KEY RISKS AND CHALLENGES

Following is a discussion of key risks and challenges facing management and the initiatives currently underway to manage such challenges. These matters involve risks that could have a material adverse effect on our results of operations, liquidity or financial condition.

Substantial Leverage, Uncertain Financial Markets and Liquidity Risk

Our substantial leverage, resulting in large part from debt incurred to finance the Merger, requires significant cash flows to be dedicated to interest and principal payments and could adversely affect our ability to raise additional capital to fund operations, limit our ability to react to changes in the economy, our industry or our business, and expose us to interest rate risk to the extent not hedged. Principal amounts of short-term borrowings and long-term debt, including amounts due currently, totaled $36.721 billion as of December 31, 2010. Taking into consideration interest-rate swap transactions, as of December 31, 2010 approximately 87% of our total long-term debt portfolio is subject to fixed interest rates, at a weighted average interest rate of 8.9%. Interest payments on long-term debt in 2011 are expected to total approximately $2.750 billion, and principal payments are expected to total $651 million.

While we believe our cash on hand and cash flow from operations combined with availability under existing credit facilities provide sufficient liquidity to fund current and projected expenses and capital requirements for 2011 (see "Financial Condition – Liquidity and Capital Resources" section below), there can be no assurance that counterparties to our credit facility and hedging arrangements will perform as expected and meet their obligations to us. Failure of such counterparties to meet their obligations or substantial changes in financial markets, the economy, regulatory requirements, our industry or our operations could result in constraints in our liquidity. While traditional counterparties with physical assets to hedge, as well as financial institutions and other parties, continue to participate in the markets, as a result of the financial crisis that arose in 2008, there has been a reduction of available counterparties for our hedging and trading activities, particularly for longer-dated transactions, which could impact our ability to hedge our commodity price and interest rate exposure to desired levels at reasonable costs. See discussion of credit risk in Item 7A, "Quantitative and Qualitative Disclosures About Market Risk," discussion of available liquidity and liquidity effects of the long-term hedging program in "Financial Condition – Liquidity and Capital Resources" and discussion of potential impact of legislative rulemakings on the OTC derivatives market in "Significant Activities and Events – Financial Services Reform Legislation."

In addition, as discussed above under "Significant Activities and Events – Natural Gas Prices and Long-Term Hedging Program," a continuation or worsening of low forward natural gas prices (and the related low wholesale electricity prices in ERCOT) could also limit our ability to hedge our wholesale electricity revenues at sufficient price levels to support our interest payments and debt maturities, result in further declines in the value of our baseload generation assets and adversely impact our efforts to refinance our substantial debt as discussed immediately below.

The TCEH Revolving Credit Facility matures in October 2013, and a substantial amount of our long-term debt matures in the period from 2014 through 2017. We are focused on improving the balance sheet and expect to opportunistically look for ways to reduce the amount, and extend the maturity, of our outstanding debt. Progress to date on this initiative includes the debt exchanges, issuances and repurchases completed in 2010 and 2009 discussed above under "Significant Activities and Events – Liability Management Program" and the August 2009 amendment to the Credit Agreement governing the TCEH Senior Secured Facilities that provided additional flexibility in restructuring debt obligations. See Note 11 to Financial Statements for additional discussion of these transactions.

In addition, because our operations are capital intensive, we expect to rely over the long-term upon access to financial markets as a significant source of liquidity for capital requirements not satisfied by cash-on-hand, operating cash flows or our available credit facilities. Our ability to economically access the capital or credit markets could be restricted at a time when we would like, or need, to access those markets. Lack of such access could have an impact on our flexibility to react to changing economic and business conditions.

Natural Gas Price and Market Heat-Rate Exposure

Wholesale electricity prices in the ERCOT market generally move with the price of natural gas because marginal demand for electricity supply is generally met with natural gas-fueled generation facilities. Historically the price of natural gas has fluctuated due to changes in industrial demand, supply availability, weather effects and other economic and market factors and such prices have been very volatile in recent years. Since 2005, forward natural gas prices ranged from above $13 per MMBtu to below $4 per MMBtu. More recent declines in forward natural gas prices reflect discovery and increased drilling of shale gas deposits combined with lingering demand weakness associated with the economic recession. The wholesale market price of electricity divided by the market price of natural gas represents the market heat rate. Market heat rate movements also affect wholesale electricity prices. Market heat rate can be affected by a number of factors including the efficiency of the marginal supplier (generally natural gas-fueled generation facilities) in generating electricity.

In contrast to our natural gas-fueled generation facilities, changes in natural gas prices have no significant effect on the cost of generating electricity from our nuclear and lignite/coal-fueled facilities. All other factors being equal, these baseload generation assets, which provided the substantial majority of supply volumes in 2010, increase or decrease in value as natural gas prices and market heat rates rise or fall, respectively, because of the effect on wholesale electricity prices in ERCOT.

With the exposure to variability of natural gas prices, retail sales price management and hedging activities are critical to the profitability of the business and maintaining consistent cash flow levels.

Our approach to managing electricity price risk focuses on the following:

- employing disciplined hedging and risk management strategies through physical and financial energy-related (electricity and natural gas) contracts intended to partially hedge gross margins;
- continuing focus on cost management to better withstand gross margin volatility;
- following a retail pricing strategy that appropriately reflects the magnitude and costs of commodity price and liquidity risk, and
- improving retail customer service to attract and retain high-value customers.

As discussed above in "Significant Activities and Events," we have implemented a long-term hedging program to mitigate the risk of lower wholesale electricity prices due to declines in natural gas prices.

The following sensitivity table provides estimates of the potential impact (in $ millions) of movements in natural gas and certain other commodity prices and market heat rates on realized pre-tax earnings for the periods presented. The estimates related to price sensitivity are based on TCEH's unhedged position and forward prices as of December 31, 2010, which for natural gas reflects estimates of electricity generation less amounts hedged through the long-term natural gas hedging program and amounts under existing wholesale and retail sales contracts. On a rolling twelve-month basis, the substantial majority of retail sales under month-to-month arrangements are deemed to be under contract.

	Balance 2011(a)	2012	2013	2014
$1.00/MMBtu change in gas price (b)	$ ~5	$ ~80	$ ~305	$ ~490
0.1/MMBtu/MWh change in market heat rate (c)	$ ~4	$ ~32	$ ~44	$ ~46
$1.00/gallon change in diesel fuel price	$ —	$ ~1	$ ~48	$ ~40

(a) Balance of 2011 is from February 1, 2011 through December 31, 2011

(b) Assumes conversion of electricity positions based on an approximate 8.0 market heat rate with natural gas being on the margin 75% to 90% of the time (i.e., when coal is forecast to be on the margin, no natural gas position is assumed to be generated).

(c) Based on Houston Ship Channel natural gas prices as of December 31, 2010.

Our market heat rate exposure is impacted by changes in the mix of generation assets resulting from generation capacity changes such as additions and retirements of generation facilities. Increased wind generation capacity could result in lower market heat rates. We expect that decreases in market heat rates would decrease the value of our generation assets because lower market heat rates generally result in lower wholesale electricity prices, and vice versa. We mitigate market heat rate risk through retail and wholesale electricity sales contracts and shorter-term market heat rate hedging transactions. We evaluate opportunities to mitigate market heat rate risk over extended periods through longer-term electricity sales contracts where practical considering pricing, credit, liquidity and related factors.

On an ongoing basis, we will continue monitoring our overall commodity risks and seek to balance our portfolio based on our desired level of exposure to natural gas prices and market heat rates and potential changes to our operational forecasts of overall generation and consumption (which is also subject to volatility resulting from customer churn, weather, economic and other factors) in our native and growth business. Portfolio balancing may include the execution of incremental transactions, including heat rate hedges, the unwinding of existing transactions and the substitution of natural gas hedges with commitments for the sale of electricity at fixed prices. As a result, commodity price exposures and their effect on earnings could materially change from time to time.

Competitive Retail Markets and Customer Retention

Competitive retail activity in Texas has resulted in retail customer churn. Our total retail customer counts rose 2% in 2008 but declined 3% in 2009 and 6% in 2010. Based upon 2010 results discussed below in "Results of Operations – Competitive Electric Segment," a 1% decline in residential customers would result in a decline in annual revenues of approximately $40 million. In responding to the competitive landscape in the ERCOT marketplace, we are focusing on the following key initiatives:

- Maintaining competitive pricing initiatives as evidenced by price reductions on most residential service plans;
- Profitably growing the retail customer base by actively competing for new and existing customers in areas in Texas open to competition. The customer retention strategy remains focused on continuing to implement initiatives to deliver world-class customer service and improve the overall customer experience,
- Establishing TXU Energy as the most innovative retailer in the Texas market by continuing to develop tailored product offerings to meet customer needs. TXU Energy plans to invest $100 million over the five-year period beginning in 2008 (including $39 million invested through 2010) in retail initiatives aimed at helping consumers conserve energy and other demand-side management initiatives that are intended to moderate consumption and reduce peak demand for electricity, and
- Focusing business market initiatives largely on programs targeted to retain the existing highest-value customers and to recapture customers who have switched REPs. Initiatives include maintaining and continuously refining a disciplined contracting and pricing approach and economic segmentation of the business market to enhance targeted sales and marketing efforts and to more effectively deploy the direct-sales force. Tactical programs put into place include improved customer service, aided by a new customer management system implemented in 2009, new product price/service offerings and a multichannel approach for the small business market.

Volatile Energy Prices and Regulatory Risk

Natural gas prices rose to unprecedented levels in the latter part of 2005, reflecting a world-wide increase in energy prices compounded by hurricane-related infrastructure damage. The related rise in electricity prices elevated public awareness of energy costs and dampened customer demand. Natural gas prices remain subject to events that create price volatility, and while not reaching 2005 levels, forward natural gas prices rose substantially in 2007 and part of 2008 before falling in the second half of 2008 through most of 2010. Sustained high energy prices and/or ongoing price volatility also creates a risk for regulatory and/or legislative intervention with the mechanisms that govern the competitive wholesale and retail markets in ERCOT. We believe that competitive markets result in a broad range of innovative pricing and service alternatives to consumers and ultimately the most efficient use of resources and that regulatory entities should continue to take actions that encourage competition in the industry. Regulatory and/or legislative intervention could materially affect the competitive electricity industry in ERCOT, including disrupting the relationship between natural gas prices and electricity prices, which could materially impact the results of our long-term hedging program. (Also see "Regulatory Matters – Sunset Review.") We continue to closely monitor any potential legislative and regulatory changes and work with legislators and regulators, providing them information on the market and related matters.

Financial Services Reform Legislation

In July 2010, financial reform legislation known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Financial Reform Act) was enacted. The primary purposes of the Financial Reform Act are, among other things, to address systemic risk in the financial system; to establish a Bureau of Consumer Financial Protection with broad powers to enforce consumer protection laws and promulgate rules against unfair, deceptive or abusive practices; to enhance regulation of the derivatives markets, including the requirement for central clearing of over-the-counter derivative instruments and additional capital and margin requirements for certain derivative market participants; and to implement a number of new corporate governance requirements for companies with listed or, in some cases, publicly-traded securities. While the legislation is broad and detailed, substantial portions of the legislation are currently under rulemakings by federal governmental agencies to implement the standards set out in the legislation and adopt new standards. As a result, the full scope and effect of the legislation will likely not be known for several years

Title VII of the Financial Reform Act provides for the regulation of the over-the-counter (OTC) derivatives market. The Financial Reform Act generally requires OTC derivatives (including the types of asset-backed OTC derivatives that we use to hedge risks associated with commodity and interest rate exposure) to be cleared by a derivatives clearing organization. However, entities are exempt from these clearing requirements if they (i) are not "Swap Dealers" or "Major Swap Participants" as will be defined in the rulemakings and (ii) use the swaps to hedge or mitigate commercial risk. The proposed definition of Swap Dealer is broad and will, as drafted, include many end users. We are evaluating whether or not the type of asset-backed OTC derivatives that we use to hedge commodity and interest rate risk is exempt from the clearing requirements. Existing swaps are grandfathered from the clearing requirements. The legislation mandates significant reporting and compliance requirements for any entity that is determined to be a Swap Dealer or Major Swap Participant.

The Financial Reform Act also requires the posting of cash collateral for uncleared swaps. Because these cash collateral requirements are unclear as to whether an end-user or its counterparty (e g., swap dealer) is required to post cash collateral, there is a risk that the cash collateral requirement could be used to effectively negate the end-user clearing exemption. However, the legislative history of the Financial Reform Act suggests that it was not Congress' intent to require end-users to post cash collateral with respect to swaps. If we were required to post cash collateral on our swap transactions with swap dealers, our liquidity would likely be materially impacted, and our ability to enter into OTC derivatives to hedge our commodity and interest rate risks would be significantly limited.

We cannot predict the outcome of the rulemakings to implement the OTC derivative market provisions of the Financial Reform Act. These rulemakings could negatively affect our ability to hedge our commodity and interest rate risks. Accordingly, we continue to closely monitor the rulemakings and any other potential legislative and regulatory changes and work with regulators and legislators, providing them information on our operations, the types of transactions in which we engage, our concerns regarding potential regulatory impacts, market characteristics and related matters.

New and Changing Environmental Regulations

We are subject to various environmental laws and regulations related to SO_2, NO_x and mercury as well as other emissions that impact air and water quality. We believe we are in compliance with all current laws and regulations, but regulatory authorities continue to evaluate existing requirements and consider proposals for changes. If we make any major modifications to our power generation facilities, we may be required to install the best available control technology or to achieve the lowest achievable emission rates as such terms are defined under the new source review provisions of the Clean Air Act. Any such modifications would likely result in substantial additional capital expenditures. (See Note 12 to Financial Statements for discussion of "Litigation Related to Generation Facilities," "Regulatory Reviews" and "Environmental Contingencies.")

We also continue to closely monitor any potential legislative, regulatory and judicial changes pertaining to global climate change. In view of the fact that a substantial portion of our generation portfolio consists of lignite/coal-fueled generation facilities, our results of operations, liquidity or financial condition could be materially adversely affected by the enactment of any legislation, regulation or judicial action that mandates a reduction in GHG emissions or that imposes financial penalties, costs or taxes on entities that produce GHG emissions, or that establishes federal renewable energy portfolio standards. For example, federal, state or regional legislation or regulation addressing global climate change could result in us either incurring increased material costs to reduce our GHG emissions or to procure emission allowances or credits to comply with a mandatory cap-and-trade emissions reduction program. See further discussion under Items 1 and 2, "Business and Properties – Environmental Regulations and Related Considerations."

Exposures Related to Nuclear Asset Outages

Our nuclear assets are comprised of two generation units at Comanche Peak, each with an installed nameplate capacity of 1,150 MW. The Comanche Peak plant represents approximately 15% of our total generation capacity. The nuclear generation units represent our lowest marginal cost source of electricity. Assuming both nuclear generation units experienced an outage, the unfavorable impact to pretax earnings is estimated (based upon market prices as of December 31, 2010) to be approximately $2 million per day before consideration of any insurance proceeds Also see discussion of nuclear facilities insurance in Note 12 to Financial Statements.

The inherent complexities and related regulations associated with operating nuclear generation facilities result in environmental, regulatory and financial risks The operation of nuclear generation facilities is complex and subject to continuing review and regulation by the NRC, covering, among other things, operations, maintenance, emergency planning, security, and environmental and safety protection. The NRC may implement changes in regulations that result in increased capital or operating costs, and it may require extended outages, modify, suspend or revoke operating licenses and impose fines for failure to comply with its existing regulations and the provisions of the Atomic Energy Act. In addition, an unplanned outage at another nuclear generation facility could result in the NRC taking action to shut down the Comanche Peak plant as a precautionary measure.

We participate in industry groups and with regulators to remain current on the latest developments in nuclear safety, operation and maintenance and on emerging threats and mitigating techniques. These groups include, but are not limited to, the NRC and the Institute of Nuclear Power Operations (INPO). We also apply the knowledge gained by continuing to invest in technology, processes and services to improve our operations and detect, mitigate and protect our nuclear generation assets. The Comanche Peak plant has not experienced an extended unplanned outage, and management continues to focus on the safe, reliable and efficient operations at the plant

Oncor's Ring-Fencing and Credit Risk

Our investment in Oncor, which represents approximately 80% of its membership interests, is a significant value driver of our overall business. Oncor's access to capital markets and cost of debt could be directly affected by its credit ratings. Any adverse action with respect to Oncor's credit ratings would generally cause borrowing costs to increase and the potential pool of investors and funding sources to decrease. Oncor's credit ratings are currently substantially higher than those of the Texas Holdings Group. If credit rating agencies were to change their views of Oncor's independence from any member of the Texas Holdings Group, Oncor's credit ratings would likely decline. This risk is substantially mitigated by the ring-fencing measures as described in Note 1 to Financial Statements.

Cyber Security and Infrastructure Protection Risk

A breach of cyber/data security measures that impairs our information technology infrastructure could disrupt normal business operations and affect our ability to control our generation and transmission assets, access retail customer information and limit communication with third parties. Any loss of confidential or proprietary data through a breach could materially and adversely affect our reputation, expose the company to legal claims or impair our ability to execute on business strategies.

We participate in industry groups and with regulators to remain current on emerging threats and mitigating techniques. These groups include, but are not limited to: the US Cyber Emergency Response Team, the National Electric Sector Cyber Security Organization, the NRC and NERC. We also apply the knowledge gained by continuing to invest in technology, processes and services to detect, mitigate and protect our cyber assets. These investments include upgrades to network architecture, regular intrusion detection monitoring and compliance with emerging industry regulation.

APPLICATION OF CRITICAL ACCOUNTING POLICIES

Our significant accounting policies are discussed in Note 1 to Financial Statements. We follow accounting principles generally accepted in the US. Application of these accounting policies in the preparation of our consolidated financial statements requires management to make estimates and assumptions about future events that affect the reporting of assets and liabilities at the balance sheet dates and revenues and expenses during the periods covered. The following is a summary of certain critical accounting policies that are impacted by judgments and uncertainties and under which different amounts might be reported using different assumptions or estimation methodologies.

Purchase Accounting

In 2007, the Merger was accounted for under purchase accounting, whereby the purchase price of the transaction was allocated to our identifiable assets acquired and liabilities assumed based upon their fair values. The estimates of the fair values recorded were determined based on the principles in accounting standards related to the determination of fair value (see Note 15 to Financial Statements) and reflect significant assumptions and judgments. Material valuation inputs for long-lived assets and liabilities included forward electricity and natural gas price curves and market heat rates, discount rates, nonperformance risk adjustments related to liabilities, retail customer attrition rates, generation plant operating and construction costs and asset lives. The valuations reflected considerations unique to the competitive wholesale power market in ERCOT as well as our assets. For example, the valuation of the baseload generation facilities considered our lignite fuel reserves and mining capabilities.

The results of the purchase price allocation included an increase in the total carrying value of our baseload generation plants and the recording of intangible assets related to the retail customer base, the TXU Energy trade name and emission credits. Further, commodity and other contracts not already subject to fair value accounting were valued, and amounts representing favorable or unfavorable contracts (versus market conditions as of the date of the Merger) were recorded as intangible assets or liabilities, respectively. Management believes all material intangible assets were identified. See Note 4 to Financial Statements for details of the intangible assets recorded.

With respect to Oncor, the realization of its assets and settlement of its liabilities are largely subject to cost-based regulatory rate-setting processes. Accordingly, the historical carrying values of a majority of Oncor's assets and liabilities were deemed to represent fair values. See discussion in Note 24 to Financial Statements regarding adjustments to the carrying values of Oncor's regulatory asset and related long-term debt.

0001205

The excess of the purchase price over the estimated fair values of the net assets acquired was recorded as goodwill. The goodwill amount recorded upon finalization of purchase accounting totaled $23.2 billion. Management believes the drivers of the goodwill amount included the incremental value of the future cash flow potential of the baseload generation facilities, including facilities under construction, over the values assigned to those assets under purchase accounting rules, considering the market-pricing mechanisms and growth potential in the ERCOT market, as well as the value derived from the scale of the retail business. Management also believes that the goodwill reflected the value of the relatively stable, long-lived cash flows of the regulated business, considering the constructive regulatory environment and market growth potential. In accordance with accounting guidance related to goodwill and other intangible assets, goodwill is not amortized to net income, but is required to be tested for impairment at least annually. This guidance requires that goodwill be assigned to "reporting units," which management has determined to be the Competitive Electric segment and the Regulated Delivery segment, which are almost entirely comprised of TCEH and Oncor, respectively. The assignment of goodwill was based on the relative estimated enterprise values of the operations as of the date of the Merger. Goodwill amounts assigned totaled $18.3 billion to the Competitive Electric segment and $4.9 billion to the Regulated Delivery segment. None of this goodwill balance is being deducted for tax purposes.

In the third quarter 2010, we recorded a goodwill impairment charge related to the Competitive Electric segment totaling $4.1 billion. In the first quarter 2009 and fourth quarter 2008, we recorded goodwill impairment charges totaling $8.950 billion, of which $8.070 billion related to the Competitive Electric segment. The $90 million charge in the first quarter 2009 resulted from the completion of the previously estimated fair value calculations supporting the initial $8.860 billion goodwill impairment charge that was recorded in the fourth quarter 2008. See discussion immediately below under "Impairment of Goodwill and Other Long-Lived Assets."

Impairment of Goodwill and Other Long-Lived Assets

We evaluate long-lived assets (including intangible assets with finite lives) for impairment, in accordance with accounting standards related to impairment or disposal of long-lived assets, whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. One of those indications is a current expectation that "more likely than not" a long-lived asset will be sold or otherwise disposed of significantly before the end of its previously estimated useful life (as was the case for the natural gas-fueled generation assets in 2008 discussed below). For our baseload generation assets, another possible indication would be an expected long-term decline in natural gas prices and/or market heat rates. We evaluate investments in unconsolidated subsidiaries for impairment when factors indicate that a decrease in the value of the investment has occurred that is not temporary. Indications of a loss in value might include a series of operating losses of the investee or a fair value of the investment that is less than its carrying amount. The determination of the existence of these and other indications of impairment involves judgments that are subjective in nature and may require the use of estimates in forecasting future results and cash flows related to an asset, group of assets or investment in unconsolidated subsidiary. Further, the unique nature of our property, plant and equipment, which includes a fleet of generation assets with a diverse fuel mix and individual plants that have varying production or output rates, requires the use of significant judgments in determining the existence of impairment indications and the grouping of assets for impairment testing.

Goodwill and intangible assets with indefinite useful lives are required to be tested for impairment at least annually (we have selected December 1) or whenever events or changes in circumstances indicate an impairment may exist, such as the possible impairments to long-lived assets discussed above. As required by accounting guidance related to goodwill and other intangible assets, we have allocated goodwill to our reporting units, which are our two segments: Competitive Electric and Regulated Delivery, and goodwill impairment testing is performed at the reporting unit level. (See Notes 1 and 3 to Financial Statements for discussion of the deconsolidation of Oncor Holdings as of January 1, 2010, which resulted in a reduction in reported goodwill for the amount related to the Regulated Delivery segment, and see above for discussion of impairment testing for equity-method investments such as Oncor Holdings.) Under this goodwill impairment analysis, if at the assessment date, a reporting unit's carrying value exceeds its estimated fair value (enterprise value), the estimated enterprise value of the reporting unit is compared to the estimated fair values of the reporting unit's operating assets (including identifiable intangible assets) and liabilities at the assessment date, and the resultant implied goodwill amount is then compared to the recorded goodwill amount. Any excess of the recorded goodwill amount over the implied goodwill amount is written off as an impairment charge.

The determination of enterprise value involves a number of assumptions and estimates. We use a combination of three fair value inputs to estimate enterprise values of our reporting units: internal discounted cash flow analyses (income approach), comparable company values and any recent pending and/or completed relevant transactions. The income approach involves estimates of future performance that reflect assumptions regarding, among other things, forward natural gas and electricity prices, market heat rates, generation plant performance and retail sales volume trends. Another key variable in the income approach is the discount rate, or weighted average cost of capital. The determination of the discount rate takes into consideration the capital structure, debt ratings and current debt yields of comparable companies as well as an estimate of return on equity that reflects historical market returns and current market volatility for the industry. Enterprise value estimates based on comparable company values involve using trading multiples of EBITDA of those selected companies to derive appropriate multiples to apply to the EBITDA of the reporting units. This approach requires an estimate, using historical acquisition data, of an appropriate control premium to apply to the reporting unit values calculated from such multiples. Critical judgments include the selection of comparable companies and the weighting of the three value inputs in developing the best estimate of enterprise value.

The 2010 annual impairment testing performed as of December 1, 2010 for goodwill and intangible assets with indefinite useful lives in accordance with accounting guidance resulted in no impairment. The goodwill testing determined that the carrying value of the Competitive Electric segment exceeded its estimated fair value (enterprise value), so the estimated enterprise value of the segment was compared to the estimated fair values of its operating assets and liabilities. This additional testing indicated that the recorded goodwill amount did not exceed the estimated implied goodwill amount, and thus no additional goodwill impairment was indicated beyond the charge recorded in the third quarter 2010 as discussed immediately below. Key variables in the tests included forward natural gas prices, electricity prices, market heat rates and discount rates, assumptions regarding each of which could have a significant effect on valuations. Because of the volatility of these factors, we cannot predict the likelihood of any future impairment.

See Note 4 to Financial Statements for a discussion of the goodwill impairment charges of $4.1 billion recorded in 2010 and $8.950 billion recorded largely in 2008. The total of $13.050 billion in impairment charges represented almost 60% of the goodwill balance resulting from purchase accounting for the Merger and reflected a decline of approximately 20% in the estimated enterprise value as of December 1, 2010 from the indicated value at the October 2007 Merger date. The impairment in 2010 reflected the estimated effect of lower wholesale power prices on the enterprise value of the Competitive Electric segment, driven by the sustained decline in forward natural gas prices. The impairment in 2008 primarily arose from the dislocation in the capital markets that increased interest rate spreads and the resulting discount rates used in estimating fair values and the effect of declines in market values of debt and equity securities of comparable companies in the second half of 2008. Also see Note 4 to Financial Statements for discussion of the impairment charge of $481 million ($310 million after-tax) related to the trade name intangible asset recorded in the fourth quarter 2008 The estimated fair value of this intangible asset is based on an assumed royalty methodology. Impairment charges totaling $501 million in 2008 related to environmental allowances and credits are also discussed in Note 4 to Financial Statements.

In 2008, we recorded an impairment charge of $229 million ($147 million after-tax) related to our natural gas-fueled generation facilities. The natural gas-fueled generation units are generally operated to meet peak demands for electricity, and the facilities were tested for impairment as an asset group. See Note 5 to Financial Statements for a discussion of the impairment. The estimated impairment was based on numerous judgments including forecasted production, forward prices of natural gas and electricity, overall generation availability in ERCOT and ERCOT grid congestion. See "Business – Significant Activities and Events" for discussion of natural gas-fueled units mothballed (idled) or retired in 2009 consistent with the factors that resulted in the impairment.

Derivative Instruments and Mark-to-Market Accounting

We enter into contracts for the purchase and sale of energy-related commodities, and also enter into other derivative instruments such as options, swaps, futures and forwards primarily to manage commodity price and interest rate risks. Under accounting standards related to derivative instruments and hedging activities, these instruments are subject to mark-to-market accounting, and the determination of market values for these instruments is based on numerous assumptions and estimation techniques.

Mark-to-market accounting recognizes changes in the fair value of derivative instruments in the financial statements as market prices change. Such changes in fair value are accounted for as unrealized mark-to-market gains and losses in net income with an offset to derivative assets and liabilities The availability of quoted market prices in energy markets is dependent on the type of commodity (e.g., natural gas, electricity, etc.), time period specified and delivery point. In computing fair value for derivatives, each forward pricing curve is separated into liquid and illiquid periods. The liquid period varies by delivery point and commodity. Generally, the liquid period is supported by exchange markets, broker quotes and frequent trading activity. For illiquid periods, fair value is estimated based on forward price curves developed using modeling techniques that take into account available market information and other inputs that might not be readily observable in the market. We estimate fair value as described in Note 15 to Financial Statements and discussed under "Fair Value Measurements" below.

Accounting standards related to derivative instruments and hedging activities allow for "normal" purchase or sale elections and hedge accounting designations at the inception of the contract, which generally eliminate or defer the requirement for mark-to-market recognition in net income and thus reduce the volatility of net income that can result from fluctuations in fair values. "Normal" purchases and sales are contracts that provide for physical delivery of quantities expected to be used or sold over a reasonable period in the normal course of business and are not subject to mark-to-market accounting if the election as normal is made. Hedge accounting designations are made with the intent to match the accounting recognition of the contract's financial performance to that of the transaction the contract is intended to hedge.

Under hedge accounting, changes in fair value of instruments designated as cash flow hedges are recorded in other comprehensive income with an offset to derivative assets and liabilities to the extent the change in value is effective; that is, it mirrors the offsetting change in fair value of the forecasted hedged transaction. Changes in value that represent ineffectiveness of the hedge are recognized in net income immediately, and the effective portion of changes in fair value initially recorded in other comprehensive income are recognized in net income in the period that the hedged transactions are recognized. Although as of December 31, 2010, we do not have any derivatives designated as cash flow or fair value hedges, we continually assess potential hedge elections and could designate positions as cash flow hedges in the future. In March 2007, the instruments making up a significant portion of the long-term hedging program that were previously designated as cash flow hedges were dedesignated as allowed under accounting standards related to derivative instruments and hedging activities, and subsequent changes in their fair value are being marked-to-market in net income. In addition, in August 2008, interest rate swap transactions in effect at that time were dedesignated as cash flow hedges in accordance with accounting standards, and subsequent changes in their fair value are being marked-to-market in net income. See further discussion of the long-term hedging program and interest rate swap transactions under "Business – Significant Activities and Events."

The following tables provide the effects on both net income and other comprehensive income of mark-to-market accounting for those derivative instruments that we have determined to be subject to fair value measurement under accounting standards related to derivative instruments and hedging activities.

	Year Ended December 31,		
	2010	2009	2008
Amounts recognized in net income (loss) (after-tax):			
Unrealized net gains on positions marked-to-market in net income (a)	$1,257	$1,573	$ 518
Unrealized net (gains) losses representing reversals of previously recognized fair values of positions settled in the period (a)	(607)	(333)	25
Unrealized ineffectiveness net losses on positions accounted for as cash flow hedges	—	—	(3)
Reversals of previously recognized unrealized net losses related to cash flow hedge positions settled in the period	1	1	—
Total	$ 651	$1,241	$ 540
Amounts recognized in other comprehensive income (after-tax):			
Net losses in fair value of positions accounted for as cash flow hedges	$ —	$ (20)	$(183)
Net losses on cash flow hedge positions recognized in net income to offset hedged transactions	59	130	122
Total	$ 59	$ 110	$ (61)

(a) Amounts for 2010, 2009 and 2008 include $785 million, $788 million and $1.503 billion in net after-tax gains related to commodity positions, respectively, and $135 million in net after-tax losses, $452 million in net after-tax gains and $960 million in net after-tax losses related to interest rate swaps, respectively.

The effect of mark-to-market and hedge accounting for derivatives on the balance sheet is as follows:

	December 31,	
	2010	2009
Commodity contract assets	$ 4,705	$ 3,860
Commodity contract liabilities	$ (1,608)	$ (2,146)
Interest rate swap assets	$ 98	$ 64
Interest rate swap liabilities	$ (1,544)	$ (1,306)
Net accumulated other comprehensive loss included in shareholders' equity (amounts after tax)	$ (69)	$ (128)

We report derivative assets and liabilities in the balance sheet without taking into consideration netting arrangements we have with counterparties. Margin deposits that contractually offset these assets and liabilities are reported separately in the balance sheet. See Note 15 to Financial Statements.

Fair Value Measurements

We determine value under the fair value hierarchy established in accounting standards. We utilize several valuation techniques to measure the fair value of assets and liabilities, relying primarily on the market approach of using prices and other market information for identical and/or comparable assets and liabilities for those items that are measured on a recurring basis. These techniques include, but are not limited to, the use of broker quotes and statistical relationships between different price curves and are intended to maximize the use of observable inputs and minimize the use of unobservable inputs. In applying the market approach, we use a mid-market valuation convention (the mid-point between bid and ask prices) as a practical expedient.

Under the fair value hierarchy, Level 1 and Level 2 valuations generally apply to our commodity-related contracts for natural gas and electricity derivative instruments entered into for hedging purposes, securities associated with the nuclear decommissioning trust, and interest rate swaps intended to fix and/or lower interest payments on long-term debt. Level 1 valuations use quoted prices in active markets for identical assets or liabilities that are accessible at the measurement date. Level 2 valuations are based on evaluated prices that reflect observable market information, such as actual trade information of similar securities, adjusted for observable differences. Level 2 inputs include:

- quoted prices for similar assets or liabilities in active markets;
- quoted prices for identical or similar assets or liabilities in markets that are not active;
- inputs other than quoted prices that are observable for the asset or liability such as interest rates and yield curves observable at commonly quoted intervals, and
- inputs that are derived principally from or corroborated by observable market data by correlation or other means.

Examples of Level 2 valuation inputs utilized include over-the-counter broker quotes and quoted prices for similar assets or liabilities that are corroborated by correlation or through statistical relationships between different price curves. For example, certain physical power derivatives are executed for a particular location at specific time periods that might not have active markets; however, an active market might exist for such derivatives for a different time period at the same location. We utilize correlation techniques to compare prices for inputs at both time periods to provide a basis to value the non-active derivative. (See Note 15 to Financial Statements for additional discussion of how broker quotes are utilized.)

Level 3 valuations generally apply to our more complex long-term power purchases and sales agreements, including longer-term wind and other power purchase and sales contracts and certain natural gas positions (collars) in the long-term hedging program. Level 3 valuations use largely unobservable inputs, with little or no supporting market activity, and assets and liabilities are classified as Level 3 if such inputs are significant to the fair value determination We use the most meaningful information available from the market, combined with our own internally developed valuation methodologies, to develop our best estimate of fair value. The determination of fair value for Level 3 assets and liabilities requires significant management judgment and estimation.

Valuations of Level 3 assets and liabilities are sensitive to the assumptions used for the significant inputs. Where market data is available, the inputs used for valuation reflect that information as of our valuation date. In periods of extreme volatility, lessened liquidity or in illiquid markets, there may be more variability in market pricing or a lack of market data to use in the valuation process. An illiquid market is one in which little or no observable activity has occurred or one that lacks willing buyers. Valuation risk is mitigated through the performance of stress testing of the significant inputs to understand the impact that varying assumptions may have on the valuation and other review processes performed to ensure appropriate valuation.

As part of our valuation of assets subject to fair value accounting, counterparty credit risk is taken into consideration by measuring the extent of netting arrangements in place with the counterparty along with credit enhancements and the estimated credit rating of the counterparty. Our valuation of liabilities subject to fair value accounting takes into consideration the market's view of our credit risk along with the existence of netting arrangements in place with the counterparty and credit enhancements posted by us. We consider the credit risk adjustment to be a Level 3 input since judgment is used to assign credit ratings, recovery rate factors and default rate factors.

Level 3 assets totaled $401 million and $350 million as of December 31, 2010 and 2009, respectively, and represented approximately 8% of the assets measured at fair value, or less than 1% of total assets in both years. Level 3 liabilities totaled $59 million and $269 million as of December 31, 2010 and 2009, respectively, and represented approximately 2% and 8%, respectively, of the liabilities measured at fair value, or less than 1% of total liabilities.

Valuations of several of our Level 3 assets and liabilities are sensitive to changes in discount rates, option-pricing model inputs such as volatility factors and credit risk adjustments. As of December 31, 2010, a $5.00 per MWh change in electricity price assumptions across unobservable inputs would cause an approximate $5 million change in net Level 3 assets A 10% change in coal price assumptions across unobservable inputs would cause an approximate $1 million change in net Level 3 assets. See Note 15 to Financial Statements for additional information about fair value measurements, including a table presenting the changes in Level 3 assets and liabilities for the twelve months ended December 31, 2010, 2009 and 2008.

Variable Interest Entities

A variable interest entity (VIE) is an entity with which we have a relationship or arrangement that indicates some level of control over the entity or results in economic risks to us Determining whether or not to consolidate a VIE requires interpretation of accounting rules and their application to existing business relationships and underlying agreements. Amended accounting rules related to VIEs became effective January 1, 2010 and resulted in the deconsolidation of Oncor Holdings, which holds an approximate 80% interest in Oncor. In determining the appropriateness of consolidation of a VIE, we evaluate its purpose, governance structure, decision making processes and risks that are passed on to its interest holders. We also examine the nature of any related party relationships among the interest holders of the VIE and the rights granted to the interest holders of the VIE to determine whether we have the right or obligation to absorb profit and loss from the VIE and the power to direct the significant activities of the VIE. See Notes 2 and 3 to Financial Statements for our analysis of the Oncor relationship and information regarding our consolidated variable interest entities.

Revenue Recognition

Our revenue includes an estimate for unbilled revenue that represents estimated daily kWh consumption after the meter read date to the end of the period multiplied by the applicable billing rates. Estimated daily kWh usage is derived using historical kWh usage information adjusted for weather and other measurable factors affecting consumption Calculations of unbilled revenues during certain interim periods are generally subject to more estimation variability because of seasonal changes in demand. Accrued unbilled revenues totaled $297 million, $546 million and $505 million as of December 31, 2010, 2009 and 2008, respectively.

Accounting for Contingencies

Our financial results may be affected by judgments and estimates related to loss contingencies. A significant contingency that we account for is the loss associated with uncollectible trade accounts receivable. The determination of such bad debt expense is based on factors such as historical write-off experience, aging of accounts receivable balances, changes in operating practices, regulatory rulings, general economic conditions, effects of hurricanes and other natural disasters and customers' behaviors. Changes in customer count and mix due to competitive activity and seasonal variations in amounts billed add to the complexity of the estimation process. Historical results alone are not always indicative of future results, causing management to consider potential changes in customer behavior and make judgments about the collectability of accounts receivable. Bad debt expense, the substantial majority of which relates to our competitive retail operations, totaled $108 million, $113 million and $81 million for the years ended December 31, 2010, 2009 and 2008, respectively.

Litigation contingencies also may require significant judgment in estimating amounts to accrue. We accrue liabilities for litigation contingencies when such liabilities are considered probable of occurring and the amount is reasonably estimable. No significant amounts have been accrued for such contingencies during the three-year period ended December 31, 2010. See Item 3, "Legal Proceedings" for discussion of major litigation.

Accounting for Income Taxes

Our income tax expense and related balance sheet amounts involve significant management estimates and judgments. Amounts of deferred income tax assets and liabilities, as well as current and noncurrent accruals, involve judgments and estimates of the timing and probability of recognition of income and deductions by taxing authorities. In assessing the likelihood of realization of deferred tax assets, management considers estimates of the amount and character of future taxable income. Actual income taxes could vary from estimated amounts due to the future impacts of various items, including changes in income tax laws, our forecasted financial condition and results of operations in future periods, as well as final review of filed tax returns by taxing authorities. Our income tax returns are regularly subject to examination by applicable tax authorities. In management's opinion, the liability recorded pursuant to income tax accounting guidance related to uncertain tax positions reflects future taxes that may be owed as a result of any examination. In 2010, we reduced our liability for uncertain tax positions by $162 million as a result of negotiations with the IRS. This reduction consisted of a $225 million reversal of accrued interest ($146 million after-tax), partially offset by a $63 million reclassification to net deferred tax liabilities. See Notes 1, 7 and 8 to Financial Statements for discussion of income tax matters.

Depreciation and Amortization

Depreciation expense related to generation facilities is based on the estimates of fair value and economic useful lives as determined in the application of purchase accounting described above. The accuracy of these estimates directly affects the amount of depreciation expense. If future events indicate that the estimated lives are no longer appropriate, depreciation expense will be recalculated prospectively from the date of such determination based on the new estimates of useful lives.

The estimated remaining lives range from 22 to 59 years for the lignite/coal- and nuclear-fueled generation units.

Finite-lived intangibles identified as a result of purchase accounting are amortized over their estimated useful lives based on the expected realization of economic effects. See Note 4 to Financial Statements for additional information.

Defined Benefit Pension Plans and OPEB Plans

We provide pension benefits based on either a traditional defined benefit formula or a cash balance formula and also provide certain health care and life insurance benefits to eligible employees and their eligible dependents upon the retirement of such employees from our company. Reported costs of providing noncontributory defined pension benefits and OPEB are dependent upon numerous factors, assumptions and estimates.

PURA provides for the recovery by Oncor of pension and OPEB costs for all applicable former employees of the regulated predecessor integrated electric utility. These costs are associated with Oncor's active and retired employees, as well as active and retired personnel engaged in other EFH Corp. activities related to their service prior to the deregulation and disaggregation of our business effective January 1, 2002. Oncor is authorized to establish a regulatory asset or liability for the difference between the amounts of pension and OPEB costs reflected in Oncor's approved (by the PUCT) billing rates and the actual amounts that would otherwise have been recorded as charges or credits to earnings. Accordingly, Oncor defers (principally as a regulatory asset or property) additional pension and OPEB costs consistent with PURA. Amounts deferred are ultimately subject to regulatory approval.

Benefit costs are impacted by actual employee demographics (including but not limited to age, compensation levels and years of accredited service), the level of contributions made to retiree plans, expected and actual earnings on plan assets and the discount rates used in determining the projected benefit obligation. Changes made to the provisions of the plans may also impact current and future benefit costs. Fluctuations in actual equity market returns as well as changes in general interest rates may result in increased or decreased benefit costs in future periods.

In accordance with accounting rules, changes in benefit obligations associated with these factors may not be immediately recognized as costs in the income statement, but are recognized in future years over the remaining average service period of plan participants. As such, significant portions of benefit costs recorded in any period may not reflect the actual level of cash benefits provided to plan participants. Pension and OPEB costs as determined under applicable accounting rules are summarized in the following table:

	Year Ended December 31, 2010	2009	2008
Pension costs	$ 100	$ 44	$ 21
OPEB costs	80	70	58
Total benefit costs	$ 180	$ 114	$ 79
Less amounts expensed by Oncor (and not consolidated)	(37)	—	—
Less amounts deferred principally as a regulatory asset or property by Oncor	(93)	(66)	(42)
Net amounts recognized as expense	$ 50	$ 48	$ 37
Discount rate (a)	5.90%	6.90%	6.55%

(a) Discount rate for OPEB was 6.85% in 2009.

See Note 20 to Financial Statements regarding other disclosures related to pension and OPEB obligations.

Sensitivity of these costs to changes in key assumptions is as follows:

Assumption	Increase/ (decrease) in 2010 Pension and OPEB Costs
Discount rate – 1% increase	$ (52)
Discount rate – 1% decrease	$ 62
Expected return on assets – 1% increase	$ (22)
Expected return on assets – 1% decrease	$ 22

RESULTS OF OPERATIONS

Effects of Change in Wholesale Electricity Market

As discussed above under "Significant Activities and Events," the nodal wholesale market design implemented by ERCOT in December 2010 resulted in operational changes that facilitate hedging and trading of power. As part of ERCOT's transition to a nodal wholesale market, volumes under nontrading bilateral purchase and sales contracts are no longer scheduled as physical power with ERCOT. As a result of these changes in market operations, reported wholesale revenues and purchased power costs in 2011 will be materially less than amounts reported in prior periods. Effective with the nodal market implementation, if volumes delivered to our retail and wholesale customers are less than our generation volumes (as determined on a daily settlement basis), we record additional wholesale revenues. Conversely, if volumes delivered to our retail and wholesale customers exceed our generation volumes, we record additional purchased power costs. The resulting additional wholesale revenues or purchased power costs are offset in net gain/(loss) from commodity hedging and trading activities.

Pro Forma Consolidated Financial Results

As the result of deconsolidation of Oncor Holdings effective 2010, the results of Oncor Holdings are reflected in the 2010 consolidated statement of income as equity in earnings of unconsolidated subsidiary (net of tax) instead of separately as revenues and expenses as they are shown for periods prior to January 1, 2010. The following pro forma results for the year ended December 31, 2009 are presented to provide for a meaningful comparison, along with the analyses on the following pages, of consolidated operating results in consideration of the deconsolidation of Oncor Holdings as discussed in Notes 1 and 3 to Financial Statements.

	Year Ended December 31, 2010	Year Ended December 31, 2009 As Reported	Year Ended December 31, 2009 Pro Forma Adjustments (a)	Year Ended December 31, 2009 Pro Forma
	(millions of dollars)			
Operating revenues	$ 8,235	$ 9,546	$ (1,632)	$ 7,914
Fuel, purchased power costs and delivery fees	(4,371)	(2,878)	(1,058)	(3,936)
Net gain from commodity hedging and trading activities	2,161	1,736	—	1,736
Operating costs	(837)	(1,598)	908	(690)
Depreciation and amortization	(1,407)	(1,754)	557	(1,197)
Selling, general and administrative expenses	(751)	(1,068)	193	(875)
Franchise and revenue-based taxes	(106)	(359)	250	(109)
Impairment of goodwill	(4,100)	(90)	—	(90)
Other income	2,051	204	(50)	154
Other deductions	(31)	(97)	34	(63)
Interest income	10	45	(1)	44
Interest expense and related charges	(3,554)	(2,912)	306	(2,606)
Income (loss) before income taxes and equity in earnings of unconsolidated subsidiaries	(2,700)	775	(493)	282
Income tax (expense) benefit	(389)	(367)	173	(194)
Equity in earnings of unconsolidated subsidiaries (net of tax)	277	—	256	256
Net income (loss)	(2,812)	408	(64)	344
Net income attributable to noncontrolling interests	—	(64)	64	—
Net income (loss) attributable to EFH Corp.	$ (2,812)	$ 344	$	$ 344

(a) All pro forma adjustments relate to Oncor Holdings and result in the presentation of the investment in Oncor Holdings under the equity method of accounting for the year ended December 31, 2009.

Consolidated Financial Results — Year Ended December 31, 2010 Compared to Pro Forma Year Ended December 31, 2009

See comparison of results of the Competitive Electric segment for discussion of variances in: operating revenues; fuel, purchased power costs and delivery fees; net gain (loss) from commodity hedging and trading activities, operating costs; depreciation and amortization, and franchise and revenue-based taxes.

SG&A expenses decreased $124 million, or 14%, to $751 million in 2010 driven by $66 million in lower transition costs associated with outsourced support services and the retail customer information system implemented in 2009, $18 million in lower employee compensation-related expense and $12 million of accounts receivable securitization program fees that are reported as interest expense and related charges in 2010 (see Notes 10 and 19 to Financial Statements).

See Note 4 to Financial Statements for discussion of the $4.1 billion impairment of goodwill recorded in the Competitive Electric segment in 2010. The $90 million impairment of goodwill recorded in 2009 largely related to the Competitive Electric segment and resulted from the completion of fair value calculations supporting a goodwill impairment charge recorded in the fourth quarter 2008 as discussed in Note 4 to Financial Statements.

Other income totaled $2.051 billion in 2010 and $154 million in 2009. Debt extinguishment gains totaled $1.814 billion and $87 million in 2010 and 2009, respectively (see discussion of debt exchanges and repurchases in Note 11 to Financial Statements). The 2010 amount also included a $116 million gain on termination of a long-term power sales contract, a $44 million gain on sale of land and related water rights and a $37 million gain on sale of interests in a natural gas gathering pipeline business. The 2009 amount included $23 million of income arising from the reversal of a use tax accrual recorded in purchase accounting related to periods prior to the Merger, which was triggered by a state ruling in the third quarter 2009, and $11 million of income arising from the reversal of exit liabilities recorded in purchase accounting due to sooner than expected transition of outsourcing services (see Note 19 to Financial Statements).

Other deductions totaled $31 million in 2010 and $63 million in 2009. The 2009 amount included an impairment charge of $34 million related to land expected to be sold. See Note 9 to Financial Statements for details of other income and deductions.

Interest income decreased $34 million, or 77%, to $10 million in 2010 reflecting lower interest on $465 million in collateral under a funding arrangement, due to settlement of the arrangement as described in Note 17 to Financial Statements.

Interest expense and related charges increased $948 million to $3.554 billion in 2010 reflecting a $207 million unrealized mark-to-market net loss related to interest rate swaps in 2010 compared to a $696 million net gain in 2009 and a $214 million decrease in capitalized interest due to completion of new generation facility construction activities, partially offset by $97 million in decreased noncash amortization of losses on interest rate swaps dedesignated as cash flow hedges, reflecting values attributed to earlier periods, as well as lower interest expense resulting from reduced debt under the liability management program as described above under "Significant Activities and Events." Also, see Note 24 to Financial Statements.

Income tax expense totaled $389 million in 2010 compared to $194 million in 2009. Excluding the effects of the $4.1 billion and $90 million nondeductible goodwill impairment charges in 2010 and 2009, respectively, the effective tax rates were 27.8% in 2010 and 52.2% in 2009. The decrease in the effective tax rate in 2010 was driven by lower interest accrued related to uncertain tax positions, including the effect of a $146 million reversal of previously accrued interest (see Note 7 to Financial Statements) net of the effect of an $8 million deferred tax charge related to the Patient Protection and Affordable Care Act (see Note 8 to Financial Statements).

Equity in earnings of unconsolidated subsidiaries (net of tax) increased $21 million to $277 million in 2010 driven by improved earnings of Oncor, which reflected higher revenues, primarily due to weather effects and rate increases, and the effect of a $25 million write off of regulatory assets in 2009, partially offset by increased noncash expenses recognized as a result of the PUCT's final order in the June 2008 rate review.

The consolidated net loss of $2.812 billion in 2010 represented a $3.156 billion decrease in results.

- Results in the Competitive Electric segment decreased $4.094 billion to a loss of $3.463 billion.
- Earnings from the Regulated Delivery segment increased $21 million to $277 million as discussed above.
- Corporate and Other net income totaled $374 million in 2010 compared to net expenses of $543 million in 2009. The amounts in 2010 and 2009 include recurring interest expense on outstanding debt and notes payable to subsidiaries, as well as corporate general and administrative expenses. The change of $917 million reflected $670 million in higher debt extinguishment gains in 2010, the $121 million Corporate and Other portion of the 2010 reversal of accrued interest on uncertain tax positions discussed above, $68 million in lower SG&A expense primarily reflecting lower transition costs associated with outsourced support services and costs allocated to the competitive operations effective 2010 and a $20 million goodwill impairment charge in 2009, partially offset by an $8 million deferred tax charge due to the implementation of the Patient Protection and Affordable Care Act in 2010 (all amounts after-tax).

Consolidated Financial Results — Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

Reference is made to comparisons of results by business segment following the discussion of consolidated results. The business segment comparisons provide additional detail and quantification of items affecting financial results.

Operating revenues decreased $1.818 billion, or 16%, to $9.546 billion in 2009.

- Operating revenues in the Competitive Electric segment decreased $1.876 billion, or 19%, to $7.911 billion.
- Operating revenues in the Regulated Delivery segment increased $110 million, or 4%, to $2.690 billion.
- Net intercompany sales eliminations increased $52 million, reflecting Oncor's higher distribution revenues from REP subsidiaries of TCEH.

Fuel, purchased power costs and delivery fees decreased $1.717 billion, or 37%, to $2.878 billion in 2009, driven by lower purchased power costs. See discussion below in the analysis of Competitive Electric segment results of operations.

Net gains from commodity hedging and trading activities totaled $1.736 billion in 2009 and $2.184 billion in 2008 Results in 2009 and 2008 included unrealized mark-to-market net gains totaling $1.277 billion and $2.281 billion, respectively, driven by the effect of lower forward market prices of natural gas on the value of positions in the long-term hedging program. See discussion below in the analysis of Competitive Electric segment results of operations.

Operating costs increased $95 million, or 6%, to $1.598 billion in 2009.

- Operating costs in the Competitive Electric segment increased $16 million, or 2%, to $693 million.
- Operating costs in the Regulated Delivery segment increased $80 million, or 10%, to $908 million.

Depreciation and amortization increased $144 million, or 9%, to $1 754 billion in 2009.

- Depreciation and amortization in the Competitive Electric segment increased $80 million, or 7%, to $1.172 billion.
- Depreciation and amortization in the Regulated Delivery segment increased $65 million, or 13%, to $557 million

SG&A expenses increased $111 million, or 12%, to $1.068 billion in 2009.

- SG&A expenses in the Competitive Electric segment increased $59 million, or 9%, to $741 million.
- SG&A expenses in the Regulated Delivery segment increased $30 million, or 18%, to $194 million.
- Corporate and Other SG&A expenses increased $22 million, or 20%, to $133 million driven by higher transition costs associated with outsourced support services.

See Note 4 to Financial Statements for discussion of the $90 million and $8.860 billion impairments of goodwill in 2009 and 2008, respectively.

Other income totaled $204 million in 2009 and $80 million in 2008, including $39 million and $44 million, respectively, in accretion of the fair value adjustment to certain regulatory assets due to purchase accounting. The 2009 amount also included an $87 million debt extinguishment gain (see discussion of debt exchanges in Note 11 to Financial Statements), $23 million of income arising from the reversal of a use tax accrual recorded in purchase accounting related to periods prior to the Merger, which was triggered by a state ruling in the third quarter of 2009, and $21 million of income arising from the reversal of exit liabilities recorded in purchase accounting due to sooner than expected transition of outsourcing services (see Note 19 to Financial Statements). The 2008 amount also included a $21 million net insurance recovery for damage to certain mining equipment.

Other deductions totaled $97 million in 2009 and $1.301 billion in 2008. The 2009 amount included an impairment charge of $34 million related to land expected to be sold within the next 12 months and a $25 million write off of regulatory assets as discussed in Note 24 to Financial Statements. The 2008 amount included impairment charges of $501 million related to NO_x and SO_2 environmental allowances intangible assets and $481 million related to trade name intangible assets, both discussed in Note 4 to Financial Statements, $229 million in impairment charges related to the natural gas-fueled generation facilities and $26 million in charges to reserve for net receivables (excluding termination related costs) from terminated hedging transactions with subsidiaries of Lehman Brothers Holdings Inc., which filed for bankruptcy under Chapter 11 of the US Bankruptcy Code. See Note 9 to Financial Statements for details of other income and deductions.

Interest income increased $18 million, or 67%, to $45 million driven by interest on $465 million in collateral under a funding arrangement described in Note 17 to Financial Statements.

Interest expense and related charges decreased $2.023 billion to $2.912 billion in 2009 reflecting a $696 million unrealized mark-to-market net gain related to interest rate swaps in 2009 as compared to a $1.477 billion net loss in 2008, which was partially offset by $118 million in increased noncash amortization of losses on interest rate swaps dedesignated as cash flow hedges and a $34 million decrease in capitalized interest. See Note 24 to Financial Statements.

Income tax expense totaled $367 million in 2009 compared to an income tax benefit of $471 million in 2008. The effective rate on income in 2009 was 47.4%, and the effective rate on a loss in 2008 was 4.5%. The increase in the rate reflects the impacts of nondeductible goodwill impairments of $90 million in 2009 and $8.860 billion in 2008, which increased the effective rate by 5.0 percentage points in 2009 and decreased the effective rate by 24.8 percentage points in 2008. The increase also reflects the effect of interest accrued for uncertain tax positions, which increased the rate on income in 2009 and decreased the rate on a loss in 2008.

Reflecting the goodwill and other impairment charges recorded in 2008, after tax-results improved $10.406 billion to $408 million in net income in 2009.

- After-tax results in the Competitive Electric segment improved $9 560 billion to $631 million in net income in 2009.
- After-tax results in the Regulated Delivery segment improved $806 million to $320 million in net income in 2009
- Corporate and Other net expenses totaled $543 million in 2009 and $583 million in 2008. The amounts in 2009 and 2008 include recurring interest expense on outstanding debt and notes payable to subsidiaries, as well as corporate general and administrative expenses. The after-tax decrease of $40 million reflected the debt extinguishment gain of $57 million and $16 million in interest income related to the collateral discussed above, partially offset by a $20 million goodwill impairment charge and the $14 million increase in SG&A expense as discussed above.

Non-GAAP Earnings Measures

In communications with investors, we use a non-GAAP earnings measure that reflects adjustments to earnings reported in accordance with US GAAP in order to review underlying operating performance. These adjusting items, which are generally noncash, consist of unrealized mark-to-market gains and losses, impairment charges, debt extinguishment gains and other charges, credits or gains that are unusual or nonrecurring. All such items and related amounts are disclosed in our annual report on Form 10-K and quarterly reports on Form 10-Q Our communications with investors also reference "Adjusted EBITDA," which is a non-GAAP measure used in calculation of ratios in covenants of certain of our debt securities (see "Financial Condition – Liquidity and Capital Resources – Financial Covenants, Credit Rating Provisions and Cross Default Provisions" below).

Competitive Electric Segment

Financial Results

	Year Ended December 31,		
	2010	2009	2008
Operating revenues	$ 8,235	$ 7,911	$ 9,787
Fuel, purchased power costs and delivery fees	(4,371)	(3,934)	(5,600)
Net gain from commodity hedging and trading activities	2,161	1,736	2,184
Operating costs	(837)	(693)	(677)
Depreciation and amortization	(1,380)	(1,172)	(1,092)
Selling, general and administrative expenses	(722)	(741)	(682)
Franchise and revenue-based taxes	(106)	(108)	(110)
Impairment of goodwill	(4,100)	(70)	(8,000)
Other income	903	59	34
Other deductions	(21)	(68)	(1,274)
Interest income	91	64	61
Interest expense and related charges	(2,957)	(1,946)	(4,010)
Income (loss) before income taxes	(3,104)	1,038	(9,379)
Income tax (expense) benefit	(359)	(407)	450
Net income (loss)	$ (3,463)	$ 631	$ (8,929)

Competitive Electric Segment

Sales Volume and Customer Count Data

	Year Ended December 31, 2010	2009	2008	2010 % Change	2009 % Change
Sales volumes:					
Retail electricity sales volumes – (GWh):					
Residential	28,208	28,046	28,135	0.6	(0.3)
Small business (a)	8,042	7,962	7,363	1.0	8.1
Large business and other customers	15,339	14,573	13,945	5.3	4.5
Total retail electricity	51,589	50,581	49,443	2.0	2.3
Wholesale electricity sales volumes (b)	51,359	42,320	46,743	21.4	(9.5)
Total sales volumes	102,948	92,901	96,186	10.8	(3.4)
Average volume (kWh) per residential customer (c)	15,532	14,855	14,780	4.6	0.5
Weather (North Texas average) – percent of normal (d):					
Cooling degree days	108.9%	98.1%	107.3%	11.0	(8.6)
Heating degree days	116.6%	105.8%	98.3%	10.2	7.6
Customer counts:					
Retail electricity customers (end of period and in thousands) (e):					
Residential	1,771	1,862	1,914	(4.9)	(2.7)
Small business (a)	217	262	275	(17.2)	(4.7)
Large business and other customers	20	23	25	(13.0)	(8.0)
Total retail electricity customers	2,008	2,147	2,214	(6.5)	(3.0)

(a) Customers with demand of less than 1 MW annually.
(b) Includes net amounts related to sales and purchases of balancing energy in the "real-time market."
(c) Calculated using average number of customers for the period
(d) Weather data is obtained from Weatherbank, Inc., an independent company that collects and archives weather data from reporting stations of the National Oceanic and Atmospheric Administration (a federal agency under the US Department of Commerce). Normal is defined as the average over a 10-year period.
(e) Based on number of meters. Typically, large business and other customers have more than one meter; therefore, number of meters does not reflect the number of individual customers. The year ended December 31, 2008 reflects reclassification of 18 thousand meters from residential to small business to conform to current presentation.

Competitive Electric Segment

Revenue and Commodity Hedging and Trading Activities

	Year Ended December 31, 2010	2009	2008	2010 % Change	2009 % Change
Operating revenues:					
Retail electricity revenues:					
Residential	$ 3,663	$3,806	$3,782	(3.8)	0.6
Small business (a)	1,052	1,164	1,099	(9.6)	5.9
Large business and other customers	1,211	1,261	1,447	(4.0)	(12.9)
Total retail electricity revenues	5,926	6,231	6,328	(4.9)	(1.5)
Wholesale electricity revenues (b) (c)	2,005	1,383	3,115	45.0	(55.6)
Amortization of intangibles (d)	16	5	(36)	—	—
Other operating revenues	288	292	380	(1.4)	(23.2)
Total operating revenues	$ 8,235	$7,911	$9,787	4.1	(19.2)
Net gain from commodity hedging and trading activities:					
Unrealized net gains from changes in fair value	$ 2,162	$1,741	$2,290	24.2	(24.0)
Unrealized net losses representing reversals of previously recognized fair values of positions settled in the current period	(1,009)	(464)	(9)	—	—
Realized net gains (losses) on settled positions	1,008	459	(97)	—	—
Total gain	$ 2,161	$1,736	$2,184	24.5	(20.5)

(a) Customers with demand of less than 1 MW annually.

(b) Upon settlement of physical derivative power sales and purchase contracts that are marked-to-market in net income, wholesale electricity revenues and fuel and purchased power costs are reported at approximated market prices, as required by accounting rules, instead of the contract price. As a result, these line item amounts include a noncash component, which the company considers "unrealized." (The offsetting differences between contract and market prices are reported in net gain from commodity hedging and trading activities.) These amounts are as follows:

	Year Ended December 31, 2010	2009	2008
Reported in revenues	$ (28)	$ (166)	$ 42
Reported in fuel and purchased power costs	96	114	6
Net gain (loss)	$ 68	$ (52)	$ 48

(c) Includes net amounts related to sales and purchases of balancing energy in the "real-time market."

(d) Represents amortization of the intangible net asset value of retail and wholesale power sales agreements resulting from purchase accounting.

Competitive Electric Segment

Production, Purchased Power and Delivery Cost Data

	Year Ended December 31, 2010	2009	2008	2010 % Change	2009 % Change
Fuel, purchased power costs and delivery fees ($ millions):					
Nuclear fuel	$ 159	$ 121(f)	$ 95	31.4	27.4
Lignite/coal	910	670	640	35.8	4.7
Total baseload fuel	1,069	791	735	35.1	7.6
Natural gas fuel and purchased power (a)	1,502	1,224	2,881	22.7	(57.5)
Amortization of intangibles (b)	161	285(f)	318	(43.5)	(10.4)
Other costs	187	202	351	(7.4)	(42.5)
Fuel and purchased power costs	2,919	2,502	4,285	16.7	(41.6)
Delivery fees (c)	1,452	1,432	1,315	1.4	8.9
Total	$ 4,371	$ 3,934	$ 5,600	11.1	(29.8)
Fuel and purchased power costs (which excludes generation facilities operating costs) per MWh:					
Nuclear fuel	$ 7.89	$ 5.98(f)	$ 4.92	31.9	21.5
Lignite/coal (d)	$ 19.19	$ 16.47	$ 15.80	16.5	4.2
Natural gas fuel and purchased power	$ 52.37	$ 44.36	$ 81.99	18.1	(45.9)
Delivery fees per MWh	$ 28.06	$ 28.09	$ 26.33	(0.1)	6.7
Production and purchased power volumes (GWh):					
Nuclear	20,208	20,104	19,218	0.5	4.6
Lignite/coal	54,775	45,684	44,923	19.9	1.7
Total baseload generation	74,983	65,788	64,141	14.0	2.6
Natural gas-fueled generation	1,648	2,447	4,122	(32.7)	(40.6)
Purchased power (e)	26,317	24,666	27,923	6.7	(11.7)
Total energy supply volumes	102,948	92,901	96,186	10.8	(3.4)
Baseload capacity factors:					
Nuclear	100.3%	100.0%	95.2%	0.3	5.0
Lignite/coal	82.2%	86.5%	87.6%	(5.0)	(1.3)
Total baseload	86.6%	90.3%	89.8%	(4.1)	0.6

(a) See note (b) on previous page.

(b) Represents amortization of the intangible net asset values of emission credits, coal purchase contracts, nuclear fuel contracts and power purchase agreements and the stepped up value of nuclear fuel resulting from purchase accounting.

(c) Includes delivery fee charges from Oncor that prior to 2010 were eliminated in consolidation.

(d) Includes depreciation and amortization of lignite mining assets, which is reported in the depreciation and amortization expense line item, but is part of overall fuel costs.

(e) Includes amounts related to line loss and power imbalances.

(f) Reflects reclassification to correct amortization.

Competitive Electric Segment – Financial Results – Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

Operating revenues increased $324 million, or 4%, to $8.235 billion in 2010.

Wholesale electricity revenues increased $622 million, or 45%, to $2.005 billion in 2010. A 21% increase in wholesale electricity sales volumes, reflecting production from the new generation units and increased sales to third-party REPs, increased revenues by $332 million. An 8% increase in average wholesale electricity prices, reflecting higher natural gas prices at the time the underlying contracts were executed, increased revenues by $149 million. The balance of the revenue increase reflected lower unrealized losses in 2010 related to physical derivative commodity sales contracts as discussed in footnote (b) to the "Revenue and Commodity Hedging and Trading Activities" table above.

Retail electricity revenues decreased $305 million, or 5%, to $5.926 billion and reflected the following:

- Lower average pricing decreased revenues by $429 million reflecting declines in both the business and residential markets. Lower average pricing is reflective of competitive activity in a lower wholesale power price environment and a change in business customer mix.
- A 2% increase in sales volumes increased revenues by $124 million reflecting increases in both the business and residential markets. A 4% increase in business markets sales volumes reflected a change in customer mix resulting from contracts executed with new customers. Residential sales volumes increased 1% reflecting higher average consumption driven by colder winter weather and hotter summer weather, partially offset by a decline in residential customer counts.

Fuel, purchased power costs and delivery fees increased $437 million, or 11%, to $4.371 billion in 2010. Higher purchased power costs contributed $255 million to the increase and reflected increased planned generation unit outages and higher retail demand, as well as increased prices driven by the effect of higher natural gas prices at the time the underlying contracts were executed. Other factors contributing to the increase included $126 million in higher lignite/coal costs at existing plants, reflecting higher purchased coal transportation and commodity costs, $114 million in increased lignite fuel costs related to production from the new generation units, a $39 million increase in nuclear fuel expense reflecting increased uranium and conversion costs, a $23 million increase in natural gas and fuel oil costs driven by higher prices, $20 million in higher delivery fees, reflecting increased retail sales volumes and tariffs, and an $18 million decrease in unrealized gains related to physical derivative commodity purchase contracts. These increases were partially offset by $124 million in lower amortization of the intangible net asset values (including the stepped-up value of nuclear fuel) resulting from purchase accounting, which reflected expiration of commodity contracts and consumption of the nuclear fuel.

Overall baseload generation production increased 14% in 2010 driven by production from the new generation units. Nuclear production increased 1%, and existing lignite/coal-fueled generation decreased 2% driven by increased economic backdown.

Following is an analysis of amounts reported as net gain from commodity hedging and trading activities for the years ended December 31, 2010 and 2009, which totaled $2.161 billion and $1.736 billion, respectively:

Year Ended December 31, 2010 — Unrealized mark-to-market net gains totaling $1.153 billion included:

- $1.157 billion in net gains related to hedge positions, which includes $2.133 billion in net gains from changes in fair value, driven by the impact of lower forward natural gas prices on the value of positions in the long-term hedging program, and $976 million in net losses that represent reversals of previously recorded net gains on positions settled in the period, and
- $4 million in net losses related to trading positions, which includes $29 million in net gains from changes in fair value, and $33 million in net losses that represent reversals of previously recorded net gains on positions settled in the period.

Realized net gains totaling $1.008 billion included:

- $961 million in net gains related to positions that primarily hedged electricity revenues recognized in the period, and
- $47 million in net gains related to trading positions.

Year Ended December 31, 2009 — Unrealized mark-to-market net gains totaling $1.277 billion included:

- $1.260 billion in net gains related to hedge positions, which includes $1.719 billion in net gains from changes in fair value, driven by the impact of lower forward natural gas prices on the value of positions in the long-term hedging program, and $459 million in net losses that represent reversals of previously recorded net gains on positions settled in the period, and
- $17 million in net gains related to trading positions, which includes $22 million in net gains from changes in fair value, and $5 million in net losses that represent reversals of previously recorded net gains on positions settled in the period.

Realized net gains totaling $459 million included:

- $449 million in net gains related to positions that primarily hedged electricity revenues recognized in the period, and
- $10 million in net gains related to trading positions.

Unrealized gains and losses that are related to physical derivative commodity contracts and are reported as revenues and purchased power costs, as required by accounting rules, totaled $68 million in net gains in 2010 and $52 million in net losses in 2009.

Operating costs increased $144 million, or 21%, to $837 million in 2010. The increase reflected $90 million in incremental expense related to the new generation units. The balance of the increase was driven by installation and maintenance of emissions control equipment at the existing lignite/coal-fueled generation facilities and higher maintenance costs at both the nuclear and existing lignite/coal-fueled facilities reflecting timing and scope of project work.

Depreciation and amortization increased $208 million, or 18%, to $1.380 billion in 2010. The increase reflected $162 million in incremental expense related to the new generation units and associated mining operations. The balance of the increase was driven by equipment additions.

SG&A expenses decreased $19 million, or 3%, to $722 million in 2010. The decrease reflected:

- $31 million in lower transition costs associated with outsourced services and the retail customer information management system implemented in 2009;
- $16 million in lower employee compensation-related expense in 2010;
- $12 million of accounts receivable securitization program fees that are reported in 2010 as interest expense and related charges (see Note 10 to Financial Statements), and
- $8 million in lower bad debt expense,

partially offset by $46 million of costs allocated from corporate in 2010, principally fees paid to the Sponsor Group.

See Note 4 to Financial Statements for discussion of the $4.1 billion impairment of goodwill recorded in 2010 and of the $70 million impairment of goodwill recorded in 2009 that resulted from the completion of fair value calculations supporting a goodwill impairment charge recorded in the fourth quarter of 2008.

Other income totaled $903 million in 2010 and $59 million in 2009. Other income in 2010 included debt extinguishment gains of $687 million, a $116 million gain on termination of a power sales contract, a $44 million gain on the sale of land and related water rights and a $37 million gain associated with the sale of interests in a natural gas gathering pipeline business. The 2009 amount included a $23 million reversal of a use tax accrual, an $11 million reversal of exit liabilities recorded in connection with the termination of outsourcing arrangements and $25 million in several individually immaterial items. Other deductions totaled $21 million in 2010 and $68 million in 2009. The 2010 amount included several individually immaterial items. The 2009 amount included $34 million in charges for the impairment of land expected to be sold, $7 million in severance charges and other individually immaterial miscellaneous expenses. See Note 9 to Financial Statements for additional details

Interest income increased $27 million, or 42%, to $91 million in 2010 reflecting higher notes receivable balances from affiliates.

Interest expense and related charges increased by $1.011 billion, or 52%, to $2.957 billion in 2010 reflecting a $207 million unrealized mark-to-market net loss related to interest rate swaps in 2010 compared to a $696 million net gain in 2009 and a $214 million decrease in capitalized interest due to completion of new generation facility construction activities, partially offset by a $97 million decrease in noncash amortization of losses on interest rate swaps dedesignated as cash flow hedges.

Income tax expense totaled $359 million in 2010 compared to $407 million in 2009. Excluding the $4.1 billion and $70 million nondeductible goodwill impairment charges in 2010 and 2009, respectively, the effective tax rates were 36.0% and 36.7%, respectively.

Results for the segment decreased $4.094 billion in 2010 to a loss of $3.463 billion reflecting the $4.1 billion goodwill impairment charge and increased interest expense, partially offset by debt extinguishment gains and an increase in net gains from commodity hedging and trading activities.

Competitive Electric Segment – Financial Results – Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

Operating revenues decreased $1 876 billion, or 19%, to $7.911 billion in 2009.

Wholesale electricity revenues decreased $1.732 billion, or 56%, to $1.383 billion in 2009 as compared to 2008. Volatility in wholesale revenues and purchased power costs reflects movements in natural gas prices, as lower natural gas prices in 2009 drove a 46% decline in average wholesale electricity sales prices. Reported wholesale revenues and purchased power costs also reflect changes in volumes of bilateral contracting activity entered into to mitigate the effects of demand volatility and congestion. Results in 2009 reflect lower demand volatility and a decline in congestion, which drove a 10% decline in wholesale sales volumes. Net purchases of balancing electricity from ERCOT totaling $80 million in 2009 and $214 million in 2008, which were previously disclosed separately, are now included within wholesale electricity revenues.

Retail electricity revenues declined $97 million, or 2%, to $6.231 billion and reflected the following:

- Lower average pricing contributed $242 million to the revenue decline. The change in average pricing reflected lower average contracted business rates driven by lower wholesale electricity prices, partially offset by higher average pricing in the residential and non-contract business markets resulting from advanced meter surcharges as well as customer mix.
- Retail sales volume growth of 2% increased revenues by $145 million. Volumes rose in the business markets driven by changes in customer mix resulting from contracting activity, but declined slightly in the residential market driven by a 3% decrease in customers.

Other operating revenues decreased $88 million, or 23%, to $292 million in 2009 due to lower natural gas prices and lower volumes on sales of natural gas to industrial customers.

The change in operating revenues also reflected a $41 million decrease in amortization of intangible assets arising from purchase accounting reflecting expiration of retail sales contracts.

Fuel, purchased power costs and delivery fees decreased $1.666 billion, or 30%, to $3.934 billion in 2009. This decrease was driven by lower purchased power costs due to the effect of lower natural gas prices, decreased demand volatility and reduced congestion as discussed above regarding wholesale revenues. Lower costs of replacement power during unplanned generation unit repair outages contributed to improved margin. Other factors contributing to lower fuel and purchased power costs included lower natural gas-fueled generation and lower related fuel costs ($374 million), the effect of lower natural gas prices on natural gas purchased for sale to industrial customers ($116 million) and lower amortization of intangible assets arising from purchase accounting ($26 million).

Overall baseload generation production increased 3% in 2009 reflecting a 5% increase in nuclear production and a 2% increase in lignite/coal-fueled production. The increase in nuclear production, which reflects two refueling outages in 2008 compared to one refueling outage in 2009 and investments to increase generation capacity, resulted in improved margin. The increase in lignite/coal-fueled production reflected generation from the new units placed in service in the fourth quarter 2009, partially offset by generation reductions during certain periods when power could be purchased in the wholesale market at prices below production costs, which was largely due to lower natural gas prices and higher wind generation availability.

Following is an analysis of amounts reported as net gain from commodity hedging and trading activities for the years ended December 31, 2009 and 2008, which totaled $1.736 billion and $2.184 billion, respectively:

Year Ended December 31, 2009 — Unrealized mark-to-market net gains totaling $1.277 billion included:

- $1.260 billion in net gains related to hedge positions, which includes $1.719 billion in net gains from changes in fair value, driven by the impact of lower forward natural gas prices on the value of positions in the long-term hedging program, and $459 million in net losses that represent reversals of previously recorded net gains on positions settled in the period, and
- $17 million in net gains related to trading positions, which includes $22 million in net gains from changes in fair value and $5 million in net losses that represent reversals of previously recorded net gains on positions settled in the period.

Realized net gains totaling $459 million included:

- $449 million in net gains related to positions that primarily hedged electricity revenues recognized in the period, and
- $10 million in net gains related to trading positions

Year Ended December 31, 2008 — Unrealized mark-to-market net gains totaling $2.281 billion included:

- $2.324 billion in net gains related to hedge positions, which includes $2.282 billion in net gains from changes in fair value and $42 million in net gains that represent reversals of previously recorded fair values of positions settled in the period;
- $68 million in "day one" net losses related to large hedge positions (see Note 17 to Financial Statements), and
- $25 million in net gains related to trading positions, which includes $76 million in net gains from changes in fair value and $51 million in net losses that represent reversals of previously recorded fair values of positions settled in the period.

Realized net losses totaling $97 million included:

- $177 million in net losses related to hedge positions that primarily offset hedged electricity revenues and fuel and purchased power costs recognized in the period, and
- $80 million in net gains related to trading positions.

Unrealized gains and losses that are related to physically settled derivative commodity contracts and are reported as revenues and purchased power costs, as required by accounting rules, totaled $52 million in net losses in 2009 and $48 million in net gains in 2008.

Operating costs increased $16 million, or 2%, to $693 million in 2009 driven by $28 million in costs related to the new lignite-fueled generation facilities. The change also reflected $19 million in higher maintenance costs incurred during planned and unplanned lignite-fueled generation unit outages in 2009 that was more than offset by the $31 million effect of two planned nuclear generation unit outages in 2008 as compared to one in 2009.

Depreciation and amortization increased $80 million, or 7%, to $1.172 billion in 2009. The increase was driven by $39 million in higher amortization expense related to the intangible asset representing retail customer relationships recorded in purchase accounting and $24 million due to the placement in service of two new generation units and related mining assets. Increased lignite generation unit depreciation as a result of normal capital additions as well as adjustments to useful lives of components was partially offset by lower natural gas generation unit depreciation resulting from an impairment in 2008.

SG&A expenses increased $59 million, or 9%, to $741 million in 2009. The increase reflected $36 million in higher retail bad debt expense, reflecting higher delinquencies due to delays in final bills and disconnects resulting from a system conversion, customer losses and general economic conditions. The increase also reflected higher employee related expenses, the implementation of a new retail customer information management system and the transition of certain previously outsourced customer operations, partially offset by $13 million in lower fees associated with the sale of receivables program.

See Note 4 to Financial Statements for discussion of the impairments of goodwill of $70 million in 2009 and $8.0 billion in 2008.

Other income totaled $59 million in 2009 and $34 million in 2008. The 2009 amount included a $23 million reversal of a use tax accrual, an $11 million reversal of exit liabilities recorded in connection with the termination of outsourcing arrangements (see Note 19 to Financial Statements), a $6 million fee received related to an interest rate swap/commodity hedge derivative agreement, $5 million in royalty income and $5 million in sales/use tax refunds. The 2008 amount included an insurance recovery of $21 million and $4 million in royalty income See Note 9 to Financial Statements for more details.

Other deductions totaled $68 million in 2009 and $1.274 billion in 2008. The 2009 amount included $34 million in charges for the impairment of land expected to be sold within the next 12 months, $7 million in charges for severance and other individually immaterial miscellaneous expenses. The 2008 amount included $501 million in impairment charges related to NO_x and SO_2 environmental allowances intangible assets and $481 million related to trade name intangible assets, both discussed in Note 4 to Financial Statements, $229 million in impairment charges related to the natural gas-fueled generation facilities discussed in Note 5 to Financial Statements and $26 million in charges to reserve for net receivables (excluding termination related costs) from terminated hedging transactions with subsidiaries of Lehman Brothers Holdings Inc., which filed for bankruptcy under Chapter 11 of the US Bankruptcy Code. See Note 9 to Financial Statements for more details.

Interest expense and related charges decreased $2.064 billion, or 51%, to $1.946 billion in 2009. The decrease reflected a $696 million unrealized mark-to-market net gain related to interest rate swaps in 2009 compared to a $1.477 billion net loss in 2008, partially offset by $118 million in increased noncash amortization of losses on interest rate swaps dedesignated as cash flow hedges in August 2008.

Income tax expense totaled $407 million in 2009 compared to an income tax benefit totaling $450 million in 2008. Excluding the impacts of the goodwill impairment of $70 million in 2009 and $8.0 billion in 2008, the effective income tax rate was 36.7% in 2009 and 32.6% in 2008. (These nondeductible charges distort the comparison; therefore, they have been excluded for purposes of a more meaningful discussion.) The increase in the rate reflects the effect of interest accrued for uncertain tax positions, which increased the rate on income in 2009 and decreased the rate on a loss in 2008.

After-tax results for the segment improved $9.560 billion to net income of $631 million in 2009, reflecting the 2008 impairment of goodwill, the 2008 impairment charges reported in other deductions and the change in unrealized mark-to-market values of interest rate swaps reported in interest expense, partially offset by lower net gains from commodity hedging and trading activities driven by lower unrealized mark-to-market net gains.

Regulated Delivery Segment

The following tables present financial operating results of the Regulated Delivery segment for the years ended December 31, 2009 and 2008. Comparative segment results for the years ended December 31, 2010 and 2009 are discussed above with consolidated results of equity in earnings of unconsolidated subsidiaries. Effective January 1, 2010, Oncor (and its majority owner, Oncor Holdings) was deconsolidated as a result of amended consolidation accounting standards related to variable interest entities (see Note 3 to Financial Statements)

Financial Results

	Year Ended December 31,	
	2009	2008
Operating revenues	$ 2,690	$ 2,580
Operating costs	(908)	(828)
Depreciation and amortization	(557)	(492)
Selling, general and administrative expenses	(194)	(164)
Franchise and revenue-based taxes	(250)	(255)
Impairment of goodwill	—	(860)
Other income	49	45
Other deductions	(34)	(19)
Interest income	43	45
Interest expense and related charges	(346)	(317)
Income (loss) before income taxes	493	(265)
Income tax expense (a)	(173)	(221)
Net income (loss)	$ 320	$ (486)

(a) Effective with the sale of noncontrolling interests (see Note 14 to Financial Statements), Oncor is taxed as a partnership and thus not subject to income taxes; however, subsequent to the sale, Oncor reflects a "provision in lieu of income taxes," and the results of segments are evaluated as if they file their own income tax returns.

Operating Data

	Year Ended December 31, 2009	2008
Operating statistics – volumes:		
Electric energy billed volumes (GWh)	103,376	107,828
Reliability statistics (a):		
System Average Interruption Duration Index (SAIDI) (nonstorm)	84.5	85.4
System Average Interruption Frequency Index (SAIFI) (nonstorm)	1.1	1.1
Customer Average Interruption Duration Index (CAIDI) (nonstorm)	77.2	74.7
Electric points of delivery (end of period and in thousands):		
Electricity distribution points of delivery (based on number of meters)	3,145	3,123
Operating revenues:		
Electricity distribution revenues (b):		
Affiliated (TCEH)	$ 1,017	$ 998
Nonaffiliated	1,339	1,264
Total distribution revenues	2,356	2,262
Third-party transmission revenues	299	280
Other miscellaneous revenues	35	38
Total operating revenues	$ 2,690	$ 2,580

(a) SAIDI is the average number of minutes electric service is interrupted per consumer in a year. SAIFI is the average number of electric service interruptions per consumer in a year. CAIDI is the average duration in minutes per electric service interruption in a year. The statistics presented are based on the preceding twelve months' data.

(b) Includes transition charge revenue associated with the issuance of securitization bonds totaling $147 million and $140 million for the years ended December 31, 2009 and 2008, respectively. Also includes disconnect/reconnect fees and other discretionary revenues for services requested by REPs.

Regulated Delivery Segment — Financial Results — Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

Operating revenues increased $110 million, or 4%, to $2.690 billion in 2009. The increase reflected:

- $55 million from increased distribution tariffs, including the August 2009 rate review order;
- $28 million from a surcharge to recover advanced metering deployment costs and $11 million from a surcharge to recover additional energy efficiency costs, both of which became effective with the January 2009 billing cycle;
- $20 million in higher transmission revenues reflecting rate increases to recover ongoing investment in the transmission system;
- an estimated $14 million impact from growth in points of delivery;
- $9 million performance bonus for meeting PUCT energy efficiency targets, and
- $7 million in higher charges to REPs related to transition bonds (with an offsetting increase in amortization of the related regulatory asset),

partially offset by an estimated $27 million in lower average consumption primarily due to the effects of milder weather and general economic conditions and $7 million due to less requested REP discretionary and third-party maintenance services.

Operating costs increased $80 million, or 10%, to $908 million in 2009. The increase reflected $45 million in higher fees paid to other transmission entities, $21 million in additional expense recognition as a result of the PUCT's August 2009 final order in the rate review (see discussion immediately below) and $10 million in costs related to programs designed to improve customer electricity demand efficiency, the majority of which are reflected in the revenue increases discussed above.

Under accounting rules for rate regulated utilities, certain costs are deferred as regulatory assets (see Note 24 to Financial Statements) when incurred and are recognized as expense when recovery of the costs are allowed in revenue under regulatory approvals. Accordingly, beginning in September 2009, the effective date of the new tariffs resulting from the rate review, Oncor began to amortize as operating costs or SG&A expenses certain costs previously deferred as regulatory assets over the recoverability period under the rate review order and recognized higher costs related to the current period. The additional expense recognized included $14 million related to storm recovery costs and $10 million related to pension and OPEB costs (including $3 million reported in SG&A expense).

Depreciation and amortization increased $65 million, or 13%, to $557 million in 2009. The increase reflected $34 million in higher depreciation due to ongoing investments in property, plant and equipment (including $11 million related to advanced meters), $24 million due to increased depreciation and amortization rates implemented upon the PUCT approval of new tariffs in September 2009 and $7 million in higher amortization of regulatory assets associated with securitization bonds (with an offsetting increase in revenues).

SG&A expenses increased $30 million, or 18%, to $194 million in 2009. The increase reflected $12 million related to advanced meters and $3 million in additional expense recognition as a result of the PUCT's final order in the rate review, both of which have related revenue increases, $8 million in higher professional and contractor fees driven by outsourcing transition and CREZ development activities and $6 million in higher costs related to employee benefit plans, partially offset by a $3 million one-time reversal of bad debt expense due to the PUCT's finalization of the Certification of Retail Electric Providers rule in April 2009. Write-offs of uncollectible amounts owed by nonaffiliated REPs are deferred as a regulatory asset.

Taxes other than amounts related to income taxes decreased $5 million, or 2%, to $250 million in 2009 reflecting a decrease in local franchise fees due to decreased volumes of electricity delivered.

See Note 4 to Financial Statements for a discussion of the $860 million goodwill impairment charge recorded in 2008.

Other income totaled $49 million in 2009 and $45 million in 2008. The 2009 and 2008 amounts included accretion of an adjustment (discount) to regulatory assets resulting from purchase accounting totaling $39 million and $44 million, respectively. The 2009 amount also included $10 million due to the reversal of exit liabilities recorded in purchase accounting related to the termination of outsourcing arrangements. See Note 19 to Financial Statements.

Other deductions totaled $34 million in 2009 and $19 million in 2008 The 2009 amount included a $25 million write off of regulatory assets (see Note 24 to Financial Statements). The 2009 and 2008 amounts included costs totaling $2 million and $13 million, respectively, associated with a rate settlement with certain cities in 2006.

Interest income decreased $2 million, or 4%, to $43 million in 2009. The decrease reflected $4 million in lower reimbursement of transition bond interest from TCEH due to lower remaining principal amounts of the bonds and $2 million in lower interest income on temporary cash investments and restricted cash due to lower interest rates, partially offset by $4 million in higher earnings on investments held for certain employee benefit plans.

Interest expense and related charges increased $29 million, or 9%, to $346 million in 2009. The increase reflected $17 million in higher average borrowings, reflecting ongoing capital investments. The increase also reflected $12 million due to higher average interest rates, which was driven by refinancing of short-term borrowings with $1.5 billion of senior secured notes issued in September 2008. The majority of the proceeds of the September 2008 notes issuance was used to pay outstanding short-term borrowings under Oncor's credit facility.

Income tax expense totaled $173 million in 2009 compared to $221 million in 2008. The effective rate decreased to 35.1% in 2009 from 37.2% in 2008, excluding the impact of the $860 million goodwill impairment in 2008. (This nondeductible charge distorts the comparison; therefore, it has been excluded for purposes of a more meaningful discussion.) The decrease in the rate was driven by the reversal of accrued interest due to the favorable resolution of uncertain tax positions.

Net income for 2009 totaled $320 million and net loss for 2008 totaled $486 million. The change reflects the $860 million goodwill impairment charge recorded in 2008, as well as $53 million in lower results in 2009 driven by the effect of lower average consumption on revenues, the write-off of certain regulatory assets and increased interest expense.

Energy-Related Commodity Contracts and Mark-to-Market Activities

The table below summarizes the changes in commodity contract assets and liabilities for the periods presented. The net changes in these assets and liabilities, excluding "other activity" as described below, represent the pretax effect on earnings of positions in the commodity contract portfolio that are marked-to-market in net income (see Note 17 to Financial Statements). The portfolio consists primarily of economic hedges but also includes trading positions.

	Year Ended December 31,		
	2010	2009	2008
Commodity contract net asset (liability) as of beginning of period	$ 1,718	$ 430	$ (1,917)
Settlements of positions (a)	(943)	(518)	39
Changes in fair value (b)	2,162	1,741	2,294
Other activity (c)	160	65	14
Commodity contract net asset as of end of period	$ 3,097	$ 1,718	$ 430

(a) Represents reversals of previously recognized unrealized gains and losses upon settlement (offsets realized gains and losses recognized in the settlement period).

(b) Represents unrealized gains and losses recognized, primarily related to positions in the long-term hedging program (see discussion above under "Long-Term Hedging Program"). Includes gains and losses recorded at contract inception dates (see Note 17 to the Financial Statements).

(c) The 2010 amount includes a $116 million noncash gain on termination of a long-term power sales contract. Includes amounts related to options purchased and sold and physical natural gas exchange transactions.

Unrealized gains and losses related to commodity contracts are summarized as follows:

	Year Ended December 31,		
	2010	2009	2008
Unrealized gains (losses) related to contracts marked-to-market	$ 1,219	$ 1,223	$ 2,333
Ineffectiveness gains (losses) related to cash flow hedges	2	2	(4)
Total unrealized gains (losses) related to commodity contracts	$ 1,221	$ 1,225	$ 2,329

Table of Contents

Maturity Table — The following table presents the net commodity contract asset arising from recognition of fair values under mark-to-market accounting as of December 31, 2010, scheduled by the source of fair value and contractual settlement dates of the underlying positions.

	Maturity dates of unrealized commodity contract asset as of December 31, 2010				
Source of fair value	**Less than 1 year**	**1-3 years**	**4-5 years**	**Excess of 5 years**	**Total**
Prices actively quoted	$ (139)	$ (9)	$ —	$ —	$ (148)
Prices provided by other external sources	1,248	1,655	—	—	2,903
Prices based on models	(7)	(21)	370	—	342
Total	$ 1,102	$ 1,625	$ 370	$ —	$ 3,097
Percentage of total fair value	36%	52%	12%	— %	100%

The "prices actively quoted" category reflects only exchange traded contracts for which active quotes are readily available. The "prices provided by other external sources" category represents forward commodity positions valued using prices for which over-the-counter broker quotes are available in active markets. Over-the-counter quotes for power in ERCOT that are deemed active markets (excluding the West hub) generally extend through 2013 and over-the-counter quotes for natural gas generally extend through 2015, depending upon delivery point. The "prices based on models" category contains the value of all nonexchange traded options, valued using option pricing models. In addition, this category contains other contractual arrangements that may have both forward and option components, as well as other contracts that are valued using proprietary long-term pricing models that utilize certain market based inputs. See Note 15 to Financial Statements for fair value disclosures and discussion of fair value measurements.

COMPREHENSIVE INCOME

Cash flow hedge activity reported in other comprehensive income included (all amounts after-tax):

	Year Ended December 31,		
	2010	2009	2008
Net decrease in fair value of cash flow hedges:			
Commodities	$ —	$ (20)	$ (8)
Financing – interest rate swaps	—	—	(175)
	—	(20)	(183)
Derivative value net losses reported in net income that relate to hedged transactions recognized in the period:			
Commodities	1	11	11
Financing – interest rate swaps	58	119	111
	59	130	122
Total income (loss) effect of cash flow hedges reported in other comprehensive income	$ 59	$ 110	$ (61)

We have historically used, and expect to continue to use, derivative instruments that are effective in offsetting future cash flow variability in interest rates and energy commodity prices, but as of December 31, 2010 and 2009, there were no such instruments accounted for as cash flow or fair value hedges. Amounts in accumulated other comprehensive income include the value of dedesignated and terminated cash flow hedges at the time of such dedesignation/ termination, less amounts reclassified to earnings as the original hedged transactions are recognized, unless the hedged transactions become probable of not occurring. The effects of the hedge will be recorded in the statement of income as the hedged transactions are actually settled and affect earnings. Also see Note 17 to Financial Statements.

FINANCIAL CONDITION

Liquidity and Capital Resources

Operating Cash Flows

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009 — Cash provided by operating activities declined $605 million to $1.106 billion in 2010. The deconsolidation of Oncor in 2010 reduced reported cash provided by operating activities by $932 million. The decrease also reflected a $350 million effect of the amended accounting standard related to the accounts receivable securitization program (see Note 10 to Financial Statements), under which the $383 million of funding under the program upon the January 1, 2010 adoption is reported as a use of operating cash flows and a source of financing cash flows, with subsequent 2010 activity reported as financing, and the $33 million decline in funding in 2009 is reported as use of operating cash flows. These accounting effects were partially offset by improved working capital performance, particularly in retail accounts receivable due to the effects in 2009 of implementing a new customer information management system and more timely collections in 2010, as well as higher cash earnings from the competitive business driven by the contribution of the new generation units.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008 — Cash provided by operating activities totaled $1.711 billion and $1.505 billion in 2009 and 2008, respectively. The $206 million increase reflected:

- a $489 million decrease in cash interest paid due to the payment of approximately $465 million of interest with an increase in toggle notes instead of cash as discussed under "Toggle Notes Interest Election" below, and
- a $57 million favorable impact of timing of advanced metering surcharges,

partially offset by a $347 million decrease in net margin deposits received primarily due to the effects of forward natural gas prices on positions in the long-term hedging program.

Depreciation and amortization expense reported in the statement of cash flows exceeded the amount reported in the statement of income by $371 million, $418 million and $460 million for the years ended December 31, 2010, 2009 and 2008, respectively. The difference represented amortization of nuclear fuel, which is reported as fuel costs in the statement of income consistent with industry practice, and amortization of intangible net assets and debt fair value discounts arising from purchase accounting that is reported in various other income statement line items including operating revenues, fuel and purchased power costs and delivery fees, other income and interest expense and related charges.

Financing Cash Flows

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009 — Cash used in financing activities totaled $264 million in 2010 compared to cash provided of $422 million in 2009. The $686 million change was driven by debt repurchases under our liability management program (see Note 11 to Financial Statements), partially offset by the effect of the amended accounting standard related to the accounts receivable securitization program (see Note 10 to Financial Statements), under which the $96 million of funding under the program in 2010 is reported as financing cash flows.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008 — Cash provided by financing activities totaled $422 million and $2.837 billion in 2009 and 2008, respectively. The $2.415 billion decrease was driven by $1.253 billion in net proceeds from the sale of noncontrolling interests in 2008 (see Note 14 to Financial Statements) and reduced borrowings in 2009 related to the construction of new generation facilities, which were nearing completion.

See Note 11 to Financial Statements for further detail of short-term borrowings and long-term debt.

Table of Contents

Investing Cash Flows

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009 — Cash used in investing activities totaled $468 million and $2.633 billion in 2010 and 2009, respectively. Capital expenditures (excluding nuclear fuel) totaled $838 million and $2.348 billion in 2010 and 2009, respectively. The $1.510 billion decline in capital spending reflected the deconsolidation of Oncor ($998 million capital expenditures in 2009) (see Note 3 to Financial Statements) in 2010 and a decrease in spending related to the construction of the now complete new generation facilities. The decline in cash used in investing activities also reflected a $400 million cash investment posted with a derivative counterparty in 2009 that was returned in 2010.

Capital expenditures in 2010 consisted of:

- $487 million for major maintenance, primarily in existing generation operations;
- $140 million related to completion of the construction of a second generation unit and mine development at Oak Grove;
- $106 million for environmental expenditures related to existing generation units;
- $42 million for information technology and other corporate investments;
- $34 million related to nuclear generation development, and
- $29 million primarily related to the new retail customer information system.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008 — Cash used in investing activities totaled $2.633 billion and $2.934 billion in 2009 and 2008, respectively, including capital expenditures totaling $2.348 billion and $2.849 billion, respectively. The decline in capital spending primarily reflected a decrease in spending related to the construction of the new generation facilities, partially offset by capital expenditures in the regulated business for advanced metering deployment and CREZ.

Debt Financing Activity — Activities related to short-term borrowings and long-term debt during the year ended December 31, 2010 are as follows (all amounts presented are principal, and repayments and repurchases include amounts related to capital leases and exclude amounts related to debt discount, financing and reacquisition expenses):

	Borrowings (a)	Repayments and Repurchases (b)
TCEH	$ 1,779	$ 2,758
EFCH	—	9
EFIH	2,180	—
EFH Corp.	1,255	4,444
Total long-term	5,214	7,211
Total short-term – TCEH (c)	172	—
Total	$ 5,386	$ 7,211

(a) Includes the following activities (see Note 11 to Financial Statements):
- $500 million of EFH Corp. 10% Notes issued by EFH Corp., the proceeds of which may be used in debt exchanges or repurchases.
- $350 million of TCEH 15% Notes issued by TCEH, the net proceeds from which were used to repurchase TCEH Senior Notes.
- Principal increases in payment of accrued interest totaling $194 million and $205 million of EFH Corp. and TCEH Toggle Notes, respectively.
- $561 million of EFH Corp. 10% Notes issued by EFH Corp. in debt exchanges.
- $2.180 billion of EFIH 10% Notes issued by EFIH in debt exchanges.
- $1.221 billion of TCEH 15% Notes issued by TCEH in debt exchanges

(b) Includes $5.862 billion of noncash retirements (including discounts captured on cash repurchases) as a result of 2010 debt exchange and repurchase transactions discussed in Note 11 to Financial Statements.

(c) Short-term amounts represent net borrowings/repayments.

See Note 11 to Financial Statements for further detail of long-term debt and other financing arrangements.

We regularly monitor the capital and bank credit markets for liability management opportunities that we believe will improve our balance sheet, including capturing debt discount and extending debt maturities. As a result, we may engage, from time to time, in liability management transactions. Future activities under the liability management program may include the purchase of our outstanding debt for cash in open market purchases or privately negotiated transactions (including pursuant to a Section 10b-5(1) plan) or via public or private exchange or tender offers. Moreover, as part of our liability management program, we may refinance our existing debt, including the TCEH Senior Secured Credit Facilities.

In evaluating whether to undertake any liability management transaction, including any refinancing, we will take into account liquidity requirements, prospects for future access to capital, contractual restrictions, the market price of our outstanding debt and other factors. Any liability management transaction, including any refinancing, may occur on a stand-alone basis or in connection with, or immediately following, other liability management transactions.

Available Liquidity — The following table summarizes changes in available liquidity for the year ended December 31, 2010 (excluding Oncor):

	Available Liquidity					
	December 31, 2010		December 31, 2009		Change	
Cash and cash equivalents	$	1,534	$	1,161	$	373
TCEH Revolving Credit Facility (a)		1,440		1,721		(281)
TCEH Letter of Credit Facility		261		399		(138)
Subtotal	$	3,235	$	3,281	$	(46)
Short-term investment (b)		—		490		(490)
Total liquidity (c)	$	3,235	$	3,771	$	(536)

(a) As of December 31, 2010 and 2009, the TCEH Revolving Credit Facility includes $94 million and $141 million, respectively, of commitments from Lehman that are only available from the fronting banks and the swingline lender.

(b) December 31, 2009 amount includes $425 million cash investment (including accrued interest) and $65 million in letters of credit posted related to certain interest rate and commodity hedge transactions. Pursuant to the related agreement, the collateral was returned in March 2010. See Note 17 to Financial Statements.

(c) As of December 31, 2010 and 2009, total liquidity includes $465 million and $333 million, respectively, of net receipts of margin deposits from counterparties related to commodity positions (net of $166 million and $187 million, respectively, posted with counterparties).

Note: Available liquidity in the future could benefit from additional exercises of the payment-in-kind (PIK) option on the EFH Corp. Toggle Notes and TCEH Toggle Notes, which for the remaining payment dates from May 2011 through November 2012 would avoid cash interest payments of approximately $424 million.

See Note 11 to Financial Statements for additional discussion of the credit facilities.

The $536 million decrease in available liquidity reflected the impact of the liability management program and an increase in letters of credit posted as collateral support with ERCOT in conjunction with ERCOT's transition to a nodal wholesale market structure.

Pension and OPEB Plan Funding — Pension and OPEB plan funding is expected to total $175 million and $26 million, respectively, in 2011. Based on the funded status of the pension plan as of December 31, 2010, funding is expected to total $932 million for the 2011 to 2015 period. The increase in funding reflects requirements under the Pension Protection Act of 2006, which were impacted by the effect of lower interest rates in the computation of our pension liability. Oncor is expected to fund 72% of this amount consistent with its share of the pension liability. We made pension and OPEB contributions of $45 million and $25 million, respectively, in 2010, of which $58 million was contributed by Oncor.

See Note 20 to Financial Statements for more information regarding the pension and OPEB plans, including the funded status of the plans as of December 31, 2010.

Toggle Notes Interest Election — EFH Corp. and TCEH have the option every six months at their discretion, ending with the interest payment due November 2012, to use the payment-in-kind (PIK) feature of their respective toggle notes in lieu of making cash interest payments. We elected to do so beginning with the May 2009 interest payment as an efficient and cost-effective method to further enhance liquidity. Once EFH Corp. and/or TCEH make a PIK election, the election is valid for each succeeding interest payment period until EFH Corp. and/or TCEH revoke the applicable election. Use of the PIK feature will be evaluated at each election period, taking into account market conditions and other relevant factors at such time.

EFH Corp made its 2010 and 2009 interest payments and will make its May 2011 interest payment on the EFH Corp. Toggle Notes by using the PIK feature of those notes. During such applicable interest periods, the interest rate on these notes is increased from 11.25% to 12.00%. EFH Corp increased the aggregate principal amount of the notes by $194 million in 2010 (excluding $130 million principal amount issued to EFIH as holder of $2.166 billion principal amount of EFH Corp. Toggle Notes acquired in the debt exchange completed in August 2010 that is eliminated in consolidation) and $309 million in 2009 and is expected to further increase the aggregate principal amount of the notes by $34 million in May 2011 (excluding $138 million principal amount expected to be issued to EFIH). The elections increased liquidity in 2010 by an amount equal to $182 million (excluding $122 million related to notes held by EFIH) and is expected to further increase liquidity in May 2011 by an amount equal to a currently estimated $32 million (excluding $129 million related to notes held by EFIH), constituting the amounts of cash interest that otherwise would have been payable on the notes.

Similarly, TCEH made its 2010 and 2009 interest payments and will make its May 2011 interest payment on the TCEH Toggle Notes by using the PIK feature of those notes. During the applicable interest periods, the interest rate on the notes is increased from 10.50% to 11.25%. TCEH increased the aggregate principal amount of the notes by approximately $212 million in 2010, including $7 million principal amount paid to EFH Corp. and eliminated in consolidation, and $202.5 million in 2009 and is expected to further increase the aggregate principal amount of the notes by $79 million in May 2011. The elections increased liquidity in 2010 by an amount equal to $198 million and is expected to further increase liquidity in May 2011 by an amount equal to an estimated $74 million, constituting the amounts of cash interest that otherwise would have been payable on the notes.

Liquidity Effects of Commodity Hedging and Trading Activities — Commodity hedging and trading transactions typically require a counterparty to post collateral if the forward price of the underlying commodity moves such that the hedging or trading instrument held by such counterparty has declined in value. TCEH uses cash, letters of credit, asset-backed liens and other forms of credit support to satisfy such collateral obligations. In addition, TCEH's Commodity Collateral Posting Facility (CCP facility), an uncapped senior secured revolving credit facility that matures in December 2012, funds the cash collateral posting requirements for a significant portion of the positions in the long-term hedging program not otherwise secured by a first-lien in the assets of TCEH. The aggregate principal amount of the CCP facility is determined by the exposure arising from higher forward market prices, regardless of the amount of such exposure, on a portfolio of certain natural gas hedging transaction volumes. Including those hedging transactions where margin deposits are covered by unlimited borrowings under the CCP facility, as of December 31, 2010, more than 95% of the long-term natural gas hedging program transactions were secured by a first-lien interest in the assets of TCEH that is pari passu with the TCEH Senior Secured Facilities, the effect of which is a significant reduction in the liquidity exposure associated with collateral requirements for those hedging transactions. Due to declines in forward natural gas prices, no amounts were borrowed against the CCP facility at December 31, 2010 and 2009. See Note 11 to Financial Statements for more information about the TCEH Senior Secured Facilities, which includes the CCP facility.

As of December 31, 2010, TCEH received or posted cash and letters of credit for commodity hedging and trading activities as follows:

- $165 million in cash has been posted with counterparties for exchange cleared transactions (including initial margin), as compared to $183 million posted as of December 31, 2009;
- $630 million in cash has been received from counterparties, net of $1 million in cash posted, for over-the-counter and other non-exchange cleared transactions, as compared to $516 million received, net of $4 million in cash posted, as of December 31, 2009;
- $473 million in letters of credit have been posted with counterparties, as compared to $379 million posted as of December 31, 2009, and
- $25 million in letters of credit have been received from counterparties, as compared to $44 million received as of December 31, 2009.

With respect to exchange cleared transactions, these transactions typically require initial margin (i.e., the upfront cash and/or letter of credit posted to take into account the size and maturity of the positions and credit quality) in addition to variance margin (i.e., the daily cash margin posted to take into account changes in the value of the underlying commodity). The amount of initial margin required is generally defined by exchange rules. Clearing agents, however, typically have the right to request additional initial margin based on various factors including market depth, volatility and credit quality, which may be in the form of cash, letters of credit, a guaranty or other forms as negotiated with the clearing agent. With respect to cash collateral that is received, such cash collateral is either used for working capital and other corporate purposes, including reducing short-term borrowings under credit facilities, or it is required to be deposited in a separate account and restricted from being used for working capital and other corporate purposes. With respect to over-the-counter transactions, counterparties generally have the right to substitute letters of credit for such cash collateral. In such event, the cash collateral previously posted would be returned to such counterparties thereby reducing liquidity in the event that it was not restricted. As of December 31, 2010, restricted cash collateral held totaled $33 million. See Note 24 to Financial Statements regarding restricted cash.

With the long-term hedging program, increases in natural gas prices generally result in increased cash collateral and letter of credit postings to counterparties. As of December 31, 2010, approximately 300 million MMBtu of positions related to the long-term hedging program were not directly secured on an asset-lien basis and thus have cash collateral posting requirements. The uncapped CCP facility supports the collateral posting requirements related to most of these transactions.

Interest Rate Swap Transactions — See Note 11 to Financial Statements for TCEH interest rate swaps entered into as of December 31, 2010.

Income Tax Refunds/Payments — Income tax payments related to the Texas margin tax are expected to total approximately $65 million, and net refunds of federal income taxes are expected to total approximately $57 million in the next 12 months. Payments in the year ended December 31, 2010 totaled $64 million. In 2009, we received a refund totaling $98 million in income taxes and related interest related to IRS audits of 1993 and 1994 income tax returns and made net payments totaling approximately $44 million related to the Texas margin tax. In 2008, we received net federal income tax refunds of $229 million, including $98 million related to 2007 tax payments and $142 million related to a net operating loss carryback to the 2006 tax year.

As discussed in Note 7 to Financial Statements, we assess uncertain tax positions under a "more-likely-than-not" standard. We cannot reasonably estimate the ultimate amounts and timing of tax payments associated with uncertain tax positions, but expect that no material federal income tax payments related to such positions will be made in 2011.

Accounts Receivable Securitization Program — TXU Energy participates in EFH Corp.'s accounts receivable securitization program with financial institutions (the funding entities). As discussed in Note 1 to Financial Statements, in accordance with amended transfers and servicing accounting standards, the trade accounts receivable amounts under the program are reported as pledged balances and the related funding amounts are reported as short-term borrowings. Under the program, TXU Energy (originator) sells retail trade accounts receivable to TXU Receivables Company, a consolidated wholly-owned bankruptcy-remote direct subsidiary of EFH Corp., which sells undivided interests in the purchased accounts receivable for cash to entities established for this purpose by the funding entities. All new trade receivables under the program generated by the originator are continuously purchased by TXU Receivables Company with the proceeds from collections of receivables previously purchased. Funding under the program totaled $96 million and $383 million as of December 31, 2010 and 2009, respectively. See Note 10 to Financial Statements for a more complete description of the program including amendments to the program in June 2010 and a related reduction in funding, the impact of the program on the financial statements for the periods presented and the contingencies that could result in termination of the program and a reduction of liquidity should the underlying financing be settled.

Liquidity Needs, Including Capital Expenditures — Capital expenditures, including capitalized interest, for 2011 are expected to total approximately $700 million and include:

- $525 million for investments in TCEH generation facilities, including approximately:
  - $450 million for major maintenance, primarily in generation operations, and
  - $75 million for environmental expenditures related to generation units (a);
- $125 million for nuclear fuel purchases, and
- $50 million for information technology and other corporate investments.

(a) Expenditures are classified as environmental in nature if the projects are the direct result of environmental regulations.

We expect cash flows from operations combined with availability under our credit facilities discussed in Note 11 to Financial Statements to provide sufficient liquidity to fund our current obligations, projected working capital requirements and capital spending for a period that includes the next twelve months.

Distributions from Oncor — Until December 31, 2012, distributions paid by Oncor to its members are limited to an amount not to exceed Oncor's net income determined in accordance with GAAP, subject to certain defined adjustments. Distributions are further limited by an agreement that Oncor's regulatory capital structure, as determined by the PUCT, will be at or below the assumed debt-to-equity ratio established periodically by the PUCT for ratemaking purposes, which is currently set at 60% debt to 40% equity. (See Note 13 to Financial Statements.) Also, see "Regulatory Matters — Oncor Matters with the PUCT" for discussion of a rate review filed by Oncor in January 2011 that, among other things, requests a revised regulatory capital structure of 55% debt to 45% equity.

In January 2009, the PUCT awarded certain CREZ construction projects to Oncor. See discussion below under "Regulatory Matters – Oncor Matters with the PUCT." As a result of the increased capital expenditures for CREZ and the debt-to-equity ratio cap, we expect distributions to EFH Corp. from Oncor will be substantially reduced or temporarily discontinued during the CREZ construction period, which is expected to be completed in 2013

Capitalization — Our capitalization ratios consisted of 120.9% and 104.6% long-term debt, less amounts due currently, and (20.9)% and (4.6)% common stock equity, as of December 31, 2010 and 2009, respectively. Total debt to capitalization, including short-term debt, was 119.6% and 104.4% as of December 31, 2010 and 2009, respectively.

Financial Covenants, Credit Rating Provisions and Cross Default Provisions — The terms of certain of our financing arrangements contain maintenance covenants with respect to leverage ratios and/or minimum net worth. As of December 31, 2010, we were in compliance with all such maintenance covenants.

Covenants and Restrictions under Financing Arrangements — Each of the TCEH Senior Secured Facilities and the indentures governing substantially all of the debt we have issued in connection with, and subsequent to, the Merger contain covenants that could have a material impact on the liquidity and operations of EFH Corp. and its subsidiaries.

Adjusted EBITDA (as used in the restricted payments covenant contained in the indenture governing the EFH Corp. Senior Secured Notes) for the year ended December 31, 2010 totaled $5.240 billion for EFH Corp. See Exhibits 99(b), 99(c) and 99(d) for a reconciliation of net income to Adjusted EBITDA for EFH Corp., TCEH and EFIH, respectively, for the years ended December 31, 2010 and 2009.

The table below summarizes TCEH's secured debt to Adjusted EBITDA ratio under the maintenance covenant in the TCEH Senior Secured Facilities and various other financial ratios of EFH Corp., EFIH and TCEH that are applicable under certain other threshold covenants in the TCEH Senior Secured Facilities and the indentures governing the TCEH Senior Notes, the TCEH Senior Secured Second Lien Notes (for 2010), the EFH Corp Senior Notes, the EFH Corp. Senior Secured Notes and the EFIH Notes as of December 31, 2010 and 2009. The debt incurrence and restricted payments/limitations on investments covenants thresholds described below represent levels that must be met in order for EFH Corp., EFIH or TCEH to incur certain permitted debt or make certain restricted payments and/or investments. EFH Corp. and its consolidated subsidiaries are in compliance with their maintenance covenants.

	December 31, 2010	December 31, 2009	Threshold Level as of December 31, 2010
Maintenance Covenant:			
TCEH Senior Secured Facilities:			
Secured debt to Adjusted EBITDA ratio (a)	5.19 to 1.00	4.76 to 1 00	Must not exceed 6.75 to 1.00 (b)
Debt Incurrence Covenants:			
EFH Corp. Senior Secured Notes:			
EFH Corp. fixed charge coverage ratio	1.3 to 1.0	1.2 to 1.0	At least 2.0 to 1.0
TCEH fixed charge coverage ratio	1.5 to 1.0	1.5 to 1.0	At least 2.0 to 1.0
EFIH Notes:			
EFIH fixed charge coverage ratio (c)	(d)	53 8 to 1.0	At least 2.0 to 1.0
TCEH Senior Notes and TCEH Senior Secured Second Lien Notes:			
TCEH fixed charge coverage ratio	1.5 to 1.0	1.5 to 1.0	At least 2.0 to 1.0
TCEH Senior Secured Facilities:			
TCEH fixed charge coverage ratio	1.5 to 1.0	1.5 to 1 0	At least 2.0 to 1.0
Restricted Payments/Limitations on Investments Covenants:			
EFH Corp. Senior Notes:			
General restrictions (Sponsor Group payments):			
EFH Corp. leverage ratio	8.5 to 1.0	9.4 to 1 0	Equal to or less than 7.0 to 1.0
EFH Corp. Senior Secured Notes:			
General restrictions (non-Sponsor Group payments):			
EFH Corp. fixed charge coverage ratio (e)	1.6 to 1.0	1.4 to 1.0	At least 2.0 to 1.0
General restrictions (Sponsor Group payments):			
EFH Corp. fixed charge coverage ratio (e)	1 3 to 1.0	1.2 to 1.0	At least 2.0 to 1.0
EFH Corp. leverage ratio	8.5 to 1.0	9.4 to 1.0	Equal to or less than 7.0 to 1.0
EFIH Notes:			
General restrictions (non-EFH Corp. payments):			
EFIH fixed charge coverage ratio (c) (f)	23.9 to 1.0	3.9 to 1.0	At least 2 0 to 1.0
General restrictions (EFH Corp payments):			
EFIH fixed charge coverage ratio (c) (f)	(d)	53 8 to 1.0	At least 2.0 to 1.0
EFIH leverage ratio	5.3 to 1.0	4.4 to 1.0	Equal to or less than 6.0 to 1.0
TCEH Senior Notes and TCEH Senior Secured Second Lien Notes.			
TCEH fixed charge coverage ratio	1.5 to 1.0	1.5 to 1.0	At least 2.0 to 1.0
TCEH Senior Secured Facilities:			
Payments to Sponsor Group:			
TCEH total debt to Adjusted EBITDA ratio	7.9 to 1.0	8.4 to 1.0	Equal to or less than 6.5 to 1.0

(a) In accordance with the terms of the TCEH Senior Secured Facilities and as the result of the new Sandow and first Oak Grove generating units achieving average capacity factors of greater than or equal to 70% for the three months ended March 31, 2010, the maintenance covenant as of December 31, 2010 includes Adjusted EBITDA for the units and the proportional amount of outstanding debt under the Delayed Draw Term Loan (see Note 11 to Financial Statements) applicable to the two units.

(b) Threshold level will decrease to a maximum of 6.50 to 1 00 effective December 31, 2011. Calculation excludes secured debt that ranks junior to the TCEH Senior Secured Facilities.

(c) Although EFIH currently meets the fixed charge coverage ratio threshold applicable to certain covenants contained in the indentures governing the EFIH Notes, EFIH's ability to use such thresholds to incur debt or make restricted payments/investments is currently limited by the covenants contained in the EFH Corp. Senior Notes and the EFH Corp. Senior Secured Notes.

(d) EFIH meets the ratio threshold. Because EFIH's interest income exceeds interest expense, the result of the ratio calculation is not meaningful.

(e) The EFH Corp. fixed charge coverage ratio for non-Sponsor Group payments includes the results of Oncor Holdings and its subsidiaries. The EFH Corp. fixed charge coverage ratio for Sponsor Group payments excludes the results of Oncor Holdings and its subsidiaries.

(f) The EFIH fixed charge coverage ratio for non-EFH Corp payments includes the results of Oncor Holdings and its subsidiaries. The EFIH fixed charge coverage ratio for EFH Corp. payments excludes the results of Oncor Holdings and its subsidiaries.

0001243

Material Credit Rating Covenants and Credit Worthiness Effects on Liquidity — As a result of TCEH's non-investment grade credit rating and considering collateral thresholds of certain retail and wholesale commodity contracts, as of December 31, 2010, counterparties to those contracts could have required TCEH to post up to an aggregate of $17 million in additional collateral. This amount largely represents the below market terms of these contracts as of December 31, 2010; thus, this amount will vary depending on the value of these contracts on any given day.

Certain transmission and distribution utilities in Texas have tariffs in place to assure adequate credit worthiness of any REP to support the REP's obligation to collect securitization bond-related (transition) charges on behalf of the utility. Under these tariffs, as a result of TCEH's below investment grade credit rating, TCEH is required to post collateral support in an amount equal to estimated transition charges over specified time periods. The amount of collateral support required to be posted, as well as the time period of transition charges covered, varies by utility. As of December 31, 2010, TCEH has posted collateral support in the form of letters of credit to the applicable utilities in an aggregate amount equal to $28 million, with $14 million of this amount posted for the benefit of Oncor.

The PUCT has rules in place to assure adequate credit worthiness of each REP, including the ability to return customer deposits, if necessary. Under these rules, as of December 31, 2010, TCEH posted letters of credit in the amount of $73 million, which are subject to adjustments.

The RRC has rules in place to assure adequate credit worthiness of parties that have mining reclamation obligations. Under these rules, should the RRC determine that the credit worthiness of Luminant Generation Company LLC (a subsidiary of TCEH) is not sufficient to support its reclamation obligations, TCEH may be required to post cash or letter of credit collateral support in an amount currently estimated to be approximately $650 million to $900 million. The actual amount (if required) could vary depending upon numerous factors, including Luminant Generation Company LLC's credit worthiness and the level of mining reclamation obligations.

ERCOT has rules in place to assure adequate credit worthiness of parties that participate in the "day-ahead" and "real-time markets" operated by ERCOT. Under these rules, TCEH has posted collateral support, predominantly in the form of letters of credit, totaling $240 million as of December 31, 2010 (which is subject to weekly adjustments based on settlement activity with ERCOT). This amount includes an increase of approximately $200 million in letters of credit in the fourth quarter 2010 driven by the December 2010 implementation of the nodal wholesale market.

Other arrangements of EFH Corp. and its subsidiaries, including Oncor's credit facility, the accounts receivable securitization program (see Note 10 to Financial Statements) and certain leases, contain terms pursuant to which the interest rates charged under the agreements may be adjusted depending on the relevant credit ratings.

In the event that any or all of the additional collateral requirements discussed above are triggered, we believe we will have adequate liquidity to satisfy such requirements.

Material Cross Default Provisions — Certain financing arrangements contain provisions that may result in an event of default if there were a failure under other financing arrangements to meet payment terms or to observe other covenants that could or does result in an acceleration of payments due. Such provisions are referred to as "cross default" provisions.

A default by TCEH or any of its restricted subsidiaries in respect of indebtedness, excluding indebtedness relating to the accounts receivable securitization program, in an aggregate amount in excess of $200 million may result in a cross default under the TCEH Senior Secured Facilities. Under these facilities, such a default will allow the lenders to accelerate the maturity of outstanding balances ($22.304 billion as of December 31, 2010) under such facilities.

The indentures governing the TCEH Senior Notes and the TCEH Senior Secured Second Lien Notes contain a cross acceleration provision where a payment default at maturity or on acceleration of principal indebtedness under any instrument or instruments of TCEH or any of its restricted subsidiaries in an aggregate amount equal to or greater than $250 million may cause the acceleration of the TCEH Senior Notes and TCEH Senior Secured Second Lien Notes.

Under the terms of a TCEH rail car lease, which had $45 million in remaining lease payments as of December 31, 2010 and terminates in 2017, if TCEH failed to perform under agreements causing its indebtedness in aggregate principal amount of $100 million or more to become accelerated, the lessor could, among other remedies, terminate the lease and effectively accelerate the payment of any remaining lease payments due under the lease.

Under the terms of another TCEH rail car lease, which had $50 million in remaining lease payments as of December 31, 2010 and terminates in 2028, if obligations of TCEH in excess of $200 million in the aggregate for payments of obligations to third party creditors under lease agreements, deferred purchase agreements or loan or credit agreements are accelerated prior to their original stated maturity, the lessor could, among other remedies, terminate the lease and effectively accelerate the payment of any remaining lease payments due under the lease.

The indentures governing the EFH Corp. Senior Secured Notes contain a cross acceleration provision whereby a payment default at maturity or on acceleration of principal indebtedness under any instrument or instruments of EFH Corp. or any of its restricted subsidiaries in an aggregate amount equal to or greater than $250 million may cause the acceleration of the EFH Corp. Senior Secured Notes.

The indentures governing the EFIH Notes contain a cross acceleration provision whereby a payment default at maturity or on acceleration of principal indebtedness under any instrument or instruments of EFIH or any of its restricted subsidiaries in an aggregate amount equal to or greater than $250 million may cause the acceleration of the EFIH Notes.

The accounts receivable securitization program contains a cross default provision with a threshold of $200 million that applies in the aggregate to the originator, any parent guarantor of an originator or any subsidiary acting as collection agent under the program. TXU Receivables Company and EFH Corporate Services Company (a direct subsidiary of EFH Corp.), as collection agent, in the aggregate have a cross default threshold of $50,000. If any of the aforementioned defaults on indebtedness of the applicable threshold were to occur, the program could terminate.

We enter into energy-related and financial contracts, the master forms of which contain provisions whereby an event of default or acceleration of settlement would occur if we were to default under an obligation in respect of borrowings in excess of thresholds, which vary, stated in the contracts. The subsidiaries whose default would trigger cross default vary depending on the contract.

Each of TCEH's natural gas hedging agreements and interest rate swap agreements that are secured with a lien on its assets on a pari passu basis with the TCEH Senior Secured Facilities contains a cross default provision. In the event of a default by TCEH or any of its subsidiaries relating to indebtedness (such amounts varying by contract but ranging from $200 million to $250 million) that results in the acceleration of such debt, then each counterparty under these hedging agreements would have the right to terminate its hedge or interest rate swap agreement with TCEH and require all outstanding obligations under such agreement to be settled.

Other arrangements, including leases, have cross default provisions, the triggering of which would not be expected to result in a significant effect on liquidity.

Long-Term Contractual Obligations and Commitments — The following table summarizes our contractual cash obligations as of December 31, 2010 (see Notes 11 and 12 to Financial Statements for additional disclosures regarding these long-term debt and noncancellable purchase obligations).

Contractual Cash Obligations	Less Than One Year	One to Three Years	Three to Five Years	More Than Five Years	Total
Long-term debt – principal (a)	$ 651	$ 533	$ 24,233	$ 10,003	$ 35,420
Long-term debt – interest (b)	2,749	5,378	3,519	5,517	17,163
Operating and capital leases (c)	69	124	96	275	564
Obligations under commodity purchase and services agreements (d)	1,357	1,347	719	1,023	4,446
Total contractual cash obligations	$ 4,826	$ 7,382	$ 28,567	$ 16,818	$ 57,593

(a) Excludes capital lease obligations, unamortized discounts and fair value premiums and discounts related to purchase accounting. Also excludes $113 million of additional principal amount of notes expected to be issued in May 2011 and due in 2016 and 2017, reflecting the election of the PIK feature on toggle notes as discussed above under "Toggle Notes Interest Election."

(b) Includes net amounts payable under interest rate swaps. Variable interest payments and net amounts payable under interest rate swaps are calculated based on interest rates in effect as of December 31, 2010.

(c) Includes short-term noncancellable leases.

(d) Includes capacity payments, nuclear fuel and natural gas take-or-pay contracts, coal contracts, business services and nuclear-related outsourcing and other purchase commitments. Amounts presented for variable priced contracts assumed the year-end 2010 price remained in effect for all periods except where contractual price adjustment or index-based prices were specified.

The following are not included in the table above:

- contracts between affiliated entities and intercompany debt;
- individual contracts that have an annual cash requirement of less than $1 million (however, multiple contracts with one counterparty that are more than $1 million on an aggregated basis have been included);
- contracts that are cancellable without payment of a substantial cancellation penalty;
- employment contracts with management;
- estimated funding of pension plan totaling $175 million in 2011 and approximately $932 million for the 2011 to 2015 period as discussed above under "Pension and OPEB Plan Funding," and
- liabilities related to uncertain tax positions totaling $1.6 billion discussed in Note 7 to Financial Statements as the ultimate timing of payment is not known.

Guarantees — See Note 12 to Financial Statements for details of guarantees.

OFF-BALANCE SHEET ARRANGEMENTS

See Notes 3 and 12 to Financial Statements regarding VIEs and guarantees.

COMMITMENTS AND CONTINGENCIES

See Note 12 to Financial Statements for discussion of commitments and contingencies.

CHANGES IN ACCOUNTING STANDARDS

See Note 1 to Financial Statements for a discussion of changes in accounting standards.

REGULATORY MATTERS

See discussions in Part I under "Environmental Regulations and Related Considerations" and in Note 12 to Financial Statements.

Sunset Review

PURA, the PUCT, the RRC, ERCOT, the TCEQ and the Office of Public Utility Counsel (OPUC) will be subject to "sunset" review by the Texas Legislature in the 2011 legislative session. Sunset review includes, generally, a comprehensive review of the need for and effectiveness of an administrative agency (the PUCT, the RRC, ERCOT, the TCEQ or the OPUC), along with an evaluation of the advisability of any changes to that agency's authorizing legislation (PURA). In 2010, the Texas Sunset Advisory Commission adopted various recommendations regarding these agencies and submitted its recommendations for the Texas Legislature's consideration early in the session, which began in January 2011. We cannot predict the outcome of the sunset review process.

Oncor Matters with the PUCT

Stipulation Approved by the PUCT — In April 2008, the PUCT entered an order (PUCT Docket No. 34077), which became final in June 2008, approving the terms of a stipulation relating to the filing in 2007 by Oncor and Texas Holdings with the PUCT pursuant to Section 14.101(b) of PURA and PUCT Substantive Rule 25.75. The filing reported an ownership change involving Texas Holdings' purchase of EFH Corp. Among other things, the stipulation required the filing of a rate case by Oncor no later than July 1, 2008 based on a test year ended December 31, 2007, which Oncor filed in June 2008 as discussed below. In July 2008, Nucor Steel filed an appeal of the PUCT's order in the 200th District Court of Travis County, Texas. A hearing on the appeal was held in June 2010, and the District Court affirmed the PUCT order in its entirety. Nucor Steel appealed that ruling to the Third District Court of Appeals in Austin, Texas in July 2010. Oral argument before the court is scheduled for March 2011. While Oncor is unable to predict the outcome of the appeal, it does not expect the appeal to affect the major provisions of the stipulation.

Rate Cases — In January 2011, Oncor filed for a rate review with the PUCT and 203 cities (PUCT Docket No. 38929) based on a test year ended June 30, 2010. If approved as requested, this review would result in an aggregate annual rate increase of approximately $353 million over the test year period adjusted for the impact of weather. Oncor also requested a revised regulatory capital structure of 55% debt to 45% equity. The debt-to-equity ratio established by the PUCT is currently set at 60% debt to 40% equity. The PUCT, cities and other participating parties, with input from Oncor, established a procedural schedule for the review. A hearing on the merits of Oncor's request is scheduled to commence in May 2011, and resolution of the proposed increase is expected to occur during the second half of 2011 Oncor cannot predict the outcome of this rate review.

In June 2008, Oncor filed for a rate review with the PUCT and 204 cities (PUCT Docket No. 35717). In August 2009, the PUCT issued a final order with respect to the rate review. The final order approved a total annual revenue requirement for Oncor of $2.64 billion, based on a 2007 test year cost of service and customer characteristics. New rates were calculated for all customer classes using 2007 test year billing metrics and the approved class cost allocation and rate design. The PUCT staff estimated that the final order resulted in an approximate $115 million increase in base rate revenues over Oncor's 2007 adjusted test year revenues, before recovery of rate case expenses. Prior to implementing the new rates in September 2009, Oncor had already begun recovering $45 million of the $115 million increase as a result of approved transmission cost recovery factor and energy efficiency cost recovery factor filings, such as those discussed below.

Key findings by the PUCT in the rate review included:

- recognizing and affirming Oncor's corporate ring-fence from EFH Corp. and its unregulated affiliates by rejecting a proposed consolidated tax savings adjustment arising out of EFH Corp.'s ability to offset Oncor's taxable income against losses from other investments;
- approving the recovery of all of Oncor's capital investment in its transmission and distribution system, including investment in certain automated meters that will be replaced pursuant to Oncor's advanced meter deployment plan;
- denying recovery of $25 million of regulatory assets, which resulted in a $16 million after-tax loss being recognized in the third quarter 2009, and
- setting Oncor's return on equity at 10.25%.

New rates were implemented upon approval of new tariffs in September 2009 In November 2009, the PUCT issued an Order on Rehearing that established a new rate class but did not change the revenue requirements. In January 2010, the PUCT denied all Second Motions for Rehearing, which made the November 2009 Order on Rehearing final and appealable. Oncor and four other parties appealed various portions of the rate case final order to a state district court. Oral arguments in the appeal were held in October 2010. In January 2011, the District Court signed its judgment reversing the PUCT with respect to two issues: the PUCT's disallowance of certain franchise fees and the PUCT's decision that PURA no longer requires imposition of a rate discount for state colleges and universities. Oncor intends to file an appeal with the Austin Court of Appeals in February 2011 with respect to the issues it appealed to the District Court and did not prevail upon, as well as the District Court's decision on discounts for state colleges and universities.

Competitive Renewable Energy Zones (CREZs) — In January 2009, the PUCT awarded Oncor 17 CREZ construction projects (PUCT Docket Nos. 35665 and 37902) requiring 14 related Certificate of Convenience and Necessity (CCN) amendment proceedings before the PUCT. As of February 2011, 16 of the 17 projects and 13 of the 14 CCN amendments have been approved by the PUCT. The projects involve the construction of transmission lines to support the transmission of electricity from renewable energy sources, principally wind generation facilities, in west Texas to population centers in the eastern part of the state. Based on the selection of final routes for the three default and nine priority projects, identification of additional costs not included in the original ERCOT estimate (e.g., wind interconnection facilities and required modifications to existing facilities) and Oncor's preferred routes for the remaining five subsequent projects, Oncor currently estimates that the cost of these projects will total approximately $1.75 billion. Individual project costs could change based on final route specifications for the subsequent projects as determined by the PUCT. In addition, ERCOT completed a study in December 2010 that will allow Oncor and other transmission service providers to build additional facilities to provide further voltage support to the transmission grid as a result of CREZ. Oncor and other transmission service providers are working with ERCOT to complete cost estimates for the required work by the second half of 2011. As of December 31, 2010, Oncor's cumulative CREZ-related capital expenditures totaled $316 million, including $202 million during the year ended December 31, 2010. It is expected that the necessary permitting actions and other requirements and all construction activities for Oncor's CREZ construction projects will be completed by the end of 2013.

Advanced Metering Deployment Surcharge Filing (PUCT Docket Nos. 35718 and 36157) — In May 2008, Oncor filed with the PUCT a description and request for approval of its proposed advanced metering system deployment plan and proposed surcharge for the recovery of estimated future investment for advanced metering deployment. In September 2008, a PUCT order became final approving a settlement reached with the majority of the parties to this surcharge filing. The settlement included the following major provisions, as amended by the final order in the 2008 rate review:

- the full deployment of over three million advanced meters to all residential and most non-residential retail electricity customers in Oncor's service area;
- a surcharge beginning on January 1, 2009 and continuing for 11 years;
- a total revenue requirement over the surcharge period of $1.023 billion;
- estimated capital expenditures for advanced metering facilities of $686 million,
- related operation and maintenance expenses for the surcharge period of $153 million;
- $204 million of operation and maintenance expense savings, and
- an advanced metering cost recovery factor of $2 19 per month per residential retail customer and varying from $2.39 to $5.15 per month for non-residential retail customers.

As of December 31, 2010, Oncor has installed approximately 1,514,000 advanced digital meters, including approximately 854,000 during the year ended December 31, 2010. As the new meters are integrated, Oncor reports 15-minute interval, billing-quality electricity consumption data to ERCOT for market settlement purposes. The data makes it possible for REPs to support new programs and pricing options. Cumulative capital expenditures for the deployment of the advanced meter system totaled $360 million as of December 31, 2010, including $164 million in 2010. Oncor expects to complete installations of the advanced meters by the end of 2012.

Oncor may, through subsequent reconciliation proceedings, request recovery of additional costs that are reasonable and necessary. While there is a presumption that costs spent in accordance with a plan approved by the PUCT are reasonable and necessary, recovery of any costs that are found not to have been spent or properly allocated, or not to be reasonable or necessary, must be refunded.

Transmission Cost Recovery and Rates (PUCT Docket Nos. 37882, 38460, 38938 and 38495) — In order to recover increases in its transmission costs, including incremental fees paid to other transmission service providers due to an increase in their rates, Oncor is allowed to request an update twice a year to the transmission cost recovery factor (TCRF) component of its retail delivery rates charged to REPs. In January 2010, an application was filed to increase the TCRF, which was administratively approved in February 2010 and became effective March 1, 2010. This application increased Oncor's annualized revenues by approximately $13 million. In July 2010, an application was filed to increase the TCRF, which was administratively approved in August 2010 and became effective September 1, 2010. This application increased Oncor's annualized revenues by approximately $15 million. In December 2010, an application was filed to increase the TCRF, which was administratively approved in January 2011 for implementation effective March 1, 2011. This application is expected to increase Oncor's annualized revenues by approximately $33 million.

In July 2010, Oncor filed an application for an interim update of its wholesale transmission rate, and the PUCT approved the new rate effective September 29, 2010. Oncor's annualized revenues increased by an estimated $43 million with $27 million of this increase recoverable through transmission rates charged to wholesale customers and the remaining $16 million recoverable from REPs through the TCRF component of Oncor's delivery rates.

PUCT Rulemaking — In 2010, the PUCT published rule changes in two proceedings that impact transmission rates. In the first proceeding (PUCT Project No. 37909), the PUCT changed the TCRF rule to allow for more complete cost recovery of wholesale transmission charges incurred by distribution service providers. Previously, increased wholesale transmission charges were recoverable by distribution service providers, effective with the March 1 and September 1 TCRF updates, but distribution service providers could not recover increased charges incurred prior to such updates. TCRF filings are still effective March 1 and September 1, but distribution service providers will be allowed to include wholesale transmission charges based on the effective date of the wholesale transmission rate changes. As a result, Oncor defers such increased costs as a regulatory asset until they are recovered in rates. In the second proceeding (PUCT Project No. 37519), the PUCT changed the wholesale transmission rules to allow transmission service providers to update their wholesale transmission rates twice in a calendar year, as compared to once per year under the previous rules, providing more timely recovery of incremental capital investment. Other changes included in this rule (i) tie the effective date of the biannual update portion of the rule to the effective date of the TCRF rule in PUCT Project No. 37909, (ii) require the PUCT to consider the effects of reduced regulatory lag when setting rates in the next full rate review and (iii) provide for administrative approval of uncontested interim wholesale transmission rate applications.

Remand of 1999 Wholesale Transmission Matrix Case (PUCT Docket No. 38780) — In October 2010, the PUCT established Docket No. 38780 for the remand of Docket No. 20381, the 1999 wholesale transmission charge matrix case. A joint settlement agreement was entered into effective October 6, 2003. This settlement resolves disputes regarding wholesale transmission pricing and charges for the period of January 1997 through August 1999, the period prior to the September 1, 1999 effective date of the legislation that authorized 100% postage stamp pricing for ERCOT wholesale transmission. Since a series of appeals has become final, the 1999 matrix docket has been remanded to the PUCT to address additional issues. If the appealing parties prevail and the PUCT rules adversely with respect to these issues, Oncor could be subject to liabilities totaling up to approximately $22 million. At this time, Oncor cannot predict the outcome of these matters

Application for 2011 Energy Efficiency Cost Recovery Factor (PUCT Docket No. 38217) — In April 2010, Oncor filed an application with the PUCT to request approval of an energy efficiency cost recovery factor (EECRF) for 2011. PUCT rules require Oncor to make an annual EECRF filing by May 1 for implementation at the beginning of the next calendar year. In September 2010, the PUCT ruled that Oncor will be allowed to recover $51 million through its 2011 EECRF, including $45 million for 2011 program costs and an $11 million performance bonus based on 2009 results partially offset by a $5 million reduction for over-recovery of 2009 costs, as compared to $54 million recovered through its 2010 EECRF. The resulting monthly charge for residential customers will be $0.91, as compared to the 2010 residential charge of $0 89 per month.

Mine Safety Disclosures — Required by the Dodd-Frank Wall Street Reform and Consumer Protection Act

Safety is a top priority in all our businesses, and accordingly, it is a key component of our focus on operational excellence, our employee performance reviews and employee compensation Our health and safety program objectives are to prevent workplace accidents and ensure that all employees return home safely and comply with all regulations.

We currently own and operate 12 surface lignite coal mines in Texas to provide fuel for our electricity generation facilities These mining operations are regulated by the US Mine Safety and Health Administration (MSHA) under the Federal Mine Safety and Health Act of 1977, as amended (the Mine Act) as well as other regulatory agencies such as the RRC. The MSHA inspects US mines, including ours, on a regular basis and if it believes a violation of the Mine Act or any health or safety standard or other regulation has occurred, it may issue a citation or order, generally accompanied by a proposed fine or assessment. Such citations and orders can be contested and appealed to the Federal Mine Safety and Health Review Commission (FMSHRC), which often results in a reduction of the severity and amount of fines and assessments and sometimes results in dismissal. The number of citations, orders and proposed assessments vary depending on the size of the mine as well as other factors.

Disclosures related to specific mines pursuant to Section 1503 of the recently enacted Dodd-Frank Wall Street Reform and Consumer Protection Act sourced from data documented as of January 10, 2011 and January 17, 2011 in the MSHA Data Retrieval System for the three months and year ended December 31, 2010, respectively (except pending legal actions, which are as of December 31, 2010), are as follows:

	Three Months Ended December 31, 2010			Year Ended December 31, 2010		
Mine (a)	Section 104 S and S Citations (b)	Proposed MSHA Assessments ($ thousands) (c)	Pending Legal Action (d)	Section 104 S and S Citations (b)	Proposed MSHA Assessments ($ thousands) (c)	Pending Legal Action (d)
Beckville	1	—	1	8	18	1
Big Brown	—	—	2	4	9	2
Kosse	6	—	—	6	1	—
Oak Hill	3	11	1	7	13	1
Sulphur Springs	1	2	3	3	3	3
Tatum	—	—	1	—	—	1
Three Oaks	1	—	1	3	9	1
Winfield South	—	1	1	1	4	1

(a) Excludes mines for which there were no applicable events.
(b) Includes MSHA citations for health or safety standards that could significantly and substantially contribute to a serious injury if left unabated.
(c) Total dollar value for proposed assessments received from MSHA for all citations and orders issued in the period ended December 31, 2010, including but not limited to Sections 104, 107 and 110 citations and orders that are not required to be reported.
(d) Pending actions before the FMSHRC involving a coal or other mine.

During the three months ended December 31, 2010, our mining operations received two citations and orders under Section 104(d) (Oak Hill mine), no citations, orders or written notices under Sections 104(b), 104(e), 107(a) or 110(b)(2) of the Mine Act, and they experienced no fatalities. During the year ended December 31, 2010, our mining operations received two citations and orders under Section 104(d) (Oak Hill Mine), one order under Section 107(a) (Beckville mine), no citations, orders or written notices under Sections 104(b), 104(e) or 110(b)(2) of the Mine Act, and they experienced no fatalities.

Summary

We cannot predict future regulatory or legislative actions or any changes in economic and securities market conditions. Such actions or changes could significantly alter our basic financial position, results of operations or cash flows.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risk is the risk that we may experience a loss in value as a result of changes in market conditions affecting factors, such as commodity prices and interest rates that may be experienced in the ordinary course of business Our exposure to market risk is affected by a number of factors, including the size, duration and composition of our energy and financial portfolio, as well as the volatility and liquidity of markets. Instruments used to manage this exposure include interest rate swaps to manage interest rate risk related to debt, as well as exchange traded, over-the-counter contracts and other contractual arrangements to manage commodity price risk.

Risk Oversight

We manage the commodity price, counterparty credit and commodity-related operational risk related to the unregulated energy business within limitations established by senior management and in accordance with overall risk management policies. Interest rate risk is managed centrally by the corporate treasury function. Market risks are monitored by risk management groups that operate independently of the wholesale commercial operations, utilizing defined practices and analytical methodologies. These techniques measure the risk of change in value of the portfolio of contracts and the hypothetical effect on this value from changes in market conditions and include, but are not limited to, Value at Risk (VaR) methodologies. Key risk control activities include, but are not limited to, transaction review and approval (including credit review), operational and market risk measurement, validation of transaction capture, portfolio valuation and reporting, including mark-to-market valuation, VaR and other risk measurement metrics.

We have a corporate risk management organization that is headed by the Chief Financial Officer, who also functions as the Chief Risk Officer. The Chief Risk Officer, through his designees, enforces applicable risk limits, including the respective policies and procedures to ensure compliance with such limits and evaluates the risks inherent in our businesses.

Commodity Price Risk

The competitive business is subject to the inherent risks of market fluctuations in the price of electricity, natural gas and other energy-related products it markets or purchases. We actively manage the portfolio of owned generation assets, fuel supply and retail sales load to mitigate the near-term impacts of these risks on results of operations. Similar to other participants in the market, we cannot fully manage the long-term value impact of structural declines or increases in natural gas and power prices and spark spreads (differences between the market price of electricity and its cost of production).

In managing energy price risk, we enter into a variety of market transactions including, but not limited to, short- and long-term contracts for physical delivery, exchange traded and over-the-counter financial contracts and bilateral contracts with customers. Activities include hedging, the structuring of long-term contractual arrangements and proprietary trading. We continuously monitor the valuation of identified risks and adjust positions based on current market conditions. We strive to use consistent assumptions regarding forward market price curves in evaluating and recording the effects of commodity price risk.

Long-Term Hedging Program See "Significant Activities and Events" above for a description of the program, including potential effects on reported results.

VaR Methodology — A VaR methodology is used to measure the amount of market risk that exists within the portfolio under a variety of market conditions. The resultant VaR produces an estimate of a portfolio's potential for loss given a specified confidence level and considers among other things, market movements utilizing standard statistical techniques given historical and projected market prices and volatilities.

A Monte Carlo simulation methodology is used to calculate VaR and is considered by management to be the most effective way to estimate changes in a portfolio's value based on assumed market conditions for liquid markets. The use of this method requires a number of key assumptions, such as use of (i) an assumed confidence level; (ii) an assumed holding period (i.e., the time necessary for management action, such as to liquidate positions), and (iii) historical estimates of volatility and correlation data.

Trading VaR — This measurement estimates the potential loss in fair value, due to changes in market conditions, of all contracts entered into for trading purposes based on a 95% confidence level and an assumed holding period of five to 60 days.

	Year Ended December 31, 2010	Year Ended December 31, 2009
Month-end average Trading VaR:	$ 3	$ 4
Month-end high Trading VaR:	$ 4	$ 7
Month-end low Trading VaR:	$ 1	$ 2

VaR for Energy-Related Contracts Subject to Mark-to-Market (MtM) Accounting — This measurement estimates the potential loss in fair value, due to changes in market conditions, of all contracts marked-to-market in net income (principally hedges not accounted for as cash flow hedges and trading positions), based on a 95% confidence level and an assumed holding period of five to 60 days.

	Year Ended December 31, 2010	Year Ended December 31, 2009
Month-end average MtM VaR:	$ 426	$ 1,050
Month-end high MtM VaR:	$ 621	$ 1,470
Month-end low MtM VaR:	$ 321	$ 638

Earnings at Risk (EaR) — This measurement estimates the potential reduction of pretax earnings for the periods presented, due to changes in market conditions, of all energy-related contracts marked-to-market in net income and contracts not marked-to-market in net income that are expected to be settled within the fiscal year (physical purchases and sales of commodities). Transactions accounted for as cash flow hedges are also included for this measurement. A 95% confidence level and a five to 60 day holding period are assumed in determining EaR.

	Year Ended December 31, 2010	Year Ended December 31, 2009
Month-end average EaR:	$ 477	$ 1,088
Month-end high EaR:	$ 662	$ 1,511
Month-end low EaR:	$ 323	$ 676

The decreases in the risk measures (MtM VaR and EaR) above reflected fewer positions in the long-term hedging program due to settlement upon maturity, lower market volatility and lower underlying commodity prices.

Interest Rate Risk

The table below provides information concerning our financial instruments as of December 31, 2010 and 2009 that are sensitive to changes in interest rates, which include debt obligations and interest rate swaps. We have entered into interest rate swaps under which we have exchanged the difference between fixed-rate and variable-rate interest amounts calculated with reference to specified notional principal amounts at dates that generally coincide with interest payments under our credit facilities. In addition, in connection with entering into certain interest rate basis swaps to further reduce fixed borrowing costs, we have changed the variable interest rate terms of certain TCEH debt from three-month LIBOR to one-month LIBOR, as discussed in Note 11 to Financial Statements. The weighted average interest rate presented is based on the rate in effect at the reporting date. Capital leases and the effects of unamortized premiums and discounts and fair value hedges are excluded from the table. See Note 11 to Financial Statements for a discussion of changes in debt obligations.

	Expected Maturity Date									
	(millions of dollars, except percentages)									
	2011	2012	2013	2014	2015	There-After	2010 Total Carrying Amount	2010 Total Fair Value	2009 Total Carrying Amount	2009 Total Fair Value
Long-term debt (including current maturities):										
Fixed rate debt amount (a)	$ 446	$ 32	$ 91	$ 483	$3,187	$ 9,798	$14,037	$10,052	$20,861	$17,296
Average interest rate	5.86%	8.17%	7.24%	5.66%	10.24%	10.32%	9.98%		8.95%	
Variable rate debt amount	$ 205	$ 205	$ 205	$20,563	$ —	$ 205	$21,383	$16,542	$21,608	$17,463
Average interest rate	3.76%	3.76%	3.76%	3.76%	— %	0.32%	3.73%		3.71%	
Total debt	$ 651	$ 237	$ 296	$21,046	$3,187	$10,003	$35,420	$26,594	$42,469	$34,759
Debt swapped to fixed:										
Amount	$ 600	$2,600	$3,600	$ 9,000	$ —	$ —	$15,800		$16,300	
Average pay rate	7.57%	7.99%	7.60%	8.18%	—	—	7.99%		7.98%	
Average receive rate	3.79%	3.79%	3.79%	3.79%	—	—	3.79%		3.74%	
Variable basis swaps:										
Amount	$5,450	$7,200	$1,500	$ 1,050	$ —	$ —	$15,200		$16,250	
Average pay rate	0.32%	0.33%	0.29%	0.33%	—	—	0.32%		0.33%	
Average receive rate	0.26%	0.26%	0.26%	0.26%	—	—	0.26%		0.24%	

(a) Reflects the remarketing date and not the maturity date for certain debt that is subject to mandatory tender for remarketing prior to maturity. See Note 11 to Financial Statements for details concerning long-term debt subject to mandatory tender for remarketing.

As of December 31, 2010, the potential reduction of annual pretax earnings due to a one percentage point (100 basis points) increase in floating interest rates on long-term debt totaled approximately $45 million, taking into account the interest rate swaps discussed in Note 11 to Financial Statements.

Credit Risk

Credit risk relates to the risk of loss associated with nonperformance by counterparties. We maintain credit risk policies with regard to our counterparties to minimize overall credit risk. These policies prescribe practices for evaluating a potential counterparty's financial condition, credit rating and other quantitative and qualitative credit criteria and specify authorized risk mitigation tools including, but not limited to, use of standardized master netting contracts and agreements that allow for netting of positive and negative exposures associated with a single counterparty. We have processes for monitoring and managing credit exposure of our businesses including methodologies to analyze counterparties' financial strength, measurement of current and potential future exposures and contract language that provides rights for netting and set-off. Credit enhancements such as parental guarantees, letters of credit, surety bonds and margin deposits are also utilized. Additionally, individual counterparties and credit portfolios are managed to assess overall credit exposure. This evaluation results in establishing exposure limits or collateral requirements for entering into an agreement with a counterparty that creates exposure. Additionally, we have established controls to determine and monitor the appropriateness of these limits on an ongoing basis. Prospective material adverse changes in the payment history or financial condition of a counterparty or downgrade of its credit quality result in the reassessment of the credit limit with that counterparty. This process can result in the subsequent reduction of the credit limit or a request for additional financial assurances.

Credit Exposure — Our gross exposure to credit risk associated with trade accounts receivable (retail and wholesale) and net asset positions (before credit collateral) arising from commodity contracts and hedging and trading activities totaled \$2.869 billion as of December 31, 2010. The components of this exposure are discussed in more detail below.

Assets subject to credit risk as of December 31, 2010 include \$615 million in retail trade accounts receivable before taking into account cash deposits held as collateral for these receivables totaling \$70 million. The risk of material loss (after consideration of bad debt allowances) from nonperformance by these customers is unlikely based upon historical experience. Allowances for uncollectible accounts receivable are established for the potential loss from nonpayment by these customers based on historical experience, market or operational conditions and changes in the financial condition of large business customers.

The remaining credit exposure arises from wholesale trade receivables, commodity contracts and hedging and trading activities, including interest rate hedging. Counterparties to these transactions include energy companies, financial institutions, electric utilities, independent power producers, oil and gas producers, local distribution companies and energy trading and marketing companies. As of December 31, 2010, the exposure to credit risk from these counterparties totaled \$2.254 billion taking into account the standardized master netting contracts and agreements described above but before taking into account \$648 million in credit collateral (cash, letters of credit and other credit support). The net exposure (after credit collateral) of \$1.606 billion increased \$309 million in the year ended December 31, 2010, reflecting the increase in derivative assets related to the long-term hedging program due to the decline in forward natural gas prices, partially offset by the return of the \$400 million in collateral discussed in Note 17 to Financial Statements and the increase in derivative liabilities related to interest rate swaps due to lower interest rates.

Of this \$1.606 billion net exposure, essentially all is with investment grade customers and counterparties, as determined using publicly available information including major rating agencies' published ratings and our internal credit evaluation process. Those customers and counterparties without a S&P rating of at least BBB- or similar rating from another major rating agency are rated using internal credit methodologies and credit scoring models to estimate a S&P equivalent rating. The company routinely monitors and manages credit exposure to these customers and counterparties on this basis.

The following table presents the distribution of credit exposure as of December 31, 2010 arising from wholesale trade receivables, commodity contracts and hedging and trading activities. This credit exposure represents wholesale trade accounts receivable and net asset positions on the balance sheet arising from hedging and trading activities after taking into consideration netting provisions within each contract, setoff provisions in the event of default and any master netting contracts with counterparties. See Note 17 to Financial Statements for further discussion of portions of this exposure related to activities marked-to-market in the financial statements.

	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Gross Exposure by Maturity: 2 years or less	Between 2-5 years	Greater than 5 years	Total
Investment grade	$ 2,229	$ 646	$ 1,583	$ 1,597	$ 632	$ —	$ 2,229
Noninvestment grade	25	2	23	26	(1)	—	25
Totals	$ 2,254	$ 648	$ 1,606	$ 1,623	$ 631	$ —	$ 2,254
Investment grade	98.9%		98.6%				
Noninvestment grade	1.1%		1.4%				

In addition to the exposures in the table above, contracts classified as "normal" purchase or sale and non-derivative contractual commitments are not marked-to-market in the financial statements. Such contractual commitments may contain pricing that is favorable considering current market conditions and therefore represent economic risk if the counterparties do not perform. Nonperformance could have a material adverse impact on future results of operations, financial condition and cash flows.

Significant (10% or greater) concentration of credit exposure exists with three counterparties, which represented 41%, 35% and 12% of the net $1.606 billion exposure. We view exposure to these counterparties to be within an acceptable level of risk tolerance due to the applicable counterparty's credit rating and the importance of our business relationship with the counterparty. However, this concentration increases the risk that a default would have a material effect on results of operations.

With respect to credit risk related to the long-term hedging program, essentially all of the transaction volumes are with counterparties with an A credit rating or better. However, there is current and potential credit concentration risk related to the limited number of counterparties that comprise the substantial majority of the program with such counterparties being in the banking and financial sector. The transactions with these counterparties contain certain credit rating provisions that would require the counterparties to post collateral in the event of a material downgrade in the credit rating of the counterparties. An event of default by one or more hedge counterparties could subsequently result in termination-related settlement payments that reduce available liquidity if amounts are owed to the counterparties related to the commodity contracts or delays in receipts of expected settlements if the hedge counterparties owe amounts to us. While the potential concentration of risk with these counterparties is viewed to be within an acceptable risk tolerance, the exposure to hedge counterparties is managed through the various ongoing risk management measures described above.

FORWARD-LOOKING STATEMENTS

This report and other presentations made by us contain "forward-looking statements." All statements, other than statements of historical facts, that are included in this report, or made in presentations, in response to questions or otherwise, that address activities, events or developments that we expect or anticipate to occur in the future, including such matters as projections, capital allocation, future capital expenditures, business strategy, competitive strengths, goals, future acquisitions or dispositions, development or operation of power generation assets, market and industry developments and the growth of our businesses and operations (often, but not always, through the use of words or phrases such as "intends," "plans," "will likely result," "are expected to," "will continue," "is anticipated," "estimated," "should," "projection," "target," "goal," "objective" and "outlook"), are forward-looking statements. Although we believe that in making any such forward-looking statement our expectations are based on reasonable assumptions, any such forward-looking statement involves uncertainties and is qualified in its entirety by reference to the discussion of risk factors under Item 1A, "Risk Factors" and the discussion under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" in this report and the following important factors, among others, that could cause our actual results to differ materially from those projected in such forward-looking statements:

- prevailing governmental policies and regulatory actions, including those of the Texas Legislature, the Governor of Texas, the US Congress, the FERC, the NERC, the TRE, the PUCT, the RRC, the NRC, the EPA, the TCEQ and the CFTC, with respect to, among other things:
  - allowed prices;
  - allowed rates of return;
  - permitted capital structure;
  - industry, market and rate structure;
  - purchased power and recovery of investments;
  - operations of nuclear generating facilities;
  - operations of fossil-fueled generating facilities;
  - operations of mines;
  - acquisition and disposal of assets and facilities;
  - development, construction and operation of facilities;
  - decommissioning costs;
  - present or prospective wholesale and retail competition;
  - changes in tax laws and policies;
  - changes in and compliance with environmental and safety laws and policies, including climate change initiatives, and
  - clearing over the counter derivatives through exchanges and posting of cash collateral therewith;
- legal and administrative proceedings and settlements;
- general industry trends;
- economic conditions, including the impact of a recessionary environment,
- our ability to attract and retain profitable customers;
- our ability to profitably serve our customers;
- restrictions on competitive retail pricing;
- changes in wholesale electricity prices or energy commodity prices;
- changes in prices of transportation of natural gas, coal, crude oil and refined products,
- unanticipated changes in market heat rates in the ERCOT electricity market;
- our ability to effectively hedge against unfavorable commodity prices, market heat rates and interest rates;
- weather conditions and other natural phenomena, and acts of sabotage, wars or terrorist activities;
- unanticipated population growth or decline, or changes in market demand and demographic patterns, particularly in ERCOT,
- changes in business strategy, development plans or vendor relationships;
- access to adequate transmission facilities to meet changing demands;
- unanticipated changes in interest rates, commodity prices, rates of inflation or foreign exchange rates,
- unanticipated changes in operating expenses, liquidity needs and capital expenditures;
- commercial bank market and capital market conditions and the potential impact of disruptions in US and international credit markets;

- the willingness of our lenders to amend and extend the maturities of our debt agreements and the terms and conditions of any such amendments;
- access to capital, the cost of such capital, and the results of financing and refinancing efforts, including availability of funds in capital markets;
- financial restrictions placed on us by the agreements governing our debt instruments;
- our ability to generate sufficient cash flow to make interest payments on, or refinance, our debt instruments;
- our ability to successfully execute our liability management program;
- competition for new energy development and other business opportunities;
- inability of various counterparties to meet their obligations with respect to our financial instruments;
- changes in technology used by and services offered by us;
- changes in electricity transmission that allow additional electricity generation to compete with our generation assets;
- significant changes in our relationship with our employees, including the availability of qualified personnel, and the potential adverse effects if labor disputes or grievances were to occur;
- changes in assumptions used to estimate costs of providing employee benefits, including medical and dental benefits, pension and OPEB, and future funding requirements related thereto;
- changes in assumptions used to estimate future executive compensation payments;
- hazards customary to the industry and the possibility that we may not have adequate insurance to cover losses resulting from such hazards;
- significant changes in critical accounting policies;
- actions by credit rating agencies;
- our ability to effectively execute our operational strategy, and
- our ability to implement cost reduction initiatives.

Any forward-looking statement speaks only as of the date on which it is made, and except as may be required by law, we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which it is made or to reflect the occurrence of unanticipated events New factors emerge from time to time, and it is not possible for us to predict all of them; nor can we assess the impact of each such factor or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement. As such, you should not unduly rely on such forward-looking statements.

INDUSTRY AND MARKET INFORMATION

The industry and market data and other statistical information used throughout this report are based on independent industry publications, government publications, reports by market research firms or other published independent sources, including certain data published by ERCOT, the PUCT and NYMEX. We did not commission any of these publications or reports. Some data is also based on good faith estimates, which are derived from our review of internal surveys, as well as the independent sources listed above. Independent industry publications and surveys generally state that they have obtained information from sources believed to be reliable, but do not guarantee the accuracy and completeness of such information. While we believe that each of these studies and publications is reliable, we have not independently verified such data and make no representation as to the accuracy of such information. Forecasts are particularly likely to be inaccurate, especially over long periods of time, and we do not know what assumptions regarding general economic growth are used in preparing the forecasts included in this report. Similarly, while we believe that such internal and external research is reliable, it has not been verified by any independent sources, and we make no assurances that the predictions contained therein are accurate.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Energy Future Holdings Corp
Dallas, Texas

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

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Energy Future Holdings Corp. and subsidiaries as of December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Notes 1 and 2 to the consolidated financial statements, EFH Corp. adopted amended consolidation accounting standards related to variable interest entities, and as also discussed in Notes 1 and 10 to the consolidated financial statements, EFH Corp. adopted amended guidance regarding transfers of financial assets effective January 1, 2010, on a prospective basis.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), EFH Corp.'s internal control over financial reporting as of December 31, 2010, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 17, 2011 expressed an unqualified opinion on EFH Corp.'s internal control over financial reporting.

/s/ Deloitte & Touche LLP
Dallas, Texas
February 17, 2011

ENERGY FUTURE HOLDINGS CORP. AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED INCOME (LOSS)
(Millions of Dollars)

	Year Ended December 31,		
	2010	2009	2008
Operating revenues	$ 8,235	$ 9,546	$ 11,364
Fuel, purchased power costs and delivery fees	(4,371)	(2,878)	(4,595)
Net gain from commodity hedging and trading activities	2,161	1,736	2,184
Operating costs	(837)	(1,598)	(1,503)
Depreciation and amortization	(1,407)	(1,754)	(1,610)
Selling, general and administrative expenses	(751)	(1,068)	(957)
Franchise and revenue-based taxes	(106)	(359)	(363)
Impairment of goodwill (Note 4)	(4,100)	(90)	(8,860)
Other income (Note 9)	2,051	204	80
Other deductions (Note 9)	(31)	(97)	(1,301)
Interest income	10	45	27
Interest expense and related charges (Note 24)	(3,554)	(2,912)	(4,935)
Income (loss) before income taxes and equity in earnings of unconsolidated subsidiaries	(2,700)	775	(10,469)
Income tax (expense) benefit (Note 8)	(389)	(367)	471
Equity in earnings of unconsolidated subsidiaries (net of tax) (Note 2)	277	—	—
Net income (loss)	(2,812)	408	(9,998)
Net (income) loss attributable to noncontrolling interests	—	(64)	160
Net income (loss) attributable to EFH Corp.	$ (2,812)	$ 344	$ (9,838)

See Notes to Financial Statements.

ENERGY FUTURE HOLDINGS CORP. AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME (LOSS)
(Millions of Dollars)

	Year Ended December 31,		
	2010	2009	2008
Net income (loss)	$(2,812)	$408	$ (9,998)
Other comprehensive income (loss), net of tax effects:			
Effects related to pension and other retirement benefit obligations (net of tax benefit of $8, $20 and $69) (Note 20)	(13)	(40)	(84)
Cash flow hedges:			
Net decrease in fair value of derivatives (net of tax benefit of $—, $10 and $99)	—	(20)	(183)
Derivative value net loss related to hedged transactions recognized during the period and reported in net income (loss) (net of tax benefit of $31, $72 and $66)	59	130	122
Total effect of cash flow hedges	59	110	(61)
Total other comprehensive income (loss)	46	70	(145)
Comprehensive income (loss)	(2,766)	478	(10,143)
Comprehensive (income) loss attributable to noncontrolling interests	—	(64)	160
Comprehensive income (loss) attributable to EFH Corp.	$(2,766)	$414	$ (9,983)

See Notes to Financial Statements.

ENERGY FUTURE HOLDINGS CORP. AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED CASH FLOWS
(Millions of Dollars)

	Year Ended December 31,		
	2010	2009	2008
Cash flows — operating activities			
Net income (loss)	$ (2,812)	$ 408	$ (9,998)
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	1,778	2,172	2,070
Deferred income tax expense (benefit) – net	604	253	(477)
Impairment of goodwill (Note 4)	4,100	90	8,860
Debt extinguishment gains (Note 11)	(1,814)	(87)	—
Unrealized net gains from mark-to-market valuations of commodity positions	(1,221)	(1,225)	(2,329)
Interest expense on toggle notes payable in additional principal (Notes 11 and 24)	446	524	83
Equity in earnings of unconsolidated subsidiaries	(277)	—	—
Unrealized net (gains) losses from mark-to-market valuations of interest rate swaps (Note 11)	207	(696)	1,477
Distributions of earnings from unconsolidated subsidiaries	169	—	—
Gain on termination of long-term power sales contract (Note 9)	(116)	—	—
Bad debt expense (Note 10)	108	113	81
Losses on dedesignated cash flow hedges (interest rate swaps)	87	184	66
Net gain on sale of assets	(81)	(5)	(1)
Stock-based incentive compensation expense	19	14	30
Reversal of reserves recorded in purchase accounting (Note 9)	—	(44)	—
Impairment of land	—	34	—
Write off of regulatory assets (Note 24)	—	25	—
Impairment of emission allowances intangible assets (Note 4)	—	—	501
Impairment of trade name intangible asset (Note 4)	—	—	481
Impairment of natural gas-fueled generation facilities (Note 5)	—	—	229
Charge related to Lehman bankruptcy (Note 9)	—	—	26
Other, net	11	(4)	(20)
Changes in operating assets and liabilities:			
Accounts receivable – trade	258	(125)	(505)
Impact of accounts receivable securitization program (Note 10)	(383)	(33)	53
Inventories	(6)	(59)	(21)
Accounts payable – trade	(93)	(141)	385
Commodity and other derivative contractual assets and liabilities	(44)	(64)	(28)
Margin deposits – net	132	248	595
Deferred advanced metering system revenues (Note 24)	—	57	—
Other – net assets	151	(43)	440
Other – net liabilities	(117)	115	(493)
Cash provided by operating activities	$ 1,106	$ 1,711	$ 1,505

ENERGY FUTURE HOLDINGS CORP. AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED CASH FLOWS (CONT.)
(Millions of Dollars)

	Year Ended December 31, 2010	2009	2008
Cash flows — financing activities			
Issuances of long-term debt/securities (Note 11):			
Pollution control revenue bonds	$ —	$ —	$ 242
Oncor long-term debt	—	—	1,500
Other long-term debt	853	522	1,443
Common stock	—	—	34
Repayments/repurchases of long-term debt/securities (Note 11):			
Pollution control revenue bonds	—	—	(242)
Other long-term debt	(1,351)	(396)	(925)
Common stock	—	—	(3)
Net short-term borrowings under accounts receivable securitization program (Note 10)	96	—	—
Increase (decrease) in other short-term borrowings (Note 11)	172	332	(481)
Proceeds from sale of noncontrolling interests, net of transaction costs (Note 14)	—	—	1,253
Decrease in note payable to unconsolidated subsidiary	(37)	—	—
Contributions from noncontrolling interests	32	48	—
Distributions paid to noncontrolling interests	—	(56)	(2)
Debt exchange and issuance costs	(62)	(49)	(21)
Other, net	33	21	39
Cash provided by (used in) financing activities	$ (264)	$ 422	$ 2,837
Cash flows — investing activities			
Capital expenditures	(838)	(2,348)	(2,849)
Nuclear fuel purchases	(106)	(197)	(166)
Money market fund redemptions (investments)	—	142	(142)
Investment redeemed/(posted) with derivative counterparty (Note 17)	400	(400)	—
Reduction of letter of credit facility deposited with trustee (Note 11)	—	115	—
Reduction of restricted cash related to pollution control revenue bonds	—	—	29
Other changes in restricted cash	(33)	9	1
Proceeds from sale of assets	147	42	80
Proceeds from sale of environmental allowances and credits	12	19	39
Purchases of environmental allowances and credits	(30)	(19)	(34)
Proceeds from sales of nuclear decommissioning trust fund securities	974	3,064	1,623
Investments in nuclear decommissioning trust fund securities	(990)	(3,080)	(1,639)
Cash settlements related to outsourcing contract termination (Note 19)	—	—	70
Settlement of loan (Note 19)	—	—	25
Other, net	(4)	20	29
Cash used in investing activities	$ (468)	$ (2,633)	$ (2,934)
Net change in cash and cash equivalents	374	(500)	1,408
Effect of deconsolidation of Oncor Holdings	(29)	—	—
Cash and cash equivalents — beginning balance	1,189	1,689	281
Cash and cash equivalents — ending balance	$ 1,534	$ 1,189	$ 1,689

See Notes to Financial Statements.

0001263

ENERGY FUTURE HOLDINGS CORP. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Millions of Dollars)

	December 31, 2010	December 31, 2009 (see Note 2)
ASSETS		
Current assets:		
Cash and cash equivalents (Note 1)	$ 1,534	$ 1,189
Investment posted with counterparty (Note 17)	—	425
Restricted cash (Note 24)	33	48
Trade accounts receivable — net (2010 includes $612 in pledged amounts related to a VIE (Notes 3 and 10))	999	1,260
Inventories (Note 24)	395	485
Commodity and other derivative contractual assets (Note 17)	2,732	2,391
Accumulated deferred income taxes (Note 8)	—	5
Margin deposits related to commodity positions	166	187
Other current assets	60	136
Total current assets	5,919	6,126
Restricted cash (Note 24)	1,135	1,149
Receivables from unconsolidated subsidiary (Note 22)	1,463	—
Investments in unconsolidated subsidiaries (Note 2)	5,544	44
Other investments (Note 18)	697	706
Property, plant and equipment — net (Note 24)	20,366	30,108
Goodwill (Note 4)	6,152	14,316
Identifiable intangible assets — net (Note 4)	2,400	2,876
Regulatory assets — net (Note 24)	—	1,959
Commodity and other derivative contractual assets (Note 17)	2,071	1,533
Other noncurrent assets, principally unamortized debt issuance costs	641	845
Total assets	$ 46,388	$ 59,662
LIABILITIES AND EQUITY		
Current liabilities:		
Short-term borrowings (2010 includes $96 related to a VIE (Notes 3 and 11))	$ 1,221	$ 1,569
Long-term debt due currently (Note 11)	669	417
Trade accounts payable	681	896
Payables due to unconsolidated subsidiary (Note 22)	254	
Commodity and other derivative contractual liabilities (Note 17)	2,283	2,392
Margin deposits related to commodity positions	631	520
Accumulated deferred income taxes (Note 8)	11	
Accrued interest	411	526
Other current liabilities	442	714
Total current liabilities	6,603	7,064
Accumulated deferred income taxes (Note 8)	5,350	6,131
Investment tax credits	—	37
Commodity and other derivative contractual liabilities (Note 17)	869	1,060
Notes or other liabilities due to unconsolidated subsidiary (Note 22)	384	—
Long-term debt, less amounts due currently (Note 11)	34,226	41,440
Other noncurrent liabilities and deferred credits (Note 24)	4,867	5,766
Total liabilities	52,299	61,498
Commitments and Contingencies (Note 12)		
Equity (Note 13):		
Common stock (shares outstanding 2010 — 1,671,812,118; 2009 — 1,668,065,133)	2	2
Additional paid-in capital	7,937	7,914
Retained earnings (deficit)	(13,666)	(10,854)
Accumulated other comprehensive income (loss)	(263)	(309)
EFH Corp. shareholders' equity	(5,990)	(3,247)
Noncontrolling interests in subsidiaries	79	1,411
Total equity	(5,911)	(1,836)
Total liabilities and equity	$ 46,388	$ 59,662

See Notes to Financial Statements.

ENERGY FUTURE HOLDINGS CORP. AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED EQUITY
(Millions of Dollars)

	Year Ended December 31,		
	2010	2009	2008
Common stock stated value of $0.001 effective May 2009 (number of authorized shares — 2,000,000,000):			
Balance as of beginning of period	$ 2	$ —	$ —
Effects of shareholder actions related to stated value of common stock	—	2	—
Balance as of end of period (number of shares outstanding: 2010 — 1,671,812,118; 2009 — 1,668,065,133; 2008 — 1,667,149,663	2	2	—
Additional paid-in capital:			
Balance as of beginning of period	7,914	7,904	8,279
Effects of stock-based incentive compensation plans	24	11	29
Effects of shareholder actions related to stated value of common stock	—	(2)	—
Effect of sale of noncontrolling interests (Note 13)	—	—	(406)
Common stock repurchases	(2)	—	—
Other	1	1	2
Balance as of end of period	7,937	7,914	7,904
Retained earnings (deficit):			
Balance as of beginning of period	(10,854)	(11,198)	(1,360)
Net income (loss) attributable to EFH Corp.	(2,812)	344	(9,838)
Balance as of end of period	(13,666)	(10,854)	(11,198)
Accumulated other comprehensive income (loss), net of tax effects:			
Pension and other postretirement employee benefit liability adjustments:			
Balance as of beginning of period	(181)	(141)	(57)
Change in unrecognized gains (losses) related to pension and other retirement benefit costs	(13)	(40)	(84)
Balance as of end of period	(194)	(181)	(141)
Amounts related to cash flow hedges:			
Balance as of beginning of period	(128)	(238)	(177)
Change during the period	59	110	(61)
Balance as of end of period	(69)	(128)	(238)
Total accumulated other comprehensive income (loss) as of end of period	(263)	(309)	(379)
EFH Corp. shareholders' equity as of end of period (Note 13)	(5,990)	(3,247)	(3,673)
Noncontrolling interests in subsidiaries (Note 14):			
Balance as of beginning of period	1,411	1,355	—
Net income (loss) attributable to noncontrolling interests	—	64	(160)
Effect of deconsolidation of Oncor Holdings (Notes 1 and 3)	(1,363)	—	—
Investments by noncontrolling interests	32	48	1,253
Effect of sale of noncontrolling interests	—	—	265
Distributions to noncontrolling interests	—	(56)	(2)
Other	(1)	—	(1)
Noncontrolling interests in subsidiaries as of end of period	79	1,411	1,355
Total equity as of end of period	$ (5,911)	$ (1,836)	$ (2,318)

See Notes to Financial Statements.

ENERGY FUTURE HOLDINGS CORP. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. BUSINESS AND SIGNIFICANT ACCOUNTING POLICIES

Description of Business

EFH Corp., a Texas corporation, is a Dallas-based holding company with operations consisting principally of our TCEH and Oncor subsidiaries. TCEH is a holding company for subsidiaries engaged in competitive electricity market activities largely in Texas, including electricity generation, wholesale energy sales and purchases, commodity risk management and trading activities, and retail electricity sales. Oncor is a majority (approximately 80%) owned subsidiary engaged in regulated electricity transmission and distribution operations in Texas. See Note 3 regarding the deconsolidation of Oncor (and it majority owner, Oncor Holdings) as a result of amended consolidation accounting standards related to variable interest entities (VIEs) effective January 1, 2010.

On October 10, 2007, EFH Corp. completed its Merger with Merger Sub. As a result of the Merger, EFH Corp. became a subsidiary of Texas Holdings, which is controlled by the Sponsor Group.

References in this report to "we," "our," "us" and "the company" are to EFH Corp and/or its subsidiaries, TCEH and/or its subsidiaries, or Oncor and/or its subsidiary as apparent in the context. See "Glossary" for other defined terms.

Various "ring-fencing" measures have been taken to enhance the credit quality of Oncor. Such measures include, among other things: the sale of a 19.75% equity interest in Oncor to Texas Transmission in November 2008; maintenance of separate books and records for the Oncor Ring-Fenced Entities; Oncor's board of directors being comprised of a majority of independent directors, and prohibitions on the Oncor Ring-Fenced Entities providing credit support to, or receiving credit support from, any member of the Texas Holdings Group. The assets and liabilities of the Oncor Ring-Fenced Entities are separate and distinct from those of the Texas Holdings Group and none of the assets of the Oncor Ring-Fenced Entities are available to satisfy the debt or contractual obligations of any member of the Texas Holdings Group. Moreover, Oncor's operations are conducted, and its cash flows managed, independently from the Texas Holdings Group.

See Note 14 for discussion of noncontrolling interests sold by Oncor in November 2008.

We have two reportable segments: the Competitive Electric segment, which is comprised principally of TCEH, and the Regulated Delivery segment, which is comprised of Oncor Holdings and its subsidiaries. See Note 23 for further information concerning reportable business segments.

Basis of Presentation

The consolidated financial statements have been prepared in accordance with US GAAP. The consolidated financial statements have been prepared on the same basis as the audited financial statements included in the 2009 Form 10-K with the exception of the prospective adoption of amended guidance regarding consolidation accounting standards related to VIEs that resulted in the deconsolidation of Oncor Holdings as discussed in Note 3 and amended guidance regarding transfers of financial assets that resulted in the accounts receivable securitization program no longer being accounted for as a sale of accounts receivable and the funding under the program now reported as short-term borrowings as discussed in Note 10. All intercompany items and transactions have been eliminated in consolidation. All acquisitions of outstanding debt for cash, including notes that had been issued in lieu of cash interest, are presented in the financing activities section of the statement of cash flows. All dollar amounts in the financial statements and tables in the notes are stated in millions of US dollars unless otherwise indicated.

Use of Estimates

Preparation of financial statements requires estimates and assumptions about future events that affect the reporting of assets and liabilities as of the balance sheet dates and the reported amounts of revenue and expense, including fair value measurements. In the event estimates and/or assumptions prove to be different from actual amounts, adjustments are made in subsequent periods to reflect more current information. No material adjustments, other than those disclosed elsewhere herein, were made to previous estimates or assumptions during the current year.

Derivative Instruments and Mark-to-Market Accounting

We enter into contracts for the purchase and sale of electricity, natural gas and other commodities and also enter into other derivative instruments such as options, swaps, futures and forwards primarily to manage our commodity price and interest rate risks. If the instrument meets the definition of a derivative under accounting standards related to derivative instruments and hedging activities, changes in the fair value of the derivative are recognized in net income as unrealized gains and losses, unless the criteria for certain exceptions are met, and an offsetting derivative asset or liability is recorded in the balance sheet. This recognition is referred to as "mark-to-market" accounting. The fair values of our unsettled derivative instruments under mark-to-market accounting are reported in the balance sheet as commodity and other derivative contractual assets or liabilities. When derivative instruments are settled and realized gains and losses are recorded, the previously recorded unrealized gains and losses and derivative assets and liabilities are reversed. See Notes 15 and 17 for additional information regarding fair value measurement and commodity and other derivative contractual assets and liabilities. Under the election criteria of accounting standards related to derivative instruments and hedging activities, we may elect the "normal" purchase and sale exemption. A commodity-related derivative contract may be designated as a "normal" purchase or sale if the commodity is to be physically received or delivered for use or sale in the normal course of business. If designated as normal, the derivative contract is accounted for under the accrual method of accounting (not marked-to-market) with no balance sheet or income statement recognition of the contract until settlement.

Because derivative instruments are frequently used as economic hedges, accounting standards related to derivative instruments and hedging activities allow for "hedge accounting," which provides for the designation of such instruments as cash flow or fair value hedges if certain conditions are met. A cash flow hedge mitigates the risk associated with the variability of the future cash flows related to an asset or liability (e.g., a forecasted sale of electricity in the future at market prices or the payment of interest related to variable rate debt), while a fair value hedge mitigates risk associated with fixed future cash flows (e.g., debt with fixed interest rate payments). In accounting for changes in the fair value of cash flow hedges, derivative assets and liabilities are recorded on the balance sheet with an offset to other comprehensive income or loss to the extent the hedges are effective and the hedged transaction remains probable of occurring. If the hedged transaction becomes probable of not occurring, hedge accounting is discontinued and the amount recorded in other comprehensive income is immediately reclassified into net income. If the relationship between the hedge and the hedged transaction ceases to exist or is dedesignated, hedge accounting is discontinued, and the amounts recorded in other comprehensive income are recognized as the previously hedged transaction impacts earnings. Changes in value of fair value hedges are recorded as derivative assets or liabilities with an offset to net income, and the carrying value of the related asset or liability (hedged item) is adjusted for changes in fair value with an offset to net income. If the fair value hedge is settled prior to the maturity of the hedged item, the cumulative fair value gain or loss associated with the hedge is amortized into income over the remaining life of the hedged item. In the statement of cash flow, the effects of settlements of derivative instruments are classified consistent with the related hedged transactions.

To qualify for hedge accounting, a hedge must be considered highly effective in offsetting changes in fair value of the hedged item. Assessment of the hedge's effectiveness is tested at least quarterly throughout its term to continue to qualify for hedge accounting. Changes in fair value that represent hedge ineffectiveness, even if the hedge continues to be assessed as effective, are immediately recognized in net income. Ineffectiveness is generally measured as the cumulative excess, if any, of the change in value of the hedging instrument over the change in value of the hedged item. See Notes 11 and 17 for additional information concerning hedging activity.

At December 31, 2010 and 2009, there were no derivative positions accounted for as cash flow or fair value hedges. Accumulated other comprehensive income includes amounts related to interest rate swaps previously designated as cash flow hedges that will be recognized in net income as the hedged transactions impact net income (see Note 11).

Realized and unrealized gains and losses from transacting in energy-related derivative instruments are primarily reported in the income statement in net gain (loss) from commodity hedging and trading activities. In accordance with accounting rules, upon settlement of physical derivative sales and purchase contracts that are marked-to-market in net income, related wholesale electricity revenues and fuel and purchased power costs are reported at approximated market prices, instead of the contract price. As a result, this noncash difference between market and contract prices is included in the operating revenues and fuel and purchased power costs and delivery fees line items of the income statement, with offsetting amounts included in net gain (loss) from commodity hedging and trading activities.

Revenue Recognition

We record revenue from electricity sales and delivery service under the accrual method of accounting. Revenues are recognized when electricity or delivery services are provided to customers on the basis of periodic cycle meter readings and include an estimated accrual for the revenues earned from the meter reading date to the end of the period (unbilled revenue).

We report physically delivered commodity sales and purchases in the income statement on a gross basis in revenues and fuel, purchased power and delivery fees, respectively, and we report all other commodity related contracts and financial instruments (primarily derivatives) in the income statement on a net basis in net gain/(loss) from commodity hedging and trading activities. As part of ERCOT's transition to a nodal wholesale market effective December 1, 2010, volumes under nontrading bilateral purchase and sales contracts, including contracts intended as hedges, are no longer scheduled as physical power with ERCOT. Accordingly, unless the volumes represent physical deliveries to customers or purchases from counterparties, effective with the nodal market implementation, such contracts are reported net in the income statement in net gain/(loss) from commodity hedging and trading activities instead of reported gross as wholesale revenues or purchased power costs. As a result of the changes in wholesale market operations, effective with the nodal market implementation, if volumes delivered to our retail and wholesale customers are less than our generation volumes (as determined on a daily settlement basis), we record additional wholesale revenues, and if volumes delivered to our retail and wholesale customers exceed our generation volumes, we record additional purchased power costs. The additional wholesale revenues or purchased power costs are offset in net gain/(loss) from commodity hedging and trading activities.

Impairment of Long-Lived Assets

We evaluate long-lived assets (including intangible assets with finite lives) for impairment whenever indications of impairment exist. The carrying value of such assets is deemed to be impaired if the projected undiscounted cash flows are less than the carrying value. If there is such impairment, a loss would be recognized based on the amount by which the carrying value exceeds the fair value. Fair value is determined primarily by discounted cash flows, supported by available market valuations, if applicable. See Note 5 for details of the impairment of the natural gas-fueled generation facilities recorded in 2008.

We evaluate investments in unconsolidated subsidiaries for impairment when factors indicate that a decrease in the value of the investment has occurred that is not temporary. Indicators that should be evaluated for possible impairment of investments include recurring operating losses of the investee or fair value measures that are less than carrying value. Any impairment recognition is based on fair value that is not reflective of temporary conditions. Fair value is determined primarily by discounted long-term cash flows, supported by available market valuations, if applicable.

Finite-lived intangibles identified as a result of purchase accounting are amortized over their estimated useful lives based on the expected realization of economic effects. See Note 4 for additional information.

Goodwill and Intangible Assets with Indefinite Lives

We evaluate goodwill and intangible assets with indefinite lives for impairment at least annually (as of December 1) See Note 4 for details of goodwill and intangible assets with indefinite lives, including discussion of fair value determinations and impairments of goodwill and trade name intangible assets recorded in 2010, 2009 and 2008.

Amortization of Nuclear Fuel

Amortization of nuclear fuel is calculated on the units-of-production method and is reported as fuel costs.

Major Maintenance

Major maintenance costs incurred during generation plant outages and the costs of other maintenance activities are charged to expense as incurred and reported as operating costs.

Defined Benefit Pension Plans and Other Postretirement Employee Benefit Plans

We offer pension benefits based on either a traditional defined benefit formula or a cash balance formula and also offer certain health care and life insurance benefits to eligible employees and their eligible dependents upon the retirement of such employees from the company. Costs of pension and OPEB plans are dependent upon numerous factors, assumptions and estimates. The pension and OPEB accrued benefit obligations reported in the balance sheet are in accordance with accounting standards related to employers' accounting for defined benefit pension and other postretirement plans. See Note 20 for additional information regarding pension and OPEB plans.

Stock-Based Incentive Compensation

Our 2007 Stock Incentive Plan authorizes discretionary grants to directors, officers and qualified managerial employees of EFH Corp. or its affiliates of non-qualified stock options, stock appreciation rights, restricted shares, shares of common stock, the opportunity to purchase shares of common stock and other stock-based awards. Stock-based compensation expense is recognized over the vesting period based on the grant-date fair value of those awards. See Note 21 for information regarding stock-based incentive compensation.

Sales and Excise Taxes

Sales and excise taxes are accounted for as a "pass through" item on the balance sheet; i.e., the tax is billed to customers and recorded as trade accounts receivable with an offsetting amount recorded as a liability to the taxing jurisdiction.

Franchise and Revenue-Based Taxes

Unlike sales and excise taxes, franchise and gross receipt taxes are not a "pass through" item. These taxes are assessed to us by state and local government bodies, based on revenues or kWh delivered, as a cost of doing business and are recorded as an expense. Rates we charge to customers are intended to recover our costs, including the franchise and gross receipt taxes, but we are not acting as an agent to collect the taxes from customers.

Income Taxes

We file a consolidated federal income tax return, and federal income taxes are calculated for our subsidiaries substantially as if the entities file separate income tax returns Deferred income taxes are provided for temporary differences between the book and tax basis of assets and liabilities. Effective with the sale of noncontrolling interests in Oncor in 2008 (see Note 14), Oncor became a partnership for US federal income tax purposes, and we provide deferred income taxes on the difference between the book and tax basis of our investment in Oncor. Investment tax credits related to Oncor's regulated operations are deferred and amortized over the lives of the related properties in accordance with regulatory treatment. Certain provisions of the accounting guidance for income taxes allow regulated enterprises to recognize deferred taxes as regulatory tax assets or tax liabilities if it is probable that such amounts will be recovered from, or returned to, customers in future rates.

We report interest and penalties related to uncertain tax positions as current income tax expense.

Accounting for Contingencies

Our financial results may be affected by judgments and estimates related to loss contingencies. Accruals for loss contingencies are recorded when management determines that it is probable that an asset has been impaired or a liability has been incurred and that such economic loss can be reasonably estimated. Such determinations are subject to interpretations of current facts and circumstances, forecasts of future events and estimates of the financial impacts of such events. See Note 12 for a discussion of contingencies.

Cash and Cash Equivalents

For purposes of reporting cash and cash equivalents, temporary cash investments purchased with a remaining maturity of three months or less are considered to be cash equivalents.

Restricted Cash

The terms of certain agreements require the restriction of cash for specific purposes. As of December 31, 2010, $1.135 billion of cash was restricted to support letters of credit. See Notes 11 and 24 for more details regarding restricted cash.

Property, Plant and Equipment

As a result of purchase accounting, carrying amounts of property, plant and equipment related to unregulated businesses were adjusted to estimated fair values at the Merger date. Subsequent additions have been recorded at cost. Oncor's properties are reported at original cost, which is considered to be fair value due to the cost-based regulated recovery and returns associated with those assets. The cost of self-constructed property additions includes materials and both direct and indirect labor and applicable overhead, including payroll-related costs.

Depreciation of our property, plant and equipment is calculated on a straight-line basis over the estimated service lives of the properties. Depreciation expense for unregulated properties is calculated on a component asset-by-asset basis. As is common in the industry for regulated operations, Oncor's depreciation expense is calculated using composite depreciation rates that reflect blended estimates of the lives of major asset groups. Estimated depreciable lives are based on management's estimates of the assets' economic useful lives or, in the case of Oncor, as set by PUCT orders. See Note 24.

Capitalized Interest

Interest related to qualifying construction projects and qualifying software projects is capitalized in accordance with accounting guidance related to capitalization of interest cost. See Note 24.

Inventories

Inventories are reported at the lower of cost (on a weighted average basis) or market unless expected to be used in the generation of electricity. Also see discussion immediately below regarding environmental allowances and credits.

Environmental Allowances and Credits

We account for all environmental allowances and credits as identifiable intangible assets with finite lives that are subject to amortization. The recorded values of these intangible assets were originally established reflecting fair value determinations as of the date of the Merger under purchase accounting. Amortization expense associated with these intangible assets is recognized on a unit of production basis as the allowances or credits are consumed in generation operations. The environmental allowances and credits are assessed for impairment when conditions or events occur that could affect the carrying value of the assets. See Note 4 for details of impairment amounts recorded in 2008.

Regulatory Assets and Liabilities

The financial statements of our regulated electricity delivery operations reflect regulatory assets and liabilities under cost-based rate regulation in accordance with accounting standards related to the effect of certain types of regulation. Regulatory decisions can have an impact on the recovery of costs, the rate earned on invested capital and the timing and amount of assets to be recovered by rates. See Note 24 for details of the regulatory assets and liabilities.

Investments

Investments in unconsolidated subsidiaries, which are 50% or less owned and/or do not meet accounting standards criteria for consolidation, are accounted for under the equity method See Note 2 for discussion of equity method investments and Note 3 for discussion of VIEs.

Investments in a nuclear decommissioning trust fund are carried at current market value in the balance sheet. Assets related to employee benefit plans represent investments held to satisfy deferred compensation liabilities and are recorded at current market value. See Note 18 for discussion of these and other investments.

Noncontrolling Interests

See Note 14 for discussion of accounting for noncontrolling interests in subsidiaries.

Changes in Accounting Standards

As of January 1, 2010, we adopted new FASB guidance that requires reconsideration of consolidation conclusions for all VIEs and other entities with which we are involved. See Note 3 for discussion of our evaluation of VIEs and the resulting deconsolidation of Oncor Holdings and its subsidiaries that resulted in our investment in Oncor Holdings and its subsidiaries being prospectively reported as an equity method investment. There were no other material effects on our financial statements as a result of the adoption of this new guidance.

As of January 1, 2010, we adopted new FASB guidance regarding accounting for transfers of financial assets that eliminates the concept of a qualifying special purpose entity, changes the requirements for derecognizing financial assets and requires additional disclosures. Accordingly, the trade accounts receivable amounts under the accounts receivable securitization program discussed in Note 10 are now reported as pledged balances, and the related funding amounts are reported as short-term borrowings. Prior to January 1, 2010, the activity was accounted for as a sale of accounts receivable in accordance with previous accounting standards, which resulted in the funding being recorded as a reduction of accounts receivable. This new guidance does not impact the covenant-related ratio calculations in our debt agreements.

2. EQUITY METHOD INVESTMENTS

Investments in unconsolidated subsidiaries consisted of the following:

	December 31, 2010	December 31, 2009
Investment in Oncor Holdings (100% owned) (a)	$ 5,544	$ —
Investment in natural gas gathering pipeline business (b)	—	44
Total investments in unconsolidated subsidiaries	$ 5,544	$ 44

(a) Oncor Holdings owns approximately 80% of the membership interests of Oncor and was deconsolidated effective January 1, 2010 (see Notes 1 and 3)

(b) A controlling interest in this previously consolidated subsidiary was sold in 2009, and the remaining interests were sold in June 2010.

Oncor Holdings

Effective January 1, 2010, we account for our investment in Oncor Holdings under the equity method (see Note 3). Prior to this date, Oncor Holdings was a consolidated subsidiary. Oncor Holdings owns approximately 80% of Oncor (an SEC registrant), which is engaged in regulated electricity transmission and distribution operations in Texas. Distribution revenues from TCEH represented 36%, 38% and 39% of total revenues for Oncor Holdings for the years ended December 31, 2010, 2009 and 2008, respectively. Condensed statements of consolidated income of Oncor Holdings for the years ended December 31, 2010, 2009 and 2008 are presented below:

	Year Ended December 31, 2010	2009	2008
Operating revenues	$ 2,914	$ 2,690	$ 2,580
Operation and maintenance expenses	(1,009)	(962)	(852)
Write off of regulatory assets	—	(25)	—
Depreciation and amortization	(673)	(557)	(492)
Taxes other than income taxes	(384)	(385)	(391)
Impairment of goodwill	—	—	(860)
Other income	36	49	45
Other deductions	(8)	(14)	(25)
Interest income	38	43	45
Interest expense and related charges	(347)	(346)	(316)
Income (loss) before income taxes	567	493	(266)
Income tax expense	(220)	(173)	(217)
Net income (loss)	347	320	(483)
Net (income) loss attributable to noncontrolling interests	(70)	(64)	160
Net income (loss) attributable to Oncor Holdings	$ 277	$ 256	$ (323)

Assets and liabilities of Oncor Holdings as of December 31, 2010 and 2009 are presented below:

	December 31,	
	2010	2009
	(millions of dollars)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 33	$ 29
Restricted cash	53	47
Trade accounts receivable — net	254	243
Trade accounts and other receivables from affiliates	182	188
Income taxes receivable from EFH Corp.	72	-
Inventories	96	92
Accumulated deferred income taxes	10	10
Prepayments	75	76
Other current assets	5	8
Total current assets	780	693
Restricted cash	16	14
Other investments	78	72
Property, plant and equipment — net	9,676	9,174
Goodwill	4,064	4,064
Note receivable due from TCEH	178	217
Regulatory assets — net	1,782	1,959
Other noncurrent assets	264	51
Total assets	$ 16,838	$ 16,244
LIABILITIES		
Current liabilities:		
Short-term borrowings	$ 377	$ 616
Long-term debt due currently	113	108
Trade accounts payable — nonaffiliates	125	129
Income taxes payable to EFH Corp.	—	5
Accrued taxes other than income	133	137
Accrued interest	108	104
Other current liabilities	109	106
Total current liabilities	965	1,205
Accumulated deferred income taxes	1,516	1,369
Investment tax credits	32	37
Long-term debt, less amounts due currently	5,333	4,996
Other noncurrent liabilities and deferred credits	1,996	1,879
Total liabilities	$ 9,842	$ 9,486

Oncor Debt Issuances and Exchanges

In September 2010, Oncor issued $475 million aggregate principal amount of 5.250% senior secured notes maturing in September 2040. Oncor used the net proceeds of approximately $465 million from the sale of the notes to repay borrowings under its revolving credit facility, including loans under the revolving credit facility made by certain of the initial purchasers of the notes or their affiliates, and for general corporate purposes. The notes are secured by a first priority lien on Oncor's assets equally and ratably with all of Oncor's other secured indebtedness.

In October 2010, Oncor issued approximately $324.4 million aggregate principal amount of 5.000% senior secured notes due 2017 and approximately $126.3 million aggregate principal amount of 5.750% senior secured notes due 2020 in exchange for an equivalent principal amount of its outstanding 6.375% senior secured notes due 2012 and 5.950% senior secured notes due 2013, respectively. Oncor did not receive any cash proceeds from the exchange.

3. CONSOLIDATION OF VARIABLE INTEREST ENTITIES

A variable interest entity (VIE) is an entity with which we have a relationship or arrangement that indicates some level of control over the entity or results in economic risks to us. We adopted amended accounting standards on January 1, 2010 that require consolidation of a VIE if we have (a) the power to direct the significant activities of the VIE and (b) the right or obligation to absorb profit and loss from the VIE (primary beneficiary). The previous standards did not require power to direct significant activities of the VIE in order to consolidate. As discussed below, our balance sheet includes assets and liabilities of VIEs that meet the consolidation standards and also reflects the deconsolidation of Oncor Holdings, which holds an approximate 80% interest in Oncor.

Our VIEs consist of equity investees. In determining the appropriateness of consolidation of a VIE, we evaluate its purpose, governance structure, decision making processes and risks that are passed on to its interest holders. We also examine the nature of any related party relationships among the interest holders of the VIE and the nature of any special rights granted to the interest holders of the VIE.

Consolidated VIEs

No additional VIEs were consolidated as a result of the new accounting standards. See discussion in Note 10 regarding the VIE related to our accounts receivable securitization program that continues to be consolidated under the amended accounting standards.

We also continue to consolidate Comanche Peak Nuclear Power Company LLC (CPNPC), which was formed by subsidiaries of TCEH and Mitsubishi Heavy Industries Ltd. (MHI) for the purpose of developing two new nuclear generation units at our existing Comanche Peak nuclear-fueled generation facility using MHI's US-Advanced Pressurized Water Reactor technology and to obtain a combined operating license from the NRC. CPNPC is currently financed through capital contributions from the subsidiaries of TCEH and MHI that hold 88% and 12% of CPNPC's equity interests, respectively (see Note 14).

The carrying amounts and classifications of the assets and liabilities related to our consolidated VIEs as of December 31, 2010 are as follows:

Assets:		Liabilities:	
Cash and cash equivalents	$ 9	Short-term borrowings (a)	$ 96
Accounts receivable (a)	612	Trade accounts payable	3
Property, plant and equipment	112	Other current liabilities	1
Other assets, including $2 of current assets	8		
Total assets	$ 741	Total liabilities	$ 100

(a) As a result of the January 1, 2010 adoption of new accounting guidance related to transfers of financial assets, the balance sheet as of December 31, 2010 reflects $612 million of pledged accounts receivable and $96 million of short-term borrowings (see Note 10).

The assets of our consolidated VIEs can only be used to settle the obligations of the VIE, and the creditors of our consolidated VIEs do not have recourse to our general credit.

Non-Consolidated VIEs

The adoption of the amended accounting standards resulted in the deconsolidation of Oncor Holdings, which holds an approximate 80% interest in Oncor, and the reporting of our investment in Oncor Holdings under the equity method on a prospective basis.

In reaching the conclusion to deconsolidate, we conducted an extensive analysis of Oncor Holdings' underlying governing documents and management structure. Oncor Holdings' unique governance structure was adopted in conjunction with the Merger, when the Sponsor Group, EFH Corp. and Oncor agreed to implement structural and operational measures to "ring-fence" (the Ring-Fencing Measures) Oncor Holdings and Oncor as discussed in Note 1. The Ring-Fencing Measures were designed to prevent, among other things, (i) increased borrowing costs at Oncor due to the attribution to Oncor of debt from any of our other subsidiaries, (ii) the activities of our unregulated operations following the Merger resulting in the deterioration of Oncor's business, financial condition and/or investment in infrastructure, and (iii) Oncor becoming substantively consolidated into a bankruptcy proceeding involving any member of the Texas Holdings Group. The Ring-Fencing Measures effectively separated the daily operational and management control of Oncor Holdings and Oncor from EFH Corp. and its other subsidiaries. By implementing the Ring-Fencing Measures, Oncor maintained its investment grade credit rating following the Merger, and we reaffirmed Oncor's independence from our unregulated businesses to the PUCT.

We determined the most significant activities affecting the economic performance of Oncor Holdings (and Oncor) are the operation, maintenance and growth of Oncor's electric transmission and distribution assets and the preservation of its investment grade credit profile. The boards of directors of Oncor Holdings and Oncor have ultimate responsibility for the management of the day-to-day operations of their respective businesses, including the approval of Oncor's capital expenditure and operating budgets and the timing and prosecution of Oncor's rate cases. While both boards include members appointed by EFH Corp., a majority of the board members are independent in accordance with rules established by the New York Stock Exchange, and therefore, we concluded for purposes of applying the amended accounting standards that EFH Corp does not have the power to control the activities deemed most significant to Oncor Holdings' (and Oncor's) economic performance.

In assessing EFH Corp.'s ability to exercise control over Oncor Holdings and Oncor, we considered whether it could take actions to circumvent the purpose and intent of the Ring-Fencing Measures (including changing the composition of Oncor Holdings' or Oncor's board) in order to gain control over the day-to-day operations of either Oncor Holdings or Oncor. We also considered whether (i) EFH Corp. has the unilateral power to dissolve, liquidate or force into bankruptcy either Oncor Holdings or Oncor, (ii) EFH Corp. could unilaterally amend the Ring-Fencing Measures contained in the underlying governing documents of Oncor Holdings or Oncor, and (iii) EFH Corp. could control Oncor's ability to pay distributions and thereby enhance its own cash flow. We concluded that, in each case, no such opportunity exists.

We account for our investment in Oncor Holdings under the equity method, as opposed to the cost method, because we have the ability to exercise significant influence (as defined by US GAAP) over its activities. Our maximum exposure to loss from our variable interests in VIEs does not exceed our carrying value. See Note 2 for additional information about equity method investments including condensed income statement and balance sheet data for Oncor Holdings.

4. GOODWILL AND IDENTIFIABLE INTANGIBLE ASSETS

Goodwill

The following table provides the goodwill balances as of December 31, 2010 and the changes in such balances for the year ended December 31, 2010. With the deconsolidation of Oncor (including its $4.064 billion goodwill balance) effective January 1, 2010, the amounts below relate only to our competitive business. None of the goodwill is being deducted for tax purposes

Goodwill before impairment charges	$	18,342
Accumulated impairment charges through 2009 (a)		(8,090)
Balance as of January 1, 2010		10,252
Additional impairment charge in 2010		(4,100)
Balance as of December 31, 2010 (b)	$	6,152

(a) Includes $90 million in 2009 ($20 million of which was recorded in Corporate and Other results) and $8.0 billion in 2008.
(b) Net of accumulated impairment charges totaling $12.190 billion.

Goodwill and Trade Name Intangible Asset Impairments

In the third quarter 2010, we recorded a $4.1 billion noncash goodwill impairment charge related to the Competitive Electric segment. The impairment testing and resulting charge was driven by the sustained decline in forward natural gas prices and reflected the estimated effect of lower wholesale power prices on the enterprise value of the business as indicated by our cash flow projections and declines in market values of securities of comparable companies.

The calculation of the goodwill impairment involved the following steps: first, we estimated the debt-free enterprise value of the business as of July 31, 2010 taking into account future estimated cash flows and current securities values of comparable companies; second, we estimated the fair values of the individual operating assets and liabilities of the business at that date; third, we calculated "implied" goodwill as the excess of the estimated enterprise value over the estimated value of the net operating assets; and finally, we compared the implied goodwill amount to the carrying value of goodwill and recorded an impairment charge for the amount the carrying value of goodwill exceeded implied goodwill.

The annual impairment testing performed as of December 1, 2010 for goodwill and intangible assets with indefinite useful lives resulted in no additional impairment beyond the charge recorded in the third quarter 2010 discussed immediately above. The annual goodwill test determined that the Competitive Electric segment carrying value exceeded its estimated fair value (enterprise value) by approximately 11%. The estimated enterprise value as of December 1, 2010 did not change materially from the estimate at July 31, 2010. Additional testing was performed to ascertain that the estimated implied goodwill amount as of December 1 had not declined further from the amount estimated at July 31.

In the first quarter 2009, we completed the fair value calculations supporting an initial $8.860 billion goodwill impairment charge that was recorded in the fourth quarter 2008 and consisted of an estimated impairment of $8.0 billion related to the Competitive Electric segment and $860 million related to the Regulated Delivery segment. A $90 million increase in the charge, largely related to the Competitive Electric segment, was recorded in the first quarter 2009. The impairment charge primarily reflected the dislocation in the capital markets during the fourth quarter 2008 that increased interest rate spreads and the resulting discount rates used in estimating fair values and the effect of declines in market values of debt and equity securities of comparable companies. The calculation involved the same steps as those discussed above for the 2010 impairment. The total $8.950 billion charge was the first goodwill impairment recorded subsequent to the Merger date.

Also in the fourth quarter 2008, we recorded a trade name intangible asset impairment charge totaling $481 million ($310 million after-tax). The impairment primarily arose from the increase in the discount rate used in estimating fair value as discussed above.

Although the annual impairment test date for goodwill and intangible assets with indefinite lives set by management at that time was October 1, management determined that in consideration of the continuing deterioration of securities values during the fourth quarter 2008, an impairment testing trigger occurred subsequent to that test date; consequently, the impairment charges were based on estimated fair values as of December 31, 2008.

The impairment determinations involved significant assumptions and judgments. The calculations supporting the estimates of the enterprise value of our businesses and the fair values of their operating assets and liabilities utilized models that take into consideration multiple inputs, including commodity prices, discount rates, debt yields, securities prices of comparable companies and other inputs, assumptions regarding each of which could have a significant effect on valuations. The fair value measurements resulting from these models are classified as non-recurring Level 3 measurements consistent with accounting standards related to the determination of fair value (see Note 15). Because of the volatility of these factors, we cannot predict the likelihood of any future impairment.

Identifiable Intangible Assets

Identifiable intangible assets reported in the balance sheet are comprised of the following:

	As of December 31, 2010 (a)			As of December 31, 2009		
Identifiable Intangible Asset	**Gross Carrying Amount**	**Accumulated Amortization**	**Net**	**Gross Carrying Amount**	**Accumulated Amortization**	**Net**
Retail customer relationship	$ 463	$ 293	$ 170	$ 463	$ 215	$ 248
Favorable purchase and sales contracts	548	257	291	700	374	326
Capitalized in-service software	278	97	181	490	167	323
Environmental allowances and credits	986	304	682	992	212	780
Land easements		—	[illegible]	188	72	116
Mining development costs	47	17	30	32	5	27
Total intangible assets subject to amortization	$ 2,322	$ 968	1,354	$ 2,865	$ 1,045	1,820
Trade name (not subject to amortization)			955			955
Mineral interests (not currently subject to amortization)			91			101
Total intangible assets			$ 2,400			$ 2,876

(a) See Notes 1 and 3 for discussion of the deconsolidation of Oncor Holdings effective January 1, 2010.

Amortization expense related to intangible assets (including income statement line item) consisted of:

Identifiable Intangible Asset	Income Statement Line	Segment	Useful lives as of December 31, 2010 (weighted average in years)	Year Ended December 31, 2010	2009	2008
Retail customer relationship	Depreciation and amortization	Competitive Electric	7	$ 78	$ 85	$ 51
Favorable purchase and sales contracts	Operating revenues/fuel, purchased power costs and delivery fees	Competitive Electric	12	35	125	168
Capitalized in-service software	Depreciation and amortization	All (a)	5	35	53	44
Environmental allowances and credits	Fuel, purchased power costs and delivery fees	Competitive Electric	27	92	91	102
Land easements	Depreciation and amortization	Regulated Delivery (a)	N/A	—	3	3
Mining development costs	Depreciation and amortization	Competitive Electric	3	11	3	1
Total amortization expense				$ 251	$ 360	$ 369

(a) See Notes 1 and 3 for discussion of the deconsolidation of Oncor Holdings effective January 1, 2010.

Separately identifiable and previously unrecognized intangible assets acquired and recorded as part of purchase accounting for the Merger are described as follows

- *Retail Customer Relationship* Retail customer relationship intangible asset represents the estimated fair value of the non-contracted customer base and is being amortized using an accelerated method based on customer attrition rates and reflecting the expected pattern in which economic benefits are realized over their estimated useful life
- *Favorable Purchase and Sales Contracts* Favorable purchase and sales contracts intangible asset primarily represents the above market value, based on observable prices or estimates, of commodity contracts for which: (i) we have made the "normal" purchase or sale election allowed by accounting standards related to derivative instruments and hedging transactions or (ii) the contracts did not meet the definition of a derivative. The amortization periods of these intangible assets are based on the terms of the contracts. Unfavorable purchase and sales contracts are recorded as other noncurrent liabilities and deferred credits (see Note 24).
- *Trade name* – The trade name intangible asset represents the estimated fair value of the TXU Energy trade name, and was determined to be an indefinite-lived asset not subject to amortization. This intangible asset is evaluated for impairment at least annually in accordance with accounting guidance related to goodwill and other intangible assets. See above for discussion of an impairment charge recorded in 2008.
- *Environmental Allowances and Credits* This intangible asset represents the fair value, based on observable prices or estimates, of environmental credits, substantially all of which were expected to be used in our power generation activities. These credits are amortized utilizing a units-of-production method.

Impairment of Environmental Allowances and Credits Intangible Assets

In March 2005, the EPA issued regulations called the Clean Air Interstate Rule (CAIR) for 28 states, including Texas, where our generation facilities are located. CAIR requires reductions of SO_2 and NO_x emissions from power generation facilities in these states. The SO_2 reductions were beyond the reductions required under the Clean Air Act's existing acid rain cap-and-trade program (the Acid Rain Program). CAIR also established a new regional cap-and-trade program for NO_x emissions reductions.

In July 2008, the US Court of Appeals for the D.C. Circuit (the D.C. Circuit Court) invalidated CAIR. The D.C. Circuit Court did not overturn the existing cap-and-trade program for SO_2 reductions under the Acid Rain Program.

Based on the D.C. Circuit Court's ruling, we recorded a noncash impairment charge to earnings in 2008. We impaired NO_x allowances in the amount of $401 million (before deferred income tax benefit). As a result of the D.C. Circuit Court's decision, NO_x allowances would no longer be needed, and thus there would not be an actively traded market for such allowances. Consequently, our NO_x allowances would likely have very little value absent reversal of the D.C. Circuit Court's decision or promulgation of new rules by the EPA. In addition, we impaired SO_2 allowances in the amount of $100 million (before deferred income tax benefit). While the D.C. Circuit Court did not invalidate the Acid Rain Program, we would have more SO_2 allowances than we would need to comply with the Acid Rain Program. While there continued to be a market for SO_2 allowances, the D.C. Circuit Court's decision resulted in a material decrease in the market price of SO_2 allowances.

The impairment amounts recorded in 2008 were reported in other deductions and reflected in the results of the Competitive Electric segment.

In December 2008, in response to an EPA petition, the D.C. Circuit Court reversed, in part, its previous ruling. Such reversal confirmed CAIR is not valid, but allowed it to remain in place while the EPA revises CAIR to correct the previously identified shortcomings. In July 2010, the EPA released a proposed rule called the Clean Air Transport Rule (CATR). The CATR, as proposed, would replace CAIR in 2012. We cannot predict the impact of a final rule on our business, results of operations and financial condition

Estimated Amortization of Intangible Assets The estimated aggregate amortization expense of intangible assets for each of the next five fiscal years is as follows:

Year		Amortization Expense
2011	$	198
2012		154
2013		132
2014		116
2015		98

5. IMPAIRMENT OF NATURAL GAS-FUELED GENERATION FACILITIES

In 2008, we performed an evaluation of our natural gas-fueled generation facilities for impairment. The impairment test was triggered by a determination that it was more likely than not that certain generation units would be retired or mothballed (idled) earlier than previously expected. The natural gas-fueled generation units are generally operated to meet peak demands for electricity and all such facilities are tested for impairment as an asset group. As a result of the evaluation, it was determined that an impairment existed, and a charge of $229 million ($147 million after-tax) was recorded to write down the assets to fair value of approximately $28 million, which was determined based on discounted estimated future cash flows. The impairment was reported in other deductions in the Competitive Electric segment.

6. MERGER-RELATED STIPULATION APPROVED BY THE PUCT

In 2008, the PUCT issued a final order approving a stipulation to resolve all outstanding issues in the PUCT review related to the Merger. The terms of the stipulation were agreed to by Oncor and Texas Holdings as well as major interested parties, conditioned on completion of the Merger. The order has been appealed with respect to certain elements, none of which are expected to affect the following major provisions of the stipulation:

- Oncor provided a one-time $72 million refund to its REP customers in the September 2008 billing cycle. The refund was in the form of a credit on distribution fee billings. The liability for the refund was recorded as part of purchase accounting.
- Consistent with a rate settlement with certain cities in 2006, Oncor filed a system-wide rate case in June 2008 based on a test-year ended December 31, 2007. In August 2009, the PUCT issued a final order on this rate case. See Note 24.
- Oncor agreed not to request recovery of approximately $56 million of regulatory assets related to self-insurance reserve costs and 2002 restructuring expenses. These regulatory assets were eliminated as part of purchase accounting.
- The cash distributions paid by Oncor to its members will be limited through December 31, 2012, to an amount not to exceed Oncor's net income (determined in accordance with US GAAP, subject to certain defined adjustments) for the period beginning October 11, 2007 and ending December 31, 2012, and are further limited by an agreement that Oncor's regulatory capital structure, as determined by the PUCT, will be at or below the assumed debt-to-equity ratio established periodically by the PUCT for ratemaking purposes, which is currently set at 60% debt to 40% equity (see Note 13).
- Oncor committed to minimum capital spending of $3.6 billion over the five-year period ending December 31, 2012, subject to certain defined conditions.
- Oncor committed to an additional $100 million in spending over the five-year period ending December 31, 2012 on demand-side management or other energy efficiency initiatives. These additional expenditures will not be recoverable in rates, and this amount was recorded as a regulatory liability as part of purchase accounting and consistent with accounting standards related to the effect of certain types of regulation.
- If Oncor's credit rating is below investment grade with two or more rating agencies, TCEH will post a letter of credit in an amount of $170 million to secure TXU Energy's payment obligations to Oncor.
- Oncor agreed not to request recovery of the $4.9 billion of goodwill resulting from purchase accounting or any future impairment of the goodwill in its rates.

7. ACCOUNTING FOR UNCERTAINTY IN INCOME TAXES

Accounting guidance related to uncertain tax positions requires that all tax positions subject to uncertainty be reviewed and assessed with recognition and measurement of the tax benefit based on a "more-likely-than-not" standard with respect to the ultimate outcome, regardless of whether this assessment is favorable or unfavorable.

We file income tax returns in US federal, state and foreign jurisdictions and are subject to examinations by the IRS and other taxing authorities. Examinations of our income tax returns for the years ending prior to January 1, 2003 are complete, but the tax years 1997 to 2002 remain in appeals with the IRS. An IRS audit of tax years 2003 to 2006 is in progress and is expected to be completed in 2011. Texas franchise and margin tax returns are under examination or still open for examination for tax years beginning after 2002.

In 2008, we participated in negotiations with the IRS regarding the 2002 worthlessness loss associated with our discontinued Europe business, and we reduced the liability for uncertain tax positions in accordance with accounting guidance. The reduction in the liability of approximately $375 million was largely offset by a reduction of deferred tax assets related to alternative minimum tax.

In 2010, we again engaged in negotiations with the IRS regarding this worthlessness loss as well as other matters. Accordingly, we have adjusted the liability for uncertain tax positions to reflect the most likely settlement of the issues. The adjustment resulted in a net reduction of the liability for uncertain tax positions totaling $162 million. This reduction consisted of a $225 million reversal of accrued interest ($146 million after tax), reported as a reduction of income tax expense, principally related to the discontinued Europe business, partially offset by $63 million in adjustments related to several other positions that have been accounted for as reclassifications to net deferred tax liabilities. The conclusion of all issues contested from the 1997 through 2002 audit, including IRS Joint Committee review, is expected to occur before the end of 2012. Upon such conclusion, we expect to further reduce the liability for uncertain tax positions by approximately $700 million with an offsetting decrease in deferred tax assets that arose largely from previous payments of alternative minimum taxes. No cash income tax liability is expected related to the conclusion of the 1997 through 2002 audit.

We classify interest and penalties related to uncertain tax positions as current income tax expense. Amounts recorded related to interest and penalties totaled a benefit of $115 million in 2010, and expenses of $42 million in 2009 and $88 million in 2008, including $29 million recorded as goodwill (all amounts after tax).

Noncurrent liabilities included a total of $164 million and $361 million in accrued interest as of December 31, 2010 and 2009, respectively. Oncor Holdings, which had $20 million in noncurrent liabilities related to accrued interest, was deconsolidated as of January 1, 2010 as discussed in Note 2. The federal income tax benefit on the interest accrued on uncertain tax positions is recorded as accumulated deferred income taxes.

The following table summarizes the changes to the uncertain tax positions, reported in other noncurrent liabilities in the consolidated balance sheet, during the years ended December 31, 2010, 2009 and 2008:

	2010	2009	2008
Balance as of January 1, excluding interest and penalties (a)	$ 1,566	$ 1,583	$ 1,834
Additions based on tax positions related to prior years	312	71	124
Reductions based on tax positions related to prior years	(308)	(82)	(451)
Additions based on tax positions related to the current year	72	66	33
Settlements with taxing authorities	—	—	43
Balance as of December 31, excluding interest and penalties	$ 1,642	$ 1,638	$ 1,583

(a) 2010 reflects the deconsolidation of Oncor Holdings, which had a balance of $72 million, as of January 1, 2010.

Of the balance as of December 31, 2010, $1.442 billion represents tax positions for which the uncertainty relates to the timing of recognition in tax returns. The disallowance of such positions would not affect the effective tax rate, but could accelerate the payment of cash to the taxing authority to an earlier period.

With respect to tax positions for which the ultimate deductibility is uncertain (permanent items), should we sustain such positions on income tax returns previously filed, tax liabilities recorded would be reduced by $200 million, and accrued interest would be reversed resulting in a $28 million after-tax benefit, resulting in increased net income and a favorable impact on the effective tax rate.

Other than the items discussed above, we do not expect the total amount of liabilities recorded related to uncertain tax positions will significantly increase or decrease within the next 12 months.

8. INCOME TAXES

The components of our income tax expense (benefit) applicable to continuing operations are as follows:

	Year Ended December 31, 2010	2009	2008
Current:			
US Federal	$ (256)	$ 64	$ (46)
State	41	51	52
Total	(215)	115	6
Deferred:			
US Federal	590	256	(482)
State	14	1	10
Total	604	257	(472)
Amortization of investment tax credits	—	(5)	(5)
Total	$ 389	$ 367	$ (471)

Reconciliation of income taxes computed at the US federal statutory rate to income tax expense:

	Year Ended December 31, 2010	2009	2008
Income (loss) before income taxes	$ (2,700)	$ 775	$ (10,469)
Income taxes at the US federal statutory rate of 35%	$ (945)	$ 271	$ (3,664)
Nondeductible goodwill impairment	1,435	32	3,101
Lignite depletion allowance	(21)	(18)	(29)
Amortization of investment tax credits, net of tax	—	(5)	(5)
Amortization (under regulatory accounting) of statutory rate changes	—	5	2
Medicare subsidy — retiree benefits	—	(7)	(6)
Nondeductible interest expense	11	13	11
Nondeductible losses (earnings) on benefit plans	—	(1)	9
Texas margin tax, net of federal benefit	34	30	39
Interest accrued for uncertain tax positions, net of tax	(115)	42	59
Deferred tax charge for effect of health care legislation	8	—	—
Reversal of previously disallowed interest resulting from debt exchanges	(21)	—	—
Other, including audit settlements	3	5	12
Income tax expense (benefit)	$ 389	$ 367	$ (471)
Effective tax rate	(14.4)%	47.4%	4.5%

Deferred Income Tax Balances

Deferred income taxes provided for temporary differences based on tax laws in effect as of December 31, 2010 and 2009 balance sheet dates are as follows:

	December 31,					
	2010 (a)			2009		
	Total	Current	Noncurrent	Total	Current	Noncurrent
Deferred Income Tax Assets						
Alternative minimum tax credit carryforwards	$ 406	$ —	$ 406	$ 438	$	$ 438
Employee benefit liabilities	216	25	191	206	22	184
Net operating loss (NOL) carryforwards	833	—	833	422		422
Unfavorable purchase and sales contracts	240	—	240	249		249
Accrued interest	157	—	157	211		211
Other	317	2	315	351	13	338
Total	2,169	27	2,142	1,877	35	1,842
Deferred Income Tax Liabilities						
Property, plant and equipment	4,321	—	4,321	4,141	—	4,141
Basis difference in Oncor partnership	—	—	—	1,369	—	1,369
Commodity contracts and interest rate swaps	1,692	31	1,661	1,325	30	1,295
Identifiable intangible assets	846	—	846	921	—	921
Debt fair value discounts	126	—	126	184	—	184
Debt extinguishment gains	503	—	503	35	—	35
Other	42	7	35	28	—	28
Total	7,530	38	7,492	8,003	30	7,973
Net Deferred Income Tax (Asset) Liability	$ 5,361	$ 11	$ 5,350	$ 6,126	$ (5)	$ 6,131

(a) See Notes 1 and 3 for discussion of the deconsolidation of Oncor Holdings effective January 1, 2010.

As of December 31, 2010 we had $406 million of alternative minimum tax credit carryforwards (AMT) available to offset future tax payments. The AMT credit carryforwards have no expiration date. As of December 31, 2010, we had net operating loss (NOL) carryforwards for federal income tax purposes of $2.4 billion that expire between 2028 and 2031. The NOL carryforwards can be used to offset future taxable income. We expect to utilize all of our NOL carryforwards prior to their expiration dates.

The component of deferred income tax liabilities referred to as "basis difference in Oncor partnership" arose as a result of the sale of noncontrolling interests in Oncor (see Note 14) at which time Oncor became a partnership for US federal income tax purposes. The amount of this basis difference at the date of the transaction represented our interest (approximately 80%) in the net deferred tax liabilities related to Oncor's individual operating assets and liabilities. The remaining net deferred tax liabilities associated with Oncor ($321 million as of December 31, 2009) that were attributable to the noncontrolling interests were reclassified as other noncurrent liabilities and deconsolidated with Oncor Holdings in 2010 as discussed in Notes 1 and 3 (see Note 24).

The income tax effects of the components included in accumulated other comprehensive income as of December 31, 2010 and 2009 totaled a net deferred tax asset of $141 million and $165 million, respectively.

See Note 7 for discussion regarding accounting for uncertain tax positions.

Effect of Health Care Legislation — The Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act enacted in March 2010 reduces, effective in 2013, the amount of OPEB costs deductible for federal income tax purposes by the amount of the Medicare Part D subsidy we receive. Under income tax accounting rules, deferred tax assets related to accrued OPEB liabilities must be reduced immediately for the future effect of the legislation. Accordingly, in the first quarter 2010, EFH Corp.'s and Oncor's deferred tax assets were reduced by $50 million. Of this amount, $8 million was recorded as a charge to income tax expense and $42 million was recorded in receivables from unconsolidated subsidiary, reflecting a regulatory asset recorded by Oncor (before gross-up for liability in lieu of deferred income taxes) as the additional income taxes are expected to be recoverable in Oncor's future rates.

9. OTHER INCOME AND DEDUCTIONS

	Year Ended December 31, 2010	2009	2008
Other income:			
Debt extinguishment gains (Note 11) (a)	$ 1,814	$ 87	$ —
Gain on termination of long-term power sales contract (b) (c)	116	—	—
Gain on sale of land/water rights (c)	44	—	—
Gain on sale of interest in natural gas gathering pipeline business (c)	37	—	—
Office space rental income (a)	12	—	—
Insurance/litigation settlements (c) (d)	6	—	21
Sales tax refund	5	5	—
Mineral rights royalty income (c)	1	6	4
Reversal of reserves recorded in purchase accounting (e)	—	44	—
Accretion of adjustment (discount) of regulatory assets resulting from purchase accounting (Note 24) (f)	—	39	44
Fee received related to interest rate swap/commodity hedge derivative agreement (Note 17) (c)	—	6	—
Other	16	17	11
Total other income	$ 2,051	$ 204	$ 80
Other deductions:			
Impairment of trade name intangible asset (Note 4) (c)	$ —	$ —	$ 481
Impairment of emission allowances intangible assets (Note 4) (c)	—		501
Charge for impairment of natural gas-fueled generation facilities (Note 5) (c)	—	—	229
Impairment of land (c)	—	34	—
Charge related to Lehman bankruptcy (g)	—	—	26
Write-off of regulatory assets (Note 24) (f)	—	25	—
Ongoing pension and OPEB expense related to discontinued businesses (a)	7	—	—
Professional fees incurred related to the Merger (h)	5	—	14
Net charges related to cancelled development of generation facilities (c)	3	6	12
Severance charges	3	7	—
Costs related to 2006 cities rate settlement (f)	—	2	13
Litigation/regulatory settlements	—	3	10
Other	13	20	15
Total other deductions	$ 31	$ 97	$ 1,301

(a) Reported in Corporate and Other segment, except for $687 million of debt extinguishment gain reported in Competitive Electric segment.

(b) In November 2010, the counterparty to a long-term power sales agreement terminated the contract, which had a remaining term of 27 years. The contract was a derivative and subject to mark-to-market accounting. The termination resulted in a noncash gain of $116 million, which represented the derivative liability as of the termination date.

(c) Reported in Competitive Electric segment

(d) 2008 amount represents insurance recovery for damage to mining equipment.

(e) Includes $23 million for reversal of a use tax accrual, related to periods prior to the Merger, due to a state ruling in 2009 (reported in Competitive Electric segment) and $21 million for reversal of excess exit liabilities recorded in connection with the termination of outsourcing arrangements (see Note 19) (reported in Competitive Electric ($11 million) and Regulated Delivery segments ($10 million)).

(f) Reported in Regulated Delivery segment.

(g) Represents reserve established against amounts due (excluding termination related costs) from subsidiaries of Lehman Brothers Holdings Inc. (Lehman) arising from commodity hedging and trading activities. Reported in Competitive Electric segment.

(h) Includes post-Merger consulting expenses related to optimizing business performance. Reported in Corporate and Other activities

10. TRADE ACCOUNTS RECEIVABLE AND ACCOUNTS RECEIVABLE SECURITIZATION PROGRAM

TXU Energy participates in EFH Corp.'s accounts receivable securitization program with financial institutions (the funding entities). Under the program, TXU Energy (originator) sells trade accounts receivable to TXU Receivables Company, which is an entity created for the special purpose of purchasing receivables from the originator and is a consolidated, wholly-owned, bankruptcy-remote, direct subsidiary of EFH Corp. TXU Receivables Company sells undivided interests in the purchased accounts receivable for cash to entities established for this purpose by the funding entities. In accordance with the amended transfers and servicing accounting standard as discussed in Note 1, the trade accounts receivable amounts under the program are reported as pledged balances, and the related funding amounts are reported as short-term borrowings. Prior to the January 1, 2010 effective date of the new accounting standard, the activity was accounted for as a sale of accounts receivable in accordance with previous accounting standards, which resulted in the funding being recorded as a reduction of accounts receivable.

In June 2010, the accounts receivable securitization program was amended. The amendments, among other things, reduced the maximum funding amount under the program to $350 million from $700 million. Program funding declined from $383 million as of December 31, 2009 to $96 million as of December 31, 2010. Under the terms of the program, available funding was reduced by $38 million of customer deposits held by the originator because TCEH's credit ratings were lower than Ba3/BB-. The declines in actual and maximum funding amounts reflected exclusion of receivables under contractual sales agreements.

All new trade receivables under the program generated by the originator are continuously purchased by TXU Receivables Company with the proceeds from collections of receivables previously purchased. Ongoing changes in the amount of funding under the program, through changes in the amount of undivided interests sold by TXU Receivables Company, reflect seasonal variations in the level of accounts receivable, changes in collection trends and other factors such as changes in sales prices and volumes. TXU Receivables Company has issued a subordinated note payable to the originator for the difference between the face amount of the uncollected accounts receivable purchased, less a discount, and cash paid to the originator that was funded by the sale of the undivided interests. The subordinated note issued by TXU Receivables Company is subordinated to the undivided interests of the funding entities in the purchased receivables. The balance of the subordinated note payable, which is eliminated in consolidation, totaled $516 million and $463 million as of December 31, 2010 and 2009, respectively.

The discount from face amount on the purchase of receivables from the originator principally funds program fees paid to the funding entities The program fees consist primarily of interest costs on the underlying financing. Consistent with the change in balance sheet presentation of the funding discussed above, the program fees are currently reported as interest expense and related charges but were previously reported as losses on sale of receivables reported in SG&A expense. The discount also funds a servicing fee, which is reported as SG&A expense, paid by TXU Receivables Company to EFH Corporate Services Company (Service Co.), a direct wholly-owned subsidiary of EFH Corp., which provides recordkeeping services and is the collection agent for the program.

Program fee amounts were as follows:

	Year Ended December 31,		
	2010	2009	2008
Program fees	$ 10	$ 12	$ 25
Program fees as a percentage of average funding (annualized)	3.8%	2.4%	5.2%

Activities of TXU Receivables Company were as follows:

	Year Ended December 31,		
	2010	2009	2008
Cash collections on accounts receivable	$ 6,334	$ 6,125	$ 6,393
Face amount of new receivables purchased	(6,100)	(6,287)	(6,418)
Discount from face amount of purchased receivables	12	14	29
Program fees paid to funding entities	(10)	(12)	(25)
Servicing fees paid to Service Co. for recordkeeping and collection services	(2)	(2)	(4)
Increase (decrease) in subordinated notes payable	53	195	(28)
Financing/operating cash flows used by (provided to) originator under the program	$ 287	$ 33	$ (53)

Changes in funding under the program have previously been reported as operating cash flows, and the amended accounting rule requires that the amount of funding under the program as of the January 1, 2010 adoption ($383 million) be reported as a use of operating cash flows and a source of financing cash flows. All changes in funding subsequent to adoption of the amended standard are reported as financing activities.

The program, which expires in October 2013, may be terminated upon the occurrence of a number of specified events, including if the delinquency ratio (delinquent for 31 days) for the sold receivables, the default ratio (delinquent for 91 days or deemed uncollectible), the dilution ratio (reductions for discounts, disputes and other allowances) or the days collection outstanding ratio exceed stated thresholds, and the funding entities do not waive such event of termination. The thresholds apply to the entire portfolio of sold receivables. In addition, the program may be terminated if TXU Receivables Company or Service Co. defaults in any payment with respect to debt in excess of $50,000 in the aggregate for such entities, or if TCEH, any affiliate of TCEH acting as collection agent other than Service Co., any parent guarantor of the originator or the originator shall default in any payment with respect to debt (other than hedging obligations) in excess of $200 million in the aggregate for such entities. As of December 31, 2010, there were no such events of termination.

Upon termination of the program, liquidity would be reduced as collections of sold receivables would be used by TXU Receivables Company to repurchase the undivided interests from the funding entities instead of purchasing new receivables. The level of cash flows would normalize in approximately 16 to 30 days.

Trade Accounts Receivable

	December 31,	
	2010 (a)	2009
Wholesale and retail trade accounts receivable, including $612 in pledged retail receivables as of December 31, 2010	$ 1,063	$ 1,726
Undivided interests in retail accounts receivable sold by TXU Receivables Company	—	(383)
Allowance for uncollectible accounts	(64)	(83)
Trade accounts receivable — reported in balance sheet	$ 999	$ 1,260

(a) See Notes 1 and 3 for discussion of the deconsolidation of Oncor Holdings effective January 1, 2010.

Gross trade accounts receivable as of December 31, 2010 and 2009 included unbilled revenues of $297 million and $546 million, respectively.

Allowance for Uncollectible Accounts Receivable

	Year Ended December 31,		
	2010	2009	2008
Allowance for uncollectible accounts receivable as of beginning of period	$ 81	$ 70	$ 32
Increase for bad debt expense	108	113	81
Decrease for account write-offs	(125)	(99)	(69)
Charge related to Lehman bankruptcy	—	—	26
Other	—	(1)	—
Allowance for uncollectible accounts receivable as of end of period	$ 64	$ 83	$ 70

Receivables from Unconsolidated Subsidiary

Receivables from unconsolidated subsidiary are measured at historical cost and primarily consist of Oncor's obligation under the EFH Corp. pension and OPEB plans. EFH Corp. reviews Oncor's credit scores to assess the overall collectability of its affiliated receivables, which totaled $1.463 billion as of December 31, 2010. There were no credit loss allowances as of December 31, 2010. See Note 22 for additional information about related party transactions.

11. SHORT-TERM BORROWINGS AND LONG-TERM DEBT

Short-Term Borrowings

As of December 31, 2010, outstanding short-term borrowings totaled $1.221 billion, which included $1.125 billion under TCEH credit facilities at a weighted average interest rate of 3.80%, excluding certain customary fees, and $96 million under the accounts receivable securitization program discussed in Note 10.

As of December 31, 2009, we had outstanding short-term borrowings of $1.569 billion at a weighted average interest rate of 2.50%, excluding certain customary fees, at the end of the period. Short-term borrowings under credit facilities totaled $953 million for TCEH and $616 million for Oncor.

Credit Facilities

Credit facilities with cash borrowing and/or letter of credit availability as of December 31, 2010 are presented below. The facilities are all senior secured facilities of TCEH.

		As of December 31, 2010			
Authorized Borrowers and Facility	**Maturity Date**	**Facility Limit**	**Letters of Credit**	**Cash Borrowings**	**Availability**
TCEH Revolving Credit Facility (a)	October 2013	$ 2,700	$ —	$ 1,125	$ 1,440
TCEH Letter of Credit Facility (b)	October 2014	1,250	—	1,250	—
Subtotal TCEH		$ 3,950	$ —	$ 2,375	$ 1,440
TCEH Commodity Collateral Posting Facility (c)	December 2012	Unlimited	$ —	$ —	Unlimited

(a) Facility used for letters of credit and borrowings for general corporate purposes. Borrowings are classified as short-term borrowings. Availability amount includes $94 million of commitments from Lehman that are only available from the fronting banks and the swingline lender and excludes $135 million of requested cash draws that have not been funded by Lehman. All outstanding borrowings under this facility as of December 31, 2010 bear interest at LIBOR plus 3.5%, and a commitment fee is payable quarterly in arrears at a rate per annum equal to 0.50% of the average daily unused portion of the facility.

(b) Facility used for issuing letters of credit for general corporate purposes, including, but not limited to, providing collateral support under hedging arrangements and other commodity transactions that are not eligible for funding under the TCEH Commodity Collateral Posting Facility. The borrowings under this facility were drawn at the inception of the facility, are classified as long-term debt, and except for $115 million related to a letter of credit drawn in June 2009, have been retained as restricted cash. Letters of credit totaling $874 million issued as of December 31, 2010 are supported by the restricted cash, and the remaining letter of credit availability totals $261 million.

(c) Revolving facility used to fund cash collateral posting requirements for specified volumes of natural gas hedges totaling approximately 330 million MMBtu as of December 31, 2010. As of December 31, 2010, there were no borrowings under this facility. See "TCEH Senior Secured Facilities" below for additional information.

Long-Term Debt

As of December 31, 2010 and December 31, 2009, long-term debt consisted of the following:

	December 31, 2010	December 31, 2009
TCEH		
Pollution Control Revenue Bonds,		
Brazos River Authority:		
5.400% Fixed Series 1994A due May 1, 2029	$ 39	$ 39
7.700% Fixed Series 1999A due April 1, 2033	111	111
6.750% Fixed Series 1999B due September 1, 2034, remarketing date April 1, 2013 (a)	16	16
7.700% Fixed Series 1999C due March 1, 2032	50	50
8.250% Fixed Series 2001A due October 1, 2030	71	71
5.750% Fixed Series 2001C due May 1, 2036, remarketing date November 1, 2011 (a)	217	217
8.250% Fixed Series 2001D-1 due May 1, 2033	171	171
0.320% Floating Series 2001D-2 due May 1, 2033 (b)	97	97
0.310% Floating Taxable Series 2001I due December 1, 2036 (c)	62	62
0.320% Floating Series 2002A due May 1, 2037 (b)	45	45
6.750% Fixed Series 2003A due April 1, 2038, remarketing date April 1, 2013 (a)	44	44
6.300% Fixed Series 2003B due July 1, 2032	39	39
6.750% Fixed Series 2003C due October 1, 2038	52	52
5.400% Fixed Series 2003D due October 1, 2029, remarketing date October 1, 2014 (a)	31	31
5.000% Fixed Series 2006 due March 1, 2041	100	100
Sabine River Authority of Texas:		
6.450% Fixed Series 2000A due June 1, 2021	51	51
5.500% Fixed Series 2001A due May 1, 2022, remarketing date November 1, 2011 (a)	91	91
5.750% Fixed Series 2001B due May 1, 2030, remarketing date November 1, 2011 (a)	107	107
5.200% Fixed Series 2001C due May 1, 2028	70	70
5.800% Fixed Series 2003A due July 1, 2022	12	12
6.150% Fixed Series 2003B due August 1, 2022	45	45
Trinity River Authority of Texas:		
6.250% Fixed Series 2000A due May 1, 2028	14	14
Unamortized fair value discount related to pollution control revenue bonds (d)	(132)	(147)
Senior Secured Facilities:		
3.764% TCEH Initial Term Loan Facility maturing October 10, 2014 (e)(f)(g)	15,895	16,079
3.764% TCEH Delayed Draw Term Loan Facility maturing October 10, 2014 (e)(f)	4,034	4,075
3.761% TCEH Letter of Credit Facility maturing October 10, 2014 (f)	1,250	1,250
0.250% TCEH Commodity Collateral Posting Facility maturing December 31, 2012 (h)	—	—
Other:		
10.25% Fixed Senior Notes due November 1, 2015 (i)	1,873	2,944
10.25% Fixed Senior Notes due November 1, 2015, Series B (i)	1,292	1,913
10.50 / 11.25% Senior Toggle Notes due November 1, 2016	1,406	1,952
15.00% Senior Secured Second Lien Notes due April 1, 2021	336	—
15.00% Senior Secured Second Lien Notes due April 1, 2021, Series B	1,235	—
7.000% Fixed Senior Notes due March 15, 2013	5	5
7.460% Fixed Secured Facility Bonds with amortizing payments through January 2015	42	55
Capital lease obligations	76	153
Other	3	—
Unamortized fair value discount (d)	(2)	(4)
Total TCEH	$ 28,848	$ 29,810

	December 31, 2010	December 31, 2009
EFCH		
9.580% Fixed Notes due in semiannual installments through December 4, 2019	$ 46	$ 51
8.254% Fixed Notes due in quarterly installments through December 31, 2021	46	50
1.087% Floating Rate Junior Subordinated Debentures, Series D due January 30, 2037 (f)	1	1
8.175% Fixed Junior Subordinated Debentures, Series E due January 30, 2037	8	8
Unamortized fair value discount (d)	(10)	(11)
Total EFCH	91	99
EFH Corp. (parent entity)		
10.875% Fixed Senior Notes due November 1, 2017 (j)	359	1,831
11.25 / 12.00% Senior Toggle Notes due November 1, 2017 (j)	571	2,797
9.75% Fixed Senior Secured Notes due October 15, 2019	115	115
10.000% Fixed Senior Secured Notes due January 15, 2020	1,061	—
5.550% Fixed Senior Notes Series P due November 15, 2014 (k)	434	983
6.500% Fixed Senior Notes Series Q due November 15, 2024 (k)	740	740
6.550% Fixed Senior Notes Series R due November 15, 2034 (k)	744	744
8.820% Building Financing due semiannually through February 11, 2022 (l)	68	75
Unamortized fair value premium related to Building Financing (d)	15	17
Capital lease obligations	4	—
Unamortized fair value discount (d)	(476)	(599)
Total EFH Corp.	3,635	6,703
EFIH		
9.75% Fixed Senior Secured Notes due October 15, 2019	141	141
10.000% Fixed Senior Secured Notes due December 1, 2020	2,180	—
Total EFIH	2,321	141
Oncor (m) (n)		
6.375% Fixed Senior Notes due May 1, 2012	—	700
5.950% Fixed Senior Notes due September 1, 2013	—	650
6.375% Fixed Senior Notes due January 15, 2015	—	500
6.800% Fixed Senior Notes due September 1, 2018	—	550
7.000% Fixed Debentures due September 1, 2022	—	800
7.000% Fixed Senior Notes due May 1, 2032	—	500
7.250% Fixed Senior Notes due January 15, 2033	—	350
7.500% Fixed Senior Notes due September 1, 2038	—	300
Unamortized discount	—	(15)
Total Oncor	—	4,335
Oncor Electric Delivery Transition Bond Company LLC (n) (o)		
4.030% Fixed Series 2003 Bonds due in semiannual installments through February 15, 2010	—	13
4.950% Fixed Series 2003 Bonds due in semiannual installments through February 15, 2013		130
5.420% Fixed Series 2003 Bonds due in semiannual installments through August 15, 2015	—	145
4.810% Fixed Series 2004 Bonds due in semiannual installments through November 15, 2012	—	197
5.290% Fixed Series 2004 Bonds due in semiannual installments through May 15, 2016		290
Total Oncor Electric Delivery Transition Bond Company LLC		775
Unamortized fair value discount related to transition bonds (d)		(6)
Total Oncor consolidated	—	5,104
Total EFH Corp. consolidated	34,895	41,857
Less amount due currently	(669)	(417)
Total long-term debt	$ 34,226	$ 41,440

(a) These series are in the multiannual interest rate mode and are subject to mandatory tender prior to maturity on the mandatory remarketing date. On such date, the interest rate and interest rate period will be reset for the bonds.

(b) Interest rates in effect as of December 31, 2010. These series are in a daily interest rate mode and are classified as long-term as they are supported by long-term irrevocable letters of credit.

(c) Interest rate in effect as of December 31, 2010. This series is in a weekly interest rate mode and is classified as long-term as it is supported by long-term irrevocable letters of credit.

(d) Amount represents unamortized fair value adjustments recorded under purchase accounting

(e) Interest rate swapped to fixed on $15.80 billion principal amount.

(f) Interest rates in effect as of December 31, 2010.

(g) 2010 amount excludes $20 million that is held by EFH Corp. and eliminated in consolidation.
(h) Interest rate in effect as of December 31, 2010, excluding a quarterly maintenance fee of $11 million. See "Credit Facilities" above for more information
(i) 2010 amounts exclude $173 million and $150 million of the TCEH Senior Notes and TCEH Senior Notes, Series B, respectively, that are held either by EFH Corp. or EFIH and eliminated in consolidation.
(j) 2010 amounts exclude $1.428 billion and $2.296 billion of EFH Corp. 10.875% Notes and EFH Corp. Toggle Notes, respectively, that are held by EFIH and eliminated in consolidation.
(k) Amounts exclude $9 million, $6 million and $3 million of the Series P, Series Q and Series R notes, respectively, that are held by EFIH and eliminated in consolidation.
(l) This financing is secured and will be serviced with cash drawn by the beneficiary of a letter of credit.
(m) Secured with first priority lien.
(n) See Notes 1 and 3 for discussion of the deconsolidation of Oncor Holdings effective as of January 1, 2010.
(o) These bonds are nonrecourse to Oncor and were issued to securitize a regulatory asset.

Debt-Related Activity in 2010 — Repayments of long-term debt in 2010 totaling $309 million included $205 million of principal payments at scheduled maturity dates as well as other repayments totaling $104 million principally related to capitalized leases. See "2010 Debt Exchanges, Repurchases and Issuances" below for discussion of $6.904 billion principal amount of debt acquired in debt exchanges and repurchases completed in the year ended December 31, 2010.

During 2010, EFH Corp. issued, through the payment-in-kind (PIK) election, $194 million principal amount of its 11.25%/12.00% Senior Toggle Notes due November 2017 (EFH Corp. Toggle Notes), and TCEH issued, through the PIK election, $205 million principal amount of its 10.50%/11.25% Senior Toggle Notes due November 2016 (TCEH Toggle Notes), in each case, in lieu of making cash interest payments

2010 Debt Exchanges, Repurchases and Issuances — Debt exchanges and repurchases completed in 2010 resulted in acquisitions of $6.904 billion aggregate principal amount of outstanding EFH Corp. and TCEH debt with due dates largely 2017 or earlier in exchange for $3.962 billion aggregate principal amount of new debt and $1.042 billion in cash. The new debt issued in exchange transactions consisted of $2.180 billion aggregate principal amount of EFIH 10% Notes due 2020, $561 million aggregate principal amount of EFH Corp 10% Notes due 2020, $336 million aggregate principal amount of TCEH 15% Senior Secured Second Lien Notes due 2021 and $885 million aggregate principal amount of TCEH 15% Senior Secured Second Lien Notes due 2021 (Series B). EFH Corp. also issued $500 million principal amount of EFH Corp. 10% Notes due 2020 for cash, and TCEH issued $350 million principal amount of TCEH 15% Senior Secured Second Lien Notes (Series B) due 2021 for cash. A discussion of these transactions and descriptions of the EFIH 10% Notes, EFH Corp. 10% Notes and TCEH 15% Senior Secured Second Lien Notes are presented below.

Transactions completed in the year ended December 31, 2010 were as follows:

- In November, TCEH and TCEH Finance issued $885 million aggregate principal amount of TCEH 15% Senior Secured Second Lien Notes (Series B) due 2021 in exchange for $850 million aggregate principal amount of TCEH 10.25% Notes and $420 million aggregate principal amount of TCEH Toggle Notes.
- In October, TCEH and TCEH Finance issued $336 million aggregate principal amount of TCEH 15% Senior Secured Second Lien Notes due 2021 in exchange for $423 million aggregate principal amount of TCEH 10.25% Notes (plus accrued interest paid in cash) and $55 million aggregate principal amount of TCEH Toggle Notes (together, the TCEH Senior Notes).
- In October, TCEH and TCEH Finance issued $350 million aggregate principal amount of TCEH 15% Senior Secured Second Lien Notes (Series B) due 2021, and used the $343 million of net proceeds to repurchase $240 million principal amount of TCEH 10.25% Notes (including $14 million from EFH Corp) and $283 million principal amount of TCEH Toggle Notes (including $83 million from EFH Corp.) and paid accrued interest from cash on hand. TCEH paid $53 million of the net proceeds for the TCEH notes held by EFH Corp., which were retired.

- In a public (registered with the SEC) debt exchange transaction in August, EFIH and EFIH Finance (together, the Issuers) issued $2.180 billion aggregate principal amount of EFIH 10% Notes due 2020 and paid $500 million in cash, plus accrued interest, in exchange for $2.166 billion aggregate principal amount of EFH Corp. Toggle Notes and $1.428 billion aggregate principal amount of EFH Corp. 10.875% Notes (together, the EFH Corp. Senior Notes).
- Between April and July, EFH Corp. issued $527 million principal amount of EFH Corp. 10% Notes due 2020 in exchange for $549 million principal amount of EFH Corp. 5.55% Series P Senior Notes (EFH Corp. 5.55% Notes), $110 million principal amount of EFH Corp. Toggle Notes, $25 million principal amount of EFH Corp. 10.875% Notes, $13 million principal amount of TCEH 10.25% Notes and $17 million principal amount of TCEH Toggle Notes.
- In March, EFH Corp. issued $34 million principal amount of EFH Corp 10% Notes due 2020 in exchange for $20 million principal amount of EFH Corp. Toggle Notes and $27 million principal amount of TCEH Toggle Notes.
- In January, EFH Corp. issued $500 million aggregate principal amount of EFH Corp. 10% Notes due 2020, with the proceeds intended to be used for general corporate purposes including debt exchanges and repurchases.
- In addition, from time to time in 2010, EFH Corp. repurchased $124 million principal amount of EFH Corp. Toggle Notes, $19 million principal amount of EFH Corp. 10.875% Notes, $181 million principal amount of TCEH 10 25% Notes, $32 million principal amount of TCEH Toggle Notes and $20 million principal amount of initial term loans under the TCEH Senior Secured Facilities for $252 million in cash plus accrued interest.

These transactions resulted in debt extinguishment gains totaling $1.814 billion (reported as other income).

In connection with the debt exchange transactions, EFH Corp. received the requisite consents from holders of the EFH Corp. Senior Notes and EFH Corp. 5.55% Notes applicable to certain amendments to the respective indentures governing such notes. These amendments, among other things, eliminated substantially all of the restrictive covenants, eliminated certain events of default, modified covenants regarding mergers and consolidations and modified or eliminated certain other provisions in such indentures.

The EFH Corp. notes acquired by EFIH and the majority of the TCEH notes and initial term loans under the TCEH Senior Secured Facilities acquired by EFH Corp. are held as investments by EFIH and EFH Corp., and are eliminated in consolidation. All other securities acquired in the above transactions have been cancelled.

Debt-Related Activity in 2009 — Repayments of long-term debt in 2009 totaling $396 million represented principal payments at scheduled maturity dates as well as other repayments totaling $50 million, principally related to capitalized leases. Payments at scheduled amortization or maturity dates included $165 million repaid under the TCEH Initial Term Loan Facility, $104 million of Oncor transition bond principal payments, $65 million repaid under a TCEH promissory note, $9 million repaid under the TCEH Delayed Draw Term Loan Facility and $3 million of EFH Corp. senior notes.

Increases in long-term debt during 2009 totaling $522 million consisted of increased borrowings under the TCEH Delayed Draw Term Loan Facility, which was fully drawn as of July 2009, to fund expenditures related to construction of new generation facilities and environmental upgrades of existing lignite/coal-fueled generation facilities. In addition, long-term debt increased as a result of EFH Corp. increasing, through the PIK election, the principal amount of its EFH Corp. Toggle Notes by $309 million, and TCEH increasing, through the PIK election, the principal amount of its TCEH Toggle Notes by $202 million, in each case, in lieu of making cash interest payments.

2009 Debt Exchanges — In November 2009, EFH Corp., EFIH and EFIH Finance completed debt exchange transactions, which resulted in the issuance of $115 million principal amount of 9.75% Senior Secured Notes due 2019 by EFH Corp. (the EFH Corp. 9.75% Notes) and $141 million principal amount of 9.75% Senior Secured Notes due 2019 by EFIH and EFIH Finance (the EFIH 9.75% Notes) (both discussed further below) in exchange for $169 million principal amount of EFH Corp. 10.875% Notes, $12 million principal amount of EFH Corp. Toggle Notes, $143 million principal amount of TCEH 10.25% Notes, $17 million of EFH Corp. 5.55% Series P Senior Notes, $10 million of EFH Corp. 6.50% Series Q Senior Notes and $6 million principal amount of EFH Corp. 6.55% Series R Senior Notes.

Maturities — Long-term debt maturities as of December 31, 2010 are as follows:

Year		
2011	$	651
2012		237
2013		296
2014		21,046
2015		3,187
Thereafter (a)		10,003
Unamortized fair value premium		15
Unamortized fair value discount (b)		(620)
Capital lease obligations		80
Total	$	34,895

(a) Long-term debt maturities for EFH Corp. (parent entity) total $7.766 billion, including $3.742 billion held by EFIH that is not included above.

(b) Unamortized fair value discount for EFH Corp. (parent entity) totals $(476) million.

TCEH Senior Secured Facilities — The applicable rate on borrowings under the TCEH Initial Term Loan Facility, the TCEH Delayed Draw Term Loan Facility, the TCEH Revolving Credit Facility and the TCEH Letter of Credit Facility as of December 31, 2010 is provided in the long-term debt table and in the discussion of short-term borrowings above and reflects LIBOR-based borrowings. These borrowings totaled $22.304 billion as of December 31, 2010, excluding $20 million held by EFH Corp. as a result of debt repurchases.

In August 2009, the TCEH Senior Secured Facilities were amended to reduce the existing first lien capacity under the TCEH Senior Secured Facilities by $1.25 billion in exchange for the ability for TCEH to issue up to an additional $4 billion of secured notes or loans ranking junior to TCEH's first lien obligations, provided that:

- such notes or loans mature later than the latest maturity date of any of the initial term loans under the TCEH Senior Secured Facilities, and
- any net cash proceeds from any such issuances are used (i) in exchange for, or to refinance, repay, retire, refund or replace indebtedness of TCEH or (ii) to acquire, directly or indirectly, all or substantially all of the property and assets or business of another person or to finance the purchase price, cost of design, acquisition, construction, repair, restoration, replacement, expansion, installation or improvement of certain fixed or capital assets.

In addition, the amended facilities permit TCEH to, among other things:

- issue new secured notes or loans, which may include, in each case, debt secured on a pari passu basis with the obligations under the TCEH Senior Secured Facilities, so long as, in each case, among other things, the net cash proceeds from any such issuance are used to prepay certain loans under the TCEH Senior Secured Facilities at par;
- upon making an offer to all lenders within a particular series, agree with lenders of that series to extend the maturity of their term loans or extend or refinance their revolving credit commitments under the TCEH Senior Secured Facilities, and pay increased interest rates or otherwise modify the terms of their loans or revolving commitments in connection with such an extension, and
- exclude from the financial maintenance covenant under the TCEH Senior Secured Facilities any new debt issued that ranks junior to TCEH's first lien obligations under the TCEH Senior Secured Facilities.

Under the terms of the TCEH Senior Secured Facilities, the commitments of the lenders to make loans to TCEH are several and not joint. Accordingly, if any lender fails to make loans to TCEH, TCEH's available liquidity could be reduced by an amount up to the aggregate amount of such lender's commitments under the TCEH Senior Secured Facilities.

The TCEH Senior Secured Facilities are unconditionally guaranteed jointly and severally on a senior secured basis by EFCH, and subject to certain exceptions, each existing and future direct or indirect wholly-owned US restricted subsidiary of TCEH. The TCEH Senior Secured Facilities, including the guarantees thereof, certain commodity hedging transactions and the interest rate swaps described under "TCEH Interest Rate Swap Transactions" below are secured by (a) substantially all of the current and future assets of TCEH and TCEH's subsidiaries who are guarantors of such facilities and (b) pledges of the capital stock of TCEH and certain current and future direct or indirect subsidiaries of TCEH.

The TCEH Initial Term Loan Facility is required to be repaid in equal quarterly installments in an aggregate annual amount equal to 1% of the original principal amount of such facility ($41 million quarterly), with the balance payable in October 2014. The TCEH Delayed Draw Term Loan Facility is required to be repaid in equal quarterly installments in an aggregate annual amount equal to 1% of the actual principal outstanding under such facility as of December 2009 ($10 million quarterly), with the balance payable in October 2014. Amounts borrowed under the TCEH Revolving Facility may be reborrowed from time to time until October 2013. The TCEH Letter of Credit Facility and TCEH Commodity Collateral Posting Facility will mature in October 2014 and December 2012, respectively.

The TCEH Senior Secured Facilities contain customary negative covenants that, among other things, restrict, subject to certain exceptions, TCEH and its restricted subsidiaries' ability to:

- incur additional debt;
- create additional liens;
- enter into mergers and consolidations;
- sell or otherwise dispose of assets;
- make dividends, redemptions or other distributions in respect of capital stock;
- make acquisitions, investments, loans and advances, and
- pay or modify certain subordinated and other material debt

In addition, the TCEH Senior Secured Facilities contain a maintenance covenant that prohibits TCEH and its restricted subsidiaries from exceeding a maximum consolidated secured leverage ratio and to observe certain customary reporting requirements and other affirmative covenants.

The TCEH Senior Secured Facilities contain certain customary events of default for senior leveraged acquisition financings, the occurrence of which would allow the lenders to accelerate all outstanding loans and terminate their commitments.

TCEH 15% Senior Secured Second Lien Notes — The TCEH 15% Senior Secured Second Lien Notes and the TCEH 15% Senior Secured Second Lien Notes (Series B) (collectively, the TCEH Senior Secured Second Lien Notes) mature in April 2021, with interest payable in cash quarterly in arrears on January 1, April 1, July 1 and October 1, beginning January 1, 2011, at a fixed rate of 15% per annum. The notes are unconditionally guaranteed on a joint and several basis by EFCH and, subject to certain exceptions, each subsidiary of TCEH (collectively, the Guarantors). The notes are secured, on a second-priority basis, by security interests in all of the assets of TCEH, and the guarantees (other than the guarantee of EFCH) are secured on a second-priority basis by all of the assets and equity interests of all of the Guarantors other than EFCH (collectively, the Subsidiary Guarantors), in each case, to the extent such assets and security interests secure obligations under the TCEH Senior Secured Credit Facilities on a first-priority basis (the TCEH Collateral), subject to certain exceptions (including the elimination of the pledge of equity interests of any subsidiary Guarantor to the extent that separate financial statements would be required to be filed with the SEC for such subsidiary Guarantor under Rule 3-16 of Regulation S-X) and permitted liens. The guarantee from EFCH is not secured.

As of December 31, 2010, there were $1.571 billion total principal amount of TCEH Senior Secured Second Lien Notes. The TCEH Senior Secured Second Lien Notes are a senior obligation and rank equally in right of payment with all senior indebtedness of TCEH, are senior in right of payment to all existing or future unsecured debt of TCEH to the extent of the value of the TCEH Collateral (after taking into account any first-priority liens on the TCEH Collateral) and are senior in right of payment to any future subordinated debt of TCEH. These notes are effectively subordinated to TCEH's obligations under the TCEH Senior Secured Credit Facilities and TCEH's commodity and interest rate hedges that are secured by a first-priority lien on the TCEH Collateral and any future obligations subject to first-priority liens on the TCEH Collateral, to the extent of the value of the TCEH Collateral, and to all secured obligations of TCEH that are secured by assets other than the TCEH Collateral, to the extent of the value of the assets securing such obligations.

The guarantees of the TCEH Senior Secured Second Lien Notes by the Subsidiary Guarantors are effectively senior to any unsecured debt of the Subsidiary Guarantors to the extent of the value of the TCEH Collateral (after taking into account any first-priority liens on the TCEH Collateral). These guarantees are effectively subordinated to all debt of the Subsidiary Guarantors secured by the TCEH Collateral on a first-priority basis or that is secured by assets that are not part of the TCEH Collateral, to the extent of the value of the collateral securing that debt. EFCH's guarantee ranks equally with its unsecured debt (including debt it guarantees on an unsecured basis) and is effectively subordinated to any of its secured debt to the extent of the value of the collateral securing that debt.

The indenture for the TCEH Senior Secured Second Lien Notes contains a number of covenants that, among other things, restrict, subject to certain exceptions, TCEH's and its restricted subsidiaries' ability to

- make restricted payments, including certain investments;
- incur debt and issue preferred stock;
- create liens;
- enter into mergers or consolidations;
- sell or otherwise dispose of certain assets, and
- engage in certain transactions with affiliates.

The indenture also contains customary events of default, including, among others, failure to pay principal or interest on the notes when due. In general, all of the series of TCEH Senior Secured Second Lien Notes vote together as a single class. As a result, if certain events of default occur under the indenture, the trustee or the holders of at least 30% of aggregate principal amount of all outstanding TCEH Senior Secured Second Lien Notes may declare the principal amount on all such notes to be due and payable immediately.

Until October 1, 2013, TCEH may redeem, with the net cash proceeds of certain equity offerings, up to 35% of the aggregate principal amount of each series of the TCEH Senior Secured Second Lien Notes from time to time at a redemption price of 115.00% of the aggregate principal amount of the notes being redeemed, plus accrued interest. TCEH may redeem each series of the notes at any time prior to October 1, 2015 at a price equal to 100% of their principal amount, plus accrued interest and the applicable premium as defined in the indenture. TCEH may also redeem each series of the notes, in whole or in part, at any time on or after October 1, 2015, at specified redemption prices, plus accrued interest. Upon the occurrence of a change of control (as described in the indenture), TCEH must offer to repurchase each series of the notes at 101% of their principal amount, plus accrued interest.

The TCEH Senior Secured Second Lien Notes were issued in private placements and have not been registered under the Securities Act. TCEH has agreed to use its commercially reasonable efforts to register with the SEC notes having substantially identical terms as the TCEH Senior Secured Second Lien Notes (except for provisions relating to transfer restrictions and payment of additional interest) as part of an offer to exchange freely tradable exchange notes for the TCEH Senior Secured Second Lien Notes unless such notes meet certain transferability conditions (as described in the related registration rights agreement). If the registration statement has not been filed and declared effective within 365 days after the original issue date (a Registration Default), the annual interest rate on the notes will increase by 25 basis points for the first 90-day period during which a Registration Default continues, and thereafter the annual interest rate on the notes will increase by 50 basis points for the remaining period during which the Registration Default continues. If the Registration Default is cured, the interest rate on the notes will revert to the original level.

TCEH Senior Notes The TCEH 10.25% Notes mature in November 2015, with interest payable in cash semi-annually in arrears on May 1 and November 1 at a fixed rate of 10.25% per annum. The TCEH Toggle Notes mature in November 2016, with interest payable semi-annually in arrears on May 1 and November 1 at a fixed rate of 10.50% per annum for cash interest and at a fixed rate of 11.25% per annum for PIK Interest. For any interest period until November 2012, TCEH may elect to pay interest on the notes (i) entirely in cash; (ii) by increasing the principal amount of the notes or by issuing new TCEH Toggle Notes (PIK Interest); or (iii) 50% in cash and 50% in PIK Interest. Once TCEH makes a PIK election, the election is valid for each succeeding interest payment period until TCEH revokes the election.

The TCEH 10.25% and Toggle Notes (collectively, the TCEH Senior Notes) had a total principal amount as of December 31, 2010 of $4.570 billion (excluding $323 million principal amount held by EFH Corp. and EFIH) and are fully and unconditionally guaranteed on a joint and several unsecured basis by TCEH's direct parent, EFCH (which owns 100% of TCEH and its subsidiary guarantors), and by each subsidiary that guarantees the TCEH Senior Secured Facilities.

TCEH may redeem the TCEH 10.25% Notes and TCEH Toggle Notes at any time prior to November 1, 2011 and 2012, respectively, at a price equal to 100% of their principal amount, plus accrued and unpaid interest and the applicable premium as defined in the indenture. TCEH may redeem the TCEH 10.25% Notes and TCEH Toggle Notes, in whole or in part, at any time on or after November 1, 2011 and 2012, respectively, at specified redemption prices, plus accrued and unpaid interest, if any. Upon the occurrence of a change of control of EFCH or TCEH, TCEH must offer to repurchase the TCEH Senior Notes at 101% of their principal amount, plus accrued and unpaid interest, if any.

The indenture for the TCEH Senior Notes contains a number of covenants that, among other things, restrict, subject to certain exceptions, TCEH's and its restricted subsidiaries' ability to:

- make restricted payments;
- incur debt and issue preferred stock;
- create liens;
- enter into mergers or consolidations;
- sell or otherwise dispose of certain assets, and
- engage in certain transactions with affiliates.

The indenture also contains customary events of default, including, among others, failure to pay principal or interest on the notes when due. If certain events of default occur and are continuing under the indenture, the trustee or the holders of at least 30% in principal amount of the notes may declare the principal amount on the notes to be due and payable immediately.

EFH Corp. 10% Notes — The EFH Corp 10% Notes mature in January 2020, with interest payable in cash semi-annually in arrears on January 15 and July 15 at a fixed rate of 10% per annum. The notes are fully and unconditionally guaranteed on a joint and several basis by EFCH and EFIH. The guarantee from EFIH is secured by EFIH's pledge of 100% of the membership interests and other investments it owns in Oncor Holdings (such membership interests and other investments, the EFIH Collateral). The guarantee from EFCH is not secured. EFIH's guarantee of the EFH Corp. 10% Notes is secured by the EFIH Collateral on an equal and ratable basis with the EFIH Notes and EFIH's guarantee of the EFH Corp. 9.75% Notes.

As of December 31, 2010, there were $1.061 billion total principal amount of EFH Corp 10% Notes. The EFH Corp. 10% Notes are a senior obligation and rank equally in right of payment with all senior indebtedness of EFH Corp. and are senior in right of payment to any future subordinated indebtedness of EFH Corp. These notes are effectively subordinated to any indebtedness of EFH Corp. secured by assets of EFH Corp. to the extent of the value of the assets securing such indebtedness and structurally subordinated to all indebtedness and other liabilities of EFH Corp.'s non-guarantor subsidiaries.

The guarantees of the EFH Corp. 10% Notes are the general senior obligations of each guarantor and rank equally in right of payment with all existing and future senior indebtedness of each guarantor. The guarantee from EFIH is effectively senior to all unsecured indebtedness of EFIH to the extent of the value of the EFIH Collateral. The guarantees are effectively subordinated to all secured indebtedness of each guarantor secured by assets other than the EFIH Collateral to the extent of the value of the assets securing such indebtedness and are structurally subordinated to any existing and future indebtedness and liabilities of EFH Corp.'s subsidiaries that are not guarantors.

The indenture for the EFH Corp. 10% Notes contains a number of covenants that, among other things, restrict, subject to certain exceptions, EFH Corp.'s and its restricted subsidiaries' ability to:

- make restricted payments;
- incur debt and issue preferred stock;
- create liens;
- enter into mergers or consolidations;
- sell or otherwise dispose of certain assets, and
- engage in certain transactions with affiliates.

These notes and indenture also contain customary events of default, including, among others, failure to pay principal or interest on the notes when due. If certain events of default occur and are continuing under these notes and the indenture, the trustee or the holders of at least 30% in principal amount outstanding of the notes may declare the principal amount of the notes to be due and payable immediately.

Until January 15, 2013, EFH Corp. may redeem, with the net cash proceeds of certain equity offerings, up to 35% of the aggregate principal amount of the EFH Corp. 10% Notes from time to time at a redemption price of 110.000% of the aggregate principal amount of the notes being redeemed, plus accrued and unpaid interest. EFH Corp. may redeem the notes at any time prior to January 15, 2015 at a price equal to 100% of their principal amount, plus accrued and unpaid interest and the applicable premium as defined in the indenture. EFH Corp. may also redeem the notes, in whole or in part, at any time on or after January 15, 2015, at specified redemption prices, plus accrued and unpaid interest. Upon the occurrence of a change of control (as described in the indenture), EFH Corp. must offer to repurchase the notes at 101% of their principal amount, plus accrued and unpaid interest.