Luminant

Rafael Flores
Senior Vice President
& Chief Nuclear Officer
rafael.flores@Luminant.com

Luminant Power
P O Box 1002
6322 North FM 56
Glen Rose, TX 76043

T 254 897 5550
C 817 559 0403
F 254 897 6652

CP-201300161

Ref. # 10 CFR 140.21(e)

Log # TXX-13025

February 5, 2013

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

SUBJECT: COMANCHE PEAK NUCLEAR POWER PLANT (CPNPP)
DOCKET NOS. 50-445 AND 50-446
GUARANTEES OF PAYMENT OF DEFERRED PREMIUMS

Dear Sir or Madam:

Pursuant to 10CFR140.21(e), Luminant Generation Company LLC (Luminant Power) hereby submits condensed consolidated financial statements for Energy Future Holdings Corp as of September 30, 2012 (enclosed), to demonstrate the Company's ability to pay deferred premiums under the Secondary Financial Program. The cash flow for the quarterly period ending September 30, 2012 is found on page 3 and 4 of the report.

This communication contains no licensing basis commitments regarding Comanche Peak Units 1 and 2.

Should you have any questions, please contact Mr. J. Seawright at (254) 897-0140.

Sincerely,

Luminant Generation Company LLC

Rafael Flores

By: Fred W. Madden

Fred W. Madden
Director, Oversight & Regulatory Affairs

Enclosure - Energy Future Holdings Corp 10Q as of September 30, 2012

c - E. E. Collins, Region IV
B. K. Singal, NRR
Resident Inspectors, Comanche Peak

M001
NRR

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

FORM 10-Q

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2012

— OR —

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

Commission File Number 1-12833

Energy Future Holdings Corp.

(Exact name of registrant as specified in its charter)

Texas	75-2669310
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1601 Bryan Street, Dallas, TX 75201-3411	(214) 812-4600
(Address of principal executive offices) (Zip Code)	(Registrant's telephone number, including area code)

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

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

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

Large accelerated filer ☐ Accelerated filer ☐ Non-Accelerated filer ☒ (Do not check if a smaller reporting company)
Smaller reporting company ☐

Indicate by check mark if the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

At October 29, 2012, there were 1,680,539,245 shares of common stock, without par value, outstanding of Energy Future Holdings Corp. (substantially all of which were owned by Texas Energy Future Holdings Limited Partnership, Energy Future Holdings Corp.'s parent holding company, and none of which is publicly traded).

TABLE OF CONTENTS

Energy Future Holdings Corp.'s (EFH Corp.) annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any amendments to those reports are made available to the public, free of charge, on the EFH Corp. website at *http://www.energyfutureholdings.com*, as soon as reasonably practicable after they have been filed with or furnished to the Securities and Exchange Commission. The information on EFH Corp.'s website shall not be deemed a part of, or incorporated by reference into, this quarterly report on Form 10-Q. The representations and warranties contained in any agreement that we have filed as an exhibit to this quarterly report on Form 10-Q or that we have or may publicly file in the future may contain representations and warranties made by and to the parties thereto at specific dates. Such representations and warranties may be subject to exceptions and qualifications contained in separate disclosure schedules, may represent the parties' risk allocation in the particular transaction, or may be qualified by materiality standards that differ from what may be viewed as material for securities law purposes.

This quarterly report on Form 10-Q and other Securities and Exchange Commission filings of EFH Corp. and its subsidiaries occasionally make references to EFH Corp. (or "we," "our," "us" or "the company"), EFCH, EFIH, TCEH, TXU Energy, Luminant, Oncor Holdings or Oncor when describing actions, rights or obligations of their respective subsidiaries. These references reflect the fact that the subsidiaries are consolidated with, or otherwise reflected in, their respective parent company's financial statements for financial reporting purposes. However, these references should not be interpreted to imply that the parent company is actually undertaking the action or has the rights or obligations of the relevant subsidiary company or vice versa.

GLOSSARY

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

2011 Form 10-K	EFH Corp.'s Annual Report on Form 10-K for the year ended December 31, 2011
Adjusted EBITDA	Adjusted EBITDA means EBITDA adjusted to exclude noncash items, unusual items and other adjustments allowable under certain of our debt arrangements. See the definition of EBITDA below. Adjusted EBITDA and EBITDA are not recognized terms under US GAAP and, thus, are non-GAAP financial measures. We are providing Adjusted EBITDA in this Form 10-Q (see reconciliations in Exhibits 99(b), 99(c) and 99(d)) solely because of the important role that Adjusted EBITDA plays in respect of certain covenants contained in our debt arrangements. We do not intend for Adjusted EBITDA (or EBITDA) to be an alternative to net income as a measure of operating performance or an alternative to cash flows from operating activities as a measure of liquidity or an alternative to any other measure of financial performance presented in accordance with US GAAP. Additionally, we do not intend for Adjusted EBITDA (or EBITDA) to be used as a measure of free cash flow available for management's discretionary use, as the measure excludes certain cash requirements such as interest payments, tax payments and other debt service requirements. Because not all companies use identical calculations, our presentation of Adjusted EBITDA (and EBITDA) may not be comparable to similarly titled measures of other companies.
CAIR	Clean Air Interstate Rule
Competitive Electric segment	the EFH Corp. business segment that consists principally of TCEH
CREZ	Competitive Renewable Energy Zone
CSAPR	the final Cross-State Air Pollution Rule issued by the EPA in July 2011 and vacated by the US Court of Appeals for the District of Columbia Circuit in August 2012 (see Note 7 to Financial Statements)
EBITDA	earnings (net income) before interest expense, income taxes, depreciation and amortization
EFCH	Energy Future Competitive Holdings Company, a direct, wholly-owned subsidiary of EFH Corp. and the direct parent of TCEH, and/or its subsidiaries, depending on context
EFH Corp.	Energy Future Holdings Corp., a holding company, and/or its subsidiaries, depending on context, whose major subsidiaries include TCEH and Oncor
EFH Corp. Senior Notes	Refers, collectively, to EFH Corp.'s 10.875% Senior Notes due November 1, 2017 (EFH Corp. 10.875% Notes) and EFH Corp.'s 11.25%/12.00% Senior Toggle Notes due November 1, 2017 (EFH Corp. Toggle Notes).
EFH Corp. Senior Secured Notes	Refers, collectively, to EFH Corp.'s 9.75% Senior Secured Notes due October 15, 2019 (EFH Corp. 9.75% Notes) and EFH Corp.'s 10.000% Senior Secured Notes due January 15, 2020 (EFH Corp. 10% Notes).
EFIH	Energy Future Intermediate Holding Company LLC, a direct, wholly-owned subsidiary of EFH Corp. and the direct parent of Oncor Holdings
EFIH Finance	EFIH Finance Inc., a direct, wholly-owned subsidiary of EFIH, formed for the sole purpose of serving as co-issuer with EFIH of certain debt securities
EFIH Notes	Refers, collectively, to EFIH's and EFIH Finance's 6.875% Senior Secured Notes due August 15, 2017 (EFIH 6.875% Notes), 9.75% Senior Secured Notes due October 15, 2019 (EFIH 9.75% Notes), 10.000% Senior Secured Notes due December 1, 2020 (EFIH 10% Notes), 11% Senior Secured Second Lien Notes due October 1, 2021 (EFIH 11% Notes) and 11.75% Senior Secured Second Lien Notes due March 1, 2022 (EFIH 11.75% Notes).
EPA	US Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas, Inc., the independent system operator and the regional coordinator of various electricity systems within Texas
GAAP	generally accepted accounting principles
GWh	gigawatt-hours
kWh	kilowatt-hours

LIBOR	London Interbank Offered Rate, an interest rate at which banks can borrow funds, in marketable size, from other banks in the London interbank market
Luminant	subsidiaries of TCEH engaged in competitive market activities consisting of electricity generation and wholesale energy sales and purchases as well as commodity risk management and trading activities, all largely in Texas
market heat rate	Heat rate is a measure of the efficiency of converting a fuel source to electricity. Market heat rate is the implied relationship between wholesale electricity prices and natural gas prices and is calculated by dividing the wholesale market price of electricity, which is based on the price offer of the marginal supplier in ERCOT (generally natural gas plants), by the market price of natural gas. Forward wholesale electricity market price quotes in ERCOT are generally limited to two or three years; accordingly, forward market heat rates are generally limited to the same time period. Forecasted market heat rates for time periods for which market price quotes are not available are based on fundamental economic factors and forecasts, including electricity supply, demand growth, capital costs associated with new construction of generation supply, transmission development and other factors.
MATS	the Mercury and Air Toxics Standard finalized by the EPA in December 2011 and published in February 2012
Merger	The transaction referred to in the Agreement and Plan of Merger, dated February 25, 2007, under which Texas Holdings agreed to acquire EFH Corp., which was completed on October 10, 2007.
MMBtu	million British thermal units
Moody's	Moody's Investors Services, Inc. (a credit rating agency)
MW	megawatts
MWh	megawatt-hours
NERC	North American Electric Reliability Corporation
NO_x	nitrogen oxides
NRC	US Nuclear Regulatory Commission
NYMEX	the New York Mercantile Exchange, a physical commodity futures exchange
Oncor	Oncor Electric Delivery Company LLC, a direct, majority-owned subsidiary of Oncor Holdings and an indirect subsidiary of EFH Corp., and/or its consolidated bankruptcy-remote financing subsidiary, Oncor Electric Delivery Transition Bond Company LLC, depending on context, that is engaged in regulated electricity transmission and distribution activities
Oncor Holdings	Oncor Electric Delivery Holdings Company LLC, a direct, wholly-owned subsidiary of EFIH and the direct majority owner of Oncor, and/or its subsidiaries, depending on context
Oncor Ring-Fenced Entities	Oncor Holdings and its direct and indirect subsidiaries, including Oncor
OPEB	other postretirement employee benefits
PUCT	Public Utility Commission of Texas
purchase accounting	The purchase method of accounting for a business combination as prescribed by US GAAP, whereby the cost or "purchase price" of a business combination, including the amount paid for the equity and direct transaction costs are allocated to identifiable assets and liabilities (including intangible assets) based upon their fair values. The excess of the purchase price over the fair values of assets and liabilities is recorded as goodwill.
Regulated Delivery segment	the EFH Corp. business segment that consists primarily of our investment in Oncor
REP	retail electric provider
RRC	Railroad Commission of Texas, which among other things, has oversight of lignite mining activity in Texas
S&P	Standard & Poor's Ratings Services, a division of the McGraw-Hill Companies Inc. (a credit rating agency)
SEC	US Securities and Exchange Commission

Securities Act	Securities Act of 1933, as amended
SG&A	selling, general and administrative
SO_2	sulfur dioxide
Sponsor Group	Refers, collectively, to certain investment funds affiliated with Kohlberg Kravis Roberts & Co. L.P., TPG Management, L.P. and GS Capital Partners, an affiliate of Goldman, Sachs & Co., that have an ownership interest in Texas Holdings.
TCEH	Texas Competitive Electric Holdings Company LLC, a direct, wholly-owned subsidiary of EFCH and an indirect subsidiary of EFH Corp., and/or its subsidiaries, depending on context, that are engaged in electricity generation and wholesale and retail energy markets activities, and whose major subsidiaries include Luminant and TXU Energy
TCEH Finance	TCEH Finance, Inc., a direct, wholly-owned subsidiary of TCEH, formed for the sole purpose of serving as co-issuer with TCEH of certain debt securities
TCEH Senior Notes	Refers, collectively, to TCEH's and TCEH Finance's 10.25% Senior Notes due November 1, 2015 and 10.25% Senior Notes due November 1, 2015, Series B (collectively, TCEH 10.25% Notes) and TCEH's and TCEH Finance's 10.50%/11.25% Senior Toggle Notes due November 1, 2016 (TCEH Toggle Notes).
TCEH Senior Secured Facilities	Refers, collectively, to the TCEH Term Loan Facilities, TCEH Revolving Credit Facility, TCEH Letter of Credit Facility and TCEH Commodity Collateral Posting Facility. See Note 6 to Financial Statements for details of these facilities.
TCEH Senior Secured Notes	TCEH's and TCEH Finance's 11.5% Senior Secured Notes due October 1, 2020
TCEH Senior Secured Second Lien Notes	Refers, collectively, to TCEH's and TCEH Finance's 15% Senior Secured Second Lien Notes due April 1, 2021 and TCEH's and TCEH Finance's 15% Senior Secured Second Lien Notes due April 1, 2021, Series B.
TCEQ	Texas Commission on Environmental Quality
Texas Holdings	Texas Energy Future Holdings Limited Partnership, a limited partnership controlled by the Sponsor Group, that owns substantially all of the common stock of EFH Corp.
Texas Holdings Group	Texas Holdings and its direct and indirect subsidiaries other than the Oncor Ring-Fenced Entities
Texas Transmission	Texas Transmission Investment LLC, a limited liability company that owns a 19.75% equity interest in Oncor and is not affiliated with EFH Corp., any of its subsidiaries or any member of the Sponsor Group
TRE	Texas Reliability Entity, Inc., an independent organization that develops reliability standards for the ERCOT region and monitors and enforces compliance with NERC standards and ERCOT protocols
TXU Energy	TXU Energy Retail Company LLC, a direct, wholly-owned subsidiary of TCEH that is a REP in competitive areas of ERCOT and is engaged in the retail sale of electricity to residential and business customers
US	United States of America
VIE	variable interest entity

PART I. FINANCIAL INFORMATION

Item 1. FINANCIAL STATEMENTS

ENERGY FUTURE HOLDINGS CORP. AND SUBSIDIARIES
CONDENSED STATEMENTS OF CONSOLIDATED INCOME (LOSS)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(millions of dollars)			
Operating revenues	$ 1,752	$ 2,321	$ 4,358	$ 5,672
Fuel, purchased power costs and delivery fees	(850)	(1,058)	(2,153)	(2,726)
Net gain (loss) from commodity hedging and trading activities	(3)	270	229	365
Operating costs	(201)	(207)	(636)	(670)
Depreciation and amortization	(335)	(379)	(1,015)	(1,119)
Selling, general and administrative expenses	(177)	(195)	(491)	(537)
Franchise and revenue-based taxes	(19)	(21)	(55)	(64)
Other income (Note 14)	6	9	25	84
Other deductions (Note 14)	(42)	(483)	(54)	(593)
Interest income	1	—	2	2
Interest expense and related charges (Note 14)	(944)	(1,523)	(2,746)	(3,467)
Loss before income taxes and equity in earnings of unconsolidated subsidiaries	(812)	(1,266)	(2,536)	(3,053)
Income tax benefit	296	443	879	1,042
Equity in earnings of unconsolidated subsidiaries (net of tax) (Note 2)	109	113	249	235
Net loss	$ (407)	$ (710)	$ (1,408)	$ (1,776)

See Notes to Financial Statements.

ENERGY FUTURE HOLDINGS CORP. AND SUBSIDIARIES
CONDENSED STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME (LOSS)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(millions of dollars)			
Net loss	$ (407)	$ (710)	$ (1,408)	$ (1,776)
Other comprehensive income (loss), net of tax effects:				
Effects related to pension and other retirement benefit obligations (net of tax (expense) benefit of $18, $(2), $13 and $(8)) (Note 11)	(33)	5	(25)	16
Cash flow hedges — Net decrease in fair value of derivatives held by unconsolidated subsidiary (net of tax benefit of $—, $13, $— and $13)	—	(24)	—	(24)
Cash flow hedges derivative value net loss related to hedged transactions recognized during the period and reported in:				
Net loss (net of tax benefit of $1, $2, $3 and $9)	1	4	5	15
Equity in earnings of unconsolidated subsidiaries (net of tax benefit of $—, $—, $1 and $—)	1	—	2	—
Total other comprehensive income (loss)	(31)	(15)	(18)	7
Comprehensive loss	$ (438)	$ (725)	$ (1,426)	$ (1,769)

See Notes to Financial Statements.

ENERGY FUTURE HOLDINGS CORP. AND SUBSIDIARIES
CONDENSED STATEMENTS OF CONSOLIDATED CASH FLOWS
(Unaudited)

	Nine Months Ended September 30,	
	2012	2011
	(millions of dollars)	
Cash flows — operating activities:		
Net loss	$ (1,408)	$ (1,776)
Adjustments to reconcile net loss to cash provided by operating activities:		
Depreciation and amortization	1,161	1,313
Deferred income tax benefit, net	(887)	(1,128)
Unrealized net loss from mark-to-market valuations of commodity positions	1,290	247
Unrealized net loss from mark-to-market valuations of interest rate swaps (Note 6)	12	879
Interest expense on toggle notes payable in additional principal (Notes 6 and 14)	177	163
Amortization of debt related costs, discounts, fair value discounts and losses on dedesignated cash flow hedges (Note 14)	183	203
Equity in earnings of unconsolidated subsidiaries	(249)	(235)
Distributions of earnings from unconsolidated subsidiaries	100	64
Impairment of emissions allowances intangible assets (Note 14)	—	418
Severance charges (Note 14)	—	49
Other asset impairments (Note 14)	31	9
Third-party fees related to debt amendment and extension (Note 14) (reported as financing)	—	100
Debt extinguishment gains (Note 6)	—	(25)
Bad debt expense (Note 5)	20	42
Accretion expense related primarily to mining reclamation obligations (Note 14)	27	36
Stock-based incentive compensation expense	10	8
Other, net	3	(7)
Changes in operating assets and liabilities:		
Margin deposits, net	(321)	277
Other operating assets and liabilities	(51)	100
Cash provided by operating activities	98	737
Cash flows — financing activities:		
Issuances of long-term debt (Note 6)	2,000	1,750
Repayments/repurchases of long-term debt (Note 6)	(31)	(987)
Net short-term borrowings under accounts receivable securitization program (Note 5)	80	115
Decrease in other short-term borrowings (Note 6)	(385)	(1,126)
Decrease in note payable to unconsolidated subsidiary (Note 12)	(20)	(28)
Settlement of agreements with unconsolidated affiliate (Note 12)	(159)	—
Sale/leaseback of equipment	15	—
Contributions from noncontrolling interests	6	13
Debt amendment, exchange and issuance costs and discounts, including third-party fees expensed	(43)	(857)
Other, net	—	(2)
Cash provided by (used in) financing activities	1,463	(1,122)

	Nine Months Ended September 30,	
	2012	2011
	(millions of dollars)	
Cash flows — investing activities:		
Capital expenditures	(526)	(374)
Nuclear fuel purchases	(155)	(125)
Proceeds from sales of assets	1	53
Restricted cash related to debt issuance (Note 6)	(680)	—
Reduction of restricted cash related to TCEH Letter of Credit Facility	—	188
Other changes in restricted cash	112	(50)
Proceeds from sales of environmental allowances and credits	—	2
Purchases of environmental allowances and credits	(19)	(12)
Proceeds from sales of nuclear decommissioning trust fund securities	56	2,385
Investments in nuclear decommissioning trust fund securities	(68)	(2,398)
Other, net	4	20
Cash used in investing activities	(1,275)	(311)
Net change in cash and cash equivalents	286	(696)
Cash and cash equivalents — beginning balance	826	1,534
Cash and cash equivalents — ending balance	$ 1,112	$ 838

See Notes to Financial Statements.

ENERGY FUTURE HOLDINGS CORP. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2012	December 31, 2011
	(millions of dollars)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,112	$ 826
Restricted cash (Note 14)	697	129
Trade accounts receivable — net (includes $594 and $524 in pledged amounts related to a VIE (Notes 3 and 5))	823	767
Inventories (Note 14)	407	418
Commodity and other derivative contractual assets (Note 10)	1,825	3,025
Margin deposits related to commodity positions	73	56
Other current assets	68	82
Total current assets	5,005	5,303
Restricted cash (Note 14)	947	947
Receivable from unconsolidated subsidiary (Note 12)	1,332	1,235
Investment in unconsolidated subsidiary (Note 2)	5,870	5,720
Other investments (Note 14)	781	709
Property, plant and equipment — net (Note 14)	18,874	19,427
Goodwill (Note 4)	6,152	6,152
Identifiable intangible assets — net (Note 4)	1,777	1,845
Commodity and other derivative contractual assets (Note 10)	852	1,552
Other noncurrent assets, primarily unamortized debt amendment and issuance costs	1,145	1,187
Total assets	$ 42,735	$ 44,077
LIABILITIES AND EQUITY		
Current liabilities:		
Short-term borrowings (includes $184 and $104 related to a VIE (Notes 3 and 6))	$ 469	$ 774
Long-term debt due currently (Note 6)	104	47
Trade accounts payable	437	574
Payables due to unconsolidated subsidiary (Note 12)	137	177
Commodity and other derivative contractual liabilities (Note 10)	1,313	1,950
Margin deposits related to commodity positions	757	1,061
Accumulated deferred income taxes	40	54
Accrued interest	734	480
Other current liabilities	391	497
Total current liabilities	4,382	5,614
Accumulated deferred income taxes	3,101	3,989
Commodity and other derivative contractual liabilities (Note 10)	1,767	1,692
Notes or other liabilities due to unconsolidated subsidiary (Note 12)	286	363
Long-term debt, less amounts due currently (Note 6)	37,428	35,360
Other noncurrent liabilities and deferred credits (Note 14)	4,937	4,816
Total liabilities	51,901	51,834
Commitments and Contingencies (Note 7)		
Equity (Note 8):		
EFH Corp. shareholders' equity	(9,267)	(7,852)
Noncontrolling interests in subsidiaries	101	95
Total equity	(9,166)	(7,757)
Total liabilities and equity	$ 42,735	$ 44,077

See Notes to Financial Statements.

ENERGY FUTURE HOLDINGS CORP. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. BUSINESS AND SIGNIFICANT ACCOUNTING POLICIES

Description of Business

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

EFH Corp., a Texas corporation, is a Dallas-based holding company that conducts its operations principally through its TCEH and Oncor subsidiaries. EFH Corp. is a subsidiary of Texas Holdings, which is controlled by the Sponsor Group. EFCH and its direct subsidiary, TCEH, are wholly-owned. 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. EFIH is wholly-owned and indirectly holds an approximately 80% equity interest in Oncor. Oncor is engaged in regulated electricity transmission and distribution operations in Texas. Oncor provides distribution services to REPs, including subsidiaries of TCEH, which sell electricity to residential, business and other consumers. Oncor (and its majority owner, Oncor Holdings) are not consolidated in EFH Corp.'s financial statements in accordance with consolidation accounting standards related to variable interest entities (VIEs) (see Note 3).

TCEH operates largely in the ERCOT market, and wholesale electricity prices in that market have generally moved with the price of natural gas. Wholesale electricity prices have significant implications to its profitability and cash flows and, accordingly, the value of its business.

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.

We have two reportable segments: the Competitive Electric segment, consisting largely of TCEH, and the Regulated Delivery segment, consisting largely of our investment in Oncor. See Note 13 for further information concerning reportable business segments.

Basis of Presentation

The condensed consolidated financial statements have been prepared in accordance with US GAAP and on the same basis as the audited financial statements included in our 2011 Form 10-K. 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 Notes 2 and 3). Adjustments (consisting of normal recurring accruals) necessary for a fair presentation of the results of operations and financial position have been included therein. All intercompany items and transactions have been eliminated in consolidation. Any 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. Certain information and footnote disclosures normally included in annual consolidated financial statements prepared in accordance with US GAAP have been omitted pursuant to the rules and regulations of the SEC. Because the condensed consolidated interim financial statements do not include all of the information and footnotes required by US GAAP, they should be read in conjunction with the audited financial statements and related notes included in our 2011 Form 10-K. The results of operations for an interim period may not give a true indication of results for a full year. 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 at 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.

2. EQUITY METHOD INVESTMENTS

Oncor Holdings

Investment in unconsolidated subsidiary totaled $5.870 billion and $5.720 billion at September 30, 2012 and December 31, 2011, respectively, and consists of our interest in Oncor Holdings (100% owned), which we account for under the equity method (see Note 3). Oncor Holdings owns approximately 80% of Oncor, which is engaged in regulated electricity transmission and distribution operations in Texas. Oncor provides services, principally electricity distribution, to TCEH's retail operations, and the related revenues represented 29% and 34% of Oncor Holdings' consolidated operating revenues in the nine months ended September 30, 2012 and 2011, respectively.

See Note 12 for discussion of Oncor Holdings' and Oncor's transactions with EFH Corp. and its other subsidiaries.

Distributions from Oncor Holdings — Oncor Holdings' distributions of earnings to us totaled $100 million and $64 million in the nine months ended September 30, 2012 and 2011, respectively. Distributions are limited to Oncor's cumulative net income and may not be paid except to the extent Oncor maintains a required regulatory capital structure, as discussed below. At September 30, 2012, $218 million was eligible to be distributed to Oncor's members after taking into account these restrictions, of which approximately 80% relates to our ownership interest in Oncor. The boards of directors of each of Oncor and Oncor Holdings can withhold distributions to the extent the applicable board determines in good faith that it is necessary to retain such amounts to meet expected future requirements of Oncor and/or Oncor Holdings.

For the period beginning October 11, 2007 and ending December 31, 2012, distributions (other than distributions of the proceeds of any equity issuance) paid by Oncor to its members are limited by a PUCT order to an amount not to exceed Oncor's cumulative net income determined in accordance with US GAAP, as adjusted. Adjustments consist of the removal of noncash impacts of purchase accounting and deducting two specific cash commitments. To date, the noncash impacts consist of removing the effect of an $860 million goodwill impairment charge in 2008 and the cumulative amount of net accretion of fair value adjustments. The two specific cash commitments are the $72 million ($46 million after tax) one-time refund to customers in September 2008 and the funds spent as part of the $100 million commitment for additional energy efficiency initiatives of which $94 million ($61 million after tax) has been spent through September 30, 2012. At September 30, 2012, $468 million was available for distribution under the cumulative net income restriction, of which approximately 80% relates to our ownership interest in Oncor.

Oncor's distributions are further limited by its regulatory capital structure, which is required to 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. At September 30, 2012, Oncor's regulatory capitalization ratio was 58.5% debt and 41.5% equity. The PUCT has the authority to determine what types of debt and equity are included in a utility's debt-to-equity ratio. For purposes of this ratio, debt is calculated as long-term debt plus unamortized gains on reacquired debt less unamortized issuance expenses, premiums and losses on reacquired debt. The debt calculation excludes bonds issued by Oncor Electric Delivery Transition Bond Company, which were issued in 2003 and 2004 to recover specific generation-related regulatory asset stranded and other qualified costs. Equity is calculated as membership interests determined in accordance with US GAAP, excluding the effects of accounting for the Merger (which included recording the initial goodwill and fair value adjustments and the subsequent related impairments and amortization). At September 30, 2012, $218 million was available for distribution under the capital structure restriction, of which approximately 80% relates to our ownership interest in Oncor.

In addition to distributions of earnings, under a tax sharing agreement we received income tax payments from Oncor and Oncor Holdings totaling $27 million and paid income tax net refunds to Oncor and Oncor Holdings totaling $89 million in the nine months ended September 30, 2012 and 2011, respectively (see Note 12).

Oncor Holdings Financial Statements — Condensed statements of consolidated income of Oncor Holdings and its subsidiaries in the three and nine months ended September 30, 2012 and 2011 are presented below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Operating revenues	$ 925	$ 897	$ 2,536	$ 2,359
Operation and maintenance expenses	(292)	(281)	(873)	(799)
Depreciation and amortization	(201)	(190)	(577)	(540)
Taxes other than income taxes	(113)	(107)	(313)	(297)
Other income	6	8	20	23
Other deductions	(1)	(2)	(4)	(7)
Interest income	3	7	24	25
Interest expense and related charges	(96)	(89)	(279)	(265)
Income before income taxes	231	243	534	499
Income tax expense	(95)	(101)	(221)	(204)
Net income	136	142	313	295
Net income attributable to noncontrolling interests	(27)	(29)	(64)	(60)
Net income attributable to Oncor Holdings	$ 109	$ 113	$ 249	$ 235

Assets and liabilities of Oncor Holdings at September 30, 2012 and December 31, 2011 are presented below:

	September 30, 2012	December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	$ 9	$ 12
Restricted cash	64	57
Trade accounts receivable — net	375	303
Trade accounts and other receivables from affiliates	154	179
Inventories	72	71
Accumulated deferred income taxes	39	73
Prepayments and other current assets	74	74
Total current assets	787	769
Restricted cash	16	16
Receivable from TCEH related to nuclear plant decommissioning	286	225
Other investments	78	73
Property, plant and equipment — net	11,191	10,569
Goodwill	4,064	4,064
Note receivable due from TCEH	—	138
Regulatory assets — net	1,542	1,505
Other noncurrent assets	77	73
Total assets	$ 18,041	$ 17,432
LIABILITIES		
Current liabilities:		
Short-term borrowings	$ 784	$ 392
Long-term debt due currently	123	494
Trade accounts payable — nonaffiliates	111	197
Income taxes payable to EFH Corp.	17	2
Accrued taxes other than income	130	151
Accrued interest	91	108
Other current liabilities	110	112
Total current liabilities	1,366	1,456
Accumulated deferred income taxes	1,750	1,688
Investment tax credits	25	28
Long-term debt, less amounts due currently	5,440	5,144
Other noncurrent liabilities and deferred credits	1,944	1,832
Total liabilities	$ 10,525	$ 10,148

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. Accounting standards 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). Our VIEs consist of equity investments in certain of our subsidiaries. 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.

As discussed below, our balance sheet includes assets and liabilities of VIEs that meet the consolidation standards. Oncor Holdings, an indirect EFH Corp. subsidiary which holds an approximate 80% interest in Oncor, is not consolidated in EFH Corp.'s financial statements, and instead is accounted for as an equity method investment, because the structural and operational "ring-fencing" measures discussed in Note 1 prevent us from having power to direct the significant activities of Oncor Holdings or Oncor. In accordance with accounting standards, we account for our investment in Oncor Holdings under the equity method, as opposed to the cost method, based on our level of influence over its activities. The maximum exposure to loss from our 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.

Consolidated VIEs

See discussion in Note 5 regarding the VIE related to our accounts receivable securitization program that is consolidated under the accounting standards.

We also 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 8).

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

Assets:	September 30, 2012	December 31, 2011	Liabilities:	September 30, 2012	December 31, 2011
Cash and cash equivalents	$ 11	$ 10	Short-term borrowings	$ 184	$ 104
Accounts receivable	594	525	Trade accounts payable	1	1
Property, plant and equipment	132	132	Other current liabilities	2	9
Other assets, including $2 million of current assets in both periods	6	6			
Total assets	$ 743	$ 673	Total liabilities	$ 187	$ 114

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 assets to settle the obligations of the VIE.

4. GOODWILL AND IDENTIFIABLE INTANGIBLE ASSETS

Goodwill

The following table provides the goodwill balances at September 30, 2012 and December 31, 2011, all of which relate to the Competitive Electric segment. There were no changes to the goodwill balances in the three and nine months ended September 30, 2012. None of the goodwill is being deducted for tax purposes.

Goodwill before impairment charges	$ 18,342
Accumulated impairment charges	(12,190)
Balance at September 30, 2012 and December 31, 2011	$ 6,152

Identifiable Intangible Assets

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

Identifiable Intangible Asset	September 30, 2012 Gross Carrying Amount	September 30, 2012 Accumulated Amortization	September 30, 2012 Net	December 31, 2011 Gross Carrying Amount	December 31, 2011 Accumulated Amortization	December 31, 2011 Net
Retail customer relationship	$ 463	$ 369	$ 94	$ 463	$ 344	$ 119
Favorable purchase and sales contracts	548	309	239	548	288	260
Capitalized in-service software	350	164	186	318	137	181
Environmental allowances and credits	596	393	203	582	375	207
Mining development costs	162	75	87	140	55	85
Total intangible assets subject to amortization	$ 2,119	$ 1,310	809	$ 2,051	$ 1,199	852
Trade name (not subject to amortization)			955			955
Mineral interests (not currently subject to amortization)(a)			13			38
Total intangible assets			$ 1,777			$ 1,845

(a) In September 2012, we recorded an impairment charge totaling $24 million related to certain mineral interests whose fair value declined as a result of lower expected natural gas drilling activity and prices. The impairment was based on a Level 3 valuation (see Note 9).

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

Identifiable Intangible Asset	Income Statement Line	Segment	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Retail customer relationship	Depreciation and amortization	Competitive Electric	$ 8	$ 13	$ 25	$ 39
Favorable purchase and sales contracts	Operating revenues/fuel, purchased power costs and delivery fees	Competitive Electric	5	6	20	23
Capitalized in-service software	Depreciation and amortization	All	10	11	29	31
Environmental allowances and credits	Fuel, purchased power costs and delivery fees	Competitive Electric	6	25	15	68
Mining development costs	Depreciation and amortization	Competitive Electric	7	13	20	19
Total amortization expense			$ 36	$ 68	$ 109	$ 180

See discussion in Note 14 regarding impairment of intangible assets in the third quarter 2011 as a result of the EPA's issuance of the CSAPR in July 2011.

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	Estimated Amortization Expense
2012	$ 154
2013	$ 129
2014	$ 112
2015	$ 102
2016	$ 84

5. TRADE ACCOUNTS RECEIVABLE AND ACCOUNTS RECEIVABLE SECURITIZATION PROGRAM

TCEH participates in an 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 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.

The maximum funding amount currently available under the program is $350 million. Program funding increased from $104 million at December 31, 2011 to $184 million at September 30, 2012. Under the terms of the program, available funding at September 30, 2012 was reduced by $37 million of customer deposits held by the originator because TCEH's credit ratings were lower than Ba3/BB-.

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 $410 million and $420 million at September 30, 2012 and December 31, 2011, 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 and are reported as interest expense and related charges. 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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Program fees	$ 2	$ 2	$ 6	$ 6
Program fees as a percentage of average funding (annualized)	4.9%	4.4%	6.2%	6.1%

Activities of TXU Receivables Company were as follows:

	Nine Months Ended September 30,	
	2012	2011
Cash collections on accounts receivable	$ 3,501	$ 3,836
Face amount of new receivables purchased	(3,571)	(3,955)
Discount from face amount of purchased receivables	8	8
Program fees paid to funding entities	(6)	(6)
Servicing fees paid to Service Co. for recordkeeping and collection services	(2)	(2)
Increase (decrease) in subordinated notes payable	(10)	4
Cash flows provided to originator under the program	$ (80)	$ (115)

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 outstanding ratio exceed stated thresholds, unless the funding entities waive such events 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 defaults in any payment with respect to debt (other than hedging obligations) in excess of $200 million in the aggregate for such entities. At September 30, 2012, there were no such events of termination.

If the program was terminated, TCEH's liquidity would be reduced because 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. We expect that the level of cash flows would normalize in approximately 16 to 30 days following termination.

Trade Accounts Receivable

	September 30, 2012	December 31, 2011
Wholesale and retail trade accounts receivable, including $594 and $524 in pledged retail receivables	$ 838	$ 794
Allowance for uncollectible accounts	(15)	(27)
Trade accounts receivable — reported in balance sheet	$ 823	$ 767

Gross trade accounts receivable at September 30, 2012 and December 31, 2011 included unbilled revenues of $269 million and $269 million, respectively.

Allowance for Uncollectible Accounts Receivable

	Nine Months Ended September 30,	
	2012	2011
Allowance for uncollectible accounts receivable at beginning of period	$ 27	$ 64
Increase for bad debt expense	20	42
Decrease for account write-offs	(32)	(47)
Reversal of reserve related to counterparty bankruptcy (Note 14)	—	(26)
Allowance for uncollectible accounts receivable at end of period	$ 15	$ 33

6. SHORT-TERM BORROWINGS AND LONG-TERM DEBT

Short-Term Borrowings

At September 30, 2012, outstanding short-term borrowings totaled $469 million, which included $285 million under the TCEH Revolving Credit Facility at a weighted average interest rate of 4.41%, excluding customary fees, and $184 million under the accounts receivable securitization program discussed in Note 5.

At December 31, 2011, outstanding short-term borrowings totaled $774 million, which included $670 million under the TCEH Revolving Credit Facility at a weighted average interest rate of 4.46%, excluding certain customary fees, and $104 million under the accounts receivable securitization program.

Credit Facilities

Credit facilities with cash borrowing and/or letter of credit availability at September 30, 2012 are presented below. The facilities are all senior secured facilities of TCEH.

		September 30, 2012			
Facility	Maturity Date	Facility Limit	Letters of Credit	Cash Borrowings	Availability
TCEH Revolving Credit Facility (a)	October 2013	$ 645	$ —	$ 90	$ 555
TCEH Revolving Credit Facility (a)	October 2016	1,409	—	195	1,214
TCEH Letter of Credit Facility (b)	October 2017 (b)	1,062	—	1,062	—
Subtotal TCEH		$ 3,116	$ —	$ 1,347	$ 1,769
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. At September 30, 2012, borrowings under the facility maturing October 2013 bear interest at LIBOR plus 3.50%, 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. At September 30, 2012, borrowings under the facility maturing October 2016 bear interest at LIBOR plus 4.50%, and a commitment fee is payable quarterly in arrears at a rate per annum equal to 1.00% of the average daily unused portion of the facility.

(b) Facility, $42 million of which matures in October 2014, 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 have been recorded by TCEH as restricted cash that supports issuances of letters of credit and are classified as long-term debt. At September 30, 2012, the restricted cash totaled $947 million, after reduction for a $115 million letter of credit drawn in 2009 related to an office building financing. At September 30, 2012, the restricted cash supports $682 million in letters of credit outstanding, leaving $265 million in available letter of credit capacity.

(c) Revolving facility used to fund cash collateral posting requirements for specified volumes of natural gas hedges totaling approximately 20 million MMBtu at September 30, 2012. At September 30, 2012, there were no borrowings under this facility.

Long-Term Debt

At September 30, 2012 and December 31, 2011, long-term debt consisted of the following:

	September 30, 2012	December 31, 2011
EFH Corp. (parent entity)		
9.75% Fixed Senior Secured First Lien Notes due October 15, 2019	$ 115	$ 115
10% Fixed Senior Secured First Lien Notes due January 15, 2020	1,061	1,061
10.875% Fixed Senior Notes due November 1, 2017 (a)	196	196
11.25 / 12.00% Senior Toggle Notes due November 1, 2017 (a)	464	438
5.55% Fixed Series P Senior Notes due November 15, 2014 (a)	326	326
6.50% Fixed Series Q Senior Notes due November 15, 2024 (a)	740	740
6.55% Fixed Series R Senior Notes due November 15, 2034 (a)	744	744
8.82% Building Financing due semiannually through February 11, 2022 (b)	53	61
Unamortized fair value premium related to Building Financing (b)(c)	12	14
Capital lease obligations	—	1
Unamortized premium	6	6
Unamortized fair value discount (c)	(404)	(430)
Total EFH Corp.	3,313	3,272
EFIH		
6.875% Fixed Senior Secured First Lien Notes due August 15, 2017	250	—
9.75% Fixed Senior Secured First Lien Notes due October 15, 2019	141	141
10% Fixed Senior Secured First Lien Notes due December 1, 2020	2,180	2,180
11% Fixed Senior Secured Second Lien Notes due October 1, 2021	406	406
11.75% Fixed Senior Secured Second Lien Notes due March 1, 2022	1,750	—
Unamortized premium	14	—
Unamortized discount	(11)	—
Total EFIH	4,730	2,727
EFCH		
9.58% Fixed Notes due in annual installments through December 4, 2019 (d)	41	41
8.254% Fixed Notes due in quarterly installments through December 31, 2021 (d)	39	43
1.245% Floating Rate Junior Subordinated Debentures, Series D due January 30, 2037 (e)	1	1
8.175% Fixed Junior Subordinated Debentures, Series E due January 30, 2037	8	8
Unamortized fair value discount (c)	(7)	(8)
Total EFCH	82	85
TCEH		
Senior Secured Facilities:		
3.757% TCEH Term Loan Facilities maturing October 10, 2014 (e)(f)	3,809	3,809
3.716% TCEH Letter of Credit Facility maturing October 10, 2014 (e)	42	42
0.181% TCEH Commodity Collateral Posting Facility maturing December 31, 2012 (g)	—	—
4.757% TCEH Term Loan Facilities maturing October 10, 2017 (a)(e)(f)	15,351	15,351
4.716% TCEH Letter of Credit Facility maturing October 10, 2017 (e)	1,020	1,020
11.5% Fixed Senior Secured Notes due October 1, 2020	1,750	1,750
15% Fixed Senior Secured Second Lien Notes due April 1, 2021	336	336
15% Fixed Senior Secured Second Lien Notes due April 1, 2021, Series B	1,235	1,235
10.25% Fixed Senior Notes due November 1, 2015 (a)	1,833	1,833
10.25% Fixed Senior Notes due November 1, 2015, Series B (a)	1,292	1,292
10.50 / 11.25% Senior Toggle Notes due November 1, 2016	1,656	1,568

	September 30, 2012	December 31, 2011
Pollution Control Revenue Bonds:		
Brazos River Authority:		
5.40% Fixed Series 1994A due May 1, 2029	39	39
7.70% Fixed Series 1999A due April 1, 2033	111	111
6.75% Fixed Series 1999B due September 1, 2034, remarketing date April 1, 2013 (h)	16	16
7.70% Fixed Series 1999C due March 1, 2032	50	50
8.25% Fixed Series 2001A due October 1, 2030	71	71
8.25% Fixed Series 2001D-1 due May 1, 2033	171	171
0.178% Floating Series 2001D-2 due May 1, 2033 (i)	97	97
0.300% Floating Taxable Series 2001I due December 1, 2036 (j)	62	62
0.178% Floating Series 2002A due May 1, 2037 (i)	45	45
6.75% Fixed Series 2003A due April 1, 2038, remarketing date April 1, 2013 (h)	44	44
6.30% Fixed Series 2003B due July 1, 2032	39	39
6.75% Fixed Series 2003C due October 1, 2038	52	52
5.40% Fixed Series 2003D due October 1, 2029, remarketing date October 1, 2014 (h)	31	31
5.00% Fixed Series 2006 due March 1, 2041	100	100
Sabine River Authority of Texas:		
6.45% Fixed Series 2000A due June 1, 2021	51	51
5.20% Fixed Series 2001C due May 1, 2028	70	70
5.80% Fixed Series 2003A due July 1, 2022	12	12
6.15% Fixed Series 2003B due August 1, 2022	45	45
Trinity River Authority of Texas:		
6.25% Fixed Series 2000A due May 1, 2028	14	14
Unamortized fair value discount related to pollution control revenue bonds (c)	(114)	(120)
Other:		
7.46% Fixed Secured Facility Bonds with amortizing payments through January 2015	12	28
7% Fixed Senior Notes due March 15, 2013	5	5
Capital leases	68	63
Other	3	3
Unamortized discount	(10)	(11)
Unamortized fair value discount (c)	(1)	(1)
Total TCEH	29,407	29,323
Total EFH Corp. consolidated	37,532	35,407
Less amount due currently	(104)	(47)
Total long-term debt	$ 37,428	$ 35,360

(a) Excludes the following debt that is held by EFIH or EFH Corp. (parent entity) and eliminated in consolidation:

	September 30, 2012	December 31, 2011
EFH Corp. 10.875% Fixed Senior Notes due November 1, 2017	$ 1,591	$ 1,591
EFH Corp. 11.25 / 12.00% Senior Toggle Notes due November 1, 2017	2,951	2,784
EFH Corp. 5.55% Fixed Series P Senior Notes due November 15, 2014	45	45
EFH Corp. 6.50% Fixed Series Q Senior Notes due November 15, 2024	6	6
EFH Corp. 6.55% Fixed Series R Senior Notes due November 15, 2034	3	3
TCEH 4.757% Term Loan Facilities maturing October 10, 2017	19	19
TCEH 10.25% Fixed Senior Notes due November 1, 2015	213	213
TCEH 10.25% Fixed Senior Notes due November 1, 2015, Series B	150	150
Total	$ 4,978	$ 4,811

(b) This financing is the obligation of a subsidiary of EFH Corp. (parent entity), is secured by a letter of credit and will be serviced with cash drawn by the beneficiary of the letter of credit.
(c) Amount represents unamortized fair value adjustments recorded under purchase accounting.
(d) EFCH's obligations with respect to these financings are guaranteed by EFH Corp. and secured on a first-priority basis by, among other things, an undivided interest in the Comanche Peak nuclear generation facility.
(e) Interest rates in effect at September 30, 2012.
(f) Interest rate swapped to fixed on $18.57 billion principal amount of maturities through October 2014 and up to an aggregate $12.6 billion principal amount from October 2014 through October 2017.
(g) Interest rate in effect at September 30, 2012, excluding a quarterly maintenance fee of $11 million. See "Credit Facilities" above for more information.
(h) 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.
(i) Interest rates in effect at September 30, 2012. 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.
(j) Interest rate in effect at September 30, 2012. 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.

Debt Amounts Due Currently

Amounts due currently (within twelve months) at September 30, 2012 total $104 million and consist of $60 million principal amount of TCEH pollution control revenue bonds (PCRBs) subject to mandatory tender and remarketing in April 2013, which we expect to repurchase in April 2013, and $44 million of scheduled installment payments on capital leases and debt securities.

Debt Repayments

Repayments of long-term debt in the nine months ended September 30, 2012 totaled $31 million and consisted of $20 million of payments of principal at scheduled maturity dates and $11 million of contractual payments under capitalized lease obligations. In addition, short-term borrowings of $385 million under the TCEH Revolving Credit Facility were repaid.

Issuances of EFIH 6.875% Senior Secured Notes in 2012

In October 2012, EFIH and EFIH Finance issued $253 million principal amount of 6.875% Senior Secured Notes due 2017 (EFIH 6.875% Notes) with the proceeds used for general corporate purposes, which may include the payment of dividends to EFH Corp. The offering was issued at a premium of $8 million, which will be amortized to interest expense over the life of the notes. In August 2012, EFIH and EFIH Finance issued $250 million principal amount of EFIH 6.875% Notes and $600 million principal amount of 11.75% Senior Secured Second Lien Notes due 2022 (EFIH 11.75% Notes). The EFIH 11.75% Notes are discussed further below. Of the net proceeds from the August 2012 issuances, $680 million was retained in cash and placed in escrow (and is reported as restricted cash in the balance sheet) to be dividended to EFH Corp. by January 2013, and EFH Corp. agreed to use the dividend and cash on hand to repay the balance of the demand notes payable by EFH Corp. to TCEH, which totaled $689 million at September 30, 2012.

The EFIH 6.875% Notes mature in August 2017, with interest payable in cash semiannually in arrears on February 15 and August 15, beginning February 15, 2013, at a fixed rate of 6.875% per annum. The EFIH 6.875% Notes are secured on a first-priority basis by EFIH's pledge of its 100% ownership of the membership interests in Oncor Holdings (the EFIH Collateral) on an equal and ratable basis with the EFIH 9.75% Notes, the EFIH 10% Notes and EFIH's guarantee of the EFH Corp. Secured Notes.

Until February 15, 2015, EFIH may redeem, with the net cash proceeds of certain equity offerings, up to 35% of the aggregate principal amount of the EFIH 6.875% Notes from time to time at a redemption price of 106.875% of the aggregate principal amount of the notes being redeemed, plus accrued interest. EFIH may redeem the notes at any time prior to February 15, 2015 at a price equal to 100% of their principal amount, plus accrued interest and the applicable premium as defined in the indenture governing the notes. EFIH may also redeem the notes, in whole or in part, at any time on or after February 15, 2015, at specified redemption prices, plus accrued interest. Upon the occurrence of a change of control (as described in the indenture governing the notes), EFIH must offer to repurchase the notes at 101% of their principal amount, plus accrued interest.

The EFIH 6.875% Notes were issued in private placements and are not registered under the Securities Act. EFIH has agreed to use its commercially reasonable efforts to register with the SEC notes having substantially identical terms as the EFIH 6.875% Notes (except for provisions relating to transfer restrictions and payment of additional interest) as part of an offer to exchange freely tradable notes for the EFIH 6.875% Notes. If the registration statement has not been filed and declared effective within 365 days after the date the initial EFIH 6.875% Notes were issued (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.

Issuances of EFIH 11.75% Senior Secured Second Lien Notes in 2012

In February and August 2012, EFIH and EFIH Finance issued $1.150 billion and $600 million principal amount of EFIH 11.75% Notes, respectively. The February 2012 offerings were issued at a discount of $12 million, and the August 2012 offering was issued at a premium of $14 million, both of which will be amortized to interest expense over the life of the notes. The net proceeds from the February 2012 issuance were used to pay a $950 million dividend to EFH Corp., and the balance was retained as cash on hand. EFH Corp. used the dividend to repay a portion of the demand notes payable by EFH Corp. to TCEH. TCEH used the majority of the $950 million to repay all borrowings under the TCEH Revolving Credit Facility.

The EFIH 11.75% Notes mature in March 2022, with interest payable in cash semiannually in arrears on March 1 and September 1 at a fixed rate of 11.75% per annum. The EFIH 11.75% Notes are secured on a second-priority basis by the EFIH Collateral on an equal and ratable basis with the EFIH 11% Notes. The EFIH 11.75% Notes have substantially the same covenants as the EFIH 11% Notes, and the holders of the EFIH 11.75% Notes will generally vote as a single class with the holders of the EFIH 11% Notes.

Until March 1, 2015, EFIH may redeem, with the net cash proceeds of certain equity offerings, up to 35% of the aggregate principal amount of the EFIH 11.75% Notes from time to time at a redemption price of 111.750% of the aggregate principal amount of the notes being redeemed, plus accrued interest. EFIH may redeem the notes at any time prior to March 1, 2017 at a price equal to 100% of their principal amount, plus accrued interest and the applicable premium as defined in the indenture governing the notes. EFIH may also redeem the notes, in whole or in part, at any time on or after March 1, 2017, at specified redemption prices, plus accrued interest. Upon the occurrence of a change of control (as described in the indenture governing the notes), EFIH must offer to repurchase the notes at 101% of their principal amount, plus accrued interest.

The EFIH 11.75% Notes were issued in private placements and are not registered under the Securities Act. EFIH has agreed to use its commercially reasonable efforts to register with the SEC notes having substantially identical terms as the EFIH 11.75% Notes (except for provisions relating to transfer restrictions and payment of additional interest) as part of an offer to exchange freely tradable notes for the EFIH 11.75% Notes. If the registration statement has not been filed and declared effective within 365 days after the date the initial EFIH 11.75% notes were issued (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.

Information Regarding Other Significant Outstanding Debt

EFH Corp. 9.75% Notes and EFIH 9.75% Notes — At September 30, 2012, the principal amounts of the EFH Corp. 9.75% Notes and EFIH 9.75% Notes totaled $115 million and $141 million, respectively. The notes mature in October 2019, with interest payable in cash semi-annually in arrears on April 15 and October 15 at a fixed rate of 9.75% per annum. The EFH Corp. 9.75% Notes are fully and unconditionally guaranteed on a joint and several basis by EFCH and EFIH. The guarantee from EFIH is secured by the EFIH Collateral. The guarantee from EFCH is not secured. The EFIH 9.75% Notes are not guaranteed but are secured by the EFIH Collateral on an equal and ratable basis with the EFIH 6.875% Notes, the EFIH 10% Notes and EFIH's guarantee of the EFH Corp. 10% Notes and the EFH Corp. 9.75% Notes.

The EFH Corp. 9.75% Notes and EFIH 9.75% Notes are senior obligations of each issuer and rank equally in right of payment with all senior indebtedness of each issuer and are senior in right of payment to any future subordinated indebtedness of each issuer. The EFH Corp. 9.75% 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 are structurally subordinated to all indebtedness and other liabilities of EFH Corp.'s non-guarantor subsidiaries. The EFIH guarantee of the EFH Corp. 9.75% Notes is effectively senior to all unsecured indebtedness of EFIH, to the extent of the value of the EFIH Collateral, and is effectively subordinated to any indebtedness of EFIH secured by assets of EFIH other than the EFIH Collateral, to the extent of the value of the assets securing such indebtedness. The EFIH 9.75% Notes are effectively senior to all unsecured indebtedness of EFIH, to the extent of the value of the EFIH Collateral, and are effectively subordinated to any indebtedness of EFIH secured by assets of EFIH other than the EFIH Collateral, to the extent of the value of such assets. Furthermore, the EFIH 9.75% Notes are structurally subordinated to all indebtedness and other liabilities of EFIH's subsidiaries (other than EFIH Finance), including Oncor Holdings and its subsidiaries.

EFH Corp. 10% Senior Secured Notes — At September 30, 2012, the principal amount of the EFH Corp. 10% Notes totaled $1.061 billion, and the 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 on the same basis as the EFH Corp. 9.75% Notes discussed above.

EFH Corp. 10.875% Senior Notes and 11.25/12.00% Senior Toggle Notes (collectively, EFH Corp. Senior Notes) — At September 30, 2012, the principal amount of the EFH Corp. Senior Notes totaled $660 million, excluding $4.542 billion principal amount held by EFIH, and the notes are fully and unconditionally guaranteed on a joint and several unsecured basis by EFCH and EFIH. The notes mature in November 2017, with interest payable in cash semi-annually in arrears on May 1 and November 1 at a fixed rate for the 10.875% Notes of 10.875% per annum and at a fixed rate for the Toggle Notes of 11.250% per annum for cash interest and 12.000% per annum for PIK Interest. For any interest period until November 1, 2012, EFH Corp. may elect to pay interest on the Toggle Notes (i) entirely in cash; (ii) by increasing the principal amount of the notes or by issuing new EFH Corp. Toggle Notes (PIK Interest); or (iii) 50% in cash and 50% in PIK Interest. Once EFH Corp. makes a PIK election, which it did effective with the May 2009 interest payment, the election is valid for each succeeding interest payment period until EFH Corp. revokes the election. EFH Corp. is not required to make an offer to repurchase the notes upon the occurrence of a change of control of EFH Corp.

TCEH Senior Secured Facilities — Borrowings under the TCEH Senior Secured Facilities totaled $20.507 billion at September 30, 2012 and consisted of:

- $3.809 billion of TCEH Term Loan Facilities maturing in October 2014 with interest payable at LIBOR plus 3.50%;
- $15.351 billion of TCEH Term Loan Facilities maturing in October 2017 with interest payable at LIBOR plus 4.50%;
- $42 million of cash borrowed under the TCEH Letter of Credit Facility maturing in October 2014 with interest payable at LIBOR plus 3.50% (see discussion under "Credit Facilities" above);
- $1.020 billion of cash borrowed under the TCEH Letter of Credit Facility maturing in October 2017 with interest payable at LIBOR plus 4.50% (see discussion under "Credit Facilities" above), and
- Amounts borrowed under the TCEH Revolving Credit Facility, which may be reborrowed from time to time until October 2013 with respect to $645 million of commitments and until October 2016 with respect to $1.409 billion of commitments, totaled $90 million and $195 million, respectively, at September 30, 2012.

The TCEH Commodity Collateral Posting Facility, under which there were no borrowings at September 30, 2012, will mature in December 2012.

Each of the loans described above that matures in 2016 or 2017 includes a "springing maturity" provision pursuant to which (i) in the event that more than $500 million aggregate principal amount of the TCEH 10.25% Notes due in 2015 (other than notes held by EFH Corp. or its controlled affiliates at March 31, 2011 to the extent held at the determination date as defined in the Credit Agreement) or more than $150 million aggregate principal amount of the TCEH Toggle Notes due in 2016 (other than notes held by EFH Corp. or its controlled affiliates at March 31, 2011 to the extent held as of the determination date as defined in the Credit Agreement), as applicable, remain outstanding as of 91 days prior to the maturity date of the applicable notes and (ii) TCEH's total debt to Adjusted EBITDA ratio (as defined in the TCEH Senior Secured Facilities) is greater than 6.00 to 1.00 at the applicable determination date, then the maturity date of the extended loans will automatically change to 90 days prior to the maturity date of the applicable notes.

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 fully and 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 subsidiary of TCEH. The TCEH Senior Secured Facilities, along with the TCEH Senior Secured Notes and certain commodity hedging transactions and the interest rate swaps described under "TCEH Interest Rate Swap Transactions" below, are secured on a first priority basis by (i) substantially all of the current and future assets of TCEH and TCEH's subsidiaries who are guarantors of such facilities and (ii) pledges of the capital stock of TCEH and certain current and future direct or indirect subsidiaries of TCEH.

TCEH 11.5% Senior Secured Notes — At September 30, 2012, the principal amount of the TCEH 11.5% Senior Secured Notes totaled $1.750 billion. The notes mature in October 2020, with interest payable in cash quarterly in arrears on January 1, April 1, July 1 and October 1, at a fixed rate of 11.5% per annum. The notes are fully and unconditionally guaranteed on a joint and several basis by EFCH and each subsidiary of TCEH that guarantees the TCEH Senior Secured Facilities (collectively, the Guarantors). The notes are secured, on a first-priority basis, by security interests in all of the assets of TCEH, and the guarantees are secured on a first-priority basis by all of the assets and equity interests held by the Guarantors, in each case, to the extent such assets and equity interests secure obligations under the TCEH Senior Secured Facilities (the TCEH Collateral), subject to certain exceptions and permitted liens.

The notes are (i) senior obligations and rank equally in right of payment with all senior indebtedness of TCEH, (ii) senior in right of payment to all existing or future unsecured and second-priority secured debt of TCEH to the extent of the value of the TCEH Collateral and (iii) senior in right of payment to any future subordinated debt of TCEH. These notes are effectively subordinated 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.

TCEH 15% Senior Secured Second Lien Notes (including Series B) — At September 30, 2012, the principal amount of the TCEH 15% Senior Secured Second Lien Notes totaled $1.571 billion. These notes mature in April 2021, with interest payable in cash quarterly in arrears on January 1, April 1, July 1 and October 1 at a fixed rate of 15% per annum. The notes are fully and unconditionally guaranteed on a joint and several basis by EFCH and, subject to certain exceptions, each subsidiary of TCEH that guarantees the TCEH Senior Secured Credit Facilities. 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, 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.

The notes are senior obligations of the issuer 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, the TCEH Senior Secured Notes 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.

TCEH 10.25% Senior Notes (including Series B) and 10.50/11.25% Senior Toggle Notes (collectively, the TCEH Senior Notes) — At September 30, 2012, the principal amount of the TCEH Senior Notes totaled $4.781 billion, excluding $363 million aggregate principal amount held by EFH Corp. and EFIH, and the notes are fully and unconditionally guaranteed on a joint and several unsecured basis by TCEH's direct parent, EFCH (which owns 100% of TCEH), and by each subsidiary that guarantees the TCEH Senior Secured Facilities. 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 Toggle 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, which it did effective with the May 2009 interest payment, the election is valid for each succeeding interest payment period until TCEH revokes the election.

EFIH 10% Senior Secured Notes — At September 30, 2012, the principal amount of the EFIH 10% Notes totaled $2.180 billion. The notes mature in December 2020, with interest payable in cash semiannually in arrears on June 1 and December 1 at a fixed rate of 10% per annum. The notes are secured by the EFIH Collateral on an equal and ratable basis with the EFIH 6.875% Notes, the EFIH 9.75% Notes and EFIH's guarantee of the EFH Corp. Senior Secured Notes as discussed above.

EFIH 11% Senior Secured Second Lien Notes — At September 30, 2012, the principal amount of the EFIH 11% Notes totaled $406 million. The notes mature in October 2021, with interest payable in cash semiannually in arrears on May 15 and November 15 at a fixed rate of 11% per annum. The EFIH 11% Notes are secured on a second-priority basis by the EFIH Collateral on an equal and ratable basis with the EFIH 11.75% Notes.

The notes were issued in a private placement and are not registered under the Securities Act. EFIH agreed to use its commercially reasonable efforts to register with the SEC notes having substantially identical terms as the EFIH 11% Notes (except for provisions relating to transfer restrictions and payment of additional interest) as part of an offer to exchange freely tradable notes for the EFIH 11% Notes, unless such notes meet certain transferability conditions (as described in the related registration rights agreement). The notes met the transferability conditions in March 2012 and became freely tradable.

Fair Value of Long-Term Debt

At September 30, 2012 and December 31, 2011, the estimated fair value of our long-term debt (excluding capital leases) totaled $25.832 billion and $23.402 billion, respectively, and the carrying amount totaled $37.464 billion and $35.343 billion, respectively. We determine fair value in accordance with accounting standards as discussed in Note 9 and at September 30, 2012 represents Level 2 valuations. We obtain security pricing from a vendor who uses broker quotes and third-party pricing services to determine fair values. Where relevant, these prices are validated through subscription services such as Bloomberg.

TCEH Interest Rate Swap Transactions

TCEH employs interest rate swaps to hedge exposure to its variable rate debt. As reflected in the table below, at September 30, 2012, TCEH has entered into the following series of interest rate swap transactions that effectively fix the interest rates at between 5.5% and 9.3%.

Fixed Rates	Expiration Dates	Notional Amount
5.5% - 9.3%	October 2012 through October 2014	$18.57 billion (a)
6.8% - 9.0%	October 2015 through October 2017	$ 12.60 billion (b)

(a) Swaps related to an aggregate $1.1 billion principal amount of debt expired in 2012. Per the terms of the transactions, the nominal amount of swaps entered into in 2011 grew by $1.02 billion, substantially offsetting the expired swaps.
(b) These swaps are effective from October 2014 through October 2017. The $12.6 billion notional amount of swaps includes $3 billion that expires in October 2015 with the remainder expiring in October 2017.

TCEH has also entered into interest rate basis swap transactions that further reduce the fixed borrowing costs achieved through the interest rate swaps. Basis swaps in effect at September 30, 2012 totaled $15.92 billion notional amount, a decrease of $1.8 billion from December 31, 2011 reflecting new and expired swaps. The basis swaps relate to debt outstanding through 2014.

The interest rate swap counterparties are secured on an equal and ratable basis by the same collateral package granted to the lenders under the TCEH Senior Secured Facilities.

The interest rate swaps have resulted in net losses reported in interest expense and related charges as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Realized net loss	$ (168)	$ (177)	$ (505)	$ (511)
Unrealized net loss	(20)	(619)	(16)	(879)
Total	$ (188)	$ (796)	$ (521)	$ (1,390)

The cumulative unrealized mark-to-market net liability related to all TCEH interest rate swaps totaled $2.248 billion and $2.231 billion at September 30, 2012 and December 31, 2011, respectively, of which $67 million and $76 million (both pretax), respectively, were reported in accumulated other comprehensive income.

7. COMMITMENTS AND CONTINGENCIES

Guarantees

We have entered into contracts that contain guarantees to unaffiliated parties that could require performance or payment under certain conditions. Material guarantees are discussed below.

Disposed TXU Gas Company operations — In connection with the sale of TXU Gas Company to Atmos Energy Corporation (Atmos) in October 2004, EFH Corp. agreed to indemnify Atmos, until October 1, 2014, for up to $500 million for any liability related to assets retained by TXU Gas Company, including certain inactive gas plant sites not acquired by Atmos, and up to $1.4 billion for contingent liabilities associated with preclosing tax and employee related matters. The maximum aggregate amount under these indemnities that we may be required to pay is $1.9 billion. To date, we have not been required to make any payments to Atmos under any of these indemnity obligations, and no such payments are currently anticipated.

See Note 6 for discussion of guarantees and security for certain of our debt.

Letters of Credit

At September 30, 2012, TCEH had outstanding letters of credit under its credit facilities totaling $682 million as follows:

- $270 million to support risk management and trading margin requirements in the normal course of business, including over-the-counter hedging transactions and collateral postings with ERCOT;
- $208 million to support floating rate pollution control revenue bond debt with an aggregate principal amount of $204 million (the letters of credit are available to fund the payment of such debt obligations and expire in 2014);
- $71 million to support TCEH's REP's financial requirements with the PUCT, and
- $133 million for miscellaneous credit support requirements.

Litigation Related to Generation Facilities

In November 2010, an administrative appeal challenging the decision of the TCEQ to renew and amend Oak Grove Management Company LLC's (Oak Grove) (a wholly-owned subsidiary of TCEH) Texas Pollutant Discharge Elimination System (TPDES) permit related to water discharges was filed by Robertson County: Our Land, Our Lives and Roy Henrichson in the Travis County, Texas District Court. Plaintiffs sought a reversal of the TCEQ's order and a remand back to the TCEQ for further proceedings. Oral argument was held in this administrative appeal on October 23, 2012, and the court affirmed the TCEQ's issuance of the TPDES permit to Oak Grove. Plaintiffs may appeal the district court's decision to the appellate court within 30 days of entry of the court's order.

In addition to this administrative appeal, in November 2010, two other petitions were filed in Travis County, Texas District Court by Sustainable Energy and Economic Development Coalition (SEED) and Paul and Lisa Rolke, respectively, who were not parties to the administrative hearing before the State Office of Administrative Hearings, challenging the TCEQ's decision to renew and amend Oak Grove's TPDES permit and asking the District Court to remand the matter to the TCEQ for further proceedings. In January 2012, the court dismissed the petition filed by Paul and Lisa Rolke, and in March 2012, the court denied the Rolkes' motion for a new trial. The deadline for the Rolkes' to appeal the court's denial of their motion for a new trial has expired. Also, in March 2012, SEED voluntarily withdrew its petition without prejudice to refiling, and SEED's deadline for refiling has since expired. Accordingly, these two cases have been favorably resolved.

In January 2012, the Sierra Club filed a petition in Travis County, Texas District Court challenging the TCEQ's decision to issue permit amendments imposing limits on emissions during planned startup, shutdown and maintenance activities at Luminant's Big Brown, Monticello, Martin Lake and Sandow Unit 4 generation facilities. In July 2012, the Sierra Club voluntarily dismissed its challenge, with prejudice to refiling these claims in state court. Accordingly, this matter has been favorably resolved.

In September 2010, the Sierra Club filed a lawsuit in the US District Court for the Eastern District of Texas (Texarkana Division) against EFH Corp. and Luminant Generation Company LLC (a wholly-owned subsidiary of TCEH) for alleged violations of the Clean Air Act (CAA) at Luminant's Martin Lake generation facility. In May 2012, the Sierra Club filed a lawsuit in the US District Court for the Western District of Texas (Waco Division) against EFH Corp. and Luminant Generation Company LLC for alleged violations of the CAA at Luminant's Big Brown generation facility. The courts have scheduled these cases for trial in the summer of 2013. While we are unable to estimate any possible loss or predict the outcome, we believe that the Sierra Club's claims are without merit, and we intend to vigorously defend these lawsuits. In addition, in December 2010 and again in October 2011, the Sierra Club informed Luminant that it may sue Luminant for allegedly violating CAA provisions in connection with Luminant's Monticello generation facility. In May 2012, the Sierra Club informed us that it may sue us for allegedly violating CAA provisions in connection with Luminant's Sandow 4 generation facility. While we cannot predict whether the Sierra Club will actually file suit regarding Monticello or Sandow 4 or the outcome of any resulting proceedings, we believe we have complied with the requirements of the CAA at all of our generation facilities.

See below for discussion of litigation regarding the CSAPR and the Texas State Implementation Plan.

Regulatory Reviews

In June 2008, the EPA issued an initial request for information to TCEH under the EPA's authority under Section 114 of CAA. The stated purpose of the request is to obtain information necessary to determine compliance with the CAA, including New Source Review Standards and air permits issued by the TCEQ for the Big Brown, Monticello and Martin Lake generation facilities. Historically, as the EPA has pursued its New Source Review enforcement initiative, companies that have received a large and broad request under Section 114, such as the request received by TCEH, have in many instances subsequently received a notice of violation from the EPA, which has in some cases progressed to litigation or settlement. In July 2012, the EPA sent us a notice of violation alleging noncompliance with the CAA's New Source Review Standards and the air permits at our Martin Lake and Big Brown generation facilities. While we cannot predict whether the EPA will initiate enforcement proceedings under the notice of violation, we believe that we have complied with all requirements of the CAA at all of our generation facilities. We cannot predict the outcome of any resulting enforcement proceedings or estimate the penalties that might be assessed in connection with any such proceedings. In September 2012, we filed a petition for review in the United States Court of Appeals for the Fifth Circuit (Fifth Circuit Court) seeking judicial review of the EPA's notice of violation. Given recent legal precedent subjecting agency orders like the notice of violation to judicial review, we filed the petition for review to preserve our ability to challenge the EPA's issuance of the notice and its defects. In October 2012, the EPA filed a motion to dismiss our petition. We cannot predict the outcome of these proceedings.

Cross-State Air Pollution Rule (CSAPR)

In July 2011, the EPA issued the CSAPR, compliance with which would have required significant additional reductions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) emissions from our fossil-fueled generation units. In September 2011, we filed a petition for review in the US Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court) challenging the CSAPR as it applies to Texas. If the CSAPR had taken effect, it would have caused us to, among other actions, idle two lignite/coal-fueled generation units and cease certain lignite mining operations by the end of 2011.

In February 2012, the EPA released a final rule (Final Revisions) and a proposed rule revising certain aspects of the CSAPR, including increases in the emissions budgets for Texas and our generation assets as compared to the July 2011 version of the rule. In March 2012, we submitted comments to the EPA on the proposed rule requesting the EPA to make additional corrections to the CSAPR's budgets for Texas. In April 2012, we filed in the D.C. Circuit Court a petition for review of the Final Revisions on the ground, among others, that the rules do not include all of the budget corrections we requested from the EPA. The parties to the case have agreed that the case should be held in abeyance pending the issuance of the mandate in the CSAPR proceeding. The mandate will issue seven days after the rehearing proceeding is concluded in the D.C. Circuit Court. In June 2012, the EPA finalized the proposed rule (Second Revised Rule). As compared to the proposed revisions to the CSAPR issued by the EPA in October 2011, these recent rules finalize emissions budgets for our generation assets that are approximately 6% lower for SO_2, 3% higher for annual NO_x and 2% higher for seasonal NO_x.

In August 2012, a three judge panel of the D.C. Circuit Court vacated the CSAPR, remanding it to the EPA for further proceedings. As a result, the CSAPR, the Final Revisions and the Second Revised Rule do not impose any immediate requirements on us, the State of Texas, or other affected parties. The D.C. Circuit Court's order stated that the EPA was expected to continue administering the CAIR (the predecessor rule to the CSAPR) pending the EPA's further consideration of the rule. In October 2012, the EPA and certain other parties that supported the CSAPR filed a petition with the D.C. Circuit Court seeking review by the full court of the panel's decision to vacate and remand the CSAPR. We cannot predict when or how the D.C. Circuit Court will rule on this petition.

State Implementation Plan (SIP)

In September 2010, the EPA disapproved a portion of the State Implementation Plan pursuant to which the TCEQ implements its program to achieve the requirements of the Clean Air Act. The EPA disapproved the Texas standard permit for pollution control projects. We hold several permits issued pursuant to the TCEQ standard permit conditions for pollution control projects. We challenged the EPA's disapproval by filing a lawsuit in the US Court of Appeals for the Fifth Circuit (Fifth Circuit Court) arguing that the TCEQ's adoption of the standard permit conditions for pollution control projects was consistent with the Clean Air Act. In March 2012, the Fifth Circuit Court vacated the EPA's disapproval of the Texas standard permit for pollution control projects and remanded the matter to the EPA for reconsideration. We cannot predict the timing or outcome of the EPA's reconsideration.

In November 2010, the EPA disapproved a different portion of the SIP under which the TCEQ had been phasing out a long-standing exemption for certain emissions that unavoidably occur during startup, shutdown and maintenance activities and replacing that exemption with a more limited affirmative defense that will itself be phased out and replaced by TCEQ-issued generation facility-specific permit conditions. We, like many other electricity generation facility operators in Texas, have asserted applicability of the exemption or affirmative defense, and the TCEQ has not objected to that assertion. We have also applied for and received the generation facility-specific permit amendments. We challenged the EPA's disapproval by filing a lawsuit in the Fifth Circuit Court arguing that the TCEQ's adoption of the affirmative defense and phase-out of that affirmative defense as permits are issued is consistent with the Clean Air Act. In July 2012, the Fifth Circuit Court denied our challenge and ruled that the EPA's actions were in accordance with the Clean Air Act. In September 2012, we filed a petition with the Fifth Circuit Court seeking rehearing asking for review by the full Fifth Circuit Court of the panel's decision. On October 12, 2012, the Fifth Circuit Court panel withdrew its original opinion and issued a new expanded opinion that again upheld the EPA's disapproval. Parties may seek rehearing within 45 days after issuance of the new opinion. We cannot predict the timing or outcome of this matter.

Other Matters

We are involved in various legal and administrative proceedings in the normal course of business, the ultimate resolutions of which, in the opinion of management, are not anticipated to have a material effect on our results of operations, liquidity or financial condition.

8. EQUITY

Dividend Restrictions

EFH Corp. has not declared or paid any dividends since the Merger.

The indentures governing the EFH Corp. Senior Notes and EFH Corp. Senior Secured Notes include covenants that, among other things and subject to certain exceptions, restrict our ability to pay dividends or make other distributions in respect of our common stock. Accordingly, our net income is restricted from being used to make distributions on our common stock unless such distributions are expressly permitted under these indentures and/or on a pro forma basis, after giving effect to such distribution, EFH Corp.'s consolidated leverage ratio is equal to or less than 7.0 to 1.0. For purposes of this calculation, "consolidated leverage ratio" is defined as the ratio of consolidated total debt (as defined in the indenture) to Adjusted EBITDA, in each case, consolidated with its subsidiaries other than Oncor Holdings and its subsidiaries. EFH Corp.'s consolidated leverage ratio was 9.6 to 1.0 at September 30, 2012.

The indentures governing the EFIH Notes generally restrict EFIH from making any cash distribution to EFH Corp. for the ultimate purpose of making a cash dividend on our common stock unless at the time, and after giving effect to such dividend, EFIH's consolidated leverage ratio is equal to or less than 6.0 to 1.0. Under the indentures governing the EFIH Notes, the term "consolidated leverage ratio" is defined as the ratio of EFIH's consolidated total debt (as defined in the indentures) to EFIH's Adjusted EBITDA on a consolidated basis (including Oncor's Adjusted EBITDA). EFIH's consolidated leverage ratio was 6.3 to 1.0 at September 30, 2012. In addition, the EFIH Notes generally restrict EFIH's ability to make distributions or loans to EFH Corp., unless such distributions or loans are expressly permitted under the indentures governing the EFIH Notes.

The TCEH Senior Secured Facilities generally restrict TCEH from making any cash distribution to any of its parent companies for the ultimate purpose of making a cash dividend on our common stock unless at the time, and after giving effect to such dividend, its consolidated total debt (as defined in the TCEH Senior Secured Facilities) to Adjusted EBITDA would be equal to or less than 6.5 to 1.0. At September 30, 2012, the ratio was 8.2 to 1.0.

In addition, the TCEH Senior Secured Facilities and indentures governing the TCEH Senior Notes, TCEH Senior Secured Notes and TCEH Senior Secured Second Lien Notes generally restrict TCEH's ability to make distributions or loans to any of its parent companies, EFCH and EFH Corp., unless such distributions or loans are expressly permitted under the TCEH Senior Secured Facilities and the indentures governing such notes.

In addition, under applicable law, we are prohibited from paying any dividend to the extent that immediately following payment of such dividend, there would be no statutory surplus or we would be insolvent.

Noncontrolling Interests

As discussed in Note 3, we consolidate a joint venture formed in 2009 for the purpose of developing two new nuclear generation units, which results in a noncontrolling interests component of equity. Net loss attributable to the noncontrolling interests was immaterial in the nine months ended September 30, 2012 and 2011.

Equity

The following table presents the changes to equity in the nine months ended September 30, 2012.

	EFH Corp. Shareholders' Equity					
	Common Stock (a)	Additional Paid-in Capital	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total Equity
Balance at December 31, 2011	$ 2	$ 7,947	$ (15,579)	$ (222)	$ 95	$ (7,757)
Net loss	—	—	(1,408)	—	—	(1,408)
Effects of stock-based incentive compensation plans	—	11	—	—	—	11
Change in unrecognized losses related to pension and OPEB plans (Note 11)	—	—	—	(25)	—	(25)
Net effects of cash flow hedges	—	—	—	5	—	5
Net effects of cash flow hedges – Oncor (b)	—	—	—	2	—	2
Investment by noncontrolling interests	—	—	—	—	6	6
Balance at September 30, 2012	$ 2	$ 7,958	$ (16,987)	$ (240)	$ 101	$ (9,166)

(a) Authorized shares totaled 2,000,000,000 at September 30, 2012. Outstanding shares totaled 1,680,539,245 and 1,679,539,245 at September 30, 2012 and December 31, 2011, respectively.

(b) Represents recognition in equity in earnings of unconsolidated subsidiaries of previous losses on interest rate hedge transactions entered into by Oncor.

The following table presents the changes to equity in the nine months ended September 30, 2011.

	EFH Corp. Shareholders' Equity					
	Common Stock (a)	Additional Paid-in Capital	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total Equity
Balance at December 31, 2010	$ 2	$ 7,937	$ (13,666)	$ (263)	$ 79	$ (5,911)
Net loss	—	—	(1,776)	—	—	(1,776)
Effects of stock-based incentive compensation plans	—	4	—	—	—	4
Change in unrecognized losses related to pension and OPEB plans	—	—	—	16	—	16
Net effects of cash flow hedges	—	—	—	15	—	15
Net effects of cash flow hedges – Oncor (b)	—	—	—	(24)	—	(24)
Investment by noncontrolling interests	—	—	—	—	13	13
Other	—	(1)	—	—	—	(1)
Balance at September 30, 2011	$ 2	$ 7,940	$ (15,442)	$ (256)	$ 92	$ (7,664)

(a) Authorized shares totaled 2,000,000,000 at September 30, 2011. Outstanding shares totaled 1,675,588,195 and 1,671,812,118 at September 30, 2011 and December 31, 2010, respectively.

(b) Represents losses on interest rate hedge transactions entered into by Oncor.

9. FAIR VALUE MEASUREMENTS

Accounting standards related to the determination of fair value define fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. We use a "mid-market" valuation convention (the mid-point price between bid and ask prices) as a practical expedient to measure fair value for the majority of our assets and liabilities subject to fair value measurement on a recurring basis. We primarily use the market approach for recurring fair value measurements and use valuation techniques to maximize the use of observable inputs and minimize the use of unobservable inputs.

We categorize our assets and liabilities recorded at fair value based upon the following fair value hierarchy:

- Level 1 valuations use quoted prices in active markets for identical assets or liabilities that are accessible at the measurement date. An active market is a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis. Our Level 1 assets and liabilities include exchange-traded commodity contracts. For example, a significant number of our derivatives are NYMEX futures and swaps transacted through clearing brokers for which prices are actively quoted.

- Level 2 valuations use inputs that, in the absence of actively quoted market prices, are observable for the asset or liability, either directly or indirectly. Level 2 inputs include: (a) quoted prices for similar assets or liabilities in active markets, (b) quoted prices for identical or similar assets or liabilities in markets that are not active, (c) 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 (d) inputs that are derived principally from or corroborated by observable market data by correlation or other means. Our Level 2 valuations utilize over-the-counter broker quotes, quoted prices for similar assets or liabilities that are corroborated by correlations or other mathematical means and other valuation inputs. For example, our Level 2 assets and liabilities include forward commodity positions at locations for which over-the-counter broker quotes are available.

- Level 3 valuations use unobservable inputs for the asset or liability. Unobservable inputs are used to the extent observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. We use the most meaningful information available from the market combined with internally developed valuation methodologies to develop our best estimate of fair value. For example, our Level 3 assets and liabilities include certain derivatives whose values are derived from pricing models that utilize multiple inputs to the valuations, including inputs that are not observable or easily corroborated through other means. See further discussion below.

Our valuation policies and procedures are developed, maintained and validated by a centralized risk management group that reports to the Chief Financial Officer, who also functions as the Chief Risk Officer. Risk management functions include valuation model validation, risk analytics, risk control, credit risk management and risk reporting.

We utilize several different 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 methods include, among others, the use of broker quotes and statistical relationships between different price curves.

In utilizing broker quotes, we attempt to obtain multiple quotes from brokers that are active in the commodity markets in which we participate (and require at least one quote from two brokers to determine a pricing input as observable); however, not all pricing inputs are quoted by brokers. The number of broker quotes received for certain pricing inputs varies depending on the depth of the trading market, each individual broker's publication policy, recent trading volume trends and various other factors. In addition, for valuation of interest rate swaps, we use a combination of dealer provided market valuations (generally non-binding) and standard rate swap valuation models utilizing month-end interest rate curves.

Certain derivatives and financial instruments are valued utilizing option pricing models that take into consideration multiple inputs including commodity prices, volatility factors, discount rates and other inputs. Additionally, when there is not a sufficient amount of observable market data, valuation models are developed that incorporate proprietary views of market factors. Significant unobservable inputs used to develop the valuation models include volatility curves, correlation curves, illiquid pricing locations and credit/non-performance risk assumptions. Those valuation models are generally used in developing long-term forward price curves for certain commodities. We believe the development of such curves is consistent with industry practice; however, the fair value measurements resulting from such curves are classified as Level 3.

The significant unobservable inputs and valuation models are developed by employees trained and experienced in market operations and fair value measurement and validated by the company's risk management group, which also further analyzes any significant changes in Level 3 measurements. Significant changes in the unobservable inputs could result in significant upward or downward changes in the fair value measurement.

With respect to amounts presented in the following fair value hierarchy tables, the fair value measurement of an asset or liability (e.g., a contract) is required to fall in its entirety in one level, based on the lowest level input that is significant to the fair value measurement. Certain assets and liabilities would be classified in Level 2 instead of Level 3 of the hierarchy except for the effects of credit reserves and non-performance risk adjustments, respectively. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability being measured.

At September 30, 2012, assets and liabilities measured at fair value on a recurring basis consisted of the following:

	Level 1	Level 2	Level 3 (a)	Reclassification (b)	Total
Assets:					
Commodity contracts	$ 245	$ 2,152	$ 71	$ 65	$ 2,533
Interest rate swaps	—	144	—	—	144
Nuclear decommissioning trust – equity securities (c)	248	145	—	—	393
Nuclear decommissioning trust – debt securities (c)	—	258	—	—	258
Total assets	$ 493	$ 2,699	$ 71	$ 65	$ 3,328
Liabilities:					
Commodity contracts	$ 299	$ 218	$ 87	$ 65	$ 669
Interest rate swaps	—	2,411	—	—	2,411
Total liabilities	$ 299	$ 2,629	$ 87	$ 65	$ 3,080

(a) See table below for description of Level 3 assets and liabilities.
(b) Fair values are determined on a contract basis, but certain contracts result in a current asset and a noncurrent liability, or vice versa, as presented in the balance sheet.
(c) The nuclear decommissioning trust investment is included in the other investments line in the balance sheet. See Note 14.

At December 31, 2011, assets and liabilities measured at fair value on a recurring basis consisted of the following:

	Level 1	Level 2	Level 3 (a)	Reclassification (b)	Total
Assets:					
Commodity contracts	$ 395	$ 3,915	$ 124	$ 1	$ 4,435
Interest rate swaps	—	142	—	—	142
Nuclear decommissioning trust – equity securities (c)	208	124	—	—	332
Nuclear decommissioning trust – debt securities (c)	—	242	—	—	242
Total assets	$ 603	$ 4,423	$ 124	$ 1	$ 5,151
Liabilities:					
Commodity contracts	$ 446	$ 727	$ 71	$ 1	$ 1,245
Interest rate swaps	—	2,397	—	—	2,397
Total liabilities	$ 446	$ 3,124	$ 71	$ 1	$ 3,642

(a) See table below for description of Level 3 assets and liabilities.
(b) Fair values are determined on a contract basis, but certain contracts result in a current asset and a noncurrent liability, or vice versa, as presented in the balance sheet.
(c) The nuclear decommissioning trust investment is included in the other investments line in the balance sheet. See Note 14.

In conjunction with ERCOT's transition to a nodal wholesale market structure effective December 2010, we have entered into certain derivative transactions (primarily congestion revenue rights transactions) that are valued at illiquid pricing locations (unobservable inputs), thus requiring classification as Level 3 assets or liabilities.

Commodity contracts consist primarily of natural gas, electricity, fuel oil, uranium and coal derivative instruments entered into for hedging purposes and include physical contracts that have not been designated "normal" purchases or sales. See Note 10 for further discussion regarding the company's use of derivative instruments.

Interest rate swaps include variable-to-fixed rate swap instruments that are economic hedges of interest on long-term debt as well as interest rate basis swaps designed to effectively reduce the hedged borrowing costs. See Note 6 for discussion of interest rate swaps.

Nuclear decommissioning trust assets represent securities held for the purpose of funding the future retirement and decommissioning of the nuclear generation units. These investments include equity, debt and other fixed-income securities consistent with investment rules established by the NRC and the PUCT.

There were no significant transfers between Level 1 and Level 2 of the fair value hierarchy in the three and nine months ended September 30, 2012 and 2011. See the table of changes in fair values of Level 3 assets and liabilities below for discussion of transfers between Level 2 and Level 3 in the three and nine months ended September 30, 2012 and 2011.

The following table presents the fair value of the Level 3 assets and liabilities by major contract type (all related to commodity contracts) and the significant unobservable inputs used in the valuations at September 30, 2012:

	Fair Value					
Contract Type (a)	**Assets**	**Liabilities**	**Total**	**Valuation Technique**	**Significant Unobservable Input**	**Range (b)**
Electricity purchases and sales	$ 7	$ (22)	$ (15)	Valuation Model	Volumes (c)	500 to 600 GWh
					Illiquid pricing locations (d)	$20 to $35 MWh
					Hourly price curve shape (e)	$20 to $50 MWh
					Probability of default (f)	0% to 30%
					Recovery rate (g)	0% to 40%
Electricity spread options	42	(14)	28	Option Pricing Model	Gas to power correlation (h)	15% to 90%
					Power volatility (i)	20% to 60%
Electricity congestion revenue rights	14	(1)	13	Market Approach (j)	Illiquid price differences between settlement points (k)	$0.00 to $0.50
Coal purchases	—	(42)	(42)	Market Approach (j)	Illiquid price variances between mines (l)	$0.00 to $1.00
					Probability of default (f)	5% to 40%
					Recovery rate (g)	0% to 40%
Other	8	(8)	—			
Total	$ 71	$ (87)	$ (16)			

(a) Electricity purchase and sales contracts include wind generation agreements and hedging positions in the ERCOT west region, as well as power contracts, the valuations of which include unobservable inputs related to the hourly shaping of the price curve. Electricity spread options consist of physical electricity call options. Electricity congestion revenue rights contracts consist of forward purchase contracts (swaps and options) used to hedge electricity price differences between settlement points within ERCOT. Coal purchase contracts relate to western (Powder River Basin) coal.

(b) The range of the inputs may be influenced by factors such as time of day, delivery period, season and location.
(c) Based on the historical average annual range of wind generation.
(d) Based on the historical range of forward average monthly ERCOT West Hub prices.
(e) Based on the historical range of forward average hourly ERCOT North Hub prices.
(f) Estimate of the range of probabilities of default based on past experience and the length of the contract as well as our and counterparties' credit ratings.
(g) Estimate of the default recovery rate based on historical corporate rates.
(h) Estimate of the historical range based on forward natural gas and on-peak power prices for the ERCOT hubs most relevant to our spread options.
(i) Based on historical forward price changes.
(j) While we use the market approach, there is either insufficient market data to consider the valuation liquid or the significance of credit reserves or non-performance risk adjustments results in a Level 3 designation.
(k) Based on the historical price differences between settlement points in ERCOT North Hub.
(l) Based on the historical range of price variances between mine locations.

The following table presents the changes in fair value of the Level 3 assets and liabilities (all related to commodity contracts) in the three and nine months ended September 30, 2012 and 2011:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Balance at beginning of period	$ 12	$ 23	$ 53	$ 342
Total realized and unrealized gains (losses) included in net loss	12	30	(5)	(18)
Purchases, issuances and settlements (a):				
Purchases	17	5	30	69
Issuances	(4)	(4)	(15)	(7)
Settlements	(56)	(60)	(34)	(47)
Transfers into Level 3 (b)	3	—	(42)	—
Transfers out of Level 3 (b)	—	(4)	(3)	(349)
Net change (c)	(28)	(33)	(69)	(352)
Balance at end of period	$ (16)	$ (10)	$ (16)	$ (10)
Net change in unrealized gains (losses) included in net loss relating to instruments held at end of period	15	12	(22)	(3)

(a) Settlements reflect reversals of unrealized mark-to-market valuations previously recognized in net income. Purchases and issuances reflect option premiums paid or received.
(b) Includes transfers due to changes in the observability of significant inputs. Transfers in and out occur at the end of each quarter, which is when the assessments are performed. Transfers out during 2012 reflect increased observability of pricing related to certain congestion revenue rights. Transfers in during 2012 were driven by an increase in nonperformance risk adjustments related to certain coal purchase contracts as well as certain power contracts that include unobservable inputs related to the hourly shaping of the price curve. Transfers out during 2011 were driven by the effect of an increase in option market trading activity on our natural gas collars for 2014 and increased liquidity in forward periods for coal purchase contracts for 2014. All Level 3 transfers during 2011 and 2012 are in and out of Level 2.
(c) Substantially all changes in values of commodity contracts are reported in the income statement in net gain (loss) from commodity hedging and trading activities. Activity excludes changes in fair value in the month the position settled as well as amounts related to positions entered into and settled in the same month.

10. COMMODITY AND OTHER DERIVATIVE CONTRACTUAL ASSETS AND LIABILITIES

Strategic Use of Derivatives

We transact in derivative instruments, such as options, swaps, futures and forward contracts, primarily to manage commodity price risk and interest rate risk exposure. Our principal activities involving derivatives consist of a commodity hedging program and the hedging of interest costs on our long-term debt. See Note 9 for a discussion of the fair value of all derivatives.

Natural Gas Price Hedging Program — TCEH has a natural gas price hedging program designed to reduce exposure to changes in future electricity prices due to changes in the price of natural gas, thereby hedging future revenues from electricity sales and related cash flows. In ERCOT, the wholesale price of electricity has generally moved with the price of natural gas. Under the program, TCEH has entered into market transactions involving natural gas-related financial instruments and has sold forward natural gas through 2014. These transactions are intended to hedge a portion of electricity price exposure related to expected lignite/coal- and nuclear-fueled generation for this period. Changes in the fair value of the instruments under the natural gas price hedging program are reported in the income statement in net gain (loss) from commodity hedging and trading activities.

Interest Rate Swap Transactions — Interest rate swap agreements are used to reduce exposure to interest rate changes by converting floating-rate debt to fixed rates, thereby hedging future interest costs and related cash flows. Interest rate basis swaps are used to effectively reduce the hedged borrowing costs. Changes in the fair value of the swaps are recorded as unrealized gains and losses in interest expense and related charges. See Note 6 for additional information about interest rate swap agreements.

Other Commodity Hedging and Trading Activity — In addition to the natural gas price hedging program, TCEH enters into derivatives, including electricity, natural gas, fuel oil, uranium, emission and coal instruments, generally for shorter-term hedging purposes. To a limited extent, TCEH also enters into derivative transactions for proprietary trading purposes, principally in natural gas and electricity markets.

Financial Statement Effects of Derivatives

Substantially all derivative contractual assets and liabilities arise from mark-to-market accounting consistent with accounting standards related to derivative instruments and hedging activities. The following tables provide detail of commodity and other derivative contractual assets and liabilities (with the column totals representing the net positions of the contracts) as reported in the balance sheets at September 30, 2012 and December 31, 2011:

September 30, 2012

	Derivative assets		Derivative liabilities		
	Commodity contracts	Interest rate swaps	Commodity contracts	Interest rate swaps	Total
Current assets	$ 1,681	$ 143	$ 1	$ —	$ 1,825
Noncurrent assets	819	1	32	—	852
Current liabilities	(14)	—	(591)	(708)	(1,313)
Noncurrent liabilities	(18)	—	(46)	(1,703)	(1,767)
Net assets (liabilities)	$ 2,468	$ 144	$ (604)	$ (2,411)	$ (403)

December 31, 2011

	Derivative assets		Derivative liabilities		
	Commodity contracts	Interest rate swaps	Commodity contracts	Interest rate swaps	Total
Current assets	$ 2,883	$ 142	$ —	$ —	$ 3,025
Noncurrent assets	1,552	—	—	—	1,552
Current liabilities	(1)	—	(1,162)	(787)	(1,950)
Noncurrent liabilities	—	—	(82)	(1,610)	(1,692)
Net assets (liabilities)	$ 4,434	$ 142	$ (1,244)	$ (2,397)	$ 935

At September 30, 2012 and December 31, 2011, there were no derivative positions accounted for as cash flow or fair value hedges.

Margin deposits that contractually offset these derivative instruments are reported separately in the balance sheet and totaled $700 million and $1.006 billion in net liabilities at September 30, 2012 and December 31, 2011, respectively. Reported amounts as presented in the above table do not reflect netting of assets and liabilities with the same counterparties under existing netting arrangements. This presentation can result in significant volatility in derivative assets and liabilities because we may enter into offsetting positions with the same counterparties, resulting in both assets and liabilities, and the underlying commodity prices can change significantly from period to period.

The following table presents the pretax effect (gains(losses)) on net income of derivatives, including realized and unrealized effects:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Derivative (income statement presentation)	2012	2011	2012	2011
Commodity contracts (Net gain (loss) from commodity hedging and trading activities) (a)	$ (95)	$ 323	$ 130	$ 494
Interest rate swaps (Interest expense and related charges) (b)	(188)	(796)	(520)	(1,390)
Net loss	$ (283)	$ (473)	$ (390)	$ (896)

(a) Amount represents changes in fair value of positions in the derivative portfolio during the period, as realized amounts related to positions settled are assumed to equal reversals of previously recorded unrealized amounts.
(b) Includes amounts reported as unrealized mark-to-market net loss as well as the net effect on interest paid/accrued, both reported in "Interest Expense and Related Charges" (see Note 14).

The following table presents the pretax effect (all losses) on net income and other comprehensive income (OCI) of derivative instruments previously accounted for as cash flow hedges. There were no amounts recognized in OCI in the three or nine months ended September 30, 2012 or 2011.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Derivative type (income statement presentation of loss reclassified from accumulated OCI into income)	2012	2011	2012	2011
Interest rate swaps (interest expense and related charges)	$ (1)	$ (6)	$ (6)	$ (23)
Interest rate swaps (depreciation and amortization)	(1)	—	(2)	(1)
Total	$ (2)	$ (6)	$ (8)	$ (24)

There were no transactions designated as cash flow hedges during the three or nine months ended September 30, 2012 or 2011.

Accumulated other comprehensive income related to cash flow hedges (excluding Oncor's interest rate hedge) at September 30, 2012 and December 31, 2011 totaled $45 million and $50 million in net losses (after-tax), respectively, substantially all of which relates to interest rate swaps. We expect that $7 million of net losses (after-tax) related to cash flow hedges included in accumulated other comprehensive income at September 30, 2012 will be reclassified into net income during the next twelve months as the related hedged transactions affect net income.

Derivative Volumes — The following table presents the gross notional amounts of derivative volumes at September 30, 2012 and December 31, 2011:

Derivative type	September 30, 2012	December 31, 2011	Unit of Measure
	Notional Volume		
Interest rate swaps:			
Floating/fixed (a)	$ 32,872	$ 32,955	Million US dollars
Basis (b)	$ 15,917	$ 19,167	Million US dollars
Natural gas:			
Natural gas price hedge forward sales and purchases (c)	1,050	1,602	Million MMBtu
Locational basis swaps	500	728	Million MMBtu
All other	2,081	841	Million MMBtu
Electricity	90,460	105,673	GWh
Congestion Revenue Rights (d)	55,800	142,301	GWh
Coal	14	23	Million tons
Fuel oil	51	51	Million gallons
Uranium	480	480	Thousand pounds

(a) Includes notional amount of interest rate swaps maturing between October 2012 and October 2014 as well as notional amount of swaps effective from October 2014 with maturity dates through October 2017 (see Note 6).

(b) The December 31, 2011 amount includes $1.417 billion notional amount of swaps entered into but not effective until February 2012.

(c) Represents gross notional forward sales, purchases and options transactions in the natural gas price hedging program. The net amount of these transactions was approximately 430 million MMBtu and 700 million MMBtu at September 30, 2012 and December 31, 2011, respectively.

(d) Represents gross forward purchases associated with instruments used to hedge price differences between settlement points in the nodal wholesale market design in ERCOT.

Credit Risk-Related Contingent Features of Derivatives

The agreements that govern our derivative instrument transactions may contain certain credit risk-related contingent features that could trigger liquidity requirements in the form of cash collateral, letters of credit or some other form of credit enhancement. Certain of these agreements require the posting of collateral if our credit rating is downgraded by one or more credit rating agencies; however, due to our credit ratings being below investment grade, substantially all of such collateral posting requirements are already effective.

At September 30, 2012 and December 31, 2011, the fair value of liabilities related to derivative instruments under agreements with credit risk-related contingent features that were not fully cash collateralized totaled $138 million and $364 million, respectively. The liquidity exposure associated with these liabilities was reduced by cash and letter of credit postings with the counterparties totaling $40 million and $78 million at September 30, 2012 and December 31, 2011, respectively. If all the credit risk-related contingent features related to these derivatives had been triggered, including cross default provisions, at September 30, 2012 and December 31, 2011, the remaining related liquidity requirement would have totaled $1 million and $7 million, respectively, after reduction for net accounts receivable and derivative assets under netting arrangements.

In addition, certain derivative agreements that are collateralized primarily with liens on certain of our assets include indebtedness cross-default provisions that could result in the settlement of such contracts if there were a failure under other financing arrangements to meet payment terms or to comply with other covenants that could result in the acceleration of such indebtedness. At September 30, 2012 and December 31, 2011, the fair value of derivative liabilities subject to such cross-default provisions, largely related to interest rate swaps, totaled $2.536 billion and $2.816 billion, respectively, before consideration of the amount of assets subject to the liens. No cash collateral or letters of credit were posted with these counterparties at September 30, 2012 or December 31, 2011 to reduce the liquidity exposure. If all the credit risk-related contingent features related to these derivatives, including amounts related to cross-default provisions, had been triggered at September 30, 2012 and December 31, 2011, the remaining related liquidity requirement after reduction for derivative assets under netting arrangements but before consideration of the amount of assets subject to the liens would have totaled $1.327 billion and $1.183 billion, respectively. See Note 6 for a description of other obligations that are supported by liens on certain of our assets.

As discussed immediately above, the aggregate fair values of liabilities under derivative agreements with credit risk-related contingent features, including cross-default provisions, totaled $2.674 billion and $3.180 billion at September 30, 2012 and December 31, 2011, respectively. These amounts are before consideration of cash and letter of credit collateral posted, net accounts receivable and derivative assets under netting arrangements and assets subject to related liens.

Some commodity derivative contracts contain credit risk-related contingent features that do not provide for specific amounts to be posted if the features are triggered. These provisions include material adverse change, performance assurance, and other clauses that generally provide counterparties with the right to request additional credit enhancements. The amounts disclosed above exclude credit risk-related contingent features that do not provide for specific amounts or exposure calculations.

Concentrations of Credit Risk Related to Derivatives

We have significant concentrations of credit risk with the counterparties to its derivative contracts. At September 30, 2012, total credit risk exposure to all counterparties related to derivative contracts totaled $2.715 billion (including associated accounts receivable). The net exposure to those counterparties totaled $276 million at September 30, 2012 after taking into effect netting arrangements, setoff provisions and collateral. At September 30, 2012, the credit risk exposure to the banking and financial sector represented 94% of the total credit risk exposure and 69% of the net exposure, a significant amount of which is related to the natural gas price hedging program, and the largest net exposure to a single counterparty totaled $72 million.

Exposure to banking and financial sector counterparties is considered to be within an acceptable level of risk tolerance because all of this exposure is with counterparties with investment grade credit ratings. However, this concentration increases the risk that a default by any of these counterparties would have a material effect on our financial condition, results of operations and liquidity. The transactions with these counterparties contain certain provisions that would require the counterparties to post collateral in the event of a material downgrade in their credit rating.

We maintain credit risk policies with regard to our counterparties to minimize overall credit risk. These policies authorize specific risk mitigation tools including, but not limited to, use of standardized master agreements that allow for netting of positive and negative exposures associated with a single counterparty. Credit enhancements such as parent guarantees, letters of credit, surety bonds, liens on assets and margin deposits are also utilized. Prospective material 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. The process can result in the subsequent reduction of the credit limit or a request for additional financial assurances. An event of default by one or more counterparties could subsequently result in termination-related settlement payments that reduce available liquidity if amounts are owed to the counterparties related to the derivative contracts or delays in receipts of expected settlements if the counterparties owe amounts to us.

11. PENSION AND OTHER POSTRETIREMENT EMPLOYEE BENEFITS (OPEB) PLANS

Net pension and OPEB costs in the three and nine months ended September 30, 2012 and 2011 are comprised of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Components of net pension costs:				
Service cost	$ 13	$ 12	$ 36	$ 34
Interest cost	38	40	118	122
Expected return on assets	(42)	(40)	(122)	(118)
Amortization of net loss	30	24	84	67
Net pension costs	39	36	116	105
Components of net OPEB costs:				
Service cost	3	3	7	11
Interest cost	11	16	33	48
Expected return on assets	(3)	(3)	(9)	(10)
Amortization of transition obligation	—	1	1	1
Amortization of prior service cost	(8)	(1)	(24)	(1)
Amortization of net loss	4	8	11	22
Net OPEB costs	7	24	19	71
Total net pension and OPEB costs	46	60	135	176
Less amounts expensed by Oncor (and not consolidated)	(8)	(9)	(26)	(27)
Less amounts deferred principally as a regulatory asset or property by Oncor	(21)	(33)	(64)	(97)
Net amounts recognized as expense by EFH Corp. and consolidated subsidiaries	$ 17	$ 18	$ 45	$ 52

The discount rate reflected in net pension costs for January through July 2012 is 5.00% and for August and September 2012 is 4.15% (see discussion below). The discount rate reflected in net OPEB costs in 2012 is 4.95%. The expected rates of return on pension and OPEB plan assets reflected in the 2012 cost amounts are 7.4% and 6.8%, respectively.

Our cash contributions in the first nine months of 2012 related to our retirement benefit plans totaled $91 million related to the pension plan, of which $89 million was funded by Oncor, and $12 million related to the OPEB plans, of which $8 million was funded by Oncor.

In August 2012, EFH Corp. approved certain amendments to its pension plan. These amendments will result in:

- splitting off assets and liabilities under the plan associated with employees of Oncor and all retirees and terminated vested participants of EFH Corp. and its subsidiaries (including discontinued businesses) to a new plan that is expected to be sponsored and administered by Oncor;
- maintaining assets and liabilities under the plan associated with active collective bargaining unit (union) employees of EFH Corp.'s competitive subsidiaries under the current plan;
- splitting off assets and liabilities under the plan associated with all other plan participants (active nonunion employees of EFH Corp.'s competitive businesses) to a Terminating Plan, freezing benefits and vesting all accrued plan benefits for these participants, and
- the termination of, distributions of benefits under, and settlement of all of EFH Corp.'s liabilities under the Terminating Plan.

These actions are expected to be completed in the fourth quarter 2012.

As a result of the amendments, plan asset values and obligations were remeasured as of July 31, 2012, resulting in the projected benefit obligation increasing by $365 million, the fair value of assets increasing by $125 million, our receivable from Oncor increasing by $160 million and the losses reported in accumulated other comprehensive income (loss) increasing by $80 million ($52 million after-tax). Assumptions used in the remeasurement included a decrease in the discount rate to 4.15% from 5.00% and no change in the expected return on assets of 7.4% assumed at December 31, 2011. The remeasurement did not materially affect reported pension expense in the three months ended September 30, 2012. Another remeasurement will be performed in the fourth quarter 2012 upon the splitting off of assets and liabilities.

The curtailment of benefits accruing to participants in the Terminating Plan resulted in the projected benefit obligation, net of our receivable from Oncor, decreasing by $21 million and the losses reported in accumulated other comprehensive income (loss) decreasing by $21 million ($14 million after-tax).

EFH Corp. currently expects that settlement of the Terminating Plan obligations and the full funding of the EFH Corp. competitive operations portion of liabilities (including discontinued businesses) under the Oncor Plan will result in aggregate cash contributions by EFH Corp.'s competitive operations of approximately $240 million in the fourth quarter 2012. In October 2012, $150 million of this amount was contributed, of which $65 million was funded by TCEH.

These funding amounts are preliminary estimates, and the final amounts could be higher or lower depending on various factors, including discount rates and values of the pension trust assets at the settlement date, as well as the form of settlement chosen by each affected participant (i.e. lump sum or annuity).

12. RELATED PARTY TRANSACTIONS

The following represent our significant related-party transactions.

- We pay an annual management fee under the terms of a management agreement with the Sponsor Group, which we reported in SG&A expense totaling $9 million in each of the three month periods ended September 30, 2012 and 2011 and $28 million and $27 million in the nine months ended September 30, 2012 and 2011, respectively.

- In 2007, TCEH entered into the TCEH Senior Secured Facilities with syndicates of financial institutions and other lenders. These syndicates included affiliates of GS Capital Partners, which is a member of the Sponsor Group. Affiliates of each member of the Sponsor Group have from time to time engaged in commercial banking transactions with us and/or provided financial advisory services to us, in each case in the normal course of business.

- In the nine months ended September 30, 2012, fees paid to Goldman, Sachs & Co. (Goldman), an affiliate of GS Capital Partners, related to debt issuances totaled $10 million, described as follows: (i) Goldman acted as a joint book-running manager and initial purchaser in the February 2012 issuance of $1.15 billion principal amount of EFIH 11.750% Senior Secured Second Lien Notes (see Note 6) for which it received fees totaling $7 million; (ii) Goldman acted as joint book-running manager and initial purchaser in the August 2012 issuance of $600 million principal amount of 11.750% Senior Secured Second Lien Notes and $250 million principal amount of EFIH 6.875% Senior Secured Notes (see Note 6) for which it received fees totaling $3 million. In the October 2012 issuance of $253 million EFIH 6.875% Notes, (i) Goldman acted as joint book-running manager and initial purchaser for which it was paid $1 million. A broker-dealer affiliate of KKR served as a co-manager and initial purchaser and an affiliate of TPG Management, L.P. (TPG) served as an advisor in all of these transactions, for which they each received a total of $4 million.

  In the nine months ended September 30, 2011, fees paid to Goldman related to debt issuances, exchanges, amendments and extensions totaled $26 million, described as follows: (i) Goldman acted as a joint lead arranger and joint book-runner in the April 2011 amendment and extension of the TCEH Senior Secured Facilities and received fees totaling $17 million and (ii) Goldman acted as a joint book-running manager and initial purchaser in the issuance of $1.750 billion principal amount of TCEH Senior Secured Notes as part of the April 2011 amendment and extension and received fees totaling $9 million. Affiliates of KKR and TPG Management, L.P. served as advisers to these transactions, and each received $5 million as compensation for their services.

- Affiliates of GS Capital Partners are parties to certain commodity and interest rate hedging transactions with us in the normal course of business.

- Affiliates of the Sponsor Group have sold or acquired, and in the future may sell or acquire, debt or debt securities issued by us in open market transactions or through loan syndications.

- TCEH has made loans to EFH Corp. in the form of demand notes that have been pledged as collateral under the TCEH Senior Secured Facilities for (i) debt principal and interest payments and (ii) other general corporate purposes (SG&A Note) for EFH Corp. The demand notes are eliminated in consolidation in these consolidated financial statements. The notes, which totaled $689 million and $1.592 billion at September 30, 2012 and December 31, 2011, respectively, including $233 million in the SG&A Note at both dates, are guaranteed by both EFCH and EFIH on an unsecured basis. The reduction of the balance of the notes in the nine months ended September 30, 2012 was funded by debt issued by EFIH. EFH Corp. agreed to settle the balance of the loans by January 2013. See Note 6 for additional discussion.

- As part of EFH Corp.'s liability management program, EFH Corp. (parent entity) and EFIH have purchased, or received in exchanges, certain debt securities of EFH Corp. (parent entity) and TCEH, which are held as investments. Principal and interest payments received by EFH Corp. (parent entity) and EFIH on these investments are used, in part, to service their outstanding debt. These investments are eliminated in consolidation in these consolidated financial statements. At September 30, 2012, EFIH held $4.596 billion principal amount of EFH Corp. (parent entity) debt and $79 million principal amount of TCEH debt. At September 30, 2012, EFH Corp. (parent entity) held $303 million principal amount of TCEH debt. See Note 6.

- TCEH's retail operations pay Oncor for services it provides, principally the delivery of electricity. Expenses recorded for these services totaled $281 million and $309 million in the three months ended September 30, 2012 and 2011, respectively, and $746 million and $798 million in the nine months ended September 30, 2012 and 2011, respectively. The fees are based on rates regulated by the PUCT that apply to all REPs. The balance sheets at September 30, 2012 and December 31, 2011 reflect amounts due currently to Oncor totaling $154 million and $138 million, respectively (included in payables due to unconsolidated subsidiary), primarily related to these electricity delivery fees.

- In August 2012, TCEH and Oncor agreed to settle at a discount two agreements related to securitization (transition) bonds issued by Oncor's bankruptcy-remote financing subsidiary in 2003 and 2004 to recover generation-related regulatory assets. Under the agreements, TCEH had been reimbursing Oncor as described immediately below. Under the settlement, TCEH paid, and Oncor received, $159 million in cash. The settlement was executed by EFIH acquiring the right to reimbursement under the agreements from Oncor and then selling these rights for the same amount to TCEH. The transaction resulted in a $2 million (after tax) decrease in investment in unconsolidated subsidiary in the three months ended September 30, 2012 in accordance with accounting rules for related party transactions.

  Oncor collects transition surcharges from its customers to recover the transition bond payment obligations. Oncor's incremental income taxes related to the transition surcharges it collects have been reimbursed by TCEH quarterly under a noninterest bearing note payable to Oncor maturing in 2016. The note balance at the settlement date totaled $159 million.

  Under an interest reimbursement agreement, TCEH has reimbursed Oncor on a monthly basis for interest expense on the transition bonds. The remaining interest to be paid through 2016 under the agreement totaled $53 million at the settlement date. Only the monthly accrual of interest under this agreement was reported as a liability. This interest expense totaled $2 million and $8 million in the three months ended September 30, 2012 and 2011, respectively, and $16 million and $24 million in the nine months ended September 30, 2012 and 2011, respectively.

- Oncor pays EFH Corp. subsidiaries for financial and other administrative services and shared facilities at cost. Such amounts reduced reported SG&A expense by $10 million and $10 million in the three months ended September 30, 2012 and 2011, respectively, and $27 million and $28 million in the nine months ended September 30, 2012 and 2011, respectively.

- Under Texas regulatory provisions, the trust fund for decommissioning the Comanche Peak nuclear generation facility is funded by a delivery fee surcharge billed to REPs by Oncor and remitted monthly to TCEH, with the intent that the trust fund assets, reported in other investments in our balance sheet, will be sufficient to fund the decommissioning liability, reported in noncurrent liabilities in our balance sheet. The delivery fee surcharges remitted to TCEH totaled $5 million in each of the three month periods ended September 30, 2012 and 2011 and $12 million and $13 million in the nine months ended September 30, 2012 and 2011, respectively. Income and expenses associated with the trust fund and the decommissioning liability incurred by us are offset by a net change in the intercompany receivable/payable between Oncor and TCEH, which in turn results in a change in Oncor's net regulatory asset/liability. At September 30, 2012 and December 31, 2011, the excess of the trust fund balance over the decommissioning liability resulted in a payable to Oncor totaling $286 million and $225 million, respectively, included in noncurrent liabilities due to unconsolidated subsidiary in our balance sheet.

- We file a consolidated federal income tax return that includes Oncor Holdings' results. Oncor is not a member of our consolidated tax group, but our consolidated federal income tax return includes our portion of Oncor's results due to our equity ownership in Oncor. We also file a consolidated Texas state margin tax return that includes all of Oncor Holdings' and Oncor's results. However, under a tax sharing agreement, Oncor Holdings' and Oncor's federal income tax and Texas margin tax expense and related balance sheet amounts, including our income taxes payable to or receivable from Oncor Holdings and Oncor, are recorded as if Oncor Holdings and Oncor file their own corporate income tax returns. Our current amount receivable from Oncor Holdings and Oncor related to income taxes totaled $17 million and $2 million at September 30, 2012 and December 31, 2011, respectively. EFH Corp. received income tax net payments from Oncor Holdings and Oncor totaling $27 million and paid income tax net refunds to Oncor Holdings and Oncor totaling $89 million in the nine months ended September 30, 2012 and 2011, respectively.

- 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 credit rating being below investment grade, TCEH is required to post collateral support in an amount equal to estimated transition charges over specified time periods. Accordingly, at September 30, 2012 and December 31, 2011, TCEH had posted letters of credit in the amount of $11 million and $12 million, respectively, for the benefit of Oncor.

- Under the Employee Retirement Income Security Act of 1974, EFH Corp. and Oncor are jointly and severally liable for the funding of the EFH Corp. pension plan. EFH Corp. is liable for the majority of the OPEB plan obligations. Oncor has contractually agreed to assume responsibility for pension and OPEB liabilities that are recoverable by Oncor under regulatory rate-setting provisions. Accordingly, at September 30, 2012 and December 31, 2011, our balance sheet reflects unfunded liabilities related to these obligations and a corresponding receivable from Oncor in the amounts of $1.332 billion and $1.235 billion, respectively, classified as noncurrent. This amount is consistent with the obligations reported by Oncor in its balance sheet. See Note 11 for discussion of pension plan changes announced in August 2012.

- Receivables from unconsolidated subsidiary are measured at historical cost and consist of Oncor's obligation under the EFH Corp. pension and OPEB plans as discussed immediately above. EFH Corp. reviews Oncor's credit quality to assess the overall collectability of its affiliated receivables. There were no credit loss allowances at September 30, 2012.

- Oncor and Texas Holdings agreed to the terms of a stipulation with major interested parties to resolve all outstanding issues in the PUCT review related to the Merger. As part of this stipulation, TCEH would be required to post a letter of credit in an amount equal to $170 million to secure its payment obligations to Oncor in the event, which has not occurred, two or more rating agencies downgrade Oncor's credit rating below investment grade.

13. SEGMENT INFORMATION

Our operations are aligned into two reportable business segments: Competitive Electric and Regulated Delivery. The segments are managed separately because they are strategic business units that offer different products or services and involve different risks.

The Competitive Electric segment is engaged in competitive market activities consisting of electricity generation, wholesale energy sales and purchases, commodity risk management and trading activities, and retail electricity sales to residential and business customers, all largely in Texas. These activities are conducted by TCEH.

The Regulated Delivery segment consists largely of our investment in Oncor. Oncor is engaged in regulated electricity transmission and distribution operations in Texas. These activities are conducted by Oncor, including its wholly owned bankruptcy-remote financing subsidiary. See Note 3 for discussion of the reporting of Oncor Holdings and, accordingly, the Regulated Delivery segment, as an equity method investment. See Note 12 for discussion of material transactions with Oncor, including payment to Oncor of electricity delivery fees, which are based on rates regulated by the PUCT.

Corporate and Other represents the remaining nonsegment operations consisting primarily of discontinued businesses, general corporate expenses and interest on EFH Corp. (parent entity), EFIH and EFCH debt.

The accounting policies of the business segments are the same as those described in the summary of significant accounting policies in Note 1 above and in Note 1 to Financial Statements in the 2011 Form 10-K. We evaluate performance based on net income (loss). We account for intersegment sales and transfers as if the sales or transfers were to third parties, that is, at current market prices or regulated rates.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Operating revenues (all Competitive Electric)	$ 1,752	$ 2,321	$ 4,358	$ 5,672
Equity in earnings of unconsolidated subsidiaries (net of tax) — Regulated Delivery (net of noncontrolling interest of $27, $29, $64 and $60)	$ 109	$ 113	$ 249	$ 235
Net income (loss):				
Competitive Electric	$ (393)	$ (730)	$ (1,319)	$ (1,722)
Regulated Delivery	109	113	249	235
Corporate and Other	(123)	(93)	(338)	(289)
Consolidated	$ (407)	$ (710)	$ (1,408)	$ (1,776)

14. SUPPLEMENTARY FINANCIAL INFORMATION

Other Income and Deductions

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Other income:				
Office space rental income (a)	$ 3	$ 3	$ 9	$ 9
Consent fee related to novation of hedge positions between counterparties (b)	—	—	6	—
Insurance settlement (b)	—	—	2	—
Sales tax refund (b)	—	2	—	2
Debt extinguishment gains (a)	—	—	—	25
Settlement of counterparty bankruptcy claims (b)(c)	—	—	—	21
Property damage claim (b)	—	—	—	7
Franchise tax refund (b)	—	—	—	6
Other	3	4	8	14
Total other income	$ 6	$ 9	$ 25	$ 84
Other deductions:				
Ongoing pension and OPEB expense related to discontinued businesses (a)	$ 4	$ 4	$ 10	$ 10
Impairment of mineral interests (Note 4) (b)	24	—	24	—
Impairment of computer software assets (a)	7	—	7	—
Counterparty contract settlement (b)	4	—	4	—
Net third-party fees paid in connection with the amendment and extension of the TCEH Senior Secured Facilities (d)	—	—	—	100
Impairment of emissions allowances (b)(e)	—	418	—	418
Severance charges (b)(e)	—	49	—	49
Impairment of assets related to mining operations (b)(e)	—	9	—	9
Other	3	3	9	7
Total other deductions	$ 42	$ 483	$ 54	$ 593

(a) Reported in Corporate and Other.
(b) Reported in Competitive Electric segment.
(c) Represents net cash received as a result of the settlement of bankruptcy claims against a hedging/trading counterparty. A reserve of $26 million was established in 2008 related to amounts then due from the counterparty.
(d) Includes $86 million reported in Competitive Electric segment and $14 million in Corporate and Other.
(e) Charges resulting from the EPA's issuance of the CSAPR in July 2011, including a $418 million impairment charge for excess emission allowances, employee severance charges totaling $49 million in anticipation of idling certain generation facilities, and $9 million in mining asset write-offs. The severance charges were reversed in the fourth quarter 2011 after the CSAPR was stayed by the D.C. Circuit Court. See Note 7 for further discussion of the CSAPR, including the D.C. Circuit Court's ruling in August 2012 vacating the CSAPR and remanding it to the EPA for further proceedings.

Interest Expense and Related Charges

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Interest paid/accrued (including net amounts settled/accrued under interest rate swaps)	$ 812	$ 792	$ 2,405	$ 2,245
Accrued interest to be paid with additional toggle notes (Note 6)	61	53	177	163
Unrealized mark-to-market net loss on interest rate swaps (a)	21	619	12	879
Amortization of interest rate swap losses at dedesignation of hedge accounting	2	5	7	22
Amortization of fair value debt discounts resulting from purchase accounting	11	14	33	41
Amortization of debt issuance, amendment and extension costs and discounts	48	48	143	141
Capitalized interest	(11)	(8)	(31)	(24)
Total interest expense and related charges	$ 944	$ 1,523	$ 2,746	$ 3,467

(a) Three and nine months ended September 30, 2012 amounts include net losses totaling $20 million and $16 million, respectively, related to TCEH swaps (see Note 6) and net losses totaling $1 million and net gains totaling $4 million, respectively, related to EFH Corp. swaps substantially closed through offsetting positions.

Restricted Cash

	September 30, 2012		December 31, 2011	
	Current Assets	Noncurrent Assets	Current Assets	Noncurrent Assets
Amounts in escrow related to EFIH's August 2012 debt issuances (Note 6)	$ 680	$ —	$ —	$ —
Amounts related to margin deposits held	17	—	129	—
Amounts related to TCEH's Letter of Credit Facility (Note 6)	—	947	—	947
Total restricted cash	$ 697	$ 947	$ 129	$ 947

Inventories by Major Category

	September 30, 2012	December 31, 2011
Materials and supplies	$ 196	$ 177
Fuel stock	185	203
Natural gas in storage	26	38
Total inventories	$ 407	$ 418

Other Investments

	September 30, 2012	December 31, 2011
Nuclear plant decommissioning trust	$ 651	$ 574
Assets related to employee benefit plans, including employee savings programs, net of distributions	89	90
Land	41	41
Miscellaneous other	—	4
Total other investments	$ 781	$ 709

Nuclear Decommissioning Trust — Investments in a trust that will be used to fund the costs to decommission the Comanche Peak nuclear generation plant are carried at fair value. Decommissioning costs are being recovered from Oncor's customers as a delivery fee surcharge over the life of the plant and deposited in the trust fund. Net gains and losses on investments in the trust fund are offset by a corresponding change in receivables from/payables due to unconsolidated subsidiary, reflecting changes in Oncor's regulatory asset/liability (see Note 12). A summary of investments in the fund follows:

	September 30, 2012			
	Cost (a)	Unrealized gain	Unrealized loss	Fair market value
Debt securities (b)	$ 242	$ 17	$ (1)	$ 258
Equity securities (c)	241	166	(14)	393
Total	$ 483	$ 183	$ (15)	$ 651

	December 31, 2011			
	Cost (a)	Unrealized gain	Unrealized loss	Fair market value
Debt securities (b)	$ 231	$ 13	$ (2)	$ 242
Equity securities (c)	230	121	(19)	332
Total	$ 461	$ 134	$ (21)	$ 574

(a) Includes realized gains and losses on securities sold.
(b) The investment objective for debt securities is to invest in a diversified tax efficient portfolio with an overall portfolio rating of AA or above as graded by S&P or Aa2 by Moody's. The debt securities are heavily weighted with municipal bonds. The debt securities had an average coupon rate of 4.36% and 4.38% at September 30, 2012 and December 31, 2011, respectively, and an average maturity of 6 years at both September 30, 2012 and December 31, 2011.
(c) The investment objective for equity securities is to invest tax efficiently and to match the performance of the S&P 500 Index.

Debt securities held at September 30, 2012 mature as follows: $88 million in one to five years, $44 million in five to ten years and $126 million after ten years.

The following table summarizes proceeds from sales of available-for-sale securities and the related realized gains and losses from such sales.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Realized gains	$ —	$ —	$ 1	$ 1
Realized losses	$ (1)	$ —	$ (2)	$ (2)
Proceeds from sales of securities	$ 25	$ 601	$ 56	$ 2,385
Investments in securities	$ (30)	$ (606)	$ (68)	$ (2,398)

Property, Plant and Equipment

At September 30, 2012 and December 31, 2011, property, plant and equipment of $18.874 billion and $19.427 billion, respectively, is stated net of accumulated depreciation and amortization of $6.551 billion and $5.579 billion, respectively.

Asset Retirement and Mining Reclamation Obligations

These liabilities primarily relate to nuclear generation plant decommissioning, land reclamation related to lignite mining, removal of lignite/coal-fueled plant ash treatment facilities and generation plant asbestos removal and disposal costs. There is no earnings impact with respect to the recognition of the asset retirement costs for nuclear decommissioning, as all costs are recoverable through the regulatory process as part of Oncor's rates.

The following table summarizes the changes to these obligations, reported in other current liabilities and other noncurrent liabilities and deferred credits in the balance sheet, in the nine months ended September 30, 2012:

	Nuclear Plant Decommissioning	Mining Land Reclamation and Other	Total
Liability at January 1, 2012	$ 348	$ 188	$ 536
Additions:			
Accretion	16	27	43
Reductions:			
Payments	—	(71)	(71)
Adjustment to reclamation costs	—	(2)	(2)
Liability at September 30, 2012	364	142	506
Less amounts due currently	—	(48)	(48)
Noncurrent liability at September 30, 2012	$ 364	$ 94	$ 458

Other Noncurrent Liabilities and Deferred Credits

The balance of other noncurrent liabilities and deferred credits consists of the following:

	September 30, 2012	December 31, 2011
Uncertain tax positions (including accrued interest)	$ 1,995	$ 1,972
Retirement plan and other employee benefits (a)	1,832	1,664
Asset retirement and mining reclamation obligations	458	505
Unfavorable purchase and sales contracts	627	647
Other	25	28
Total other noncurrent liabilities and deferred credits	$ 4,937	$ 4,816

(a) Includes $1.332 billion and $1.235 billion at September 30, 2012 and December 31, 2011, respectively, representing pension and OPEB liabilities related to Oncor (see Note 12).

The conclusion of all issues contested from the 1997 through 2002 US Internal Revenue Service audit, including Joint Committee review, could 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. Any cash income tax liability related to the conclusion of the 1997 through 2002 audit is expected to be immaterial. Other than these items, we do not expect the total amount of liabilities recorded related to uncertain tax positions will change significantly in the next 12 months.

Unfavorable Purchase and Sales Contracts – The amortization of unfavorable purchase and sales contracts totaled $6 million and $7 million in the three months ended September 30, 2012 and 2011, respectively, and $20 million in both of the nine month periods ended September 30, 2012 and 2011. See Note 4 for intangible assets related to favorable purchase and sales contracts.

The estimated amortization of unfavorable purchase and sales contracts for each of the next five fiscal years is as follows:

Year	Amount
2012	$ 26
2013	$ 26
2014	$ 25
2015	$ 25
2016	$ 25

Supplemental Cash Flow Information

	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Cash payments (receipts) related to:		
Interest paid (a)	$ 2,150	$ 1,906
Capitalized interest	$ (31)	$ (24)
Interest paid (net of capitalized interest) (a)	$ 2,119	$ 1,882
Income taxes	$ 67	$ 34
Noncash investing and financing activities:		
Principal amount of toggle notes issued in lieu of cash interest (Note 6)	$ 114	$ 100
Construction expenditures (b)	$ 55	$ 36
Debt exchange transactions	$ —	$ (22)
Capital leases	$ —	$ 1

(a) Net of interest received on interest rate swaps.
(b) Represents end-of-period accruals.

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

The following discussion and analysis of our financial condition and results of operations in the three and nine months ended September 30, 2012 and 2011 should be read in conjunction with our consolidated financial statements and the notes to those statements. Unless otherwise noted, disclosures in the following paragraphs related to hedged or estimated generation output and commodity price sensitivities reflect the expected effects on our operations of the currently governing Clean Air Interstate Rule (CAIR). See "Recent EPA Actions" below for discussion of the EPA's Cross-State Air Pollution Rule (CSAPR).

All dollar amounts in the tables in the following discussion and analysis are stated in millions of US dollars unless otherwise indicated.

Business

EFH Corp., a Texas corporation, is a Dallas-based holding company that conducts its operations principally through its TCEH and Oncor subsidiaries. EFH Corp. is a subsidiary of Texas Holdings, which is controlled by the Sponsor Group. EFCH and its direct subsidiary, TCEH, are wholly-owned by EFH Corp. 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. EFIH is wholly-owned by EFH Corp. and indirectly holds an approximately 80% equity interest in Oncor. Oncor is engaged in regulated electricity transmission and distribution operations in Texas. Oncor provides distribution services to REPs, including subsidiaries of TCEH, which sell electricity to residential, business and other consumers. Various "ring-fencing" measures have been taken to enhance the credit quality of Oncor. See Notes 1 and 3 to Financial Statements for a discussion of the reporting of our investment in Oncor (and its majority owner, Oncor Holdings) as an equity method investment and a description of the "ring-fencing" measures implemented with respect to Oncor. These measures were put in place to further enhance Oncor's credit quality and mitigate Oncor's exposure to the Texas Holdings Group with the intent to minimize the risk that a court would order any of the Oncor Ring-Fenced Entities' assets and liabilities to be substantively consolidated with those of any member of the Texas Holdings Group in the event any such member were to become a debtor in a bankruptcy case. We believe, as several major credit rating agencies have acknowledged, that the likelihood of such substantive consolidation of Oncor's assets and liabilities is remote in consideration of the ring-fencing measures and applicable law.

Operating Segments

We have aligned and report our business activities as two operating segments: the Competitive Electric segment and the Regulated Delivery segment. The Competitive Electric segment consists largely of TCEH. The Regulated Delivery segment consists largely of our investment in Oncor.

See Note 13 to Financial Statements for further information regarding reportable business segments.

Significant Activities and Events and Items Influencing Future Performance

Natural Gas Prices and Natural Gas Price Hedging Program — Because wholesale electricity prices in ERCOT have generally moved with natural gas prices, TCEH has a natural gas price hedging program designed to mitigate the effect of natural gas price changes on future electricity prices. Under the program, we have entered into market transactions involving natural gas-related financial instruments, and at September 30, 2012, have effectively sold forward approximately 430 million MMBtu of natural gas (equivalent to the natural gas exposure of approximately 51,000 GWh at an assumed 8.5 market heat rate) at weighted average annual hedge prices as shown in the table below. Volumes and hedge values associated with the natural gas price hedging program are inclusive of offsetting purchases entered into to take into account new wholesale and retail electricity sales contracts and avoid over-hedging. This activity results in both commodity contract asset and liability balances pending the maturity and settlement of the offsetting transactions.

Taking together forward wholesale electricity sales transactions, forward retail sales and the natural gas positions in the hedging program, we have effectively hedged an estimated 99%, 87% and 39% of the price exposure, on a natural gas equivalent basis, related to TCEH's expected generation output for 2012, 2013 and 2014, respectively (assuming an 8.5 market heat rate). The hedges were entered into with the continuing expectation that wholesale electricity prices in ERCOT will generally move with prices of natural gas, which we expect to be the marginal fuel for the purpose of setting electricity prices generally 70% to 90% of the time in the ERCOT market. If the relationship changes in the future, the cash flows targeted under the natural gas price hedging program may not be achieved.

The company has entered into related put and call transactions (referred to as collars), primarily for 2014, that effectively hedge natural gas prices within a range. These transactions represented 35% of the positions in the natural gas price hedging program at September 30, 2012, with the approximate weighted average strike prices under the collars being a floor of $7.80 per MMBtu and a ceiling of $11.75 per MMBtu.

The following table summarizes the natural gas positions in the hedging program at September 30, 2012:

	Measure	Balance 2012 (a)	2013	2014	Total
Natural gas hedge volumes (b)	mm MMBtu	~74	~211	~146	~431
Weighted average hedge price (c)	$/MMBtu	~7.35	~6.89	~7.80	—
Average market price (d)	$/MMBtu	3.32	3.84	4.18	—
Realization of hedge gains (e)	$ billions	~$0.4	~$0.9	~$0.6	~$1.9

(a) Balance of 2012 is from October 1, 2012 through December 31, 2012.
(b) Where collars are reflected, the volumes are based on the notional position of the derivatives to represent protection against downward price movements. The notional volumes for collars are approximately 150 million MMBtu, which corresponds to a delta position of approximately 143 million MMBtu in 2014.
(c) Weighted average hedge prices are based on NYMEX Henry Hub prices of forward natural gas sales positions in the natural gas price hedging program (excluding the impact of offsetting purchases for rebalancing). Where collars are reflected, sales price represents the collar floor price.
(d) Based on NYMEX Henry Hub prices.
(e) Based on cumulative unrealized mark-to-market gain at September 30, 2012.

Changes in the fair value of the instruments in the natural gas price hedging program are being recorded as unrealized gains and losses in net gain (loss) from commodity hedging and trading activities in the statement of income, which has and could continue to result in significant volatility in reported net income. Based on the size of the natural gas price hedging program at September 30, 2012, a $1.00/MMBtu change in natural gas prices across the hedged period would result in the recognition of up to approximately $430 million in pretax unrealized mark-to-market gains or losses.

The natural gas price hedging program has resulted in reported net gains (losses) as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Realized net gain	$ 440	$ 290	$ 1,459	$ 911
Unrealized net gain (loss) including reversals of previously recorded amounts related to positions settled	(539)	102	(1,244)	(299)
Total	$ (99)	$ 392	$ 215	$ 612

The cumulative unrealized mark-to-market net gain related to positions in the natural gas price hedging program totaled $1.880 billion and $3.124 billion at September 30, 2012 and December 31, 2011, respectively. The decline was driven by settlement of maturing positions.

Given the volatility of natural gas prices, it is not possible to predict future reported unrealized mark-to-market gains or losses and the actual gains or losses that will ultimately be realized upon settlement of the hedge positions in future years. If natural gas prices at settlement are lower than the prices of the hedge positions, the hedges are expected to mitigate the otherwise negative effect on earnings of lower wholesale electricity prices. However, if natural gas prices at settlement are higher than the prices of the hedge positions, the hedges are expected to dampen the otherwise positive effect on earnings of higher wholesale electricity prices and will in this context be viewed as having resulted in an opportunity cost.

The significant cumulative unrealized mark-to-market net gain related to positions in the natural gas price hedging program reflects the sustained decline in forward market natural gas prices as presented in the table below. Forward natural gas prices have generally trended downward over the past several years. While the natural gas price hedging program is designed to mitigate the effect on earnings of low wholesale electricity prices, depressed forward natural gas prices are challenging to the long-term profitability of our generation assets. Specifically, these lower natural gas prices and their potential effect on wholesale electricity prices could have a material impact on the overall profitability of our generation assets for periods in which we do not have significant hedge positions.

	Forward Market Prices for Calendar Year ($/MMBtu) (a)				
Date	2012 (b)	2013	2014	2015	2016
December 31, 2008	$ 7.23	$ 7.15	$ 7.15	$ 7.21	$ 7.30
March 31, 2009	$ 6.96	$ 7.11	$ 7.18	$ 7.25	$ 7.33
June 30, 2009	$ 7.16	$ 7.30	$ 7.43	$ 7.57	$ 7.71
September 30, 2009	$ 7.00	$ 7.06	$ 7.17	$ 7.31	$ 7.43
December 31, 2009	$ 6.53	$ 6.67	$ 6.84	$ 7.05	$ 7.24
March 31, 2010	$ 5.79	$ 6.07	$ 6.36	$ 6.68	$ 7.00
June 30, 2010	$ 5.68	$ 5.89	$ 6.10	$ 6.37	$ 6.68
September 30, 2010	$ 5.07	$ 5.29	$ 5.42	$ 5.60	$ 5.76
December 31, 2010	$ 5.08	$ 5.33	$ 5.49	$ 5.64	$ 5.79
March 31, 2011	$ 5.06	$ 5.41	$ 5.73	$ 6.08	$ 6.41
June 30, 2011	$ 4.84	$ 5.16	$ 5.42	$ 5.70	$ 5.98
September 30, 2011	$ 4.24	$ 4.80	$ 5.13	$ 5.39	$ 5.61
December 31, 2011	$ 3.24	$ 3.94	$ 4.34	$ 4.60	$ 4.85
March 31, 2012	$ 2.50	$ 3.47	$ 3.96	$ 4.26	$ 4.51
June 30, 2012	$ 2.96	$ 3.58	$ 3.95	$ 4.13	$ 4.29
September 30, 2012	$ 3.32	$ 3.84	$ 4.18	$ 4.37	$ 4.55

(a) Based on NYMEX Henry Hub prices.
(b) For March 31, 2012, June 30, 2012 and September 30, 2012, natural gas prices for 2012 represent the average of forward prices for April through December, July through December and October through December, respectively.

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 pretax earnings for the periods presented. The estimates related to price sensitivity are based on TCEH's unhedged position and forward prices at September 30, 2012, which for natural gas reflects estimates of electricity generation less amounts hedged through the natural gas price hedging program and amounts under existing wholesale and retail sales contracts. On a rolling basis, generally twelve-months, the substantial majority of retail sales under month-to-month arrangements are deemed to be under contract.

	Balance 2012 (a)	2013	2014	2015	2016
$1.00/MMBtu change in gas price (b)	$ ~1	$ ~60	$ ~280	$ ~485	$ ~495
0.1/MMBtu/MWh change in market heat rate (c)	$ ~1	$ ~10	$ ~30	$ ~35	$ ~40
$1.00/gallon change in diesel fuel price	$ —	$ ~10	$ ~40	$ ~50	$ ~55

(a) Balance of 2012 is from November 1, 2012 through December 31, 2012.
(b) Assumes conversion of electricity positions based on an approximate 8.5 market heat rate with natural gas generally being on the margin 70% to 90% of the time in the ERCOT market (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 at September 30, 2012.

TCEH Interest Rate Swap Transactions — TCEH employs interest rate swaps to hedge exposure to its variable rate debt. As reflected in the table below, at September 30, 2012, TCEH has entered into the following series of interest rate swap transactions that effectively fix the interest rates at between 5.5% and 9.3%.

Fixed Rates	Expiration Dates	Notional Amount
5.5% — 9.3%	October 2012 through October 2014	$18.57 billion (a)
6.8% — 9.0%	October 2015 through October 2017	$12.60 billion (b)

(a) Swaps related to an aggregate $1.1 billion principal amount of debt expired in 2012. Per the terms of the transactions, the notional amount of swaps entered into in 2011 grew by $1.02 billion, substantially offsetting the expired swaps.

(b) These swaps are effective from October 2014 through October 2017. The $12.6 billion notional amount of swaps includes $3 billion that expires in October 2015 with the remainder expiring in October 2017.

We may enter into additional interest rate hedges from time to time.

TCEH has also entered into interest rate basis swap transactions that further reduce the fixed borrowing costs achieved through the interest rate swaps. Basis swaps in effect at September 30, 2012 totaled $15.92 billion notional amount, a decrease of $1.8 billion from December 31, 2011 reflecting new and expired swaps. The basis swaps relate to debt outstanding through 2014.

The interest rate swaps have resulted in net losses reported in interest expense and related charges as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Realized net loss	$ (168)	$ (177)	$ (505)	$ (511)
Unrealized net loss	(20)	(619)	(16)	(879)
Total	$ (188)	$ (796)	$ (521)	$ (1,390)

The cumulative unrealized mark-to-market net liability related to all TCEH interest rate swaps totaled $2.248 billion and $2.231 billion at September 30, 2012 and December 31, 2011, respectively, of which $67 million and $76 million (both pretax), respectively, were reported in accumulated other comprehensive income. These fair values can change materially as market conditions change, which could result in significant volatility in reported net income. For example, at September 30, 2012, a one percent change in interest rates would result in an increase or decrease of approximately $725 million in our cumulative unrealized mark-to-market net liability.

First-Lien Security for Natural Gas Hedging Program and Interest Rate Swaps — Approximately 90% of the positions in the natural gas price hedging program and all of the TCEH interest rate swaps are secured by a first-lien interest in the assets of TCEH that is pari passu with the TCEH Senior Secured Facilities. Certain entities are counterparties to both our natural gas hedge program positions and our interest rate swaps and have entered into master agreements that provide for netting and setoff of amounts related to these positions. At September 30, 2012, our net liability positions related to these counterparties together with liability positions related to entities that are counterparties to only our interest rate swaps totaled approximately $1.3 billion. This amount is not expected to change materially through 2013 assuming market values do not change significantly.

Pension Plan Actions — In August 2012, EFH Corp. approved certain amendments to its pension plan. These amendments will result in:

- splitting off assets and liabilities under the plan associated with employees of Oncor and all retirees and terminated vested participants of EFH Corp. and its subsidiaries (including discontinued businesses) to a new plan that is expected to be sponsored and administered by Oncor (the Oncor Plan);
- maintaining assets and liabilities under the plan associated with active collective bargaining unit (union) employees of EFH Corp.'s competitive subsidiaries under the current plan;
- splitting off assets and liabilities under the plan associated with all other plan participants (active nonunion employees of EFH Corp.'s competitive businesses) to a Terminating Plan, freezing benefits and vesting all accrued plan benefits for these participants, and
- the termination of, distributions of benefits under, and settlement of all of EFH Corp.'s liabilities under the Terminating Plan.

These actions are expected to be completed in the fourth quarter 2012 (see Note 11 to Financial Statements).

EFH Corp. currently expects that settlement of the Terminating Plan obligations and the full funding of the EFH Corp. competitive operations portion of liabilities (including discontinued businesses) under the Oncor Plan will result in aggregate cash contributions by EFH Corp.'s competitive operations of approximately $240 million in the fourth quarter 2012. In October 2012, $150 million of this amount was contributed, of which $65 million was funded by TCEH.

EFH Corp. expects its competitive operations to record a charge of approximately $75 million in the fourth quarter 2012 related to the settlement of the Terminating Plan, which amount represents the previously unrecognized actuarial losses reported in accumulated other comprehensive income (loss). We have not yet determined the accounting for the actuarial losses related to the competitive business obligations (including discontinued operations) that are being assumed under the Oncor Plan, which could result in an additional competitive operations charge of approximately $200 million in the fourth quarter 2012 or amortization of this amount over time.

These amounts are preliminary estimates, and the final amounts could be higher or lower depending on various factors, including discount rates and values of the pension trust assets at the settlement date, as well as the form of settlement chosen by each affected participant (i.e. lump sum or annuity).

Liability Management Program — At September 30, 2012, EFH Corp. and its consolidated subsidiaries had $38.0 billion principal amount of long-term debt outstanding. In October 2009, we implemented a liability management program designed to reduce debt, capture debt discount and extend debt maturities through debt exchanges, repurchases and extensions. Activities under the liability management program do not include debt issued by Oncor or its subsidiaries.

Amendments to the TCEH Senior Secured Facilities completed in April 2011 resulted in the extension of $16.4 billion in loan maturities under the TCEH Term Loan Facilities and the TCEH Letter of Credit Facility from October 2014 to October 2017 and $1.4 billion of commitments under the TCEH Revolving Credit Facility from October 2013 to October 2016.

Other liability management activities since October 2009 include debt exchange, issuance and repurchase activities as follows (all transactions occurred prior to 2012):

Security (except where noted, debt amounts are principal amounts)	Debt Acquired (a)	Debt Issued/Cash Paid
EFH Corp. 10.875% Notes due 2017	$ 1,804	$ —
EFH Corp. Toggle Notes due 2017	2,661	53
EFH Corp. 5.55% Series P Senior Notes due 2014	674	—
EFH Corp. 6.50% Series Q Senior Notes due 2024	10	—
EFH Corp. 6.55% Series R Senior Notes due 2034	6	—
TCEH 10.25% Notes due 2015	1,875	—
TCEH Toggle Notes due 2016	751	—
TCEH Senior Secured Facilities due 2013 and 2014	1,623	—
EFH Corp. and EFIH 9.75% Notes due 2019	—	256
EFH Corp 10% Notes due 2020	—	561
EFIH 11% Notes due 2021	—	406
EFIH 10% Notes due 2020	—	2,180
TCEH 15% Notes due 2021	—	1,221
TCEH 11.5% Notes due 2020 (b)	—	1,604
Cash paid, including use of proceeds from debt issuances in 2010 (c)	—	1,062
Total	$ 9,404	$ 7,343

(a) Includes an aggregate $4.933 billion principal amount of these securities held by EFH Corp. and EFIH. All other debt acquired has been canceled.
(b) Excludes from the $1.750 billion principal amount $12 million in debt discount and $134 million in proceeds used for transaction costs related to the issuance of these notes and the amendment and extension of the TCEH Senior Secured Facilities. All other proceeds were used to repay borrowings under the TCEH Senior Secured Facilities, and the remaining transaction costs were funded with cash on hand.
(c) Includes $100 million of the proceeds from the January 2010 issuance of $500 million principal amount of EFH Corp. 10% Notes due 2020 and $290 million of the proceeds from the October 2010 issuance of $350 million principal amount of TCEH 15% Senior Secured Second Lien Notes due 2021. The total $390 million of proceeds was used to repurchase debt.

Since inception, the transactions in the liability management program have resulted in the capture of $2 billion of debt discount and the extension of approximately $23.5 billion of debt maturities to 2017-2021.

See Note 6 to Financial Statements for discussion of issuances of notes by EFIH in 2012 and use of proceeds.

Financial Services Reform Legislation — In July 2010, the US Congress enacted financial reform legislation known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Financial Reform Act). 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, a few key rulemaking decisions remain to be made by federal governmental agencies to fully implement the Financial Reform Act.

Title VII of the Financial Reform Act provides for the regulation of the over-the-counter (OTC) derivatives (Swaps) 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, under the end-user clearing exemption, entities are exempt from these clearing requirements if they (i) are not "Swap Dealers" or "Major Swap Participants" as defined and (ii) use the Swaps to hedge or mitigate commercial risk. Existing swaps are grandfathered from the clearing requirements. The legislation mandates significant compliance requirements for any entity that is determined to be a Swap Dealer or Major Swap Participant.

In May 2012, the US Commodity Futures Trading Commission (CFTC) published its final rule defining the terms Swap Dealer and Major Swap Participant. Additionally, in July 2012, the CFTC approved the final rules defining the term Swap and the end-user clearing exemption. The definition of the term Swap and the Swap Dealer/Major Swap Participant rule became effective in October 2012. Beginning in October 2012, we are required to assess our activity to determine if we will be required to register as a Swap Dealer or Major Swap Participant. In October 2012, the CFTC issued various no-action letters granting temporary relief from enforcement from certain aspects of the definition of Swap and the Swap Dealer/Major Swap Participant rule.

Additionally, in September 2012, the District Court for the District of Columbia issued an order that vacated and remanded to the CFTC its Position Limit Rule (PLR), which would have been effective in October 2012. The PLR provided for specific position limits related to 28 Core Referenced Futures Contracts, including the NYMEX Henry Hub Natural Gas Futures Contract. If the PLR had been approved by the court, we would have been required to comply with the portion of the PLR applicable to the NYMEX Henry Hub Natural Gas Futures Contract. We cannot predict when, or in what form, the CFTC will change the PLR.

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 final rulemakings to implement the OTC derivative market provisions of the Financial Reform Act. Based on our assessment and published guidance from the CFTC, we do not believe our historical practices or Swap positions make us a Swap Dealer or Major Swap Participant and that we will be able to take advantage of the End-User Exemption for Swaps that hedge or mitigate commercial risk; however, the remaining rulemakings related to how Swap Dealers and other market participants administer margin requirements could negatively affect our ability to hedge our commodity and interest rate risks. Accordingly, we (and other market participants) continue to closely monitor the rulemakings and any other potential legislative and regulatory changes and work with regulators and legislators. We have provided them information on our operations, the types of transactions in which we engage, our concerns regarding potential regulatory impacts, market characteristics and related matters.

Recent EPA Actions — *Cross-State Air Pollution Rule* (also see Note 7 to Financial Statements) — In 2005, the EPA issued a final rule (the Clean Air Interstate Rule or CAIR) intended to implement the provisions of the Clean Air Act Section 110(a)(2)(D)(i)(I) (CAA Section 110) requiring states to reduce emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) that significantly contribute to other states failing to attain or maintain compliance with the EPA's National Ambient Air Quality Standards (NAAQS) for fine particulate matter and/or ozone. In 2008, the US Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court) invalidated CAIR, but allowed the rule to continue until the EPA issued a final replacement rule. In August 2010, the EPA issued for comment a proposed replacement rule for CAIR called the Clean Air Transport Rule (CATR), similarly intended to implement CAA Section 110. As proposed, the CATR did not include Texas in its annual SO_2 or NO_x programs to address alleged downwind fine particulate matter effects.

In July 2011, the EPA issued the final replacement rule for CAIR (as finally issued, the Cross-State Air Pollution Rule (CSAPR)). Unlike the CATR, the CSAPR included Texas in its annual SO_2 and NO_x emissions reduction programs, as well as the seasonal NO_x emissions reduction program. These programs would have required significant additional reductions of SO_2 and NO_x emissions from fossil-fueled generation units in covered states (including Texas) and instituted a limited "cap and trade" system as an additional compliance tool to achieve reductions the EPA contends are necessary to implement CAA Section 110. As adopted in July 2011, the CSAPR would have required our fossil-fueled generation units to (i) reduce their annual SO_2 and NO_x emissions by approximately 137,000 tons (64 percent) and 9,200 tons (22 percent), respectively (compared to 2010 actual levels), each beginning on January 1, 2012 and (ii) reduce their seasonal NO_x emissions by approximately 3,400 tons (19 percent) (compared to 2010 actual levels) beginning on May 1, 2012, which is the start of the ozone season.

In September 2011, we filed a petition for review in the D.C. Circuit Court challenging the CSAPR as it applies to Texas.

In February 2012, the EPA released a final rule (Final Revisions) and a proposed rule revising certain aspects of the CSAPR, including emissions budgets for the State of Texas. In March 2012, we submitted comments to the EPA on the proposed rule requesting the EPA to make additional corrections to the CSAPR's budgets for Texas. In June 2012, the EPA finalized the proposed rule (Second Revised Rule). The Final Revisions increased the emissions budgets for the State of Texas by 50,517 tons for the annual SO_2 program and 1,375 tons for each of the annual NO_x and seasonal NO_x programs. The Second Revised Rule further increased (over the Final Revisions) the Texas annual NO_x emissions budget by 2,731 tons and the seasonal NO_x emissions budget by 1,142 tons. In total, the emissions budgets established by the Final Revisions along with the Second Revised Rule would require our fossil-fueled generation units to reduce (i) their annual SO_2 and NO_x emissions by approximately 120,600 tons (56 percent) and 9,000 tons (22 percent), respectively, compared to 2010 actual levels, and (ii) their seasonal NO_x emissions by approximately 3,300 tons (18 percent) compared to 2010 levels. The company could comply with these emissions limits either through physical reductions or through the purchase of emissions credits from third parties, but the volume of SO_2 credits that may be purchased from sources outside of Texas is subject to limitations starting in 2014, as described in our 2011 Form 10-K. In April 2012, we filed in the D.C. Circuit Court a petition for review of the Final Revisions on the ground, among others, that the rules do not include all of the budget corrections we requested from the EPA. The parties to the case have agreed that the case should be held in abeyance pending the issuance of the mandate in the CSAPR proceeding. The mandate will issue seven days after the rehearing proceeding is concluded in the D.C. Circuit Court.

In August 2012, a three judge panel of the D.C. Circuit Court vacated the CSAPR, remanding it to the EPA for further proceedings. As a result, the CSAPR, the Final Revisions and the Second Revised Rule do not impose any immediate requirements on us, the State of Texas, or other affected parties. The D.C. Circuit Court's order stated that the EPA was expected to continue administering the CAIR pending the EPA's further consideration of the rule. In October 2012, the EPA and certain other parties that supported the CSAPR filed a petition with the D.C. Circuit Court seeking review by the full court of the panel's decision to vacate and remand the CSAPR. We cannot predict when or how the D.C. Circuit Court will rule on this petition.

Mercury and Air Toxics Standard— In 2005, the EPA published a final rule requiring reductions of mercury emissions from lignite/coal-fueled generation plants. The Clean Air Mercury Rule (CAMR) was based on a nationwide cap and trade approach. The mercury reductions were required to be phased in between 2010 and 2018. In March 2008, the D.C. Circuit Court vacated CAMR. In February 2009, the US Supreme Court refused to hear the appeal of the D.C. Circuit Court's ruling. In December 2011, the EPA finalized a new rule (called the Mercury and Air Toxics Standard or MATS). MATS regulates the emissions of mercury, nonmercury metals, hazardous organic compounds and acid gases. Any additional control equipment retrofits on our lignite/coal-fueled generation units required to comply with MATS as finalized would need to be installed within three to four years from the April 2012 effective date of the rule. In April 2012, we filed a petition for review of MATS in the D.C. Circuit Court. Certain states and industry participants have also filed petitions for review in the D.C. Circuit Court. We cannot predict the timing or outcome of these petitions.

Regional Haze — SO_2 and NO_x reductions required under the proposed regional haze/visibility rule (or so-called BART rule) only apply to units built between 1962 and 1977. The reductions are required on a unit-by-unit basis. In February 2009, the TCEQ submitted a State Implementation Plan (SIP) concerning regional haze to the EPA, which we believe will not have a material impact on our generation facilities. In December 2011, the EPA proposed a limited disapproval of the SIP and a Federal Implementation Plan for Texas providing that the inclusion in the CSAPR programs meets the regional haze requirements for SO_2 and NO_x reductions. In June 2012, the EPA finalized the limited disapproval of the Texas regional haze SIP, but did not finalize a Federal Implementation Plan for Texas. We cannot predict whether or when the EPA will finalize a Federal Implementation Plan for Texas regarding regional haze or its impact on our results of operations, liquidity or financial condition. In August 2012, we filed a petition for review in the Fifth Circuit Court challenging the EPA's limited disapproval of the Texas regional haze SIP. In September 2012, we filed a petition to intervene in a case filed by industry groups and other states and private parties in the D.C. Circuit Court challenging the EPA's limited disapproval and issuance of Federal Implementation Plans regarding regional haze. The parties in these cases have mutually agreed that the cases should be held in abeyance pending issuance of the mandate in the CSAPR proceeding. We cannot predict when or how the Fifth Circuit Court or the D.C. Circuit Court will rule on these petitions.

Greenhouse Gas Emissions — In March 2012, the EPA released a proposal for a performance standard for greenhouse gas emissions from new electric generation units (EGUs). The proposal, which is currently limited to new sources, is based on the carbon dioxide emission rate from a natural gas-fueled combined cycle EGU. None of our existing generation units would be considered a new source under the proposed rule. While we do not believe the proposed rule, as released, affects our existing generation units, we provided comments on it to the EPA and continue to monitor the proposed rule.

In December 2010, the EPA adopted a rule to take over the issuance of permits for greenhouse gas (GHG) emissions from the TCEQ. The State of Texas challenged that rule and the GHG permitting rules through litigation and has refused to implement the GHG permitting rules issued by the EPA. In June 2012, the D.C. Circuit Court upheld all of the EPA's GHG rules and regulations. A number of members of the US Congress from both parties have introduced legislation to either block or delay EPA regulation of GHGs under the Clean Air Act, and legislative activity in this area in the future is possible. Additionally, in August 2012, various industry groups and states that challenged the rule filed a petition with the D.C. Circuit Court seeking rehearing asking for review by the full D.C. Circuit Court of the panel's decision. We cannot predict when or how the D.C. Circuit Court will rule on the rehearing petition.

Environmental Capital Expenditures — We have revised our estimates of capital expenditures for environmental control equipment to comply with regulatory requirements, based on analysis and testing of options to comply with the MATS rule, as well as estimates related to other EPA regulations, including expenditures previously incurred related to the CSAPR. Between 2011 and the end of the decade, we estimate that we will incur more than $1 billion in capital expenditures for environmental control equipment, though the ultimate total will depend on the evolution of pending or future regulatory requirements. Based on regulations currently in effect, we estimate that we will incur approximately $500 million of capital expenditures for environmental control equipment between 2013 and 2017, including amounts required to maintain installed environmental control equipment. Our current plan includes the ongoing use of lignite coal as part of the fuel mix at all of our coal facilities, in varying proportions that reflect the economically available fuel supply as well as the configuration of environmental control equipment for each unit.

Recent PUCT/ERCOT Actions — In response to ERCOT's publication of reports (known as the Capacity, Demand, and Reserves report and the Seasonal Assessment of Resource Adequacy report) showing declining reserve margins in ERCOT, the PUCT and the ERCOT Board of Directors have taken action to implement or approve in 2012 several changes to ERCOT protocols designed to establish minimum offer floors for wholesale power offers during deployment of certain reliability-related services, including non-spinning reserve, responsive reserve, reliability unit commitment, and other services. In addition, in June and October 2012 the PUCT approved rules that, among other things, increased the system-wide offer cap that applies to wholesale power offers in ERCOT from its previous level of $3,000 per MWh to $4,500 per MWh effective August 1, 2012, and increased the cap to $5,000, $7,000, and $9,000 per MWh in the summers of 2013, 2014, and 2015, respectively, for the stated purpose of sending appropriate price signals to encourage development of generation resources in ERCOT. Also in June 2012, the Brattle Group, an independent consultant engaged by ERCOT to assess the incentives for generation investment in the ERCOT market, issued a report on potential next steps for addressing generation resource adequacy. The Brattle report discusses a range of potential solutions that could promote resource adequacy in the ERCOT market, ranging from enhancing the current energy-only structure in ERCOT to creating a capacity market structure, whereby generators receive capacity payments to ensure available generation in the market and provide a return on the generator's investment, similar to those used in certain other competitive markets in the US. The Brattle report concluded that, even if the wholesale energy offer cap were increased to $9,000 per MWh, the expected corresponding reserve margin that would be obtained in the current energy-only market design would be approximately 10%. ERCOT's current target reserve margin is 13.75%. Discussions are ongoing among ERCOT, the PUCT, market participants and other stakeholders regarding the range of solutions presented in the Brattle report and the actions necessary to continue providing reliable electricity supply in ERCOT.

Suspension of Certain Generation Operations — In August 2012, we filed notice with ERCOT that we intend to suspend operations at two of the three generation units at our Monticello generation facility due to persistently low wholesale power prices and other market conditions. Pending ERCOT approval, beginning December 1, 2012 we intend to suspend operations for approximately six months and not greater than seven months, with both units expected to return to service during the peak demand months in the summer of 2013. Our mines will continue year round operations and there will be no reduction in our full-time work force as a result of this action. Based on cash flow projections and related analysis, no impairment was recorded as a result of the suspension. At current wholesale market prices of electricity, we do not expect the suspension of operations to significantly impact our results of operations, liquidity or financial condition. In September 2012, we received notice from ERCOT that it is evaluating whether the units are needed for reliability-must-run service in order to support transmission reliability in ERCOT. We expect ERCOT will make their final determination in late October 2012.

Settlement of Make-Whole Agreements with Oncor — See Note 12 to Financial Statements for discussion of the settlement in the third quarter 2012 of our interest and tax-related reimbursement agreements with Oncor associated with Oncor's bankruptcy-remote financing subsidiary's securitization bonds.

Oncor Technology Initiatives — Oncor continues to invest in technology initiatives that include development of a modernized grid through the replacement of existing meters with advanced digital metering equipment and development of advanced digital communication, data management, real-time monitoring and outage detection capabilities. This modernized grid is producing electricity service reliability improvements and providing the potential for additional products and services from REPs that enable businesses and consumers to better manage their electricity usage and costs. Oncor's plans provide for the full deployment of over three million advanced meters to all residential and most non-residential retail electricity customers in Oncor's service area. The advanced meters can be read remotely, rather than by a meter reader physically visiting the location of each meter. Advanced meters facilitate automated demand side management, which allows consumers to monitor the amount of electricity they are consuming and adjust their electricity consumption habits.

At September 30, 2012, Oncor had installed 3,104,000 advanced digital meters, including 802,000 in 2012. 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 $642 million at September 30, 2012, including $124 million in 2012. Oncor expects to complete installations of the advanced meters by the end of 2012.

Oncor Matters with the PUCT — *Competitive Renewable Energy Zones (CREZs)* — In 2009, the PUCT awarded Oncor CREZ construction projects (PUCT Docket Nos. 35665 and 37902) requiring 14 related Certificate of Convenience and Necessity (CCN) amendment proceedings before the PUCT for 17 projects. All 17 projects and 14 CCN amendments have been approved by the PUCT. The projects involve the construction of transmission lines and stations to support the transmission of electricity from renewable energy sources, principally wind generation facilities, in the western part of Texas to population centers in the eastern part of Texas. In addition to these projects, ERCOT completed a study in December 2010 that will result in Oncor and other transmission service providers building additional facilities to provide further voltage support to the transmission grid as a result of CREZ. Oncor currently estimates, based on these additional voltage support facilities and the approved routes and stations for its awarded CREZ projects, that CREZ construction costs will total approximately $2.0 billion. CREZ-related costs could change based on finalization of costs for the additional voltage support facilities and final detailed designs of subsequent project routes. At September 30, 2012, Oncor's cumulative CREZ-related capital expenditures totaled $1.360 billion, including $461 million in 2012. Oncor expects that all necessary permitting actions and other requirements and all line and station construction activities for Oncor's CREZ construction projects will be completed by the end of 2013 with additional voltage support projects completed by early 2014.

Transmission Cost Recovery and Rates (PUCT Docket Nos. 40451, 39940, 40603 and 40142) — In order to reflect increases or decreases in its wholesale transmission costs, including fees paid to other transmission service providers, Oncor is allowed to update the transmission cost recovery factor (TCRF) component of its retail delivery rates charged to REPs twice a year. In June 2012, Oncor filed an application to update the TCRF, which became effective September 1, 2012. This application was designed to increase Oncor's revenues for the period from September 2012 through February 2013 by $129 million. In November 2011, Oncor filed an application to update the TCRF, which was approved by the PUCT in January 2012 and became effective in March 2012. This application was designed to lower Oncor's revenues for the period from March 2012 through August 2012 by $41 million, reflecting over-recoveries due to hot weather in the summer of 2011.

In July 2012, Oncor filed an application for an interim update of its wholesale transmission rate. The new rate was approved by the PUCT and became effective in August 2012. Oncor's annualized revenues are expected to increase by an estimated $30 million with approximately $19 million of this increase recoverable through transmission costs charged to wholesale customers and $11 million recoverable from REPs through the TCRF component of Oncor's delivery rates. In January 2012, Oncor filed an application for an interim update of its wholesale transmission rate. The new rate was approved by the PUCT and became effective in March 2012. Oncor's annualized revenues are expected to increase by an estimated $2 million with approximately 65% of this increase recoverable through transmission costs charged to wholesale customers and the remaining 35% recoverable from REPs through the TCRF component of Oncor's delivery rates.

Stipulation Approved by the PUCT (PUCT Docket No. 34077) — In April 2008, the PUCT entered an order, which became final in June 2008, approving the terms of a stipulation relating to a filing in 2007 by Oncor and Texas Holdings with the PUCT pursuant to Section 14.101(b) of the Texas Public Utility Regulatory Act and PUCT Substantive Rule 25.75. Among other things, the stipulation required Oncor to file a rate review no later than July 1, 2008 based on a test year ended December 31, 2007, which Oncor filed in June 2008. The PUCT issued a final order with respect to the rate review in August 2009. In July 2008, Nucor Steel filed an appeal of the PUCT's order in the 200th District Court of Travis County, Texas (District Court). 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 Texas Third Court of Appeals (Austin Court of Appeals) in July 2010. In March 2012, the Austin Court of Appeals affirmed the District Court's ruling, which is now final.

Application for 2013 Energy Efficiency Cost Recovery Factor (PUCT Docket No. 40361) — In May 2012, Oncor filed an application with the PUCT to request approval of an energy efficiency cost recovery factor (EECRF) for 2013. PUCT rules require Oncor to make an annual EECRF filing by the first business day in May for implementation at the beginning of the next calendar year. The requested 2013 EECRF is $73 million as compared to $54 million established for 2012, and would result in a monthly charge for residential customers of $1.23 as compared to the 2012 residential charge of $0.99 per month effective December 31, 2012. In August 2012, the PUCT issued a final order approving the 2013 EECRF, which is designed to recover $62 million of Oncor's costs for the 2013 program year, a $9 million performance bonus based on Oncor's 2011 results and a $2 million increase for under-recovery of 2011 costs.

Summary — We cannot predict future regulatory or legislative actions or any changes in economic and securities market conditions. Such actions or changes could significantly affect our results of operations, liquidity or financial condition.

RESULTS OF OPERATIONS

Consolidated Financial Results – Three Months Ended September 30, 2012 Compared to Three Months Ended September 30, 2011

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; SG&A expenses and franchise and revenue-based taxes.

See Note 14 to Financial Statements for details of other income and deductions.

Interest expense and related charges decreased $579 million, or 38%, to $944 million in 2012. The decrease was driven by $598 million in lower unrealized mark-to-market net losses on interest rate swaps.

Income tax benefit totaled $296 million and $443 million in 2012 and 2011, respectively. The effective rate was 36.5% and 35.0% in 2012 and 2011, respectively. The increase in the effective rate reflected an increase in the lignite depletion deduction based on the 2011 federal income tax return filed in September 2012.

Equity in earnings of our Oncor Holdings unconsolidated subsidiary (net of tax) decreased $4 million to $109 million in 2012 reflecting lower earnings at Oncor due to the effect of milder weather on revenues and higher interest and depreciation expense, partially offset by higher tariffs.

Net loss decreased $303 million to $407 million in 2012.

- Net loss in the Competitive Electric segment decreased $337 million to $393 million.
- Earnings from the Regulated Delivery segment decreased $4 million to $109 million as discussed above.
- After-tax net expenses from Corporate and Other activities totaled $123 million and $93 million in 2012 and 2011, respectively. The amounts in 2012 and 2011 include recurring interest expense on outstanding debt, as well as corporate general and administrative expenses. The $30 million increase was driven by increased interest expense, reflecting debt issuances at EFIH and PIK interest payments on EFH Corp. Toggle Notes, partially offset by lower intercompany borrowings, reflecting the repayment of a portion of the demand notes payable by EFH Corp. to TCEH (see Note 6 to Financial Statements).

Consolidated Financial Results – Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011

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; SG&A expenses and franchise and revenue-based taxes.

See Note 14 to Financial Statements for details of other income and deductions.

Interest expense and related charges decreased $721 million, or 21%, to $2.746 billion in 2012. The decrease was driven by $867 million lower unrealized mark-to-market net losses on interest rate swaps, partially offset by $160 million higher interest accrued/paid reflecting issuances of EFIH Notes and amendment and extension of the TCEH Senior Secured Facilities in April 2011 (see Note 6 to Financial Statements).

Income tax benefit totaled $879 million and $1.042 billion in 2012 and 2011, respectively. The effective rate was 34.7% and 34.1% in 2012 and 2011, respectively. The increase in the effective rate reflected higher Texas margin tax expense in 2011 due to a taxable gain arising from the amendments to the TCEH Senior Secured Facilities completed in April 2011 and an increased lignite depletion deduction based on the 2011 federal income tax return filed in September 2012.

Equity in earnings of our Oncor Holdings unconsolidated subsidiary (net of tax) increased $14 million to $249 million in 2012 reflecting higher earnings at Oncor due to higher tariffs, partially offset by the effect of milder weather on revenues and higher depreciation, operation and maintenance and interest expense.

Net loss decreased $368 million to $1.408 billion in 2012.

- Net loss in the Competitive Electric segment decreased $403 million to $1.319 billion.
- Earnings from the Regulated Delivery segment increased $14 million to $249 million as discussed above.
- After-tax net expenses from Corporate and Other activities totaled $338 million and $289 million in 2012 and 2011, respectively. The amounts in 2012 and 2011 include recurring interest expense on outstanding debt, as well as corporate general and administrative expenses. The $49 million increase reflected debt extinguishment gains totaling $16 million in 2011 and increased interest expense, reflecting debt issuances at EFIH and PIK interest payments on EFH Corp. Toggle Notes, partially offset by lower intercompany borrowings, reflecting the repayment of a portion of the demand notes payable by EFH Corp. to TCEH (see Note 6 to Financial Statements).

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 adjustments, 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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Operating revenues	$ 1,752	$ 2,321	$ 4,358	$ 5,672
Fuel, purchased power costs and delivery fees	(850)	(1,058)	(2,153)	(2,726)
Net gain (loss) from commodity hedging and trading activities	(3)	270	229	365
Operating costs	(201)	(207)	(636)	(670)
Depreciation and amortization	(328)	(371)	(992)	(1,098)
Selling, general and administrative expenses	(174)	(192)	(484)	(529)
Franchise and revenue-based taxes	(19)	(21)	(55)	(64)
Other income	2	5	12	40
Other deductions	(31)	(478)	(37)	(569)
Interest income	10	20	36	66
Interest expense and related charges	(785)	(1,405)	(2,303)	(3,116)
Loss before income taxes	(627)	(1,116)	(2,025)	(2,629)
Income tax benefit	234	386	706	907
Net loss	$ (393)	$ (730)	$ (1,319)	$ (1,722)

Competitive Electric Segment
Sales Volume and Customer Count Data

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	% Change	2012	2011	% Change
Sales volumes:						
Retail electricity sales volumes – (GWh):						
Residential	7,891	9,586	(17.7)	18,682	22,362	(16.5)
Small business (a)	1,757	2,116	(17.0)	4,694	5,688	(17.5)
Large business and other customers	2,846	3,445	(17.4)	7,892	9,955	(20.7)
Total retail electricity	12,494	15,147	(17.5)	31,268	38,005	(17.7)
Wholesale electricity sales volumes (b)	9,337	7,336	27.3	24,085	24,961	(3.5)
Total sales volumes	21,831	22,483	(2.9)	55,353	62,966	(12.1)
Average volume (kWh) per residential customer (c)	5,019	5,698	(11.9)	11,707	13,044	(10.2)
Weather (North Texas average) – percent of normal (d):						
Cooling degree days	105.5%	129.2%	(18.3)	113.7%	134.2%	(15.3)
Heating degree days	—	—	—	74.6%	110.5%	(32.5)
Customer counts:						
Retail electricity customers (end of period and in thousands) (e):						
Residential				1,566	1,658	(5.5)
Small business (a)				176	190	(7.4)
Large business and other customers				17	20	(15.0)
Total retail electricity customers				1,759	1,868	(5.8)

(a) Customers with demand of less than 1 MW annually.
(b) Includes net amounts related to sales and purchases of 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.

Competitive Electric Segment
Revenue and Commodity Hedging and Trading Activities

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	% Change	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011	% Change
Operating revenues:						
Retail electricity revenues:						
Residential	$ 982	$ 1,185	(17.1)	$ 2,322	$ 2,759	(15.8)
Small business (a)	214	264	(18.9)	583	719	(18.9)
Large business and other customers	195	277	(29.6)	549	781	(29.7)
Total retail electricity revenues	1,391	1,726	(19.4)	3,454	4,259	(18.9)
Wholesale electricity revenues (b) (c)	291	513	(43.3)	715	1,193	(40.1)
Amortization of intangibles (d)	7	11	(36.4)	15	16	(6.3)
Other operating revenues	63	71	(11.3)	174	204	(14.7)
Total operating revenues	$ 1,752	$ 2,321	(24.5)	$ 4,358	$ 5,672	(23.2)
Net gain (loss) from commodity hedging and trading activities:						
Realized net gains on settled positions	$ 538	$ 135	—	$ 1,553	$ 625	—
Unrealized net gains (losses)	(541)	135	—	(1,324)	(260)	—
Total	$ (3)	$ 270	—	$ 229	$ 365	—

(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 we deem "unrealized." (The offsetting differences between contract and market prices are reported in net gain (loss) from commodity hedging and trading activities.) The amounts represent net gains for the periods presented and are as follows:

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Reported in revenues	$ 4	$ 1	$ —	$ 1
Reported in fuel and purchased power costs	11	2	34	12
Net gain	$ 15	$ 3	$ 34	$ 13

(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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	% Change	2012	2011	% Change
Fuel, purchased power costs and delivery fees ($ millions):						
Fuel for nuclear facilities	$ 47	$ 40	17.5	$ 139	$ 119	16.8
Fuel for lignite/coal facilities	251	284	(11.6)	606	776	(21.9)
Total nuclear and lignite/coal facilities	298	324	(8.0)	745	895	(16.8)
Fuel for natural gas facilities and purchased power costs (a)	97	146	(33.6)	248	356	(30.3)
Amortization of intangibles (b)	14	42	(66.7)	39	110	(64.5)
Other costs	58	107	(45.8)	147	255	(42.4)
Fuel and purchased power costs	467	619	(24.6)	1,179	1,616	(27.0)
Delivery fees (c)	383	439	(12.8)	974	1,110	(12.3)
Total	$ 850	$ 1,058	(19.7)	$ 2,153	$ 2,726	(21.0)
Fuel and purchased power costs (which excludes generation facilities operating costs) per MWh:						
Nuclear facilities	$ 8.85	$ 8.14	8.7	$ 8.83	$ 8.14	8.5
Lignite/coal facilities (d)	$ 20.21	$ 19.46	3.9	$ 21.01	$ 19.59	7.2
Natural gas facilities and purchased power (e)	$ 44.98	$ 62.91	(28.5)	$ 45.26	$ 55.17	(18.0)
Delivery fees per MWh	$ 30.56	$ 28.91	5.7	$ 31.06	$ 29.13	6.6
Production and purchased power volumes (GWh):						
Nuclear facilities	5,276	4,956	6.5	15,772	14,546	8.4
Lignite/coal facilities	15,179	16,473	(7.9)	35,929	45,096	(20.3)
Total nuclear and lignite/coal facilities (f)	20,455	21,429	(4.5)	51,701	59,642	(13.3)
Natural gas facilities	594	737	(19.4)	1,117	1,133	(1.4)
Purchased power (g)	782	317	—	2,535	2,191	15.7
Total energy supply volumes	21,831	22,483	(2.9)	55,353	62,966	(12.1)
Capacity factors (f):						
Nuclear facilities	103.9%	97.6%	6.5	104.3%	96.5%	8.1
Lignite/coal facilities	85.7%	93.1%	(7.9)	68.2%	86.8%	(21.4)
Total	89.8%	94.1%	(4.6)	76.2%	89.0%	(14.4)

(a) See note (b) to the "Revenue and Commodity Hedging and Trading Activities" table 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.
(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, and excludes unrealized gains as discussed in footnote (b) to the "Revenue and Commodity Hedging and Trading Activities" table above.
(e) Excludes volumes related to line loss and power imbalances and unrealized gains as referenced in footnote (d) immediately above.
(f) Includes the estimated effects of economic backdown of lignite/coal-fueled units totaling 2,510 GWh and 590 GWh in the three months ended September 30, 2012 and 2011, respectively, and 7,480 GWh and 2,430 GWh in the nine months ended September 30, 2012 and 2011, respectively.
(g) Includes amounts related to line loss and power imbalances.

Competitive Electric Segment – Financial Results — Three Months Ended September 30, 2012 Compared to Three Months Ended September 30, 2011

Operating revenues decreased $569 million, or 25%, to $1.752 billion in 2012.

Retail electricity revenues decreased $335 million, or 19%, to $1.391 billion reflecting a $303 million decline in sales volumes and $32 million in lower average prices. Sales volumes fell 18% reflecting declines in both the residential and business markets. Residential market volumes were lower due to much milder weather and a 6% decline in customer count driven by competitive activity. Business market volumes were lower due to a change in customer mix as well as lower customer counts driven by competitive activity. Overall average retail pricing declined 2% driven by business markets.

Wholesale electricity revenues decreased $222 million, or 43%, to $291 million in 2012 reflecting $362 million in lower average prices, partially offset by $140 million from increased sales volumes. Lower average prices reflected much milder weather, including the effects on prices of very hot weather in the summer of 2011, as well as lower natural gas prices. The increase in sales volumes reflected more of our generation volumes being sold into the wholesale market as volumes in our retail operations declined as discussed immediately above.

Fuel, purchased power costs and delivery fees decreased $208 million, or 20%, to $850 million in 2012. Purchased power and other costs (ancillary services) decreased $59 million reflecting lower wholesale electricity prices and lower natural gas prices. Delivery fees declined $56 million reflecting lower retail volumes. Lignite/coal fuel costs decreased $33 million reflecting lower production, lower emission allowance costs and an increase of $11 million in unrealized gains (as discussed in footnote (b) to the "Revenue and Commodity Hedging and Trading Activities" table above), partially offset by the effect of an increased western coal fuel blend. Natural gas fuel costs decreased $32 million reflecting lower prices and volumes. Amortization of intangible assets decreased $28 million reflecting lower amortization of emission allowances due to an impairment recorded in the third quarter 2011 and expiration of contracts fair-valued under purchase accounting at the Merger date.

An 8% decrease in lignite/coal-fueled production was driven by increased economic backdown in 2012, while nuclear-fueled production increased 6% reflecting an unplanned outage in 2011.

Following is an analysis of amounts reported as net gain (loss) from commodity hedging and trading activities, which totaled $3 million in net losses for the three months ended September 30, 2012 and $270 million in net gains for the three months ended September 30, 2011, which reflected the natural gas price hedging program discussed above under "Natural Gas Prices and Natural Gas Price Hedging Program":

	Three Months Ended September 30, 2012		
	Net Realized Gains	Net Unrealized Losses	Total
Hedging positions	$ 494	$ (475)	$ 19
Trading positions	44	(66)	(22)
Total	$ 538	$ (541)	$ (3)

	Three Months Ended September 30, 2011		
	Net Realized Gains	Net Unrealized Gains	Total
Hedging positions	$ 100	$ 124	$ 224
Trading positions	35	11	46
Total	$ 135	$ 135	$ 270

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 $15 million and $3 million in net gains in 2012 and 2011, respectively (as discussed in footnote (b) to the "Revenue and Commodity Hedging and Trading Activities" table above).

Operating costs decreased $6 million, or 3%, to $201 million in 2012. The decrease reflected lower lignite-fueled generation maintenance costs in 2012 due to fewer unplanned outage days.

Depreciation and amortization decreased $43 million, or 12%, to $328 million in 2012. The decrease reflected increased useful lives and retirements of certain generation assets and accelerated mine asset depreciation in 2011 due to then planned mine closures needed to comply with the CSAPR.

SG&A expenses decreased $18 million, or 9%, to $174 million in 2012. The decrease reflected $8 million in lower bad debt expense due to improved collection and customer care processes, customer mix and lower revenues, $8 million in lower employee compensation and benefit costs and $6 million in lower retail marketing and related expense.

Other deductions totaled $31 million in 2012 and $478 million in 2011. Other deductions in 2012 included a $24 million impairment of mineral interests as discussed in Note 4 to Financial Statements. Other deductions in 2011 resulting from the issuance of the CSAPR included a $418 million impairment charge for excess SO_2 emission allowances due to emission allowance limitations under the CSAPR, $49 million in employee severance charges associated with the CSAPR that were reversed in the fourth quarter 2011 and a $9 million impairment of mining assets. See Note 14 to Financial Statements.

Interest expense and related charges decreased $620 million, or 44%, to $785 million in 2012. The decrease was driven by $599 million lower unrealized mark-to-market net losses on interest rate swaps.

Income tax benefit totaled $234 million and $386 million on pretax losses in 2012 and 2011, respectively. The effective rate was 37.3% and 34.6% in 2012 and 2011, respectively. The increase in the effective rate reflected an increase in the lignite depletion deduction based on the 2011 federal income tax return filed in September 2012.

After-tax loss for the segment decreased $337 million to $393 million in 2012 reflecting lower unrealized mark-to-market net losses on interest rate swaps and the emission allowances impairment in 2011. These improvements were partially offset by lower revenues net of fuel, purchased power and delivery fees as well as lower results from commodity hedging and trading activities driven by unrealized losses in 2012.

Competitive Electric Segment – Financial Results — Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011

Operating revenues decreased $1.314 billion, or 23%, to $4.358 billion in 2012.

Retail electricity revenues decreased $805 million, or 19%, to $3.454 billion reflecting a $756 million decline in sales volumes and $49 million in lower average prices. Sales volumes fell 18% reflecting declines in both the residential and business markets. Residential market volumes were lower due to much milder weather and a 6% decrease in customer counts driven by competitive activity. Business market volumes were lower due to a change in customer mix and lower average customer counts driven by competitive activity. Overall average retail pricing declined 1% driven by business markets.

Wholesale electricity revenues decreased $478 million, or 40%, to $715 million in 2012 reflecting $436 million in lower average prices and $42 million in lower volumes sold. Lower average prices reflected much milder weather, including the effects of very hot weather on prices in the summer of 2011, and lower natural gas prices. The decrease in sales volumes reflected a 13% net decline in nuclear and coal-fueled generation volumes and milder weather (discussed below).

Fuel, purchased power costs and delivery fees decreased $573 million, or 21%, to $2.153 billion in 2012. Lignite/coal fuel costs decreased $170 million reflecting an increase in economic backdown and planned and unplanned generation unit outages as well as lower emission allowance costs and an increase of $23 million in unrealized gains (as discussed in footnote (b) to the "Revenue and Commodity Hedging and Trading Activities" table above), partially offset by higher lignite mining costs. Purchased power and other costs (ancillary services) decreased $122 million reflecting lower wholesale electricity prices and natural gas prices. Delivery fees declined $136 million reflecting lower retail volumes. Natural gas fuel costs decreased $65 million reflecting lower prices and volumes. Amortization of intangibles decreased $71 million reflecting lower amortization of emission allowances due to an impairment recorded in the third quarter 2011 and expiration of contracts fair-valued under purchase accounting at the Merger date.

A 20% decrease in lignite/coal-fueled production was driven by increased economic backdown and generation unit outages, while nuclear-fueled production increased 8% reflecting a spring refueling outage in 2011.

Following is an analysis of amounts reported as net gain (loss) from commodity hedging and trading activities, which totaled $229 million and $365 million in net gains for the nine months ended September 30, 2012 and 2011, respectively, which reflected the natural gas price hedging program discussed above under "Natural Gas Prices and Natural Gas Price Hedging Program":

	Nine Months Ended September 30, 2012		
	Net Realized Gains	Net Unrealized Losses	Total
Hedging positions	$ 1,504	$ (1,310)	$ 194
Trading positions	49	(14)	35
Total	$ 1,553	$ (1,324)	$ 229

	Nine Months Ended September 30, 2011		
	Net Realized Gains	Net Unrealized Gains (Losses)	Total
Hedging positions	$ 567	$ (276)	$ 291
Trading positions	58	16	74
Total	$ 625	$ (260)	$ 365

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 $34 million and $13 million in net gains in 2012 and 2011, respectively (as discussed in footnote (b) to the "Revenue and Commodity Hedging and Trading Activities" table above).

Operating costs decreased $34 million, or 5%, to $636 million in 2012. The decrease reflected $30 million in lower nuclear generation maintenance costs reflecting activities performed during the planned refueling outage in 2011 and the absence of a spring refueling outage in 2012 and $9 million in lower costs related to new systems implementation and process improvements at generation facilities, partially offset by $5 million in higher lignite-fueled generation maintenance costs in 2012 reflecting more planned and unplanned outage days.

Depreciation and amortization decreased $106 million, or 10%, to $992 million in 2012. The decrease reflected increased useful lives and retirements of certain generation assets and accelerated mine asset depreciation in 2011 due to then planned mine closures needed to comply with CSAPR.

SG&A expenses decreased $45 million, or 9%, to $484 million in 2012. The decrease reflected $22 million in lower bad debt expense due to improved collection and customer care processes, customer mix and lower revenues, $14 million in lower retail marketing and related expense and $12 million in lower employee compensation and benefit costs.

Other income totaled $12 million in 2012 and $40 million in 2011. Other income in 2012 included a $6 million fee received to novate certain hedge transactions between counterparties. Other income in 2011 included $21 million related to the settlement of bankruptcy claims against a counterparty, $7 million for a property damage claim and $6 million from a franchise tax refund related to prior years. See Note 14 to Financial Statements.

Other deductions totaled $37 million in 2012 and $569 million in 2011. Other deductions in 2012 included a $24 million impairment of mineral interests as discussed in Note 4 to Financial Statements. Other deductions in 2011 resulting from the issuance of the CSAPR included a $418 million impairment charge for excess SO_2 emission allowances due to emission allowance limitations under the CSAPR, $49 million in employee severance charges associated with the CSAPR that were reversed in the fourth quarter 2011 and a $9 million impairment of mining assets. Other deductions in 2011 also included $86 million in third party fees related to the amendment and extension of the TCEH Senior Secured Facilities. See Note 14 to Financial Statements.

Interest income decreased $30 million, or 45%, to $36 million. The decrease was driven by lower intercompany debt balances.

Interest expense and related charges decreased $813 million, or 26%, to $2.303 billion in 2012. The decrease was driven by $863 million lower unrealized mark-to-market net losses on interest rate swaps.

Income tax benefit totaled $706 million and $907 million on pretax losses in 2012 and 2011, respectively. The effective rate was 34.9% and 34.5% in 2012 and 2011, respectively. The increase in the effective rate reflected net changes in several individually insignificant items.

After-tax loss for the segment decreased $403 million to $1.319 billion in 2012 reflecting lower unrealized mark-to-market net losses on interest rate swaps and the emission allowances impairment in 2011. These improvements were partially offset by lower revenues net of fuel, purchased power and delivery fees as well as lower results from commodity hedging and trading activities driven by unrealized losses in 2012.

Competitive Electric Segment — Energy-Related Commodity Contracts and Mark-to-Market Activities

The table below summarizes the changes in commodity contract assets and liabilities in the nine months ended September 30, 2012 and 2011. The net change in these assets and liabilities, excluding "other activity" as described below, reflects $1.290 billion and $247 million in unrealized net losses in 2012 and 2011, respectively, arising from mark-to-market accounting for positions in the commodity contract portfolio. The portfolio consists primarily of economic hedges but also includes trading positions.

	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Commodity contract net asset at beginning of period	$ 3,190	$ 3,097
Settlements of positions (a)	(1,420)	(741)
Changes in fair value of positions in the portfolio (b)	130	494
Other activity (c)	(36)	12
Commodity contract net asset at end of period	$ 1,864	$ 2,862

(a) Represents reversals of previously recognized unrealized gains and losses upon settlement (offsets realized gains and losses recognized in the settlement period). Excludes changes in fair value in the month the position settled as well as amounts related to positions entered into and settled in the same month.

(b) Represents unrealized net gains recognized, reflecting net gains related to positions in the natural gas price hedging program (see discussion above under "Natural Gas Prices and Natural Gas Price Hedging Program"), partially offset by net losses related to other hedging positions. Excludes changes in fair value in the month the position settled as well as amounts related to positions entered into and settled in the same month.

(c) These amounts do not represent unrealized gains or losses. Includes initial values of positions involving the receipt or payment of cash or other consideration, generally related to options purchased/sold.

Maturity Table — The following table presents the net commodity contract asset arising from recognition of fair values at September 30, 2012, scheduled by the source of fair value and contractual settlement dates of the underlying positions.

	Maturity dates of unrealized commodity contract net asset at September 30, 2012				
Source of fair value	**Less than 1 year**	**1-3 years**	**4-5 years**	**Excess of 5 years**	**Total**
Prices actively quoted	$ (35)	$ (19)	$ —	$ —	$ (54)
Prices provided by other external sources	1,116	818	—	—	1,934
Prices based on models	14	(30)	—	—	(16)
Total	$ 1,095	$ 769	$ —	$ —	$ 1,864
Percentage of total fair value	59%	41%	—%	—%	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's North Hub that are deemed active markets extend through 2014 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 non-exchange-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 9 to Financial Statements for fair value disclosures and discussion of fair value measurements.

FINANCIAL CONDITION

Liquidity and Capital Resources

***Cash Flow** — Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011* — Cash provided by operating activities decreased $639 million to $98 million in 2012 driven by net changes in margin deposits totaling $598 million. The change in margin deposits largely relates to the natural gas hedging program; in 2012 more margin deposits were returned to counterparties due to settlement of maturing positions than were received from counterparties due to decreases in natural gas prices, while activity in 2011 reflected the opposite. The decrease in cash provided by operating activities also reflected $237 million in higher cash interest payments, partially offset by $152 million in higher net distributions (including income tax payments) received from Oncor Holdings.

Depreciation and amortization expense reported in the statement of cash flows exceeded the amount reported in the statement of income by $146 million and $194 million in the nine months ended September 30, 2012 and 2011, 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 arising from purchase accounting that is reported in various other income statement line items including operating revenues and fuel and purchased power costs and delivery fees.

Cash provided by financing activities totaled $1.463 billion in 2012 compared to cash used in financing activities totaling $1.122 billion in 2011. Activity in 2012 reflected the issuance of $2.0 billion of EFIH senior notes, the proceeds from which were used to repay $950 million in borrowings under the TCEH Revolving Credit Facility and fund a $680 million escrow account to repay EFH Corp. demand notes payable to TCEH by January 2013 (see Note 6 to Financial Statements). Activity in 2012 also included a $159 million payment to settle transition bond reimbursement agreements with Oncor (see Note 12 to Financial Statements). Activity in 2011 reflected the amendment and extension of the TCEH Senior Secured Facilities and an EFIH debt exchange transaction.

See Note 6 to Financial Statements for further detail of short-term borrowings and long-term debt.

Cash used in investing activities totaled $1.275 billion and $311 million in 2012 and 2011, respectively. Capital expenditures increased $152 million to $526 million in 2012 reflecting increased environmental-related spending. Nuclear fuel purchases increased $30 million to $155 million due to advance purchases necessary to fabricate fuel assemblies in time for the two nuclear unit refueling outages planned for 2014. Activity in 2012 also included a $680 million increase in restricted cash related to the issuance of EFIH senior notes discussed above. Activity in 2011 also included a $188 million reduction in restricted cash related to the TCEH Letter of Credit Facility facilitated by the amendment and extension of the TCEH Senior Secured Facilities.

Debt Financing Activity — Activities related to short-term borrowings and long-term debt during the nine months ended September 30, 2012 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	Repayments and Repurchases
TCEH (a)	$ 103	$ (26)
EFCH	—	(4)
EFIH	2,000	—
EFH Corp. (b)	26	(9)
Total long-term	2,129	(39)
Total short-term – TCEH (c)	—	(385)
Total	$ 2,129	$ (424)

(a) Borrowings represent $88 million of noncash principal increases of TCEH Toggle Notes issued in May 2012 in payment of accrued interest as discussed below under "Toggle Notes Interest Election" and sale/leaseback transactions for mining equipment entered into in 2012. Repayments represent $16 million of payments of principal at scheduled maturity dates and $10 million of payments of capital lease liabilities (see Note 6 to Financial Statements).

(b) Borrowings represent $26 million of noncash principal increases of EFH Corp. Toggle Notes issued in May 2012 in payment of accrued interest as discussed below under "Toggle Notes Interest Election."

(c) Short-term amount represents net repayments of borrowings under the TCEH Revolving Credit Facility.

See Note 6 to Financial Statements for further detail of long-term debt and other financing arrangements, including $104 million of debt due currently (within 12 months) at September 30, 2012.

We regularly evaluate potential opportunities to improve our balance sheet through transactions that extend debt maturities or reduce the amount of our debt or our cash interest expense. Future activities under this liability management program may include, among others, the purchase of our outstanding debt for cash in open market purchases or privately negotiated refinancing, extension and exchange transactions (including pursuant to a Rule 10b-5(1) plan) or via public or private exchange or tender offers.

In evaluating whether to undertake any liability management transaction, including any refinancing or extension, 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 or extension, 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 in the nine months ended September 30, 2012.

	Available Liquidity		
	September 30, 2012	December 31, 2011	Change
Cash and cash equivalents – EFH Corp. (parent entity)	$ 625	$ 660	$ (35)
Cash and cash equivalents – EFIH (a)	858	46	812
Cash and cash equivalents – TCEH	309	120	189
TCEH Revolving Credit Facility	1,769	1,384	385
TCEH Letter of Credit Facility	265	169	96
Total liquidity	$ 3,826	$ 2,379	$ 1,447

(a)Includes $680 million in cash held in escrow to settle the demand notes payable by EFH Corp. to TCEH (see Note 6 to Financial Statements).

Available liquidity increased $1.447 billion since December 31, 2011 reflecting proceeds from the issuance of $2.0 billion of EFIH senior notes (see Note 6 to Financial Statements), a portion of which was used to repay borrowings under the TCEH Revolving Credit Facility. The change in liquidity also reflected use of cash of $583 million for the nine months ended September 30, 2012 as capital expenditures, including nuclear fuel purchases, exceeded cash provided by operating activities. See discussion of cash flows above.

Secured Debt Capacity — At October 26, 2012, we believe that we (excluding the Oncor Ring-Fenced Entities) are permitted under our applicable debt agreements to issue additional senior secured debt (in each case, subject to certain exceptions and conditions set forth in their applicable debt documents) as follows:

- EFH Corp. and EFIH collectively are permitted to issue up to approximately $700 million of additional aggregate principal amount of debt secured by EFIH's equity interest in Oncor Holdings on a second-priority basis;
- TCEH is permitted to issue approximately $2.1 billion of additional aggregate principal amount of debt secured by substantially all of the assets of TCEH and certain of its subsidiaries (of which $750 million can be on a first-priority basis and the remainder on a second-priority basis), and
- TCEH is permitted to issue an unlimited amount of additional first-priority debt in order to refinance the first-priority debt outstanding under the TCEH Senior Secured Facilities.

These amounts are estimates based on our current interpretation of the covenants set forth in our debt agreements and do not take into account exceptions in the debt agreements that may allow for the incurrence of additional secured debt, including, but not limited to, acquisition debt, coverage ratio debt, refinancing debt, capital leases and hedging obligations. Moreover, such amounts could change from time to time as a result of, among other things, the termination of any debt agreement (or specific terms therein) or amendments to the debt agreements that result from negotiations with new or existing lenders. In addition, covenants included in agreements governing additional future debt may impose greater restrictions on our incurrence of secured debt. Consequently, the actual amount of senior secured debt that we are permitted to incur under our debt agreements could be materially different than the amounts provided above.

Pension and OPEB Plan Funding — See Note 11 to Financial Statements and "Pension Plan Actions" above.

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.

EFH Corp. made its May 2012 interest payment and expects to make its November 2012 interest payment on the EFH Corp. Toggle Notes by using the PIK feature of those notes. During the applicable interest periods, the interest rate on these notes is increased from 11.25% to 12.00%. As a result of the PIK election, EFH Corp. increased the aggregate principal amount of the notes by $26 million in May 2012 and is expected to issue an additional $28 million in November 2012. Also, as a result of EFIH's ownership of EFH Corp. Toggle Notes ($2.951 billion principal amount at September 30, 2012 that is eliminated in consolidation), EFH Corp. issued to EFIH an additional $167 million aggregate principal amount of the notes in May 2012 and is expected to issue to EFIH an additional $177 million in November 2012. The elections increased liquidity in May 2012 by an amount equal to $25 million (excluding $156 million related to notes held by EFIH) and are expected to further increase liquidity in November 2012 by an amount equal to a currently estimated $26 million (excluding $166 million related to notes held by EFIH), constituting the amounts of cash interest that otherwise would have been payable on the notes. See Note 6 to Financial Statements for further discussion of the EFH Corp. Toggle Notes.

Similarly, TCEH made its May 2012 interest payment and expects to make its November 2012 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%. As a result of the PIK election, TCEH increased the aggregate principal amount of the notes by $88 million in May 2012 and is expected to further increase the aggregate principal amount of the notes by $93 million in November 2012. The elections increased liquidity in May 2012 by an amount equal to $82 million and are expected to further increase liquidity in November 2012 by an amount equal to an estimated $87 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 posting 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 portion of the positions in the natural gas price hedging program not otherwise secured by a first-lien interest 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, at September 30, 2012, approximately 90% 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 posting requirements for those hedging transactions. Due to declines in forward natural gas prices, no amounts were outstanding under the CCP facility at September 30, 2012 or December 31, 2011. See Note 6 to Financial Statements for more information about the TCEH Senior Secured Facilities, which include the CCP facility.

Exchange cleared 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. Cash collateral received from counterparties is either used for working capital and other corporate purposes, including reducing short-term borrowings under credit facilities, or 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. At September 30, 2012, restricted cash collateral held totaled $17 million. See Note 14 to Financial Statements regarding restricted cash.

With the natural gas price hedging program, increases in natural gas prices generally result in increased cash collateral and letter of credit postings to counterparties. At September 30, 2012, approximately 95 million MMBtu of positions related to the natural gas price hedging program were not directly secured on an asset-lien basis and thus are subject to cash collateral posting requirements. The uncapped CCP facility supports the collateral posting requirements related to a portion of these positions. The positions supported by the CCP facility, under which there were no borrowings at September 30, 2012, mature by the end of 2012, when the CCP facility matures.

At September 30, 2012, TCEH received or posted cash and letters of credit for commodity hedging and trading activities as follows:

- $66 million in cash has been posted with counterparties for exchange cleared transactions (including initial margin), as compared to $50 million posted at December 31, 2011;
- $750 million in cash has been received from counterparties, net of $7 million in cash posted, for over-the-counter and other non-exchange cleared transactions, as compared to $1.055 billion received, net of $6 million in cash posted, at December 31, 2011;
- $270 million in letters of credit have been posted with counterparties, as compared to $363 million posted at December 31, 2011, and
- $33 million in letters of credit have been received from counterparties, as compared to $103 million received at December 31, 2011.

Income Tax Matters — EFH Corp. files a federal income tax return on behalf of its consolidated group, whose members include EFCH, TCEH and EFIH, as well as other wholly-owned subsidiaries, but does not include Oncor. Members of the consolidated group have joint and several liability to the US Internal Revenue Service (IRS) for income tax reported on the consolidated tax return. EFH Corp. and its consolidated group members are parties to a tax sharing agreement, the provisions of which are pursuant to the Treasury regulations governed by the IRS.

An excess loss account (ELA) and a deferred intercompany gain (DIG) are reflected in the tax basis of the EFCH stock held by EFH Corp. The ELA, totaling approximately $19 billion, was created in connection with the Merger. The DIG, totaling approximately $4 billion, was created as a result of a reorganization prior to the Merger. The ELA and/or DIG could be triggered as taxable income in certain limited situations, including an EFH Corp. disposition of EFCH stock. We have no plans to separate EFCH from EFH Corp. or otherwise enter into a transaction to trigger the ELA or DIG as taxable income. We continue to evaluate various tax strategies to potentially reduce or eliminate the ELA and DIG without tax consequences.

Income Tax Refunds/Payments — In the next twelve months, income tax payments related to the Texas margin tax are expected to total approximately $60 million, and no payments or refunds of federal income taxes are expected. Payments totaled $67 million in the nine months ended September 30, 2012.

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 the next twelve months (see Note 14 to Financial Statements).

Interest Rate Swap Transactions — See Note 6 to Financial Statements for discussion of TCEH's interest rate swaps.

Accounts Receivable Securitization Program — TCEH participates in EFH Corp.'s accounts receivable securitization program with financial institutions (the funding entities). In accordance with 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 $184 million and $104 million at September 30, 2012 and December 31, 2011, respectively. See Note 5 to Financial Statements.

Distributions of Earnings from Oncor Holdings — Oncor Holdings' distributions of earnings to us totaled $100 million and $64 million in the nine months ended September 30, 2012 and 2011, respectively. We expect to receive a distribution totaling approximately $47 million from Oncor Holdings on October 30, 2012. See Note 2 to Financial Statements for discussion of limitations on amounts Oncor can distribute to its members.

In 2009, the PUCT awarded certain CREZ construction projects to Oncor. See discussion above under "Significant Activities and Events — Oncor Matters with the PUCT." As a result of the increased capital expenditures for CREZ and the debt-to-equity ratio cap, our distributions from Oncor could be substantially reduced or temporarily discontinued during the CREZ construction period, which is expected to be largely completed by the end of 2013.

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. At September 30, 2012, we were in compliance with all such covenants.

Covenants and Restrictions under Financing Arrangements — 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 our liquidity and operations. In particular, the TCEH Senior Secured Facilities include a requirement to timely deliver to the lenders copies of audited annual financial statements that are not qualified as to the status of TCEH and its subsidiaries as a going concern.

Adjusted EBITDA (as used in the restricted payments covenant contained in the indenture governing the EFH Corp. Senior Secured Notes) in the twelve months ended September 30, 2012 totaled $5.258 billion for EFH Corp. See Exhibits 99(b), 99(c) and 99(d) for a reconciliation of net income (loss) to Adjusted EBITDA for EFH Corp., TCEH and EFIH, respectively, in the nine and twelve months ended September 30, 2012 and 2011.

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 Notes, the TCEH Senior Secured Second Lien Notes, the EFH Corp. Senior Notes, the EFH Corp. Senior Secured Notes and the EFIH Notes at September 30, 2012 and December 31, 2011. 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.

	September 30, 2012	December 31, 2011	Threshold Level at September 30, 2012
Maintenance Covenant:			
TCEH Senior Secured Facilities:			
Secured debt to Adjusted EBITDA ratio (a)	5.59 to 1.00	5.78 to 1.00	Must not exceed 8.00 to 1.00 (b)
Debt Incurrence Covenants:			
EFH Corp. Senior Secured Notes:			
EFH Corp. fixed charge coverage ratio	1.0 to 1.0	1.1 to 1.0	At least 2.0 to 1.0
TCEH fixed charge coverage ratio	1.2 to 1.0	1.3 to 1.0	At least 2.0 to 1.0
EFIH Notes:			
EFIH fixed charge coverage ratio (c)	(d)	(d)	At least 2.0 to 1.0
TCEH Senior Notes, Senior Secured Notes and Senior Secured Second Lien Notes:			
TCEH fixed charge coverage ratio	1.2 to 1.0	1.3 to 1.0	At least 2.0 to 1.0
TCEH Senior Secured Facilities:			
TCEH fixed charge coverage ratio	1.2 to 1.0	1.3 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	9.6 to 1.0	9.7 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)	1.4 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)	1.0 to 1.0	1.1 to 1.0	At least 2.0 to 1.0
EFH Corp. leverage ratio	9.6 to 1.0	9.7 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)	6.6 to 1.0	81.7 to 1.0	At least 2.0 to 1.0
General restrictions (EFH Corp. payments):			
EFIH fixed charge coverage ratio (c) (f)	(d)	(d)	At least 2.0 to 1.0
EFIH leverage ratio	6.3 to 1.0	5.3 to 1.0	Equal to or less than 6.0 to 1.0
TCEH Senior Notes, Senior Secured Notes and Senior Secured Second Lien Notes:			
TCEH fixed charge coverage ratio	1.2 to 1.0	1.3 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	8.2 to 1.0	8.7 to 1.0	Equal to or less than 6.5 to 1.0

(a) At September 30, 2012, includes actual Adjusted EBITDA for both Oak Grove units and the Sandow 5 unit and all outstanding debt under the Delayed Draw Term Loan. At December 31, 2011, includes pro forma Adjusted EBITDA for the new Oak Grove 2 generation unit as well as actual Adjusted EBITDA for Sandow 5 and Oak Grove 1 units and all outstanding debt under the Delayed Draw Term Loan.
(b) Calculation excludes secured debt that ranks junior to the TCEH Senior Secured Facilities and up to $1.5 billion ($906 million excluded at September 30, 2012) principal amount of TCEH senior secured first lien notes whose proceeds are used to prepay term loans or deposit letter of credit loans under 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 indentures governing 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.

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, at September 30, 2012, counterparties to those contracts could have required TCEH to post up to an aggregate of $30 million in additional collateral. This amount largely represents the below market terms of these contracts at September 30, 2012; 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. At September 30, 2012, TCEH has posted collateral support in the form of letters of credit to the applicable utilities in an aggregate amount equal to $27 million, with $11 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, at September 30, 2012, TCEH posted letters of credit in the amount of $71 million, which are subject to adjustments.

The RRC has rules in place to assure that parties can meet their mining reclamation obligations, including through self-bonding when appropriate. If Luminant Generation Company LLC (a subsidiary of TCEH) does not continue to meet the self-bonding requirements as applied by the RRC, TCEH may be required to post cash, letter of credit or other tangible assets as collateral support in an amount currently estimated to be approximately $850 million to $1.1 billion. The actual amount (if required) could vary depending upon numerous factors, including the amount of Luminant Generation Company LLC's self-bond accepted by the RRC 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 $110 million at September 30, 2012 (which is subject to daily adjustments based on settlement activity with ERCOT).

Oncor and Texas Holdings agreed to the terms of a stipulation with major interested parties to resolve all outstanding issues in the PUCT review related to the Merger. As part of this stipulation, TCEH would be required to post a letter of credit in an amount equal to $170 million to secure its payment obligations to Oncor in the event, which has not occurred, two or more rating agencies downgrade Oncor's credit ratings below investment grade.

Other arrangements of EFH Corp. and its subsidiaries, including Oncor's credit facility, the accounts receivable securitization program (see Note 5 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 would have adequate liquidity and/or financing capacity to satisfy such requirements.

Material Cross Default/Acceleration Provisions — Certain of our financing arrangements contain provisions that could 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" or "cross acceleration" 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 ($20.507 billion at September 30, 2012) under such facilities.

The indentures governing the TCEH Senior Notes, TCEH Senior Secured 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, TCEH Senior Secured Notes and TCEH Senior Secured Second Lien Notes.

Under the terms of a TCEH rail car lease, which had $41 million in remaining lease payments at September 30, 2012 and terminates in 2017, if TCEH failed to perform under agreements causing its indebtedness in an 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 $45 million in remaining lease payments at September 30, 2012 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 or of any debt that EFIH guarantees 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 these cross default provisions were triggered, the program could be terminated.

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.

Guarantees — See Note 7 to Financial Statements for details of guarantees.

OFF–BALANCE SHEET ARRANGEMENTS

See Notes 3 and 7 to Financial Statements regarding VIEs and guarantees, respectively.

COMMITMENTS AND CONTINGENCIES

See Note 7 to Financial Statements for discussion of commitments and contingencies.

CHANGES IN ACCOUNTING STANDARDS

There have been no recently issued accounting standards effective after September 30, 2012 that are expected to materially impact our financial statements.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

All dollar amounts in the tables in the following discussion and analysis are stated in millions of US dollars unless otherwise indicated.

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.

Natural Gas Price 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.

	Nine Months Ended September 30, 2012	Year Ended December 31, 2011
Month-end average Trading VaR:	$ 9	$ 4
Month-end high Trading VaR:	$ 12	$ 8
Month-end low Trading VaR:	$ 4	$ 1

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.

	Nine Months Ended September 30, 2012	Year Ended December 31, 2011
Month-end average MtM VaR:	$ 137	$ 195
Month-end high MtM VaR:	$ 206	$ 268
Month-end low MtM VaR:	$ 96	$ 121

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.

	Nine Months Ended September 30, 2012	Year Ended December 31, 2011
Month-end average EaR:	$ 107	$ 170
Month-end high EaR:	$ 161	$ 228
Month-end low EaR:	$ 77	$ 121

The increase in the Trading VaR risk measure above reflected higher market volatility and an increase in trading positions. The decreases in the MtM VaR and EaR risk measures above reflected a reduction of positions in the natural gas price hedging program due to maturities and lower forward natural gas prices.

Interest Rate Risk

At September 30, 2012, the potential reduction of annual pretax earnings over the next twelve months due to a one percentage-point (100 basis points) increase in floating interest rates on long-term debt totaled $9 million, taking into account the interest rate swaps discussed in Note 6 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 authorize specific risk mitigation tools including, but not limited to, use of standardized master 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 setoff. 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 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 $1.647 billion at September 30, 2012. The components of this exposure are discussed in more detail below.

Assets subject to credit risk at September 30, 2012 include $594 million in retail trade accounts receivable before taking into account cash deposits held as collateral for these receivables totaling $65 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. At September 30, 2012, the exposure to credit risk from these counterparties totaled $1.053 billion taking into account the netting provisions of the master agreements described above but before taking into account $777 million in credit collateral (cash, letters of credit and other credit support). The net exposure (after credit collateral) of $276 million decreased $305 million in the nine months ended September 30, 2012, driven by maturities of positions in the natural gas price hedging program, increased collateral received due to credit rating downgrades of financial institution counterparties and contractual credit enhancements.

Of this $276 million 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 at September 30, 2012 arising from wholesale trade receivables, commodity contracts and hedging and trading activities. This credit exposure represents wholesale trade accounts receivable and net asset positions in 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. Credit collateral includes cash and letters of credit, but excludes other credit enhancements such as liens on assets. See Note 10 to Financial Statements for further discussion of portions of this exposure related to activities marked-to-market in the financial statements.

				Gross Exposure by Maturity			
	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	2 years or less	Between 2-5 years	Greater than 5 years	Total
Investment grade	$ 1,046	$ 775	$ 271	$ 964	$ 82	$ —	$ 1,046
Noninvestment grade	7	2	5	7	—	—	7
Totals	$ 1,053	$ 777	$ 276	$ 971	$ 82	$ —	$ 1,053
Investment grade	99.3%		98.2%				
Noninvestment grade	0.7%		1.8%				

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 impact on future results of operations, liquidity and financial condition.

Significant (10% or greater) concentration of credit exposure exists with three counterparties, which represented 20%, 12% and 11% of the $276 million net exposure. We view exposure to these counterparties to be within an acceptable level of risk tolerance due to the counterparties' credit ratings, each of which is rated as investment grade, and the importance of our business relationship with the counterparties.

With respect to credit risk related to the natural gas price hedging program, all of the transaction volumes are with counterparties that have an investment grade credit rating. 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 financial or operational 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," "expected," "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" in this report, our quarterly report on Form 10-Q for the quarterly period ended June 30, 2012 and our 2011 Form 10-K and the discussion under Item 2, "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 US Federal Energy Regulatory Commission, the NERC, the TRE, the PUCT, the RRC, the NRC, the EPA, the TCEQ, the US Mine Safety and Health Administration and the US Commodity Futures Trading Commission, 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 generation facilities;
  - operations of fossil-fueled generation 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 the CSAPR, MATS and 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, including the price of natural gas;
- 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, including the price of natural gas, market heat rates and interest rates;
- weather conditions, including drought and limitations on access to water, and other natural phenomena, and acts of sabotage, wars or terrorist or cybersecurity threats or activities;
- unanticipated population growth or decline, or changes in market supply or 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 extend the maturities of our debt instruments and the terms and conditions of any such extensions;

- access to capital, the cost of such capital, and the results of financing and refinancing efforts, including availability of funds in capital markets;
- activity in the credit default swap market related to our debt instruments;
- 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 or otherwise address our debt maturities;
- any defaults under certain of our financing arrangements that could trigger cross default or cross acceleration provisions under other financing arrangements;
- our ability to make intercompany loans or otherwise transfer funds among different entities in our corporate structure;
- 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;
- adverse claims by our creditors or holders of our debt securities;
- our ability to effectively execute our operational strategy, and
- our ability to implement cost reduction initiatives.

Any forward-looking statement speaks only at 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 4. CONTROLS AND PROCEDURES

An evaluation was performed under the supervision and with the participation of our management, including the principal executive officer and principal financial officer, of the effectiveness of the design and operation of the disclosure controls and procedures in effect at the end of the current period included in this quarterly report. Based on the evaluation performed, our management, including the principal executive officer and principal financial officer, concluded that the disclosure controls and procedures were effective. During the most recent fiscal quarter covered by this quarterly report, there has been no change in our internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

Reference is made to the discussion in Note 7 to Financial Statements regarding legal proceedings.

ITEM 1A. RISK FACTORS

In addition to the other information set forth in this report, you should carefully consider the risk factors discussed in Part I, "Item 1A. Risk Factors" in our 2011 Form 10-K and Part II, "Item 1A. Risk Factors" in our quarterly report on Form 10-Q for the quarterly period ended June 30, 2012. The risks described in such reports are not the only risks facing our Company.

Item 4. MINE SAFETY DISCLOSURES

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. Disclosure of MSHA citations, orders and proposed assessments are provided in Exhibit 95(a) to this quarterly report on Form 10-Q.

Item 5. OTHER INFORMATION

On October 26, 2012, Lyndon L. Olson, Jr. notified EFH Corp. that he declined to stand for reelection to the board of directors of EFH Corp.

On October 26, 2012, pursuant to a unanimous written consent of the EFH Corp. shareholders executed in lieu of an annual meeting of shareholders, the following directors were reelected to the board of directors of EFH Corp. to serve until the next annual meeting of the shareholders or until their respective successors are duly elected and qualify:

Arcilia C. Acosta
David Bonderman
Donald L. Evans
Thomas D. Ferguson
Brandon A. Freiman
Scott Lebovitz
Jeffrey Liaw
Marc S. Lipschultz
Michael MacDougall
Kenneth Pontarelli
William K. Reilly
Jonathan D. Smidt
John F. Young
Kneeland Youngblood

Item 6. Exhibits

(a) Exhibits filed or furnished as part of Part II are:

Exhibits	Previously Filed With File Number*	As Exhibit		
(3(i))	**Articles of Incorporation**			
3(a)	1-12833 Form 8-K (filed October 11, 2007)	3.1	-	Restated Certificate of Formation of Energy Future Holdings Corp.
(3(ii))	**By-laws**			
3(b)	1-12833 Form 10-Q (Quarter ended June 30, 2012) (filed July 31, 2012)	3(b)	-	Amended and Restated Bylaws of Energy Future Holdings Corp.
(4)	**Instruments Defining the Rights of Security Holders, Including Indentures**			
	Energy Future Intermediate Holding Company LLC			
4(a)	1-12833 Form 8-K (filed August 17, 2012)	4.1	-	Indenture, dated August 14, 2012, among Energy Future Intermediate Holding Company LLC, EFIH Finance Inc. and the Bank of New York Mellon Trust Company, N.A., as trustee, relating to 6.875% Senior Secured Notes due 2017.
4(b)	1-12833 Form 8-K (filed August 17, 2012)	4.2	-	Fourth Supplemental Indenture, dated August 14, 2012, among Energy Future Intermediate Holding Company LLC, EFIH Finance Inc. and the Bank of New York Mellon Trust Company, N.A., as trustee, relating to 11.75% Senior Secured Second Lien Notes due 2022.
4(c)	1-12833 Form 8-K (filed August 17, 2012)	4.3	-	Registration Rights Agreement, dated August 14, 2012, among Energy Future Intermediate Holding Company LLC, EFIH Finance Inc. and the initial purchasers named therein.
4(d)	1-12833 Form 8-K (filed October 24, 2012)	4.1	-	First Supplemental Indenture, dated October 23, 2012, among Energy Future Intermediate Holding Company LLC, EFIH Finance Inc., and the Bank of New York Mellon Trust Company, N.A., as trustee, relating to 6.875% Senior Secured Notes due 2017.
4(e)	1-12833 Form 8-K (filed October 24, 2012)	4.2	-	Registration Rights Agreement, dated October 23, 2012, among Energy Future Intermediate Holding Company LLC, EFIH Finance Inc. and the initial purchasers named therein.
(10)	**Material Contracts**			
10(a)			-	Third Amendment to the EFH Salary Deferral Program, effective September 20, 2012.
10(b)			-	Federal and State Income Tax Allocation Agreement, effective January 1, 2010, by and among members of the Energy Future Holdings Corp. consolidated group.
(31)	**Rule 13a - 14(a)/15d - 14(a) Certifications**			
31(a)			-	Certification of John Young, principal executive officer of Energy Future Holdings Corp., pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(b)			-	Certification of Paul M. Keglevic, principal financial officer of Energy Future Holdings Corp., pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

Exhibits	Previously Filed With File Number*	As Exhibit		
(32)	**Section 1350 Certifications**			
32(a)			-	Certification of John Young, principal executive officer of Energy Future Holdings Corp., pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32(b)			-	Certification of Paul M. Keglevic, principal financial officer of Energy Future Holdings Corp., pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(95)	**Mine Safety Disclosures**			
95(a)			-	Mine Safety Disclosures.
(99)	**Additional Exhibits**			
99(a)			-	Condensed Statement of Consolidated Income – Twelve Months Ended September 30, 2012.
99(b)			-	Energy Future Holdings Corp. Consolidated Adjusted EBITDA reconciliation for the nine and twelve months ended September 30, 2012 and 2011.
99(c)			-	Texas Competitive Electric Holdings Company LLC Consolidated Adjusted EBITDA reconciliation for the nine and twelve months ended September 30, 2012 and 2011.
99(d)			-	Energy Future Intermediate Holding Company LLC Consolidated Adjusted EBITDA reconciliation for the nine and twelve months ended September 30, 2012 and 2011.
	XBRL Data Files			
101.INS			-	XBRL Instance Document
101.SCH			-	XBRL Taxonomy Extension Schema Document
101.CAL			-	XBRL Taxonomy Extension Calculation Document
101.DEF			-	XBRL Taxonomy Extension Definition Document
101.LAB			-	XBRL Taxonomy Extension Labels Document
101.PRE			-	XBRL Taxonomy Extension Presentation Document

* Incorporated herein by reference

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

Energy Future Holdings Corp.

By:	/s/ STAN SZLAUDERBACH
Name:	Stan Szlauderbach
Title:	Senior Vice President and Controller (Principal Accounting Officer)

Date: October 29, 2012

Exhibit 10(a)

Amendment No.3
to the
EFH Salary Deferral Program

This Amendment No.3 to the EFH Salary Deferral Program ("Amendment") is made effective as of the 20 th day of September, 2012, except as otherwise provided herein.

WHEREAS, Energy Future Holdings Corp. (the "Company") sponsors and maintains the EFH Salary Deferral Program, as amended and restated as of January 1,2010, and as previously amended effective as of January 1,2011 (the "Plan"); and

WHEREAS, the Company wishes to amend the Plan to provide that as of August 15, 2012, the Accounts of all current Participants shall be one hundred percent (100%) vested;

WHEREAS, the Company wishes to amend the Plan to: (i) expand the provisions of Section 8.1 (d) of the Plan to provide for the offset of the benefit of particular Participants under the Plan as of September 20, 2012, by the amount of the lump sum benefit increase provided to such Participants under the EFH Retirement Plan as of such date; (ii) freeze the Plan effective for the 2013 Plan Year to prohibit further Plan deferrals thereafter; (iii) fully vest all Accounts effective as of August 15,2012; and (iv) permit the Company after January 1,2013 to "cash out" Participants to the extent permitted by section 409A of the Internal Revenue Code of 1986, as amended;

NOW, THEREFORE, the Plan is hereby amended as follows:

1. Section 8.1 (d) of the Plan is hereby amended by replacing such section in its entirety with the following language:

    (d) Offset of Benefit Provided Under Qualified Retirement Plan. Notwithstanding any other provision of this Plan, the amount of a Participant's benefit as otherwise determined under this Plan: (i) as of September 30, 2009 (or, if less, the balance as of December 31, 2009); and (ii) as of September 20, 2012, shall each be offset by the applicable lump sum benefit (if any) provided as of the applicable date to such Participant under Section 7.5 of the EFH Retirement Plan and specified in Part (II) of Appendix F thereof. Each such offset shall be applied first to the portion of the Participant's Account that is subject to the Retirement Option form of payment as described in Section 8.2(b), and second, to the portion of a Participant's Account subject to the Seven-Year Option (beginning with the portion of the account that was most recently deferred and that, therefore, would otherwise be subject to distribution from this Plan at the latest time). Each such offset shall finally be applied to offset the amount credited to the Participant's EFH Stock Fund Account, but only to the extent the amount subject to reduction is no longer deemed invested in Company Stock.

2. The Plan is hereby amended by adding the following language as a new Section 19, which shall be and read in full as follows.

    19. Freezing of Plan Effective January 1, 2013. Effective as of January 1,2013, the Plan shall be frozen and, except with respect to deferrals of Bonuses previously elected for Bonuses to be paid in 2013 for services performed during 2012, no further contributions shall be permitted under the Plan thereafter. Thus, no Deferrals shall be effective under the Plan for Salary, Bonus (except as provided for above), DICP Amounts or any other compensation payable with respect to any period beginning on or after January 1,2013 and any such Deferral requests by any Participant shall be null and void.

3. The Plan is hereby amended by adding the following language as a new Section 5.4, which shall be and read in full as follows.

5.4 Full Vesting as of August 15.2012. Notwithstanding anything else provided in this Plan, including in Sections 5.2 and 5.3, as of August 15,2012 all Matching Awards of any current Participant in the Plan shall at all times thereafter be one hundred percent (100%) vested, such that as of August 15,2012, the entire Account of each current Participant in the Plan shall be one hundred percent (100%) vested.

4. The Plan is hereby amended by adding the following language as a new Section 20, which shall be and read in full as follows.

Notwithstanding any other provision of this Plan, on and after January 1,2013, the Company may make a mandatory lump sum distribution of any Participant's entire Account under the Plan if such Participant's aggregate amount deferred under the Plan (and under all other deferral arrangements which would be aggregated with the Plan for purposes of Code Section 409A) does not exceed the applicable dollar amount under Code Section 402(g)(l)(B) as of the date of such distribution. Any such cash out of a Participant's Account shall be made in a manner consistent with the provisions of Treasury Regulation Section 1.409A-3(j)(4)(v).

5. Except as otherwise defined herein, the capitalized terms used herein shall have the meanings given to them in the Plan.

6. Except as amended hereby, the Plan shall remain in full force and effect.

Executed effective as of the 20th day of September, 2012.

ENERGY FUTURE HOLDINGS CORP.

By: /s/ Carrie L. Kirby
Title: SVP, Human Resources

Exhibit 10(b)

FEDERAL AND STATE INCOME TAX ALLOCATION AGREEMENT AMONG THE MEMBERS OF THE ENERGY FUTURE HOLDINGS CORP. CONSOLIDATED GROUP

THIS AGREEMENT ("Agreement") is executed on May 15, 2012 but effective as of January 1, 2010, by and among Energy Future Holdings Corp., a Texas corporation, and the undersigned entities.

RECITALS:

WHEREAS, Energy Future Holdings Corp. is the common parent of an affiliated group of corporations within the meaning of section 1504(a) of the Internal Revenue Code of 1986, as amended from time to time (the "Code"), and the undersigned are members of such affiliated group or entities that are, for federal income tax purposes, disregarded as separate from a member of such affiliated group (the "Group");

WHEREAS, it is the desire and intention of the parties to provide for the method of allocation of the consolidated United States income tax liability among them and that such allocation fairly preserve the economic rights and privileges that would have accrued to each of them from the filing of separate returns, including the benefit of losses and credits utilized in the consolidated return; and

WHEREAS, it is the desire and intention of the parties to provide for the method of allocation of the consolidated or combined state income or Texas franchise (or margin) tax liability among them and that such allocation fairly preserve the economic rights and privileges that would have accrued to each of them from the filing of separate returns, including the benefit of losses and credits utilized in the consolidated return;

NOW, THEREFORE, for and in consideration of the mutual covenants hereinafter contained, the parties hereto agree as follows:

Article 1 - Method of Allocation

1.1 Generally. If Energy Future Holdings Corp., or its successor as the common parent within the meaning of section 1504(a) of the Code (the "Common Parent"), files a consolidated United States Corporation Income Tax Return, the total consolidated United States income tax liability (which shall include any alternative minimum tax liability) after all credits allowed in arriving at such tax liability (the "Consolidated Tax Liability") shall be allocated to each member of the Group in accordance with paragraph 1.2. The amount of liability so allocated to any member shall be an obligation of each such member due and owing in accordance with Article 3. To the extent it is determined that a tax benefit is properly allocable to any member in accordance with the allocation prescribed in paragraph 1.2, the amount of benefit so allocated shall be an obligation due and owing to each such member in accordance with Article 3.

1.2 Allocation of Consolidated Tax Liability. The members of the Group shall determine and allocate the Consolidated Tax Liability among themselves in the following manner:

Step 1: Each member shall be allocated a portion of the Consolidated Tax Liability equal to the Consolidated Tax Liability multiplied by a fraction, the numerator of which is the taxable income of such member and the denominator of which is the sum of the taxable incomes of all the members. A member's taxable income shall be the separate taxable income of the member determined under Treasury regulation section 1.1502-12, adjusted for the following items pursuant to Treasury regulation section 1.1552-1(a)(1)(ii):

(a) the portion of the consolidated net operating loss deduction, the consolidated charitable contributions deduction, the consolidated dividends received deduction, the consolidated section 247 deduction, the consolidated section 582(c) net loss, and the consolidated section 922 deduction attributable to such member;

(b) such member's net capital loss and section 1231 net loss, reduced by the portion of the consolidated net capital loss attributable to such member; and

(c) the portion of any consolidated net capital loss carryover attributable to such member that is absorbed in the taxable year.

The additional amount allocated to a member under this Step 1 shall be further allocated under principles similar to those in this Step 1 to any entity that is, for federal income tax purposes, disregarded as an entity separate from such member.

Step 2: Pursuant to Treasury regulation section 1.1502-33(d)(3), an additional amount shall be allocated to each member equal to 100% of the excess, if any, of (i) the "separate return tax liability" of such member for the taxable year, over (ii) the amount allocated in Step 1 of this paragraph 1.2. As provided more fully in Treasury regulation section 1.1552-1(a)(2)(ii), a member's separate return tax liability shall equal the member's tax liability computed as if it had filed a separate return for the year except that:

(a) gain or loss on intercompany transactions shall be taken into account as provided in Treasury regulation section 1.1502-13 as if a consolidated return had been filed for the year;

(b) gain or loss relating to inventory adjustments shall be taken into account as provided in Treasury regulation section 1.1502-18 as if a consolidated return had been filed for the year;

(c) transactions with respect to stock, bonds or other obligations of members shall be reflected as provided in Treasury regulation section 1.1502-13(f) and (g) as if a consolidated return had been filed for the year;

(d) excess losses shall be included in income as provided in Treasury regulation section 1.1502-19 as if a consolidated return had been filed for the year;

(e) in the computation of the deduction under section 167, property shall not lose its character as new property as a result of a transfer from one member to another member during the year;

(f) a dividend distributed by one member to another member shall not be taken into account in computing the deductions under sections 243(a)(1), 244(a), 245, or 247 (relating to deductions with respect to dividends received and dividends paid);

(g) basis shall be determined under Treasury regulation sections 1.1502-31 and 1.1502-32, and earnings and profits shall be determined under Treasury regulation section 1.1502-33 as if a consolidated return had been filed for the year; and

(h) subparagraph (2) of Treasury regulation section 1.1502-3(f) shall apply as if a consolidated return had been filed for the year.

The additional amount allocated to a member under this Step 2 shall be further allocated under principles similar to those in this Step 2 to any entity that is, for federal income tax purposes, disregarded as an entity separate from such member.

Step 3: The additional amount allocated to members or disregarded entities pursuant to Step 2 of this paragraph 1.2 shall be paid by such members, or disregarded entities that are parties hereto, to the Common Parent on behalf of those other members that had items of income, deductions, net operating losses, or tax credits to which such total is attributable pursuant to a consistent method that reasonably reflects such items of income, deductions, net operating losses, or tax credits, such consistency and reasonableness to be determined by the Chief Financial Officer of the Common Parent (the "Chief Financial Officer"). Any income, deductions, net operating losses, or tax credits of any such other member that are attributable to any disregarded entity directly or indirectly owned by such other members shall be further allocated by such other member to such disregarded entity. In general, the amounts paid to members, or disregarded entities, will be deemed to be consistent and reasonable if paid on a basis equal to the applicable federal corporate income tax rate of net operating losses used and 100% of tax credits used unless such an allocation would be inequitable.

The method of allocation described in this paragraph 1.2 is intended to be consistent with Treasury regulation sections 1.1552-1(a)(1) and 1.1502-33(d)(3).

1.3 Quarterly Estimated Tax Payments. For purposes of determining each member's share of any quarterly estimated tax payments due with respect to the Consolidated Tax Liability, or if applicable, material state income or franchise tax liability, such quarterly Consolidated Tax Liability or state income or franchise tax liability shall be allocated among the members of the Group in accordance with paragraph 1.2 above. Any payments made by a member with respect to such quarterly estimated tax payments shall be a credit against any amounts due from such member with respect to the annual Consolidated Tax Liability. If the aggregate amount of quarterly payments made pursuant to this paragraph 1.3 for a taxable period exceeds the amount due and owing from such member with respect to the entire taxable period, such excess shall be refunded to such member pursuant to Article 3.

1.4 Carrybacks and Carryforwards. If part or all of a loss or credit is allocated to a member of the Group pursuant to Treasury regulation section 1.1502-21(b) or Treasury regulation section 1.1502-79, or a similar provision, and is carried back or carried forward to a year in which such member filed a separate return or a consolidated return with a different affiliated group, any refund or reduction in the Consolidated Tax Liability arising from such carryback or carryforward shall be for the benefit of such member. If a member of the Group has a loss or credit in a separate return year that may be carried back to a year in which the Group filed a consolidated United States Corporation Income Tax Return, any refund or reduction in the Consolidated Tax Liability arising from such carryback shall be for the benefit of the Group and shall be retained by the Common Parent. If a member of the Group has a loss or credit in a separate return year that may be carried forward to a year in which the Group filed a consolidated United States Corporation Income Tax Return, any refund or reduction in the Consolidated Tax Liability arising from such carryforward shall be allocated in accordance with paragraph 1.2. Notwithstanding the above, the Common Parent shall determine whether an election shall be made not to carry back part or all of a consolidated net operating loss for any tax year in accordance with Regulation Section 1.1502-21(b)(3).

1.5 Consolidated Alternative Minimum Tax. The amount of consolidated alternative minimum tax ("AMT") allocated to a member is determined by multiplying the consolidated AMT by a fraction, the numerator of which is the separate adjusted AMT (as defined in proposed Treasury regulation section 1.1502-55(h)(6)(iv)) of the member for the year, and the denominator of which is the sum of all members' separate adjusted AMT for the year. The amount of allowable consolidated minimum tax credit ("MTC") in a taxable year must be allocated among the members in accordance with the principles of proposed Treasury regulation section 1.1502-55(h)(6)(iv) and (7).

1.6 Earnings and Profits. For purposes of computing the earnings and profits of members of the Group, the Consolidated Tax Liability of the Group shall be calculated and allocated in accordance with Code section 1552(a)(1). Any difference between the amount of the Consolidated Tax Liability allocated to a member under this Agreement and the amount of Consolidated Tax Liability allocated to a member under Code section 1552(a)(1) shall be treated as a distribution or contribution, or both, as appropriate. The Group has not made any election to make extended tax allocations under Treasury regulation section 1.1502-33(d).

1.7 Allocation of State Taxes.

(a) With the exception of state income and franchise taxes calculated on the basis of consolidated or combined taxable income, including the Texas margin tax, each member has filed state and local tax returns on a separate company or separate group basis, such that each member of the Group has paid tax solely on their respective tax items and not on the basis of any consolidated or combined reporting of their respective tax items. Accordingly, this agreement makes no provision for any allocation of separately computed state and local income or franchise tax liabilities.

(b) Except for Texas margin tax (which is provided for in paragraph 1.7(c)), the amount of state income tax liability for the Group that is computed on a combined or consolidated basis shall be allocated to each member, and among any entity disregarded as an entity separate from such member, of the Group in accordance with similar principles to those set forth in paragraph 1.2.

(c)

(i) The amount of combined Texas margin tax ("TMT") for a taxable year is allocated among the members of the Group and other parties to this Agreement which are included in such combined group by multiplying (i) such combined TMT by (ii) a fraction, the numerator of which is the amount of TMT that each such entity would have paid if it had computed its TMT liability for the taxable year on a separate entity basis rather than as a part of the combined group (the "separate entity TMT"), and the denominator of which is the sum of all entities' separate entity TMT for the year. Each entity's separate entity TMT shall be based on the combined group's deduction election pursuant to section 171.101(a)(1)(B)(ii) of the Texas Tax Code.

(ii) If an entity's separate entity TMT exceeds the amount allocated to such entity under paragraph 1.7(c)(i) above, then such entity shall be allocated an additional amount to reflect such excess. The additional amount allocated under this paragraph 1.7(c)(ii) shall be paid by such entity to the Common Parent on behalf of those other entities whose deductions, credits or other tax attributes resulted in such excess. Such allocation shall be made pursuant to a consistent method that reasonably reflects such deductions, credits or other tax attributes, such consistency and reasonableness to be determined by the Chief Financial Officer.

Article 2 - Authority to Administer Agreement

2 To effectuate the stated intent of the parties hereto as contained in this Agreement, the Chief Financial Officer shall be authorized to:

(a) determine the Consolidated Tax Liability and any state tax liability under paragraph 1.7 of the Group for each taxable period for which the Common Parent files a consolidated United States Corporation Income Tax Return, or similar combined or consolidated state tax return, by making the necessary elections and selecting the tax accounting methods that provide the maximum tax benefit for the Group;

(b) determine and allocate to each member of the Group the appropriate liability or refund, if any, of the Consolidated Tax Liability in accordance with paragraph 1.2 and any state tax liability or refund, if any, in accordance with paragraph 1.7;

(c) prescribe any tax elections or tax provisions that shall apply to each member of the Group;

(d) prescribe the computer software, methods and procedures each member shall use to maintain such member's tax records and to prepare its tax returns; and

(e) do all other things necessary and proper to effectuate the stated intent of the parties and the purposes of this Agreement.

Article 3 - Settlement of Allocations

3 The rights and obligations between and among the various members of the Group accruing under the provisions of this Agreement shall arise and be settled as follows:

(a) Each member, or disregarded entity which is a party hereto, shall pay to the Common Parent its allocated share of Consolidated Tax Liability under Step 1 of paragraph 1.2 within 30 days after the Common Parent files a consolidated United States Corporation Income Tax Return for any taxable period (or with interest at such later date as agreed to by the Common Parent and the applicable member or disregarded entity).

(b) Each member, or disregarded entity which is a party hereto, benefitting from another member's net operating losses, tax credits, or other tax attributes shall pay to the Common Parent its additional allocation determined under Step 2 of paragraph 1.2 within 30 days after the Common Parent files a consolidated United States Corporation Income Tax Return for any taxable period (or with interest at such later date as agreed to by the Common Parent and the applicable member or disregarded entity).

(c) The Common Parent shall pay to each member, or disregarded entity which is a party hereto, with a net operating loss, tax credits, or other tax attributes during the taxable year, its allocable share of the total of the additional amounts due from other members as determined under Step 3 of paragraph 1.2 within 30 days after the Common Parent files a consolidated United States Corporation Income Tax Return for any taxable period (or with interest at such later date as agreed to by the Common Parent and the applicable member or disregarded entity).

(d) Each member or disregarded entity which is a party hereto, as the case may be, shall pay to the Common Parent its allocated share of any state income or TMT liability under paragraph 1.7 within 30 days after the Common Parent files a consolidated or combined state income tax or TMT return or report for any taxable period (or with interest at such later date as agreed to by the Common Parent and the applicable member or disregarded entity). The Common Parent shall pay to each member, or disregarded entity which is a party hereto, with a net operating loss, tax credits, deductions or other tax attributes during the taxable year, its allocable share of the total of the additional amounts due from other members as determined under paragraph 1.7 within 30 days after the Common Parent files a consolidated or combined state income tax or TMT return or report for any taxable period (or with interest at such later date as agreed to by the Common Parent and the applicable member or disregarded entity).

(e) All payments pursuant to this Article 3 shall be adjusted to reflect any quarterly estimated tax payments made pursuant to paragraph 1.3.

Article 4 - Adjustments

4.1 Tax. In the event the Consolidated Tax Liability is subsequently changed or otherwise adjusted by reason of an amended return, a claim for refund, a final "determination" as that term is defined in section 1313(a) of the Code, or any of the events specified in section 6213(b) or (d) of the Code, or otherwise, the Chief Financial Officer shall adjust the allocations accordingly. The amounts of any such adjustment shall become due and owing in accordance with Article 3 on the 30 th day following the date giving rise to the recomputation (or with interest at such later date as agreed to by the Common Parent and the applicable member or disregarded entity). In the case of any refund, the Common Parent shall pay each member its share of such refund, determined in the same manner as in paragraph 1.2, within 30 days after receiving such refund (or with interest at such later date as agreed to by the Common Parent and the applicable member or disregarded entity), and in the case of an increase in tax liability, each member or disregarded entity, as the case may be, shall pay the Common Parent its allocable share of such increased tax liability within 30 days after receiving notice of such liability from the Common Parent (or with interest at such later date as agreed to by the Common Parent and the applicable member or disregarded entity).

4.2 Interest. If any interest is to be paid or received as a result of a consolidated tax deficiency or refund, such interest will be allocated among the members as follows:

(a) any member having an overpayment of tax shall be credited with interest on such overpayment calculated in accordance with section 6611; and

(b) any member having an underpayment of tax shall be allocated a portion of the total interest due equal to the amount of interest on such underpayment calculated in accordance with section 6601.

4.3 Penalties. Any penalty shall be allocated (i) if such penalty is associated with or attributable to the income or any act or omission of a particular member or members (or their disregarded subsidiaries), equitably to such member or among such members (or disregarded entities), or (ii) in all other cases, upon such basis as the Chief Financial Officer deems just and proper in view of all applicable circumstances.

4.4 State Tax Adjustments. In the event that any state income tax or TMT liability is subsequently changed or otherwise adjusted by reason of an amended return or any audit, litigation or similar proceeding, or otherwise, such change or adjustment, and any interest or penalties related thereto, shall be allocated under principles similar to paragraphs 4.1, 4.2 and 4.3.

Article 5 - Cooperation; Records; Contests

5.1 Cooperation. Each member of the Group and any disregarded entity shall cooperate with each other and with each other's agents, including accounting firms and legal counsel, in connection with tax matters relating to the parties and their affiliates including (a) preparation and filing of tax returns, (b) determining the liability for and amount of any taxes due (including estimated taxes) or the right to and amount of any refund of taxes, (c) examinations of tax returns, and (d) any administrative or judicial proceeding in respect of taxes assessed or proposed to be assessed. Such cooperation shall include making all information and documents in their possession available to such other parties as provided in paragraph 5.2. Each member and disregarded entity shall also make available, as reasonably requested and available, personnel (including officers, directors, employees and agents of the parties or their respective affiliates) responsible for preparing, maintaining, and interpreting information and documents relevant to taxes, and personnel reasonably required as witnesses or for purposes of providing information or documents in connection with any administrative or judicial proceedings relating to taxes. Any information or documents provided under this paragraph 5.1 shall be kept confidential by the party receiving the information or documents, except as may otherwise be necessary in connection with the filing of tax returns or in connection with any administrative or judicial proceedings relating to taxes.

5.2 Records. Each member and disregarded entity shall preserve and keep all tax records, whether they be paper, electronic or other medium, related to the Consolidated Tax Liability or any state income tax or TMT liability for so long as the contents thereof may become material in the administration of any matter under the Code or other applicable tax law, but in any event until the expiration of any applicable statutes of limitation. If, prior to the expiration of the applicable statute of limitation a member reasonably determines that any tax records which it is required to preserve and keep under this paragraph 5.2 are no longer material in the administration of any matter under the Code or other applicable tax law, such party may dispose of such records upon 90 days prior notice to the other members. Such notice shall include a list of the records to be disposed of describing in reasonable detail each file, book, or other record accumulation being disposed. The notified parties shall have the opportunity, at their cost and expense, to copy or remove, within such 90-day period, all or any part of such tax records. The members of the Group and any disregarded entity shall make available to each other for inspection and copying during normal business hours upon reasonable notice all tax records in their possession to the extent reasonably required by the other member in connection with the preparation of tax returns, audits, litigation, or the resolution of items under this Agreement.

5.3 Tax Contests. The Common Parent shall control the defense or prosecution of any audit, assessment, or administrative or judicial proceeding relating to, or with potential impact upon, any Consolidated Tax Liability or state income tax or TMT liability ("Tax Contest") for any Group tax return or TMT return. As provided in paragraph 5.1, members of the Group shall provide information and documents reasonably requested of them by the Common Parent or by the Internal Revenue Service or other state taxing authorities with respect to matters relating to their respective tax items.

Article 6 - Miscellaneous Provisions

6.1 This Agreement supersedes all previous tax allocation agreements among the Common Parent and the members of the Group and other federal income tax allocation agreements or arrangements among the parties to this Agreement.

6.2 It is understood and acknowledged that, in accordance with Treasury regulation section 1.1502-77, the Common Parent will be the agent for all members of the Group with respect to all matters referred to therein and the Common Parent has the power, without the consent of any member, to exercise the authority with respect to the matters set forth therein, including without limitation, making or revoking any elections. Any notice, demand, request or report required or permitted to be given or made to any party under this Agreement shall be in writing and shall be deemed given or made when hand-delivered or when sent by first class mail or by other commercially reasonable means of written communication (including delivery by an internationally recognized courier service or by facsimile transmission) to the party at the party's address as follows:

If to Common Parent: Tax Department
EFH Corporate Services Company
1601 Bryan Street
Dallas, TX 75201

If to any other member: Tax Department
EFH Corporate Services Company
1601 Bryan Street
Dallas, Texas 75201

A party may change the address for receiving notices under this Agreement by providing written notice of the change of address to the other parties.

6.3 The parties hereto recognize that from time to time other companies may become members of the Group and hereby agree that such new members will become parties to this Agreement by the signature of an officer of such new member on a document in the form attached hereto as Annex A and it shall not be necessary that the existing members re-execute this Agreement or join with such new member in signing a counterpart of Annex A.

6.4 In order to reflect the parties' course of dealing since January 1, 2010, this Agreement shall be effective for all open taxable years beginning after December 31, 2009, unless the Common Parent otherwise agrees to the termination of the rights and obligations of any party hereunder under such terms and conditions as are mutually agreed upon by the Common Parent and the terminating party, which terms and conditions shall not inure to the detriment of any other party hereto. Notwithstanding such termination, this Agreement shall continue in effect with respect to any payment (including any payment attributable to an adjustment governed by Article 4) or refunds due for all taxable periods prior to termination. Any refund allocated to a member of the Group that, at the time the allocation is made, has left the Group due to sale, merger, liquidation or otherwise shall be made to the member of the Group that received the proceeds of such sale, merger or other transaction or the assets of the former member unless another method of allocation is agreed to prior to the member leaving the Group.

6.5 The Common Parent shall have authority to amend this Agreement through a collateral agreement with any member to take into account any special facts and circumstances of such member. The collateral agreement shall be effective upon execution by all affected parties and need not be executed by members whose rights and liabilities under this Agreement are not affected by the collateral agreement. Any such amendment shall be consistent with the principles of this Agreement.

6.6 This Agreement may be unilaterally amended by the Common Parent in response to legislative or regulatory changes in the tax law; provided that any such amendment shall be consistent with the principles of this Agreement.

6.7 Failure of one or more parties to qualify as a member of the Group shall not operate to terminate this Agreement with respect to the other parties so long as two or more parties continue to so qualify.

6.8 This Agreement shall bind and inure to the benefit of the respective successors and assigns of the parties, but no assignment shall relieve any party's obligations hereunder without the written consent of the other parties except as otherwise provided in paragraph 6.4.

6.9 This Agreement shall be governed by the laws of the State of Texas and the United States of America.

6.10 Any matter not specifically covered by this Agreement shall be handled in the manner determined by the Common Parent in a manner consistent with the principles of this Agreement. Any dispute concerning the interpretation of this Agreement shall be settled in a fair and reasonable manner by the Chief Financial Officer.

6.11 The Chief Financial Officer may delegate any authority and duties granted hereunder to the VP Tax or General Tax Counsel.

6.12 This Agreement contains the entire understanding of the parties with respect to the subject matter contained herein. No alteration, amendment or modification of any of the terms of this Agreement shall be valid unless made by an authorized officer of each member of the Group that is a party hereto except as otherwise provided in paragraphs 6.5 and 6.6. In the event of any inconsistency between this Agreement and any other agreements, the provisions of this Agreement shall control.

6.13 The language in all parts of this Agreement shall in all cases be construed according to its fair meaning and shall not be strictly construed for or against any party.

6.14 The parties shall execute and deliver all documents, provide all information, and take or refrain from taking action as may be necessary or appropriate to achieve the purposes of this Agreement, including the execution and delivery to the other parties and their affiliates and representatives of such powers of attorney or other authorizing documentation as is reasonably necessary or appropriate in connection with Tax Contests (or portions thereof) under the control of such other parties in accordance with Article 5.

6.15 If any provision of this Agreement is or becomes invalid, illegal or unenforceable in any respect, the validity, legality, and enforceability of the remaining provisions contained herein shall not be affected thereby.

6.16 No failure by any party to insist upon the strict performance of any obligation under this Agreement or to exercise any right or remedy under this Agreement shall constitute waiver of any such obligation, right, or remedy or any other obligation, rights, or remedies under this Agreement.

6.17 This Agreement may be executed simultaneously in two or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be duly executed as of the 15 th day of May, 2012.

[Signatures Appear on Following Page]

Energy Future Holdings Corp.

By: /s/ PAUL M. KEGLEVIC

Printed name: Paul M. Keglevic

Title: Executive Vice President and Chief Financial Officer

TXU Receivables Company

By: /s/ PAUL M. KEGLEVIC

Printed name: Paul M. Keglevic

Title: President

EFH Australia (No. 2) Holdings Co.

By: /s/ PAUL M. KEGLEVIC

Printed name: Paul M. Keglevic

Title: President

EFH FS Holdings Co.

By: /s/ PAUL M. KEGLEVIC

Printed name: Paul M. Keglevic

Title: President

EFH Finance (No. 2) Holdings Co.

By: /s/ PAUL M. KEGLEVIC

Printed name: Paul M. Keglevic

Title: President

EFH Vermont Insurance Company

By: /s/ PAUL M. KEGLEVIC

Printed name: Paul M. Keglevic

Title: Executive Vice President and Chief Financial Officer

Basic Resources Inc.

By: /s/ PAUL M. KEGLEVIC

Printed name: Paul M. Keglevic

Title: President

Energy Future Competitive Holdings Company

By: /s/ PAUL M. KEGLEVIC

Printed name: Paul M. Keglevic

Title: Executive Vice President and Chief Financial Officer

EFIH Finance Inc.

By: /s/ PAUL M. KEGLEVIC

Printed name: Paul M. Keglevic

Title: Executive Vice President and Chief Financial Officer

Energy Future Intermediate Holdings Co. LLC

By: /s/ PAUL M. KEGLEVIC

Printed name: Paul M. Keglevic

Title: Executive Vice President and Chief Financial Officer

EFH Corporate Services Company

By: /s/ PAUL M. KEGLEVIC

Printed name: Paul M. Keglevic

Title: President

LSGT Gas Company LLC

By: /s/ PAUL M. KEGLEVIC

Printed name: Paul M. Keglevic

Title: President

TCEH Finance Inc.

By: /s/ PAUL M. KEGLEVIC

Printed name: Paul M. Keglevic

Title: Executive Vice President and Chief Financial Officer

LSGT SACROC Inc.

By: /s/ PAUL M. KEGLEVIC

Printed name: Paul M. Keglevic

Title: President

EEC Holdings Inc.

By: /s/ PAUL M. KEGLEVIC

Printed name: Paul M. Keglevic

Title: President

EECI, Inc.

By: /s/ PAUL M. KEGLEVIC

Printed name: Paul M. Keglevic

Title: President

Texas Competitive Electric Holdings Company LLC

By: /s/ PAUL M. KEGLEVIC

Printed name: Paul M. Keglevic

Title: Executive Vice President and Chief Financial Officer

EFH Properties Company

By: /s/ ANTHONY R. HORTON

Printed name: Anthony R. Horton

Title: Treasurer

Generation SVC Company

By: /s/ ANTHONY R. HORTON

Printed name: Anthony R. Horton

Title: Treasurer

Luminant Energy Company LLC

By: /s/ ANTHONY R. HORTON

Printed name: Anthony R. Horton

Title: Treasurer

Luminant Energy Trading (CA) Co.

By: /s/ ANTHONY R. HORTON

Printed name: Anthony R. Horton

Title: Treasurer

Luminant ET Services Co.

By: /s/ ANTHONY R. HORTON

Printed name: Anthony R. Horton

Title: Treasurer

Luminant Generation Company LLC

By: /s/ ANTHONY R. HORTON

Printed name: Anthony R. Horton

Title: Treasurer

Luminant Holding Company LLC

By: /s/ ANTHONY R. HORTON

Printed name: Anthony R. Horton

Title: Treasurer

Luminant Mining Company LLC

By: /s/ ANTHONY R. HORTON

Printed name: Anthony R. Horton

Title: Treasurer

TXU Energy Retail Company LLC

By: /s/ ANTHONY R. HORTON

Printed name: Anthony R. Horton

Title: Treasurer

TXU Retail Services Company

By: /s/ ANTHONY R. HORTON

Printed name: Anthony R. Horton

Title: Treasurer

TXU SEM Company

By: /s/ ANTHONY R. HORTON

Printed name: Anthony R. Horton

Title: Treasurer

4Change Energy Company (F/K/A TXU SESCO Energy Services Company)

By: /s/ ANTHONY R. HORTON

Printed name: Anthony R. Horton

Title: Treasurer

Luminant Mining Company LLC
As successor to Luminant Mining Services Co.

By: /s/ ANTHONY R. HORTON

Printed name: Anthony R. Horton

Title: Treasurer

Luminant Generation Company LLC
As successor to Luminant Power Services Co.

By: /s/ ANTHONY R. HORTON

Printed name: Anthony R. Horton

Title: Treasurer

Luminant Energy Company LLC
As successor to Luminant Energy Services Co.

By: /s/ ANTHONY R. HORTON

Printed name: Anthony R. Horton

Title: Treasurer

ANNEX A

ADMISSION OF NEW GROUP MEMBER

THIS AGREEMENT is made as of the ___ day of _________, ____ between Energy Future Holdings Corp. ("EFH"), a Delaware corporation, and (the "New Member").

RECITALS:

WHEREAS, EFH is the common parent of an affiliated group of corporations within the meaning of section 1504(a) of the Internal Revenue Code of 1986, as amended from time to time (the "Code"); and

WHEREAS, EFH and the members of its affiliated group within the meaning of section 1504(a) of the Code and certain entities disregarded for federal income tax purposes as an entity separate from a member of such affiliated group (the "Group") executed the Federal and State Income Tax Allocation Agreement Among the Members of the Energy Future Holdings Corp. Consolidated Group (the "Agreement") as of the ___ day of ______, ____, to allocate federal and state income tax liability and Texas margin tax liability among them; and

WHEREAS, the New Member has become a member of the Group since the Group executed the Agreement;

NOW, THEREFORE, the parties hereto agree as follows:

The New Member shall by its execution of this Admission of New Group Member become subject to the terms of the Agreement effective as of the date first stated above.

Energy Future Holdings Corp.

By ______________________________________

[Name]
[Title]

[NAME OF NEW MEMBER]

By ______________________________________

[Name]
[Title]

Exhibit 31(a)

ENERGY FUTURE HOLDINGS CORP.
Certificate Pursuant to Section 302
of Sarbanes - Oxley Act of 2002

I, John F. Young certify that:

1. I have reviewed this quarterly report on Form 10-Q of Energy Future Holdings Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 29, 2012

/s/ JOHN F. YOUNG

Name: John F. Young

Title: President and Chief Executive Officer

Exhibit 31(b)

ENERGY FUTURE HOLDINGS CORP.
Certificate Pursuant to Section 302
of Sarbanes - Oxley Act of 2002

I, Paul M. Keglevic, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Energy Future Holdings Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 29, 2012

/s/ PAUL M. KEGLEVIC

Name: Paul M. Keglevic

Title: Executive Vice President and Chief Financial Officer

Exhibit 32(a)

ENERGY FUTURE HOLDINGS CORP.
Certificate Pursuant to Section 906
of Sarbanes - Oxley Act of 2002
CERTIFICATION OF CEO

The undersigned, John F. Young, President and Chief Executive Officer of Energy Future Holdings Corp. (the "Company"), DOES HEREBY CERTIFY that, to his knowledge:

1. The Company's Quarterly Report on Form 10-Q for the period ended September 30, 2012 (the "Report") fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. Information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

IN WITNESS WHEREOF, the undersigned has caused this instrument to be executed this 29th day of October, 2012.

/s/ JOHN F. YOUNG

Name: John F. Young
Title: President and Chief Executive Officer

A signed original of this written statement required by Section 906 has been provided to Energy Future Holdings Corp. and will be retained by Energy Future Holdings Corp. and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(b)

ENERGY FUTURE HOLDINGS CORP.
Certificate Pursuant to Section 906
of Sarbanes - Oxley Act of 2002
CERTIFICATION OF CFO

The undersigned, Paul M. Keglevic, Executive Vice President and Chief Financial Officer of Energy Future Holdings Corp. (the "Company"), DOES HEREBY CERTIFY that, to his knowledge:

1. The Company's Quarterly Report on Form 10-Q for the period ended September 30, 2012 (the "Report") fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. Information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

IN WITNESS WHEREOF, the undersigned has caused this instrument to be executed this 29th day of October, 2012.

/s/ PAUL M. KEGLEVIC

Name: Paul M. Keglevic
Title: Executive Vice President and Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to Energy Future Holdings Corp. and will be retained by Energy Future Holdings Corp. and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 95(a)

Mine Safety Disclosures

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 Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K sourced from data documented as of October 2, 2012 in the MSHA Data Retrieval System for the three months ended September 30, 2012 (except pending legal actions, which are at September 30, 2012), are as follows:

Mine (a)	Section 104 S and S Citations (b)	Section 104(b) Orders	Section 104(d) Citations and Orders	Section 110(b)(2) Violations	Section 107(a) Orders	Total Dollar Value of MSHA Assessments Proposed (c)	Total Number of Mining Related Fatalities	Received Notice of Pattern of Violations Under Section 104(e)	Received Notice of Potential to Have Pattern Under Section 104(e)	Legal Actions Pending as of Last Day of Period (d)	Legal Actions Initiated During Period	Legal Actions Resolved During Period
Beckville	1	—	—	—	—	19	—	—	—	5	—	—
Big Brown	2	—	—	—	—	3	—	—	—	3	—	—
Kosse	1	—	—	—	—	135	—	—	—	5	—	—
Oak Hill	—	—	—	—	—	—	—	—	—	2	—	—
Sulphur Springs	—	—	—	—	—	3	—	—	—	1	—	—
Tatum	1	—	—	—	—	3	—	—	—	2	—	1
Three Oaks	2	—	—	—	—	3	—	—	—	1	—	—
Turlington	—	—	—	—	—	—	—	—	—	1	—	—
Winfield South	1	—	—	—	—	1	—	—	—	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 value in thousands of dollars for proposed assessments received from MSHA for all citations and orders issued in the three months ended September 30, 2012, 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. All 21 are contests of proposed penalties.

Exhibit 99(a)

ENERGY FUTURE HOLDINGS CORP. AND SUBSIDIARIES
CONDENSED STATEMENT OF CONSOLIDATED INCOME (LOSS)
(Unaudited)

	Twelve Months Ended September 30, 2012
	(millions of dollars)
Operating revenues	$ 5,726
Fuel, purchased power costs and delivery fees	(2,823)
Net gain from commodity hedging and trading activities	875
Operating costs	(890)
Depreciation and amortization	(1,395)
Selling, general and administrative expenses	(696)
Franchise and revenue-based taxes	(87)
Other income	59
Other deductions	(14)
Interest income	2
Interest expense and related charges	(3,573)
Loss before income taxes and equity in earnings of unconsolidated subsidiaries	(2,816)
Income tax benefit	971
Equity in earnings of unconsolidated subsidiaries (net of tax)	300
Net loss	$ (1,545)

Exhibit 99(b)

Energy Future Holdings Corp. Consolidated
Adjusted EBITDA Reconciliation
(millions of dollars)

	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011	Twelve Months Ended September 30, 2012	Twelve Months Ended September 30, 2011
Net loss	$ (1,408)	$ (1,776)	$ (1,545)	$ (1,615)
Income tax benefit	(879)	(1,042)	(971)	(989)
Interest expense and related charges	2,746	3,467	3,573	3,929
Depreciation and amortization	1,015	1,119	1,395	1,483
EBITDA	$ 1,474	$ 1,768	$ 2,452	$ 2,808
Oncor distributions/dividends	100	64	152	91
Interest income	(2)	(2)	(2)	(3)
Amortization of nuclear fuel	124	104	162	142
Purchase accounting adjustments (a)	74	182	96	233
Impairment and write-down of assets (b)	9	429	13	441
Debt extinguishment gains	—	(25)	(26)	(673)
Equity in earnings of unconsolidated subsidiary	(249)	(235)	(300)	(272)
Unrealized net loss resulting from hedging and trading transactions	1,290	247	985	641
Amortization of "day one" net loss on Sandow 5 power purchase agreement	—	—	—	(2)
Noncash compensation expense (c)	11	8	16	13
Severance expense	1	54	(46)	54
Transition and business optimization costs (d)	31	30	40	36
Transaction and merger expenses (e)	29	27	39	38
Restructuring and other (f)	7	74	6	(41)
Expenses incurred to upgrade or expand a generation station (g)	69	100	100	100
Adjusted EBITDA per Incurrence Covenant	$ 2,968	$ 2,825	$ 3,687	$ 3,606
Add Oncor Adjusted EBITDA (reduced by Oncor Holdings distributions)	1,254	1,206	1,571	1,508
Adjusted EBITDA per Restricted Payments Covenant	$ 4,222	$ 4,031	$ 5,258	$ 5,114

(a) Purchase accounting adjustments include amortization of the intangible net asset value of retail and wholesale power sales agreements, environmental credits, coal purchase contracts, nuclear fuel contracts and power purchase agreements and the stepped up value of nuclear fuel. Also include certain credits and gains on asset sales not recognized in net income due to purchase accounting. Nine and twelve months ended 2011 includes $46 million related to an asset sale.

(b) Impairment of assets in the nine and twelve months ended 2011 includes impairment of emission allowances and certain mining assets due to EPA rule issued in July 2011.

(c) Noncash compensation expenses represent amounts recorded under stock-based compensation accounting standards and exclude capitalized amounts.

(d) Transition and business optimization costs include certain incentive compensation expenses, as well as professional fees and other costs related to generation plant reliability and supply chain efficiency initiatives.

(e) Transaction and merger expenses primarily represent Sponsor Group management fees.

(f) Restructuring and other includes gains on termination of a long-term power sales contract and settlement of amounts due from hedging/trading counterparty, fees related to the April 2011 amendment and extension of the TCEH Senior Secured Facilities, and reversal of certain liabilities accrued in purchase accounting.

(g) Expenses incurred to upgrade or expand a generation station reflect noncapital outage costs.

Exhibit 99(c)

Texas Competitive Electric Holdings Company LLC Consolidated
Adjusted EBITDA Reconciliation
(millions of dollars)

	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011	Twelve Months Ended September 30, 2012	Twelve Months Ended September 30, 2011
Net loss	$ (1,252)	$ (1,660)	$ (1,332)	$ (1,397)
Income tax benefit	(670)	(874)	(713)	(732)
Interest expense and related charges	2,200	3,020	2,879	3,344
Depreciation and amortization	992	1,097	1,365	1,450
EBITDA	$ 1,270	$ 1,583	$ 2,199	$ 2,665
Interest income	(36)	(66)	(57)	(92)
Amortization of nuclear fuel	124	104	162	142
Purchase accounting adjustments (a)	54	147	64	186
Impairment and write-down of assets (b)	1	427	4	439
Debt extinguishment gains	—	—	—	(687)
Unrealized net loss resulting from hedging and trading transactions	1,290	247	985	641
Net loss attributable to noncontrolling interests	1	—	1	—
EBITDA amount attributable to consolidated unrestricted subsidiaries	(6)	(5)	(8)	(5)
Amortization of "day one" net loss on Sandow 5 power purchase agreement	—	—	—	(2)
Corporate depreciation, interest and income tax expenses included in SG&A expense	13	11	18	11
Noncash compensation expense (c)	8	8	12	11
Severance expense	1	52	(46)	52
Transition and business optimization costs (d)	30	33	39	40
Transaction and merger expenses (e)	29	28	38	37
Restructuring and other (f)	6	70	3	(51)
Expenses incurred to upgrade or expand a generation station (g)	69	100	100	100
Adjusted EBITDA per Incurrence Covenant	$ 2,854	$ 2,739	$ 3,514	$ 3,487
Expenses related to unplanned generation station outages	64	162	83	172
Pro forma adjustment for Oak Grove 2 reaching 70% capacity in Q2 2011 (h)	—	32	—	64
Other adjustments allowed to determine Adjusted EBITDA per Maintenance Covenant (i)	—	8	—	18
Adjusted EBITDA per Maintenance Covenant	$ 2,918	$ 2,941	$ 3,597	$ 3,741

(a) Purchase accounting adjustments include amortization of the intangible net asset value of retail and wholesale power sales agreements, environmental credits, coal purchase contracts, nuclear fuel contracts and power purchase agreements and the stepped up value of nuclear fuel. Also include certain credits and gains on asset sales not recognized in net income due to purchase accounting. Nine and twelve months ended 2011 includes $46 million related to an asset sale.

(b) Impairment of assets in the nine and twelve months ended 2011 includes impairment of emission allowances and certain mining assets due to EPA rule issued in July 2011.

(c) Noncash compensation expenses represent amounts recorded under stock-based compensation accounting standards and exclude capitalized amounts.

(d) Transition and business optimization costs include certain incentive compensation expenses, as well as professional fees and other costs related to generation plant reliability and supply chain efficiency initiatives.

(e) Transaction and merger expenses primarily represent Sponsor Group management fees.

(f) Restructuring and other includes gains on termination of a long-term power sales contract and settlement of amounts due from hedging/trading counterparty, fees related to the April 2011 amendment and extension of the TCEH Senior Secured Facilities, and reversal of certain liabilities accrued in purchase accounting.

(g) Expenses incurred to upgrade or expand a generation station reflect noncapital outage costs.

(h) Pro forma adjustment for the nine and twelve months ended September 30, 2011 represents the annualization of the actual six months ended September 30, 2011 EBITDA results for Oak Grove 2, which achieved the requisite 70% average capacity factor in the second quarter 2011.

(i) Primarily pre-operating expenses relating to Oak Grove and Sandow 5.

Exhibit 99(d)

Energy Future Intermediate Holding Company LLC Consolidated
Adjusted EBITDA Reconciliation
(millions of dollars)

	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011	Twelve Months Ended September 30, 2012	Twelve Months Ended September 30, 2011
Net income	$ 308	$ 367	$ 358	$ 438
Income tax expense	35	72	36	89
Interest expense and related charges	368	259	457	341
EBITDA	$ 711	$ 698	$ 851	$ 868
Oncor Holdings distributions	100	64	152	91
Interest income	(462)	(463)	(551)	(596)
Equity in earnings of unconsolidated subsidiary (net of tax)	(249)	(235)	(300)	(272)
Adjusted EBITDA per Incurrence Covenant	$ 100	$ 64	$ 152	$ 91
Add Oncor Adjusted EBITDA (reduced by Oncor Holdings distributions)	1,254	1,206	1,571	1,508
Adjusted EBITDA per Restricted Payments Covenant	$ 1,354	$ 1,270	$ 1,723	$ 1,599