DCPMidstream,LLC
ConsolidatedFinancialStatementsforthe YearsEndedDecember31,2010,2009and2008

DCP MIDSTREAM, LLC
CONSOLIDATED FINANCIAL STATEMENTS

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INDEPENDENTAUDITORS'REPORT

TotheBoardofDirectorsandMembersof
DCPMidstream,LLC
Denver,Colorado

Wehaveauditedtheaccompanyingconsolidatedbalan cesheetsofDCPMidstream,LLCandsubsidiaries(t he"Company")asof December31,2010and2009,andtherelatedconsoli datedstatementsofoperations,comprehensiveincom e,changesinequity,and cashflowsforeachofthethreeyearsintheperio dendedDecember31,2010.Theseconsolidatedfinan cialstatementsarethe responsibilityoftheCompany'smanagement.Ourres ponsibilityistoexpressanopinionontheseconso lidatedfinancialstatements basedonouraudits.

Weconductedourauditsinaccordancewithauditing standardsgenerallyacceptedintheUnitedStates ofAmerica.Thosestandards requirethatweplanandperformtheaudittoobtai nreasonableassuranceaboutwhetherthefinancial statementsarefreeofmaterial misstatement.Anauditincludesconsiderationofin ternalcontroloverfinancialreportingasabasis fordesigningauditproceduresthat areappropriateinthecircumstances,butnotfort hepurposeofexpressinganopinionontheeffectiv enessoftheCompany'sinternal controloverfinancialreporting.Accordingly,wee xpressnosuchopinion .Anauditalsoincludesexamining,onatestbasis, evidence supportingtheamountsanddisclosuresinthefinan cialstatements,assessingtheaccountingprinciple susedandsignificantestimates madebymanagement,aswellasevaluatingtheovera llfinancialstatementpresentation.Webelievetha tourauditsprovidea reasonablebasisforouropinion.

Inouropinion,suchconsolidatedfinancialstateme ntspresentfairly,inallmaterialrespects,thef inancialpositionoftheCompanyas ofDecember31,2010and2009,andtheresultsofi tsoperationsanditscashflowsforeachoftheth reeyearsintheperiodended December31,2010,inconformitywithaccountingpr inciplesgenerallyacceptedintheUnitedStatesof America.

AsdiscussedinNote1totheconsolidatedfinancia lstatements,in2009theCompanyadoptedtheamend edprovisionsofASC810, *Consolidation*,asitpertainstononcontrollinginterests,anda saresultretrospectivelyadjustedits2008consol idatedfinancial statements.

The consolidated financial statements give retrospe ctive effect to the changes to the preliminary purc hase price allocation for MarysvilleHydrocarbonHoldings,Inc.asdescribed inNote4totheconsolidatedfinancialstatements.

/s/Deloitte&ToucheLLP

February18,2011
(September14,2011astoNotes1,4and20)

Memberof
DeloitteToucheTohmatsu

DCPMIDSTREAM,LLC
CONSOLIDATEDBALANCESHEETS
(millions)

	December31, 2010	December31, 2009
ASSETS		
Currentassets:		
Cashandcashequivalents	$ 8	$ 264
Accountsreceivable:		
Customers,netofallowancefordoubtfulaccounts of$2millionand$3million, respectively	1,013	898
Affiliates	239	255
Other	18	35
Inventories	108	83
Unrealizedgainsonderivativeinstruments	144	259
Other	43	15
Totalcurrentassets	1,543	1,809
Property,plantandequipment,net	5,287	4,922
Restrictedinvestments	—	10
Investmentsinunconsolidatedaffiliates	159	175
Intangibleassets,net	387	313
Goodwill	721	662
Unrealizedgainsonderivativeinstruments	25	41
Otherlong-termassets	86	60
Totalassets	$ 8,238	$ 7,992
LIABILITIESANDEQUITY		
Currentliabilities:		
Accountspayable:		
Trade	$ 1,105	$ 1,003
Affiliates	79	90
Other	33	38
Short-termborrowings	187	3
Currentmaturitiesoflong-termdebt	250	800
Distributionspayabletomembers	77	71
Unrealizedlossesonderivativeinstruments	180	229
Accruedtaxes	60	47
Other	235	253
Totalcurrentliabilities	2,206	2,534
Deferredincometaxes	135	104
Long-termdebt	3,223	2,841
Unrealizedlossesonderivativeinstruments	65	78
Otherlong-termliabilities	128	117
Totalliabilities	5,757	5,674
Commitmentsandcontingentliabilities		
Equity:		
Members'interest	2,073	2,020
Accumulatedothercomprehensiveloss	(13)	(17)
Totalmembers'equity	2,060	2,003
Noncontrollinginterest	421	315
Totalequity	2,481	2,318
Totalliabilitiesandequity	$ 8,238	$ 7,992

SeeNotestoConsolidatedFinancialStatements.

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.

DCPMIDSTREAM,LLC
CONSOLIDATEDSTATEMENTSOFCOMPREHENSIVEINCOME
(millions)

	Year Ended December 31,		
	2010	**2009**	**2008**
Netincome	$ 619	$ 323	$ 1,519
Othercomprehensiveincome(loss):			
Netunrealizedlossesoncashflowhedges	(19)	(14)	(33)
Reclassificationofcashflowhedgesintoearnings	24	22	9
Totalothercomprehensiveincome(loss)	5	8	(24)
Totalcomprehensiveincome	624	331	1,495
Totalcomprehensive(income)lossattributableto noncontrolling interests	(28)	8	(70)
Totalcomprehensiveincomeattributabletomembers' interests	$ 596	$ 339	$ 1,425

SeeNotestoConsolidatedFinancialStatements.

DCPMIDSTREAM,LLC
CONSOLIDATEDSTATEMENTSOFCASHFLOWS
(millions)

	Year Ended December 31,		
	2010	**2009**	**2008**
Cashflowsfromoperatingactivities:			
Netincome	$ 619	$ 323	$ 1,519
Adjustmentstoreconcilenetincometonetcashprovidedbyoperatingactivities:			
(Gain)lossonsaleofassets	(1)	2	(15)
Depreciationandamortization	413	405	365
Earningsfromunconsolidatedaffiliates	(34)	(24)	(20)
Distributionsfromunconsolidatedaffiliates	47	35	44
Stepacquisition—equityinterestre-measurement gain	(9)	—	—
Deferredincometax(benefit)loss	(4)	14	(13)
Other,net	(3)	3	42
Changesinoperatingassetsandliabilitieswhich provided(used)cash:			
Accountsreceivable	(74)	(189)	715
Inventories	(5)	(43)	74
Netunrealizedlosses(gains)onderivativeinstruments	74	74	(181)
Accountspayable	69	145	(693)
Other	(97)	92	(49)
Netcashprovidedbyoperatingactivities	995	837	1,788
Cashflowsfrominvestingactivities:			
Capitalexpenditures	(538)	(471)	(557)
Acquisitions,netofcashacquired	(281)	(45)	(214)
Investmentsinunconsolidatedaffiliates	(2)	(7)	(7)
Purchasesofavailable-for-salesecurities	(623)	(1)	(1,157)
Proceedsfromsalesofavailable-for-salesecurities	633	51	1,207
Proceedsfromsaleofassets	2	5	41
Other	—	—	(2)
Netcashusedininvestingactivities	(809)	(468)	(689)
Cashflowsfromfinancingactivities:			
Paymentofdividendsanddistributionstomembers	(575)	(202)	(1,861)
Proceedsfromdebt	1,655	680	2,230
Paymentofdebt	(1,636)	(742)	(1,494)
Proceedsfromissuanceofcommonunitsbyasubsidiary,netofofferingcosts	189	70	132
Distributionspaidtononcontrollinginterests	(64)	(55)	(48)
Contributionsfromnoncontrollinginterests	—	14	6
Purchaseofadditionalinterestinasubsidiary	(4)	—	—
Deferredfinancingcosts	(7)	(3)	(2)
Netcashusedinfinancingactivities	(442)	(238)	(1,037)
Netchangeincashandcashequivalents	(256)	131	62
Cashandcashequivalents,beginningofperiod	264	133	71
Cashandcashequivalents,endofperiod	$ 8	$ 264	$ 133

SeeNotestoConsolidatedFinancialStatements.

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.

The December 31, 2010 balance sheet included in this report has been retrospectively adjusted to reflect changes to the preliminary purchase price allocation relating to DCP Partners' December 2010 acquisition of Marysville Hydrocarbons Holdings, LLC, or Marysville.

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 were classified 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 unit's 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. 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.

We have updated our accounting for the Marysville business combination for the fair value of assets acquired and liabilities assumed including intangible assets and property, plant and equipment and goodwill. The December 31, 2010 consolidated balance sheet included in this report has been retrospectively adjusted to reflect the impact of changes to our preliminary purchase accounting for Marysville.. The purchase price allocation is preliminary and is based on initial estimates of fair values at the date of acquisition. 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. This allocation may change in subsequent financial statements pending the final estimates of fair value and the final outcome of our estimated tax liabilities. The preliminary purchase price allocation reported in our condensed financial statements issued on February 18, 2011 compared to the preliminary purchase price allocation included in this report is as follows:

	As Previously Reported December 31, 2010	As Currently Reported December 31, 2010	Change
		(millions)	
Aggregate consideration	$ 101	$ 101	$ —
Cash	$ 3	$ 3	$ —
Accounts receivable	1	1	—
Inventory	6	5	(1)
Other current assets	1	1	—
Property, plant and equipment	130	58	(72)
Intangible assets	—	32	32
Goodwill	—	40	40
Other long-term assets	—	1	1
Deferred income taxes	(35)	(35)	—
Other current liabilities	(5)	(5)	—
Total preliminary purchase price allocation	$ 101	$ 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 aboveground 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 re-measured 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 CPChem, 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 ExxonMobil 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.

Wehadbalanceswithrelatedpartiesandaffiliates asfollows:

	December31, 2010	December31, 2009
	(millions)	
ConocoPhillips:		
Accountsreceivable	$ 221	$ 237
Accountspayable	$ (46)	$ (41)
Otherassets	$ 2	$ —
SpectraEnergy:		
Accountsreceivable	$ 2	$ 2
Accountspayable	$ (20)	$ (27)
Otherassets	$ 2	$ —
Unconsolidatedaffiliates:		
Accountsreceivable	$ 16	$ 16
Accountspayable	$ (13)	$ (22)

6.Inventories

Inventorieswereasfollows:

	December31, 2010	December31, 2009
	(millions)	
Naturalgas	$ 11	$ 19
NGLs	97	64
Totalinventories	$ 108	$ 83

7.Property,PlantandEquipment

Property,plantandequipmentbyclassificationis asfollows:

	Depreciable Life	December31, 2010	December31, 2009
		(millions)	
Gathering andtransmissionsystems	15 - 30years	$ 5,441	$ 5,322
Processing,storageandterminalfacilities (a)	20 - 50 years	2,807	2,517
Other	3 - 30 years	253	235
Constructionworkinprogress		545	218
Property,plantandequipment		9,046	8,292
Accumulateddepreciation		(3,759)	(3,370)
Property,plantandequipment,net		$ 5,287	$ 4,922

(a) Includes$58millionofproperty,plantandequipmentpurchasedthroughDCP Partners'acquisitionofMarysvilleonDecember30, 2010.

DuringtheyearendedDecember31,2010,were-assessedourmajorclassesofproperty,plantandequipmentandchangedthe presentation.

DepreciationexpensefortheyearsendedDecember31,2010,2009and2008was$390million,$384millionand$344million, respectively.Interestcapitalizedonconstruction projectsin2010,2009and2008,was$13million,$11millionand$10million, respectively.

AssetRetirementObligations —AsofDecember31,2010and2009,wehad$79millionand$73million,respectively,ofasset retirementobligationsinotherlong-termliabilitiesintheconsolidatedbalancesheets.Accretionexpensefortheyearsended December31,2010,2009and2008was$5million,$5millionand$5million,respectively,whichisrecordedwithinoperatingand maintenanceexpenseinourconsolidatedstatements ofoperations.

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	59	4
End of period	$ 721	$ 662

Goodwill increased in 2010 by $40 million as a result of DCP Partners' acquisition of Marysville, $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	$ 523	$ 426
Accumulated amortization	(136)	(113)
Intangible assets, net	$ 387	$ 313

Intangible assets increased in 2010 by $35 million as a result of our acquisition from Ceritas, $32 million as a result of DCP Partners' acquisition of Marysville, 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.

The weighted-average remaining amortization is 20 years for the $32 million of intangible assets acquired with DCP Partners' acquisition of Marysville.

Estimated future amortization for these intangible assets is as follows:

	Estimated Future Amortization (millions)
2011	$ 25
2012	26
2013	26
2014	20
2015	19
Thereafter	271
Total	$ 387

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.

Earningsfromunconsolidatedaffiliatesamountedtothefollowing:

	YearEndedDecember31,		
	2010	2009	2008
		(millions)	
DiscoveryProducerServices , LLC	$ 25	$ 16	$ 17
MainPassOilGatheringCompany	4	5	2
MontBelvieuI	5	2	(1)
SycamoreGasSystemGeneralPartnership	—	(1)	—
Otherunconsolidatedaffiliates	—	2	2
Totalearnings from unconsolidatedaffiliates	34	24	20

Thefollowingsummarizescombinedfinancialinformationofunconsolidatedaffiliates:

	YearEndedDecember31,		
	2010	2009	2008
		(millions)	
IncomeStatement:			
Operatingrevenues	$ 302	$ 247	$ 336
Operatingexpenses	$ 222	$ 186	$ 307
Netincome	$ 78	$ 59	$ 34

	December31,	
	2010	2009
	(millions)	
Balancesheet:		
Currentassets	$ 66	$ 80
Long-termassets	496	537
Currentliabilities	(28)	(29)
Long-termliabilities	(47)	(43)
Netassets	$ 487	$ 545

10.FairValueMeasurement

DeterminationofFairValue

Belowisageneraldescriptionofourvaluationmethodologiesforderivativefinancialassetsandliabilities,aswellasshort-term andrestrictedinvestments,whicharemeasuredatfairvalue.Fairvaluesaregenerallybaseduponquotedmarketprices,where available.Iflistedmarketpricesorquotesarenotavailable,wedeterminefairvaluebaseduponamarketquote,adjustedbyother market-basedorindependentlysourcedmarketdatasuchashistoricalcommodityvolatilities,crudeoilfutureyieldcurves,and/or counterpartyspecificconsiderations.Theseadjustmentsresultinafairvalueforeachassetorliabilityunderan“exitprice” methodology,inlinewithhowwebelieveamarketplaceparticipantwouldvaluethatassetorliability.Theseadjustmentsmayinclude amountstoreflectcounterpartycreditquality,theeffectofourowncreditworthiness,thetimevalueofmoneyand/ortheliquidityof themarket.

- Counterpartycreditvaluationadjustmentsarenecessarywhenthemarketpriceofaninstrumentisnotindicativeofthefair valueasaresultofthecreditqualityofthecounterparty.Generally,marketquotesassumethatallcounterpartieshavenear zero,orlow,defaultratesandhaveequalcreditquality.Therefore,anadjustmentmaybenecessarytoreflectthecredit qualityofaspecificcounterpartytodeterminethefairvalueoftheinstrument.Werecordcounterpartycreditvaluation adjustmentsonallderivativesthatareinanetassetpositionasofthemeasurementdateinaccordancewithourestablished counterpartycreditpolicy,whichtakesintoaccountanycollateralmarginthatacounterpartymayhavepostedwithusas wellasanylettersofcreditthattheyhaveprovided.

- Entityvaluationadjustmentsarenecessarytoreflecttheeffectofourowncreditqualityonthefairvalueofournetliability positionwitheachcounterparty.Thisadjustmenttakesintoaccountanycreditenhancements,suchascollateralmarginwe mayhavepostedwithacounterparty,aswellasanylettersofcreditthatwehaveprovided.Themethodologytodetermine

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 online, 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

fromindependentthirdpartiesforcoststhatwouldbeincurredtorestoreleasedpropertytothecontractuallystipulatedcondition,and wouldgenerallybeclassifiedwithinLevel3.

Weutilizefairvalueonarecurringbasistomeasureourcontingentconsiderationthatisaresultofcertainacquisitions.The inputsusedtodeterminesuchfairvalueareprimarilybaseduponinternallydevelopedcashflowmodelsandareclassifiedwithin Level3.

Thefollowingtablepresentsthefinancialinstrumentscarriedatfairvalueasof December31,2010and2009,byconsolidated balancesheetcaptionandbyvaluationhierarchy,asdescribedabove:

	December31,2010				December31,2009			
	Level1	Level2	Level3	Total Carrying Value	Level1	Level2	Level3	Total Carrying Value
	(millions)							
Currentassets(a):								
Commodityderivatives	$ 41	$ 52	$ 50	$ 143	$ 72	$ 111	$ 73	$ 256
Interestratederivatives	$ —	$ 1	$ —	$ 1	$ —	$ 3	$ —	$ 3
Long-termassets:								
Commodityderivatives(b)	$ 11	$ 4	$ 10	$ 25	$ 9	$ 14	$ 18	$ 41
Restrictedinvestments	$ —	$ —	$ —	$ —	$ —	$ 10	$ —	$ 10
Companyownedlifeinsurance(c)	$ —	$ 16	$ —	$ 16	$ —	$ —	$ —	$ —
Currentliabilities:								
Commodityderivatives(d)	$ (45)	$ (73)	$ (45)	$ (163)	$ (20)	$ (101)	$ (88)	$ (209)
Interestratederivatives(d)	$ —	$ (17)	$ —	$ (17)	$ —	$ (20)	$ —	$ (20)
Acquisitionrelatedcontingent consideration(e)	$ —	$ —	$ (2)	$ (2)	$ —	$ —	$ —	$ —
Long-termliabilities:								
Commodityderivatives(f)	$ (14)	$ (40)	$ (1)	$ (55)	$ (3)	$ (57)	$ (6)	$ (66)
Interestratederivatives(f)	$ —	$ (10)	$ —	$ (10)	$ —	$ (12)	$ —	$ (12)

(a) Includedincurrentunrealizedgainsonderivativeinstrumentsinourconsolidatedbalancesheets.
(b) Includedinlong-termunrealizedgainsonderivativeinstrumentsinourconsolidatedbalancesheets.
(c) Includedinotherlong-termassetsinourconsolidatedbalancesheets.
(d) Includedincurrentunrealizedlossesonderivativeinstrumentsinourconsolidatedbalancesheets.
(e) Includedinothercurrentliabilitiesinourconsolidatedbalancesheets.
(f) Includedinlong-termunrealizedlossesonderivativeinstrumentsinourconsolidatedbalancesheets.

ChangesinLevel3FairValueMeasurements

Thetablesbelowillustratearollforwardoftheamountsincludedinourconsolidatedbalancesheetsforderivativefinancial instrumentsthatwehaveclassifiedwithinLevel3. ThedeterminationtoclassifyafinancialinstrumentwithinLevel3isbasedupon thesignificanceoftheunobservablefactorsusedindeterminingtheoverallfairvalueoftheinstrument.Sincefinancialinstruments classifiedasLevel3typicallyincludeacombinationofobservablecomponents(thatis,componentsthatareactivelyquotedandcan bevalidatedtoexternalsources)andunobservablecomponents,thegainsandlossesinthetablebelowmayincludechangesinfair valuedueinparttoobservablemarketfactors,orchangestoourassumptionsontheunobservablecomponents.Dependinguponthe informationreadilyobservableinthemarket,and/ortheuseofunobservableinputs,whicharesignificanttotheoverallvaluation,the classificationofanyindividualfinancialinstrumentmaydifferfromonemeasurementdatetothenext.Intheeventthatthereisa movementto/fromtheclassificationofaninstrumentasLevel3,wehavereflectedsuchitemsinthetablebelowwithinthe“Transfers intoLevel3”and“TransfersoutofLevel3”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 Cerita of $3 million, and the purchase of an additional interest in a subsidiary of $1 million, which were 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

	December31, 2010	December31, 2009
	(millions)	
Shortterm -borrowings	$ 187	$ 3
DCPMidstream'sdebtsecurities:		
IssuedAugust2000,interestat7.875%payablesemiannually,dueAugust2010(a)	—	800
IssuedJanuary2001,interestat6.875%payablesemiannually,dueFebruary2011(b)	250	250
IssuedNovember2008,interestat9.700%payablesemiannually,dueDecember2013	250	250
IssuedOctober2005,interestat5.375%payablesemiannually,dueOctober2015	200	200
IssuedFebruary2009,interestat9.750%payablesemiannually,dueMarch2019	450	450
IssuedMarch2010,interestat5.350%payablesemiannually,dueMarch2020	600	—
IssuedAugust2000,interestat8.125%payablesemiannually,dueAugust2030(c)	300	300
IssuedOctober2006,interestat6.450%payablesemiannually,dueNovember2036	300	300
IssuedSeptember2007,interestat6.750%payablesemiannually,dueSeptember2037	450	450
DCP Partners'debtsecurities:		
IssuedSeptember2010,interestat3.250%, payablesemiannually,dueOctober2015	250	—
DCPPartners'creditfacilityrevolver,weighted-averagevariableinterestrateof 1.14% and0.69%,respectively,dueJune2012(d)	398	603
DCPPartners'creditfacility termloan ,variableinterestrateof0.34%,dueJune2012(e)	—	10
Fairvalueadjustmentsrelatedtointerestrateswapfairvaluehedges(a)(b)(c)	37	40
Unamortizeddiscount	(12)	(12)
Total debt	3,660	3,644
Currentmaturitiesoflong-termdebt	(250)	(800)
Shorttermborrowings	(187)	(3)
Long-termdebt	$ 3,223	$ 2,841

(a) InJuly2009,$500millionofdebtwasswappedtoafloatinginterestrateobligation.TheseswapsmaturedinAugust 2010.
(b) InJuly2009,$200millionofdebtwasswappedtoafloatinginterestrateobligation.
(c) InDecember2008,theswapsassociatedwiththisdebtwereterminated.Theremaininglong-termfairvalueof approximately$37millionrelatedtotheswapsisbeingamortizedasareductiontointerestexpensethroughthe maturitydateofthedebt.
(d) $275millionofinterestrateexposurehasbeenswappedtoafixedinterestrateobligationwitheffectivefixedinterest ratesrangingfrom3.97%to5.19%,foraneteffectiveinterestrateof4.28%onthe$398millionofoutstandingdebt undertheDCPPartners'revolvingcreditfacilityasofDecember31,2010.
(e) TheDCPPartners'termloanfacilitywasfullysecuredbyrestrictedinvestmentsasofDecember31,2009.Theterm loanwasrepaidduringthefirstquarterof2010.

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's 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 Partner's 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 CPChem, 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	December 31, 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

Thefollowingtablesummarizestheimpactonourco nsolidatedbalancesheetandconsolidatedstatement ofoperationsofour derivativeinstruments,netofnoncontrollinginter est,thatareaccountedforusingthecashflowhed gemethodofaccounting.

	LossRecognizedin AOCIonDerivatives –EffectivePortion		LossReclassified fromAOCIto Earnings –Effective Portion			Gain(Loss) RecognizedinIncome onDerivatives – IneffectivePortionand AmountExcluded fromEffectiveness Testing			DeferredGains (Losses)in AOCI Expectedtobe Reclassified intoEarnings OvertheNext 12Months
	YearEndedDecember31,								
	2010	2009	2010	2009		2010	2009		
	(millions)								
Commodityderivatives	$ —	$ (2)	$ —	$ —	(a)	$ —	$ —	(a)(c)	$ —
Interestratederivatives	$ (6)	$ (4)	$ (10)	$ (6)	(b)	$ —	$ —	(b)(c)	$ (6)

(a) Includedinsalesofnaturalgasandpetroleumprod uctsinourconsolidatedstatementsofoperations.
(b) Includedininterestexpenseinourconsolidatedst atementsofoperations.
(c) FortheyearsendedDecember31,2010and2009,no derivativegainsorlosseswerereclassifiedfromA OCItocurrentperiodearningsasa resultofthediscontinuanceofcashflowhedgesre latedtocertainforecastedtransactionsthataren otprobableofoccurring.

Changesinvalueofderivativeinstruments,forwhi chthehedgemethodofaccountinghasnotbeenelec tedfromoneperiodtothe next,arerecordedintheconsolidatedstatementso foperations.Thefollowingsummarizestheseamount sandthelocationwithinthe consolidatedstatementsofoperationsthatsuchamo untsarereflected:

CommodityDerivatives:StatementofOperationsLine Item	YearEnded December31, 2010	2009	2008
	(millions)		
Realizedgains (losses)	$ 118	$ 127	$ (93)
Unrealized(losses)gains......................	(74)	(77)	194
Tradingandmarketinggains,net.................	$ 44	$ 50	$ 101

Wedonothaveanyderivativefinancialinstruments thatqualifyasahedgeofanetinvestment.

Thefollowingtablesrepresent,bycommoditytype, ournetlongorshortpositions,aswellasthenum berofoutstandingcontracts thatareexpectedtopartiallyorentirelysettlei neachrespectiveyear.Totheextentthatwehave longdatedderivativepositionsthat spanmultiplecalendaryears,thecontractwillapp earinmorethanonelineiteminthetablebelow. Additionally,relativetothe hedgingofcertainofourstorageand/ortransporta tionassets,wemayexecutebasistransactionsfor naturalgas,whichmayresultina netlong/shortpositionofzero.Thistablealsopr esentsournetlongorshortnaturalgasbasisswap positionsseparatelyfromournet longorshortnaturalgaspositions.

	December31,2010								
	CrudeOil		NaturalGas		NaturalGasLiquids			NaturalGas BasisSwaps	
Yearof Expiration	NetLong (Short) Position (Bbls)	Number of Contracts	NetLong (Short) Position (MMBtu)	Number of Contracts	NetLong (Short) Position (Bbls)	Number of Contracts		NetLong (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) Includes27physicalindexbasedderivativecontrac tstotaling(13,083,000)Bbls
(b) Includes2physicalindexbasedderivativecontract stotaling(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 Expenseat December31, 2010 (millions)	Estimated Forfeiture Rate	Weighted-Average Remaining Vesting (years)
DCPMidstream LTIP:				
RelativePerformanceUnits(RPUs)	3	$ —	—	—
StrategicPerformanceUnits (SPUs)	3	$ 6	15%-28%	1
PhantomUnits	5	$ 5	15%-28%	1
DCPPartners'PhantomUnits	3	$ —	28%	2
DCPPartners'LTIP:				
PerformanceUnits	3	$ 1	21%-30%	1
PhantomUnits	0.5	$ —	0%	—
RestrictedPhantomUnits	3	$ 1	21%-30%	1
DukeEnergy1998LTIPandSpectraEnergy2007LTIP:				
StockOptions	0-10	$ —	5%	—
PhantomAwards	1-5	$ —	1%	—

DCPMidstreamLTIP —UndertheDCPMidstreamLTIP,equityinstruments maybegrantedtoourkeyemployees.TheDCP MidstreamLTIPprovidesforthegrantofRelativeP erformanceUnits,orRPUs,StrategicPerformanceUn its,orSPUs,andPhantom Units.TheRPUs,SPUsandPhantomUnitsconsistof anotionalunitbasedonthevalueofcommonshares orunitsofConocoPhillips, DukeEnergy,SpectraEnergyandDCPPartners.Thew eightingvariesdependingonwhentheunitsweregr anted.TheDCPPartners' PhantomUnitsconstituteanotionalunitequaltot hefairvalueofDCPPartners'commonunits.Eacha wardprovidesforthegrantof dividendordistributionequivalentrights,orDERs .TheLTIPisadministeredbythecompensationcomm itteeofourboardof directors.Allawardsaresubjecttocliffvesting.

RelativePerformanceUnits— ThenumberofRPUsthatwillultimatelyvestrange from0%to200%oftheoutstandingRPUs, dependingontheachievementofspecifiedperforman cetargetsoverathreeyearperiod.Thefinalperf ormancepayoutisdetermined bythecompensationcommitteeofourboardofdirec tors.Aftertheperformanceperiodthevaluederive dfromtheRPUsistransferred toourNon-QualifiedDeferredCompensationplan,an dinvestedaccordingtotheparticipant'sinvestmen telections.TheDERsare paidincashattheendoftheperformanceperiod. Thefollowingtablespresentsinformationrelatedt oRPUs:

	Units	GrantDate Weighted-AveragePrice PerUnit	Measurement Date Weighted-AveragePrice PerUnit
OutstandingatJanu ary1,2008	62,167	$ 43.41	
Forfeited	(5,850)	$ 43.36	
Vestedorpaidincash	(3,047)	$ 42.86	
OutstandingatDecember31,2008	53,270	$ 43.44	
Forfeited	(530)	$ 43.91	
TransferredtoNon -QualifiedExecutiveDeferred CompensationPlan(a)	(27,700)	$ 42.90	
OutstandingatDecember31,2009	25,040	$ 44.02	
TransferredtoNon -QualifiedExecutiveDeferred CompensationPlan(a)	(25,040)	$ 44.02	
OutstandingatDecember31,2010	—	$ —	$ —

(a)Aftertheperformanceperiodthevaluederived fromtheRPUsistransferredtoourNon-Qualified DeferredCompensationplan,andinvestedaccording totheparticipant'sinvestmentelections.Units vestingin2010and2009,transferredat100%and1 70%,respectively.

StrategicPerformanceUnits— ThenumberofSPUsthatwillultimatelyvestrange from0%to200%oftheoutstandingSPUs, dependingontheachievementofspecifiedperformancetargetsoverathreeyearperiod.Thefinalperformancepayoutisdetermined bythecompensationcommitteeofourboardofdirectors.TheDERsarepaidincashattheendoftheperformanceperiod.The followingtablepresentsinformationrelatedtoSPUs:

	Units	GrantDate Weighted-AveragePrice PerUnit	Measurement Date Weighted-AveragePrice PerUnit
OutstandingatJanuary1,2008	140,019	$ 43.49	
Granted	112,930	$ 35.49	
Forfeited	(14,617)	$ 41.86	
Vestedorpaidincash	(3,047)	$ 42.86	
OutstandingatDecember31,2008	235,285	$ 39.76	
Granted	209,110	$ 18.51	
Forfeitedorcancelled	(7,039)	$ 34.20	
Vestedorpaidincash(a)	(62,439)	$ 42.94	
OutstandingatDecember31,2009	374,917	$ 27.48	
Granted	139,900	$ 30.03	
Forfeited	(7,710)	$ 26.79	
Vestedorpaidincash(b)(c)	(166,237)	$ 41.59	
OutstandingatDecember31,2010	340,870	$ 21.66	$ 36.81
Expectedtovest	294,872	$ 22.73	$ 36.74

(a) The2006grantsvestedat70%.
(b) The2007grantsvestedat100%
(c) The2008grantsvestedat59%

TheestimateofRPUsandSPUsthatareexpectedtovestisbasedonhighlysubjectiveassumptionsthat couldchangeovertime, includingtheexpectedforfeiturerateandachievementofperformancetargets.Thereforetheamountsofunrecognizedcompensation expensenotedabovedoesnotnecessarilyrepresentthevaluethatwillultimatelyberealizedinourconsolidatedstatementsof operations.

Thefollowingtablepresentsthefairvalueofunitsvestedandtheunit-basedliabilitiespaidforunitbasedawardsrelatedtothe strategicperformanceunits:

	Units	FairValueof UnitsVested	Unit-Based LiabilitiesPaid
		(millions)	
Vestedin2008	3,047	$ —	$ —
Vestedin2009	62,439	$ 2	$ 2
Vestedin2010(a)	166,237	$ 4	$ 2

(a) 105,670oftheunitsandtherelatedDERsthatvestedin2010willbepaidin2011.

PhantomUnits— TheDERsarepaidquarterlyinarrears.Thefollowi ngtablepresentsinformationrelatedtoPhantomUn its:

	Units	GrantDate Weighted-AveragePrice PerUnit	Measurement Date Weighted-AveragePrice PerUnit
OutstandingatJanuary1,2008	33,800	$ 43.57	
Granted	112,930	$ 35.49	
Forfeited	(5,270)	$ 39.15	
OutstandingatDecember31,2008	141,460	$ 37.29	
Granted	209,110	$ 18.51	
Forfeited	(6,040)	$ 32.51	
Vested	(680)	$ 43.38	
OutstandingatDecember31,2009	343,850	$ 25.94	
Granted	139,800	$ 30.04	
Forfeited	(7,690)	$ 27.04	
Vested	(105,670)	$ 40.15	
OutstandingatDecember31,2010	370,290	$ 23.41	$ 34.62
Expectedtovest	299,124	$ 25.03	$ 37.73

Thefollowingtablepresentsthefairvalueofunit svestedandtheunit-basedliabilitiespaidforun itbasedawardsrelatedtothe phantomunits:

	Units	FairValueof UnitsVested	Unit-Based LiabilitiesPaid
		(millions)	
Vestedin2009	680	$ —	$ —
Vestedin2010(a)	105,670	$ 3	$ —

(a) 105,670oftheunitsandtherelatedDERsthatvest edin2010willbepaidin2011.

DCPPartners'PhantomUnits— TheDERsarepaidquarterlyinarrears.Thefollowi ngtablepresentsinformationrelatedtothe DCPPartners'PhantomUnits:

	Units	GrantDate Weighted-AveragePrice PerUnit	Measurement DatePricePer Unit
OutstandingatJanuary1,2008	51,750	$ 34.33	
Forfeited	(2,750)	$ 51.10	
OutstandingatDecember 31,2008	49,000	$ 33.39	
Vested	(38,250)	$ 28.60	
OutstandingatDecember31,2009	10,750	$ 50.43	
Granted	17,300	$ 35.56	
Vested	(10,750)	$ 31.87	
OutstandingatDecember31,2010	17,300	$ 47.09	$ 37.40
Expectedtovest	12,456	$ 35.56	$ 37.40

Thefairvalueofunitsthatvested,andtheunit-b asedliabilitiespaidduringtheyearendedDecembe r31,2010and2009wasless than$1million,respectively.

DCPPartners'LTIP —UnderDCPPartners'LTIP,whichwasadoptedbyDCP MidstreamGP,LLC,equityinstrumentsmaybe grantedtokeyemployees,consultantsanddirectors ofDCPMidstreamGP,LLCanditsaffiliateswhoperformservicesforDCP Partners.TheDCPPartners'LTIPprovidesforthegrantoflimitedpartnerunits,orLPUs,phantomunits,unitoptionsandsubstitute awards,and,withrespecttounitoptionsandphantomunits,thegrantofdividendequivalentrights, orDERs.Subjecttoadjustment forcertainevents,anaggregateof850,000LPUsmaybedeliveredpursuanttoawardsundertheDCPPartners'LTIP.Awardsthatare canceledorforfeited,orarewithheldtosatisfyDCPMidstreamGP,LLC'staxwithholdingobligations, areavailablefordelivery pursuanttootherawards.TheDCPPartners'LTIPis administeredbythecompensationcommitteeofDCP MidstreamGP,LLC's boardofdirectors.Allawardsaresubjecttocliff vesting,withtheexceptionofthePhantomUnitsissuedtothedirectorsin conjunctionwiththeinitialpublicoffering,which aresubjecttogradedvestingprovisions.Substantiallyallawardsareaccountedfor asliabilityawards.

PerformanceUnits— DCPPartner'shasawardedphantomLPUsorPerformanceUnits,pursuanttotheLTIPtocertain employees.ThenumberofPerformanceUnitsthatwillultimatelyvestrangefrom0%to200%oftheoutstandingPerformanceUnits, dependingontheachievementofspecifiedperformancetargetsoverthreeyearperformanceperiods.The finalperformance percentagepayoutisdeterminedbythecompensation committeeofDCPPartners'boardofdirectors.The DERsarepaidincashat theendoftheperformanceperiod.Thefollowingtablepresentsinformationrelatedtothe Performance Units:

	Units	GrantDate Weighted-AveragePrice PerUnit	Measurement Date Price PerUnit
OutstandingatJanuary1,2008	46,960	$ 34.09	
Granted	17,085	$ 33.85	
Forfeited	(12,025)	$ 33.14	
OutstandingatDecember31,2008	52,020	$ 34.23	
Granted	52,450	$ 10.05	
Vested(a)	(37,330)	$ 34.51	
OutstandingatDecember31,2009	67,140	$ 15.18	
Granted	16,630	$ 31.80	
Forfeited	(2,205)	$ 15.61	
Vested(b)	(14,215)	$ 33.44	
OutstandingatDecember31,2010	67,350	$ 15.42	$ 37.40
Expectedtovest	63,435	$ 14.04	$ 37.40

(a) Theunitsvestedat103%
(b) Theunitsvestedat0%.

TheestimateofPerformanceUnitsthatareexpected tovestisbasedonhighlysubjectiveassumptions thatcouldpotentially changeovertime,includingtheexpectedforfeiture rateandachievementofperformancetargets.Therefore theamountof unrecognizedcompensationexpensenotedabovedoes notnecessarilyrepresentthevaluethatwillultimatelyberealizedinour consolidatedstatementsofoperations.

Thefollowingtablepresentsthefairvalueofunitsvestedandtheunit-basedliabilitiespaidforunitbasedawardsrelatedto PerformanceUnits,includingtherelatedDERs:

	Units	FairValueof UnitsVested	Unit-Based LiabilitiesPaid
		(millions)	
Vestedin2009(a)	37,330	$ 1	$ —
Vestedin2010(a)	14,215	—	$ 1

(a) 22,860oftheunitsandtherelatedDERsthatvestedin2009werepaidin2010.

PhantomUnits— Inconjunctionwithitsinitialpublicoffering,in January2006DCPPartnersGeneralPartner'sboard of directorsawardedPhantomLPUs,orPhantomUnits,tokeyemployees,andtodirectorswhoarenotofficersoremployeesofDCP MidstreamGP,LLC,oritsaffiliateswhoperformservicesforDCPPartners.Alloftheseunitsvested during2009.

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 millions 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.

Thefollowingtableshowsinformationregardingopt ionstopurchaseDukeEnergy'scommonstockgranted toouremployees, reflectingsharesoutstandingasimpactedbytheco nversion.

	Shares	Weighted-Average ExercisePrice	Weighted-Average Remaining Life (years)	Aggregate IntrinsicValue (millions)
OutstandingatJanuary1,2008	1,815,956	$ 17.89	3.2	
Exercised	(151,480)	$ 13.45		
Forfeited	(106,889)	$ 19.77		
OutstandingatDecember31,2008	1,557,587	$ 18.19	2.4	
Exercised	(166,869)	$ 12.80		
Forfeited	(223,926)	$ 16.19		
OutstandingatDecember31,2009	1,166,792	$ 19.34		
Exercised	(56,245)	$ 8.42		
Forfeited	(401,562)	$ 24.19		
Outstanding andExercisable atDecember 31,2010	708,985	$ 17.46	1.3	$ 2

Thetotalintrinsicvalueofoptionsexercisedduri ngtheyearsendedDecember31,2010,2009,wasles sthan$1millionforboth periods,andfortheyearendedDecember31,2008, wasapproximately$1million.

Thefollowingtableshowsinformationregardingopt ionstopurchaseSpectraEnergy'scommonstockgran tedtoouremployees, reflectingsharesoutstandingasimpactedbytheco nversion.

	Shares	Weighted-Average ExercisePrice	Weighted-Average Remaining Life (years)	Aggregate IntrinsicValue (millions)
OutstandingatJanuary1,2008	937,248	$ 26.80	3.2	
Exercised	(68,869)	$ 18.91		
Forfeited	(72,400)	$ 28.06		
OutstandingatDecember 31,2008	795,979	$ 27.36	2.4	
Exercised	(13,861)	$ 11.93		
Forfeited	(183,822)	$ 23.36		
OutstandingatDecember31,2009	598,296	$ 28.95	1.9	
Exercised	(33,768)	$ 13.22		
Forfeited	(202,187)	$ 36.55		
Outstanding and Exercisable atDecember 31,2010	362,341	$ 26.18	1.3	$ 1

Thetotalintrinsicvalueofoptionsexercisedduri ngtheyearsendedDecember31,2010and2009,was lessthan$1millionfor bothperiods,andfortheyearendedDecember31,2 008,wasapproximately$1million.

Stock-BasedPerformanceAwards— Therewerenostock-basedperformanceawardsgrant edduringtheyearsendedDecember 31,2010,2009and2008.

Thefollowingtablessummarizeinformationaboutst ock-basedperformanceawardsactivity,reflectings haresoutstandingas impactedbytheconversion:

DukeEnergy1998LTIP	Shares	GrantDate Weighted-AveragePrice PerUnit	Measurement Date Weighted-AveragePrice PerUnit
OutstandingatJanuary1,2008	173,365	$ 15.58	
Vested	(83,762)	$ 15.39	
Forfeited	(59,663)	$ 15.39	
OutstandingatDecember31,2008	29,940	$ 16.50	
Vested	(25,329)	$ 16.50	
Forfeited	(4,611)	$ 16.50	
OutstandingatDecember31,2010and 2009	—	$ —	$ —

SpectraEnergy2007LTIP	Shares	GrantDate Weighted-AveragePrice PerUnit	Measurement Date Weighted-AveragePrice PerUnit
OutstandingatJanuary1,2008	86,683	$ 23.54	
Vested	(41,884)	$ 23.25	
Forfeited	(29,829)	$ 23.25	
OutstandingatDecember31,2008	14,970	$ 24.94	
Vested	(12,665)	$ 24.94	
Forfeited	(2,305)	$ 24.94	
OutstandingatDecember31,20 10and 2009	—	$ —	$ —

Thetotalfairvalueoftheperformancestockaward sthatvestedduringtheyearsendedDecember31,2 009and2008wasless than$1millionandapproximately$2million,respe ctively.Noawardsweregrantedduringtheyearsen dedDecember31,2010and 2009.

PhantomStockAwards— Therewerenophantomstockawardsgrantedduring theyearsendedDecember31,2010,2009and 2008.

Thefollowingtablessummarizeinformationaboutph antomstockawardsactivity,reflectingsharesouts tandingasimpactedby theconversion:

DukeEnergy1998LTIP	Shares	GrantDate Weighted-AveragePrice PerUnit	Measurement Date Weighted-AveragePrice PerUnit
OutstandingatJanuary1,2008	77,210	$ 15.62	
Vested	(24,419)	$ 15.57	
Forfeited	(3,287)	$ 15.38	
OutstandingatDecember31,2008	49,504	$ 15.66	
Vested	(22,689)	$ 15.58	
Forfeited	(307)	$ 15.38	
OutstandingatDecember31,2009	26,508	$ 15.72	
Vested	(22,516)	$ 15.59	
Forfeited	—	$ —	
OutstandingatDecember31,2010	3,992	$ 16.50	$ 17.81
Expectedtovest	3,958	$ 16.50	$ 17.81

SpectraEnergy2007LTIP	Shares	GrantDate Weighted-AveragePrice PerUnit	Measurement Date Weighted-AveragePrice PerUnit
OutstandingatJanuary1,2008	38,605	$ 23.60	
Vested	(12,209)	$ 23.53	
Forfeited	(1,644)	$ 23.24	
OutstandingatDecember31,2008	24,752	$ 23.66	
Vested	(11,344)	$ 23.55	
Forfeited	(154)	$ 23.24	
OutstandingatDecember31,2009	13,254	$ 23.76	
Vested	(11,258)	$ 23.55	
Forfeited	—	$ —	
OutstandingatDecember31,2010	1,996	$ 24.94	$ 24.99
Expectedtovest	1,971	$ 24.94	$ 24.99

Thetotalfairvalueofthephantomstockawardsth atvestedduringtheyearsendedDecember31,2010 and2009waslessthan$1 millionforbothperiods.Noawardsweregranteddu ringtheyearsendedDecember31,2010and2009.

OtherStockAwards —Therewerenootherstockawardsgrantedduring theyearsendedDecember31,2010and2009.

14.Benefits

AllCompanyemployeeswhohavereachedtheageof1 8andworkatleast20hoursperweekareeligible forparticipationinour 401(k)andretirementplan,towhichwecontribute arangeof4%to7%ofeacheligibleemployee'squa lifiedearningstothe retirementplan,basedonyearsofservice.Additio nally,wematchemployees'contributionsinthe401 (k)planupto6%ofqualified earnings.DuringtheyearsendedDecember31,2010, 2009and2008weexpensedplancontributionsof$2 1million,$22millionand $19million,respectively.Inconjunctionwiththe MarysvilleacquisitiononDecember30,2010,weacq uiredtwo401(k)planswith termssubstantiallysimilartoourexisting401(k) andretirementplan.

Weoffercertaineligibleexecutivestheopportunit ytoparticipateinDCPMidstreamLP'sNon-Qualifie dExecutiveDeferred CompensationPlan.Thisplanallowsparticipantsto defercurrentcompensationonapre-taxbasisand toreceivetaxdeferredearnings onsuchcontributions.Theplanalsohasmake-whole provisionsforplanparticipantswhomayotherwise belimitedintheamountthat wecancontributetothe401(k)planonthepartici pant'sbehalf.Allamountscontributedtoorearned bytheplan'sinvestmentsare heldinatrustaccountforthebenefitofthepart icipants.Thetrustandtheliabilitytothepartic ipantsarepartofourgeneralassetsand liabilities,respectively.

15.IncomeTaxes

Wearestructuredasalimitedliabilitycompany,whichisapass-throughentityforfederalincometaxpurposes.Weownacorporationthatfilesitsownfederal,foreignandstatecorporateincometaxreturns.Theincometax(expense)benefitrelatedtothiscorporationisincludedinourincometax(expense)benefit,alongwithstateandlocaltaxesofthelimitedliabilitycompanyandothersubsidiaries.OnDecember30,2010,DCPPartnersacquiredalloftheinterestsinMarysvilleHydrocarbonsHoldings,LLC,anentitythatownsataxableC-Corporationconsolidatedreturngroup.Wehaveestimated$35millionoffederaldeferredtaxliabilitiesresultingfrombuilt-intaxgainsrecognizedinthetransactionandhaverecordedthisinourpreliminarypurchasepriceallocationasofDecember31,2010.

TheStateofTexasimposesamargintaxthatisassessedat1%oftaxablemarginapportionedtoTexas.Accordingly,wehaverecordedcurrenttaxexpensefortheTexasmargintaxbeginningin2007.ThestateofMichiganimposesabusinesstaxof0.8%ongrossreceiptsand4.95%ofMichigantaxableincome.Thesumofgrossreceiptsandincometaxissubjecttoataxsurchargeof21.99%.Michiganprovidestaxcreditsthatmayreduceourfinalincometaxliability.

Incometax(expense)benefitconsistsofthefollowing:

	YearEndedDecember31,		
	2010	2009	2008
		(millions)	
Current:			
Federal	$ —	$ —	$ 3
State	(9)	(4)	(13)
Deferred:			
Federal	5	(14)	13
State	(1)	—	—
Totalincometax(expense)benefit	$ (5)	$ (18)	$ 3

Wehadnetlong-termdeferredtaxliabilitiesof$135millionand$104millionasofDecember31,2010and2009,respectively.Thenetlong-termdeferredtaxliabilitiesareincludedindeferredincometaxesontheconsolidatedbalancesheets.Thedeferredtaxliabilitiesof$159millionand$119millionasofDecember31,2010and2009,respectively,areprimarilyassociatedwithdepreciationandamortizationrelatedtotheacquiredintangibleassetsandproperty,plantandequipment.Offsettingthedeferredtaxliabilitiesaredeferredtaxassetsrelatedtothenetoperatinglossofanaffiliatecorporationofapproximately$24millionand$15millionasofDecember31,2010and2009,respectively.Thenetoperatinglossesbeginexpiringin2027.Weexpecttofullyutilizethenetoperatinglosscarryovers,and,accordinglywehavenotprovidedavaluationallowanceforthenetdeferredtaxasset.

OnJanuary4,2011,DCPPartnersmergedtwowholly-ownedsubsidiariesacquiredintheMarysvilleacquisitionandconvertedthecombinedentity'sorganizationalstructurefromaC-Corporationtoalimitedliabilitycompany.Thisconversiontoalimitedliabilitycompanytriggeredtaxliabilities,stemmingfrombuilt-intaxgainsrecognizedintheacquisitionofMarysville,tobecomecurrentlypayable.Accordingly,$35millionofestimateddeferredtaxliabilitiesassociatedwiththisacquisitionandrecordedatDecember31,2010,becamecurrenttaxliabilities.

Oureffectivetaxratediffersfromstatutoryratesprimarilyduetoourbeingstructuredasalimitedliabilitycompany,whichisapass-throughentityforfederalincometaxpurposes,whilebeingtreatedasataxableentityincertainstates.Additionally,someofoursubsidiariesaretaxpayingentitiesforfederalincometaxpurposes.

16.CommitmentsandContingentLiabilities

Litigation—Themidstreamindustryhasseenanumberofclassactionlawsuitsinvolvingroyaltydisputes,mismeasurementandmispaymentallegations.Wearecurrentlynamedasdefendantsinsomeofthesecasesandcustomershaveassertedindividualauditclaimsrelatedtomismeasurementandmispayment.Managementbelieveswehavemeritoriousdefensestothesecasesand,therefore,willcontinuetodefendthemvigorously.Theseclaims,however,canbecostlyandtimeconsumingtodefend.Wearealsoapartytovariouslegal,administrativeandregulatoryproceedingsthathavearisenintheordinarycourseofourbusiness,including,fromtimetotime,disputeswithcustomersovervariousmeasurementandsettlementissues.

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. We have evaluated subsequent events occurring through September 14, 2011, the date the consolidated financial statements were reissued.

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.