Spectra Energy Corp.
Form 10-K
February 25, 2010

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2009 or

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

Commission file number 1-33007

SPECTRA ENERGY CORP

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	20-5413139 (I.R.S. Employer Identification No.)
5400 Westheimer Court, Houston, Texas (Address of principal executive offices)	77056 (Zip Code)

713-627-5400

(Registrant s telephone number, including area code)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $0.001	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes x No ¨

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes ¨ No x

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer, and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer x	Accelerated filer ¨	Non-accelerated filer ¨	Smaller reporting company ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ¨ No x

Estimated aggregate market value of the common equity held by nonaffiliates of the registrant June 30, 2009: $10,900,000,000

Number of shares of Common Stock, $0.001 par value, outstanding at February 12, 2010: 647,483,298

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2010 Annual Meeting of Shareholders are incorporated by reference in Part III.

SPECTRA ENERGY CORP

FORM 10-K FOR THE YEAR ENDED

DECEMBER 31, 2009

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This document includes 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. Forward-looking statements are based on management s beliefs and assumptions. These forward-looking statements are identified by terms and phrases such as: anticipate, believe, intend, estimate, expect, continue, should, could, may, plan, project, predict, will, potential, forecast, and similar expressions. Forward-looking statements involve risks and uncertainties that may cause actual results to be materially different from the results predicted. Factors that could cause actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an effect on rate structure, and affect the speed at and degree to which competition enters the natural gas industries;

outcomes of litigation and regulatory investigations, proceedings or inquiries;

weather and other natural phenomena, including the economic, operational and other effects of hurricanes and storms;

the timing and extent of changes in commodity prices, interest rates and foreign currency exchange rates;

general economic conditions, which can affect the long-term demand for natural gas and related services;

potential effects arising from terrorist attacks and any consequential or other hostilities;

changes in environmental, safety and other laws and regulations;

results of financing efforts, including the ability to obtain financing on favorable terms, which can be affected by various factors, including credit ratings and general market and economic conditions;

increases in the cost of goods and services required to complete capital projects;

declines in the market prices of equity and debt securities and resulting funding requirements for defined benefit pension plans;

growth in opportunities, including the timing and success of efforts to develop U.S. and Canadian pipeline, storage, gathering, processing and other infrastructure projects and the effects of competition;

the performance of natural gas transmission and storage, distribution, and gathering and processing facilities;

the extent of success in connecting natural gas supplies to gathering, processing and transmission systems and in connecting to expanding gas markets;

- the effects of accounting pronouncements issued periodically by accounting standard-setting bodies;
- conditions of the capital markets during the periods covered by the forward-looking statements; and
- the ability to successfully complete merger, acquisition or divestiture plans; regulatory or other limitations imposed as a result of a merger, acquisition or divestiture; and the success of the business following a merger, acquisition or divestiture.

In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than Spectra Energy Corp has described. Spectra Energy Corp undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

PART I

Item 1. Business.

The terms we, our, us, and Spectra Energy as used in this report refer collectively to Spectra Energy Corp and its subsidiaries unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Spectra Energy.

General

Spectra Energy Corp, through its subsidiaries and equity affiliates, owns and operates a large and diversified portfolio of complementary natural gas-related energy assets and is one of North America s leading natural gas infrastructure companies. For close to a century, we and our predecessor companies have developed critically important pipelines and related energy infrastructure connecting natural gas supply sources to premium markets. We operate in three key areas of the natural gas industry: gathering and processing, transmission and storage, and distribution. Based in Houston, Texas, we provide transportation and storage of natural gas to customers in various regions of the northeastern and southeastern United States, the Maritime Provinces in Canada and the Pacific Northwest in the United States and Canada, and in the province of Ontario, Canada. We also provide natural gas sales and distribution services to retail customers in Ontario, and natural gas gathering and processing services to customers in western Canada. We also have a 50% ownership in DCP Midstream, LLC (DCP Midstream), one of the largest natural gas gatherers and processors in the United States, based in Denver, Colorado. Our internet website is *http://www.spectraenergy.com*.

Our natural gas pipeline systems consist of approximately 19,100 miles of transmission pipelines. Our proportional throughput for our pipelines totaled 3,987 trillion British thermal units (TBtu) in 2009, compared to 3,733 TBtu in 2008 and 3,642 TBtu in 2007. These amounts include throughput on wholly owned U.S. and Canadian pipelines and our proportional share of throughput on pipelines that are not wholly owned. Our storage facilities provide approximately 285 billion cubic feet (Bcf) of storage capacity in the United States and Canada.

Spin-off from Duke Energy Corporation

On January 2, 2007, Duke Energy Corporation (Duke Energy) completed the spin-off of Spectra Energy. Duke Energy contributed the natural gas businesses, primarily comprised of the Natural Gas Transmission and Field Services business segments of Duke Energy that were owned through Duke Energy s then wholly owned subsidiary, Spectra Energy Capital, LLC (Spectra Capital). Duke Energy contributed its ownership interests in Spectra Capital to us and all of our outstanding common stock was distributed to Duke Energy s shareholders.

Businesses

We manage our business in four reportable segments: U.S. Transmission, Distribution, Western Canada Transmission & Processing, and Field Services. The remainder of our business operations is presented as Other and consists of unallocated corporate costs, wholly owned captive insurance subsidiaries, employee benefit plan assets and liabilities, and other miscellaneous activities. The following sections describe the operations of each of our businesses. For financial information on our business segments, see Part II, Item 8. Financial Statements and Supplementary Data, Note 4 of Notes to Consolidated Financial Statements.

U.S. TRANSMISSION

Our U.S. Transmission business provides transportation and storage of natural gas for customers in various regions of the northeastern and southeastern United States and the Maritime Provinces in Canada. Our U.S. pipeline systems consist of more than 14,300 miles of transmission pipelines with seven primary transmission systems: Texas Eastern Transmission, LP (Texas Eastern), Algonquin Gas Transmission, LLC (Algonquin), East Tennessee Natural Gas, LLC (East Tennessee), Maritimes & Northeast Pipeline, L.L.C. and Maritimes & Northeast Pipeline Limited Partnership (collectively, Maritimes & Northeast Pipeline), Ozark Gas Transmission, L.L.C. (Ozark Gas Transmission), Gulfstream Natural Gas System, LLC (Gulfstream) and Southeast Supply Header, LLC (SESH). The pipeline systems in our U.S. Transmission business receive natural gas from major North American producing regions for delivery to their respective markets. U.S. Transmission s proportional throughput for its pipelines totaled 2,574 TBtu in 2009, compared to 2,218 TBtu in 2008 and 2,202 TBtu in 2007. This includes throughput on wholly owned pipelines and our proportional share of throughput on pipelines that are not wholly owned. A majority of contracted transportation volumes are under long-term firm service agreements. Interruptible services are provided on a short-term or seasonal basis.

U.S. Transmission provides storage services through Saltville Gas Storage Company L.L.C. (Saltville), Market Hub Partners Holding s (Market Hub s) Moss Bluff and Egan storage facilities, Steckman Ridge, LP (Steckman Ridge) and Texas Eastern s facilities. Gathering services are provided through Ozark Gas Gathering, L.L.C (Ozark Gas Gathering). In the course of providing transportation services, U.S. Transmission also processes natural gas on its Texas Eastern system. Demand on the pipeline systems is seasonal, with the highest throughput occurring during colder periods in the first and fourth calendar quarters.

Most of U.S. Transmission s pipeline and storage operations are regulated by the Federal Energy Regulatory Commission (FERC) and are subject to the jurisdiction of various federal, state and local environmental agencies. FERC is the U.S. agency that regulates the transportation of natural gas in interstate commerce.

In July 2007, we completed our initial public offering (IPO) of Spectra Energy Partners, LP (Spectra Energy Partners), a newly formed, natural gas infrastructure master limited partnership which is part of the U.S. Transmission segment. Subsequent to an additional drop-down of assets into Spectra Energy Partners in 2008 and the acquisition of NOARK Pipeline System, Limited Partnership (NOARK) in 2009, we currently retain a 74% equity interest in Spectra Energy Partners, which owns 100% of East Tennessee, 100% of Saltville, 100% of Ozark Gas Gathering and Ozark Gas Transmission, 50% of Market Hub and a 24.5% interest in Gulfstream. Spectra Energy retained a 50% direct ownership interest in Market Hub and a 25.5% direct ownership interest in Gulfstream. Spectra Energy Partners is a separate, publicly traded entity which trades on the New York Stock Exchange under the symbol SEP.

Texas Eastern

The Texas Eastern gas transmission system extends approximately 1,700 miles from producing fields in the Gulf Coast region of Texas and Louisiana to Ohio, Pennsylvania, New Jersey and New York. It consists of two parallel systems, one with three large-diameter parallel pipelines and the other with one to three large-diameter pipelines. Texas Eastern s onshore system consists of approximately 8,700 miles of pipeline and 73 compressor stations (facilities that increase the pressure of gas to facilitate its pipeline transmission). Texas Eastern also owns and operates two offshore Louisiana pipeline systems, which extend approximately 100 miles into the Gulf of Mexico and include approximately 500 miles of Texas Eastern s pipeline system. Texas Eastern has two joint venture storage facilities in Pennsylvania and one wholly owned and operated storage field in Maryland. Texas Eastern s total working capacity in these three fields is 74 Bcf.

Algonquin

The Algonquin pipeline connects with Texas Eastern s facilities in New Jersey, and extends approximately 250 miles through New Jersey, New York, Connecticut, Rhode Island and Massachusetts where it connects to Maritimes & Northeast Pipeline. The system consists of approximately 1,100 miles of pipeline with seven compressor stations.

East Tennessee

East Tennessee s transmission system crosses Texas Eastern s system at two points in Tennessee and consists of two mainline systems totaling approximately 1,510 miles of pipeline in Tennessee, Georgia, North Carolina and Virginia, with 21 compressor stations. East Tennessee has a liquefied natural gas (LNG, natural gas that has been converted to liquid form) storage facility in Tennessee with a total working capacity of 1 Bcf. East Tennessee also connects to the Saltville storage facilities in Virginia that have a working gas capacity of approximately 5 Bcf.

We have an effective 74% ownership interest in East Tennessee through our ownership of Spectra Energy Partners.

Maritimes & Northeast Pipeline

Maritimes & Northeast Pipeline s gas transmission system is operated through Maritimes & Northeast Pipeline Limited Partnership (M&N LP), the Canadian portion of this system, and Maritimes & Northeast Pipeline, L.L.C. (M&N LLC), the U.S. portion. We have 78% ownership interests in both segments of the system and affiliates of Exxon Mobil Corporation and Emera, Inc. have the remaining interests. The Maritimes & Northeast Pipeline transmission system consists of approximately 900 miles of pipeline originating from landfall of the producing fields in Nova Scotia through New Brunswick, Maine, New Hampshire and Massachusetts, connecting to Algonquin in Beverly, Massachusetts. There are seven compressor stations on the system.

Ozark

We have an effective 74% interest in Ozark Gas Transmission and Ozark Gas Gathering, which was acquired by Spectra Energy Partners in May 2009. Ozark Gas Transmission consists of a 565-mile interstate natural gas pipeline system extending from southeastern Oklahoma through Arkansas to southeastern Missouri. Ozark Gas Gathering consists of a 365-mile gathering system that primarily serves Arkoma basin producers in eastern Oklahoma.

Gulfstream

We have an effective 44% investment in Gulfstream, a 745-mile interstate natural gas pipeline system operated jointly by us and The Williams Companies, Inc. Gulfstream transports natural gas from Mississippi, Alabama, Louisiana and Texas, crossing the Gulf of Mexico to markets in central and southern Florida. Gulfstream has three compressor stations. Gulfstream is owned 25.5% by Spectra Energy, 24.5% by Spectra Energy Partners and 50% by affiliates of The Williams Companies, Inc. Our investment in Gulfstream is accounted for under the equity method of accounting.

SESH

We have a 50% investment in SESH, a 274-mile interstate natural gas pipeline system with three mainline compressor stations owned and operated jointly by us and CenterPoint Energy, Inc. SESH, which began operations in September 2008, extends from the Perryville Hub in northeastern Louisiana where the emerging shale gas production of eastern Texas, northern Louisiana and Arkansas along with conventional production, is reached from five major interconnections. SESH extends to Alabama, interconnecting with 14 major north-south pipelines and three high deliverability storage facilities. Our investment in SESH is accounted for under the equity method of accounting.

Market Hub

We have an effective 87% ownership interest in Market Hub, which owns and operates two natural gas storage facilities, Moss Bluff and Egan, with a total storage capacity of approximately 43 Bcf. The Moss Bluff facility consists of three storage caverns located in southeast Texas and has access to five pipeline systems including the Texas Eastern system. The Egan facility consists of four storage caverns located in south central Louisiana and has access to seven pipeline systems including the Texas Eastern system. Market Hub is a general partnership in which Spectra Energy and Spectra Energy Partners each have a 50% interest.

Saltville

We have an effective 74% ownership interest in Saltville through our ownership of Spectra Energy Partners. Saltville owns and operates natural gas storage facilities in Virginia with a total storage capacity of approximately 5 Bcf. The storage facilities interconnect with East Tennessee s system. This salt cavern facility offers high deliverability capabilities and is strategically located near markets in Tennessee, Virginia and North Carolina.

Steckman Ridge

We have a 50% investment in Steckman Ridge, a depleted reservoir storage facility located in south central Pennsylvania that has a total storage capacity of 12 Bcf and interconnects with Texas Eastern. Steckman Ridge, which began operations in April 2009, is operated by us and owned 50% by NJR Steckman Ridge Storage Company. Our investment in Steckman Ridge is accounted for under the equity method of accounting.

Competition

Our U.S. Transmission transportation and storage businesses compete with similar facilities that serve our supply and market areas in the transportation and storage of natural gas. The principal elements of competition are rates, terms of service, and flexibility and reliability of service.

The natural gas that we transport in our transmission business competes with other forms of energy available to our customers and end-users, including electricity, coal, propane and fuel oils. Factors that influence the demand for natural gas include price changes, the availability of natural gas and other forms of energy, the level of business activity, long-term economic conditions, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, weather and other factors.

Customers and Contracts

In general, our U.S. Transmission pipelines provide transportation and storage services to local distribution companies (LDCs, companies that obtain a major portion of their revenues from retail distribution systems for the delivery of natural gas for ultimate consumption), electric power generators, exploration and production companies, and industrial and commercial customers, as well as energy marketers. Transportation and storage services are generally provided under firm agreements where customers reserve capacity in pipelines and storage facilities. The vast majority of these agreements provide for fixed reservation charges that are paid monthly regardless of actual volumes transported on the pipelines or injected or withdrawn from our storage facilities plus a small variable component that is based on volumes transported to recover variable costs.

We also provide interruptible transportation and storage services where customers can use capacity if it is available at the time of the request. Interruptible revenues depend on the amount of volumes transported or stored and the associated market rates for this interruptible service. New projects placed into service may initially have higher levels of interruptible services at inception. Storage operations also provide a variety of other value-added services including natural gas parking, loaning and balancing services to meet our customers needs.

DISTRIBUTION

We provide distribution services in Canada through our subsidiary, Union Gas Limited (Union Gas). Union Gas owns pipeline, storage and compression facilities used in the transportation, storage and distribution of natural gas. Union Gas system consists of approximately 37,300 miles of distribution main and service pipelines. Distribution pipelines carry or control the supply of natural gas from the point of local supply to customers. Union Gas underground natural gas storage facilities have a working capacity of approximately 156 Bcf in 23 underground facilities located in depleted gas fields. Its transmission system consists of approximately 3,000 miles of high-pressure pipeline and six mainline compressor stations.

Union Gas distributes natural gas to approximately 1.3 million residential, commercial and industrial customers in northern, southwestern and eastern Ontario and provides storage, transportation and related services to utilities and other energy market participants. Union Gas is regulated by the Ontario Energy Board (OEB) pursuant to the provisions of the Ontario Energy Board Act (1998) and is subject to regulation in a number of areas including rates.

Union Gas storage and transmission system forms an important link in moving natural gas from western Canadian and U.S. supply basins to central Canadian and northeastern U.S. markets.

Competition

As Union Gas distribution business is regulated by the OEB, it is not generally subject to third-party competition within its distribution franchise area. However, as a result of a 2006 decision by the OEB, physical bypass of Union Gas facilities even within its distribution franchise area may be permitted. In addition, other companies could enter Union Gas markets or regulations could change.

Union Gas competes with other forms of energy available to its customers and end-users, including electricity, coal, propane and fuel oils. Factors that influence the demand for natural gas include price changes, the availability of natural gas and other forms of energy, the level of business activity, economic conditions, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, weather and other factors.

In November 2006, the OEB issued a decision on the regulation of rates for gas storage services in Ontario involving, among other things, phase-out of the sharing with customers of margins on Union Gas long-term storage transactions. This phase-out will occur over a four-year period that began in 2008, with the share accruing to Union Gas increasing ratably over that period. As a result of its finding that the market for storage services is competitive, the OEB does not regulate the rates for storage services to customers outside Union Gas franchise area or the rates for new storage services to customers within its franchise area. For these unregulated services, Union Gas competes against third-party storage providers for storage on the basis of price, terms of service, and flexibility and reliability of service. Existing storage services to customers within Union Gas franchise area continue to be provided at cost-based rates and are not subject to third-party competition.

Customers and Contracts

The rates that Union Gas charges for its regulated services are subject to the approval of the OEB. Union Gas distribution service area extends throughout northern Ontario from the Manitoba border to the North Bay/Muskoka area, through southern Ontario from Windsor to west of Toronto, and across eastern Ontario from Port Hope to Cornwall. Union Gas serves approximately 1.3 million customers in a franchise area with more than 400 communities and a diversified commercial and industrial base.

Union Gas distribution services to power generation and industrial customers are affected by weather, economic conditions and the price of competitive energy sources. Most of Union Gas power generation, industrial and large commercial customers, and a portion of residential customers, purchase their natural gas directly from suppliers or marketers. Because Union Gas earns income from the distribution of natural gas and not the sale of the natural gas commodity, gas distribution margins are not affected by the source of customers gas supply.

Union Gas also provides natural gas storage and transportation services for other utilities and energy market participants, including large natural gas transmission and distribution companies. A substantial amount of Union Gas annual transportation and storage revenue is generated by fixed demand charges. The average term of these contracts is approximately eight years, with the longest being almost 25 years.

WESTERN CANADA TRANSMISSION & PROCESSING

Our Western Canada Transmission & Processing business is comprised of the BC Pipeline and BC Field Services operations, and the natural gas liquids (NGLs) marketing and Canadian Midstream operations.

BC Pipeline and BC Field Services provide natural gas transportation and gas gathering and processing services. BC Pipeline is regulated by the National Energy Board (NEB) under full cost of service regulation and transports processed natural gas from facilities primarily in northeast British Columbia (BC) to markets in BC, Alberta and the U.S. Pacific Northwest. BC Pipeline has approximately 1,800 miles of transmission pipeline in BC and Alberta, as well as 18 mainline compressor stations. Throughput for the BC Pipeline totaled 604 TBtu in 2009, compared to 615 TBtu in 2008 and 596 TBtu in 2007.

The BC Field Services business, which is regulated by the NEB under a light-handed regulatory model, consists of raw gas gathering pipelines and gas processing facilities, primarily in northeast BC. These facilities provide services to natural gas producers to remove impurities from the raw gas stream including water, carbon dioxide, hydrogen sulfide and other substances. Where required, these facilities also remove various NGLs for subsequent sale by the producers. NGLs are liquid hydrocarbons extracted during the processing of natural gas. Principal commercial NGLs include butanes, propane, natural gasoline and ethane. The BC Field Services business includes five gas processing plants located in BC, 17 field compressor stations and approximately 1,500 miles of gathering pipelines.

The Canadian Midstream business provides similar gas gathering and processing services in BC and Alberta and consists of 11 natural gas processing plants and approximately 600 miles of gathering pipelines.

The Empress NGL business provides NGL extraction, fractionation, transportation, storage and marketing services to western Canadian producers and NGL customers throughout Canada and the northern tier of the United States. Assets include, among other things, a majority ownership interest in an NGL extraction plant, an integrated NGL fractionation facility, an NGL transmission pipeline, seven terminals where NGLs are loaded for shipping or transferred into product sales pipelines, two NGL storage facilities and an NGL marketing and gas supply business. The Empress extraction and fractionation plant is located in Empress, Alberta.

Competition

Western Canada Transmission & Processing businesses compete with third-party midstream companies, exploration and production companies, and pipelines in the gathering, processing and transportation of natural gas and the extraction and marketing of NGL products. Western Canada Transmission & Processing competes directly with other pipeline facilities serving its market areas. The principal elements of competition are rates, terms of service, and flexibility and reliability of service. Customer demands for toll certainty and lower cost tailored services have promoted increased competition from other midstream service companies and producers.

Natural gas competes with other forms of energy available to Western Canada Transmission & Processing s customers and end-users, including electricity, coal and fuel oils. The primary competitive factor is price. Changes in the availability or price of natural gas, NGLs and other forms of energy, the level of business activity, long-term economic conditions, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, weather and other factors affect the demand for natural gas in the areas we serve.

In addition to the fee for service pipeline and gathering and processing businesses, we compete with other NGL extraction facilities at Empress, Alberta for the right to extract and purchase NGLs from natural gas shippers on the TransCanada pipeline system. To extract and acquire NGLs, we must be competitive in the premium or fee we pay to natural gas shippers. We also compete with other NGL marketers in the various markets we serve.

Customers & Contracts

BC Pipeline provides: (i) transportation services from the outlet of natural gas processing plants primarily in northeast BC to LDCs, end-use industrial and commercial customers, marketers, and exploration and production companies requiring transportation services to the nearest natural gas trading hub; and (ii) transportation services primarily to downstream markets in the Pacific Northwest (both United States and Canada). The majority of transportation services are provided under firm agreements, which provide for fixed reservation charges that are paid monthly regardless of actual volumes transported on the pipeline, plus a small variable component that is based on volumes transported to recover variable costs. BC Pipeline also provides interruptible transportation services where customers can use capacity if it is available at the time of request. Payments under these services are based on volumes transported.

The BC Field Services and Canadian Midstream operations in western Canada provide raw natural gas gathering and processing services to exploration and production companies under agreements which are primarily fee-for-service contracts which do not expose us to commodity-price risk. These operations provide both firm and interruptible services.

The NGL extraction operation at Empress, Alberta has capacity to produce approximately 63,000 barrels of NGLs per day (our share is approximately 58,000 barrels per day), comprised of approximately 50% ethane, 32% propane, 12% butanes and 6% condensate. At Empress, we extract and purchase NGLs from natural gas shippers on the TransCanada Pipeline system. In addition to paying shippers a negotiated extraction fee, we keep the shipper whole by returning an equivalent amount of natural gas for the NGLs that were extracted. After NGLs are extracted, we fractionate, or separate, the NGLs into ethane, propane, butanes and condensate, and sell these products into the marketplace. All ethane is sold to Alberta-based petrochemical companies. In addition to paying for natural gas shrinkage, the ethane buyers pay us a negotiated cost-of-service price or a negotiated fixed price. We sell the remaining products propane, butane and condensate at market prices and are exposed to the difference between the selling prices and the shrinkage makeup price of natural gas plus the extraction premium and operating costs. The majority of propane is sold to propane retailers. Butane is sold mainly into the motor gasoline refinery market and condensate sales are directed to the crude blending and crude diluent markets. The prices we can obtain for these products are affected by numerous factors including competition, weather, transportation costs and supply and demand factors.

FIELD SERVICES

Field Services consists of our 50% investment in DCP Midstream, which is accounted for as an equity investment. DCP Midstream gathers and processes natural gas and fractionates, markets and trades NGLs. ConocoPhillips owns the remaining 50% interest in DCP Midstream.

DCP Midstream operates in 26 states in the United States. DCP Midstream s gathering systems include connections to several interstate and intrastate natural gas and NGL pipeline systems and one natural gas storage facility. DCP Midstream gathers raw natural gas through gathering systems located in nine major natural gas producing regions: Mid-Continent, Rocky Mountain, East Texas-North Louisiana, Barnett Shale, Gulf Coast, South Texas, Central Texas, Antrim Shale and Permian Basin. DCP Midstream owns or operates approximately 60,000 miles of gathering and transmission pipeline, with approximately 36,000 active receipt points.

DCP Midstream s natural gas processing operations separate raw natural gas that has been gathered on its own systems and third-party systems into condensate, NGLs and residue gas. DCP Midstream operates 58 natural gas processing plants.

The NGLs separated from the raw natural gas are either sold and transported as NGL raw mix or further separated through a fractionation process into their individual components (ethane, propane, butane, and natural gasoline) and then sold as components. DCP Midstream fractionates NGL raw mix at six processing facilities that it owns and operates and at four third-party-operated facilities in which it has an ownership interest. In addition, DCP Midstream operates a propane wholesale marketing business.

The residue gas separated from the raw natural gas is sold at market-based prices to marketers and end-users, including large industrial customers and natural gas and electric utilities serving individual consumers. DCP Midstream also stores residue gas at its 8 Bcf natural gas storage facility located in southeast Texas.

DCP Midstream uses NGL trading and storage at the Mont Belvieu, Texas and Conway, Kansas NGL market centers to manage its price risk and to provide additional services to its customers. Asset-based gas trading and marketing activities are supported by ownership of the Spindletop storage facility near Beaumont, Texas and various intrastate pipelines which provide access to market centers/hubs such as Katy, Texas and the Houston Ship Channel. DCP Midstream undertakes these NGL and gas trading activities through the use of fixed-forward sales, basis and spread trades, storage opportunities, put/call options, term contracts and spot market trading.

DCP Midstream s operating results are significantly affected by changes in average NGL and crude oil prices, which decreased approximately 42% and 38%, respectively, in 2009 compared to 2008. DCP Midstream closely monitors the risks associated with these price changes. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Quantitative and Qualitative Disclosures About Market Risk for a discussion of DCP Midstream s exposure to changes in commodity prices.

Competition

In gathering and processing natural gas and in marketing and transporting natural gas and NGLs, DCP Midstream competes with major integrated oil companies, major interstate and intrastate pipelines, national and local natural gas gatherers and processors, and brokers, marketers and distributors of natural gas supplies. Competition for natural gas supplies is based primarily on the reputation, efficiency and reliability of operations, the availability of gathering and transportation to high-demand markets, the pricing arrangement offered by the gatherer/processor and the ability of the gatherer/processor to obtain a satisfactory price for the producer s residue gas and extracted NGLs. Competition for sales to customers is based primarily upon reliability, services offered and price of delivered natural gas and NGLs.

Customers and Contracts

DCP Midstream sells NGLs to a variety of customers ranging from large, multi-national petrochemical and refining companies to small regional retail propane distributors. Substantially all of DCP Midstream s NGL sales are made at market-based prices, including approximately 40% of its NGL production that is committed to ConocoPhillips and its affiliate, Chevron Phillips Chemical Company LLC, under existing contracts that have primary terms that are effective until January 1, 2015. In 2009, sales to ConocoPhillips and Chevron Phillips Chemical Company LLC, combined, represented approximately 25% of DCP Midstream s consolidated revenues.

The residual natural gas (primarily methane) that results from processing raw natural gas is sold at market-based prices to marketers and end-users. End-users include large industrial companies, natural gas distribution companies and electric utilities. DCP Midstream purchases or takes custody of substantially all of its raw natural gas from producers, principally under the following types of contractual arrangements. Of the gas that is gathered and processed, more than 70% of volumes are under percentage-of-proceeds contracts.

Percentage-of-proceeds arrangements. In general, DCP Midstream purchases natural gas from producers, transports and processes it and then sells the residue natural gas and NGLs in the market. The payment to the producer is an agreed upon percentage of the proceeds from those sales. DCP Midstream s revenues from these arrangements correlate directly with the price of natural gas and NGLs.

Fee-based arrangements. DCP Midstream receives a fee or fees for the various services it provides including gathering, compressing, treating, processing or transporting natural gas. The revenue DCP Midstream earns from these arrangements is directly related to the volume of natural gas that flows through its systems and is not directly dependent on commodity prices.

Keep-whole and wellhead purchase arrangement. DCP Midstream gathers or purchases raw natural gas from producers for processing and then markets the NGLs. DCP Midstream keeps the producer whole by returning an equivalent amount of natural gas after the processing is complete. DCP Midstream is exposed to the frac-spread, which is the price difference between NGLs and natural gas prices, representing the theoretical gross margin for processing liquids from natural gas.

As defined by the terms of the above arrangements, DCP Midstream also sells condensate, which is generally similar to crude oil and is produced in association with natural gas gathering and processing.

Supplies and Raw Materials

We purchase a variety of manufactured equipment and materials for use in operations and expansion projects. The primary equipment and materials utilized in operations and project execution processes are steel pipe, compression engines, valves, fittings, polyethylene plastic pipe, gas meters and other consumables.

We operate a North American supply chain management network with employees dedicated to this function in the United States and Canada. Our supply chain management group uses economies-of-scale to maximize the efficiency of supply networks where applicable. DCP Midstream performs its own supply chain management function.

There can be no assurance that the ability to obtain sufficient equipment and materials will not be adversely affected by unforeseen developments. In addition, the price of equipment and materials may vary, perhaps substantially, from year to year.

Regulations

Most of our U.S. gas transmission pipeline and storage operations are regulated by the FERC. The FERC regulates natural gas transportation in U.S. interstate commerce including the establishment of rates for services. The FERC also regulates the construction of U.S. interstate pipelines and storage facilities including extension, enlargement and abandonment of facilities. In addition, certain operations are subject to oversight by state regulatory commissions.

The FERC may propose and implement new rules and regulations affecting interstate natural gas transmission and storage companies, which remain subject to the FERC s jurisdiction. These initiatives may also affect certain transportation of gas by intrastate pipelines.

Our U.S. Transmission and DCP Midstream operations are subject to the jurisdiction of the Environmental Protection Agency (EPA) and various other federal, state and local environmental agencies. See Environmental Matters for a discussion of environmental regulation. Our U.S. interstate natural gas pipelines and certain of DCP Midstream s gathering and transmission pipelines are also subject to the regulations of the U.S. Department of Transportation concerning pipeline safety.

The natural gas transmission and distribution, and approximately two-thirds of the storage operations in Canada are subject to regulation by the NEB or the provincial agencies in Canada, such as the OEB. These agencies have jurisdiction similar to the FERC for regulating rates, the terms and conditions of service, the construction of additional facilities and acquisitions. Our BC Field Services business in western Canada is regulated by the NEB pursuant to a framework for light-handed regulation under which the NEB acts on a complaints-basis for rates associated with that business. Similarly, the rates charged by the Canadian Midstream operations for gathering and processing services in western Canada are regulated on a complaints-basis by applicable provincial regulators. The Empress NGL businesses are not under any form of rate regulation.

The intrastate natural gas and NGL pipelines owned by DCP Midstream are subject to state regulation. To the extent that the natural gas intrastate pipelines provide services under Section 311 of the Natural Gas Policy Act of 1978, they are also subject to FERC regulation. The natural gas gathering and processing activities of DCP Midstream are not subject to FERC regulation.

Environmental Matters

We are subject to various U.S. federal, state and local laws and regulations, as well as Canadian national and provincial regulations, with regard to air and water quality, hazardous and solid waste disposal and other environmental matters. These regulations often impose substantial testing and certification requirements.

Environmental laws and regulations affecting us include, but are not limited to:

The Clean Air Act (CAA) and the 1990 amendments to the CAA, as well as state laws and regulations affecting air emissions (including State Implementation Plans related to existing and new national ambient air quality standards), which may limit new sources of air emissions. Our natural gas processing, transmission and storage assets are considered sources of air emissions and are thereby subject to the CAA. Owners and/or operators of air emission sources, such as us, are responsible for obtaining permits for existing and new sources of air emissions and for annual compliance and reporting.

The Federal Water Pollution Control Act (Clean Water Act), which requires permits for facilities that discharge wastewaters into the environment. The Oil Pollution Act (OPA), was enacted in 1990 and amends parts of the Clean Water Act and other statutes as they pertain to the prevention of and response to oil spills. OPA imposes certain spill prevention, control and countermeasure requirements. Although we are primarily a natural gas business, OPA affects our business primarily because of the presence of liquid hydrocarbons (condensate) in our offshore pipelines.

The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), which imposes liability for remediation costs associated with environmentally contaminated sites. Under CERCLA, any individual or entity that currently owns or in the past owned or operated a disposal site can be held liable and required to share in remediation costs, as well as transporters or generators of hazardous substances sent to a disposal site. Because of the geographical extent of our operations, we have disposed of waste at many different sites and have CERCLA liabilities at some properties we own.

The Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act, which requires certain solid wastes, including hazardous wastes, to be managed pursuant to a comprehensive regulatory regime. As part of our business, we generate solid waste within the scope of these regulations and therefore must comply with such regulations.

The Toxic Substances Control Act, which requires that polychlorinated biphenyl (PCB) contaminated materials be managed in accordance with a comprehensive regulatory regime. Because of the historical use of lubricating oils containing PCBs, the internal surfaces of some of our pipeline systems are contaminated with PCBs, and liquids and other materials removed from these pipelines must be managed in compliance with such regulations.

The National Environmental Policy Act, which requires federal agencies to consider potential environmental effects in their decisions, including site approvals. Many of our capital projects require federal agency review, and therefore the environmental effect of proposed projects is a factor in determining whether we will be permitted to complete proposed projects.

The Fisheries Act (Canada), which regulates activities near any body of water in Canada.

The Environmental Management Act (British Columbia), the Environmental Protection and Enhancement Act (Alberta), and the Environmental Protection Act (Ontario) are each provincial laws governing various aspects, including permitting and site remediation obligations, of our facilities and operations in those provinces.

The Canadian Environmental Protection Act, pursuant to which, among other things, regulations require reporting of greenhouse gas (GHG) emissions from our operations in Canada. Additional regulations to be promulgated under the Act may require the reduction of GHGs, nitrogen oxides, sulphur oxides, volatile organic compounds and particulate matter.

The Alberta Climate Change and Emissions Management Act, which, pursuant to regulations that came into effect in 2007, requires certain facilities to meet reductions in emission intensity starting in 2007. The Act was applicable to our Empress facility in Alberta beginning in 2008.

For more information on environmental matters, including possible liability and capital costs, see Item 8. Financial Statements and Supplementary Data, Notes 5 and 17 of Notes to Consolidated Financial Statements.

Except to the extent discussed in Notes 5 and 17, compliance with international, federal, state and local provisions regulating the discharge of materials into the environment, or otherwise protecting the environment, is incorporated into the routine cost structure of our various business units and is not expected to have a material adverse effect on our competitive position or consolidated results of operations, financial position or cash flows.

Geographic Regions

For a discussion of our Canadian operations and the risks associated with them, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations, Quantitative and Qualitative Disclosures About Market Risk Foreign Currency Risk, and Notes 4 and 19 of Notes to Consolidated Financial Statements.

Employees

We had approximately 5,400 employees as of December 31, 2009, including approximately 3,500 employees outside of the United States, all in Canada. In addition, DCP Midstream employed approximately 2,700 employees as of such date. Approximately 1,500 of our employees, all of whom are located in Canada, are subject to collective bargaining agreements governing their employment with us. Approximately 20% of those employees are covered under agreements that have expired or will expire by December 31, 2010.

Executive and Other Officers

The following table sets forth information regarding our executive and other officers.

Name	Age	Position
Gregory L. Ebel	45	President and Chief Executive Officer, Director
J. Patrick Reddy	57	Chief Financial Officer
Dorothy M. Ables	52	Chief Administrative Officer
John R. Arensdorf	59	Chief Communications Officer
Alan N. Harris	56	Chief Development and Operations Officer
Reginald D. Hedgebeth	42	General Counsel
Allen C. Capps	39	Vice President and Treasurer
Sabra L. Harrington	47	Vice President and Controller

Gregory L. Ebel assumed his current position as President and Chief Executive Officer on January 1, 2009. He previously served as Group Executive and Chief Financial Officer from January 2007. Mr. Ebel served as President of Union Gas from January 2005 until January 2007. Prior to then, Mr. Ebel served as Vice President, Investor & Shareholder Relations of Duke Energy from November 2002 until January 2005. Mr. Ebel currently serves on the Board of Directors of DCP Midstream, LLC.

J. Patrick Reddy joined Spectra Energy in January 2009 as Chief Financial Officer. Mr. Reddy served as Senior Vice President and Chief Financial Officer at Atmos Energy Corporation from September 2000 to December 2008. Mr. Reddy currently serves on the Board of Directors of DCP Midstream, LLC.

Dorothy M. Ables assumed her current position as Chief Administrative Officer in November 2008. Prior to then, she served as Vice President of Audit Services and as Chief Ethics and Compliance Officer from January 2007; Vice President of Audit Services for Duke Energy Corporation from April 2006 to December 2006; and Vice President, Audit Services and Chief Compliance Officer for Duke Energy Corporation from February 2004 to March 2006.

John R. Arensdorf assumed his current position in November 2008. He previously served as Vice President, Investor Relations from January 2007. Prior to then, Mr. Arensdorf served as General Manager, Investor Relations at Duke Energy from April 2006 to December 2006 and as General Manager, Internal Controls from November 2004 to April 2006.

Alan N. Harris assumed his current position as Chief Development Officer and Chief Operations Officer in November 2008. He previously served as Group Executive and Chief Development Officer since January 2007. Prior to then, Mr. Harris served as Group Vice President and Chief Financial Officer of Duke Energy Gas Transmission from February 2004 to January 2007. Mr. Harris currently serves on the Board of Directors of DCP Midstream Partners, LP.

Reginald D. Hedgebeth assumed his current position as General Counsel in March 2009. He previously served as Senior Vice President, General Counsel and Secretary with Circuit City Stores, Inc. from July 2005 to March 2009 and in various roles, including Vice President-Legal, at The Home Depot, Inc. from February 1999 to June 2005.

Allen C. Capps joined Spectra Energy in December 2007 as Vice President and Treasurer. Prior to then, Mr. Capps served as Director of Finance of EPCO, Inc., a midstream energy company, from April 2006. Mr. Capps served as Interim Controller of TEPPCO Partners, LP, an energy logistics partnership, from June 2005 to April 2006 and as Director of Technical Accounting and Compliance from April 2004 until June 2005.

Sabra L. Harrington assumed her current position as Vice President and Controller in January 2007. Prior to then, she served as Vice President, Financial Strategy of Duke Energy Gas Transmission from February 2006 and as Vice President and Controller of Duke Energy Gas Transmission from August 2003 until February 2006.

Additional Information

We were incorporated on July 28, 2006 as a Delaware corporation. Our principal executive offices are located at 5400 Westheimer Court, Houston, Texas 77056 and our telephone number is 713-627-5400. We electronically file various reports with the Securities and Exchange Commission (SEC), including annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxies and amendments to such reports. The public may read and copy any materials that we file with the SEC at the SEC s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains an internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC at *http://www.sec.gov*. Additionally, information about us, including our reports filed with the SEC, is available through our web site at *http://www.spectraenergy.com*. Such reports are accessible at no charge through our web site and are made available as soon as reasonably practicable after such material is filed with or furnished to the SEC. Our website and the information contained on that site, or connected to that site, are not incorporated by reference into this report.

Item 1A. Risk Factors.

Discussed below are the more significant risk factors relating to Spectra Energy.

Reductions in demand for natural gas and low market prices of commodities adversely affect our operations and cash flows.

Our regulated businesses are generally economically stable and are not significantly affected in the short-term by changing commodity prices. However, all of our businesses can be negatively affected in the long term by sustained downturns in the economy or long-term conservation efforts, which could affect long-term demand and market prices for natural gas and NGLs, all of which are beyond our control and could impair the ability to meet long-term goals.

Most of our revenues are based on regulated tariff rates, which include the recovery of certain fuel costs. However, lower overall economic output would cause a decline in the volume of natural gas transported and distributed or gathered and processed at our plants, resulting in lower earnings and cash flows. This decline would primarily affect distribution revenues in the short term. Transmission revenues could be affected by long-term economic declines that result in the non-renewal of long-term contracts at the time of expiration. Lower demand for natural gas and lower prices for natural gas and NGLs could result from multiple factors that affect the markets where we operate, including:

- weather conditions, including abnormally mild winter or summer weather that cause lower energy usage for heating or cooling purposes, respectively;
- supply of and demand for energy commodities, including any decreases in the production of natural gas which could negatively affect our processing business due to lower throughput;
- capacity and transmission service into or out of our markets; and
- petrochemical demand for NGLs.

The lack of availability of natural gas resources may cause customers to seek alternative energy resources, which could materially adversely affect our revenues, earnings and cash flows.

Our natural gas businesses are dependent on the continued availability of natural gas production and reserves. Prices for natural gas, regulatory limitations, or a shift in supply sources could adversely affect development of additional reserves and production that are accessible by our pipeline, gathering, processing and distribution assets. Lack of commercial quantities of natural gas available to these assets could cause customers to seek alternative energy resources, thereby reducing their reliance on our services, which in turn would materially adversely affect our revenues, earnings and cash flows.

Investments and projects located in Canada expose us to fluctuations in currency rates that may adversely affect our results of operations, cash flows and compliance with debt covenants.

We are exposed to foreign currency risk from investments and operations in Canada. An average 10% devaluation in the Canadian dollar exchange rate during 2009 would have resulted in an estimated net loss on the translation of local currency earnings of approximately $35 million on our Consolidated Statement of Operations. In addition, if a 10% devaluation had occurred on December 31, 2009, the Consolidated Balance Sheet would be negatively impacted by $518 million through a cumulative translation adjustment in Accumulated Other Comprehensive Income (AOCI). At December 31, 2009, one U.S. dollar translated into 1.05 Canadian dollars.

In addition, we maintain credit facilities that typically include financial covenants which limit the amount of debt that can be outstanding as a percentage of total capital for Spectra Energy or of a specific subsidiary. Failure to maintain these covenants could preclude us from issuing commercial paper or letters of credit or borrowing under our revolving credit facilities and could require other affiliates to immediately pay down any outstanding drawn amounts under other revolving credit agreements, which could adversely affect cash flow or restrict business. Foreign currency fluctuations have a direct impact on our ability to maintain certain of these financial covenants.

Natural gas gathering and processing operations are subject to commodity price risk, which could result in a decrease in our earnings and reduced cash flows.

We have gathering and processing operations that consist of contracts to buy and sell commodities, including contracts for natural gas, NGLs and other commodities that are settled by the delivery of the commodity or cash. We are primarily exposed to market price fluctuations of NGL prices in our Field Services segment and to frac-spreads in the Empress operations in Canada. Since NGL prices have historically been correlated with crude oil prices, we disclose our NGL price sensitivities in terms of crude oil price changes. Based on a sensitivity analysis as of December 31, 2009, at our forecasted NGL-to-oil price relationships, a $10 per barrel move in oil prices would affect our annual pre-tax earnings by approximately $100 million in 2010 ($90 million from Field Services and $10 million from U.S. Transmission). Assuming crude oil prices average approximately $80 per barrel, each 1% change in the price relationship between NGLs and crude oil would change our annual pre-tax earnings by approximately $10 million. At crude oil prices above $80 per barrel, the impact of a 1% change in the NGL-to-oil price relationship would increase, and at crude oil prices below $80 per barrel, the impact of a 1% change in the NGL-to-oil price relationship would decrease.

With respect to the frac-spread risk related to Empress processing and NGL marketing activities in western Canada, as of December 31, 2009, a $0.50 change in the difference between the Btu-equivalent price of propane (used as a proxy for Empress NGL production) and the price of natural gas in Alberta, Canada would affect our pre-tax earnings by approximately $12 million on an annual basis in 2010.

These hypothetical calculations consider estimated production levels, but do not consider other potential effects that might result from such changes in commodity prices. The actual effect of commodity price changes on our earnings could be significantly different than these estimates.

Our business is subject to extensive regulation that affects our operations and costs.

Our U.S. assets and operations are subject to regulation by various federal, state and local authorities, including regulation by the FERC and by various authorities under federal, state and local environmental laws. Our natural gas assets and operations in Canada are also subject to regulation by federal, provincial and local authorities including the NEB and the OEB and by various federal and provincial authorities under environmental laws. Regulation affects almost every aspect of our business, including, among other things, the ability to determine terms and rates for services provided by some of our businesses, make acquisitions, construct, expand and operate facilities, issue equity or debt securities, and pay dividends.

In addition, regulators in both the U.S. and Canada have taken actions to strengthen market forces in the gas pipeline industry, which have led to increased competition. In a number of key markets, natural gas pipeline and storage operators are facing competitive pressure from a number of new industry participants, such as alternative suppliers as well as traditional pipeline competitors. Increased competition driven by regulatory changes could have a material effect on our business, earnings, financial condition and cash flows.

Execution of our capital projects subjects us to construction risks, increases in labor and material costs and other risks that may adversely affect our financial results.

A significant portion of our growth is accomplished through the construction of new pipelines and storage facilities as well as the expansion of existing facilities. Construction of these facilities is subject to various regulatory, development, operational and market risks, including:

- the ability to obtain necessary approvals and permits by regulatory agencies on a timely basis and on acceptable terms;
- the availability of skilled labor, equipment, and materials to complete expansion projects;
- potential changes in federal, state and local statutes and regulations, including environmental requirements, that prevent a project from proceeding or increase the anticipated cost of the project;
- impediments on our ability to acquire rights-of-way or land rights on a timely basis and on acceptable terms;
- the ability to construct projects within anticipated costs, including the risk of cost overruns resulting from inflation or increased costs of equipment, materials or labor, weather, geologic conditions or other factors beyond our control, that may be material; and
- general economic factors that affect the demand for natural gas infrastructure.

Any of these risks could prevent a project from proceeding, delay its completion or increase its anticipated costs. As a result, new facilities may not achieve their expected investment return, which could adversely affect our results of operations, financial position or cash flows.

Gathering and processing, transmission and storage, and distribution activities involve numerous risks that may result in accidents or otherwise affect our operations.

There are a variety of hazards and operating risks inherent in natural gas gathering and processing, transmission and storage, and distribution activities, such as leaks, explosions and mechanical problems that could cause substantial financial losses. In addition, these risks could result in significant injury, loss of human life, significant damage to property, environmental pollution and impairment of operations, any of which could result in substantial losses. For pipeline and storage assets located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, the level of damage resulting from these risks could be greater. We do not maintain insurance coverage against all of these risks and losses, and any insurance coverage we might maintain may not fully cover the damages caused by those risks and losses. Therefore, should any of these risks materialize, it could have a material adverse effect on our business, earnings, financial condition and cash flows.

We are subject to numerous environmental laws and regulations, compliance with which requires significant capital expenditures, can increase our cost of operations, and may affect or limit our business plans, or expose us to environmental liabilities.

We are subject to numerous environmental laws and regulations affecting many aspects of our present and future operations, including air emissions, water quality, wastewater discharges, solid waste and hazardous waste. These laws and regulations can result in increased capital, operating and other costs. These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Compliance with environmental laws and regulations can require significant expenditures, including expenditures for cleanup costs and damages arising out of contaminated properties, and failure to comply with environmental regulations may result in the imposition of fines, penalties and injunctive measures affecting our operating assets. In addition, changes in environmental laws and regulations or the enactment of new environmental laws or regulations could result in a material increase in our cost of compliance with such laws and regulations. We may not be able to obtain or maintain from time to time all required environmental regulatory approvals for our operating assets or development projects. If there is a delay in obtaining any required environmental regulatory approvals, if we fail to obtain or comply with them or if environmental laws or regulations change or are administered in a more stringent manner, the operation of facilities or the development of new facilities could be prevented, delayed or become subject to additional costs. No assurance can be made that the costs that will be incurred to comply with environmental regulations in the future will not have a material adverse effect.

The enactment of future climate change legislation could result in increased operating costs and delays in obtaining necessary permits for our capital projects.

The current international climate framework, the United Nations-sponsored Kyoto Protocol, prescribes specific targets to reduce GHG emissions for developed countries for the 2008-2012 period. The Kyoto Protocol expires in 2012 and has not been signed by the United States. United Nations-sponsored international negotiations were held in Copenhagen, Denmark in December 2009 with the intent of defining a future agreement for 2012 and beyond. While the talks resulted in a non-binding political agreement, to date, a binding successor accord to the Kyoto Protocol has not been realized.

While Canada is a signatory to the Kyoto Protocol, the Canadian federal government has confirmed it will not achieve the targets within the timeframes specified. Instead, the government in 2008 outlined a regulatory framework mandating GHG reductions from large final emitters. Regulatory design details from the Government of Canada remain forthcoming. We expect a number of our assets and operations in Canada will be affected by pending federal climate change regulations. However, the materiality of any potential compliance costs is unknown at this time as the final form of the regulation and compliance options has yet to be determined by policymakers.

In the United States, climate change action is evolving at state, regional and federal levels. We expect that a number of our assets and operations in the United States could be affected by eventual mandatory GHG programs; however, the timing and specific policy objectives in many jurisdictions, including at the federal level, remain uncertain. In addition, a number of Canadian provinces and U.S. states have joined regional greenhouse gas initiatives, and a number are developing their own programs that would mandate reductions in GHG emissions. We expect a number of our assets and operations could be affected either directly or indirectly by state or regional programs. However, as the key details of future GHG restrictions and compliance mechanisms remain undefined, the likely future effects on our business are highly uncertain.

The EPA has proposed the Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule in 2009 to address how GHG emissions would be regulated under the existing Clean Air Act. This proposed rulemaking has not yet been finalized. Regulation of GHG emissions under the Clean Air Act would subject our new capital projects to additional permitting requirements which may result in delays in completing such projects. In addition, several legislative proposals have been introduced and discussed in the U.S. Congress that would impose GHG emissions constraints, including H.R. 2454 the American Clean Energy and Security Act, which passed the House of Representatives in June 2009. To date, similar legislation has not been considered by the full U.S. Senate. Due to the speculative outlook regarding any U.S. federal and state policies and the uncertainty of the Canadian federal and provincial policies, we cannot estimate the potential effect of proposed GHG policies on our future consolidated results of operations, financial position or cash flows. However, such legislation could materially increase our operating costs, require material capital expenditures or create additional permitting, which could delay proposed construction projects.

We are involved in numerous legal proceedings, the outcome of which are uncertain, and resolutions adverse to us could negatively affect our results of operations, financial condition and cash flows.

We are subject to numerous legal proceedings. Litigation is subject to many uncertainties, and we cannot predict the outcome of individual matters with assurance. It is reasonably possible that the final resolution of some of the matters in which we are involved could require additional expenditures, in excess of established reserves, over an extended period of time and in a range of amounts that could have a material effect on our cash flows and results of operations.

We rely on access to short-term and long-term capital markets to finance capital requirements and support liquidity needs, and access to those markets can be adversely affected, particularly if we or our rated subsidiaries are unable to maintain an investment-grade credit rating, which could adversely affect our cash flows or restrict business.

Our business is financed to a large degree through debt. The maturity and repayment profile of debt used to finance investments often does not correlate to cash flows from assets. Accordingly, we rely on access to both short-term and long-term capital markets as a source of liquidity for capital requirements not satisfied by the cash flows from operations and to fund investments originally financed through debt. Our senior unsecured long-term debt is currently rated investment-grade by various rating agencies. If the rating agencies were to rate us or our rated subsidiaries below investment-grade, our borrowing costs would increase, perhaps significantly. In addition, we would likely be required to pay a higher interest rate in future financings, and our potential pool of investors and funding sources could decrease.

We maintain revolving credit facilities to provide back-up for commercial paper programs for borrowings and/or letters of credit at various entities. These facilities typically include financial covenants which limit the amount of debt that can be outstanding as a percentage of the total capital for the specific entity. Failure to maintain these covenants at a particular entity could preclude that entity from issuing commercial paper or letters of credit or borrowing under the revolving credit facility and could require other affiliates to immediately pay down any outstanding drawn amounts under other revolving credit agreements, which could adversely affect cash flow or restrict businesses. Furthermore, if our short-term debt rating were to be below tier 2 (for example, A-2 for Standard and Poor s and P-2 for Moody s Investor Service), access to the commercial paper market could be significantly limited, although this would not affect our ability to draw under the credit facilities.

If we are not able to access capital at competitive rates, our ability to finance operations and implement our strategy may be adversely affected. Restrictions on our ability to access financial markets may also affect our ability to execute our business plan as scheduled. An inability to access capital may limit our ability to pursue improvements or acquisitions that we may otherwise rely on for future growth. Any downgrade or other event negatively affecting the credit ratings of our subsidiaries could make their costs of borrowing higher or access to funding sources more limited, which in turn could increase our need to provide liquidity in the form of capital contributions or loans to such subsidiaries, thus reducing the liquidity and borrowing availability of the consolidated group.

We may be unable to secure long-term transportation agreements, which could expose our transportation volumes and revenues to increased volatility.

We may be unable to secure long-term transportation agreements in the future for our gas transmission business as a result of economic factors, lack of commercial gas supply to our systems, increased competition or changes in regulation. Without long-term transportation agreements, our revenues and contract volumes would be exposed to increased volatility. The inability to secure these agreements would materially adversely affect our business, earnings, financial condition and cash flows.

We are exposed to the credit risk of our customers.

We are exposed to the credit risk of our customers in the ordinary course of our business. Generally, our customers are rated investment-grade, are otherwise considered creditworthy or provide us security to satisfy credit concerns. Approximately 85% of our credit exposures for transportation, storage, and gathering and processing services are with customers who have an investment-grade rating or equivalent based on our evaluation. However, we cannot predict to what extent our business would be impacted by deteriorating conditions in the economy, including possible declines in our customers creditworthiness. As a result of future capital projects for which natural gas producers may be the primary customer, the percentage of our customers who are rated investment-grade may decline. While we monitor these situations carefully and take appropriate measures when deemed necessary, it is possible that customer payment defaults, if significant, could have a material adverse effect on our earnings and cash flows.

Market-based natural gas storage operations are subject to commodity price volatility, which could result in variability in our earnings and cash flows.

We have market-based rates for some of our storage operations and sell our storage services based on natural gas market spreads and volatility. If natural gas market spreads or volatility deviate from historical norms or there is significant growth in the amount of storage capacity available to natural gas markets relative to demand, our approach to managing our market-based storage contract portfolio may not protect us from significant variations in storage revenues.

Native land claims have been asserted in British Columbia and Alberta, which could affect future access to public lands, and the success of these claims could have a significant adverse effect on natural gas production and processing.

Certain aboriginal groups have claimed aboriginal and treaty rights over a substantial portion of public lands on which our facilities in British Columbia and Alberta, and the gas supply areas served by those facilities, are located. The existence of these claims, which range from the assertion of rights of limited use to aboriginal title, has given rise to some uncertainty regarding access to public lands for future development purposes. Such claims, if successful, could have a significant adverse effect on natural gas production in British Columbia and Alberta, which could have a material adverse effect on the volume of natural gas processed at our facilities and of NGLs and other products transported in the associated pipelines. In addition, certain aboriginal groups in Ontario have claimed aboriginal and treaty rights in areas where Union Gas Dawn storage and transmission assets are located and also in areas where the Dawn-to-Trafalgar pipeline route is located. The existence of these claims could give rise to future uncertainty regarding land tenure depending upon their negotiated outcomes. We cannot predict the outcome of any of these claims or the effect they may ultimately have on our business and operations.

Protecting against potential terrorist activities requires significant capital expenditures and a successful terrorist attack could adversely affect our business.

Acts of terrorism and any possible reprisals as a consequence of any action by the United States and its allies could be directed against companies operating in the United States. This risk is particularly great for companies, like ours, operating in any energy infrastructure industry that handles volatile gaseous and liquid hydrocarbons. The potential for terrorism has subjected our operations to increased risks that could have a material adverse effect on our business. In particular, we may experience increased capital and operating costs to implement increased security for our facilities and pipelines, such as additional physical facility and pipeline security, and additional security personnel. Moreover, any physical damage to high profile facilities resulting from acts of terrorism may not be covered, or covered fully, by insurance. We may be required to expend material amounts of capital to repair any facilities, the expenditure of which could adversely affect our cash flows and business.

Changes in the insurance markets attributable to terrorist attacks may make certain types of insurance more difficult for us to obtain. Moreover, the insurance that may be available to us may be significantly more expensive than our existing insurance coverage. Instability in the financial markets as a result of terrorism or war could also affect our ability to raise capital.

Poor investment performance of our pension plan holdings and other factors affecting pension plan costs could unfavorably affect our earnings, financial position and liquidity.

Our costs of providing defined benefit pension plans are dependent upon a number of factors, such as the rates of return on plan assets, discount rates used to measure pension liabilities, actuarial gains and losses, future government regulation and our contributions made to the plans. Without sustained growth in the pension plan investments over time to increase the value of our plan assets, and depending upon the other factors impacting our costs as listed above, we could experience net asset, expense and funding volatility. This volatility could have a material effect on our earnings and cash flows.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

At December 31, 2009, we had over 100 primary facilities located in the United States and Canada. We generally own sites associated with our major pipeline facilities, such as compressor stations. However, we generally operate our transmission facilities transmission and distribution pipelines using rights of way pursuant to easements to install and operate pipelines, but we do not own the land. Except as described in Part II, Item 8. Financial Statements and Supplementary Data, Note 14 of Notes to Consolidated Financial Statements, none of our properties were secured by mortgages or other material security interests at December 31, 2009.

Our corporate headquarters are located at 5400 Westheimer Court, Houston, Texas 77056, which is a leased facility. The lease expires in April 2018.We also maintain offices in, among other places, Calgary, Alberta; Vancouver, British Columbia; Chatham, Ontario; Waltham, Massachusetts; Tampa, Florida; Halifax, Nova Scotia; Toronto, Ontario; and Nashville, Tennessee. For a description of our material properties, see Item 1. Business.

Item 3. Legal Proceedings.

For information regarding legal proceedings, including regulatory and environmental matters, see Notes 5 and 17 of Notes to Consolidated Financial Statements.

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

None.

PART II

Item 5. Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Our common stock is traded on the New York Stock Exchange under the symbol SE. As of February 12, 2010, there were approximately 148,000 holders of record of our common stock and approximately 450,000 beneficial owners.

Common Stock Data by Quarter

	Dividends Per	Stock Price Range(a)	
2009	**Common Share**	**High**	**Low**
First Quarter	$ 0.25	$ 17.47	$ 11.21
Second Quarter	0.25	17.61	13.75
Third Quarter	0.25	19.73	15.81
Fourth Quarter	0.25	20.78	18.26
2008			
First Quarter	0.23	26.26	21.41
Second Quarter	0.23	29.18	22.67
Third Quarter	0.25	29.13	22.00
Fourth Quarter	0.25	23.77	13.36

(a) Stock prices represent the intra-day high and low stock price.

Stock Performance Graph

The following graph reflects the comparative changes in the value from January 3, 2007, the first trading day of Spectra Energy common stock on the New York Stock Exchange, through December 31, 2009 of $100 invested in (1) Spectra Energy s common stock, (2) the Standard & Poor s 500 Stock Index, and (3) the Standard & Poor s 500 Oil & Gas Storage & Transportation Index. The amounts included in the table were calculated assuming the reinvestment of dividends at the time dividends were paid.

	January 3,	December 31,		
	2007	2007	2008	2009
Spectra Energy Corp	$ 100.00	$ 93.47	$ 59.54	$ 82.34
S&P 500 Stock Index	100.00	105.60	66.53	84.14
S&P 500 Storage & Transportation Index	100.00	114.30	56.81	79.38

Dividends

We currently anticipate an average dividend payout ratio over time of approximately 60-65% of our estimated annual net income from controlling interests per share of common stock and expect to continue our policy of paying regular cash dividends. The actual payout ratio, however, may vary from year to year depending on earnings levels. The declaration and payment of dividends are subject to the sole discretion of our Board of Directors and depends upon many factors, including the financial condition, earnings and capital requirements of our operating subsidiaries, covenants associated with certain debt obligations, legal requirements, regulatory constraints and other factors deemed relevant by our Board of Directors.

Item 6. Selected Financial Data.

The following selected financial data should be read in conjunction with Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and Item 8. Financial Statements and Supplementary Data.

On January 2, 2007, Duke Energy completed the spin-off of its natural gas businesses, primarily comprised of the Natural Gas Transmission and Field Services business segments of Duke Energy that were owned through Duke Energy s then wholly owned subsidiary, Spectra Capital. Spectra Capital is treated as our predecessor entity for financial statement reporting purposes. Accordingly, the information presented below for periods prior to 2007 is that of Spectra Capital. This information is not necessarily indicative of future performance or what the financial position and results of operations would have been if we had operated as a separate, stand-alone entity for periods presented prior to 2007.

	2009	2008	2007	2006(a)	2005(b)
	(dollars in millions, except per-share amounts)				
Statements of Operations					
Operating revenues	$ 4,552	$ 5,074	$ 4,704	$ 4,501	$ 9,412
Operating income	1,475	1,480	1,426	1,234	1,844
Income from continuing operations(c)	918	1,192	1,002	972	1,914
Net income controlling interests	848	1,129	957	1,244	674
Ratio of Earnings to Fixed Charges	3.1	3.6	3.1	3.0	4.3
Common Stock Data					
Earnings per share from continuing operations					
Basic	$ 1.31	$ 1.82	$ 1.48	n/a	n/a
Diluted	1.31	1.81	1.48	n/a	n/a
Earnings per share					
Basic	1.32	1.82	1.51	n/a	n/a
Diluted	1.32	1.81	1.51	n/a	n/a
Dividends per share	1.00	0.96	0.88	n/a	n/a

			December 31,		
	2009	2008	2007	2006	2005
			(in millions)		
Balance Sheet					
Total assets	$ 24,079	$ 21,924	$ 22,970	$ 20,345	$ 35,056
Long-term debt including capital leases, less current maturities	8,947	8,290	8,345	7,726	8,790

(a) Significant transactions reflected in 2006 results include: the transfer of certain businesses to Duke Energy in December 2006 in preparation of our spin-off from Duke Energy, with total assets of approximately $5.1 billion and operating revenues of $1.0 billion; our indirect transfer of Duke Energy North America (DENA)

Midwestern assets to Duke Energy Ohio, Inc., with approximately $1.6 billion of assets and operating revenues of $788 million; a $250 million gain associated with the creation of the Crescent Resources joint venture; and the subsequent deconsolidation of Crescent Resources.

(b) Significant transactions reflected in 2005 results include pre-tax losses of approximately $1.1 billion related to sales of DENA s assets and contracts outside the Midwestern United States; the deconsolidation of DCP Midstream effective July 1, 2005; and the DCP Midstream sale of TEPPCO.

(c) Includes noncontrolling interests of $75 million, $65 million, $70 million, $61 million and $529 million for the years 2009 through 2005, respectively.

n/a Indicates not applicable.

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

INTRODUCTION

Management s Discussion and Analysis should be read in conjunction with Item 8. Financial Statements and Supplementary Data.

EXECUTIVE OVERVIEW

Throughout 2009, we continued to successfully execute on the strategies and objectives we outlined for our shareholders. These included exceeding our earnings objectives, the successful execution on capital expansion plans that underlie our growth objectives, and maintaining a strong balance sheet. In addition, we executed contracts in 2009 that support substantial continued growth of our market positions.

During 2009, our fee-based businesses at U.S. Transmission, Distribution and Western Canada Transmission & Processing performed well by meeting the needs of our customers and generated increased earnings and cash flows as a result of successful expansion projects placed into service. Commodity prices negatively affected the comparison to 2008 for our Field Services segment and the Empress operations at Western Canada Transmission & Processing.

We reported net income from controlling interests of $848 million, and $1.32 of diluted earnings per share for 2009 compared to net income from controlling interests of $1,129 million, and $1.81 of diluted earnings per share for 2008. The decrease in 2009 primarily reflects lower earnings from Field Services and Western Canada Transmission & Processing, as a result of the lower NGL prices associated with lower crude oil prices in 2009. Crude oil averaged $62 per barrel for 2009 versus $100 per barrel in 2008. The decrease in earnings in 2009 was partially offset by the recognition of a $135 million deferred gain ($85 million after-tax) in 2009 associated with partnership units previously issued by DCP Midstream Partners, LP (DCP Partners), DCP Midstream s master limited partnership, as well as earnings from growth projects.

We reported $1.0 billion of capital and investment expenditures for 2009, including approximately $500 million of expansion capital expenditures. This does not include the $295 million acquisition of NOARK. We successfully completed our 2009 expansion plans, with returns on these projects slightly above our targeted 10-12% return on capital employed range. Return on capital employed as it relates to expansion projects is calculated by us as incremental earnings before interest and taxes generated by a project divided by the total cost of the project. We plan to increase our expansion capital spending to a total of approximately $5.0 billion from 2010 through 2014, with approximately $1.0 billion planned for 2010, as we continue to pursue opportunities around new natural gas supply volumes in Western Canada and the Appalachian and Southeast regions of the United States.

We issued approximately $1.0 billion of new long-term debt in 2009, the need for which was driven by our 2009 and 2010 capital expansion plans, as well as refinancing of project debt. As of December 31, 2009, we continue to have ongoing access to approximately $2.3 billion available under our credit facilities and expect to continue to utilize commercial paper and revolving lines of credit, as needed, to fund liquidity needs throughout

2010. Financing activities in 2010 will include the refinancing of debt maturities of approximately $800 million and the issuance of commercial paper under our revolving credit facilities. We may also access the capital markets for other long-term financing if conditions are favorable.

In February 2009, in order to enhance our capital structure, we issued 32.2 million shares of our common stock and received net proceeds of $448 million.

In May 2009, Spectra Energy Partners acquired all of the ownership interests of NOARK from Atlas Pipeline Partners, L.P. (Atlas) for approximately $295 million in cash. In the second quarter of 2009, Spectra Energy Partners issued 9.8 million of its common units to the public, representing limited partner interests, and 0.2 million general partner units to Spectra Energy, in connection with the refinancing of the purchase of NOARK, resulting in net proceeds of $212 million and a reduction of our ownership interest in Spectra Energy Partners from 84% to 74%. See Notes 2 and 3 of Notes to Consolidated Financial Statements for further discussion.

Our Strategy. Our primary business objective is to create superior and sustainable value for our investors, customers, employees and communities by providing natural gas gathering, processing, transmission, storage and distribution services. We intend to accomplish this objective by executing the following overall business strategies, which remain consistent with our 2009 strategies:

- Deliver on 2010 financial commitments.
- Develop new opportunities and projects that add long-term shareholder value and meet customers needs.
- Effectively execute on our 2010 expansion plans.
- Enhance and solidify our profile and position as an advisor and partner of choice.
- Build on our high-performance culture by focusing on safety and employee engagement.

We know we are successful when we are the supplier of choice for our customers, the employer of choice for individuals, the advisor of choice on policy and regulation for governments and regulators, the partner of choice for our communities, and the investment opportunity of choice for investors.

2009 Financial Results. We reported net income from controlling interests of $848 million in 2009 compared to net income from controlling interests of $1,129 million in 2008. The decrease in net income from controlling interests primarily reflects lower earnings from Field Services and Western Canada Transmission & Processing, partially offset by the recognition of a $135 million deferred gain ($85 million after-tax) in 2009 associated with partnership units previously issued by DCP Partners, as well as earnings from growth projects. Highlights for 2009 include the following:

- U.S. Transmission s results reflect higher earnings from expansion projects placed into service late in 2008 and in 2009, lower project development costs in 2009 and an impairment of the Islander East project in 2008, partially offset by lower gas processing revenues in 2009, increased operating costs and a customer bankruptcy settlement in 2008,
- Distribution results reflect a weaker Canadian dollar, lower customer usage and higher expenses related to expansion projects, partially offset by higher storage and transportation revenues,
- Western Canada Transmission & Processing earnings decreased primarily as a result of lower NGL gross margins related to the Empress processing plant and a weaker Canadian dollar, partially offset by higher gathering and processing revenues and lower plant fuel and electricity costs, and

Field Services earnings reflect lower NGL and natural gas prices, and lower gathering and processing margins, partially offset by the recognition of a deferred gain associated with partnership units previously issued by DCP Partners.

Significant Economic Factors For Our Business. Our regulated businesses are generally economically stable and are not significantly affected in the short-term by changing commodity prices. However, all of our businesses can be negatively affected in the long term by sustained downturns in the economy or long-term conservation efforts, which could affect long-term demand and market prices for natural gas and NGLs, all of which are beyond our control and could impair our ability to meet long-term goals.

Most of our revenues are based on regulated tariff rates, which include the recovery of certain fuel costs. However, lower overall economic output would cause a decline in the volume of natural gas transported and distributed or gathered and processed at our plants, resulting in lower earnings and cash flows. This decline would primarily affect distribution revenues in the short term. Transmission revenues could be affected by long-term economic declines that result in the non-renewal of long-term contracts at the time of expiration. Pipeline transportation and storage customers continue to renew most contracts as they expire. Processing revenues and the earnings and distributions from our Field Services segment are also affected by volumes of natural gas made available to our systems, which are primarily driven by levels of natural gas drilling activity. Current levels of interest remain strong for natural gas exploration and drilling in the areas that affect our Western Canada and Field Services segments, primarily driven by recent positive developments around unconventional gas reserves production in numerous locations within North America.

Our combined key markets the northeastern and the southeastern United States, the Pacific Northwest, British Columbia and Ontario are projected to continue to exhibit higher than average annual growth in natural gas demand versus the North American and U.S. Lower 48 average growth rates through 2019. This demand growth is primarily driven by the natural gas-fired electric generation sector. The natural gas industry is currently experiencing a significant shift in the sources of supply, and this dramatic change is affecting our growth strategies. Traditionally, supply to our markets has come from the Gulf Coast region, both onshore and offshore, as well as from fields in western and eastern Canada. The national supply profile is shifting to new sources of gas from basins in the Rockies, Mid-Continent, Appalachia, Texas and Louisiana. In addition, the natural gas supply outlook includes new LNG re-gasification facilities on the Gulf Coast and in the Northeast. LNG will clearly be an important new source of supply, but the timing and extent of incremental supply from LNG is yet to be determined and, at present, LNG remains a small percentage of the overall supply to the markets we serve. These supply shifts are shaping the growth strategies that we will pursue, and therefore, will affect the nature of the projects anticipated in the capital and investment expenditure increases discussed below in Liquidity and Capital Resources.

Our businesses in the United States are subject to regulations on the federal and state level. Regulations applicable to the gas transmission and storage industry have a significant effect on the nature of the businesses and the manner in which they operate. Changes to regulations are ongoing and we cannot predict the future course of changes in the regulatory environment or the ultimate effect that any future changes will have on our businesses. Additionally, investments and projects located in Canada expose us to risks related to Canadian laws, taxes, economic conditions, fluctuations in currency rates, political conditions and policies of the Canadian government. From 2002 through 2009, the Canadian dollar strengthened significantly compared to the U.S. dollar, which favorably affected earnings and equity during these periods, except in the fourth quarter 2008 and the first quarter 2009 when the Canadian dollar weakened significantly in a very short period of time. Changes in this exchange rate or other of these factors are difficult to predict and may affect our future results and financial position.

Certain of our earnings are affected by fluctuations in commodity prices, especially the earnings of DCP Midstream and the Empress NGL operations in Canada. We evaluate, on an ongoing basis, the risks associated with commodity price volatility and currently do not have any plans to enter into hedge positions around these earnings.

Based on current projections, it is expected that our effective income tax rate on continuing operations will approximate 28 29% for 2010. Our overall effective tax rate largely depends on the proportion of earnings in the United States, subject to a 35% federal statutory tax rate, to the earnings of our Canadian operations, with an effective tax rate of approximately 21% that is driven by lower statutory rates and recognition of certain regulatory tax benefits.

As we execute on our strategic objectives, capital expansion projects will continue to be an important part of our growth plan. We currently anticipate capital and investment expenditures in 2010 of approximately $1.6 billion. We issued approximately $1.0 billion of new long-term debt in 2009, and financing activities in 2010 will include the refinancing of debt maturities of approximately $800 million and the issuance of commercial paper under our revolving credit facilities. We may also access capital markets for other long-term financing if conditions are favorable. An inability to access capital at competitive rates could adversely affect our ability to implement our strategy. Market disruptions or a downgrade in our credit ratings may increase the cost of borrowing or adversely affect our ability to access one or more sources of liquidity.

During the past few years, capital expansion projects have been exposed to cost pressures associated with the availability of skilled labor and the pricing of materials. Although certain costs have begun to decrease in the current economic conditions, there will be continual focus on project management activities to address these pressures as we move forward with planned expansion opportunities. Significant cost increases could negatively affect the returns ultimately earned on current and future expansions.

For further information related to management s assessment of our risk factors, see Part I, Item 1A. Risk Factors.

RESULTS OF OPERATIONS

	2009	2008	2007
		(in millions)	
Operating revenues	$ 4,552	$ 5,074	$ 4,704
Operating expenses	3,088	3,636	3,291
Gains on sales of other assets and other, net	11	42	13
Operating income	1,475	1,480	1,426
Other income and expenses	406	844	649
Interest expense	610	636	633
Earnings from continuing operations before income taxes	1,271	1,688	1,442
Income tax expense from continuing operations	353	496	440
Income from continuing operations	918	1,192	1,002
Income from discontinued operations, net of tax	5	2	25
Net income	923	1,194	1,027
Net income noncontrolling interests	75	65	70
Net income controlling interests	$ 848	$ 1,129	$ 957

2009 Compared to 2008

Operating Revenues. The $522 million, or 10%, decrease was driven primarily by:

lower NGL prices and sales volumes associated with the Empress operations at Western Canada Transmission & Processing,

the effects of a weaker Canadian dollar on revenues at Western Canada Transmission & Processing and Distribution, and

lower natural gas prices passed through to customers without a mark-up at Distribution, partially offset by higher earnings from expansion projects placed into service late in 2008 and in 2009 at U.S. Transmission.

Supplementary Data

Net tons sold								
	307,940	221,943	**32,552**	23,727	**10**	7	**340,502**	245,677
Depreciation expense								
	$16,354	$17,869	**$8,291**	$7,787			**$24,645**	$25,656

Results of individual business units are presented based on our management accounting practices and management structure. There is no comprehensive, authoritative body of guidance for management accounting equivalent to accounting principles generally accepted in the United States of America; therefore, the financial results of individual business units are not necessarily comparable with similar information for any other company. The management accounting process uses assumptions and allocations to measure performance of the business units. Methodologies are refined from time to time as management accounting practices are enhanced and businesses change. The costs incurred by support areas not directly aligned with the business unit are allocated primarily based on an estimated utilization of support area services
or included in Other and Unallocated in the table above. Certain prior period information has been reclassified to conform to the current period presentation.

Management evaluates results of operations before non-cash pension income, restructuring related charges, unusual items, effects of asset dispositions and insurance recoveries because it believes this is a more meaningful representation of the operating performance of its core papermaking businesses, the profitability of business units and the extent of cash flow generated from core operations. This presentation is closely aligned with the management and operating structure of our company. It is also on this basis that the Company s performance is evaluated internally and by the Company s Board of Directors.

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13. GUARANTOR FINANCIAL STATEMENTS

Our 7 1/8% Senior Notes have been fully and unconditionally guaranteed, on a joint and several basis, by certain of our 100%-owned domestic subsidiaries, PHG Tea Leaves, Inc., Mollanvick,Inc., The Glatfelter Pulp Wood Company, GLT International Finance, LLC and Glenn-Wolfe, Inc.

The following presents our condensed consolidating statements of income for the three and six months ended June 30, 2006 and
2005 and our condensed consolidating balance sheets as of June 30, 2006 and December 31, 2005. These financial statements reflect P. H. Glatfelter Company (the parent), the guarantor subsidiaries (on a combined basis), the non-guarantor subsidiaries (on a combined basis) and elimination entries necessary to combine such entities on a consolidated basis.

Condensed Consolidating Statement of Income for the three months ended June 30, 2006

In thousand	Parent Company	Guarantors	Non Guarantors	Adjustments/ Eliminations	Consolidated
Net sales	$ 203,462	$ 8,567	$ 84,526	$ (16,835)	$ 279,720
Energy sales net	2,847				2,847
Total revenues	206,309	8,567	84,526	(16,835)	282,567
Costs of products sold	210,588	7,822	75,143	(16,719)	276,834
Gross profit	(4,279)	745	9,383	(116)	5,733
Selling, general and administrative expenses	17,488	987	6,566	(1)	25,040
Shutdown and restructuring charges	6,616	506	(465)		6,657
Gains on dispositions of plant, equipment and timberlands, net	34	(1,129)			(1,095)
Gains from insurance recoveries	(205)				(205)
Operating income	(28,212)	381	3,282	(115)	(24,664)
Non-operating income (expense)					
Interest expense	(6,155)	(463)	(553)	1	(7,170)
Other income (expense) net	(3,036)	13,459	(720)	(10,473)	(770)
Total other income (expense)	(9,191)	12,996	(1,273)	(10,472)	(7,940)
Income (loss) before income taxes	(37,403)	13,377	2,009	(10,587)	(32,604)
Income tax provision (benefit)	(16,681)	4,755	425	(381)	(11,882)
Net income (loss)	$ (20,722)	$ 8,622	$ 1,584	$ (10,206)	$ (20,722)

Condensed Consolidating Statement of Income for the three months ended June 30, 2005

Parent	Non	Adjustments/

In thousand	Company	Guarantors	Guarantors	Eliminations	Consolidated
Net sales	$ 94,489	$ 8,626	$ 55,460	$ (13,292)	$ 145,283
Energy sales net	2,715				2,715
Total revenues	97,204	8,626	55,460	(13,292)	147,998
Costs of products sold	85,369	8,300	47,601	(13,105)	128,165
Gross profit	11,835	326	7,859	(187)	19,833
Selling, general and administrative expenses	10,286	520	6,167	1	16,974
Shutdown and restructuring charges					
Gains on dispositions of plant, equipment and timberlands, net	8	(68)	39		(21)
Gains from insurance recoveries	(2,200)				(2,200)
Operating income	3,741	(126)	1,653	(188)	5,080
Non-operating income (expense)					
Interest expense	(2,703)		(587)		(3,290)
Other income (expense) net	(2,028)	9,940	(355)	(7,023)	534
Total other income (expense)	(4,731)	9,940	(942)	(7,023)	(2,756)
Income (loss) before income taxes	(990)	9,814	711	(7,211)	2,324
Income tax provision (benefit)	(2,699)	3,373	228	(287)	615
Net income (loss)	$ 1,709	$ 6,441	$ 483	$ (6,924)	$ 1,709

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Condensed Consolidating Statement of Income for the six months ended June 30, 2006

In thousand	Parent Company	Guarantors	Non Guarantors	Adjustments/ Eliminations	Consolidated
Net sales	$ 305,809	$ 18,207	$ 148,325	$ (32,015)	$ 440,326
Energy sales net	5,304				5,304
Total revenues	311,113	18,207	148,325	(32,015)	445,630
Costs of products sold	305,406	16,199	129,806	(31,779)	419,632
Gross profit	5,707	2,008	18,519	(236)	25,998
Selling, general and administrative expenses	27,248	1,426	13,063		41,737
Shutdown and restructuring charges	25,875	462	(382)		25,955
Gains on dispositions of plant, equipment and timberlands, net	80	(1,202)	37		(1,085)
Gains from insurance recoveries	(205)				(205)
Operating income	(47,291)	1,322	5,801	(236)	(40,404)
Non-operating income (expense)					
Interest expense	(8,956)	(463)	(1,144)		(10,563)
Other income (expense) net	(4,081)	25,391	(1,456)	(19,608)	246
Total other income (expense)	(13,037)	24,928	(2,600)	(19,608)	(10,317)
Income (loss) before income taxes	(60,328)	26,250	3,201	(19,844)	(50,721)
Income tax provision (benefit)	(27,741)	9,338	1,033	(764)	(18,134)
Net income (loss)	$ (32,587)	$ 16,912	$ 2,168	$ (19,080)	$ (32,587)

Condensed Consolidating Statement of Income for the six months ended June 30, 2005

In thousand	Parent Company	Guarantors	Non Guarantors	Adjustments/ Eliminations	Consolidated
Net sales	$ 187,211	$ 17,726	$ 110,408	$ (26,166)	$ 289,179
Energy sales net	5,259				5,259
Total revenues	192,470	17,726	110,408	(26,166)	294,438
Costs of products sold	162,687	16,653	92,972	(26,301)	246,011
Gross profit	29,783	1,073	17,436	135	48,427
Selling, general and administrative expenses	20,992	1,014	12,358		34,364

Shutdown and restructuring charges					
Gains on dispositions of plant, equipment and timberlands, net	18	(129)	30		(81)
Gains from insurance recoveries	(2,200)				(2,200)
Operating income	10,973	188	5,048	135	16,344
Non-operating income (expense)					
Interest expense	(5,395)		(1,155)		(6,550)
Other income (expense) net	(2,223)	19,639	(619)	(15,504)	1,293
Total other income (expense)	(7,618)	19,639	(1,774)	(15,504)	(5,257)
Income (loss) before income taxes	3,355	19,827	3,274	(15,369)	11,087
Income tax provision (benefit)	(4,644)	6,927	1,184	(379)	3,088
Net income (loss)	$ 7,999	$ 12,900	$ 2,090	$ (14,990)	$ 7,999

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Condensed Consolidating Balance Sheet as of June 30, 2006

In thousands	Parent Company	Guarantors	Non Guarantors	Adjustments/ Eliminations	Consolidated
Assets					
Current assets					
Cash and cash equivalents	$ (3)	$ 225	$ 23,579	$	$ 23,801
Other current assets	235,286	9,337	103,176	8,289	356,088
Plant, equipment and timberlands net	306,070	13,428	206,282		525,780
Other assets	1,246,280	896,929	(56,591)	(1,710,955)	375,663
Total assets	$ 1,787,633	$ 919,919	$ 276,446	$ (1,702,666)	$ 1,281,332
Liabilities and Shareholders Equity					
Current liabilities	$ 164,111	$ 4,080	$ 34,270	$	$ 202,461
Long-term debt	300,075		78,758		378,833
Deferred income taxes	176,729	13,972	22,774	(9,930)	203,545
Other long-term liabilities	742,407	60,073	98,120	(808,418)	92,182
Total liabilities	1,383,322	78,125	233,922	(818,348)	877,021
Shareholders equity	404,311	841,794	42,524	(884,318)	404,311
Total liabilities and shareholders equity	$ 1,787,633	$ 919,919	$ 276,446	$ (1,702,666)	$ 1,281,332

Condensed Consolidating Balance Sheet as of December 31, 2005

In thousands	Parent Company	Guarantors	Non Guarantors	Adjustments/ Eliminations	Consolidated
Assets					
Current assets					
Cash and cash equivalents	$ 14,404	$ 30,149	$ 12,857	$ 32	$ 57,442
Other current assets	90,964	462	76,118	(1,429)	166,115
Plant, equipment and timberlands net	322,208	13,537	143,083		478,828
Other assets	1,065,934	739,840	23,009	(1,486,191)	342,592
Total assets	$ 1,493,510	$ 783,988	$ 255,067	$ (1,487,588)	$ 1,044,977
Liabilities and Shareholders Equity					

Current liabilities	$ 75,465	$ 999	$ 63,400	$ 14	$ 139,878
Long-term debt	150,000		34,000		184,000
Deferred income taxes	174,854	10,585	24,003	(3,173)	206,269
Other long-term liabilities	660,879	30,071	91,951	(700,383)	82,518
Total liabilities	1,061,198	41,655	213,354	(703,542)	612,665
Shareholders equity	432,312	742,333	41,713	(784,046)	432,312
Total liabilities and shareholders equity	$ 1,493,510	$ 783,988	$ 255,067	$ (1,487,588)	$ 1,044,977

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Condensed Consolidating Statement of Cash Flows for the six months ended June 30, 2006

In thousands	Parent Company	Guarantors	Non Guarantors	Adjustments/ Eliminations	Consolidated
Net cash provided (used) by Operating Activities	$ (57,331)	$ 36,524	$ (10,695)	$ (32)	$ (31,534)
Investing Activities					
Purchase of plant, equipment and timberlands	(22,233)	(480)	(2,537)		(25,250)
Proceeds from disposal plant, equipment and timberlands	14	1,075	3		1,092
Proceeds from sale of subsidiary, net of cash dividend	(84,562)	(67,043)			(151,605)
Total Investing Activities	(106,781)	(66,448)	(2,534)		(175,763)
Financing Activities					
Net (repayments of) proceeds from indebtedness	150,358		22,577		172,935
Payment of Dividends	(7,967)				(7,967)
Proceeds from Stock Options exercised	7,314				7,314
Total Financing Activities	149,705		22,577		172,282
Effect of Exchange Rate on Cash			1,374		1,374
Net Increase (decrease) in cash	(14,407)	(29,924)	10,722	(32)	(33,641)
Cash at the beginning of period	14,404	30,149	12,857	32	57,442
Cash at the end of period	$ (3)	$ 225	$ 23,579	$	$ 23,801

Condensed Consolidating Statement of Cash Flows for the six months ended June 30, 2005

In thousands	Parent Company	Guarantors	Non Guarantors	Adjustments/ Eliminations	Consolidated
Net cash provided (used) by Operating Activities	$ 480	$ 371	$ 4,319	$ (259)	$ 4,911
Investing Activities					
Purchase of plant, equipment and timberlands	(8,180)	(638)	(5,187)		(14,005)
Proceeds from disposal plant, equipment and timberlands	130				130
Proceeds from sale of subsidiary, net of cash dividend					
Total Investing Activities	(8,050)	(638)	(5,187)		(13,875)

Financing Activities					
Net (repayments of) proceeds from indebtedness			1,338		1,338
Payment of Dividends	(7,914)				(7,914)
Proceeds from Stock Options exercised	116				116
Total Financing Activities	(7,798)		1,338		(6,460)
Effect of Exchange Rate on Cash			(1,878)		(1,878)
Net decrease in cash	(15,368)	(267)	(1,408)	(259)	(17,302)
Cash at the beginning of period	20,399	412	18,881	259	39,951
Cash at the end of period	$ 5,031	$ 145	$ 17,473	$	$ 22,649

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ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion should be read in conjunction with the information in the unaudited condensed consolidated financial statements and notes thereto included herein and Glatfelter s Financial Statements and Management s Discussion and Analysis of Financial Condition and Results of Operations included in its 2005 Annual Report on Form 10-K.

Forward-Looking Statements This Quarterly Report on Form 10-Q includes forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. All statements other than statements of historical fact, including statements regarding industry prospects and future consolidated financial position or results of operations, made in this Report on Form 10-Q are forward looking. We use words such as anticipates , believes , expects , future , intends and similar expressions to identify forward-looking statements. Forward-looking statements reflect management s current expectations and are inherently uncertain. Our actual results may differ significantly from such expectations. The following discussion includes forward-looking statements regarding expectations of, among others, net sales, costs of products sold, non-cash pension income, environmental costs, capital expenditures and liquidity, all of which are inherently difficult to predict. Although we make such statements based on assumptions that we believe to be reasonable, there can be no assurance that actual results will not differ materially from our expectations. Accordingly, we identify the following important factors, among others, which could cause our results to differ from any results that might be projected, forecasted or estimated in any such forward-looking statements:

i. variations in demand for, or pricing of, our products;

ii. changes in the cost or availability of raw materials we use, in particular market pulp, pulp substitutes, and abaca fiber, and changes in energy-related costs;

iii. our ability to develop new, high value-added Specialty Papers and Composite Fibers (formerly Long Fiber & Overlay Papers);

iv. the impact of competition, changes in industry paper production capacity, including the construction of new mills, the closing of mills and incremental changes due to capital expenditures or productivity increases;

v. cost and other effects of environmental compliance, cleanup, damages, remediation or restoration, or personal injury or property damages related thereto, such as the costs of natural resource restoration or damages related to the presence of polychlorinated biphenyls (PCBs) in the lower Fox River on which our Neenah mill is located; and the costs of environmental matters at our former Ecusta Division mill;

vi. the gain or loss of significant customers and/or on-going viability of such customers;

vii. risks associated with our international operations, including local economic and political environments and fluctuations in currency exchange rates;

viii. geopolitical events, including war and terrorism;

ix. enactment of adverse state, federal or foreign tax or other legislation or changes in government policy or regulation;

x. adverse results in litigation;

xi. disruptions in production and/or increased costs due to labor disputes including the successful negotiation of a new contract for our Chillicothe Union that expires in August;

xii. the resolution of the European Commission s review of our Lydney mill acquisition;

xiii. our ability to successfully implement the EURO Program;

xiv. our ability to successfully execute our timberland strategy to realize the value of our timberlands;

xv. our ability to execute the planned shutdown of the Neenah facility in an orderly manner; and

xvi. our ability to finance, consummate and integrate acquisitions.

Introduction We manufacture, both domestically and internationally, a wide array of specialty papers and engineered products. Substantially all of our revenue is earned from the sale of our products to customers in numerous markets, including book publishing, envelope & converting, carbonless papers and forms, food and beverage, decorative laminates for furniture and flooring, and other highly technical niche markets.

Overview The analysis of our financial results for the first six months of 2006 versus the first six months of 2005 reflects the following significant items:

1) We completed our $65 million acquisition of J R Crompton s Lydney mill on March 13, 2006. This mill s revenue in 2005 was approximately $75 million;

2) On April 3, 2006, we completed our acquisition of Chillicothe, the carbonless paper operation of NewPage Corporation with 2005 revenue of $441.5 million, for $81.8 million in cash, subject to post-closing working capital adjustments;

3) On June 30, 2006, we ceased production at our Neenah, WI facility and recorded shutdown related charges totaling $50.7 million;

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4) We refinanced our bank credit facility with a $100 million term loan and a $200 million revolving credit facility in addition to the issuance of $200 million 7 1/8% bonds to replace our $150 million 6 7/8% notes due July 2007.

5) During the second quarter we completed the regularly scheduled annual maintenance outages at our Chillicothe and Spring Grove facilities;

6) Demand for products in our North America-based Specialty Papers business unit remained strong as our domestic mills operated at or near capacity and selling prices strengthened;

7) The results of our Composite Fibers business unit, based in Europe, improved due to strengthening order patterns, although selling prices declined moderately;

RESULTS OF OPERATIONS

Six Months Ended June 30, 2006 versus the Six Months Ended June 30, 2005

The following table sets forth summarized results of operations:

In thousands, except per share	Six Months Ended June 30 **2006**	2005
Net sales	**$ 440,326**	$ 289,179
Gross profit	**25,998**	48,427
Operating income (loss)	**(40,404)**	16,344
Net income (loss)	**(32,587)**	7,999
Earnings per share	**(0.73)**	0.18

The consolidated results of operations for the six months ended June 30, 2006 includes the following significant items:

In thousands, except per share	**After-tax**	**Diluted EPS**
2006	*Gain (loss)*	
Shutdown and restructuring charges	**$ (32,506)**	**$ (0.73)**
Acquisition integration related costs	**(3,263)**	**(0.07)**
Redemption premium	**(1,820)**	**(0.04)**
Timberland sales	**590**	**0.01**
Insurance recoveries	**130**	**0.00**
2005		
Insurance recoveries	$ 1,430	$ 0.03

The above items decreased earnings by $36.9 million, or $0.83 per diluted share in the first six months of 2006.

Business Units The following table sets forth profitability information by business unit and the composition of consolidated income before income taxes:

Business Unit Performance	For The Six Months Ended June 30,							
In thousands	Specialty Papers		Composite Fibers		Other and Unallocated		Total	
	2006	2005	**2006**	2005	**2006**	2005	**2006**	2005
Net sales	**$ 305,810**	$ 187,227	**$ 134,516**	$ 101,924	**$ 0**	$ 28	**$ 440,326**	$ 289,179
Energy sales, net	**5,304**	5,259					**5,304**	5,259
Total revenue	**311,114**	192,486	**134,516**	101,924	**0**	28	**445,630**	294,438
Cost of products sold	**286,493**	169,353	**115,722**	84,041	**17,417**	(7,383)	**419,632**	246,011
Gross profit (loss)	**24,621**	23,133	**18,794**	17,883	**(17,417)**	7,411	**25,998**	48,427
SG&A	**23,987**	20,069	**12,585**	12,270	**5,165**	2,025	**41,737**	34,364
Shutdown and restructuring charges					**25,955**		**25,955**	
Gains on dispositions of plant, equipment and timberlands					**(1,085)**	(81)	**(1,085)**	(81)
Gain on insurance recoveries					**(205)**	(2,200)	**(205)**	(2,200)
Total operating income (loss)	**634**	3,064	**6,209**	5,613	**(47,247)**	7,667	**(40,404)**	16,344
Nonoperating income (expense)					**(10,317)**	(5,257)	**(10,317)**	(5,257)
Income (loss) before income taxes	**$ 634**	$ 3,064	**$ 6,209**	$ 5,613	**$ (57,564)**	$ 2,410	**$ (50,721)**	$ 11,087
Supplementary Data								
Net tons sold	**307,940**	221,943	**32,552**	23,727	**10**	7	**340,502**	245,677
Depreciation expense	**$ 16,354**	$ 17,869	**$ 8,291**	$ 7,787			**$ 24,645**	$ 25,656

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Results of individual business units are presented based on our management accounting practices and management structure. There is no comprehensive, authoritative body of guidance for management accounting equivalent to accounting principles generally accepted in the United States of America; therefore, the financial results of individual business units are not necessarily comparable with similar information for any other company. The management accounting process uses assumptions and allocations to measure performance of the business units. Methodologies are refined from time to time as management accounting practices are enhanced and businesses change. The costs incurred by support areas not directly aligned with the business unit are allocated primarily based on an estimated utilization of support area services or included in Other and Unallocated in the table above. Certain prior period information has been reclassified to conform to the current period presentation.

Management evaluates results of operations before non-cash pension income, restructuring related charges, unusual items, effects of asset dispositions and insurance recoveries because it believes this is a more meaningful representation of the operating performance of its core papermaking businesses, the profitability of business units and the extent of cash flow generated from core operations. This presentation is closely aligned with the management and operating structure of our company. It is also on this basis that the Company s performance is evaluated internally and by the Company s Board of Directors .

Sales and Costs of Products Sold

	Six Months Ended June 30		
In thousands	**2006**	2005	Change
Net sales	**$ 440,326**	$ 289,179	$ 151,147
Energy sales net	**5,304**	5,259	45
Total revenues	**445,630**	294,438	151,192
Costs of products sold	**419,632**	246,011	173,621
Gross profit	**$ 25,998**	$ 48,427	$ (22,429)
Gross profit as a percent of Net sales	**5.9%**	16.7%	

The following table sets forth the contribution to consolidated net sales by each business unit:

	Percent of Total	
	2006	2005
Business Unit		
Specialty Papers	**69.5%**	64.7%
Composite Fibers	**30.5**	35.3
Total	**100.0%**	100.0%

Net sales totaled $440.3 million for the first six months of 2006, an increase of $151.1 million, or 52.3%, compared to the same period a year ago. Net sales from the Chillicothe and Lydney mill acquisitions totaled $127.6 million. These acquisitions are reported in the Specialty Papers and Composite Fibers business units, respectively. Organic growth was driven by a 3.8% increase in volume and $8.8 million from higher average selling prices in the Specialty Papers business unit. Excluding results of the Lydney mill, Composite Fibers volumes shipped increased 20.7%. The translation of foreign currencies unfavorably impacted this business unit s net sales by $4.0 million and average selling prices declined $3.9 million compared to the same period a year ago.

In connection with the Chillicothe acquisition, the Company permanently shutdown its Neenah, WI facility. Products previously manufactured at the Neenah facility have been transferred to Chillicothe. The results of operations for the first six months of 2006 include related pre-tax charges of $50.7 million, of which $24.8 million is reflected in the consolidated income statement as components of cost of products sold and $25.9 million is reflected as Shutdown and restructuring charges.

Costs of products sold totaled $419.6 million for the six months of 2006, an increase of $173.6 million compared with the same quarter a year ago. As discussed above, the 2006 costs of products sold includes a $24.8 million charge for inventory write-downs and accelerated depreciation on property and equipment to be abandoned in connection with the Neenah shutdown. Excluding these charges, the increase in costs of products sold was primarily due to the inclusion of the Chillicothe and Lydney acquisitions, a $22.5 million effect of increased shipping volumes, as well as higher raw material and energy prices that increased costs of products sold by approximately $8.1 million. The translation of foreign currencies reduced costs of products sold by $3.6 million. During the second quarters of 2006 and 2005, the Company completed its annually scheduled maintenance shutdown of its Spring Grove, PA facility, and, in the 2006 second quarter, the annual maintenance shutdown of the Chillicothe facility was completed. These shutdowns result in increased maintenance spending and reduced production leading to unfavorable manufacturing variances that negatively affect costs of products sold. The combined maintenance shutdowns had an estimated impact on gross profit of approximately $17.4 million in the second quarter of 2006 and $5.9 million in the comparable quarter a year ago.

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Non-Cash Pension Income Non-cash pension income results from the over-funded status of our pension plans. The amount of pension income recognized each year is determined using various actuarial assumptions and certain other factors, including the fair value of our pension assets as of the beginning of the year. The following summarizes non-cash pension income for each of the first six months of 2006 and 2005:

	Six Months Ended June 30		
In thousands	**2006**	2005	Change
Recorded as:			
Costs of products sold	**$ 7,453**	$ 7,413	$ 40
SG&A expense	**512**	833	(321)
Total	**$ 7,965**	$ 8,246	$ (281)

Selling, general and administrative (SG&A) expenses totaled $41.7 million in for the first six months of 2006 compared to $34.4 million a year ago. SG&A expenses increased due to approximately $5.1 million of acquisition integration costs and $4.9 million from the inclusion of the Chillicothe and Lydney acquisitions in the current period s results of operations. Lower professional and legal fees favorably impacted the period to period comparison.

Insurance Recoveries During the first six months of 2006 and 2005, we reached successful resolution of certain claims under insurance policies related to the Fox River environmental matter. Insurance recoveries included in the results of operations totaled $0.2 million in the first six months of 2006 and $2.2 million in the first six months of 2005. All recoveries were received in cash prior to the end of the applicable period.

Shutdown and Restructuring Charges Neenah Facility Shutdown As discussed above, in the first six months of 2006 we committed to a plan to permanently shutdown our Neenah facility. The following table summarizes restructuring charges incurred in connection with these initiatives:

In thousands	**Six Months Ended June 30, 2006**
Restructuring initiative:	
Recorded as:	
Costs of products sold	**$ 24,868**
Shutdown and restructuring charge	**25,875**
Total	**$ 50,743**

The components of the charge are as follows:

In thousands	**Six Months Ended June 30, 2006**
Accelerated depreciation	**$ 22,457**
Inventory write-down	**2,411**
Severance and benefit continuation	**6,592**

Pension and other retirement benefits curtailments		**7,675**
Contract termination costs		**11,386**
Other		**222**
Total	**$**	**50,743**

The Neenah facility supported our Specialty Papers business unit. Shutdown of this facility resulted in the elimination of approximately 200 positions. As part of the Neenah shutdown, we terminated our long-term steam supply contract, as provided for within the contract, resulting in a termination fee of approximately $11.4 million. Through June 30, 2006, approximately $0.03 million has been paid related to these charges.

The first six months results of operations also include $0.08 million of charges related to the European Restructuring and Optimization (EURO) Program.

We expect to record in the third and fourth quarters additional shutdown related charges totaling approximately $2.5 million and $4.0 million.

Non-operating Income (Expense) During April 2006, we completed the placement of a $200 million bond offering, the proceeds of which were used to redeem the then outstanding $150 million notes scheduled to mature in July 2007. In connection with the early redemption, a charge of $2.9 million, related to a redemption premium and the write-off of unamortized debt issuance costs, was recorded in Consolidated Statement of Income as Non-operating expense under the caption Other and Unallocated .

Income Taxes Our results of operations for the first six months of 2006 reflects an effective tax rate of 35.8% compared to 27.9% in the same period a year ago. The increase in the effective tax rate is primarily due to a higher effective state tax rate due to the Chillicothe acquisition and the absence of tax credits associated with the expiration of the research and development tax credit law at the end of 2005. In addition, the lower rate in 2005 reflects the resolution of certain state tax matters.

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Foreign Currency We own and operate paper and pulp mills in Germany, France and the United Kingdom as well as the Philippines. The local currency in Germany and France is the Euro, in the UK the British Pound Sterling, and in the Philippines the currency is the Peso. During the first six months of 2006, these operations generated approximately 28% of our sales and 27% of operating expenses. The translation of the results from these international operations into U.S. dollars is subject to changes in foreign currency exchange rates. The table below summarizes the effect from foreign currency translation on 2006 reported results compared to 2005:

In thousands	Six Months Ended June 30
	Favorable (unfavorable)
Net sales	**($3,981)**
Costs of products sold	**3,602**
SG&A expenses	**404**
Income taxes and other	**49**
Net income	**$ 74**

The above table only presents the financial reporting impact of foreign currency translations. It does not present the impact of certain competitive advantages or disadvantages of operating or competing in multi-currency markets.

Three Months Ended June 30, 2006 versus the Three Months Ended June 30, 2005

The following table sets forth summarized results of operations:

In thousands, except per share	Three Months Ended June 30 **2006**	2005
Net sales	**$ 279,720**	$ 145,283
Gross profit	**5,733**	19,833
Operating income	**(24,664)**	5,080
Net income (loss)	**(20,722)**	1,709
Earnings (loss) per share	**(0.46)**	0.04

The consolidated results of operations for the three months ended June 30, 2006 includes the following significant items:

In thousands, except per share	**After-tax**	**Diluted EPS**
2006	*Gain (loss)*	
Shutdown and restructuring charges	**$ (14,901)**	**$(0.33)**
Acquisition integration related costs	**(2,319)**	**(0.05)**
Redemption premium	**(1,820)**	**(0.04)**
Timberland sales	**590**	**0.01**
Insurance recoveries	**130**	**0.00**

	2005		
Insurance recoveries		$ 1,430	$ 0.03

Business Units The following table sets forth profitability information by business unit and the composition of consolidated income before income taxes:

Business Unit Performance	For the Three Months Ended June 30,							
In thousands, except net tons sold	Specialty Papers		Composite Fibers		Other and Unallocated		Total	
	2006	2005	**2006**	2005	**2006**	2005	**2006**	2005
Net sales	**$ 203,461**	$ 94,497	**$ 76,263**	$ 50,779	**$ (4)**	$ 7	**$ 279,720**	$ 145,283
Energy sales, net	**2,847**	2,715					**2,847**	2,715
Total revenue	**206,308**	97,212	**76,263**	50,779	**(4)**	7	**282,567**	147,998
Cost of products sold	**197,459**	89,202	**66,693**	42,831	**12,682**	(3,868)	**276,834**	128,165
Gross profit (loss)	**8,849**	8,010	**9,570**	7,948	**(12,686)**	3,875	**5,733**	19,833
SG&A	**14,705**	9,707	**6,504**	6,125	**3,831**	1,142	**25,040**	16,974
Shutdown and restructuring charges					**6,657**		**6,657**	
Gains on dispositions of plant, equipment and timberlands					**(1,095)**	(21)	**(1,095)**	(21)
Gain on insurance recoveries					**(205)**	(2,200)	**(205)**	(2,200)
Total operating income (loss)	**(5,856)**	(1,697)	**3,066**	1,823	**(21,874)**	4,954	**(24,664)**	5,080
Non-operating income (expense)					**(7,940)**	(2,756)	**(7,940)**	(2,756)
Income (loss) before income taxes	**$ (5,856)**	$ (1,697)	**$ 3,066**	$ 1,823	**$ (29,814)**	$ 2,198	**$ (32,604)**	$ 2,324
Supplementary Data								
Net tons sold	**188,854**	111,205	**17,667**	12,048	**10**	2	**206,531**	123,255
Depreciation expense	**$ 7,679**	$ 9,000	**$ 4,493**	$ 3,790			**$ 12,172**	$ 12,790

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The following table summarizes sales and costs of products sold for the three months ended June 30, 2006 and 2005.

Sales and Costs of Products Sold

In thousands	Three Months Ended June 30 **2006**	2005	Change
Net sales	**$ 279,720**	$ 145,283	$ 134,437
Energy sales net	**2,847**	2,715	132
Total revenues	**282,567**	147,998	134,569
Costs of products sold	**276,834**	128,165	148,669
Gross profit	**$ 5,733**	$ 19,833	$ (14,100)
Gross profit as a percent of Net sales	**2.0%**	13.7%	

The following table sets forth the contribution to consolidated net sales by each business unit:

	Percent of Total **2006**	**2005**
Business Unit		
Specialty Papers	**72.7%**	**65.0%**
Composite Fibers	**27.3**	**35.0**
Total	**100.0%**	**100.0%**

Net sales totaled $279.7 million for the second quarter of 2006, an increase of $134.4 million, or 92.5%, compared to the same quarter a year ago. Net sales from the Chillicothe and Lydney mill acquisitions totaled $124.1 million. These acquisitions are reported in the Specialty Papers and Composite Fibers business units, respectively. Organic growth, was driven by a 3.0% increase in volume and $5.6 million from higher average selling prices in the Specialty Papers business unit. Excluding results of the Lydney mill, Composite Fibers volumes shipped increased 20%. The translation of foreign currencies unfavorably impacted this business unit s net sales by $2.5 million and average selling prices declined $1.3 million compared to the same quarter a year ago.

Costs of products sold totaled $276.8 million for the second quarter of 2006, an increase of $148.7 million compared with the same quarter a year ago. As discussed above, the 2006 second quarter costs of products sold includes a $16.6 million pre-tax charge for inventory write-downs and accelerated depreciation on property and equipment to be abandoned in connection with the Neenah shutdown. Excluding these charges, the increase in costs of products sold was primarily due to the inclusion of the Chillicothe and Lydney acquisitions, an $8.3 million effect of increased shipping volumes, as well as higher raw material and energy prices that increased costs of products sold by approximately $4.4 million. The translation of foreign currencies reduced costs of products sold by $2.1 million. During the second quarters of 2006 and 2005, we completed our annually scheduled maintenance shutdown of the Spring Grove, PA facility, and, in the 2006 second quarter, the annual maintenance shutdown of the Chillicothe facility was completed. These shutdowns result in increased maintenance spending and reduced production leading to unfavorable manufacturing variances that negatively affect costs of products sold. The combined maintenance shutdowns had an estimated impact on gross profit of approximately $17.4 million in the second quarter of 2006 and $5.9 million in the comparable quarter a year ago.

Non-Cash Pension Income Non-cash pension income results from the considerably over-funded status of our pension plans. The amount of pension income recognized each year is determined using various actuarial assumptions and certain other factors, including the fair value of our pension assets as of the beginning of the year. The following summarizes non-cash pension income for each quarter:

	Three Months Ended June 30		
In thousands	**2006**	2005	Change
Recorded as:			
Costs of products sold	**$ 3,964**	$ 3,877	$ 87
SG&A expense	**280**	489	(209)
Total	**$ 4,244**	$ 4,366	$ (122)

Selling, general and administrative (SG&A) expenses totaled $25.0 million in the second quarter of 2006 compared with $17.0 million in the year-earlier second quarter. The amounts reported for the second quarter of 2006 include approximately $3.7 million of acquisition integration related expenses. Excluding these non-recurring costs, the balance of the increase in SG&A expenses, is primarily due to the inclusion of the Chillicothe and Lydney acquisitions in the current quarter s results of operations.

Shutdown and restructuring charges Neenah Facility Shutdown As discussed above, in the first six months of 2006 we committed to a plan to permanently shutdown our Neenah facility. The following table summarizes restructuring charges incurred in connection with these initiatives:

In thousands	**Three Months Ended June 30, 2006**
Restructuring initiative:	
Recorded as:	
Costs of products sold	**$ 16,645**
Shutdown and restructuring charges	**6,616**
Total	**$ 23,261**

The components of the charge are as follows:

In thousands	**Three Months Ended June 30, 2006**
Accelerated depreciation	**$ 16,645**
Inventory write-down	**-**
Severance and benefit continuation	**4,831**
Pension and other retirement benefits curtailments	**1,372**
Contract termination costs	**277**
Other	**136**
Total	**$ 23,261**

Income Taxes Our results of operations for the second quarter of 2006 reflects an effective tax rate of 36.4% compared to 26.5% in the same period a year ago. The increase in the effective tax rate is primarily due to a higher effective state tax rate due to the Chillicothe acquisition and the absence of tax credits associated with the expiration of the research and development tax credit law at the end of 2005.

Foreign Currency We own and operate paper and pulp mills in Germany, France and the United Kingdom as well as the Philippines. The local currency in Germany and France is the Euro, in the UK the British Pound Sterling, and in the Philippines the currency is the Peso. During the second quarter of 2006, these operations generated approximately 25% of our sales and 24% of operating expenses. The translation of the results from these international operations into U.S. dollars is subject to changes in foreign currency exchange rates.

The table below summarizes the effect from foreign currency translation on reported results for the second quarter of 2006 compared to the same quarter of 2005:

In thousands	Three Months Ended June 30, 2006
	Favorable (unfavorable)
Net sales	**$ (2,467)**
Costs of products sold	**2,075**
SG&A expenses	**258**
Income taxes and other	**(29)**
Net income	**$ (163)**

The above table only presents the financial reporting impact of foreign currency translations. It does not present the impact of certain competitive advantages or disadvantages of operating or competing in multi-currency markets. Nor does it reflect the impact of making certain A/R, A/P and other transactions to market at the end of the period.

LIQUIDITY AND CAPITAL RESOURCES

Our business is capital intensive and requires expenditures for new or enhanced equipment, for environmental compliance matters and to support our business strategy and research and development efforts. The following table summarizes cash flow information for each of the periods presented.

In thousands	Six Months Ended June 30 **2006**	2005
Cash and cash equivalents at beginning of period	**$ 57,442**	$ 39,951
Cash provided by (used for)		
Operating activities	**(31,534)**	4,911
Investing activities	**(175,763)**	(13,875)
Financing activities	**172,282**	(6,460)
Effect of exchange rate changes on cash	**1,374**	(1,878)
Net cash provided (used)	**(33,641)**	(17,302)
Cash and cash equivalents at end of period	**$ 23,801**	$ 22,649

During the first six months of 2006 operations used $31.5 million of cash compared to $4.9 million of cash provided by operating activities in the prior year period. The change in the comparison was primarily due to $21.7 million used to settle a cross currency rate swap that matured in June 2006 and $17.1 million of income tax payments made during the first six months of 2006.

The changes in investing cash flows reflects the use of approximately $151.6 million to fund the Chillicothe and Lydney mill acquisitions. The acquisitions were financed with additional borrowings under our revolving credit facility and new term loan.

The following table sets forth our outstanding long-term indebtedness:

In thousands	**June 30, 2006**	December 31, 2005
New revolving credit facility, due April 2011	**$ 52,893**	$
Term loan, due April 2011	**99,440**	
Revolving credit facility, due June 2006		19,650
7 1/8% Notes, due May 2016	**200,000**	
6 1/8% Notes, due July 2007		150,000
Note payable SunTrust, due March 2008	**34,000**	34,000
Total long-term debt	**386,333**	203,650
Less current portion	**(7,500)**	(19,650)
Long-term debt, excluding current portion	**$ 378,833**	$ 184,000

As more fully discussed in Item 1 Financial Statements, Note 10, on April 3, 2006 we refinanced the revolving credit facility set forth in the table above. The significant terms of the new credit facility are also set forth therein. In addition, on April 28, 2006, we completed a private placement offering of $200.0 million aggregate principal amount of our 7^1/8% Senior Notes due 2016. We used the net proceeds to redeem $150.0 million aggregate principal amount of our outstanding 6^7/8% notes due July 2007, plus the payment of the applicable redemption premium and accrued interest. We expect to use the remaining net proceeds for working capital and general corporate purposes.

During the first six months of 2006 and 2005, cash dividends paid on common stock totaled $7.9 million in each period. Our Board of Directors determines what, if any, dividends will be paid to our shareholders. Dividend payment decisions are based upon then-existing factors and conditions and, therefore, historical trends of dividend payments are not necessarily indicative of future payments.

We are subject to loss contingencies resulting from regulation by various federal, state, local and foreign governmental authorities with respect to the environmental impact of mills we operate, or have operated. To comply with environmental laws and regulations, we have incurred substantial capital and operating expenditures in past years. We anticipate that environmental regulation of our operations will continue to become more burdensome and that capital and operating expenditures necessary to comply with environmental regulations will continue, and perhaps increase, in the future. In addition, we may incur obligations to remove or mitigate any adverse effects on the environment resulting from our operations, including the restoration of natural resources and liability for personal injury and for damages to property and natural resources. Because environmental regulations are not consistent worldwide, our ability to compete in the world marketplace may be adversely affected by capital and operating expenditures required for environmental compliance.

We expect to meet all of our near- and longer-term cash needs from a combination of operating cash flow, cash and cash equivalents, proceeds generated from the execution of our Timberland Strategy existing credit facility or other bank lines of credit and other long-term debt. However, as discussed in Item 1 Financial Statements Note 11, an unfavorable outcome of various environmental matters could have a material adverse impact on our consolidated financial position, liquidity and/or results of operations.

Off-Balance-Sheet Arrangements As of June 30, 2006 and December 31, 2005, we had not entered into any off-balance-sheet arrangements. A financial derivative instrument to which we are a party and guarantees of indebtedness, which solely consists of obligations of subsidiaries and a partnership, are reflected in the consolidated balance sheets included herein in Item 1 Financial Statements.

Outlook We expect orders for our product offerings in the North America-based Specialty Papers business unit to be at or near capacity. In addition, pricing has strengthened and is expected to remain at or above these levels. We expect these conditions to prevail through most of 2006.

In our Composite Fibers business unit we expect order patterns to continue to improve and pricing conditions are expected to remain stable.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISKS

	Year Ended December 31					At June 30, 2006	
Dollars in thousands	2006	2007	2008	2009	2010	Carrying Value	Fair Value
Long-term debt							
Average principal outstanding							
At fixed interest rates	$ 234,000	$ 234,000	$ 208,500	$ 200,000	$ 200,000	$ 234,000	$ 222,931
At variable interest rates	152,333	146,709	129,834	107,959	82,959	152,333	152,333
Weighted-average interest rate							
On fixed interest rate debt	6.64%	6.64%	6.99%	7.13%	7.13%		
On variable interest rate debt	5.49	5.47	5.47	5.25	4.99		

Our market risk exposure primarily results from changes in interest rates and currency exchange rates. At June 30, 2006, we had long-term debt outstanding of $386.3 million, of which $152.3 million or 39.4% was at variable interest rates.

The table above presents average principal outstanding and related interest rates for the next five years. Fair values included herein have been determined based upon rates currently available to us for debt with similar terms and remaining maturities.

Variable-rate debt outstanding represents borrowings under our revolving credit facility that incur interest based on the domestic prime rate or a Eurocurrency rate, at our option, plus a margin. At June 30, 2006, the interest rate paid was 5.49%. A hypothetical 100 basis point increase or decrease in the interest rate on variable rate debt would increase or decrease annual interest expense by $1.5 million.

We are subject to certain risks associated with changes in foreign currency exchange rates to the extent our operations are conducted in currencies other than the U.S. Dollar. During the six months ended June 30, 2006, approximately 72.0% of our net sales were shipped from the United States, 19.5% from Germany, and 8.5% from other international locations.

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ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures Our chief executive officer and our principal financial officer, after evaluating the effectiveness of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of June 30, 2006, have concluded that, as of the evaluation date, our disclosure controls and procedures are effective.

Changes in Internal Controls On March 13, 2006, we completed the acquisition of the Lydney mill from J R Crompton Limited and on April 3, 2006, we completed the acquisition of Chillicothe, the carbonless paper operation of NewPage Corporation. We performed due diligence procedures associated with these acquisitions and are in the process of evaluating how the separate financial reporting processes applicable to these newly acquired entities will be incorporated into our internal control structure. There were no other changes in our internal control over financial reporting during the six months ended June 30, 2006, that have materially affected or is reasonably likely to materially affect our internal control over financial reporting.

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PART II

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

The Annual Meeting of holders of Glatfelter common stock was held on April 26, 2006. At this meeting, shareholders voted on the following matters (with the indicated tabulated results).

i. The election of two members of the Board of Directors to serve for full three-year terms expiring in 2009.

Director	For	Withheld
George H. Glatfelter II	38,223,792	241,283
Ronald J. Naples	38,111,900	353,175
Richard J. Smoot	37,556,332	908,743

ITEM 6. EXHIBITS

(a) Exhibits

The following exhibits are filed herewith.

31.1	Certification of George H. Glatfelter II, Chairman and Chief Executive Officer of Glatfelter, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of John P. Jacunski, Senior Vice President and Chief Financial Officer of Glatfelter, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of George H. Glatfelter II, Chairman and Chief Executive Officer of Glatfelter, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350.
32.2	Certification of John P. Jacunski, Senior Vice President and Chief Financial Officer of Glatfelter, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350.

SIGNATURES

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

P. H. GLATFELTER COMPANY
(Registrant)

August 9, 2006

By: /s/ David C. Elder
David C. Elder
Corporate Controller

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EXHIBIT INDEX

Exhibit Number	Description
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31.2	Certification of John P. Jacunski, Senior Vice President and Chief Financial Officer of Glatfelter, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 Chief Financial Officer, filed herewith.
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