Energy Future Holdings

TXU energy

Luminant

ONCOR

EFH Corp.
Q4 2010 Investor Call

February 18, 2011

Safe Harbor Statement

Forward Looking Statements

This presentation contains forward-looking statements, which are subject to various risks and uncertainties. Discussion of risks and uncertainties that could cause actual results to differ materially from management's current projections, forecasts, estimates and expectations is contained in EFH Corp.'s filings with the Securities and Exchange Commission (SEC). In addition to the risks and uncertainties set forth in EFH Corp.'s SEC filings, the forward-looking statements in this presentation regarding the company's long-term hedging program could be affected by, among other things: any change in the ERCOT electricity market, including a regulatory or legislative change, that results in wholesale electricity prices not being largely correlated to natural gas prices; any decrease in market heat rates as the long-term hedging program generally does not mitigate exposure to changes in market heat rates; the unwillingness or failure of any hedge counterparty or the lenders under the commodity collateral posting facility to perform their respective obligations; or any other unforeseen event that results in the inability to continue to use a first lien on TCEH's assets to secure a substantial portion of the hedges under the long-term hedging program.

Regulation G

This presentation includes certain non-GAAP financial measures. A reconciliation of these measures to the most directly comparable GAAP measures is included in the appendix to this presentation.

Today's Agenda

Financial and Operational Overview

Paul Keglevic
Executive Vice President & CFO

Q4 2010 Review

Q&A

EFH Corp.
Adjusted (Non-GAAP) Operating Results - QTR

Consolidated: reconciliation of GAAP net income to adjusted (non-GAAP) operating results
Q4[1] 09 vs. Q4 10 ; $ millions, after tax

Factor	Q4 09	Q4 10	Change
EFH Corp. GAAP net income	137	161	24
Items excluded from adjusted (non-GAAP) operating results (after tax) - noncash:			
Unrealized commodity-related mark-to-market net (gains) losses	(330)	254	584
Unrealized mark-to-market net gains on interest rate swaps	(110)	(218)	(108)
Debt extinguishment gains – debt exchanges and repurchases	(56)	(417)	(361)
Gain on termination of long-term power sales contract	-	(75)	(75)
Other (noncash)[2]	8	-	(8)
EFH Corp. adjusted (non-GAAP) operating loss	(351)	(295)	56

1 Three months ended December 31
2 Q4 09 reflects $22 million of land impairment partially offset by $14 million of reversal of purchase accounting reserves.

EFH Corp.
Adjusted (Non-GAAP) Operating Results Key Drivers (after tax) - QTR

Consolidated key drivers of the change in (non-GAAP) operating results
Q4[1] 10 vs. Q4 09; $ millions, after tax

Description/Drivers	Better (Worse) Than Q4 09
Competitive business[2]:	
Impact of new lignite-fueled generation units	35
Higher production from legacy baseload generation units	26
Lower amortization of intangibles arising from purchase accounting	21
Lower net margin from asset management and retail activities	(22)
Higher fuel costs at legacy baseload units due to increased coal transportation expenses and higher uranium and conversion costs	(19)
Lower retail volumes primarily due to weather	(17)
All other - net	(3)
Contribution margin	21
Lower net interest expense driven by liability management program and lower noncash amortization of swap losses	36
Improvement in effective tax rate due primarily to lower accrued interest on uncertain tax positions	25
Lower costs related to outsourcing transition and other SG&A reductions	13
Lower retail bad debt expense	6
Higher depreciation reflecting the new lignite-fueled generation units and mining facilities and ongoing investment in the generation fleet	(31)
Higher operating costs related to the new and legacy baseload generation units	(12)
All other - net	(7)
Total improvement - Competitive business	51
Regulated business:	
Higher revenues from transmission rate increases, distribution tariffs approved in the September 2009 rate order and AMS surcharge	18
Higher depreciation reflecting infrastructure investment and higher depreciation rates approved in the September 2009 rate order	(9)
Lower volumes primarily due to weather	(4)
Total improvement – Regulated business (~80% owned by EFH Corp.)	5
Total improvement in EFH Corp. adjusted (non-GAAP) operating results	**56**

1 Three months ended December 31
2 Competitive business consists of Competitive Electric segment and Corp. & Other.

EFH Corp.
Adjusted (Non-GAAP) Operating Results – Full Year

Consolidated: reconciliation of GAAP net income to adjusted (non-GAAP) operating results
FY[1] 09 vs. FY 10; $ millions, after tax

Factor	FY 09	FY 10	Change
EFH Corp. GAAP net income (loss)	344	(2,812)	(3,156)
Items excluded from adjusted (non-GAAP) operating results (after tax) - noncash:			
Unrealized commodity-related mark-to-market net gains	(788)	(786)	2
Unrealized mark-to-market net (gains) losses on interest rate swaps	(452)	134	586
Goodwill impairment	90	4,100	4,010
Debt extinguishment gains – debt exchanges and repurchases	(56)	(1,168)	(1,112)
Reduction of income tax expense due to expected resolution of IRS tax audit for 1997- 2002	-	(146)	(146)
Gain on termination of long-term power sales contract	-	(75)	(75)
Income tax charge recorded as a result of health care legislation	-	8	8
Other (noncash)[2]	10	-	(10)
EFH Corp. adjusted (non-GAAP) operating loss	(852)	(745)	107

1 Full year ended December 31

2 Full year 09 reflects, after tax, $22 million of land impairment and $16 million of write-off of rate case disallowed regulatory assets, partially offset by $14 million of reversal of purchase accounting reserves and $14 million arising from the reversal of a use tax accrual recorded in purchase accounting related to periods prior to the October 2007 merger.

EFH Corp.
Adjusted (Non-GAAP) Operating Results Key Drivers (after tax) – FY

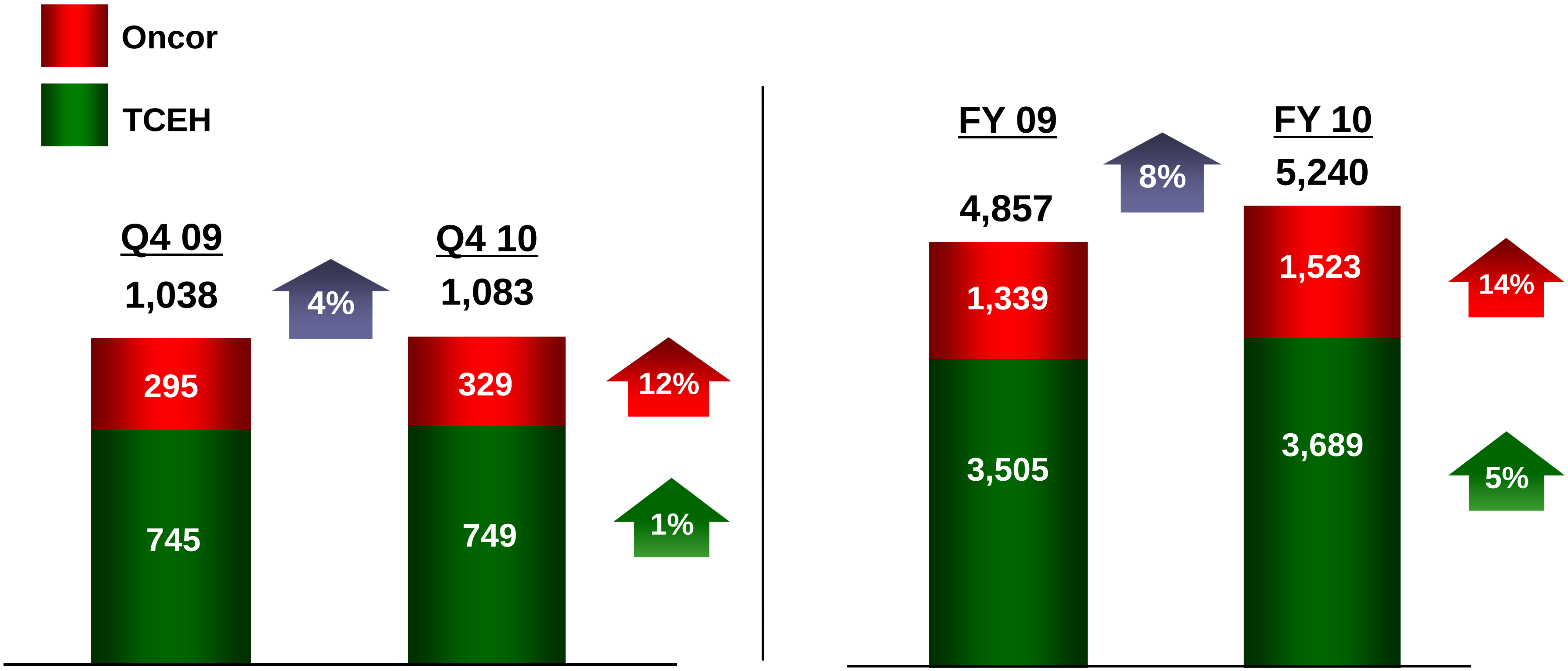
Consolidated key drivers of the change in (non-GAAP) operating results
FY[1] 10 vs. FY 09; $ millions, after tax

Description/Drivers	Better (Worse) Than FY 09
Competitive business[2]:	
Impact of new lignite-fueled generation units	255
Lower amortization of intangibles arising from purchase accounting	87
Higher retail volumes primarily due to weather	8
Higher fuel costs at legacy baseload units due to increased coal transportation expenses and higher uranium and conversion costs	(106)
Lower net margin from asset management and retail activities	(37)
All other - net	(4)
Contribution margin	203
Lower costs related to outsourcing transition, new retail customer care system and other SG&A reductions	75
Gains on sales of assets (reported in other income)	57
Improvement in effective tax rate due primarily to lower accrued interest on uncertain tax positions	37
Lower retail bad debt expense	5
Higher depreciation reflecting the new lignite-fueled generation units and mining facilities and ongoing investment in the generation fleet	(135)
Higher operating costs related to the new and legacy baseload generation units	(95)
Higher net interest expense driven by lower capitalized interest due to completion of the new generation units	(51)
Total improvement - Competitive business	96
Regulated business:	
Higher distribution tariffs, including the rates approved in the September 2009 rate review order	62
Higher volumes primarily driven by the effects of weather	31
Surcharge to recover AMS deployment costs	30
Higher transmission revenues primarily due to a rate increase to recover ongoing investment	17
Higher depreciation reflecting higher depreciation rates approved in the September rate review order and infrastructure investment	(75)
Higher costs reflecting amortization of regulatory assets approved for recovery, AMS implementation and higher transmission fees	(52)
Change in effective tax rate due to accrued interest adjustment in 2009 and tax on Medicare subsidy	(21)
All other – net primarily includes noncontrolling interests and lower contractor, professional and outsourced services	19
Total improvement – Regulated business (~80% owned by EFH Corp.)	11
Total improvement in EFH Corp. adjusted (non-GAAP) operating results	**107**

[1] Full year ended December 31
[2] Competitive business consists of Competitive Electric segment and Corp. & Other.

EFH Corp. Adjusted EBITDA (Non-GAAP)

EFH Corp. Adjusted EBITDA (non-GAAP)[1]
Q4[2] 09 vs. Q4 10 and FY[3] 09 vs. FY 10; $ millions



Q4 and FY 10 performance was largely driven by the same key drivers impacting adjusted (non-GAAP) operating results.

[1] See Appendix for Regulation G reconciliations and definition. Includes $(2) million, $5 million, $13 million and $28 million in Q4 09, Q4 10, FY 09 and FY 10, respectively, of Corp. & Other Adjusted EBITDA.
[2] Three months ended December 31
[3] Full year ended December 31

Luminant Operational Results

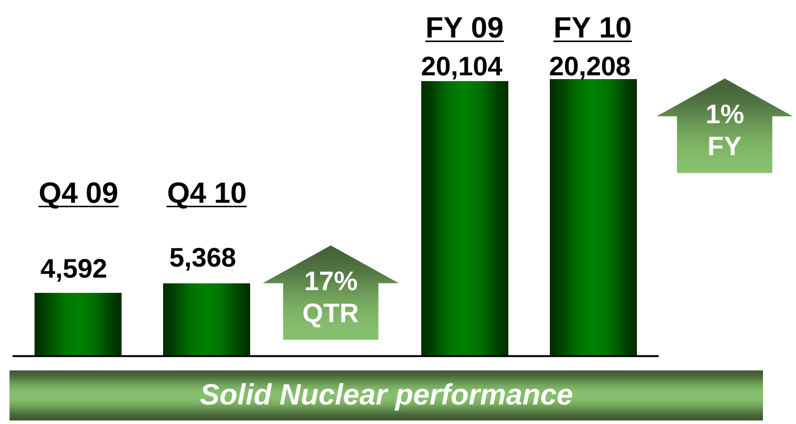
Q4 2010 Results
- New plants generated 2.9 TWh
- Nuclear performance 17% higher than Q4 2009 due to outage timing; 2010 outage in Q2, 2009 outage in Q4
- Improved legacy coal-fueled plant performance offset by higher economic backdown

FY 2010 Nuclear Plant Results
- Solid safety performance
- 3rd shortest Spring 2010 outage in the industry
- Top decile industry performance for reliability and cost

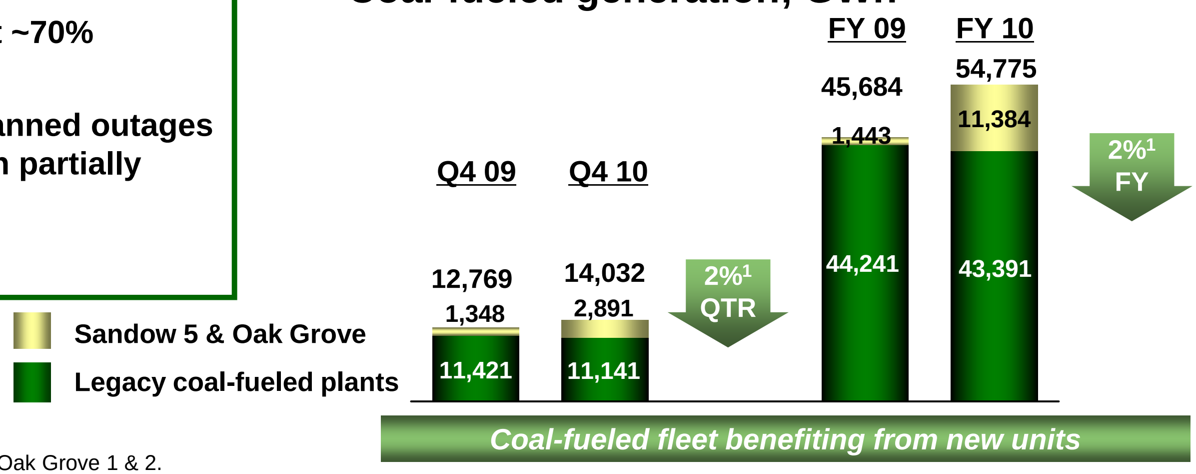
FY 2010 Coal-fueled Plant Results
- New plants collectively operated at ~70% capacity factor
- Lower generation due to higher planned outages and increased economic backdown partially offset by improved performance
- Top quartile industry performance

Luminant

Nuclear-fueled generation; GWh



Coal-fueled generation; GWh



1 Variance does not include generation from Sandow 5 and Oak Grove 1 & 2.

TXU Energy Operational Results

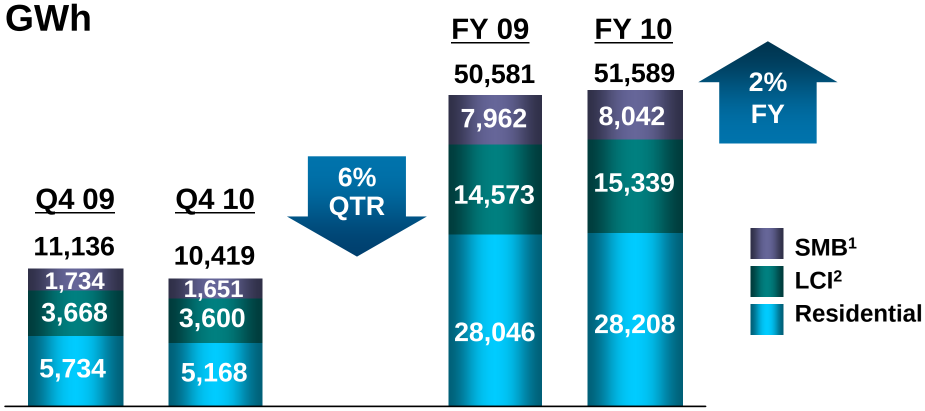
Q4 2010 Results

- Lower residential sales volumes driven by lower customer counts and unfavorable weather

FY 2010 Results

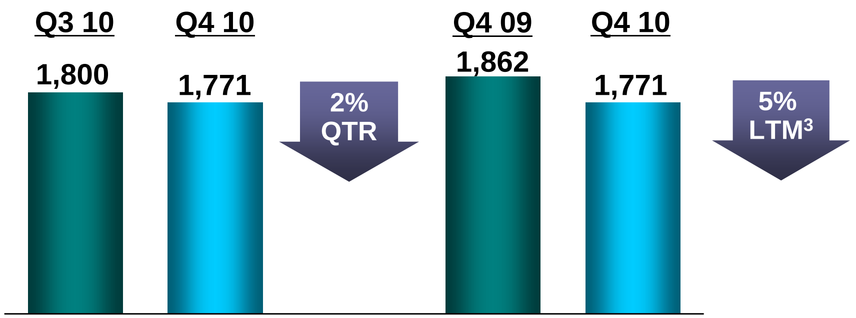
- Lower residential sales volumes driven by lower customer counts partially offset by favorable weather
- Lower residential customer counts reflect competitive activity in the marketplace
- Business load growth attributable to new customers and improved economy

Retail electricity sales volumes by customer class; GWh



FY volume increases due to weather and improved economy

Total residential customers
End of period, thousands



Continued strong competitive activity

[1] SMB – small business
[2] LCI - large commercial and industrial
[3] Latest twelve months

Oncor Operational Results

ONCOR

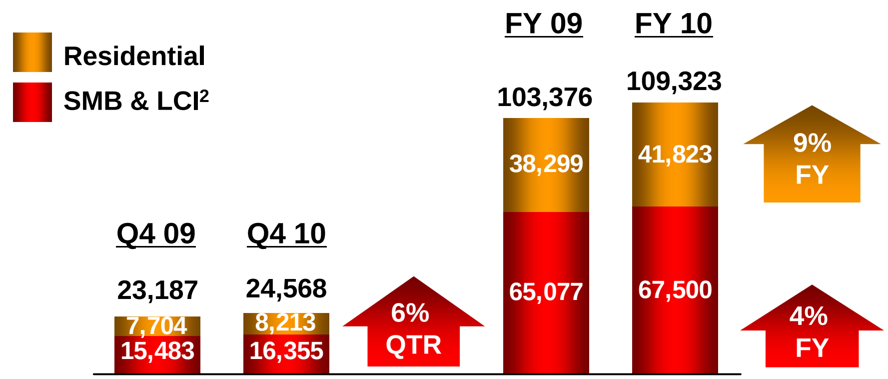
Q4 2010 Results

- Higher SMB & LCI energy volumes due to improved economy
- Execution of AMS[1] plan – ~171,000 advanced meters installed during Q4 10
- 2 Certificates of Convenience and Necessity (CCNs) approved by the Public Utility Commission of Texas (PUCT)

FY 2010 Results

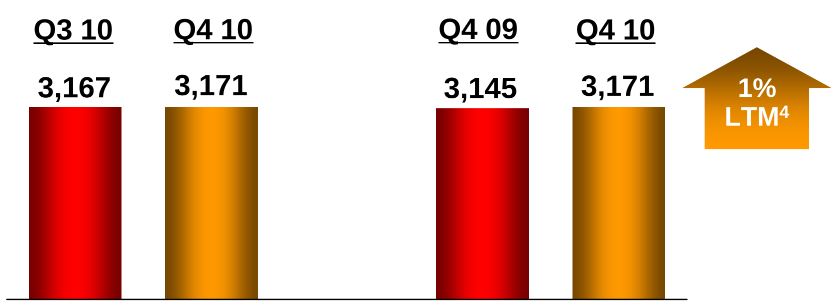
- Higher billed residential energy volumes due to warmer weather in Q4 10 and colder weather in Q1 10 compared to 2009 and premise growth
- Higher SMB and LCI[2] energy volumes due to a slightly improved economy
- Execution of AMS[1] plan – ~854,000 advanced meters installed during 2010; over 1.5 million installed through December 2010
- All CCNs filed with the PUCT; 13 of 14 CCNs approved through December 2010

Billed electric energy volumes[3]; GWh



Volume increases due to weather and improved economy

Electricity distribution points of delivery
End of period, thousands of meters

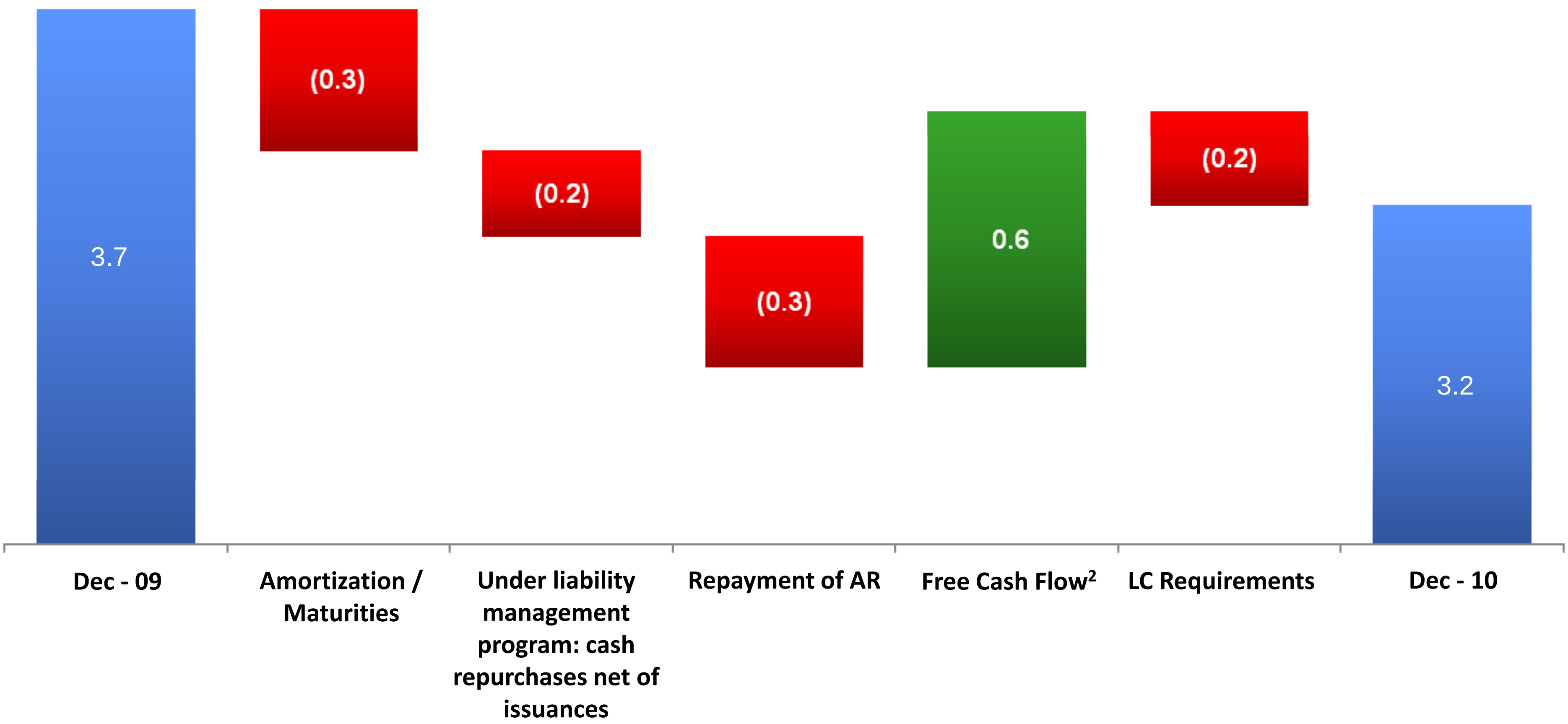


Demand growth below ERCOT estimated CAGR of 1.9%[5]

1 AMS – Advanced Metering System
2 SMB – small business; LCI – large commercial and industrial
3 Billed volumes are on a 15-day lag therefore include impacts from the prior quarter
4 Latest twelve months
5 ERCOT's peak demand growth per May CDR for the period of 2010 to 2015

2010 Ending Liquidity Walkforward
2009A – 2010A

Ending Liquidity Walkforward[1]
($ in billions)



[1] Values may not foot due to rounding.
[2] Free Cash Flow defined as Operating activities plus Investing activities excluding changes in restricted cash, plus Financing activities excluding issuances and repayments of debt and changes in short term borrowings. See Table 4 for Free Cash Flow reconciliation.

Commodity Prices

Commodity prices
Q4 09, Q4 10, YTD 10 and 11E; mixed measures

Commodity	Units	Q4 09 Actual	Q4 10 Actual	YTD 10 Actual	11E[1]
NYMEX gas price[2]	$/MMBtu	$4.26	$3.78	$4.37	$4.55
HSC gas price	$/MMBtu	$4.25	$3.75	$4.34	$4.49
7x24 market heat rate (HSC)[3]	MMBtu/MWh	7.52	7.70	8.34	7.93
North Hub 7x24 power price	$/MWh	$31.68	$28.64	$36.07	$35.59
TCEH weighted avg. hedge price[4]	$/MMBtu	$8.07	$7.81	$7.80	$7.56
Gulf Coast ultra-low sulfur diesel	$/gallon	$1.96	$2.34	$2.15	$2.59
PRB 8400 coal	$/ton	$7.18	$9.80	$9.76	$11.03
LIBOR interest rate[5]	percent	0.52%	0.45%	0.52%	0.78%

1 BOY 11 estimate based on commodity prices as of 12/31/10 for January 1, 2011 through December 31, 2011
2 Based on NYMEX forward curve
3 Based on ERCOT market clearing price for North Hub power
4 Weighted average prices in the TCEH long-term natural gas hedging program. Based on NYMEX Henry Hub prices of forward natural gas sales positions in the long-term hedging program (excluding the impact of offsetting purchases for rebalancing and pricing point basis transactions).
5 The index for the settled value is a 6-month LIBOR rate.

Unrealized Mark-To-Market Impact Of Hedging

Unrealized mark-to-market impact of hedging program
12/31/10 vs. 9/30/10; mixed measures, pre-tax

Factor	Measure	2010	2011	2012	2013	2014	Total or Avg.
9/30/10							
Natural gas hedges	mm MMBtu	~84	~315	~454	~285	~112	~1,250
Wtd. avg. hedge price[1]	$/MMBtu	~$7.82	~$7.56	~$7.36	~$7.19	~$7.80	
Natural gas prices	$/MMBtu	~$3.94	~$4.44	~$5.07	~$5.29	~$5.42	
Cum. MtM gain at 9/30/10[2]	$ billions	~$0.4	~$1.2	~$1.1	~$0.5	~$0.4	~$3.6
12/31/10							
Natural gas hedges[3]	mm MMBtu	-	~220	~398	~282	~110	~1,010
Wtd. avg. hedge price[1]	$/MMBtu	-	~$7.56	~$7.36	~$7.19	~$7.80	
Natural gas prices	$/MMBtu	-	~$4.55	~$5.08	~$5.33	~$5.49	
Cum. MtM gain at 12/31/10[2]	$ billions	~$0	~$1.2	~$1.1	~$0.5	~$0.4	~$3.2
Q4 10 MtM (loss) gain	$ billions	~$(0.4)	~$0.0	~$0.0	~$0.0	~$0.0	~$(0.4)

Forward positions in the hedge program slightly lost value due to higher natural gas prices at the end of Q4, while additional losses resulted from the reversal of previously recognized gains in the current period, resulting in a ~$400 million (~$260 million after tax) unrealized net loss.

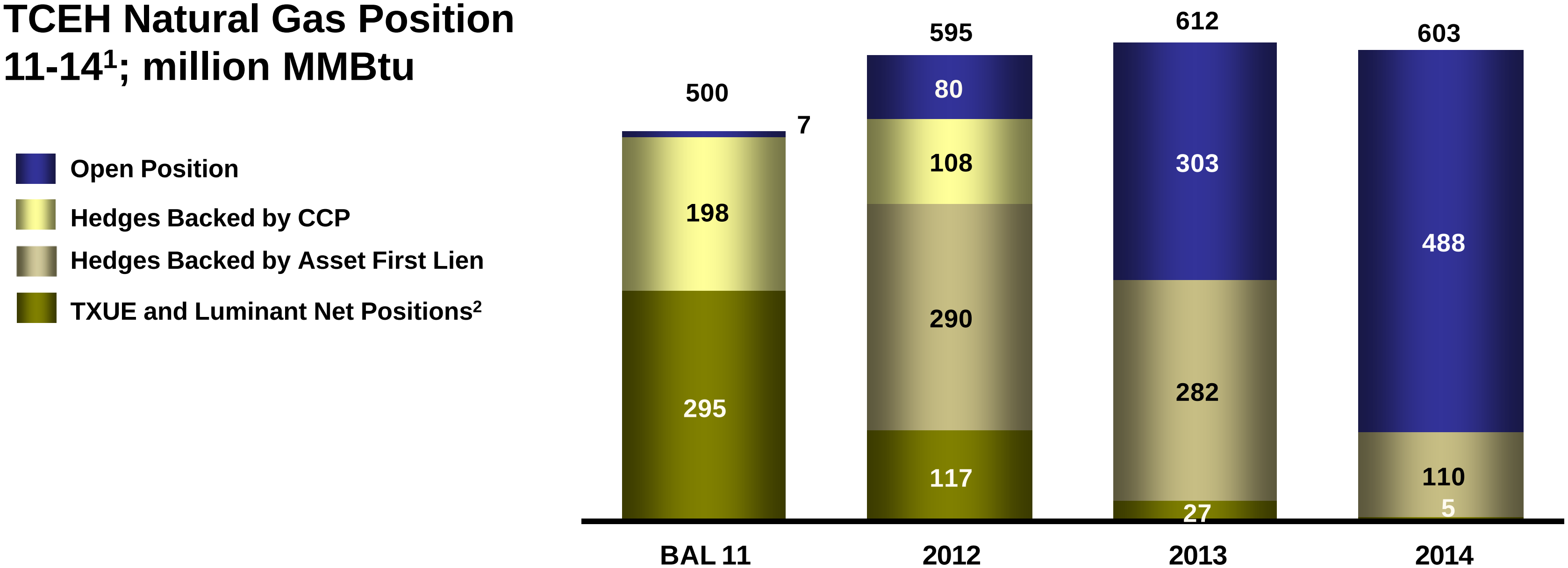
1 Weighted average prices are based on NYMEX Henry Hub prices of forward natural gas sales positions in the long-term hedging program (excluding the impact of offsetting purchases for rebalancing and pricing point basis transactions). Where collars are reflected, sales price represents the collar floor price. 12/31/10 prices for 2011 represent January 1, 2011 through December 31, 2011 values.

2 MtM values include the effects of all transactions in the long-term hedging program including offsetting purchases (for re-balancing) and natural gas basis deals.

3 As of 12/31/10. 2011 represents January 1, 2011 through December 31, 2011 volumes. Where collars are reflected, the volumes are estimated based on the natural gas price sensitivity (i.e., delta position) of the derivatives. The notional volumes for collars are approximately 150 million MMBtu, which corresponds to a delta position of approximately 110 million MMBtu in 2014.

TCEH Natural Gas Exposure

TCEH Natural Gas Position 11-14[1]; million MMBtu



Factor	Measure	BAL 11	2012	2013	2014	Total or Average
Natural gas hedging program	million MMBtu	~198	~398	~282	~110	~988
TXUE and Luminant net positions	million MMBtu	~295	~117	~27	~5	~444
Overall estimated percent of total NG position hedged	percent	~99%	~87%	~51%	~19%	~62%

TCEH has hedged approximately 62% of its estimated Henry Hub-based natural gas price exposure from February 1, 2011 through December 31, 2014. More than 95% of the NG Hedges are supported directly by a first lien or by the TCEH Commodity Collateral Posting Facility.

[1] As of 12/31/10. Balance of 2011 is from February 1, 2011 to December 31, 2011. Assumes conversion of electricity positions based on a ~8.0 heat rate with natural gas being on the margin ~75-90% of the time (i.e. when other technologies are forecast to be on the margin, no natural gas position is assumed to be generated).

[2] Includes estimated retail/wholesale effects. 2011 position includes ~8 million MMBtu of short gas positions associated with proprietary trading positions; excluding these positions, 2011 position is ~97% hedged.

EFH Corp. Adjusted EBITDA Sensitivities

Impact on EFH Corp. Adjusted EBITDA[1]
11E; mixed measures

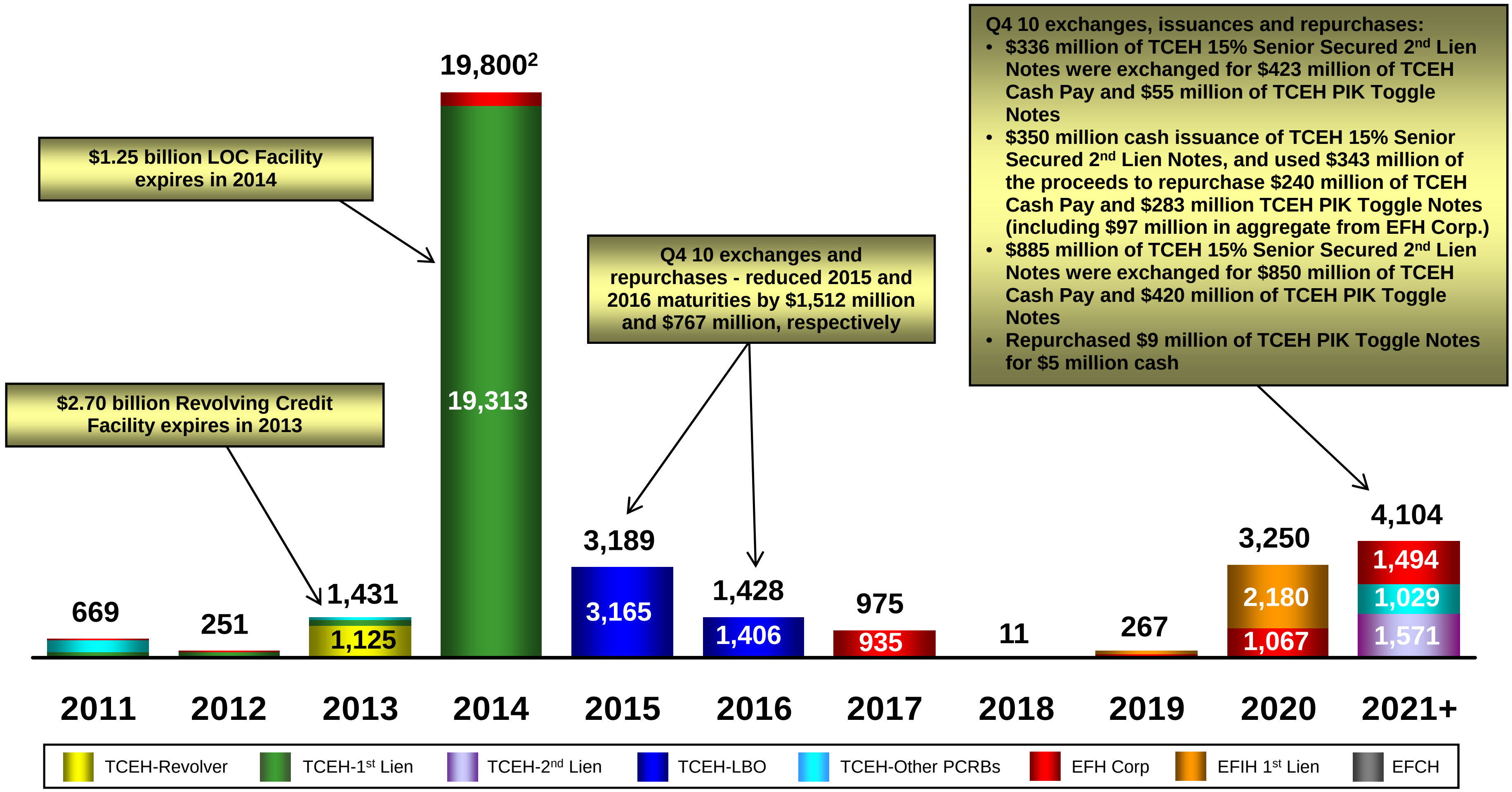
Commodity	Percent Hedged at December 31, 2010	Change	BOY 11E Impact $ millions
7X24 market heat rate (MMBtu/MWh)[2]	>85	0.1 MMBtu/MWh	~4
NYMEX gas price ($/MMBtu)[3]	>95	$1/MMBtu	~5
Texas gas vs. NYMEX Henry Hub price ($/MMBtu)[3,4]	>95	$0.10/MMBtu	~1
Diesel ($/gallon)[5]	~100	$1/gallon	~0
Base coal ($/ton)[6]	>95	$5/ton	~2
Generation operations			
Baseload generation (TWh)	n.a.	1 TWh	~15
Retail operations	FY 2011		
Residential contribution margin ($/MWh)	26 TWh	$1/MWh	~25
Residential consumption	26 TWh	1%	~11
Business markets consumption	24 TWh	1%	~4

The majority of 2011 commodity-related risks are significantly mitigated.

[1] 2011 estimate based on commodity positions as of 12/31/10, net of long-term hedges and wholesale/retail effects, excludes gains and losses incurred prior to December 31, 2010. See Appendix for definition.
[2] Simplified representation of heat rate position in a single TWh position. In reality, heat rate impacts are differentiated across plants and respective pricing periods: baseload (linked primarily to changes in North Hub 7x24), natural gas plants (primarily North Hub 5x16) and wind (primarily West Hub7x8).
[3] Assumes conversion of electricity positions based on a ~8.0 market heat rate with natural gas being on the margin ~75-90% of the time (i.e., when coal is forecast to be on the margin, no natural gas position is assumed to be generated).
[4] The percentage hedged represents the amount of estimated natural gas exposure based on Houston Ship Channel (HSC) gas price sensitivity as a proxy for Texas gas price.
[5] Includes positions related to fuel surcharge on rail transportation.
[6] Excludes fuel surcharge on rail transportation.

Current Maturity Profile

EFH Corp. debt maturities[1] (excluding Oncor), 2011-2021 and thereafter
As of 12/31/10; $ millions



[1] Includes amortization of the $16.5 billion Initial Term Loan, $4.1 billion Delayed Draw Term Loan and excludes unamortized discounts and premiums.
[2] Excludes the Deposit Letter of Credit Facility maturing in 2014.

Today's Agenda

Financial and Operational Overview

Q4 2010 Review

John Young
President & CEO

Q&A

Today's Agenda

Financial and Operational Overview

Q4 2010 Review

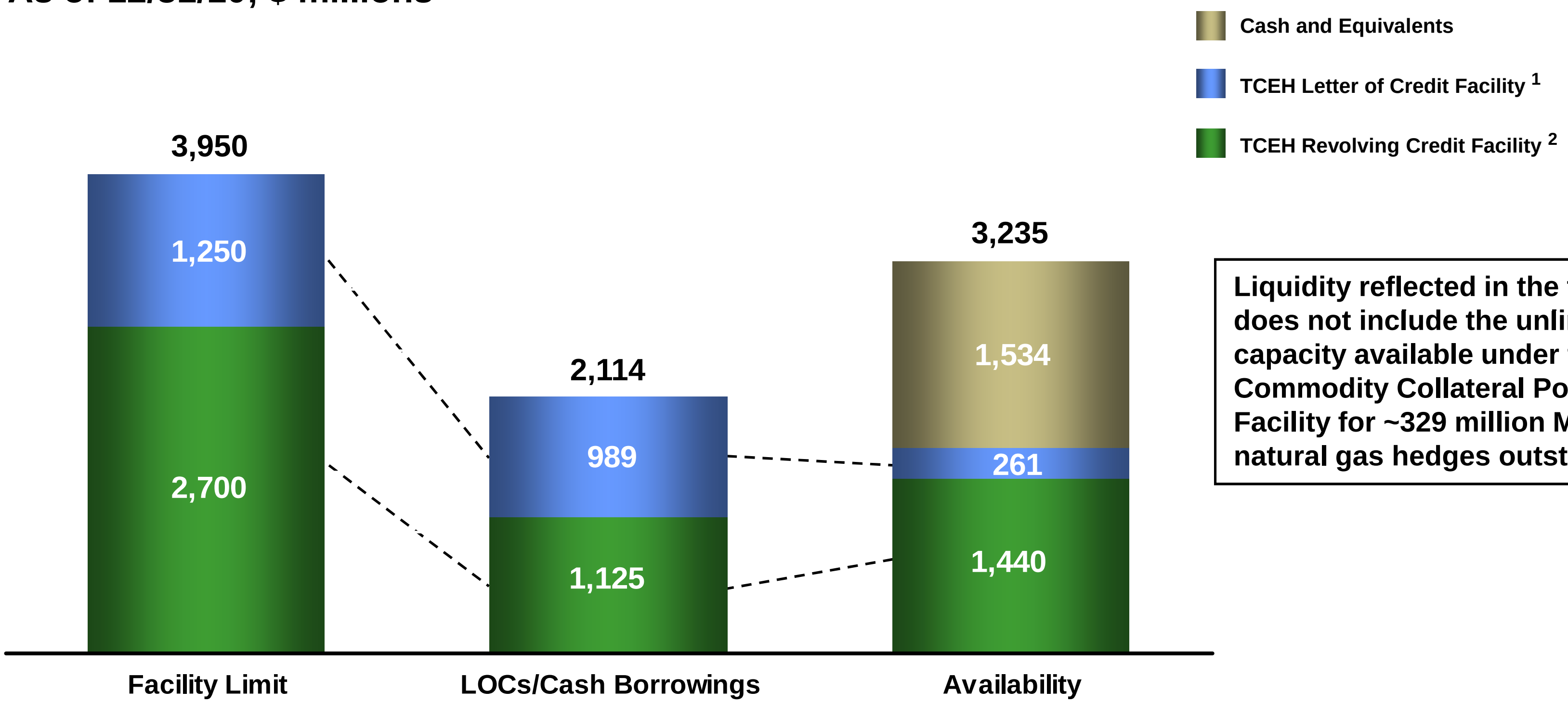
Q&A — **EFH Corp. Senior Executive Team**

Questions & Answers

Appendix – Additional Slides and Regulation G Reconciliations

EFH Corp. Liquidity Management

EFH Corp. (excluding Oncor) available liquidity
As of 12/31/10; $ millions



Liquidity reflected in the table does not include the unlimited capacity available under the Commodity Collateral Posting Facility for ~329 million MMBtu[3] of natural gas hedges outstanding.

EFH Corp. and TCEH have sufficient liquidity to meet their anticipated short-term needs, but will continue to monitor market conditions to ensure financial flexibility.

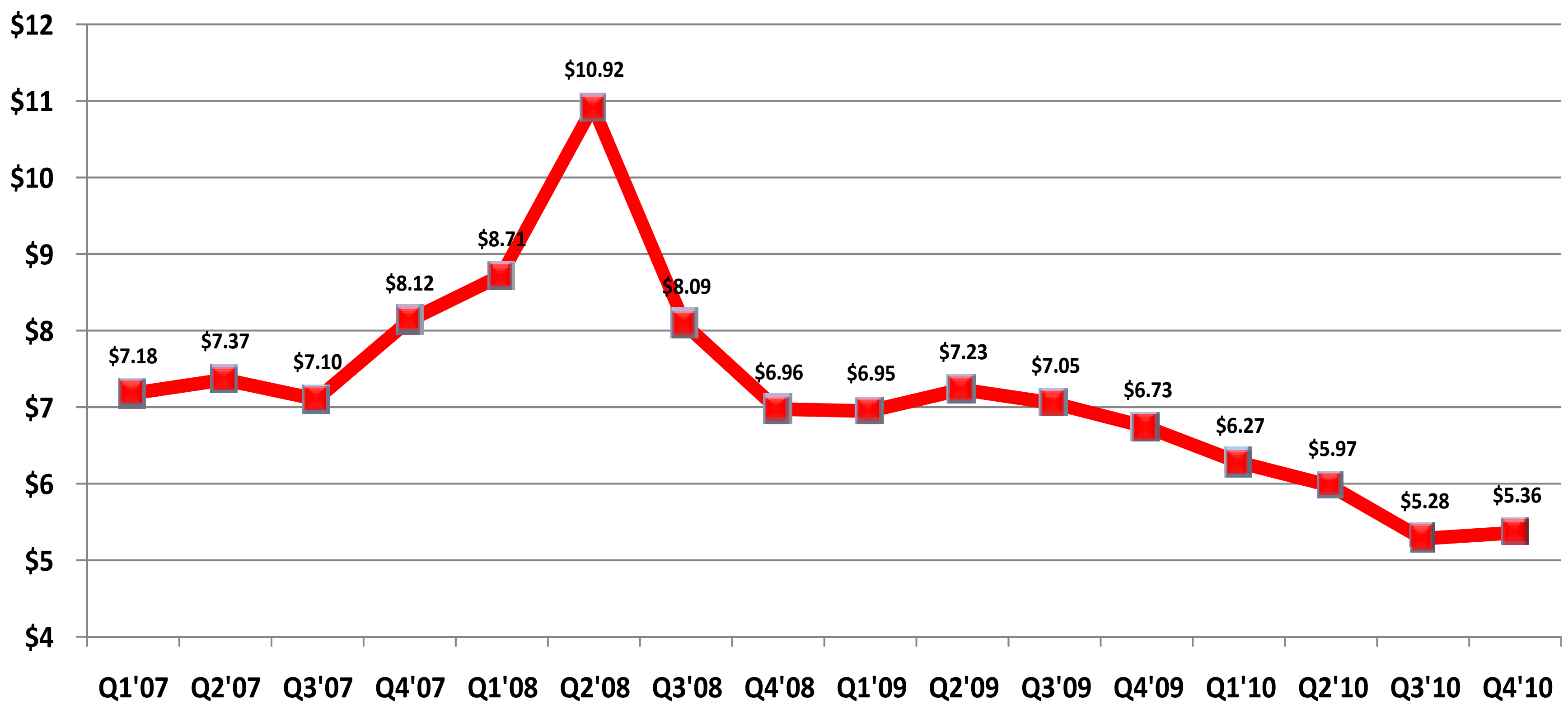
1 Facility to be used for issuing letters of credit for general corporate purposes. Cash borrowings of $1.250 billion were drawn on this facility in October 2007, and except for $115 million related to a letter of credit drawn in June 2009, have been retained as restricted cash. Outstanding letters of credit are supported by the restricted cash.

2 Facility availability includes $94 million of undrawn commitments from a subsidiary of Lehman Brothers that is in bankruptcy. These funds are only available from the fronting banks and the swingline lender, and exclude $135 million of requested draws not funded by the Lehman subsidiary.

3 Total capacity remaining for natural gas hedges under the CCP facility is ~420 million MMBtu of which TCEH currently has ~329 million MMBtu of hedges outstanding.

Historical 2014 Forward Natural Gas Prices

Historical 2014 Forward Houston Ship Channel (HSC) Gas Prices
Q1’07-Q4’10; $/MMBtu



Unrealized Mark-To-Market Impact Of Hedging

Unrealized mark-to-market impact of hedging program
12/31/10 vs. 12/31/09; mixed measures, pre-tax

Factor	Measure	2010	2011	2012	2013	2014	Total or Avg.
12/31/09							
Natural gas hedges	mm MMBtu	~240	~447	~490	~300	~97	~1,574
Wtd. avg. hedge price[1]	$/MMBtu	~$7.79	~$7.56	~$7.36	~$7.19	~$7.80	
Natural gas prices	$/MMBtu	~$5.79	~$6.34	~$6.53	~$6.67	~$6.84	
Cum. MtM gain at 12/31/09[2]	$ billions	~$0.8	~$0.4	~$0.4	~$0.2	~$0.2	~$2.0
12/31/10							
Natural gas hedges[3]	mm MMBtu	-	~220	~398	~282	~110	~1,010
Wtd. avg. hedge price[1]	$/MMBtu	-	~$7.56	~$7.36	~$7.19	~$7.80	
Natural gas prices	$/MMBtu	-	~$4.55	~$5.08	~$5.33	~$5.49	
Cum. MtM gain at 12/31/10[2]	$ billions	~$0	~$1.2	~$1.1	~$0.5	~$0.4	~$3.2
YTD10 MtM (loss) gain	$ billions	~($0.8)	~$0.8	~$0.7	~$0.3	~$0.2	~$1.2

Forward positions in the hedge program gained value due to lower natural gas prices as of the end of 2010, partially offset by losses resulting from the reversal of previously recognized gains during the year. Overall result for the year was a ~$1.2 billion (~$780 million after tax) unrealized net gain.

1 Weighted average prices are based on NYMEX Henry Hub prices of forward natural gas sales positions in the long-term hedging program (excluding the impact of offsetting purchases for rebalancing and pricing point basis transactions). Where collars are reflected, sales price represents the collar floor price. 12/31/10 prices for 2011 represent January 1, 2011 through December 31, 2011 values.

2 MtM values include the effects of all transactions in the long-term hedging program including offsetting purchases (for re-balancing) and natural gas basis deals.

3 As of 12/31/10. 2011 represents January 1, 2011 through December 31, 2011 volumes. Where collars are reflected, the volumes are estimated based on the natural gas price sensitivity (i.e., delta position) of the derivatives. The notional volumes for collars are approximately 150 million MMBtu, which corresponds to a delta position of approximately 110 million MMBtu in 2014.

Currently Installed[1] Environmental Control Equipment At Luminant Coal Units

✗ **Currently installed**

Coal Unit	Capacity (MW)	FGD (Scrubber)[2]	Activated Carbon Injection[3]	ESP[4]	SNCR[5]	SCR[5]	Bag-house[4]
Oak Grove 1	800	✗	✗			✗	✗
Oak Grove 2	800	✗	✗			✗	✗
Sandow 4	557	✗	✗	✗		✗	
Sandow 5	580	✗	✗		✗		✗
Martin Lake 1	750	✗	✗	✗			
Martin Lake 2	750	✗	✗	✗			
Martin Lake 3	750	✗	✗	✗			
Monticello 1	565		✗	✗	✗		✗
Monticello 2	565		✗	✗	✗		✗
Monticello 3	750	✗	✗	✗	✗		
Big Brown 1	575		✗	✗	✗		✗
Big Brown 2	575		✗	✗	✗		✗

[1] There is no assurance that the currently installed control equipment will satisfy the requirements under any change to applicable law or any future Environmental Protection Agency or Texas Commission on Environmental Quality regulations.
[2] FGD refers to flue gas desulfurization systems that reduce SO2 emissions with co-benefits of other emissions reductions.
[3] Activated carbon injection systems reduce mercury emissions.
[4] ESP refers to electro-static precipitation systems . ESP and bag-house systems reduce particulate emissions with co-benefits of other emissions reductions.
[5] SNCR refers to selective non-catalytic reduction systems. SCR refers to selective catalytic reduction systems. Both systems reduce Nox emissions.

2011 TCEH Adjusted EBITDA (non-GAAP) Key Drivers

Illustrative for discussion purposes

2010 TCEH Adjusted EBITDA

Key Drivers	2011 Est. Impact vs 2010 (millions)		Assumptions
Higher Baseload Generation	↑	$50 - $60	▪ 3 – 4 incremental TWh from new lignite units ▪ ~$15 / MWh average incremental margin[1]
Nuclear Outage	↓	$50 - $60	▪ 2 refueling outages in 2011 vs 1 in 2010 and related outage expenses
Mining / Expenses	↓	$60 - $70	▪ Higher emissions control costs (~$25mm) ▪ Higher lignite costs driven by aging deposits ▪ Higher healthcare, pension/OPEB expenses
Commodity	↓	$200 - $300	▪ Lower weighted average NG hedge price[2] of ~$0.22 - $0.25/mmbtu for ~540 mm mmbtu ▪ Higher heat rate of ~0.10 – 0.15 on ~73 - 75 TWh[3] ▪ Impact of normal weather & load related costs on 2011 asset management margins relative to 2010 ▪ Delivered PRB prices up ~$4/ton on ~14 mm tons
Retail	↓	$25 - $125	▪ Potential decline driven by lower customer count, price environment and normal weather in 2011
Development	↓	$50 - $70	▪ Reduced non-core asset sales in 2011

[1] Based on ERCOT North Hub 7X24 HSC power prices for 2011 of ~$33/MWh as of 9/30/10.

[2] Weighted average prices are based on NYMEX Henry Hub prices of forward natural gas sales positions in the long-term hedging program (excluding the impact of offsetting purchases for rebalancing and pricing point basis transactions).

[3] Excludes volume committed under a long term purchase contract.

2011 TCEH Open EBITDA (non-GAAP) Estimate

TCEH Open EBITDA (non-GAAP)[1] Estimate
11E: $ millions

Open EBITDA does not include:

- TXU Energy value proposition relative to competitors
- Asset management results
- Long-term wholesale contracts with load serving entities

Assumptions	Units	2011E
Wholesale		
Total baseload generation	TWh	78 – 81
Estimated power price[2]	$/MWh	$32 - $34
Average baseload cost[3]	$/MWh	$26 - $28
Retail		
Revenues[4]	$	$4.8 - $5.2B
Profitability percentage (after tax)[5]	%	5-10%

[1] Open EBITDA estimates assume generation is sold at market observed forward prices less production costs and retail volumes are sold at market observed retail rates and historical retail profitability percentage. Estimates exclude all impacts of natural gas and power hedging activities, specifically the impacts of the TCEH Long-Term Hedging Program and any heat rate hedges. Additionally, this calculation includes provisions for fuel expense and O&M based on expected power generation output along with purchased power for sales to retail customers, and SG&A based on the generation output and sales to retail customers. See Appendix for Regulation G definition.

[2] Estimated wholesale power prices for 2011 is based on average ERCOT North Hub prices as of 9/30/10.

[3] Includes fuel (excluding nuclear fuel amortization), O&M and SG&A expenses

[4] Based on an 10¢ / kWh average residential new offer pricing as reflected on the www.powertochoose.org and $ 2.3 billion of small and large business revenue based on trailing 12 months.

[5] Calculation assumes a 35% overall tax rate

Financial Definitions

Measure	Definition
Adjusted (non-GAAP) Operating Results	Net income (loss) adjusted for items representing income or losses that are not reflective of underlying operating results. These items include unrealized mark-to-market gains and losses, noncash impairment charges and other charges, credits or gains that are unusual or nonrecurring. EFH uses adjusted (non-GAAP) operating results as a measure of performance and believes that analysis of its business by external users is enhanced by visibility to both net income (loss) prepared in accordance with GAAP and adjusted (non-GAAP) operating earnings (losses).
Adjusted EBITDA (non-GAAP)	EBITDA adjusted to exclude interest income, noncash items, unusual items, income from discontinued operations and other adjustments allowable under the EFH senior secured notes indenture. Adjusted EBITDA plays an important role in respect of certain covenants contained in this indenture. Adjusted EBITDA is not intended to be an alternative to GAAP results 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 GAAP, nor is it intended to be used as a measure of free cash flow available for EFH'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, Adjusted EBITDA may not be comparable to similarly titled measures of other companies. See EFH's filings with the SEC for a detailed reconciliation of EFH's net income prepared in accordance with GAAP to Adjusted EBITDA.
Competitive Business Results	Refers to the combined results of the Competitive Electric segment and Corporate & Other.
Contribution Margin (non-GAAP)	Operating revenues less fuel, purchased power costs, and delivery fees, plus or minus net gain (loss) from commodity hedging and trading activities, which on an adjusted (non-GAAP) basis, exclude unrealized gains and losses.
EBITDA (non-GAAP)	Net income (loss) before interest expense and related charges, income tax expense (benefit) and depreciation and amortization.
GAAP	Generally accepted accounting principles.
Purchase Accounting	The purchase method of accounting for a business combination as prescribed by GAAP, whereby the purchase price of a business combination is 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. Depreciation and amortization due to purchase accounting represents the net increase in such noncash expenses due to recording the fair market values of property, plant and equipment, debt and other assets and liabilities, including intangible assets such as emission allowances, customer relationships and sales and purchase contracts with pricing favorable to market prices at the date of the Merger. Amortization is reflected in revenues, fuel, purchased power costs and delivery fees, depreciation and amortization and interest expense in the income statement.
Regulated Business Results	Refers to the results of Oncor and the Oncor ring-fenced entities.

Table 1: EFH Corp. Adjusted EBITDA Reconciliation
Three and Twelve Months Ended December 31, 2009 and 2010
$ millions

Factor	Q4 09	Q4 10	FY 09	FY 10
Net income (loss) attributable to EFH Corp.	137	161	344	(2,812)
Income tax expense	113	54	367	389
Interest expense and related charges	776	465	2,912	3,554
Depreciation and amortization	467	363	1,754	1,407
EBITDA	**1,493**	**1,043**	**5,377**	**2,538**
Adjustments to EBITDA (pre-tax):	-			
Oncor EBITDA	(310)	-	(1,354)	-
Oncor distributions	99	28	216	169
Interest income	(15)	(2)	(45)	(10)
Amortization of nuclear fuel	28	38	101	140
Purchase accounting adjustments[1]	83	51	340	210
Impairment of goodwill[2]	-	-	90	4,100
Impairment of assets and inventory write-down	37	12	42	15
Net gain on debt exchange offers	(87)	(648)	(87)	(1,814)
Net income attributable to noncontrolling interests	10	-	64	-
Equity in earnings of unconsolidated subsidiary	-	(37)	-	(277)
EBITDA amount attributable to consolidated unrestricted subsidiaries	-	1	3	1
Unrealized net (gain) loss resulting from hedging transactions	(513)	394	(1,225)	(1,221)
Amortization of "day one" net loss on Sandow 5 power purchase agreement	(3)	(3)	(10)	(22)
Losses on sale of receivables	3	-	12	-

Note: Table and footnotes to this table continue on following page

Table 1: EFH Adjusted EBITDA Reconciliation (continued from previous page)
Three and Twelve Months Ended December 31, 2009 and 2010
$ millions

Factor	Q4 09	Q4 10	FY 09	FY 10
Noncash compensation expense[3]	2	5	11	18
Severance expense[4]	1	1	10	4
Transition and business optimization costs[5]	-	6	22	4
Transaction and merger expenses[6]	16	11	81	48
Restructuring and other [7]	(3)	(118)	(14)	(117)
Expenses incurred to upgrade or expand a generation station[8]	-	-	100	100
EFH Corp. Adjusted EBITDA per Incurrence Covenant	**841**	**782**	**3,734**	**3,886**
Add Oncor Adjusted EBITDA (reduced by Oncor distributions)	197	301	1,123	1,354
EFH Corp. Adjusted EBITDA per Restricted Payments Covenant	**1,038**	**1,083**	**4,857**	**5,240**

1 Includes 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 includes certain credits not recognized in net income due to purchase accounting.

2 Reflects the noncash goodwill impairment recorded in the third quarter of 2010 and the completion in the first quarter of 2009 of the fair value calculation supporting the noncash goodwill impairment charge that was recorded in the fourth quarter of 2008.

3 Accounted for under accounting standards related to stock compensation and excludes capitalized amounts.

4 Includes amounts incurred related to outsourcing, restructuring and other amounts deemed to be in excess of normal recurring amounts.

5 Includes professional fees primarily for retail billing and customer care systems enhancements and certain incentive compensation.

6 Includes costs related to the 2007 merger and abandoned strategic transactions, outsourcing transition costs, administrative costs related to the cancelled program to develop coal-fueled facilities, the Sponsor Group management fee, costs related to certain growth initiatives and costs related to the Oncor sale of noncontrolling interests.

7 2010 includes a gain on termination of a long-term power sales contract. 2009 includes reversal of certain liabilities accrued in purchase accounting.

8 Reflects noncapital outage costs.

Table 2: TCEH Adjusted EBITDA Reconciliation
Three and Twelve Months Ended December 31, 2009 and 2010
$ millions

Factor	Q4 09	Q4 10	FY 09	FY 10
Net income (loss)	216	263	709	(3,383)
Income tax expense	117	142	447	402
Interest expense and related charges	502	320	1,833	2,837
Depreciation and amortization	310	353	1,172	1,380
EBITDA	1,145	1,078	4,161	1,236
Adjustments to EBITDA (pre-tax):				
Interest income	(24)	(26)	(64)	(91)
Amortization of nuclear fuel	28	38	101	140
Purchase accounting adjustments[1]	71	39	293	163
Impairment of goodwill[2]	-	-	70	13
Impairment of assets and inventory writedown	34	12	36	4,100
Net gain on debt exchange offers	-	(687)	-	(687)
EBITDA amount attributable to consolidated unrestricted subsidiaries	-	1	3	1
Unrealized net (gain) loss resulting from hedging transactions	(513)	394	(1,225)	(1,221)
Amortization of "day one" net loss on Sandow 5 power purchase agreement	(3)	(3)	(10)	(22)
Corp. depreciation, interest and income tax expense included in SG&A	1	-	6	9
Losses on sale of receivables	3	-	12	-
Noncash compensation expense[3]	-	3	1	14
Severance expense[4]	1	-	10	3
Transition and business optimization costs[5]	3	7	25	9
Transaction and merger expenses[6]	2	9	5	38

Note: Table and footnotes continue on following page

Table 2: TCEH Adjusted EBITDA Reconciliation (continued from previous page)
Three and Twelve Months Ended December 31, 2009 and 2010
$ millions

Factor	Q4 09	Q4 10	FY 09	FY 10
Restructuring and other[7]	(3)	(116)	(19)	(116)
Expenses incurred to upgrade or expand a generation station[8]	-	-	100	100
TCEH Adjusted EBITDA per Incurrence Covenant	**745**	**749**	**3,505**	**3,689**
Expenses related to unplanned generation station outages	30	10	91	132
Other adjustments allowed to determine Adjusted EBITDA per Maintenance Covenant[9]	17	10	38	29
TCEH Adjusted EBITDA per Maintenance Covenant	**792**	**769**	**3,634**	**3,850**

1 Includes 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 includes certain credits not recognized in net income due to purchase accounting.

2 Reflects the noncash goodwill impairment recorded in the third quarter of 2010 and the completion in the first quarter of 2009 of the fair value calculation supporting the noncash goodwill impairment charge that was recorded in the fourth quarter of 2008.

3 Excludes capitalized amounts.

4 Includes amounts incurred related to outsourcing, restructuring and other amounts deemed to be in excess of normal recurring amounts.

5 Includes professional fees primarily for retail billing and customer care systems enhancements and certain incentive compensation.

6 Includes costs related to the 2007 merger, outsourcing transition costs and costs related to certain growth initiatives.

7 2010 includes a gain on termination of a long-term power sales contract. 2009 includes reversal of certain liabilities accrued in purchase accounting.

8 Reflects noncapital outage costs.

9 Primarily pre-operating expenses related to Oak Grove and Sandow 5 generation facilities.

Table 3: Oncor Adjusted EBITDA Reconciliation
Three and Twelve Months Ended December 31, 2009 and 2010
$ millions

Factor	Q4 09	Q4 10	FY 09	FY 10
Net income	48	48	320	352
Income tax expense	33	41	173	215
Interest expense and related charges	88	88	346	347
Depreciation and amortization	152	166	557	673
EBITDA	321	343	1,396	1,587
Interest income	(11)	(9)	(43)	(38)
Purchase accounting adjustments[1]	(9)	(8)	(39)	(34)
Transition and business optimization costs	(6)	3	25	8
Oncor Adjusted EBITDA	295	329	1,339	1,523

[1] Purchase accounting adjustments consist of amounts related to the accretion of an adjustment (discount) to regulatory assets resulting from purchase accounting.

Table 4: EFH Free Cash Flow[1] Reconciliation
Twelve Months Ended December 31, 2010
$ millions

Factor	FY 10
Cash provided by operating activities	1,106
Cash used in investing activities	(468)
Other changes in restricted cash	33
Cash used in financing activities	(264)
Issuances of long-term debt	(853)
Repayments of long-term debt	1,351
Net short-term borrowings under accounts receivable securitization program	(96)
Increase (decrease) in other short-term borrowings	(172)
Free Cash Flow	**637**

[1] Free Cash Flow defined as Operating activities plus Investing activities excluding changes in restricted cash, plus Financing activities excluding issuances and repayments of debt and changes in short term borrowings.