (5,483) |
| Increase (decrease) in accounts payable, accrued interest and accrued expenses | (3,562) | (12,180) | 29,414 | 18,875 |
| Other assets and liabilities | 6,783 | 11 | (5,015) | (1,855) |
| Net cash provided by operating activities | 57,594 | 178,716 | 143,347 | 34,860 |
| ***CASH FLOWS FROM INVESTING ACTIVITIES:*** | | | | |
| Capital expenditures well servicing | (27,422) | (57,857) | (51,064) | (26,469) |
| Capital expenditures contract drilling | (3,894) | (19,861) | (15,884) | (8,282) |
| Capital expenditures other | (10,180) | (15,979) | (15,802) | (3,422) |
| Proceeds from sale of fixed assets | 788 | 4,258 | 3,415 | 2,722 |
| Notes receivable from related parties | | | (1,500) | (2,315) |
| Acquisitions well servicing | (105,365) | (17,273) | (2,345) | |
| Acquisitions contract drilling | | (2,037) | (800) | |
| Net cash used in investing activities | (146,073) | (108,749) | (83,980) | (37,766) |
| ***CASH FLOWS FROM FINANCING ACTIVITIES:*** | | | | |
| Repayment of long-term debt | (16,413) | (309,559) | (373,998) | (39,438) |
| Repayment of capital lease obligations | (4,902) | (10,182) | (8,542) | (11,639) |
| Borrowings under line of credit | 68,000 | | | |
| Proceeds from equity offerings, net of expenses | | 42,590 | | 100,571 |
| Proceeds from long-term debt | | 258,500 | 205,210 | 12,000 |
| Debt issuance costs | (3,026) | (1,585) | (4,958) | |
| Proceeds from forward sale, net of expenses | | | | 18,236 |
| Proceeds from exercise of warrants | | | 847 | 8,473 |
| Proceeds from exercise of stock options | 433 | 3,219 | 14,617 | 1,098 |
| Other | (38) | (298) | (318) | |
| Net cash provided by (used in) financing activities | 44,054 | (17,315) | (167,142) | 89,301 |
| Effect of exchange rates on cash | (678) | (603) | | |
| Net increase (decrease) in cash | (45,103) | 52,049 | (107,775) | 86,395 |
| Cash and cash equivalents at beginning of period | 54,147 | 2,098 | 109,873 | 23,478 |
| Cash and cash equivalents at end of period | $ 9,044 | $ 54,147 | $ 2,098 | $ 109,873 |

*See the accompanying notes which are an integral part of these consolidated financial statements.*

**Key Energy Services Inc.**

**Consolidated Statements of Stockholders' Equity**

**(Thousands)**

| | Common Stock | | | | | | |
|---|---|---|---|---|---|---|---|
| | **Number of Shares** | **Amount at par** | **Additional Paid-in Capital** | **Treasury Stock** | **Accumulated Other Comprehensive Income** | **Retained Earnings** | **Total** |
| **BALANCE AT JUNE 30, 1999** | 83,155 | $ 8,317 | $ 301,615 | $ (9,682) | $ 9 | $ (12,165) | $ 288,094 |
| Foreign currency transition adjustment, net of tax | | | | | (1) | | (1) |
| Exercise of warrants | 2,431 | 243 | 8,230 | | | | 8,473 |
| Exercise of options | 241 | 24 | 1,074 | | | | 1,098 |
| Conversion of 7% Debentures | 380 | 38 | 3,568 | | | | 3,606 |
| Issuance of common stock in equity offering, net of offering costs | 11,000 | 1,100 | 99,471 | | | | 100,571 |
| Other | 3 | 1 | 4 | | | | 5 |
| Net loss | | | | | | (18,959) | (18,959) |
| **BALANCE AT JUNE 30, 2000** | 97,210 | $ 9,723 | $ 413,962 | $ (9,682) | $ 8 | $ (31,124) | $ 382,887 |
| Derivative transition adjustment (see Note 6) | | | | | (778) | | (778) |
| Oil and natural gas derivatives adjustment, net of tax (See Note 6) | | | | | 306 | | 306 |
| Amortization of oil and natural gas derivatives (see Note 6) | | | | | 558 | | 558 |
| Foreign currency translation adjustment, net of tax | | | | | (32) | | (32) |
| Exercise of warrants | 185 | 19 | 828 | | | | 847 |
| Exercise of options | 3,106 | 308 | 14,309 | | | | 14,617 |
| Conversion of 7% Debentures | 101 | 10 | 947 | | | | 957 |
| Issuance of common stock for acquisitions | 838 | 84 | 8,036 | | | | 8,120 |
| Deferred tax benefit compensation expense | | | 7,004 | | | | 7,004 |
| Other | | | (318) | | | | (318) |
| Net income | | | | | | 62,710 | 62,710 |
| **BALANCE AT JUNE 30, 2001** | 101,440 | $ 10,144 | $ 444,768 | $ (9,682) | $ 62 | $ 31,586 | $ 476,878 |
| Oil and natural gas derivatives adjustment, net of tax (See Note 6) | | | | | (279) | | (279) |
| Amortization of oil and natural gas derivatives (see Note 6) | | | | | (367) | | (367) |
| Foreign currency translation adjustment, net of tax | | | | | (48,383) | | (48,383) |
| Exercise of warrants | 7 | 1 | (1) | | | | |
| Exercise of options | 659 | 66 | 3,153 | | | | 3,219 |
| Issuance of common stock for acquisitions | 2,801 | 280 | 24,787 | | | | 25,067 |
| Issuance of common stock in equity offering, net of offering costs | 5,400 | 540 | 42,050 | | | | 42,590 |
| Other | 1 | | (5) | | | | (5) |
| Net income | | | | | | 38,146 | 38,146 |
| **BALANCE AT JUNE 30, 2002** | 110,308 | $ 11,031 | $ 514,752 | $ (9,682) | $ (48,967) | $ 69,732 | $ 536,866 |

| | Common Stock | | | | | | |
|---|---|---|---|---|---|---|---|
| Oil and natural gas derivatives adjustment, net of tax (See Note 6) | | | | | (775) | | (775) |
| Amortization of oil and natural gas derivatives (see Note 6) | | | | | 609 | | 609 |
| Foreign currency translation adjustment, net of tax | | | | | 3,702 | | 3,702 |
| Exercise of options | 139 | 14 | 419 | | | | 433 |
| Issuance of common stock for acquisitions | 18,311 | 1,831 | 158,115 | | | | 159,946 |
| Other | | | (37) | | | | (37) |
| Net loss | | | | | | (4,376) | (4,376) |
| **BALANCE AT DECEMBER 31, 2002** | 128,758 | $ 12,876 | $ 673,249 | $ (9,682) | $ (45,431) | $ 65,356 | 696,368 |

*See the accompanying notes which are an integral part of these consolidated financial statements.*



**Key Energy Services Inc.**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

**December 31, 2002, June 30, 2002, 2001 and 2000**

## 1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

### The Company

Based on the number of rigs owned and available industry data, Key Energy Services, Inc. (the "Company" or "Key"), is the largest onshore, rig-based well servicing contractor in the world, with approximately 1,489 well service rigs and 2,295 oilfield service vehicles as of December 31, 2002. The Company provides a complete range of well services to major oil companies and independent oil and natural gas production companies, including: rig-based well maintenance, workover, completion, and recompletion services (including horizontal recompletions); oilfield trucking services; well intervention services; and ancillary oilfield services. Key conducts well servicing operations onshore in the continental United States in the following regions: Gulf Coast (including South Texas, Central Gulf Coast of Texas, and South Louisiana), Permian Basin of West Texas and Eastern New Mexico, Mid-Continent (including the Anadarko, Hugoton and Arkoma Basins, Forth Worth Basin and the ArkLaTex region), Four Corners (including the San Juan, Piceance, Uinta, and Paradox Basins), Eastern (including the Appalachian, Michigan and Illinois Basins), Rocky Mountains (including the Denver-Julesberg, Powder River, Wind River, Green River and Williston Basins), and California (the San Joaquin Basin), and internationally in Argentina and Canada (Ontario) and Egypt. Based on the number of rigs owned and available industry data, the Company is also a leading onshore drilling contractor, with approximately 79 land drilling rigs as of December 31, 2002. Key conducts land drilling operations in a number of major domestic producing basins, as well as in Argentina and in Canada (Ontario). Key also produces and develops oil and natural gas reserves in the Permian Basin region and Texas Panhandle.

### Basis of Presentation

The Company's consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries. All significant inter-company transactions and balances have been eliminated. The accounting policies presented below have been followed in preparing the accompanying consolidated financial statements.

### Estimates and Uncertainties

Preparation of the accompanying consolidated financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the reported amount of assets and liabilities and disclosures of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

### Revenue Recognition

*Well Servicing Rigs.* Well servicing rig services consists primarily of maintenance services, workover services, completion services and plugging and abandonment services. The Company recognizes revenue when services are performed, collection of the relevant receivables is probable, persuasive evidence of an arrangement exists and the price is fixable or determinable. Primarily, the Company prices well servicing rig services by the hour of service performed. Depending on the type of job, the Company may charge by the project or by the day.



*Oilfield Trucking.* Oilfield trucking consists primarily of fluid and equipment transportation services and frac tanks which are used in conjunction with fluid hauling services. The Company recognizes revenue when services are performed, collection of the relevant receivables is probable, persuasive evidence of an arrangement exists and the price is fixable or determinable. Primarily, the Company prices oilfield trucking services by the project or by the quantities hauled.

*Well Intervention Services.* Well intervention services consists primarily of fishing and rental tool services and pressure pumping services. The Company recognizes revenue when services are performed, collection of the relevant receivables is probable, persuasive evidence of an arrangement exists and the price is fixable or determinable. Generally, the Company prices fishing and rental tool services by the day and pressure pumping services by the job.

*Ancillary Oilfield Services.* Ancillary oilfield services includes wireline services, wellsite construction, roustabout services, foam units and air drilling services among others. The Company recognizes revenue when services are performed, collection of the relevant receivables is probable, persuasive evidence of an arrangement exists and the price is fixable or determinable. The Company prices ancillary oilfield services by the hour, day or project depending on the type of service performed.

*Contract Drilling.* The Company recognizes revenue when services are performed, collection of the relevant receivables is probable, persuasive evidence of an arrangement exists and the price is fixable or determinable. Contract drilling services are primarily provided under standard day rate, and, to a lesser extent, footage or turnkey contracts. The Company recognizes revenues on day rate contracts as earned daily. The Company follows the percentage of completion method of accounting for footage contracts. Under this method, revenues are recognized over the time it takes to drill the well based on the footage completed. On turnkey contracts, the Company recognizes revenue when the well is completed.

**Inventories**

Inventories, which consist primarily of oilfield service parts and supplies held for consumption, are valued at the lower of average cost or market.

**Property and Equipment**

The Company provides for depreciation and amortization of oilfield service and related equipment using the straight-line method, excluding its drilling rigs, over the following estimated useful lives of the assets:

| Description | Years |
|---|---|
| Well service rigs | 25 |
| Motor vehicles | 5 |
| Furniture and equipment | 3-7 |
| Buildings and improvements | 10-40 |
| Gas processing facilities | 10 |
| Disposal wells | 15-30 |
| Trucks, trailers and related equipment | 7-15 |

The components of a well service rig that generally require replacement during the rig's life are depreciated over their estimated useful lives, which range from three to 15 years. The basic rigs, excluding



components, have estimated useful lives from date of original manufacture ranging from 25 to 35 years. Salvage values are assigned to the rigs based on an estimate of 10%.

The Company uses the units-of-production method to depreciate its drilling rigs. This method takes into consideration the number of days the rigs are actually in service each month and depreciation is recorded for at least 15 days each month for each rig that is available for service. The Company believes that this method appropriately reflects its financial results by matching revenues with expenses and appropriately reflects how the assets are to be used over time.

The Company uses the successful efforts method of accounting for its oil and gas properties. Under this method, all costs associated with productive wells and nonproductive development wells are capitalized, while nonproductive exploration costs and geological and geophysical costs (if any), are expensed. Capitalized costs relating to proved properties are depleted using the units-of-production method. Due to the immateriality of the oil and natural gas operations in terms of revenue, net income and total assets, the Company does not provide disclosures on its oil and gas properties in accordance with FASB Statement No. 69, Disclosures about Oil and Gas Producing Activities ("SFAS 69").

On July 1, 2002, the Company adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations ("SFAS 143"). Adoption of SFAS 143 is required for all companies with fiscal years beginning after June 15, 2002. The new standard requires the Company to recognize a liability for the present value of all legal obligations associated with the retirement of tangible long-lived assets and capitalize an equal amount as a cost of the asset depreciating the additional cost over the estimated useful life of the asset. On July 1, 2002, the Company recorded additional costs, net of accumulated depreciation, of approximately $3,347,000, a non-current liability of approximately $7,980,000 and an after-tax charge of approximately $2,873,000 for the cumulative effect on prior years for depreciation of the additional costs and accretion expense on the liability related to expected abandonment costs of its oil and natural gas producing properties and salt water disposal wells. At December 31, 2002, the asset retirement obligation was approximately $9,231,000, and the increase in the balance from July 1, 2002 of $1,251,000 is due to accretion expense of approximately $226,000 and asset retirement obligations of QSI of $1,025,000 assumed in the purchase transaction. The pro forma amounts of the asset retirement obligation as of June 30, 2002, 2001, 2000 and 1999, were approximately $7,980,000, $7,581,000, $7,182,000 and $6,783,000, respectively. The pro forma amounts of the asset retirement obligation were measured using information, assumptions and interest rates as of the adoption date of July 1, 2002. Pro forma net income (loss) and related per share amounts for the years ended June 30, 2002, 2001 and 2000, assuming SFAS 143 had been applied in each year are as follows:

| | Year Ended | | |
|---|---|---|---|
| | 2002 | 2001 | 2000 |
| | (Thousands, except per share amount) | | |
| Pro forma net income (loss) | $ 37,894 | $ 62,460 | $ (19,252) |
| Earnings (loss) per share | | | |
| Basic | $ 0.36 | $ 0.64 | $ (0.23) |
| Diluted | $ 0.35 | $ 0.61 | $ (0.23) |

On July 1, 2002, the Company adopted Statement of Financial Accounting Standards No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets ("SFAS 144"). This statement requires that long-lived assets including certain identifiable intangibles, held and used by the Company, be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset



may not be recoverable. For purposes of applying this statement, the Company groups its long-lived assets on a yard-by-yard basis and compares the estimated future cash flows of each yard to the yard's net carrying value. The yard level represents the lowest level for which identifiable cash flows are available. The Company would record an impairment charge, reducing the yard's net carrying value to an estimated fair value, if the estimated future cash flows were less than the yard's net carrying value. No impairment charges have been required. Prior to July 1, 2002, the Company applied the provisions of FASB Statement No. 121, Accounting for Impairment or Disposal of Long Lived Assets.

**Hedging and Derivative Financial Instruments**

The Company uses derivative financial instruments, primarily commodity option contracts to reduce the exposure of its oil and gas producing operations to changes in the market price of natural gas and crude oil and to fix the price for natural gas and crude oil independently of the physical sale.

The financial instruments that the Company accounts for as hedging contracts must meet the following criteria: the underlying asset or liability must expose the Company to price risk that is not offset in another asset or liability, the hedging contract must reduce that price risk, and the instrument must be designated as a hedge at the inception of the contract and throughout the contract period. In order to qualify as a hedge, there must be clear correlation between changes in the fair value of the financial instrument and the fair value of the underlying asset or liability such that changes in the market value of the financial instrument will be offset by the effect of price rate changes on the exposed items.

Prior to the adoption of SFAS 133, premiums paid for commodity option contracts, which qualify as hedges, are amortized to oil and natural gas sales over the terms of the contracts. Unamortized premiums are included in other assets in the consolidated balance sheet. Amounts receivable under the commodity option contracts are accrued as an increase in oil and natural gas sales for the applicable periods.

Effective July 1, 2000, the Company adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133") as amended by SFAS No. 137 and No. 138 ("SFAS 138"). SFAS 133 establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts and hedging activities. It requires the recognition of all derivative instruments as assets and liabilities in the Company's balance sheet and measurement of those instruments at fair value. The accounting treatment of changes in fair value is dependent upon whether or not a derivative instrument is designated as a hedge and if so, the type of hedge. For derivatives designated as cash flow hedges, changes in fair value are recognized in other comprehensive income until the hedged item is recognized in earnings. See Note 6.

**Comprehensive Income**

The Company follows the provisions of Statement of Financial Accounting Standards No. 130, "Reporting Comprehensive Income" ("SFAS 130"). SFAS 130 establishes standards for reporting and presentation of comprehensive income and its components. SFAS 130 requires that all items that are required to be recognized under accounting standards as components of comprehensive income be reported in a financial statement that is displayed with the same prominence as other financial statements. In accordance with the provisions of SFAS 130, the Company has presented the components of comprehensive income in its Consolidated Statements of Comprehensive Income.



**Environmental**

The Company is subject to extensive federal, state and local environmental laws and regulations. These laws, which are constantly changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the adverse environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a non-capital nature are recorded when environmental assessment and/or remediation is probable, and the costs can be reasonably estimated.

**Goodwill and Other Intangible Assets**

The Company adopted Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets ("SFAS 142") on July 1, 2001. SFAS 142 eliminates the amortization for goodwill and other intangible assets with indefinite lives. Intangible assets with lives restricted by contractual, legal, or other means will continue to be amortized over their useful lives. Goodwill and other intangible assets not subject to amortization are tested for impairment annually or more frequently if events or changes in circumstances indicate that the asset might be impaired. SFAS 142 requires a two-step process for testing impairment. First, the fair value of each reporting unit is compared to its carrying value to determine whether an indication of impairment exists. If impairment is indicated, then the fair value of the reporting unit's goodwill is determined by allocating the unit's fair value to its assets and liabilities (including any unrecognized intangible assets) as if the reporting unit had been acquired in a business combination. The amount of impairment for goodwill is measured as the excess of its carrying value over its fair value. The Company completed its assessment of goodwill impairment as of the date of adoption during the three months ended December 31, 2001, as allowed by SFAS 142, and a subsequent annual impairment assessment as of June 30, 2002. The assessments did not result in an indication of goodwill impairment as of either date.

Intangible assets subject to amortization under SFAS 142 consist of noncompete agreements and patents. Amortization expense for the noncompete agreements is calculated using the straight-line method over the period of the agreement, ranging from three to seven years. Amortization expense for patents is calculated using the straight-line method over the useful life of the patent, ranging from five to seven years.

The gross carrying amount of noncompete agreements subject to amortization totaled approximately $18,669,000, $11,727,000 and $8,324,000 at December 31, 2002 and June 30, 2002 and 2001, respectively. Accumulated amortization related to these intangible assets totaled approximately $7,511,000, $6,130,000 and $4,953,000 at December 31, 2002 and June 30, 2002 and 2001, respectively. Amortization expense for the six months ended December 31, 2002 was approximately $2,333,000 and for the years ended June 30, 2002, 2001 and 2000 was approximately $1,914,000, $1,801,000 and $1,410,000, respectively. Amortization expense for the next five succeeding years is estimated to be approximately $3,885,000, $2,750,000, $2,122,000, $1,711,000 and $662,000.

The gross carrying amount of patents subject to amortization totaled approximately $2,380,000 at December 31, 2002. The Company acquired patents on July 16, 2002. Accumulated amortization and amortization expense related to these intangible assets totaled approximately $160,000 as of and for the six months ended December 31, 2002. Amortization expense for the next five succeeding years is estimated to be approximately $511,000, $352,000, $352,000, $352,000, and $296,000.



The Company has identified its reporting segments to be well servicing and contract drilling. Goodwill allocated to such reporting segments at December 31, 2002 is approximately $307,987,000 and $14,283,000, and at June 30, 2002 is $186,819,000 and $14,250,000, respectively. The change in the carrying amount of goodwill for the six months ended December 31, 2002 of $121,201,000 and for the year ended June 30, 2002 of approximately $11,194,000 relates principally to goodwill from well servicing assets acquired during the period and the translation adjustment for Argentina.

The effects of the adoption of SFAS 142 on net income and earnings per share for the years ended June 30, 2001 and 2000 are as follows:

| | Year Ended June 30, | |
|---|---|---|
| | **2001** | **2000** |
| | (thousands, except per share data) | |
| Reported net income (loss) | $ 62,710 | $ (18,959) |
| Add back: goodwill amortization | 9,322 | 9,840 |
| Adjusted net income (loss) | $ 72,032 | $ (9,119) |
| **Basic Earnings (Loss) Per Share:** | | |
| Reported net income (loss) | $ 0.64 | $ (0.23) |
| Add back: goodwill amortization | 0.09 | 0.12 |
| Adjusted net income (loss) | $ 0.73 | $ (0.11) |
| **Diluted Earnings (Loss) Per Share:** | | |
| Reported net income (loss) | $ 0.61 | $ (0.23) |
| Add back: goodwill amortization | 0.09 | 0.12 |
| Adjusted net income (loss) | $ 0.70 | $ (0.11) |

**Deferred Costs**

Deferred costs totaling $35,955,000 at December 31, 2002 and $32,928,000 and $31,052,000 at June 30, 2002 and 2001, respectively, represent debt issuance costs and are recorded net of accumulated amortization of $22,452,000 at December 31, 2002 and $20,348,000 and $13,428,000 at June 30, 2002 and 2001, respectively. Deferred costs are amortized to interest expense using the straight-line method over the life of each applicable debt instrument or to gain (loss) on retirement of debt. This method approximates the amortization which would be recorded using the effective interest method. Amortization of deferred costs totaled approximately $2,103,000 for the six months ended December 31, 2002 and $2,581,000, $3,578,000 and $5,176,000 for the years ended June 30, 2002, 2001 and 2000, respectively. Unamortized debt issuance costs written off and included in the determination of the gain (loss) on retirement of debt for the years ended June 30, 2002 and 2001, totaled approximately $4,339,000 and $2,583,000, respectively. For the six months ended December 31, 2002 and the year ended June 30, 2000, there were no unamortized debt issuance costs included in the determination of gain (loss) on the retirement of debt.

**Income Taxes**

The Company accounts for income taxes based upon Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes" ("SFAS 109"). Under SFAS 109, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using statutory tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rate is recognized in income in the period that includes the statutory enactment date. A valuation allowance for deferred tax assets is recognized when it is more likely than not that the benefit of deferred tax assets will not be realized.

The Company and its eligible subsidiaries file a consolidated U. S. federal income tax return. Certain subsidiaries that are consolidated for financial reporting purposes are not eligible to be included in the consolidated U. S. federal income tax return and separate provisions for income taxes have been determined for these entities or groups of entities.

**Earnings Per Share**

The Company presents earnings per share information in accordance with the provisions of Statement of Financial Accounting Standards No. 128, "Earnings per Share" ("SFAS 128"). Under SFAS 128, basic earnings per common share are determined by dividing net earnings applicable to common stock by the weighted average number of common shares actually outstanding during the year. Diluted earnings per



common share is based on the increased number of shares that would be outstanding assuming conversion of dilutive outstanding convertible securities using the "as if converted" method.

| | Six Months Ended December 31, 2002 | Year Ended June 30, 2002 | 2001 | 2000 |
|---|---|---|---|---|
| | (thousands, except per share data) | | | |
| **Basic EPS Computation:** | | | | |
| *Numerator* | | | | |
| Net income (loss) before cumulative effect | $ (1,503) | $ 38,146 | $ 62,710 | $ (18,959) |
| Cumulative effect, net of tax(1) | (2,873) | | | |
| Net income (loss) | $ (4,376) | $ 38,146 | $ 62,710 | $ (18,959) |
| *Denominator* | | | | |
| Weighted average common shares outstanding | 125,367 | 105,766 | 98,195 | 83,815 |
| **Basic EPS:** | | | | |
| Before cumulative effect (loss) | $ (0.01) | $ 0.36 | $ 0.63 | $ (0.23) |
| Cumulative effect, net of tax(1) | (0.02) | | | |
| Net income (loss) | $ (0.03) | $ 0.36 | $ 0.63 | $ (0.23) |

| Diluted EPS Computation: | Six Months Ended December 31, 2002 | Year Ended June 30, | | |
|---|---|---|---|---|
| *Numerator* | | | | |
| Net income (loss) before cumulative effect and effect of dilutive securities, tax effected | $ (1,503) | $ 38,146 | $ 62,710 | $ (18,959) |
| Convertible securities | | | 5 | |
| Net income (loss) before cumulative effect | (1,503) | 38,146 | 62,715 | (18,959) |
| Cumulative effect, net of tax(1) | (2,873) | | | |
| Net income (loss) | $ (4,376) | $ 38,146 | $ 62,715 | $ (18,959) |
| *Denominator* | | | | |
| Weighted average common shares outstanding | 125,367 | 105,766 | 98,195 | 83,815 |
| Warrants | | 402 | 205 | |
| Stock options | | 1,294 | 3,853 | |
| 7% Convertible Debentures | | | 18 | |
| | 125,367 | 107,462 | 102,271 | 83,815 |
| **Diluted EPS:** | | | | |
| Before cumulative effect | $ (0.01) | $ 0.35 | $ 0.61 | $ (0.23) |
| Cumulative effect, net of tax(1) | (0.02) | | | |
| Net income (loss) | $ (0.03) | $ 0.35 | $ 0.61 | $ (0.23) |

(1) See section entitled Property and Equipment set forth in this Note 1.

The diluted earnings per share calculation for the years ended June 30, 2002 and 2001 excludes the effect of the potential exercise of stock options of 1,177,000 and 360,000, respectively, and the potential

41

conversion of the Company's 5% Convertible Subordinated Notes because the effects of such instruments on earnings per share would be anti-dilutive.

The diluted earnings per share calculation for the six months ended December 31, 2002 and the year ended June 30, 2000 excludes the effect of the potential conversion of all of the Company's then outstanding convertible debt and the potential exercise of all of the Company's then outstanding warrants and stock options because the effects of such instruments on loss per share would be anti-dilutive.

**Concentration of Credit Risk**

Financial instruments, which potentially subject the Company to concentrations of credit risk, consist primarily of temporary cash investments and trade receivables. The Company restricts investment of temporary cash investments to financial institutions with high credit standing and, by policy, limits the amount of credit exposure to any one financial institution. The Company's customer base consists primarily of multi-national and independent oil and natural gas producers. This may affect the Company's overall exposure to credit risk either positively or negatively in as much as its customers are affected by economic conditions in the oil and gas industry, which have historically been cyclical. However, account receivables are well diversified among many customers and a significant portion of the receivables are from major oil companies, which management believes minimizes potential credit risk. Historically, credit losses have been insignificant. Receivables are generally not collateralized, although the Company may generally secure a receivable at any time by filing a mechanic's or material-man's lien on the well serviced. The Company maintains reserves for potential credit losses, and such losses have been within management's expectations.

Key's customers include major oil companies, independent oil and natural gas production companies, and foreign national oil and natural gas production companies. One customer during the year ended June 30, 2002, Occidental Petroleum Corporation, accounted for approximately 10% of Key's consolidated revenues. The Company did not have any one customer which represented 10% or more of consolidated revenues for the six months ended December 31, 2002 or the years ended June 30, 2001 or 2000.

**Stock-Based Compensation**

The Company accounts for stock option grants to employees using the intrinsic value method of accounting prescribed by APB Opinion No. 25 ("APB 25"), "Accounting for Stock Issued to Employees." Under the Company's stock incentive plan, which is described more fully in Note 8, the price of the stock on the grant date is the same as the amount an employee must pay to exercise the option to acquire the stock; accordingly, the options have no intrinsic value at grant date, and in accordance with the provisions of APB 25, no compensation cost is recognized.

Statement of Financial Accounting Standards No. 123 ("SFAS 123"), "Accounting for Stock-Based Compensation," sets forth alternative accounting and disclosure requirements for stock-based compensation arrangements. Companies may continue to follow the provisions of APB 25 to measure and recognize employee stock-based compensation; however, SFAS 123 requires disclosure of pro forma net income and earnings per share that would have been reported under the fair value based recognition provisions of SFAS 123. The following table illustrates the effect on net income and earnings per share if



the Company had applied the fair value recognition provisions of SFAS 123 to stock-based employee compensation

| | Six Months Ended December 31, 2002 | Year Ended June 30, 2002 | Year Ended June 30, 2001 | Year Ended June 30, 2000 |
|---|---|---|---|---|
| | (thousands, except per share data) | | | |
| Net income (loss): | | | | |
| As reported | $ (4,376) | $ 38,146 | $ 62,710 | $ (18,959) |
| Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of tax | (4,994) | (11,826) | (10,372) | (6,725) |
| Pro forma | $ (9,370) | $ 26,320 | $ 52,338 | $ (25,684) |
| Basic earnings per share: | | | | |
| As reported | $ (0.03) | $ 0.36 | $ 0.64 | $ (0.23) |
| Pro forma | (0.07) | 0.25 | 0.53 | (0.31) |
| Diluted earnings per share: | | | | |
| As reported | $ (0.03) | $ 0.35 | $ 0.61 | $ (0.23) |
| Pro forma | (0.07) | 0.24 | 0.51 | (0.31) |

See Note 8 for additional information regarding the computations presented here.

**Foreign Currency Gains and Losses**

The local currency is the functional currency for the Company's foreign operations in Argentina and Canada. The cumulative translation gains and losses, resulting from translating each foreign subsidiary's financial statements from the functional currency to U.S. dollars, is included in other comprehensive income and accumulated in stockholders' equity until a partial or complete sale or liquidation of the Company's net investment in the foreign entity.

**Cash and Cash Equivalents**

The Company considers all unrestricted highly liquid investments with less than a three-month maturity when purchased, as cash equivalents.

**Reclassifications**

Certain reclassifications have been made to the consolidated financial statements for the years ended June 30, 2001 and 2000 to conform to the year ended June 30, 2002 and the six months ended December 31, 2002 presentation. The reclassifications consist primarily of reclassifying certain items from general and administrative expense to direct expenses. In addition on July 1, 2002, the Company adopted the provisions of SFAS 145. See Note 19.



**Change in Fiscal Year**

In December 2002, the Company's Board of Directors approved the Company's change of its fiscal year end from June 30 to December 31 of each year. The unaudited financial information for the six-month period ended December 31, 2001, is as follows:

| | Six Months Ended December 31, 2001 (thousands, except per share data) | |
|---|---|---|
| Revenues | $ | 462,574 |
| Operating profit | | 165,810 |
| Income tax benefit | | (29,419) |
| Net income | | 48,635 |
| Earnings per share | | |
| Basic | $ | 0.47 |
| Diluted | $ | 0.47 |

**2. BUSINESS AND PROPERTY ACQUISITIONS**

During the six months ended December 31, 2002, the Company completed several small acquisitions for total consideration of $15,620,000, which consisted of a combination of cash, a deferred non-compete payment and shares of the Company's common stock. During the years ended June 30, 2002 and 2001, the Company completed several small acquisitions for total consideration of $44,378,000 and $11,965,000, respectively, which consisted of a combination of cash, notes and shares of the Company's common stock. Other than QSI, none of the acquisitions completed in the six months ended December 31, 2002 or the years ended June 30, 2002 and 2001 were material individually or in the aggregate, thus the pro forma effect of these acquisitions is not presented. Each of the acquisitions was accounted for using the purchase method and the results of the operations generated from the acquired assets are included in the Company's results of operations as of the completion date of each acquisition. There were no acquisitions completed by the Company for the year ended June 30, 2000.

**Acquisition of Q Services, Inc.**

On July 19, 2002, Key acquired Q Services, Inc.("QSI") pursuant to an Agreement and Plan of Merger dated May 13, 2002, as amended, by and among Key, Key Merger Sub, Inc. and QSI. As consideration for the acquisition, the Company issued approximately 17.1 million shares of its common stock to the QSI shareholders and paid approximately $94.2 million in cash at the closing to retire debt and preferred stock of QSI and to satisfy certain other obligations of QSI. In addition to assuming the positive working capital of QSI, the Company incurred other direct acquisition costs and assumed certain other liabilities of QSI, resulting in the Company recording an aggregate purchase price of approximately $250 million. The value of the shares issued was based on the closing price of the Key common stock on the closing date of $8.75 per share. The results of QSI's operations have been included in the consolidated financial statements since the closing date. Prior to the acquisition, QSI was a privately held corporation conducting field production, pressure pumping, and other service operations in Louisiana, New Mexico, Oklahoma, Texas, and the Gulf of Mexico. The Company and QSI operated in adjacent and /or overlapping locations and expect to realize future cost savings and synergies in connection with the merger.

44

The following table summarizes the estimated fair value of the assets acquired and liabilities assumed at the date of acquisition:

| | At July 19, 2002 (Thousands) |
|---|---|
| Current assets | $ 37,734 |
| Property and equipment | 139,023 |
| Intangible assets | 3,242 |
| Other assets | 344 |
| Goodwill | 119,174 |
| Total assets acquired | 299,517 |
| Current liabilities | 17,393 |
| Capital lease obligations | 77 |
| Non-current accrued expenses | 17,908 |
| Deferred tax liability | 14,347 |
| Total liabilities assumed | 49,725 |
| Net assets acquired | $ 249,792 |

The $3,242,000 of intangible assets consists of noncompete agreements which have a weighted-average useful life of approximately two years. The $119,174,000 of goodwill was allocated to the well servicing reporting segment. Of that amount, approximately $11,645,000 is expected to be deductible for income taxes.

The following unaudited pro forma results of operations have been prepared as though QSI had been acquired on July 1, 2001. Pro forma amounts are not necessarily indicative of the results that may be reported in the future.

| | Six Months Ended 12/31/02 | Six Months Ended 12/31/01 |
|---|---|---|
| | (Thousands, except per share amount) | |
| Revenues | $ 416,701 | $ 566,198 |
| Income (loss) before cumulative effect of a change in accounting principle, net of tax | (2,563) | 60,568 |
| Cumulative effect of a change in accounting principle, net of tax | (2,873) | |
| Net income (loss) | (5,436) | 60,568 |
| Basic earnings (loss) per share | $ (0.04) | $ 0.51 |

## 3. COMMITMENTS AND CONTINGENCIES

Various suits and claims arising in the ordinary course of business are pending against the Company. Management does not believe that the disposition of any of these items will result in a material adverse impact to the consolidated financial position, results of operations or cash flows of the Company.

In order to retain qualified senior management, the Company enters into employment agreements with its executive officers. These employment agreements run for periods ranging from three to five years,



but can be automatically extended on a yearly basis unless terminated by the Company or the executive officer. In addition to providing a base salary for each executive officer, the employment agreements provide for severance payments for each executive officer equal to three years of the executive officer's base salary. On December 1, 2001, the Company paid to Mr. John an incentive retention payment in connection with his amended and restated employment agreement, which Mr. John will earn over a ten-year period beginning on June 30, 2002 (See Note 12). At December 31, 2002 the annual base salaries for the executive officers covered under such employment agreements totaled approximately $1,190,000. The Company also enters into employment agreements with other key employees as it deems necessary in order to retain qualified personnel.

**4. LONG-TERM DEBT**

The components of the Company's long-term debt are as follows:

| | December 31, 2002 | June 30, 2002 | June 30, 2001 |
|---|---|---|---|
| | (Thousands) | | |
| Senior Credit Facility Revolving Loans(i) | $ 52,000 | $ | $ 2,000 |
| $8^3/_8$% Senior Notes Due 2008(ii) | 276,331 | 276,433 | 175,000 |
| 14% Senior Subordinated Notes Due 2009(iii) | 94,411 | 94,257 | 134,466 |
| 5% Convertible Subordinated Notes Due 2004(iv) | 49,554 | 49,951 | 158,426 |
| Capital lease obligations | 21,164 | 22,829 | 22,964 |
| Other notes payable | 105 | 140 | 1,051 |
| | 493,565 | 443,610 | 493,907 |
| Less current portion | 7,008 | 7,674 | 7,946 |
| Total long-term debt | $ 486,557 | $ 435,936 | $ 485,961 |

**(i) Senior Credit Facility**

On July 15, 2002, the Company entered into a Third Amended and Restated Credit Agreement, as amended by the First Amendment to the Third Amended and Restated Credit Agreement (the "Senior Credit Facility"). The Senior Credit Facility consists of a $150,000,000 revolving loan facility with a $75,000,000 sublimit for letters of credit. The loans are secured by most of the tangible and intangible assets of the Company. The revolving loan commitment will terminate on July 15, 2005 and all revolving loans must be paid on or before that date. The revolving loans bear interest based upon, at the Company's option, the prime rate plus a variable margin of 0.00% to 1.00% or a Eurodollar rate plus a variable margin of 1.75% to 3.00%.

The Senior Credit Facility contains various financial covenants, including: (i) a maximum consolidated senior leverage ratio of 3.25 to 1.00, (ii) a minimum consolidated fixed coverage ratio of 1.10 to 1.00, and (iii) a maximum consolidated total leverage ratio of 4.25 to 1.00. The Company is also required to maintain a minimum net worth of $436,972,000 plus (i) 50% of consolidated net income and (ii) 75% of the net cash proceeds from the sale of equity. As of December 31, 2002, the Company was in compliance with all covenants contained in the Senior Credit Facility.

The Senior Credit Facility subjects the Company to other restrictions, including restrictions upon the Company's ability to incur additional debt, liens and guarantee obligations, to merge or consolidate with other persons, to make acquisitions, to sell assets, to make dividends, purchases of our stock or subordinated debt, or to make investments, loans and advances or changes to debt instruments and organizational documents. All obligations under the New Senior Credit Facility are guaranteed by most of the Company's subsidiaries and are secured by most of the Company's assets, including the Company's accounts receivable, inventory and most equipment.

The Company drew down approximately $43 million on its revolver under the Company's prior senior credit facility (the "Prior Senior Credit Facility") on January 14, 2002 in order to redeem a portion of the 14% Senior Subordinated Notes then outstanding. The funds were repaid with the issuance of additional $8^3/_8$% Notes in March 2002.

During the year ended June 30, 2001, a portion of the net proceeds from the 2000 Equity Offering (see Note 8) was used to repay the entire outstanding balance of the Tranche A term loan then outstanding under the Prior Senior Credit Facility and $2.3 million of the Tranche B term loan then outstanding under the Prior Senior Credit Facility. In addition, $65 million of the net proceeds from the 2000 Equity Offering were used to reduce the principal amount outstanding under the revolver. The remainder of the net proceeds of the 2000 Equity Offering was used to retire other long-term debt. A portion of the proceeds from the Company's $8^3/_8$% Senior Note offering in calendar year 2001 was used to repay the entire outstanding balance of the Tranche B term loan then outstanding under the Prior Senior Credit Facility and approximately $59.1 million under the revolver.

At December 31, 2002, there was an outstanding balance of $52,000,000 under the revolving loans. As of June 30, 2002, there was no outstanding balance under the revolving loans under the Prior Senior Credit Facility. Additionally, the Company had outstanding letters of credit of approximately $34,963,000 as of December 31, 2002 and $27,963,000 and $11,995,000 as of June 30, 2002 and 2001, respectively, under the Prior Senior Credit Facility related to its workers' compensation insurance.

**(ii) $8^3/_8$% Senior Subordinated Notes**

On March 6, 2001, the Company completed a private placement of $175,000,000 of $8^3/_8$% Senior Notes due 2008 (the "$8^3/_8$% Senior Notes"). The net cash proceeds from the private placement were used to repay all of the remaining balance of the original term loans under the Prior Senior Credit Facility, and a portion of the revolving loan facility under the Senior Credit Facility then outstanding. On March 1, 2002, the Company completed a public offering of an additional $100,000,000 of $8^3/_8$% Senior Notes due 2008. The net cash proceeds from the public offering were used to repay all of the remaining balance of the revolving loan facility under the Prior Senior Credit Facility. The $8^3/_8$% Senior Notes are senior unsecured obligations. The $8^3/_8$% Senior Notes are effectively subordinated to Key's secured indebtedness which includes borrowings under the Senior Credit Facility.

On and after March 1, 2005, the Company may redeem some or all of the $8^3/_8$% Senior Notes at any time at varying redemption prices in excess of par, plus accrued interest. In addition, before March 1, 2004, the Company may redeem up to 35% of the aggregate principal amount of the $8^3/_8$% Senior Notes with the proceeds of certain sales of equity at 108.375% of par plus accrued interest.

At December 31, 2002, $275,000,000 principal amount of the $8^3/_8$% Senior Notes remained outstanding. The $8^3/_8$% Senior Notes require semi-annual interest payments on March 1 and September 1



of each year. Interest of approximately $11,516,000 was paid on September 1, 2002. As of December 31, 2002, the Company was in compliance with all covenants contained in the $8^3/_8$% Senior Notes.

**(iii) 14% Senior Subordinated Notes**

On January 22, 1999, the Company completed the private placement of 150,000 units (the "Units") consisting of $150,000,000 of 14% Senior Subordinated Notes due 2009 (the "14% Senior Subordinated Notes") and 150,000 warrants to purchase 2,173,433 shares of the Company's Common Stock at an exercise price of $4.88125 per share (the "Unit Warrants"). The net cash proceeds from the private placement were used to repay substantially all of the remaining $148,600,000 principal amount (plus accrued interest) owed under the Company's bridge loan facility arranged in connection with the acquisition of Dawson Production Services, Inc. ("Dawson").

On and after January 15, 2004, the Company may redeem some or all of the 14% Senior Subordinated Notes at any time at varying redemption prices in excess of par, plus accrued interest. In addition, before January 15, 2002, the Company was allowed to redeem up to 35% of the aggregate principal amount of the 14% Senior Subordinated Notes at 114% of par plus accrued interest with the proceeds of certain sales of equity. During the year ended June 30, 2001, the Company exercised its right of redemption for $10,313,000 principal amount of the 14%

Senior Subordinated Notes at a price of 114% of the principal amount plus accrued interest. This transaction resulted in a loss of approximately $2,561,000. On January 14, 2002 the Company exercised its right of redemption for $35,403,000 principal amount of the 14% Senior Subordinated Notes at a price of 114% of the principal amount plus accrued interest. This transaction resulted in a loss of approximately $8,468,000. Also, during the year ended June 30, 2002, the Company purchased and canceled $6,784,000 principal amount of the 14% Senior Subordinated Notes at a price of 116% of the principal amount plus accrued interest. These transactions resulted in losses of approximately $1,821,000.

The Unit Warrants have separated from the 14% Senior Subordinated Notes and became exercisable on January 25, 2000. On the date of issuance, the value of the Unit Warrants was estimated at $7,434,000 and is classified as a discount to the 14% Senior Subordinated Notes on the Company's consolidated balance sheet. The discount is being amortized to interest expense over the term of the 14% Senior Subordinated Notes. The 14% Senior Subordinated Notes mature and the Unit Warrants expire on January 15, 2009. The 14% Senior Subordinated Notes are subordinate to the Company's senior indebtedness, which includes borrowings under the Senior Credit Facility and the $8^3/_8$% Senior Notes.

At December 31, 2002, $97,500,000 principal amount of the 14% Senior Subordinated Notes remained outstanding. The 14% Senior Subordinated Notes pay interest semi-annually on January 15 and July 15 of each year. Interest of approximately $6,825,000 was paid on July 15, 2002. As of December 31, 2002, 63,500 Unit Warrants had been exercised, producing approximately $4,173,000 of proceeds to the Company and leaving 86,500 Unit Warrants outstanding. As of December 31, 2002, the Company was in compliance with all covenants contained in the 14% Senior Subordinated Notes.

**(iv) 5% Convertible Subordinated Notes**

In 1997, the Company completed a private placement of $216,000,000 of 5% Convertible Subordinated Notes due 2004 (the "5% Convertible Subordinated Notes"). The 5% Convertible Subordinated Notes are subordinate to the Company's senior indebtedness which includes borrowings under the Senior Credit Facility, the 14% Senior Subordinated Notes and the $8^3/_8$% Senior Notes. The 5% Convertible Subordinated Notes are convertible, at the holder's option, into shares of the Company's

48

common stock at a conversion price of $38.50 per share, subject to certain adjustments. The 5% Convertible Subordinated Notes are redeemable, at the Company's option, on and after September 15, 2000, in whole or part, together with accrued and unpaid interest. The initial redemption price is 102.86% for the year beginning September 15, 2000 and declines ratably thereafter on an annual basis.

During the year ended June 30, 2001, the Company repurchased (and canceled) $47,384,000 principal amount of the 5% Convertible Subordinated Notes. These repurchases resulted in gains of approximately $4,564,000. During the year ended June 30, 2002, the Company repurchased (and canceled) $108,475,000 principal amount of the 5% Convertible Subordinated Notes, leaving $49,951,000 principal amount of the 5% Convertible Subordinated Notes outstanding at June 30, 2002. These repurchases resulted in gains of approximately $5,633,000. During the six months ended December 31, 2002, the Company repurchased (and canceled) $397,000 principal amount of the 5% Convertible Subordinated Notes, leaving $49,554,000 principal amount of the 5% Convertible Subordinated Notes outstanding at December 31, 2002. The repurchases resulted in a gain of approximately $18,000. Interest on the 5% Convertible Subordinated Notes is payable on March 15 and September 15 of each year. Interest of approximately $1,244,000 was paid on September 15, 2002. As of December 31, 2002, the Company was in compliance with all covenants contained in the 5% Convertible Subordinated Notes.

**Capitalized Debt Issuance Costs, Repayment Schedule and Interest Expense**

The Company capitalized a total of approximately $3,026,000 in fees and costs in connection with the Senior Credit Facility and its $8^3/_8$% Senior Notes during the six months ended December 31, 2002. The Company capitalized a total of approximately $1,877,000 and $4,958,000 in fees and costs in connection with its various financings during the years ended June 30, 2002 and 2001, respectively. The Company did not incur any fees or costs in connection with financing activities during the year ended June 30, 2000.

Presented below is a schedule of the repayment requirements of long-term debt (excluding the discount on the 14% Senior Subordinated Notes, the premium on the $8^3/_8$% Senior Notes and the revolving loans under the Senior Credit Facility) for each of the next five years and thereafter as of December 31, 2002:

| Year Ending December 31, | Principal Amount |
| --- | --- |

| Year Ending December 31, | Principal Amount |
|---|---|
| | (thousands) |
| 2003 | $ 7,107 |
| 2004 | 7,106 |
| 2005 | 56,607 |
| 2006 | |
| 2007 | |
| Thereafter | 372,500 |
| | $ 443,320 |

49

The Company's interest expense for the six months ended December 31, 2002 and the years ended June 30, 2002, 2001, and 2000 consisted of the following:

| | December 31, 2002 | June 30, 2002 | June 30, 2001 | June 30, 2000 |
|---|---|---|---|---|
| | (thousands) | | | |
| Cash payments for interest | $ 20,898 | $ 42,085 | $ 51,524 | $ 61,956 |
| Commitment and agency fees paid | 730 | 1,183 | 1,203 | 1,139 |
| Accretion of discount and premium on notes | 52 | 424 | 739 | 743 |
| Amortization of debt issuance costs | 2,103 | 2,581 | 3,578 | 5,176 |
| Net change in accrued interest | 362 | (1,275) | 146 | 2,916 |
| Capitalized interest | (1,402) | (1,666) | (630) | |
| | $ 22,743 | $ 43,332 | $ 56,560 | $ 71,930 |

## 5. FAIR VALUE OF FINANCIAL INSTRUMENTS

The following table presents the carrying amounts and estimated fair values of the Company's financial instruments at December 31, 2002 and June 30, 2002 and June 30, 2001. FASB Statement No. 107, "Disclosures about Fair Value of Financial Instruments," defines the fair value of a financial instrument as the amount at which the instrument could be exchanged in a current transaction between willing parties.

| | December 31, 2002 | | June 30, 2002 | | June 30, 2001 | |
|---|---|---|---|---|---|---|
| | Carrying Value | Fair Value | Carrying Value | Fair Value | Carrying Value | Fair Value |
| | (thousands) | | | | | |
| Financial Assets: | | | | | | |
| Cash and cash equivalents | $ 9,044 | $ 9,044 | $ 54,147 | $ 54,147 | $ 2,098 | $ 2,098 |
| Accounts receivable, net | 141,958 | 141,958 | 117,907 | 117,907 | 177,016 | 177,016 |
| Notes receivable related parties | 251 | 251 | 274 | 274 | 6,050 | 6,600 |
| Commodity option contracts | 34 | 34 | 246 | 246 | 1,035 | 1,035 |
| Financial Liabilities: | | | | | | |
| Accounts payable | 28,818 | 28,818 | 24,625 | 24,625 | 42,544 | 42,544 |
| Commodity option contracts | | | | | 344 | 344 |

| | December 31, 2002 | | June 30, 2002 | | June 30, 2001 | |
|---|---|---|---|---|---|---|
| Long-term debt: | | | | | | |
| Senior Credit Facility | 52,000 | 52,000 | | | 2,000 | 2,000 |
| $8\frac{3}{8}$% Senior Notes | 276,331 | 289,547 | 276,433 | 287,491 | 175,000 | 176,094 |
| 14% Senior Subordinated Notes | 94,411 | 109,752 | 94,257 | 109,338 | 134,466 | 153,498 |
| 5% Convertible Subordinated Notes | 49,554 | 47,324 | 49,951 | 46,942 | 158,426 | 141,989 |
| Capital lease obligations | 21,164 | 21,164 | 22,829 | 22,829 | 22,964 | 22,964 |
| Other notes payable | 105 | 105 | 140 | 140 | 1,051 | 1,051 |

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

Cash, trade receivables and trade payables: The carrying amounts approximate fair value because of the short maturity of those instruments.



Commodity option contracts: under SFAS 133, the carrying amount of the commodity option contracts approximate fair value. The fair value of the commodity option contracts is estimated using the discounted forward prices of each option's index price, for the term of each option contract.

Notes receivable related parties: The amounts reported relate to notes receivable from officers and other employees of the Company.

Long-term debt: The fair value of the Company's long-term debt is based upon the quoted market prices for the various notes and debentures at December 31, 2002 and June 30, 2002 and 2001, and the carrying amounts outstanding under the Company's senior credit facility then outstanding.

## 6. DERIVATIVE FINANCIAL INSTRUMENTS

The Company utilizes derivative financial instruments to manage well defined commodity price risks. The Company is exposed to credit losses in the event of nonperformance by the counter-parties to its commodity hedges. The Company only deals with reputable financial institutions as counter-parties and anticipates that such counter-parties will be able to fully satisfy their obligations under the contracts. The Company does not obtain collateral or other security to support financial instruments subject to credit risk but monitors the credit standing of the counter-parties.

The Company periodically hedges a portion of its oil and natural gas production through collar and option agreements. The purpose of the hedges is to provide a measure of stability in the volatile environment of oil and natural gas prices and to manage exposure to commodity price risk under existing sales commitments. The Company's risk management objective is to lock in a range of pricing for expected production volumes. This allows the Company to forecast future earnings within a predictable range. The Company meets this objective by entering into collar and option arrangements which allow for acceptable cap and floor prices.

The Company does not enter into derivative instruments for any purpose other than for economic hedging. The Company does not speculate using derivative instruments. The Company has identified the following derivative instruments:

*Freestanding Derivatives.* On March 30, 2000 the Company entered into a collar arrangement for a 22-month period whereby the Company will pay if the specified price is above the cap index and the counter-party will pay if the price should fall below the floor index. The hedge defines a range of cash flows bounded by the cap and floor prices. On May 25, 2001 the Company entered into an option arrangement for a 12-month period beginning March 2002 whereby the counter-party will pay if the price should fall below the floor index. On May 2, 2002 the Company entered into an option arrangement for a 12-month period beginning March 2003 whereby the counter-party will pay if the price should fall below the floor index. The Company desires a measure of stability to ensure that cash flows do not fall below a certain level.

Prior to the adoption of SFAS 133 as discussed in Note 1, these collars and options were accounted for as cash flow type hedges. Accordingly, the transition adjustment resulted in recording a $778,000 liability for the fair value of the collars and an offset to accumulated other comprehensive income. The transition adjustment to accumulated other comprehensive income of approximately $258,000 and $520,000 was recognized in earnings during the years ended June 30, 2002 and 2001, respectively. While this arrangement was intended to be an economic hedge, as of July 1, 2000, the Company had not documented the March 30, 2000 oil and natural gas collars as cash flow hedges and therefore reported a charge to operations of approximately $565,000 for the increase in fair value of the liability as of September 30, 2000

51

in other income. As of October 1, 2000, the Company documented these collars as cash flow hedges. As of May 25, 2001, the Company had not documented the May 25, 2001 oil and natural gas options as cash flow hedges and therefore has included income of $768,000 for the increase in fair value of the asset as of June 30, 2001 in other income. As of July 1, 2001, the Company documented these options as cash flow hedges. As of May 2, 2002, the Company had documented the May 2, 2002 oil and natural gas options as cash flow hedges. The Company recorded a net decrease in derivative assets net of derivative liabilities of $51,000 during the six months ended December 31, 2002. The Company recorded a net decrease in derivative assets net of derivative liabilities of $543,000 and a net increase of $999,000 during the years ended June 30, 2002 and 2001, respectively.

The Company recorded no ineffectiveness for the six months ended December 31, 2002 and recorded in earnings an ineffectiveness expense of $85,000 and ineffectiveness income of $132,000 for the years ended June 30, 2002 and 2001, respectively.

*Embedded Derivatives.* The Company is party to a volumetric production payment that meets the definition of an embedded derivative under SFAS 133. Effective July 1, 2000, the Company determined and documented that the volumetric production payment is excluded from the scope of SFAS 133 under the normal purchases/sales exclusion as set forth in SFAS 138.

For the year ended June 30, 2000, gains and amortization of premiums paid on option contracts are recognized as an adjustment to sales revenue when the related transactions being hedged are finalized. The net effect of the Company's commodity hedging activities decreased oil and natural gas revenues for the year ended June 30, 2000 by approximately $822,000.

52

The following table sets forth the future volumes hedged by year and the weighted-average strike price of the option contracts at December 31, 2002 and June 30, 2002 and 2001:

| | Monthly Income | | | Strike Price Per Bbl/MMbtu | | |
|---|---|---|---|---|---|---|
| | Oil (Bbls) | Gas (MMbtu) | Term | Floor | Cap | Fair Value |
| At December 31, 2002 | | | | | | |
| Oil Put | 5,000 | | Mar 2002-Feb 2003 | $ 22.00 | | $ |
| Oil Put | 4,000 | | Mar 2003-Feb 2004 | $ 21.00 | | $ 34,000 |
| Gas Put | | 75,000 | Mar 2002-Feb 2003 | $ 3.00 | | $ |
| At June 30, 2002 | | | | | | |
| Oil Put | 5,000 | | Mar 2002-Feb 2003 | $ 22.00 | | $ 24,000 |
| Oil Put | 4,000 | | Mar 2003-Feb 2004 | $ 21.00 | | $ 118,000 |
| Gas Put | | 75,000 | Mar 2002-Feb 2003 | $ 3.00 | | $ 104,000 |
| At June 30, 2001 | | | | | | |
| Oil Collar | 5,000 | | Mar 2001-Feb 2002 | $ 19.70 | $ 23.70 | $ (115,000) |
| Oil Put | 5,000 | | Mar 2002-Feb 2003 | $ 22.00 | | $ 141,000 |
| Gas Collar | | 40,000 | Mar 2001-Feb 2002 | $ 2.40 | $ 2.91 | $ (229,000) |
| Gas Put | | 75,000 | Mar 2002-Feb 2003 | $ 3.00 | | $ 894,000 |

(The strike prices for the oil collars and puts are based on the NYMEX spot price for West Texas Intermediate; the strike prices for the natural gas collars are based on the Inside FERC-West Texas Waha spot price; the strike price for the natural gas put is based on the Inside FERC-El Paso Permian spot price.)

**7. OTHER ACCRUED LIABILITIES**

Other accrued liabilities consist of the following:

| | | December 31, 2002 | | June 30, 2002 | | June 30, 2001 |
|---|---|---|---|---|---|---|
| | | (Thousands) | | | | |
| Accrued payroll, taxes and employee benefits | $ | 30,615 | $ | 28,479 | $ | 31,242 |
| State sales, use and other taxes | | 2,292 | | 2,344 | | 5,825 |
| Oil and natural gas revenue distribution | | 1,401 | | 1,271 | | 1,606 |
| Other | | 23,515 | | 17,371 | | 10,250 |
| Total | $ | 57,823 | $ | 49,465 | $ | 48,923 |

Other non-current accrued expenses consist primarily of workers' compensation reserves.

**8. STOCKHOLDERS' EQUITY**

**Equity Offerings**

On December 19, 2001, the Company closed a public offering of 5,400,000 shares of common stock, yielding approximately $43.2 million, or $8.00 per share, to the Company (the "Equity Offering"). Net proceeds from the Equity Offering of approximately $42.6 million were used to temporarily reduce



amounts outstanding under the Company's revolving line of credit. The net proceeds of the Equity Offering were ultimately used in January 2002 to redeem a portion of the Company's 14% Senior Subordinated Notes fully utilizing the Company's equity "claw-back" rights for up to 35% of the original $150 million issued.

On June 30, 2000, the Company closed a public offering of 11,000,000 shares of common stock at $9.625 per share, or approximately $106 million (the "2000 Equity Offering"). Net proceeds from the 2000 Equity Offering of approximately $101 million were used to repay a portion of the Company's term loan borrowings and revolving line of credit under its senior credit facility and retire other long-term debt.

**Stock Incentive Plans**

On January 13, 1998 the Company's shareholders approved the Key Energy Group, Inc. 1997 Incentive Plan, as amended (the "1997 Incentive Plan"). The 1997 Incentive Plan is an amendment and restatement of the plans formerly known as the "Key Energy Group, Inc. 1995 Stock Option Plan" (the "1995 Option Plan") and the "Key Energy Group, Inc. 1995 Outside Directors Stock Option Plan" (the "1995 Directors Plan") (collectively, the "Prior Plans").

All options previously granted under the Prior Plans and outstanding as of November 17, 1997 (the date on which the Company's board of directors adopted the plan) were assumed and continued, without modification, under the 1997 Incentive Plan.

Under the 1997 Incentive Plan, the Company may grant the following awards to key employees, directors who are not employees ("Outside Directors") and consultants of the Company, its controlled subsidiaries, and its parent corporation, if any: (i) incentive stock options ("ISOs") as defined in Section 422 of the Internal Revenue Code of 1986, as amended (the "Code"), (ii) "nonstatutory" stock options ("NSOs"), (iii) stock appreciation rights ("SARs"), (iv) shares of the restricted stock, (v) performance shares and performance units, (vi) other stock-based awards and (vii) supplemental tax bonuses (collectively, "Incentive Awards"). ISOs and NSOs are sometimes referred to collectively herein as "Options".

The Company may grant Incentive Awards covering an aggregate of the greater of (i) 3,000,000 shares of the Company's common stock and (ii) 10% of the shares of the Company's common stock issued and outstanding on the last day of each calendar quarter, provided, however, that a decrease in the number of issued and outstanding shares of the Company's common stock from the previous calendar quarter shall not result in a decrease in the number of shares available for issuance under the 1997 Incentive Plan. As a result of the Company's equity offerings discussed above, as of December 31, 2002, the number of shares of the Company's common stock that may be covered by Incentive Awards has increased to approximately 12.9 million.

Any shares of the Company's common stock that are issued and are forfeited or are subject to Incentive Awards under the 1997 Incentive Plan that expire or terminate for any reason will remain available for issuance with respect to the granting of Incentive Awards during the term of the 1997 Incentive Plan, except as may otherwise be provided by applicable law. Shares of the Company's common stock issued under the 1997 Incentive Plan may be either newly issued or treasury shares, including shares of the Company's common stock that the Company receives in connection with the exercise of an Incentive Award. The number and kind of securities that may be issued under the 1997 Incentive Plan and pursuant to then outstanding Incentive Awards are subject to adjustments to prevent enlargement or dilution of rights resulting from stock dividends, stock splits, recapitalizations, reorganization or similar transactions.



The maximum number of shares of the Company's common stock subject to Incentive Awards that may be granted or that may vest, as applicable, to any one Covered Employee (defined below) during any calendar year shall be 500,000 shares, subject to adjustment under the provisions of the 1997 Incentive Plan.

The maximum aggregate cash payout subject to Incentive Awards (including SARs, performance units and performance shares payable in cash, or other stock-based awards payable in cash) that may be granted to any one Covered Employee during any fiscal year is $2,500,000. For purposes of the 1997 Incentive Plan, "Covered Employees" means a named executive officer who is one of the group covered employees as defined in Section 162(m) of the Code and the regulation promulgated thereunder (i.e., generally the chief executive officer and the other four most highly compensated executive officers for a given year.)

The 1997 Incentive Plan is administrated by the Compensation Committee appointed by the Board of Directors (the "Committee") consisting of not less than two directors each of whom is (i) an "outside director" under Section 162(m) of the Code and (ii) a "non-employee director" under Rule 16b-3 of the Securities Exchange Act of 1934. In addition, subject to applicable shareholder approval requirements, the Company may issue NSOs outside the 1997 Incentive Plan.

The exercise price of options granted under the 1997 Incentive Plan and outside the 1997 Incentive Plan is at or above the fair market value per share on the date the options are granted. The exercise of NSOs results in a U. S. tax deduction to the Company equal to the income tax effect of the difference between the exercise price and the market price at the exercise date. The following table summarizes the stock option activity related to the Company's plans (shares in thousands):

| | Six Months Ended December 31, 2002 | | Year Ended June 30, 2002 | | Year Ended June 30, 2001 | | Year Ended June 30, 2000 | |
|---|---|---|---|---|---|---|---|---|
| | **Shares** | **Weighted Average Exercise Price** | **Shares** | **Weighted Average Exercise Price** | **Shares** | **Weighted Average Exercise Price** | **Shares** | **Weighted Average Exercise Price** |
| Outstanding: | | | | | | | | |
| Beginning of period | 10,008 | $ 7.80 | 8,703 | $ 7.49 | 9,470 | $ 6.37 | 6,920 | $ 5.55 |
| Granted | 183 | 8.59 | 1,988 | 8.16 | 2,533 | 8.08 | 3,688 | 8.61 |
| Exercised | (139) | 3.12 | (659) | 4.53 | (3,106) | 4.70 | (241) | 4.56 |
| Forfeited | (26) | 7.00 | (24) | 4.86 | (194) | 4.92 | (897) | 9.80 |
| End of period | 10,026 | 7.88 | 10,008 | 7.80 | 8,703 | 7.49 | 9,470 | 6.37 |
| Exercisable end of period | 6,979 | | 6,273 | | 5,820 | | 4,370 | |



The following table summarizes information about the stock options outstanding at December 31, 2002 (shares in thousands):

| Range of Exercise Prices | Options Outstanding: Weighted Average Remaining Contractual Life | Options Outstanding: Number of Shares Outstanding at December 31, 2002 | Options Outstanding: Weighted Average Exercise Price | Options Exercisable: Number of Shares Outstanding at December 31, 2002 | Options Exercisable: Weighted Average Exercise Price |
|---|---|---|---|---|---|
| $3.00 - $ 7.13 | 5.14 | 1,913 | $ 4.75 | 1,548 | $ 5.06 |
| 7.25 - 8.13 | 7.74 | 1,949 | 7.86 | 905 | 7.81 |
| 8.25 - 8.31 | 6.71 | 2,080 | 8.26 | 1,968 | 8.26 |
| 8.35 - 8.50 | 7.25 | 2,225 | 8.48 | 1,229 | 8.47 |
| 8.88 - 13.25 | 6.88 | 1,859 | 9.97 | 1,329 | 10.34 |

The total fair value of stock options granted during the six months ended December 31, 2002 and the years ended June 30, 2002, 2001 and 2000 was approximately $747,000, $7,700,000, $11,217,000 and $19,541,000, respectively. The fair value of each stock option grant was estimated on the date of grant using the Black-Sholes option-pricing model, based on the following weighted-average assumptions.

| | Period of Grant | | | |
|---|---|---|---|---|
| | | Year Ended | | |
| | Six Months Ended December 31, 2002 | June 30, 2002 | June 30, 2001 | June 30, 2000 |
| Risk-free interest rate | 2.73% | 3.35% | 4.30% | 6.40% |
| Expected life of options | 5 years | 5 years | 5 years | 5 years |
| Expected volatility of the Company's stock price | 52% | 50% | 59% | 67% |
| Expected dividends | none | none | none | none |

## 9. INCOME TAXES

Components of income tax expense (benefit) are as follows:

| | Six Months Ended December 31, 2002 | Year Ended June 30, 2002 | 2001 | 2000 |
|---|---|---|---|---|
| | | (Thousands) | | |
| Federal and State: | | | | |
| Current | $ 33 | $ 914 | $ 2,304 | $ (5,588) |
| Deferred | | | | |
| U.S. | (552) | 21,385 | 34,953 | (1,238) |
| Foreign | | | | |
| Income tax expense (benefit) | $ (519) | $ 22,299 | $ 37,257 | $ (6,826) |

The Company made federal income tax payments during the year ended June 30, 2002 which were refunded during the six months ended December 31, 2002. The Company made state income tax payments of approximately $234,000 and $1,767,000 during the six months ended December 31, 2002 and the year ended June 30, 2002, respectively. No federal or state income tax payments were made during the years ended June 30, 2001 or June 30, 2000. Additionally a deferred tax benefit of approximately $83,000,

$267,000 and $7,004,000 has been allocated to stockholders' equity for the six months ended December 31, 2002 and the years ended June 30, 2002 and June 30, 2001, respectively, for compensation expense for income tax purposes in excess of amounts recognized for financial reporting purposes.

Income tax expense (benefit) differs from amounts computed by applying the statutory federal rate as follows:

| | Six Months Ended December 31, 2002 | Year Ended June 30, 2002 | 2001 | 2000 |
|---|---|---|---|---|
| | (Thousands) | | | |
| Income tax computed at statutory rate | (35.0)% | 35.0% | 35.0% | (35.0)% |
| Amortization of goodwill disallowance | | | 2.2 | 7.0 |
| State taxes | 1.6 | 2.8 | 1.4 | |
| Change in valuation allowance and other | 7.7 | (0.9) | (1.4) | 1.5 |
| Income tax expense (benefit) | (25.7)% | 36.9% | 37.2% | (26.5)% |

Deferred tax assets (liabilities) are comprised of the following:

| | Six Months Ended December 31, 2002 | Year Ended June 30, 2002 | 2001 |
|---|---|---|---|
| | (Thousands) | | |
| Net operating loss and tax credit carry forwards | $ 56,276 | $ 50,089 | $ 69,376 |
| Property and equipment | (222,212) | (191,834) | (183,068) |
| Self insurance reserves | 7,274 | 6,254 | 405 |
| Allowance for bad debts | 1,577 | 1,477 | 1,542 |
| Asset retirement obligations | 1,769 | | |
| Other | 6,892 | (2,456) | 148 |
| Net deferred tax liability | (148,424) | (136,470) | (111,597) |
| Valuation allowance for deferred tax assets | (12,841) | (13,520) | (15,803) |
| Net deferred tax liability, net of valuation allowance | $ (161,265) | $ (149,990) | $ (127,400) |

A valuation allowance is provided when it is more likely than not that some portion of the deferred tax assets will not be realized. As described below, due to annual limitations on certain net operating loss carryforwards, it does not appear more likely than not that the Company will be able to utilize all available carryforwards prior to their ultimate expiration.

The Company estimates that as of December 31, 2002, the Company will have available approximately $161,443,000 of net operating loss carryforwards. Approximately $75,950,000 of the net operating loss carryforwards are subject to an annual limitation of approximately $2,028,000, under Sections 382 and 383 of the Internal Revenue Code.

**10. OPERATING LEASING ARRANGEMENTS**

The Company leases certain property and equipment under non-cancelable operating leases that generally expire at various dates through calendar 2007. The term of the operating leases generally run from 24 months to 60 months with varying payment dates throughout each month.

As of December 31, 2002, the future minimum lease payments under non-cancelable operating leases are as follows (in thousands):

| Year Ending June 30, | Lease Payments |
|---|---|
| 2003 | $ 10,090 |
| 2004 | 9,038 |
| 2005 | 8,139 |
| 2006 | 5,136 |
| 2007 | 2,092 |
| | $ 34,495 |

Operating lease expense was approximately $5,008,000 for the six months ended December 31, 2002 and $6,456,000, $6,072,000, and $6,460,000 for the years ended June 30, 2002, 2001 and 2000, respectively.

**11. EMPLOYEE BENEFIT PLANS**

In order to retain quality personnel, the Company maintains 401(k) plans as part of its employee benefits package. From January 1, 1999 through March 31, 2000, the Company elected not to match employee contributions. Commencing April 1, 2000, the Company matched 100% of employee contributions into its 401(k) plan up to a maximum of $250 per participant per year. The maximum limit was increased to $500 effective October 1, 2000, $750 effective January 1, 2001 and $1,000 effective July 1, 2001. The Company's matching contributions for the six months ended December 31, 2002 were approximately $888,000 and for the years ended June 30, 2002, 2001 and 2000 were approximately $2,123,000, $1,857,000 and $77,000, respectively.

**12. TRANSACTIONS WITH RELATED PARTIES**

Effective as of July 1, 2001, the Company entered into an amended and restated employment agreement with Francis D. John (the "Employment Agreement") pursuant to which Mr. John serves as the Chairman of the Board, President and Chief Executive Officer of the Company. The Employment Agreement provided for the payment of a one-time retention incentive payment. The purpose of this retention incentive payment was to retire all amounts owed by Mr. John under incentive-based loans previously made to him (which, because certain performance criteria had been previously met, the Company was scheduled to forgive ratably over a ten-year period as long as Mr. John continued to serve the Company in his present capacity) and in the process provide Mr. John with incentive to remain with the Company for the next ten years. On December 1, 2001, the incentive retention payment was paid to Mr. John and was comprised of two components: (i) approximately $7.5 million in principal and interest accrued through the date of the payment and (ii) approximately $5.6 million in a tax "gross-up" payment. The entire payment was withheld by the Company and used to satisfy Mr. John's tax obligations and his obligations under the loans. Pursuant to the Employment Agreement, Mr. John will earn the incentive retention payment over a ten-year period beginning July 1, 2001, with one-tenth of the total bonus being earned on June 30 of each year, beginning on June 30, 2002. For the six months ended December 31, 2002 and the year ended June 30, 2002, Mr. John earned approximately $0.6 and $1.3 million, respectively, of the retention incentive payment. If Mr. John voluntarily terminates his employment with the Company or if Mr. John is terminated by the Company for Cause (as defined in the Employment Agreement), Mr. John will be obligated to repay the entire remaining unearned balance of the retention incentive payment



immediately upon such termination. However, if Mr. John's employment with the Company is terminated (i) by the Company other than for Cause, (ii) by Mr. John for Good Reason (as defined in the Employment Agreement), (iii) as a result of Mr. John's death or Disability (as defined in the Employment Agreement), or (iv) as a result of a Change in Control (as defined in the Employment Agreement), the remaining unearned balance of the retention incentive payment will be treated as earned as of the date of such event.

**13. BUSINESS SEGMENT INFORMATION**

The Company's reportable business segments are well servicing and contract drilling. Oil and natural gas production operations are presented in "corporate/other."

*Well Servicing:* The Company's operations provide well servicing (ongoing maintenance of existing oil and natural gas wells), workover (major repairs or modifications necessary to optimize the level of production from existing oil and natural gas wells) and production services (fluid hauling and fluid storage tank rental, fishing and rental tool services and pressure pumping services).

*Contract Drilling:* The Company provides contract drilling services for major and independent oil companies onshore the continental United States, Argentina and Ontario, Canada.

The Company's management evaluates the performance of its operating segments based on net income and operating profits (revenues less direct operating expenses). Corporate expenses include general corporate expenses associated with managing all reportable operating segments. Corporate assets



consist principally of cash and cash equivalents, deferred debt financing costs and deferred income tax assets.

| | Well Servicing | Contract Drilling | Corporate / Other | Total | |
|---|---|---|---|---|---|
| **Six Months Ended December 31, 2002** | | | | | |
| Operating revenues | $ 370,871 | $ 33,632 | $ 4,495 | $ 408,998 | |
| Operating profit | 107,276 | 10,216 | 2,561 | 120,053 | |
| Depreciation, depletion and amortization | 43,982 | 4,799 | 2,330 | 51,111 | |
| Interest expense | 534 | | 22,209 | 22,743 | |
| Net income (loss) before cumulative effect of a change in accounting principle* | 19,492 | 1,504 | (22,499) | (1,503) | |
| Identifiable assets | 834,019 | 90,534 | 255,179 | 1,179,732 | |
| Capital expenditures (excluding acquisitions) | 27,422 | 3,894 | 10,180 | 41,496 | |
| **Twelve Months Ended June 30, 2002** | | | | | |
| Operating revenues | $ 706,629 | $ 87,077 | $ 8,858 | $ 802,564 | |
| Operating profit | 216,947 | 26,516 | 4,328 | 247,791 | |
| Depreciation, depletion and amortization | 64,540 | 9,191 | 4,534 | 78,265 | |
| Interest expense | 1,448 | | 41,884 | 43,332 | |
| Net income (loss) before cumulative effect of a change in accounting principle* | 76,547 | 7,630 | (46,031) | 38,146 | |
| Identifiable assets | 686,425 | 91,374 | 264,127 | 1,041,926 | |
| Capital expenditures (excluding acquisitions) | 57,857 | 19,861 | 15,979 | 93,697 | |
| **Twelve Months Ended June 30, 2001** | | | | | |
| Operating revenues | $ 758,273 | $ 107,639 | $ 7,350 | $ 873,262 | |
| U.S.: | | | | | |
| Large cap | 676 | | | | 676 |
| Other | 25 | | | | 25 |
| Fixed Income: | | | | | |
| Corporate debt instruments | | 215 | | | 215 |
| U.S. Treasury securities and agency debentures | 80 | 63 | | | 143 |
| State and municipal | | 102 | | | 102 |
| Other | | 15 | | | 15 |
| Cash equivalents and other | 10 | 61 | | | 71 |
| Restricted cash equivalents | | 169 | | | 169 |
| Total assets | $ 791 | $ 637 | $ 15 | | $ 1,443 |
| **Liabilities** | | | | | |
| Derivatives: | | | | | |
| Commodity | $ | $ 5 | $ 1 | | $ 6 |

| | Well Servicing | Contract Drilling | Corporate / Other | Total |
|---|---|---|---|---|
| Total liabilities | $ | $ 5 | $ 1 | $ 6 |

(1) Includes investments held in the nuclear decommissioning and rabbi trusts.

Table of Contents

The following table presents the net change in Virginia Power s assets and liabilities measured at fair value on a recurring basis and included in the Level 3 fair value category:

| (millions) | Three Months Ended June 30, 2011 | Three Months Ended June 30, 2010 | Six Months Ended June 30, 2011 | Six Months Ended June 30, 2010 |
|---|---|---|---|---|
| Beginning balance | **$ (7)** | $ (15) | **$ 14** | $ (10) |
| Total realized and unrealized gains (losses): | | | | |
| Included in earnings | **(24)** | 6 | **(8)** | 26 |
| Included in regulatory assets/liabilities | **(11)** | 20 | **(32)** | 15 |
| Settlements | **24** | (6) | **8** | (26) |
| Ending balance | **$ (18)** | $ 5 | **$ (18)** | $ 5 |

The gains and losses included in earnings in the Level 3 fair value category were classified in electric fuel and other energy-related purchases in Virginia Power s Consolidated Statements of Income for the three and six months ended June 30, 2011 and 2010. There were no unrealized gains and losses included in earnings in the Level 3 fair value category relating to assets/liabilities still held at the reporting date for the three and six months ended June 30, 2011 and 2010.

***Fair Value of Financial Instruments***

Substantially all of Dominion s and Virginia Power s financial instruments are recorded at fair value, with the exception of the instruments described below that are reported at historical cost. Estimated fair values have been determined using available market information and valuation methodologies considered appropriate by management. The carrying amount of cash and cash equivalents, customer and other receivables, short-term debt and accounts payable are representative of fair value because of the short-term nature of these instruments. For Dominion s and Virginia Power s financial instruments that are not recorded at fair value, the carrying amounts and estimated fair values are as follows:

| (millions) | June 30, 2011 Carrying Amount | June 30, 2011 Estimated Fair Value(1) | December 31, 2010 Carrying Amount | December 31, 2010 Estimated Fair Value(1) |
|---|---|---|---|---|
| **Dominion** | | | | |
| Long-term debt, including securities due within one year(2) | **$ 15,578** | **$ 17,323** | $ 14,520 | $ 16,112 |
| Junior subordinated notes payable to affiliates | **268** | **275** | 268 | 261 |
| Enhanced junior subordinated notes | **1,467** | **1,576** | 1,467 | 1,560 |
| Subsidiary preferred stock(3) | **257** | **264** | 257 | 249 |
| **Virginia Power** | | | | |
| Long-term debt, including securities due within one year(2) | **$ 6,869** | **$ 7,782** | $ 6,717 | $ 7,489 |
| Preferred stock(3) | **257** | **264** | 257 | 249 |

(1) Fair value is estimated using market prices, where available, and interest rates currently available for issuance of debt with similar terms and remaining maturities. The carrying amount of debt issues with short-term maturities and variable rates refinanced at current market rates is a reasonable estimate of their fair value.

(2) Includes amounts which represent the unamortized discount and premium. At June 30, 2011 and December 31, 2010, includes the valuation of certain fair value hedges associated with Dominion s fixed rate debt of approximately $81 million and $49 million, respectively.

(3) Includes issuance expenses of $2 million at June 30, 2011 and December 31, 2010.

**Note 10. Derivatives and Hedge Accounting Activities**

Dominion s and Virginia Power s accounting policies and objectives and strategies for using derivative instruments are discussed in Note 2 to the Consolidated Financial Statements in their Annual Report on Form 10-K for the year ended December 31, 2010. See Note 9 in this report for further information about fair value measurements and associated valuation methods for derivatives.

Table of Contents

The following table presents the volume of Dominion s derivative activity as of June 30, 2011. These volumes are based on open derivative positions and represent the combined absolute value of their long and short positions, except in the case of offsetting deals, for which they represent the absolute value of the net volume of their long and short positions.

| | Current | Noncurrent |
|---|---|---|
| Natural Gas (bcf): | | |
| Fixed price(1) | **245** | **60** |
| Basis | **1,019** | **458** |
| Electricity (MWh): | | |
| Fixed price(1) | **19,363,209** | **24,512,834** |
| FTRs | **108,707,777** | **1,074,048** |
| Capacity (MW) | **201,416** | **297,985** |
| Liquids (gallons)(2) | **143,136,000** | **300,006,000** |
| Interest rate | **$ 600,000,000** | **$ 3,100,000,000** |

(1) Includes options.
(2) Includes NGLs and oil.

For the three and six months ended June 30, 2011 and 2010, gains or losses on hedging instruments determined to be ineffective were not material. Amounts excluded from the assessment of effectiveness include gains or losses attributable to changes in the time value of options and changes in the differences between spot prices and forward prices and were not material for the three and six months ended June 30, 2011 and 2010.

The following table presents selected information related to gains (losses) on cash flow hedges included in AOCI in Dominion s Consolidated Balance Sheet at June 30, 2011:

| (millions) | AOCI After-Tax | Amounts Expected to be Reclassified to Earnings during the next 12 Months After-Tax | Maximum Term |
|---|---|---|---|
| Commodities: | | | |
| Gas | **$ (14)** | **$ (5)** | **42 months** |
| Electricity | **42** | **30** | **54 months** |
| NGLs | **(75)** | **(32)** | **42 months** |
| Other | **6** | **2** | **47 months** |
| Interest rate | **14** | **(6)** | **378 months** |
| Total | **$ (27)** | **$ (11)** | |

The amounts that will be reclassified from AOCI to earnings will generally be offset by the recognition of the hedged transactions (e.g., anticipated sales) in earnings, thereby achieving the realization of prices contemplated by the underlying risk management strategies and will vary from the expected amounts presented above as a result of changes in market prices and interest rates.

The sale of the majority of Dominion s remaining E&P operations during 2010 resulted in the discontinuance of hedge accounting for certain cash flow hedges, as discussed in Note 3.

In addition, changes to Dominion s financing needs during the first and second quarters of 2010 resulted in the discontinuance of hedge accounting for certain cash flow hedges, since it became probable that forecasted interest payments would not occur. In connection with the discontinuance of hedge accounting for these contracts, Dominion recognized a benefit recorded to interest and related charges reflecting the reclassification of gains from AOCI to earnings of $70 million ($43 million after-tax) in the three months ended June 30, 2010 and $110 million

($67 million after-tax) in the six months ended June 30, 2010. The reclassification of gains from AOCI to earnings was partially offset by subsequent changes in fair value of $37 million ($23 million after-tax) for the three and six months ended June 30, 2010.

Table of Contents

***Fair Value and Gains and Losses on Derivative Instruments***

The following table presents the fair values of Dominion s derivatives and where they are presented in its Consolidated Balance Sheets:

| (millions) | Fair Value Derivatives under Hedge Accounting | Fair Value Derivatives not under Hedge Accounting | Total Fair Value |
|---|---|---|---|
| **June 30, 2011** | | | |
| **ASSETS** | | | |
| **Current Assets** | | | |
| Commodity | **$ 163** | **$ 273** | **$ 436** |
| Interest rate | **40** | | **40** |
| Total current derivative assets | **203** | **273** | **476** |
| **Noncurrent Assets** | | | |
| Commodity | **82** | **70** | **152** |
| Interest rate | **45** | | **45** |
| Total noncurrent derivative assets[1] | **127** | **70** | **197** |
| Total derivative assets | **$ 330** | **$ 343** | **$ 673** |
| **LIABILITIES** | | | |
| **Current Liabilities** | | | |
| Commodity | **$ 172** | **$ 344** | **$ 516** |
| Interest rate | **27** | | **27** |
| Total current derivative liabilities[2] | **199** | **344** | **543** |
| **Noncurrent Liabilities** | | | |
| Commodity | **146** | **80** | **226** |
| Interest rate | **7** | | **7** |
| Total noncurrent derivative liabilities[3] | **153** | **80** | **233** |
| Total derivative liabilities | **$ 352** | **$ 424** | **$ 776** |
| December 31, 2010 | | | |
| **ASSETS** | | | |
| **Current Assets** | | | |
| Commodity | $ 291 | $ 425 | $ 716 |
| Interest rate | 23 | | 23 |
| Total current derivative assets | 314 | 425 | 739 |
| **Noncurrent Assets** | | | |
| Commodity | 44 | 83 | 127 |
| Interest rate | 31 | | 31 |
| Total noncurrent derivative assets[1] | 75 | 83 | 158 |

| | | | |
|---|---|---|---|
| Total derivative assets | $ 389 | $ 508 | $ 897 |
| **LIABILITIES** | | | |
| Current Liabilities | | | |
| Commodity | $ 178 | $ 455 | $ 633 |
| Total current derivative liabilities[2] | 178 | 455 | 633 |
| Noncurrent Liabilities | | | |
| Commodity | 86 | 106 | 192 |
| Interest rate | 5 | | 5 |
| Total noncurrent derivative liabilities[3] | 91 | 106 | 197 |
| Total derivative liabilities | $ 269 | $ 561 | $ 830 |

Table of Contents

(1) Noncurrent derivative assets are presented in other deferred charges and other assets in Dominion s Consolidated Balance Sheets.
(2) Current derivative liabilities are presented in other current liabilities in Dominion s Consolidated Balance Sheets.
(3) Noncurrent derivative liabilities are presented in other deferred credits and other liabilities in Dominion s Consolidated Balance Sheets.

The following tables present the gains and losses on Dominion s derivatives, as well as where the associated activity is presented in its Consolidated Balance Sheets and Statements of Income:

| **Derivatives in cash flow hedging relationships** (millions) | **Amount of Gain (Loss) Recognized in AOCI on Derivatives - Effective Portion(1)** | **Amount of Gain (Loss) Reclassified from AOCI to Income** | **Increase (Decrease) in Derivatives Subject to Regulatory Treatment(2)** |
|---|---|---|---|
| **Three Months Ended June 30, 2011** | | | |
| Derivative Type and Location of Gains (Losses) | | | |
| Commodity: | | | |
| Operating revenue | | **$ 32** | |
| Purchased gas | | **(7)** | |
| Electric fuel and other energy-related purchases | | **1** | |
| Purchased electric capacity | | **1** | |
| Total commodity | **$ 49** | **27** | **$ (4)** |
| Interest rate(3) | **(31)** | | **1** |
| Total | **$ 18** | **$ 27** | **$ (3)** |
| Three Months Ended June 30, 2010 | | | |
| Derivative Type and Location of Gains (Losses) | | | |
| Commodity: | | | |
| Operating revenue | | $ 114 | |
| Purchased gas | | (19) | |
| Electric fuel and other energy-related purchases | | (5) | |
| Purchased electric capacity | | 1 | |
| Total commodity | $ (16) | 91 | $ 2 |
| Interest rate(3) | | 70 | (23) |
| Foreign currency(4) | | (1) | (1) |
| Total | $ (16) | $ 160 | $ (22) |
| **Six Months Ended June 30, 2011** | | | |
| Derivative Type and Location of Gains (Losses) | | | |
| Commodity: | | | |
| Operating revenue | | **$ 60** | |
| Purchased gas | | **(55)** | |
| Electric fuel and other energy-related purchases | | **2** | |
| Purchased electric capacity | | **2** | |
| Total commodity | **$ (93)** | **9** | **$ (9)** |

| | | | |
|---|---|---|---|
| Interest rate[3] | **(32)** | | |
| Total | **$ (125)** | **$ 9** | **$ (9)** |
| Six Months Ended June 30, 2010 | | | |
| Derivative Type and Location of Gains (Losses) | | | |
| Commodity: | | | |
| Operating revenue | | $ 295 | |
| Purchased gas | | (116) | |
| Electric fuel and other energy-related purchases | | (8) | |
| Purchased electric capacity | | 2 | |
| Total commodity | $ 283 | 173 | $ (11) |
| Interest rate[3] | (3) | 110 | (24) |
| Foreign currency[4] | | | (2) |
| Total | $ 280 | $ 283 | $ (37) |

Table of Contents

(1) Amounts deferred into AOCI have no associated effect in Dominion s Consolidated Statements of Income.
(2) Represents net derivative activity deferred into and amortized out of regulatory assets/liabilities. Amounts deferred into regulatory assets/liabilities have no associated effect in Dominion s Consolidated Statements of Income.
(3) Amounts recorded in Dominion s Consolidated Statements of Income are classified in interest and related charges.
(4) Amounts recorded in Dominion s Consolidated Statements of Income are classified in electric fuel and other energy-related purchases.

| Derivatives not designated as hedging instruments | Amount of Gain (Loss) Recognized in Income on Derivatives[1] | | | |
|---|---|---|---|---|
| | Three Months Ended June 30, | | Six Months Ended June 30, | |
| | **2011** | 2010 | **2011** | 2010 |
| (millions) | | | | |
| Derivative Type and Location of Gains (Losses) | | | | |
| Commodity | | | | |
| Operating revenue | **$ 23** | $ (14) | **$ 42** | $ 26 |
| Purchased gas | **(7)** | 2 | **(18)** | (29) |
| Electric fuel and other energy-related purchases | **(24)** | 5 | **(8)** | 26 |
| Interest rate[2] | | (37) | | (37) |
| Total | **$ (8)** | $ (44) | **$ 16** | $ (14) |

(1) Includes derivative activity amortized out of regulatory assets/liabilities. Amounts deferred into regulatory assets/liabilities have no associated effect in Dominion s Consolidated Statements of Income.
(2) Amounts recorded in Dominion s Consolidated Statements of Income are classified in interest and related charges.

**Note 11. Investments**

**Dominion**

**Equity and Debt Securities**

***Rabbi Trust Securities***

Marketable equity and debt securities and cash equivalents held in Dominion s rabbi trusts and classified as trading totaled $98 million and $93 million at June 30, 2011 and December 31, 2010, respectively. Net unrealized gains on trading securities totaled $1 million and $4 million for the three and six months ended June 30, 2011, respectively. Net unrealized losses on trading securities totaled $3 million and $1 million for the three and six months ended June 30, 2010, respectively. Cost-method investments held in Dominion s rabbi trusts totaled $17 million and $18 million at June 30, 2011 and December 31, 2010, respectively.

PAGE 26

Table of Contents

***Decommissioning Trust Securities***

Dominion holds marketable equity and debt securities (classified as available-for-sale), cash equivalents and cost method investments in nuclear decommissioning trust funds to fund future decommissioning costs for its nuclear plants. Dominion s decommissioning trust funds are summarized below.

| (millions) | Amortized Cost | Total Unrealized Gains[(1)] | Total Unrealized Losses [(1)] | Fair Value |
|---|---|---|---|---|
| **June 30, 2011** | | | | |
| Marketable equity securities | | | | |
| U.S.: | | | | |
| Large Cap | **$ 1,187** | **$ 597** | **$** | **$ 1,784** |
| Other | **41** | **11** | | **52** |
| Marketable debt securities: | | | | |
| Corporate bonds | **274** | **18** | **(1)** | **291** |
| U.S. Treasury securities and agency debentures | **499** | **14** | **(1)** | **512** |
| State and municipal | **213** | **13** | **(1)** | **225** |
| Other | **22** | | | **22** |
| Cost method investments | **110** | | | **110** |
| Cash equivalents and other[(2)] | **44** | | | **44** |
| Total | **$ 2,390** | **$ 653** | **$ (3)**[(3)] | **$ 3,040** |
| December 31, 2010 | | | | |
| Marketable equity securities: | | | | |
| U.S.: | | | | |
| Large Cap | $ 1,161 | $ 515 | $ | $ 1,676 |
| Other | 39 | 11 | | 50 |
| Marketable debt securities: | | | | |
| Corporate bonds | 310 | 18 | (1) | 327 |
| U.S. Treasury securities and agency debentures | 380 | 12 | (1) | 391 |
| State and municipal | 244 | 7 | (4) | 247 |
| Other | 19 | | | 19 |
| Cost method investments | 108 | | | 108 |
| Cash equivalents and other[(2)] | 79 | | | 79 |
| Total | $ 2,340 | $ 563 | $ (6)[(3)] | $ 2,897 |

(1) Included in AOCI and the decommissioning trust regulatory liability.
(2) Includes pending purchases of securities of $25 million and $43 million at June 30, 2011 and December 31, 2010, respectively.
(3) The fair value of securities in an unrealized loss position was $235 million and $252 million at June 30, 2011 and December 31, 2010, respectively.

PAGE 27

**Table of Contents**

The fair value of Dominion s marketable debt securities held in nuclear decommissioning trust funds at June 30, 2011 by contractual maturity is as follows:

| (millions) | Amount |
|---|---|
| Due in one year or less | **$ 100** |
| Due after one year through five years | **300** |
| Due after five years through ten years | **316** |
| Due after ten years | **334** |
| Total | **$ 1,050** |

Presented below is selected information regarding Dominion s marketable equity and debt securities held in nuclear decommissioning trust funds.

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| (millions) | **2011** | 2010 | **2011** | 2010 |
| Proceeds from sales | **$ 437** | $ 627 | **$ 939** | $ 1,140 |
| Realized gains[(1)] | **18** | 17 | **32** | 73 |
| Realized losses[(1)] | **12** | 28 | **20** | 54 |

(1) Includes realized gains or losses recorded to the decommissioning trust regulatory liability.

Dominion recorded other-than-temporary impairment losses on investments held in nuclear decommissioning trust funds as follows:

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| (millions) | **2011** | 2010 | **2011** | 2010 |
| Total other-than-temporary impairment losses[(1)] | **$ 10** | $ 41 | **$ 15** | $ 48 |
| Losses recorded to decommissioning trust regulatory liability | **(4)** | (13) | **(6)** | (16) |
| Losses recognized in other comprehensive income (before taxes) | **(1)** | (1) | **(1)** | (2) |
| Net impairment losses recognized in earnings | **$ 5** | $ 27 | **$ 8** | $ 30 |

(1) Amount includes other-than-temporary impairment losses for debt securities of $1 million for the three months ended June 30, 2011 and 2010, and $2 million and $3 million for the six months ended June 30, 2011 and 2010, respectively.

Table of Contents

**Virginia Power**

***Decommissioning Trust Securities***

Virginia Power holds marketable equity and debt securities (classified as available-for-sale), cash equivalents and cost method investments in nuclear decommissioning trust funds to fund future decommissioning costs for its nuclear plants. Virginia Power s decommissioning trust funds are summarized below.

| | Amortized Cost | Total Unrealized Gains[(1)] | Total Unrealized Losses[(1)] | Fair Value |
|---|---|---|---|---|
| (millions) | | | | |
| **June 30, 2011** | | | | |
| Marketable equity securities: | | | | |
| U.S.: | | | | |
| Large Cap | **$ 474** | **$ 243** | **$** | **$ 717** |
| Other | **20** | **6** | | **26** |
| Marketable debt securities: | | | | |
| Corporate bonds | **166** | **10** | **(1)** | **175** |
| U.S. Treasury securities and agency debentures | **232** | **4** | **(1)** | **235** |
| State and municipal | **76** | **2** | | **78** |
| Other | **17** | | | **17** |
| Cost method investments | **110** | | | **110** |
| Cash equivalents and other[(2)] | **21** | | | **21** |
| Total | **$ 1,116** | **$ 265** | **$ (2)[(3)]** | **$ 1,379** |
| December 31, 2010 | | | | |
| Marketable equity securities | | | | |
| U.S.: | | | | |
| Large Cap | $ 469 | $ 207 | $ | $ 676 |
| Other | 20 | 5 | | 25 |
| Marketable debt securities: | | | | |
| Corporate bonds | 205 | 10 | | 215 |
| U.S. Treasury securities and agency debentures | 141 | 2 | | 143 |
| State and municipal | 103 | 1 | (2) | 102 |
| Other | 15 | | | 15 |
| Cost method investments | 108 | | | 108 |
| Cash equivalents and other[(2)] | 35 | | | 35 |
| Total | $ 1,096 | $ 225 | $ (2)[(3)] | $ 1,319 |

(1) Included in AOCI and the decommissioning trust regulatory liability.
(2) Includes pending purchases of securities of $27 million and $35 million at June 30, 2011 and December 31, 2010, respectively.
(3) The fair value of securities in an unrealized loss position was $134 million and $159 million at June 30, 2011, and December 31, 2010, respectively.

The fair value of Virginia Power s debt securities at June 30, 2011, by contractual maturity is as follows:

| | Amount |
|---|---|
| (millions) | |

| | |
|---|---|
| Due in one year or less | $ **11** |
| Due after one year through five years | **157** |
| Due after five years through ten years | **199** |
| Due after ten years | **138** |
| Total | $ **505** |

**Table of Contents**

Presented below is selected information regarding Virginia Power s marketable equity and debt securities.

| (millions) | Three Months Ended June 30, 2011 | Three Months Ended June 30, 2010 | Six Months Ended June 30, 2011 | Six Months Ended June 30, 2010 |
|---|---|---|---|---|
| Proceeds from sales | **$ 253** | $ 407 | **$ 596** | $ 711 |
| Realized gains[(1)] | **6** | 8 | **11** | 37 |
| Realized losses[(1)] | **4** | 2 | **8** | 20 |

(1) Includes realized gains or losses recorded to the decommissioning trust regulatory liability.

Virginia Power recorded other-than-temporary impairment losses on investments as follows:

| (millions) | Three Months Ended June 30, 2011 | Three Months Ended June 30, 2010 | Six Months Ended June 30, 2011 | Six Months Ended June 30, 2010 |
|---|---|---|---|---|
| Total other-than-temporary impairment losses[(1)] | **$ 5** | $ 16 | **$ 7** | $ 19 |
| Losses recorded to decommissioning trust regulatory liability | **(4)** | (13) | **(6)** | (16) |
| Net impairment losses recognized in earnings | **$ 1** | $ 3 | **$ 1** | $ 3 |

(1) Amount includes other-than-temporary impairment losses for debt securities of $1 million for the three months ended June 30, 2011 and 2010, and $2 million for the six months ended June 30, 2011 and 2010.

**Note 12. Regulatory Matters**

Other than the following matters, there have been no significant developments regarding the pending regulatory matters disclosed in Note 14 to the Consolidated Financial Statements in Dominion s and Virginia Power s Annual Report on Form 10-K for the year ended December 31, 2010 and Note 12 to the Consolidated Financial Statements in Dominion s and Virginia Power s Quarterly Report on Form 10-Q for the quarter ended March 31, 2011.

*Virginia Fuel Expenses*

In May 2011, Virginia Power submitted its annual fuel factor filing to the Virginia Commission, proposing an annual increase for the rate year beginning July 1, 2011. This revised factor included a projected $434 million balance of prior year under-recovered fuel expenses. To reduce the impact to customers, as an alternative, Virginia Power proposed to

**Table of Contents**

recover this projected prior year deferred fuel balance over a two-year period beginning July 1, 2011. In June 2011, the Virginia Commission approved the two-year recovery proposal, resulting in an increase of approximately $319 million.

*Generation Riders R and S*

In connection with the Bear Garden and Virginia City Hybrid Energy Center projects, in June 2011, Virginia Power filed annual updates for Riders R and S with the Virginia Commission. Virginia Power proposed an approximately $81 million revenue requirement for Rider R and an approximately $249 million revenue requirement for Rider S for the April 1, 2012 to March 31, 2013 rate year. The filings utilize a 12.5% placeholder ROE (inclusive of a 100 basis point performance incentive), pending the Virginia Commission s ROE determination in the 2011 biennial review, plus a 100 basis point statutory enhancement for certain generation facilities. These requested revenue requirements for Riders R and S represent increases of approximately $3 million and $50 million, respectively, over the revenue requirements associated with the customer rates currently in effect for Riders R and S. Construction of Bear Garden was completed and the facility commenced commercial operations in the second quarter of 2011.

*Transmission Rider T*

In May 2011, Virginia Power filed its annual update to Rider T with the Virginia Commission. The proposed $481 million annual revenue requirement, effective September 1, 2011, represented an increase of approximately $144 million over the revenue requirement associated with the Rider T customer rates currently in effect. In July 2011, the Virginia Commission issued an order approving a revenue requirement of $466 million for the September 1, 2011 to August 31, 2012 rate year.

PAGE 31

*Generation Rider W*

In May 2011, Virginia Power requested approval from the Virginia Commission to construct and operate an intermediate, combined-cycle, natural gas-fired power station in Warren County, Virginia. Subject to the receipt of regulatory approvals, the project is expected to generate more than 1,300 MW of electricity, with commercial operations expected to commence by late 2014. The facility is expected to cost approximately $1.1 billion, excluding financing costs. In connection with the proposed Warren County power station, in May 2011, Virginia Power requested Virginia Commission approval of Rider W. Virginia Power proposed an approximately $39 million revenue requirement for Rider W for the April 1, 2012 to March 31, 2013 rate year. The filing utilizes a 12.5% placeholder ROE (inclusive of a 100 basis point performance incentive), pending the Virginia Commission s ROE determination in the 2011 biennial review, plus a 100 basis point statutory enhancement for certain generation facilities.

*Generation Rider B*

In June 2011, Virginia Power filed applications with the Virginia Commission seeking regulatory approval to convert three of its coal-fired power stations to biomass. The expected cost of converting the Altavista, Hopewell and Southampton County power stations is approximately $166 million, excluding financing costs. The applications included a request for approval of Rider B. Virginia Power proposed an approximately $7 million revenue requirement for the April 1, 2012 to March 31, 2013 rate year. The filing utilizes a 12.5% placeholder ROE (inclusive of a 100 basis point performance incentive), pending the Virginia Commission s ROE determination in the 2011 biennial review, plus a 200 basis point statutory enhancement for renewable generation facilities. To qualify for federal production tax credits associated with renewable energy generation, the power stations must commence operation as biomass generation facilities by December 31, 2013. Virginia Power has requested Virginia Commission approval of the biomass conversions on a schedule that will enable qualification for these tax credits.

*Electric Transmission Projects*

In October 2008, the Virginia Commission authorized construction of the Meadow Brook-to-Loudoun line and Carson-to-Suffolk line. The Meadow Brook-to-Loudoun line was energized in April 2011 and the Carson-to-Suffolk line was energized in May 2011.

***FERC Gas Regulation***

*DTI Appalachian Gateway Project*

In June 2011, FERC approved DTI s $634 million Appalachian Gateway Project. The project is expected to provide approximately 484,000 dekatherms per day of firm transportation services for new Appalachian gas supplies from the supply areas in the Appalachian Basin in West Virginia and southwestern Pennsylvania to an interconnection with Texas Eastern Transmission, LP at Oakford, Pennsylvania. Subject to receipt of FERC approval to commence construction, transportation services are scheduled to begin by September 2012.

*Cove Point*

In May 2011, Cove Point filed a general rate case for its FERC-jurisdictional services, with proposed rates to be effective July 1, 2011. Cove Point proposed an annual cost of service of approximately $150 million. In June 2011, FERC accepted a July 1, 2011 effective date for all proposed rates but two which were suspended to be effective December 1, 2011.

***Ohio Regulation***

In March 2011, East Ohio filed a request with the Ohio Commission to accelerate the PIR program by nearly doubling its PIR spending to more than $200 million annually. East Ohio plans to accelerate the pace of the program by investing more resources in its infrastructure in the near term, in an effort to promote ongoing public safety and reduce operating costs over the longer term. In July 2011, East Ohio, the Staff of the Ohio Commission and other interested parties filed a stipulation and recommendation and requested approval from the Ohio Commission. The stipulation provides for an increase in annual PIR capital investment from the current level of approximately $120 million to approximately $160 million. In addition, the stipulation provides for cost recovery over a five-year period commencing upon the approval of the Ohio Commission.

**Note 13. Variable Interest Entities**

As discussed in Note 16 to the Consolidated Financial Statements in Dominion s and Virginia Power s Annual Report on Form 10-K for the year ended December 31, 2010, certain variable pricing terms in some of the Companies long-term power and capacity contracts cause them to be considered variable interests in the counterparties.

Virginia Power has long-term power and capacity contracts with four non-utility generators with an aggregate summer generation capacity of approximately 870 MW. These contracts contain certain variable pricing mechanisms in the form of partial fuel reimbursement that Virginia Power considers to be variable interests. After an evaluation of the information provided by these entities, Virginia Power was unable to determine whether they were VIEs. However, the information they provided, as well as Virginia Power s knowledge of generation facilities in Virginia, enabled Virginia Power to conclude that, if they were VIEs, it would not be the primary beneficiary. This conclusion reflects Virginia Power s determination that its variable interests do not convey the power to direct the most significant activities that impact the economic performance of the entities during the remaining terms of Virginia Power s contracts and for the years the entities are expected to operate after its contractual relationships expire. The contracts expire at various dates ranging from 2015 to 2021. Virginia Power is not subject to any risk of loss from these potential VIEs other than its remaining purchase commitments which totaled $1.4 billion as of June 30, 2011. Virginia Power paid $52 million and $53 million for electric capacity and $26 million and $34 million for electric energy to these entities in the three months ended June 30, 2011 and 2010, respectively. Virginia Power paid $105 million and $107 million for electric capacity and $65 million and $75 million for electric energy to these entities in the six months ended June 30, 2011 and 2010, respectively.

Virginia Power purchased shared services from DRS, an affiliated VIE, of approximately $99 million and $107 million for the three months ended June 30, 2011 and 2010, respectively, and $192 million and $248 million for the six months ended June 30, 2011 and 2010, respectively. Virginia Power determined that it is not the most closely associated entity with DRS and therefore not the primary beneficiary. DRS provides accounting, legal, finance and certain administrative and technical services to all Dominion subsidiaries, including Virginia Power. Virginia Power has no obligation to absorb more than its allocated share of DRS costs.

**Note 14. Significant Financing Transactions**

***Credit Facilities and Short-term Debt***

Dominion and Virginia Power use short-term debt to fund working capital requirements and as a bridge to long-term debt financings. The levels of borrowing may vary significantly during the course of the year, depending upon the timing and amount of cash requirements not satisfied by cash from operations. In addition, Dominion utilizes cash and letters of credit to fund collateral requirements. Collateral requirements are impacted by commodity prices, hedging levels, Dominion s credit ratings and the credit quality of its counterparties.

At June 30, 2011, Dominion s commercial paper and letters of credit outstanding, as well as capacity available under credit facilities, were as follows:

| (millions) | Facility Limit | Outstanding Commercial Paper | Outstanding Letters of Credit | Facility Capacity Available |
|---|---|---|---|---|
| Three-year joint revolving credit facility(1) | $ 3,000 | $ 1,786 | $ 1 | $ 1,213 |
| Three-year joint revolving credit facility(2) | 500 | | 54 | 446 |
| Total | $ 3,500 | $ 1,786 | $ 55 | $ 1,659 |

(1) This credit facility was entered into in September 2010 and terminates in September 2013. This credit facility can be used to support bank borrowings and the issuance of commercial paper, as well as to support up to $1.5 billion of letters of credit.

(2) This credit facility was entered into in September 2010 and terminates in September 2013. This credit facility can be used to support bank borrowings, commercial paper and letter of credit issuances.

Virginia Power s short-term financing is supported by two three-year joint revolving credit facilities with Dominion. These credit facilities are being used for working capital, as support for the combined commercial paper programs of Dominion and Virginia Power and for other general corporate purposes.

At June 30, 2011, Virginia Power s share of commercial paper and letters of credit outstanding, as well as its capacity available under its joint credit facilities with Dominion were as follows:

| (millions) | Facility Sub-limit | Outstanding Commercial Paper | Outstanding Letters of Credit | Facility Capacity Available |
|---|---|---|---|---|
| Three-year joint revolving credit facility(1) | $ 1,000 | $ 933 | $ 1 | $ 66 |
| Three-year joint revolving credit facility(2) | 250 | | 30 | 220 |
| Total | $ 1,250 | $ 933 | $ 31 | $ 286 |

(1) This credit facility was entered into in September 2010 and terminates in September 2013. This credit facility can be used to support bank borrowings and the issuance of commercial paper, as well as to support up to $1.5 billion (or the sub-limit, whichever is less) of letters of credit. Virginia Power s applicable sub-limit under this credit facility can be increased or decreased multiple times per year.

(2) This credit facility was entered into in September 2010 and terminates in September 2013. This credit facility can be used to support bank borrowings, commercial paper and letter of credit issuances. Virginia Power s applicable sub-limit under this credit facility can be increased or decreased multiple times per year.

In addition to the credit facility commitments disclosed above, Virginia Power also has a three-year $120 million credit facility that was entered into in September 2010. The facility, which terminates in September 2013, supports certain tax-exempt financings of Virginia Power.

***Long-term Debt***

In December 2010, Brayton Point borrowed $160 million and $75 million in connection with the Massachusetts Development Finance Agency Recovery Zone Facility Bonds, Series 2010 A and the Solid Waste Disposal Revenue Bonds, Series 2010 B, respectively, which mature in 2041. The proceeds are being used to finance certain qualifying facilities at Brayton Point. Due to unfavorable market conditions, Dominion acquired the bonds upon issuance in December 2010 with the intention of remarketing them to third parties at a later time. At June 30, 2011 and December 31, 2010, these bonds had not been remarketed and thus were not reflected on the Consolidated Balance Sheets. In July 2011, the Series 2010 B bonds were remarketed to a third party using a remarketing process, and bear interest at a variable rate for the first five years, after which they will bear interest at a market rate to be determined at that time. Dominion intends to remarket the Series 2010 A bonds to third parties at a later time.

In March 2011, Dominion issued $500 million of 4.45% senior notes that mature in 2021 and $400 million of 1.80% senior notes that mature in 2014. The proceeds were used for general corporate purposes including the repayment of short-term debt.

In December 2010 and September 2009, Virginia Power borrowed $100 million and $60 million, respectively, in connection with the $160 million Industrial Development Authority of Wise County Solid Waste and Sewage Disposal Revenue Bonds, Series 2009 A, which mature in 2040. The proceeds are being used to finance certain qualifying facilities at the Virginia City Hybrid Energy Center. Due to unfavorable market conditions, Virginia Power acquired the bonds upon issuance with the intention of remarketing them to third parties at a later time. At December 31, 2010, these bonds had not been remarketed and thus were not reflected on the Consolidated Balance Sheets. In March 2011, the bonds were remarketed to a third party and bear interest at a variable rate for the first five years, after which they will bear interest at a market rate to be determined at that time.

***Convertible Securities***

At June 30, 2011, Dominion had $199 million of outstanding contingent convertible senior notes that are convertible by holders into a combination of cash and shares of Dominion s common stock under certain circumstances. The conversion feature requires that the principal amount of each note be repaid in cash, while amounts payable in excess of the principal amount will be paid in common stock. The conversion rate is subject to adjustment upon certain events such as subdivisions, splits, combinations of common stock or the issuance to all common stock holders of certain common stock rights, warrants or options and certain dividend increases. As of June 30, 2011, the conversion rate has been adjusted, primarily due to individual dividend payments above the level paid at issuance, to 28.7160 shares of common stock per $1,000 principal amount of senior notes, which represents a conversion price of $34.82.

The senior notes are eligible for conversion during any calendar quarter when the closing price of Dominion s common stock was equal to or higher than 120% of the conversion price for at least 20 out of the last 30 consecutive trading days of the preceding quarter. There were no significant conversions of these notes during the six months ended June 30, 2011. The senior notes are eligible for conversion during the third quarter of 2011.

Table of Contents

*Issuance of Common Stock*

Dominion maintains Dominion Direct® and a number of employee savings plans through which employer and employee contributions may be invested in the Company s common stock. These shares may either be newly issued or purchased on the open market with proceeds contributed to these plans by employees and the Company.

Since February 2010, Dominion Direct® and the Dominion employee savings plans have been purchasing Dominion common stock on the open market with the proceeds received through these programs, rather than having additional new common shares issued.

During the six months ended June 30, 2011, Dominion issued approximately 1 million shares of common stock and received cash proceeds of $32 million through the exercise of employee stock options.

*Repurchase of Common Stock*

Dominion expects to repurchase between $600 million and $700 million of common stock with cash tax savings resulting from the extension of the bonus depreciation allowance discussed in Note 6 to the Consolidated Financial Statements in Dominion s and Virginia Power s Annual Report on Form 10-K for the year ended December 31, 2010. During the six months ended June 30, 2011, Dominion repurchased approximately 13 million shares of common stock for approximately $601 million on the open market under this program, at an average price of $46.37 per share. Dominion will make a decision later in the year on whether to repurchase additional shares under this program.

**Note 15. Commitments and Contingencies**

As a result of issues generated in the ordinary course of business, Dominion and Virginia Power are involved in legal proceedings before various courts and are periodically subject to governmental examinations (including by regulatory authorities), inquiries and investigations. Certain legal proceedings and governmental examinations involve demands for unspecified amounts of damages, are in an initial procedural phase, involve uncertainty as to the outcome of pending appeals or motions, or involve significant factual issues that need to be resolved, such that it is not possible for the Companies to estimate a range of possible loss. For such matters that the Companies cannot estimate, a statement to this effect is made in the description of the matter. Other matters may have progressed sufficiently through the litigation or investigative processes such that the Companies are able to estimate a range of possible loss. For legal proceedings and governmental examinations for which the Companies are able to reasonably estimate a range of possible losses, an estimated range of possible loss is provided, in excess of the accrued liability (if any) for such matters. This estimated range is based on currently available information and involves elements of judgment and significant uncertainties. This estimated range of possible loss does not represent the Companies maximum possible loss exposure. The circumstances of such legal proceedings and governmental examinations will change from time to time and actual results may vary significantly from the current estimate. For current proceedings not specifically reported below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on Dominion s or Virginia Power s financial position, liquidity or results of operations.

*Environmental Matters*

Dominion and Virginia Power are subject to costs resulting from a number of federal, state and local laws and regulations designed to protect human health and the environment. These laws and regulations affect future planning and existing operations. They can result in increased capital, operating and other costs as a result of compliance, remediation, containment and monitoring obligations.

**Air**

In July 2011, the EPA issued a final replacement rule for CAIR, called CSAPR, that requires 27 states to reduce power plant emissions that cross state lines. CSAPR establishes new $SO_2$ and $NO_x$ emissions cap and trade programs that are completely independent of the current ARP. Specifically, CSAPR requires reductions in $SO_2$ and $NO_x$ emissions from fossil fuel-fired electric generating units of 25 MW or more through annual $NO_x$ emissions caps, $NO_x$ emissions caps during the ozone season (May 1 through September 30) and annual $SO_2$ emission caps with differing requirements for two groups of affected states. At June 30, 2011, Dominion and Virginia Power held $57 million and $43 million, respectively, of $SO_2$ and $NO_X$ emissions allowances, primarily reflecting $SO_2$ allowances obtained for ARP and CAIR compliance. Due to CSAPR s establishment of a new allowance program and the elimination of CAIR, Dominion and Virginia Power have more emissions allowances than needed for ARP compliance and accordingly expect to impair substantially all of the carrying amount of these allowances in the third quarter of 2011 in order to write the allowances down to their estimated fair value. Dominion and Virginia Power are currently evaluating CSAPR for other impacts and are unable to make an estimate of the potential financial statement impacts related to this matter.

The CAA is a comprehensive program utilizing a broad range of regulatory tools to protect and preserve the nation s air quality. At a minimum, states are required to establish regulatory programs to address all requirements of the CAA. However, states

PAGE 35

may choose to develop regulatory programs that are more restrictive. Many of Dominion s and Virginia Power s facilities are subject to the CAA s permitting and other requirements.

In February 2008, Dominion received a request for information pursuant to Section 114 of the CAA from the EPA. The request concerns historical operating changes and capital improvements undertaken at State Line and Kincaid. In April 2009, Dominion received a second request for information. Dominion provided information in response to both requests. Also in April 2009, Dominion received a Notice and Finding of Violations from the EPA claiming violations of the CAA New Source Review requirements, New Source Performance Standards, the Title V permit program and the stations respective State Implementation Plans. The Notice states that the EPA may issue an order requiring compliance with the relevant CAA provisions and may seek injunctive relief and/or civil penalties, all pursuant to the EPA s enforcement authority under the CAA.

Dominion believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The CAA authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation at each generating unit, depending on the date of the alleged violation. In addition to any such penalties that may be awarded, an adverse outcome could require substantial capital expenditures or affect the timing of currently budgeted capital expenditures that cannot be determined at this time. Such expenditures could affect future results of operations, cash flows, and financial condition. Dominion is currently unable to make an estimate of the potential financial statement impacts related to these matters.

In June 2010, the Conservation Law Foundation and Healthlink Inc., filed a Complaint in the District Court of Massachusetts against Dominion Energy New England, Inc. alleging that Salem Harbor units 1, 2, 3, and 4 have been and are in violation of visible emissions standards and monitoring requirements of the Massachusetts State Implementation Plan and the station s state and federal operating permits. Although Dominion cannot predict the outcome of this matter at this time, it is not expected to have a material effect on results of operations, financial condition and/or cash flows.

**Water**

In October 2003, the EPA and the Massachusetts Department of Environmental Protection each issued new NPDES permits for Brayton Point. The new permits contained identical conditions that in effect require the installation of cooling towers to address concerns over the withdrawal and discharge of cooling water. Currently, Dominion estimates the total cost to install these cooling towers at approximately $600 million, with remaining expenditures of approximately $150 million included in its planned capital expenditures through 2013.

In October 2007, the VSWCB issued a renewed VPDES permit for North Anna. BREDL, and other persons, appealed the VSWCB s decision to the Richmond Circuit Court, challenging several permit provisions related to North Anna s discharge of cooling water. In February 2009, the court ruled that the VSWCB was required to regulate the thermal discharge from North Anna into the waste heat treatment facility. Virginia Power filed a motion for reconsideration with the court in February 2009, which was denied. The final order was issued by the court in September 2009. The court s order allows North Anna to continue to operate pursuant to the currently issued VPDES permit. In October 2009, Virginia Power filed a Notice of Appeal of the court s Order with the Richmond Circuit Court, initiating the appeals process to the Virginia Court of Appeals. In June 2010, the Virginia Court of Appeals reversed the Richmond Circuit Court s September 2009 order. The Virginia Court of Appeals held that the lower court had applied the wrong standard of review, and that the VSWCB s determination not to regulate the station s thermal discharge into the waste heat treatment facility was lawful. In July 2010, BREDL and the other original appellants filed a petition for appeal to the Supreme Court of Virginia requesting that it review the Court of Appeals decision. In December 2010, the Supreme Court of Virginia granted BREDL s petition. Briefing on the merits of the case was completed in February 2011. The court has not yet scheduled oral argument. Dominion is currently unable to make an estimate of the potential financial statement impacts related to this matter. However, an adverse resolution could ultimately require significant capital expenditures which could have a material effect on Virginia Power s results of operations, financial condition and/or cash flows.

In September 2010, Millstone s NPDES permit was reissued under the CWA. The conditions of the permit require an evaluation of control technologies that could result in additional expenditures in the future, however Dominion cannot currently predict the outcome of this evaluation. In October 2010, the permit issuance was appealed to the state court by a private plaintiff. The permit is expected to remain in effect during the appeal. Dominion is currently unable to make an estimate of the potential financial statement impacts related to this matter.

**Solid and Hazardous Waste**

In March 2011, the EPA issued a final rule identifying NHSMs that would be considered solid waste when burned in combustion units, as opposed to being legitimate fuels or ingredients. The rule s premise is that any combusted NHSM is a solid waste unless such material satisfies the rule s criteria for either a fuel or an ingredient. Sources that combust solid waste are

**Table of Contents**

considered solid waste incinerators rather than industrial or utility boilers and would have to comply with EPA s more stringent emission standards for solid waste incinerators. Dominion and Virginia Power have several electric generating units that combust fuel materials that may be subject to the rule. Some units use a technology that combusts residual coal in fly ash to recover additional energy from unburned carbon. This technology also produces a final ash product that is marketable for beneficial reuse in cement production. Because of the uncertainty associated with the rule s potential applicability to this and other processes, in June 2011, Dominion filed a petition for review with the Court of Appeals for the District of Columbia Circuit challenging the final rule. Dominion is currently unable to make an estimate of the potential financial statement impacts related to this matter.

The CERCLA, as amended, provides for immediate response and removal actions coordinated by the EPA in the event of threatened releases of hazardous substances into the environment and authorizes the U.S. government either to clean up sites at which hazardous substances have created actual or potential environmental hazards or to order persons responsible for the situation to do so. Under the CERCLA as amended, generators and transporters of hazardous substances, as well as past and present owners and operators of contaminated sites, can be strictly, jointly and severally liable for the cost of cleanup. These potentially responsible parties can be ordered to perform a cleanup, be sued for costs associated with an EPA-directed cleanup, voluntarily settle with the U.S. government concerning their liability for cleanup costs, or voluntarily begin a site investigation and site remediation under state oversight.

From time to time, Dominion or Virginia Power may be identified as a potentially responsible party to a Superfund site. The EPA (or a state) can either allow such a party to conduct and pay for a remedial investigation, feasibility study and remedial action or conduct the remedial investigation and action itself and then seek reimbursement from the potentially responsible parties. Each party can be held jointly, severally and strictly liable for the cleanup costs. These parties can also bring contribution actions against each other and seek reimbursement from their insurance companies. As a result, Dominion or Virginia Power may be responsible for the costs of remedial investigation and actions under the Superfund law or other laws or regulations regarding the remediation of waste. The Companies do not believe this will have a material effect on results of operations, financial condition and/or cash flows.

Dominion has determined that it is associated with 17 former manufactured gas plant sites. Studies conducted by other utilities at their former manufactured gas plant sites have indicated that those sites contain coal tar and other potentially harmful materials. None of the 17 former sites with which Dominion is associated is under investigation by any state or federal environmental agency. At one of the former sites, Dominion is conducting a state-approved post closure groundwater monitoring program and an environmental land use restriction has been recorded. Another site has been accepted into a state-based voluntary remediation program and Dominion has not yet estimated the future remediation costs. Due to the uncertainty surrounding these sites, Dominion is unable to make an estimate of the potential financial statement impacts related to these sites.

***Guarantees***

**Dominion**

At June 30, 2011, Dominion had issued $91 million of guarantees, primarily to support equity method investees. No significant amounts related to these guarantees have been recorded. As of June 30, 2011, Dominion s exposure under these guarantees was $49 million, primarily related to certain reserve requirements associated with non-recourse financing.

Dominion also enters into guarantee arrangements on behalf of its consolidated subsidiaries, primarily to facilitate their commercial transactions with third parties. To the extent that a liability subject to a guarantee has been incurred by one of Dominion s consolidated subsidiaries, that liability is included in its Consolidated Financial Statements. Dominion is not required to recognize liabilities for guarantees issued on behalf of its subsidiaries unless it becomes probable that it will have to perform under the guarantees. Terms of the guarantees typically end once obligations have been paid. Dominion currently believes it is unlikely that it would be required to perform or otherwise incur any losses associated with guarantees of its subsidiaries obligations.

Table of Contents

At June 30, 2011, Dominion had issued the following subsidiary guarantees:

| (millions) | Stated Limit | Value[(1)] |
|---|---|---|
| Subsidiary debt[(2)] | $ 126 | $ 126 |
| Commodity transactions[(3)] | 3,054 | 468 |
| Lease obligation for power generation facility[(4)] | 731 | 731 |
| Nuclear obligations[(5)] | 231 | 75 |
| Other[(6)] | 441 | 105 |
| Total | $ 4,583 | $ 1,505 |

(1) Represents the estimated portion of the guarantee s stated limit that is utilized as of June 30, 2011 based upon prevailing economic conditions and fact patterns specific to each guarantee arrangement. For those guarantees related to obligations that are recorded as liabilities by Dominion s subsidiaries, the value includes the recorded amount.

(2) Guarantees of debt of certain DEI subsidiaries. In the event of default by the subsidiaries, Dominion would be obligated to repay such amounts.

(3) Guarantees related to energy trading and marketing activities and other commodity commitments of certain subsidiaries, including subsidiaries of Virginia Power and DEI. These guarantees were provided to counterparties in order to facilitate physical and financial transactions in gas, oil, electricity, pipeline capacity, transportation and related commodities and services. If any of these subsidiaries fail to perform or pay under the contracts and the counterparties seek performance or payment, Dominion would be obligated to satisfy such obligation. Dominion and its subsidiaries receive similar guarantees as collateral for credit extended to others. The value provided includes certain guarantees that do not have stated limits.

(4) Guarantee of a DEI subsidiary s leasing obligation for Fairless.

(5) Guarantees related to certain DEI subsidiaries potential retrospective premiums that could be assessed if there is a nuclear incident under Dominion s nuclear insurance programs and guarantees for a DEI subsidiary s and Virginia Power s commitment to buy nuclear fuel. Excludes Dominion s agreement to provide up to $150 million and $60 million to two DEI subsidiaries to pay the operating expenses of Millstone and Kewaunee, respectively, in the event of a prolonged outage, as part of satisfying certain Nuclear Regulatory Commission requirements concerned with ensuring adequate funding for the operations of nuclear power stations.

(6) Guarantees related to other miscellaneous contractual obligations such as leases, environmental obligations and construction projects. Also includes guarantees related to certain DEI subsidiaries obligations for equity capital contributions and energy generation associated with Fowler Ridge and NedPower.

***Spent Nuclear Fuel***

Under provisions of the Nuclear Waste Policy Act of 1982, Dominion and Virginia Power entered into contracts with the DOE for the disposal of spent nuclear fuel. The DOE failed to begin accepting the spent fuel on January 31, 1998, the date provided by the Nuclear Waste Policy Act and by the Companies contracts with the DOE. In January 2004, Dominion and Virginia Power filed lawsuits in the U.S. Court of Federal Claims against the DOE requesting damages in connection with its failure to commence accepting spent nuclear fuel. In October 2008, the Court issued an opinion and order for Dominion in the amount of approximately $155 million, which includes approximately $112 million in damages incurred by Virginia Power for spent fuel-related costs at Surry and North Anna and approximately $43 million in damages incurred for spent nuclear fuel-related costs at Millstone through June 30, 2006. In December 2008, the government appealed the judgment to the U.S. Court of Appeals for the Federal Circuit. The government s initial brief in the appeal was filed in June 2010. The issues raised by the government on appeal pertained to the damages awarded to Dominion for Millstone. The government did not take issue with the damages awarded to Virginia Power for Surry or North Anna. As a result, Virginia Power recognized a receivable in the amount of $174 million, largely offset against property, plant and equipment and regulatory assets and liabilities, representing certain spent nuclear fuel-related costs incurred through June 30, 2010.

In the second quarter of 2011, the Federal Appeals Court issued a decision affirming the trial court s damages award. The government did not seek rehearing of the Federal Appeals Court decision or seek review by the U.S. Supreme Court. As a result, Dominion recognized a receivable in the amount of $64 million for certain Millstone spent nuclear fuel-related costs incurred through June 30, 2011 that are now considered probable of recovery. Dominion recognized a pre-tax benefit of $24 million, with $17 million recorded in other operations and maintenance expense and the remaining $7 million recorded in depreciation, depletion and amortization expense for the six months ended June 30, 2011, with the remainder largely offset against property, plant and equipment. Dominion expects to receive payment of the $155 million damages award, including $112 million of damages incurred by Virginia Power, during the third quarter of 2011.

The Companies continue to recognize receivables for certain spent nuclear fuel-related costs that they believe are probable of recovery from the DOE. At June 30, 2011, Dominion s and Virginia Power s receivables for spent nuclear fuel-related costs totaled $254 million and $187 million, respectively. The Companies will continue to manage their spent fuel until it is accepted by the DOE.

*Surety Bonds and Letters of Credit*

As of June 30, 2011, Dominion had purchased $120 million of surety bonds, including $40 million at Virginia Power, and authorized the issuance of standby letters of credit by financial institutions of $55 million, including $31 million at Virginia Power, to facilitate commercial transactions by its subsidiaries with third parties. Under the terms of the surety bonds, the Companies are obligated to indemnify the respective surety bond company for any amounts paid.

*Merchant Generation Operations*

Dominion continually reviews its portfolio of assets to determine which assets fit strategically and support its objectives to improve return on invested capital and shareholder value. If Dominion identifies assets that do not support its objectives and believes they may be of greater value to another owner, Dominion may consider such assets for divestiture. In connection with this effort, in the first quarter of 2011, Dominion decided to pursue the sale of Kewaunee. If these efforts are successful, Dominion may be required to present Kewaunee s assets and liabilities that are subject to sale as held for sale in its Consolidated Balance Sheet and Kewaunee s results of operations in discontinued operations in its Consolidated Statements of Income. Held for sale classification would require that amounts be recorded at the lower of book value or sale price less costs to sell and could result in the recording of an impairment charge. Any sale of Kewaunee would be subject to the approval of Dominion s Board of Directors, as well as applicable state and federal approvals.

During the second quarter of 2011, Dominion announced that State Line would shut down by mid-2014, and that it would cease operating two of the four units at Salem Harbor by the end of 2011 and plans to retire all four units on June 1, 2014. In the second quarter of 2011, Dominion recorded a $17 million ($11 million after-tax) charge in other operations and maintenance expense for severance costs related to the expected closings of these merchant generation facilities.

**Note 16. Credit Risk**

Dominion s and Virginia Power s accounting policies for credit risk are discussed in Note 24 to the Consolidated Financial Statements in their Annual Report on Form 10-K for the year ended December 31, 2010.

At June 30, 2011, Dominion s gross credit exposure totaled $311 million. After the application of collateral, credit exposure is unchanged. Of this amount, investment grade counterparties, including those internally rated, represented 80%. Two counterparty exposures each represent 11% of Dominion s total exposure and are large financial institutions rated investment grade.

*Credit-Related Contingent Provisions*

The majority of Dominion s derivative instruments contain credit-related contingent provisions. These provisions require Dominion to provide collateral upon the occurrence of specific events, primarily a credit rating downgrade. If the credit-related contingent features underlying these instruments that are in a liability position and not fully collateralized with cash were fully triggered as of June 30, 2011 and December 31, 2010, Dominion would have been required to post an additional $112 million and $88 million, respectively, of collateral to its counterparties. The collateral that would be required to be posted includes the impacts of any offsetting asset positions and any amounts already posted for derivatives, non-derivative contracts and derivatives elected under the normal purchases and normal sales exception, per contractual terms. Dominion had posted $92 million in collateral, including $87 million of letters of credit, at June 30, 2011 and $54 million in collateral, including $19 million of letters of credit, at December 31, 2010, related to derivatives with credit-related contingent provisions that are in a liability position and not fully collateralized with cash. The collateral posted includes any amounts paid related to non-derivative contracts and derivatives elected under the normal purchases and normal sales exception, per contractual terms. The aggregate fair value of all derivative instruments with credit-related contingent provisions that are in a liability position and not fully collateralized with cash as of June 30, 2011 and December 31, 2010 was $247 million and $210 million, respectively, which does not include the impact of any offsetting asset positions. See Note 10 for further information about derivative instruments.

**Note 17. Related Party Transactions**

Virginia Power engages in related-party transactions primarily with other Dominion subsidiaries (affiliates). Virginia Power s receivable and payable balances with affiliates are settled based on contractual terms or on a monthly basis, depending on the nature of the underlying transactions. Virginia Power is included in Dominion s consolidated federal income tax return and participates in certain Dominion benefit plans. A discussion of significant related party transactions follows.

Table of Contents

**Transactions with Affiliates**

Virginia Power transacts with affiliates for certain quantities of natural gas and other commodities in the ordinary course of business. Virginia Power also enters into certain commodity derivative contracts with affiliates. Virginia Power uses these contracts, which are principally comprised of commodity swaps, to manage commodity price risk associated with purchases of natural gas.

DRS provides accounting, legal, finance and certain administrative and technical services to Virginia Power. Presented below are significant transactions with DRS and other affiliates:

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | **2011** | 2010 | **2011** | 2010 |
| (millions) | | | | |
| Commodity purchases from affiliates | **$ 90** | $ 89 | **$ 152** | $ 156 |
| Services provided by affiliates | **100** | 108 | **193** | 249 |

Virginia Power has borrowed funds from Dominion under short-term borrowing arrangements. Virginia Power s outstanding borrowings, net of repayments, under the Dominion money pool for its non-regulated subsidiaries totaled $58 million and $24 million, as of June 30, 2011 and December 31, 2010, respectively. Virginia Power s short-term demand note borrowings from Dominion were $79 million as of December 31, 2010. There were no short-term demand note borrowings as of June 30, 2011. Virginia Power s interest charges related to its borrowings from Dominion were immaterial for the three and six months ended June 30, 2011 and 2010.

In March 2010, Virginia Power issued 14,600 shares of its common stock to Dominion reflecting the conversion of approximately $433 million of short-term demand note borrowings from Dominion to equity.

**Note 18. Employee Benefit Plans**

The components of Dominion s provision for net periodic benefit cost were as follows:

| | Pension Benefits | | Other Postretirement Benefits | |
|---|---|---|---|---|
| | **2011** | 2010 | **2011** | 2010 |
| (millions) | | | | |
| **Three Months Ended June 30,** | | | | |
| Service cost | **$ 27** | $ 25 | **$ 12** | $ 14 |
| Interest cost | **65** | 68 | **24** | 25 |
| Expected return on plan assets | **(111)** | (106) | **(19)** | (18) |
| Amortization of prior service cost (credit) | **1** | 1 | **(4)** | (1) |
| Amortization of net loss | **24** | 15 | **3** | 3 |
| Settlements and curtailments | | | **(1)** | (1) |
| Special termination benefits | | 1 | | |
| Net periodic benefit cost | **$ 6** | $ 4 | **$ 15** | $ 22 |
| **Six Months Ended June 30,** | | | | |
| Service cost | **$ 54** | $ 52 | **$ 24** | $ 28 |
| Interest cost | **129** | 134 | **47** | 50 |
| Expected return on plan assets | **(221)** | (205) | **(39)** | (35) |
| Amortization of prior service cost (credit) | **2** | 2 | **(7)** | (3) |
| Amortization of net loss | **48** | 30 | **6** | 6 |
| Settlements and curtailments[1] | | 84 | **(1)** | 37 |
| Special termination benefits[2] | | 10 | | 1 |

| | | | | |
|---|---|---|---|---|
| Net periodic benefit cost | **$ 12** | $ 107 | **$ 30** | $ 84 |

(1) 2010 amounts relate to the sale of Peoples and a workforce reduction program.
(2) Represents a one-time special termination benefit for certain employees in connection with a workforce reduction program.

PAGE 40

**Table of Contents**

***Employer Contributions***

During the six months ended June 30, 2011, Dominion made no contributions to its defined benefit pension plans or OPEB plans. Dominion expects to contribute approximately $18 million to its OPEB plans through Voluntary Employees Beneficiary Associations during the remainder of 2011.

**Note 19. Operating Segments**

Dominion and Virginia Power are organized primarily on the basis of products and services sold in the U.S. A description of the operations included in the Companies primary operating segments is as follows:

| Primary Operating Segment | Description of Operations | Dominion | Virginia Power |
|---|---|---|---|
| DVP | Regulated electric distribution | X | X |
| | Regulated electric transmission | X | X |
| | Nonregulated retail energy marketing (electric and gas) | X | |
| Dominion Generation | Regulated electric fleet | X | X |
| | Merchant electric fleet | X | |
| Dominion Energy | Gas transmission and storage | X | |
| | Gas distribution | X | |
| | LNG import and storage | X | |
| | Producer services | X | |

In addition to the operating segments above, the Companies also report a Corporate and Other segment.

*The Corporate and Other Segment of Dominion* includes its corporate, service company and other functions (including unallocated debt) and certain specific items that are not included in profit measures evaluated by executive management in assessing segment performance or allocating resources among the segments.

In the six months ended June 30, 2011, Dominion reported after-tax net expenses of $64 million for specific items in the Corporate and Other segment, with $56 million of these net expenses attributable to its operating segments. In the six months ended June 30, 2010, Dominion reported after-tax net benefits of $933 million for specific items in the Corporate and Other segment, with $1.1 billion of these net benefits attributable to its operating segments.

The net expenses for specific items in 2011 primarily related to the impact of the following items:

- A $55 million ($39 million after-tax) impairment charge related to State Line, attributable to Dominion Generation; and

- A $37 million ($20 million after-tax) loss from the operations of Kewaunee, attributable to Dominion Generation. Kewaunee s results of operations have been reflected in the Corporate and Other segment due to Dominion s decision in the first quarter of 2011 to pursue the sale of Kewaunee.

The net benefits for specific items in 2010 primarily related to the impact of the following items:

- A $2.5 billion ($1.4 billion after-tax) benefit resulting from the gain on the sale of substantially all of Dominion s Appalachian E&P operations net of charges related to the divestiture, attributable to Dominion Energy; partially offset by

A $338 million ($206 million after-tax) charge primarily reflecting severance pay and other benefits related to a workforce reduction program, attributable to:

- DVP ($67 million after-tax);
- Dominion Energy ($24 million after-tax); and
- Dominion Generation ($115 million after-tax);

A $134 million ($147 million after-tax) loss from the discontinued operations of Peoples primarily reflecting a net loss on the sale, attributable to the Corporate and Other segment; and

A $163 million ($95 million after-tax) impairment charge related to State Line, attributable to Dominion Generation.

*The Corporate and Other Segment of Virginia Power* primarily includes certain specific items that are not included in profit measures evaluated by executive management in assessing segment performance or allocating resources among the segments. In the six months ended June 30, 2011 and 2010, Virginia Power reported after-tax net expenses of $5 million and $141 million, respectively, for specific items attributable to its operating segments in the Corporate and Other segment.

PAGE 41

Table of Contents

The net expenses for specific items in 2010 primarily related to the impact of the following:

A $202 million ($123 million after-tax) charge primarily reflecting severance pay and other benefits related to a workforce reduction program, attributable to:

DVP ($63 million after-tax); and

Dominion Generation ($60 million after-tax).

The following table presents segment information pertaining to Dominion s operations:

| (millions) | DVP | Dominion Generation | Dominion Energy | Corporate and Other | Adjustments/ Eliminations | Consolidated Total |
|---|---|---|---|---|---|---|
| **Three Months Ended June 30,** | | | | | | |
| **2011** | | | | | | |
| Total revenue from external customers | **$ 828** | **$ 1,760** | **$ 379** | **$ 37** | **$ 337** | **$ 3,341** |
| Intersegment revenue | **18** | **87** | **294** | **151** | **(550)** | |
| Total operating revenue | **846** | **1,847** | **673** | **188** | **(213)** | **3,341** |
| Net income (loss) attributable to Dominion | **115** | **194** | **104** | **(77)** | | **336** |
| **2010** | | | | | | |
| Total revenue from external customers | $ 787 | $ 1,831 | $ 450 | $ (6) | $ 271 | $ 3,333 |
| Intersegment revenue | 19 | 108 | 294 | 167 | (588) | |
| Total operating revenue | 806 | 1,939 | 744 | 161 | (317) | 3,333 |
| Income from discontinued operations, net of tax | | | | 2 | | 2 |
| Net income attributable to Dominion | 112 | 276 | 86 | 1,287 | | 1,761 |
| **Six Months Ended June 30,** | | | | | | |
| **2011** | | | | | | |
| Total revenue from external customers | **$ 1,879** | **$ 3,623** | **$ 1,213** | **$ 73** | **$ 610** | **$ 7,398** |
| Intersegment revenue | **113** | **157** | **502** | **294** | **(1,066)** | |
| Total operating revenue | **1,992** | **3,780** | **1,715** | **367** | **(456)** | **7,398** |
| Net income (loss) attributable to Dominion | **264** | **492** | **273** | **(214)** | | **815** |
| **2010** | | | | | | |
| Total revenue from external customers | $ 1,790 | $ 3,809 | $ 1,300 | $ 34 | $ 568 | $ 7,501 |
| Intersegment revenue | 107 | 210 | 567 | 399 | (1,283) | |
| Total operating revenue | 1,897 | 4,019 | 1,867 | 433 | (715) | 7,501 |
| Loss from discontinued operations, net of tax | | | | (147) | | (147) |

| | | | | | |
|---|---|---|---|---|---|
| Net income attributable to Dominion | 226 | 601 | 261 | 847 | 1,935 |

Intersegment sales and transfers for Dominion are based on contractual arrangements and may result in intersegment profit or loss that is eliminated in consolidation.

Table of Contents

The following table presents segment information pertaining to Virginia Power s operations:

| (millions) | DVP | Dominion Generation | Corporate and Other | Consolidated Total |
|---|---|---|---|---|
| **Three Months Ended June 30,** | | | | |
| **2011** | | | | |
| Operating revenue | **$ 430** | **$ 1,328** | **$ (1)** | **$ 1,757** |
| Net income (loss) | **102** | **144** | **(5)** | **241** |
| **2010** | | | | |
| Operating revenue | $ 398 | $ 1,313 | $ | $ 1,711 |
| Net income | 105 | 160 | 2 | 267 |
| **Six Months Ended June 30,** | | | | |
| **2011** | | | | |
| Operating revenue | **$ 883** | **$ 2,632** | **$ (1)** | **$ 3,514** |
| Net income (loss) | **215** | **309** | **(5)** | **519** |
| **2010** | | | | |
| Operating revenue | $ 800 | $ 2,650 | $ | $ 3,450 |
| Net income (loss) | 198 | 303 | (139) | 362 |

Table of Contents

## ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS

## OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

MD&A discusses Dominion s and Virginia Power s results of operations and general financial condition. MD&A should be read in conjunction with the Companies Consolidated Financial Statements.

**Contents of MD&A**

MD&A consists of the following information:



**Forward-Looking Statements**

This report contains statements concerning Dominion s and Virginia Power s expectations, plans, objectives, future financial performance and other statements that are not historical facts. These statements are forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. In most cases, the reader can identify these forward-looking statements by such words as anticipate, estimate, forecast, expect, believe, should, could, plan, may, target or other similar words.

Dominion and Virginia Power make forward-looking statements with full knowledge that risks and uncertainties exist that may cause actual results to differ materially from predicted results. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Additionally, other factors may cause actual results to differ materially from those indicated in any forward-looking statement. These factors include but are not limited to:

Unusual weather conditions and their effect on energy sales to customers and energy commodity prices;

Extreme weather and geophysical events, including earthquakes, hurricanes, tornadoes, high winds and severe storms, that can cause outages and property damage to facilities;

Federal, state and local legislative and regulatory developments;

Changes to federal, state and local environmental laws and regulations, including those related to climate change, water temperature and quality, the tightening of emission or discharge limits for GHGs and other emissions, more extensive permitting requirements and the regulation of additional substances;

Cost of environmental compliance, including those costs related to climate change;

Risks associated with the operation of nuclear facilities, including costs associated with the disposal of spent nuclear fuel, decommissioning, plant maintenance and changes in existing regulations governing such facilities;

Unplanned outages of the Companies facilities;

Fluctuations in energy-related commodity prices and the effect these could have on Dominion s earnings and Dominion s and Virginia Power s liquidity position and the underlying value of their assets;

Counterparty credit and performance risk;

Capital market conditions, including the availability of credit and the ability to obtain financing on reasonable terms;

Risks associated with Virginia Power s membership and participation in PJM related to obligations created by the default of other participants;

Price risk due to investments held in nuclear decommissioning trusts by Dominion and Virginia Power and in benefit plan trusts by Dominion;

Fluctuations in interest rates;

Changes in federal and state tax laws and regulations;

Changes in rating agency requirements or credit ratings and their effect on availability and cost of capital;

Changes in financial or regulatory accounting principles or policies imposed by governing bodies;

Employee workforce factors including collective bargaining agreements and labor negotiations with union employees;

The risks of operating businesses in regulated industries that are subject to changing regulatory structures;

Receipt of approvals for and timing of closing dates for acquisitions and divestitures;

Changes in rules for RTOs and ISOs in which Dominion and Virginia Power participate, including changes in rate designs and new and evolving capacity models;

Table of Contents

Political and economic conditions, including inflation and deflation;

Domestic terrorism and other threats to the Companies physical and intangible assets;

Industrial, commercial and residential growth or decline in the Companies service areas and changes in customer growth or usage patterns, including as a result of energy conservation programs;

Additional competition in electric markets in which Dominion s merchant generation facilities operate;

Changes in technology, particularly with respect to new, developing or alternative sources of generation and smart grid technologies;

Changes to regulated electric rates collected by Virginia Power and regulated gas distribution, transportation and storage rates, including LNG storage, collected by Dominion;

Timing and receipt of regulatory approvals necessary for planned construction or expansion projects;

The inability to complete planned construction projects within the terms and time frames initially anticipated; and

Adverse outcomes in litigation matters.

Additionally, other risks that could cause actual results to differ from predicted results are set forth in Item 1A. Risk Factors in Dominion s and Virginia Power s Annual Report on Form 10-K for the year ended December 31, 2010 and in Part II, Item 1A. Risk Factors in this report.

Dominion s and Virginia Power s forward-looking statements are based on beliefs and assumptions using information available at the time the statements are made. The Companies caution the reader not to place undue reliance on their forward-looking statements because the assumptions, beliefs, expectations and projections about future events may, and often do, differ materially from actual results. Dominion and Virginia Power undertake no obligation to update any forward-looking statement to reflect developments occurring after the statement is made.

**Accounting Matters**

**Critical Accounting Policies and Estimates**

As of June 30, 2011, there have been no significant changes with regard to the critical accounting policies and estimates disclosed in MD&A in Dominion s and Virginia Power s Annual Report on Form 10-K for the year ended December 31, 2010. The policies disclosed included the accounting for regulated operations, AROs, income taxes, derivative contracts and other instruments at fair value, goodwill and long-lived asset impairment testing, employee benefit plans and unbilled revenue.

**Dominion**

**Results of Operations**

Presented below is a summary of Dominion s consolidated results:

| (millions, except EPS) | **2011** | 2010 | $ Change |
|---|---|---|---|
| **Second Quarter** | | | |
| Net income attributable to Dominion | **$ 336** | $ 1,761 | $ (1,425) |
| Diluted EPS | **0.58** | 2.98 | (2.40) |
| **Year-To-Date** | | | |
| Net income attributable to Dominion | **$ 815** | $ 1,935 | $ (1,120) |
| Diluted EPS | **1.41** | 3.25 | (1.84) |

**Overview**

***Second Quarter 2011 vs. 2010***

Net income attributable to Dominion decreased by $1.4 billion. The primary driver is the absence of a gain on the sale of Dominion s Appalachian E&P operations recorded in 2010.

***Year-To-Date 2011 vs. 2010***

Net income attributable to Dominion decreased by $1.1 billion. Unfavorable drivers include the absence of a gain on the sale of Dominion s Appalachian E&P operations recorded in 2010, lower margins from merchant generation operations and the impact of less favorable weather on Dominion s electric utility operations. Favorable drivers include the absence of charges related to a workforce reduction program and a loss on the sale of Peoples, both recorded in 2010, and a decrease in impairment charges related to State Line.

Table of Contents

**Analysis of Consolidated Operations**

Presented below are selected amounts related to Dominion s results of operations:

| | Second Quarter | | | Year-To-Date | | |
|---|---|---|---|---|---|---|
| (millions) | **2011** | 2010 | $ Change | **2011** | 2010 | $ Change |
| Operating revenue | **$ 3,341** | $ 3,333 | $ 8 | **$ 7,398** | $ 7,501 | $ (103) |
| Electric fuel and other energy-related purchases | **978** | 956 | 22 | **2,027** | 1,984 | 43 |
| Purchased electric capacity | **116** | 109 | 7 | **235** | 217 | 18 |
| Purchased gas | **365** | 391 | (26) | **1,007** | 1,183 | (176) |
| Net revenue | **1,882** | 1,877 | 5 | **4,129** | 4,117 | 12 |
| Other operations and maintenance | **777** | 853 | (76) | **1,638** | 1,921 | (283) |
| Depreciation, depletion and amortization | **255** | 262 | (7) | **517** | 531 | (14) |
| Other taxes | **125** | 119 | 6 | **286** | 288 | (2) |
| Gain on sale of Appalachian E&P operations | | 2,467 | (2,467) | | 2,467 | (2,467) |
| Other income (loss) | **39** | (25) | 64 | **96** | 46 | 50 |
| Interest and related charges | **216** | 188 | 28 | **443** | 371 | 72 |
| Income tax expense | **208** | 1,134 | (926) | **518** | 1,429 | (911) |
| Income (loss) from discontinued operations | | 2 | (2) | | (147) | 147 |

An analysis of Dominion s results of operations follows:

**Second Quarter 2011 vs. 2010**

**Net revenue** increased $5 million, primarily reflecting:

A $44 million increase from electric utility operations primarily reflecting:

The impact of rate adjustment clauses ($44 million);

An increase in ancillary revenues received from PJM ($21 million); partially offset by

The net impact ($15 million) of a decrease in sales to retail customers primarily due to a decrease in cooling degree days ($54 million) and an increase in sales due to the effect of favorable economic conditions on customer usage and other factors ($39 million);

A $30 million increase in producer services primarily related to favorable price changes on economic hedging positions and higher physical margins, all associated with natural gas aggregation, marketing and trading activities;

A $13 million increase in retail energy marketing activities primarily due to a decrease in purchased gas expense; and

A $9 million increase from Dominion s gas transmission business primarily related to an increase in revenue from NGLs.
These increases were partially offset by:

A $76 million decrease from merchant generation operations, primarily reflecting:

A decline at certain fossil generation facilities ($47 million) largely due to lower generation ($22 million) and unfavorable prices ($20 million); and

A decline at nuclear generation facilities ($29 million) largely due to lower realized prices ($47 million), partially offset by increased generation ($21 million); and

A $19 million decrease reflecting the sale of substantially all of Dominion s Appalachian E&P operations in April 2010.
**Other operations and maintenance** decreased 9%, primarily reflecting:

A $163 million decrease due to the absence of an impairment charge recorded in 2010 related to State Line; partially offset by

A $55 million increase in planned outage costs due to an increase in scheduled outage days at certain electric utility and merchant generation facilities;

A $17 million charge for severance costs related to the expected closings of certain merchant generation plants; and

An $11 million increase in salaries, wages and benefits.

PAGE 46

Table of Contents

**Gain on sale of Appalachian E&P operations** reflects a gain on the sale of these operations.

**Other income (loss)** increased $64 million, primarily reflecting a decrease in charitable contributions.

**Interest and related charges** increased 15%, primarily due to the absence of a benefit recorded in 2010 resulting from the discontinuance of hedge accounting for certain interest rate derivatives.

**Income tax expense** decreased 82%, primarily reflecting lower federal and state taxes largely due to the absence of a gain from the sale of Dominion s Appalachian E&P operations recorded in 2010.

**Year-To-Date 2011 vs. 2010**

**Net revenue** increased $12 million, primarily reflecting:

- A $90 million increase from electric utility operations primarily reflecting:
  - The impact of rate adjustment clauses ($91 million);
  - An increase in ancillary revenues received from PJM ($28 million); partially offset by
  - The net impact ($29 million) of a decrease in sales to retail customers primarily due to a decrease in cooling degree days ($99 million) and an increase in sales due to the effect of favorable economic conditions on customer usage and other factors ($70 million);
- A $90 million increase from regulated natural gas distribution operations primarily reflecting increased rider revenue related to low income assistance programs;
- A $45 million increase in producer services primarily related to higher physical margins and favorable price changes on economic hedging positions, all associated with natural gas aggregation, marketing and trading activities;
- A $41 million increase in retail energy marketing activities primarily due to a decrease in purchased gas expense; and
- A $10 million increase from Dominion s gas transmission business primarily related to an increase in revenue from NGLs.

These increases were partially offset by:

- A $142 million decrease from merchant generation operations, primarily reflecting:
  - A decline at certain fossil generation facilities ($73 million) largely due to lower generation ($33 million) and unfavorable prices ($32 million); and

A decline at nuclear generation facilities ($69 million) largely due to lower realized prices ($94 million), partially offset by increased generation ($33 million); and

A $125 million decrease reflecting the sale of substantially all of Dominion s Appalachian E&P operations in April 2010.

**Other operations and maintenance** decreased 15%, primarily reflecting:

A $326 million decrease due to the absence of charges recorded in 2010 related to a workforce reduction program; and

A $108 million decrease in impairment charges related to State Line.

These decreases were partially offset by:

A $74 million increase in bad debt expense at regulated natural gas distribution operations, primarily related to low income assistance programs. These expenses are recovered through rates and do not impact net income; and

A $71 million increase in planned outage costs due to an increase in scheduled outage days at certain electric utility and merchant generation facilities.

**Gain on sale of Appalachian E&P operations** reflects a gain on the sale of these operations.

**Other income (loss)** increased $50 million, primarily reflecting a decrease in charitable contributions.

**Interest and related charges** increased 19%, primarily due to the absence of a benefit recorded in 2010 resulting from the discontinuance of hedge accounting for certain interest rate derivatives.

**Income tax expense** decreased 64%, primarily reflecting lower federal and state taxes largely due to the absence of a gain from the sale of Dominion s Appalachian E&P operations recorded in 2010.

**Income (loss) from discontinued operations** reflects the sale of Peoples in February 2010.

Table of Contents

**Segment Results of Operations**

Segment results include the impact of intersegment revenues and expenses, which may result in intersegment profit and loss. Presented below is a summary of contributions by Dominion s operating segments to net income attributable to Dominion:

| | Net Income attributable to Dominion | | | Diluted EPS | | |
|---|---|---|---|---|---|---|
| **Second Quarter** | **2011** | 2010 | $ Change | **2011** | 2010 | $ Change |
| (millions, except EPS) | | | | | | |
| DVP | **$ 115** | $ 112 | $ 3 | **$ 0.20** | $ 0.19 | $ 0.01 |
| Dominion Generation | **194** | 276 | (82) | **0.34** | 0.47 | (0.13) |
| Dominion Energy | **104** | 86 | 18 | **0.18** | 0.14 | 0.04 |
| Primary operating segments | **413** | 474 | (61) | **0.72** | 0.80 | (0.08) |
| Corporate and Other | **(77)** | 1,287 | (1,364) | **(0.14)** | 2.18 | (2.32) |
| Consolidated | **$ 336** | $ 1,761 | $ (1,425) | **$ 0.58** | $ 2.98 | $ (2.40) |
| **Year-To-Date** | | | | | | |
| DVP | **$ 264** | $ 226 | $ 38 | **$ 0.46** | $ 0.38 | $ 0.08 |
| Dominion Generation | **492** | 601 | (109) | **0.85** | 1.01 | (0.16) |
| Dominion Energy | **273** | 261 | 12 | **0.47** | 0.44 | 0.03 |
| Primary operating segments | **1,029** | 1,088 | (59) | **1.78** | 1.83 | (0.05) |
| Corporate and Other | **(214)** | 847 | (1,061) | **(0.37)** | 1.42 | (1.79) |
| Consolidated | **$ 815** | $ 1,935 | $ (1,120) | **$ 1.41** | $ 3.25 | $ (1.84) |

**DVP**

Presented below are selected operating statistics related to DVP s operations:

| | Second Quarter | | | Year-To-Date | | |
|---|---|---|---|---|---|---|
| | **2011** | 2010 | % Change | **2011** | 2010 | % Change |
| Electricity delivered (million MWh) | **19.9** | 20.0 | (1)% | **40.8** | 41.2 | (1)% |
| Degree days (electric distribution service area): | | | | | | |
| Cooling | **630** | 724 | (13) | **631** | 724 | (13) |
| Heating | **222** | 197 | 13 | **2,290** | 2,323 | (1) |
| Average electric distribution customer accounts (thousands)(1) | **2,435** | 2,420 | 1 | **2,435** | 2,419 | 1 |
| Average retail energy marketing customer accounts (thousands)(1) | **2,164** | 2,046 | 6 | **2,144** | 1,996 | 7 |

(1) Period average.

Table of Contents

Presented below, on an after-tax basis, are the key factors impacting DVP s net income contribution:

| | Second Quarter 2011 vs. 2010 Increase (Decrease) | | Year-To-Date 2011 vs. 2010 Increase (Decrease) | |
|---|---|---|---|---|
| (millions, except EPS) | Amount | EPS | Amount | EPS |
| Regulated electric sales: | | | | |
| Weather | $ (10) | $ (0.02) | $ (19) | $ (0.03) |
| Other | 3 | | 10 | 0.02 |
| FERC transmission equity return | 12 | 0.02 | 20 | 0.03 |
| Retail energy marketing operations | 6 | 0.01 | 23 | 0.04 |
| Storm damage and service restoration electric distribution operations | (3) | | 3 | |
| Other | (5) | (0.01) | 1 | |
| Share accretion | | 0.01 | | 0.02 |
| Change in net income contribution | $ 3 | $ 0.01 | $ 38 | $ 0.08 |

**Dominion Generation**

Presented below are selected operating statistics related to Dominion Generation s operations:

| | Second Quarter | | | Year-To-Date | | |
|---|---|---|---|---|---|---|
| | **2011** | 2010 | % Change | **2011** | 2010 | % Change |
| Electricity supplied (million MWh): | | | | | | |
| Utility | **19.9** | 20.0 | (1)% | **40.8** | 41.2 | (1)% |
| Merchant[(1)] | **10.7** | 10.5 | 2 | **21.9** | 22.9 | (4) |
| Degree days (electric utility service area): | | | | | | |
| Cooling | **630** | 724 | (13) | **631** | 724 | (13) |
| Heating | **222** | 197 | 13 | **2,290** | 2,323 | (1) |

(1) Includes 1.3 and 2.1 million MWh for the quarter and year-to-date periods ended June 30, 2011, respectively, and 1.3 and 2.5 million MWh for the quarter and year-to-date periods ended June 30, 2010, respectively, related to Kewaunee.

PAGE 49

Table of Contents

Presented below, on an after-tax basis, are the key factors impacting Dominion Generation s net income contribution:

| | Second Quarter 2011 vs. 2010 Increase (Decrease) | | Year-To-Date 2011 vs. 2010 Increase (Decrease) | |
|---|---|---|---|---|
| (millions, except EPS) | Amount | EPS | Amount | EPS |
| Merchant generation margin | $ (35) | $ (0.06) | $ (73) | $ (0.12) |
| Outage costs | (33) | (0.06) | (27) | (0.04) |
| Kewaunee 2010 earnings(1) | (10) | (0.02) | (15) | (0.03) |
| Regulated electric sales: | | | | |
| Weather | (23) | (0.04) | (41) | (0.06) |
| Other | 21 | 0.04 | 38 | 0.06 |
| Rate adjustment clause equity return | 4 | 0.01 | 19 | 0.03 |
| Other | (6) | (0.01) | (10) | (0.02) |
| Share accretion | | 0.01 | | 0.02 |
| Change in net income contribution | $ (82) | $ (0.13) | $ (109) | $ (0.16) |

(1) Kewaunee s 2011 results of operations have been reflected in the Corporate and Other segment due to Dominion s decision, in the first quarter of 2011, to pursue a sale of the power station.

**Dominion Energy**

Presented below are selected operating statistics related to Dominion Energy s operations:

| | Second Quarter | | | Year-To-Date | | |
|---|---|---|---|---|---|---|
| | **2011** | 2010 | % Change | **2011** | 2010 | % Change |
| Gas distribution throughput (bcf): | | | | | | |
| Sales | **4** | 4 | % | **20** | 19 | 5% |
| Transportation | **45** | 37 | 22 | **155** | 136 | 14 |
| Heating degree days (gas distribution service area) | **613** | 436 | 41 | **3,756** | 3,383 | 11 |
| Average gas distribution customer accounts (thousands)(1): | | | | | | |
| Sales | **249** | 257 | (3) | **254** | 260 | (2) |
| Transportation | **1,051** | 1,047 | | **1,051** | 1,050 | |

(1) Period average.

Presented below, on an after-tax basis, are the key factors impacting Dominion Energy s net income contribution:

| | Second Quarter 2011 vs. 2010 Increase (Decrease) | | Year-To-Date 2011 vs. 2010 Increase (Decrease) | |
|---|---|---|---|---|
| (millions, except EPS) | Amount | EPS | Amount | EPS |
| Producer services margin | $ 14 | $ 0.02 | $ 23 | $ 0.04 |
| Gas distribution margin | 8 | 0.01 | 8 | 0.01 |
| E&P disposed operations | (3) | | (17) | (0.03) |
| Other | (1) | | (2) | |

| | | | | |
|---|---|---|---|---|
| Share accretion | | 0.01 | | 0.01 |
| Change in net income contribution | $ 18 | $ 0.04 | $ 12 | $ 0.03 |

PAGE 50

Table of Contents

**Corporate and Other**

Presented below are the Corporate and Other segment s after-tax results:

| (millions, except EPS) | Second Quarter **2011** | Second Quarter 2010 | Second Quarter $ Change | Year-To-Date **2011** | Year-To-Date 2010 | Year-To-Date $ Change |
|---|---|---|---|---|---|---|
| Specific items attributable to operating segments | **$ (2)** | $ 1,280 | $ (1,282) | **$ (56)** | $ 1,065 | $ (1,121) |
| Specific items attributable to corporate operations: | | | | | | |
| Peoples discontinued operations | | 2 | (2) | | (147) | 147 |
| Other | | 53 | (53) | **(8)** | 15 | (23) |
| Total specific items | **(2)** | 1,335 | (1,337) | **(64)** | 933 | (997) |
| Other corporate operations | **(75)** | (48) | (27) | **(150)** | (86) | (64) |
| Total net benefit (expense) | **$ (77)** | $ 1,287 | $ (1,364) | **$ (214)** | $ 847 | $ (1,061) |
| EPS impact | **$ (0.14)** | $ 2.18 | $ (2.32) | **$ (0.37)** | $ 1.42 | $ (1.79) |

***Total Specific Items***

Corporate and Other includes specific items that are not included in profit measures evaluated by management in assessing segment performance or in allocating resources among the segments. See Note 19 to the Consolidated Financial Statements for discussion of these items.

***Other Corporate Operations***

**Second Quarter and Year-To-Date 2011 vs. 2010**

Net expenses increased primarily due to the absence of a net benefit recorded in 2010 from the discontinuance of hedge accounting and subsequent changes in fair value of certain interest rate derivatives and lower consolidated state income tax benefits.

Table of Contents

**Virginia Power**

**Results of Operations**

Presented below is a summary of Virginia Power s consolidated results:

| | Second Quarter | | | Year-To-Date | | |
|---|---|---|---|---|---|---|
| | **2011** | 2010 | $ Change | **2011** | 2010 | $ Change |
| (millions) | | | | | | |
| Net income | **$ 241** | $ 267 | $ (26) | **$ 519** | $ 362 | $ 157 |

**Overview**

***Second Quarter 2011 vs. 2010***

Net income decreased by $26 million largely due to less favorable weather and an increase in scheduled outage costs, partially offset by favorable economic conditions and other factors.

***Year-To-Date 2011 vs. 2010***

Net income increased by $157 million largely due to the absence of charges related to a workforce reduction program recorded in 2010 and the impact of favorable economic conditions and other factors, partially offset by less favorable weather.

PAGE 52

Table of Contents

**Analysis of Consolidated Operations**

Presented below are selected amounts related to Virginia Power s results of operations:

| | Second Quarter | | | Year-To-Date | | |
|---|---|---|---|---|---|---|
| (millions) | **2011** | 2010 | $ Change | **2011** | 2010 | $ Change |
| Operating revenue | **$ 1,757** | $ 1,711 | $ 46 | **$ 3,514** | $ 3,450 | $ 64 |
| Electric fuel and other energy-related purchases | **583** | 589 | (6) | **1,176** | 1,221 | (45) |
| Purchased electric capacity | **116** | 108 | 8 | **234** | 215 | 19 |
| Net revenue | **1,058** | 1,014 | 44 | **2,104** | 2,014 | 90 |
| Other operations and maintenance | **356** | 317 | 39 | **658** | 836 | (178) |
| Depreciation and amortization | **175** | 165 | 10 | **349** | 328 | 21 |
| Other taxes | **56** | 53 | 3 | **115** | 117 | (2) |
| Other income | **10** | 28 | (18) | **39** | 42 | (3) |
| Interest and related charges | **84** | 83 | 1 | **176** | 171 | 5 |
| Income tax expense | **156** | 157 | (1) | **326** | 242 | 84 |

An analysis of Virginia Power s results of operations follows:

**Second Quarter 2011 vs. 2010**

**Net revenue** increased 4%, primarily reflecting:

The impact of rate adjustment clauses ($44 million);

An increase in ancillary revenues received from PJM ($21 million); partially offset by

The net impact ($15 million) of a decrease in sales to retail customers primarily due to a decrease in cooling degree days ($54 million) and an increase in sales due to the effect of favorable economic conditions on customer usage and other factors ($39 million).

**Other operations and maintenance** increased 12%, primarily reflecting a $33 million increase in planned outage costs due to an increase in scheduled outage days at certain generation facilities.

**Year-To-Date 2011 vs. 2010**

**Net revenue** increased 4%, primarily reflecting:

The impact of rate adjustment clauses ($91 million);

An increase in ancillary revenues received from PJM ($28 million); partially offset by

The net impact ($29 million) of a decrease in sales to retail customers primarily due to a decrease in cooling degree days ($99 million) and an increase in sales due to the effect of favorable economic conditions on customer usage and other factors ($70 million).

**Other operations and maintenance** decreased 21%, primarily reflecting the absence of charges recorded in 2010 related to a workforce reduction program.

**Income tax expense** increased 35%, primarily reflecting higher pre-tax income in 2011.

**Table of Contents**

**Segment Results of Operations**

Presented below is a summary of contributions by Virginia Power s operating segments to net income:

| | Second Quarter | | | Year-To-Date | | |
|---|---|---|---|---|---|---|
| | **2011** | 2010 | $ Change | **2011** | 2010 | $ Change |
| (millions) | | | | | | |
| DVP | **$ 102** | $ 105 | $ (3) | **$ 215** | $ 198 | $ 17 |
| Dominion Generation | **144** | 160 | (16) | **309** | 303 | 6 |
| Primary operating segments | **246** | 265 | (19) | **524** | 501 | 23 |
| Corporate and Other | **(5)** | 2 | (7) | **(5)** | (139) | 134 |
| Consolidated | **$ 241** | $ 267 | $ (26) | **$ 519** | $ 362 | $ 157 |

**DVP**

Presented below are operating statistics related to Virginia Power s DVP segment:

| | Second Quarter | | | Year-To-Date | | |
|---|---|---|---|---|---|---|
| | **2011** | 2010 | % Change | **2011** | 2010 | % Change |
| Electricity delivered (million MWh) | **19.9** | 20.0 | (1)% | **40.8** | 41.2 | (1)% |
| Degree days (electric distribution service area): | | | | | | |
| Cooling | **630** | 724 | (13) | **631** | 724 | (13) |
| Heating | **222** | 197 | 13 | **2,290** | 2,323 | (1) |
| Average electric distribution customer accounts (thousands)[(1)] | **2,435** | 2,420 | 1 | **2,435** | 2,419 | 1 |

(1) Period average.

Presented below, on an after-tax basis, are the key factors impacting Virginia Power s DVP segment s net income contribution:

| | Second Quarter 2011 vs. 2010 Increase (Decrease) | Year-To-Date 2011 vs. 2010 Increase (Decrease) |
|---|---|---|
| (millions) | | |
| Regulated electric sales: | | |
| Weather | $ (10) | $ (19) |
| Other | 3 | 10 |
| FERC transmission equity return | 12 | 20 |
| Storm damage and service restoration electric distribution operations | (3) | 3 |
| Other | (5) | 3 |
| Change in net income contribution | $ (3) | $ 17 |

Table of Contents

**Dominion Generation**

Presented below are operating statistics related to Virginia Power s Dominion Generation segment:

| | Second Quarter | | | Year-To-Date | | |
|---|---|---|---|---|---|---|
| | **2011** | 2010 | % Change | **2011** | 2010 | % Change |
| Electricity supplied (million MWh): | **19.9** | 20.0 | (1)% | **40.8** | 41.2 | (1)% |
| Degree days (electric utility service area): | | | | | | |
| Cooling | **630** | 724 | (13) | **631** | 724 | (13) |
| Heating | **222** | 197 | 13 | **2,290** | 2,323 | (1) |

Presented below, on an after-tax basis, are the key factors impacting Virginia Power s Dominion Generation segment s net income contribution:

| | Second Quarter | Year-To-Date |
|---|---|---|
| | 2011 vs. 2010 Increase (Decrease) | 2011 vs. 2010 Increase (Decrease) |
| (millions) | | |
| Outage costs | $ (20) | $ (10) |
| Regulated electric sales: | | |
| Weather | (23) | (41) |
| Other | 21 | 38 |
| Rate adjustment clause equity return | 4 | 19 |
| Other | 2 | |
| Change in net income contribution | $ (16) | $ 6 |

**Corporate and Other**

Corporate and Other includes specific items that are not included in profit measures evaluated by management in assessing segment performance or in allocating resources among the segments. See Note 19 to the Consolidated Financial Statements for discussion of these items.

**Liquidity and Capital Resources**

Dominion and Virginia Power depend on both internal and external sources of liquidity to provide working capital and to fund capital requirements. Short-term cash requirements not met by cash provided by operations are generally satisfied with proceeds from short-term borrowings. Long-term cash needs are met through issuances of debt and/or equity securities.

At June 30, 2011, Dominion had $1.7 billion of unused capacity under its credit facilities, including $286 million of unused capacity under joint credit facilities available to Virginia Power.

A summary of Dominion s cash flows is presented below:

| (millions) | **2011** | 2010 |
|---|---|---|
| Cash and cash equivalents at January 1 | **$ 62** | $ 50 |
| Cash flows provided by (used in): | | |
| Operating activities | **1,287** | 1,406 |
| Investing activities | **(1,535)** | 1,661 |
| Financing activities | **266** | (2,706) |

| | | | | |
|---|---|---|---|---|
| Net increase in cash and cash equivalents | | **18** | | 361 |
| Cash and cash equivalents at June 30 | **$** | **80** | $ | 411 |

PAGE 55

Table of Contents

A summary of Virginia Power s cash flows is presented below:

| (millions) | 2011 | 2010 |
|---|---|---|
| Cash and cash equivalents at January 1 | **$ 5** | $ 19 |
| Cash flows provided by (used in): | | |
| Operating activities | **837** | 559 |
| Investing activities | **(973)** | (1,112) |
| Financing activities | **184** | 549 |
| Net increase (decrease) in cash and cash equivalents | **48** | (4) |
| Cash and cash equivalents at June 30 | **$ 53** | $ 15 |

**Operating Cash Flows**

Net cash provided by Dominion s operating activities decreased by $119 million, primarily due to higher margin collateral requirements, lower merchant generation margins, the absence of E&P operations, the impact of less favorable weather on electric utility operations and net changes in working capital items. The decrease was partially offset by lower rate refunds related to the 2009 base rate case, an increase in cash flow from Virginia rate adjustment clauses, lower income tax payments and the absence of a contribution to Dominion s pension plans made in 2010.

Net cash provided by Virginia Power s operating activities increased by $278 million, primarily due to lower income tax payments and lower rate refunds related to the 2009 base rate case, as well as an increase in cash flow from rate adjustment clauses. The increase was partially offset by the impact of less favorable weather, lower deferred fuel cost recoveries, and net changes in other working capital items.

Dominion believes that its operations provide a stable source of cash flow to contribute to planned levels of capital expenditures and maintain or grow the dividend on common shares. Virginia Power believes that its operations provide a stable source of cash flow to contribute to planned levels of capital expenditures and provide dividends to Dominion.

The Companies operations are subject to risks and uncertainties that may negatively impact the timing or amounts of operating cash flows, which are discussed in Item 1A. Risk Factors in Dominion s and Virginia Power s Annual Report on Form 10-K for the year ended December 31, 2010 and Part II, Item 1A. Risk Factors in this report.

***Credit Risk***

Dominion s exposure to potential concentrations of credit risk results primarily from its energy marketing and price risk management activities. Presented below is a summary of Dominion s credit exposure as of June 30, 2011 for these activities. Gross credit exposure for each counterparty is calculated prior to the application of collateral and represents outstanding receivables plus any unrealized on- or off-balance sheet exposure, taking into account contractual netting rights.

| (millions) | Gross Credit Exposure | Credit Collateral | Net Credit Exposure |
|---|---|---|---|
| Investment grade[(1)] | **$ 202** | **$** | **$ 202** |
| Non-investment grade[(2)] | **5** | | **5** |
| No external ratings: | | | |
| Internally rated investment grade[(3)] | **46** | | **46** |
| Internally rated non-investment grade[(4)] | **58** | | **58** |
| Total | **$ 311** | **$** | **$ 311** |

(1) Designations as investment grade are based upon minimum credit ratings assigned by Moody s and Standard & Poor s. The five largest counterparty exposures, combined, for this category represented approximately 40% of the total net credit exposure.
(2) The five largest counterparty exposures, combined, for this category represented approximately 2% of the total net credit exposure.
(3) The five largest counterparty exposures, combined, for this category represented approximately 9% of the total net credit exposure.
(4) The five largest counterparty exposures, combined, for this category represented approximately 13% of the total net credit exposure.

Table of Contents

Virginia Power s exposure to potential concentrations of credit risk results primarily from sales to wholesale customers. Gross credit exposure for each counterparty is calculated prior to the application of collateral and represents outstanding receivables plus any unrealized on- or off-balance sheet exposure, taking into account contractual netting rights. At June 30, 2011, Virginia Power s exposure to potential concentrations of credit risk was not considered material.

**Investing Cash Flows**

For the six months ended June 30, 2011, net cash used in Dominion s investing activities was $1.5 billion as compared to net cash provided by investing activities of $1.7 billion in 2010, primarily reflecting the absence of the proceeds received from the sale of Dominion s Appalachian E&P operations in April 2010 and the sale of Peoples in February 2010.

Net cash used in Virginia Power s investing activities decreased by $139 million, primarily due to lower capital expenditures.

**Financing Cash Flows and Liquidity**

Dominion and Virginia Power rely on capital markets as significant sources of funding for capital requirements not satisfied by cash provided by their operations. As discussed further in *Credit Ratings* and *Debt Covenants* in Dominion s and Virginia Power s Annual Report on Form 10-K for the year ended December 31, 2010, the Companies ability to borrow funds or issue securities and the return demanded by investors are affected by credit ratings. In addition, the raising of external capital is subject to certain regulatory requirements, including registration with the SEC and, in the case of Virginia Power, approval by the Virginia Commission.

Each of the Companies meets the definition of a well-known seasoned issuer under SEC rules governing the registration, communications and offering processes under the Securities Act of 1933, as amended. The rules provide for a streamlined shelf registration process to provide registrants with timely access to capital. This allows the Companies to use automatic shelf registration statements to register any offering of securities, other than those for business combination transactions.

For the six months ended June 30, 2011, net cash provided by Dominion s financing activities was $266 million as compared to net cash used in financing activities of $2.7 billion in 2010, primarily due to net debt issuances in 2011 compared to net debt repayments in 2010, partially reflecting the use of proceeds from the sales of Dominion s Appalachian E&P operations and Peoples.

Net cash provided by Virginia Power s financing activities decreased by $365 million, primarily due to lower net debt issuances in 2011 as a result of higher cash flow from operations.

See Note 14 to the Consolidated Financial Statements for further information regarding Dominion s and Virginia Power s credit facilities, liquidity and significant financing transactions, including stock repurchases.

**Credit Ratings**

Credit ratings are intended to provide banks and capital market participants with a framework for comparing the credit quality of securities and are not a recommendation to buy, sell or hold securities. In the *Credit Ratings* section of MD&A in Dominion s and Virginia Power s Annual Report on Form 10-K for the year ended December 31, 2010, there is a discussion on the use of capital markets by the Companies, as well as the impact of credit ratings on the accessibility and costs of using these markets. As of June 30, 2011, there have been no changes in the Companies credit ratings.

**Debt Covenants**

In the *Debt Covenants* section of MD&A in Dominion s and Virginia Power s Annual Report on Form 10-K for the year ended December 31, 2010, there is a discussion on the various covenants present in the enabling agreements underlying the Companies debt. As of June 30, 2011, there have been no material changes to debt covenants, nor any events of default under the Companies debt covenants.

**Future Cash Payments for Contractual Obligations and Planned Capital Expenditures**

As of June 30, 2011, there have been no material changes outside the ordinary course of business to Dominion s or Virginia Power s contractual obligations nor any material changes to planned capital expenditures as disclosed in MD&A in the Companies Annual Report on Form 10-K for the year ended December 31, 2010.

**Use of Off-Balance Sheet Arrangements**

***Leasing Arrangement***

Dominion leases the Fairless generating facility in Pennsylvania, which began commercial operations in June 2004. The lease expires in 2013 and, at that time, Dominion may renew the lease on terms mutually agreeable to Dominion and the lessor based on original project costs and current market conditions; purchase Fairless at its original construction cost ($898 million) plus

51% of any appraised value in excess of original construction cost; or sell Fairless, on behalf of the lessor, to an independent third party. As an operating lease, the asset and related borrowings used to finance the construction of the asset are not included in the Consolidated Balance Sheets.

As of June 30, 2011, the lessor held two power plant leases, including Fairless. In late July 2011, the other lessee notified the lessor that it will not renew its lease upon expiration in the fourth quarter of 2011. This may impact Dominion s determination of whether it must consolidate the lessor. Dominion is evaluating multiple alternatives for the Fairless lease, including pursuing alternative financing structures or purchasing the plant. Pending a decision to pursue a specific course of action, Dominion cannot predict the outcome of this matter at this time.

There have been no other material changes in the off-balance sheet arrangements disclosed in MD&A in Dominion s Annual Report on Form 10-K for the year ended December 31, 2010.

**Future Issues and Other Matters**

The following discussion of future issues and other information includes current developments of previously disclosed matters and new issues arising during the period covered by, and subsequent to, the dates of Dominion s and Virginia Power s Consolidated Financial Statements that may impact the Companies future results of operations, financial condition and/or cash flows. This section should be read in conjunction with Item 1. Business and Future Issues and Other Matters in MD&A in Dominion s and Virginia Power s Annual Report on Form 10-K for the year ended December 31, 2010 and Future Issues and Other Matters in Dominion s and Virginia Power s Quarterly Report on Form 10-Q for the quarter ended March 31, 2011.

**Regulatory Matters**

See Note 14 to the Consolidated Financial Statements in Dominion s and Virginia Power s Annual Report on Form 10-K for the year ended December 31, 2010, Note 12 to the Consolidated Financial Statements in Dominion s and Virginia Power s Quarterly Report on Form 10-Q for the quarter ended March 31, 2011 and Note 12 to the Consolidated Financial Statements in this report for additional information on various regulatory matters.

**Environmental Matters**

Dominion and Virginia Power are subject to costs resulting from a number of federal, state and local laws and regulations designed to protect human health and the environment. These laws and regulations affect future planning and existing operations. They can result in increased capital, operating and other costs as a result of compliance, remediation, containment and monitoring obligations. See Note 23 to the Consolidated Financial Statements in Dominion s and Virginia Power s Annual Report on Form 10-K for the year ended December 31, 2010, Note 15 to the Consolidated Financial Statements in Dominion s and Virginia Power s Quarterly Report on Form 10-Q for the quarter ended March 31, 2011 and Note 15 to the Consolidated Financial Statements in this report for additional information on various environmental matters.

***Water***

Pursuant to a November 2010 settlement, in April 2011, EPA published the proposed rule related to CWA Section 316(b) in the Federal Register.

The rule in its proposed form seeks to establish a uniform national standard for impingement, but forgoes the creation of a single technology standard for entrainment. Instead, the EPA proposes to delegate entrainment technology decisions to state regulators. State regulators are to make case-by-case entrainment technology determinations after an examination of nine facility-specific factors, including a social cost-benefit test.

The proposed rule governs all electric generating stations with water withdrawals above two MGD, with a heightened entrainment analysis for those facilities over 125 MGD. Under this proposal, Dominion has 18 facilities that may be subject to these proposed regulations. If finalized as proposed, Dominion anticipates that the Company will have to install impingement control technologies at many of these stations that have once-through cooling systems. Dominion and Virginia Power cannot estimate the need or potential for entrainment controls under the proposed rule as these decisions will be made on a case-by-case basis after a thorough review of detailed biological, technology, cost and benefit studies. However, the impacts of this rule may be material.

***Air***

The EPA is proceeding with the development of a MACT rulemaking for coal and oil-fired electric utility steam generating units. These rules, as proposed in March 2011, require significant reductions in mercury and other hazardous air pollutants, including acid gases and non-mercury metals, from electric generation facilities. Dominion continues to be governed by individual state mercury emission reduction regulations in Massachusetts and Illinois. The Companies cannot currently predict with certainty whether or to what extent the new rules will ultimately require additional controls, however, if significant

PAGE 58

**Table of Contents**

expenditures are required, it could have an adverse impact on Dominion s and Virginia Power s financial statements.

***Nuclear Matters***

In March 2011, a magnitude 9.0 earthquake and subsequent tsunami caused significant damage at the Fukushima Daiichi nuclear power station in northeast Japan. It is expected that these events will result in significant nuclear safety reviews required by the NRC, industry groups such as INPO and/or international organizations. Like other U.S. nuclear operators, Dominion is currently gathering data to respond to INPO recommendations related to the ability to respond to design-basis and beyond-design-basis events at its stations. In July 2011, an NRC Task Force provided initial recommendations based on its review of the Fukushima Daiichi accident. The NRC Commissioners are considering these recommendations, and a longer term NRC review of the accident is also underway. Such reviews and recommendations, if adopted, could require nuclear plant modifications and may impact future operations and/or capital requirements at U.S. nuclear facilities, including those owned by Dominion and Virginia Power.

**Legal Matters**

See Item 3. Legal Proceedings in Dominion s and Virginia Power s Annual Report on Form 10-K for the year ended December 31, 2010, Part II, Item 1. Legal Proceedings in Dominion s and Virginia Power s Quarterly Report on Form 10-Q for the quarter ended March 31, 2011 and Part II, Item 1. Legal Proceedings in this report for additional information on various legal matters.

**Keystone Connector Project**

In August 2009, Dominion announced the proposed development of the Keystone Connector Project, a joint venture with The Williams Companies that would transport new natural gas supplies from the Appalachian Basin to Transcontinental Gas Pipe Line Corporation s Station 195, providing access to markets throughout the eastern U.S. The joint venture was terminated in June 2011. DTI is currently independently marketing its Keystone Connector Project. Project timing is subject to producer drilling plans in the Appalachian Basin, as well as customer demand throughout the mid-Atlantic and Northeast regions.

**Natrium Project**

In July 2011, Dominion announced the development of a natural gas processing and fractionation facility in Natrium, West Virginia and executed a contract for the construction of the first phase of the facility. This phase of the project is currently over 90% contracted and is expected to be in service by December 2012. The Phase 1 costs for processing, fractionation, plant inlet and outlet natural gas transportation, gathering, and various modes of NGL transportation is approximately $500 million. The complete project is designed to gather up to 400,000 Mcf of natural gas per day and fractionate up to 59,000 barrels of NGLs per day.

**Dodd-Frank Act**

The Dodd-Frank Act was enacted into law in July 2010 in an effort to improve regulation of financial markets. The Dodd-Frank Act includes provisions that will require certain over-the-counter derivatives, or swaps, to be centrally cleared and executed through an exchange or other approved trading platform. Non-financial entities that use swaps to hedge or mitigate commercial risk, often referred to as end users, can choose to exempt their hedging transactions from these clearing and exchange trading requirements. In addition, the Dodd-Frank Act allows applicable regulators, including the CFTC and SEC, to impose initial and variation margin requirements on entities who execute swaps. End users were not expressly exempted from these requirements for non-cleared swaps and rules have been proposed that address the margin obligations to be imposed on non-cleared swaps entered with end users. Final rules for the over-the-counter derivative-related provisions of the Dodd-Frank Act, including the clearing, exchange trading and margin requirements, will be established through the ongoing rulemaking process of the applicable regulators. In June 2011 both the CFTC and SEC confirmed that they would not complete the required rulemaking by the July 2011 deadline under the Dodd-Frank Act. Each agency has granted certain temporary relief from specific derivative-related provisions of the Act until the effective date of the applicable rules. The CFTC s temporary relief would expire no later than December 31, 2011, if not extended. If, as a result of the rulemaking process, Dominion s or Virginia Power s derivative activities are not exempted from the clearing, exchange trading or margin requirements, the Companies could be subject to higher costs for their derivative activities, including from higher margin requirements. In addition, implementation of, and compliance with, the over-the-counter derivative provisions of the Dodd-Frank Act by the Companies swap counterparties could result in increased costs related to the Companies derivative activities. Due to the ongoing rulemaking process, the Companies are currently unable to assess the potential financial statement impact of the Dodd-Frank Act s derivative-related provisions.

**Collective Bargaining Agreement**

In July 2011, members of the Local 310, representing about 180 employees at Kewaunee, ratified a new two-year extension of the current labor contract with Dominion. The new contract runs through October 21, 2013.

## ITEM 3.

## QUANTITATIVE AND QUALITATIVE

## DISCLOSURES ABOUT MARKET RISK

The matters discussed in this Item may contain forward-looking statements as described in the introductory paragraphs under Part I, Item 2. MD&A of this Form 10-Q. The reader s attention is directed to those paragraphs for discussion of various risks and uncertainties that may impact Dominion and Virginia Power.

### Market Risk Sensitive Instruments and Risk Management

Dominion s and Virginia Power s financial instruments, commodity contracts and related financial derivative instruments are exposed to potential losses due to adverse changes in commodity prices, interest rates and equity security prices as described below. Commodity price risk is present in Dominion s and Virginia Power s electric operations, Dominion s gas procurement operations, and Dominion s energy marketing and trading operations due to the exposure to market shifts in prices received and paid for electricity, natural gas and other commodities. The Companies use commodity derivative contracts to manage price risk exposures for these operations. Interest rate risk is generally related to their outstanding debt. In addition, they are exposed to investment price risk through various portfolios of equity and debt securities.

The following sensitivity analysis estimates the potential loss of future earnings or fair value from market risk sensitive instruments over a selected time period due to a 10% unfavorable change in commodity prices or interest rates.

#### *Commodity Price Risk*

To manage price risk, Dominion and Virginia Power primarily hold commodity-based financial derivative instruments for non-trading purposes associated with purchases and sales of electricity, natural gas and other energy-related products. As part of its strategy to market energy and to manage related risks, Dominion also holds commodity-based financial derivative instruments for trading purposes.

The derivatives used to manage commodity price risk are executed within established policies and procedures and may include instruments such as futures, forwards, swaps, options and FTRs that are sensitive to changes in the related commodity prices. For sensitivity analysis purposes, the hypothetical change in market prices of commodity-based financial derivative instruments is determined based on models that consider the market prices of commodities in future periods, the volatility of the market prices in each period, as well as the time value factors of the derivative instruments. Prices and volatility are principally determined based on observable market prices.

A hypothetical 10% unfavorable change in market prices of Dominion s non-trading commodity-based financial derivative instruments would have resulted in a decrease in fair value of approximately $253 million and $183 million as of June 30, 2011 and December 31, 2010, respectively. The increase in sensitivity is largely due to settlements of commodity derivative positions existing as of the beginning of the period. A hypothetical 10% unfavorable change in commodity prices would not have resulted in a material change in the fair value of Dominion s commodity-based financial derivative instruments held for trading purposes as of June 30, 2011 or December 31, 2010.

The impact of a change in energy commodity prices on Dominion s non-trading commodity-based financial derivative instruments at a point in time is not necessarily representative of the results that will be realized when the contracts are ultimately settled. Net losses from commodity derivative instruments used for hedging purposes, to the extent realized, will generally be offset by recognition of the hedged transaction, such as revenue from physical sales of the commodity.

#### *Interest Rate Risk*

Dominion and Virginia Power manage their interest rate risk exposure predominantly by maintaining a balance of fixed and variable rate debt. They also enter into interest rate sensitive derivatives, including interest rate swaps and interest rate lock agreements. For variable rate debt and interest rate swaps designated under fair value hedging and outstanding for Dominion and Virginia Power, a hypothetical 10% increase in market interest rates would not have resulted in a material change in annual earnings at June 30, 2011 or December 31, 2010.

Additionally, Dominion and Virginia Power may use forward-starting interest rate swaps and interest rate lock agreements as anticipatory hedges. As of June 30, 2011, Dominion and Virginia Power had $1.7 billion and $200 million, respectively, in aggregate notional amounts of these interest rate derivatives outstanding. A hypothetical 10% decrease in market interest rates would have resulted in a decrease of approximately $53 million in the fair value of Dominion s interest rate derivatives at June 30, 2011. A hypothetical 10% decrease in market interest rates would not have resulted in a material change in the fair value of Virginia Power s interest rate derivatives at June 30, 2011. None of these interest rate derivatives were outstanding at December 31, 2010.

The impact of a change in interest rates on Dominion s and Virginia Power s interest rate-based financial derivative instruments at a point in time is not necessarily representative of the results that will be realized when the contracts are ultimately settled. Net losses from interest rate derivative instruments used for hedging purposes, to the extent realized, will generally be offset by recognition of the hedged transaction.

***Investment Price Risk***

Dominion and Virginia Power are subject to investment price risk due to securities held as investments in nuclear decommissioning and rabbi trust funds that are managed by third-party investment managers. These trust funds primarily hold marketable securities that are reported in the Consolidated Balance Sheets at fair value.

Dominion recognized net realized gains (including investment income) on nuclear decommissioning and rabbi trust investments of $50 million, $40 million and $95 million for the six months ended June 30, 2011 and 2010 and for the year ended December 31, 2010, respectively. Net realized gains and losses include gains and losses from the sale of investments as well as any other-than-temporary declines in fair value. For the six months ended June 30, 2011 and the year ended December 31, 2010, Dominion recorded, in AOCI and regulatory liabilities, a net increase in unrealized gains on these investments of $98 million and $182 million, respectively. For the six months ended June 30, 2010, Dominion recorded, in AOCI and regulatory liabilities, a net increase in unrealized losses on these investments of $109 million.

Virginia Power recognized net realized gains (including investment income) on nuclear decommissioning trust investments of $16 million, $20 million and $44 million for the six months ended June 30, 2011 and 2010 and for the year ended December 31, 2010, respectively. Net realized gains and losses include gains and losses from the sale of investments as well as any other-than-temporary declines in fair value. Virginia Power recorded, in AOCI and regulatory liabilities, a net increase in unrealized gains on these investments of $43 million and $67 million for the six months ended June 30, 2011 and for the year ended December 31, 2010, respectively. For the six months ended June 30, 2010, Virginia Power recorded, in AOCI and regulatory liabilities, a net increase in unrealized losses on these investments of $48 million.

Dominion sponsors employee pension and other postretirement benefit plans, in which Dominion s and Virginia Power s employees participate, that hold investments in trusts to fund benefit payments. If the values of investments held in these trusts decline, it will result in future increases in the periodic cost recognized for such employee benefit plans and will be included in the determination of the amount of contributions to be made to the employee benefit plans.

## ITEM 4. CONTROLS AND PROCEDURES

Senior management of each of Dominion and Virginia Power, including Dominion s and Virginia Power s CEO and CFO, evaluated the effectiveness of each of their respective Companies disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation process, each of Dominion s and Virginia Power s CEO and CFO have concluded that each of their respective Companies disclosure controls and procedures are effective.

There were no changes in either Dominion s or Virginia Power s internal control over financial reporting that occurred during the last fiscal quarter that have materially affected, or are reasonably likely to materially affect, either of the Companies internal control over financial reporting.

# PART II. OTHER INFORMATION

## ITEM 1. LEGAL PROCEEDINGS

From time to time, Dominion and Virginia Power are alleged to be in violation or in default under orders, statutes, rules or regulations relating to the environment, compliance plans imposed upon or agreed to by the Companies, or permits issued by various local, state and/or federal agencies for the construction or operation of facilities. Administrative proceedings may also be pending on these matters. In addition, in the ordinary course of business, the Companies and their subsidiaries are involved in various legal proceedings. Dominion and Virginia Power believe that the ultimate resolution of these proceedings will not have a material adverse effect on their financial position, liquidity or results of operations. See Notes 12 and 15 to the

Consolidated Financial Statements, *Future Issues* in MD&A and Dominion s and Virginia Power s Annual Report on Form 10-K for the year ended December 31, 2010 and their Quarterly Report on Form 10-Q for the quarter ended March 31, 2011 for discussions on various environmental and other regulatory proceedings to which the Companies are a party.

**ITEM 1A. RISK FACTORS**

Dominion s and Virginia Power s businesses are influenced by many factors that are difficult to predict, involve uncertainties that may materially affect actual results and are often beyond the Companies control. A number of these risk factors have been identified in Dominion s and Virginia Power s Annual Report on Form 10-K for the year ended December 31, 2010, which should be taken into consideration when reviewing the information contained in this report. There have been no material changes with regard to the risk factors previously disclosed in Dominion s and Virginia Power s Annual Report on Form 10-K for the year ended December 31, 2010 or their Quarterly Report on Form 10-Q for the quarter ended March 31, 2011. For other factors that may cause actual results to differ materially from those indicated in any forward-looking statement or projection contained in this report, see *Forward-Looking Statements* in MD&A.

**ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS**

**Dominion**

**ISSUER PURCHASES OF EQUITY SECURITIES**

| Period | (a) Total Number of Shares (or Units) Purchased(1) | (b) Average Price Paid per Share (or Unit)(2) | (c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs | (d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased under the Plans or Programs(3) |
|---|---|---|---|---|
| 4/1/11-4/30/11 | 199,007 | $ 44.70 | | 26,540,390 shares/ $1.50 billion |
| 5/1/11-5/31/11 | 2,440,392 | 47.00 | 2,435,774 | 24,104,616 shares/ $1.39 billion |
| 6/1/11-6/30/11 | 4,475,618 | 47.48 | 4,475,557 | 19,629,059 shares/ $1.18 billion |
| Total | 7,115,017 | $ 47.24 | 6,911,331 | 19,629,059 shares/ $1.18 billion |

(1) In April, May and June 2011, 199,007 shares, 4,618 shares and 61 shares, respectively, were tendered by employees to satisfy tax withholding obligations on vested restricted and goal-based stock.

(2) Represents the weighted-average price paid per share.

(3) The remaining repurchase authorization is pursuant to repurchase authority granted by the Dominion Board of Directors in February 2005, as modified in June 2007. The aggregate authorization granted by the Dominion Board of Directors was 86 million shares (as adjusted to reflect a two-for-one stock split distributed in November 2007) not to exceed $4 billion.

Table of Contents

**ITEM 6. EXHIBITS**

| Exhibit Number | Description | Dominion | Virginia Power |
|---|---|---|---|
| 3.1.a | Dominion Resources, Inc. Articles of Incorporation as amended and restated effective May 20, 2010 (Exhibit 3.1, Form 8-K filed May 20, 2010, File No. 1-8489). | X | |
| 3.1.b | Virginia Electric and Power Company Amended and Restated Articles of Incorporation, as in effect on March 3, 2011 (Exhibit 3.1b, Form 10-Q filed April 29, 2011, File No. 1-2255). | | X |
| 3.2.a | Dominion Resources, Inc. Amended and Restated Bylaws, effective May 18, 2010 (Exhibit 3.2, Form 8-K filed May 20, 2010, File No. 1-8489). | X | |
| 3.2.b | Virginia Electric and Power Company Amended and Restated Bylaws, effective June 1, 2009 (Exhibit 3.1, Form 8-K filed June 3, 2009, File No. 1-2255). | | X |
| 4 | Dominion Resources, Inc. and Virginia Electric and Power Company agree to furnish to the Securities and Exchange Commission upon request any other instrument with respect to long-term debt as to which the total amount of securities authorized does not exceed 10% of either of their total consolidated assets. | X | X |
| 12.1 | Ratio of earnings to fixed charges for Dominion Resources, Inc. (filed herewith). | X | |
| 12.2a | Ratio of earnings to fixed charges for Virginia Electric and Power Company (filed herewith). | | X |
| 12.2b | Ratio of earnings to fixed charges and dividends for Virginia Electric and Power Company (filed herewith). | | X |
| 31.a | Certification by Chief Executive Officer of Dominion Resources, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith). | X | |
| 31.b | Certification by Chief Financial Officer of Dominion Resources, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith). | X | |
| 31.c | Certification by Chief Executive Officer of Virginia Electric and Power Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith). | | X |
| 31.d | Certification by Chief Financial Officer of Virginia Electric and Power Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith). | | X |
| 32.a | Certification to the Securities and Exchange Commission by Chief Executive Officer and Chief Financial Officer of Dominion Resources, Inc. as required by Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith). | X | |
| 32.b | Certification to the Securities and Exchange Commission by Chief Executive Officer and Chief Financial Officer of Virginia Electric and Power Company as required by Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith). | | X |
| 99 | Condensed consolidated earnings statements (filed herewith) | X | X |
| 101^ | The following financial statements from Dominion Resources, Inc. s and Virginia Electric and Power Company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, filed on July 29, 2011, formatted in XBRL: (i) Consolidated Statements of Income, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Cash Flows, and (vi) the Notes to Consolidated Financial Statements. | X | X |

^ *This exhibit will not be deemed filed for purposes of Section 18 of the Securities Exchange Act of 1934 (15 U.S.C. 78r), or otherwise subject to the liability of that section. Such exhibit will not be deemed to be incorporated by reference into any filing under the Securities Act or Securities Exchange Act, except to the extent that one of the Companies specifically incorporates it by reference.*

Table of Contents

**SIGNATURE**

Pursuant to the requirements 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.

**DOMINION RESOURCES, INC.**
Registrant

July 29, 2011

/s/ Ashwini Sawhney
Ashwini Sawhney

Vice President Accounting and Controller

(Chief Accounting Officer)

**VIRGINIA ELECTRIC AND POWER COMPANY**
Registrant

July 29, 2011

/s/ Ashwini Sawhney
Ashwini Sawhney

Vice President Accounting

(Chief Accounting Officer)

PAGE 64

Table of Contents

**EXHIBIT INDEX**

| Exhibit Number | Description | Dominion | Virginia Power |
|---|---|---|---|
| 3.1.a | Dominion Resources, Inc. Articles of Incorporation as amended and restated effective May 20, 2010 (Exhibit 3.1, Form 8-K filed May 20, 2010, File No. 1-8489). | X | |
| 3.1.b | Virginia Electric and Power Company Amended and Restated Articles of Incorporation, as in effect on March 3, 2011 (Exhibit 3.1b, Form 10-Q filed April 29, 2011, File No. 1-2255). | | X |
| 3.2.a | Dominion Resources, Inc. Amended and Restated Bylaws, effective May 18, 2010 (Exhibit 3.2, Form 8-K filed May 20, 2010, File No. 1-8489). | X | |
| 3.2.b | Virginia Electric and Power Company Amended and Restated Bylaws, effective June 1, 2009 (Exhibit 3.1, Form 8-K filed June 3, 2009, File No. 1-2255). | | X |
| 4 | Dominion Resources, Inc. and Virginia Electric and Power Company agree to furnish to the Securities and Exchange Commission upon request any other instrument with respect to long-term debt as to which the total amount of securities authorized does not exceed 10% of either of their total consolidated assets. | X | X |
| 12.1 | Ratio of earnings to fixed charges for Dominion Resources, Inc. (filed herewith). | X | |
| 12.2a | Ratio of earnings to fixed charges for Virginia Electric and Power Company (filed herewith). | | X |
| 12.2b | Ratio of earnings to fixed charges and dividends for Virginia Electric and Power Company (filed herewith). | | X |
| 31.a | Certification by Chief Executive Officer of Dominion Resources, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith). | X | |
| 31.b | Certification by Chief Financial Officer of Dominion Resources, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith). | X | |
| 31.c | Certification by Chief Executive Officer of Virginia Electric and Power Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith). | | X |
| 31.d | Certification by Chief Financial Officer of Virginia Electric and Power Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith). | | X |
| 32.a | Certification to the Securities and Exchange Commission by Chief Executive Officer and Chief Financial Officer of Dominion Resources, Inc. as required by Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith). | X | |
| 32.b | Certification to the Securities and Exchange Commission by Chief Executive Officer and Chief Financial Officer of Virginia Electric and Power Company as required by Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith). | | X |
| 99 | Condensed consolidated earnings statements (filed herewith) | X | X |
| 101^ | The following financial statements from Dominion Resources, Inc.   s and Virginia Electric and Power Company   s Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, filed on July 29, 2011, formatted in XBRL: (i) Consolidated Statements of Income, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Cash Flows, and (vi) the Notes to Consolidated Financial Statements. | X | X |