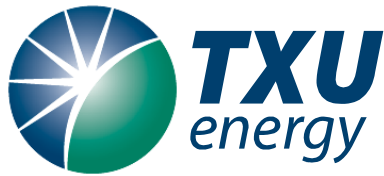


# Energy Future Holdings



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## EFH Corp. Q2 2011 Investor Call

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July 29, 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 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**

**Q2 2011 Review**

**Q&A**

# EFH Corp.

## Adjusted (Non-GAAP) Operating Results - QTR

**Consolidated: reconciliation of GAAP net income to adjusted (non-GAAP) operating results  
Q2<sup>1</sup> 10 vs. Q2 11 ; \$ millions, after tax**

Factor	Q2 10	Q2 11	Change
EFH Corp. GAAP net loss	(426)	(705)	(279)
<b>Items excluded from adjusted (non-GAAP) operating results (after tax) - noncash:</b>			
Unrealized commodity-related mark-to-market net losses	93	45	(48)
Unrealized mark-to-market net losses on interest rate swaps	165	262	97
Debt extinguishment gains	(83)	(16)	67
Third-party fees associated with April 2011 TCEH amendment and extension transactions	-	64	64
State income tax charge due to April 2011 TCEH amendment and extension transactions	-	13	13
<b>EFH Corp. adjusted (non-GAAP) operating loss</b>	<b>(251)</b>	<b>(337)</b>	<b>(86)</b>

<sup>1</sup> Three months ended June 30

# EFH Corp.

## Adjusted (Non-GAAP) Operating Results Key Drivers (after tax) - QTR

Consolidated key drivers of the change in (non-GAAP) operating results  
Q2<sup>1</sup> 10 vs. Q2 11; \$ millions, after tax

Description/Drivers	Better (Worse) Than Q2 10
<b>Competitive business<sup>2</sup>:</b>	
Lower net margin from asset management and retail activities, including commodity hedging	(49)
Higher fuel costs at legacy generation units primarily due to increased costs of purchased coal and related transportation	(8)
Impact of new lignite-fueled generation units	18
Higher retail consumption primarily due to warmer weather	11
Higher net production from legacy generation units	5
Lower amortization of intangibles arising from purchase accounting	3
<b>Contribution margin</b>	<b>(20)</b>
Gains in 2010 on sales of assets (reported in other income)	(48)
Higher net interest expense driven by higher amortization of debt issuance and amendment costs and lower capitalized interest	(20)
Higher depreciation reflecting the new lignite-fueled generation units and ongoing investment in the legacy generation fleet	(14)
Higher operating costs due to increased planned outage maintenance expense at nuclear generation facility and the impact of new lignite-fueled generation units	(12)
Lower retail bad debt expense reflecting improved collections and customer mix	7
Effect of accrued interest on uncertain income tax positions (included in income tax expense)	6
All other - net	2
<b>Total change - Competitive business</b>	<b>(99)</b>
<b>Regulated business:</b>	
Higher revenues from transmission rate and distribution tariff increases and growth in points of delivery	19
Higher revenues from increased consumption primarily due to warmer weather	16
Higher depreciation reflecting infrastructure investment	(9)
Higher transmission fees	(5)
Higher net interest expense	(2)
All other - net	(6)
<b>Total change - Regulated business (~80% owned by EFH Corp.)</b>	<b>13</b>
<b>Total change in EFH Corp. adjusted (non-GAAP) operating results</b>	<b>(86)</b>

<sup>1</sup> Three months ended June 30

<sup>2</sup> Competitive business consists of Competitive Electric segment and Corp. & Other.

# EFH Corp.

## Adjusted (Non-GAAP) Operating Results - YTD

**Consolidated: reconciliation of GAAP net income to adjusted (non-GAAP) operating results  
YTD<sup>1</sup> 10 vs. YTD 11 ; \$ millions, after tax**

Factor	YTD 10	YTD 11	Change
EFH Corp. GAAP net loss	(71)	(1,066)	(995)
<b>Items excluded from adjusted (non-GAAP) operating results (after tax) - noncash:</b>			
Unrealized commodity-related mark-to-market net (gains) losses	(546)	248	794
Unrealized mark-to-market net losses on interest rate swaps	235	170	(65)
Debt extinguishment gains	(93)	(16)	77
Third-party fees associated with April 2011 TCEH amendment and extension transactions	-	64	64
Gain related to counterparty bankruptcy settlement	-	(14)	(14)
Income tax charges <sup>2</sup>	8	13	5
<b>EFH Corp. adjusted (non-GAAP) operating loss</b>	<b>(467)</b>	<b>(601)</b>	<b>(134)</b>

<sup>1</sup> Six months ended June 30

<sup>2</sup> YTD 2010 charges recorded as a result of health care legislation in 2010; YTD 2011 state income tax charges recorded as a result of TCEH amendment and extension transaction.

# EFH Corp.

## Adjusted (Non-GAAP) Operating Results Key Drivers (after tax) - YTD

Consolidated key drivers of the change in (non-GAAP) operating results  
YTD<sup>1</sup> 10 vs. YTD 11; \$ millions, after tax

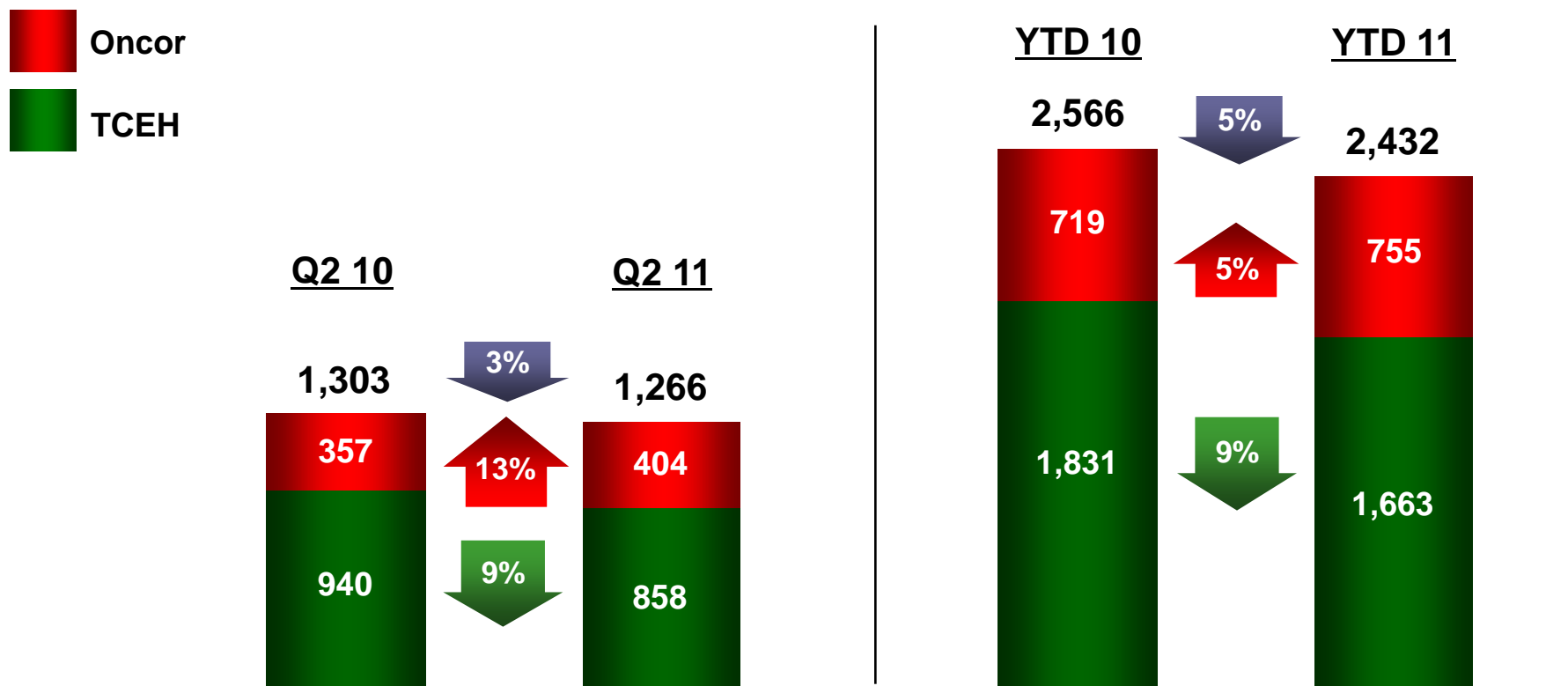
Description/Drivers	Better (Worse) Than YTD 10
<b>Competitive business<sup>2</sup>:</b>	
Lower net margin from asset management and retail activities, including commodity hedging	(96)
Impact of winter weather event	(17)
Higher fuel costs at legacy generation units primarily due to increased costs of purchased coal and related transportation	(14)
Impact of new lignite-fueled generation units	36
Lower amortization of intangibles arising from purchase accounting	10
All other – net	(9)
<b>Contribution margin</b>	<b>(90)</b>
Gains in 2010 on sales of assets (reported in other income)	(52)
Higher depreciation reflecting the new lignite-fueled generation units and ongoing investment in the legacy generation fleet	(31)
Higher operating costs due to increased planned outage maintenance expense at nuclear generation facility and the impact of new lignite-fueled generation units	(24)
Lower retail bad debt expense reflecting improved collections and customer mix	21
Lower net interest expense driven by reduced amortization of dedesignated swap losses	14
Lower accrued interest on uncertain tax positions	14
Other - net	14
<b>Total change - Competitive business</b>	<b>(134)</b>
<b>Regulated business:</b>	
Higher net revenues reflecting transmission rate and distribution tariff increases, including AMS surcharge and growth in points of delivery	32
Higher revenues from increased consumption primarily due to warmer weather	5
Higher depreciation reflecting infrastructure investment	(12)
Higher operating costs, primarily transmission fees and vegetation management expense	(11)
Higher net interest expense driven by average rates	(5)
Lower accretion resulting from purchase accounting	(4)
All other – net	(5)
<b>Total change - Regulated business (~80% owned by EFH Corp.)</b>	<b>-</b>
<b>Total change in EFH Corp. adjusted (non-GAAP) operating results</b>	<b>(134)</b>

<sup>1</sup> Six months ended June 30

<sup>2</sup> Competitive business consists of Competitive Electric segment and Corp. & Other.

# EFH Corp. Adjusted EBITDA (Non-GAAP)

EFH Corp. Adjusted EBITDA (non-GAAP)<sup>1</sup>  
 Q2<sup>2</sup> 10 vs. Q2 11 and YTD<sup>3</sup> 10 vs. YTD 11; \$ millions



*Q2 and YTD performance was largely driven by the same key drivers impacting adjusted (non-GAAP) operating results. Adjusted EBITDA includes cash proceeds from sale of mineral interests of \$43 million which is not included in GAAP operating results.*

<sup>1</sup> See Appendix for Regulation G reconciliations and definition. Includes \$6 million, \$4 million, \$16 million and \$14 million in Q2 10, Q2 11, YTD 10 and YTD 11, respectively, of Corp. & Other Adjusted EBITDA.

<sup>2</sup> Three months ended June 30

<sup>3</sup> Six months ended June 30

# Luminant Operational Results





**Luminant**

## Q2 2011 Nuclear Plant Results

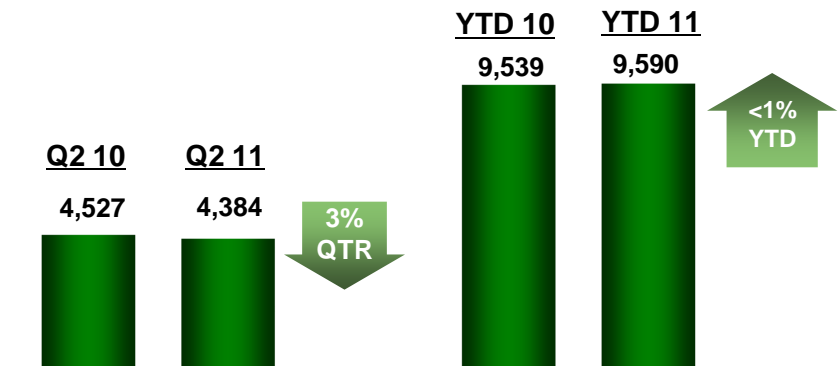
- Solid safety performance
- Refueling outages in both Q2 2011 and Q2 2010; lower generation due to unplanned outage
- Top decile industry performance for reliability and cost

## Q2 2011 Coal-Fueled Plant Results

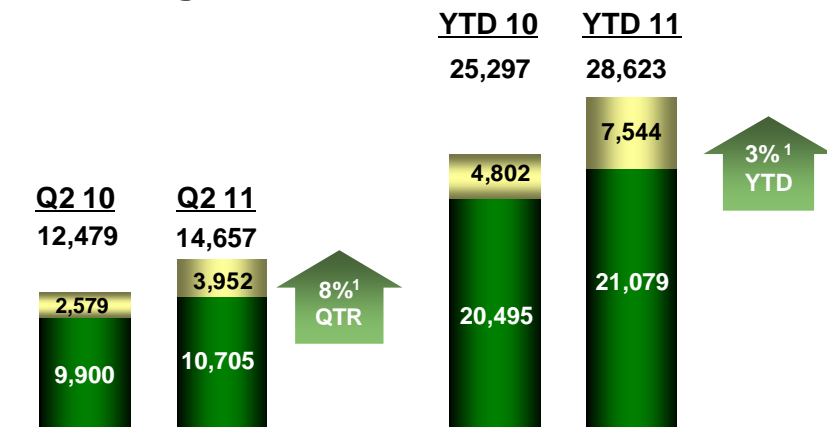
- New plants operated at ~83% capacity factor for 1.4 TWh higher generation
- Higher legacy coal-fueled generation due to fewer planned outages and improved reliability
- Top quartile industry performance

 Sandow 5 & Oak Grove  
 Legacy coal-fueled plants

## Nuclear-fueled generation; GWh



## Coal-fueled generation; GWh



<sup>1</sup> Variance does not include generation from Sandow 5 and Oak Grove 1 & 2.

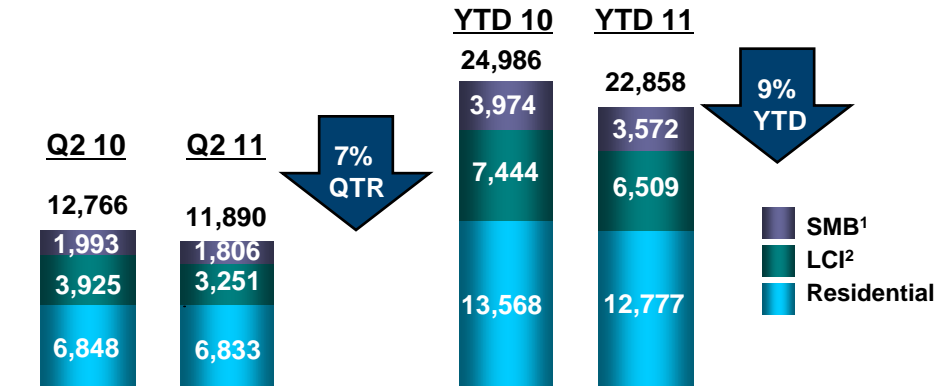
# TXU Energy Operational Results



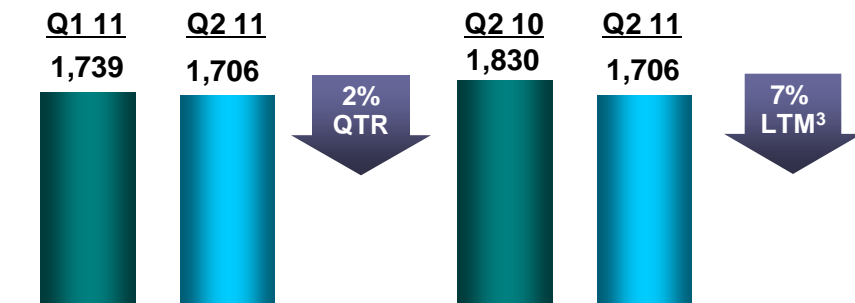
## Q2 2011 Results

- Lower LCI volumes reflect competitive intensity and TXU Energy focus on margin discipline
- Lower residential sales volumes driven by lower customer counts offset by warmer weather in Q2 11 compared to Q2 10
- Launched TXU Energy FlexPower prepaid product to expand customer base for control focused, cash based and deposit required customer segments

## Retail electricity sales volumes by customer class; GWh



## Total residential customers End of period, thousands



<sup>1</sup> SMB – small business  
<sup>2</sup> LCI - large commercial and industrial  
<sup>3</sup> Latest twelve months

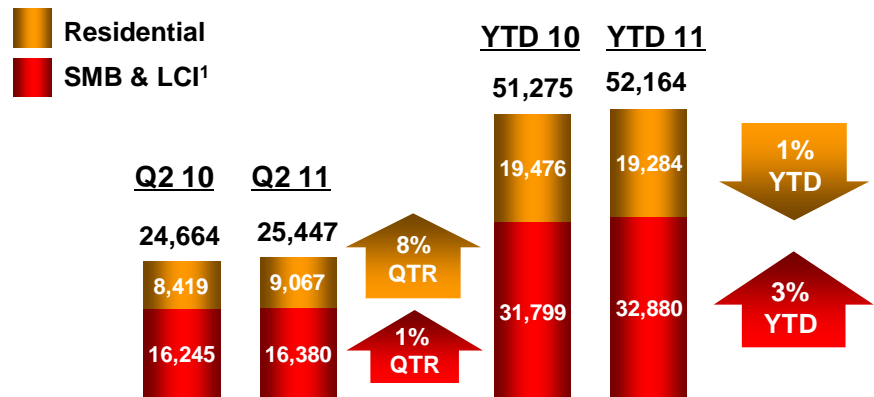
# Oncor Operational Results



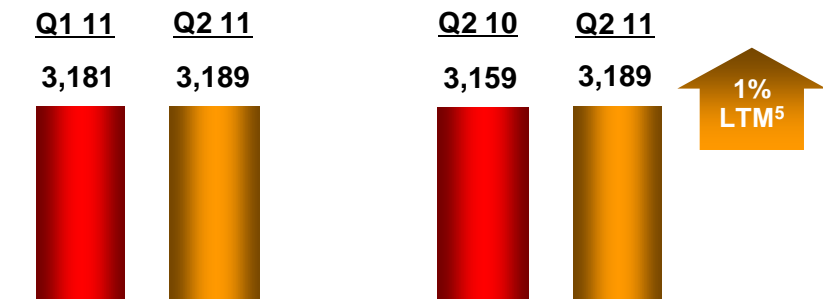
## Q2 2011 Results

- Higher volumes principally due to warmer weather in Q2 11 compared to Q2 10
- Higher SMB & LCI<sup>1</sup> energy volumes due to improved economy and warmer weather
- Execution of AMS<sup>2</sup> plan – ~227,000 advanced meters installed during Q2 11; over 1.8 million installed through June 30, 2011
- \$538 million spent on CREZ<sup>3</sup> through June 30, 2011; \$222 million spent YTD 11

## Electric energy billed volumes<sup>4</sup>; GWh



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



<sup>1</sup> SMB – small business; LCI – large commercial and industrial

<sup>2</sup> AMS – Advanced Metering System

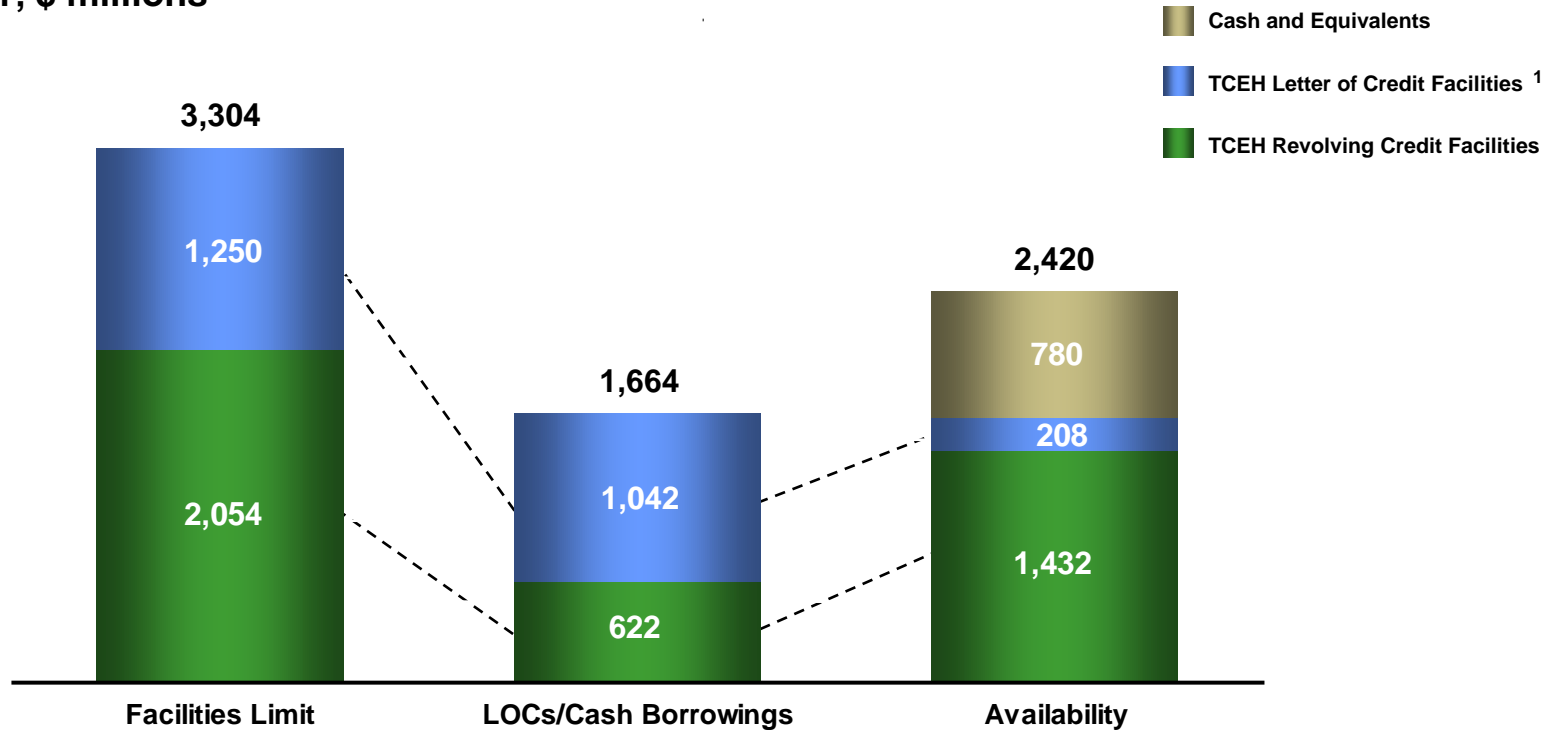
<sup>3</sup> CREZ – Competitive Renewable Energy Zone

<sup>4</sup> On average, billed volumes are on an approximate 17-day calendar lag; therefore, amounts shown reflect partial impacts from prior quarters

<sup>5</sup> Latest twelve months

# EFH Corp. Liquidity Management As of June 30, 2011

EFH Corp. (excluding Oncor) available liquidity  
As of 6/30/11; \$ millions



*EFH Corp. and TCEH continue to monitor capital market conditions to ensure liquidity needs and financial flexibility.*

<sup>1</sup> 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.

# Commodity Prices

## Commodity prices Q2 11, Q2 10, YTD 11 and BOY 11E; mixed measures

Commodity	Units	Q2 11 Actual	Q2 10 Actual	YTD 11 Actual	BOY 11E <sup>1</sup>
NYMEX gas price <sup>2</sup>	\$/MMBtu	\$4.35	\$4.30	\$4.26	\$4.47
HSC gas price	\$/MMBtu	\$4.32	\$4.25	\$4.21	\$4.46
7x24 market heat rate (HSC) <sup>3</sup>	MMBtu/MWh	8.08	8.17	8.72	8.42
North Hub 7x24 power price <sup>4</sup>	\$/MWh	\$34.82	\$34.85	\$36.95	\$37.51
TCEH weighted avg. hedge price <sup>5</sup>	\$/MMBtu	\$7.35	\$7.51	\$7.64	\$7.49
Gulf Coast ultra-low sulfur diesel	\$/gallon	\$3.08	\$2.14	\$2.95	\$3.00
PRB 8400 coal	\$/ton	\$10.36	\$9.59	\$10.91	\$11.40
LIBOR interest rate <sup>6</sup>	percent	0.42%	0.63%	0.44%	0.40%

<sup>1</sup> BOY 11 estimate based on commodity prices as of 06/30/11 for July 1, 2011 through December 31, 2011

<sup>2</sup> Based on NYMEX forward curve

<sup>3</sup> Based on ERCOT market clearing price for North Hub power for 2011 and ERCOT market clearing price for North Zone for 2010

<sup>4</sup> Excluding the volatile pricing that occurred in early February 2011 (2<sup>nd</sup> and 3<sup>rd</sup>), North Hub 7X24 power prices averaged approximately \$32.54 and the 7X24 market heat rate averaged 7.71 MMBtu/MWh during the first 6 months of 2011

<sup>5</sup> 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). The index for the settled value is a 6-month LIBOR rate.

<sup>6</sup> The index for the settled value is a six-month LIBOR rate

# Unrealized Mark-To-Market Impact Of Hedging

## Unrealized mark-to-market impact of hedging program 06/30/11 vs. 3/31/11; mixed measures, pre-tax

Factor	Measure	2011	2012	2013	2014	2015	Total or Avg.
<b>3/31/11</b>							
Natural gas hedges	mm MMBtu	~150	~398	~274	~149	~0	~971
Wtd. avg. hedge price	\$/MMBtu	~\$7.45	~\$7.36	~\$7.19	~\$7.80	N/A	
Natural gas prices	\$/MMBtu	~\$4.57	~\$5.06	~\$5.41	~\$5.73	~\$6.08	
Cum. MtM gain at 3/31/11 <sup>2</sup>	\$ billions	~\$0.8	~\$1.1	~\$0.5	~\$0.4	N/A	~\$2.8
<b>06/30/11</b>							
Natural gas hedges <sup>3</sup>	mm MMBtu	~88	~383	~265	~149	~0	~885
Wtd. avg. hedge price <sup>1</sup>	\$/MMBtu	~\$7.49	~\$7.36	~\$7.19	~\$7.80	N/A	
Natural gas prices	\$/MMBtu	~\$4.47	~\$4.84	~\$5.16	~\$5.42	~\$5.70	
Cum. MtM gain at 06/30/11 <sup>2</sup>	\$ billions	~\$0.6	~\$1.2	~\$0.6	~\$0.4	~\$0	~\$2.7
Q2 11 MtM (loss) gain	\$ billions	~\$(0.2)	~\$0.1	~\$0.1	~\$0	N/A	~\$(0.1)

*The overall value of the hedge program remained relatively flat as transactions maturing during the quarter were offset by increases in value in the forward years of the program.*

<sup>1</sup> 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. 6/30/11 prices for 2011 represent July 1, 2011 through December 31, 2011 values.

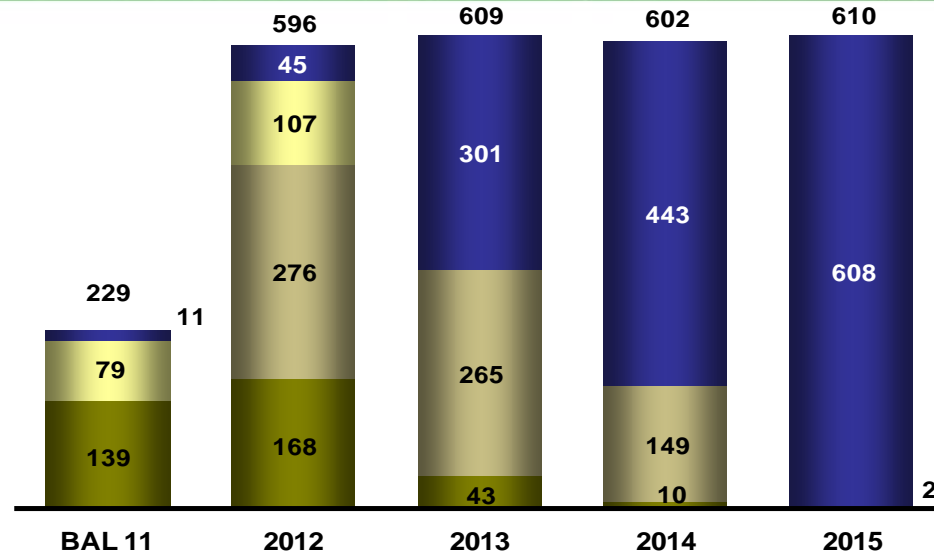
<sup>2</sup> MtM values include the effects of all transactions in the long-term hedging program including offsetting purchases (for re-balancing) and natural gas basis deals.

<sup>3</sup> As of 6/30/11, 2011 represents July 1, 2011 through December 31, 2011 volumes. Where collars are reflected, the volumes are estimated based on the notional position of the derivatives to provide protection against downward price movements. The notional volumes for collars are approximately 150 million MMBtu, which corresponds to a delta position of approximately 115 million MMBtu in 2014.

# TCEH Natural Gas Exposure

## TCEH Natural Gas Position 11-15<sup>1</sup>; million MMBtu

- Open Position
- Hedges Backed by CCP
- Hedges Backed by Asset First Lien
- TXUE and Luminant Net Positions<sup>2</sup>
- - - 100% Hedge Level



Factor	Measure	BAL 11	2012	2013	2014	2015	Total or Average
Natural gas hedging program	million MMBtu	~79	~383	~265	~149	~0	~876
TXUE and Luminant net positions	million MMBtu	~139	~168	~43	~10	~2	~362
Overall estimated percent of total NG position hedged	percent	~95%	~93%	~51%	~26%	~0%	~47%

*TCEH has hedged approximately 47% of its estimated Henry Hub-based natural gas price exposure from August 1, 2011 through December 31, 2015. More than 90% of the margin requirements for the NG Hedges are supported directly by a first lien or by the TCEH Commodity Collateral Posting Facility.*

<sup>1</sup> As of 06/30/11. Balance of 2011 is from August 1, 2011 to December 31, 2011. Assumes conversion of electricity positions based on a ~8.0 heat rate with natural gas generally 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).

<sup>2</sup> Includes estimated retail/wholesale effects. 2011 position includes ~2 million MMBtu of short gas positions associated with proprietary trading positions; excluding these positions, 2011 position is ~94% hedged.

# EFH Corp. Adjusted EBITDA Sensitivities

## Impact on EFH Corp. Adjusted EBITDA<sup>1</sup> 11E; mixed measures

Commodity	Percent Hedged at June 30, 2011	Change	BOY 11E Impact \$ millions
7X24 market heat rate (MMBtu/MWh) <sup>2</sup>	~90	0.1 MMBtu/MWh	~2
NYMEX gas price (\$/MMBtu)	>95	\$1/MMBtu	~11
Texas gas vs. NYMEX Henry Hub price (\$/MMBtu) <sup>3,4</sup>	~90	\$0.10/MMBtu	~2
Diesel (\$/gallon) <sup>5</sup>	>95	\$1/gallon	~1
Base coal (\$/ton) <sup>6</sup>	>95	\$2/ton	~1
<b>Generation operations</b>			
Nuclear- and coal / lignite-fueled generation (TWh)	N/A	1 TWh	~15
<b>Retail operations</b>			
	FY 2011		
Residential contribution margin (\$/MWh)	13 TWh	\$1/MWh	~13
Residential consumption	13 TWh	1%	~4
Business markets consumption	11 TWh	1%	~1

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

<sup>1</sup> 2011 estimate based on commodity positions as of 06/30/11, net of long-term hedges and wholesale/retail effects, excludes gains and losses incurred prior to June 30, 2011. See Appendix for definition.

<sup>2</sup> Simplified representation of heat rate position in a single TWh position. In reality, heat rate impacts are differentiated across plants and respective pricing periods: nuclear- and coal / lignite-fueled plants (linked primarily to changes in North Hub 7x24), natural gas plants (primarily North Hub 5x16) and wind (primarily West Hub7x8).

<sup>3</sup> Assumes conversion of electricity positions based on a ~8.0 market heat rate with natural gas generally 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).

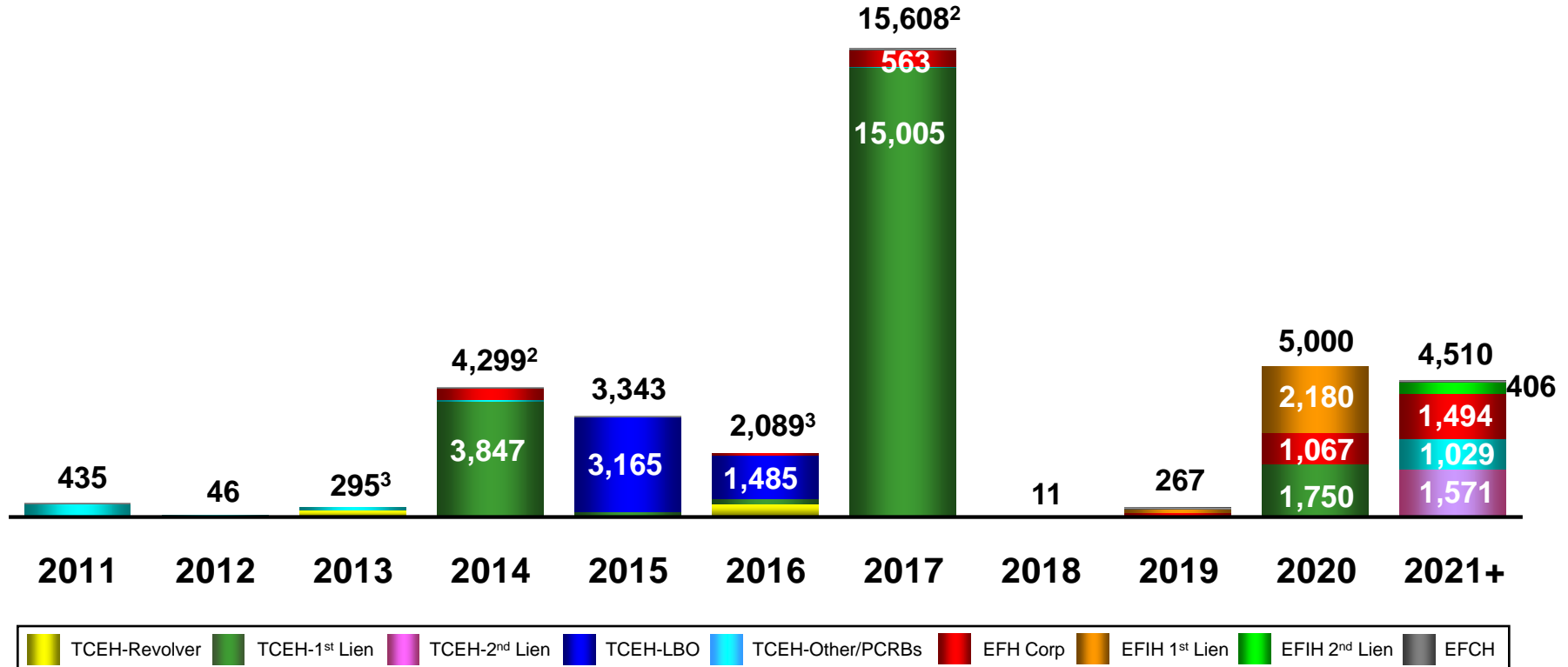
<sup>4</sup> The percentage hedged represents the amount of estimated natural gas exposure based on Houston Ship Channel (HSC) gas price sensitivity as a proxy for Texas gas price.

<sup>5</sup> Includes positions related to fuel surcharge on rail transportation.

<sup>6</sup> Excludes fuel surcharge on rail transportation.

# EFH Corp. Maturity Profile

EFH Corp. debt maturities<sup>1</sup> (excluding Oncor), 2011-2021 and thereafter  
As of 6/30/11; \$ millions



<sup>1</sup> Includes amortization of the \$15.4 billion Term Loan/DDTL facility beginning in Q4 2014 and excludes unamortized discounts and premiums.

<sup>2</sup> Excludes the Deposit Letter of Credit Loans maturing in 2014 and 2017.

<sup>3</sup> Non-Extended Revolver and Extended Revolver capacities are \$645 million and \$1.409 billion respectively.

# Today's Agenda

**Financial and Operational  
Overview**

**Q2 2011 Review**

**John Young  
President & CEO**

**Q&A**

# Currently Installed<sup>1</sup> Environmental Control Equipment At Luminant Coal Units

**x** Currently installed

Coal Unit	Capacity (MW)	FGD (Scrubber) <sup>2</sup>	Activated Carbon Injection <sup>3</sup>	ESP <sup>4</sup>	SNCR <sup>5</sup>	SCR <sup>5</sup>	Bag-house <sup>4</sup>	Fuel Source
Oak Grove 1	800	x	x			x	x	Lignite
Oak Grove 2	800	x	x			x	x	Lignite
Sadow 4	557	x	x	x		x		Lignite
Sadow 5	580	x	x		x		x	Lignite
Martin Lake 1	750	x	x	x				Lignite/PRB <sup>6</sup>
Martin Lake 2	750	x	x	x				Lignite/PRB
Martin Lake 3	750	x	x	x				Lignite/PRB
Monticello 1	565		x	x	x		x	Lignite/PRB
Monticello 2	565		x	x	x		x	Lignite/PRB
Monticello 3	750	x	x	x	x			Lignite/PRB
Big Brown 1	575		x	x	x		x	Lignite/PRB
Big Brown 2	575		x	x	x		x	Lignite/PRB

<sup>1</sup> 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.

<sup>2</sup> FGD refers to flue gas desulfurization systems that reduce SO<sub>2</sub> emissions with co-benefits of other emissions reductions.

<sup>3</sup> Activated carbon injection systems reduce mercury emissions.

<sup>4</sup> ESP refers to electro-static precipitation systems. ESP and bag-house systems reduce particulate emissions with co-benefits of other emissions reductions.

<sup>5</sup> SNCR refers to selective non-catalytic reduction systems. SCR refers to selective catalytic reduction systems. Both systems reduce NO<sub>x</sub> emissions.

<sup>6</sup> PRB refers to Powder River Basin coal transported to plants via railcar.

# Cross State Air Pollution Rule Compliance Options

- Emissions reduction must be achieved beginning January 1, 2012; impossible to retrofit units in time to reach required emissions reductions beginning that date
- Existing scrubbers on our legacy units cannot achieve 90-95% reductions
- Switching from lignite to PRB (lower sulfur) fuel would have significant impacts on Texas jobs; switching will impact costs and result in de-rates until boiler components can be replaced
- Expect insufficient near-term liquidity in emissions markets to buy required allowances
- Near-term compliance will require deploying a combination of the compliance options listed below:

Option	Why We Are Considering This Option
<ul style="list-style-type: none"> <li>• Dry sorbent injection (DSI), assuming adequate supply of sorbent</li> </ul>	<ul style="list-style-type: none"> <li>• DSI potentially promising in SO<sub>2</sub> removal; not yet proven on large scale or with sustained operations. Sorbent market depth not fully tested</li> </ul>
<ul style="list-style-type: none"> <li>• Increased levels of scrubber utilization at sites with installed equipment</li> </ul>	<ul style="list-style-type: none"> <li>• At legacy Luminant units, maximum scrubber emissions reductions generally in the 80-85% range before causing significant unit capacity reductions</li> </ul>
<ul style="list-style-type: none"> <li>• Fuel switching</li> </ul>	<ul style="list-style-type: none"> <li>• Switching from lignite to PRB fuel would reduce emissions, but impacts costs, jobs, and infrastructure</li> <li>• Fuel switching at Luminant units requires de-rates due to higher boiler temperatures until large boiler components can be replaced</li> <li>• May be in conjunction with mothballing/closure of related lignite mines</li> </ul>
<ul style="list-style-type: none"> <li>• Reduced operating levels or seasonal/temporary shut-downs at certain fossil plants</li> </ul>	<ul style="list-style-type: none"> <li>• Reduced operations may be required to ensure compliance, due to impossibility of achieving sufficient reductions through other means beginning January 1, 2012</li> <li>• Options include systematic reductions in operating levels, seasonal shutdowns, temporary shutdowns, or mothballing certain fossil units</li> </ul>
<ul style="list-style-type: none"> <li>• Mothballing certain fossil-fueled units and lignite mines</li> </ul>	<ul style="list-style-type: none"> <li>• Mothballing certain units may be efficient, due to impossibility of achieving reductions with current scrubbers or retrofitting by January 1, 2012</li> <li>• Fuel switching to PRB would lead to lack of demand for lignite</li> </ul>

# Luminant Coal/Lignite Plant And Mine Employees

Plant/Mine Site	FTEs <sup>1</sup>
Big Brown Plant	121
Big Brown Mine	225
Martin Lake Plant	256
Martin Lake Mine	688
Monticello Plant	195
Monticello Mine	289
Sadow Plant	145
Three Oaks Mine	259
Oak Grove Plant	149
Kosse Mine	319
<b>Total coal/lignite plant employees</b>	<b>866</b>
<b>Total mine employees</b>	<b>1,780</b>
<b>Luminant – total coal/lignite plant and mine employees</b>	<b>2,646</b>

<sup>1</sup> Full Time Equivalent employees as of June 30, 2011

# Today's Agenda

**Financial and Operational  
Overview**

**Q2 2011 Review**

**Q&A**

**EFH Corp. Senior Executive Team**

# Questions & Answers

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## **Appendix – Additional Slides and Regulation G Reconciliations**

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# 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 Six Months Ended June 30, 2010 and 2011

\$ millions

Factor	Q2 10	Q2 11	YTD 10	YTD 11
Net loss attributable to EFH Corp.	(426)	(705)	(71)	(1,066)
Income tax benefit	(237)	(384)	(35)	(599)
Interest expense and related charges	1,122	1,301	2,074	1,945
Depreciation and amortization	350	371	692	740
<b>EBITDA</b>	<b>809</b>	<b>583</b>	<b>2,660</b>	<b>1,020</b>
<b>Adjustments to EBITDA (pre-tax):</b>				
Oncor distributions/dividends	57	16	87	32
Interest income	-	-	(9)	(2)
Amortization of nuclear fuel	27	32	64	69
Purchase accounting adjustments <sup>1</sup>	58	88	114	138
Impairment of assets and inventory write-down <sup>2</sup>	2	1	2	1
Net gain on debt exchange offers	(129)	(25)	(143)	(25)
Equity in earnings of unconsolidated subsidiary	(59)	(72)	(122)	(122)
Unrealized net (gain) loss resulting from hedging transactions	145	69	(848)	385
Amortization of "day one" net loss on Sandow 5 power purchase agreement	(5)	-	(11)	-
Noncash compensation expense <sup>3</sup>	4	3	13	3
Severance expense	-	2	3	5
Transition and business optimization costs <sup>4</sup>	-	9	-	14
Transaction and merger expenses <sup>5</sup>	11	9	24	18
Restructuring and other <sup>6</sup>	6	100	-	73
Expenses incurred to upgrade or expand a generation station <sup>7</sup>	77	64	100	100
<b>EFH Corp. Adjusted EBITDA per Incurrence Covenant</b>	<b>1,003</b>	<b>879</b>	<b>1,934</b>	<b>1,709</b>
<b>Add back Oncor adjustments</b>	<b>300</b>	<b>387</b>	<b>632</b>	<b>723</b>
<b>EFH Corp. Adjusted EBITDA per Restricted Payments Covenant</b>	<b>1,303</b>	<b>1,266</b>	<b>2,566</b>	<b>2,432</b>

<sup>1</sup> 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 and gains on asset sales not recognized in net income due to purchase accounting.

<sup>2</sup> Impairment of assets includes impairments of land.

<sup>3</sup> Represents amounts recorded under stock-based compensation accounting standards and excludes capitalized amounts.

<sup>4</sup> Includes incentive compensation expenses and professional fees primarily for retail billing and customer care systems enhancements.

<sup>5</sup> Includes costs related to the 2007 merger and abandoned strategic transactions, the Sponsor Group management fee, outsourcing transition costs, administrative costs related to the cancelled program to develop coal-fueled facilities, and costs related to certain growth initiatives.

<sup>6</sup> Includes net third-party fees paid in connection with the amendment and extension of the TCEH Senior Secured Facilities, gains on termination of a long-term power sales contract and settlement of amounts due from a hedging/trading counterparty and reversal of certain liabilities accrued in purchase accounting.

<sup>7</sup> Reflects noncapital outage costs.

## Table 2: TCEH Adjusted EBITDA Reconciliation Three and Six Months Ended June 30, 2010 and 2011 \$ millions

Factor	Q2 10	Q2 11	YTD 10	YTD 11
Net income (loss)	(406)	(650)	43	(951)
Income tax expense (benefit)	(212)	(343)	46	(499)
Interest expense and related charges	915	1,150	1,664	1,651
Depreciation and amortization	344	364	681	726
<b>EBITDA</b>	<b>641</b>	<b>521</b>	<b>2,434</b>	<b>927</b>
<b>Adjustments to EBITDA (pre-tax):</b>				
Interest income	(21)	(19)	(42)	(46)
Amortization of nuclear fuel	27	32	64	69
Purchase accounting adjustments <sup>1</sup>	47	77	91	115
Impairment of assets and inventory write down <sup>2</sup>	1	-	1	-
Unrealized net (gain) loss resulting from hedging transactions	145	69	(848)	385
EBITDA amount attributable to consolidated unrestricted subsidiaries	-	(1)	-	(3)
Amortization of "day one" net loss on Sandow 5 power purchase agreement	(5)	-	(11)	-
Corp. depreciation, interest and income tax expense included in SG&A	3	4	5	7
Noncash compensation expense <sup>3</sup>	3	3	10	3
Severance expense	-	2	3	2
Transition and business optimization costs <sup>4</sup>	1	9	2	15
Transaction and merger expenses <sup>5</sup>	10	8	21	19
Restructuring and other <sup>6</sup>	11	89	1	70
Expenses incurred to upgrade or expand a generation station <sup>7</sup>	77	64	100	100
<b>TCEH Adjusted EBITDA per Incurrence Covenant</b>	<b>940</b>	<b>858</b>	<b>1,831</b>	<b>1,663</b>
Expenses related to unplanned generation station outages	32	33	91	91
Pro forma adjustment for Oak Grove 2 reaching 70% average capacity in Q2 2011 <sup>8</sup>	-	25	-	25
Other adjustments allowed to determine Adjusted EBITDA per Maintenance Covenant <sup>9</sup>	4	-	9	8
<b>TCEH Adjusted EBITDA per Maintenance Covenant</b>	<b>976</b>	<b>916</b>	<b>1,931</b>	<b>1,787</b>

<sup>1</sup> 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 and gains on asset sales not recognized in net income due to purchase accounting.

<sup>2</sup> Includes impairment of land.

<sup>3</sup> Includes expenses recorded under stock-based compensation accounting standards and excludes capitalized amounts.

<sup>4</sup> Includes incentive compensation expenses and professional fees primarily for retail billing and customer care systems enhancements.

<sup>5</sup> Includes costs related to the 2007 merger, the Sponsor Group management fee, outsourcing transition costs and costs related to certain growth initiatives.

<sup>6</sup> Includes net third-party fees paid in connection with the amendment and extension of the TCEH Senior Secured Facilities, gains on termination of a long-term power sales contract and settlement of amounts due from a hedging/trading counterparty, and reversal of certain liabilities accrued in purchase accounting.

<sup>7</sup> Reflects noncapital outage costs.

<sup>8</sup> Represents the annualization of the actual three months ended June 30, 2011 EBITDA results for Oak Grove 2. The TCEH senior secured facilities provide that upon achievement of 70% average capacity factor the applicable unit's EBITDA shall be included in the EBITDA calculation.

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

## Table 3: Oncor Adjusted EBITDA Reconciliation Three Months Ended June 30, 2010 and 2011 \$ millions

Factor	Q2 10	Q2 11	YTD 10	YTD 11
Net income	76	92	155	157
Income tax expense	47	58	96	98
Interest expense and related charges	86	88	170	177
Depreciation and amortization	164	178	331	350
<b>EBITDA</b>	<b>373</b>	<b>416</b>	<b>752</b>	<b>782</b>
Interest income	(9)	(8)	(19)	(18)
Purchase accounting adjustments <sup>1</sup>	(9)	(7)	(18)	(15)
Transition and business optimization costs and other	2	3	4	6
<b>Oncor Adjusted EBITDA</b>	<b>357</b>	<b>404</b>	<b>719</b>	<b>755</b>

<sup>1</sup> Purchase accounting adjustments consist of amounts related to the accretion of an adjustment (discount) to regulatory assets.