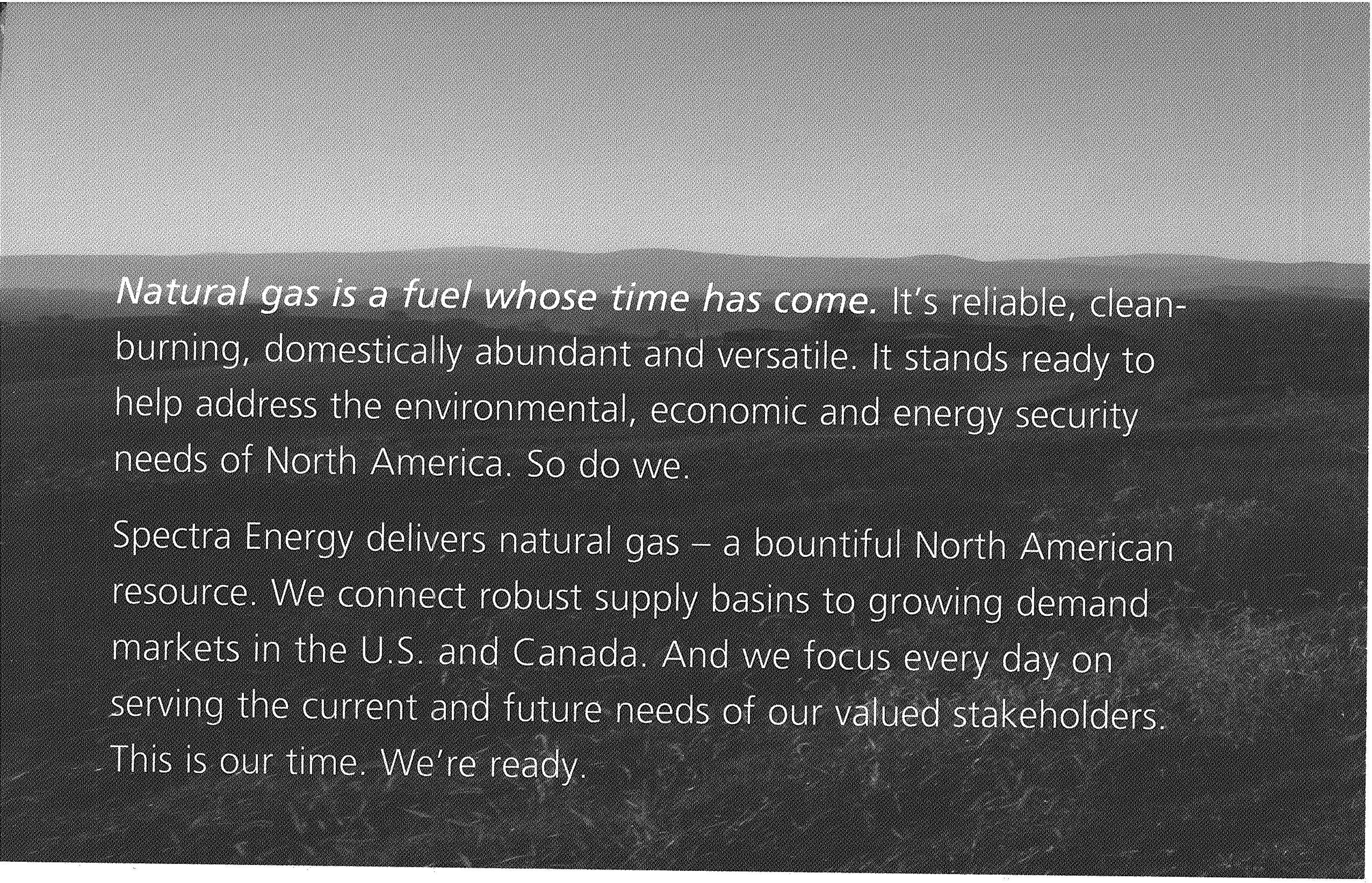
Spectra Energy
2010 Annual Report

By 2012, we will be leading our sector in...

safety and reliability...

customer responsiveness...

and profitability.



Natural gas is a fuel whose time has come. It's reliable, clean-burning, domestically abundant and versatile. It stands ready to help address the environmental, economic and energy security needs of North America. So do we.

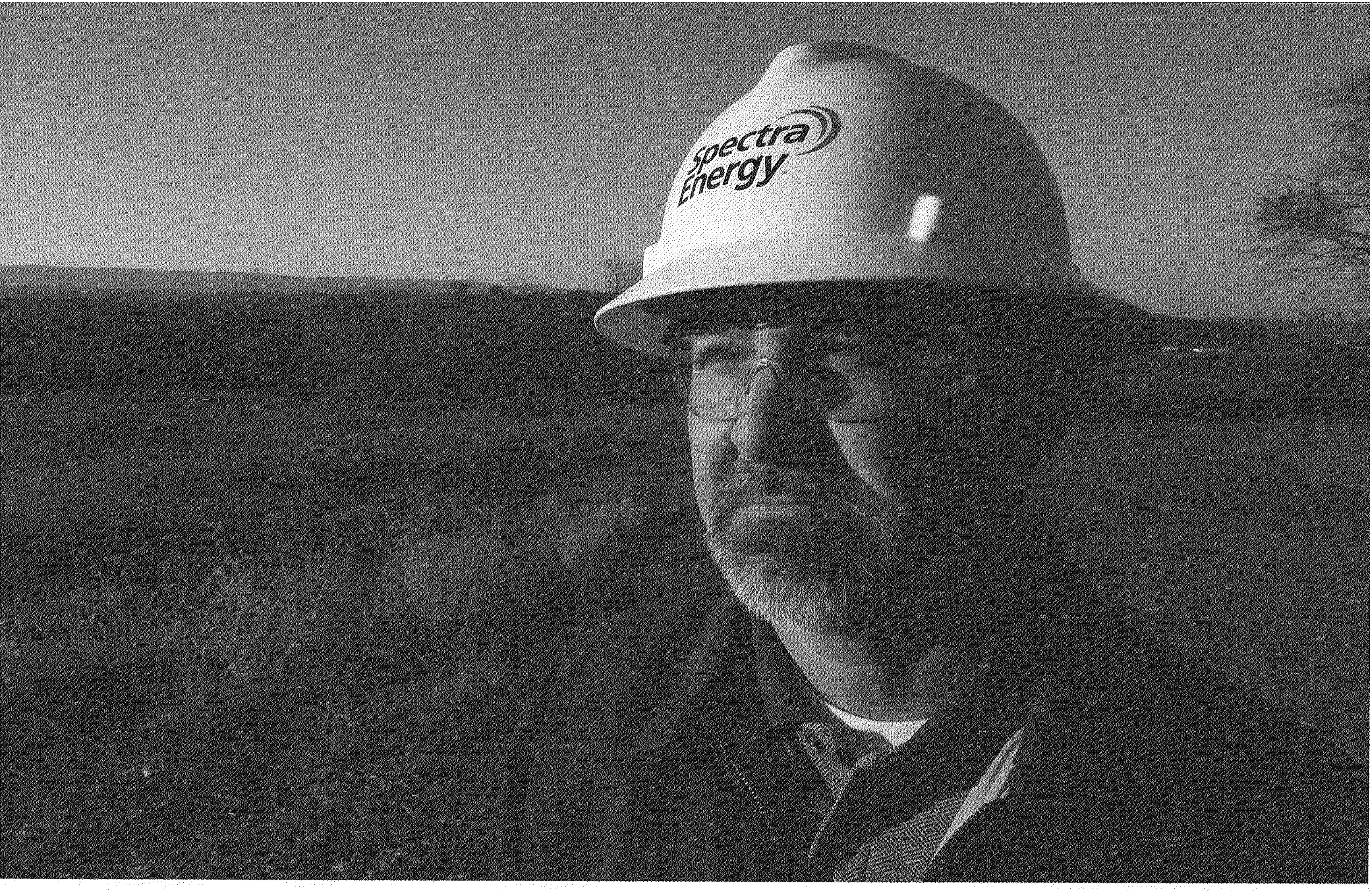
Spectra Energy delivers natural gas – a bountiful North American resource. We connect robust supply basins to growing demand markets in the U.S. and Canada. And we focus every day on serving the current and future needs of our valued stakeholders. This is our time. We're ready.

Contents

Spectra Energy Corp (NYSE: SE), a *FORTUNE 500* company, is one of North America's premier natural gas infrastructure companies serving three key links in the natural gas value chain: gathering and processing, transmission and storage, and distribution. For nearly a century, Spectra Energy and its predecessor companies have developed critically important pipelines and related infrastructure connecting natural gas supply sources to premium markets. Based in Houston, Texas, the company operates in the United States and Canada with approximately 19,000 miles of transmission pipeline and more than 305 billion cubic feet of storage, as well as natural gas gathering and processing, natural gas liquids operations and local distribution assets. The company also has a 50 percent ownership in DCP Midstream, one of the largest natural gas gatherers and processors in the United States. Spectra Energy is a member of the Dow Jones Sustainability World and North America Indexes and the U.S. S&P 500 Carbon Disclosure Project's Leadership Index for both Carbon Performance and Disclosure.

SE LISTED NYSE

On the cover: Spectra Energy's goals are embraced and championed by more than 5,500 employees across North America. Shown on the cover, clockwise from top: Michael Terry, pipeliner working at East Tennessee Natural Gas System in Glade Spring, Virginia; Arvis Hagger, senior talent representative, corporate human resources; and Chris Harvey, lead certificates and rates representative, Northeast rates and certificates.



Our goal is clear:

By 2012, Spectra Energy will be leading the North American natural gas infrastructure sector in terms of safety and reliability, customer responsiveness and profitability. We will rely on an unparalleled network of assets and people to meet our customers' energy needs and deliver long-term value.

Letter from the
President & CEO

"Tomorrow's energy imperatives are upon us. So are tremendous opportunities to invest, serve growing markets, create lasting value and help usher in a responsible new era in energy."

Letter to Shareholders

To our valued investors and stakeholders:

We are dedicating this annual report to describing our progress toward the goal of leading North America's natural gas infrastructure sector by 2012 in three vital areas: safety and reliability; customer responsiveness; and profitability.

We're looking forward because we believe in delivering energy today – and tomorrow. The signs are good: the economy is improving and the natural gas sector is strengthening at an even greater pace. As such, natural gas is positioned to play an increasingly important role in North America's energy future. These positive trends bode well for Spectra Energy investors.

Tomorrow's energy imperatives are upon us. So are tremendous opportunities to invest, serve growing markets, create lasting value and help usher in a responsible new era in energy. And we know that long-term, sustainable performance rests in our ability not only to deliver in the present, but to anticipate and act on what comes next. As our investors, you can be confident in the road ahead, because we are focusing on both the needs of today and the frontiers of opportunity ahead.

The fuel of choice

The second decade of the 21st century will become known as the era when natural gas was recognized as North America's 'fuel of choice.' In 2010, we witnessed and participated in productive discussion around the issues of energy security, infrastructure and the environmental impacts of energy consumption. While natural gas has long been a key contributor to North America's energy portfolio, it has recently moved to the forefront of public dialogue. Both the U.S. Senate and U.S. House of Representatives have established natural gas caucuses, focused on raising the profile of natural gas and advancing equitable legislative treatment. Similar advocacy efforts are under way in Canada, underlining growing government and private sector support for natural gas.

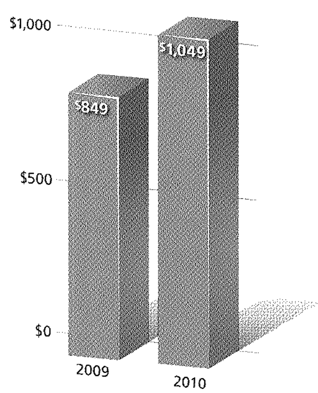
Natural gas is a fuel whose time has come. We are gratified that it is increasingly viewed as a near-term, viable option to reduce greenhouse gas emissions and deliver affordable and dependable energy to growing markets. Conservative estimates now point to 100-plus years of natural gas supply in North America, and that's good news for you, as an owner in one of the continent's largest, fastest-growing and most reliable natural gas infrastructure companies.

At Spectra Energy, we continue to solidify our position as 'advisor of choice,' providing leadership in numerous business and industry forums to address the energy policy issues and regulation that may affect our industry, our company and our stakeholders. Our employees understand the need to engage and have written thousands of letters to elected officials, citing the virtues of natural gas and urging them to take steps toward energy independence by making natural gas the fuel of choice for North America. Employees also encouraged members of the U.S. Congress to maintain lower taxation on the stock dividends that companies like Spectra Energy pay to investors like you. I want to thank our employees for their willingness to make their voices heard on issues important to our company, industry and future.

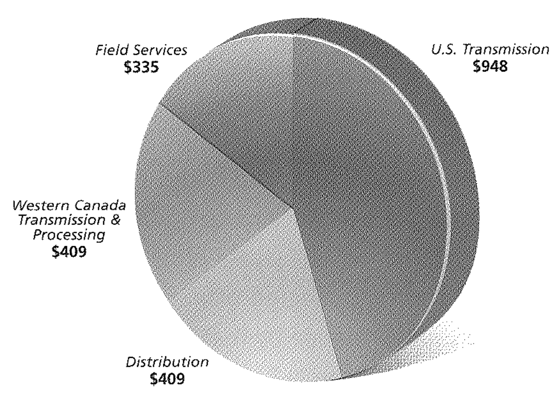
Financial Highlights

(In millions, except per share amounts and percentages)	**2010**	2009	2008
Common Stock Data			
Earnings per share			
Basic	**$ 1.62**	$ 1.32	$ 1.82
Diluted	**$ 1.61**	$ 1.32	$ 1.81
Dividends per share	**$ 1.00**	$ 1.00	$ 0.96
Shares outstanding			
Year-end	**649**	647	611
Weighted average – basic	**648**	642	622
Weighted average – diluted	**650**	643	624
Income Statement			
Operating revenues	**$ 4,945**	$ 4,552	$ 5,074
Total reportable segment EBIT	**2,101**	1,869	2,311
Net income – controlling interests	**1,049**	849	1,132
Balance Sheet			
Total assets	**$26,686**	$24,091	$21,924
Total debt	**11,320**	9,918	10,047
Capitalization			
Common equity – controlling interests	**39%**	40%	34%
Common equity – noncontrolling interests and preferred stock	**5%**	4%	4%
Total debt	**56%**	56%	62%
Capital and Investment Expenditures, including Acquisitions	**$ 1,848**	$ 1,336	$ 2,304

Net Income
in millions



2010 EBIT by Business Segment
in millions



Safe and reliable operations

Our license to operate rests with the public's trust in our ability to manage existing assets and construct new facilities to the highest safety standards. Nothing is more fundamental to our success or more compelling to our employees. We'll judge our progress toward the goal of leading our sector by 2012 in safety and reliability on metrics such as achieving top-decile performance in our employee injury frequency rate, and sector-leading performance in compression reliability, line break frequency, and bringing projects into service on time and on budget.

While we're not there yet, I'm pleased with the advances we are making toward our 'zero injury or work-related illness' goal. We achieved a significant overall improvement in our 2010 safety record, with a 30 percent decline in personal injuries among employees. We continue to identify process and performance changes aimed at protecting our employees, the communities in which we operate, and the environment. Although our employee injury numbers improved last year, we still have work to do in terms of reducing the number of vehicle incidents occurring across our business and ensuring that our contractors embrace our safe work practices as their own.

The priority we place on safe, reliable operations is evident in our annual commitment of capital to maintain our existing $17 billion in property, plant and equipment. Since 2007, we've invested more than half a billion dollars annually in maintenance and pipeline integrity. We work hard to ensure our assets are available to meet both the base and peak needs of customers, and in 2010 we achieved more than 99 percent transmission compression reliability across our system.

We pair market responsiveness and resource development with a profound sense of responsibility, and an eye toward long-term sustainability and being a 'partner of choice.' In 2010 we took steps to more closely manage our carbon footprint and reduce the environmental impacts of our operations. For the third consecutive year, Spectra Energy was named to the Dow Jones North America Sustainability Index. We were also named for the first time to the Dow Jones Sustainability World Index and led the energy sector on the 2010 Carbon Disclosure Project's Leadership Index.

We will know we're successful when we are the:

- *Supplier of choice for our customers*
- *Employer of choice for individuals*
- *Advisor of choice on policy and regulation for governments and regulators*
- *Partner of choice for our communities*
- *Investment opportunity of choice for investors*

Sustainability is also about the way we operate our business and care for the people affected by our operations. From hundreds of stakeholder meetings that help define our projects... to distributing 100,000 free energy saving kits per year to our Union Gas customers... to our annual Helping Hands in Action employee volunteer event – we listen and respond to communities across North America.

Our forward-looking philosophy applies to our employee team, and we commit significant focus to training, development and recruitment efforts to ensure we maintain our human capital advantage. We're working hard to ensure we are the 'employer of choice' for the men and women of Spectra Energy, and in 2010 we achieved a number of significant milestones: Spectra Energy was recognized as one of Houston's Top Workplaces; and Union Gas, our distribution business, was named one of Canada's Top 100 Employers. We were recently named one of Alberta's Top 50 Employers for 2011, and were proud to have our diversity efforts recognized with a 100 percent score on the Human Rights Campaign's 2011 Corporate Equality Index.

Customer responsiveness

We are proud to serve customers and communities across North America, and we measure our customer responsiveness success in terms of contract renewal rates across all our businesses, and connecting new and existing natural gas supply sources to growing markets.

We are connected to both conventional gas supply basins and prolific unconventional gas reserves like the Appalachian Basin's Marcellus, the Horn River and Montney in Western Canada, the Eagle Ford in South Texas and many others. Our businesses in the U.S. and Canada are ideally situated to serve the fastest-growing demand markets in North America, enabling us to move quickly on emerging opportunities.

That focus on being the 'supplier of choice' was evident in 2010, when we placed half a dozen pipeline, storage and processing growth projects into service on time and on budget, for a total investment of more than $900 million. Those facilities, ranging from Northeast British Columbia to Florida, Pennsylvania and Ontario, Canada, will provide returns well above expectations by adding some $200 million a year in new earnings before interest and taxes.

We also solidified our leading natural gas storage position in the Gulf Coast region by acquiring a new storage development that we will build out progressively through 2015. Upon completion, the Bobcat Storage project will provide customers with numerous options to reliably manage their needs in the Southeast U.S. And we reached a significant milestone on our New Jersey – New York project, with the filing of our certificate application late last year with the Federal Energy Regulatory Commission. We continue to make good progress on that important project, which will deliver new, affordable, clean-burning natural gas supplies to consumers in New Jersey and New York.

We see abundant opportunities ahead. Over the next five years we expect to invest at least $1 billion a year to be the 'supplier of choice' for both existing and new customers. Whether it's new infrastructure to serve the growing fleet of natural gas-fired generation in North America or new pipelines to bring domestic natural gas to factories and homes across the continent, Spectra Energy will be there.

Profitability

We know that as Spectra Energy investors, you're keenly interested in our ongoing profitability. We remain dedicated to growing our business and delivering a steady stream of value. I'm pleased by our record in this important area, and by our progress toward being the 'investment opportunity of choice' by leading our sector in profitability.

Our profitability metrics are straightforward: deliver a return on capital employed between 10 and 12 percent and rank within our sector's top quintile in total shareholder return. And, we are delivering. As investors, you realized a 2010 total shareholder return of 28 percent, compared with a 15 percent return from the S&P 500 and a 14 percent return from the Dow Jones Industrial Average. Between 2007 and 2010, we've invested $4 billion in capital expansion for an average annual return on capital employed of 14.5 percent. You would be hard pressed to find any of our peers who can match those results. And notably, we offer investors an attractive dividend, and true to our pledge to grow the dividend as we increase earnings, Spectra Energy's board of directors increased our quarterly dividend 4 percent, to 26 cents per share, effective in the first quarter of 2011.

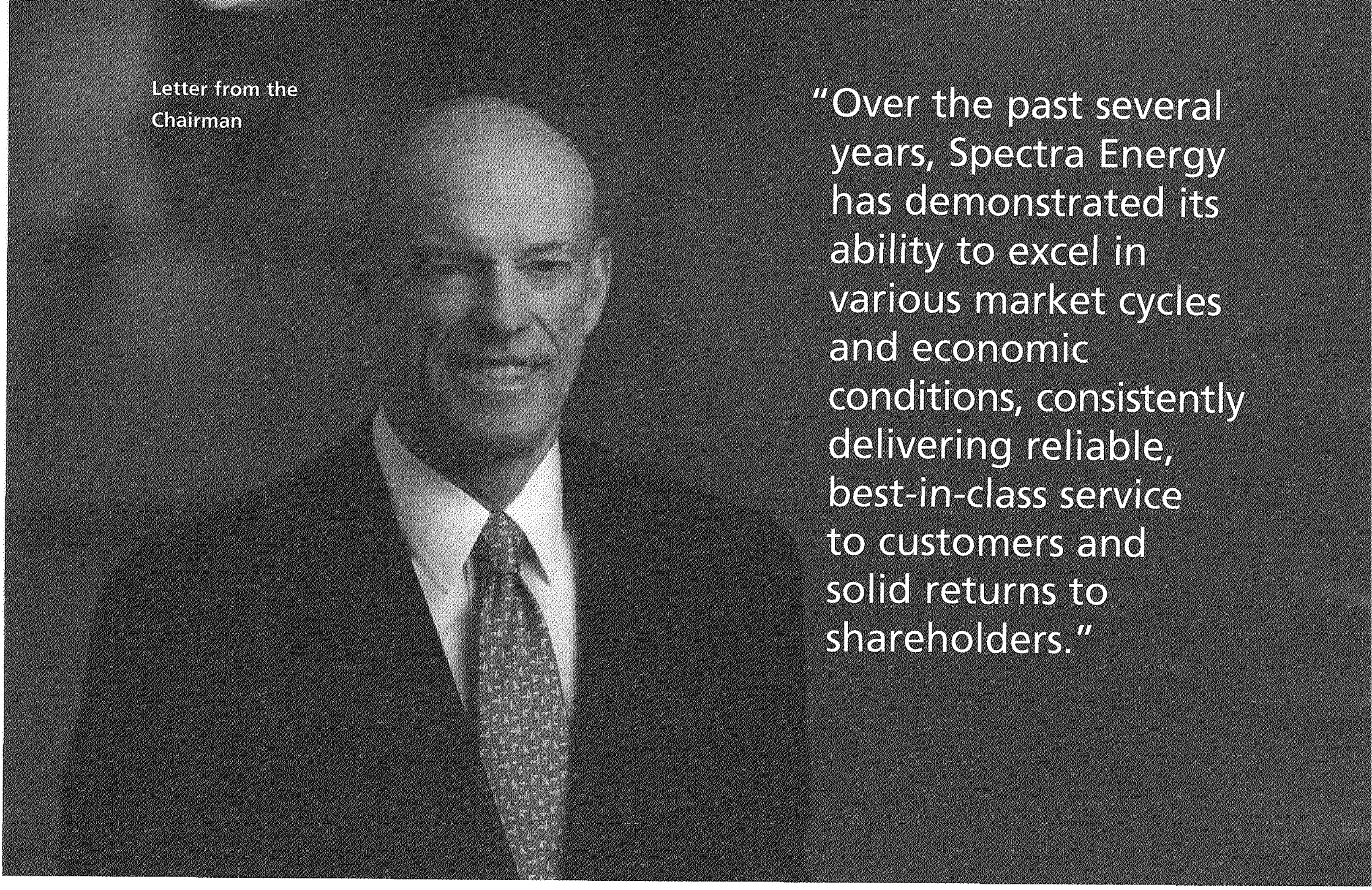
We are exceptionally well positioned financially, with an investment-grade balance sheet, strong ongoing cash flow, ample liquidity and excellent access to capital. Spectra Energy offers investors a number of benefits – benefits detailed in the following pages. But perhaps our greatest appeal is the fact that we profitably deliver an essential product that stands ready to address important societal needs: the need for a reliable, secure, domestic energy source; the need for economic growth; and the need for a cleaner, sustainable environment. We believe today's investors increasingly recognize the long-term value of natural gas and share our commitment to delivering on its tremendous promise. We'll deliver on that promise – and on the goals we've set for 2012 and beyond.

We are grateful to you, our long-term investors, for your ongoing trust and support. We also appreciate the engagement of our chairman and board of directors, who champion your interests every day and inspire our management team to provide the best possible results for you, our investors.

Respectfully,

Gregory L. Ebel, *president and chief executive officer*

Letter from the Chairman



"Over the past several years, Spectra Energy has demonstrated its ability to excel in various market cycles and economic conditions, consistently delivering reliable, best-in-class service to customers and solid returns to shareholders."

Dear fellow investors:

As you've seen in the page of financial highlights, Spectra Energy delivered strong operating and financial results in 2010. Each of our major businesses generated solid results and growing cash flows. Your company has also made excellent progress on the major initiatives and goals we've established that will enable Spectra Energy to lead our industry and create lasting shareholder value.

Over the past several years, Spectra Energy has demonstrated its ability to excel in various market cycles and economic conditions, consistently delivering reliable, best-in-class service to customers and solid returns to shareholders. That record of reliability and resiliency readies us for the future – a future whose fuel of choice will be natural gas, delivered by Spectra Energy, North America's natural gas infrastructure company of choice.

I have great confidence in the men and women committed to securing that future: from president and CEO Greg Ebel, whose dedicated, dynamic leadership defines the company's high-performance culture…to an executive team who brings integrity and deep, diverse experience to every decision and action…to employees in field locations and offices across North America who work diligently on your behalf. The shared values of the Spectra Energy team shape the character of your company.

The people of Spectra Energy stand behind a strong, diverse portfolio of businesses, assets, geography and market position. The company is ideally positioned in both growing North American demand markets and established and emerging supply basins. The enviable scale and scope of our infrastructure assets would be nearly impossible to replicate today, making us uniquely poised to capture opportunities with speed and efficiency.

I am equally proud of Spectra Energy's record of serving communities in a responsible, sustainable manner. In his letter, Greg reports on the company's notable progress in serving the social, environmental and economic needs of communities across North America. The bar of expectations for sustainable performance rises every year, and the employees of Spectra Energy continue to deliver critically-needed energy infrastructure with a focus on safety, stewardship and community service.

Your board of directors is steadfastly committed to representing your needs and expectations. Our role is absolutely clear: to ensure that management best serves the long-term interests of shareholders and other stakeholders.

Toward that end, we've adopted principles of governance that ensure the board remains informed, independent and involved in your company. We work with your strong management team in reviewing course-setting strategy and the capital investments that will expand Spectra Energy's market presence and earnings capacity. We also assure that the corporation operates at the highest levels of transparency, compliance and ethical performance. We are vigilant in aligning CEO and executive compensation fairly and equitably in support of investor interests.

Your board met seven times in 2010. In January 2011, we were pleased to authorize a 4 percent increase in Spectra Energy's quarterly dividend, from $0.25 per share to $0.26 per share, effective in the first quarter of 2011. As earnings growth continues, we would expect to provide investors with future dividend increases consistent with the company's targeted payout ratio of 65 percent.

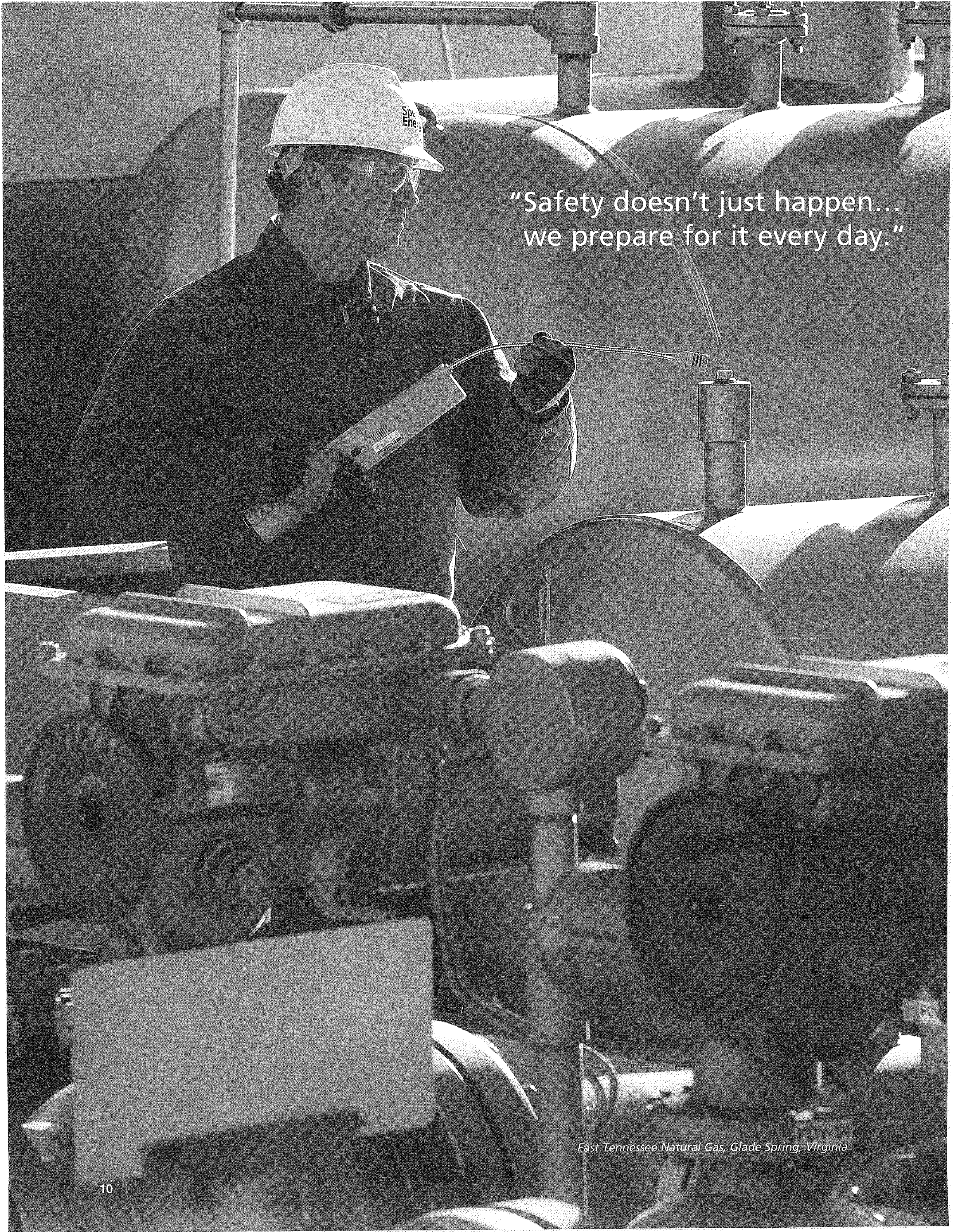
In 2010 we welcomed Joseph Netherland to our board. Joe is the former chairman of the board and CEO of FMC Technologies. He brings a wealth of business knowledge and petroleum industry experience to the company, and his wide-ranging expertise and keen insights are valuable assets to our board. With this addition, your board numbers 11 directors, who are fully committed to overseeing Spectra Energy's strategic direction and executive decision-making. We embrace that role and have great confidence in the direction, values and leadership of Spectra Energy.

This report is organized around the company's goal of leading its sector by 2012 in the areas of safety and reliability, customer responsiveness and profitability. There aren't many management teams willing to put such a tall and public stake in the ground – fewer still that I'd trust to succeed and surpass that goal. Based on their impressive record of execution and the solid foundation of management excellence, market insight, financial stability and solid values, I fully expect Greg and the Spectra Energy team to deliver on that pledge.

Thank you for sharing that confidence, and for your continued interest and support.

Bill Esrey

William T. Esrey, *chairman of the board*



"Safety doesn't just happen...
we prepare for it every day."

East Tennessee Natural Gas, Glade Spring, Virginia

Leading in Safety and Reliability

Spectra Energy is committed to being a safe and reliable operator, and to environmental stewardship in every region where we operate.

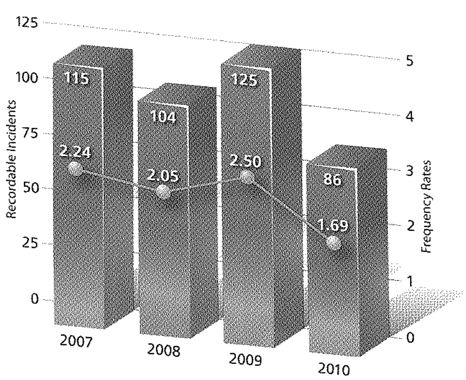
Our safety efforts are guided by the vision of a 'zero injury and zero work-related illness' culture for both employees and contractors. We're making progress toward that aspiration, realizing a 30 percent reduction in the number of employee injuries in 2010. But better is never good enough when it comes to safety, so we continue our unrelenting quest to improve, learn from mistakes and near misses, prevent recurrence and enhance processes that move us toward our zero goal.

We pursue the safety of the public and our facilities with vigor, committing between $500 to $700 million annually in maintenance capital to ensure our assets operate to the highest standards of safety, efficiency, reliability and customer service. Our maintenance program also helps us reduce methane emissions year after year through voluntary partnership with the U.S. Environmental Protection Agency's Natural Gas STAR Program.

We monitor our pipelines continuously, through round-the-clock electronic monitoring, regular air and ground surveillance and routine maintenance inspection. We maintain open and ongoing dialogue with our project and asset neighbors, and each year we mail more than 500,000 brochures to homeowners, businesses, potential excavators and public officials along our pipeline systems to inform them of the presence of pipelines and provide important safety information.

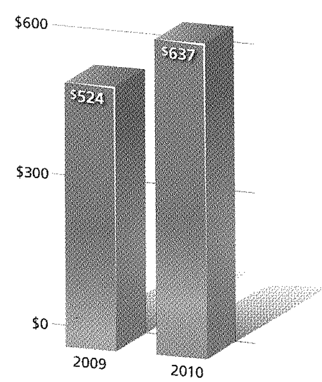
The greatest threat to natural gas pipeline integrity is inadvertent third-party excavation damage. Spectra Energy actively participates in U.S. and Canadian One-Call systems, centralized sources of information regarding the location of buried infrastructure. We are also a sponsor of the Common Ground Alliance, a non-profit organization dedicated to shared responsibility in damage prevention to ensure public safety, environmental protection and the integrity of critical infrastructure.

Employee Recordable Incidents & Frequency Rates

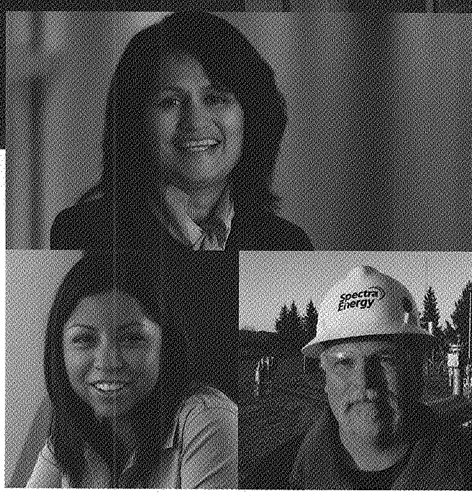


Note: Frequency rate = total number of employee incidents x 200,000 / total number of hours worked

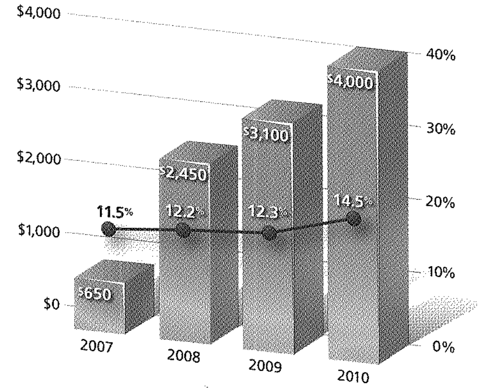
Maintenance CapEx
dollars in millions



Pine River Processing Plant, British Columbia



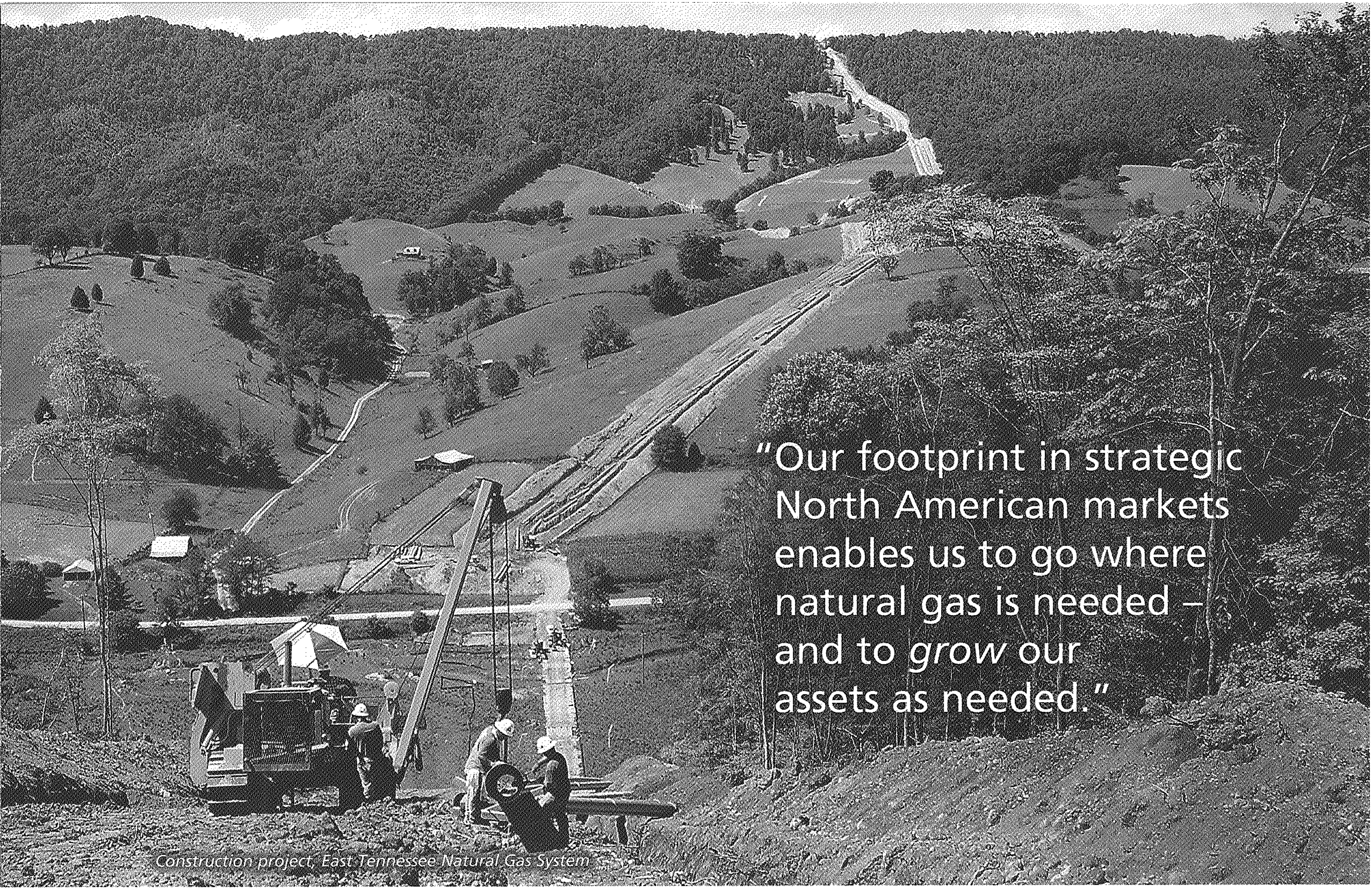
Expansion Projects: Cumulative Capital Investments & Return on Capital Employed
dollars in millions



Note: left rule depicts cumulative capital investment; right rule depicts return on capital employed

FREE Energy Saving Kit

Helping Customers Save Dollars and Resources: Since 1997, Union Gas has helped customers save an estimated $1.6 billion through energy saving initiatives, including 820 million cubic meters of natural gas and 1.6 million tonnes of CO_2 emissions — the equivalent of taking more than 240,000 cars off North American roads.

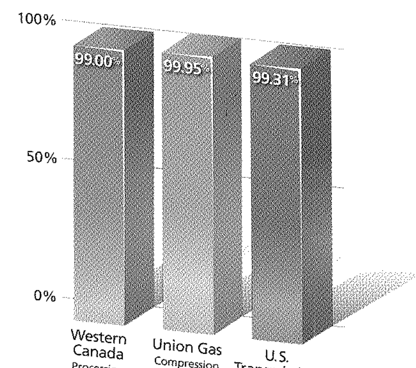


Construction project, East Tennessee Natural Gas System

Leading in Customer Responsiveness

Spectra Energy serves a broad range of customers, including utilities, municipalities, energy merchants, producers and, through Union Gas, more than a million residential, commercial and industrial customers. We also serve the communities in which we operate through responsible corporate citizenship, volunteerism and focused corporate giving.

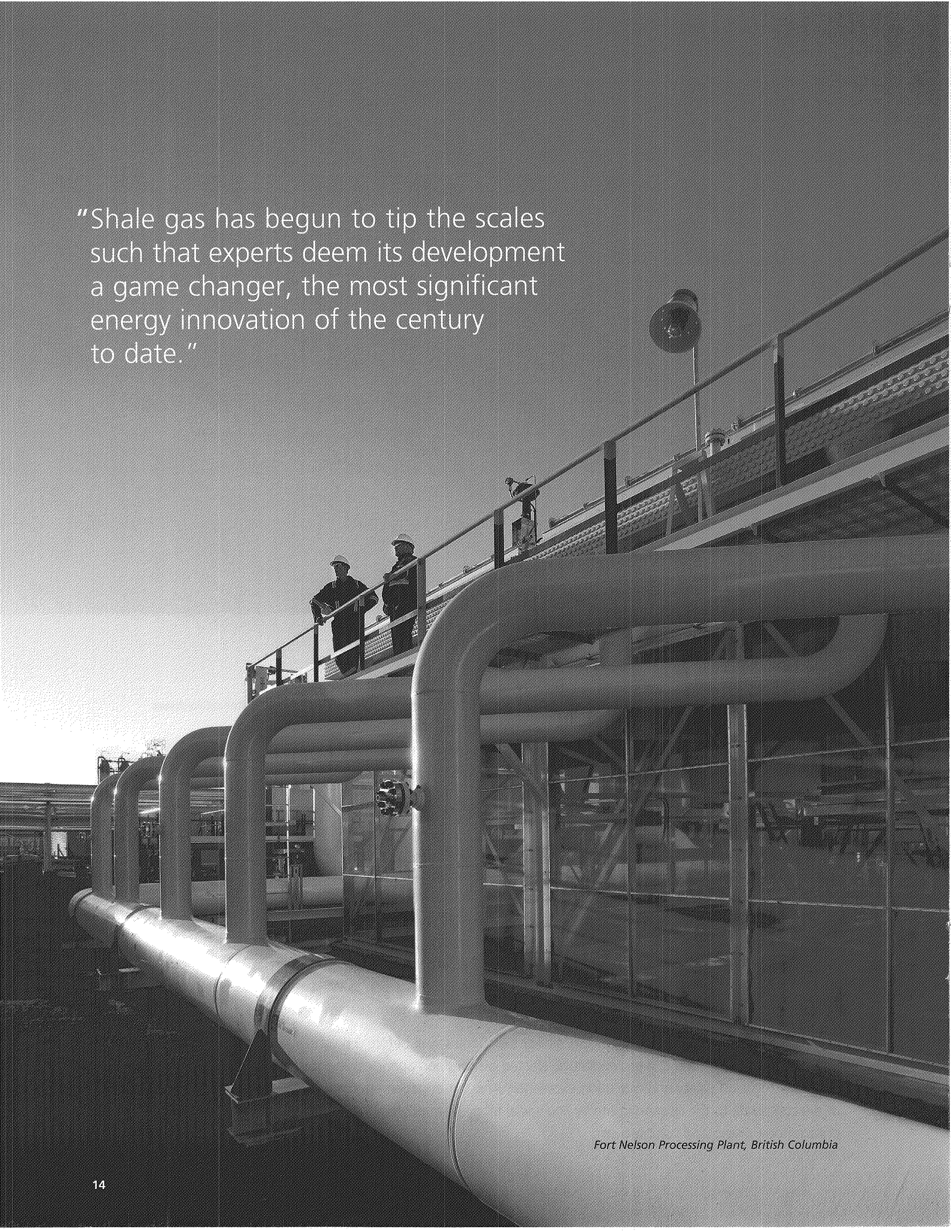
2010 Reliability Rates



Our customer responsiveness is evident in our dedication to building and operating the energy infrastructure needed across North America. We're in the midst of an expansive capital program, committing more than $1 billion annually over the next five years, and in 2010 we brought into service projects like Algonquin East to West, which allows shippers to reach growing Northeast markets; the first phase of TEMAX/TIME III, which permits shippers to receive new natural gas supplies from Western U.S. basins along our Texas Eastern system; and nine of the 10 gathering and processing projects that make up our massive Fort Nelson expansion in Western Canada. Substantially all of our projects in execution and development are supported by long-term customer contracts.

With growth comes responsibility – responsibility that begins well before a project's launch, when we reach out to stakeholders, consult with regulators, elected officials and agencies, and partner with contractors who share our focus on safety and execution excellence. And our engagement continues throughout operation and as we contribute to the economic vitality and social fabric of the communities we serve through wages, taxes, philanthropic giving and volunteerism.

"Shale gas has begun to tip the scales such that experts deem its development a game changer, the most significant energy innovation of the century to date."



Fort Nelson Processing Plant, British Columbia

Leading in Profitability

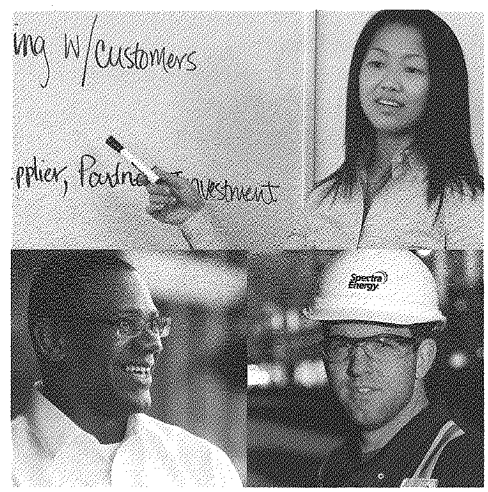
At Spectra Energy, we look at every decision and opportunity through the lens of long-term value creation. Toward that end, efficient capital deployment is essential, and we're investing more than $1 billion annually to grow our business at industry-leading returns, increase earnings and deliver attractive dividends to our owners.

Between 2007 and 2010, we placed 47 fee-based expansion projects into service, totaling $4 billion of investment with returns on capital employed above 14.5 percent. Our future prospects are similarly compelling: in the next five years, we plan to invest about $5 billion in expansion projects and expect to realize incremental earnings before interest and taxes of $500 to $600 million for a return on capital employed in the 10 to 12 percent range.

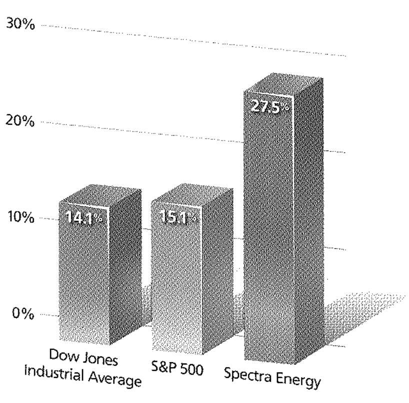
We're well positioned financially, with an investment-grade balance sheet, strong cash flow, ample liquidity and excellent access to capital. Our strong credit ratings allowed us to take advantage of 2010's attractive debt market, and we issued more than $1 billion of debt at excellent rates.

We continue to evaluate acquisition opportunities and in 2010 completed the acquisition of the Bobcat Storage facility, which further secures our premier storage position in the U.S. Gulf Coast.

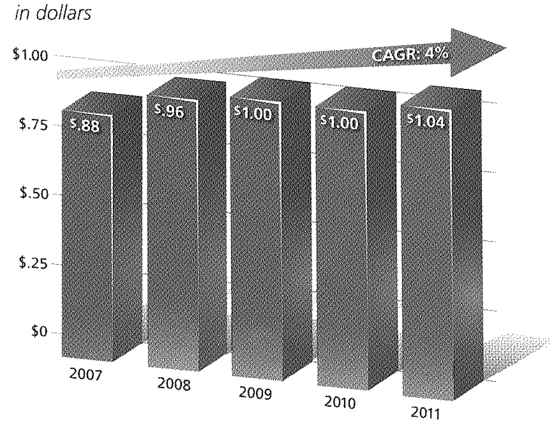
We gain additional flexibility through our master limited partnership, Spectra Energy Partners, and in 2010 completed the drop down of substantially all of our remaining interest in the Gulfstream system to Spectra Energy Partners. And we have a strong, competitive business in DCP Midstream, our 50/50 joint venture with ConocoPhillips, which provided strong cash generation, investment returns and distributions of nearly $300 million to Spectra Energy during the year.



Total Shareholder Return 2010



Dividend Per Share Growth
in dollars



Condensed Consolidated Statements of Operations

(In millions, except per share amounts)	**2010**	Years Ended December 31, 2009	2008
Operating Revenues			
Transportation, storage and processing of natural gas	**$2,870**	$2,565	$2,343
Distribution of natural gas	**1,450**	1,451	1,731
Sales of natural gas liquids	**459**	389	772
Other	**166**	147	228
Total operating revenues	**4,945**	4,552	5,074
Operating Expenses			
Natural gas and petroleum products purchased	**1,056**	1,098	1,586
Operating, maintenance and other	**1,575**	1,406	1,481
Depreciation and amortization	**650**	584	569
Total operating expenses	**3,281**	3,088	3,636
Gains on Sales of Other Assets and Other, Net	**10**	11	42
Operating Income	**1,674**	1,475	1,480
Other Income and Expenses			
Equity in earnings of unconsolidated affiliates	**430**	369	778
Other income and expenses, net	**32**	37	66
Total other income and expenses	**462**	406	844
Interest Expense	**630**	610	636
Earnings From Continuing Operations Before Income Taxes	**1,506**	1,271	1,688
Income Tax Expense From Continuing Operations	**383**	352	493
Income From Continuing Operations	**1,123**	919	1,195
Income From Discontinued Operations, Net of Tax	**6**	5	2
Net Income	**1,129**	924	1,197
Net Income – Noncontrolling Interests	**80**	75	65
Net Income – Controlling Interests	**$1,049**	$ 849	$1,132
Earnings per Common Share			
Basic	**$ 1.62**	$ 1.32	$ 1.82
Diluted	**$ 1.61**	$ 1.32	$ 1.81
Dividends per Common Share	**$ 1.00**	$ 1.00	$ 0.96

Condensed Consolidated Balance Sheets

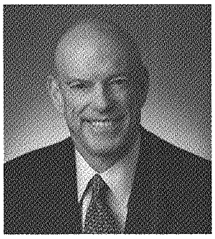
(In millions)	December 31, 2010	2009
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 130**	$ 166
Receivables	**1,018**	778
Inventory	**287**	321
Other	**203**	164
Total current assets	**1,638**	1,429
Investments and Other Assets		
Investments in and loans to unconsolidated affiliates	**2,033**	2,001
Goodwill	**4,305**	3,948
Other	**665**	407
Total investments and other assets	**7,003**	6,356
Property, Plant and Equipment, Net	**16,980**	15,347
Regulatory Assets and Deferred Debits	**1,065**	959
Total Assets	**$26,686**	$24,091
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	**$ 369**	$ 333
Short-term borrowings and commercial paper	**836**	162
Current maturities of long-term debt	**315**	809
Other	**1,003**	1,191
Total current liabilities	**2,523**	2,495
Long-term Debt	**10,169**	8,947
Deferred Credits and Other Liabilities		
Deferred income taxes	**3,555**	3,209
Regulatory and other	**1,694**	1,634
Total deferred credits and other liabilities	**5,249**	4,843
Preferred Stock of Subsidiaries	**258**	225
Equity		
Controlling interests	**7,809**	7,041
Noncontrolling interests	**678**	540
Total equity	**8,487**	7,581
Total Liabilities and Equity	**$26,686**	$24,091

Condensed Consolidated Statements of Cash Flows

	Years Ended December 31,		
(In millions)	**2010**	2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	**$ 1,129**	$ 924	$ 1,197
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**664**	598	581
Deferred income tax expense	**205**	176	158
Equity in earnings of unconsolidated affiliates	**(430)**	(369)	(778)
Distributions received from unconsolidated affiliates	**391**	195	777
Changes in working capital	**(424)**	365	(168)
Other	**(127)**	(129)	38
Net cash provided by operating activities	**1,408**	1,760	1,805
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	**(1,346)**	(980)	(1,502)
Investments in and loans to unconsolidated affiliates	**(10)**	(61)	(528)
Acquisitions, net of cash acquired	**(492)**	(295)	(274)
Sales (purchases) of available-for-sale securities, net	**(216)**	32	124
Purchases of held-to-maturity securities	**(49)**	(121)	—
Net proceeds from the sales of other assets	**—**	—	105
Distributions received from unconsolidated affiliates	**17**	164	218
Receipt from affiliate – repayment of loan	**—**	186	—
Other	**(5)**	54	(6)
Net cash used in investing activities	**(2,101)**	(1,021)	(1,863)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net increase (decrease) in short-term borrowings, commercial paper and long-term debt	**1,152**	(670)	1,406
Dividends paid on common stock	**(650)**	(631)	(598)
Proceeds from issuances of Spectra Energy Partners LP common units	**216**	208	—
Proceeds from issuance of Spectra Energy common stock	**—**	448	—
Repurchases of Spectra Energy common stock	**—**	—	(600)
Contributions from (distributions to) noncontrolling interests, net	**(73)**	(172)	45
Other	**11**	14	(39)
Net cash provided by (used in) financing activities	**656**	(803)	214
Effect of exchange rate changes on cash	**1**	25	(11)
Net increase (decrease) in cash and cash equivalents	**(36)**	(39)	145
Cash and cash equivalents at beginning of period	**166**	205	60
Cash and cash equivalents at end of period	**$ 130**	$ 166	$ 205

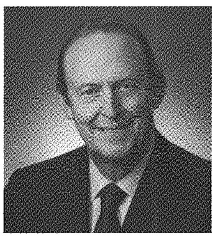
Condensed Consolidated Statements of Equity and Comprehensive Income

(In millions)	Common Stock/ Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income: Foreign Currency Translation Adjustments	Accumulated Other Comprehensive Income: Other	Noncontrolling Interests	Total
December 31, 2007	$4,604	$ 356	$ 2,026	$(216)	$ 581	$ 7,351
Net income	—	1,132	—	—	65	1,197
Other comprehensive income (loss)						
Foreign currency translation adjustments	—	—	(1,140)	—	(2)	(1,142)
Other, net	—	—	—	(144)	—	(144)
Total comprehensive income (loss)						(89)
Spectra Energy common stock repurchases	(600)	—	—	—	—	(600)
Dividends on common stock	—	(598)	—	—	—	(598)
Contributions from noncontrolling interests, net	—	—	—	—	42	42
Purchase of Spectra Energy Income Fund units	—	—	—	—	(208)	(208)
Other, net	46	—	—	—	(8)	38
December 31, 2008	4,050	890	886	(360)	470	5,936
Net income	—	849	—	—	75	924
Other comprehensive income						
Foreign currency translation adjustments	—	—	796	—	11	807
Other, net	—	—	—	(15)	—	(15)
Total comprehensive income						1,716
Dividends on common stock	—	(651)	—	—	—	(651)
Spectra Energy common stock issuance	448	—	—	—	—	448
Spectra Energy Partners LP common unit issuance	25	—	—	—	168	193
Distributions to noncontrolling interests, net	—	—	—	—	(172)	(172)
Other, net	123	—	—	—	(12)	111
December 31, 2009	4,646	1,088	1,682	(375)	540	7,581
Net income	—	1,049	—	—	80	1,129
Other comprehensive income						
Foreign currency translation adjustments	—	—	328	—	16	344
Other, net	—	—	—	(34)	—	(34)
Total comprehensive income						1,439
Dividends on common stock	—	(650)	—	—	—	(650)
Spectra Energy Partners LP common unit issuance	50	—	—	—	140	190
Distributions to noncontrolling interests, net	—	—	—	—	(73)	(73)
Other, net	31	—	—	(6)	(25)	—
December 31, 2010	**$4,727**	**$1,487**	**$ 2,010**	**$(415)**	**$ 678**	**$ 8,487**



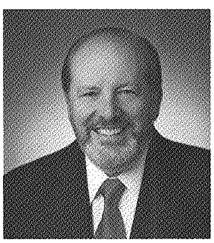
William T. Esrey, Chairman

Bill Esrey chairs Spectra Energy's board of directors and is chairman emeritus of Sprint Corporation. He served as Sprint's chief executive officer from 1985 to 2003 and as that company's chairman from 1990 to 2003. He also served as chairman of Japan Telecom from 2003 to 2004. Esrey is a director of General Mills, Inc. Esrey serves on Spectra Energy's audit and corporate governance committees.



Austin A. Adams

Austin Adams is the former executive vice president and chief information officer (CIO) of JPMorgan Chase. He assumed that role in 2004, when JPMorgan Chase and Bank One Corporation merged. Before joining Bank One in 2001, Adams served as CIO for First Union Corporation. He is a director of NCO Group, owned by JPMorgan Private Equity, and Dun & Bradstreet Corporation. Adams is a member of Spectra Energy's audit and finance and risk management committees.

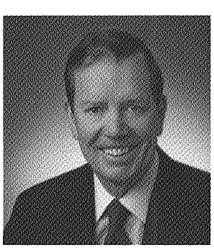


Paul M. Anderson

Paul Anderson served as chairman of Spectra Energy's board of directors from 2007 to 2009. He previously served in two executive roles with Duke Energy, as chairman of the board and earlier as president and chief operating officer. He also served as managing director and chief executive officer of BHP Billiton. Anderson also is a director of BP and BAE Systems. Anderson chairs Spectra Energy's finance and risk management committee.

Pamela L. Carter

Pamela Carter is president of Cummins Distribution Business. She previously served as president of Cummins Filtration, as vice president and general manager of Cummins' Europe, Middle East and Africa business and operations, and as vice president and general counsel for Cummins Inc. Prior to joining Cummins, she practiced law in the private sector and served as attorney general for the State of Indiana from 1993 to 1997. Carter is a member of the Export-Import Bank of the United States' Sub-Saharan Africa Advisory Council and a director of CSX Corporation. She is a member of Spectra Energy's compensation and corporate governance committees.

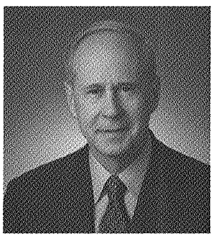


F. Anthony Comper

Tony Comper is the retired president and chief executive officer of BMO Financial Group. He was appointed to that position in February 1999 and served as chairman from July 1999 to May 2004. He previously served on the board of directors of the Bank of Montreal. Comper is a member of Spectra Energy's compensation and finance and risk management committees.

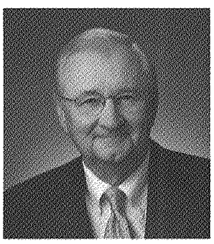
Gregory L. Ebel

Greg Ebel is president and chief executive officer of Spectra Energy. He previously served in a number of leadership roles for Spectra Energy and its predecessor companies, including chief financial officer; president of Union Gas; vice president of investor and shareholder relations; managing director of mergers and acquisitions; and vice president of strategic development. Ebel also is a member of DCP Midstream's board of directors.



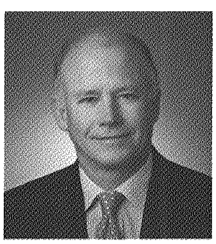
Peter B. Hamilton

Peter Hamilton is the senior vice president and chief financial officer of Brunswick Corporation. He previously served Brunswick in a number of executive leadership capacities, including vice chairman, Brunswick Corporation; president, Brunswick Boat Group; president, Life Fitness Division; and president, Brunswick Bowling & Billiards. Hamilton chairs Spectra Energy's audit committee and also serves on the corporate governance committee.



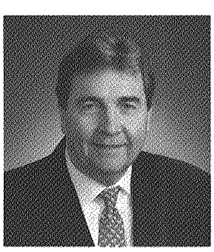
Dennis R. Hendrix

Dennis Hendrix is the retired chairman of the board of PanEnergy Corp. He served as chairman from 1990 to 1997, as chief executive officer from 1990 to 1995 and as president from 1990 to 1993. He has served as a director of Duke Energy, Allied Waste Industries and Newfield Exploration Company. Hendrix chairs Spectra Energy's corporate governance committee and is a member of the compensation committee.



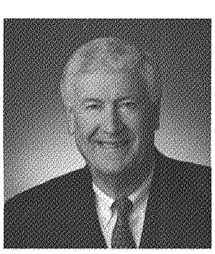
Michael McShane

Mike McShane is the former chairman, president and chief executive officer of Grant Prideco, Inc. He previously served as senior vice president of finance, chief financial officer and director of BJ Services Company. McShane is a director of Complete Production Services, Inc., Oasis Petroleum, Inc., and additionally serves on the board of directors for two private companies. He also serves Advent International as an advisor. McShane is a member of Spectra Energy's audit and finance and risk management committees.



Joseph H. Netherland

Joe Netherland served as chairman of FMC Technologies from December 2001 until his retirement in 2008. He also served as president of FMC Technologies from 2001 to 2006 and as chief executive officer from 2001 to 2007. He remains a director of FMC Technologies, and serves on the boards of Newfield Exploration Company and Tidewater Inc. He also serves as an advisory director of CVC Capital Partners. Netherland serves on Spectra Energy's compensation and corporate governance committees.



Michael E.J. Phelps

Michael Phelps is chairman of Dornoch Capital Inc., a private investment company. He served as president and chief executive officer of Westcoast Energy Inc. from 1988 to 1992 and as chairman and chief executive officer until 2002. He is a director of Canadian Pacific Railway Company, Prodigy Gold Inc. and Marathon Oil Corporation. Phelps chairs Spectra Energy's compensation committee and is a member of the finance and risk management committee.

Spectra Energy Leadership Team

Greg Ebel is president and chief executive officer and a member of the company's board of directors. He also serves on the board of directors of DCP Midstream.

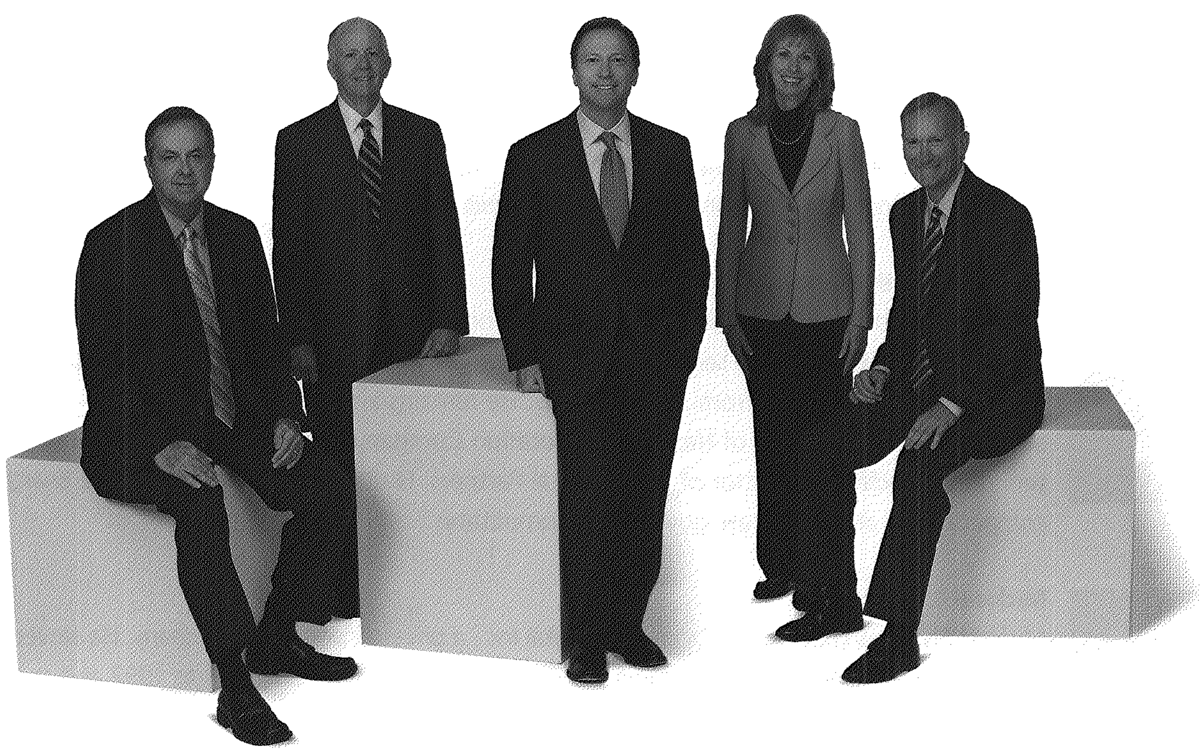
Dorothy Ables is chief administrative officer, responsible for the company's information technology, audit services, human resources and community relations functions.

John Arensdorf is chief communications officer. He directs the company's communications with internal and external audiences, including investors, the media, employees and other stakeholders. He also oversees Spectra Energy's sustainability efforts.

Doug Bloom is president of the company's Western Canada operations, responsible for the company's western-based divisions: BC Pipeline, BC Field Services, Midstream and the Natural Gas Liquids division.

Julie Dill is president of Union Gas, one of Ontario's largest natural gas utilities. Union Gas also provides natural gas storage and transportation services to other utilities and energy market participants in Ontario, Quebec and the U.S.

Mark Fiedorek is group vice president of Southeast U.S. Transmission and Storage. He is responsible for the southern portion of Texas Eastern Transmission, East Tennessee Natural Gas, Steckman Ridge, Gulfstream Natural Gas, Southeast Supply Header, Market Hub Partners and Bobcat Storage. Fiedorek also serves on the board of directors of the company's publicly traded master limited partnership, Spectra Energy Partners.



Alan Harris is chief development and operations officer. He oversees the company's strategy, planning, corporate development and merger and acquisition activities, as well as project execution, the operations of Spectra Energy's U.S. pipeline and storage business, environment, health and safety, procurement and Spectra Energy Partners, the company's master limited partnership. He also serves on the board of directors for DCP Midstream Partners.

Reggie Hedgebeth is general counsel. As chief legal officer, he leads the company's legal and corporate secretary functions, as well as ethics and compliance, regulatory affairs and government relations.

Pat Reddy is chief financial officer. He leads the finance function, which includes the controller's office, treasury, tax, risk management and insurance. He also serves on the board of directors for DCP Midstream.

Bill Yardley is group vice president of Northeast U.S. Transmission. He is responsible for the company's Northeast U.S. assets, which include the northern portion of Texas Eastern Transmission, Algonquin Gas Transmission and Spectra Energy's interest in Maritimes & Northeast Pipeline.

Spectra Energy's Leadership Team:
The members of Spectra Energy's executive leadership team, from left:
Alan Harris, John Arensdorf, Greg Ebel, Julie Dill, Bill Yardley,
Mark Fiedorek, Dorothy Ables, Reggie Hedgebeth, Pat Reddy and Doug Bloom.

Shareholder Services

BNY Mellon Shareowner Services is the Transfer Agent and Registrar for Spectra Energy Corp common stock. Registered shareholders may direct questions about stock accounts, legal transfer requirements, address changes, dividend checks, lost certificates or other services by calling toll free 1-866-406-6840 (U.S. and Canadian callers) or 1-201-680-6578 (international callers).

Please send written requests to:

Spectra Energy Corp
c/o BNY Mellon Shareowner Services
480 Washington Blvd.
Jersey City, NJ 07310

For electronic correspondence, visit the BNY Mellon Shareowner Services Web site at www.bnymellon.com/shareowner/isd.

Stock Exchange Listing

Spectra Energy's common stock is listed on the New York Stock Exchange under the trading symbol SE.

Stock Purchase and Dividend Reinvestment Plan

The Spectra Energy Stock Purchase and Dividend Reinvestment Plan provides a simple and convenient way to purchase common stock directly through the company, without incurring brokerage fees. The Plan provides for full reinvestment, direct deposit or cash payment of dividends. Purchases may be made weekly. Additional options include bank drafts for monthly purchases and depositing certificates into the Plan for safekeeping. Visit the BNY Mellon Shareowner Services Web site at www.bnymellon.com/shareowner/isd for account management access.

Financial Publications

Spectra Energy's Securities & Exchange Commission reports and related financial publications can be found on our Web site at www.spectraenergy.com/investors. Printed copies are available on request.

Electronic Delivery

Spectra Energy encourages shareholders to enroll in electronic delivery of financial information and proxy statements. To enroll in electronic delivery, go to http://enroll.icsdelivery.com/se.

Duplicate Mailings

If your shares are registered in different accounts, you may receive duplicate mailings of annual reports, proxy statements and other shareholder information. Contact BNY Mellon Shareowner Services for instructions on how to combine your accounts or eliminate duplicate mailings.

Dividend Payment

Dividends on common stock are expected to be paid in March, June, September and December 2011, subject to declaration by the board of directors.

Web Site

Additional investor information may be obtained on Spectra Energy's Web site at www.spectraenergy.com.

Bond Trustee

If you have questions regarding your bond account, please call 1-800-254-2826, or address written correspondence to:

The Bank of New York Mellon Trust Company, N.A.
601 Travis Street, 16th Floor
Houston, TX 77002

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

FORM 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2010 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 ☒ 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 ☒

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

Indicate by check mark 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 ☒ 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 ☒ 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 ☒

Estimated aggregate market value of the common equity held by nonaffiliates of the registrant June 30, 2010: $13,000,000,000

Number of shares of Common Stock, $0.001 par value, outstanding at January 31, 2011: 648,616,985

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2011 Annual Meeting of Shareholders are incorporated by reference in Part III.

SPECTRA ENERGY CORP
FORM 10-K FOR THE YEAR ENDED
DECEMBER 31, 2010

TABLE OF CONTENTS

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, including the risk of a prolonged economic slowdown or decline, or the risk of delay in a recovery, 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;
- the development of alternative energy resources;
- 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 related 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 these 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.

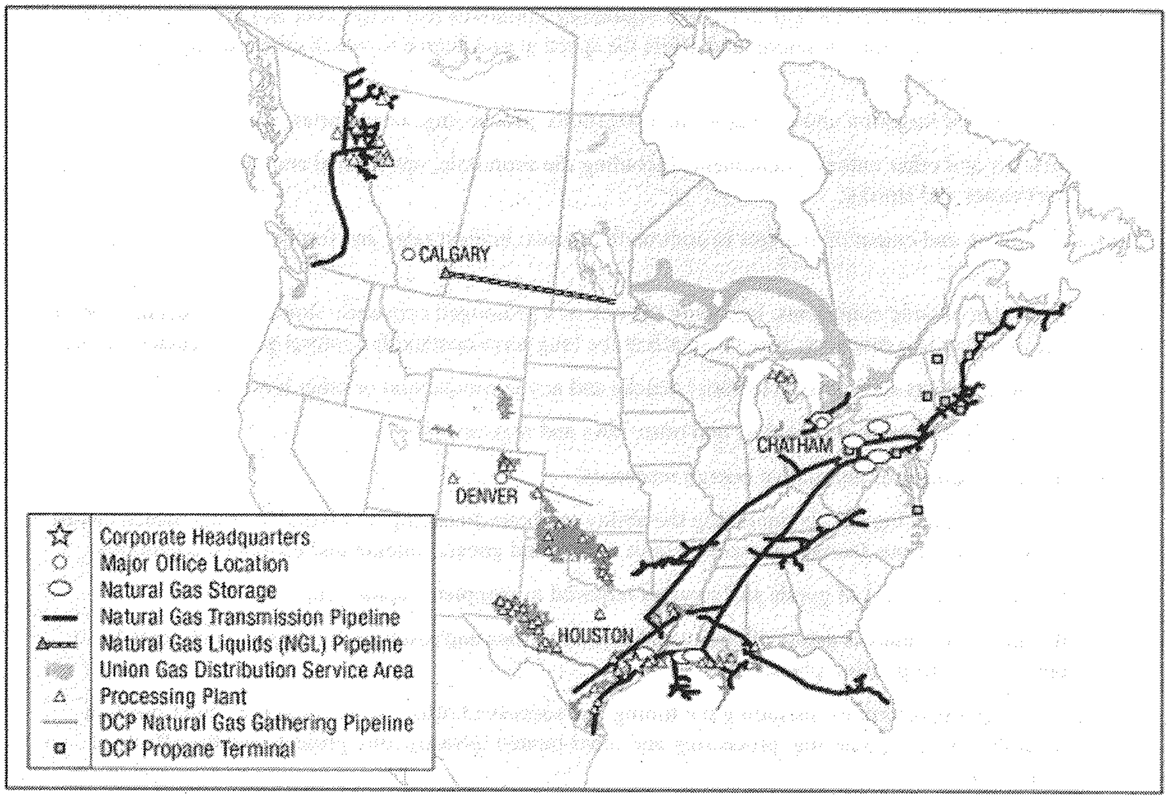
In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than Spectra Energy Corp has described. Spectra Energy Corp undertakes no obligation to publicly update or revise 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. In addition, we hold a 50% ownership interest 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 over 19,000 miles of transmission pipelines. Our proportional throughput for our pipelines totaled 4,248 trillion British thermal units (TBtu) in 2010, compared to 3,987 TBtu in 2009 and 3,733 TBtu in 2008. 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 305 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 5 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 14,400 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 2,708 TBtu in 2010, compared to 2,574 TBtu in 2009 and 2,218 TBtu in 2008. 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.

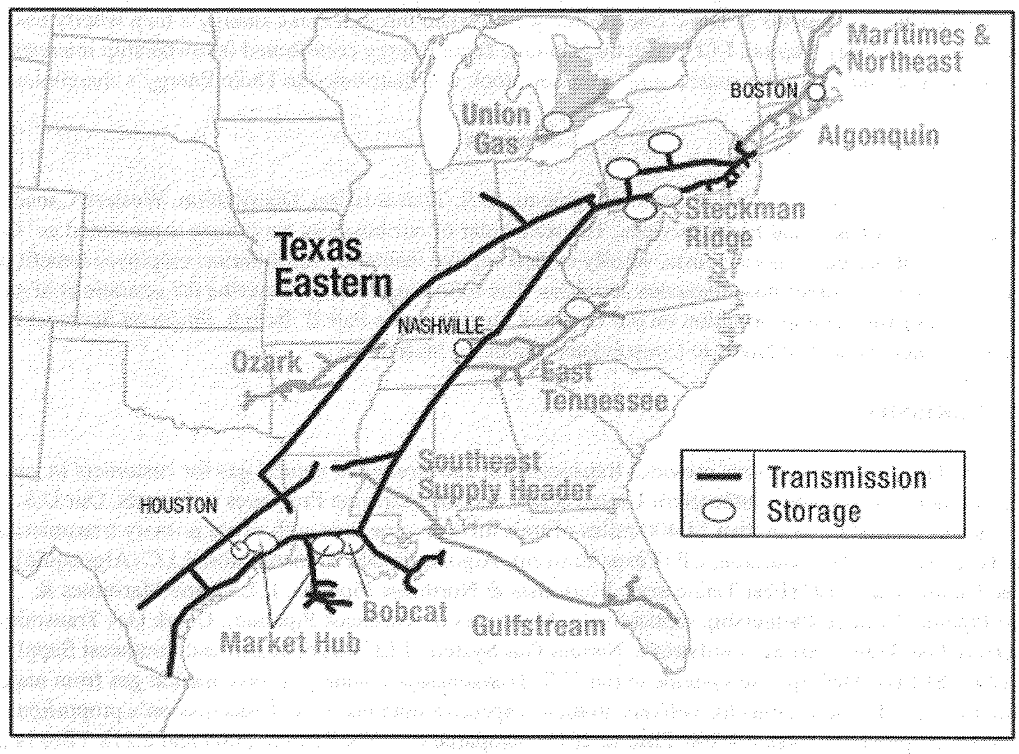
U.S. Transmission provides storage services through Saltville Gas Storage Company L.L.C. (Saltville), Market Hub Partners Holding's (Market Hub's) Moss Bluff and Egan storage facilities, Steckman Ridge, LP (Steckman Ridge), Bobcat Gas Storage (Bobcat) and Texas Eastern's facilities. Gathering services 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 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 the dropdown of Saltville and the P-25 pipeline assets into Spectra Energy Partners in 2008, the acquisition of NOARK Pipeline System, Limited Partnership (NOARK) in 2009 and an additional dropdown of ownership interests in Gulfstream in 2010, we currently retain a 69% 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 49% of Gulfstream. Spectra Energy directly owns a 50% interest in Market Hub and a 1% interest in Gulfstream. Spectra Energy Partners is a separate, publicly traded entity which trades on the New York Stock Exchange under the symbol "SEP."

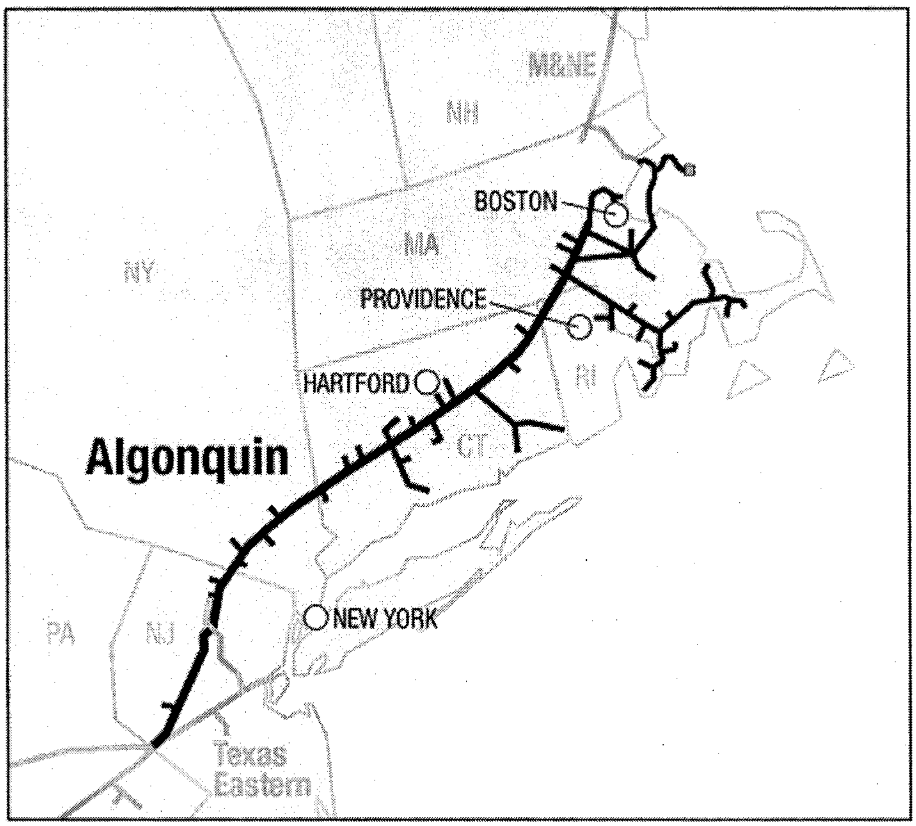
Texas Eastern



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 storage facilities in Pennsylvania held through joint ventures and one wholly owned and operated storage facility in Maryland. Texas Eastern's total working capacity in these three facilities is 74 Bcf. In addition, Texas Eastern's system is connected to Steckman Ridge, a 12 Bcf storage facility in Pennsylvania owned by our joint venture with New Jersey Resources (NJR), and three storage facilities in Texas and Louisiana, aggregating 63 Bcf, owned by Market Hub Partners and Bobcat Gas Storage.

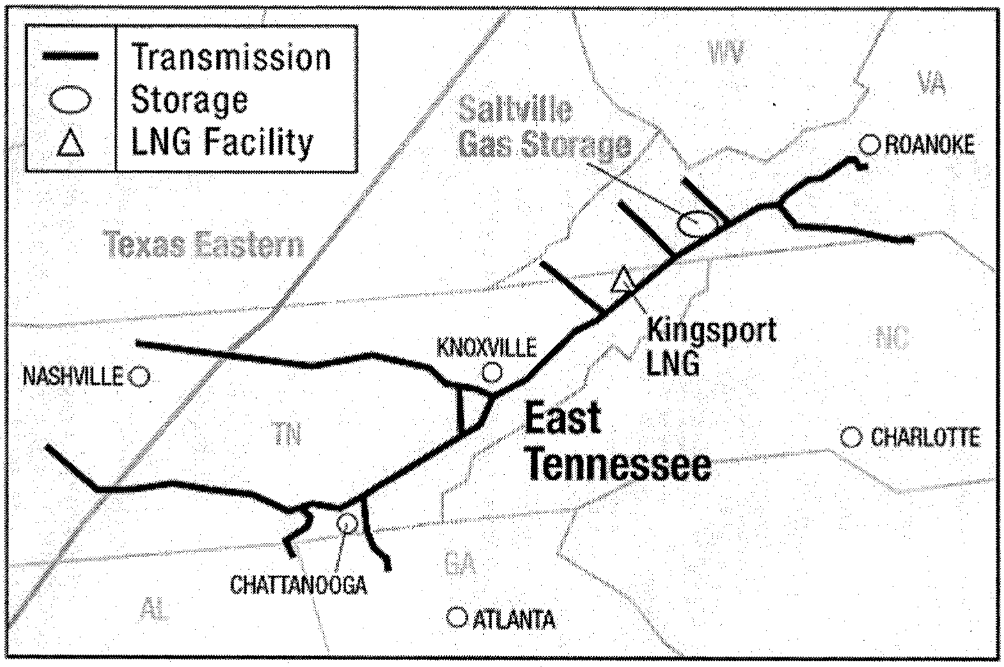
New Jersey-New York Expansion. This expansion of the Texas Eastern pipeline system is designed to transport new, critically needed natural gas supplies to high-demand markets in northern New Jersey and New York City. With a capacity of 800 million cubic-feet-per-day (Mmcf/d) of natural gas, the project is fully subscribed with commitments for firm transportation service. In December 2010, we filed an application with the FERC for this expansion project. Substantial design, environmental and related work will be ongoing throughout 2011. As discussed under Item 1A. Risk Factors, risks associated with any capital expansion program include regulatory, development, operational and market risks. The $850 million project is expected to be in service in November 2013 and should help to eliminate existing bottlenecks in the region's interstate transmission pipeline grid.

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 1,125 miles of pipeline with seven compressor stations.

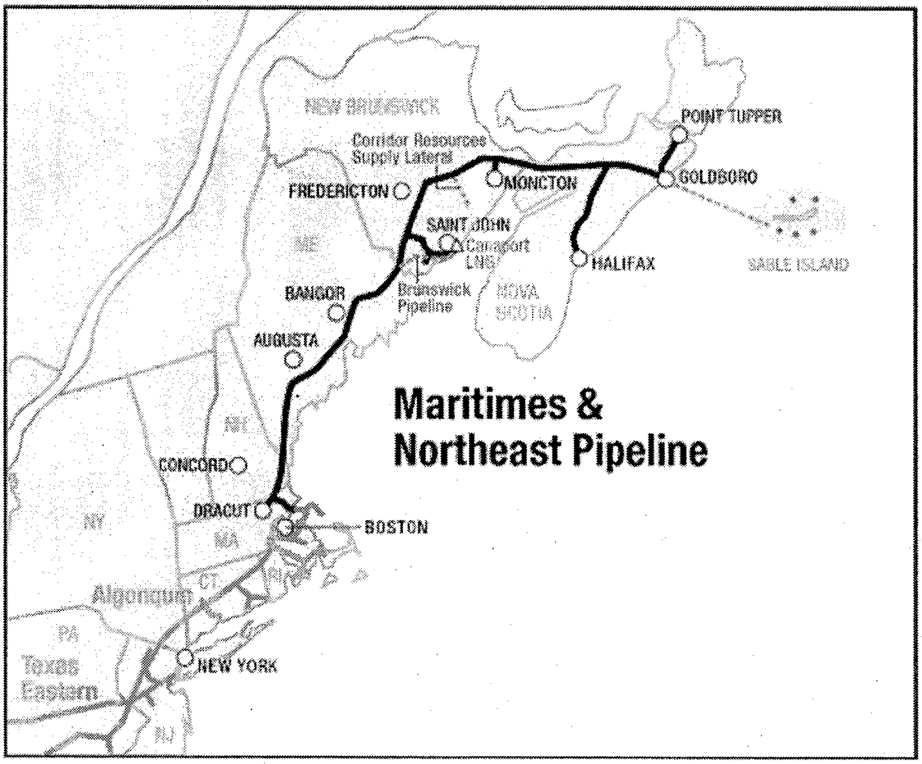
East Tennessee



East Tennessee's transmission system crosses Texas Eastern's system at two points in Tennessee and consists of two mainline systems totaling approximately 1,500 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.

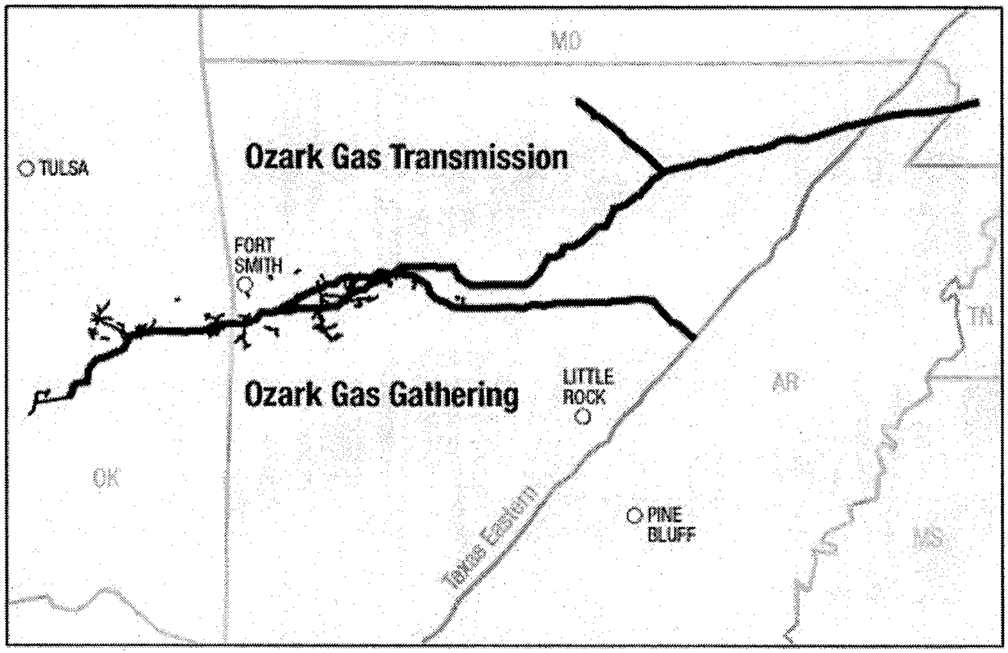
We have an effective 69% ownership interest in East Tennessee through our ownership of Spectra Energy Partners.

Maritimes & Northeast Pipeline



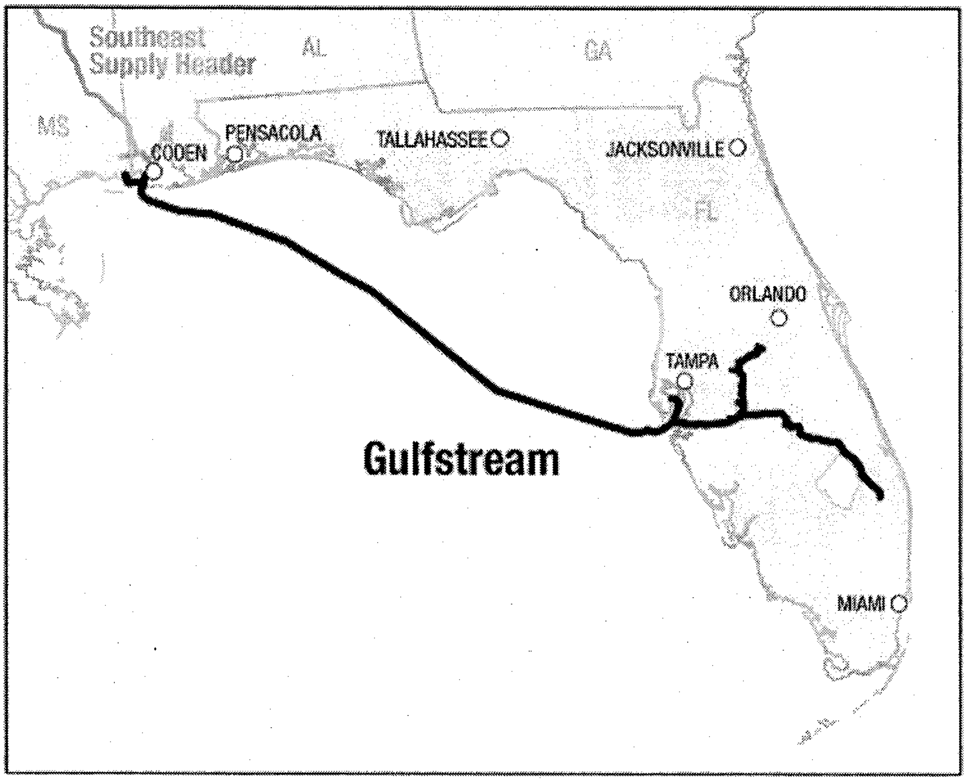
Maritimes & Northeast Pipeline's gas transmission system is operated through Maritimes & Northeast Pipeline Limited Partnership (M&N LP), the Canadian portion of this system, and Maritimes & Northeast Pipeline, L.L.C. (M&N LLC), the U.S. portion. We have 78% ownership interests in both segments of the system and affiliates of Exxon Mobil Corporation and Emera, Inc. have the remaining interests. The Maritimes & Northeast Pipeline transmission system consists of approximately 850 miles of pipeline originating from landfall of the producing fields in Nova Scotia through New Brunswick, Maine, New Hampshire and Massachusetts, connecting to the Algonquin system in Beverly, Massachusetts. There are seven compressor stations on the Maritimes & Northeast Pipeline system.

Ozark



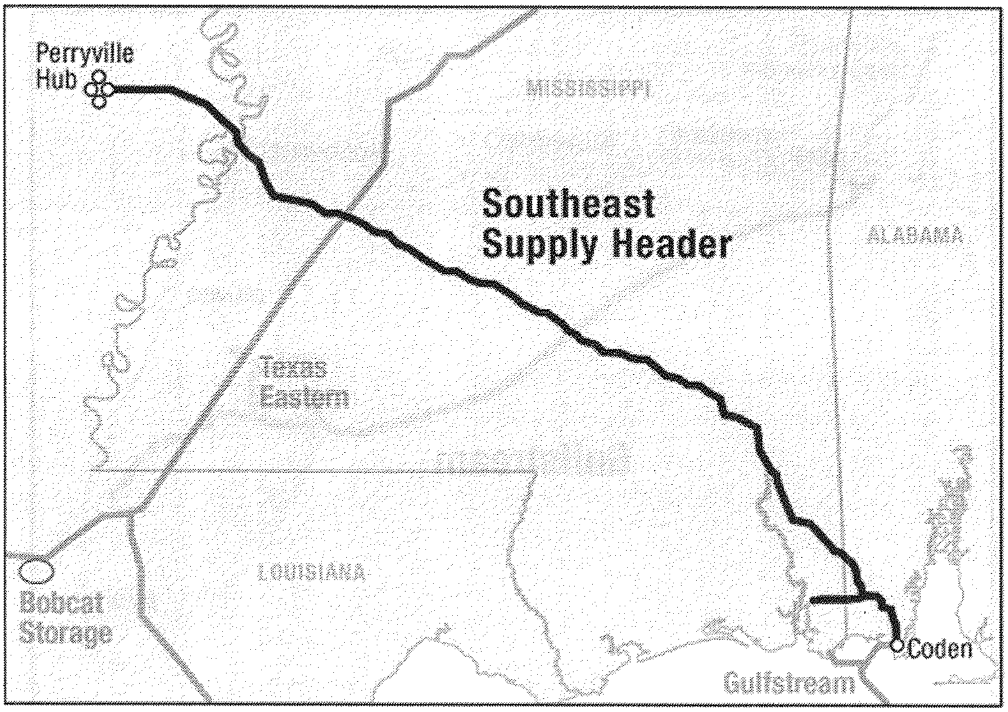
We have an effective 69% ownership interest in Ozark Gas Transmission and Ozark Gas Gathering, which was acquired by Spectra Energy Partners in 2009. Ozark Gas Transmission consists of a 565-mile interstate natural gas pipeline system extending from southeastern Oklahoma through Arkansas to southeastern 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 35% 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 directly owned 1% by Spectra Energy, 49% 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 275-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 85% 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 45 Bcf. The Moss Bluff facility consists of three salt dome storage caverns located in southeast Texas and has access to five pipeline systems including the Texas Eastern system. The Egan facility consists of four salt dome 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% direct interest.

Saltville

We have an effective 69% 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.

Bobcat

We have a 100% ownership interest in Bobcat, an 18 Bcf salt dome facility which was acquired in August 2010. Bobcat is strategically located on the Gulf Coast near Henry Hub and interconnects with five major interstate pipelines, including Texas Eastern. Bobcat's storage capacity is expected to be 46 Bcf by the end of 2016 when fully developed.

Steckman Ridge

We have a 50% investment in Steckman Ridge, a 12 Bcf depleted reservoir storage facility located in south central Pennsylvania that interconnects with the Texas Eastern system. Steckman Ridge, which began operations in April 2009, is operated by us and owned 50% by us and 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.

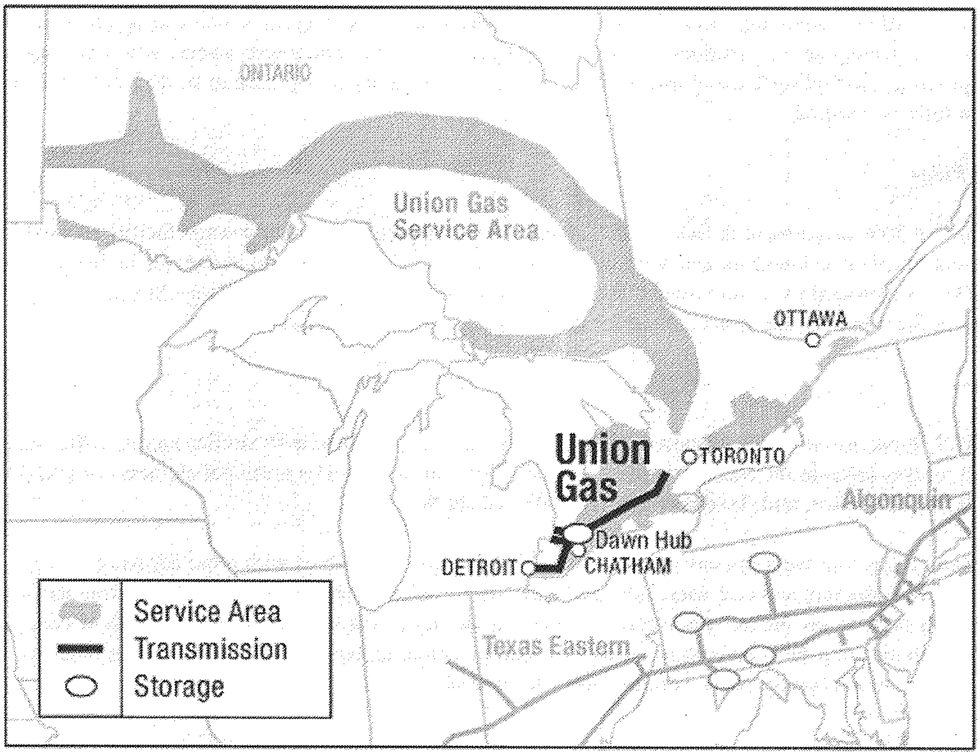
The natural gas that we transport in our transmission business competes with other forms of energy available to our customers and end-users, including electricity, coal, propane and fuel oils. Factors that influence the demand for natural gas include price changes, the availability of natural gas and other forms of energy, levels 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, injected or withdrawn, which is intended 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 is a major Canadian natural gas storage, transmission and distribution company based in Ontario. The distribution business serves approximately 1.3 million residential, commercial and industrial customers in more than 400 communities across northern, southwestern and eastern Ontario. Union Gas' growing storage and transmission business offers services to customers at the Dawn Hub, the largest underground storage facility in Canada and one of the largest in North America. It offers customers an important link in the movement of natural gas from Western Canada and U.S. supply basins to markets in central Canada and the northeast United States.

Union Gas' system consists of approximately 37,600 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 155 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.

Competition

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 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 new expansion 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.

The incentive regulation framework approved by the OEB in 2008 establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts. The allowed return on equity (ROE) for Union Gas is formula-based and is periodically established by the OEB. The established ROE for 2008 will remain unchanged throughout the five-year incentive regulation period (2008-2012). In 2011, Union Gas expects to make an application to the OEB that will result in new rates for 2013 and future periods. This filing will include updated revenue and cost forecasts to reset rates, as well a proposal to increase to the allowed ROE pursuant to the OEB's policy report on the Cost of Capital for Ontario's Regulated Utilities. In addition, the application will include proposals for the next incentive regulation framework.

In 2006, the OEB found that the market for storage services is sufficiently competitive, and therefore decided to deregulate the prices for storage services to customers outside Union Gas' franchise area and the prices for new storage services to customers within its franchise area. This Storage Forbearance Decision created an unregulated storage operation within Union Gas and provides the framework required to support new unregulated storage investments. 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. The Storage Forbearance Decision requires Union Gas to continue to share long-term storage margins with ratepayers over a four-year phase-out period that started in 2008. Effective in 2011, there will no longer be any sharing of margins with Union Gas customers on long-term storage transactions.

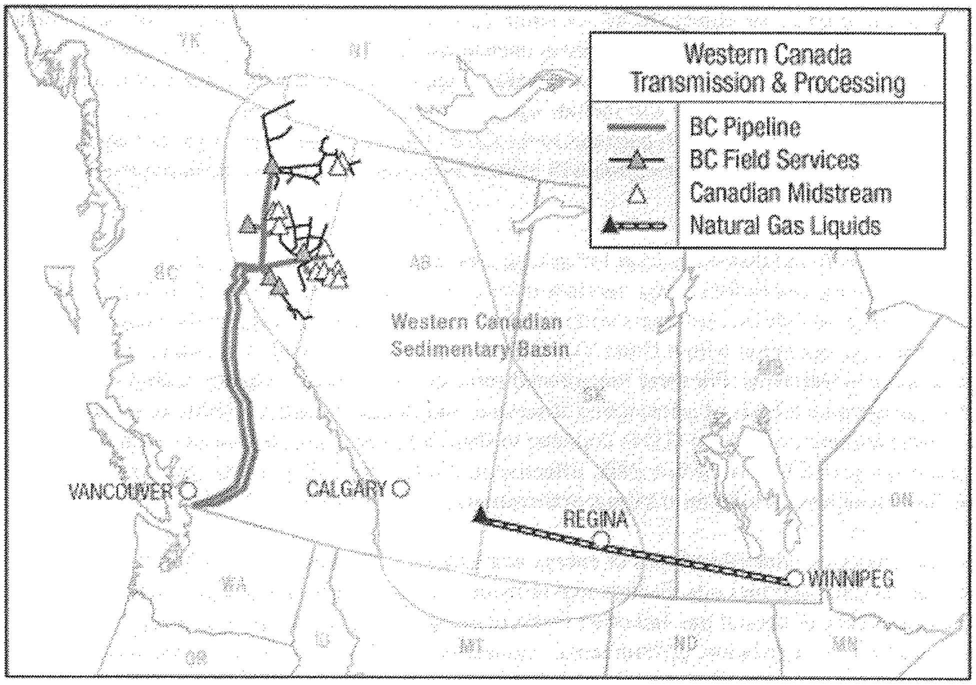
Union Gas competes with other forms of energy available to its customers and end-users, including electricity, coal, propane and fuel oils. Factors that influence the demand for natural gas include weather, price changes, the availability of natural gas and other forms of energy, levels of business activity,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

Customers and Contracts

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 either the source of customers' gas supply or its price.

Union Gas provides its in-franchise customers with regulated distribution, transmission and storage services. Union Gas also provides unregulated natural gas storage and regulated 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 approximately 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 fee-based 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 1,725 miles of transmission pipeline in BC and Alberta, as well as 18 mainline compressor stations. Throughput for the BC Pipeline totaled 627 TBtu in 2010, compared to 604 TBtu in 2009 and 615 TBtu in 2008.

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 1,550 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 650 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 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 business. The Empress extraction and fractionation plant is located in Empress, Alberta.

Fort Nelson Expansion. In 2009, firm contracts for approximately 800 Mmcf/d were signed for incremental gathering and processing service in the Fort Nelson area of northeastern British Columbia. The Fort Nelson expansion program consists of a series of 10 discrete gathering and processing projects, with a total projected capital expenditure of approximately $1 billion. Nine of the ten projects were placed in service in 2009 and 2010. The new 250 Mmcf/d Fort Nelson North processing facility, which is the final phase and most significant capital outlay of the program, is under construction and is expected to be brought in-service in 2012. Upon completion, we will operate over 1.2 Bcf/d of raw gas processing capacity and associated gathering pipelines in the Fort Nelson area.

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, levels 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 Western Canada Transmission & Processing serves.

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. Declines in eastbound flows of natural gas through Empress, Alberta caused an increase in 2010 in the premiums that we paid to shippers to extract NGLs.

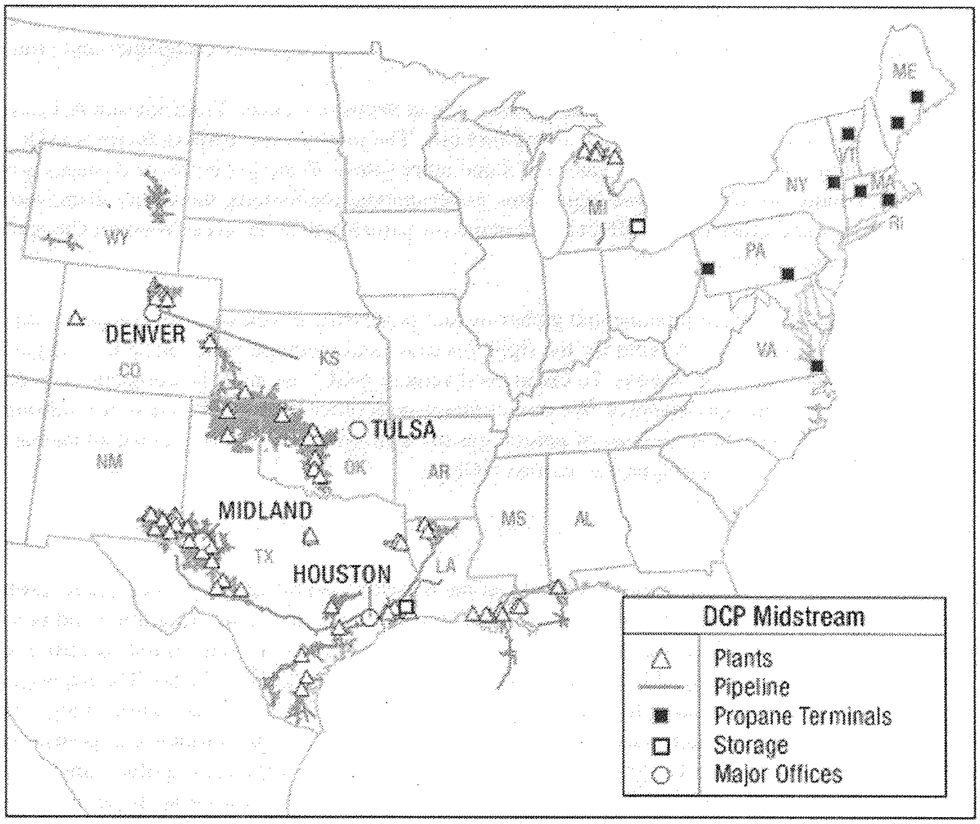
Customers & Contracts

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 is jointly owned with a partner and has capacity to produce approximately 63,000 barrels of NGLs per day (our share is approximately 58,000 barrels per day at full capacity). 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 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 owns a 30% interest in DCP Midstream Partners, LP (DCP Partners), a master limited partnership. As its general partner, DCP Midstream accounts for its investment in DCP Partners as a consolidated subsidiary.

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 61,000 miles of gathering and transmission pipeline, with approximately 37,000 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 61 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 in the Northeastern U.S. which includes nine propane terminals.

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 9 Bcf Spindletop natural gas storage facility located near Beaumont, 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 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, natural gas and crude oil prices, which have fluctuated significantly over the last few years. DCP Midstream closely monitors the risks associated with these price changes. See Part II. 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 mostly 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 mostly upon reliability, services offered and the prices 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 2010, sales to ConocoPhillips and Chevron Phillips Chemical Company LLC, combined, represented approximately 22% 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. More than 70% of volumes of gas that are gathered and processed 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 prices of natural gas, crude oil and NGLs.
- *Fee-based arrangements.* DCP Midstream receives a fee 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 the 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. Our Canadian operations are governed by the NEB, the Technical Standards and Safety Authority and various other federal and local agencies 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 our Canadian Midstream operations for gathering and processing services in western Canada are regulated on a complaints-basis by applicable provincial regulators. Our 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, like ourselves, 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. The OPA imposes certain spill prevention, control and countermeasure requirements. Although we are primarily a natural gas business, the 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 effects of proposed projects are 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 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 this 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 Part II. Item 8. Financial Statements and Supplementary Data, Notes 6 and 19 of Notes to Consolidated Financial Statements.

Except to the extent discussed in Notes 6 and 19, 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 Part II. 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 5 and 18 of Notes to Consolidated Financial Statements.

Employees

We had approximately 5,500 employees as of December 31, 2010, including approximately 3,500 employees outside of the United States, all in Canada. In addition, DCP Midstream employed approximately 2,800 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 60% of those employees are covered under agreements that either have expired or will expire by December 31, 2011.

Executive and Other Officers

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

Name	Age	Position
Gregory L. Ebel	46	President and Chief Executive Officer, Director
J. Patrick Reddy	58	Chief Financial Officer
Dorothy M. Ables	53	Chief Administrative Officer
John R. Arensdorf	60	Chief Communications Officer
Alan N. Harris	57	Chief Development and Operations Officer
Reginald D. Hedgebeth	43	General Counsel
Steve W. Baker	47	Vice President and Treasurer
Sabra L. Harrington	48	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. 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 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.

Steve W. Baker assumed his current position as Vice-President and Treasurer in April 2010. He previously served as Vice-President, Business Development Storage and Transmission at Union Gas from September 2007 to March 2010 and Vice-President, Business Development and Commercial Accounts at Union Gas from January 2004 to August 2007.

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 material 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, such as 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 our Canadian operations. An average 10% devaluation in the Canadian dollar exchange rate during 2010 would have resulted in an estimated net loss on the translation of local currency earnings of approximately $48 million on our Consolidated Statement of Operations. In addition, if a 10% devaluation had occurred on December 31, 2010, the Consolidated Balance Sheet would have been negatively impacted by $595 million through a cumulative translation adjustment in Accumulated Other Comprehensive Income (AOCI). At December 31, 2010, one U.S. dollar translated into one Canadian dollar.

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 flows 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 exposed to market price fluctuations of NGLs, natural gas and oil primarily in our Field Services segment. Based on a sensitivity analysis as of December 31, 2010, a 10¢ per-gallon move in NGL prices would affect our annual pre-tax earnings by approximately $65 million in 2011, primarily from Field Services. For the same period, a 50¢ per-million-British-thermal-units (MMbtu) move in natural gas prices would affect our annual pre-tax earnings by approximately $15 million and a $10 per-barrel move in oil prices would affect our annual pre-tax earnings by approximately $25 million.

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 effects 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 United States 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 may 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 cost. As a result, new facilities may not achieve their expected investment return, which could adversely affect our earnings, financial position and 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, 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 pipeline safety laws and regulations, compliance with which can require significant capital expenditures, can increase our cost of operations and may affect or limit our business plans.

Our interstate pipeline operations are subject to pipeline safety regulation administered by the Pipeline and Hazardous Materials Safety Administration (the PHMSA) of the U.S. Department of Transportation. These laws and regulations require us to comply with a significant set of requirements for the design, construction, maintenance and operation of our interstate pipelines. These regulations, among other things, include requirements to monitor and maintain the integrity of our pipelines. The regulations determine the pressures at which our pipelines can operate. Pipeline failures or failure to comply with applicable regulations could result in reduction of allowable operating pressures as authorized by the PHMSA, which would reduce available capacity on our pipelines. Should any of these risks materialize, it could have a material adverse effect on our operations, earnings, financial condition and cash flows.

We are subject to numerous environmental laws and regulations, compliance with which can require significant capital expenditures, 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 operations 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 may be incurred to comply with environmental regulations in the future will not have a material adverse effect on our earnings and cash flows.

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 Cancun, Mexico in December 2010 with the intent of defining a future agreement for 2012 and beyond. While the talks resulted in a limited 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 future 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 some of our assets and operations in the United States could be affected either directly or indirectly 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. 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 finalized a 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. Regulation is scheduled to begin in 2011, and over time, certain existing Spectra Energy U.S. facilities will be subject to this regulation. Some new construction and modification projects in the future may be subject to this regulation as well. At this time, it is not anticipated that the costs will be material; however, many implementation details are still unknown. There may be additional permitting requirements which may result in delays in completing capital projects. In addition, several legislative proposals that would impose GHG emissions constraints have been considered by the U.S. Congress. To date, no such legislation has been enacted into law.

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 or regulation 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 earnings, 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 earnings and cash flows.

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 flows or restrict business. 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 our credit facilities, borrowing costs could be significantly higher.

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 renewals of long-term transportation agreements, which could expose our transportation volumes and revenues to increased volatility.

We may be unable to secure renewals of long-term transportation agreements in the future for our natural gas transmission business as a result of economic factors, lack of commercial gas supply available to our systems, changing gas supply flow patterns in North America, 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 90% of our credit exposures for transportation, storage, and gathering and processing services are with customers who have an investment-grade rating (or the equivalent based on our evaluation) or are secured by collateral. 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 as contracts renew.

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-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, including cyber-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 business and cash flows.

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, 2010, 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 15 of Notes to Consolidated Financial Statements, none of our properties were secured by mortgages or other material security interests at December 31, 2010.

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.

We have no material pending legal proceedings that are required to be disclosed hereunder. See Note 19 of Notes to Consolidated Financial Statements for discussions of other legal proceedings.

Item 4. [Removed and Reserved]

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 January 31, 2011, there were approximately 141,000 holders of record of our common stock and approximately 450,000 beneficial owners.

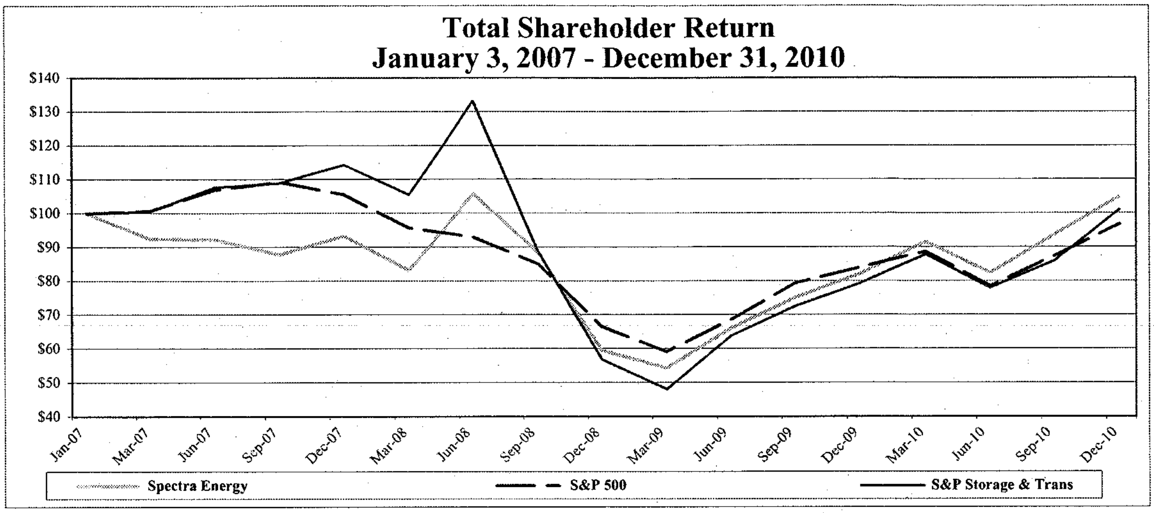
Common Stock Data by Quarter

	Dividends Per Common Share	Stock Price Range (a)	
2010		**High**	**Low**
First Quarter	$0.25	$23.06	$20.30
Second Quarter	0.25	23.85	18.57
Third Quarter	0.25	22.81	19.67
Fourth Quarter	0.25	25.45	22.37
2009			
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

(a) Stock prices represent the intra-day high and low 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, 2010 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, 2007	December 31, 2007	2008	2009	2010
Spectra Energy Corp	$100.00	$ 93.47	$59.54	$82.34	$104.95
S&P 500 Stock Index	100.00	105.60	66.53	84.14	96.81
S&P 500 Storage & Transportation Index	100.00	114.30	56.81	79.38	101.13

Dividends

We currently anticipate an average dividend payout ratio over time of approximately 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 2006 is that of Spectra Capital. This information is not necessarily indicative of future performance or what our results of operations and financial position would have been if we had operated as a separate, stand-alone entity in 2006.

We have identified certain immaterial errors in our previously issued financial statements. The following selected financial data reflect the corrections of those errors. See Item 8. Financial Statements and Supplementary Data, Note 2 of Notes to Consolidated Financial Statements for further discussion.

	2010	2009(a)	2008(a)	2007(b)	2006(b,c)
			(Unaudited)		
	(dollars in millions, except per-share amounts)				
Statements of Operations					
Operating revenues	$4,945	$4,552	$5,074	$4,704	$4,501
Operating income	1,674	1,475	1,480	1,426	1,234
Income from continuing operations	1,123	919	1,195	990	917
Net income—noncontrolling interests	80	75	65	70	61
Net income—controlling interests	1,049	849	1,132	945	1,189
Ratio of Earnings to Fixed Charges	3.1	2.8	3.6	3.1	3.0
Common Stock Data					
Earnings per share from continuing operations					
Basic	$ 1.61	$ 1.31	$ 1.82	$ 1.47	n/a
Diluted	1.60	1.31	1.81	1.46	n/a
Earnings per share					
Basic	1.62	1.32	1.82	1.49	n/a
Diluted	1.61	1.32	1.81	1.49	n/a
Dividends per share	1.00	1.00	0.96	0.88	n/a

	December 31,				
	2010	2009(d)	2008	2007	2006
	(in millions)				
Balance Sheets					
Total assets	$26,686	$24,091	$21,924	$22,970	$20,345
Long-term debt including capital leases, less current maturities	10,169	8,947	8,290	8,345	7,726

(a) See Note 2 of Notes to Consolidated Financial Statements for amounts previously reported.

(b) Amounts previously reported: Income from Continuing Operations—$1,002 million (2007) and $972 million (2006); Net Income—Controlling Interests—$957 million (2007) and $1,244 million (2006); Earnings Per Share From Continuing Operations—Basic and Diluted—$1.48 (2007); Earnings Per Share—Basic and Diluted—$1.51 (2007).

(c) 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 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.

(d) Total Assets previously reported as $24,079 million as of December 31, 2009.

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.

During 2010, we identified certain immaterial errors in our previously issued financial statements related primarily to the impacts of enacted Canadian federal and provincial tax rate changes on deferred income tax balances associated with our Canadian operations. The following discussions reflect the correction of these immaterial errors. See Note 2 of Notes to Consolidated Financial Statements for further discussion.

EXECUTIVE OVERVIEW

Throughout 2010, we continued to successfully execute on the long-term strategies and objectives we have 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 2010 that support substantial continued growth of our market positions.

We also advanced our position as an advisor and partner of choice by continuing to build productive relationships with stakeholders that enable us to successfully permit projects and achieve sector-leading ratings on both the Dow Jones Sustainability Index and the Carbon Disclosure Project. Our "advisor of choice" efforts focused on ensuring stable regulatory environments where we operate, advocating the benefits of natural gas and engaging our employees in reaching out to their elected officials on issues important to us and the natural gas industry. In 2010, we saw noteworthy improvements in our safety metrics related to our high-performance culture objective, with employee recordable incidents down significantly.

During 2010, our fee-based businesses at U.S. Transmission, Distribution and Western Canada Transmission & Processing performed well by meeting the needs of our customers and generating increased earnings and cash flows from successful expansion projects placed in service. In addition, commodity prices at Field Services and a strengthened Canadian dollar improved significantly compared to 2009 and positively affected our earnings in 2010. We reported net income from controlling interests of $1,049 million, and $1.61 of diluted earnings per share for 2010 compared to net income from controlling interests of $849 million, and $1.32 of diluted earnings per share for 2009.

We invested $1.4 billion of capital and investment expenditures in 2010, including approximately $700 million of expansion capital expenditures. This does not include the $540 million acquisition of the Bobcat assets and development project. We successfully completed our 2010 expansion plans, with returns on these projects well 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 2011 through 2015, with approximately $1.4 billion planned for 2011, 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.

Financing activities in 2010 and the capital growth projected in 2011 through 2015 are based on continued strong fee-based earnings and cash flows, as well as continued prudent financial management of our capitalization structure. We are committed to an investment grade balance sheet. Debt, including short-term borrowings and commercial paper, increased $1.4 billion in 2010. However, at December 31, 2010, our debt-to-capitalization ratio remained at 56%. Total capitalization benefited from earnings, a strengthening Canadian dollar and the issuance of additional public units of Spectra Energy Partners in 2010.

As of December 31, 2010, we continue to have ongoing access to approximately $1.6 billion available under our credit facilities and expect to continue to utilize commercial paper and revolving lines of credit, as needed, to complement our ongoing cash flows to fund liquidity needs throughout 2011. Financing activities in 2011 will include the refinancing of debt maturities of approximately $300 million and the issuance of commercial paper under our revolving credit facilities. We also anticipate accessing the markets for other long-term financing to fund our ongoing capital expansion program.

In the fourth quarter of 2010, Spectra Energy Partners acquired an additional 24.5% interest in Gulfstream from Spectra Energy (the Gulfstream acquisition) for approximately $330 million. Also in the fourth quarter of 2010, Spectra Energy Partners issued 6.9 million common units to the public and 0.1 million general partner units to Spectra Energy, netting us proceeds from the issuances of $216 million. Total Stockholders' Equity, including Noncontrolling Interests, increased $180 million as a result of these transactions. See Note 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 2010 strategies:

- Deliver on 2011 financial commitments.
- Develop new opportunities and projects that add long-term shareholder value and meet customers' needs.
- Effectively execute on our 2011 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.

2010 Financial Results. We reported net income from controlling interests of $1,049 million in 2010 compared to net income from controlling interests of $849 million in 2009. The increase in net income from controlling interests mainly reflects the positive impact of NGL prices on earnings from Field Services, a stronger Canadian dollar and expansion projects at U.S. Transmission and Western Canada Transmission & Processing. NGL prices are correlated to higher crude oil prices, which averaged $80 per barrel for 2010 versus $62 per barrel in 2009. These increases in earnings were 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.

Highlights for 2010 include the following:

- U.S. Transmission's earnings benefited from successful execution of planned expansion projects as well as the Bobcat acquisition, partially offset by higher operating costs as a result of a reimbursement of project development costs and the capitalization of previously expensed development costs in 2009,
- Distribution's earnings increased mainly as a result of a stronger Canadian dollar, and lower operating fuel costs, partially offset by lower customer usage of natural gas due to warmer weather in the first half of 2010 and higher employee benefit costs,
- Western Canada Transmission & Processing earnings increased mainly as a result of higher gathering and processing earnings from expansions and a stronger Canadian dollar, partially offset by higher operating and maintenance costs due partly to plant maintenance turnarounds in 2010, and

- Field Services earnings benefited from higher commodity prices, partially offset by a gain recognized in 2009 associated with partnership units issued by DCP Partners and lower gathering and processing margins resulting from lower volumes and efficiencies in 2010.

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 Transmission & Processing 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. 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 2010, 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. 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 2011. 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 19% that is driven by lower statutory rates and recognition of certain regulatory tax benefits.

Our strategic objectives include a critical focus on capital expansion projects that will require access to capital markets. 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

	2010	2009	2008
		(in millions)	
Operating revenues	$4,945	$4,552	$5,074
Operating expenses	3,281	3,088	3,636
Gains on sales of other assets and other, net	10	11	42
Operating income	1,674	1,475	1,480
Other income and expenses	462	406	844
Interest expense	630	610	636
Earnings from continuing operations before income taxes	1,506	1,271	1,688
Income tax expense from continuing operations	383	352	493
Income from continuing operations	1,123	919	1,195
Income from discontinued operations, net of tax	6	5	2
Net income	1,129	924	1,197
Net income—noncontrolling interests	80	75	65
Net income—controlling interests	$1,049	$ 849	$1,132

2010 Compared to 2009

Operating Revenues. The $393 million, or 9%, increase was driven mainly by:

- the effects of a stronger Canadian dollar on revenues at Western Canada Transmission & Processing and Distribution,
- higher earnings from acquisitions and expansion projects at U.S. Transmission and Western Canada Transmission & Processing, and
- higher NGL revenues due to higher product prices, net of lower sales volumes, from the Empress operations at Western Canada Transmission & Processing, partially offset by
- lower natural gas prices passed through to customers at Distribution.

Operating Expenses. The $193 million, or 6%, increase was driven mainly by:

- the effects of a stronger Canadian dollar at Western Canada Transmission & Processing and Distribution,
- a reimbursement of project development costs by customers and the capitalization of previously expensed costs on northeast expansions in 2009 and higher operating costs at U.S. Transmission in 2010,

- higher prices of natural gas purchased, net of lower production volumes, at the Empress operations and higher facilities maintenance costs related to an increase in scheduled plant turnarounds at Western Canada Transmission & Processing, and
- lower net corporate costs mainly due to a benefit related to an early termination notice made by Westcoast Energy Inc. (Westcoast) for capacity contracts held on the Alliance pipeline in 2010, partially offset by
- lower natural gas prices passed through to customers and lower operating fuel costs at Distribution.

Operating Income. The $199 million increase was mainly driven by a stronger Canadian dollar, earnings from expansion projects at U.S. Transmission and Western Canada Transmission & Processing, lower operating fuel costs at Distribution and lower net corporate costs, partially offset by a reimbursement of project development costs by customers and the capitalization of previously expensed costs in 2009 at U.S. Transmission.

Other Income and Expenses. The $56 million increase was attributable to higher equity earnings from Field Services primarily due to increased commodity prices, substantially offset by a $135 million gain recognized in 2009 associated with partnership units previously issued by DCP Partners compared to a gain of $30 million in 2010.

Interest Expense. The $20 million increase was mainly due to a stronger Canadian dollar, mostly offset by lower average rates and balances.

Income Tax Expense from Continuing Operations. The $31 million increase was a result of higher earnings from continuing operations in 2010, partially offset by favorable tax settlements in 2010. The effective tax rate for income from continuing operations was 25% in 2010 compared to 28% in 2009. The lower effective tax rate in 2010 was primarily due to favorable tax settlements, including an administrative change by the Canadian federal government that resulted in cash tax refunds from historical tax years and a reduction to the deferred tax liability.

Income from Discontinued Operations, Net of Tax. The $1 million increase was due to an immaterial positive income tax adjustment in 2010 related to previously discontinued operations, mostly offset by payments by us in 2010 to an affiliate of DCP Midstream to reimburse them for damages resulting from an alleged breach by a third party of certain scheduled propane deliveries to us under the terms of a settlement agreement related to prior LNG operations.

Net Income—Noncontrolling Interests. The $5 million increase was driven by an increase in the noncontrolling interests ownership percentage due to the Spectra Energy Partners public sale of additional partner units in the second quarter of 2009 and higher earnings from Spectra Energy Partners mainly as a result of the dropdown of an additional 24.5% of Gulfstream in December 2010, partially offset by lower earnings from M&N LP and M&N LLC.

For a more detailed discussion of earnings drivers, see the segment discussions that follow.

2009 Compared to 2008

Operating Revenues. The $522 million, or 10%, decrease was driven mainly 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.

Operating Expenses. The $548 million, or 15%, decrease was driven mainly by:

- lower prices and volumes of natural gas purchased for the Empress facility at Western Canada Transmission & Processing,
- the effects of a weaker Canadian dollar at Western Canada Transmission & Processing and Distribution,
- lower natural gas prices passed through to customers without a mark-up at Distribution, and
- lower project development costs at U.S. Transmission.

Gain on Sales of Other Assets and Other, net. The $31 million decrease was primarily due to a 2008 customer bankruptcy settlement at U.S. Transmission.

Operating Income. The $5 million decrease was mainly due to lower NGL margins associated with the Empress operations at Western Canada Transmission & Processing, a weaker Canadian dollar and a 2008 customer bankruptcy settlement at U.S. Transmission, mostly offset by higher earnings from expansion projects placed into service late in 2008 and in 2009, and lower project development costs at U.S. Transmission.

Other Income and Expenses. The $438 million decrease was attributable to lower equity in earnings from Field Services, primarily reflecting lower commodity prices in 2009 compared to 2008, partially offset by a gain recognized in the first quarter of 2009 associated with partnership units previously issued by DCP Partners.

Interest Expense. The $26 million decrease reflects mainly the recognition of gains from the termination of fair value hedges, the effects of a weaker Canadian dollar, and lower balances and rates on commercial paper, partially offset by higher debt balances.

Income Tax Expense from Continuing Operations. The $141 million decrease was a result of lower earnings from continuing operations in 2009. The effective tax rate for income from continuing operations was 28% compared to 29% in 2008. The lower effective tax rate for 2009 was mainly due to proportionally higher income generated from our Canadian operations, which are subject to lower tax rates compared to our U.S. operations, and favorable tax settlements in 2009.

Net Income—Noncontrolling Interests. The $10 million increase was driven by an increase in the noncontrolling interests ownership percentage due to the Spectra Energy Partners public sale of additional partner units in the second quarter of 2009 and higher earnings from Spectra Energy Partners and M&N LLC.

For a more detailed discussion of earnings drivers, see the segment discussions that follow.

Segment Results

We evaluate segment performance based on earnings before interest and taxes (EBIT) from continuing operations less noncontrolling interests related to those earnings. On a segment basis, EBIT represents earnings from continuing operations (both operating and non-operating) before interest and taxes, net of noncontrolling interests related to those earnings. Cash, cash equivalents and investments are managed centrally, so the gains and losses on foreign currency remeasurement, and interest and dividend income on those balances, are excluded from the segments' EBIT. We consider segment EBIT to be a good indicator of each segment's operating performance from its continuing operations, as it represents the results of our ownership interest in operations without regard to financing methods or capital structures.

U.S. Transmission 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.

Distribution provides retail natural gas distribution service in Ontario, Canada, as well as natural gas transportation and storage services to other utilities and energy market participants.

Western Canada Transmission & Processing provides transportation of natural gas, natural gas gathering and processing services, and NGL extraction, fractionation, transportation, storage and marketing to customers in western Canada and the northern tier of the United States.

Field Services gathers and processes natural gas and fractionates, markets and trades NGLs. It conducts operations through DCP Midstream, which is owned 50% by us and 50% by ConocoPhillips. Field Services 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.

Our segment EBIT may not be comparable to similarly titled measures of other companies because other companies may not calculate EBIT in the same manner. Segment EBIT is summarized in the following table and detailed discussions follow:

EBIT by Business Segment

	2010	2009	2008
		(in millions)	
U.S. Transmission	$ 948	$ 894	$ 844
Distribution	409	336	353
Western Canada Transmission & Processing	409	343	398
Field Services	335	296	716
Total reportable segment EBIT	2,101	1,869	2,311
Other	(38)	(74)	(78)
Total reportable segment and other EBIT	2,063	1,795	2,233
Interest expense	630	610	636
Interest income and other (a)	73	86	91
Earnings from continuing operations before income taxes	$1,506	$1,271	$1,688

(a) Includes foreign currency transaction gains and losses and the add-back of noncontrolling interests related to segment EBIT.

Noncontrolling interests as presented in the following segment-level discussions includes only noncontrolling interests related to EBIT of non-wholly owned subsidiaries. It does not include noncontrolling interests related to interest and taxes of those operations. The amounts discussed below include intercompany transactions that are eliminated in the Consolidated Financial Statements.

U.S. Transmission

	2010	2009	Increase (Decrease)	2008	Increase (Decrease)
		(in millions, except where noted)			
Operating revenues	$1,821	$1,690	$131	$1,600	$ 90
Operating expenses					
Operating, maintenance and other	671	577	94	595	(18)
Depreciation and amortization	258	246	12	232	14
Gains on sales of other assets and other, net	11	11	—	42	(31)
Operating income	903	878	25	815	63
Other income and expenses	126	91	35	86	5
Noncontrolling interests	81	75	6	57	18
EBIT	$ 948	$ 894	$ 54	$ 844	$ 50
Proportional throughput, TBtu (a)	2,708	2,574	134	2,218	356

(a) Revenues are not significantly affected by pipeline throughput fluctuations, since revenues are primarily composed of demand charges.

2010 Compared to 2009

Operating Revenues. The $131 million increase was driven by:

- an $86 million increase from expansion projects and acquisitions of Ozark Gas Gathering and Ozark Gas Transmission (collectively, Ozark) in May 2009 and Bobcat in August 2010,
- a $22 million increase in processing revenues associated with pipeline operations resulting from higher prices, and
- a $19 million increase in recoveries of electric power and other costs passed through to customers.

Operating, Maintenance and Other. The $94 million increase was driven by:

- a $35 million increase in project development costs, mainly resulting from a 2009 reimbursement by customers and the capitalization of previously expensed costs on northeast expansions in 2009,
- a $23 million increase from higher electric power and other costs passed through to customers,
- a $20 million increase from acquisitions and expansion projects, and
- a $16 million increase in benefits, pipeline integrity costs, software costs and other operating costs.

Depreciation and Amortization. The $12 million increase was driven by expansion projects placed in service in 2009 and a stronger Canadian dollar at M&N LP.

Other Income and Expenses. The $35 million increase was mainly a result of an $18 million charge in 2009 due to the discontinuance of rate regulated accounting treatment by SESH, a $13 million increase in the allowance for funds used during construction-equity (AFUDC-equity) in 2010 as a result of higher capital spending, and a $10 million increase in equity earnings from expansion projects on Gulfstream and Steckman Ridge that were placed in service in 2009.

Noncontrolling Interests. The $6 million increase was driven by an increase in the noncontrolling interests ownership percentage due to the Spectra Energy Partners public sale of additional partner units in the second quarter of 2009 and higher earnings from Spectra Energy Partners mainly as a result of the dropdown of an additional 24.5% of Gulfstream in December 2010, partially offset by lower earnings from M&N LP and M&N LLC.

EBIT. The $54 million increase was mainly due to higher earnings from expansion projects, partially offset by higher operating costs as a result of a reimbursement of project development costs by customers and the capitalization of previously expensed costs in 2009 on northeast expansions.

2009 Compared to 2008

Operating Revenues. The $90 million increase was driven mainly by:

- a $136 million increase from expansion projects placed into service late in 2008 and 2009,
- a $43 million increase in transportation and other revenues primarily from Ozark Gas Transmission acquired in May 2009, and
- a $14 million increase mainly in transportation and storage revenues from recoveries of fuel, electric power and other costs passed through to customers, partially offset by
- an $88 million decrease in processing revenues associated with pipeline operations, caused by lower prices and volumes,
- an $11 million decrease resulting from a weaker Canadian dollar at M&N LP, and
- a $9 million decrease in interruptible transportation revenue due to weather and other market conditions.

Operating, Maintenance and Other. The $18 million decrease was driven mainly by:

- an $82 million decrease in project development costs, reflecting a net benefit of $39 million in 2009 mainly due to a reimbursement of project development costs by customers and the capitalization of previously expensed costs on northeast expansions compared to expensed project development costs of $43 million in 2008, partially offset by
- a $17 million increase from expansion projects placed in service late in 2008 and in 2009,
- a $16 million increase from Ozark Gas Transmission,
- a $15 million increase in operating costs, including pipeline integrity costs, equipment repairs and maintenance costs, and software costs, and
- a $13 million increase in operating costs from higher fuel, electric power and other costs passed through to customers.

Depreciation and Amortization. The $14 million increase was primarily driven by expansion projects placed into service late in 2008 and in 2009.

Gains on Sales of Other Assets and Other, net. The $31 million decrease was driven by a customer bankruptcy settlement in June 2008.

Other Income and Expenses. The $5 million increase was mainly a result of an impairment of the Islander East project in 2008 and earnings from expansion projects on Gulfstream and SESH placed into service in late 2008, mostly offset by lower AFUDC—equity associated with construction projects and from the discontinuance of rate regulated accounting treatment by SESH.

Noncontrolling Interests. The $18 million increase was driven by an increase in the noncontrolling interests ownership percentage resulting from the Spectra Energy Partners public sale of additional partner units in the second quarter of 2009 and higher earnings from Spectra Energy Partners and M&N LLC.

EBIT. The $50 million increase was mainly due to higher earnings from expansion projects, lower project development costs in 2009 and an impairment of the Islander East project in 2008. These increases were partially offset by lower processing revenues, increased operating costs and a customer bankruptcy settlement in 2008.

Matters Affecting Future U.S. Transmission Results

U.S. Transmission plans to continue earnings growth through capital efficient projects, such as transportation and storage expansion to support a two-pronged "supply push" / "market pull" strategy, as well as continued focus on optimizing the performance of the existing operations through organizational efficiencies and cost control. "Supply push" is when producers agree to pay to transport specified volumes of natural gas in order to support the construction of new pipelines or the expansion of existing pipelines. "Market pull" is taking gas away from established liquid supply points and building pipeline transportation capacity to satisfy end-user demand in new markets or demand growth in existing markets.

Future earnings growth will be dependent on the success of expansion plans in both the market and supply areas of the pipeline network, which includes, among other things, shale gas exploration and development areas, the ability to continue renewing service contracts and continued regulatory stability. Natural gas storage prices have recently been challenged as a result of increasing natural gas supply and narrower seasonal price spreads. NGL prices will continue to affect processing revenues that are associated with transportation services.

Distribution

	2010	2009	Increase (Decrease)	2008	Increase (Decrease)
		(in millions, except where noted)			
Operating revenues	$1,779	$1,745	$ 34	$1,991	$(246)
Operating expenses					
Natural gas purchased	770	878	(108)	1,094	(216)
Operating, maintenance and other	406	358	48	372	(14)
Depreciation and amortization	194	172	22	175	(3)
Operating income	409	337	72	350	(13)
Other income and expenses	—	(1)	1	3	(4)
EBIT	$ 409	$ 336	$ 73	$ 353	$ (17)
Number of customers, thousands	1,344	1,325	19	1,309	16
Heating degree days, Fahrenheit	6,832	7,435	(603)	7,491	(56)
Pipeline throughput, TBtu	913	809	104	900	(91)
Canadian dollar exchange rate, average	1.03	1.14	(0.11)	1.07	0.07

2010 Compared to 2009

Operating Revenues. The $34 million increase was driven by:

- a $184 million increase resulting from a stronger Canadian dollar,
- an $11 million increase due to a 2009 charge for a settlement on 2008 earnings to be shared with customers,
- a $9 million increase in long-term storage resulting from a lower 2010 approved ratio of earnings to be shared with customers, and
- a $5 million increase due to growth in the number of customers, partially offset by
- a $152 million decrease from lower natural gas prices passed through to customers. Prices charged to customers are based on the 12 month New York Mercantile Exchange (NYMEX) forecast.
- a $14 million decrease in customer usage of natural gas due to weather that was more than 8% warmer than in 2009.

Natural Gas Purchased. The $108 million decrease was driven mainly by:

- a $152 million decrease from lower natural gas prices passed through to customers,
- a $28 million decrease in operating fuel costs, and
- a $2 million decrease due to lower volumes of natural gas sold as a result of weather that was more than 8% warmer than in 2009, partially offset by
- an $87 million increase resulting from a stronger Canadian dollar.

Operating, Maintenance and Other. The $48 million increase was driven mainly by:

- a $38 million increase resulting from a stronger Canadian dollar, and
- a $10 million increase related to higher employee benefits costs primarily associated with higher amortization of pension plan market value losses that have occurred in recent years.

Depreciation and Amortization. The $22 million increase was driven primarily by a stronger Canadian dollar.

EBIT. The $73 million increase was mainly a result of a stronger Canadian dollar, lower operating fuel costs, a 2009 settlement on 2008 earnings sharing and higher storage and transportation revenues, partially offset by a decrease in customer usage of natural gas due to warmer weather in 2010 and higher employee benefits costs.

2009 Compared to 2008

Operating Revenues. The $246 million decrease was driven mainly by:

- a $160 million decrease resulting from a weaker Canadian dollar,
- a $130 million decrease from lower natural gas prices passed through to customers without a mark-up,
- a $69 million decrease in customer usage of natural gas due to the impacts of the economic recession, and
- an $11 million decrease due to a 2009 settlement on 2008 earnings to be shared with customers, partially offset by
- a $56 million increase due to growth in the number of customers,
- a $40 million increase in storage and transportation revenues attributable to expansion of the storage system and an increase in short-term transportation services provided to customers,
- a $15 million increase resulting from a charge in 2008 due to an unfavorable decision from the OEB related to unregulated storage revenues, and
- a $9 million increase due to lower 2009 regulated earnings to be shared with customers.

Natural Gas Purchased. The $216 million decrease was driven mainly by:

- a $130 million decrease from lower natural gas prices passed through to customers without a mark-up,
- a $91 million decrease resulting from a weaker Canadian dollar, and
- a $56 million decrease in customer usage of natural gas due to the impacts of the economic recession, partially offset by
- a $48 million increase due to growth in the number of customers, and
- a $6 million increase in fuel used in operations.

Operating, Maintenance and Other. The $14 million decrease was driven primarily by:

- a $24 million decrease resulting from a weaker Canadian dollar, partially offset by
- a $9 million increase as a result of expansion projects.

Depreciation and Amortization. The $3 million decrease was driven by:

- a $12 million decrease resulting from a weaker Canadian dollar, mostly offset by
- a $9 million increase as a result of expansion projects.

EBIT. The $17 million decrease was mainly a result of a weaker Canadian dollar, lower customer usage and higher expenses related to expansion projects. These decreases were partially offset by higher storage and transportation revenues and growth in the number of customers.

Matters Affecting Future Distribution Results

We expect that the long-term demand for natural gas in North America will continue to grow. However, potential lasting effects of the economic recession could impact retail and industrial gas usage by Union Gas distribution customers in the near term. Distribution's earnings are affected significantly by weather during the winter heating season.

Union Gas expects to make an initial filing in 2011 to begin the OEB review process that will result in new rates for 2013 and possibly future periods. This filing will include updated revenue and cost forecasts, as well as revised assumptions about ROE and the incentive regulation framework.

Future growth prospects for Union Gas include opportunities around unregulated storage operations. Natural gas storage prices have recently been challenged as a result of increasing natural gas supply and narrower seasonal price spreads. These market factors will continue to affect Union Gas' unregulated storage revenues.

From 2002 through 2010, the Canadian dollar has generally strengthened compared to the U.S. dollar, which favorably affected earnings 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 the exchange rate or any other factors are difficult to predict and may affect future results.

Western Canada Transmission & Processing

	2010	2009	Increase (Decrease)	2008	Increase (Decrease)
	(in millions, except where noted)				
Operating revenues	$1,345	$1,115	$ 230	$1,482	$(367)
Operating expenses					
Natural gas and petroleum products purchased	290	222	68	496	(274)
Operating, maintenance and other	486	407	79	445	(38)
Depreciation and amortization	169	144	25	147	(3)
Loss on sales of other assets and other, net	(1)	—	(1)	—	—
Operating income	399	342	57	394	(52)
Other income and expenses	10	1	9	5	(4)
Noncontrolling interests	—	—	—	1	(1)
EBIT	$ 409	$ 343	$ 66	$ 398	$ (55)
Pipeline throughput, TBtu	627	604	23	615	(11)
Volumes processed, TBtu	664	655	9	698	(43)
Empress inlet volumes, TBtu	600	737	(137)	820	(83)
Canadian dollar exchange rate, average	1.03	1.14	(0.11)	1.07	0.07

2010 Compared to 2009

Operating Revenues. The $230 million increase was driven by:

- a $125 million increase as a result of a stronger Canadian dollar,
- a $76 million increase due to higher NGL product prices associated with the Empress operations,
- a $52 million increase resulting from higher gathering and processing revenues due to contracted volumes from expansions associated with non-conventional supply discoveries in the Fort Nelson, South Peace and West Doe areas, and
- a $10 million increase from recovery of carbon and other non-income tax expense from customers, partially offset by
- a $40 million decrease due to lower NGL sales volumes, including lower volumes associated with an approximate 25-day scheduled plant turnaround in 2010 at the Empress operations.

Natural Gas and Petroleum Products Purchased. The $68 million increase was driven by:

- a $65 million increase as a result of higher prices of natural gas purchased for the Empress facility caused primarily by higher extraction premiums, and
- a $26 million increase caused by a stronger Canadian dollar, partially offset by
- a $23 million decrease due primarily to lower production volumes at the Empress operations, including lower volumes associated with the scheduled plant turnaround in 2010.

Operating, Maintenance and Other. The $79 million increase was driven by:

- a $44 million increase caused by a stronger Canadian dollar,
- a $13 million increase relating to an increase in scheduled plant turnarounds at various locations including Empress and Grizzly Valley,
- a $10 million increase in carbon and other non-income tax expense, and
- a $7 million increase in maintenance costs related primarily to new facilities.

Depreciation and Amortization. The $25 million increase was driven mainly by a stronger Canadian dollar, expansion projects placed in service and maintenance capital incurred in 2009 and 2010.

Other Income and Expenses. The $9 million increase was a result of income arising from the replacement of a natural gas purchase contract at the McMahon cogeneration facility and an increase in the equity earnings of this equity investment.

EBIT. The $66 million increase was driven mainly by a stronger Canadian dollar and higher gathering and processing earnings from expansions, partially offset by higher operating and maintenance costs.

2009 Compared to 2008

Operating Revenues. The $367 million decrease was driven mainly by:

- a $263 million decrease due to lower NGL product prices associated with the Empress operations,
- a $101 million decrease due primarily to lower NGL sales volumes related to the Empress operations as a result of reduced natural gas production by producers caused by lower natural gas prices and high royalties, and
- a $71 million decrease as a result of a weaker Canadian dollar, partially offset by

- a $53 million increase resulting primarily from higher gathering and processing revenues due to higher firm contract revenue, and
- a $15 million increase in revenues to recover carbon tax expense from customers.

Natural Gas and Petroleum Products Purchased. The $274 million decrease was driven mainly by:

- a $186 million decrease arising from primarily lower prices of natural gas purchased for the Empress facility,
- a $75 million decrease mainly as a result of lower volumes of natural gas purchased for the Empress facility, and
- a $13 million decrease caused by a weaker Canadian dollar.

Operating, Maintenance and Other. The $38 million decrease was driven mainly by:

- a $32 million decrease caused by a weaker Canadian dollar, and
- a $29 million decrease in plant fuel and electricity costs at the Empress facility, partially offset by
- a $15 million increase in the carbon tax expense, and
- an $8 million increase in maintenance and other project costs.

Depreciation and Amortization. The $3 million decrease was driven primarily by:

- an $8 million decrease resulting from a weaker Canadian dollar, mostly offset by
- a $5 million increase as a result of expansion projects placed into service in 2009.

EBIT. The $55 million decrease was driven mainly by lower NGL gross margins that negatively impacted the Empress operations, as well as a weaker Canadian dollar, partially offset by higher gathering and processing revenues, and lower plant fuel and electricity costs at the Empress facility.

Matters Affecting Future Western Canada Transmission & Processing Results

Western Canada Transmission & Processing plans to continue earnings growth through capital efficient "supply push" projects, primarily associated with gathering and processing expansion to support drilling activity in northern British Columbia. Earnings will also continue to benefit through optimizing the performance of the existing system and through organizational efficiencies. Earnings can fluctuate from period-to-period as a result of the timing of processing plant turnarounds that reduce revenues while a plant is out of service and increase operating costs as a result of the turnaround maintenance work. Western Canada Transmission & Processing's 17 processing plants are generally scheduled for turnaround work every three to four years, with the work being staggered to prevent significant outages at any given time in a single geographic area. Future earnings will also be affected by the ability to renew service contracts and regulatory stability. Earnings from processing services will be affected by the ability to access additional natural gas reserves. In addition, the Empress NGL business will be affected by both gas flows and the effects of natural gas and NGL commodity prices.

From 2002 through 2010, the Canadian dollar has generally strengthened compared to the U.S. dollar, which favorably affected earnings during these periods, except in the fourth quarter 2008 and the first quarter of 2009 when the Canadian dollar weakened significantly in a very short period of time. Changes in the exchange rate or any other factors are difficult to predict and may affect future results.

While current drilling levels are below recent historical averages, the continued strength of land sales and other indicators of development interest specifically relating to shale gas exploration and development in the areas of British Columbia and Alberta that are in close proximity to our facilities support the increase in long-term growth rates that occurred in 2008 and were sustained in 2009 and 2010. It is possible, however, that sustained lower natural gas prices brought about by increasing gas reserves could reduce producer demand for both expansions of the British Colombia gas processing plants as well as renewals of existing gas processing contracts.

Field Services

	2010	2009	Increase (Decrease)	2008	Increase (Decrease)
	(in millions, except where noted)				
Equity in earnings of unconsolidated affiliates	$ 335	$ 296	$ 39	$ 716	$ (420)
EBIT	$ 335	$ 296	$ 39	$ 716	$ (420)
Natural gas gathered and processed/transported, TBtu/d (a,b)	6.9	6.9	—	7.1	(0.2)
NGL production, MBbl/d (a,c)	369	358	11	360	(2)
Average natural gas price per MMBtu (d)	$ 4.39	$ 3.99	$ 0.40	$ 9.03	$ (5.04)
Average NGL price per gallon (e)	$ 0.98	$ 0.71	$ 0.27	$ 1.23	$ (0.52)
Average crude oil price per barrel (f)	$79.53	$61.81	$17.72	$99.67	$(37.86)

(a) Reflects 100% of volumes.
(b) Trillion British thermal units per day.
(c) Thousand barrels per day.
(d) Average price based on NYMEX Henry Hub.
(e) Does not reflect results of commodity hedges.
(f) Average price based on NYMEX calendar month.

2010 Compared to 2009

EBIT. Higher equity earnings of $39 million were mainly the result of the following variances, each representing our 50% ownership portion of the earnings drivers at DCP Midstream:

- a $186 million increase from commodity-sensitive processing arrangements due to increased commodity prices, and
- a $15 million increase in earnings from DCP Partners primarily as a result of lower mark-to-market losses on derivative instruments used to protect distributable cash flows, partially offset by
- a $105 million decrease as a result of a gain of $135 million in 2009 associated with the issuance of partnership units by DCP Partners compared to a gain of $30 million in 2010,
- a $26 million decrease in gathering and processing margins due to lower volumes and efficiencies, largely attributable to the impact of severe weather, curtailments and third party outages in 2010 that affected operations, partially offset by growth,
- a $14 million decrease due to higher income tax expense primarily reflecting the de-recognition of certain deferred tax assets,
- a $12 million decrease due to lower results from NGL trading and gas marketing, and
- a $7 million decrease due to higher operating expenses largely resulting from DCP Partners' acquisitions growth, increased repairs and maintenance costs, the impact of hurricane insurance recoveries in 2009 and increased benefits costs.

2009 Compared to 2008

EBIT. Lower equity in earnings of $420 million were mainly the result of the following variances, each representing our 50% ownership portion of the earnings drivers at DCP Midstream:

- a $492 million decrease from commodity-sensitive processing arrangements, due to decreased commodity prices,
- a $48 million decrease in gathering and processing margins largely attributable to lower volumes resulting primarily from reduced drilling and lower recoveries and efficiencies, partially offset by the impact of hurricanes in 2008,
- a $28 million decrease due to higher net interest expense resulting from increased debt associated with growth, acquisitions and a special distribution paid in 2008, and higher borrowing costs during 2009,
- a $23 million decrease in earnings from DCP Partners primarily as a result of mark-to-market losses on derivative instruments used to protect distributable cash flows, compared to gains in 2008, and
- a $9 million decrease primarily attributable to gains on sales of assets in 2008, partially offset by
- a $135 million gain associated with partnership units previously issued by DCP Partners,
- a $29 million increase in NGL trading and gas marketing, and
- a $17 million increase mainly as a result of lower operating and maintenance expenses due to a cost reduction initiative and the impact of decreased commodity prices in 2009, partially offset by higher depreciation expense as a result of capital spending and acquisitions in 2008 and 2009.

Supplemental Data

Below is supplemental information for DCP Midstream's operating results (presented at 100%):

	2010	2009	2008
		(in millions)	
Operating revenues	$10,981	$8,560	$16,398
Operating expenses	10,138	8,026	14,704
Operating income	843	534	1,694
Other income and expenses	34	24	20
Interest expense, net	253	254	198
Income tax expense (benefit)	5	(2)	(3)
Net income	619	306	1,519
Net income (loss)—noncontrolling interests	27	(16)	88
Net income attributable to members' interests	$ 592	$ 322	$ 1,431

As a result of the adoption of a new accounting standard in 2009, DCP Midstream reclassified to equity certain deferred gains on sales of common units in DCP Partners. Our proportionate 50% share, totaling $135 million in 2009 and $30 million in 2010, were recorded in Equity in Earnings of Unconsolidated Affiliates in the Consolidated Statement of Operations.

Matters Affecting Future Field Services Results

Overall drilling and rig counts continue to improve from the drilling levels experienced in 2009, but still remain below peak levels seen in 2008. The drilling levels vary by geographic area, but in general, drilling remains robust in areas with a high content of liquids in the gas stream. In other areas, drilling continues to remain relatively modest. In addition, advances in technology, such as horizontal drilling and fractionation in shale plays, have led to certain geographic areas becoming increasingly accessible. NGL production increased during 2010 as compared to 2009 due to drilling occurring in liquids rich areas. Gas prices currently remain modest due to the increased supply, high inventory and reduced demand. Under DCP Midstream's contract structures, which are predominantly percent-of-proceeds contracts, DCP Midstream receives payments in-kind in the form of commodities and, as a result, typically has a "long" natural gas position. As such, a decrease in natural gas prices can negatively impact DCP Midstream's margin. However, any decline would be partially offset by its keep-whole contracts where gross margin is directly related to the price of NGLs and inversely related to the price of natural gas. DCP Midstream's long-term view is that as economic conditions improve, natural gas prices will return to levels that will support sustainable levels of natural gas-related drilling.

Other

	2010	2009	Increase (Decrease)	2008	Increase (Decrease)
			(in millions)		
Operating revenues	$ 58	$ 47	$ 11	$ 45	$ 2
Operating expenses	95	130	(35)	125	5
Operating loss	(37)	(83)	46	(80)	(3)
Other income and expenses	(1)	9	(10)	2	7
EBIT	$(38)	$ (74)	$ 36	$ (78)	$ 4

2010 Compared to 2009

EBIT. The $36 million increase in EBIT reflects a benefit of $31 million related to an early termination notice made by Westcoast for capacity contracts held on the Alliance pipeline and favorable captive insurance results in 2010, partially offset by a $7 million charge in 2010 for resolution of a corporate legal matter.

2009 Compared to 2008

EBIT. The $4 million increase in EBIT reflects slightly lower corporate costs in 2009.

Matters Affecting Future Other Results

Future Other results will continue to include corporate and business services we provide for our operations, and will also include operating costs and self-insured losses associated with our captive insurance entities. The results for Other could be impacted by the number and severity of insured property losses, particularly during hurricane season.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The application of accounting policies and estimates is an important process that continues to evolve as our operations change and accounting guidance is issued. We have identified a number of critical accounting policies and estimates that require the use of significant estimates and judgments.

We base our estimates and judgments on historical experience and on other assumptions that we believe are reasonable at the time of application. These estimates and judgments may change as time passes and more information becomes available. If estimates are different than the actual amounts recorded, adjustments are made in subsequent periods to take into consideration the new information. We discuss our critical accounting policies and estimates and other significant accounting policies with our Audit Committee.

Regulatory Accounting

We account for certain of our operations under accounting for regulated entities. As a result, we record assets and liabilities that result from the regulated ratemaking process that would not be recorded under generally accepted accounting principles for non-regulated entities. Regulatory assets generally represent incurred costs that have been deferred because such costs are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections for costs that either are not likely to or have yet to be incurred. We continually assess whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes and recent rate orders to other regulated entities. Based on this assessment, we believe our existing regulatory assets are probable of recovery. This assessment reflects the current political and regulatory climate at the state, provincial and federal levels, and is subject to change in the future. If future recovery of costs ceases to be probable, asset write-offs would be required. Additionally, regulatory agencies can provide flexibility in the manner and timing of the depreciation of property, plant and equipment and amortization of regulatory assets. Total regulatory assets were $1,061 million as of December 31, 2010 and $976 million as of December 31, 2009. Total regulatory liabilities were $559 million as of December 31, 2010 and $678 million as of December 31, 2009.

In 2009, we recorded $18 million of charges due to the discontinuance of rate regulated accounting treatment by SESH as a result of significant increases in construction costs of the SESH pipeline beyond the original estimates. These costs were not accompanied by equivalent increases in negotiated rates charged by SESH to its customers.

In 2008, we recorded a $44 million charge representing our share of impaired assets associated with the Islander East pipeline project. Triggered by certain 2008 legal and economic events, costs associated with this project were evaluated as to probability of recovery under FERC-approved tariff rates associated with any future alternative project plan. See Note 11 of Notes to Consolidated Financial Statements for further discussion.

Impairment of Goodwill

We perform an annual goodwill impairment test and update the test if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying amount. No impairments of goodwill were recorded in 2010, 2009 or 2008. Effective with our 2009 annual impairment test, we changed our test date from August 31 to April 1 in order to alleviate the information and resource constraints that historically existed during the third quarter and to better coincide with the completion of our long-term financial projections.

We had goodwill balances of $4,305 million at December 31, 2010 and $3,948 million at December 31, 2009. The increase in goodwill in 2010 was the result of foreign currency translation and $188 million of goodwill at U.S. Transmission associated with the acquisition of Bobcat in August 2010. The majority of our goodwill relates to the acquisition of Westcoast in 2002, which owns significantly all of our Canadian operations. As of the acquisition date or upon a change in reporting units, we allocate goodwill to a reporting unit, which we define as an operating segment or one level below an operating segment.

We primarily use a discounted cash flow analysis to determine fair value for each reporting unit. Key assumptions used in the determination of fair value include the use of an appropriate discount rate and estimated future cash flows. In estimating cash flows, we incorporate expected long-term growth rates in key markets served by our operations, regulatory stability, the ability to renew contracts, commodity prices (where appropriate) and foreign currency exchange rates, as well as other factors that affect our revenue, expense and capital expenditure projections.

The long-term growth rates used for our reporting units reflect continued expansion of our assets, driven by new natural gas supplies such as shale gas in North America and increasing demand for natural gas transportation capacity on our pipeline systems. We assumed a weighted average long-term growth rate of 3.7% for our 2010 goodwill impairment analysis. Had we assumed a 100 basis point lower growth rate for each of our reporting units, except for the Distribution reporting unit, there would have been no impairment of goodwill. The Distribution reporting unit used a long-term growth rate assumption at the lower end of our growth rate range and therefore has a lower sensitivity to growth rate declines.

We continue to monitor the effects of the economic downturn that global economies are currently facing on the long-term cost of capital utilized to calculate our reporting unit fair values. In evaluating our reporting units for our 2010 goodwill impairment analysis, we assumed weighted-average costs of capital ranging from 7.1% to 9.4% that market participants would use. Had we assumed a 100 basis point increase in the weighted- average cost of capital for each of our reporting units, there would have been no impairment of goodwill. For our regulated businesses in Canada, if an increase in the cost of capital occurred, we assume that the effect on the corresponding reporting unit's fair value would be ultimately offset by a similar increase in the reporting unit's regulated revenues since those rates include a component that is based on the reporting unit's cost of capital.

Based on the results of our annual impairment testing, the fair values of our reporting units at April 1, 2010 significantly exceeded their carrying values. No triggering events or changes in circumstances occurred during the period April 1, 2010 (our testing date) through December 31, 2010 that would warrant re-testing for goodwill impairment.

Revenue Recognition

Revenues from the transportation, storage, distribution and sales of natural gas, and from the sales of NGLs, are recognized when either the service is provided or the product is delivered. Revenues related to these services provided or products delivered but not yet billed are estimated each month. These estimates are generally based on contract data, regulatory information, estimated distribution usage based on historical data adjusted for heating degree days, commodity prices and preliminary throughput and allocation measurements. Final bills for the current month are billed and collected in the following month. Differences between actual and estimated unbilled revenues are immaterial.

Pension and Other Post-Retirement Benefits

The calculations of pension and other post-retirement expense and liabilities require the use of numerous assumptions. Changes in these assumptions can result in different reported expense and liability amounts, and future actual experience can differ from the assumptions. We believe that the most critical assumptions for pension and other post-retirement benefits are the expected long-term rate of return on plan assets and the assumed discount rate. Medical and prescription drug cost trend rate assumptions are also critical assumptions for other post-retirement benefits.

Capital market declines and volatility experienced during 2008 and 2009 adversely impacted the market value of investment assets used to fund Spectra Energy's defined benefit employee retirement plans. Future changes in plan asset returns, assumed discount rates and various other factors related to the participants in our pension and post-retirement plans will impact future pension expense and funding.

The expected return on plan assets is important, since certain of our pension and other post-retirement benefit plans are funded. Expected long-term rates of return on plan assets are developed by using a weighted average of expected returns for each asset class to which the plan assets are allocated. For 2010, the assumed average return ranged from 7.00% to 7.25% for the U.S. and Canadian pension plan assets and 6.51% for the U.S. other post-retirement benefit assets. A change in the rate of return of 25 basis points for these assets would impact annual benefit expense by approximately $3 million before tax. The Canadian other post-retirement benefit plans are not funded.

Since pension and other post-retirement benefit liabilities are measured on a discounted basis, the discount rate is also a significant assumption. Discount rates used for our defined benefit and other post-retirement benefit plans are based on the yields constructed from a portfolio of high-quality bonds for which the timing and amount of cash outflows approximate the estimated payouts of the plans. The average discount rates of 5.31% for the U.S. plans and 5.88% for the Canadian plans used to calculate 2010 plan expenses represent a weighted average of the applicable rates. A 25 basis-point change in the discount rates would impact annual benefit expense by approximately $3 million before tax.

See Note 24 of Notes to Consolidated Financial Statements for more information on pension and other post-retirement benefits.

LIQUIDITY AND CAPITAL RESOURCES

Known Trends and Uncertainties

We will rely upon cash flows from operations and various financing transactions, which may include issuances of short-term and long-term debt, to fund our liquidity and capital requirements for 2011. As of December 31, 2010, we had negative working capital of approximately $885 million. This balance includes short-term borrowings and commercial paper totaling $836 million and current maturities of long-term debt of $315 million. We also have access to four revolving credit facilities, with available combined capacities of approximately $1.6 billion at December 31, 2010. With the exception of the Spectra Energy Partners facility which is used for bank borrowings, these facilities will be used principally as back-stops for commercial paper programs or for the issuance of letters of credit. At Union Gas, we primarily use commercial paper to support our short-term working capital fluctuations. At Spectra Capital and Westcoast, we primarily use commercial paper for temporary funding of our capital expenditures. We also utilize commercial paper, other variable-rate debt and interest rate swaps to achieve our desired mix of fixed and variable-rate debt. See Credit Ratings Summary—Other Financing Matters for discussions of effective shelf registrations and available credit facilities.

Our consolidated capital structure includes long-term debt, short-term borrowings, commercial paper and preferred stock of subsidiaries. As of December 31, 2010, our capital structure was 56% debt, 39% common equity of controlling interests and 5% noncontrolling interests and preferred stock of subsidiaries.

Cash flows from operations for our businesses are fairly stable given that approximately 90% of revenues are derived from fee-based services, of which most are regulated. However, total operating cash flows are subject to a number of factors, including, but not limited to, earnings sensitivities to weather, commodity prices, distributions from our equity affiliates and the timing of cost recoveries pursuant to regulatory approvals. See Part I. Item 1A. Risk Factors for further discussion.

In particular, cash distributions from our equity affiliate DCP Midstream can fluctuate, primarily as a result of earnings sensitivities to commodity prices, as well as their levels of capital expenditures and other investing activities. DCP Midstream funds its operations and investing activities primarily from its operating cash flows, third-party debt and equity transactions associated with DCP Partners. DCP Midstream is required to make quarterly tax distributions to us based on allocated taxable income. In addition to tax distributions, periodic distributions are determined by DCP Midstream's board of directors based on net income, operating cash flows and other factors, including capital expenditures and other investing activities, commodity prices outlook and the credit environment. We received total tax and periodic distributions from DCP Midstream of $288 million in 2010, $101 million in 2009 and $930 million in 2008. As discussed in Note 1 of the Notes to Consolidated Financial Statements, a portion of these distributions are classified within Operating Cash Flows and the remainder is classified as Investing Cash Flows. We continually assess the effect of commodity prices and other activities at DCP Midstream on cash expected to be received from DCP Midstream, and adjust our expansion or other activities as necessary.

Capital market declines and volatility experienced during 2008 and 2009 adversely impacted the market value of investment assets used to fund Spectra Energy's defined benefit employee retirement plans. See further discussion of the expected impact of these changes under Quantitative and Qualitative Disclosures About Market

Risk—Equity Price Risk. Future changes in plan asset returns, assumed discount rates and various other factors related to the participants in our pension and post-retirement plans will impact future pension expense and funding.

As we execute on our strategic objectives around organic growth and expansion projects, expansion expenditures are expected to approximate $1.4 billion in 2011 and an aggregate total of $5.0 billion through 2015. The timing and extent of these expenditures are likely to vary significantly from year to year, depending mostly on general economic conditions and market requirements. Given that we expect to continue to pursue expansion opportunities over the next several years and also given the normal scheduled maturities of our existing debt instruments, capital resources will continue to include long-term borrowings. We remain committed to maintaining a capital structure and liquidity profile that continues to support an investment-grade credit rating.

Operating Cash Flows

Net cash provided by operating activities decreased $352 million to $1,408 million in 2010 compared to 2009. This change was driven mostly by:

- a $212 million increase in tax payments in 2010, and
- a $429 million net working capital decrease at Union Gas largely resulting from the timing of gas cost expenditures and recoveries from customers pursuant to regulatory cost recovery mechanisms. Refunds were made in 2010 for gas cost collections from customers in 2009 that exceeded the actual cost of gas during that period. These decreases were partially offset by
- higher earnings in 2010, and
- an increase of $196 million in distributions received from unconsolidated affiliates in 2010 reflecting the effects of higher commodity prices on earnings and cash flows of DCP midstream.

Net cash provided by operating activities decreased $45 million to $1,760 million in 2009 compared to 2008. This change was driven mostly by:

- a decrease of $582 million in distributions received from unconsolidated affiliates in 2009, driven by lower commodity prices at DCP Midstream, partially offset by
- a $402 million net working capital increase at Union Gas primarily resulting from higher amounts of approved gas cost collections from customers that exceeded the actual cost of gas in 2009 compared to such amounts collected in 2008, and
- a $222 million decrease in tax payments in 2009, primarily the result of the U.S. Economic Stimulus Plan, which deferred significant amounts of tax payments to future periods.

Investing Cash Flows

Net cash flows used in investing activities increased $1,080 million to $2,101 million in 2010 compared to 2009. This change was driven mostly by:

- a $366 million increase in capital and investment expenditures in 2010,
- a $492 million cash outlay in 2010 for the acquisition of Bobcat,
- a $186 million receipt from SESH in 2009 to repay our loan to them, and
- a $148 million distribution from Gulfstream in 2009 from the proceeds of a Gulfstream debt issuance, partially offset by
- the $295 million acquisition of Ozark in 2009.

Net cash flows used in investing activities decreased $842 million to $1,021 million in 2009 compared to 2008. This change was driven mostly by:

- a $989 million decrease in capital and investment expenditures in 2009 as a result of the planned reduction in capital expansion levels for 2009,
- a $186 million receipt from SESH in 2009 to repay our loan to them, and
- a $274 million acquisition of units of the Income Fund in 2008 that were held by non-affiliated holders, partially offset by
- the $295 million acquisition of Ozark in 2009.

The $186 million receipt from SESH, recorded as Receipt From Affiliate—Repayment of Loan on the Consolidated Statement of Cash Flows, represents repayment of the remaining balance of an outstanding loan receivable from SESH. A portion of these funds were from the proceeds of a debt issuance by SESH.

In 2009, we also received a $148 million special distribution from Gulfstream from the proceeds of a debt issuance by Gulfstream, of which $144 million was classified as Cash Flows from Investing Activities—Distributions Received From Unconsolidated Affiliates on the Consolidated Statement of Cash Flows.

Capital and Investment Expenditures by Business Segment

Capital and investment expenditures are detailed by business segment in the following table. Capital and investment expenditures presented below include expenditures from both continuing and discontinued operations.

	2010	2009	2008
		(in millions)	
Capital and Investment Expenditures(a)			
U.S. Transmission	$ 641	$ 432	$1,400
Distribution	227	224	373
Western Canada Transmission & Processing	449	353	222
Other	39	32	35
Total consolidated	$1,356	$1,041	$2,030

(a) Excludes the acquisitions of Bobcat in 2010, Ozark in 2009 and units of the Income Fund in 2008. See Note 4 of Notes to Consolidated Financial Statements for further discussion.

On August 30, 2010, we acquired the Bobcat assets and development project for $540 million, of which approximately $37 million has been withheld pending certain outcomes. We expect to invest an additional $400 million to $450 million to fully develop the Bobcat facility by the end of 2016. The acquisition, initially funded through the issuance of commercial paper, supports our stated plan of at least $1 billion per year in expansion capital investing through at least 2015. See Note 4 of Notes to Consolidated Financial Statements for further discussion of the acquisition of Bobcat.

	Bobcat Acquisition
	(in millions)
Cash purchase price	$540
Working capital and other purchase adjustments	6
Total	546
Withheld	(37)
Cash acquired	(17)
Net cash outlay for acquisition	$492

Capital and investment expenditures for 2010 totaled $1,356 million and included $719 million for expansion projects and $637 million for maintenance and other projects. We project 2011 capital and investment expenditures of approximately $2.1 billion, consisting of approximately $1.0 billion for U.S. Transmission, $0.3 billion for Distribution and $0.8 billion for Western Canada Transmission & Processing. Total projected 2011 capital and investment expenditures include approximately $1.4 billion of expansion capital expenditures and $0.7 billion for maintenance and upgrades of existing plants, pipelines and infrastructure to serve growth. Projected capital expenditures in 2011 represents an almost 50% increase over 2010, primarily related to expansion projects.

Capital expansion projects are developed and executed using results-proven project management processes. We evaluate the strategic fit and commercial and execution risks, and continuously measure performance compared to plan. Ongoing communications between project teams and senior leadership ensure we maintain the right focus and deliver the expected results.

Expansion capital expenditures included several key projects placed into service in 2010, including:

- East to West—A 281 MMcf/d expansion of the Algonquin system to facilitate west-bound transportation of gas delivered into the eastern end of the system.
- BC Transmission North—An expansion of existing western Canada transmission capacity to increase downstream capacity from the McMahon natural gas processing plant in northern Alberta.

In addition, there were multi-year expansion programs, further described below, large portions of which were placed into service in 2010, including:

- Fort Nelson Expansion, an 830 MMcf/d expansion of the Fort Nelson system in western Canada, where significant sections of both pipeline looping and reactivation were placed into service and compression expansion at the existing Fort Nelson Plant was completed.
- TEMAX / Time III, where compressor and pipeline facilities representing approximately one-half of the total Texas Eastern project were placed into service.
- Egan Storage, where storage capacity was increased as part of the multi-year Market Hub Storage expansion project.

Significant 2011 expansion projects expenditures are expected to include:

- TEMAX / Time III—An expansion of the Texas Eastern pipeline system from both Oakford, Pennsylvania and Clarington, Ohio to an eastern Pennsylvania interconnection with a major interstate pipeline to transport an additional 455 MMcf/d of natural gas. In-service phased in between 2010 and 2011.
- TEAM 2012—A 190 MMcf/d expansion of the Texas Eastern pipeline system consisting of new pipeline and compression construction. The project is designed to transport gas produced in the Marcellus Shale production regions to markets in the U.S. Northeast. In-service is anticipated in late 2012.
- New Jersey-New York Expansion—An 800 MMcf/d expansion of the Texas Eastern pipeline system consisting of a new 16 mile pipeline extension into lower Manhattan and other related facilities. The project is designed to transport gas produced in the Marcellus Shale regions into New York. In-service is anticipated in late 2013.
- Bobcat Storage—The development of an additional 9.9 Bcf working gas storage cavern along with above-ground facilities. In-service scheduled for late 2012.
- Fort Nelson Expansion—The new 250 Mmcf/d Fort Nelson North processing facility, which is the final phase and most significant capital outlay of the program, is under construction and is expected to be brought in-service in 2012. Upon completion, we will operate over 1.2 Bcf/d of raw gas processing capacity and associated gathering pipelines in the Fort Nelson area.

- Dawson Expansion—The development of a sour gas processing plant and an additional pipeline in western Canada. Phase 1 of 100 MMcf/d will be in-service in 2011 and phase 2 for an additional 100 MMcf/d is expected to be in service by 2013.
- T-North 2011—Additional facilities required to increase downstream take-away capacity by 170 MMcf/d from the Fort Nelson area in western Canada. The project consists of compression, pipeline looping and the construction of a new sales gas line to interconnect with a major pipeline system. In-service scheduled for 2012.
- Northeast Tennessee Project—An expansion of the East Tennessee system to transport 150 MMcf/d to a new gas-fired power plant in northeast Tennessee. The project consists of installation of pipeline, main line looping and regulation. In-service scheduled in 2011.

Financing Cash Flows and Liquidity

Net cash provided by financing activities totaled $656 million in 2010 compared to $803 million used in financing in 2009. This $1,459 million change was driven mostly by:

- $669 million of short-term borrowings in 2010, which included funds used for the acquisition of Bobcat and increased capital expenditures, compared to a $774 million decrease in 2009 as a result of the planned reduction in commercial paper outstanding during 2009 to preserve liquidity during that period of economic downturn and instability, and
- $483 million of net long-term debt issuances in 2010, which included the collateralized term loan at Spectra Energy Partners, compared to $104 million of net issuances in 2009, partially offset by
- $101 million of lower distributions to noncontrolling interests in 2010, and
- proceeds of $448 million in 2009 from the issuance of Spectra Energy common stock.

Net cash used in financing activities totaled $803 million in 2009 compared to $214 million provided by financing in 2008. This $1,017 million change was driven mostly by:

- a $774 million decrease in short-term borrowings in 2009 compared to a $249 million increase in the 2008 period,
- a $113 million decrease in contributions from noncontrolling interests in 2009,
- a $104 million increase in distributions to noncontrolling interests in 2009, primarily from proceeds of the debt issuance at M&N LLC, and
- $104 million of net proceeds from the issuance of long-term debt in 2009 compared to $1,157 million in 2008, partially offset by
- proceeds of $448 million in 2009 from the issuance of Spectra Energy common stock,
- proceeds of $208 million in 2009 from the issuance of Spectra Energy Partners' common units, and
- repurchases of Spectra Energy common stock in 2008 of $600 million.

Significant Financing Activities—2010

Debt Issuances. The following debt issuances were completed during 2010 as part of our overall financing plan to fund capital expenditures, to refinance maturing debt obligations and for other corporate purposes:

	Amount (in millions)	Interest Rate	Due Date
Texas Eastern	$ 300	4.125%	2020
Westcoast	249(a)	3.28%	2016
Westcoast	235(a)	4.57%	2020
Union Gas	241(a)	5.20%	2040

(a) U.S. dollar equivalent at time of issuance.

In December 2010, Spectra Energy Partners issued 6.9 million common units to the public, representing limited partner interests, and 0.1 million general partner units to Spectra Energy. Total net proceeds to Spectra Energy Partners from the issuances was $221 million (the net proceeds to Spectra Energy was $216 million), with $209 million used to purchase qualifying investment-grade securities, $7 million used to pay the debt owed to a subsidiary of Spectra Energy and $5 million used for Spectra Energy Partners' general partnership purposes. Spectra Energy Partners also borrowed $207 million of term debt using the investment-grade securities as collateral and paid off an equal amount of its outstanding revolving credit facility loan.

Significant Financing Activities—2009

Debt Issuances. The following debt issuances were completed during 2009:

	Amount (in millions)	Interest Rate	Due Date
Spectra Capital	$300	5.65%	2020
M&N LP	167(a)	4.34%	2019
M&N LLC	500	7.50%	2014

(a) U.S. dollar equivalent at time of issuance.

Ozark Acquisition. In 2009, Spectra Energy Partners acquired all of the ownership interests of Ozark from Atlas for approximately $295 million. The transaction was initially funded by Spectra Energy Partners with $218 million drawn on its bank credit facility, $70 million borrowed under a credit facility with Spectra Energy that was created for the sole purpose of funding a portion of the acquisition, and $7 million of cash on hand. This transaction was partially refinanced by Spectra Energy Partners in 2009 through the issuance of 9.8 million common units to the public, representing limited partner interests, and 0.2 million general partner units to Spectra Energy, resulting in net proceeds of $212 million. Funds from the sale of the partner units were used by Spectra Energy Partners to repay the $70 million owed to Spectra Energy and $142 million of the amount initially drawn on the Spectra Energy Partners bank credit facility. Effective with the repayment to Spectra Energy, the credit facility with Spectra Energy was terminated.

Common Stock Issuance. In 2009, in order to further protect our capitalization structure against a potential extreme decline in the Canadian dollar, we issued 32.2 million shares of our common stock and received net proceeds of $448 million. We used the net proceeds to repay commercial paper as it matured. Borrowings from the commercial paper were used for capital expenditures and for other general corporate purposes.

Significant Financing Activities—2008

Debt Issuances. The following debt issuances were completed during 2008:

	Amount	Interest Rate	Due Date
	(in millions)		
Spectra Capital	$500	6.20%	2018
Spectra Capital	250	5.90%	2013
Spectra Capital	250	7.50%	2038
Union Gas	198(a)	5.35%	2018
Union Gas	281(a)	6.05%	2038
Westcoast	48(a)	5.60%	2019
Westcoast	250(a)	5.60%	2019

(a) U.S. dollar equivalent at time of issuance

In 2008, M&N LLC paid $288 million to retire its outstanding bonds and bank debt and an additional $54 million early-extinguishment premium for the bonds. The payment of the premium, a regulatory asset, is presented within Cash Flows from Financing Activities—Other on the Consolidated Statements of Cash Flows.

Common Stock Repurchases. We repurchased a cumulative total of $600 million of our outstanding common stock in 2008.

Available Credit Facilities and Restrictive Debt Covenants

	Expiration Date	Credit Facilities Capacity	Outstanding at December 31, 2010 Commercial Paper	Revolving Credit	Letters of Credit	Total	Available Credit Facilities Capacity
			(in millions)				
Spectra Capital (a)							
Multi-year syndicated	2012	$1,500	$679	$ —	$13	$ 692	$ 808
Westcoast (b)							
Multi-year syndicated	2011	200	—	—	—	—	200
Union Gas (c)							
Multi-year syndicated	2012	501	157	—	—	157	344
Spectra Energy Partners							
Multi-year syndicated	2012	500	—	299	—	299	201
Total		$2,701	$836	$299	$13	$1,148	$1,553

(a) Credit facility contains a covenant requiring the debt-to-total capitalization ratio to not exceed 65%.

(b) U.S. dollar equivalent at December 31, 2010. The credit facilities totals 200 million Canadian dollars and contains a covenant that requires the Westcoast non-consolidated debt-to-total capitalization ratio to not exceed 75%. The ratio was 44% at December 31, 2010.

(c) U.S. dollar equivalent at December 31, 2010. The credit facilities totals 500 million Canadian dollars and contains a covenant that requires the Union Gas debt-to-total capitalization ratio to not exceed 75% and a provision which requires Union Gas to repay all borrowings under the facility for a period of two days during the second quarter of each year. The ratio was 64% at December 31, 2010.

The issuance of commercial paper, letters of credit and other borrowings reduces the amount available under the credit facilities.

Our credit agreements contain various financial and other covenants, including the maintenance of certain financial ratios. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements. As of December 31, 2010, we were in compliance with those covenants. In addition, our credit agreements allow for the acceleration of payments or termination of the agreements due to nonpayment, or in some cases, due to the acceleration of other significant indebtedness of the borrower or some of its subsidiaries. Our debt and credit agreements do not contain provisions that trigger an acceleration of indebtedness based solely on the occurrence of a material adverse change in our financial condition or results of operations.

As noted above, the terms of our Spectra Capital credit agreement require our consolidated debt-to-total-capitalization ratio to be 65% or lower. This ratio was 56% at December 31, 2010 and December 31, 2009. Our equity, and as a result, this ratio, is sensitive to significant movements of the Canadian dollar relative to the U.S. dollar due to the significance of our Canadian operations as discussed in "Quantitative and Qualitative Disclosures About Market Risk—Foreign Currency Risk." Based on the strength of our total capitalization as of December 31, 2010, however, it is not likely that a material adverse effect would occur as a result of a weakened Canadian dollar.

Credit Ratings

	Standard and Poor's	Moody's Investor Service	Fitch Ratings	DBRS
As of January 31, 2011				
Spectra Capital (a)	BBB	Baa2	BBB	n/a
Texas Eastern (a)	BBB+	Baa1	BBB+	n/a
Westcoast (a)	BBB+	n/a	n/a	A (low)
Union Gas (a)	BBB+	n/a	n/a	A
M&N LLC (a)	BBB	Baa3	n/a	n/a
M&N LP (b)	A	A2/A3	n/a	A

(a) Represents senior unsecured credit rating.
(b) Represents senior secured credit rating. The A2 rating applies to M&N LP's 6.9% notes due 2019 and the A3 rating applies to its 4.34% notes due 2019.
n/a Indicates not applicable.

The above credit ratings are dependent upon, among other factors, the ability to generate sufficient cash to fund capital and investment expenditures, our results of operations, market conditions and other factors. Our credit ratings could impact our ability to raise capital in the future, impact the cost of our capital and, as a result, have an impact on our liquidity.

Dividends. We currently anticipate an average dividend payout ratio over time of approximately 65% of estimated annual net income from controlling interests per share of common stock. The actual payout ratio, however, may vary from year to year depending on earnings levels. We expect to continue our policy of paying regular cash dividends. The declaration and payment of dividends are subject to the sole discretion of our Board of Directors and will depend 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. A dividend of $0.26 per common share, representing a 4% increase from the previous dividend level, was declared on January 3, 2011 and will be paid on March 14, 2011.

Other Financing Matters. Spectra Energy Corp and Spectra Capital have an effective shelf registration statement on file with the SEC to register the issuance of unspecified amounts of various equity and debt securities, respectively. Spectra Energy Partners has an effective shelf registration statement on file with the SEC to register the issuance of limited partner common units and various debt securities up to $1.1 billion in aggregate. In addition, as of December 31, 2010, certain of our subsidiaries in Canada have 1.75 billion Canadian dollars (approximately $1.75 billion) available for issuance in the Canadian market under debt shelf prospectuses that expire in October 2012.

Off-Balance Sheet Arrangements

We enter into guarantee arrangements in the normal course of business to facilitate commercial transactions with third parties. These arrangements include financial guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. See Note 20 of Notes to Consolidated Financial Statements for further discussion of guarantee arrangements.

Most of the guarantee arrangements that we enter into enhance the credit standings of certain subsidiaries, non-consolidated entities or less than wholly owned entities, enabling them to conduct business. As such, these guarantee arrangements involve elements of performance and credit risk which are not included on the Consolidated Balance Sheets. The possibility of us having to honor our contingencies is largely dependent upon the future operations of our subsidiaries, investees and other third parties, or the occurrence of certain future events.

Issuance of these guarantee arrangements is not required for the majority of our operations. As such, if we discontinued issuing these guarantee arrangements, there would not be a material impact to our consolidated results of operations, financial position or cash flows.

In connection with our spin-off from Duke Energy, certain guarantees that were previously issued by us were assigned to, or replaced by, Duke Energy as guarantor. For any remaining guarantees of other Duke Energy obligations, Duke Energy has indemnified us against any losses incurred under these guarantee arrangements.

We do not have any other material off-balance sheet financing entities or structures, except for normal operating lease arrangements, guarantee arrangements and financings entered into by equity investment pipeline and field services operations. For additional information on these commitments, see Notes 19 and 20 of Notes to Consolidated Financial Statements.

Contractual Obligations

We enter into contracts that require payment of cash at certain periods based on certain specified minimum quantities and prices. The following table summarizes our contractual cash obligations for each of the periods presented. The table below excludes all amounts classified as Total Current Liabilities on the December 31, 2010 Consolidated Balance Sheet other than Current Maturities of Long-Term Debt. It is expected that the majority of Total Current Liabilities will be paid in cash in 2011.

Contractual Obligations as of December 31, 2010

	Payments Due By Period				
	Total	2011	2012 & 2013	2014 & 2015	2016 & Beyond
			(in millions)		
Long-term debt (a)	$16,755	$ 941	$3,133	$2,446	$10,235
Operating leases (b)	180	30	59	53	38
Purchase Obligations: (c)					
Firm capacity payments (d)	893	243	234	236	180
Energy commodity contracts (e)	402	362	31	9	—
Other purchase obligations (f)	403	206	133	38	26
Other long-term liabilities on the Consolidated Balance Sheet (g)	55	55	—	—	—
Total contractual cash obligations	$18,688	$1,837	$3,590	$2,782	$10,479

(a) See Note 15 of Notes to Consolidated Financial Statements. Amounts include estimated scheduled interest payments over the life of the associated debt.
(b) See Note 19.
(c) Purchase obligations reflected in the Consolidated Balance Sheets have been excluded from the above table.
(d) Includes firm capacity payments that provide us with uninterrupted firm access to natural gas transportation and storage.
(e) Includes contractual obligations to purchase physical quantities of NGLs and natural gas. Amounts include certain hedges as defined by applicable accounting standards. For contracts where the price paid is based on an index, the amount is based on forward market prices at December 31, 2010.
(f) Includes contracts for software and consulting or advisory services. Amounts also include contractual obligations for engineering, procurement and construction costs for pipeline projects. Amounts exclude certain open purchase orders for services that are provided on demand, where the timing of the purchase cannot be determined.
(g) Includes estimated 2011 retirement plan contributions and estimated 2011 payments related to uncertain tax positions, including interest (see Notes 7 and 24). We are unable to reasonably estimate the timing of uncertain tax positions and interest payments in years beyond 2011 due to uncertainties in the timing of cash settlements with taxing authorities and cannot estimate retirement plan contributions beyond 2011 due primarily to uncertainties about market performance of plan assets. Excludes cash obligations for asset retirement activities (see Note 14) because the amount of cash flows to be paid to settle the asset retirement obligations is not known with certainty as we may use internal or external resources to perform retirement activities. Amounts also exclude reserves for litigation and environmental remediation (see Note 19) and regulatory liabilities (see Note 6) because we are uncertain as to the amount and/or timing of when cash payments will be required. Also, amounts exclude deferred income taxes and investment tax credits on the Consolidated Balance Sheets since cash payments for income taxes are determined primarily by taxable income for each discrete fiscal year.

Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risks associated with commodity prices, credit exposure, interest rates, equity prices and foreign currency exchange rates. We have established comprehensive risk management policies to monitor and manage these market risks. Our Chief Financial Officer is responsible for the overall governance of managing credit risk and commodity price risk, including monitoring exposure limits.

Commodity Price Risk

We are exposed to the impact of market fluctuations in the prices of NGLs and natural gas purchased as a result of our investment in DCP Midstream, and ownership of the Empress assets in western Canada and processing plants associated with our U.S. pipeline assets. Price risk represents the potential risk of loss from adverse changes in the market price of these energy commodities. Our exposure to commodity price risk is influenced by a number of factors, including contract size, length, market liquidity, location and unique or specific contract terms.

We employ established policies and procedures to manage Spectra Energy's risks associated with Empress' commodity price fluctuations, which may include the use of forward physical transactions as well as commodity derivatives. There were no significant commodity hedge transactions by Spectra Energy during 2010, 2009 or 2008.

Our equity affiliate, DCP Midstream, also has risk exposures primarily associated with market prices of NGLs and natural gas. DCP Midstream manages these risks separate from Spectra Energy, and utilizes various risk management strategies, including the use of commodity derivatives.

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 exposed to market price fluctuations of NGLs, natural gas and oil primarily in our Field Services segment. Based on a sensitivity analysis as of December 31, 2010 and 2009, a 10¢ per-gallon move in NGL prices would affect our annual pre-tax earnings by approximately $65 million in 2011, primarily from Field Services, as compared with approximately $60 million in 2010. For the same periods, a 50¢ per-MMbtu move in natural gas prices would affect our annual pre-tax earnings by approximately $15 million in 2011 and 2010, and a $10 per-barrel move in oil prices would affect our annual pre-tax earnings by approximately $25 million in 2011 and 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.

See also Notes 1 and 18 of Notes to Consolidated Financial Statements.

Credit Risk

Credit risk represents the loss that we would incur if a counterparty fails to perform under its contractual obligations. Our principal customers for natural gas transportation, storage, and gathering and processing services are industrial end-users, marketers, exploration and production companies, LDCs and utilities located throughout the United States and Canada. We have concentrations of receivables from natural gas utilities and their affiliates, industrial customers and marketers throughout these regions, as well as retail distribution customers in Canada. These concentrations of customers may affect our overall credit risk in that risk factors can negatively affect the credit quality of the entire sector. Credit risk associated with gas distribution services are primarily affected by general economic conditions in the service territory.

Where exposed to credit risk, we analyze the customers' financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of those limits on an ongoing basis. We also obtain parental guarantees, cash deposits or letters of credit from customers to provide credit support, where appropriate, based on our financial analysis of the customer and the regulatory or contractual terms and conditions applicable to each contract. Approximately 90% of our credit exposures for transportation, storage, and gathering and processing services are with customers who have an investment-grade rating (or the equivalent based on our evaluation) or are secured by collateral. 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.

We manage cash and restricted cash positions to maximize value while assuring appropriate amounts of cash are available, as required. We invest our available cash in high-quality money market securities. Such money market securities are designed for safety of principal and liquidity, and accordingly, do not include equity-based securities.

We had no net exposure to any customer that represented greater than 10% of the gross fair value of trade accounts receivable at December 31, 2010.

Based on our policies for managing credit risk, our current exposures and our credit and other reserves, we do not anticipate a materially adverse effect on our consolidated financial position or results of operations as a result of non-performance by any counterparty.

Interest Rate Risk

We are exposed to risk resulting from changes in interest rates as a result of our issuance of variable and fixed-rate debt and commercial paper. We manage our interest rate exposure by limiting our variable-rate exposures to percentages of total debt and by monitoring the effects of market changes in interest rates. We also enter into financial derivative instruments, including, but not limited to, interest rate swaps and rate lock agreements to manage and mitigate interest rate risk exposure. See also Notes 1, 15 and 18 of Notes to Consolidated Financial Statements.

As of December 31, 2010, we had interest rate hedges in place for various purposes. We are party to "pay floating—receive fixed" interest rate swaps with a total notional amount of $1,500 million to hedge against changes in the fair value of our fixed-rate debt that arise as a result of changes in market interest rates. These swaps also allow us to transform a portion of the underlying cash flows related to our long-term fixed-rate debt securities into variable-rate debt in order to achieve our desired mix of fixed and variable-rate debt. These positions essentially doubled in 2010 compared to 2009 as we sought to balance our financing portfolio to achieve our desired mix. At Spectra Energy Partners, we have third-party "pay fixed—receive floating" interest rate swaps with a total notional amount of $40 million to mitigate our exposure to variable interest rates on loans outstanding under the Spectra Energy Partners revolving credit facility.

Based on a sensitivity analysis as of December 31, 2010, it was estimated that if short-term interest rates average 100 basis points higher (lower) in 2011 than in 2010, interest expense, net of offsetting impacts in interest income, would increase (decrease) by $23 million. Comparatively, based on a sensitivity analysis as of December 31, 2009, had short-term interest rates averaged 100 basis points higher (lower) in 2010 than in 2009, it was estimated that interest expense, net of offsetting interest income, would have fluctuated by approximately $9 million. These amounts were estimated by considering the effect of the hypothetical interest rates on variable-rate debt outstanding, adjusted for interest rate hedges, investments, and cash and cash equivalents outstanding as of December 31, 2010 and 2009. The $14 million increase in our estimated exposure to changes in short-term market interest rates is mainly attributable to an increase in the amount of "pay floating – receive fixed" interest rate swaps outstanding as of December 31, 2010 compared to December 31, 2009 and an increase in commercial paper. As discussed above, this increase is consistent with our overall targeted mix of fixed and variable-rate debt. If short-term interest rates changed significantly, we would likely take action to manage our exposure to the change. However, due to the uncertainty of the specific actions that would be taken and their possible effects, the sensitivity analysis assumes no changes in our financial structure.

Equity Price Risk

Our cost of providing non-contributory defined benefit retirement and postretirement benefit plans are dependent upon, among other things, rates of return on plan assets. These plan assets expose us to price fluctuations in equity markets. In addition, our captive insurance companies maintain various investments to fund certain business risks and losses. Those investments may, from time to time, include investments in equity securities. Volatility of equity markets, particularly declines, will not only impact our cost of providing retirement and postretirement benefits, but will also impact the funding level requirements of those benefits.

We manage equity price risk by, among other things, diversifying our investments in equity investments, setting target allocations of investment types, periodically reviewing actual asset allocations and rebalancing allocations if warranted, and utilizing outside consultants.

Foreign Currency Risk

We are exposed to foreign currency risk from our Canadian operations. To mitigate risks associated with foreign currency fluctuations, contracts may be denominated in or indexed to the U.S. dollar and/or local inflation rates, or investments may be naturally hedged through debt denominated or issued in the foreign currency.

To monitor our currency exchange rate risks, we use sensitivity analysis, which measures the effect of devaluation of the Canadian dollar. An average 10% devaluation in the Canadian dollar exchange rate during 2010 would have resulted in an estimated net loss on the translation of local currency earnings of approximately $48 million on our Consolidated Statement of Operation. In addition, if a 10% devaluation had occurred on December 31, 2010, the Consolidated Balance Sheet would have been negatively impacted by $595 million through a cumulative translation adjustment in AOCI. At December 31, 2010, one U.S. dollar translated into one Canadian dollar.

As discussed earlier, 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 flows or restrict business. As a result of the impact of foreign currency fluctuations on our consolidated equity, these fluctuations have a direct impact on our ability to maintain certain of these financial covenants.

OTHER ISSUES

Global Climate Change. Policymakers at regional, federal and international levels continue to evaluate potential legislative and regulatory compliance mechanisms to achieve reductions in global GHG emissions in an effort to address the challenge of climate change. Certain of our assets and operations in the U.S. and Canada are subject to direct and indirect effects of current global climate change regulatory actions in their respective jurisdictions, and it is likely that other assets and operations in the U.S. and Canada will become subject to direct and indirect effects of current and possible future global climate change regulatory actions.

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 Cancun, Mexico in December 2010 with the intent of defining a future agreement for 2012 and beyond. While the talks resulted in a limited 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 future 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.

The province of British Columbia enacted a carbon tax, effective July 1, 2008. The tax applies to the purchase or use of fossil fuels, including natural gas. This tax is being recovered from customers through service tolls. British Columbia has also introduced legislation establishing targets for the purpose of reducing GHG emissions to at least 33% less than 2007 levels by 2020 and to at least 80% less than 2007 levels by 2050. In 2008, the province established additional interim GHG reduction targets of 6% below 2007 levels by 2012 and 18% below by 2016. British Columbia has also issued consultation papers regarding potential development of a cap and trade program; however, the final details and implementation have not been released. The materiality of any potential compliance costs is unknown at this time as the final form of additional regulations and compliance options has yet to be determined by policymakers.

In 2007, the province of Alberta adopted legislation which requires existing large emitters (facilities releasing 100,000 metric tons or more of GHG emissions annually) to reduce their annual emissions intensity by 12% beginning July 1, 2007. In 2010, one of our facilities was subject to this regulation. The regulation has not had a material impact on our consolidated results of operations, financial position or cash flows.

In the United States, climate change action is evolving at state, regional and federal levels. We expect that some 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.

The United States is not a signatory to the Kyoto Protocol, nor has the federal government adopted a mandatory GHG emissions reduction requirement. However, the EPA issued a final Mandatory Greenhouse Gas Reporting rule in 2009 that required annual reporting of GHG emissions data from certain of our U.S. operations beginning in 2010. In November 2010, the EPA released additional requirements for natural gas system reporting that will expand the reporting requirements for GHG emissions in 2011. These reporting requirements are not anticipated to have a material impact on our consolidated results of operations, financial position or cash flows. The EPA also finalized a Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule in May 2010 to address how GHG emissions would be regulated under the existing Clean Air Act. Regulation is scheduled to begin in 2011, and over time, certain of our U.S. facilities will be subject to this regulation. Some new construction and modification projects in the future may be subject to this regulation as well. At this time, it is not anticipated that the costs will be material; however, many implementation details are unknown.

In addition, several legislative proposals that would impose GHG emissions constraints have been considered by the U.S. Congress. To date, no such legislation has been enacted into law. A number of states in the United States are establishing or considering state or regional programs that would mandate reductions in GHG emissions. These regional programs include the Regional Greenhouse Gas Initiative which applies only to power producers in select northeastern states, the Western Climate Initiative which includes a number of western states and the provinces of British Columbia, Ontario and Quebec, and the Midwestern Greenhouse Gas Reduction Accord which includes six midwestern states and one Canadian province. We expect some 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.

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 or regulation could materially increase our operating costs, require material capital expenditures or create additional permitting, which could delay proposed construction projects. We continue to monitor the development of greenhouse gas regulatory policies in both countries.

Other. For additional information on other issues, see Notes 6 and 19 of Notes to Consolidated Financial Statements.

New Accounting Pronouncements

See Note 1 of Notes to Consolidated Financial Statements for discussion.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Quantitative and Qualitative Disclosures About Market Risk for discussion.

Item 8. Financial Statements and Supplementary Data.

Management's Annual Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining an adequate system of internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Our internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes, in accordance with generally accepted accounting principles. Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies and procedures may deteriorate.

Our management, including our Chief Executive Officer and Chief Financial Officer, has conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2010 based on the framework in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation, management concluded that our internal control over financial reporting was effective at the resonable assurance level as of December 31, 2010.

Deloitte & Touche LLP, our independent registered public accounting firm, has audited and issued a report on the effectiveness of our internal control over financial reporting. Their report is included herein.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Spectra Energy Corp:

We have audited the accompanying consolidated balance sheets of Spectra Energy Corp and subsidiaries (the "Company") as of December 31, 2010 and 2009, and the related consolidated statements of operations, cash flows and equity and comprehensive income for each of the three years in the period ended December 31, 2010. Our audits also included the financial statement schedule listed in the Index at Item 15. We also have audited the Company's internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these financial statements and financial statement schedule and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Spectra Energy Corp and subsidiaries as of December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on the criteria established in Internal Control—*Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.*

/s/ Deloitte & Touche LLP

Houston, Texas
February 24, 2011

SPECTRA ENERGY CORP

CONSOLIDATED STATEMENTS OF OPERATIONS
(In millions, except per-share amounts)

	Years Ended December 31, 2010	2009	2008
Operating Revenues			
Transportation, storage and processing of natural gas	$2,870	$2,565	$2,343
Distribution of natural gas	1,450	1,451	1,731
Sales of natural gas liquids	459	389	772
Other	166	147	228
Total operating revenues	4,945	4,552	5,074
Operating Expenses			
Natural gas and petroleum products purchased	1,056	1,098	1,586
Operating, maintenance and other	1,278	1,144	1,235
Depreciation and amortization	650	584	569
Property and other taxes	297	262	246
Total operating expenses	3,281	3,088	3,636
Gains on Sales of Other Assets and Other, net	10	11	42
Operating Income	1,674	1,475	1,480
Other Income and Expenses			
Equity in earnings of unconsolidated affiliates	430	369	778
Other income and expenses, net	32	37	66
Total other income and expenses	462	406	844
Interest Expense	630	610	636
Earnings From Continuing Operations Before Income Taxes	1,506	1,271	1,688
Income Tax Expense From Continuing Operations	383	352	493
Income From Continuing Operations	1,123	919	1,195
Income From Discontinued Operations, net of tax	6	5	2
Net Income	1,129	924	1,197
Net Income—Noncontrolling Interests	80	75	65
Net Income—Controlling Interests	$1,049	$ 849	$1,132
Common Stock Data			
Weighted-average shares outstanding			
Basic	648	642	622
Diluted	650	643	624
Earnings per share from continuing operations			
Basic	$ 1.61	$ 1.31	$ 1.82
Diluted	$ 1.60	$ 1.31	$ 1.81
Earnings per share			
Basic	$ 1.62	$ 1.32	$ 1.82
Diluted	$ 1.61	$ 1.32	$ 1.81
Dividends per share	$ 1.00	$ 1.00	$ 0.96

See Notes to Consolidated Financial Statements.

SPECTRA ENERGY CORP

CONSOLIDATED BALANCE SHEETS
(In millions)

	December 31, 2010	December 31, 2009
ASSETS		
Current Assets		
Cash and cash equivalents	$ 130	$ 166
Receivables (net of allowance for doubtful accounts of $9 and $14 at December 31, 2010 and 2009, respectively)	1,018	778
Inventory	287	321
Other	203	164
Total current assets	1,638	1,429
Investments and Other Assets		
Investments in and loans to unconsolidated affiliates	2,033	2,001
Goodwill	4,305	3,948
Other	665	407
Total investments and other assets	7,003	6,356
Property, Plant and Equipment		
Cost	22,162	19,960
Less accumulated depreciation and amortization	5,182	4,613
Net property, plant and equipment	16,980	15,347
Regulatory Assets and Deferred Debits	1,065	959
Total Assets	$26,686	$24,091

See Notes to Consolidated Financial Statements.

SPECTRA ENERGY CORP

CONSOLIDATED BALANCE SHEETS
(In millions, except per-share amounts)

	December 31, 2010	December 31, 2009
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	$ 369	$ 333
Short-term borrowings and commercial paper	836	162
Taxes accrued	59	139
Interest accrued	167	167
Current maturities of long-term debt	315	809
Other	777	885
Total current liabilities	2,523	2,495
Long-term Debt	10,169	8,947
Deferred Credits and Other Liabilities		
Deferred income taxes	3,555	3,209
Regulatory and other	1,694	1,634
Total deferred credits and other liabilities	5,249	4,843
Commitments and Contingencies		
Preferred Stock of Subsidiaries	258	225
Equity		
Preferred stock, $0.001 par, 22 million shares authorized, no shares outstanding	—	—
Common stock, $0.001 par, 1 billion shares authorized, 649 million and 647 million shares outstanding at December 31, 2010 and 2009, respectively	1	1
Additional paid-in capital	4,726	4,645
Retained earnings	1,487	1,088
Accumulated other comprehensive income	1,595	1,307
Total controlling interests	7,809	7,041
Noncontrolling interests	678	540
Total equity	8,487	7,581
Total Liabilities and Equity	$26,686	$24,091

See Notes to Consolidated Financial Statements.

SPECTRA ENERGY CORP

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Years Ended December 31,		
	2010	**2009**	**2008**
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 1,129	$ 924	$ 1,197
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	664	598	581
Deferred income tax expense	205	176	158
Equity in earnings of unconsolidated affiliates	(430)	(369)	(778)
Distributions received from unconsolidated affiliates	391	195	777
Decrease (increase) in			
Receivables	(50)	143	(36)
Inventory	14	7	(76)
Other current assets	4	69	(36)
Increase (decrease) in			
Accounts payable	(67)	35	24
Taxes accrued	(141)	78	8
Other current liabilities	(184)	33	(52)
Other, assets	(49)	(62)	81
Other, liabilities	(78)	(67)	(43)
Net cash provided by operating activities	1,408	1,760	1,805
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(1,346)	(980)	(1,502)
Investments in and loans to unconsolidated affiliates	(10)	(61)	(528)
Acquisitions, net of cash acquired	(492)	(295)	(274)
Purchases of held-to-maturity securities	(1,117)	(231)	—
Proceeds from sales and maturities of held-to-maturity securities	1,068	110	—
Purchases of available-for-sale securities	(254)	—	(1,132)
Proceeds from sales and maturities of available-for-sale securities	38	32	1,256
Net proceeds from the sale of other assets	—	—	105
Distributions received from unconsolidated affiliates	17	164	218
Receipt from affiliate—repayment of loan	—	186	—
Other	(5)	54	(6)
Net cash used in investing activities	(2,101)	(1,021)	(1,863)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from the issuance of long-term debt	4,389	4,127	3,557
Payments for the redemption of long-term debt	(3,906)	(4,023)	(2,400)
Net increase (decrease) in short-term borrowings and commercial paper	669	(774)	249
Distributions to noncontrolling interests	(73)	(174)	(70)
Contributions from noncontrolling interests	—	2	115
Proceeds from the issuance of Spectra Energy common stock	—	448	—
Proceeds from the issuance of Spectra Energy Partners, LP common units	216	208	—
Repurchases of Spectra Energy common stock	—	—	(600)
Dividends paid on common stock	(650)	(631)	(598)
Other	11	14	(39)
Net cash provided by (used in) financing activities	656	(803)	214
Effect of exchange rate changes on cash	1	25	(11)
Net increase (decrease) in cash and cash equivalents	(36)	(39)	145
Cash and cash equivalents at beginning of period	166	205	60
Cash and cash equivalents at end of period	$ 130	$ 166	$ 205
Supplemental Disclosures			
Cash paid for interest, net of amount capitalized	$ 615	$ 587	$ 611
Cash paid for income taxes	312	100	322
Property, plant and equipment noncash accruals	58	24	44

See Notes to Consolidated Financial Statements.

SPECTRA ENERGY CORP

CONSOLIDATED STATEMENTS OF EQUITY AND COMPREHENSIVE INCOME
(In millions)

				Accumulated Other Comprehensive Income			
	Common Stock	Additional Paid-in Capital	Retained Earnings	Foreign Currency Translation Adjustments	Other	Noncontrolling Interests	Total
December 31, 2007	$ 1	$4,603	$ 356	$ 2,026	$(216)	$ 581	$ 7,351
Net income	—	—	1,132	—	—	65	1,197
Other comprehensive income (loss)							
Foreign currency translation adjustments	—	—	—	(1,140)	—	(2)	(1,142)
Unrealized mark-to-market net loss on hedges	—	—	—	—	(11)	—	(11)
Reclassification of cash flow hedges into earnings	—	—	—	—	2	—	2
Pension and benefits impact	—	—	—	—	(135)	—	(135)
Total comprehensive income (loss)							(89)
Spectra Energy common stock repurchase	—	(600)	—	—	—	—	(600)
Dividends on common stock	—	—	(598)	—	—	—	(598)
Stock-based compensation	—	38	—	—	—	—	38
Purchase of Spectra Energy Income Fund units	—	—	—	—	—	(208)	(208)
Distributions to noncontrolling interests	—	—	—	—	—	(73)	(73)
Contributions from noncontrolling interests	—	—	—	—	—	115	115
Other, net	—	8	—	—	—	(8)	—
December 31, 2008	1	4,049	890	886	(360)	470	5,936
Net income	—	—	849	—	—	75	924
Other comprehensive income							
Foreign currency translation adjustments	—	—	—	796	—	11	807
Unrealized mark-to-market net loss on hedges	—	—	—	—	(9)	—	(9)
Reclassification of cash flow hedges into earnings	—	—	—	—	1	—	1
Pension and benefits impact	—	—	—	—	(7)	—	(7)
Total comprehensive income							1,716
Dividends on common stock	—	—	(651)	—	—	—	(651)
Stock-based compensation	—	9	—	—	—	—	9
Spectra Energy common stock issuance	—	448	—	—	—	—	448
Spectra Energy Partners, LP common unit issuance	—	25	—	—	—	168	193
Reclassification of deferred gain on sale of units of Spectra Energy Partners, LP	—	59	—	—	—	—	59
Distributions to noncontrolling interests	—	—	—	—	—	(174)	(174)
Contributions from noncontrolling interests	—	—	—	—	—	2	2
Other, net	—	55	—	—	—	(12)	43
December 31, 2009	1	4,645	1,088	1,682	(375)	540	7,581
Net income	—	—	1,049	—	—	80	1,129
Other comprehensive income							
Foreign currency translation adjustments	—	—	—	328	—	16	344
Unrealized mark-to-market net loss on hedges	—	—	—	—	(28)	—	(28)
Reclassification of cash flow hedges into earnings	—	—	—	—	1	—	1
Pension and benefits impact	—	—	—	—	(7)	—	(7)
Total comprehensive income							1,439
Dividends on common stock	—	—	(650)	—	—	—	(650)
Stock-based compensation	—	36	—	—	—	—	36
Spectra Energy Partners, LP common unit issuance	—	50	—	—	—	140	190
Transfer of interest in Gulfstream to Spectra Energy Partners, LP	—	19	—	—	—	(29)	(10)
Distributions to noncontrolling interests	—	—	—	—	—	(73)	(73)
Other, net	—	(24)	—	—	(6)	4	(26)
December 31, 2010	$ 1	$4,726	$1,487	$ 2,010	$(415)	$ 678	$ 8,487

See Notes to Consolidated Financial Statements.

SPECTRA ENERGY CORP

Notes to Consolidated Financial Statements

INDEX

1. Summary of Operations and Significant Accounting Policies

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.

Nature of Operations. Spectra Energy Corp, through its subsidiaries and equity affiliates, owns and operates a large and diversified portfolio of complementary natural gas-related energy assets, operating in three key areas of the natural gas industry: gathering and processing, transmission and storage, and distribution. 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. In addition, we own a 50% interest in DCP Midstream, LLC (DCP Midstream), one of the largest natural gas gatherers and processors in the United States.

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.

Basis of Presentation. The accompanying Consolidated Financial Statements include our accounts, our majority-owned subsidiaries where we have control and those variable interest entities, if any, where we are the primary beneficiary.

See Note 2 for a discussion of corrections of immaterial errors in our previously issued financial statements.

Use of Estimates. To conform with generally accepted accounting principles (GAAP) in the United States, we make estimates and assumptions that affect the amounts reported in the Consolidated Financial Statements and Notes to Consolidated Financial Statements. Although these estimates are based on our best available knowledge at the time, actual results could differ.

Fair Value Measurements. We measure the fair value of financial assets and liabilities by maximizing the use of observable inputs and minimizing the use of unobservable inputs. Fair value is the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date.

Cost-Based Regulation. The economic effects of regulation can result in a regulated company recording assets for costs that have been or are expected to be approved for recovery from customers or recording liabilities for amounts that are expected to be returned to customers in the rate-setting process in a period different from the period in which the amounts would be recorded by an unregulated enterprise. Accordingly, we record assets and liabilities that result from the regulated ratemaking process that may not be recorded under GAAP for non-regulated entities. We continually assess whether regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes and recent rate orders to other regulated entities. Based on this assessment, we believe our existing regulatory assets are probable of recovery. These regulatory assets and liabilities are primarily classified in the Consolidated Balance Sheets as Regulatory Assets and Deferred Debits, and Deferred Credits and Other Liabilities. We evaluate our regulated assets, and consider factors such as regulatory changes and the effect of competition. If cost-based regulation ends or competition increases, we may have to reduce our asset balances to reflect a market basis less than cost and write-off the associated regulatory assets and liabilities. See Note 6 for further discussion.

Foreign Currency Translation. The Canadian dollar has been determined to be the functional currency of our Canadian operations based on an assessment of the economic circumstances of those operations. Assets and liabilities of our Canadian operations are translated into U.S. dollars at current exchange rates. Translation adjustments resulting from fluctuations in exchange rates are included as a separate component of Accumulated Other Comprehensive Income (AOCI) on the Consolidated Statements of Equity and Comprehensive Income. Revenue and expense accounts of these operations are translated at average monthly exchange rates prevailing during the periods. Gains and losses arising from transactions denominated in currencies other than the functional currency are included in the results of operations of the period in which they occur. Foreign currency transaction gains (losses) totaled \$(9) million in 2010, \$6 million in 2009 and \$11 million in 2008, and are included in Other Income and Expenses, Net on the Consolidated Statements of Operations. Deferred taxes are not provided on translation gains and losses where we expect earnings of a foreign operation to be permanently reinvested.

Revenue Recognition. Revenues from the transportation, storage, distribution and sales of natural gas, and from the sales of natural gas liquids (NGLs) are recognized when either the service is provided or the product is delivered. Revenues related to these services provided or products delivered but not yet billed are estimated each month. These estimates are generally based on contract data, regulatory information, estimated distribution usage based on historical data, historical data adjusted for heating degree days, commodity prices and preliminary throughput and allocation measurements. Final bills for the current month are billed and collected in the following month. Differences between actual and estimated unbilled revenues are immaterial. There were no customers accounting for 10% or more of consolidated revenues during 2010, 2009 or 2008.

Stock-Based Compensation. For employee awards, equity classified stock-based compensation cost is measured at the grant date based on the fair value of the award and is recognized as expense over the requisite service period, which generally begins on the date the award is granted through the earlier of the date the award vests or the date the employee becomes retirement eligible. Awards, including stock options, granted to employees that are retirement eligible are deemed to have vested immediately upon issuance, and therefore, compensation cost for those awards is recognized on the date such awards are granted. See Note 23 for further discussion.

Allowance for Funds Used During Construction (AFUDC). AFUDC, which represents the estimated debt and equity costs of capital funds necessary to finance the construction of certain new regulated facilities, consists of two components, an equity component and an interest expense component. The equity component is a non-cash item. AFUDC is capitalized as a component of Property, Plant and Equipment cost, with offsetting credits to the Consolidated Statements of Operations through Other Income and Expenses, Net for the equity component and Interest Expense for the interest expense component. After construction is completed, we are permitted to recover these costs through inclusion in the rate base and in the depreciation provision. The total amount of AFUDC included in the Consolidated Statements of Operations was $52 million in 2010 (an equity component of $37 million and an interest expense component of $15 million), $40 million in 2009 (an equity component of $21 million and an interest expense component of $19 million) and $58 million in 2008 (an equity component of $33 million and an interest expense component of $25 million).

Income Taxes. Deferred income taxes are recognized for differences between the financial reporting and tax bases of assets and liabilities at enacted statutory tax rates in effect for the years in which the differences are expected to reverse. The effect on deferred taxes of a change in tax rates is recognized in income in the period that includes the enactment date. Actual income taxes could vary from these estimates due to future changes in income tax law or results from the final review of tax returns by federal, state or foreign tax authorities.

Financial statement effects on tax positions are recognized in the period in which it is more likely than not that the position will be sustained upon examination, the position is effectively settled or when the statute of limitations to challenge the position has expired. Interest and penalties related to unrecognized tax benefits are recorded as interest expense and other expense, respectively.

Cash and Cash Equivalents. Highly liquid investments with original maturities of three months or less at the date of acquisition, except for the investments that are pledged as collateral against long-term debt as discussed in Note 15, are considered cash equivalents.

Inventory. Inventory consists of natural gas and NGLs held in storage for transmission and processing, and also includes materials and supplies. Natural gas inventories primarily relate to the Distribution segment in Canada and are valued at costs approved by the regulator, the Ontario Energy Board (OEB). The difference between the approved price and the actual cost of gas purchased is recorded in either accounts receivable or other current liabilities, as appropriate, for future disposition with customers, subject to approval by the OEB. The remaining inventory is recorded at cost, primarily using average cost. The components of inventory are as follows:

	December 31, 2010	December 31, 2009
	(in millions)	
Natural gas	$175	$219
NGLs	41	21
Materials and supplies	71	81
Total inventory	$287	$321

Natural Gas Imbalances. The Consolidated Balance Sheets include in-kind balances as a result of differences in gas volumes received and delivered for customers. Since settlement of imbalances is in-kind, changes in the balances do not have an effect on our Consolidated Statements of Cash Flows. Receivables and Other Current Liabilities each include $271 million as of December 31, 2010 and $165 million as of December 31, 2009 related to gas imbalances. Natural gas volumes owed to or by us are valued at natural gas market index prices as of the balance sheet dates.

Risk Management and Hedging Activities and Financial Instruments. Currently, our use of derivative instruments is primarily limited to interest rate positions. All derivative instruments that do not qualify for the normal purchases and normal sales exception are recorded on the Consolidated Balance Sheets at fair value. Cash inflows and outflows related to derivative instruments are a component of Cash Flows From Operating Activities in the accompanying Consolidated Statements of Cash Flows.

Cash Flow and Fair Value Hedges. Qualifying energy commodity and other derivatives may be designated as either a hedge of a forecasted transaction (cash flow hedge) or a hedge of a recognized asset, liability or firm commitment (fair value hedge). For all hedge contracts, we prepare documentation of the hedge in accordance with accounting standards and assess whether the hedge contract is highly effective, both at inception and on a quarterly basis, in offsetting changes in cash flows or fair values of hedged items. We document hedging activity by instrument type (futures or swaps) and risk management strategy (commodity price risk or interest rate risk).

Changes in the fair value of a derivative designated and qualified as a cash flow hedge, to the extent effective, are included in the Consolidated Statements of Equity and Comprehensive Income as AOCI until earnings are affected by the hedged item. We discontinue hedge accounting prospectively when we have determined that a derivative no longer qualifies as an effective hedge or when it is no longer probable that the hedged forecasted transaction will occur. When hedge accounting is discontinued because the derivative no longer qualifies as an effective hedge, the derivative is subject to the mark-to-market model of accounting prospectively. Gains and losses related to discontinued hedges that were previously accumulated in AOCI will remain in AOCI until the underlying transaction is reflected in earnings, unless it is probable that the hedged forecasted transaction will not occur at which time associated deferred amounts in AOCI are immediately recognized in current earnings.

For derivatives designated as fair value hedges, we recognize the gain or loss on the derivative instrument, as well as the offsetting gain or loss on the hedged item in earnings, to the extent effective, in the current period. In the event the hedge is not effective, there is no offsetting gain or loss recognized in earnings for the hedged item. All derivatives designated and accounted for as hedges are classified in the same category as the item being hedged in the Consolidated Statements of Cash Flows. In addition, all components of each derivative gain or loss are included in the assessment of hedge effectiveness.

Investments. We may actively invest a portion of our available cash and restricted funds balances in various financial instruments, including taxable or tax-exempt debt securities. In addition, we invest in short-term money market securities, some of which are restricted due to debt collateral or insurance requirements. Investments in available-for-sale (AFS) securities are carried at fair value. Investments in money market securities are also accounted for at fair value. Realized gains and losses; and dividend and interest income related to these securities, including any amortization of discounts or premiums arising at acquisition, are included in earnings. The cost of securities sold is determined using the specific identification method. Purchases and sales of AFS and held-to-maturity (HTM) securities are presented on a gross basis within Cash Flows From Investing Activities in the accompanying Consolidated Statements of Cash Flows.

Goodwill. We perform our goodwill impairment test annually and evaluate goodwill when events or changes in circumstances indicate that its carrying value may not be recoverable. No impairments of goodwill were recorded in 2010, 2009 or 2008. Effective with our 2009 annual impairment test, we changed our test date from August 31 to April 1 in order to alleviate the information and resource constraints that historically existed during the third quarter and to better coincide with the completion of our long-term financial projections. See Note 12 for further discussion.

We perform the annual review for goodwill impairment at the reporting unit level, which we have determined to be an operating segment or one level below.

Impairment testing of goodwill consists of a two-step process. The first step involves a comparison of the implied fair value of a reporting unit with its carrying amount. If the carrying amount of the reporting unit exceeds its fair value, the second step of the process involves a comparison of the fair value and carrying value of the goodwill of that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the implied fair value of that goodwill, an impairment loss is recognized in an amount equal to the excess. Additional impairment tests are performed between the annual reviews if events or changes in circumstances make it more likely than not that the fair value of a reporting unit is below its carrying amount.

We primarily use a discounted cash flow analysis to determine fair value for each reporting unit. Key assumptions in the determination of fair value include the use of an appropriate discount rate and estimated future cash flows. In estimating cash flows, we incorporate expected long-term growth rates in key markets served by our operations, regulatory stability, the ability to renew contracts, commodity prices (where appropriate) and foreign currency exchange rates, as well as other factors that affect our revenue, expense and capital expenditure projections.

Property, Plant and Equipment. Property, plant and equipment is stated at historical cost less accumulated depreciation. We capitalize all construction-related direct labor and material costs, as well as indirect construction costs. Indirect costs include general engineering, taxes and the cost of funds used during construction. The costs of renewals and betterments that extend the useful life or increase the expected output of property, plant and equipment are also capitalized. The costs of repairs, replacements and major maintenance projects that do not extend the useful life or increase the expected output of property, plant and equipment are expensed as incurred. Depreciation is generally computed over the asset's estimated useful life using the straight-line method.

When we retire regulated property, plant and equipment, we charge the original cost plus the cost of retirement, less salvage value, to accumulated depreciation and amortization. When we sell entire regulated operating units, or retire non-regulated properties, the cost is removed from the property account and the related accumulated depreciation and amortization accounts are reduced. Any gain or loss is recorded in earnings, unless otherwise required by the applicable regulatory body.

Preliminary Project Costs. Project development costs, including expenditures for preliminary surveys, plans, investigations, environmental studies, regulatory applications and other costs incurred for the purpose of determining the feasibility of capital expansion projects, are capitalized for U.S. rate-regulated enterprises when it is determined that recovery of such costs through regulated revenues of the completed project is probable. Any inception-to-date costs of the project that were initially expensed are reversed and capitalized as Property, Plant and Equipment.

Long-Lived Asset Impairments. We evaluate whether long-lived assets, excluding goodwill, have been impaired when circumstances indicate the carrying value of those assets may not be recoverable. For such long-lived assets, an impairment exists when its carrying value exceeds the sum of estimates of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used in developing estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on these estimated future undiscounted cash flows, an impairment loss is measured as the excess of the asset's carrying value over its fair value, such that the asset's carrying value is adjusted to its estimated fair value.

We assess the fair value of long-lived assets using commonly accepted techniques and may use more than one source. Sources to determine fair value include, but are not limited to, recent third-party comparable sales, internally developed discounted cash flow analyses and analyses from outside advisors. Significant changes in market conditions resulting from events such as changes in natural gas available to our systems, the condition of an asset, a change in our intent to utilize the asset or a significant change in contracted revenues or regulatory recoveries would generally require us to reassess the cash flows related to the long-lived assets.

Asset Retirement Obligations. We recognize asset retirement obligations (AROs) for legal commitments associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset and conditional AROs in which the timing or method of settlement are conditional on a future event that may or may not be within our control. The fair value of a liability for an ARO is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made and is added to the carrying amount of the associated asset. This additional carrying amount is depreciated over the estimated useful life of the asset.

Unamortized Debt Premium, Discount and Expense. Premiums, discounts and expenses incurred with the issuance of outstanding long-term debt are amortized over the terms of the debt issues. Any call premiums or unamortized expenses associated with refinancing higher-cost debt obligations to finance regulated assets and operations are amortized consistent with regulatory treatment of those items, where appropriate.

Environmental Expenditures. We expense environmental expenditures related to conditions caused by past operations that do not generate current or future revenues. Environmental expenditures related to operations that generate current or future revenues are expensed or capitalized, as appropriate. Undiscounted liabilities are recorded when the necessity for environmental remediation becomes probable and the costs can be reasonably estimated, or when other potential environmental liabilities are reasonably estimable and probable.

Captive Insurance Reserves. We have captive insurance subsidiaries which provide insurance coverage to our consolidated subsidiaries as well as certain equity affiliates, on a limited basis, for various business risks and losses, such as workers compensation, property, business interruption and general liability. Liabilities include provisions for estimated losses incurred but not yet reported, as well as provisions for known claims which have been estimated on a claims-incurred basis. Incurred but not yet reported reserve estimates involve the use of assumptions and are based upon historical loss experience, industry data and other actuarial assumptions. Reserve estimates are adjusted in future periods as actual losses differ from historical experience.

Guarantees. Upon issuance or modification of a guarantee made by us, we recognize a liability at the time of issuance or material modification for the estimated fair value of the obligation we assume under that guarantee, if any. Fair value is estimated using a probability-weighted approach. We reduce the obligation over the term of the guarantee or related contract in a systematic and rational method as risk is reduced under the obligation.

Accounting For Sales of Stock by a Subsidiary. We adopted the provisions of Accounting Standards Codification (ASC) 810-10-65, "Consolidations—Overall—Transition," effective January 1, 2009. Prior to the adoption of this accounting standard, we accounted for sales of stock by a subsidiary under Staff Accounting Bulletin (SAB) No. 51, "Accounting for Sales of Stock of a Subsidiary." Under SAB No. 51, companies could elect, via an accounting policy decision, to record a gain on the sale of stock of a subsidiary equal to the amount of proceeds received in excess of the carrying value of the shares. We had elected to treat such excesses as gains in earnings. Effective upon the adoption of the provisions of ASC 810-10-65, sales of stock by a subsidiary are required to be accounted for as equity transactions in those instances where a change in control does not take place, which effectively nullified the SAB No. 51 gain alternative. As a result of the adoption of the provisions of ASC 810-10-65, a $59 million deferred gain associated with the formation of Spectra Energy Partners, LP (Spectra Energy Partners), a majority-owned subsidiary, was reclassified from Deferred Credits and Other Liabilities—Regulatory and Other to Additional Paid-in Capital in the Consolidated Balance Sheet on January 1, 2009. See Note 3 for further discussion.

Segment Reporting. Operating segments are components of an enterprise for which separate financial information is available and evaluated regularly by the chief operating decision maker in deciding how to allocate resources and evaluate performance. Two or more operating segments may be aggregated into a single reportable segment provided certain criteria are met. There is no such aggregation within our defined business segments. A description of our reportable segments, consistent with how business results are reported internally to management, and the disclosure of segment information is presented in Note 5.

Consolidated Statements of Cash Flows. Cash flows from discontinued operations are combined with cash flows from continuing operations within operating, investing and financing cash flows. Cash received from insurance proceeds are classified depending on the activity that resulted in the insurance proceeds. For example, business interruption insurance proceeds are included as a component of operating activities while insurance proceeds from damaged property are included as a component of investing activities. With respect to cash overdrafts, book overdrafts are included within operating cash flows while bank overdrafts are included within financing cash flows. Cash flows from borrowings and repayments under revolving credit facilities are presented gross within Proceeds From the Issuance of Long-Term Debt and Payments for the Redemption of Long-Term Debt, respectively, within financing activities.

Distributions from Unconsolidated Affiliates. We consider dividends received from unconsolidated affiliates which do not exceed cumulative equity in earnings subsequent to the date of investment to be a return on investment and classify these amounts as Cash Flows From Operating Activities within the accompanying Consolidated Statements of Cash Flows. Cumulative dividends received in excess of cumulative equity in earnings subsequent to the date of investment are considered to be a return of investment and are classified as Cash Flows From Investing Activities.

New Accounting Pronouncements—2010. The following new accounting pronouncements were adopted during 2010 and the effect of such adoption, if applicable, has been presented in the accompanying Consolidated Financial Statements:

In June 2009, the Financial Accounting Standards Board (FASB) issued an accounting standard which is intended to address (1) the effects on certain consolidation provisions as a result of the elimination of the concept of qualifying special-purpose entities and (2) constituent concerns about the application of certain consolidation provisions including those in which the accounting and disclosures do not always provide timely and useful information about an enterprise's involvement in a variable interest entity. The adoption of the provisions on January 1, 2010 did not have any impact on our consolidated results of operations, financial position or cash flows.

2009. The following significant accounting pronouncements were adopted during 2009 and the effects of such adoptions, if any, are presented in the accompanying Consolidated Financial Statements:

ASC 105, "Generally Accepted Accounting Principles." This accounting standard results in the FASB Accounting Standards Codification (the Codification) becoming the source of authoritative U.S. GAAP recognized by the FASB to be applied by nongovernmental entities. Rules and interpretive releases of the Securities and Exchange Commission (SEC) are also considered sources of authoritative GAAP for SEC registrants. The Codification supersedes all then-existing non-SEC accounting and reporting standards. All other nongrandfathered, non-SEC accounting literature not included in the Codification is nonauthoritative. The adoption of the provisions of this accounting standard did not change the application of existing GAAP for us, and as a result, did not have any impact on our consolidated results of operations, financial position or cash flows.

ASC 820, "Fair Value Measurement and Disclosures." This accounting standard defines fair value, establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. The FASB issued an amendment to this standard which delayed its effective date for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). The adoption of the provisions of this amended standard on January 1, 2009 for the measurement of our asset retirement obligations and for our goodwill impairment test did not have any impact on our consolidated results of operations, financial position or cash flows.

ASC 805, "Business Combinations." This accounting standard requires an acquiring entity in a business combination to recognize all and only the assets acquired and liabilities assumed in the transaction, establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed, and requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. This standard applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. We adopted the provisions of this standard on January 1, 2009 as required.

ASC 810-10-65, "Consolidations—Overall—Transition and Open Effective Date Information." This accounting standard requires all entities to report noncontrolling interests in subsidiaries as equity in the consolidated financial statements. This standard also requires that transactions between an entity and noncontrolling interests be treated as equity transactions. We adopted the provisions of this standard effective January 1, 2009 as required.

When adopting the presentation and disclosure items, retrospective application to conform previously reported financial statements is required. Accordingly, the 2008 data contained in the Consolidated Financial Statements and Notes to Consolidated Financial Statements reflect the new reporting requirements of this standard. Changes to reflect the new measurement guidance for increases or decreases in ownership and other changes must be done prospectively. The new requirements for noncontrolling interests, results of operations and comprehensive income of subsidiaries change the presentation of operating results, related per-share information and equity. This standard requires net income and comprehensive income to be displayed for both the controlling and the noncontrolling interests. Additional required disclosures and reconciliations include a separate schedule that shows the effects of any transactions with the noncontrolling interests on the equity attributable to the controlling interest.

As discussed previously, a deferred gain associated with the formation of Spectra Energy Partners totaling $59 million was reclassified from Deferred Credits and Other Liabilities—Regulatory and Other to Additional Paid-in Capital on the Consolidated Balance Sheet upon adoption of this standard on January 1, 2009. See Note 3 for further discussion.

In November 2008, the FASB ratified ASC 323-10-35, "Investments—Equity Method and Joint Ventures—Subsequent Measure," which addresses certain aspects of accounting for business combinations and noncontrolling interests on an entity's accounting for equity-method investments. The consensus indicates, among other things, that transaction costs for an investment should be included in the cost of the equity-method investment (and not expensed) and shares subsequently issued by the equity-method investee that reduce the investor's ownership percentage should be accounted for as if the investor had sold a proportionate share of its investment, with gains or losses recorded through earnings. For us, these amendments were effective for transactions occurring after December 31, 2008.

As discussed in Note 11, a $135 million increase to Equity in Earnings of Unconsolidated Affiliates was recorded in the first quarter of 2009 related to DCP Midstream's reclassification of certain deferred gains on sales of common units in its master limited partnership to equity as a result of their adoption of these amendments.

ASC 815-10, "Derivatives and Hedging—Overall." This accounting standard expands the disclosure requirements related to derivative instruments and hedging activities with the intent to provide users of financial statements an enhanced understanding of how and why derivative instruments are used, how derivative instruments and related hedged items are accounted for and how they affect an entity's financial position, financial performance and cash flows. We adopted the provisions of this standard effective January 1, 2009 as required.

ASC 275-10, "Risks and Uncertainties—Overall" and ASC 350-30, "Intangibles—Goodwill and Other—General Intangible Other than Goodwill." These accounting standards amend the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset. The adoption of the provisions of these standards on January 1, 2009 did not have any impact on our consolidated results of operations, financial position or cash flows.

ASC 808-10, "Collaborative Arrangements—Overall." This accounting standard defines collaborative arrangements and establishes reporting requirements for transactions between participants in a collaborative arrangement and between participants in the arrangement and third parties. A collaborative arrangement is a contractual arrangement that involves a joint operating activity. These arrangements involve two (or more) parties who are both (a) active participants in the activity and (b) exposed to significant risks and rewards dependent on the commercial success of the activity. An entity should report the effects of applying this accounting standard as a change in accounting principle through retrospective application to all prior periods presented for all arrangements existing as of the effective date. The adoption of the provisions of this standard on January 1, 2009 did not have any impact on our consolidated results of operations, financial position or cash flows.

ASC 260-10, "Earnings per Share—Overall." This standard addresses whether instruments granted in share-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the earnings allocation in computing earnings per share (EPS) under the two-class method. The adoption of the provisions of this standard on January 1, 2009 did not have any material effect on our computation of EPS.

ASC 855-10, "Subsequent Events—Overall." This accounting standard establishes general standards for the accounting for and disclosure of events that occur subsequent to the balance sheet date but before the financial statements of an entity are issued or are available to be issued. The adoption of the provisions of this standard effective June 30, 2009 did not have any impact on our consolidated results of operations, financial position or cash flows.

2008. There were no significant accounting pronouncements adopted during 2008 that had a material impact on our consolidated results of operations, financial position or cash flows.

2. Corrections of Immaterial Errors

During the fourth quarter of 2010, we identified certain errors in our previously issued financial statements related primarily to the impacts of Canadian federal and provincial tax rate changes on deferred income tax balances associated with our Canadian operations. These errors caused Income Tax Expense From Continuing Operations to be understated in 2006 and 2007, and to be overstated in 2008 and 2009. During the second quarter of 2010, we identified an incorrect presentation of certain restricted cash balances which caused Cash and Cash Equivalents to be overstated and Other Current Assets to be understated at December 31, 2009. We evaluated the materiality of the errors from both a qualitative and a quantitative perspective and concluded that these errors are immaterial to our previously issued consolidated financial statements. We have corrected the consolidated financial statements presented herein to reflect the correction of these errors.

The corrections related to deferred income tax balances are as follows:

Consolidated Statements of Operations	Income Tax Expense From Continuing Operations	Income From Continuing Operations	Net Income	Net Income – Controlling Interests
	(in millions)			
2009				
As previously reported	$353	$ 918	$ 923	$ 848
Increase (decrease)	(1)	1	1	1
As corrected	$352	$ 919	$ 924	$ 849
2008				
As previously reported	$496	$1,192	$1,194	$1,129
Increase (decrease)	(3)	3	3	3
As corrected	$493	$1,195	$1,197	$1,132

Consolidated Balance Sheet	Regulatory Assets and Deferred Debits	Total Assets / Total Liabilities and Equity	Deferred Credits and Other Liabilities – Deferred Income Taxes	Total Deferred Credits and Other Liabilities	Equity – Additional Paid-in Capital	Equity – Retained Earnings	Equity – Accumulated Other Comprehensive Income	Equity – Controlling Interests	Total Equity
	(in millions)								
December 31, 2009									
As previously reported	$947	$24,079	$3,113	$4,747	$4,700	$1,096	$1,328	$7,125	$7,665
Increase (decrease)	12	12	96	96	(55)	(8)	(21)	(84)	(84)
As corrected	$959	$24,091	$3,209	$4,843	$4,645	$1,088	$1,307	$7,041	$7,581

Consolidated Statements of Cash Flows	Net Income	Deferred Income Tax Expense
	(in millions)	
2009		
As previously reported	$ 923	$177
Increase (decrease)	1	(1)
As corrected	$ 924	$176
2008		
As previously reported	$1,194	$161
Increase (decrease)	3	(3)
As corrected	$1,197	$158

Consolidated Statements of Equity and Comprehensive Income	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income – Foreign Currency Translation Adjustments	Accumulated Other Comprehensive Income – Other	Total Equity
			(in millions)		
December 31, 2009					
As previously reported	$4,700	$1,096	$1,686	$(358)	$7,665
Decrease	(55)	(8)	(4)	(17)	(84)
As corrected	$4,645	$1,088	$1,682	$(375)	$7,581
December 31, 2008					
As previously reported	$4,104	$ 899	$ 881	$(345)	$6,010
Increase (decrease)	(55)	(9)	5	(15)	(74)
As corrected	$4,049	$ 890	$ 886	$(360)	$5,936
December 31, 2007					
As previously reported	$4,658	$ 368	$2,033	$(203)	$7,438
Decrease	(55)	(12)	(7)	(13)	(87)
As corrected	$4,603	$ 356	$2,026	$(216)	$7,351

The corrections related to restricted cash are as follows:

Consolidated Balance Sheet	Cash and Cash Equivalents	Other Current Assets
	(in millions)	
December 31, 2009		
As previously reported	$196	$134
Increase (decrease)	(30)	30
As corrected	$166	$164

Consolidated Statements of Cash Flows	Cash Flows from Investing Activities-Purchases of Held-to-Maturity Securities	Cash Flows From Investing Activities - Proceeds from Sales and Maturities of Held-to-Maturity Securities	Cash Flows From Investing Activities - Other	Net Cash Used in Investing Activities	Net Increase (Decrease) in Cash and Cash Equivalents	Cash and Cash Equivalents at Beginning of Period	Cash and Cash Equivalents at End of Period
				(in millions)			
2009							
As previously reported	$ —	$ —	$ (46)	$(1,000)	$ (18)	$214	$196
Increase (decrease)	(231)	110	100	(21)	(21)	(9)	(30)
As corrected	$(231)	$110	$ 54	$(1,021)	$ (39)	$205	$166
2008							
As previously reported	$ —	$ —	$ (31)	$(1,888)	$120	$ 94	$214
Increase (decrease)	—	—	25	25	25	(34)	(9)
As corrected	$ —	$ —	$ (6)	$(1,863)	$145	$ 60	$205

3. Spectra Energy Partners, LP

As of December 31, 2010, Spectra Energy owned 69% of Spectra Energy Partners, including its 2% general partner interest.

Formation. In 2007, Spectra Energy completed its initial public offering (IPO) of Spectra Energy Partners, a newly formed natural gas infrastructure master limited partnership. Spectra Energy contributed to Spectra Energy Partners 100% of the ownership of East Tennessee Natural Gas, LLC (East Tennessee), 50% of the ownership of Market Hub Partners, LLC, including the Moss Bluff and Egan natural gas storage operations, and a 24.5% interest in Gulfstream Natural Gas System, LLC (Gulfstream).

Accounting rules in effect at the time of Spectra Energy Partners' IPO allowed for recognition of a gain associated with such a sale only if the class of securities sold by the subsidiary did not contain any preference over the subsidiary's other classes of securities. Since the common units of Spectra Energy Partners had preferential cash distribution rights as compared to the subordinated units, we previously deferred recognition of the gain associated with the sale of the common units until the subordinated units owned by Spectra Energy were converted into common units with rights equivalent to the remaining unitholders. As discussed in Note 1, the deferred gain, totaling $59 million, was reclassified from Deferred Credits and Other Liabilities—Regulatory and Other to Additional Paid-in Capital in the Consolidated Balance Sheet on January 1, 2009 upon the adoption of ASC 810-10-65.

Gulfstream. In November 2010, Spectra Energy Partners acquired an additional 24.5% interest in Gulfstream from Spectra Energy (the Gulfstream acquisition) for approximately $330 million, consisting of approximately $66 million in newly issued partnership units, the assumption of approximately $7 million in debt owed to a subsidiary of Spectra Energy and approximately $257 million in cash from borrowings under its revolving credit facility. The acquisition price received by Spectra Energy exceeded the book value of the Gulfstream investment. Therefore, this transfer of assets between entities resulted in an increase to Spectra Energy's Additional Paid-in Capital of $29 million ($19 million net of tax) and a decrease to Equity-Noncontrolling Interests of $29 million on the Consolidated Balance Sheet, representing the portion of the excess that was associated with the public unitholders of Spectra Energy Partners. The Gulfstream acquisition increased Spectra Energy Partners' interest in Gulfstream to 49% and decreased our effective ownership interest in Gulfstream to 35%.

NOARK Pipeline System, Limited Partnership. In 2009, Spectra Energy Partners acquired all of the ownership interests of NOARK Pipeline System, Limited Partnership (NOARK) from Atlas Pipeline Partners, L.P. (Atlas) for approximately $295 million. See Note 4 for further discussion.

Saltville. In 2008, Spectra Energy sold Saltville Gas Storage Company L.L.C. (Saltville) and the P-25 pipeline to Spectra Energy Partners for $107 million. Proceeds from the sale consisted of 4.2 million Spectra Energy Partners common units, 0.1 million general partner units and $5 million in cash. No gain or loss was recognized on the disposition since this transaction represented a transfer of entities under common control.

Sales of Spectra Energy Partners Common Units. In December 2010, Spectra Energy Partners issued 6.9 million common units to the public, representing limited partner interests, and 0.1 million general partner units to Spectra Energy. Total net proceeds to Spectra Energy Partners from the issuances was $221 million (net proceeds to Spectra Energy was $216 million), with $209 million used to purchase qualifying investment-grade securities, $7 million used to pay the debt owed to a subsidiary of Spectra Energy and $5 million used for Spectra Energy Partners' general partnership purposes. Spectra Energy Partners also borrowed $207 million of term debt using the investment-grade securities as collateral and paid off an equal amount of its outstanding revolving credit facility loan. In connection with the sale of the partner units, an $80 million gain ($50 million net of tax) to Additional Paid-in Capital and a $140 million increase in Equity—Noncontrolling Interests were recorded on the Consolidated Balance Sheet in 2010.

In 2009, Spectra Energy Partners issued 9.8 million 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. The net proceeds were comprised of $208 million for the common units and $4 million for the general partner units. In connection with the sale of the partner units and the dilution of Spectra Energy's ownership interest in Spectra Energy Partners, a $40 million gain ($25 million net of tax) to Additional Paid-in Capital and a $168 million increase in Equity—Noncontrolling Interests were recorded in 2009.

4. Acquisitions and Dispositions

Acquisitions. We consolidate assets and liabilities from acquisitions as of the purchase date and include earnings from acquisitions in consolidated earnings after the purchase date. Assets acquired and liabilities assumed are recorded at estimated fair values on the date of acquisition. The purchase price minus the estimated fair value of the acquired assets and liabilities meeting the definition of a "business" is recorded as goodwill. The allocation of the purchase price may be adjusted if additional information is received during the allocation period, which generally does not exceed one year from the consummation date.

On August 30, 2010, we acquired Bobcat Gas Storage assets and development project (Bobcat) from Haddington Energy Partners III LP and GE Energy Financial Services for $540 million, of which approximately $37 million was withheld pending certain outcomes. The withheld amounts are primarily recorded within Deferred Credits and Other Liabilities—Regulatory and Other on the Consolidated Balance Sheets at December 31, 2010.

Strategically located on the Gulf Coast in southeastern Louisiana near Henry Hub, the Bobcat assets interconnect with five major interstate pipelines, including our Texas Eastern Transmission, LP pipeline, and complement our existing pipeline and storage portfolio in the region. Bobcat is part of the U.S. Transmission segment. Once fully developed and operational, these high-deliverability salt dome storage caverns are expected to have a total working gas storage capacity of 46 billion cubic feet. Storage infrastructure such as Bobcat plays a vital role in meeting customers' needs for managing demand swings on a seasonal basis, satisfying the increasing demand for natural gas-fired power generation and providing customers with the advantage and flexibility to access all the major markets in the United States.

The following table summarizes the fair values of the assets and liabilities acquired as of August 30, 2010:

	Purchase Price Allocation
	(in millions)
Cash purchase price	$540
Working capital and other purchase adjustments	6
Total	546
Cash	17
Other current assets	3
Property, plant and equipment	350
Current liabilities	(10)
Deferred credits and other liabilities	(2)
Total assets acquired/liabilities assumed	358
Goodwill	$188

In 2009, Spectra Energy Partners acquired all of the ownership interests of NOARK from Atlas for approximately $295 million. NOARK's assets consisted of 100% ownership interests in Ozark Gas Transmission, L.L.C. (Ozark Gas Transmission), a 565-mile Federal Energy Regulatory Commission (FERC) regulated interstate natural gas transmission system, and Ozark Gas Gathering, L.L.C., a 365-mile, fee-based, state-regulated natural gas gathering system. The transaction was initially funded by Spectra Energy Partners with $218 million drawn on its bank credit facility, $70 million borrowed under a credit facility with Spectra Energy that was created for the sole purpose of funding a portion of this acquisition and $7 million of cash on hand. This transaction was partially refinanced by Spectra Energy Partners through the issuance of units as discussed in Note 3. Funds from the sale of the partner units were used by Spectra Energy Partners to repay the $70 million owed to Spectra Energy and $142 million of the amount drawn on the Spectra Energy Partners bank credit facility. Effective with the repayment to Spectra Energy, the credit facility with Spectra Energy was terminated.

The following table summarizes the fair values of the NOARK assets acquired and liabilities assumed:

	Purchase Price Allocation
	(in millions)
Purchase price	$295
Current assets	7
Property, plant and equipment	139
Regulatory assets and deferred debits	5
Current liabilities	(5)
Deferred credits and other liabilities	(1)
Total assets acquired/liabilities assumed	145
Goodwill	$150

Goodwill related to the acquisitions of Bobcat and the ownership interests of NOARK is deductible for income tax purposes.

In 2008, we acquired the 24.4 million units of the Spectra Energy Income Fund (Income Fund) that were held by non-affiliated holders for 279 million Canadian dollars (approximately $274 million). We now own 100% of the Canadian Midstream operations. Prior to the acquisition, the Income Fund indirectly held 54% of our consolidated Canadian Midstream operations and we indirectly held the remaining 46%. The transaction, primarily driven by changes in Canadian federal tax rules as related to income trusts, was accounted for as a step acquisition, using the purchase method of accounting. Equity—Noncontrolling Interests decreased approximately $208 million as a result of the transaction.

Pro forma results of operations reflecting the acquisitions of Bobcat and NOARK (both part of the U.S. Transmission segment) and the units of the Income Fund (part of the Western Canada Transmission & Processing segment) as if those transactions had occurred as of the beginning of the periods presented in this report do not materially differ from actual reported results.

Dispositions. As discussed in Note 3, in November 2010, Spectra Energy sold a 24.5% interest in Gulfstream to Spectra Energy Partners for $330 million. In 2008, Spectra Energy sold Saltville and the P-25 pipeline to Spectra Energy Partners for $107 million. See Note 3 for further discussion.

In 2008, we also sold our interests in certain natural gas gathering and processing facilities to a third party. See Note 8 for further discussion.

5. Business Segments

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.

Our chief operating decision maker regularly reviews financial information about each of these segments in deciding how to allocate resources and evaluate performance. There is no aggregation within our defined business segments.

U.S. Transmission 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. The natural gas transmission and storage operations in the U.S. are primarily subject to the FERC's rules and regulations.

Distribution provides retail natural gas distribution service in Ontario, Canada, as well as natural gas transportation and storage services to other utilities and energy market participants. These services are provided by Union Gas Limited (Union Gas), and are primarily subject to the rules and regulations of the OEB.

Western Canada Transmission & Processing provides transportation of natural gas, natural gas gathering and processing services, and NGLs extraction, fractionation, transportation, storage and marketing to customers in western Canada and the northern tier of the United States. This segment conducts business mostly through BC Pipeline, BC Field Services, and the NGL marketing and Canadian Midstream businesses. BC Pipeline and BC Field Services operations are primarily subject to the rules and regulations of Canada's National Energy Board (NEB).

Field Services gathers and processes natural gas and fractionates, markets and trades NGLs. It conducts operations through DCP Midstream, which is owned 50% by us and 50% by ConocoPhillips. 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.

Our reportable segments offer different products and services and are managed separately as business units. Management evaluates segment performance based on earnings before interest and taxes (EBIT) from continuing operations less noncontrolling interests related to those earnings.

On a segment basis, EBIT represents earnings from continuing operations (both operating and non-operating) before interest and taxes, net of noncontrolling interests related to those earnings. Cash, cash equivalents and short-term investments are managed centrally, so the associated realized and unrealized gains and losses from foreign currency transactions and interest and dividend income on those balances are excluded from the segments' EBIT. Transactions between reportable segments are accounted for on the same basis as transactions with unaffiliated third parties.

Business Segment Data

	Unaffiliated Revenues	Intersegment Revenues	Total Operating Revenues (a)	Segment EBIT/ Consolidated Earnings from Continuing Operations before Income Taxes (a)	Depreciation and Amortization (a)	Capital and Investment Expenditures (a)	Segment Assets
				(in millions)			
2010							
U.S. Transmission	$1,816	$ 5	$1,821	$ 948	$258	$ 641(b)	$11,120
Distribution	1,779	—	1,779	409	194	227	5,473
Western Canada Transmission & Processing	1,341	4	1,345	409	169	449	5,013
Field Services	—	—	—	335	—	—	1,101
Total reportable segments	4,936	9	4,945	2,101	621	1,317	22,707
Other	9	49	58	(38)	29	39	4,217
Eliminations	—	(58)	(58)	—	—	—	(238)
Interest expense	—	—	—	630	—	—	—
Interest income and other (c)	—	—	—	73	—	—	—
Total consolidated	$4,945	$ —	$4,945	$1,506	$650	$1,356	$26,686
2009							
U.S. Transmission	$1,683	$ 7	$1,690	$ 894	$246	$ 432(d)	$ 9,904
Distribution	1,745	—	1,745	336	172	224	5,034
Western Canada Transmission & Processing	1,115	—	1,115	343	144	353	4,421
Field Services	—	—	—	296	—	—	1,053
Total reportable segments	4,543	7	4,550	1,869	562	1,009	20,412
Other	9	38	47	(74)	22	32	3,753
Eliminations	—	(45)	(45)	—	—	—	(74)
Interest expense	—	—	—	610	—	—	—
Interest income and other (c)	—	—	—	86	—	—	—
Total consolidated	$4,552	$ —	$4,552	$1,271	$584	$1,041	$24,091
2008							
U.S. Transmission	$1,595	$ 5	$1,600	$ 844	$232	$1,400	
Distribution	1,991	—	1,991	353	175	373	
Western Canada Transmission & Processing	1,482	—	1,482	398	147	222(e)	
Field Services	—	—	—	716	—	—	
Total reportable segments	5,068	5	5,073	2,311	554	1,995	
Other	6	39	45	(78)	15	35	
Eliminations	—	(44)	(44)	—	—	—	
Interest expense	—	—	—	636	—	—	
Interest income and other (c)	—	—	—	91	—	—	
Total consolidated	$5,074	$ —	$5,074	$1,688	$569	$2,030	

(a) Excludes amounts associated with entities included in discontinued operations.
(b) Excludes the acquisition of Bobcat ($492 million).
(c) Includes foreign currency transaction gains and losses and the add-back of noncontrolling interests related to segment EBIT.
(d) Excludes the acquisition of NOARK ($295 million).
(e) Excludes the acquisition of units of the Income Fund ($274 million).

Geographic Data

	U.S.	Canada	Consolidated
		(in millions)	
2010			
Consolidated revenues (a)	$1,688	$ 3,257	$ 4,945
Consolidated long-lived assets	9,382	13,225	22,607
2009			
Consolidated revenues (a)	1,562	2,990	4,552
Consolidated long-lived assets	8,418	12,012	20,430
2008			
Consolidated revenues (a)	1,423	3,651	5,074
Consolidated long-lived assets	7,984	10,096	18,080

(a) Excludes revenues associated with businesses included in discontinued operations.

6. Regulatory Matters

Regulatory Assets and Liabilities. We record assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for non-regulated entities. See Note 1 for further discussion.

	December 31, 2010	December 31, 2009	Recovery/ Refund Period Ends
	(in millions)		
Regulatory Assets (a)(b)			
Net regulatory asset related to income taxes (c)	$ 910	$796	(d)
Project costs	29	33	2024
Vacation accrual	17	14	2011
Deferred debt expense/premium (e)	50	57	(d)
Environmental clean-up costs	5	6	2016
Gas in storage (included in Inventory)	28	35	2011
Gas purchase costs (included in Other Current Assets)	9	11	2011
Other	13	24	(f)
Total Regulatory Assets	$1,061	$976	
Regulatory Liabilities (b)			
Removal costs (e)(g)	$ 417	$389	(h)
Gas purchase costs (i)	66	185	2011
Pipeline rate credit (g)	31	32	(d)
Storage and transportation liability (i)	9	19	2011
Earnings sharing liability (i)	4	4	2011
Account rebates (i)	—	18	(f)
Other (g)	32	31	2011
Total Regulatory Liabilities	$ 559	$678	

(a) Included in Regulatory Assets and Deferred Debits unless otherwise noted.
(b) All regulatory assets and liabilities are excluded from rate base unless otherwise noted.
(c) All amounts are expected to be included in future rate filings.
(d) Recovery/refund is over the life of the associated asset or liability.
(e) Included in rate base.
(f) Recovery/refund period currently unknown.
(g) Included in Deferred Credits and Other Liabilities—Regulatory and Other.
(h) Liability is extinguished as the associated assets are retired.
(i) Included in Other Current Liabilities.

Rate Related Information

Maritimes & Northeast Pipeline, L.L.C. (M&N LLC). During 2009, M&N LLC filed a rate case with the FERC. The rate case included the impact of the Phase IV expansion facilities that went into service in January 2009 and resulted in lower recourse rates that went into effect in August 2009. In April 2010, the FERC approved a settlement that resolves all issues in the case. Although the settlement results in a reduction to M&N LLC's recourse rates, the settlement did not have a material impact on consolidated results of operations.

Maritimes & Northeast Pipeline Limited Partnership (M&N LP). M&N LP initiated interim rates effective January 1, 2010 which were equal to final approved 2009 rates. Settlement on all 2010 issues, other than compensation for funds held in escrow for the retirement of certain long-term debt, was reached in March 2010. Effective April 1, 2010, M&N LP received NEB approval of the interim rates related to the resolved issues. These 2010 interim rates are retroactive back to January 1, 2010. Final 2010 rates with respect to the issue of compensation for funds held in escrow will be determined after a proceeding before the NEB. M&N LP filed an application with the NEB on July 26, 2010 seeking compensation for funds held in escrow and finalizing 2010 tolls. The NEB issued an order setting March 1, 2011 as the initial hearing date for the escrow issue.

On December 16, 2010, M&N LP interim 2011 rates were approved by the NEB.

Algonquin Gas Transmission, LLC (Algonquin). Algonquin continues to operate under rates approved by the FERC in a 1999 settlement.

Gulfstream. Gulfstream operates under rates approved by the FERC in 2007. In 2007, the FERC issued an order approving Gulfstream's Phase III expansion project. That order also required Gulfstream to file a Cost and Revenue Study three years after the Phase III facilities go in service. The projected filing date is in the fall of 2011.

East Tennessee Natural Gas, LLC. East Tennessee continues to operate under rates approved by the FERC in a 2005 settlement.

Ozark Gas Transmission. Ozark Gas Transmission operates under rates established as a result of an uncontested settlement agreement with customers approved by the FERC in 2000. A Cost and Revenue Study was filed on February 1, 2011 by Ozark Gas Transmission as a result of a rate proceeding initiated by the FERC. Any resulting rate changes, if necessary, would be prospective.

Texas Eastern Transmission, L.P. (Texas Eastern). Texas Eastern continues to operate under rates approved by the FERC in 1998 in an uncontested settlement between Texas Eastern and its customers.

Southeast Supply Header, LLC (SESH). SESH operates under rates approved by the FERC in 2008. That order required SESH to file a Cost and Revenue Study at the end of three years of operations. The projected filing date is in the summer of 2011.

Union Gas. The incentive regulation framework approved by the OEB in 2008 establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts. The allowed return on equity (ROE) for Union Gas is formula-based and is periodically established by the OEB. The established ROE for 2008 will remain unchanged throughout the five-year incentive regulation period (2008-2012). The incentive regulation framework initially included a provision for a review of the pricing mechanism contained in that framework. That review was triggered if there was a variance of 300 basis points or more between Union Gas' actual utility ROE as normalized for weather and the utility ROE determined by the OEB.

In 2009, we recorded an $11 million charge to Operating Revenues—Distribution of Natural Gas in the Consolidated Statement of Operations as a result of a settlement with Union Gas' stakeholders that was approved by the OEB. The settlement preserves the incentive regulation framework and replaces the provision for a review of the framework with a 90/10 sharing mechanism, in favor of customers, for any utility earnings of 300 basis points or more above the benchmark utility ROE for the year and is retroactive to 2008. The $11 million charge represents the adjustment to credit customers with 90% of Union Gas' 2008 utility earnings that exceeded the 2008 benchmark utility ROE by 300 basis points.

In late 2010, the OEB approved Union Gas' 2011 regulated distribution, storage and transmission rates as determined pursuant to the incentive regulation framework. Changes to Union Gas' revenues are not expected to be material as a result of the new rates.

In 2006, Union Gas received a decision from the OEB on the regulation of rates for gas storage services in Ontario (the Storage Forbearance Decision). The OEB determined that it would 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. The Storage Forbearance Decision requires Union Gas to continue to share long-term storage margins with ratepayers over a four-year phase-out period that started in 2008. Effective in 2011, there will no longer be any sharing of margins with Union Gas customers on long-term storage transactions.

In 2008, the OEB issued its decision on Union Gas' annual disposition of the 2007 non-commodity deferral account balances, finding that Union Gas should share revenue on all long-term storage contracts. Union Gas had previously interpreted the Storage Forbearance Decision to apply only to those contracts that were in existence as of the date of that decision. In 2008, Union Gas recorded a $15 million charge to Transportation, Storage and Processing of Natural Gas operating revenues in the Consolidated Statement of Operations as a result of the 2008 decision.

Union Gas has regulatory assets of $214 million as of December 31, 2010 and $165 million as of December 31, 2009 related to deferred income tax liabilities. Under the current OEB-authorized rate structure, income tax costs are recovered in rates based on the current income tax payable and do not include accruals for deferred income tax. However, as income taxes become payable as a result of the reversal of timing differences that created the deferred income taxes, it is expected that rates will be adjusted to recover these taxes. Since substantially all of these timing differences are related to property, plant and equipment costs, recovery of these regulatory assets is expected to occur over the life of those assets, which ranges from 2-30 years.

Union Gas has removal costs of $410 million as of December 31, 2010 and $378 million as of December 31, 2009. These regulatory liabilities represent collections from customers under approved rates for future removal activities that are expected to occur associated with the regulated facilities.

In addition, Union Gas has regulatory liabilities of $39 million as of December 31, 2010 and $176 million as of December 31, 2009 representing gas cost collections from customers under approved rates that exceeded the actual cost of gas for the associated periods. Union Gas files quarterly with the OEB to ensure that customers' rates reflect future expected prices based on published forward-market prices. The difference between the approved and the actual cost of gas is deferred for future repayment to or refund from customers and is a component of quarterly gas commodity rates.

BC Pipeline and BC Field Services. BC Pipeline and its customers reached a settlement agreement, which was approved by the NEB in January 2011, regarding the determination of final tolls for transmission services for 2011, 2012 and 2013.

The BC Field Services' gathering and processing facilities currently operate under a Framework for Light-Handed Regulation (the Framework) approved by the NEB. The Framework established policies and guidelines which, among other things, permit the negotiation by BC Field Services of contracts for gathering and processing services with new and existing shippers. The Framework also provides that BC Field Services' operations are responsible for the level of utilization of its gathering and processing facilities and, consequently, bears the opportunities and risks associated with that responsibility. BC Field Services' tolls and other service conditions for gathering and processing services are subject to NEB oversight.

The BC Pipeline and BC Field Services businesses in Western Canada have regulatory assets of $584 million as of December 31, 2010 and $526 million as of December 31, 2009 related to deferred income tax liabilities. Under the current NEB-authorized rate structure, income tax costs are recovered in tolls based on the current income tax payable and do not include accruals for deferred income tax. However, as income taxes become payable as a result of the reversal of timing differences that created the deferred income taxes, it is expected that transportation and field services tolls will be adjusted to recover these taxes. Since most of these timing differences are related to property, plant and equipment costs, this recovery is expected to occur over a 20 to 30 year period.

When evaluating the recoverability of the BC Pipelines' and BC Field Services' regulatory assets, we take into consideration the NEB regulatory environment, natural gas reserve estimates for reserves located or expected to be located near these assets, the ability to remain competitive in the markets served, and projected demand growth estimates for the areas served by the BC Pipeline and BC Field Services businesses. Based on current evaluation of these factors, we believe that recovery of these tax costs is probable over the periods described above.

We believe that the effects of the above matters will not have a material adverse effect on our future consolidated results of operations, financial position or cash flows.

7. Income Taxes

Income Tax Expense Components

	2010	2009	2008
	(in millions)		
Current income taxes			
Federal	$105	$ 35	$240
State	22	1	19
Foreign	38	145	78
Total current income taxes	165	181	337
Deferred income taxes			
Federal	168	207	108
State	13	17	6
Foreign	37	(53)	42
Total deferred income taxes	218	171	156
Income tax expense from continuing operations	383	352	493
Income tax expense (benefit) from discontinued operations	(17)	1	3
Total income tax expense	$366	$353	$496

Earnings from Continuing Operations before Income Taxes

	2010	2009	2008
		(in millions)	
Domestic	$ 899	$ 807	$1,128
Foreign	607	464	560
Total earnings from continuing operations before income taxes	$1,506	$1,271	$1,688

Reconciliation of Income Tax Expense at the U.S. Federal Statutory Tax Rate to Actual Income Tax Expense from Continuing Operations

	2010	2009	2008
		(in millions)	
Income tax expense, computed at the statutory rate of 35%	$ 527	$ 445	$ 591
State income tax, net of federal income tax effect	18	12	9
Tax differential on foreign earnings	(104)	(62)	(62)
Domestic production activities deduction	(6)	(4)	(13)
Noncontrolling interests	(28)	(26)	(22)
British Columbia harmonization of tax pools	(24)	—	—
Valuation allowance on state net operating losses	1	—	—
Other items, net	(1)	(13)	(10)
Total income tax expense from continuing operations-controlling interests	$ 383	$ 352	$ 493
Effective tax rate	25.4%	27.7%	29.2%

Net Deferred Income Tax Liability Components

	December 31,	
	2010	2009
	(in millions)	
Deferred credits and other liabilities	$ 352	$ 170
Federal effects of uncertain tax benefits	16	15
Other	47	57
Total deferred income tax assets	415	242
Valuation allowance	(23)	(19)
Net deferred income tax assets	392	223
Investments and other assets	(1,283)	(1,044)
Accelerated depreciation rates	(2,414)	(2,276)
Regulatory assets and deferred debits	(256)	(117)
Total deferred income tax liabilities	(3,953)	(3,437)
Total net deferred income tax liabilities	$(3,561)	$(3,214)

The above deferred tax amounts have been classified in the Consolidated Balance Sheets as follows:

	December 31,	
	2010	2009
	(in millions)	
Other current assets	$ 26	$ 59
Other current liabilities	(32)	(64)
Deferred credits and other liabilities	(3,555)	(3,209)
Total net deferred income tax liabilities	$(3,561)	$(3,214)

At December 31, 2010, we had an unused state net operating loss carryforward of approximately $146 million that expires beginning in 2014. The deferred tax asset attributable to the state net operating loss and credit carryovers is $7 million (net of federal impacts) at December 31, 2010. In 2010, we established a valuation allowance of $1 million (net of federal impacts).

At December 31, 2010, we had a foreign net operating loss carryforward of $59 million that expires at various times beginning in 2027. The deferred tax asset attributable to the foreign net operating loss is $15 million. At December 31, 2010, we also had a foreign capital loss carryforward of $160 million with an indefinite expiration period. The deferred tax asset attributable to the foreign capital loss carryforward is $20 million. We have a valuation allowance of $20 million at December 31, 2010 and $19 million at December 31, 2009 against the deferred tax asset related to the foreign capital loss carryforward.

Reconciliation of Gross Unrecognized Income Tax Benefits

	2010	2009	2008
		(in millions)	
Balance at January 1	$ 61	$ 76	$ 86
Increases related to prior year tax positions	9	11	10
Decreases related to prior year tax positions	(2)	(29)	(10)
Increases related to current year tax positions	23	2	7
Settlements	—	(1)	—
Reductions due to lapse of statute of limitations	(11)	(3)	(10)
Foreign currency translation	2	5	(7)
Balance at December 31	$ 82	$ 61	$ 76

Unrecognized tax benefits totaled $82 million at December 31, 2010. Of this, $69 million would reduce the annual effective tax rate if recognized on or after January 1, 2011. We recorded a net increase of $21 million in gross unrecognized tax benefits during 2010. Of this, $2 million increased income tax expense and $19 million was attributable to deferred tax liabilities and foreign currency exchange rate fluctuations.

We recognize potential accrued interest and penalties related to unrecognized tax benefits as interest expense and as other expense, respectively. We recognized interest expense of $4 million in both 2010 and 2008 related to unrecognized tax benefits. Accrued interest and penalties totaled $20 million at December 31, 2010 and $16 million at December 31, 2009.

Although uncertain, we believe the total amount of unrecognized tax benefits will not materially change prior to December 31, 2011.

We have entered into an indemnification agreement with Duke Energy related to certain federal and state income taxes, including interest and penalties, for periods in which we were included in a Duke Energy consolidated, combined or unitary filing for years ended December 31, 2006 and prior. The indemnifications comprise a liability of $67 million presented in Deferred Credits and Other Liabilities—Regulatory and Other and a receivable of $23 million in Current Assets—Other on the Consolidated Balance Sheet as of December 31, 2010. The receivable results from the 2010 settlement of the federal examination for years 1999 through 2003. The indemnifications pursuant to the agreement with Duke Energy are closed for tax years prior to 1997 for state liabilities and for tax years prior to 1999 for federal liabilities.

We remain subject to examination for Canada income tax return filings for years 2002 through 2009 and U.S. income tax return filings for 2007 through 2009.

Cumulative undistributed earnings of our foreign subsidiaries at December 31, 2010 totaled $75 million for which we have not provided U.S. deferred income taxes and foreign withholding taxes since we intend to permanently reinvest such earnings in our foreign operations. Unrecognized U.S. deferred income taxes and foreign withholding taxes on these undistributed earnings are expected to be $29 million.

8. Discontinued Operations

Discontinued operations is mostly comprised of the net effects of a settlement arrangement related to prior liquefied natural gas contracts and an immaterial positive income tax adjustment in 2010 related to previously discontinued operations.

The following table summarizes results classified as Income From Discontinued Operations, Net of Tax in the accompanying Consolidated Statements of Operations:

	Operating Revenues	Pre-tax Earnings (Loss)	Income Tax Expense (Benefit)	Income From Discontinued Operations, Net of Tax
		(in millions)		
2010				
Other	$126	$ (11)	$(17)	$ 6
Total consolidated	$126	$ (11)	$(17)	$ 6
2009				
Western Canada Transmission & Processing	$ 2	$ 3	$ 1	$ 2
Other	171	3	—	3
Total consolidated	$173	$ 6	$ 1	$ 5
2008				
Western Canada Transmission & Processing	$ 24	$ 2	$ —	$ 2
Other	86	—	—	—
Total consolidated	$110	$ 2	$ —	$ 2

Spectra Energy LNG Sales, Inc. (Spectra Energy LNG) reached a settlement agreement in 2007 related to an arbitration proceeding regarding Spectra Energy LNG's claims for the period prior to May 2002 under certain liquefied natural gas (LNG) transportation contracts with Sonatrach and Sonatrading Amsterdam B.V. (Sonatrach). Spectra Energy LNG was one of the entities contributed to us by Duke Energy in connection with our spin-off from Duke Energy and has been reflected as discontinued operations. In 2008, Sonatrach and Spectra Energy entered into a settlement agreement under which Spectra Energy LNG's claims for the period after May 2002 were to be satisfied pursuant to commercial transactions involving the purchase of propane by Spectra Energy Propane, LLC (a subsidiary) from Sonatrach. We subsequently entered into associated agreements with what are now affiliates of DCP Midstream for the sale of this propane. Net purchases and sales of propane under these arrangements are reflected as Other discontinued operations. Income From Discontinued Operations, Net of Tax in 2010 includes an expense of $17 million ($11 million after-tax) for payments by us to a DCP Midstream affiliate for reimbursement of damages resulting from an alleged breach by Sonatrach of certain scheduled propane deliveries to us in the fourth quarter of 2010. We are in discussions with Sonatrach to recover these losses.

In 2008, we sold our interests in the Nevis and Brazeau River natural gas gathering and processing facilities, which were part of the Western Canada Transmission & Processing segment for 129 million Canadian dollars (approximately $104 million) and recognized a $2 million pre-tax and after-tax gain on the sale.

9. Earnings per Common Share

Basic EPS is computed by dividing net income from controlling interests by the weighted-average number of common shares outstanding during the period. Diluted EPS is computed by dividing net income from controlling interests by the diluted weighted-average number of common shares outstanding during the period. Diluted EPS reflects the potential dilution that could occur if securities or other agreements to issue common stock, such as stock options, stock-based performance unit awards and phantom stock awards, were exercised, settled or converted into common stock.

The following table presents our basic and diluted EPS calculations:

	2010	2009	2008
	(in millions, except per-share amounts)		
Income from continuing operations, net of tax—controlling interests	$1,043	$ 844	$1,132
Income from discontinued operations, net of tax—controlling interests	6	5	—
Net income—controlling interests	$1,049	$ 849	$1,132
Weighted average common shares, outstanding			
Basic	648	642	622
Diluted	650	643	624
Basic earnings per common share			
Continuing operations	$ 1.61	$1.31	$ 1.82
Discontinued operations, net of tax	0.01	0.01	—
Total basic earnings per common share	$ 1.62	$1.32	$ 1.82
Diluted earnings per common share			
Continuing operations	$ 1.60	$1.31	$ 1.81
Discontinued operations, net of tax	0.01	0.01	—
Total diluted earnings per common share	$ 1.61	$1.32	$ 1.81

Weighted-average shares used to calculate diluted EPS includes the effect of certain options and restricted stock awards. Certain other options and stock awards related to approximately ten million shares in each of 2010, 2009 and 2008 were not included in the calculation of diluted EPS because either the option exercise prices were greater than the average market price of the shares during these periods or performance measures related to the awards had not yet been met.

10. Marketable Securities and Restricted Funds

Interest income, associated primarily with marketable securities, totaled $3 million in 2010, $4 million in 2009 and $22 million in 2008, and is included in Other Income and Expenses, Net on the Consolidated Statements of Operations.

AFS Marketable Securities. During 2010, we invested a portion of the proceeds from Spectra Energy Partners' issuance of common units to the public in AFS marketable securities, which include investments in money market and commercial paper. These investments, which totaled $209 million as of December 31, 2010, are pledged as collateral against Spectra Energy Partners' term loan and are classified as Investments and Other Assets—Other on the Consolidated Balance Sheet. In addition, we had $15 million of other AFS marketable securities at December 31, 2010 and $7 million at December 31, 2009.

Additional information regarding AFS investments follows:

	December 31, 2010			December 31, 2009		
	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value
			(in millions)			
Corporate debt securities	$—	$—	$222	$—	$—	$—
Money market funds	—	—	2	—	—	7
Total available-for-sale investments	$—	$—	$224	$—	$—	$ 7

HTM Marketable Securities. HTM marketable securities, totaling $182 million at December 31, 2010 and $121 million at December 31, 2009, are classified as Investments and Other Assets—Other in the Consolidated Balance Sheets. These securities, primarily Canadian government securities, are restricted funds pursuant to certain M&N LP debt agreements. These funds, plus future cash from operations that would otherwise be available for distribution to the partners of M&N LP, are placed in escrow until the balance in escrow is sufficient to fund all future debt service on the notes. The notes payable, totaling $234 million, have semi-annual interest and principal payments and are due in 2019.

Additional information regarding HTM investments follows:

	December 31, 2010			December 31, 2009		
	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value
			(in millions)			
Canadian government securities	$—	$—	$182	$—	$—	$113
Money market funds	—	—	—	—	—	8
Total held-to-maturity investments	$—	$—	$182	$—	$—	$121

Other Restricted Funds. In addition to the HTM securities held in escrow described above, we had funds totaling $44 million and $38 million at December 31, 2010 and 2009, respectively, classified as Current Assets—Other, and $5 million and $5 million, respectively, classified as Investments and Other Assets—Other, that were also considered restricted funds. These restricted funds are mostly related to insurance and additional amounts for the M&N LP debt service requirements.

Changes in restricted cash balances are presented within Cash Flows From Investing Activities on our Consolidated Statements of Cash Flows.

Short-term investments. We had no short-term investments outstanding at December 31, 2010 or 2009. In 2009, we redeemed $13 million of short-term investments and had no purchases. In 2008, we transferred $13 million in investments associated with captive insurance from restricted reserves, and had no other sales or purchases.

During 2008, the U.S. Transmission segment received shares of stock as consideration for a customer bankruptcy settlement and recorded a $31 million ($21 million after tax) gain based on the quoted market price on the date of receipt which is reflected in Gains on Sales of Other Assets and Other, Net in the Consolidated Statement of Operations. The stock was subsequently sold in 2008, resulting in net proceeds of $27 million, reflected in Cash Flows from Operating Activities on the Consolidated Statements of Cash Flows, and a loss of $4 million recorded as Other Income and Expenses, Net.

11. Investments in and Loans to Unconsolidated Affiliates and Related Party Transactions

Investments in affiliates for which we are not the primary beneficiary, but over which we have significant influence, are accounted for using the equity method. As of December 31, 2010 and 2009, the carrying amounts of investments in affiliates approximated the amounts of underlying equity in net assets. We received distributions from our equity investments of $391 million in 2010, $359 million in 2009 and $995 million in 2008. Cumulative undistributed earnings of unconsolidated affiliates totaled $228 million at December 31, 2010 and $192 million at December 31, 2009.

U.S. Transmission. As of December 31, 2010, investments are mostly comprised of a 35% effective interest in Gulfstream, and 50% interests in SESH and Steckman Ridge, LP (Steckman Ridge). Gulfstream is an interstate natural gas pipeline that extends from Mississippi and Alabama across the Gulf of Mexico to Florida. SESH is an interstate natural gas pipeline that extends from northeast Louisiana to Mobile County, Alabama where it connects to the Gulfstream system. Steckman Ridge is a storage project located in Bedford County, Pennsylvania.

In 2007, we and CenterPoint Energy Gas Transmission Company (the co-owner of SESH) entered into a loan agreement with SESH whereby each member agreed to loan funds to SESH, as needed and on a pro rata basis, in connection with the construction of its pipeline facilities. In 2009, $137 million of the outstanding loan from us was re-characterized as a capital infusion to SESH. In addition, we received $186 million from SESH in 2009, recorded as Cash Flows From Investing Activities—Receipt From Affiliate—Repayment of Loan on the Consolidated Statement of Cash Flows, representing full repayment of the remaining balance of the outstanding loan receivable. A portion of these funds were from the proceeds of a debt issuance by SESH. We recorded interest income on the SESH loan of $4 million in 2009 and $10 million in 2008.

In 2009, we received a $148 million special distribution from Gulfstream from the proceeds of a debt issuance by Gulfstream, of which $144 million was classified as Cash Flows from Investing Activities—Distributions Received From Unconsolidated Affiliates on the Consolidated Statement of Cash Flows.

We have made loans to Steckman Ridge in connection with the construction of its storage facilities. The loans carry market-based interest rates and are due the earlier of December 31, 2017 or coincident with the closing of any long-term financings by Steckman Ridge. The loan receivable from Steckman Ridge, including accrued interest, totaled $71 million at both December 31, 2010 and December 31, 2009. We recorded interest income on the Steckman Ridge loan of $1 million in each of 2010, 2009 and 2008.

We are also a 50% equity partner and operator for Islander East Pipeline Company, L.L.C. (Islander East), an entity formed to develop and own a pipeline that would connect natural gas supplies to markets on Long Island, New York. Algonquin, a wholly owned subsidiary, also had a companion project, the AGT Islander East Lease Project. During 2008, Islander East was denied a petition for certiorari by the U.S. Supreme Court with respect to a water quality certificate that had been denied by the State of Connecticut.

As Islander East considered various project path alternatives in 2008 for connecting natural gas supplies to Long Island, it became evident that credit and recessionary pressures would likely result in significant further delay of any alternative project ultimately agreed upon with the appropriate customers. Triggered by fourth quarter 2008 legal and economic events, capitalized development costs associated with Islander East were evaluated as to probability of recovery. We evaluated the likelihood of various project outcomes in order to estimate the fair value of recoverable costs. This analysis resulted in an impairment charge in 2008 of $44 million before tax ($12 million in Operating, Maintenance and Other expenses and $32 million in Equity in Earnings of Unconsolidated Affiliates), representing our share of impaired assets associated with Islander East.

Field Services. Our most significant investment in unconsolidated affiliates is our 50% investment in DCP Midstream which is accounted for under the equity method of accounting. DCP Midstream is a limited liability company which is a pass-through entity for U.S. income tax purposes. DCP Midstream also owns corporations who file their own respective federal, foreign and state income tax returns. Income tax expense related to these corporations is included in the income tax expense of DCP Midstream. Therefore, DCP Midstream's net income attributable to members' interests does not include income taxes for earnings which are passed through to the members based upon their ownership percentage. We recognize the tax effects of our share of DCP Midstream's pass-through earnings in Income Tax Expense from Continuing Operations in the Consolidated Statements of Operations.

In 2005, DCP Midstream formed DCP Midstream Partners, LP (DCP Partners), a master limited partnership, and completed an IPO of DCP Partners. As a result of the adoption of ASC 810-10-65 in January 2009, DCP Midstream reclassified to equity certain deferred gains on sales of common units in DCP Partners. Our proportionate 50% share, totaling $135 million pre-tax, was recorded in Equity in Earnings of Unconsolidated Affiliates in the Consolidated Statement of Operations in the first quarter of 2009. In 2010, DCP Midstream recorded to equity gains on additional sales of common units of DCP Partners. Our proportionate share, totaling $30 million, was recorded in Equity in Earnings of Unconsolidated Affiliates.

Investments in and Loans to Unconsolidated Affiliates

	December 31, 2010			December 31, 2009		
	Domestic	International	Total	Domestic	International	Total
			(in millions)			
U.S. Transmission	$ 932	$—	$ 932	$ 969	$—	$ 969
Distribution	—	19	19	—	—	—
Western Canada Transmission & Processing	—	19	19	—	14	14
Field Services	1,063	—	1,063	1,018	—	1,018
Total	$1,995	$38	$2,033	$1,987	$14	$2,001

Equity in Earnings of Unconsolidated Affiliates

	2010			2009			2008		
	Domestic	International	Total	Domestic	International	Total	Domestic	International	Total
					(in millions)				
U.S. Transmission	$ 94	$—	$ 94	$ 74	$—	$ 74	$ 59	$—	$ 59
Western Canada Transmission & Processing	—	1	1	—	(1)	(1)	—	4	4
Field Services	335	—	335	296	—	296	715	—	715
Total	$429	$ 1	$430	$370	$ (1)	$369	$774	$ 4	$778

Summarized Combined Financial Information of Unconsolidated Affiliates (Presented at 100%)

Statements of Operations

	2010			2009			2008		
	DCP Midstream	Other	Total	DCP Midstream	Other	Total	DCP Midstream	Other	Total
	(in millions)								
Operating revenues	$10,981	$483	$11,464	$8,560	$446	$9,006	$16,398	$330	$16,728
Operating expenses	10,138	203	10,341	8,026	199	8,225	14,704	222	14,926
Operating income	843	280	1,123	534	247	781	1,694	108	1,802
Net income	619	223	842	306	168	474	1,519	102	1,621
Net income attributable to members' interests	592	223	815	322	168	490	1,431	102	1,533

Balance Sheets

	December 31, 2010			December 31, 2009		
	DCP Midstream	Other	Total	DCP Midstream	Other	Total
	(in millions)					
Current assets	$ 1,574	$ 212	$ 1,786	$ 1,809	$ 198	$ 2,007
Non-current assets	6,664	3,340	10,004	6,183	3,572	9,755
Current liabilities	(2,206)	(96)	(2,302)	(2,534)	(65)	(2,599)
Non-current liabilities	(3,551)	(1,667)	(5,218)	(3,140)	(1,891)	(5,031)
Equity—total	2,481	1,789	4,270	2,318	1,814	4,132
Equity—noncontrolling interests	(421)	—	(421)	(315)	—	(315)
Equity—controlling interests	$ 2,060	$ 1,789	$ 3,849	$ 2,003	$ 1,814	$ 3,817

Related Party Transactions

DCP Midstream. DCP Midstream processes certain of our pipeline customers' gas to meet gas quality specifications in order to be transported on our Texas Eastern system. DCP Midstream processes the gas and sells the NGLs that are extracted from the gas. A portion of the proceeds from those sales are retained by DCP Midstream and the balance is remitted to us. We received proceeds of $82 million in 2010, $63 million in 2009 and $121 million in 2008 from DCP Midstream related to those sales, classified as Other Operating Revenues.

As discussed in Note 8, we entered into a propane sales agreement with an affiliate of DCP Midstream in 2008. We recorded revenues of $85 million in 2010, $98 million in 2009 and $49 million in 2008 associated with this agreement, as well as an expense of $17 million in 2010, classified within Income From Discontinued Operations, Net of Tax.

In addition to the above, we recorded other revenues from DCP Midstream and its affiliates totaling $8 million in 2010 and $7 million in both 2009 and 2008, primarily within Transportation, Storage and Processing of Natural Gas.

We had accounts receivable from DCP Midstream and its affiliates of $21 million at December 31, 2010 and $15 million at December 31, 2009. In addition, we had distributions receivable from DCP Midstream of $38 million at December 31, 2010 and $36 million at December 31, 2009 recorded within Receivables on the Consolidated Balance Sheet. Total distributions received from DCP Midstream were $288 million in 2010, $101 million in 2009 and $930 million in 2008. Of these distributions, $288 million in 2010, $101 million in 2009 and $715 million in 2008 were recorded within Cash Flows from Operating Activities, and $215 million in 2008 were recorded within Cash Flows from Investing Activities.

Other. We provide certain administrative and other services to our equity investment operating entities. We recorded recoveries of costs from these affiliates of $23 million in 2010, $24 million in 2009 and $54 million in 2008. Outstanding receivables from these affiliates totaled $5 million at December 31, 2010 and $5 million at December 31, 2009.

See also Notes 4, 16 and 18 for additional related party information.

12. Goodwill

The following tables show the components and activity within goodwill:

	December 31, 2008	Increases (a)	December 31, 2009	Increases (a)	December 31, 2010
			(in millions)		
U. S. Transmission	$2,019	$372	$2,391	$278	$2,669
Distribution	727	104	831	42	873
Western Canada Transmission & Processing	635	91	726	37	763
Total consolidated	$3,381	$567	$3,948	$357	$4,305

(a) Increases consist of foreign currency translation and $150 million of goodwill at U.S. Transmission associated with the acquisition of NOARK in 2009 and $188 million associated with the acquisition of Bobcat in 2010. NOARK and Bobcat are part of U.S. Transmission. See Note 4 for further discussion.

The following goodwill amounts originating from the acquisition of Westcoast Energy, Inc. (Westcoast) in 2002 are included in Other within the segment data presented in Note 5:

	December 31, 2010	December 31, 2009
	(in millions)	
U.S. Transmission	$1,872	$1,781
Distribution	870	828
Western Canada Transmission & Processing	724	690

No impairments of goodwill were recorded in 2010, 2009 or 2008. Based on the results of our annual impairment testing, the fair values of our reporting units with associated goodwill at December 31, 2010 significantly exceeded their carrying value. See Note 1 for discussion of goodwill impairment testing.

13. Property, Plant and Equipment

	Estimated Useful Life	December 31, 2010	December 31, 2009
	(years)	(in millions)	
Plant			
Natural gas transmission	20–100	$11,851	$11,047
Natural gas distribution	27–60	2,732	2,484
Gathering and processing facilities	25–40	3,459	3,069
Storage	5–122	1,795	1,377
Land rights and rights of way	21–122	377	356
Other buildings and improvements	10–50	102	94
Equipment	3–40	377	389
Vehicles	5–20	90	94
Land	—	91	91
Construction in process	—	660	419
Software	4–25	294	232
Other	5–82	334	308
Total property, plant and equipment		22,162	19,960
Total accumulated depreciation and amortization		(5,182)	(4,613)
Total net property, plant and equipment		$16,980	$15,347

We had no material capital leases at December 31, 2010 or 2009.

Almost 90% of our property, plant and equipment is regulated with estimated useful lives based on rates approved by the applicable regulatory authorities in the United States and Canada: the FERC, the NEB and the OEB. Composite weighted-average depreciation rates were 3.14% for 2010, 3.17% for 2009 and 3.29% for 2008.

Amortization expense of intangible assets totaled $58 million in 2010, $54 million in 2009 and $50 million in 2008. Estimated amortization expense for the next five years follows:

	Estimated Amortization Expense
	(in millions)
2011	$66
2012	68
2013	67
2014	33
2015	32

14. Asset Retirement Obligations

Our asset retirement obligations relate mostly to the retirement of certain gathering pipelines and processing facilities, obligations related to right-of-way agreements and contractual leases for land use. However, we have determined that a significant portion of our assets have an indeterminate life, and as such, the fair value of the retirement obligation is not reasonably estimable. These assets include onshore and some offshore pipelines, and certain processing plants and distribution facilities, whose retirement dates will depend mostly on the various natural gas supply sources that connect to our systems and the ongoing demand for natural gas usage in the markets we serve. We expect these supply sources and market demands to continue for the foreseeable future, therefore we are unable to estimate retirement dates that would result in asset retirement obligations.

Asset retirement obligations are adjusted each period for liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows.

Reconciliation of Changes in Asset Retirement Obligation Liabilities

	2010	2009
	(in millions)	
Balance at beginning of year	$143	$ 84
Accretion expense	8	6
Revisions in estimated cash flows	1	45
Foreign currency exchange impact	7	13
Liabilities settled	(2)	(5)
Balance at end of year (a)	$157	$143

(a) Amounts included in Deferred Credits and Other Liabilities in the Consolidated Balance Sheets.

15. Debt and Credit Facilities

Summary of Debt and Related Terms

	Weighted-Average Interest Rate	Year Due	December 31, 2010	2009
			(in millions)	
Unsecured debt	6.4%	2011–2040	$ 9,812	$9,299
Secured debt	4.0%	2011–2019	618	418
Commercial paper (a)	0.5%	—	836	162
Fair value hedge carrying value adjustment		2011–2025	70	51
Unamortized debt discount and premium, net			(16)	(12)
Total debt (b)			11,320	9,918
Current maturities of long-term debt			(315)	(809)
Short-term borrowings and commercial paper (c)			(836)	(162)
Total long-term debt			$10,169	$8,947

(a) The weighted-average days to maturity was 11 days as of December 31, 2010 and 7 days as of December 31, 2009.

(b) As of December 31, 2010 and 2009, respectively, $4,746 million and $4,239 million of debt was denominated in Canadian dollars.

(c) Weighted-average rates on outstanding short-term borrowings and commercial paper were 0.5% as of December 31, 2010 and 0.3% as of December 31, 2009.

In 2008, M&N LLC paid $288 million to retire its outstanding bonds and bank debt, and an additional $54 million early-extinguishment premium for the bonds. The payment of the premium, a regulatory asset, is presented within Cash Flows from Financing Activities—Other on the Consolidated Statement of Cash Flows.

Secured Debt. Secured debt as of December 31, 2010 and 2009 includes project financing for M&N LP. Ownership interests in M&N LP and certain of its accounts, revenues, business contracts and other assets are pledged as collateral.

Secured debt also included the term debt of Spectra Energy Partners which is collateralized by investment-grade securities. The terms of the secured debt allow for the liquidation of collateral to fund capital expenditures or certain acquisitions provided that an equal amount of the term loan is repaid. Investments in marketable securities totaling $209 million as of December 31, 2010 were pledged as collateral against the term loan. See Note 10 for further discussion.

Floating Rate Debt. Unsecured, secured and other debt included approximately $1,342 million of floating-rate debt as of December 31, 2010 and $402 million as of December 31, 2009. The weighted average interest rate of borrowings outstanding that contained floating rates was 0.5% at both December 31, 2010 and 2009.

Annual Maturities

	December 31, 2010
	(in millions)
2011	$ 315
2012	832
2013	1,162
2014	1,185
2015	334
Thereafter	6,656
Total long-term debt (a)	$10,484

(a) Excludes short-term borrowings and commercial paper of $836 million.

We have the ability under certain debt facilities to call and repay the obligations prior to scheduled maturities. Therefore, the actual timing of future cash repayments could be materially different than presented above.

Available Credit Facilities and Restrictive Debt Covenants

	Expiration Date	Credit Facilities Capacity	Outstanding at December 31, 2010 Commercial Paper	Revolving Credit	Letters of Credit	Total	Available Credit Facilities Capacity
			(in millions)				
Spectra Capital (a)							
Multi-year syndicated	2012	$1,500	$679	$ —	$13	$ 692	$ 808
Westcoast (b)							
Multi-year syndicated	2011	200	—	—	—	—	200
Union Gas (c)							
Multi-year syndicated	2012	501	157	—	—	157	344
Spectra Energy Partners							
Multi-year syndicated	2012	500	—	299	—	299	201
Total		$2,701	$836	$299	$13	$1,148	$1,553

(a) Credit facility contains a covenant requiring the debt-to-total capitalization ratio to not exceed 65%.

(b) U.S. dollar equivalent at December 31, 2010. The credit facilities totals 200 million Canadian dollars and contains a covenant that requires the Westcoast non-consolidated debt-to-total capitalization ratio to not exceed 75%. The ratio was 44% at December 31, 2010.

(c) U.S. dollar equivalent at December 31, 2010. The credit facilities totals 500 million Canadian dollars and contains a covenant that requires the Union Gas debt-to-total capitalization ratio to not exceed 75% and a provision which requires Union Gas to repay all borrowings under the facility for a period of two days during the second quarter of each year. The ratio was 64% at December 31, 2010.

The issuance of commercial paper, letters of credit and other borrowings reduces the amounts available under the credit facilities.

Our credit agreements contain various financial and other covenants, including the maintenance of certain financial ratios. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements. As of December 31, 2010, we were in compliance with those covenants. In addition, our credit agreements allow for the acceleration of payments or termination of the agreements due to nonpayment, or in some cases, due to the acceleration of other significant indebtedness of the borrower or some of its subsidiaries. Our debt and credit agreements do not contain provisions that trigger an acceleration of indebtedness based solely on the occurrence of a material adverse change in our financial condition or results of operations.

As noted above, the terms of our Spectra Capital credit agreement require our consolidated debt-to-total capitalization ratio to be 65% or lower. As of December 31, 2010, this ratio was 56%. Approximately $6.1 billion of our equity (net assets) was considered restricted at December 31, 2010, representing the minimum amount of equity required to maintain the 65% consolidated debt-to-total capitalization ratio at December 31, 2010.

16. Preferred Stock of Subsidiaries

Westcoast and Union Gas have outstanding preferred shares that are generally not redeemable prior to specified redemption dates. On or after those dates, the shares may be redeemed, in whole or in part, for cash at the option of Westcoast and Union Gas, as applicable. The shares are not subject to any sinking fund or mandatory redemption and are not convertible into any other securities of Westcoast or Union Gas. As redemption of the shares is not solely within our control, we have classified the preferred stock of subsidiaries as temporary equity on our Consolidated Balance Sheets. Dividends are cumulative and payable quarterly, and are included in Net Income—Noncontrolling Interests in the Consolidated Statements of Operations.

17. Fair Value Measurements

The following table presents, for each of the fair value hierarchy levels, assets and liabilities that are measured and recorded at fair value on a recurring basis:

Description	Consolidated Balance Sheet Caption	December 31, 2010 Total	Level 1	Level 2	Level 3
		(in millions)			
Corporate debt securities	Cash and cash equivalents	$ 74	$—	$ 74	$—
Corporate debt securities	Investments and other assets—other	222	—	222	—
Derivative assets—interest rate swaps	Investments and other assets—other	48	—	48	—
Money market funds	Investments and other assets—other	25	25	—	—
Total Assets		$369	$25	$344	$—
Derivative liabilities—natural gas purchase contracts	Deferred credits and other liabilities—regulatory and other	$ 6	$—	$ —	$ 6
Derivative liabilities—interest rate swaps	Deferred credits and other liabilities—regulatory and other	20	—	20	—
Total Liabilities		$ 26	$—	$ 20	$ 6

Description	Consolidated Balance Sheet Caption	December 31, 2009 Total	Level 1	Level 2	Level 3
		(in millions)			
Money market funds	Cash and cash equivalents	$ 14	$14	$ —	$—
Corporate debt securities	Cash and cash equivalents	50	—	50	—
Derivative assets—natural gas purchase contracts	Investments and other assets—other	15	—	—	15
Derivative assets—interest rate swaps	Investments and other assets—other	18	—	18	—
Money market funds	Investments and other assets—other	25	25	—	—
Total Assets		$122	$39	$ 68	$15
Derivative liabilities—interest rate swaps	Deferred credits and other liabilities—regulatory and other	$ 17	$—	$ 17	$—
Total Liabilities		$ 17	$—	$ 17	$—

The following table presents changes in Level 3 assets and liabilities that are measured at fair value on a recurring basis using significant unobservable inputs:

	December 31, 2010	December 31, 2009
	(in millions)	
Long-term derivative assets (liabilities)		
Fair value, beginning of period	$ 15	$ 36
Total realized/unrealized gains (losses):		
Included in earnings	—	(7)
Included in Investments and Other Assets—Other	—	2
Included in other comprehensive income	(21)	(16)
Fair value, end of period	$ (6)	$ 15
Total gains (losses) for the period included in earnings (or changes in net assets) attributable to the change in unrealized gains or losses relating to assets/liabilities held at the end of the period	$ (2)	$ (6)

Level 1

Level 1 valuations represent quoted unadjusted prices for identical instruments in active markets.

Level 2 Valuation Techniques

Fair values of our financial instruments that are actively traded in the secondary market, primarily corporate debt securities, are determined based on market-based prices. These valuations may include inputs such as quoted market prices of the exact or similar instruments, broker or dealer quotations, or alternative pricing sources that may include models or matrix pricing tools, with reasonable levels of price transparency.

For interest rate swaps, we utilize data obtained from multiple sources for the determination of fair value. Both the future cash flows for the fixed-leg and floating-leg of our swaps are discounted to present value. In addition, credit default swap rates are used to develop the adjustment for credit risk embedded in our positions. We believe that since some of the inputs and assumptions for the calculations of fair value are derived from observable market data, a Level 2 classification is appropriate.

Level 3 Valuation Techniques

We do not have significant amounts of assets or liabilities measured and reported using Level 3 valuation techniques, which include the use of pricing models, discounted cash flow methodologies or similar techniques where at least one significant model assumption or input is unobservable. Level 3 financial instruments also include those for which the determination of fair value requires significant management judgment or estimation.

Financial Instruments

The fair values of financial instruments that are recorded and carried at book value are summarized in the following table. Judgment is required in interpreting market data to develop the estimates of fair value. These estimates are not necessarily indicative of the amounts we could have realized in current markets.

	December 31,			
	2010		2009	
	Book Value	Approximate Fair Value	Book Value	Approximate Fair Value
	(in millions)			
Notes receivable, current (a)	$ 50	$ 51	$ —	$ —
Notes receivable, noncurrent (b)	71	71	116	118
Long-term debt, including current maturities	10,484	11,874	9,756	10,690

(a) Included within Receivables on the Consolidated Balance Sheets.
(b) Included within Investments and Other Assets—Other on the Consolidated Balance Sheets.

The fair values of long-term debt consider the terms of the related debt absent the impacts of derivative/hedging activities. The book values of long-term debt include the impacts of certain "pay floating—receive fixed" interest rate swaps that are designated as fair value hedges.

The fair values of cash and cash equivalents, restricted cash, short-term investments, accounts receivable, accounts payable, short-term borrowings and commercial paper are not materially different from their carrying amounts because of the short-term nature of these instruments or because the stated interest rates approximate market rates.

During 2010 and 2009, there were no material adjustments to assets and liabilities measured at fair value on a nonrecurring basis.

18. Risk Management and Hedging Activities

We are exposed to the impact of market fluctuations in the prices of NGLs and natural gas purchased as a result of our equity investment in DCP Midstream and our Empress operations in Canada. Exposure to interest rate risk exists as a result of the issuance of variable and fixed-rate debt and commercial paper. We are exposed to foreign currency risk from our Canadian operations. We employ established policies and procedures to manage our risks associated with these market fluctuations, which may include the use of forward physical transactions as well as other derivatives, primarily around interest rate exposures.

Our equity investment affiliate, DCP Midstream, also has risk exposures primarily associated with market prices of NGLs and natural gas. DCP Midstream manages these risks separate from Spectra Energy, and utilizes various risk management strategies, including the use of commodity derivatives.

Derivative Portfolio Carrying Value as of December 31, 2010

Asset/(Liability)	Maturity in 2011	Maturity in 2012	Maturity in 2013	Maturity in 2014 and Thereafter	Total Carrying Value
			(in millions)		
Hedging	$ (3)	$ (2)	$33	$ 13	$ 41
Undesignated	—	—	—	(19)	(19)
Total	$ (3)	$ (2)	$33	$ (6)	$ 22

These amounts represent the combination of amounts presented as assets (liabilities) for unrealized gains and losses on mark-to-market and hedging transactions on our Consolidated Balance Sheet and do not include any derivative positions of DCP Midstream.

Accumulated unrealized mark-to-market net losses on hedges included in AOCI on the Consolidated Balance Sheet totaled $52 million as of December 31, 2010.

See Note 17 for information regarding the presentation of these derivative positions on our Consolidated Balance Sheets.

Commodity Cash Flow Hedges. Our Empress operations are exposed to market fluctuations in the prices of natural gas and NGLs related to natural gas processing and marketing activities. We closely monitor the potential effects of commodity price changes and may choose to enter into contracts to protect margins for a portion of future sales and fuel expenses by using financial commodity instruments, such as swaps, forward contracts and options. There were no significant commodity cash flow hedge transactions during 2010, 2009 or 2008.

Interest Rate Hedges. Changes in interest rates expose us to risk as a result of our issuance of variable and fixed-rate debt and commercial paper. We manage our interest rate exposure by limiting our variable-rate exposures to percentages of total debt and by monitoring the effects of market changes in interest rates. We also enter into financial derivative instruments, including, but not limited to, interest rate swaps and rate lock agreements to manage and mitigate interest rate risk exposure.

For interest rate derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk is recognized in the Consolidated Statements of Operations. There were no material amounts of gains or losses, either effective or ineffective, recognized in net income or other comprehensive income in 2010, 2009 or 2008.

At December 31, 2010, we had interest rate hedges in place for various purposes. We had "pay floating—receive fixed" interest rate swaps with a total notional principal amount of $1,500 million to hedge against changes in the fair value of our fixed-rate debt that arise as a result of changes in market interest rates. These swaps also allow us to transform a portion of the underlying cash flows related to our long-term fixed-rate debt securities into variable-rate debt in order to achieve our desired mix of fixed and variable-rate debt. At Spectra Energy Partners, we had third-party "pay fixed—receive floating" interest rate swaps with a total notional principal amount of $40 million to mitigate our exposure to variable interest rates on loans outstanding under its revolving credit facility.

Foreign Currency Risk. We are exposed to foreign currency risk from investments and operations in Canada. To mitigate risks associated with foreign currency fluctuations, contracts may be denominated in or indexed to the U.S. dollar and/or local inflation rates, or investments may be naturally hedged through debt denominated or issued in the foreign currency. To monitor our currency exchange rate risks, we use sensitivity analysis, which measures the effect of devaluation of the Canadian dollar.

Credit Risk. Our principal customers for natural gas transportation, storage and gathering and processing services are industrial end-users, marketers, exploration and production companies, local distribution companies and utilities located throughout the United States and Canada. We have concentrations of receivables from natural gas utilities and their affiliates, industrial customers and marketers throughout these regions, as well as retail distribution customers in Canada. These concentrations of customers may affect our overall credit risk in that risk factors can negatively affect the credit quality of the entire sector. Where exposed to credit risk, we analyze the customers' financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of those limits on an ongoing basis. We also obtain parental guarantees, cash deposits or letters of credit from customers to provide credit support, where appropriate, based on our financial analysis of the customer and the regulatory or contractual terms and conditions applicable to each contract.

Included in Other Current Liabilities and Deferred Credits and Other Liabilities—Regulatory and Other are collateral liabilities of $78 million at December 31, 2010 and $88 million at December 31, 2009, which represent cash collateral posted by third parties with us.

19. Commitments and Contingencies

General Insurance

We carry, either directly or through our captive insurance companies, insurance coverages consistent with companies engaged in similar commercial operations with similar type properties. Our insurance program includes (1) commercial general and excess liability insurance for liabilities to third parties for bodily injury and property damage resulting from our operations; (2) workers' compensation liability coverage to required statutory limits; (3) automobile liability insurance for all owned, non-owned and hired vehicles covering liabilities to third parties for bodily injury and property damage; (4) insurance policies in support of the indemnification provisions of our by-laws; and (5) property insurance, including machinery breakdown, on an all-risk-replacement valued basis, onshore business interruption and extra expense. All coverages are subject to certain deductibles, terms and conditions common for companies with similar types of operations.

Environmental

We are subject to various U.S. federal, state and local laws and regulations, as well as Canadian federal and provincial laws, regarding air and water quality, hazardous and solid waste disposal and other environmental matters. These laws and regulations can change from time to time, imposing new obligations on us.

Like others in the energy industry, we and our affiliates are responsible for environmental remediation at various contaminated sites. These include some properties that are part of our ongoing operations, sites formerly owned or used by us, and sites owned by third parties. Remediation typically involves management of contaminated soils and may involve groundwater remediation. Managed in conjunction with relevant international, federal, state/provincial and local agencies, activities vary with site conditions and locations, remedial requirements, complexity and sharing of responsibility. If remediation activities involve statutory joint and several liability provisions, strict liability, or cost recovery or contribution actions, we or our affiliates could potentially be held responsible for contamination caused by other parties. In some instances, we may share liability associated with contamination with other potentially responsible parties, and may also benefit from insurance policies or contractual indemnities that cover some or all cleanup costs. All of these sites generally are managed in the normal course of business or affiliated operations.

Included in Deferred Credits and Other Liabilities—Regulatory and Other on the Consolidated Balance Sheets are accruals related to extended environmental-related activities totaling $14 million as of December 31, 2010 and $16 million as of December 31, 2009. These accruals represent provisions for costs associated with remediation activities at some of our current and former sites, as well as other environmental contingent liabilities.

Litigation

Litigation and Legal Proceedings. We are involved in legal, tax and regulatory proceedings in various forums arising in the ordinary course of business, including matters regarding contract and payment claims, some of which involve substantial monetary amounts. We have insurance coverage for certain of these losses should they be incurred. We believe that the final disposition of these proceedings will not have a material adverse effect on our consolidated results of operations, financial position or cash flows.

Legal costs related to the defense of loss contingencies are expensed as incurred. We had no material reserves recorded as of December 31, 2010 or 2009 related to litigation.

Other Commitments and Contingencies

See Note 20 for a discussion of guarantees and indemnifications.

Operating Lease Commitments

We lease assets in various areas of our operations. Consolidated rental expense for operating leases classified in Income From Continuing Operations was $49 million in 2010, $47 million in 2009 and $50 million in 2008, which is included in Operating, Maintenance and Other on the Consolidated Statements of Operations. Capital leases are of negligible amounts. The following is a summary of future minimum lease payments under operating leases which at inception had a noncancelable term of more than one year. We had no material capital lease commitments at December 31, 2010.

	Long-term Operating Leases
	(in millions)
2011	$ 30
2012	30
2013	29
2014	27
2015	26
Thereafter	38
Total future minimum lease payments	$180

20. Guarantees and Indemnifications

We have various financial guarantees and indemnifications which are issued in the normal course of business. As discussed below, these contracts include financial guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. We enter into these arrangements to facilitate a commercial transaction with a third party by enhancing the value of the transaction to the third party. To varying degrees, these guarantees involve elements of performance and credit risk, which are not included on the Consolidated Balance Sheets. The possibility of having to perform under these guarantees and indemnifications is largely dependent upon future operations of various subsidiaries, investees and other third parties, or the occurrence of certain future events.

We have issued performance guarantees to customers and other third parties that guarantee the payment and performance of other parties, including certain non-wholly owned entities. In connection with our spin-off from Duke Energy, certain guarantees that were previously issued by us were assigned to, or replaced by, Duke Energy as guarantor in 2006. For any remaining guarantees of other Duke Energy obligations, Duke Energy has indemnified us against any losses incurred under these guarantee arrangements. The maximum potential amount of future payments we could have been required to make under these performance guarantees as of December 31, 2010 was approximately $406 million, which has been indemnified by Duke Energy as discussed above. One of our outstanding performance guarantees expires in 2028. The remaining guarantees have no contractual expirations.

We have also issued joint and several guarantees to some of the Duke/Fluor Daniel (D/FD) project owners, guaranteeing the performance of D/FD under its engineering, procurement and construction contracts and other contractual commitments. D/FD is one of the entities transferred to Duke Energy in connection with our spin-off from Duke Energy. Substantially all of these guarantees have no contractual expiration and no stated maximum amount of future payments that we could be required to make. Fluor Enterprises Inc., as 50% owner in D/FD, has issued similar joint and several guarantees to the same D/FD project owners.

Westcoast, a wholly owned subsidiary, has issued performance guarantees to third parties guaranteeing the performance of unconsolidated entities, such as equity method investments, and of entities previously sold by Westcoast to third parties. Those guarantees require Westcoast to make payment to the guaranteed third party upon the failure of such unconsolidated or sold entity to make payment under some of its contractual obligations, such as debt, purchase contracts and leases. Certain guarantees that were previously issued by Westcoast for obligations of entities that remained a part of Duke Energy are considered guarantees of third party performance; however, Duke Energy has indemnified us against any losses incurred under these guarantee arrangements. The maximum potential amount of future payments Westcoast could have been required to make under those performance guarantees of unconsolidated entities and third-party entities as of December 31, 2010 was $60 million. Of these guarantees, $5 million expire in 2015 and the remaining have no contractual expirations.

We have entered into various indemnification agreements related to purchase and sale agreements and other types of contractual agreements with vendors and other third parties. These agreements typically cover environmental, tax, litigation and other matters, as well as breaches of representations, warranties and covenants. Typically, claims may be made by third parties for various periods of time depending on the nature of the claim. Our potential exposure under these indemnification agreements can range from a specified amount, such as the purchase price, to an unlimited dollar amount, depending on the nature of the claim and the particular transaction. We are unable to estimate the total potential amount of future payments under these indemnification agreements due to several factors, such as the unlimited exposure under certain guarantees.

As of December 31, 2010, the amounts recorded for the guarantees and indemnifications, described above, including the indemnifications by Duke Energy to us, are not material, both individually and in the aggregate.

21. Common Stock Issuance and Repurchases

In 2009, we issued 32.2 million shares of our common stock and received net proceeds of $448 million. We used the net proceeds to repay commercial paper as it matured. Borrowings from the commercial paper were used for capital expenditures and for other general corporate purposes.

In 2008, our Board of Directors authorized a share repurchase program of up to $600 million under which purchases of our common stock under the program were made from time to time in the open market. During 2008, we repurchased a total of 22.3 million shares for $600 million, and the share repurchase program was concluded. The shares were retired upon repurchase and are presented as a reduction to Additional Paid-in Capital.

22. Effects of Changes in Noncontrolling Interests Ownership

The following table presents the effects of changes in our ownership interests in non-wholly owned consolidated subsidiaries:

	2010	2009	2008
	(in millions)		
Net Income—Controlling Interests	$1,049	$849	$1,132
Increase in Additional Paid-in Capital resulting from sales of units of Spectra Energy Partners (a)	50	25	—
Total Net Income—Controlling Interests and changes in Equity—Controlling Interests	$1,099	$874	$1,132

(a) See Note 3 for further discussion.

23. Stock-Based Compensation

The Spectra Energy Corp 2007 Long-Term Incentive Plan (the 2007 LTIP) provides for the granting of stock options, restricted stock awards and units, unrestricted stock awards and units, and other equity-based awards, to employees and other key individuals who perform services for us. A maximum of 30 million shares of common stock may be awarded under the 2007 LTIP.

Options granted under the 2007 LTIP are issued with exercise prices equal to the fair market value of our common stock on the grant date, have ten year terms and generally vest immediately or over terms not to exceed three years. Compensation expense related to stock options is recognized over the requisite service period. The requisite service period for stock options is the same as the vesting period, with the exception of retirement eligible employees, who have shorter requisite service periods ending when the employees become retirement eligible.

Restricted, performance and phantom stock awards granted under the 2007 LTIP typically become 100% vested on the three-year anniversary of the grant date. The fair value of the awards granted is measured based on the fair value of the shares on the date of grant. Related compensation expense is recognized over the requisite service period which is the same as the vesting period.

At the time of our spin-off from Duke Energy, Duke Energy converted stock options, restricted stock awards, performance awards and phantom stock awards (collectively, Stock-Based Awards) of Duke Energy common stock held by our employees and Duke Energy employees. One replacement Duke Energy Stock-Based Award and one-half Spectra Energy Stock-Based Award were distributed to each holder of Duke Energy Stock-Based Awards for each award held at the time of the spin-off. The Spectra Energy Stock-Based Awards resulting from the conversion are considered to have been issued under the 2007 LTIP.

After the spin-off, we receive all cash proceeds related to the exercise of Spectra Energy stock options held by Duke Energy employees; however, Duke Energy will recognize all associated expense and resulting tax benefits relating to such stock options. Similarly, we will recognize all associated expense and tax benefits relating to Duke Energy awards held by our employees. We recognize compensation expense, receive all cash proceeds and retain all tax benefits relating to Spectra Energy awards held by our employees.

We recorded pre-tax stock-based compensation expense in continuing operations as follows, the components of which are further described below:

	2010	2009	2008
	(in millions)		
Stock options	$—	$—	$ 3
Phantom stock	13	8	10
Performance awards	13	6	6
Total	$26	$14	$19

The tax benefit in income from continuing operations associated with the recorded expense was $4 million in 2010, $3 million in 2009 and $7 million in 2008. We recognized tax benefits from stock-based compensation cost of approximately $2 million in 2010, $3 million in 2009 and $14 million in 2008 in Additional Paid-in Capital.

Stock Option Activity

	Options	Weighted-Average Exercise Price	Weighted-Average Remaining Life	Aggregate Intrinsic Value
	(in thousands)		(in years)	(in millions)
Outstanding at December 31, 2009	10,976	$26	3.6	$16
Exercised	(787)	16		
Forfeited or expired	(1,636)	36		
Outstanding at December 31, 2010	8,553	25	3.2	23
Exercisable at December 31, 2010	8,553	25	3.2	23
Options expected to vest	—			

We granted employees 20,000 non-qualified stock options in 2009, with a fair value of less than $1 million and a market price of $4.73 per share. We did not award any non-qualified stock options to employees during 2010 or 2008. Under the terms of the 2007 LTIP, the exercise price of a non-qualified stock option shall not be less than 100% of the fair market value of our common stock on the date of grant, and the maximum option term is ten years. We issue new shares upon exercising or vesting of share-based awards. The Black-Scholes option-pricing model was used to estimate the fair value of options at grant date.

Weighted-Average Assumptions for Option Pricing

The following weighted average assumptions were used for option pricing in 2009:

	2009
Risk-free rate of return	1.4%
Expected life	7 years
Expected volatility	41%
Expected dividend yield	5.3%

The risk-free rate of return was determined based on a yield curve of U.S. Treasury rates ranging from six months to ten years and a period commensurate with the expected life of the options granted. The expected volatility was established based on historical volatility and implied volatility of a group of 19 peer company stock prices. The expected dividend yield was determined based on our annual dividend amount as a percentage of the average stock price at the time of grant.

Coincident with our spin-off, all exercisable Duke Energy options were converted in accordance with the share conversion guidelines on a two-to-one basis, with no change to overall intrinsic value. The total intrinsic value of options exercised was $6 million in 2010, $1 million in 2009 and $4 million in 2008. Cash received by us from options exercised was $13 million in 2010, $3 million in 2009 and $12 million in 2008. We recognized a nominal tax benefit in each of 2010, 2009 and 2008 since the options exercised were predominately held by Duke Energy employees. As of December 31, 2010, we do not expect to recognize future compensation costs related to stock options.

Stock Awards Activity

	Performance Awards		Phantom Stock Awards	
	Shares	Weighted Average Grant Date Fair Value	Shares	Weighted Average Grant Date Fair Value
	(shares in thousands)			
Outstanding at December 31, 2009	1,225	$20	1,763	$20
Granted	624	31	655	21
Vested	—	—	(444)	26
Forfeited	(21)	24	(21)	19
Outstanding at December 31, 2010	1,828	24	1,953	19
Awards expected to vest	1,806	24	1,929	19

Performance Awards

Under the 2007 LTIP, we can also grant performance awards. Stock-based performance awards generally vest over three years at the earliest, if performance metrics are met. We granted 624,100 performance awards during 2010 (fair value of $19 million), 830,100 awards during 2009 (fair value of $12 million), and 497,500 awards during 2008 (fair value of $15 million). The unvested and outstanding performance awards granted contain market conditions based on the total shareholder return of Spectra Energy common stock relative to a pre-defined peer group. These awards are valued using the Monte Carlo valuation method.

Weighted-Average Assumptions for Performance Awards

	2010	2009	2008
Risk-free rate of return	1.4%	1.4%	2.3%
Expected life	3 years	3 years	3 years
Expected volatility—Spectra Energy	38%	41%	24%
Expected volatility—peer group	22%–59%	21%–53%	14%–29%
Market index	30%	29%	14%

The risk-free rate of return was determined based on a yield of three-year U.S. Treasury bonds on the grant date. The expected volatility was established based on historical volatility over three years using daily stock price observations. A shorter period was used if three years of data was not available. Because the award payout includes dividend equivalents, no dividend yield assumption is required.

No performance awards vested in 2010, as Spectra Energy performance awards were first granted in 2008. The total fair value of shares vested in 2009 was $11 million and $10 million in 2008. These awards were related to the converted Stock-Based Awards previously discussed. As of December 31, 2010, we expect to recognize $19 million of future compensation cost related to outstanding performance awards over a weighted-average period of less than two years.

Phantom Stock Awards

Stock-based phantom awards granted under the 2007 LTIP generally vest over three years. We awarded 655,100 phantom awards to our employees in 2010 (fair value of $14 million), 837,900 phantom awards in 2009 (fair value of $11 million) and 545,000 phantom awards in 2008 (fair value of $13 million).

The total fair value of the shares vested in 2010 was $12 million, $5 million in 2009 and $10 million in 2008. As of December 31, 2010, we expect to recognize $15 million of future compensation cost related to phantom stock awards over a weighted-average period of less than two years.

24. Employee Benefit Plans

Retirement Plans. We have a qualified non-contributory defined benefit (DB) retirement plan for U.S. employees and non-qualified plans for various executive retirement and savings plans. The qualified plan covers U.S. employees using a cash balance formula. Under a cash balance formula, a plan participant accumulates a retirement benefit consisting of pay credits that are based upon a percentage (which may vary with age and years of service) of current eligible earnings and current interest credits.

In addition, our Westcoast subsidiary maintains qualified and non-qualified contributory and non-contributory DB and defined contribution (DC) retirement plans covering substantially all employees of our Canadian operations. The DB plans provide retirement benefits based on each plan participant's years of service and final average earnings. Under the DC plan, company contributions are determined according to the terms of the plan and based on each plan participant's age, years of service and current eligible earnings. We also provide non-qualified defined benefit supplemental pensions to all employees who retire under a defined benefit qualified pension plan and whose pension is limited by the maximum pension limits under the Income Tax Act (Canada). We report our Canadian benefit plans separate from the U.S. plans due to differences in actuarial assumptions.

Our policy is to fund our retirement plans on an actuarial basis to provide assets sufficient to meet benefits to be paid to plan participants or as required by legislation or plan terms. We made discretionary contributions of $30 million to our U.S. retirement plans in 2010 and made no contributions in 2009 or 2008. We made total contributions to the Canadian DC and qualified DB plans of $68 million in 2010, $61 million in 2009, and $40 million in 2008. We anticipate that we will make total contributions of approximately $20 million to the U.S. plans and approximately $75 million to the Canadian plans in 2011.

Actuarial gains and losses are amortized over the average remaining service period of active employees. The average remaining service period of active employees covered by the qualified DB retirement plans is 10 years for both the U.S. and Canadian plans. The average remaining service period of active employees covered by the non-qualified DB retirement plans is nine years for the U.S. plan and 14 years for the Canadian plans. We determine the market-related value of plan assets using a calculated value that recognizes changes in fair value of the plan assets over five years for the U.S. plans and over three years for the Canadian plans.

Qualified Pension Plans

Qualified Pension Plans—Change in Projected Benefit Obligation and Change in Fair Value of Plan Assets

	U.S.		Canada	
	2010	2009	2010	2009
	(in millions)			
Change in Projected Benefit Obligation				
Projected benefit obligation, beginning of period	$485	$461	$ 765	$ 570
Service cost	11	9	16	12
Interest cost	25	27	45	39
Actuarial loss	21	24	57	71
Participant contributions	—	—	4	4
Benefits paid	(32)	(36)	(38)	(34)
Prior service cost	—	—	—	6
Foreign currency translation effect	—	—	46	97
Projected benefit obligation, end of period	510	485	895	765
Change in Fair Value of Plan Assets				
Plan assets, beginning of period	405	353	605	442
Actual return on plan assets	44	88	85	62
Benefits paid	(32)	(36)	(38)	(34)
Employer contributions	30	—	61	56
Plan participants' contributions	—	—	4	4
Foreign currency translation effect	—	—	37	75
Plan assets, end of period	447	405	754	605
Net amount recognized(a)	$(63)	$(80)	$(141)	$(160)

(a) Recognized in Deferred Credits and Other Liabilities—Regulatory and Other in the Consolidated Balance Sheets.

The plans noted above had accumulated benefit obligations in excess of plan assets. The accumulated benefit obligation was $485 million at December 31, 2010 and $464 million at December 31, 2009 for the U.S. plan, and $837 million at December 31, 2010 and $696 million at December 31, 2009 for the Canadian plans.

Qualified Pension Plans—Amounts Recognized in Accumulated Other Comprehensive Income

	U.S.		Canada	
	December 31,		December 31,	
	2010	2009	2010	2009
	(in millions)			
Net actuarial loss	$178	$178	$251	$247
Prior service costs	1	1	12	14
Net reduction of AOCI	$179	$179	$263	$261

Qualified Pension Plans—Components of Net Periodic Pension Costs

	U.S.			Canada		
	2010	2009	2008	2010	2009	2008
	(in millions)					
Net Periodic Pension Cost						
Service cost benefit earned	$ 11	$ 9	$ 9	$ 16	$ 12	$ 16
Interest cost on projected benefit obligation	25	27	27	45	39	38
Expected return on plan assets	(31)	(33)	(36)	(45)	(42)	(46)
Amortization of prior service cost	—	—	—	2	1	1
Amortization of loss	8	5	3	17	2	5
Net periodic pension cost	13	8	3	35	12	14
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income						
Current year actuarial loss (gain)	8	(31)	169	18	51	77
Amortization of actuarial loss	(8)	(5)	(3)	(17)	(2)	(5)
Amortization of prior service credit	—	—	—	(2)	(1)	(1)
Current year prior service cost	—	—	—	—	6	4
Foreign currency translation effect	—	—	—	3	17	(38)
Total decrease (increase) in other comprehensive income	—	(36)	166	2	71	37
Total Recognized in Net Periodic Pension Cost and Other Comprehensive Income	$ 13	$(28)	$169	$ 37	$ 83	$ 51

At December 31, 2010, approximately $11 million of actuarial losses for the U.S. plans and $24 million for the Canadian plans will be amortized from AOCI on the Consolidated Balance Sheets into net periodic benefit cost in 2011. At December 31, 2010, approximately $2 million of prior service costs were included in AOCI that will be recognized in net periodic costs in 2011 for the Canadian plans.

Qualified Pension Plans—Assumptions Used for Pension Benefits Accounting

	U.S.			Canada		
	2010	2009	2008	2010	2009	2008
Benefit Obligations						
Discount rate	4.82%	5.28%	5.91%	5.25%	5.87%	6.46%
Salary increase	4.68	4.73	5.77	3.25	3.50	3.50
Net Periodic Benefit Cost						
Discount rate	5.28	5.91	6.00	5.87	6.46	5.25
Salary increase	4.73	5.77	5.71	3.50	3.50	3.50
Expected long-term rate of return on plan assets	7.25	7.25	7.50	7.00	7.00	7.25

The discount rates used to determine the pension obligations are the rates at which the pension obligations could be effectively settled. The discount rate for our U.S. plan is developed from yields on available high-quality bonds and reflects the plan's expected cash flows. For our Canadian plans, the discount rate is the yield on Canadian corporate AA bonds with cash flows that match the timing and amount of the expected benefit payments under the plans.

The long-term rates of return for the U.S. and Canadian plan assets as of December 31, 2010 were developed using weighted-average calculations of expected returns based primarily on future expected returns across classes considering the use of active asset managers applied against the U.S. and Canadian plans' respective targeted asset mix.

Qualified Pension Plan Assets

Asset Category	U.S. Target Allocation	U.S. December 31, 2010	U.S. December 31, 2009	Canada Target Allocation	Canada December 31, 2010	Canada December 31, 2009
U.S. equity securities	30%	32%	46%	14%	14%	15%
Canadian equity securities	—	—	—	28	29	31
Fixed income securities	15	15	20	13	13	15
Debt securities	49	48	34	45	44	39
Other investments	6	5	—	—	—	—
Total	100%	100%	100%	100%	100%	100%

Pension plan assets are maintained in master trusts in both the U.S. and Canada. The investment objective of the master trusts is to achieve reasonable returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for plan participants. The asset allocation targets were set after considering the investment objective and the risk profile with respect to the trusts. Equities are held for their high expected return. Other equities and debt securities are held for diversification. Investments within asset classes are diversified to achieve broad market participation and reduce the effects of individual managers or investments. We regularly review our actual asset allocation and periodically rebalance our investments to the targeted allocation when considered appropriate.

The following table summarizes the fair values of pension plan assets recorded at each fair value hierarchy level, as determined in accordance with the valuation techniques described in Note 17:

	U.S. Total	U.S. Level 1	U.S. Level 2	U.S. Level 3	Canada Total	Canada Level 1	Canada Level 2	Canada Level 3
	(in millions)							
December 31, 2010								
Cash and cash equivalents	$ 1	$ 1	$—	$—	$ 3	$ 3	$ —	$—
Fixed income securities	213	213	—	—	333	—	333	—
Equity securities	209	209	—	—	415	—	415	—
Other	24	—	—	24	3	—	—	3
Total	$447	$423	$—	$24	$754	$ 3	$748	$ 3
December 31, 2009								
Cash and cash equivalents	$ —	$ —	$—	$—	$ 3	$ 3	$ —	$—
Fixed income securities	147	147	—	—	236	—	236	—
Equity securities	256	256	—	—	363	—	363	—
Other	2	—	2	—	3	—	—	3
Total	$405	$403	$ 2	$—	$605	$ 3	$599	$ 3

The change in the U.S. pension plan assets categorized as Level 3 is attributable to new investments made during 2010.

Qualified Pension Plans—Expected Benefit Payments

	U.S.	Canada
	(in millions)	
2011	$ 43	$ 43
2012	44	45
2013	43	48
2014	42	51
2015	45	53
2016 – 2020	252	301

Non-Qualified Pension Plans

We maintain non-qualified, non-contributory defined benefit plans which cover certain U.S. executives and Canadian employees. The non-qualified plans have no plan assets.

Non-Qualified Pension Plans—Change in Projected Benefit Obligation and Fair Value of Plan Assets

	U.S.		Canada	
	2010	2009	2010	2009
	(in millions)			
Change in Projected Benefit Obligation				
Projected benefit obligation, beginning of period	$ 19	$ 20	$ 97	$ 72
Service cost	—	1	1	1
Interest cost	1	1	6	5
Actuarial loss (gain)	(1)	1	7	12
Benefits paid	(1)	(1)	(6)	(5)
Foreign currency translation effect	—	—	5	12
Settlements	—	(3)	—	—
Projected benefit obligation, end of period	18	19	110	97
Change in Fair Value of Plan Assets				
Plan assets, beginning of period	—	—	—	—
Benefits paid	(1)	(1)	(6)	(5)
Employer contributions	1	4	6	5
Settlements	—	(3)	—	—
Fair value of plan assets, end of period	—	—	—	—
Amount recognized, end of period (a)	$(18)	$(19)	$(110)	$(97)
Accumulated Benefit Obligation	$ 16	$ 16	$ 106	$ 93

(a) Amounts are reflected primarily in Deferred Credits and Other Liabilities—Regulatory and Other within the Consolidated Balance Sheets.

We paid lump sum amounts (settlements) in 2009 which fully released plan obligations of approximately $3 million.

Non-Qualified Pension Plans—Amounts Recognized in Accumulated Other Comprehensive Income

The amounts recognized in AOCI for the U.S. plan were $1 million at December 31, 2010 and $2 million at December 31, 2009. Net actuarial losses for the Canadian non-qualified pension plans totaling $27 million at December 31, 2010 and $21 million at December 31, 2009 were recognized in AOCI.

At December 31, 2010, $1 million of unrecognized losses was included in AOCI that will be recognized in net periodic non-qualified pension costs in 2011 for the U.S. and Canadian plans.

Non-Qualified Pension Plans—Components of Net Periodic Pension Costs

	U.S.			Canada		
	2010	2009	2008	2010	2009	2008
	(in millions)					
Net Periodic Pension Cost						
Service cost benefit earned	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1
Interest cost on projected benefit obligation	1	1	1	6	5	5
Amortization of loss	—	—	—	1	—	1
Net periodic pension cost	2	2	2	8	6	7
Other Changes in Plan Assets and Benefits Obligations Recognized in Other Comprehensive Income						
Current year actuarial loss (gain)	(1)	1	1	7	12	(12)
Amortization of actuarial loss	—	—	—	(1)	—	(1)
Foreign currency translation effect	—	—	—	—	—	(2)
Total decrease (increase) in other comprehensive income	(1)	1	1	6	12	(15)
Total recognized in net periodic pension cost and other comprehensive income	$ 1	$ 3	$ 3	$14	$18	$ (8)

The lump sum payments in 2009 associated with the settlements previously discussed did not have a significant effect on net periodic pension cost.

Non-Qualified Pension Plans—Assumptions Used for Pension Benefits Accounting

	U.S.			Canada		
	2010	2009	2008	2010	2009	2008
Benefit Obligations						
Discount rate	4.82%	5.28%	5.91%	5.25%	5.87%	6.46%
Salary increase	4.39	4.45	4.77	3.25	3.50	3.50
Net Periodic Benefit Cost						
Discount rate	5.28	5.91	6.00	5.87	6.46	5.25
Salary increase	4.45	4.77	5.08	3.50	3.50	3.50

The discount rates used to determine the pension obligations are the rates at which the pension obligations could be effectively settled. The discount rate for our U.S. plan is developed from yields on available high-quality bonds and reflects the plan's expected cash flows. For our Canadian plan, the discount rate is the yield on Canadian corporate AA bonds with cash flows that match the timing and amount of the expected benefit payments under the plan.

Non-Qualified Pension Plans—Expected Benefit Payments

	U.S.	Canada
	(in millions)	
2011	$1	$ 6
2012	1	6
2013	2	6
2014	2	6
2015	2	6
2016 – 2020	8	32

Contributions for the non-qualified pension plans are equal to that of benefit payments, therefore, we expect to contribute $1 million to the U.S. plan and $6 million to the Canadian plan in 2011.

Other Post-Retirement Benefit Plans

U.S. Other Post-Retirement Benefits. We provide certain health care and life insurance benefits for retired employees on a contributory and non-contributory basis. Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans.

These benefit costs are accrued over an employee's active service period to the date of full benefits eligibility. The 1993 net unrecognized transition obligation from the adoption of a new accounting standard is being amortized over approximately 20 years, with three years remaining. Actuarial gains and losses are amortized over the average remaining service period of the active employees of 12 years. We determine the market-related value of the plan assets using a calculated value that recognizes changes in fair value of the plan assets over five years for the U.S. plans.

Canadian Other Post-Retirement Benefits. We provide health care and life insurance benefits for retired employees on a non-contributory basis for our Canadian operations predominantly under defined contribution plans. Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans. The Canadian plans are not funded.

Other Post-Retirement Benefit Plans—Change in Projected Benefit Obligation and Fair Value of Plan Assets

	U.S.		Canada	
	2010	2009	2010	2009
	(in millions)			
Change in Benefit Obligation				
Accumulated post-retirement benefit obligation, beginning of period	$ 213	$ 241	$ 109	$ 80
Service cost	1	1	3	2
Interest cost	11	14	7	6
Plan participants' contribution	3	3	—	—
Actuarial loss (gain)	2	(24)	13	11
Medicare subsidy receivable	2	3	—	—
Benefits paid	(20)	(22)	(4)	(4)
Plan amendments	(7)	(3)	—	—
Foreign currency translation effect	—	—	7	14
Accumulated post-retirement benefit obligation, end of period	205	213	135	109
Change in Fair Value of Plan Assets				
Plan assets, beginning of period	75	68	—	—
Actual return on plan assets	5	8	—	—
Benefits paid	(20)	(22)	(4)	(4)
Employer contributions	15	18	4	4
Plan participants' contributions	3	3	—	—
Plan assets, end of period	78	75	—	—
Amount recognized, end of period (a)	$(127)	$(138)	$(135)	$(109)

(a) Recognized primarily in Deferred Credits and Other Liabilities—Regulatory and Other on the Consolidated Balance Sheets.

Other Post-Retirement Benefit Plans—Amounts Recognized in Accumulated Other Comprehensive Income

	U.S.		Canada	
	December 31,		December 31,	
	2010	2009	2010	2009
	(in millions)			
Prior service costs (credits)	$—	$—	$ (8)	$ (8)
Net actuarial loss	22	22	22	9
Transition obligation	2	12	—	—
Net decrease in AOCI	$24	$34	$14	$ 1

As of December 31, 2010, approximately $1 million of transition obligations and $2 million of actuarial losses were included in AOCI in the Consolidated Balance Sheet that will be recognized in net periodic costs in 2011 for the U.S. plan. As of December 31, 2010, approximately $1 million of prior service credits were included in AOCI that will be recognized in net periodic costs in 2011 for the Canadian plans. These credits will be offset by $1 million of actuarial losses that were also included in AOCI at December 31, 2010 and will be amortized through net periodic costs in 2011.

	U.S.			Canada		
	2010	2009	2008	2010	2009	2008
	(in millions)					
Other Post-Retirement Benefit Plans—Components of Net Periodic Benefit Cost						
Service cost benefit earned	$ 1	$ 1	$ 1	$ 3	$ 2	$ 3
Interest cost on accumulated post-retirement benefit obligation	11	13	14	7	6	5
Expected return on plan assets	(5)	(5)	(5)	—	—	—
Amortization of net transition liability	4	5	5	—	—	—
Amortization of prior service credit	—	—	—	(1)	(1)	—
Amortization of loss	1	2	2	1	—	—
Net periodic other post-retirement benefit cost	12	16	17	10	7	8
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income						
Current year actuarial loss (gain)	1	(27)	14	13	11	(13)
Amortization of actuarial loss	(1)	(2)	(2)	(1)	—	—
Current year prior service credit	(6)	(3)	—	—	—	—
Amortization of prior service credit	—	—	—	1	1	—
Amortization of transition asset/obligation	(4)	(5)	(5)	—	—	—
Foreign currency translation effect	—	—	—	—	(1)	1
Total decrease (increase) in other comprehensive income	(10)	(37)	7	13	11	(12)
Total recognized in net periodic benefit cost and other comprehensive income	$ 2	$(21)	$24	$23	$18	$ (4)

Other Post-Retirement Benefits Plans—Assumptions Used for Benefits Accounting

	U.S.			Canada		
	2010	2009	2008	2010	2009	2008
Benefit Obligations						
Discount rate for post-retirement life plans	5.09%	5.51%	6.01%	5.31%	5.95%	6.57%
Discount rate for post-retirement medical plans	4.83	5.30	5.95	5.31	5.95	6.57
Salary increase	4.68	4.73	5.71	3.25	3.50	3.50
Net Periodic Benefit Cost						
Discount rate for post-retirement life plans	5.51	6.01	6.00	5.95	6.57	5.25
Discount rate for post-retirement medical plans	5.30	5.95	6.00	5.95	6.57	5.25
Salary increase	4.73	5.77	5.71	3.50	3.50	3.50
Expected return on plan assets for post-retirement life plans	7.25	7.25	7.25	n/a	n/a	n/a
Expected return on plan assets for post-retirement medical plans	6.18	6.17	6.29	n/a	n/a	n/a

n/a Indicates not applicable.

The discount rates used to determine the post-retirement obligations are the rates at which the pension obligations could be effectively settled. The discount rate for our U.S. plan is developed from yields on available high-quality bonds and reflects the plan's expected cash flows. For our Canadian plan, the discount rate is the yield on Canadian corporate AA bonds with cash flows that match the timing and amount of the expected benefit payments under the plan.

Assumed Health Care Cost Trend Rates

	U.S. and Canada	
	2010	2009
Health care cost trend rate assumed for next year	8.00%	8.00%
Rate to which the cost trend is assumed to decline	5.00%	5.00%
Year that the rate reaches the ultimate trend rate	2017	2016

Sensitivity to Changes in Assumed Health Care Cost Trend Rates

	U.S.		Canada	
	1% Point Increase	1% Point Decrease	1% Point Increase	1% Point Decrease
	(in millions)			
Effect on total service and interest costs	$1	$(1)	$ 1	$(1)
Effect on post-retirement benefit obligations	9	(8)	10	(9)

Other Post-Retirement Plan Assets

	U.S. December 31,	
Asset Category	2010	2009
Equity securities	45%	49%
Debt securities	50	45
Other assets	5	6
Total	100%	100%

A portion of our other post-retirement plan assets are maintained within the two master trusts discussed under pension plans above. We also invest other post-retirement plan assets in the Spectra Energy Corp Employee Benefits Trust (VEBA I) and the Spectra Energy Corp Post-Retirement Medical Benefits Trust (VEBA II). The investment objective of the VEBAs is to achieve sufficient returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of promoting the security of plan benefits for participants. The VEBA trusts are passively managed.

The asset allocation table above includes the other post-retirement benefit assets held in the master trusts, VEBA I and VEBA II.

The following table summarizes the fair values of the other post-retirement plan assets recorded at each fair value hierarchy level as determined in accordance with the valuation techniques described in Note 17:

	U.S.							
	VEBA I and VEBA II Trusts				Master Trust			
	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3
	(in millions)							
December 31, 2010								
Cash and cash equivalents	$ 2	$ 2	$—	$—	$—	$—	$—	$—
Fixed income securities	23	—	23	—	16	16	—	—
Equity securities	19	—	19	—	16	16	—	—
Other investments	—	—	—	—	2	—	—	2
Total	$44	$ 2	$42	$—	$34	$32	$—	$ 2
December 31, 2009								
Cash and cash equivalents	$ 5	$ 5	$—	$—	$—	$—	$—	$—
Fixed income securities	23	—	23	—	11	11	—	—
Equity securities	17	—	17	—	19	19	—	—
Total	$45	$ 5	$40	$—	$30	$30	$—	$—

The increase in the Master Trust plan assets categorized as Level 3 is attributable to new investments made during 2010.

Other Post-Retirement Benefit Plans-Payments and Receipts

We expect to make future benefit payments, which reflect expected future service, as appropriate. As our plans provide benefits that are actuarially equivalent to the benefits received by Medicare recipients, we expect to receive future subsidies under Medicare Part D. The following benefit payments and subsidies are expected to be paid (or received) over each of the next five years and thereafter.

	Benefit Payments		Medicare Part D Subsidy Receipts
	U.S.	Canada	U.S.
	(in millions)		
2011	$21	$ 5	$3
2012	20	5	2
2013	20	5	2
2014	20	6	2
2015	20	6	2
2016 – 2020	90	29	9

We anticipate making contributions of $6 million to the U.S. plans in 2011 and $5 million to the Canadian plans.

Retirement Savings Plan

We have an employee savings plan that covers substantially all U.S. employees. Most employees participate in a matching contribution formula where we provide a matching contribution generally equal to 100% of before-tax employee contributions, of up to 6% of eligible pay per pay period. We expensed pre-tax employer matching contributions of $11 million in both 2010 and 2009, and $10 million in 2008.

25. Consolidating Financial Information

Spectra Energy Corp has agreed to fully and unconditionally guarantee the payment of principal and interest under all series of notes outstanding under the Senior Indenture of Spectra Capital, a wholly owned, consolidated subsidiary. In accordance with SEC rules, the following condensed consolidating financial information is presented. The information shown for Spectra Energy Corp and Spectra Capital is presented utilizing the equity method of accounting for investments in subsidiaries, as required. The non-guarantor subsidiaries column represents all wholly owned subsidiaries of Spectra Capital. This information should be read in conjunction with our accompanying Consolidated Financial Statements and notes thereto.

Spectra Energy Corp
Condensed Consolidating Statement of Operations
Year Ended December 31, 2010
(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total operating revenues	$ —	$ —	$4,945	$ —	$4,945
Total operating expenses	15	2	3,264	—	3,281
Gains on sales of other assets and other, net	—	—	10	—	10
Operating income (loss)	(15)	(2)	1,691	—	1,674
Equity in earnings of unconsolidated affiliates	—	—	430	—	430
Equity in earnings of subsidiaries	1,062	1,492	—	(2,554)	—
Other income and expenses, net	—	(4)	36	—	32
Interest expense	—	199	431	—	630
Earnings from continuing operations before income taxes	1,047	1,287	1,726	(2,554)	1,506
Income tax expense (benefit) from continuing operations	(2)	225	160	—	383
Income from continuing operations	1,049	1,062	1,566	(2,554)	1,123
Income from discontinued operations, net of tax	—	—	6	—	6
Net income	1,049	1,062	1,572	(2,554)	1,129
Net income—noncontrolling interests	—	—	80	—	80
Net income—controlling interests	$1,049	$1,062	$1,492	$(2,554)	$1,049

Spectra Energy Corp
Condensed Consolidating Statement of Operations
Year Ended December 31, 2009
(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total operating revenues	$ —	$ —	$4,552	$ —	$4,552
Total operating expenses	10	7	3,071	—	3,088
Gains on sales of other assets and other, net	—	—	11	—	11
Operating income (loss)	(10)	(7)	1,492	—	1,475
Equity in earnings of unconsolidated affiliates	—	—	369	—	369
Equity in earnings of subsidiaries	857	1,239	—	(2,096)	—
Other income and expenses, net	1	23	13	—	37
Interest expense	1	207	402	—	610
Earnings from continuing operations before income taxes	847	1,048	1,472	(2,096)	1,271
Income tax expense (benefit) from continuing operations	(2)	191	163	—	352
Income from continuing operations	849	857	1,309	(2,096)	919
Income from discontinued operations, net of tax	—	—	5	—	5
Net income	849	857	1,314	(2,096)	924
Net income—noncontrolling interests	—	—	75	—	75
Net income—controlling interests	$849	$ 857	$1,239	$(2,096)	$ 849

Spectra Energy Corp
Condensed Consolidating Statement of Operations
Year Ended December 31, 2008
(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total operating revenues	$ —	$ —	$5,074	$ —	$5,074
Total operating expenses	7	—	3,629	—	3,636
Gains on sales of other assets and other, net	—	—	42	—	42
Operating income (loss)	(7)	—	1,487	—	1,480
Equity in earnings of unconsolidated affiliates	—	—	778	—	778
Equity in earnings of subsidiaries	1,126	1,651	—	(2,777)	—
Other income and expenses, net	1	23	42	—	66
Interest expense	—	249	387	—	636
Earnings from continuing operations before income taxes	1,120	1,425	1,920	(2,777)	1,688
Income tax expense (benefit) from continuing operations	(12)	299	206	—	493
Income from continuing operations	1,132	1,126	1,714	(2,777)	1,195
Income from discontinued operations, net of tax	—	—	2	—	2
Net income	1,132	1,126	1,716	(2,777)	1,197
Net income—noncontrolling interests	—	—	65	—	65
Net income—controlling interests	$1,132	$1,126	$1,651	$(2,777)	$1,132

Spectra Energy Corp
Condensed Consolidating Balance Sheet
December 31, 2010
(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash and cash equivalents	$ —	$ —	$ 130	$ —	$ 130
Receivables (payables)—consolidated subsidiaries	(46)	208	(162)	—	—
Receivables (payables)—other	(4)	1	1,021	—	1,018
Other current assets	63	37	390	—	490
Total current assets	13	246	1,379	—	1,638
Investments in and loans to unconsolidated affiliates	—	74	1,959	—	2,033
Investments in consolidated subsidiaries	10,683	13,979	—	(24,662)	—
Advances receivable (payable)—consolidated subsidiaries	(2,835)	3,463	(57)	(571)	—
Goodwill	—	—	4,305	—	4,305
Other assets	43	45	577	—	665
Property, plant and equipment, net	—	—	16,980	—	16,980
Regulatory assets and deferred debits	—	13	1,052	—	1,065
Total Assets	$ 7,904	$17,820	$26,195	$(25,233)	$26,686
Accounts payable—other	$ 1	$ 76	$ 292	$ —	$ 369
Short-term borrowings and commercial paper	—	1,250	157	(571)	836
Accrued taxes payable (receivable)	(145)	99	105	—	59
Current maturities of long-term debt	—	8	307	—	315
Other current liabilities	76	67	801	—	944
Total current liabilities	(68)	1,500	1,662	(571)	2,523
Long-term debt	—	3,302	6,867	—	10,169
Deferred credits and other liabilities	163	2,335	2,751	—	5,249
Preferred stock of subsidiaries	—	—	258	—	258
Equity					
Controlling interests	7,809	10,683	13,979	(24,662)	7,809
Noncontrolling interests	—	—	678	—	678
Total equity	7,809	10,683	14,657	(24,662)	8,487
Total Liabilities and Equity	$ 7,904	$17,820	$26,195	$(25,233)	$26,686

Spectra Energy Corp
Condensed Consolidating Balance Sheet
December 31, 2009
(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash and cash equivalents	$ —	$ —	$ 166	$ —	$ 166
Receivables (payables)—consolidated subsidiaries	(28)	248	(220)	—	—
Receivables (payables)—other	(4)	2	780	—	778
Other current assets	6	6	473	—	485
Total current assets	(26)	256	1,199	—	1,429
Investments in and loans to unconsolidated affiliates	—	74	1,927	—	2,001
Investments in consolidated subsidiaries	9,235	12,454	—	(21,689)	—
Advances receivable (payable)—consolidated subsidiaries	(2,063)	2,440	(30)	(347)	—
Goodwill	—	—	3,948	—	3,948
Other assets	38	30	339	—	407
Property, plant and equipment, net	—	—	15,347	—	15,347
Regulatory assets and deferred debits	1	15	943	—	959
Total Assets	$ 7,185	$15,269	$23,673	$(22,036)	$24,091
Accounts payable (receivable)—consolidated subsidiaries	$ —	$ 41	$ (41)	$ —	$ —
Accounts payable—other	1	93	239	—	333
Short-term borrowings and commercial paper	—	388	121	(347)	162
Accrued taxes payable (receivable)	(93)	54	178	—	139
Current maturities of long-term debt	—	9	800	—	809
Other current liabilities	64	64	924	—	1,052
Total current liabilities	(28)	649	2,221	(347)	2,495
Long-term debt	—	3,282	5,665	—	8,947
Deferred credits and other liabilities	172	2,103	2,568	—	4,843
Preferred stock of subsidiaries	—	—	225	—	225
Equity					
Controlling interests	7,041	9,235	12,454	(21,689)	7,041
Noncontrolling interests	—	—	540	—	540
Total equity	7,041	9,235	12,994	(21,689)	7,581
Total Liabilities and Equity	$ 7,185	$15,269	$23,673	$(22,036)	$24,091

Spectra Energy Corp
Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2010
(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 1,049	$ 1,062	$ 1,572	$(2,554)	$ 1,129
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization	—	—	664	—	664
Equity in earnings of unconsolidated affiliates	—	—	(430)	—	(430)
Equity in earnings of subsidiaries	(1,062)	(1,492)	—	2,554	—
Distributions received from unconsolidated affiliates	—	—	391	—	391
Other	(239)	122	(229)	—	(346)
Net cash provided by (used in) operating activities	(252)	(308)	1,968	—	1,408
CASH FLOWS FROM INVESTING ACTIVITIES					
Capital expenditures	—	—	(1,346)	—	(1,346)
Investments in and loans to unconsolidated affiliates	—	—	(10)	—	(10)
Acquisitions, net of cash acquired	—	—	(492)	—	(492)
Purchases of held-to-maturity securities	—	—	(1,117)	—	(1,117)
Proceeds from sales and maturities of held-to-maturity securities	—	—	1,068	—	1,068
Purchases of available-for-sale securities	—	—	(254)	—	(254)
Proceeds from sales and maturities of available-for-sale securities	—	—	38	—	38
Distributions received from unconsolidated affiliates	—	—	17	—	17
Other	—	—	(5)	—	(5)
Net cash used in investing activities	—	—	(2,101)	—	(2,101)
CASH FLOWS FROM FINANCING ACTIVITIES					
Proceeds from the issuance of long-term debt	—	—	4,389	—	4,389
Payments for the redemption of long-term debt	—	—	(3,906)	—	(3,906)
Net increase in short-term borrowings and commercial paper	—	637	257	(225)	669
Distributions to noncontrolling interests	—	—	(73)	—	(73)
Proceeds from the issuance of Spectra Energy Partners, LP common units	—	—	216	—	216
Dividends paid on common stock	(650)	(3)	—	3	(650)
Distributions and advances from (to) affiliates	887	(326)	(783)	222	—
Other	15	—	(4)	—	11
Net cash provided by financing activities	252	308	96	—	656
Effect of exchange rate changes on cash	—	—	1	—	1
Net decrease in cash and cash equivalents	—	—	(36)	—	(36)
Cash and cash equivalents at beginning of period	—	—	166	—	166
Cash and cash equivalents at end of period	$ —	$ —	$ 130	$ —	$ 130

Spectra Energy Corp
Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2009
(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 849	$ 857	$ 1,314	$(2,096)	$ 924
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization	—	—	598	—	598
Equity in earnings of unconsolidated affiliates	—	—	(369)	—	(369)
Equity in earnings of subsidiaries	(857)	(1,239)	—	2,096	—
Distributions received from unconsolidated affiliates	—	—	195	—	195
Other	31	137	244	—	412
Net cash provided by (used in) operating activities	23	(245)	1,982	—	1,760
CASH FLOWS FROM INVESTING ACTIVITIES					
Capital expenditures	—	—	(980)	—	(980)
Investments in and loans to unconsolidated affiliates	—	(29)	(32)	—	(61)
Acquisitions, net of cash acquired	—	—	(295)	—	(295)
Purchases of held-to-maturity securities	—	—	(231)	—	(231)
Proceeds from sales and maturities of held-to-maturity securities	—	—	110	—	110
Proceeds from sales and maturities of available-for-sale securities	—	—	32	—	32
Distributions received from unconsolidated affiliates	—	—	164	—	164
Receipt from affiliate—repayment of loan	—	186	—	—	186
Other	—	—	54	—	54
Net cash provided by (used in) investing activities	—	157	(1,178)	—	(1,021)
CASH FLOWS FROM FINANCING ACTIVITIES					
Proceeds from the issuance of long-term debt	—	300	3,827	—	4,127
Payments for the redemption of long-term debt	—	(648)	(3,375)	—	(4,023)
Net decrease in short-term borrowings and commercial paper	—	(726)	(48)	—	(774)
Distributions to noncontrolling interests	—	—	(174)	—	(174)
Contributions from noncontrolling interests	—	—	2	—	2
Proceeds from the issuance of Spectra Energy common stock	448	—	—	—	448
Proceeds from the issuance of Spectra Energy Partners, LP common units	—	—	208	—	208
Dividends paid on common stock	(631)	(12)	—	12	(631)
Distributions and advances from (to) affiliates	136	1,116	(1,240)	(12)	—
Other	24	(2)	(8)	—	14
Net cash provided by (used in) financing activities	(23)	28	(808)	—	(803)
Effect of exchange rate changes on cash	—	—	25	—	25
Net increase (decrease) in cash and cash equivalents	—	(60)	21	—	(39)
Cash and cash equivalents at beginning of period	—	60	145	—	205
Cash and cash equivalents at end of period	$ —	$ —	$ 166	$ —	$ 166

Spectra Energy Corp
Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2008
(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 1,132	$ 1,126	$ 1,716	$(2,777)	$ 1,197
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization	—	—	581	—	581
Equity in earnings of unconsolidated affiliates	—	—	(778)	—	(778)
Equity in earnings of subsidiaries	(1,126)	(1,651)	—	2,777	—
Distributions received from unconsolidated affiliates	—	—	777	—	777
Other	(63)	112	(21)	—	28
Net cash provided by (used in) operating activities	(57)	(413)	2,275	—	1,805
CASH FLOWS FROM INVESTING ACTIVITIES					
Capital expenditures	—	—	(1,502)	—	(1,502)
Investments in and loans to unconsolidated affiliates	—	(219)	(309)	—	(528)
Acquisitions, net of cash acquired	—	—	(274)	—	(274)
Purchases of available-for-sale securities	—	—	(1,132)	—	(1,132)
Proceeds from sales and maturities of available-for-sale securities	—	—	1,256	—	1,256
Net proceeds from the sales of other assets	—	—	105	—	105
Distributions received from unconsolidated affiliates	—	—	218	—	218
Other	—	—	(6)	—	(6)
Net cash used in investing activities	—	(219)	(1,644)	—	(1,863)
CASH FLOWS FROM FINANCING ACTIVITIES					
Proceeds from the issuance of long-term debt	—	1,000	2,557	—	3,557
Payments for the redemption of long-term debt	—	—	(2,400)	—	(2,400)
Net increase (decrease) in short-term borrowings and commercial paper	—	290	(41)	—	249
Distributions to noncontrolling interests	—	—	(70)	—	(70)
Contributions from noncontrolling interests	—	—	115	—	115
Repurchases of Spectra Energy common stock	(600)	—	—	—	(600)
Dividends paid on common stock	(598)	(13)	—	13	(598)
Distributions and advances from (to) affiliates	1,241	(585)	(643)	(13)	—
Other	14	—	(53)	—	(39)
Net cash provided by (used in) financing activities	57	692	(535)	—	214
Effect of exchange rate changes on cash	—	—	(11)	—	(11)
Net increase in cash and cash equivalents	—	60	85	—	145
Cash and cash equivalents at beginning of period	—	—	60	—	60
Cash and cash equivalents at end of period	$ —	$ 60	$ 145	$ —	$ 205

26. Quarterly Financial Data (Unaudited)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	(in millions, except per share amounts)				
2010					
Operating revenues	$1,480	$1,063	$1,019	$1,383	$4,945
Operating income	492	342	341	499	1,674
Net income	378	191	219	341	1,129
Net income—controlling interests	358	174	197	320	1,049
Earnings per share (a)					
Basic	0.55	0.27	0.30	0.49	1.62
Diluted	0.55	0.27	0.30	0.49	1.61
2009					
Operating revenues	1,384	937	933	1,298	4,552
Operating income	425	317	353	380	1,475
Net income	315	157	212	240	924
Net income—controlling interests	298	140	191	220	849
Earnings per share (a)					
Basic	0.47	0.22	0.30	0.34	1.32
Diluted	0.47	0.22	0.30	0.34	1.32

(a) Quarterly earnings-per-share amounts are stand-alone calculations and may not be additive to full-year amounts due to rounding.

Unusual or Infrequent Items

During the fourth quarter of 2010, we recorded a $31 million benefit ($22 million after tax) to Operating, Maintenance and Other Expenses related to an early termination notice made by us for certain capacity contracts on a third-party pipeline.

During the first quarter of 2009, we recorded in Equity in Earnings of Unconsolidated Affiliates in the Consolidated Statement of Operations a $135 million gain ($85 million after tax) associated with the reclassification by DCP Midstream of certain deferred gains on sales of common units in its master limited partnership. See Note 11 for further discussion.

As previously discussed, during 2010, we identified certain immaterial errors in our previously issued financial statements related primarily to the impacts of enacted Canadian federal and provincial tax rate changes on deferred income tax balances associated with our Canadian operations. The following is a reconciliation of the amounts previously reported to the corrected amounts as presented in the above financial data table.

	Fourth Quarter	Total
2009	(in millions)	
Net income		
As previously reported	$239	$923
Adjustment	1	1
As corrected	$240	$924
Net income – controlling interests		
As previously reported	$219	$848
Adjustment	1	1
As corrected	$220	$849

SPECTRA ENERGY CORP

SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

	Balance at Beginning of Period	Additions: Charged to Expense	Additions: Charged to Other Accounts	Deductions (a)	Balance at End of Period
			(in millions)		
December 31, 2010:					
Allowance for doubtful accounts	$ 14	$ 5	$ 1	$ 11	$ 9
Other (b)	139	33	28	45	155
	$153	$38	$29	$ 56	$164
December 31, 2009:					
Allowance for doubtful accounts	$ 12	$ 4	$ 2	$ 4	$ 14
Other (b)	175	60	12	108	139
	$187	$64	$14	$112	$153
December 31, 2008:					
Allowance for doubtful accounts	$ 22	$ 7	$—	$ 17	$ 12
Other (b)	204	34	5	68	175
	$226	$41	$ 5	$ 85	$187

(a) Principally cash payments and reserve reversals.

(b) Principally income tax, insurance-related, litigation and other reserves, included primarily in Deferred Credits and Other Liabilities—Regulatory and Other on the Consolidated Balance Sheets.

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

None.

Item 9A. Controls and Procedures.

Disclosure controls and procedures are controls and other procedures that are designed to ensure that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 (Exchange Act) is recorded, processed, summarized, and reported within the time periods specified by the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to provide reasonable assurance that information required to be disclosed by us in the reports we file or submit under the Exchange Act is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, we have evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2010, and, based upon this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that these controls and procedures are effective at the reasonable assurance level.

Changes in Internal Control over Financial Reporting

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, we have evaluated changes in internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the fiscal quarter ended December 31, 2010 and found no change that has materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

Management's Annual Report on Internal Control over Financial Reporting

The report of management required under this Item 9A is contained in Item 8. Financial Statements and Supplementary Data, Management's Annual Report on Internal Control over Financial Reporting.

Attestation Report of Independent Registered Public Accounting Firm

The attestation report required under this Item 9A is contained in Item 8. Financial Statements and Supplementary Data, Report of Independent Registered Public Accounting Firm.

Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

Reference to "Executive Officers" is included in "Part I. Item 1. Business" of this report. Other information in response to this item is incorporated by reference from our Proxy Statement relating to our 2011 annual meeting of shareholders.

Item 11. Executive Compensation.

Information in response to this item is incorporated by reference from our Proxy Statement relating to our 2011 annual meeting of shareholders.

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

Information in response to this item is incorporated by reference from our Proxy Statement relating to our 2011 annual meeting of shareholders.

Item 13. Certain Relationships and Related Transactions, and Director Independence.

Information in response to this item is incorporated by reference from our Proxy Statement relating to our 2011 annual meeting of shareholders.

Item 14. Principal Accounting Fees and Services.

Information in response to this item is incorporated by reference from our Proxy Statement relating to our 2011 annual meeting of shareholders.

PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a) Consolidated Financial Statements, Supplemental Financial Data and Supplemental Schedules included in Part II of this annual report are as follows:

Spectra Energy Corp:
- Report of Independent Registered Accounting Firm
- Consolidated Statements of Operations
- Consolidated Balance Sheets
- Consolidated Statements of Cash Flows
- Consolidated Statements of Equity and Comprehensive Income
- Notes to Consolidated Financial Statements
- Consolidated Financial Statement Schedule II—Valuation and Qualifying Accounts and Reserves

Separate Financial Statements of Subsidiaries not Consolidated Pursuant to Rule 3-09 of Regulation S-X:

DCP Midstream, LLC:
- Independent Auditors' Report
- Consolidated Balance Sheets
- Consolidated Statements of Operations
- Consolidated Statements of Comprehensive Income
- Consolidated Statements of Cash Flows
- Consolidated Statements of Changes in Equity
- Notes to Consolidated Financial Statements

All other schedules are omitted because they are not required or because the required information is included in the Consolidated Financial Statements or Notes.

(c) Exhibits—See Exhibit Index immediately following the signature page.

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.

Date: February 24, 2011

SPECTRA ENERGY CORP

By: /s/ Gregory L. Ebel

Gregory L. Ebel
President and Chief Executive Officer

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

(i) Gregory L. Ebel*
President and Chief Executive Officer (Principal Executive Officer and Director)
(ii) J. Patrick Reddy*
Chief Financial Officer (Principal Financial Officer)
(iii) Sabra L. Harrington*
Vice President and Controller (Principal Accounting Officer)
(iv) William T. Esrey*
Chairman of the Board of Directors
Austin A. Adams*
Director
Paul M. Anderson*
Director
Pamela L. Carter*
Director
Tony Comper*
Director
Peter B. Hamilton*
Director
Dennis R. Hendrix*
Director
Michael McShane*
Director
Joseph H. Netherland*
Director
Michael E.J. Phelps *
Director

Date: February 24, 2011

J. Patrick Reddy, by signing his name hereto, does hereby sign this document on behalf of the registrant and on behalf of each of the above-named persons previously indicated by asterisk pursuant to a power of attorney duly executed by the registrant and such persons, filed with the Securities and Exchange Commission as an exhibit hereto.

By: /s/ J. Patrick Reddy

J. Patrick Reddy
Attorney-In-Fact

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DCP MIDSTREAM, LLC

CONSOLIDATED FINANCIAL STATEMENTS

TABLE OF CONTENTS

Deloitte.

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INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Members of
DCP Midstream, LLC
Denver, Colorado

We have audited the accompanying consolidated balance sheets of DCP Midstream, LLC and subsidiaries (the "Company") as of December 31, 2010 and 2009, and the related consolidated statements of operations, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2010. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2010 and 2009, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated financial statements, in 2009 the Company adopted the amended provisions of ASC 810, *Consolidation*, as it pertains to noncontrolling interests, and as a result retrospectively adjusted its 2008 consolidated financial statements.

/s/ Deloitte & Touche LLP

February 18, 2011

DCP MIDSTREAM, LLC

CONSOLIDATED BALANCE SHEETS
(millions)

	December 31, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents	$ 8	$ 264
Accounts receivable:		
Customers, net of allowance for doubtful accounts of $2 million and $3 million, respectively	1,013	898
Affiliates	239	255
Other	18	35
Inventories	109	83
Unrealized gains on derivative instruments	144	259
Other	43	15
Total current assets	1,574	1,809
Property, plant and equipment, net	5,359	4,922
Restricted investments	—	10
Investments in unconsolidated affiliates	159	175
Intangible assets, net	355	313
Goodwill	681	662
Unrealized gains on derivative instruments	25	41
Other long-term assets	85	60
Total assets	$8,238	$7,992
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$1,105	$1,003
Affiliates	79	90
Other	33	38
Short-term borrowings	187	3
Current maturities of long-term debt	250	800
Distributions payable to members	77	71
Unrealized losses on derivative instruments	180	229
Accrued taxes	60	47
Other	235	253
Total current liabilities	2,206	2,534
Deferred income taxes	135	104
Long-term debt	3,223	2,841
Unrealized losses on derivative instruments	65	78
Other long-term liabilities	128	117
Total liabilities	5,757	5,674
Commitments and contingent liabilities		
Equity:		
Members' interest	2,073	2,020
Accumulated other comprehensive loss	(13)	(17)
Total members' equity	2,060	2,003
Noncontrolling interest	421	315
Total equity	2,481	2,318
Total liabilities and equity	$8,238	$7,992

See Notes to Consolidated Financial Statements.

DCP MIDSTREAM, LLC

CONSOLIDATED STATEMENTS OF OPERATIONS
(millions)

	Year Ended December 31, 2010	2009	2008
Operating revenues:			
Sales of natural gas and petroleum products	$ 8,163	$6,080	$12,456
Sales of natural gas and petroleum products to affiliates	2,414	2,140	3,507
Transportation, storage and processing	360	327	334
Trading and marketing gains, net	44	50	101
Total operating revenues	10,981	8,597	16,398
Operating costs and expenses:			
Purchases of natural gas and petroleum products	8,208	6,213	12,489
Purchases of natural gas and petroleum products from affiliates	736	650	1,045
Operating and maintenance	552	520	586
Depreciation and amortization	413	405	365
General and administrative	239	236	234
Step acquisition — equity interest re-measurement gain	(9)	—	—
(Gain) loss on sale of assets	(1)	2	(15)
Total operating costs and expenses	10,138	8,026	14,704
Operating income	843	571	1,694
Earnings from unconsolidated affiliates	34	24	20
Interest income	1	1	12
Interest expense	(254)	(255)	(210)
Income before income taxes	624	341	1,516
Income tax (expense) benefit	(5)	(18)	3
Net income	619	323	1,519
Net (income) loss attributable to noncontrolling interests	(27)	16	(88)
Net income attributable to members' interests	$ 592	$ 339	$ 1,431

See Notes to Consolidated Financial Statements.

DCP MIDSTREAM, LLC

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(millions)

	Year Ended December 31,		
	2010	2009	2008
Net income	$ 619	$ 323	$ 1,519
Other comprehensive income (loss):			
Net unrealized losses on cash flow hedges	(19)	(14)	(33)
Reclassification of cash flow hedges into earnings	24	22	9
Total other comprehensive income (loss)	5	8	(24)
Total comprehensive income	624	331	1,495
Total comprehensive (income) loss attributable to noncontrolling interests	(28)	8	(70)
Total comprehensive income attributable to members' interests	$ 596	$ 339	$ 1,425

See Notes to Consolidated Financial Statements.

DCP MIDSTREAM, LLC

CONSOLIDATED STATEMENTS OF CASH FLOWS
(millions)

	Year Ended December 31, 2010	2009	2008
Cash flows from operating activities:			
Net income	$ 619	$ 323	$ 1,519
Adjustments to reconcile net income to net cash provided by operating activities:			
(Gain) loss on sale of assets	(1)	2	(15)
Depreciation and amortization	413	405	365
Earnings from unconsolidated affiliates	(34)	(24)	(20)
Distributions from unconsolidated affiliates	47	35	44
Step acquisition — equity interest re-measurement gain	(9)	—	—
Deferred income tax (benefit) loss	(4)	14	(13)
Other, net	(3)	3	42
Changes in operating assets and liabilities which provided (used) cash:			
Accounts receivable	(74)	(189)	715
Inventories	(5)	(43)	74
Net unrealized losses (gains) on derivative instruments	74	74	(181)
Accounts payable	69	145	(693)
Other	(97)	92	(49)
Net cash provided by operating activities	995	837	1,788
Cash flows from investing activities:			
Capital expenditures	(538)	(471)	(557)
Acquisitions, net of cash acquired	(281)	(45)	(214)
Investments in unconsolidated affiliates	(2)	(7)	(7)
Purchases of available-for-sale securities	(623)	(1)	(1,157)
Proceeds from sales of available-for-sale securities	633	51	1,207
Proceeds from sale of assets	2	5	41
Other	—	—	(2)
Net cash used in investing activities	(809)	(468)	(689)
Cash flows from financing activities:			
Payment of dividends and distributions to members	(575)	(202)	(1,861)
Proceeds from debt	1,655	680	2,230
Payment of debt	(1,636)	(742)	(1,494)
Proceeds from issuance of common units by a subsidiary, net of offering costs	189	70	132
Distributions paid to noncontrolling interests	(64)	(55)	(48)
Contributions from noncontrolling interests	—	14	6
Purchase of additional interest in a subsidiary	(4)	—	—
Deferred financing costs	(7)	(3)	(2)
Net cash used in financing activities	(442)	(238)	(1,037)
Net change in cash and cash equivalents	(256)	131	62
Cash and cash equivalents, beginning of period	264	133	71
Cash and cash equivalents, end of period	$ 8	$ 264	$ 133

See Notes to Consolidated Financial Statements.

DCP MIDSTREAM, LLC

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(millions)

	Members' Equity			
	Members' Interest	Accumulated Other Comprehensive (Loss) Income	Noncontrolling Interest	Total Equity
Balance, January 1, 2008	$ 1,974	$(11)	$193	$ 2,156
Contributions	—	—	6	6
Dividends and distributions	(1,738)	—	(48)	(1,786)
Purchase of business	—	—	2	2
Issuance of equity securities of a subsidiary	—	—	89	89
Comprehensive income (loss):				
Net income	1,431	—	88	1,519
Net unrealized losses on cash flow hedges	—	(11)	(22)	(33)
Reclassifications of cash flow hedges into earnings	—	5	4	9
Total comprehensive income (loss)	1,431	(6)	70	1,495
Balance, December 31, 2008	1,667	(17)	312	1,962
Contributions	—	—	14	14
Dividends and distributions	(274)	—	(55)	(329)
Issuance of equity securities of a subsidiary	18	—	52	70
Reclassification of deferred liability	270	—	—	270
Comprehensive income (loss):				
Net income (loss)	339	—	(16)	323
Net unrealized losses on cash flow hedges	—	(6)	(8)	(14)
Reclassifications of cash flow hedges into earnings	—	6	16	22
Total comprehensive income (loss)	339	—	(8)	331
Balance, December 31, 2009	2,020	(17)	315	2,318
Dividends and distributions	(581)	—	(64)	(645)
Purchase of additional interest in a subsidiary	—	—	(5)	(5)
Issuance of common units by a subsidiary	42	—	147	189
Comprehensive income:				
Net income	592	—	27	619
Net unrealized losses on cash flow hedges	—	(6)	(13)	(19)
Reclassifications of cash flow hedges into earnings	—	10	14	24
Total comprehensive income	592	4	28	624
Balance, December 31, 2010	$ 2,073	$(13)	$421	$ 2,481

See Notes to Consolidated Financial Statements.

DCP MIDSTREAM, LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Years Ended December 31, 2010, 2009 and 2008

1. Description of Business and Basis of Presentation

DCP Midstream, LLC, with its consolidated subsidiaries, or us, we, our, or the Company, is a joint venture owned 50% by Spectra Energy Corp and its affiliates, or Spectra Energy, and 50% by ConocoPhillips and its affiliates, or ConocoPhillips. We operate in the midstream natural gas industry. Our primary operations consist of gathering, processing, compressing, transporting and storing of natural gas, and fractionating, transporting, gathering, treating, processing and storing of natural gas liquids, or NGLs, and/or condensate as well as marketing, from which we generate revenues primarily by trading and marketing natural gas and NGLs.

DCP Midstream Partners, LP, or DCP Partners, is a master limited partnership, of which a wholly-owned subsidiary of ours acts as general partner. As of December 31, 2010 and 2009, we owned an approximately 29% and 34% limited partner interest, respectively, in DCP Partners. Additionally, as of December 31, 2010 and 2009, we owned an approximately 1% general partner interest in DCP Partners, for both periods, as well as incentive distribution rights that entitle us to receive an increasing share of available cash as pre-defined distribution targets are achieved. As the general partner of DCP Partners, we have responsibility for its operations. We exercise control over DCP Partners and we account for it as a consolidated subsidiary.

We are governed by a five member board of directors, consisting of two voting members from each parent company and our Chief Executive Officer and President, a non-voting member. All decisions requiring the approval of our board of directors' are made by simple majority vote of the board, but must include at least one vote from both a Spectra Energy and ConocoPhillips board member. In the event the board cannot reach a majority decision, the decision is appealed to the Chief Executive Officers of both Spectra Energy and ConocoPhillips.

The consolidated financial statements include the accounts of the Company and all majority-owned subsidiaries where we have the ability to exercise control and undivided interests in jointly owned assets. We also consolidate DCP Partners, which we control as the general partner and where the limited partners do not have substantive kick-out or participating rights. Investments in greater than 20% owned affiliates that are not variable interest entities and where we do not have the ability to exercise control, and investments in less than 20% owned affiliates where we have the ability to exercise significant influence, are accounted for using the equity method. Intercompany balances and transactions have been eliminated.

We adopted Financial Accounting Standards Board, or FASB, Accounting Standards Codification 810, or ASC 810, effective January 1, 2009, which required us to retrospectively recast our consolidated financial statements for all periods presented. As a result of adoption, we have reclassified our noncontrolling interest on our consolidated balance sheets, from a component of liabilities to a component of equity and have also reclassified net income or loss attributable to noncontrolling interest on our consolidated statements of operations, to below net income for all periods presented. Furthermore, we have displayed the portion of other comprehensive income that is attributable to noncontrolling interest within our consolidated statements of comprehensive income. We also added a rollforward of the noncontrolling interest within our consolidated statements of changes in equity and have combined the members' interest and retained earnings columns within the rollforward. Additionally, in the first quarter of 2009 we reclassified $270 million deferred liabilities relating to the sale of common equity by a subsidiary from long-term liabilities to members' interest within our consolidated balance sheets.

Certain amounts in the prior year's consolidated financial statements have been reclassified to the current year presentation.

2. Summary of Significant Accounting Policies

Use of Estimates — Conformity with accounting principles generally accepted in the United States of America, or GAAP, requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and notes. Although these estimates are based on management's best available knowledge of current and expected future events, actual results could differ from those estimates.

Cash and Cash Equivalents — Cash and cash equivalents include all cash balances and investments in highly liquid financial instruments purchased with an original stated maturity of 90 days or less.

Short Term and Restricted Investments — We may invest available cash balances in various financial instruments, such as commercial paper and money market instruments. These instruments provide for a high degree of liquidity through features which allow for the redemption of the investment at its face amount plus earned income. As we generally intend to sell these instruments within one year or less from the balance sheet date, and as they are available for use in current operations, they are classified as current assets, unless otherwise restricted.

Restricted investments are used as collateral to secure the term loan portion of DCP Partners' credit facility and to finance acquisitions. We classify all short-term and restricted investments as available-for-sale as we do not intend to hold them to maturity, nor are they bought or sold with the objective of generating profit on short-term differences in prices. These investments are recorded at fair value, with changes in fair value recorded as unrealized gains and losses in accumulated other comprehensive income (loss), or AOCI. The cost including accrued interest on investments approximates fair value, due to the short-term, highly liquid nature of the securities held by us; interest rates are re-set on a daily, weekly or monthly basis.

Allowance for Doubtful Accounts — Management estimates the amount of required allowances for the potential non-collectability of accounts receivable generally based upon number of days past due, past collection experience and consideration of other relevant factors. However, past experience may not be indicative of future collections and therefore additional charges could be incurred in the future to reflect differences between estimated and actual collections.

Inventories — Inventories, which consist primarily of natural gas and NGLs held in storage for transportation and processing and sales commitments, are recorded at the lower of weighted-average cost or market value. Transportation costs are included in inventory.

Accounting for Risk Management and Derivative Activities and Financial Instruments — We designate each energy commodity derivative as either trading or non-trading. Certain non-trading derivatives are further designated as either a hedge of a forecasted transaction or future cash flow (cash flow hedge), a hedge of a recognized asset, liability or firm commitment (fair value hedge), or normal purchases or normal sales contract. The remaining non-trading derivatives, which are related to asset based activities for which the hedge accounting or the normal purchase or normal sale exception are not elected, are recorded at fair value in the consolidated balance sheets as unrealized gains or unrealized losses on derivative instruments, with changes in the fair value recognized in the consolidated statements of operations. For each derivative, the accounting method and presentation of gains and losses or revenue and expense in the consolidated statements of operations are as follows:

Classification of Contract	Accounting Method	Presentation of Gains & Losses or Revenue & Expense
Trading Derivatives	Mark-to-market method (a)	Net basis in trading and marketing gains and losses
Non-Trading Derivatives:		
Cash Flow Hedge	Hedge method (b)	Gross basis in the same consolidated statements of operations category as the related hedged item
Fair Value Hedge	Hedge method (b)	Gross basis in the same consolidated statements of operations category as the related hedged item
Normal Purchases or Normal Sales	Accrual method (c)	Gross basis upon settlement in the corresponding consolidated statements of operations category based on purchase or sale
Non-Trading Derivatives	Mark-to-market method (a)	Net basis in trading and marketing gains and losses

(a) Mark-to-market method — An accounting method whereby the change in the fair value of the asset or liability is recognized in the consolidated statements of operations in trading and marketing gains and losses during the current period.

(b) Hedge method — An accounting method whereby the change in the fair value of the asset or liability is recorded in the consolidated balance sheets as unrealized gains or unrealized losses on derivative instruments. For cash flow hedges, there is no recognition in the consolidated statements of operations for the effective portion until the service is provided or the associated delivery period impacts earnings. For fair value hedges, the changes in the fair value of the asset or liability, as well as the offsetting changes in value of the hedged item, are recognized in the consolidated statements of operations in the same category as the related hedged item.

(c) Accrual method — An accounting method whereby there is no recognition in the consolidated balance sheets or consolidated statements of operations for changes in fair value of a contract until the service is provided or the associated delivery period impacts earnings.

Cash Flow and Fair Value Hedges — For derivatives designated as a cash flow hedge or a fair value hedge, we maintain formal documentation of the hedge. In addition, we formally assess both at the inception of the hedging relationship and on an ongoing basis, whether the hedge contract is highly effective in offsetting changes in cash flows or fair values of hedged items. All components of each derivative gain or loss are included in the assessment of hedge effectiveness, unless otherwise noted.

The fair value of a derivative designated as a cash flow hedge is recorded in the consolidated balance sheets as unrealized gains or unrealized losses on derivative instruments. The effective portion of the change in fair value of a derivative designated as a cash flow hedge is recorded in the consolidated balance sheets as AOCI and the ineffective portion is recorded in the consolidated statements of operations. During the period in which the hedged transaction impacts earnings, amounts in AOCI associated with the hedged transaction are reclassified to the consolidated statements of operations in the same accounts as the item being hedged. Hedge accounting is discontinued prospectively when it is determined that the derivative no longer qualifies as an effective hedge, or when it is probable that the hedged transaction will not occur. When hedge accounting is discontinued because the derivative no longer qualifies as an effective hedge, the derivative is subject to the mark-to-market accounting method prospectively. The derivative continues to be carried on the consolidated balance sheets at its fair value; however, subsequent changes in its fair value are recognized in current period earnings. Gains and losses related to discontinued hedges that were previously accumulated in AOCI will remain in AOCI until the hedged transaction impacts earnings, unless it is probable that the hedged transaction will not occur, in which case, the gains and losses that were previously deferred in AOCI will be immediately recognized in current period earnings.

The fair value of a derivative designated as a fair value hedge is recorded for balance sheet purposes as unrealized gains or unrealized losses on derivative instruments. We recognize the gain or loss on the derivative instrument, as well as the offsetting loss or gain on the hedged item in earnings in the current period. All derivatives designated and accounted for as fair value hedges are classified in the same category as the item being hedged in the consolidated results of operations.

Valuation — When available, quoted market prices or prices obtained through external sources are used to determine a contract's fair value. For contracts with a delivery location or duration for which quoted market prices are not available, fair value is determined based on internally developed pricing models developed primarily from historical relationships with quoted market prices and the expected relationship with quoted market prices.

Values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions. Changes in market prices and management estimates directly affect the estimated fair value of these contracts. Accordingly, it is reasonably possible that such estimates may change in the near term.

Property, Plant and Equipment — Property, plant and equipment are recorded at historical cost. The cost of maintenance and repairs, which are not significant improvements, are expensed when incurred. Depreciation is computed using the straight-line method over the estimated useful lives of the assets.

Asset retirement obligations associated with tangible long-lived assets are recorded at fair value in the period in which they are incurred, if a reasonable estimate of fair value can be made, and added to the carrying amount of the associated asset. This additional carrying amount is then depreciated over the life of the asset. The liability is determined using a risk free interest rate and increases due to the passage of time based on the time value of money until the obligation is settled.

Asset Retirement Obligations — Our asset retirement obligations relate primarily to the retirement of various gathering pipelines and processing facilities, obligations related to right-of-way easement agreements, and contractual leases for land use. We adjust our asset retirement obligation each quarter for any liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows.

Investments in Unconsolidated Affiliates — We use the equity method to account for investments in greater than 20% owned affiliates that are not variable interest entities and where we do not have the ability to exercise control, and investments in less than 20% owned affiliates where we have the ability to exercise significant influence.

We evaluate our investments in unconsolidated affiliates for impairment whenever events or changes in circumstances indicate that the carrying value of such investments may have experienced an other than temporary decline in value. When evidence of loss in value has occurred, we compare the estimated fair value of the investment to the carrying value of the investment to determine whether impairment has occurred. We assess the fair value of our investments in unconsolidated affiliates using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models. If the estimated fair value is considered to be permanently less than the carrying value and management considers the decline in value to be other than temporary, the excess of the carrying value over the estimated fair value is recognized as an impairment loss.

Goodwill and Intangible Assets — Goodwill is the cost of an acquisition less the fair value of the net assets of the acquired business. We perform an annual impairment test of goodwill in the third quarter, and update the test during interim periods when we believe events or changes in circumstances indicate that we may not be able to recover the carrying value of a reporting unit. Impairment testing consists of a two-step process. The first step involves comparing the fair value of the reporting unit, to which goodwill has been allocated, with its carrying amount. If the carrying amount of the reporting unit exceeds its fair value, the second step of the process involves comparing the fair value and carrying value of the goodwill of that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the fair value of that goodwill, the excess of the carrying value over the fair value is recognized as an impairment loss. We use a discounted cash flow analysis supported by market valuation multiples to perform the assessment. Key assumptions in the analysis include the use of an appropriate discount rate and estimated future cash flows. In estimating cash flows, we incorporate current market information, as well as historical and other factors, into our forecasted commodity prices. If actual results are not consistent with our assumptions and estimates, or our assumptions and estimates change due to new information, we may be exposed to goodwill impairment charges, which would be recognized in the period in which the carrying value exceeds fair value.

Intangible assets consist primarily of customer contracts, including commodity purchase, transportation and processing contracts and related relationships. These intangible assets are amortized on a straight-line basis over the period of expected future benefit. Intangible assets are removed from the gross carrying amount and the total of accumulated amortization in the period in which they become fully amortized.

Long-Lived Assets — We evaluate whether the carrying value of long-lived assets has been impaired when circumstances indicate the carrying value of those assets may not be recoverable. This evaluation is based on undiscounted cash flow projections. The carrying amount is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. We consider various factors when determining if these assets should be evaluated for impairment, including but not limited to:

- a significant adverse change in legal factors or business climate;

- a current period operating or cash flow loss combined with a history of operating or cash flow losses, or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset;
- an accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset;
- significant adverse changes in the extent or manner in which an asset is used, or in its physical condition;
- a significant adverse change in the market value of an asset; or
- a current expectation that, more likely than not, an asset will be sold or otherwise disposed of before the end of its estimated useful life.

If the carrying value is not recoverable, the impairment loss is measured as the excess of the asset's carrying value over its fair value. We assess the fair value of long-lived assets using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models. Significant changes in market conditions resulting from events such as the condition of an asset or a change in management's intent to utilize the asset would generally require management to reassess the cash flows related to the long-lived assets.

Unamortized Debt Premium, Discount and Expense — Premiums, discounts and expenses incurred with the issuance of long-term debt are amortized over the term of the debt using the effective interest method. These premiums and discounts are recorded on the consolidated balance sheets within long-term debt. These unamortized expenses are recorded on the consolidated balance sheets as other long-term assets.

Noncontrolling Interest — Noncontrolling interest represents the ownership interests of third-party entities in the net assets of consolidated affiliates, including ownership interest of DCP Partners' public unitholders, through DCP Partners' publicly traded common units, in net assets of DCP Partners and the noncontrolling interest which is recorded in DCP Partners' consolidated balance sheets. For financial reporting purposes, the assets and liabilities of these entities are consolidated with those of our own, with any third party interest in our consolidated balance sheet amounts shown as noncontrolling interest in equity. Distributions to and contributions from noncontrolling interests represent cash payments to and cash contributions from, respectively, such third-party investors.

Distributions — Under the terms of the Second Amended and Restated LLC Agreement dated July 5, 2005, as amended, or the LLC Agreement, we are required to make quarterly distributions to Spectra Energy and ConocoPhillips based on allocated taxable income. The LLC Agreement provides for taxable income to be allocated in accordance with Internal Revenue Code Section 704(c). This Code Section accounts for the variation between the adjusted tax basis and the fair market value of assets contributed to the joint venture. The distribution is based on the highest taxable income allocated to either member, with the other member receiving a proportionate amount to maintain the ownership capital accounts at 50% for both Spectra Energy and ConocoPhillips. Distributions to the members are calculated based on estimated annual taxable income allocated to the members according to their respective ownership percentages at the date the distributions became due. Our board of directors determines the amount of the periodic dividends to be paid to Spectra Energy and ConocoPhillips, by considering net income attributable to members' interests, cash flow or any other criteria deemed appropriate. The LLC Agreement restricts payment of dividends except with the approval of both members. Tax distributions are allocated to the members in accordance with their respective ownership percentages.

DCP Partners considers the payment of a quarterly distribution to the holders of its common units, to the extent DCP Partners has sufficient cash from its operations after establishment of cash reserves and payment of fees and expenses, including payments to its general partner, a wholly-owned subsidiary of ours. There is no guarantee, however, that DCP Partners will pay the minimum quarterly distribution on the units in any quarter. DCP Partners will be prohibited from making any distributions to unitholders if it would cause an event of default, or an event of default exists, under its credit agreement.

Revenue Recognition — We generate the majority of our revenues from natural gas gathering, processing, compressing, transporting and storing, and NGL fractionating, transporting, gathering, treating, processing and storing, as well as trading and marketing of natural gas and NGLs. We realize revenues either by selling the residue natural gas and NGLs, or by receiving fees.

We obtain access to commodities and provide our midstream services principally under contracts that contain a combination of one or more of the following arrangements.

- *Fee-based arrangements* — Under fee-based arrangements, we receive a fee or fees for one or more of the following services: gathering, compressing, treating, processing, storing, or transporting of natural gas, and storing and transporting NGLs. Our fee-based arrangements include natural gas purchase arrangements pursuant to which we purchase natural gas at the wellhead, or other receipt points, at an index related price at the delivery point less a specified amount, generally the same as the fees we would otherwise charge for gathering of natural gas from the wellhead location to the delivery point. The revenues we earn are directly related to the volume of natural gas or NGLs that flows through our systems and are not directly dependent on commodity prices. However, to the extent a sustained decline in commodity prices results in a decline in volumes our revenues from these arrangements would be reduced.
- *Percent-of-proceeds/index arrangements* — Under percent-of-proceeds/index arrangements, we generally purchase natural gas from producers at the wellhead or other receipt points, gather the wellhead natural gas through our gathering system, treat and process the natural gas, and then sell the resulting residue natural gas and NGLs based on index prices from published index market prices. We remit to the producers either an agreed-upon percentage of the actual proceeds that we receive from our sales of the residue natural gas and NGLs, or an agreed-upon percentage of the proceeds based on index related prices for the natural gas and the NGLs, regardless of the actual amount of the sales proceeds we receive. Certain of these arrangements may also result in our returning all or a portion of the residue natural gas and/or the NGLs to the producer, in lieu of returning sales proceeds. Our revenues under percent-of-proceeds/index arrangements relate directly with the price of natural gas and/or NGLs.
- *Keep-whole arrangements and wellhead purchase arrangements* — Under the terms of a keep-whole processing contract, we gather natural gas from the producer for processing, sell the NGLs and return to the producer residue natural gas with a British thermal unit, or Btu, content equivalent to the Btu content of the natural gas gathered. This arrangement keeps the producer whole to the thermal value of the natural gas received. Under the terms of a wellhead purchase contract, we purchase natural gas from the producer at the wellhead or defined receipt point for processing and then market the resulting NGLs and residue gas at market prices. Under these types of contracts, we are exposed to the "frac spread." The frac spread is the difference between the value of the NGLs extracted from processing and the value of the Btu equivalent of the residue natural gas. We benefit in periods when NGL prices are higher relative to natural gas prices.

Our trading and marketing of natural gas and petroleum products, consists of physical purchases and sales, as well as derivative instruments.

We recognize revenues for sales and services under the four revenue recognition criteria, as follows:

- *Persuasive evidence of an arrangement exists* — Our customary practice is to enter into a written contract.
- *Delivery* — Delivery is deemed to have occurred at the time custody is transferred, or in the case of fee-based arrangements, when the services are rendered. To the extent we retain product as inventory, delivery occurs when the inventory is subsequently sold and custody is transferred to the third party purchaser.
- *The fee is fixed or determinable* — We negotiate the fee for our services at the outset of our fee-based arrangements. In these arrangements, the fees are nonrefundable. For other arrangements, the amount of revenue, based on contractual terms, is determinable when the sale of the applicable product has been completed upon delivery and transfer of custody.
- *Collectability is reasonably assured* — Collectability is evaluated on a customer-by-customer basis. New and existing customers are subject to a credit review process, which evaluates the customers' financial position (for example, credit metrics, liquidity and credit rating) and their ability to pay. If collectability is not considered probable at the outset of an arrangement in accordance with our credit review process, revenue is not recognized until the cash is collected.

We generally report revenues gross in the consolidated statements of operations, as we typically act as the principal in these transactions, take custody of the product, and incur the risks and rewards of ownership. New or amended contracts for certain sales and purchases of inventory with the same counterparty, when entered into in contemplation of one another, are reported net as one transaction. We recognize revenues for our NGL and residue gas derivative trading activities net in the consolidated statements of operations as trading and marketing gains and losses. These activities include mark-to-market gains and losses on energy trading contracts, and the settlement of financial or physical energy trading contracts.

Revenue for goods and services provided but not invoiced is estimated each month and recorded along with related purchases of goods and services used but not invoiced. These estimates are generally based on estimated commodity prices, preliminary throughput measurements and allocations and contract data. There are no material differences between the actual amounts and the estimated amounts of revenues and purchases recorded at December 31, 2010, 2009 and 2008.

Quantities of natural gas or NGLs over-delivered or under-delivered related to imbalance agreements with customers, producers or pipelines are recorded monthly as accounts receivable or accounts payable using current market prices or the weighted-average prices of natural gas or NGLs at the plant or system. These balances are settled with deliveries of natural gas or NGLs, or with cash. Included in the consolidated balance sheets as accounts receivable — other as of December 31, 2010 and 2009 were imbalances totaling $17 million and $28 million, respectively. Included in the consolidated balance sheets as accounts payable — other, as of December 31, 2010 and 2009 were imbalances totaling $33 million and $38 million, respectively.

Significant Customers — ConocoPhillips, a related party, was a significant customer in each of the past three years. See Note 5 Agreements and Transactions with Related Parties and Affiliates.

Environmental Expenditures — Environmental expenditures are expensed or capitalized as appropriate, depending upon the future economic benefit. Expenditures that relate to an existing condition caused by past operations, and that do not generate current or future revenue, are expensed. Liabilities for these expenditures are recorded on an undiscounted basis when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated.

Equity-Based Compensation — Equity classified equity-based compensation cost is measured at fair value, based on the closing unit price at grant date, and is recognized as expense over the vesting period. Liability classified equity-based compensation cost is remeasured at each reporting date at fair value, based on the closing unit price, and is recognized as expense over the requisite service period. Compensation expense for awards with graded vesting provisions is recognized on a straight-line basis over the requisite service period of each separately vesting portion of the award. Awards granted to non-employees for acquiring, or in conjunction with selling, goods and services are measured at the estimated fair value of the goods or services, or the fair value of the award, whichever is more reliably measured.

Accounting for Sales of Units by a Subsidiary — We account for sales of units by a subsidiary by recording an increase in members' interest equal to the amount of net proceeds received in excess of the carrying value of the units sold. Prior to January 1, 2009, we accounted for sales of units by a subsidiary by recording a deferred item on the sale of common equity of a subsidiary equal to the amount of net proceeds received in excess of the carrying value of the units sold. The remaining net proceeds are recorded as an increase to noncontrolling interest. Prior to the first quarter of 2009, DCP Partners had two classes of units outstanding, consisting of subordinated and limited partner units, which required us to record a deferred liability of $270 million within our consolidated balance sheets. During the first quarter of 2009 the subordination period ended and these units were converted into limited partner units and we reclassified these deferred liabilities from long-term liabilities to members' interest within our consolidated balance sheets.

Income Taxes — We are structured as a limited liability company, which is a pass-through entity for federal income tax purposes. We own a corporation that files its own federal, foreign and state corporate income tax returns. The income tax expense related to this corporation is included in our income tax expense, along with state, local, franchise and margin taxes of the limited liability company and other subsidiaries.

We follow the asset and liability method of accounting for income taxes. Under this method, deferred income taxes are recognized for the tax consequences of temporary differences between the financial statement carrying amounts and the tax basis of the assets and liabilities. Our taxable income or loss, which may vary substantially from the net income or loss reported in the consolidated statements of operations, is included in the federal returns of each partner.

3. Recent Accounting Pronouncements

***FASB, Accounting Standards Update, or ASU, 2010-29 "Business Combinations (Topic 805): Disclosure of Supplementary Pro Forma Information for Business Combinations",* or ASU 2010-29** — In December 2010, the FASB issued ASU 2010-29 which amended ASC Topic 805 "Business Combinations" to specify that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination that occurred during the year had occurred as of the beginning of the comparable prior annual reporting period only. The ASU also expands the supplemental pro forma disclosures under Topic 805 to include a description of the nature and the amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. ASU 2010-29 is effective for business combinations for which the acquisition date is on or after January 1, 2011 and we will disclose information in accordance with the ASU within all financial statements issued after the effective date.

***ASU 2010-28 "Intangibles—Goodwill and Other (Topic 350): When to Perform Step 2 of the Goodwill Impairment Test for Reporting Units with Zero or Negative Carrying Amounts",* or ASU 2010-28** — In December 2010, the FASB issued ASU 2010-28 which amended ASC Topic 350 "Goodwill and Other". ASU 2010-28 requires an entity with reporting units that have carrying amounts that are zero or negative to assess whether it is more likely than not that the reporting units' goodwill is impaired. If the entity determines that it is more likely than not that the goodwill of one or more of its reporting units is impaired, the entity is required to perform Step 2 of the goodwill impairment test for those reporting unit(s) and record any resulting impairment as a cumulative-effect adjustment to beginning retained earnings. The provisions of ASU 2010-28 became effective for us on January 1, 2011, and we will disclose information in accordance with the ASU within all financial statements issued after the effective date.

***ASU, 2010-06 "Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements,"* or ASU 2010-06** — In January 2010, the FASB issued ASU 2010-06 which amended the ASC Topic 820-10 "Fair Value Measurement and Disclosures — Overall." ASU 2010-06 requires new disclosures regarding transfers in and out of assets and liabilities measured at fair value classified within the valuation hierarchy as either Level 1 or Level 2 and information about sales, issuances and settlements on a gross basis for assets and liabilities classified as Level 3. ASU 2010-06 clarifies existing disclosures on the level of disaggregation required and inputs and valuation techniques. The provisions of ASU 2010-06 became effective for us on January 1, 2010, except for disclosure of information about sales, issuances and settlements on a gross basis for assets and liabilities classified as Level 3, which is effective for us on January 1, 2011. The provisions of ASU 2010-06 impact only disclosures and we have disclosed information in accordance with the revised provisions of ASU 2010-06 within these financial statements.

***ASU 2009-17 "Consolidation (Topic 810): Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities,"* or ASU 2009-17** — In December 2009, the FASB issued ASU 2009-17 which amended ASC Topic 810 "Consolidation." ASU 2009-17 requires entities to perform additional analysis of their variable interest entities and consolidation methods. This ASU became effective for us on January 1, 2010 and upon adoption we did not change our conclusions on which entities we consolidate in our consolidated financial statements.

***ASU 2009-13 "Revenue Recognition (Topic 605) Multiple-Deliverable Revenue Arrangements,"* or ASU 2009-13** — In October 2009, the FASB issued ASU 2009-13 which amended ASC Topic 605 "Revenue Recognition." The ASU addresses the accounting for multiple-deliverable arrangements, to enable vendors to account for products or services separately rather than as a combined unit. ASU 2009-13 became effective for us on January 1, 2011 and there was no impact on our consolidated results of operations, cash flows and financial position as a result of adoption.

4. Acquisitions

On December 30, 2010, DCP Partners acquired all of the interests in Marysville Hydrocarbons Holdings, LLC, or Marysville. The acquisition involved three separate transactions with a number of parties. DCP Partners acquired a 90% interest in Marysville from Dart Energy Corporation, a 5% interest in Marysville from Prospect Street Energy, LLC and 100% of EE Group, LLC, which owned the remaining 5% interest in Marysville. DCP

Partners paid a purchase price of $95 million and $6 million for net working capital and other adjustments, for an aggregate purchase price of $101 million, subject to customary purchase price adjustments, for DCP Partners' 100% interest. The purchase was financed at closing with borrowings under DCP Partners revolving credit facility. $21 million of the purchase price has been deposited in an indemnity escrow to satisfy certain tax liabilities and provide for breaches of representations and warranties of the sellers.

On January 4, 2011, DCP Partners merged two wholly-owned subsidiaries acquired in the Marysville acquisition and converted the combined entity's organizational structure from a corporation to a limited liability company. This conversion to a limited liability company triggers tax liabilities, resulting from built-in tax gains recognized in the transaction, to become currently payable. Accordingly, $35 million of estimated deferred tax liabilities associated with this transaction and recorded at December 31, 2010, became current tax liabilities as of January 4, 2011. These tax liabilities are unrelated to the tax liabilities of Marysville for which the indemnity escrow has been established. We estimate that these tax liabilities may be greater or less than the $35 million currently recorded in deferred income taxes in our balance sheet as of December 31, 2010.

Given the recent timing of this acquisition, we have not completed the final accounting for the Marysville business combination and have not made certain disclosures. These disclosures include the final fair value of assets acquired and liabilities assumed and pro-forma information. The final accounting and related disclosures for business combinations will be made in subsequent financial statements. The purchase price allocation is preliminary and is based on initial estimates of fair values at the date of acquisition. Currently all amounts included in Property, plant and equipment are classified as Processing, storage and terminal facilities. This allocation may change in subsequent financial statements. We are currently evaluating the preliminary purchase price allocation, which will be adjusted as additional information relative to the fair values of assets and liabilities becomes available. The preliminary purchase price allocation is as follows:

	(millions)
Aggregate consideration	$101
Cash	$ 3
Accounts receivable and other current assets	2
Inventory	6
Property, plant and equipment	130
Tax liabilities	(35)
Accounts payable and other current liabilities	(1)
Deferred storage revenue	(4)
Total preliminary purchase price allocation	$101

On July 30, 2010, DCP Partners acquired Atlantic Energy, a wholly-owned subsidiary of UGI Corporation, for $49 million plus propane inventory and other working capital of $17 million. DCP Partners has incurred additional post-closing purchase price adjustments for net working capital of $2 million, for an aggregate purchase price of $68 million. Atlantic Energy has a contractual agreement with Spectra Energy, the supplier of the acquired propane inventory, in which the final price of the acquired inventory will be determined based upon index rates at established future dates. Atlantic Energy's sales agreements specify floating pricing terms in excess of the floating pricing terms established in the contractual agreement with Spectra. The acquisition was financed at closing with borrowings under the DCP Partners' revolving credit facility. Atlantic Energy owns and operates a marine import terminal with 20 million gallons of above ground storage in the Port of Chesapeake, Virginia. The assets serve as a supply point for propane customers in the mid-Atlantic region, and will extend DCP Partners' existing northeast U.S. wholesale propane business into the mid-Atlantic.

The purchase price allocation is preliminary and is based on initial estimates of fair values at the date of the acquisition. We will continue to evaluate the initial purchase price allocation, which may be adjusted as additional information relative to the fair value of assets and liabilities becomes available. The preliminary purchase price allocation is as follows:

	(millions)
Aggregate consideration	$ 68
Accounts receivable	$ 3
Inventory	17
Property, plant and equipment	15
Intangible assets	27
Goodwill	7
Other liabilities	(1)
Total preliminary purchase price allocation	$ 68

On July 30, 2010, DCP Partners acquired an additional 50% interest in Black Lake Pipeline Company, or Black Lake, from an affiliate of BP PLC, for $15 million in cash, financed at closing with borrowings under the DCP Partners' revolving credit facility, bringing DCP Partners' ownership interest in Black Lake to 100%. Prior to this transaction, we accounted for Black Lake under the equity method of accounting. Subsequent to this transaction we account for Black Lake as a consolidated subsidiary through our interest in DCP Partners. As a result of acquiring an additional 50% interest in Black Lake, we have remeasured our initial 50% interest in Black Lake to its fair value. Accordingly, we recognized a gain of $9 million in step acquisition — equity interest re-measurement gain in our consolidated statement of operations for the year ended December 31, 2010, which reflects the increase from the net assets historical carrying value, to the net assets fair value for our initial 50% interest.

The calculation of the step acquisition — equity interest re-measurement gain is as follows:

	(millions)
Fair value of 50% equity interest in Black Lake	$ 15
Less: Carrying value of 50% equity interest in Black Lake	6
Step acquisition — equity interest re-measurement gain	$ 9

On June 29, 2010, we acquired the Raywood processing plant and Liberty gathering system, which are located in Liberty County, Texas, from Ceritas Holdings, LP, or Ceritas, for $79 million, subject to customary purchase price adjustments. We may pay up to an additional $6 million to Ceritas based upon recovery of certain currently non-producing wells over a period of approximately one year. We initially recorded a liability in other current liabilities of $3 million, which represented the fair value of the contingent consideration. As of September 30, 2010, we reassessed the fair value of the contingent consideration and adjusted the fair value of the liability to $2 million, and there has been no change to our assessment of the fair value of the contingent consideration as of December 31, 2010. This liability is recorded in other current liabilities within the consolidated balance sheets as of December 31, 2010. Accordingly, we have recognized $1 million as an offset to operating expense within the consolidated results of operations during the year ended December 31, 2010.

The acquired system will connect with our existing southeast Texas assets. The purchase price allocation is preliminary and is based on initial estimates of fair values at the date of the acquisition. We will continue to evaluate the initial purchase price allocation, which may be adjusted as additional information relative to the fair value of working capital becomes available. The preliminary purchase price allocation is as follows:

	(millions)
Cash consideration	$ 79
Property, plant and equipment	$ 35
Intangible assets	35
Goodwill	12
Other current assets	3
Other current liabilities	(3)
Contingent consideration	(3)
Total preliminary purchase price allocation	$ 79

5. Agreements and Transactions with Related Parties and Affiliates

Dividends and Distributions

During the years ended December 31, 2010, 2009 and 2008, we paid tax distributions of $275 million, $92 million and $721 million, respectively, based on estimated annual taxable income allocated to ConocoPhillips and Spectra Energy according to their respective ownership percentages at the date the distributions became due. During the years ended December 31, 2010, 2009 and 2008, we declared and paid dividends of $300 million, $110 million and $1,140 million, respectively, to Spectra Energy and ConocoPhillips, allocated in accordance with their respective ownership percentages.

During the years ended December 31, 2010, 2009 and 2008, DCP Partners paid distributions of $57 million, $50 million and $45 million, respectively, to its public unitholders.

ConocoPhillips

Long-Term NGL Purchases Contract and Transactions — We sell a portion of our residue gas and NGLs to ConocoPhillips. In addition, we purchase natural gas from and provide gathering, transportation and other services to ConocoPhillips. Approximately 40% of our NGL production is committed to ConocoPhillips and CP Chem, both related parties, under an existing 15-year contract, which expires in 2015. Should the contract not be renegotiated or renewed, it provides for a five year ratable wind-down period through 2020. The NGL contract also grants ConocoPhillips the right to purchase at index-based prices certain quantities of NGLs produced at processing plants that are acquired and/or constructed by us in the future in various counties in the Mid-Continent and Permian Basin regions, and the Austin Chalk area. We anticipate continuing to purchase and sell these commodities and provide these services to ConocoPhillips in the ordinary course of business.

On January 1, 2011, we entered into a 15-year gathering and processing agreement with ConocoPhillips, whereby ConocoPhillips has dedicated all of its natural gas production within an area of mutual interest in Oklahoma and Texas. This contract replaces and extends certain contracts that we previously had with ConocoPhillips.

Spectra Energy

Commodity Transactions — We sell a portion of our residue gas and NGLs to, purchase natural gas and other petroleum products from, and provide gathering, transportation and other services to Spectra Energy. Management anticipates continuing to purchase and sell commodities and provide services to Spectra Energy in the ordinary course of business.

DCP Partners has a propane supply agreement with Spectra Energy, effective from May 1, 2008 through April 30, 2012, which provides DCP Partners propane supply at its Providence marine terminal for up to approximately 120 million gallons of propane annually. On June 15, 2010, DCP Partners entered into an amendment to the supply agreement to shorten the term of the agreement by two years to April 30, 2012, which previously terminated on April 30, 2014. In consideration for shortening the term, Spectra Energy has provided DCP Partners a cash payment of $3 million, which has been recognized as an offset to operating and maintenance expense in the consolidated results of operations.

In conjunction with DCP Partners' acquisition of Atlantic Energy in July 2010, DCP Partners' acquired a propane supply agreement with Spectra Energy, effective from May 1, 2010 to April 30, 2012, which provides DCP Partners' propane supply for its Chesapeake marine terminal, for up to approximately 65 million gallons of propane annually.

In December 2010, Spectra Energy's international propane supplier breached its contract with Spectra Energy by failing to make certain scheduled propane deliveries that were to be delivered to us under our propane supply contracts with Spectra Energy. We were able to secure spot shipments on the open market at a price higher than our contract price to cover these missing deliveries. In December 2010 Spectra Energy made a $17 million payment to us to reimburse us for the damages we incurred for our open market purchases.

Transactions with DCP Partners

On November 4, 2010, we entered into agreements with DCP Partners, to sell a 33.33% interest in the DCP Southeast Texas business for $150 million. The DCP Southeast Texas business is a fully integrated midstream business which includes: 675 miles of natural gas pipelines; three natural gas processing plants totaling 350 MMcf/d of processing capacity; natural gas storage assets with 9 Bcf of existing storage capacity; and NGL market deliveries direct to Exxon Mobil and to Mont Belvieu via DCP Partners' Black Lake NGL pipeline. The terms of the joint venture agreement provide that DCP Partners' distributions from the joint venture for the first seven years related to storage and transportation gross margin will be pursuant to a fee-based arrangement, based on storage capacity and tailgate volumes. Distributions related to the gathering and processing business, along with reductions for all expenditures, will be pursuant to our and DCP Partners' respective ownership interests in the DCP Southeast Texas business. This transaction closed on January 1, 2011. We will continue to consolidate these assets in our financial statements, through our 66.67% interest in the joint venture and our consolidation of DCP Partners.

Transactions with other unconsolidated affiliates

We sell a portion of our residue gas and NGLs to, purchase natural gas and other petroleum products from, and provide gathering and transportation services to, unconsolidated affiliates. We anticipate continuing to purchase and sell commodities and provide services to unconsolidated affiliates in the ordinary course of business.

The following table summarizes our transactions with related parties and affiliates:

	Year Ended December 31, 2010	2009	2008
		(millions)	
ConocoPhillips:			
Sales of natural gas and petroleum products to affiliates	$2,365	$2,097	$3,413
Transportation, storage and processing	$ 18	$ 24	$ 17
Purchases of natural gas and petroleum products from affiliates	$ 435	$ 356	$ 689
Operating and general and administrative expenses	$ 4	$ 5	$ 2
Spectra Energy:			
Sales of natural gas and petroleum products to affiliates	$ 1	$ —	$ —
Transportation, storage and processing	$ —	$ 1	$ —
Purchases of natural gas and petroleum products from affiliates (a)	$ 173	$ 182	$ 172
Operating and general and administrative expenses	$ 6	$ —	$ 7
Unconsolidated affiliates:			
Sales of natural gas and petroleum products to affiliates	$ 48	$ 43	$ 94
Transportation, storage and processing	$ 19	$ 14	$ 26
Purchases of natural gas and petroleum products from affiliates	$ 128	$ 112	$ 184

(a) Includes a $17 million payment received in December 2010, for reimbursement of damages we incurred when an international propane supplier breached its contract with Spectra Energy.

We had balances with related parties and affiliates as follows:

	December 31, 2010	2009
	(millions)	
ConocoPhillips:		
Accounts receivable	$221	$237
Accounts payable	$ (46)	$ (41)
Other assets	$ 2	$ —
Spectra Energy:		
Accounts receivable	$ 2	$ 2
Accounts payable	$ (20)	$ (27)
Other assets	$ 2	$ —
Unconsolidated affiliates:		
Accounts receivable	$ 16	$ 16
Accounts payable	$ (13)	$ (22)

6. Inventories

Inventories were as follows:

	December 31, 2010	2009
	(millions)	
Natural gas	$ 11	$19
NGLs	97	64
Other	1	—
Total inventories	$109	$83

7. Property, Plant and Equipment

Property, plant and equipment by classification is as follows:

	Depreciable Life	December 31, 2010	December 31, 2009
		(millions)	
Gathering and transmission systems	15 -30 years	$ 5,441	$ 5,322
Processing, storage and terminal facilities (a)	20 -50 years	2,879	2,517
Other	3 - 30 years	253	235
Construction work in progress		545	218
Property, plant and equipment		9,118	8,292
Accumulated depreciation		(3,759)	(3,370)
Property, plant and equipment, net		$ 5,359	$ 4,922

(a) Includes $130 million of property, plant and equipment purchased through DCP Partners' acquisition of Marysville on December 30, 2010.

During the year ended December 31, 2010, we re-assessed our major classes of property, plant and equipment and changed the presentation.

Depreciation expense for the years ended December 31, 2010, 2009 and 2008 was $390 million, $384 million and $344 million, respectively. Interest capitalized on construction projects in 2010, 2009 and 2008, was $13 million, $11 million and $10 million, respectively.

Asset Retirement Obligations — As of December 31, 2010 and 2009, we had $79 million and $73 million, respectively, of asset retirement obligations in other long-term liabilities in the consolidated balance sheets. Accretion expense for the years ended December 31, 2010, 2009 and 2008 was $5 million, $5 million and $5 million, respectively, which is recorded within operating and maintenance expense in our consolidated statements of operations.

The following table summarizes changes in the asset retirement obligations, included in our balance sheets:

	December 31, 2010	December 31, 2009
	(millions)	
Balance, beginning of period	$73	$68
Accretion expense	5	5
Liabilities incurred	2	1
Liabilities settled	(1)	(1)
Balance, end of period	$79	$73

We identified various assets as having an indeterminate life, for which there is no requirement to establish a fair value for future retirement obligations associated with such assets. These assets include certain pipelines, gathering systems and processing facilities. A liability for these asset retirement obligations will be recorded only if and when a future retirement obligation with a determinable life is identified. These assets have an indeterminate life because they are owned and will operate for an indeterminate future period when properly maintained. Additionally, if the portion of an owned plant containing asbestos were to be modified or dismantled, we would be legally required to remove the asbestos. We currently have no plans to take actions that would require the removal of the asbestos in these assets. Accordingly, the fair value of the asset retirement obligation related to this asbestos cannot be estimated and no obligation has been recorded.

8. Goodwill and Intangible Assets

The change in the carrying amount of goodwill is as follows:

	December 31, 2010	December 31, 2009
	(millions)	
Beginning of period	$662	$658
Acquisitions	19	4
End of period	$681	$662

Goodwill increased in 2010 by $12 million as a result of our acquisition from Ceritas and by $7 million as a result of DCP Partners' acquisition of Atlantic Energy.

Our annual goodwill impairment tests indicated that our reporting units' fair value exceeded the carrying or book value; therefore, we did not record any impairment charges during the years ended December 31, 2010, 2009 and 2008.

Intangible assets consist of customer contracts, including commodity purchase, transportation and processing contracts, and related relationships. The gross carrying amount and accumulated amortization of these intangible assets are included in the accompanying consolidated balance sheets as intangible assets, net, and are as follows:

	December 31, 2010	December 31, 2009
	(millions)	
Gross carrying amount	$ 491	$ 426
Accumulated amortization	(136)	(113)
Intangible assets, net	$ 355	$ 313

Intangible assets increased in 2010 by $35 million as a result of our acquisition from Ceritas and by $27 million as a result of DCP Partners' acquisition of Atlantic Energy and $3 million as a result of DCP Partners' acquisition of an additional 50% interest in Black Lake.

For the years ended December 31, 2010, 2009 and 2008, we recorded amortization expense of $23 million, $21 million and $21 million, respectively. As of December 31, 2010, the remaining amortization periods ranged from less than one year to 25 years, with a weighted-average remaining period of approximately 19 years.

The weighted-average remaining amortization for the $35 million of intangible assets acquired with our acquisition from Ceritas is 15 years. The weighted-average remaining amortization for the $27 million of intangible assets acquired with DCP Partners' acquisition of Atlantic Energy is 25 years. The weighted-average remaining amortization for the $3 million of intangible assets acquired with DCP Partners' acquisition of an additional 50% interest in Black Lake is 20 years.

Estimated future amortization for these intangible assets is as follows:

	Estimated Future Amortization (millions)
2011	$ 24
2012	24
2013	24
2014	19
2015	17
Thereafter	247
Total	$ 355

9. Investments in Unconsolidated Affiliates

We have investments in the following unconsolidated affiliates accounted for using the equity method:

	2010 and 2009 Ownership	December 31, 2010	December 31, 2009
		(millions)	
Discovery Producer Services, LLC	40.00%	$ 105	$ 107
Main Pass Oil Gathering Company	66.67%	32	37
Mont Belvieu I	20.00%	12	13
Sycamore Gas System General Partnership	48.45%	8	9
Other unconsolidated affiliates	Various	2	9
Total investments in unconsolidated affiliates		$ 159	$ 175

There was a deficit between the carrying amount of the investment and the underlying equity of Discovery Producer Services, LLC of $35 million and $38 million at December 31, 2010 and 2009, respectively, which is associated with, and is being accreted over the life of, the underlying long-lived assets of Discovery.

There was an excess of the carrying amount of the investment over the underlying equity of Main Pass Oil Gathering Company of $9 million and $10 million at December 31, 2010 and 2009, respectively, which is associated with, and is being amortized over the life of, the underlying long-lived assets of Main Pass.

There was a deficit between the carrying amount of the investment and the underlying equity of Mont Belvieu I of $7 million and $8 million at December 31, 2010 and 2009, respectively, which is associated with, and is being accreted over the life of, the underlying long-lived assets of Mont Belvieu I.

There was an excess of the carrying amount of the investment over the underlying equity of Sycamore Gas System General Partnership of $4 million and $5 million at December 31, 2010 and 2009, respectively, which is associated with, and is being amortized over the life of, the underlying long-lived assets of Sycamore.

Earnings from unconsolidated affiliates amounted to the following:

	Year Ended December 31,		
	2010	2009	2008
		(millions)	
Discovery Producer Services, LLC	$25	$16	$17
Main Pass Oil Gathering Company	4	5	2
Mont Belvieu I	5	2	(1)
Sycamore Gas System General Partnership	—	(1)	—
Other unconsolidated affiliates	—	2	2
Total earnings from unconsolidated affiliates	34	24	20

The following summarizes combined financial information of unconsolidated affiliates:

	Year Ended December 31,		
	2010	2009	2008
		(millions)	
Income Statement:			
Operating revenues	$302	$247	$336
Operating expenses	$222	$186	$307
Net income	$ 78	$ 59	$ 34

	December 31,	
	2010	2009
	(millions)	
Balance sheet:		
Current assets	$ 66	$ 80
Long-term assets	496	537
Current liabilities	(28)	(29)
Long-term liabilities	(47)	(43)
Net assets	$487	$545

10. Fair Value Measurement

Determination of Fair Value

Below is a general description of our valuation methodologies for derivative financial assets and liabilities, as well as short-term and restricted investments, which are measured at fair value. Fair values are generally based upon quoted market prices, where available. If listed market prices or quotes are not available, we determine fair value based upon a market quote, adjusted by other market-based or independently sourced market data such as historical commodity volatilities, crude oil future yield curves, and/or counterparty specific considerations. These adjustments result in a fair value for each asset or liability under an "exit price" methodology, in line with how we believe a marketplace participant would value that asset or liability. These adjustments may include amounts to reflect counterparty credit quality, the effect of our own creditworthiness, the time value of money and/or the liquidity of the market.

- Counterparty credit valuation adjustments are necessary when the market price of an instrument is not indicative of the fair value as a result of the credit quality of the counterparty. Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. Therefore, an adjustment may be necessary to reflect the credit quality of a specific counterparty to determine the fair value of the instrument. We record counterparty credit valuation adjustments on all derivatives that are in a net asset position as of the measurement date in accordance with our established counterparty credit policy, which takes into account any collateral margin that a counterparty may have posted with us as well as any letters of credit that they have provided.
- Entity valuation adjustments are necessary to reflect the effect of our own credit quality on the fair value of our net liability position with each counterparty. This adjustment takes into account any credit enhancements, such as collateral margin we may have posted with a counterparty, as well as any letters of credit that we have provided. The methodology to determine this adjustment is consistent with how we evaluate counterparty credit risk, taking into account our own credit rating, current credit spreads, as well as any change in such spreads since the last measurement date.
- Liquidity valuation adjustments are necessary when we are not able to observe a recent market price for financial instruments that trade in less active markets for the fair value to reflect the cost of exiting the position. Exchange traded contracts are valued at market value without making any additional valuation adjustments and, therefore, no liquidity reserve is applied. For contracts other than exchange traded instruments, we mark our positions to the midpoint of the bid/ask spread, and record a liquidity reserve based upon our total net position. We believe that such practice results in the most reliable fair value measurement as viewed by a market participant.

We manage our derivative instruments on a portfolio basis and the valuation adjustments described above are calculated on this basis. We believe that the portfolio level approach represents the highest and best use for these assets as there are benefits inherent in naturally offsetting positions within the portfolio at any given time, and this approach is consistent with how a market participant would view and value the assets and liabilities. Although we take a portfolio approach to managing these assets/liabilities, in order to reflect the fair value of any one individual contract within the portfolio, we allocate all valuation adjustments down to the contract level, to the extent deemed necessary, based upon either the notional contract volume, or the contract value, whichever is more applicable.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. While we believe that our valuation methods are appropriate and consistent with other market participants, we recognize that the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different estimate of fair value at the reporting date. We review our fair value policies on a regular basis taking into consideration changes in the marketplace and, if necessary, will adjust our policies accordingly. See Note 12, Risk Management and Hedging Activities, Credit Risk and Financial Instruments.

Valuation Hierarchy

Our fair value measurements are grouped into a three-level valuation hierarchy. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date. The three levels are defined as follows:

- Level 1 — inputs are unadjusted quoted prices for *identical* assets or liabilities in active markets.
- Level 2 — inputs include quoted prices for *similar* assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3 — inputs are unobservable and considered significant to the fair value measurement.

A financial instrument's categorization within the hierarchy is based upon the input that requires the highest degree of judgment in the determination of the instrument's fair value. Following is a description of the valuation methodologies used as well as the general classification of such instruments pursuant to the hierarchy.

Commodity Derivative Assets and Liabilities

We enter into a variety of derivative financial instruments, which may include exchange traded instruments (such as New York Mercantile Exchange, or NYMEX, crude oil or natural gas futures) or over-the-counter, or OTC, instruments (such as natural gas contracts, costless collars, crude oil or NGL swaps). The exchange traded instruments are generally executed on the NYMEX exchange with a highly rated broker dealer serving as the clearinghouse for individual transactions.

Our activities expose us to varying degrees of commodity price risk. To mitigate a portion of this risk, and to manage commodity price risk related primarily to owned natural gas storage and pipeline assets, we engage in natural gas asset based trading and marketing, and we may enter into natural gas and crude oil derivatives to lock in a specific margin when market conditions are favorable. A portion of this may be accomplished through the use of exchange traded derivative contracts. Such instruments are generally classified as Level 1 since the value is equal to the quoted market price of the exchange traded instrument as of our balance sheet date, and no adjustments are required. Depending upon market conditions and our strategy we may enter into exchange traded derivative positions with a significant time horizon to maturity. Although such instruments are exchange traded, market prices may only be readily observable for a portion of the duration of the instrument. In order to calculate the fair value of these instruments, readily observable market information is utilized to the extent it is available; however, in the event that readily observable market data is not available, we may interpolate based upon observable data. In instances where we utilize an interpolated value, and it is considered significant to the valuation of the contract as a whole, we would classify the instrument within Level 2. In certain limited instances, we may extrapolate based upon the last readily observable data, developing our own expectation of fair value. To the extent that we have utilized extrapolated data, and it is considered significant to the valuation of the contract as a whole, we would classify the instrument within Level 3.

We also engage in the business of trading energy related products and services, which expose us to market variables and commodity price risk. We may enter into physical contracts or financial instruments with the objective of realizing a positive margin from the purchase and sale of these commodity-based instruments. We may enter into derivative instruments for NGLs or other energy related products, primarily using the OTC derivative instrument markets, which are not as active and liquid as exchange traded instruments. Market quotes for such contracts may only be available for short dated positions (up to six months), and an active market itself may not exist beyond such time horizon. Contracts entered into with a relatively short time horizon for which prices are readily observable in the OTC market are generally classified within Level 2. Contracts with a longer time horizon, for which we internally generate a forward curve to value such instruments, are generally classified within Level 3. The internally generated curve may utilize a variety of assumptions including, but not limited to, data obtained from third party pricing services, historical and future expected relationship of NGL prices to crude oil prices, the knowledge of expected supply sources coming on line, expected weather trends within certain regions of the United States, and the future expected demand for NGLs.

Each instrument is assigned to a level within the hierarchy at the end of each financial quarter depending upon the extent to which the valuation inputs are observable. Generally, an instrument will move toward a level within the hierarchy that requires a lower degree of judgment as the time to maturity approaches, and as the markets in which the asset trades will likely become more liquid and prices more readily available in the market, thus reducing the need to rely upon our internally developed assumptions. However, the level of a given instrument may change, in either direction, depending upon market conditions and the availability of market observable data.

Interest Rate Derivative Assets and Liabilities

We use interest rate swap agreements as part of our overall capital strategy. These instruments effectively exchange a portion of our floating rate debt for fixed rate debt or our fixed rate debt for floating rate debt. The swaps are generally priced based upon a London Interbank Offered Rate, or LIBOR, instrument with similar duration, adjusted by the credit spread between our company and the LIBOR instrument. Given that a portion of the swap value is derived from the credit spread, which may be observed by comparing similar assets in the market, these instruments are classified within Level 2. Default risk on either side of the swap transaction is also considered in the valuation. We record counterparty credit and entity valuation adjustments in the valuation of our interest rate swaps; however, these reserves are not considered to be a significant input to the overall valuation.

Restricted Investments

We were required to post collateral to secure the term loan portion of DCP Partners' credit facility. As of December 31, 2010, we held no restricted investments, as a result of the DCP Partners' term loan facility being fully repaid during the first quarter of 2010.

Long-Term Assets

We offer certain eligible executives the opportunity to participate in DCP Midstream LP's Non-Qualified Executive Deferred Compensation plan, and have elected to fund a portion of this participation by investing in company owned life insurance policies. These investments are reflected within our consolidated balance sheets as long-term assets and are considered financial instruments that are recorded at fair value, with any changes in fair value being recorded as a gain or loss in the consolidated statements of operations. Given that the value of these life insurance policies is determined based upon certain publicly traded mutual funds whose value is readily observable in the marketplace, these investments are classified within Level 2.

Nonfinancial Assets and Liabilities

We utilize fair value on a non-recurring basis to perform impairment tests as required on our property, plant and equipment, goodwill and intangible assets. Assets and liabilities acquired in business combinations are recorded at their fair value on the date of acquisition. The inputs used to determine such fair value are primarily based upon internally developed cash flow models and would generally be classified within Level 3, in the event that we were required to measure and record such assets at fair value within our consolidated financial statements. Additionally, we use fair value to determine the inception value of our asset retirement obligations. The inputs used to determine such fair value are primarily based upon costs incurred historically for similar work, as well as estimates from independent third parties for costs that would be incurred to restore leased property to the contractually stipulated condition, and would generally be classified within Level 3.

We utilize fair value on a recurring basis to measure our contingent consideration that is a result of certain acquisitions. The inputs used to determine such fair value are primarily based upon internally developed cash flow models and are classified within Level 3.

The following table presents the financial instruments carried at fair value as of December 31, 2010 and 2009, by consolidated balance sheet caption and by valuation hierarchy, as described above:

	December 31, 2010				December 31, 2009			
	Level 1	Level 2	Level 3	Total Carrying Value	Level 1	Level 2	Level 3	Total Carrying Value
	(millions)							
Current assets (a):								
Commodity derivatives	$ 41	$ 52	$ 50	$ 143	$ 72	$ 111	$ 73	$ 256
Interest rate derivatives	$ —	$ 1	$ —	$ 1	$ —	$ 3	$ —	$ 3
Long-term assets:								
Commodity derivatives (b)	$ 11	$ 4	$ 10	$ 25	$ 9	$ 14	$ 18	$ 41
Restricted investments	$ —	$ —	$ —	$ —	$ —	$ 10	$ —	$ 10
Company owned life insurance (c)	$ —	$ 16	$ —	$ 16	$ —	$ —	$ —	$ —
Current liabilities:								
Commodity derivatives (d)	$(45)	$(73)	$(45)	$(163)	$(20)	$(101)	$(88)	$(209)
Interest rate derivatives (d)	$ —	$(17)	$ —	$ (17)	$ —	$ (20)	$ —	$ (20)
Acquisition related contingent consideration (e)	$ —	$ —	$ (2)	$ (2)	$ —	$ —	$ —	$ —
Long-term liabilities:								
Commodity derivatives (f)	$(14)	$(40)	$ (1)	$ (55)	$ (3)	$ (57)	$ (6)	$ (66)
Interest rate derivatives (f)	$ —	$(10)	$ —	$ (10)	$ —	$ (12)	$ —	$ (12)

(a) Included in current unrealized gains on derivative instruments in our consolidated balance sheets.
(b) Included in long-term unrealized gains on derivative instruments in our consolidated balance sheets.
(c) Included in other long-term assets in our consolidated balance sheets.
(d) Included in current unrealized losses on derivative instruments in our consolidated balance sheets.
(e) Included in other current liabilities in our consolidated balance sheets.
(f) Included in long-term unrealized losses on derivative instruments in our consolidated balance sheets.

Changes in Level 3 Fair Value Measurements

The tables below illustrate a rollforward of the amounts included in our consolidated balance sheets for derivative financial instruments that we have classified within Level 3. The determination to classify a financial instrument within Level 3 is based upon the significance of the unobservable factors used in determining the overall fair value of the instrument. Since financial instruments classified as Level 3 typically include a combination of observable components (that is, components that are actively quoted and can be validated to external sources) and unobservable components, the gains and losses in the table below may include changes in fair value due in part to observable market factors, or changes to our assumptions on the unobservable components. Depending upon the information readily observable in the market, and/or the use of unobservable inputs, which are significant to the overall valuation, the classification of any individual financial instrument may differ from one measurement date to the next. In the event that there is a movement to/from the classification of an instrument as Level 3, we have reflected such items in the table below within the "Transfers into Level 3" and "Transfers out of Level 3" captions.

We manage our overall risk at the portfolio level, and in the execution of our strategy, we may use a combination of financial instruments, which may be classified within any level. Since Level 1 and Level 2 risk management instruments are not included in the rollforward below, the gains or losses in the table do not reflect the effect of our total risk management activities.

	Commodity Derivative Instruments			
	Current Assets	Long-Term Assets	Current Liabilities	Long-Term Liabilities
	(millions)			
Year ended December 31, 2010:				
Beginning balance	$ 73	$18	$ (88)	$ (6)
Net realized and unrealized gains (losses) included in earnings	55	(7)	(36)	5
Transfers into Level 3 (a)	—	—	—	—
Transfers out of Level 3 (a)	(4)	—	1	—
Purchases, issuances and settlements, net	(74)	(1)	78	—
Ending balance	$ 50	$10	$ (45)	$ (1)
Net unrealized gains (losses) still held included in earnings (b)	$ 50	$ (6)	$ (45)	$ 5
Year ended December 31, 2009:				
Beginning balance	$ 210	$22	$(155)	$(44)
Net realized and unrealized gains (losses) included in earnings	33	(4)	(30)	38
Net transfers (out) of/in to Level 3 (c)	—	—	3	—
Purchases, issuances and settlements, net	(170)	—	94	—
Ending balance	$ 73	$18	$ (88)	$ (6)
Net unrealized gains (losses) still held included in earnings (b)	$ 73	$ (1)	$ (88)	$ 38

(a) Amounts transferred in and amounts transferred out are reflected at fair value as of the end of the period.
(b) Represents the amount of total gains or losses for the period, included in trading and marketing gains, net, attributable to changes in unrealized gains or losses relating to assets and liabilities classified as Level 3 that are still held as of December 31, 2010 and 2009.
(c) Amounts transferred in are reflected at the fair value as of the beginning of the period and amounts transferred out are reflected at the fair value at the end of the period.

During 2010, we recognized the fair value of our contingent consideration, which is classified as Level 3, in relation to our acquisition from Ceritas of $3 million, and the purchase of an additional interest in a subsidiary of $1 million, which we recorded to other current liabilities in our consolidated balance sheets. During the year ended December 31, 2010 we re-assessed the fair value of the contingent consideration and adjusted the fair value of the liability to $2 million. Accordingly, we recognized $2 million as an offset to operating expense within the consolidated results of operations during the year ended December 31, 2010.

During the year ended December 31, 2010, we had no significant transfers into and out of Levels 1, 2 and 3. To qualify as a transfer, the assets or liability must have existed in the previous reporting period and moved into a different level during the current reporting period.

Estimated Fair Value of Financial Instruments

We have determined fair value amounts using available market information and appropriate valuation methodologies. However, considerable judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we could realize in a current market exchange. The use of different market assumptions and/or estimation methods may have a material effect on the estimated fair value amounts.

The fair value of restricted investments, accounts receivable, accounts payable and short-term borrowings are not materially different from their carrying amounts because of the short-term nature of these instruments or the stated rates approximating market rates. Unrealized gains and unrealized losses on derivative instruments are carried at fair value. As of December 31, 2010, the carrying and fair value of our long-term debt, including current maturities of long-term debt, was $3,473 million and $3,790 million, respectively. As of December 31, 2009, the carrying and fair value of our long-term debt, including current maturities of long-term debt, was $3,641 million and $3,830 million, respectively. We determine the fair value of our variable rate debt based upon the discounted present value of expected future cash flows, taking into account the difference between the contractual borrowing spread and the spread for similar credit facilities available in the marketplace.

11. Financing

	December 31, 2010	December 31, 2009
	(millions)	
Short term-borrowings	$ 187	$ 3
DCP Midstream's debt securities:		
Issued August 2000, interest at 7.875% payable semiannually, due August 2010 (a)	—	800
Issued January 2001, interest at 6.875% payable semiannually, due February 2011 (b)	250	250
Issued November 2008, interest at 9.700% payable semiannually, due December 2013	250	250
Issued October 2005, interest at 5.375% payable semiannually, due October 2015	200	200
Issued February 2009, interest at 9.750% payable semiannually, due March 2019	450	450
Issued March 2010, interest at 5.350% payable semiannually, due March 2020	600	—
Issued August 2000, interest at 8.125% payable semiannually, due August 2030 (c)	300	300
Issued October 2006, interest at 6.450% payable semiannually, due November 2036	300	300
Issued September 2007, interest at 6.750% payable semiannually, due September 2037	450	450
DCP Partners' debt securities:		
Issued September 2010, interest at 3.250%, payable semiannually, due October 2015	250	—
DCP Partners' credit facility revolver, weighted-average variable interest rate of 1.14% and 0.69%, respectively, due June 2012 (d)	398	603
DCP Partners' credit facility term loan, variable interest rate of 0.34%, due June 2012 (e)	—	10
Fair value adjustments related to interest rate swap fair value hedges (a) (b) (c)	37	40
Unamortized discount	(12)	(12)
Total debt	3,660	3,644
Current maturities of long-term debt	(250)	(800)
Short term borrowings	(187)	(3)
Long-term debt	$3,223	$2,841

(a) In July 2009, $500 million of debt was swapped to a floating interest rate obligation. These swaps matured in August 2010.

(b) In July 2009, $200 million of debt was swapped to a floating interest rate obligation.

(c) In December 2008, the swaps associated with this debt were terminated. The remaining long-term fair value of approximately $37 million related to the swaps is being amortized as a reduction to interest expense through the maturity date of the debt.

(d) $275 million of interest rate exposure has been swapped to a fixed interest rate obligation with effective fixed interest rates ranging from 3.97% to 5.19%, for a net effective interest rate of 4.28% on the $398 million of outstanding debt under the DCP Partners' revolving credit facility as of December 31, 2010.

(e) The DCP Partners' term loan facility was fully secured by restricted investments as of December 31, 2009. The term loan was repaid during the first quarter of 2010.

Approximate future maturities of long-term debt in the year indicated are as follows at December 31, 2010:

	Debt Maturities (millions)
2011	$ 250
2012	398
2013	250
2014	—
2015	450
Thereafter	2,100
	3,448
Fair value adjustments related to interest rate swap fair value hedges	37
Unamortized discount	(12)
Current maturities of long-term debt	(250)
Long-term debt	$3,223

DCP Midstream's Debt Securities — In March 2010, we issued $600 million principal amount of 5.35% Senior Notes due 2020, or the 5.35% Notes, for proceeds of approximately $597 million, net of unamortized discounts and related offering costs. The 5.35% Notes mature and become due and payable on March 15, 2020. We pay interest semiannually on March 15 and September 15 of each year, and our first payment was on September 15, 2010. The net proceeds from this offering were used to repay a portion of our $800 million 7.875% Notes due August 2010, and for general corporate purposes.

In February 2009, we issued $450 million principal amount of 9.75% Senior Notes due 2019, or the 9.75% Notes, for proceeds of $441 million, net of unamortized discounts and related offering costs. The 9.75% Notes mature and become due and payable on March 15, 2019. We pay interest semiannually on March 15 and September 15 of each year, our first payment was on September 15, 2009. The net proceeds from this offering were used for general corporate purposes, which included repayment of outstanding borrowings.

The debt securities mature and become payable on the respective due dates, and are not subject to any sinking fund provisions. The debt securities are unsecured and are redeemable at a premium at our option.

DCP Midstream's Credit Facilities with Financial Institutions — We have a $450 million revolving credit facility, or the $450 Million Facility, which matures in April 2012. Any outstanding borrowings under the $450 Million Facility at maturity may, at our option, be converted into an unsecured one-year term loan. There were no borrowings outstanding under the $450 Million Facility as of December 31, 2010 and 2009.

In January 2010, we entered into a $350 million revolving credit facility, or the $350 Million Facility, that matures in April 2012. There were no borrowings outstanding under the $350 Million Facility as of December 31, 2010.

The $450 Million Facility and the $350 Million Facility, or together, the Facilities, provide us with total revolving credit availability of $800 million. The $800 million of revolving credit from the Facilities may be used to support our commercial paper program, and for working capital requirements and other general corporate purposes. The $450 Million Facility may also be used for letters of credit. As of December 31, 2010 and 2009, we had $187 million and $0 of commercial paper outstanding, respectively, backed by the Facilities. As of

December 31, 2010 and 2009, there were $6 million and $5 million, respectively, in letters of credit outstanding. As of December 31, 2010, the available capacity under the Facilities was $607 million.

The $450 Million Credit Facility bears interest at either; (1) the higher of Wells Fargo's prime rate or the Federal Funds rate plus 0.50%; or (2) the LIBOR plus an applicable margin, which is 0.31% based on our current credit rating. The facility incurs an annual fee of 0.09% based on our current credit rating. This fee is paid on drawn and undrawn portions of the facility.

The $350 Million Facility bears interest at either: (1) the higher of Wells Fargo's prime rate or the Federal Funds rate plus 0.50%; or (2) LIBOR plus an applicable margin, which is 2.00% based on our credit rating. The facility incurs an annual fee of 0.50% based on our current credit rating. This fee is paid on drawn and undrawn portions of the facility.

The Facilities require us to maintain a consolidated leverage ratio (the ratio of consolidated indebtedness to consolidated EBITDA, in each case as is defined by the Facilities) or not more than 5.0 to 1.0, and on a temporary basis for not more than three consecutive quarters (including the quarter in which such acquisition is consummated), following the consummation of qualifying asset acquisitions as defined by the Facilities, in the midstream energy business of not more than 5.5 to 1.0.

DCP Partners' Debt Securities — On September 30, 2010, DCP Partners issued $250 million of 3.25% Senior Notes due October 1, 2015. DCP Partners' received net proceeds of $248 million, net of unamortized discounts and related offering costs, which were used to repay funds borrowed under the revolver portion of the DCP Partners' Credit Facility. Interest on the notes will be paid semiannually on April 1 and October 1 of each year, commencing April 1, 2011. The notes will mature on October 1, 2015 unless redeemed prior to maturity. The notes are senior unsecured obligations, ranking equally in right of payment with DCP Partners' existing unsecured indebtedness, including indebtedness under the DCP Partners' Credit Facility. DCP Partners is not required to make mandatory redemption or sinking fund payments with respect to these notes. The notes are redeemable at a premium at DCP Partners option.

DCP Partners' Credit Facilities with Financial Institutions — DCP Partners has an $850 million revolving credit facility that matures on June 21, 2012, or the DCP Partners' Credit Agreement. Effective June 28, 2010, DCP Partners transferred both the funded and the unfunded portions of the former Lehman Brothers Commercial Bank's commitment to Morgan Stanley. The transfer reinstated $25 million of available capacity to DCP Partners' revolving credit facility.

At December 31, 2010 and 2009, DCP Partners had $32 million and less than $1 million, respectively, of letters of credit issued under the DCP Partners' Credit Agreement outstanding. As of December 31, 2009, DCP Partners had $10 million outstanding term loan balances under DCP Partners' Credit Agreement, which were fully collateralized by investments in high-grade securities classified as restricted investments in the accompanying consolidated balance sheet as of December 31, 2009. As of December 31, 2010, the unused capacity under the revolving credit facility was $420 million.

DCP Partners' borrowing capacity is limited at December 31, 2010, by the DCP Partners' Credit Agreement's financial covenant requirements. Except in the case of a default, amounts borrowed under DCP Partners' credit facility will not mature prior to the June 21, 2012, maturity date.

Under DCP Partners' Credit Agreement, indebtedness under the revolving credit facility bears interest at either: (1) the higher of Wells Fargo Bank's prime rate or the Federal Funds rate plus 0.50%; or (2) LIBOR plus an applicable margin of 0.44% based upon DCP Partner's current credit rating. The DCP Partners' revolving credit facility incurs an annual facility fee of 0.11% based upon DCP Partner's credit rating. This fee is paid on drawn and undrawn portions of DCP Partners' revolving credit facility.

The DCP Partners' Credit Agreement requires DCP Partners to maintain a leverage ratio (the ratio of its consolidated indebtedness to its consolidated EBITDA, in each case as is defined by the DCP Partners' Credit Agreement) of not more than 5.0 to 1.0, and on a temporary basis for not more than three consecutive quarters (including the quarter in which such acquisition is consummated) following the consummation of asset acquisitions in the midstream energy business of not more than 5.5 to 1.0.

Other Agreements — As of December 31, 2010, DCP Partners had a contingent letter of credit facility for up to $10 million, on which DCP Partners pays a fee of 0.50% per annum. As of December 31, 2010, DCP Partners has no letters of credit issued under this facility. Any letters of credit issued on this facility will incur a net fee of 1.75% per annum and will not reduce the available capacity under the DCP Partners' Credit Agreement.

Other Financing — In November 2010, DCP Partners issued 2,875,000 common units at $34.96 per unit. DCP Partners received proceeds of $96 million, net of offering costs.

In August 2010, DCP Partners issued 2,990,000 common units at $32.57 per unit. DCP Partners received proceeds of $93 million, net of offering costs.

In November and December 2009, DCP Partners issued 2,875,000 common limited partner units at $25.40 per unit. DCP Partners received proceeds of approximately $70 million, net of offering costs.

In April 2009, we contributed an additional 25.1% membership interest in East Texas to DCP Partners in exchange for 3,500,000 DCP Partners Class D units. The Class D units converted into DCP Partners' common units on a one-for-one basis on August 17, 2009, and the holders of the Class D units became eligible to receive quarterly distribution payments, beginning with the DCP Partners' second quarter distribution on August 14, 2009.

12. Risk Management and Hedging Activities, Credit Risk and Financial Instruments

Our day-to-day operations expose us to a variety of risks including but not limited to changes in the prices of commodities that we buy or sell, changes in interest rates, and the creditworthiness of each of our counterparties. We manage certain of these exposures by using physical and financial derivative instruments. All of our commodity derivative activities are conducted under the governance of internal Risk Management Committees that establishes policies, limiting exposure to market risk and requiring daily reporting to management of potential financial exposure. These policies include statistical risk tolerance limits using historical price movements to calculate daily value at risk. The following briefly describes each of the risks that we manage.

Commodity Price Risk

Our portfolio of commodity derivative activity is primarily accounted for using the mark-to-market method of accounting; however, depending upon our risk profile and objectives, in certain limited cases, we may execute transactions that qualify for the hedge method of accounting. The risks, strategies and instruments used to mitigate such risks, as well as the method of accounting are discussed and summarized in the tables below.

Natural Gas Asset Based Trading and Marketing

Our natural gas asset based trading and marketing activities engage in the business of trading energy related products and services, including managing purchase and sales portfolios, storage contracts and facilities, and transportation commitments for products. These energy trading operations are exposed to market variables and commodity price risk with respect to these products and services, and we may enter into physical contracts and financial instruments with the objective of realizing a positive margin from the purchase and sale of commodity-based instruments. We manage commodity price risk related to owned and leased natural gas storage and pipeline assets by engaging in natural gas asset based trading and marketing. The commercial activities related to our natural gas asset based trading and marketing primarily consist of time spreads and basis spreads.

We may execute a time spread transaction when the difference between the current price of natural gas (cash or futures) and the futures market price for natural gas exceeds our cost of storing physical gas in our owned and/or leased storage facilities. The time spread transaction allows us to lock in a margin when this market condition exists. A time spread transaction is executed by establishing a long gas position at one point in time and establishing a corresponding short gas position at a different point in time. We typically use swaps to execute these transactions, which are not designated as hedging instruments and are recorded at fair value with changes in fair value recorded in the current period consolidated statement of operations. While gas held in our storage locations is recorded at the lower of average cost or market, the derivative instruments that are used to manage our storage facilities are recorded at fair value and any changes in fair value are currently recorded in our consolidated statements of operations. Even though we may have economically hedged our exposure and locked in a future margin the use of lower-of-cost-or-market accounting for our physical inventory and the use of mark-to-market accounting for our derivative instruments may subject our earnings to market volatility.

We may execute basis spread transactions when the market price differential between locations on a pipeline asset exceeds our cost of transporting physical gas through our owned and/or leased pipeline asset. When this market condition exists, we may execute derivative instruments around this differential at the market price. This basis spread transaction allows us to lock in a margin on our physical purchases and sales of gas. We typically use swaps to execute these transactions, which are not designated as hedging instruments and are recorded at fair value with changes in fair value recorded in the current period consolidated statements of operations. As discussed above, the accounting for physical gas purchases and sales and the accounting for the derivative instruments used to manage such purchases and sales differ, and may subject our earnings to market volatility, even though the transaction represents an economic hedge in which we have locked in a future margin.

Additionally, in order for our storage facilities to remain operational, we maintain a minimum level of base gas in each storage cavern, which is capitalized on our consolidated balance sheets as a component of property, plant and equipment, net. In the fourth quarter of 2008 we commenced a capacity expansion project for one of our storage caverns, which required us to sell all of the base gas within the cavern. During 2009, the expansion project was completed and base gas was repurchased to restore our storage cavern to operation. To mitigate the risk associated with the forecasted re-purchase of base gas, we executed a series of derivative financial instruments, which were designated as cash flow hedges. The cash paid upon settlement of these hedges economically offsets the cash paid to purchase the base gas. A deferred loss of $3 million was recognized and will remain in AOCI until such time that our cavern is emptied and the base gas is sold.

NGL Proprietary Trading

Our NGL proprietary trading activity includes trading energy related products and services. We undertake these activities through the use of fixed forward sales and purchases, basis and spread trades, storage opportunities, put/call options, term contracts and spot market trading. These energy trading operations are exposed to market variables and commodity price risk with respect to these products and services, and these operations may enter into physical contracts and financial instruments with the objective of realizing a positive margin from the purchase and sale of commodity-based instruments. These physical and financial instruments are not designated as hedging instruments and are recorded at fair value with changes in fair value recorded in the current period consolidated statements of operations.

Commodity Cash Flow Protection Activities at DCP Partners

As a result of DCP Partners' operations of gathering, processing and transporting natural gas, DCP Partners takes title to a portion of residue gas, NGLs and condensate, which are considered to be Partners' equity volumes. The possession of and the related operations of transporting and marketing of NGLs, creates commodity price risk due to market changes in commodity prices, primarily with respect to the prices of NGLs, natural gas and crude oil. DCP Partners has mitigated a portion of its expected commodity price risk associated with these equity volumes through 2015 with natural gas and crude oil derivatives. Additionally, given the limited depth of the NGL derivatives market, DCP Partners utilizes crude oil swaps and costless collars to mitigate a portion of its commodity price risk exposure for propane and heavier NGLs. These transactions are primarily accomplished through the use of swaps that exchange DCP Partners floating price risk for a fixed price, but the type of instrument that is used to mitigate risk may vary depending upon DCP Partners' risk objective. These transactions are not designated as hedging instruments for accounting purposes and the change in fair value is reflected in the current period within our consolidated statements of operations.

Interest Rate Risk

We enter into debt arrangements that have either fixed or floating rates, therefore we are exposed to market risks related to changes in interest rates. We periodically use interest rate swaps to hedge interest rate risk associated with our debt. Our primary goals include (1) maintaining an appropriate ratio of fixed-rate debt to floating-rate debt; (2) reducing volatility of earnings resulting from interest rate fluctuations; and (3) locking in attractive interest rates based on historical rates.

In July 2009, we entered into interest rate swaps to convert the fixed interest rate on $500 million of debt securities under our 7.875% Notes due August 2010 and $200 million of debt securities under our 6.875% Notes due February 2011 to a floating rate. The interest rate fair value hedges associated with our 7.875% Notes expired in August 2010. The interest rate fair value hedges associated with our 6.875% Notes are at a floating rate based on one month LIBOR, which resets monthly and are paid semi-annually through their expiration in February 2011. The swaps meet conditions that permit the assumption of no ineffectiveness. As such, for the life of the swaps, no ineffectiveness will be recognized.

Additionally, we previously had fair value interest rate hedges associated with our $300 million 8.125% Notes, or the 8.125% Notes, that were terminated in December 2008. As a result of this termination, the fair value of the underlying debt being hedged has been adjusted and will be amortized as a reduction to our interest expense over the remaining term of the 8.125% Notes through 2030.

DCP Partners mitigates a portion of its interest rate risk with interest rate swaps, which reduce DCP Partners' exposure to market fluctuations by converting variable interest rates to fixed interest rates. These interest rate swap agreements convert the interest rate associated with the indebtedness outstanding under the DCP Partners' revolving credit facility to a fixed rate obligation.

At December 31, 2010, DCP Partners had interest rate swap agreements totaling $450 million, of which $275 million are designated as cash flow hedges. The remaining $175 million of interest rate swap agreements are accounted for under the mark-to-market method of accounting. The entire $450 million of these swap agreements mitigate DCP Partners' interest rate risk through June 2012, with $150 million extending from June 2012 through June 2014.

DCP Partners' has designated $275 million of interest rate swap agreements as cash flow hedges, and effectiveness is determined by matching the principal balance and terms with that of the specified obligation. The effective portions of changes in fair value are recognized in AOCI in the consolidated balance sheets and are reclassified into earnings as the hedged transactions impact earnings. However, due to the volatility of the interest rate markets, the corresponding value in AOCI is subject to change prior to its reclassification into earnings. Ineffective portions of changes in fair value are recognized in earnings.

As of December 31, 2010, $300 million of the agreements reprice prospectively approximately every 90 days and the remaining $150 million of the agreements reprice prospectively approximately every 30 days. Under the terms of the interest rate swap agreements, DCP Partners pays fixed rates ranging from 2.94% to 5.19%, and receives interest payments based on the three-month and one-month LIBOR. The differences to be paid or received under the interest rate swap agreements are recognized as an adjustment to interest expense.

At December 31, 2009 DCP Partners' had interest rate swap agreements totaling $575 million, all of which were designated as cash flow hedges. In September 2010, in conjunction with the issuance of $250.0 million of DCP Partners' 3.25% Senior Notes, DCP Partners, paid down the its revolving credit facility and discontinued hedge accounting on $225 million of the interest rate swap agreements. In addition DCP Partners modified certain interest rate swap agreements to reduce the total outstanding amount by $125 million. The term on $150 million of the remaining $450 million of interest rate swap agreements was extended through June 2014. This resulted in $450 million of these swap agreements mitigating our interest rate risk through June 2012, with $150 million extending from June 2012 through June 2014.

We previously had interest rate cash flow hedges in place that were terminated in 2000. As a result, the remaining net loss deferred in AOCI relative to these cash flow hedges will be reclassified to interest expense through the remaining term of the debt through 2030, as the underlying transactions impact earnings.

Credit Risk

Our principal customers range from large, natural gas marketing services to industrial end-users for our natural gas products and services, as well as large multi-national petrochemical and refining companies, to small regional propane distributors for our NGL products and services. Substantially all of our natural gas and NGL sales are made at market-based prices. Approximately 40% of our NGL production is committed to ConocoPhillips and CP Chem, both related parties, under an existing 15-year contract, the primary production commitment of which expires in 2015. This concentration of credit risk may affect our overall credit risk, in that these customers may be similarly affected by changes in economic, regulatory or other factors. Where exposed to credit risk, we analyze the counterparties' financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of these limits on an ongoing basis. We may use various master agreements that include language giving us the right to request collateral to mitigate credit exposure. The collateral language provides for a counterparty to post cash or letters of credit for exposure in excess of the established threshold. The threshold amount represents an open credit limit, determined in accordance with our credit policy. The collateral language also provides that the inability to post collateral is sufficient cause to terminate a contract and liquidate all positions. In addition, our master agreements and our standard gas and NGL sales contracts contain adequate assurance provisions, which allow us to suspend deliveries and cancel agreements, or continue deliveries to the buyer after the buyer provides security for payment in a satisfactory form.

Contingent Credit Features

Each of the above risks is managed through the execution of individual contracts with a variety of counterparties. Certain of our derivative contracts may contain credit-risk related contingent provisions that may require us to take certain actions in certain circumstances.

We have International Swap Dealers Association, or ISDA, contracts which are standardized master legal arrangements that establish key terms and conditions which govern certain derivative transactions. These ISDA contracts contain standard credit-risk related contingent provisions. Some of the provisions we are subject to are outlined below.

- In the event that we were to be downgraded below investment grade by at least one of the major credit rating agencies, certain of our ISDA counterparties may have the right to reduce our collateral threshold to zero, potentially requiring us to fully collateralize any commodity contracts in a net liability position.
- In some cases, our ISDA contracts contain cross-default provisions that could constitute a credit-risk related contingent feature. For example, if we were to fail to make a required interest or principal payment on a debt instrument, above a predefined threshold level, and after giving effect to any applicable notice or grace period as defined in the ISDA contracts, our ISDA counterparties may have the right to request early termination and net settlement of any outstanding derivative positions.
- Additionally, if DCP Partners, our consolidated subsidiary, were to have an effective event of default under the DCP Partners' Credit Agreement that occurs and is continuing, DCP Partners' ISDA counterparties may have the right to request early termination and net settlement of any outstanding derivative liability positions.

Depending upon the movement of commodity prices and interest rates, each of our individual contracts with counterparties to our commodity derivative instruments or interest rate swap instruments are in either a net asset or net liability position. Our commodity derivative contracts that are not governed by ISDA contracts do not have any credit-risk related contingent features. As of December 31, 2010, we had $74 million of individual commodity derivative contracts that contain credit-risk related contingent features that were in a net liability position, and have not posted any cash collateral relative to such positions. If a credit-risk related event were to occur and we were required to net settle our position with an individual counterparty, our ISDA contracts permit us to net all outstanding contracts with that counterparty, whether in a net asset or net liability position, as well as any cash collateral already posted. As of December 31, 2010, if a credit-risk related event were to occur, we may be required to post additional collateral. Additionally, although our commodity derivative contracts that contain credit-risk related contingent features were in a net liability position as of December 31, 2010, if a credit-risk related event were to occur, the net liability position would be partially offset by contracts in a net asset position reducing our net liability to $64 million.

As of December 31, 2010, DCP Partners' interest rate swaps were in a net liability position of $27 million of which, the entire amount is subject to credit-risk related contingent features. If DCP Partners were to have an event of default relative to any covenants of its credit agreement, that occurs and is continuing, the counterparties to DCP Partners' swap instruments may have the right to request early termination and settlement of the outstanding derivative position.

Collateral

As of December 31, 2010, we held cash of $1 million, included in other current liabilities in the consolidated balance sheets related to unrealized gains on financial or physical instruments, and letters of credit of $94 million from counterparties to secure their future performance under financial or physical contracts. We had cash deposits with counterparties of $26 million, included in other current assets as of December 31, 2010, to secure our obligations to provide future services or to perform financial contracts. As of December 31, 2010, DCP Partners had a contingent letter of credit facility for up to $10 million, on which DCP Partners had no letters of credit issued. This contingent letter of credit facility was issued directly by a financial institution and does not reduce the available capacity under the DCP Partners' Credit Agreement. As of December 31, 2010, DCP Partners had $32 million of letters of credit issued under the DCP Partners' Credit Agreement outstanding. As of December 31, 2010, DCP Partners had no other cash collateral posted with counterparties to its commodity derivative instruments. As of December 31, 2010, we had issued and outstanding parental guarantees totaling $108 million in favor of certain counterparties to DCP Partners' commodity derivative instruments to mitigate a portion of DCP Partners' collateral requirements with those counterparties. DCP Partners pays us a fee of 0.50% per annum on $65 million of these guarantees. These parental guarantees and contingent letter of credit facility reduce the amount of cash DCP Partners may be required to post as collateral. Collateral amounts held or posted may be fixed or may vary, depending on the value of the underlying contracts, and could cover normal purchases and sales, trading and hedging contracts. In many cases, we and our counterparties publicly disclose credit ratings, which may impact the amounts of collateral requirements.

Physical forward contracts and financial derivatives are generally cash settled at the expiration of the contract term. These transactions are generally subject to specific credit provisions within the contracts that would allow the seller, at its discretion, to suspend deliveries, cancel agreements or continue deliveries to the buyer after the buyer provides security for payment satisfactory to the seller.

Summarized Derivative Information

The following summarizes the balance within AOCI, net of noncontrolling interest, relative to our commodity and interest rate cash flow hedges:

	December 31,	
	2010	2009
	(millions)	
Commodity cash flow hedges:		
Net deferred losses in AOCI	$ (3)	$ (3)
Interest rate cash flow hedges:		
Net deferred losses in AOCI	(10)	(14)
Total AOCI	$(13)	$(17)

The fair value of our derivative instruments that are designated as hedging instruments, those that are marked-to-market each period, and the location of each within our consolidated balance sheets, by major category, is summarized as follows:

Balance Sheet Line Item	December 31, 2010	December 31, 2009	Balance Sheet Line Item	December 31, 2010	December 31, 2009
	(millions)			(millions)	
Derivative Assets Designated as Hedging Instruments:			**Derivative Liabilities Designated as Hedging Instruments:**		
Interest rate derivatives:			**Interest rate derivatives:**		
Unrealized gains on derivative instruments – current	$ 1	$ 3	Unrealized losses on derivative instruments – current	$ (12)	$ (20)
Unrealized gains on derivative instruments – long-term	—	—	Unrealized losses on derivative instruments – long-term	(5)	(12)
	$ 1	$ 3		$ (17)	$ (32)
Commodity derivatives:			**Commodity derivatives:**		
Unrealized gains on derivative instruments – current	$ —	$ 1	Unrealized losses on derivative instruments – current	$ —	$ (3)
	$ —	$ 1		$ —	$ (3)
Derivative Assets Not Designated as Hedging Instruments:			**Derivative Liabilities Not Designated as Hedging Instruments:**		
Interest rate derivatives:			**Interest rate derivatives:**		
Unrealized gains on derivative instruments – current	$ —	$ —	Unrealized losses on derivative instruments – current	$ (5)	$ —
Unrealized gains on derivative instruments – long-term	—	—	Unrealized losses on derivative instruments – long-term	(5)	—
	$ —	$ —		$ (10)	$ —
Commodity derivatives:			**Commodity derivatives:**		
Unrealized gains on derivative instruments – current	$143	$255	Unrealized losses on derivative instruments – current	$(163)	$(206)
Unrealized gains on derivative instruments – long-term	25	41	Unrealized losses on derivative instruments – long-term	(55)	(66)
	$168	$296		$(218)	$(272)

The following table summarizes the impact on our consolidated statement of operations of our derivative instruments that are accounted for using the fair value hedge method of accounting.

Derivatives in Fair Value Hedging Relationships	Location of Gain (Loss) Recognized in Earnings	Amount of Gain (Loss) Recognized in Earnings — Year Ended December 31, 2010	2009
Interest rate derivatives	Interest expense	$1	$3

The following table summarizes the impact on our consolidated balance sheet and consolidated statement of operations of our derivative instruments, net of noncontrolling interest, that are accounted for using the cash flow hedge method of accounting.

	Loss Recognized in AOCI on Derivatives – Effective Portion		Loss Reclassified from AOCI to Earnings – Effective Portion		Gain (Loss) Recognized in Income on Derivatives – Ineffective Portion and Amount Excluded from Effectiveness Testing		Deferred Gains (Losses) in AOCI Expected to be Reclassified into Earnings Over the Next 12 Months
	Year Ended December 31,						
	2010	2009	2010	2009	2010	2009	
	(millions)						
Commodity derivatives	$—	$(2)	$ —	$— (a)	$—	$— (a)(c)	$—
Interest rate derivatives	$ (6)	$(4)	$(10)	$ (6)(b)	$—	$— (b)(c)	$ (6)

(a) Included in sales of natural gas and petroleum products in our consolidated statements of operations.
(b) Included in interest expense in our consolidated statements of operations.
(c) For the years ended December 31, 2010 and 2009, no derivative gains or losses were reclassified from AOCI to current period earnings as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring.

Changes in value of derivative instruments, for which the hedge method of accounting has not been elected from one period to the next, are recorded in the consolidated statements of operations. The following summarizes these amounts and the location within the consolidated statements of operations that such amounts are reflected:

Commodity Derivatives: Statement of Operations Line Item	Year Ended December 31, 2010	2009	2008
	(millions)		
Realized gains (losses)	$118	$127	$ (93)
Unrealized (losses) gains	(74)	(77)	194
Trading and marketing gains, net	$ 44	$ 50	$101

We do not have any derivative financial instruments that qualify as a hedge of a net investment.

The following tables represent, by commodity type, our net long or short positions, as well as the number of outstanding contracts that are expected to partially or entirely settle in each respective year. To the extent that we have long dated derivative positions that span multiple calendar years, the contract will appear in more than one line item in the table below. Additionally, relative to the hedging of certain of our storage and/or transportation assets, we may execute basis transactions for natural gas, which may result in a net long/short position of zero. This table also presents our net long or short natural gas basis swap positions separately from our net long or short natural gas positions.

	December 31, 2010							
	Crude Oil		Natural Gas		Natural Gas Liquids		Natural Gas Basis Swaps	
Year of Expiration	Net Long (Short) Position (Bbls)	Number of Contracts	Net Long (Short) Position (MMBtu)	Number of Contracts	Net Long (Short) Position (Bbls)	Number of Contracts	Net Long (Short) Position (MMBtu)	Number of Contracts
2011	(1,333,804)	549	(12,647,000)	290	(12,316,395)	707(a)	(2,910,000)	158
2012	(874,358)	165	269,000	64	(8,258,400)	11(b)	8,220,000	19
2013	(465,250)	46	(165,000)	5	(9,000,000)	2(b)	—	—
2014	(547,500)	5	(365,000)	3	(9,000,000)	2(b)	—	—
2015	(182,500)	1	—	—	—	—	—	—

(a) Includes 27 physical index based derivative contracts totaling (13,083,000) Bbls
(b) Includes 2 physical index based derivative contracts totaling (9,000,000) Bbls

	December 31, 2009							
	Crude Oil		Natural Gas		Natural Gas Liquids		Natural Gas Basis Swaps	
Year of Expiration	Net Long (Short) Position (Bbls)	Number of Contracts	Net Long (Short) Position (MMBtu)	Number of Contracts	Net Long (Short) Position (Bbls)	Number of Contracts	Net Long (Short) Position (MMBtu)	Number of Contracts
2010	(1,479,972)	525	(9,478,500)	240	(11,250,605)	609(a)	(30,160,000)	261
2011	(749,000)	80	(2,084,000)	73	(7,143,000)	34(b)	(5,315,000)	65
2012	(388,750)	33	(734,600)	43	(9,000,000)	2(b)	(366,000)	1
2013	(748,250)	4	(365,000)	1	(9,000,000)	2(b)	(365,000)	1
2014	(365,000)	3	—	—	(9,000,000)	2(b)	—	—

(a) Includes 29 physical index based derivative contracts totaling (12,271,900) Bbls
(b) Includes 2 physical index based derivative contracts totaling (9,000,000) Bbls

As of December 31, 2010, we had interest rate swap instruments outstanding, which in the aggregate, exchange $200 million of our fixed rate obligation for a floating rate obligation. These swaps expire in February 2011. As of December 31, 2010, DCP Partners had interest rate swaps outstanding with individual notional values of $50 million, which, in aggregate, exchange up to $300 million of DCP Partners' floating rate obligation for a fixed rate obligation through June 2012, and interest rate swaps outstanding with individual notional values of between $70 million and $80 million, which in aggregate, exchange up to $150 million of DCP Partners' floating rate obligation for a fixed rate obligation through June 2014.

13. Equity-Based Compensation

We recorded equity-based compensation (benefit) expense as follows, the components of which are further described below:

	Year Ended December 31,		
	2010	2009	2008
		(millions)	
DCP Midstream, LLC Long-Term Incentive Plan	$12	$ 8	$—
DCP Partners' Long-Term Incentive Plan (DCP Partners' LTIP)	3	2	(1)
Duke Energy 1998 Plan and Spectra Energy's 2007 Long-Term Incentive Plan (Duke Energy 1998 LTIP and Spectra Energy 2007 LTIP)	—	—	(1)
Total	$15	$10	$ (2)

	Vesting Period (years)	Unrecognized Compensation Expense at December 31, 2010 (millions)	Estimated Forfeiture Rate	Weighted-Average Remaining Vesting (years)
DCP Midstream LTIP:				
Relative Performance Units (RPUs)	3	$—	—	—
Strategic Performance Units (SPUs)	3	$ 6	15%-28%	1
Phantom Units	5	$ 5	15%-28%	1
DCP Partners' Phantom Units	3	$—	28%	2
DCP Partners' LTIP:				
Performance Units	3	$ 1	21%-30%	1
Phantom Units	0.5	$—	0%	—
Restricted Phantom Units	3	$ 1	21%-30%	1
Duke Energy 1998 LTIP and Spectra Energy 2007 LTIP:				
Stock Options	0-10	$—	5%	—
Phantom Awards	1-5	$—	1%	—

DCP Midstream LTIP — Under the DCP Midstream LTIP, equity instruments may be granted to our key employees. The DCP Midstream LTIP provides for the grant of Relative Performance Units, or RPUs, Strategic Performance Units, or SPUs, and Phantom Units. The RPUs, SPUs and Phantom Units consist of a notional unit based on the value of common shares or units of ConocoPhillips, Duke Energy, Spectra Energy and DCP Partners. The weighting varies depending on when the units were granted. The DCP Partners' Phantom Units constitute a notional unit equal to the fair value of DCP Partners' common units. Each award provides for the grant of dividend or distribution equivalent rights, or DERs. The LTIP is administered by the compensation committee of our board of directors. All awards are subject to cliff vesting.

Relative Performance Units — The number of RPUs that will ultimately vest range from 0% to 200% of the outstanding RPUs, depending on the achievement of specified performance targets over a three year period. The final performance payout is determined by the compensation committee of our board of directors. After the performance period the value derived from the RPUs is transferred to our Non-Qualified Deferred Compensation plan, and invested according to the participant's investment elections. The DERs are paid in cash at the end of the performance period. The following tables presents information related to RPUs:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2008	62,167	$43.41	
Forfeited	(5,850)	$43.36	
Vested or paid in cash	(3,047)	$42.86	
Outstanding at December 31, 2008	53,270	$43.44	
Forfeited	(530)	$43.91	
Transferred to Non-Qualified Executive Deferred Compensation Plan (a)	(27,700)	$42.90	
Outstanding at December 31, 2009	25,040	$44.02	
Transferred to Non-Qualified Executive Deferred Compensation Plan (a)	(25,040)	$44.02	
Outstanding at December 31, 2010	—	$ —	$—

(a) After the performance period the value derived from the RPUs is transferred to our Non-Qualified Deferred Compensation plan, and invested according to the participant's investment elections. Units vesting in 2010 and 2009, transferred at 100% and 170%, respectively.

Strategic Performance Units — The number of SPUs that will ultimately vest range from 0% to 200% of the outstanding SPUs, depending on the achievement of specified performance targets over a three year period. The final performance payout is determined by the compensation committee of our board of directors. The DERs are paid in cash at the end of the performance period. The following tables presents information related to SPUs:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2008	140,019	$ 43.49	
Granted	112,930	$ 35.49	
Forfeited	(14,617)	$ 41.86	
Vested or paid in cash	(3,047)	$ 42.86	
Outstanding at December 31, 2008	235,285	$ 39.76	
Granted	209,110	$ 18.51	
Forfeited or cancelled	(7,039)	$ 34.20	
Vested or paid in cash (a)	(62,439)	$ 42.94	
Outstanding at December 31, 2009	374,917	$ 27.48	
Granted	139,900	$ 30.03	
Forfeited	(7,710)	$ 26.79	
Vested or paid in cash (b)(c)	(166,237)	$ 41.59	
Outstanding at December 31, 2010	340,870	$ 21.66	$ 36.81
Expected to vest	294,872	$ 22.73	$ 36.74

(a) The 2006 grants vested at 70%.
(b) The 2007 grants vested at 100%
(c) The 2008 grants vested at 59%

The estimate of RPUs and SPUs that are expected to vest is based on highly subjective assumptions that could change over time, including the expected forfeiture rate and achievement of performance targets. Therefore the amounts of unrecognized compensation expense noted above does not necessarily represent the value that will ultimately be realized in our consolidated statements of operations.

The following table presents the fair value of units vested and the unit-based liabilities paid for unit based awards related to the strategic performance units:

	Units	Fair Value of Units Vested	Unit-Based Liabilities Paid
		(millions)	
Vested in 2008	3,047	$ —	$ —
Vested in 2009	62,439	$ 2	$ 2
Vested in 2010 (a)	166,237	$ 4	$ 2

(a) 105,670 of the units and the related DERs that vested in 2010 will be paid in 2011.

Phantom Units — The DERs are paid quarterly in arrears. The following table presents information related to Phantom Units:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2008	33,800	$43.57	
Granted	112,930	$35.49	
Forfeited	(5,270)	$39.15	
Outstanding at December 31, 2008	141,460	$37.29	
Granted	209,110	$18.51	
Forfeited	(6,040)	$32.51	
Vested	(680)	$43.38	
Outstanding at December 31, 2009	343,850	$25.94	
Granted	139,800	$30.04	
Forfeited	(7,690)	$27.04	
Vested	(105,670)	$40.15	
Outstanding at December 31, 2010	370,290	$23.41	$34.62
Expected to vest	299,124	$25.03	$37.73

The following table presents the fair value of units vested and the unit-based liabilities paid for unit based awards related to the phantom units:

	Units	Fair Value of Units Vested	Unit-Based Liabilities Paid
		(millions)	
Vested in 2009	680	$—	$—
Vested in 2010 (a)	105,670	$ 3	$—

(a) 105,670 of the units and the related DERs that vested in 2010 will be paid in 2011.

DCP Partners' Phantom Units — The DERs are paid quarterly in arrears. The following table presents information related to the DCP Partners' Phantom Units:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Price Per Unit
Outstanding at January 1, 2008	51,750	$34.33	
Forfeited	(2,750)	$51.10	
Outstanding at December 31, 2008	49,000	$33.39	
Vested	(38,250)	$28.60	
Outstanding at December 31, 2009	10,750	$50.43	
Granted	17,300	$35.56	
Vested	(10,750)	$31.87	
Outstanding at December 31, 2010	17,300	$47.09	$37.40
Expected to vest	12,456	$35.56	$37.40

The fair value of units that vested, and the unit-based liabilities paid during the year ended December 31, 2010 and 2009 was less than $1 million, respectively.

DCP Partners' LTIP — Under DCP Partners' LTIP, which was adopted by DCP Midstream GP, LLC, equity instruments may be granted to key employees, consultants and directors of DCP Midstream GP, LLC and its affiliates who perform services for DCP Partners. The DCP Partners' LTIP provides for the grant of limited partner units, or LPUs, phantom units, unit options and substitute awards, and, with respect to unit options and phantom units, the grant of dividend equivalent rights, or DERs. Subject to adjustment for certain events, an aggregate of 850,000 LPUs may be delivered pursuant to awards under the DCP Partners' LTIP. Awards that are canceled or forfeited, or are withheld to satisfy DCP Midstream GP, LLC's tax withholding obligations, are available for delivery pursuant to other awards. The DCP Partners' LTIP is administered by the compensation committee of DCP Midstream GP, LLC's board of directors. All awards are subject to cliff vesting, with the exception of the Phantom Units issued to the directors in conjunction with the initial public offering, which are subject to graded vesting provisions. Substantially all awards are accounted for as liability awards.

Performance Units — DCP Partner's has awarded phantom LPUs or Performance Units, pursuant to the LTIP to certain employees. The number of Performance Units that will ultimately vest range from 0% to 200% of the outstanding Performance Units, depending on the achievement of specified performance targets over three year performance periods. The final performance percentage payout is determined by the compensation committee of DCP Partners' board of directors. The DERs are paid in cash at the end of the performance period. The following table presents information related to the Performance Units:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Price Per Unit
Outstanding at January 1, 2008	46,960	$34.09	
Granted	17,085	$33.85	
Forfeited	(12,025)	$33.14	
Outstanding at December 31, 2008	52,020	$34.23	
Granted	52,450	$10.05	
Vested (a)	(37,330)	$34.51	
Outstanding at December 31, 2009	67,140	$15.18	
Granted	16,630	$31.80	
Forfeited	(2,205)	$15.61	
Vested (b)	(14,215)	$33.44	
Outstanding at December 31, 2010	67,350	$15.42	$37.40
Expected to vest	63,435	$14.04	$37.40

(a) The units vested at 103%
(b) The units vested at 0%.

The estimate of Performance Units that are expected to vest is based on highly subjective assumptions that could potentially change over time, including the expected forfeiture rate and achievement of performance targets. Therefore the amount of unrecognized compensation expense noted above does not necessarily represent the value that will ultimately be realized in our consolidated statements of operations.

The following table presents the fair value of units vested and the unit-based liabilities paid for unit based awards related to Performance Units, including the related DERs:

	Units	Fair Value of Units Vested	Unit-Based Liabilities Paid
		(millions)	
Vested in 2009 (a)	37,330	$ 1	$—
Vested in 2010 (a)	14,215	—	$ 1

(a) 22,860 of the units and the related DERs that vested in 2009 were paid in 2010.

Phantom Units — In conjunction with its initial public offering, in January 2006 DCP Partners General Partner's board of directors awarded Phantom LPUs, or Phantom Units, to key employees, and to directors who are not officers or employees of DCP Midstream GP, LLC, or its affiliates who perform services for DCP Partners. All of these units vested during 2009.

In 2010, DCP Partners granted 5,200 Phantom Units, pursuant to the DCP Partners' LTIP, to directors who are not officers or employees of affiliates of DCP Midstream as part of its annual director fees in 2010. All of these units vested during 2010.

In 2009, DCP Partners granted 16,000 Phantom Units, pursuant to the DCP Partners' LTIP, to directors who are not officers or employees of affiliates of DCP Midstream as part of its annual director fees in 2009. All of these units vested during 2009.

In 2008, DCP Partners granted 4,000 Phantom Units, pursuant to the DCP Partners' LTIP, to directors who are not officers or employees of affiliates of DCP Midstream as part of its annual director fees in 2008. All of these units vested during 2008.

The DERs are paid quarterly in arrears.

The following table presents information related to the Phantom Units:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Price Per Unit
Outstanding at January 1, 2008	20,199	$24.56	
Granted	4,000	$35.88	
Forfeited	(4,000)	$24.05	
Vested	(6,501)	$32.91	
Outstanding at December 31, 2008	13,698	$24.05	
Granted	16,000	$10.05	
Vested	(29,698)	$16.51	
Outstanding at December 31, 2009	—	$ —	
Granted	5,200	$31.80	
Vested	(5,200)	$31.80	
Outstanding at December 31, 2010	—	$ —	$—

The fair value of the units that vested and the unit based liabilities paid for the years ended December 31, 2010, 2009 and 2008 were less than $1 million for all periods.

Restricted Phantom Units — DCP Midstream Partners' General Partner's board of directors awarded restricted phantom LPUs, or RPUs, to key employees under the LTIP. The RPUs are expected to vest over a three year period. The DERs are paid quarterly in arrears. The following table presents information related to the RPUs:

	Units	Grant Date Weighted-Average Price per Unit	Measurement Date Price per Unit
Outstanding at January 1, 2008	—	$ —	
Granted	17,085	$33.85	
Forfeited	(2,395)	$35.88	
Outstanding at December 31, 2008	14,690	$33.52	
Granted	52,450	$10.05	
Outstanding at December 31, 2009	67,140	$15.18	
Granted	16,630	$31.80	
Forfeited	(2,205)	$15.61	
Vested	(14,215)	$33.44	
Outstanding at December 31, 2010	67,350	$15.42	$37.40
Expected to vest	66,403	$18.64	$37.40

The following table presents the fair value of units vested and the unit-based liabilities paid for unit based awards related to Restricted Phantom Units:

	Units	Fair Value of Units Vested	Unit-Based Liabilities Paid
		(millions)	
Vested in 2010 (a)	14,215	$1	$—

(a) 14,215 of the units and the related DERs that vested in 2010 will be paid in 2011.

The estimate of RPUs that are expected to vest is based on highly subjective assumptions that could potentially change over time, including the expected forfeiture rate. Therefore, the amount of unrecognized compensation expense noted above does not necessarily represent the value that will ultimately be realized in our consolidated statement of operations.

All awards issued under the DCP Midstream LTIP and the DCP Partners' LTIP are intended to be settled in cash at each reporting period or units upon vesting. Compensation expense is recognized ratably over each vesting period, and will be remeasured each reporting period for all awards outstanding until the units are vested. The fair value of all awards is determined based on the closing price of the relevant underlying securities at each measurement date.

Duke Energy 1998 LTIP and Spectra Energy 2007 LTIP — Under the Duke Energy 1998 LTIP, Duke Energy granted certain of our key employees stock options, stock-based performance awards, phantom stock awards and other stock awards to be settled in shares of Duke Energy's common stock, or the Stock-Based Awards. Upon execution of the 50-50 Transaction in July 2005, our employees incurred a change in status from Duke Energy employees to non-employees. As a result, we began accounting for these awards using the fair value method. No awards have been and we do not expect to settle any awards granted under the Duke Energy 1998 LTIP with cash.

In connection with the Spectra spin, one replacement Duke Energy Stock-Based Award and one-half Spectra Energy Stock-Based Award were distributed to each holder of Duke Energy Stock-Based Awards for each award held at the time of the Spectra spin. Substantially all converted Stock-Based Awards are subject to the terms and conditions applicable to the original Duke Energy Stock-Based Awards. The Spectra Energy Stock-Based Awards resulting from the conversion are considered to have been issued under the Spectra Energy 2007 LTIP.

The Spectra Energy 2007 LTIP provides for the granting of stock options, restricted stock awards and units, unrestricted stock awards and units, and other equity-based awards, to employees and other key individuals who perform services for Spectra Energy. A maximum of 30 million shares of common stock may be awarded under the Spectra Energy 2007 LTIP. Options granted under the Spectra Energy 2007 LTIP are issued with exercise prices equal to the fair market value of Spectra Energy common stock on the grant date, have ten year terms, and vest immediately or over terms not to exceed five years. Compensation expense related to stock options is recognized over the requisite service period. The requisite service period for stock options is the same as the vesting period, with the exception of retirement eligible employees, who have shorter requisite service periods ending when the employees become retirement eligible. Restricted, performance and phantom stock awards granted under the Spectra Energy 2007 LTIP typically become 100% vested on the three-year anniversary of the grant date. The fair value of the awards granted is measured based on the fair market value of the shares on the date of grant, and the related compensation expense is recognized over the requisite service period which is the same as the vesting period.

Stock Options — Under the Duke Energy 1998 LTIP, the exercise price of each option granted could not be less than the market price of Duke Energy's common stock on the date of grant. Effective July 1, 2005, these options were accounted using the fair value method. As a result, compensation expense subsequent to July 1, 2005, is recognized based on the change in the fair value of the stock options at each reporting date until vesting.

The following table shows information regarding options to purchase Duke Energy's common stock granted to our employees, reflecting shares outstanding as impacted by the conversion.

	Shares	Weighted-Average Exercise Price	Weighted-Average Remaining Life (years)	Aggregate Intrinsic Value (millions)
Outstanding at January 1, 2008	1,815,956	$17.89	3.2	
Exercised	(151,480)	$13.45		
Forfeited	(106,889)	$19.77		
Outstanding at December 31, 2008	1,557,587	$18.19	2.4	
Exercised	(166,869)	$12.80		
Forfeited	(223,926)	$16.19		
Outstanding at December 31, 2009	1,166,792	$19.34		
Exercised	(56,245)	$ 8.42		
Forfeited	(401,562)	$24.19		
Outstanding and Exercisable at December 31, 2010	708,985	$17.46	1.3	$2

The total intrinsic value of options exercised during the years ended December 31, 2010, 2009, was less than $1 million for both periods, and for the year ended December 31, 2008, was approximately $1 million.

The following table shows information regarding options to purchase Spectra Energy's common stock granted to our employees, reflecting shares outstanding as impacted by the conversion.

	Shares	Weighted-Average Exercise Price	Weighted-Average Remaining Life (years)	Aggregate Intrinsic Value (millions)
Outstanding at January 1, 2008	937,248	$26.80	3.2	
Exercised	(68,869)	$18.91		
Forfeited	(72,400)	$28.06		
Outstanding at December 31, 2008	795,979	$27.36	2.4	
Exercised	(13,861)	$11.93		
Forfeited	(183,822)	$23.36		
Outstanding at December 31, 2009	598,296	$28.95	1.9	
Exercised	(33,768)	$13.22		
Forfeited	(202,187)	$36.55		
Outstanding and Exercisable at December 31, 2010	362,341	$26.18	1.3	$1

The total intrinsic value of options exercised during the years ended December 31, 2010 and 2009, was less than $1 million for both periods, and for the year ended December 31, 2008, was approximately $1 million.

Stock-Based Performance Awards — There were no stock-based performance awards granted during the years ended December 31, 2010, 2009 and 2008.

The following tables summarize information about stock-based performance awards activity, reflecting shares outstanding as impacted by the conversion:

Duke Energy 1998 LTIP	Shares	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2008	173,365	$15.58	
Vested	(83,762)	$15.39	
Forfeited	(59,663)	$15.39	
Outstanding at December 31, 2008	29,940	$16.50	
Vested	(25,329)	$16.50	
Forfeited	(4,611)	$16.50	
Outstanding at December 31, 2010 and 2009	—	$ —	$—

Spectra Energy 2007 LTIP	Shares	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2008	86,683	$23.54	
Vested	(41,884)	$23.25	
Forfeited	(29,829)	$23.25	
Outstanding at December 31, 2008	14,970	$24.94	
Vested	(12,665)	$24.94	
Forfeited	(2,305)	$24.94	
Outstanding at December 31, 2010 and 2009	—	$ —	$—

The total fair value of the performance stock awards that vested during the years ended December 31, 2009 and 2008 was less than $1 million and approximately $2 million, respectively. No awards were granted during the years ended December 31, 2010 and 2009.

Phantom Stock Awards — There were no phantom stock awards granted during the years ended December 31, 2010, 2009 and 2008.

The following tables summarize information about phantom stock awards activity, reflecting shares outstanding as impacted by the conversion:

Duke Energy 1998 LTIP	Shares	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2008	77,210	$15.62	
Vested	(24,419)	$15.57	
Forfeited	(3,287)	$15.38	
Outstanding at December 31, 2008	49,504	$15.66	
Vested	(22,689)	$15.58	
Forfeited	(307)	$15.38	
Outstanding at December 31, 2009	26,508	$15.72	
Vested	(22,516)	$15.59	
Forfeited	—	$ —	
Outstanding at December 31, 2010	3,992	$16.50	$17.81
Expected to vest	3,958	$16.50	$17.81

Spectra Energy 2007 LTIP	Shares	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2008	38,605	$23.60	
Vested	(12,209)	$23.53	
Forfeited	(1,644)	$23.24	
Outstanding at December 31, 2008	24,752	$23.66	
Vested	(11,344)	$23.55	
Forfeited	(154)	$23.24	
Outstanding at December 31, 2009	13,254	$23.76	
Vested	(11,258)	$23.55	
Forfeited	—	$ —	
Outstanding at December 31, 2010	1,996	$24.94	$24.99
Expected to vest	1,971	$24.94	$24.99

The total fair value of the phantom stock awards that vested during the years ended December 31, 2010 and 2009 was less than $1 million for both periods. No awards were granted during the years ended December 31, 2010 and 2009.

Other Stock Awards — There were no other stock awards granted during the years ended December 31, 2010 and 2009.

14. Benefits

All Company employees who have reached the age of 18 and work at least 20 hours per week are eligible for participation in our 401(k) and retirement plan, to which we contribute a range of 4% to 7% of each eligible employee's qualified earnings to the retirement plan, based on years of service. Additionally, we match employees' contributions in the 401(k) plan up to 6% of qualified earnings. During the years ended December 31, 2010, 2009 and 2008 we expensed plan contributions of $21 million, $22 million and $19 million, respectively. In conjunction with the Marysville acquisition on December 30, 2010, we acquired two 401(k) plans with terms substantially similar to our existing 401(k) and retirement plan.

We offer certain eligible executives the opportunity to participate in DCP Midstream LP's Non-Qualified Executive Deferred Compensation Plan. This plan allows participants to defer current compensation on a pre-tax basis and to receive tax deferred earnings on such contributions. The plan also has make-whole provisions for plan participants who may otherwise be limited in the amount that we can contribute to the 401(k) plan on the participant's behalf. All amounts contributed to or earned by the plan's investments are held in a trust account for the benefit of the participants. The trust and the liability to the participants are part of our general assets and liabilities, respectively.

15. Income Taxes

We are structured as a limited liability company, which is a pass-through entity for federal income tax purposes. We own a corporation that files its own federal, foreign and state corporate income tax returns. The income tax (expense) benefit related to this corporation is included in our income tax (expense) benefit, along with state and local taxes of the limited liability company and other subsidiaries. On December 30, 2010, DCP Partners acquired all of the interests in Marysville Hydrocarbons Holdings, LLC, an entity that owns a taxable C-Corporation consolidated return group. We have estimated $35 million of federal deferred tax liabilities resulting from built-in tax gains recognized in the transaction and have recorded this in our preliminary purchase price allocation as of December 31, 2010.

The State of Texas imposes a margin tax that is assessed at 1% of taxable margin apportioned to Texas. Accordingly, we have recorded current tax expense for the Texas margin tax beginning in 2007. The state of Michigan imposes a business tax of 0.8% on gross receipts and 4.95% of Michigan taxable income. The sum of gross receipts and income tax is subject to a tax surcharge of 21.99%. Michigan provides tax credits that may reduce our final income tax liability.

Income tax (expense) benefit consists of the following:

	Year Ended December 31,		
	2010	2009	2008
		(millions)	
Current:			
Federal	$—	$ —	$ 3
State	(9)	(4)	(13)
Deferred:			
Federal	5	(14)	13
State	(1)	—	—
Total income tax (expense) benefit	$ (5)	$(18)	$ 3

We had net long-term deferred tax liabilities of $135 million and $104 million as of December 31, 2010 and 2009, respectively. The net long-term deferred tax liabilities are included in deferred income taxes on the consolidated balance sheets. The deferred tax liabilities of $159 million and $119 million as of December 31, 2010 and 2009, respectively, are primarily associated with depreciation and amortization related to the acquired intangible assets and property, plant and equipment. Offsetting the deferred tax liabilities are deferred tax assets related to the net operating loss of an affiliate corporation of approximately $24 million and $15 million as of December 31, 2010 and 2009, respectively. The net operating losses begin expiring in 2027. We expect to fully utilize the net operating loss carryovers, and, accordingly we have not provided a valuation allowance for the net deferred tax asset.

On January 4, 2011, DCP Partners merged two wholly-owned subsidiaries acquired in the Marysville acquisition and converted the combined entity's organizational structure from a C-Corporation to a limited liability company. This conversion to a limited liability company triggered tax liabilities, stemming from built-in tax gains recognized in the acquisition of Marysville, to become currently payable. Accordingly, $35 million of estimated deferred tax liabilities associated with this acquisition and recorded at December 31, 2010, became current tax liabilities.

Our effective tax rate differs from statutory rates primarily due to our being structured as a limited liability company, which is a pass-through entity for federal income tax purposes, while being treated as a taxable entity in certain states. Additionally, some of our subsidiaries are tax paying entities for federal income tax purposes.

16. Commitments and Contingent Liabilities

Litigation — The midstream industry has seen a number of class action lawsuits involving royalty disputes, mismeasurement and mispayment allegations. We are currently named as defendants in some of these cases and customers have asserted individual audit claims related to mismeasurement and mispayment. Management believes we have meritorious defenses to these cases and, therefore, will continue to defend them vigorously. These claims, however, can be costly and time consuming to defend. We are also a party to various legal, administrative and regulatory proceedings that have arisen in the ordinary course of our business, including, from time to time, disputes with customers over various measurement and settlement issues.

In January 2010, we and DCP Partners entered into a settlement agreement with El Paso E&P Company, or El Paso, to resolve all claims brought by El Paso pursuant to lawsuits in Texas and Louisiana relating to a commercial dispute involving DCP Partners' Minden processing plant which dates back to August 2000. Under the terms of the settlement agreement, we and DCP Partners collectively paid El Paso approximately $4 million during the first quarter of 2010. The cases have been dismissed in both Texas and Louisiana.

Management currently believes that these matters, taken as a whole, and after consideration of amounts accrued, insurance coverage and other indemnification arrangements, will not have a material adverse effect upon our consolidated results of operations, financial position or cash flows.

General Insurance — Our insurance coverage is carried with an affiliate of ConocoPhillips, an affiliate of Spectra Energy and third-party insurers. Our insurance coverage includes: (1) general liability insurance covering third-party exposures; (2) statutory workers' compensation insurance; (3) automobile liability insurance for all owned, non-owned and hired vehicles; (4) excess liability insurance above the established primary limits for general liability and automobile liability insurance; (5) property insurance, which covers the replacement value of real and personal property and includes business interruption; and (6) directors and officers insurance covering our directors and officers for acts related to our business activities. All coverage is subject to certain limits and deductibles, the terms and conditions of which are common for companies with similar types of operations.

Environmental — The operation of pipelines, plants and other facilities for gathering, transporting, processing, treating, or storing natural gas, NGLs and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of these facilities, we must comply with United States laws and regulations at the federal, state and local levels that relate to air and water quality, hazardous and solid waste storage, management, transportation and disposal, and other environmental matters including recently adopted EPA regulations related to reporting of greenhouse gas emissions which became effective in January 2010. The cost of planning, designing, constructing and operating pipelines, plants, and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures, including citizen suits, which can include the assessment of monetary penalties, the imposition of remedial requirements, the issuance of injunctions or restrictions on operations. Management believes that, based on currently known information, compliance with these laws and regulations will not have a material adverse effect on our consolidated results of operations, financial position or cash flows.

We make expenditures in connection with environmental matters as part of our normal operations. Environmental liabilities as of December 31, 2010 and 2009, included in the consolidated balance sheets as other current liabilities amounted to $6 million and $5 million, respectively, and environmental liabilities included in the consolidated balance sheets as other long-term liabilities amounted to $9 million and $11 million, respectively.

Operating Leases — We utilize assets under operating leases in several areas of operations. Consolidated rental expense, including leases with no continuing commitment, amounted to $38 million, $40 million and $45 million in 2010, 2009 and 2008, respectively. Rental expense for leases with escalation clauses is recognized on a straight line basis over the initial lease term.

Minimum rental payments under our various operating leases in the year indicated are as follows:

	Minimum Rental Payments (millions)
2011	$ 56
2012	51
2013	46
2014	36
2015	27
Thereafter	91
Total minimum lease payments	$ 307

17. Guarantees and Indemnifications

We periodically enter into agreements for the acquisition or divestiture of assets. These agreements contain indemnification provisions that may provide indemnity for environmental, tax, employment, outstanding litigation, breaches of representations, warranties and covenants, or other liabilities related to the assets being acquired or divested. Claims may be made by third parties under these indemnification agreements for various periods of time depending on the nature of the claim. The effective periods on these indemnification provisions generally have terms of one to five years, although some are longer. Our maximum potential exposure under these indemnification agreements can vary depending on the nature of the claim and the particular transaction. We are unable to estimate the total maximum potential amount of future payments under indemnification agreements due to several factors, including uncertainty as to whether claims will be made under these indemnities. We have issued guarantees for certain of our consolidated subsidiaries, however, we are not required to, and have not, recognized such guarantees as a liability in our consolidated financial statements.

18. Supplemental Cash Flow Information

	Year Ended December 31,		
	2010	2009	2008
		(millions)	
Cash paid for interest, net of capitalized interest	$ 256	$ 216	$ 190
Cash paid for income taxes, net of income tax refunds	$ 6	$ 10	$ 5
Non-cash investing and financing activities:			
Distributions payable to members	$ 77	$ 71	$ —
Property, plant and equipment acquired with accounts payable	$ 72	$ 24	$ 44
Other non-cash additions of property, plant and equipment	$ 7	$ 10	$ 6
Acquisition related contingent consideration	$ 4	$ —	$ —

During the years ended December 31, 2010 and 2009, we received distributions from DCP Partners of $45 million and $37 million, respectively, which are eliminated in consolidation.

19. Valuation and Qualifying Accounts and Reserves

Our valuation and qualifying accounts and reserves for the years ended December 31, 2010, 2009 and 2008 are as follows:

	Balance at Beginning of Period	Charged to Consolidated Statements of Operations	Charged to Other Accounts (b)	Deductions (c)	Balance at End of Period
			(millions)		
December 31, 2010:					
Allowance for doubtful accounts	$ 3	$—	$—	$ (1)	$ 2
Environmental	16	3	—	(4)	15
Litigation	6	—	—	(4)	2
Other (a)	1	—	4	(2)	3
	$26	$ 3	$ 4	$(11)	$22
December 31, 2009:					
Allowance for doubtful accounts	$ 6	$ 2	$—	$ (5)	$ 3
Environmental	18	2	—	(4)	16
Litigation	4	2	—	—	6
Other (a)	3	—	—	(2)	1
	$31	$ 6	$—	$(11)	$26
December 31, 2008:					
Allowance for doubtful accounts	$ 5	$ 2	$—	$ (1)	$ 6
Environmental	12	10	—	(4)	18
Litigation	15	—	—	(11)	4
Other (a)	3	—	—	—	3
	$35	$12	$—	$(16)	$31

(a) Principally consists of other contingency reserves, which are included in other current liabilities.

(b) Consists of the fair value of contingent consideration recognized in relation to acquisitions and the purchase of an additional interest in a subsidiary.

(c) Consists of cash payments, collections, reserve reversals, liabilities settled, and the re-measurement of the fair value of contingent consideration.

20. Subsequent Events

We have evaluated subsequent events occurring through February 18, 2011, the date the consolidated financial statements were issued.

On January 27, 2011, the board of directors of DCP Partners' general partner declared a quarterly distribution of $0.6175 per unit, payable on February 14, 2011 to unitholders of record on February 7, 2011.

On January 1, 2011, we completed the previously announced sale of a 33.33% interest in the DCP Southeast Texas business to DCP Partners for $150 million, in a transaction among entities under common control. The transaction was financed with borrowing under the DCP Partners' revolving credit facility.

In January 2011, our board of directors approved an $83 million dividend which was paid in January 2011.

EXHIBIT INDEX

Exhibit No.	Exhibit Description
2.1	Separation and Distribution Agreement by and between Duke Energy Corporation and Spectra Energy Corp, dated as of December 13, 2006 (filed as Exhibit No. 2.1 to Form 8-K of Spectra Energy Corp on December 15, 2006).
2.2	Reorganization Agreement by and among ConocoPhillips, Duke Capital LLC and DCP Midstream, LLC, dated as of May 26, 2005 (filed as Exhibit No. 10.4 to Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2005, File No. 1-4928).
2.2.1	First Amendment to Reorganization Agreement by and among ConocoPhillips, Duke Capital LLC and DCP Midstream, LLC, dated as of June 30, 2005 (filed as Exhibit No. 10.4.1 to Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2005).
2.2.2	Second Amendment to Reorganization Agreement by and among ConocoPhillips, Duke Capital LLC and DCP Midstream, LLC, dated as of July 11, 2005 (filed as Exhibit No. 10.4.2 to Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2005).
2.3	Amended and Restated Combination Agreement, dated as of September 20, 2001, among Duke Energy Corporation, 3058368 Nova Scotia Company, 3946509 Canada Inc. and Westcoast Energy Inc. (filed as Exhibit No. 10.7 to Form 10-Q of Duke Energy Corporation for the quarter ended September 30, 2001).
2.4	Spectra Energy Support Agreement dated as of January 1, 2007, between Spectra Energy Corp, Duke Energy Canada Call Co. and Duke Energy Canada Exchangeco Inc. (filed as Exhibit No. 2.2 to Form S-3 of Spectra Energy Corp on January 17, 2007).
2.5	Spectra Energy Voting and Exchange Trust Agreement dated as of January 1, 2007, between Spectra Energy Corp, Duke Energy Canada Exchangeco Inc. and Computershare Trust Company, Inc. (filed as Exhibit No. 2.3 to Form S-3 of Spectra Energy Corp on January 17, 2007).
2.6	Plan of Arrangement, as approved by the Supreme Court of British Columbia by final order dated December 15, 2006 (filed as Exhibit No. 2.4 to Form S-3 of Spectra Energy Corp on January 17, 2007).
3.1	Amended and Restated Certificate of Incorporation of Spectra Energy Corp (filed as Exhibit No. 3.1 to Form 8-K of Spectra Energy Corp on December 15, 2006).
3.1.1	Certificate of Amendment to the Amended and Restated Certificate of Incorporation of Spectra Energy Corp (filed as Exhibit No. 3.1 to Form 8-K of Spectra Energy Corp on May 13, 2009).
3.2	Amended and Restated By-laws of Spectra Energy Corp (Amended and Restated as of May 8, 2009) (filed as Exhibit No. 3.2 to Form 8-K of Spectra Energy Corp on May 13, 2009).
4.1	Senior Indenture between Duke Capital Corporation and The Chase Manhattan Bank, dated as of April 1, 1998 (filed as Exhibit No. 4.1 to Form S-3 of Duke Capital Corporation on April 1, 1998, File No. 333-71297).
4.2	First Supplemental Indenture, dated July 20, 1998, between Duke Capital Corporation and The Chase Manhattan Bank (filed as Exhibit No. 4.2 to Form 10-K of Duke Capital Corporation on March 16, 2004).
4.3	Second Supplemental Indenture, dated September 28, 1999, between Duke Capital Corporation and The Chase Manhattan Bank (filed as Exhibit No. 4.3 to Form 10-K of Duke Capital Corporation on March 16, 2004).
4.4	Fifth Supplemental Indenture, dated February 15, 2002, between Duke Capital Corporation and JPMorgan Chase Bank (filed as Exhibit No. 4.6 to Form 10-K of Duke Capital Corporation on March 16, 2004).

Exhibit No.	Exhibit Description
4.5	Ninth Supplemental Indenture, dated February 20, 2004, between Duke Capital Corporation and JPMorgan Chase Bank (filed as Exhibit No. 4.10 to Form 10-K of Duke Capital Corporation on March 16, 2004).
4.6	Eleventh Supplemental Indenture, dated August 19, 2004, between Duke Capital LLC and JPMorgan Chase Bank (filed as Exhibit No. 4.6 to Form S-3 of Spectra Energy Corp and Spectra Energy Capital, LLC on March 26, 2008, File No. 333-141982).
4.7	Twelfth Supplemental Indenture, dated December 14, 2007, among Spectra Energy Capital, LLC, Spectra Energy Corp and The Bank of New York (filed as Exhibit No. 10.1 to Form 8-K of Spectra Energy Corp on December 20, 2007).
4.8	Thirteenth Supplemental Indenture, dated as of April 10, 2008, between Spectra Energy Capital, LLC, Spectra Energy Corp and The Bank of New York Trust Company, N.A. (filed as Exhibit No. 4.1 to Form 8-K on April 10, 2008).
4.9	Fourteenth Supplemental Indenture, dated as of September 8, 2008, between Spectra Energy Capital, LLC, Spectra Energy Corp and The Bank of New York Mellon Trust Company, N.A. (filed as Exhibit No. 4.1 to Form 8-K on September 9, 2008).
4.10	Indenture, dated May 14, 2009, between Maritimes & Northeast Pipeline, LLC and Deutsche Bank Trust Company Americas (filed as Exhibit No. 4.1 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2009).
4.11	First Supplemental Indenture, dated May 14, 2009, between Maritimes & Northeast Pipeline, LLC and Deutsche Bank Trust Company Americas (filed as Exhibit No. 4.2 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2009).
4.12	Fifteenth Supplemental Indenture, dated as of August 28, 2009, between Spectra Energy Capital, LLC, Spectra Energy Corp and The Bank of New York Mellon Trust Company, N.A. (filed as Exhibit No. 4.1 to Form 8-K on August 28, 2009).
10.1	Tax Matters Agreement by and among Duke Energy Corporation, Spectra Energy Corp, and The Other Spectra Energy Parties, dated as of December 13, 2006 (filed as Exhibit No. 10.1 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2009).
10.2	Employee Matters Agreement by and between Duke Energy Corporation and Spectra Energy Corp, dated as of December 13, 2006 (filed as Exhibit No. 10.3 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2009).
10.2.1	First Amendment to Employee Matters Agreement, dated as of September 28, 2007, by and between Duke Energy Corporation and Spectra Energy Corp (filed as Exhibit No. 10.3.1 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2009).
10.3	Purchase and Sale Agreement, dated as of February 24, 2005, by and between Enterprise GP Holdings LP and DCP Midstream, LLC (filed as Exhibit No. 10.4 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2009).
10.4	Term Sheet Regarding the Restructuring of DCP Midstream LLC, dated as of February 23, 2005, between Duke Energy Corporation and ConocoPhillips (filed as Exhibit No. 10.26 to Form 10-K of Duke Energy Corporation for the year ended December 31, 2004).
10.5	Second Amended and Restated Limited Liability Company Agreement of DCP Midstream, LLC by and between ConocoPhillips Gas Company and Duke Energy Enterprises Corporation, dated as of July 5, 2005 (filed as Exhibit No. 10.5 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2009).

Exhibit No.	Exhibit Description
10.6	Limited Liability Company Agreement of Gulfstream Management & Operating Services, LLC, dated as of February 1, 2001, between Duke Energy Gas Transmission Corporation and Williams Gas Pipeline Company (filed as Exhibit No. 10.18 to Form 10-K of Duke Energy Corporation for the year ended December 31, 2002).
10.7	Loan Agreement, dated as of February 25, 2005, between DCP Midstream, LLC and Duke Capital LLC (filed as Exhibit No. 10.6 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2009).
+10.8	Spectra Energy Corp Directors' Savings Plan (filed as Exhibit No. 10.1 to Form 8-K of Spectra Energy Corp on December 22, 2006).
+10.8.1	Fourth Amendment, dated February 22, 2010, to Spectra Energy Corp Directors' Savings Plan (filed as Exhibit No 10.1 to Form 10-Q of Spectra Energy Corp for the quarter ended March 31, 2010).
*+10.8.2	Fifth Amendment, dated December 6, 2010, to Spectra Energy Corp Directors' Savings Plan.
+10.9	Spectra Energy Corp Executive Savings Plan (filed as Exhibit No. 10.2 to Form 8-K of Spectra Energy Corp on December 22, 2006).
+10.9.1	Fourth Amendment, dated February 22, 2010, to Spectra Energy Corp Executive Savings Plan (filed as Exhibit No 10.2 to Form 10-Q of Spectra Energy Corp for the quarter ended March 31, 2010).
*+10.9.2	Fifth Amendment, dated December 6, 2010, to Spectra Energy Corp Executive Savings Plan.
+10.10	Spectra Energy Corp Executive Cash Balance Plan (filed as Exhibit No. 10.3 to Form 8-K of Spectra Energy Corp on December 22, 2006).
+10.10.1	Third Amendment, dated December 8, 2009, to Spectra Energy Corp Executive Cash Balance Plan (filed as Exhibit 10.10.1 to Form 10-K of Spectra Energy Corp for the year ended December 31, 2009).
*+10.10.2	Fourth Amendment, dated December 6, 2010, to Spectra Energy Corp Executive Cash Balance Plan.
+10.11	Form of Change of Control Severance Agreements (filed as Exhibit No. 10.4 to Form 8-K of Spectra Energy Corp on December 22, 2006).
+10.12	Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.13 to Amendment No. 3 to Form 10 of Spectra Energy Corp on December 6, 2006).
*+10.12.1	First Amendment, dated October 31, 2007, to Spectra Energy Corp 2007 Long-Term Incentive Plan.
*+10.12.2	Second Amendment, dated December 8, 2008, to Spectra Energy Corp 2007 Long-Term Incentive Plan.
*+10.12.3	Third Amendment, dated December 6, 2010, to Spectra Energy Corp 2007 Long-Term Incentive Plan.
+10.13	Form of Non-Qualified Stock Option Agreement pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.18 to Form 10-K of Spectra Energy Corp for the year ended December 31, 2006).
+10.14	Form of Phantom Stock Award Agreement pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.19 to Form 10-K of Spectra Energy Corp for the year ended December 31, 2006).
10.15	$1,500,000,000 Credit Agreement, dated as of May 21, 2007, among Spectra Energy Capital, LLC, the banks listed therein, JPMorgan Chase Bank, N.A., as Administration Agent and Citibank, N.A., as Syndication Agent (filed as Exhibit No. 10.1 to Form 8-K of Spectra Energy Capital, LLC on May 22, 2007).

Exhibit No.	Exhibit Description
10.15.1	Amendment No. 1, dated April 8, 2008, among Spectra Energy Corp, Spectra Energy Capital, LLC, JPMorgan Chase Bank, N.A., as Administrative Agent and the banks listed therein to the Credit Agreement dated May 21, 2007 (filed as Exhibit No. 10.2 to Form 10-Q of Spectra Energy Corp for the quarter ended March 31, 2008).
10.15.2	Amendment No. 2, dated September 28, 2009, among Spectra Energy Corp, Spectra Energy Capital, LLC, JPMorgan Chase Bank, N.A., as Administrative Agent and the banks listed therein to the Credit Agreement dated May 21, 2007 (filed as Exhibit No. 10.1 to Form 10-Q of Spectra Energy Corp for the quarter ended September 30, 2009).
10.16	Support Agreement among Spectra Energy Midstream Holdco Management Partnership, Spectra Energy Income Fund and Spectra Energy Commercial Trust, dated March 4, 2008 (filed as Exhibit No. 10.1 to Form 10-Q of Spectra Energy Corp for the quarter ended March 31, 2008).
+10.17	Form of Phantom Stock Award Agreement pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.1 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2008).
+10.18	Form of Performance Award Agreement pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit 10.2 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2008).
+10.19	Form of Phantom Stock Award Agreement (2010) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit 10.19 to Form 10-K of Spectra Energy Corp for the year ended December 31, 2009).
+10.20	Form of Performance Award Agreement (2010) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit 10.20 to Form 10-K of Spectra Energy Corp for the year ended December 31, 2009).
+10.21	Form of Retention Stock Award Agreement (2010) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No 10.1 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2010).
+10.22	Spectra Energy Corp Executive Short-Term Incentive Plan (filed as Exhibit No. 10.14 to Amendment No. 3 to Form 10 of Spectra Energy Corp on December 6, 2006).
*12.1	Computation of Ratio of Earnings to Fixed Charges.
*21.1	Subsidiaries of the Registrant.
*23.1	Consent of Independent Registered Public Accounting Firm.
*23.2	Consent of Independent Auditors.
*24.1	Power of Attorney.
*31.1	Certification of the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification of the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*101.INS	XBRL Instance Document.
*101.SCH	XBRL Taxonomy Extension Schema.
*101.CAL	XBRL Taxonomy Extension Calculation Linkbase.

Exhibit No.	Exhibit Description
*101.DEF	XBRL Taxonomy Extension Definition Linkbase.
*101.LAB	XBRL Taxonomy Extension Label Linkbase.
*101.PRE	XBRL Taxonomy Extension Presentation Linkbase.

\+ Denotes management contract or compensatory plan or arrangement.

* Filed herewith.