



Earnings Conference Call 2nd Quarter 2010

July 22, 2010



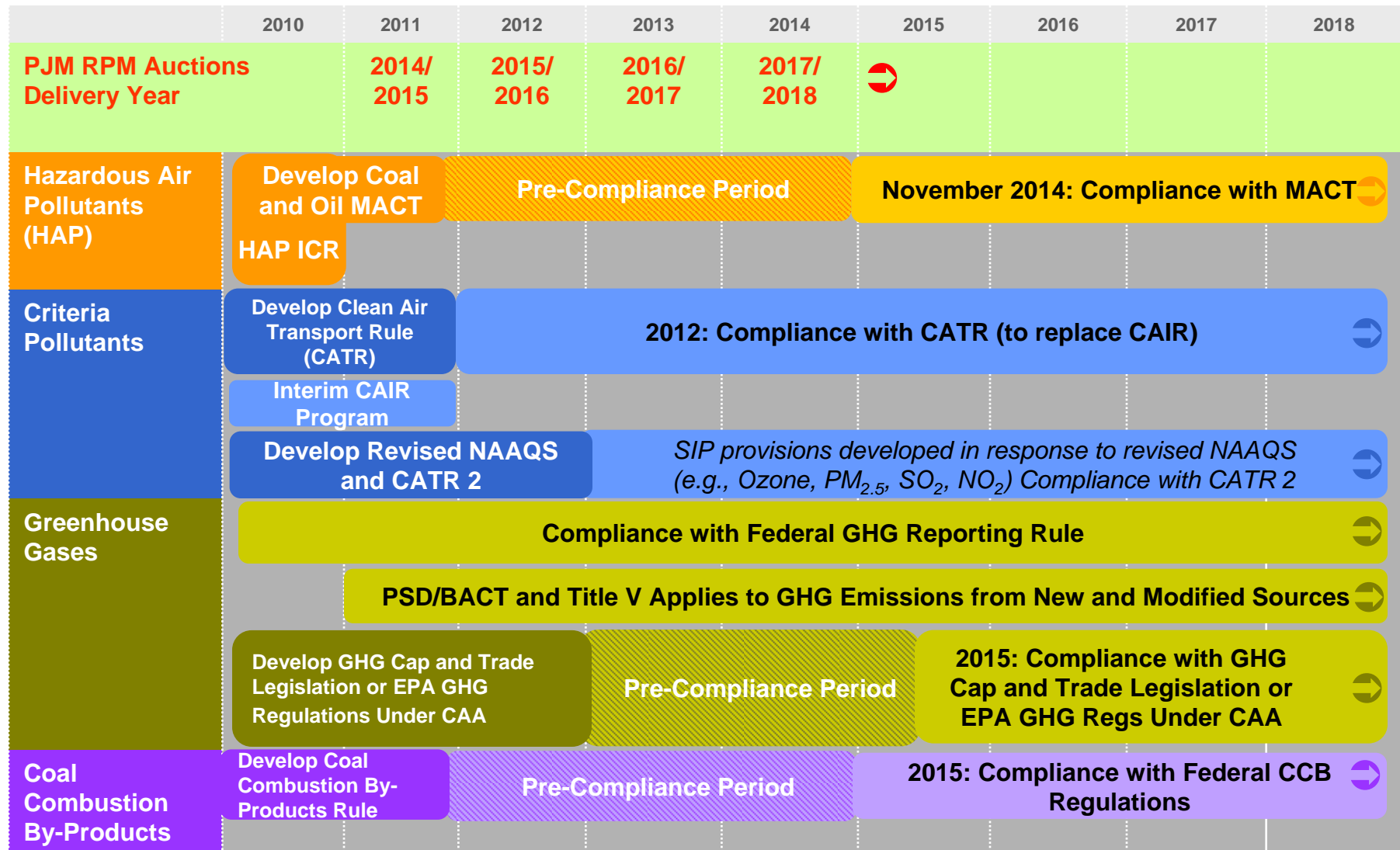
Forward-Looking Statements



This presentation includes forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from these forward-looking statements include those discussed herein as well as those discussed in (1) Exelon's 2009 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 18; (2) Exelon's Second Quarter 2010 Quarterly Report on Form 10-Q (to be filed on July 22, 2010) in (a) Part II, Other Information, ITEM 1A. Risk Factors, (b) Part 1, Financial Information, ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 12 and (3) other factors discussed in filings with the Securities and Exchange Commission (SEC) by Exelon Corporation, Commonwealth Edison Company, PECO Energy Company and Exelon Generation Company, LLC (Companies). Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this presentation. None of the Companies undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this presentation.

This presentation includes references to adjusted (non-GAAP) operating earnings and non-GAAP cash flows that exclude the impact of certain factors. We believe that these adjusted operating earnings and cash flows are representative of the underlying operational results of the Companies. Please refer to the appendix to this presentation for a reconciliation of adjusted (non-GAAP) operating earnings to GAAP earnings. Please refer to the footnotes of the following slides for a reconciliation of non-GAAP cash flows to GAAP cash flows.

EPA Regulations Will Begin to Affect Upcoming PJM RPM Auctions



Notes: Reliability Pricing Model (RPM) auctions take place annually in May.

For definition of the EPA regulations referred to on this slide, please see the EPA's Terms of Environment (<http://www.epa.gov/OCEPAterms/>).

Signs of Power Market Recovery



- Forward natural gas prices remain stable
 - In-line with our fundamental view

- Heat rates in the spot market are improving
 - We believe forward heat rate expansion is not fully reflected in the market, particularly Ni-Hub

- Positive results from recent PJM RPM capacity auction
 - Half of our capacity is in premium eastern zones

Exelon has the largest upside to a recovery of any of our merchant peers

Organic Growth Opportunities



Nuclear Upgrades

1,300–1,500 MW of new Exelon nuclear capacity by 2017, the equivalent of a new nuclear plant at roughly half the cost of a new plant and no incremental operating costs

Transmission

Leveraging transmission expertise through utility companies, Exelon Transmission Company and Exelon Generation

Smart Grid

Industry-leading energy efficiency and smart grid investments over the coming years with a regulated return

Rate Cases

Executing regulatory recovery plans at ComEd and PECO with three active distribution rate cases

Key Financial Messages



➤ Operating results for 2Q10

- Operating earnings of \$0.99/share ⁽¹⁾
- 94.8% nuclear capacity factor
- Continuing to manage O&M costs

➤ Forward power price outlook improving

- Upside in off-peak prices due to increased load
- Continued signs of economic recovery in our service areas

➤ Pursuing three rate cases at PECO and ComEd

- ComEd filed electric distribution rate case on June 30, 2010
- PECO electric and gas distribution rate cases on schedule

Raising 2010 operating earnings guidance to \$3.80 - \$4.10/share ⁽¹⁾

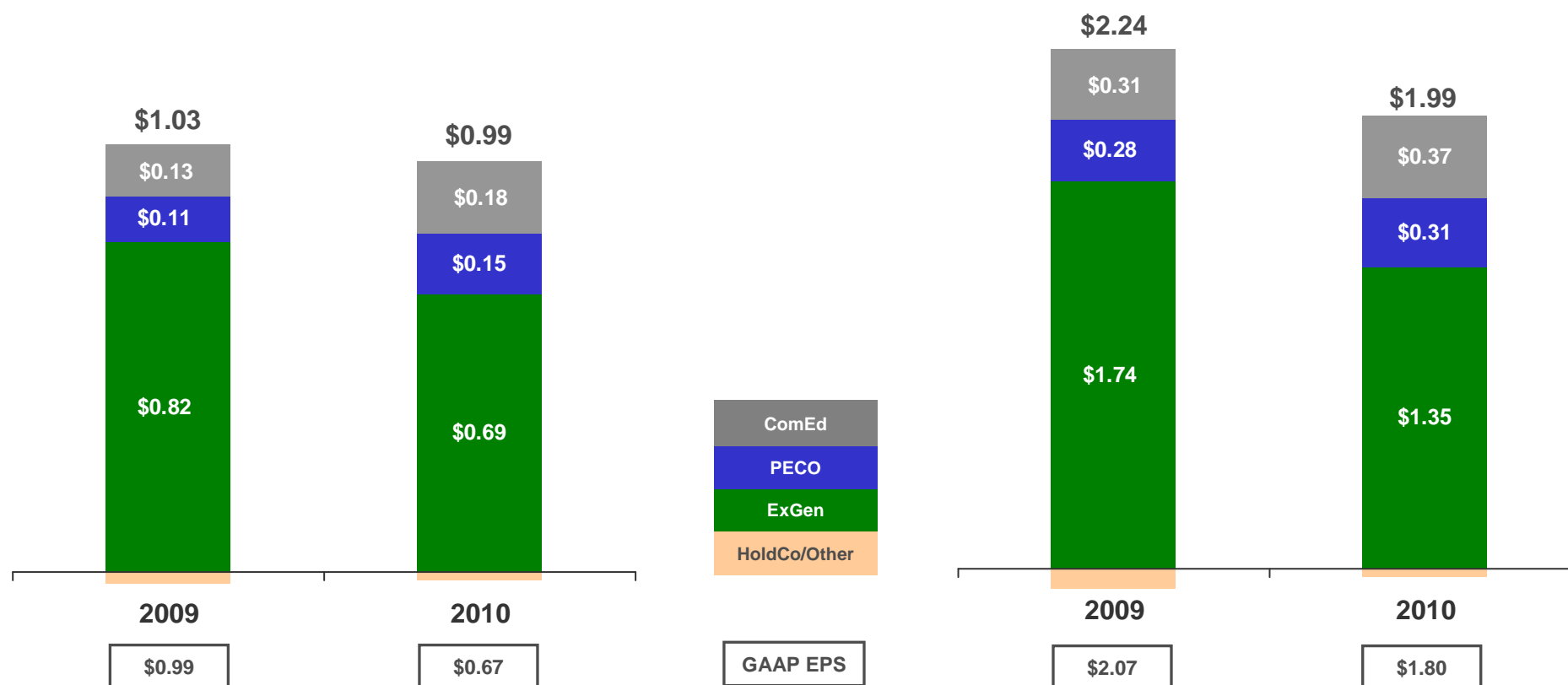
(1) Refer to Earnings Release Attachments for additional details and to the Appendix for a reconciliation of adjusted (non-GAAP) operating EPS to GAAP EPS.

Operating EPS



2nd Quarter (2Q)⁽¹⁾

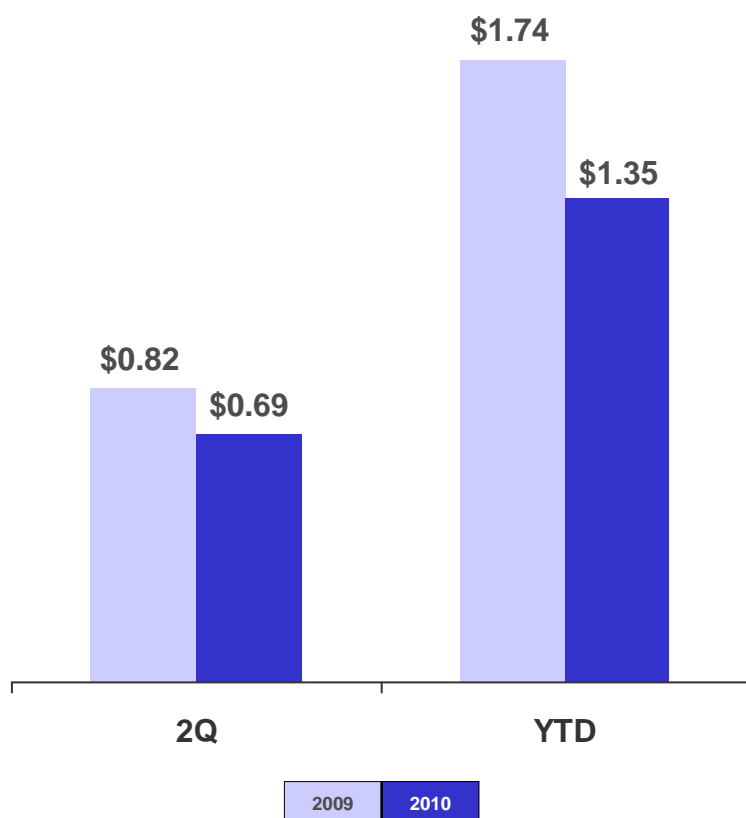
Year-to-Date (YTD)⁽¹⁾



Strong performance at the utilities offset by lower ExGen margins driving quarter over quarter earnings lower; however, 2Q10 earnings exceeded guidance of \$0.80-\$0.90/share

(1) Refer to Earnings Release Attachments for additional details and to the Appendix for a reconciliation of adjusted (non-GAAP) operating EPS to GAAP EPS.

Exelon Generation Operating EPS Contribution



Key Drivers – 2Q10 vs. 2Q09 ⁽¹⁾

- Lower energy prices under the PECO PPA: \$(0.04), including CTC offset at PECO \$(0.05) and other pricing of \$0.01
- Unfavorable market/portfolio conditions: \$(0.05)
- Higher nuclear fuel costs: \$(0.03)
- Favorable RPM capacity pricing: \$0.03
- Higher O&M costs primarily driven by inflation: \$(0.02)

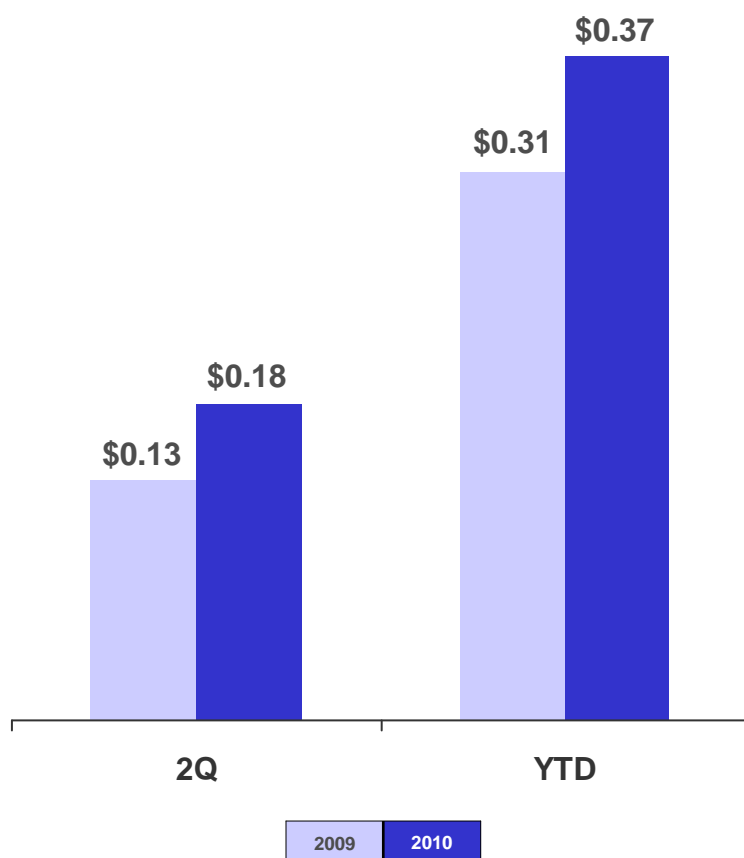
Outage Days ⁽²⁾	2Q09	2Q10
Refueling	57	44
Non-refueling	21	15

(1) Refer to the Earnings Release Attachments for additional details and to the Appendix for a reconciliation of adjusted (non-GAAP) operating EPS to GAAP EPS.

(2) Outage days exclude Salem.

Note: PPA = Power Purchase Agreement

ComEd Operating EPS Contribution



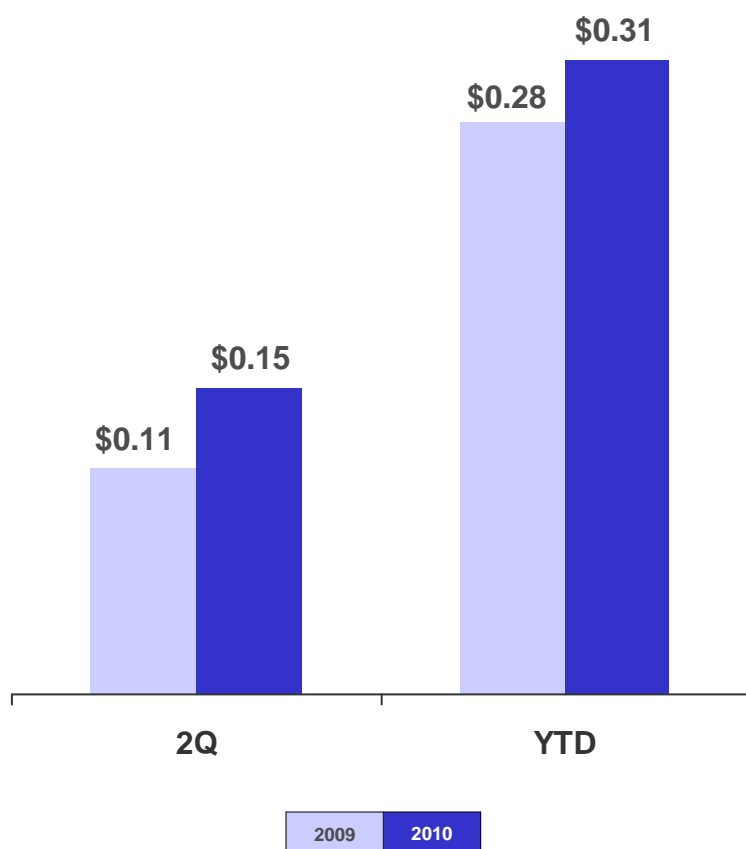
Key Drivers – 2Q10 vs. 2Q09 ⁽¹⁾

- IL distribution tax: \$0.02
- Weather: \$0.02
- Load growth: \$0.01
- Increased storm costs: \$(0.01)

	2Q10		
	<u>Actual</u>	<u>Normal</u>	<u>% Change</u>
Heating Degree-Days	519	766	(32)%
Cooling Degree-Days	312	224	39%

(1) Refer to the Earnings Release Attachments for additional details and to the Appendix for a reconciliation of adjusted (non-GAAP) operating EPS to GAAP EPS.

PECO Operating EPS Contribution



Key Drivers – 2Q10 vs. 2Q09 ⁽¹⁾

- Increased CTC revenue resulting in lower energy prices paid to Generation under the PPA, offset at Generation: \$0.05
- Weather: \$0.03
- Increased storm costs: \$(0.01)
- CTC amortization \$(0.04)

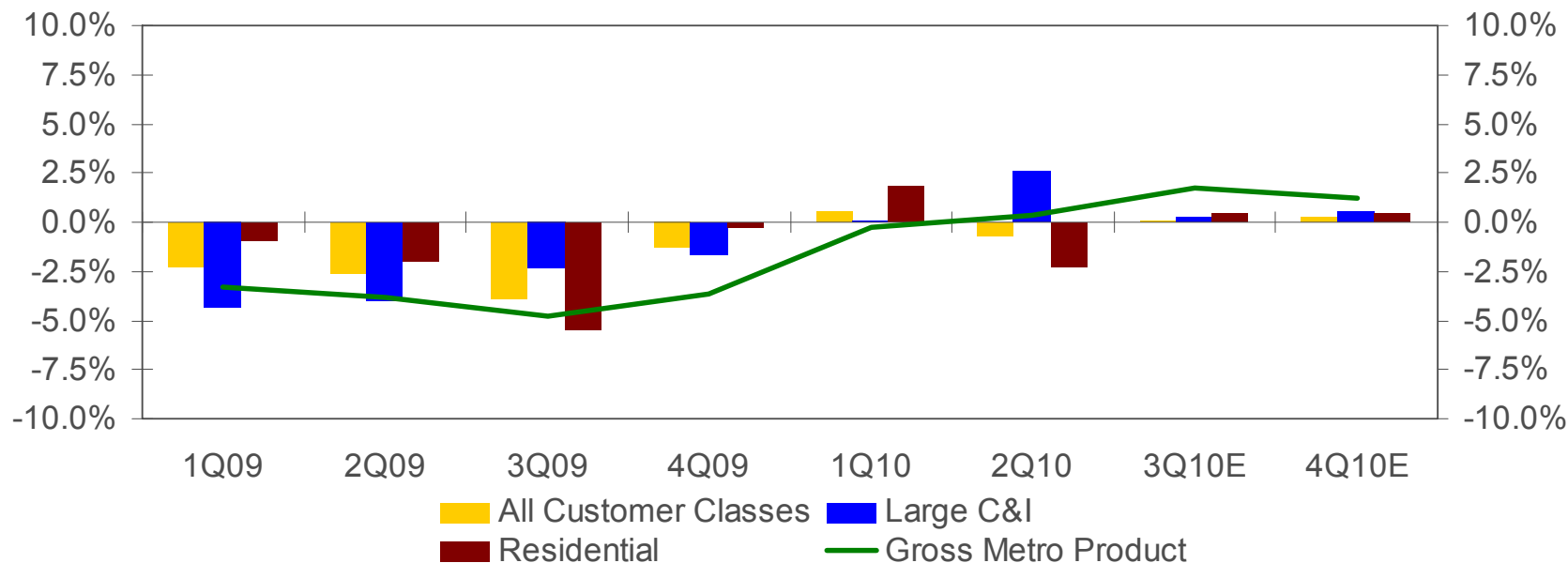
	2Q10		
	<u>Actual</u>	<u>Normal</u>	<u>% Change</u>
Heating Degree-Days	299	458	(35)%
Cooling Degree-Days	586	332	77%

(1) Refer to the Earnings Release Attachments for additional details and to the Appendix for a reconciliation of adjusted (non-GAAP) operating EPS to GAAP EPS.

PECO Load Trends



Weather-Normalized Load Year-over-Year ⁽³⁾



Key Economic Indicators

Philadelphia

Unemployment rate ⁽¹⁾	9.2%
2010 annualized growth in gross domestic/metro product ⁽²⁾	0.8%

(1) Source: U.S Dept. of Labor Preliminary data (June 2010)

(2) Source: PECO estimate

(3) Not adjusted for leap year effect

Weather-Normalized Load

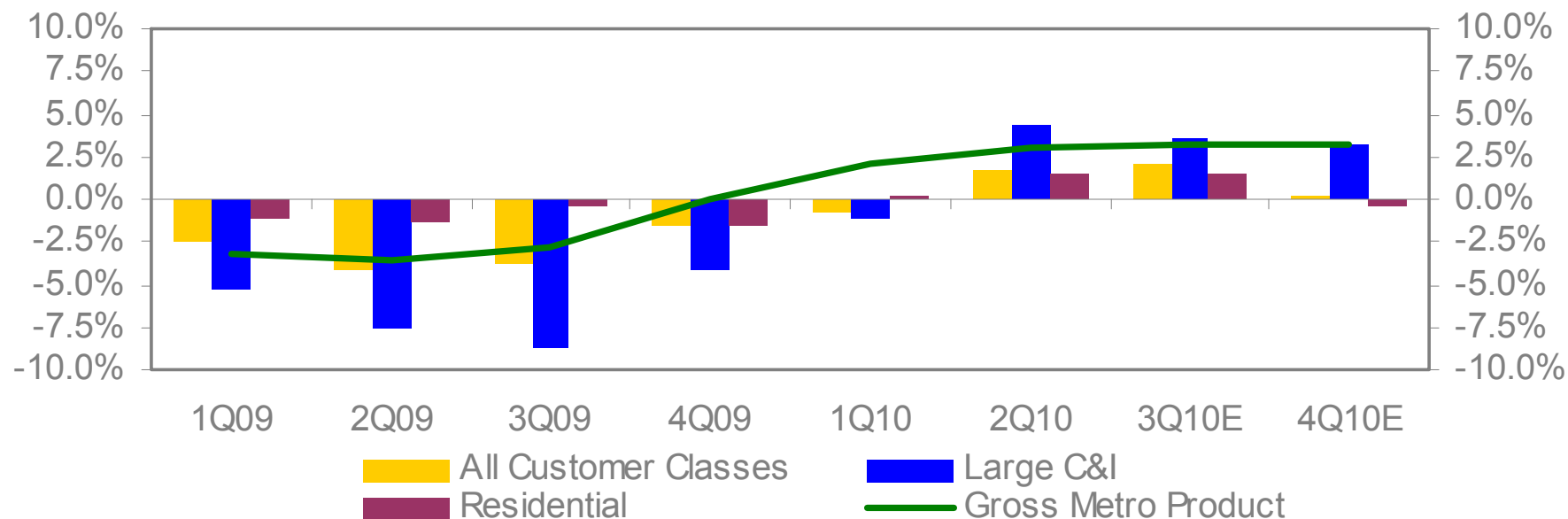
	2009 ⁽³⁾	2Q10	2010E
Average Customer Growth	(0.2)%	0.2%	0.0%
Average Use-Per-Customer	<u>(2.1)%</u>	<u>(2.5)%</u>	<u>0.3%</u>
Total Residential	(2.3)%	(2.3)%	0.2%
Small C&I	(2.7)%	(5.1)%	(1.8)%
Large C&I	(3.0)%	2.6%	0.9%
All Customer Classes	(2.6)%	(0.7)%	0.1%

Note: C&I = Commercial & Industrial

ComEd Load Trends



Weather-Normalized Load Year-over-Year ⁽⁴⁾



Key Economic Indicators

Chicago

Unemployment rate ⁽¹⁾	10.2%
2010 annualized growth in gross domestic/metro product ⁽²⁾	2.9%
4/10 Home price index ⁽³⁾	(1.5)%

(1) Source: Illinois Dept. of Employment Security (June 2010)

(2) Source: Global Insight (June 2010)

(3) Source: S&P Case-Shiller Index

(4) Not adjusted for leap year effect

Weather-Normalized Load

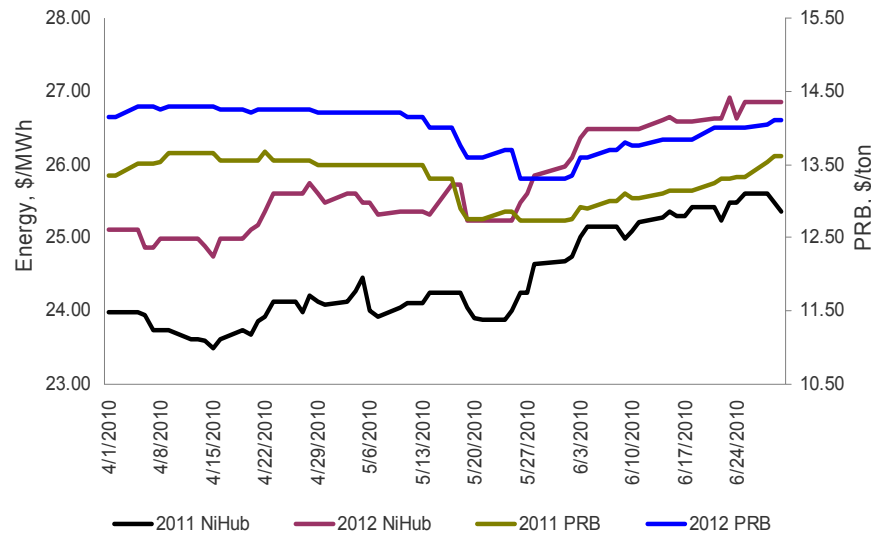
	2009 ⁽⁴⁾	2Q10	2010E
Average Customer Growth	(0.4)%	0.2%	0.2%
Average Use-Per-Customer	(1.0)%	1.4%	0.5%
Total Residential	(1.4)%	1.6%	0.7%
Small C&I	(2.2)%	(0.1)%	(0.6)%
Large C&I	(6.7)%	4.3%	2.5%
All Customer Classes	(3.3)%	1.8%	0.8%

Note: C&I = Commercial & Industrial

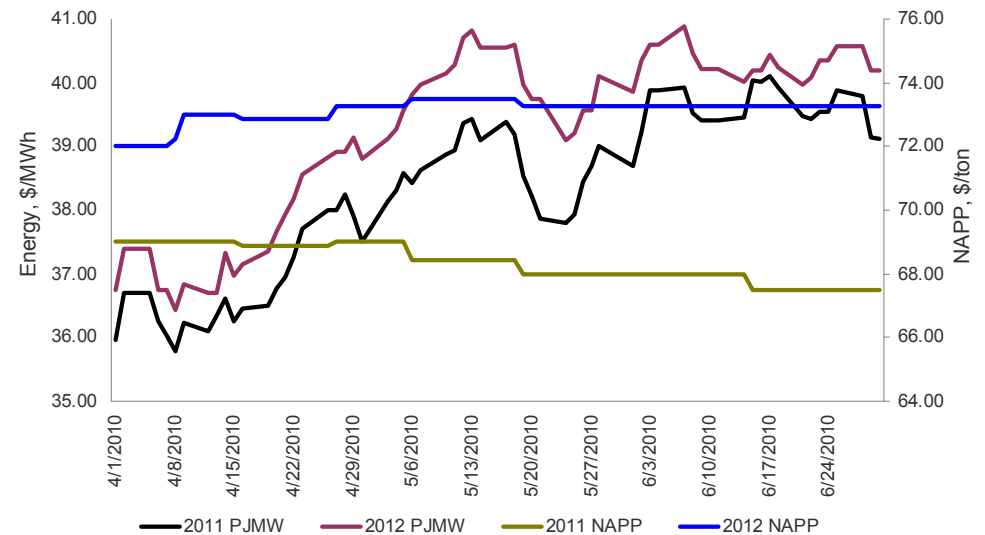
Off-Peak Energy Price Improvement



NiHub Off-Peak and Powder River Basin (PRB) Coal



PJMW Hub Off-Peak and Northern Appalachian (NAPP) Coal



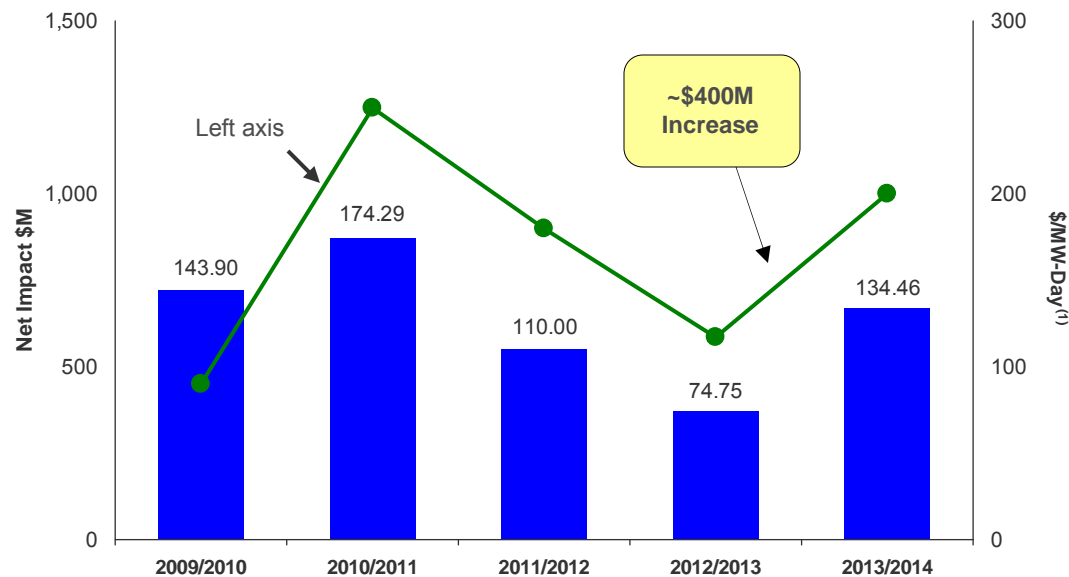
- Both Powder River Basin and Northern Appalachian coal prices have remained relatively stable over the past quarter
- However, NiHub and PJMW Hub off-peak energy prices have increased over the same period

Stabilizing coal prices and recovery in load are providing upside to prices, particularly in the off-peak

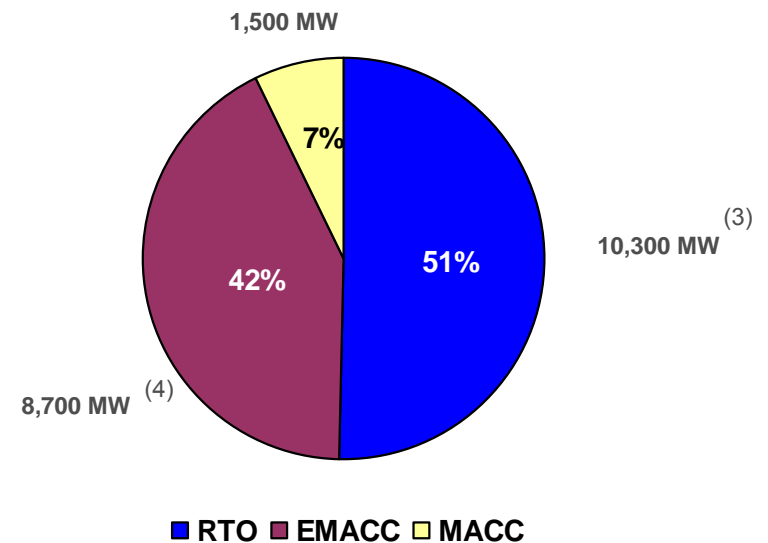
PJM RPM Capacity Auction



PJM RPM Capacity Prices and Auction (\$/MW-day)



Capacity by Region Eligible for 2014/15 RPM Base Residual Auction ⁽²⁾



2013/14 RPM capacity prices result in a \$400 million revenue increase to Exelon over the prior auction; expect 2014/15 auction to result in blended prices at least as high

- (1) Weighted average \$/MW-Day would apply if all generation cleared in the highlighted zone.
- (2) All generation values are approximate and not inclusive of wholesale transactions; All capacity values are in installed capacity terms (summer ratings) located in the areas.
- (3) Elwood contract expires on 12/31/12 and Kincaid contract expires on 2/28/13.
- (4) Reflects decision in December 2010 to permanently retire Cromby Station and Eddystone Units 1&2 as of 5/31/11. None of these 933 MW cleared in the 2011/2012 or 2012/2013 auctions.

2010 Projected Sources and Uses of Cash



(\$ millions)	ComEd			Exelon ⁽⁹⁾
Beginning Cash Balance ⁽¹⁾				\$1,050
Cash Flow from Operations ⁽¹⁾⁽²⁾	1,100	1,025	2,400	4,575
CapEx (excluding Nuclear Fuel, Nuclear Upgrades and Solar Project, Utility Growth CapEx)	(700)	(400)	(800)	(1,950)
Nuclear Fuel	n/a	n/a	(850)	(850)
Dividend ⁽³⁾				(1,400)
Nuclear Upgrades and Solar Project	n/a	n/a	(325)	(325)
Utility Growth CapEx ⁽⁴⁾	(225)	(100)	n/a	(325)
Net Financing (excluding Dividend):				
Planned Debt Issuances ⁽⁵⁾⁽⁶⁾	500	--	250	750
Planned Debt Retirements ⁽⁷⁾	(225)	(400)	--	(1,025)
Other ⁽⁸⁾	(50)	125	--	0
Ending Cash Balance ⁽¹⁾				\$500

(1) Excludes counterparty collateral activity.

(2) Cash Flow from Operations primarily includes net cash flows provided by operating activities and net cash flows used in investing activities other than capital expenditures. Cash Flow from Operations for PECO and Exelon includes \$550 million for competitive transition charges.

(3) Assumes 2010 dividend of \$2.10/share. Dividends are subject to declaration by the Board of Directors.

(4) Represents new business and smart grid/smart meter investment.

(5) Excludes Exelon Generation's \$212 million and ComEd's \$191 million of tax-exempt bonds that are backed by letters of credit. Excludes PECO's \$225 million Accounts Receivable (A/R) Agreement with Bank of Tokyo. Assumes PECO's A/R Agreement is extended in accordance with its terms beyond September 16, 2010.

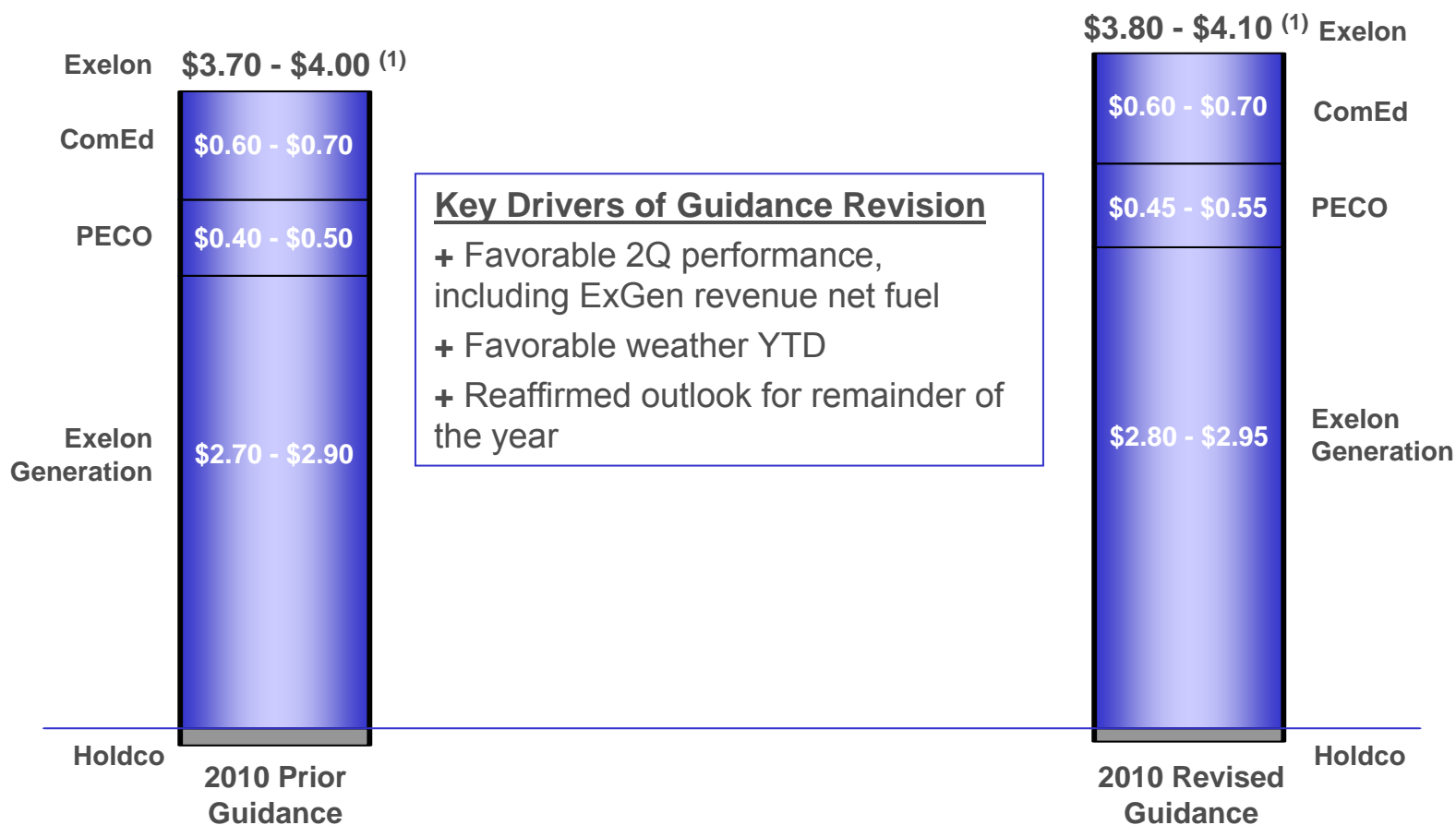
(6) Exelon Generation's financing includes \$250 million of debt to refinance a portion of Exelon Corp's \$400 million maturity.

(7) Excludes Exelon Generation's and ComEd's tax-exempt bonds. PECO's planned debt retirement of \$400 million represents the final retirement of the PECO Energy Transition Trust.

(8) "Other" includes PECO Parent Receivable, proceeds from options and expected changes in short-term debt.

(9) Includes cash flow activity from Holding Company, eliminations, and other corporate entities.

2010 Operating Earnings Guidance



Revised 2010 operating earnings guidance to \$3.80-\$4.10/share – expect 3Q10 results of \$1.00 - \$1.10/share⁽¹⁾

(1) Refer to Earnings Release Attachments for additional details and to the Appendix for a reconciliation of adjusted (non-GAAP) operating EPS to GAAP EPS.



Exelon Generation Hedging Disclosures

(as of June 30, 2010)

Important Information



The following slides are intended to provide additional information regarding the hedging program at Exelon Generation and to serve as an aid for the purposes of modeling Exelon Generation's gross margin (operating revenues less purchased power and fuel expense). The information on the following slides is not intended to represent earnings guidance or a forecast of future events. In fact, many of the factors that ultimately will determine Exelon Generation's actual gross margin are based upon highly variable market factors outside of our control. The information on the following slides is as of June 30, 2010. We update this information on a quarterly basis.

Certain information on the following slides is based upon an internal simulation model that incorporates assumptions regarding future market conditions, including power and commodity prices, heat rates, and demand conditions, in addition to operating performance and dispatch characteristics of our generating fleet. Our simulation model and the assumptions therein are subject to change. For example, actual market conditions and the dispatch profile of our generation fleet in future periods will likely differ – and may differ significantly – from the assumptions underlying the simulation results included in the slides. In addition, the forward-looking information included in the following slides will likely change over time due to continued refinement of our simulation model and changes in our views on future market conditions.

Portfolio Management Objective

Align Hedging Activities with Financial Commitments



➤ **Exelon's hedging program is designed to protect the long-term value of our generating fleet and maintain an investment-grade balance sheet**

- Hedge enough commodity risk to meet future cash requirements if prices drop
- Consider: financing policy (credit rating objectives, capital structure, liquidity); spending (capital and O&M); shareholder value return policy

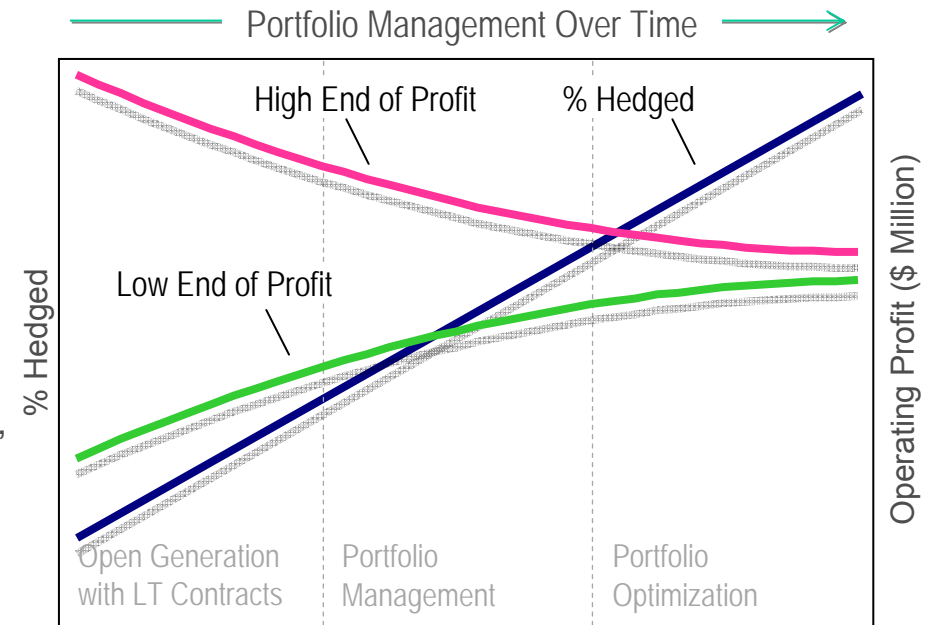
➤ **Consider market, credit, operational risk**

➤ **Approach to managing volatility**

- Increase hedging as delivery approaches
- Have enough supply to meet peak load
- Purchase fossil fuels as power is sold
- Choose hedging products based on generation portfolio – sell what we own

➤ **Power Team utilizes several product types and channels to market**

- Wholesale and retail sales
- Block products
- Load-following products and load auctions
- Put/call options
- Heat rate options
- Fuel products
- Capacity
- Renewable credits



Exelon Generation Hedging Program



- **Our normal practice is to hedge commodity risk on a ratable basis over the three years leading to the spot market**
- Carry operational length into spot market to manage forced outage and load-following risks
 - By using the appropriate product mix, expected generation hedged approaches the mid-90s percentile as the delivery period approaches
 - Participation in larger procurement events, such as utility auctions, and some flexibility in the timing of hedging may mean the hedge program is not strictly ratable from quarter to quarter

Percentage of Expected Generation Hedged

$$= \frac{\text{Equivalent MWs Sold}}{\text{Expected Generation}}$$

- How many equivalent MW have been hedged at forward market prices; all hedge products used are converted to an equivalent average MW volume
- Takes ALL hedges into account whether they are power sales or financial products

Exelon Generation Open Gross Margin and Reference Prices



	2010	2011	2012
Estimated Open Gross Margin (\$ millions) ⁽¹⁾⁽²⁾	\$5,700	\$5,300	\$5,100

Open gross margin assumes all expected generation is sold at the Reference Prices listed below

Reference Prices ⁽¹⁾

Henry Hub Natural Gas (\$/MMBtu)	\$4.77	\$5.34	\$5.68
NI-Hub ATC Energy Price (\$/MWh)	\$33.17	\$32.63	\$34.22
PJM-W ATC Energy Price (\$/MWh)	\$44.76	\$45.54	\$46.86
ERCOT North ATC Spark Spread (\$/MWh) ⁽³⁾	\$1.28	\$(0.02)	\$0.53

(1) Based on June 30, 2010 market conditions.

(2) Gross margin is defined as operating revenues less fuel expense and purchased power expense, excluding the impact of decommissioning and other incidental revenues. Open gross margin is estimated based upon an internal model that is developed by dispatching our expected generation to current market power and fossil fuel prices. Open gross margin assumes there is no hedging in place other than fixed assumptions for capacity cleared in the RPM auctions and uranium costs for nuclear power plants. Open gross margin contains assumptions for other gross margin line items such as various ISO bill and ancillary revenues and costs and PPA capacity revenues and payments. The estimation of open gross margin incorporates management discretion and modeling assumptions that are subject to change.

(3) ERCOT North ATC spark spread using Houston Ship Channel Gas, 7,200 heat rate, \$2.50 variable O&M.

Generation Profile



	2010	2011	2012
Expected Generation (GWh) ⁽¹⁾	167,500	163,000	162,600
Midwest	100,000	98,700	97,500
Mid-Atlantic	58,900	57,000	57,000
South	8,600	7,300	8,100
Percentage of Expected Generation Hedged ⁽²⁾	96-99%	86-89%	57-60%
Midwest	96-99	86-89	54-57
Mid-Atlantic	96-99	90-93	59-62
South	97-100	66-69	51-54
Effective Realized Energy Price (\$/MWh) ⁽³⁾			
Midwest	\$46.00	\$43.50	\$44.50
Mid-Atlantic	\$36.50	\$57.50	\$51.00
ERCOT North ATC Spark Spread	\$0.00	\$(2.00)	\$(5.50)

- (1) Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted for capacity. Expected generation is based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Expected generation assumes 10 refueling outages in 2010 and 11 refueling outages in 2011 and 2012 at Exelon-operated nuclear plants and Salem. Expected generation assumes capacity factors of 94.1%, 93.2% and 92.9% in 2010, 2011 and 2012 at Exelon-operated nuclear plants. These estimates of expected generation in 2011 and 2012 do not represent guidance or a forecast of future results as Exelon has not completed its planning or optimization processes for those years.
- (2) Percent of expected generation hedged is the amount of equivalent sales divided by the expected generation. Includes all hedging products, such as wholesale and retail sales of power, options, and swaps. Uses expected value on options. Reflects decision to permanently retire Cromby Station and Eddystone Units 1&2 as of May 31, 2011. Current RMR discussions do not impact metrics presented in the hedging disclosure.
- (3) Effective realized energy price is representative of an all-in hedged price, on a per MWh basis, at which expected generation has been hedged. It is developed by considering the energy revenues and costs associated with our hedges and by considering the fossil fuel that has been purchased to lock in margin. It excludes uranium costs and RPM capacity revenue, but includes the mark-to-market value of capacity contracted at prices other than RPM clearing prices including our load obligations. It can be compared with the reference prices used to calculate open gross margin in order to determine the mark-to-market value of Exelon Generation's energy hedges.

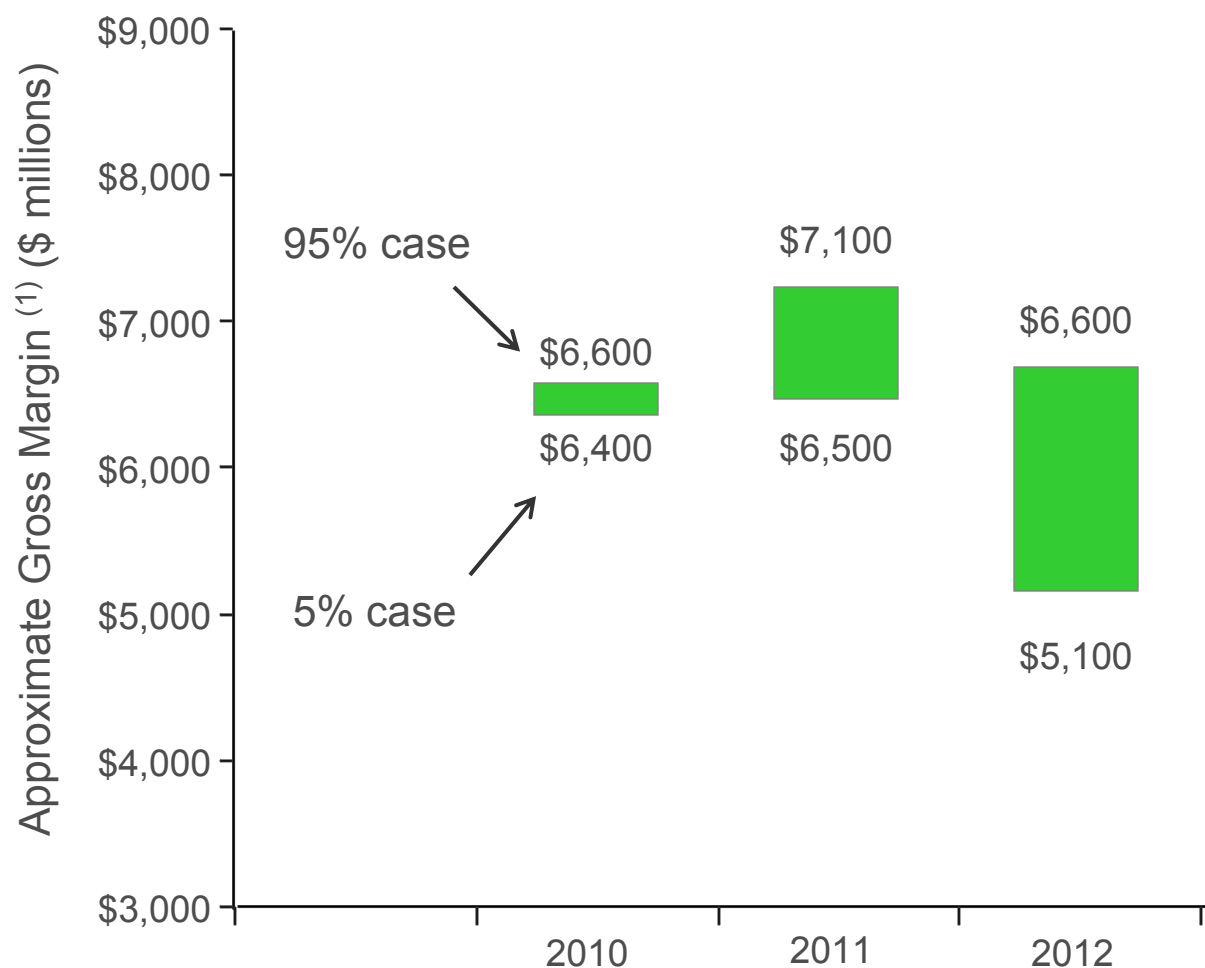
Exelon Generation Gross Margin Sensitivities (with Existing Hedges)



	2010	2011	2012
Gross Margin Sensitivities with Existing Hedges (\$ millions)⁽¹⁾			
Henry Hub Natural Gas			
+ \$1/MMBtu	\$20	\$100	\$260
- \$1/MMBtu	\$(15)	\$(90)	\$(245)
<hr/>			
NI-Hub ATC Energy Price			
+\$5/MWH	\$10	\$75	\$220
-\$5/MWH	\$(5)	\$(65)	\$(210)
<hr/>			
PJM-W ATC Energy Price			
+\$5/MWH	\$5	\$30	\$130
-\$5/MWH	\$ -	\$(25)	\$(125)
<hr/>			
Nuclear Capacity Factor			
+1% / -1%	+/- \$25	+/- \$45	+/- \$45

(1) Based on June 30, 2010 market conditions and hedged position. Gas price sensitivities are based on an assumed gas-power relationship derived from an internal model that is updated periodically. Power prices sensitivities are derived by adjusting the power price assumption while keeping all other prices inputs constant. Due to correlation of the various assumptions, the hedged gross margin impact calculated by aggregating individual sensitivities may not be equal to the hedged gross margin impact calculated when correlations between the various assumptions are also considered.

Exelon Generation Gross Margin Upside / Risk (with Existing Hedges)



(1) Represents an approximate range of expected gross margin, taking into account hedges in place, between the 5th and 95th percent confidence levels assuming all unhedged supply is sold into the spot market. Approximate gross margin ranges are based upon an internal simulation model and are subject to change based upon market inputs, future transactions and potential modeling changes. These ranges of approximate gross margin in 2011 and 2012 do not represent earnings guidance or a forecast of future results as Exelon has not completed its planning or optimization processes for those years. The price distributions that generate this range are calibrated to market quotes for power, fuel, load following products, and options as of June 30, 2010.

Illustrative Example

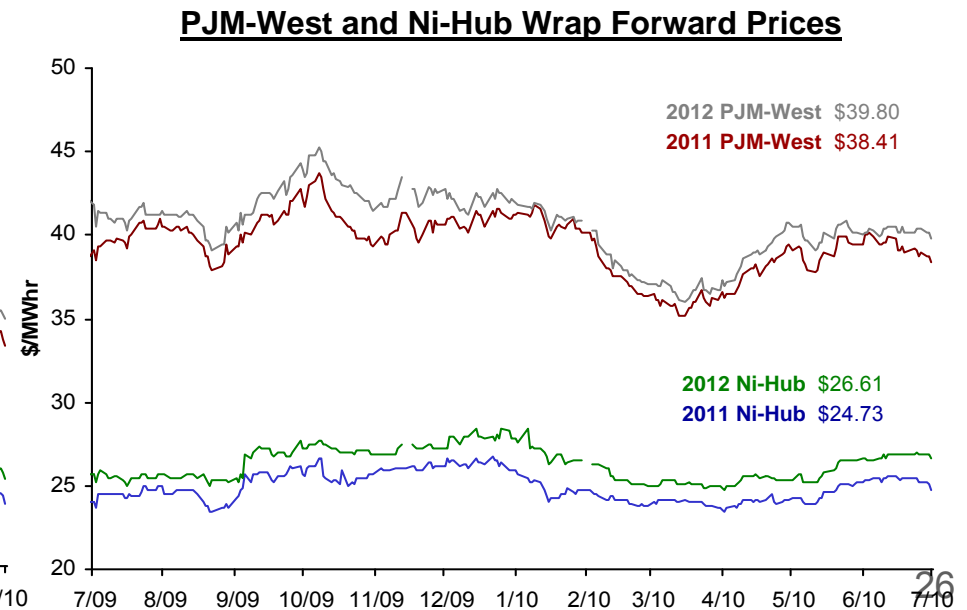
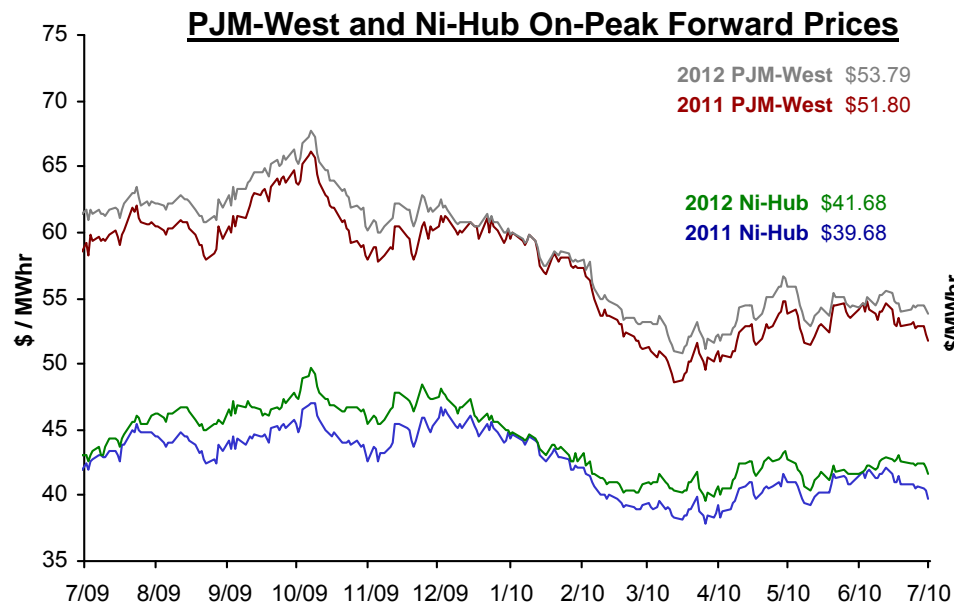
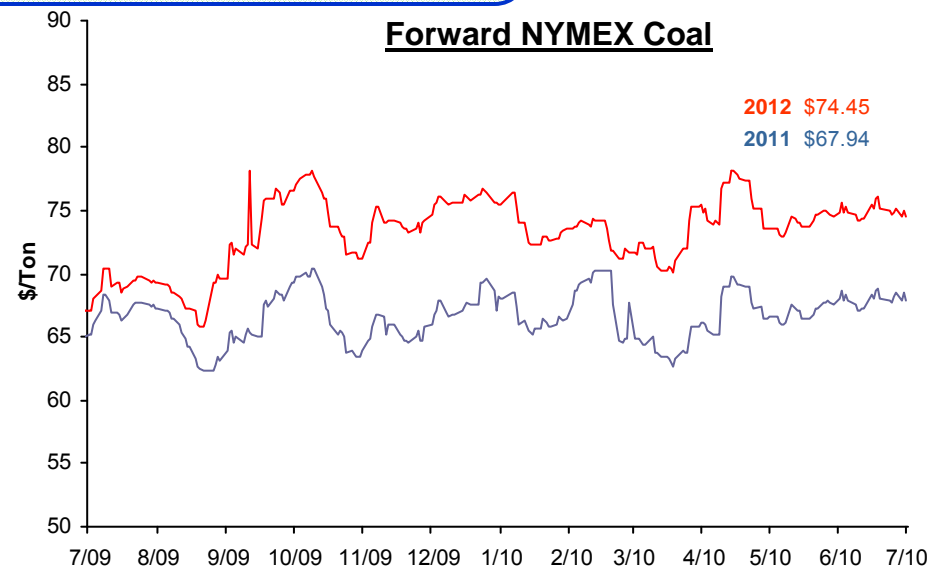
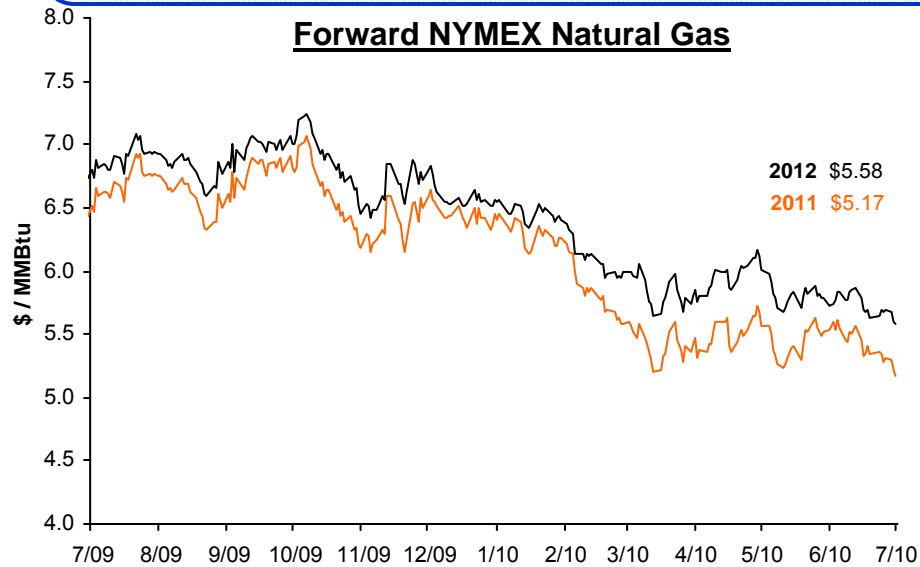
of Modeling Exelon Generation 2010 Gross Margin
(with Existing Hedges)



	Midwest	Mid-Atlantic	ERCOT
Step 1 Start with fleetwide open gross margin	<div> <div></div> <div>\$5.70 billion</div> <div></div> </div>		
Step 2 Determine the mark-to-market value of energy hedges	100,000GWh * 97% * (\$46.00/MWh-\$33.17/MWh) = \$1.24 billion	58,900GWh * 97% * (\$36.50/MWh-\$44.76/MWh) = \$(0.47 billion)	8,600GWh * 98% * (\$0.00/MWh-\$1.28/MWh) = \$(0.01) billion
Step 3 Estimate hedged gross margin by adding open gross margin to mark-to-market value of energy hedges	Open gross margin: MTM value of energy hedges: Estimated hedged gross margin:	\$5.70 billion <u>\$1.24 billion + \$(0.47 billion) + \$(0.01) billion</u> \$6.46 billion	

Market Price Snapshot

Rolling 12 months, as of July 14th, 2010. Source: OTC quotes and electronic trading system. Quotes are daily.

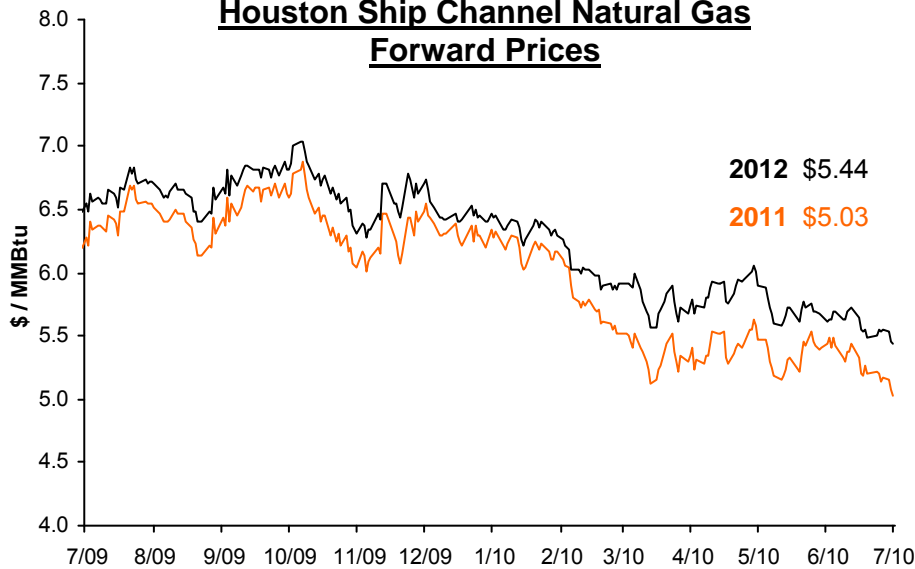


Market Price Snapshot

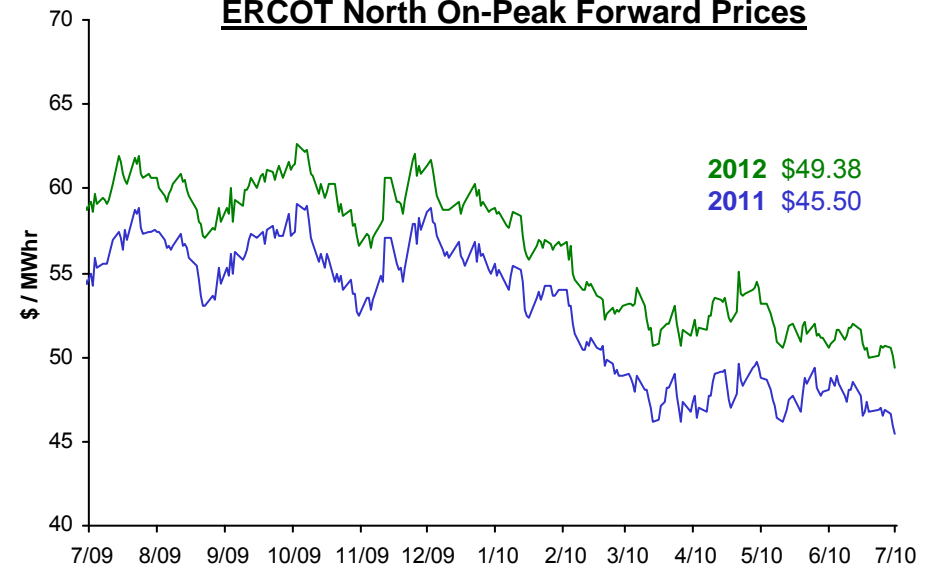
Rolling 12 months, as of July 14th, 2010. Source: OTC quotes and electronic trading system. Quotes are daily.



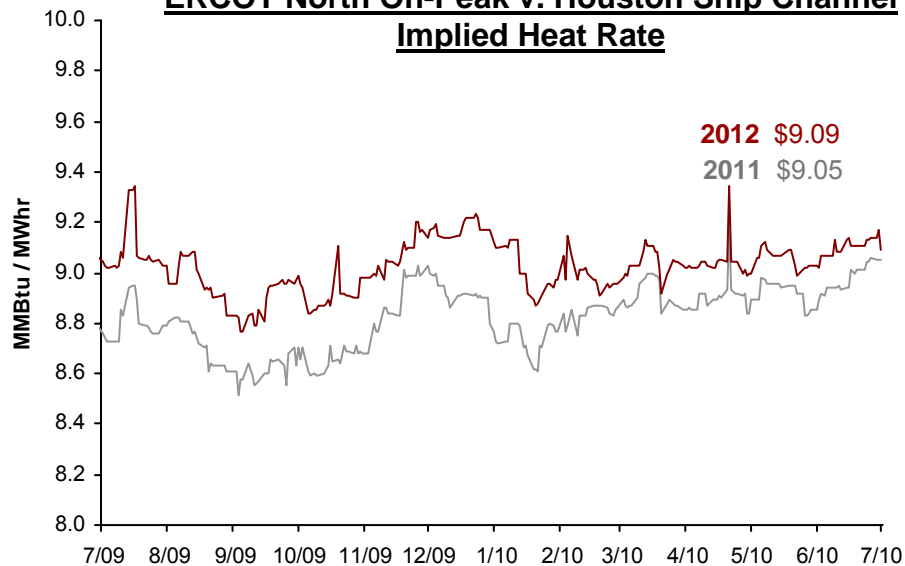
Houston Ship Channel Natural Gas Forward Prices



ERCOT North On-Peak Forward Prices

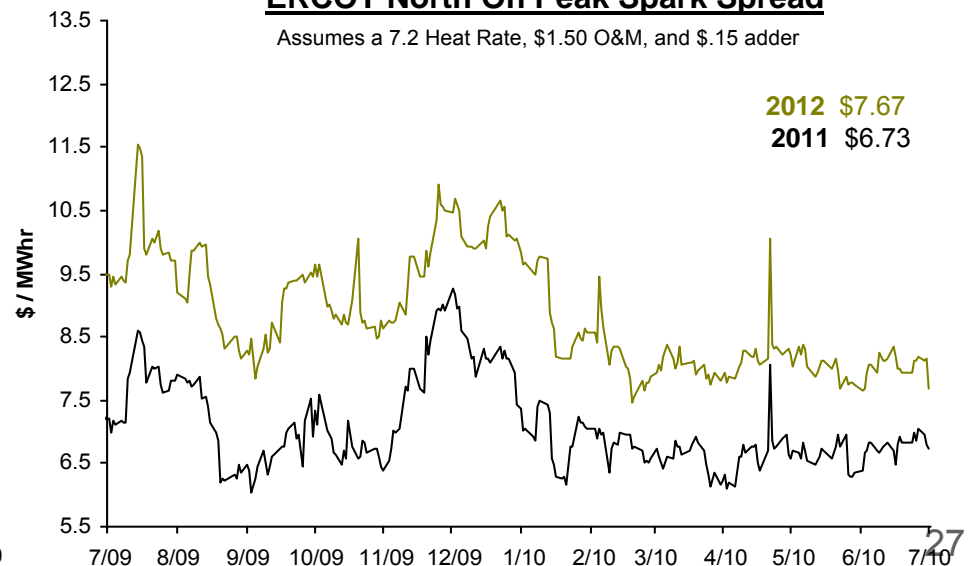


ERCOT North On-Peak v. Houston Ship Channel Implied Heat Rate



ERCOT North On Peak Spark Spread

Assumes a 7.2 Heat Rate, \$1.50 O&M, and \$.15 adder



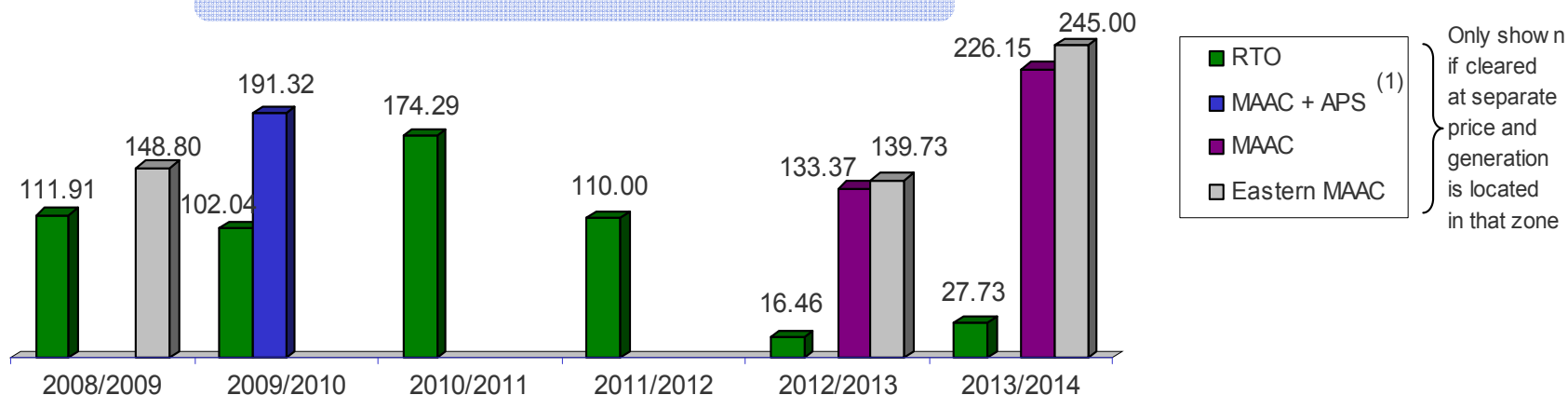


Appendix

RPM Auction Results



PJM RPM Auction (\$/MW-day)



Exelon Generation Eligible Capacity within PJM Reliability Pricing Model ⁽²⁾

	2009/2010		2010/2011		2011/2012	2012/2013	2013/2014
<i>in MW</i>	Capacity ⁽³⁾	Obligation	Capacity ⁽³⁾	Obligation	Capacity ⁽³⁾	Capacity ⁽³⁾	Capacity ⁽³⁾
RTO	12,800	3,800 - 4,100 ⁽⁵⁾	23,900	9,300 - 9,400 ⁽⁴⁾	23,200	12,100 ⁽⁶⁾	10,300 ⁽⁶⁾
EMAAC						9,500	8,700 ⁽⁷⁾
MAAC + APS	11,100	9,300 - 9,400 ⁽⁵⁾					
MAAC						1,500	1,500
Avg (\$/MW-Day) ⁽⁸⁾	\$143.90		\$174.29		\$110.00	\$74.75	\$134.46

(1) MAAC = Mid-Atlantic Area Council; APS = Allegheny Power System.

(2) All generation values are approximate and not inclusive of wholesale transactions.

(3) All capacity values are in installed capacity terms (summer ratings) located in the areas.

(4) Obligation represents the remainder of the ComEd auction load that ends in May 2010.

(5) Obligation consists of load obligations from PECO. PECO PPA expires December 2010.

(6) Elwood contract expires on 12/31/12 and Kincaid contract expires on 2/28/13.

(7) Reflects decision in December 2010 to permanently retire Cromby Station and Eddystone Units 1&2 as of 5/31/11. None of these 933 MW cleared in the 2011/2012 or 2012/2013 auctions.

(8) Weighted average \$/MW-Day would apply if all generation cleared in the highlighted zones.

Note: Data contained on this slide is rounded.

ComEd Delivery Service Rate Case Filing Summary



(\$ in millions)	Requested Revenue Increase
Rate Base: \$7,717 million ⁽¹⁾	\$179 ⁽²⁾
Capital Structure ⁽³⁾ : ROE – 11.50% / Common Equity – 47.33% / ROR – 8.99%	\$95
Pension and Post-retirement health care expenses ⁽⁴⁾	\$55
Bad debt costs (resets base level of bad debt to 2009 test year)	\$22
Other adjustments ⁽⁵⁾	\$45
Total (\$2,337 million revenue requirement) ⁽⁶⁾	\$396

Primary drivers of rate request are new plant investment, pension/retiree health care and cost of capital

- (1) Filed June 30, 2010 based on 2009 test year, including pro forma capital additions through June 2011, and certain other 2010 pro forma adjustments.
- (2) Includes increased depreciation expense.
- (3) Requested capital structure does not include goodwill; ICC docket 07-0566 allowed 10.3% ROE, 45.04% equity ratio and 8.36% ROR. ROE includes 0.40% adder for energy efficiency incentive.
- (4) Reflects 2010 expense levels, compared to 2007 expense levels allowed in last rate case.
- (5) Includes reductions to O&M and taxes other than income, offset by wage increases, normalization of storm costs and the Illinois Electric Distribution Tax, other O&M increases, and decreases in load.
- (6) Net of Other Revenues.

Note: ROE = Return on Equity, ROR = Return on Rate Base, ICC = Illinois Commerce Commission.

ComEd Delivery Rate Case Alternative Regulation (Alt Reg) Proposal



- ComEd plans to make a companion Alt Reg filing proposing to recover the costs of smart grid and other projects outside of the traditional rate case process
 - 9-month statutory process
- The proposal includes a “flow-through mechanism” to recover capital carrying costs and incremental O&M, as incurred

\$ millions	O&M	Capital
Accelerated Smart Grid Deployment <ul style="list-style-type: none"> • 190,000 additional AMI Meters and Outage Management System Interface • Accelerated deployment of Distribution Automation • Customer Applications 	\$10 - \$20	\$55 \$40 -
Electric Vehicle Fleet Purchase	-	\$5
Expanded funding for low income CARE programs ⁽¹⁾	\$10	-
Man-hole refurbishment and cable replacement	\$15	\$30

- Costs and investments will be rolled in to future rate cases, when they occur
- Assured savings to customers – \$2 million on capped O&M costs for program costs (excluding CARE)
- Includes an incentive/penalty mechanism for performance above or under budget

Alt Reg Proposal is permitted under section 9-244 of the IL Public Utilities Act

(1) Total CARE amount for two-year proposal is \$20 million.

ComEd Residential Rate Design Straight Fixed/Variable Proposal



- Filing includes a proposal to gradually move more of residential delivery bill to the fixed customer charge, rather than usage-based kwh component through three step phase-in

Current rate design: 37% fixed / 63% variable split

Proposed: 60%/40% split in June 2011, 70%/30% in June 2012, and 80%/20% in June 2013

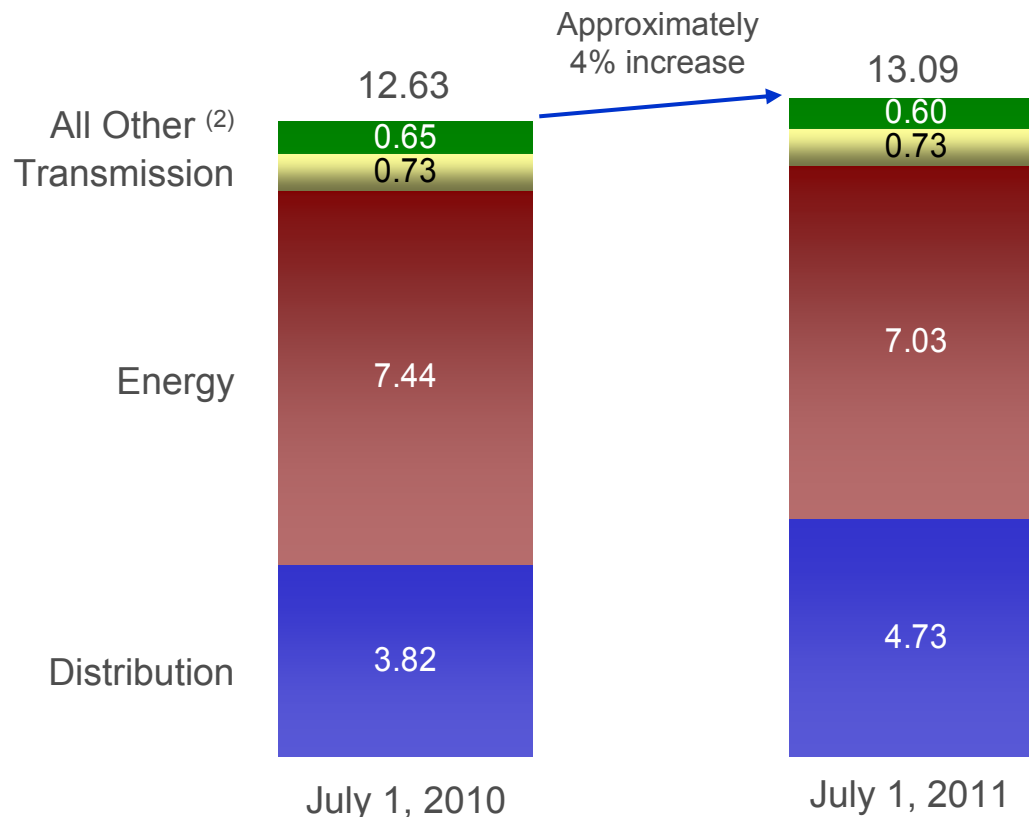
- Mitigates impact of weather and load fluctuations due to weather and economy
- Rate design reflects current cost structure and sends appropriate price signals
 - Fixed costs to be collected via fixed charges (i.e. Customer Charge, Meter Charge)
 - Variable costs to be collected via variable charges (i.e. per kWh)
- Eliminates economic disincentive to promote energy efficiency

**Proposed Straight Fixed/Variable rate design is consistent with ICC
orders in other recent cases**

ComEd Delivery Rate Case Residential Rate Impacts 2010 to 2011 ⁽¹⁾



Unit rates: cents / kWh



Comments

Transmission: Subject to FERC formula rate annual update

Energy: Reflects reduced PJM capacity price that PJM has published for the June 2011 – May 2012 planning period. Energy component may vary

Distribution: As proposed

Proposed residential rate impact of 7% will be mitigated by impact of lower capacity prices resulting in an increase of 4%

(1) Reflects change in distribution rates only. Assumes Energy, Transmission and all other components remain constant as of June 2010, except as noted above.

(2) "All Other" includes impact of riders that are applicable to residential bills.

Note: Amounts may not add due to rounding.

ComEd Delivery Service Rate Case Tentative Schedule



- Delivery Service Rate Case Filed – June 30, 2010
- Alt Reg Proposal Filed – August / September 2010
- Intervenor and Rebuttal Testimony – 4Q 2010
- Hearings – December 2010 / January 2011
- Administrative Law Judge Order – February 2011
- Final Order Expected – May 2011
- New Rates Effective – June 2011

Note: Dates are based on typical approach to rate cases but the ICC will set the actual schedule, which is expected in 3Q 2010.

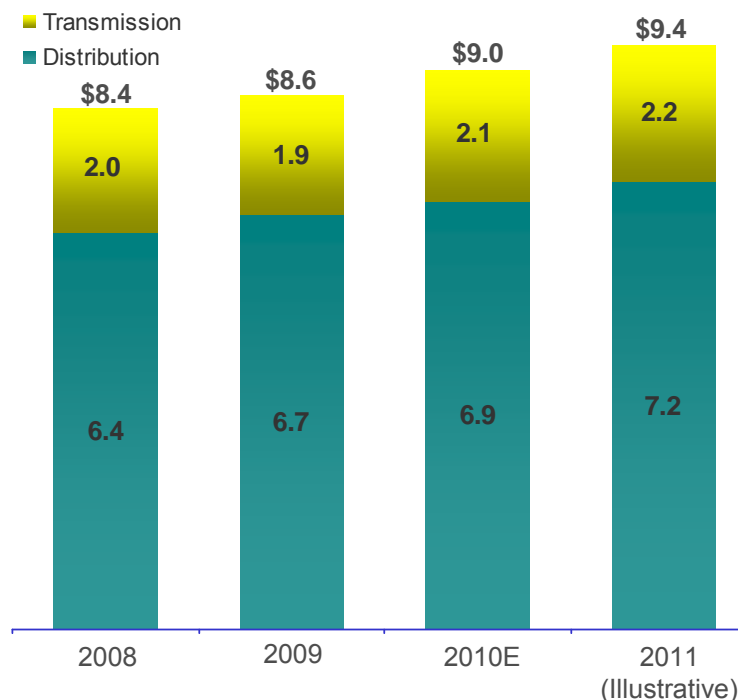
ComEd Building Strength



Producing Results with Regulatory Recovery Plan

- Significant improvement in earned ROE, from 5.5% in 2008 to 8.5% in 2009, targeting at least 10% in 2010
- Continued strong operational performance
- Filed electric distribution rate case on June 30, 2010
- Benefiting from regular transmission updates through a formula rate plan
- Illinois Power Agency's 2010 procurement approved by the ICC on April 30
- Uncollectibles expense rider tariff approved by ICC in February 2010
- Smart Meter pilot program and rider approved by ICC and underway
- Standard & Poor's raised credit ratings in 3Q09 and Fitch in 1Q10

End of Year Rate Base (\$ in billions) ⁽¹⁾



Equity ⁽²⁾	45.4%	46.4%	~45%	~43%
Earned ROE	5.5%	8.5%	≥10%	≥10%

ComEd executing on regulatory recovery plan resulting in healthy increases in earned ROE

(1) Provided solely to illustrate possible future outcomes that are based on a number of different assumptions, including an ROE target, all of which are subject to uncertainties and should not be relied upon as a forecast of future results. Amounts do not reflect pro forma adjustments that may be made to determine rate base for rate case filing.

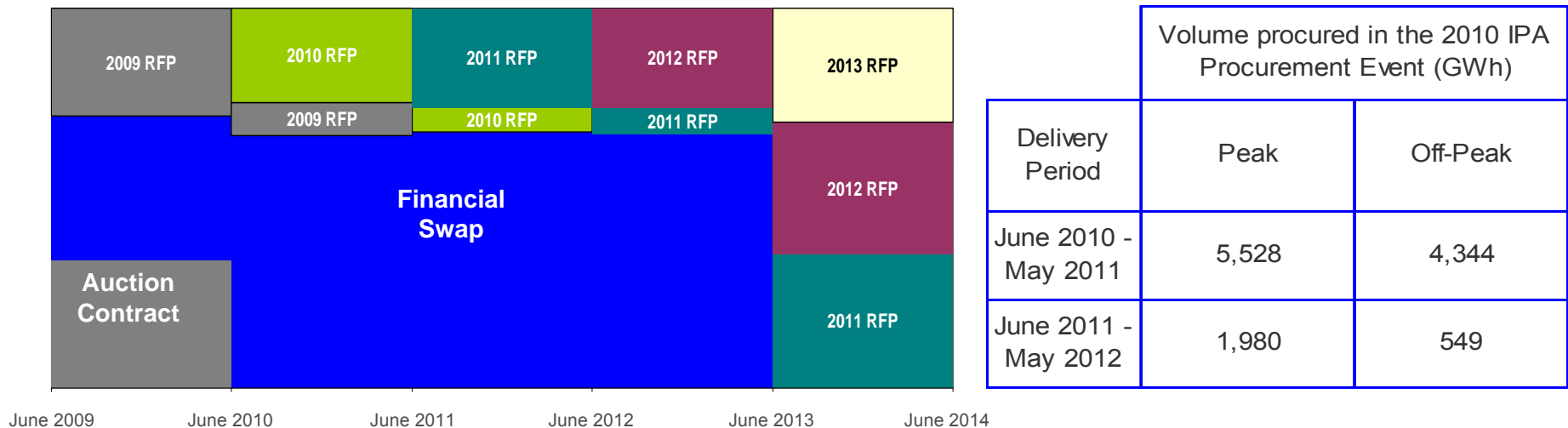
(2) Equity based on definition provided in most recent ICC distribution rate case order (book equity less goodwill).

Note: Amounts may not add due to rounding.

Illinois Power Agency (IPA) RFP Procurement



- On April 30, 2010, the ICC approved the bids from the RFP Procurement held on April 28, 2010, for the remaining ComEd 2010-2011 load (~25% of the total) and a portion of its 2011-2012 load (~6% of the total)
 - Contracts were awarded to 12 successful bidders
 - \$32.54 around-the-clock (ATC) price for 2010-2011 planning year, in addition to:
 - Financial Swap price (ATC baseload energy only) of \$50.15 for June 2010 – December 2010 and \$51.26 for January 2011 – December 2011; increase in notional quantity to 3,000 MW on June 1, 2010

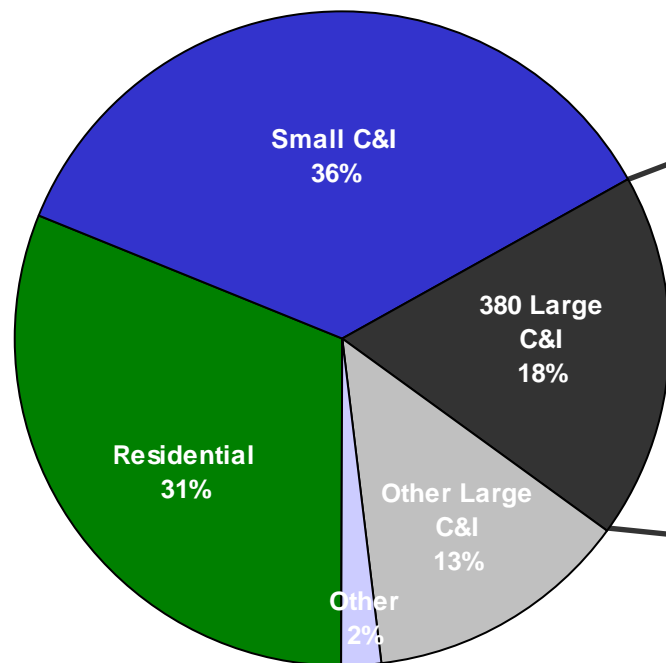


Note: Chart is for illustrative purposes only. Data on this slide is rounded.

ComEd Customer Usage Breakdown



Customer Usage by Revenue Class



Top 380 Customer Usage by Segment

Manufacturing	52%
Government	13%
Health & Educational Services	12%
Finance, Professional & Business Services	11%
Trade, Transportation & Utilities	9%
Leisure & Hospitality	3%

Limited survey of select Large C&I customers has indicated an increase in production via longer production runs and additional shifts due to improved economic conditions for manufacturing-based customers, especially in the steel and transportation sectors, along with data center expansions.

PECO – Electric & Gas Distribution Rate Case Filing Summary



On March 31, PECO filed electric and gas distribution rate cases

- First electric distribution rate case since 1989
 - Act 129 energy efficiency and smart meter costs recovered separately through rider
- Last gas delivery rate case in 2008

Rate Case Request	Electric	Gas
Docket #	R-2010-2161575	R-2010-2161592
Test Year	2010 ⁽¹⁾	2010 ⁽¹⁾
Rate Base	\$3,236 million	\$1,100 million
Common Equity Ratio	53.18%	53.18%
Requested Returns	ROE: 11.75% ROR: 8.95%	ROE: 11.75% ROR: 8.95%
Revenue Requirement Increase	\$316 million	\$44 million
2011 Proposed Distribution Price Increase as % of Overall Customer Bill	6.94% ⁽²⁾	5.28%

PECO executing its post-transition regulatory plan to secure fair and reasonable returns on its distribution investment

(1) With pro forma adjustments.

(2) Excluding Alternative Energy Portfolio Standards and default service surcharge.

Note: Electric and gas rate case filings available on PAPUC (Pennsylvania Public Utility Commission) website or www.peco.com/know.

PECO – Timeline for Rate Cases



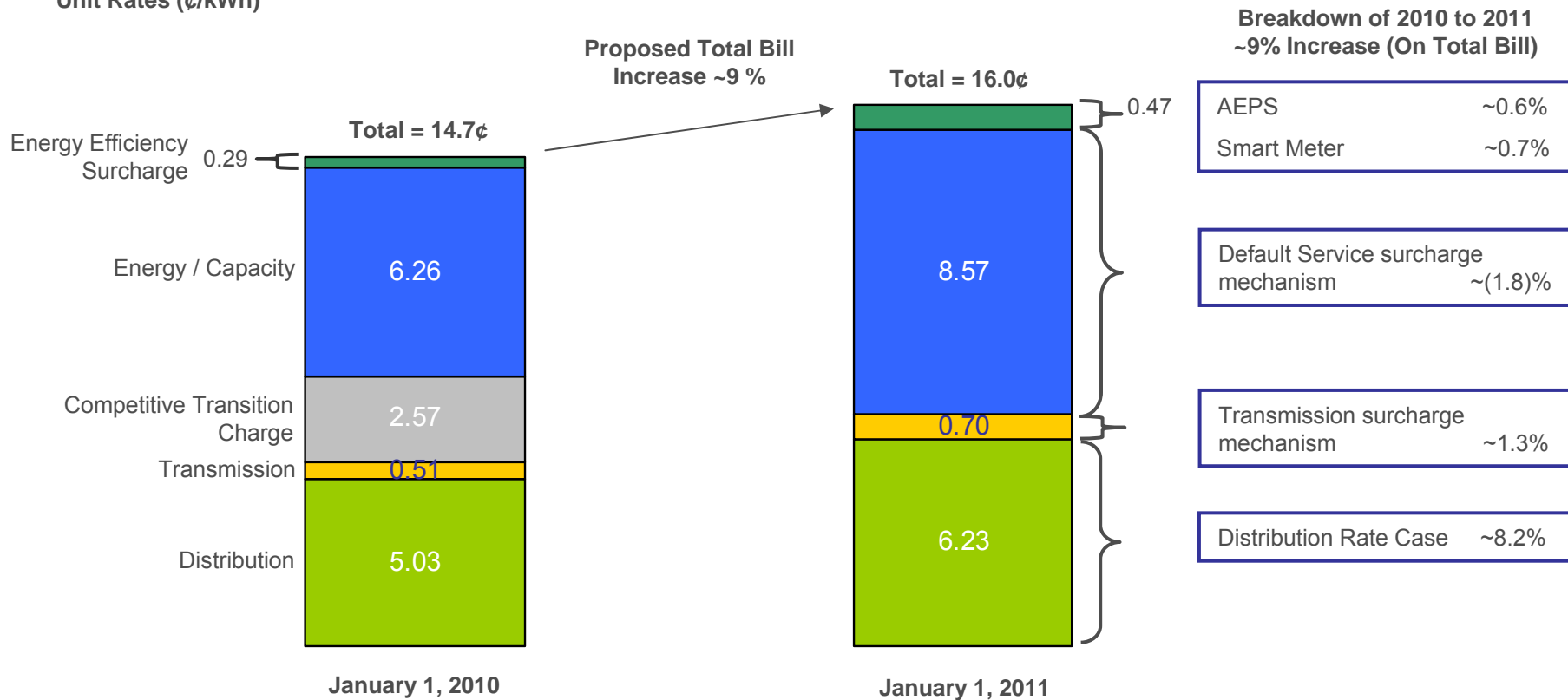
	<u>Electric</u>	<u>Gas</u>
➤ Filed:	March 31, 2010	March 31, 2010
➤ Opposing Parties' Testimony:	July 7, 2010	June 30, 2010
➤ Rebuttal Testimony:	August 3, 2010	July 23, 2010
➤ Hearings:	August 16-20, 2010	August 9-11, 2010
➤ Administrative Law Judge Orders:	November 2, 2010	November 2, 2010
➤ Final Orders Expected:	December 16, 2010	December 16, 2010
➤ New Rates Effective:	January 1, 2011	January 1, 2011

PAPUC has a nine-month process for litigation of the rate case filings

PECO Electric Residential Rate Increases 2010 to 2011



Unit Rates (¢/kWh)



Notes:

- Assume results from final procurement in September 2010 are the same as May 2010 procurement.
- Rates effective January 1, 2010 include Act 129 Energy Efficiency surcharge of 2%.
- Low income discounted rates were subsidized in the PPA in 2010 and will be recovered through distribution rates in 2011.

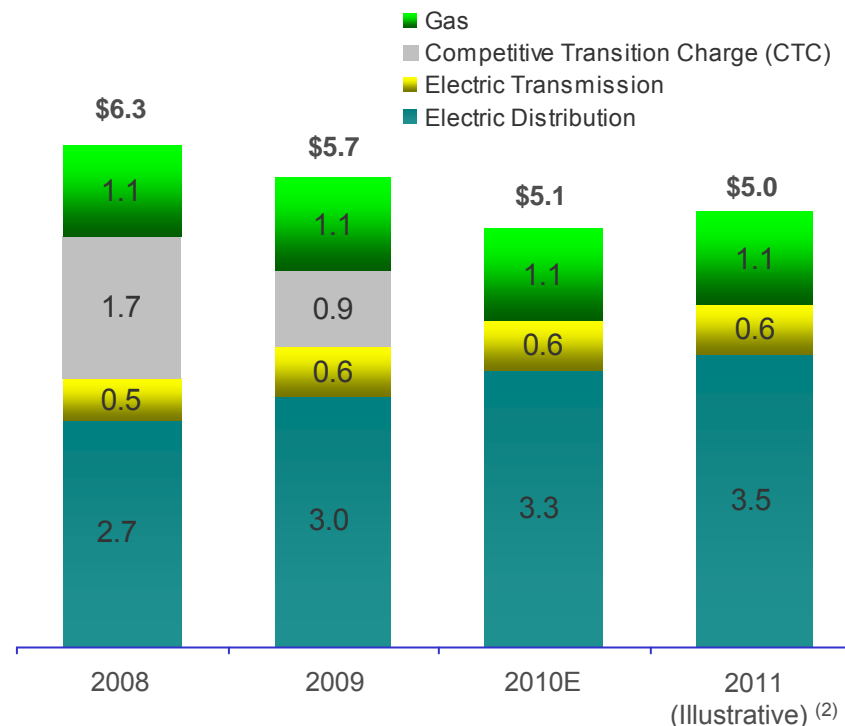
PECO Executing on Transition Plan



Actively Engaged in Transition

- Targeted earned ROE of ~11% in 2010; 9-11% post transition
- Electric and gas rate cases filed on March 31, 2010
- Selected as 1 of 6 companies to receive maximum Federal stimulus award of \$200 million for smart grid / smart meter investment
- PAPUC approved Smart Meter Plan under Pennsylvania Act 129 in April 2010
- Fixed price PPA with ExGen ends December 31, 2010
- Three of four procurement events for electricity supply beginning January 1, 2011 have been conducted, including 72% of 2011 residential load

End of Year Rate Base (\$ in billions) ⁽¹⁾



Equity	Not applicable due to transition rate structure	~50 – 53%
Rate Making ROE		~9 – 11%

PECO is managing through its transition period and is positioned for continued strong financial performance post-2010

(1) Rate base as determined for rate-making purposes. Amounts do not reflect pro forma adjustments that may be made to determine rate base for rate case filing purposes.

(2) Provided solely to illustrate possible future outcomes that are based on a number of different assumptions, all of which are subject to uncertainties and should not be relied upon as a forecast of future results.

PECO Procurement



PECO Procurement Plan ⁽¹⁾

Customer Class	Products
Residential	<ul style="list-style-type: none"> ✓75% full requirements ✓20% block energy ✓5% energy only spot
Small Commercial (peak demand <100 kW)	<ul style="list-style-type: none"> ✓90% full requirements ✓10% full requirements spot
Medium Commercial (peak demand >100 kW but ≤ 500 kW)	<ul style="list-style-type: none"> ✓85% full requirements ✓15% full requirements spot
Large Commercial & Industrial (peak demand >500 kW)	<ul style="list-style-type: none"> ✓Fixed-priced full requirements ⁽³⁾ ✓Hourly full requirements

2011 Supply Procured

Residential

- ✓ June '09 RFP average price of \$88.61/MWh ⁽²⁾
- ✓ Sept '09 RFP average price of \$79.96/MWh ⁽²⁾
- ✓ May '10 RFP average price of \$69.38/MWh ⁽²⁾
- ✓ Remaining 28% of full requirements to be procured in Sep '10

Small Commercial

- ✓ Sept '09 / May '10 RFP aggregate result \$77.65/MWh ⁽²⁾
- ✓ Remaining 40% of full requirements to be procured in Sep '10

Medium Commercial

- ✓ Sept '09 / May '10 RFP aggregate result \$77.89/MWh ⁽²⁾
- ✓ Remaining 42% of full requirements to be procured in Sep '10

Large Commercial and Industrial

- ✓ Average price of \$77.55/MWh ⁽²⁾
- ✓ 100% of fixed-price full requirements procured in May '10 ⁽³⁾

Next RFP to be held on September 20, 2010

(1) See PECO Procurement website (<http://www.pecoprocurement.com>) for additional details regarding PECO's procurement plan and RFP results.

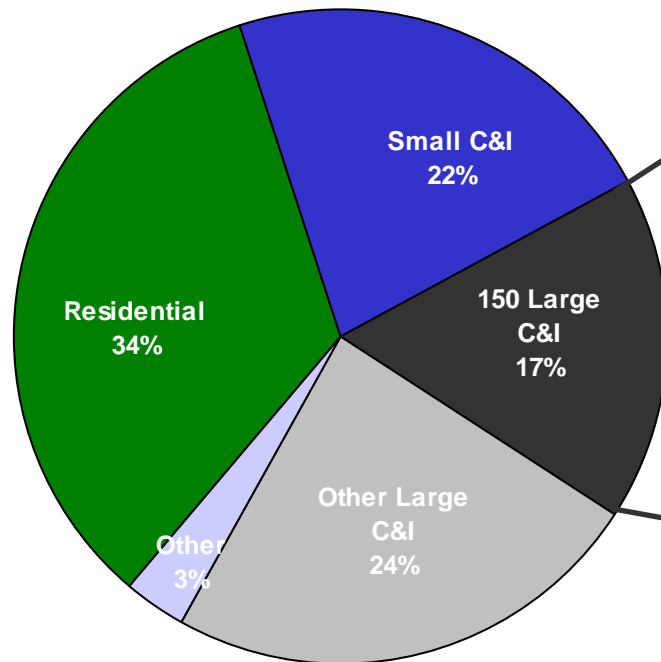
(2) Wholesale prices. No Small/Medium Commercial products were procured in the June 2009 RFP.

(3) For Large C&I customers who have opted to participate in the 2011 fixed-priced full requirements product.

PECO Customer Usage Breakdown



Customer Usage by Revenue Class



Top 150 Customer Usage by Segment

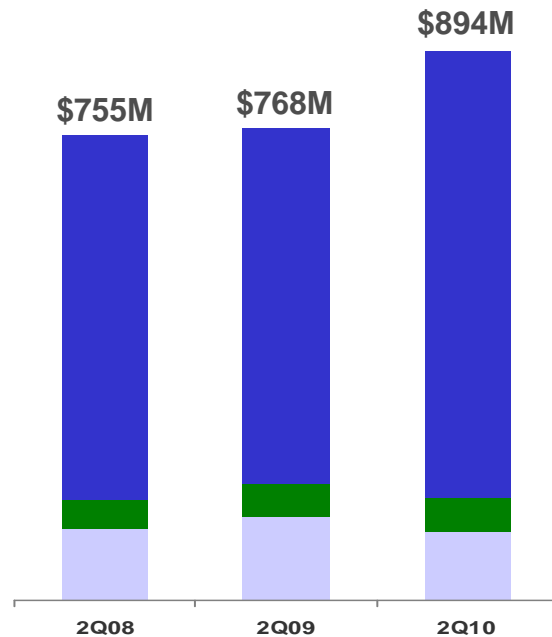
Petroleum	22%
Manufacturing	18%
Health & Educational Services	18%
Transportation, Communication & Utilities	13%
Pharmaceuticals	12%
Finance, Insurance & Real Estate	9%
Other	7%
Retail Trade	2%

PECO's load is relatively diversified by customer class and industry

ComEd and PECO Accounts Receivable



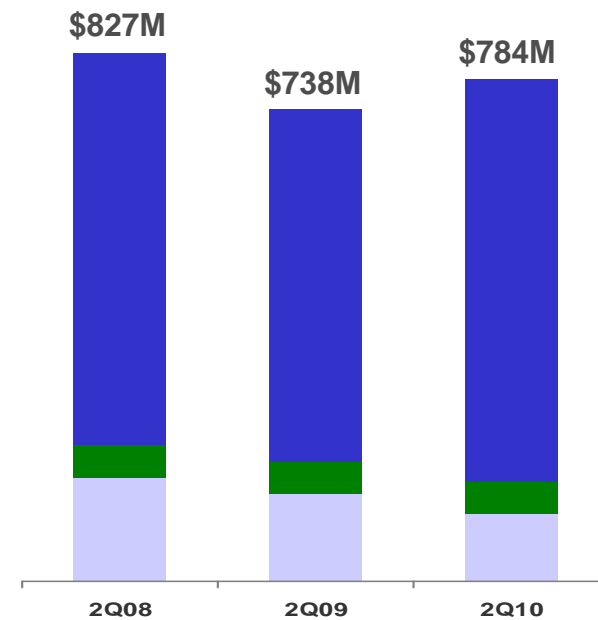
ComEd A/R (1)



% of AR



PECO A/R (1)






(1) Accounts receivable amounts include unbilled receivables and are gross of allowance for uncollectible accounts at ComEd and PECO and include, for PECO, pledged and long-term receivables.

Note: Data contained on this slide is rounded.

Sufficient Liquidity



Available Capacity Under Bank Facilities as of July 14, 2010

(\$ millions)	 An Exelon Company	 An Exelon Company	 An Exelon Company	Exelon ⁽³⁾
Aggregate Bank Commitments ⁽¹⁾	\$1,000	\$574	\$4,834	\$7,365
Outstanding Facility Draws	--	--	--	--
Outstanding Letters of Credit	(195)	(3)	(231)	(434)
Available Capacity Under Facilities ⁽²⁾	805	571	4,603	6,931
Outstanding Commercial Paper	(187)	--	--	(187)
Available Capacity Less Outstanding Commercial Paper	\$618	\$571	\$4,603	\$6,744

Exelon bank facilities are largely untapped

(1) Excludes previous commitment from Lehman Brothers Bank and commitments from Exelon's Community and Minority Bank Credit Facility.

(2) Available Capacity Under Facilities represents the unused bank commitments under the borrower's credit agreements net of outstanding letters of credit and facility draws. The amount of commercial paper outstanding does not reduce the available capacity under the credit agreements.

(3) Includes other corporate entities.

Projected 2010 Key Credit Measures



		With PPA & Pension / OPEB ⁽¹⁾	Without PPA & Pension / OPEB ⁽²⁾	Moody's Credit Ratings ⁽³⁾	S&P Credit Ratings ⁽³⁾	Fitch Credit Ratings ⁽³⁾
Exelon Consolidated:	FFO / Interest	6.3x	6.7x	Baa1	BBB-	BBB+
	FFO / Debt	27%	37%			
	Rating Agency Debt Ratio	58%	48%			
ComEd:	FFO / Interest	3.6x	3.3x	Baa1	A-	BBB+
	FFO / Debt	16%	17%			
	Rating Agency Debt Ratio	50%	43%			
PECO:	FFO / Interest	4.6x	4.2x	A2	A-	A
	FFO / Debt	21%	23%			
	Rating Agency Debt Ratio	50%	48%			
Generation:	FFO / Interest	11.8x	21.2x	A3	BBB	BBB+
	FFO / Debt	47%	96%			
	Rating Agency Debt Ratio	47%	29%			
Generation / Corp:	FFO / Interest	9.6x	14.1x			
	FFO / Debt	39%	69%			
	Rating Agency Debt Ratio	70%	55%			

Notes: Exelon and PECO metrics exclude securitization debt. See following slide for FFO (Funds from Operations)/Interest, FFO/Debt and Adjusted Book Debt Ratio reconciliations to GAAP.

(1) FFO/Debt metrics include the following standard adjustments: debt equivalents for PV of Operating Leases, PPAs, unfunded Pension and OPEB obligations (after-tax), Capital Adequacy for Energy Trading, and other minor debt equivalents.

(2) Excludes items listed in note (1) above.

(3) Current senior unsecured ratings for Exelon and Exelon Generation and senior secured ratings for ComEd and PECO as of July 15, 2010.

FFO Calculation and Ratios



FFO Calculation

Net Cash Flows provided by Operating Activities

- +/- Change in Working Capital
- + Other Non-Cash items ⁽¹⁾
- AFUDC/Cap. Interest
- Decommissioning activity
- PECO Transition Bond Principal Paydown

= FFO

FFO Interest Coverage

$$\frac{\text{FFO} + \text{Adjusted Interest}}{\text{Adjusted Interest}}$$

Net Interest Expense

- PECO Transition Bond Interest Expense
- + AFUDC & Capitalized interest

+ 6% interest on Present Value (PV) of Operating Leases

+ Interest on imputed debt related to PV of PPA

= Adjusted Interest

Debt to Total Cap

$$\frac{\text{Adjusted Book Debt}}{\text{Total Adjusted Capitalization}}$$

Debt:

- + LTD
- + STD
- Transition Bond Principal Balance

= Adjusted Book Debt

$$\frac{\text{Rating Agency Debt}}{\text{Rating Agency Capitalization}}$$

Adjusted Book Debt

- + Off-balance sheet debt equivalents ⁽²⁾

= Rating Agency Debt

Capitalization:

- + Total Shareholders' Equity
- + Preferred Securities of Subsidiaries
- + Adjusted Book Debt

= Total Adjusted Capitalization

Total Adjusted Capitalization

- + Off-balance sheet debt equivalents ⁽²⁾

= Total Rating Agency Capitalization

FFO Debt Coverage

$$\frac{\text{FFO}}{\text{Adjusted Debt}^{(3)}}$$

Debt:

- + LTD
- + STD
- PECO Transition Bond Principal Balance
- + Off-balance sheet debt equivalents ⁽²⁾

= Adjusted Debt

(1) Reflects depreciation adjustment for PPAs and operating leases and pension/OPEB contribution normalization.

(2) Metrics are calculated in presentation unadjusted and adjusted for debt equivalents for PV of Operating Leases, PPAs, unfunded Pension and OPEB obligations (after-tax), Capital Adequacy for Energy Trading, and other minor debt equivalents.

(3) Uses current year-end adjusted debt balance.

2Q GAAP EPS Reconciliation



<u>Three Months Ended June 30, 2009</u>	<u>ExGen</u>	<u>ComEd</u>	<u>PECO</u>	<u>Other</u>	<u>Exelon</u>
2009 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$0.82	\$0.13	\$0.11	\$(0.03)	\$1.03
Mark-to-market adjustments from economic hedging activities	(0.16)	-	-	-	(0.16)
2007 Illinois electric rate settlement	(0.03)	-	-	-	(0.03)
Unrealized gains related to nuclear decommissioning trust funds	0.10	-	-	-	0.10
NRG acquisition costs	-	-	-	(0.01)	(0.01)
2009 severance charges	(0.02)	(0.02)	-	-	(0.04)
Non-cash remeasurement of income tax uncertainties and reassessment of state deferred income taxes	0.06	0.06	-	(0.02)	0.10
2Q09 GAAP Earnings (Loss) Per Share	\$0.77	\$0.17	\$0.11	\$(0.06)	\$0.99

<u>Three Months Ended June 30, 2010</u>	<u>ExGen</u>	<u>ComEd</u>	<u>PECO</u>	<u>Other</u>	<u>Exelon</u>
2010 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$0.69	\$0.18	\$0.15	\$(0.02)	\$0.99
Mark-to-market adjustments from economic hedging activities	(0.11)	-	-	-	(0.11)
2007 Illinois electric rate settlement	(0.01)	-	-	-	(0.01)
Unrealized losses related to nuclear decommissioning trust funds	(0.08)	-	-	-	(0.08)
Retirement of fossil generating units	(0.02)	-	-	-	(0.02)
Non-cash remeasurement of income tax uncertainties	0.10	(0.16)	(0.03)	(0.01)	(0.10)
2Q10 GAAP Earnings (Loss) Per Share	\$0.57	\$0.02	\$0.11	\$(0.03)	\$0.67

NOTE: All amounts shown are per Exelon share and represent contributions to Exelon's EPS. Data contained on this slide is rounded.

YTD GAAP EPS Reconciliation



<u>Six Months Ended June 30, 2009</u>	<u>ExGen</u>	<u>ComEd</u>	<u>PECO</u>	<u>Other</u>	<u>Exelon</u>
2009 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$1.74	\$0.31	\$0.28	\$(0.09)	\$2.24
Mark-to-market adjustments from economic hedging activities	0.01	-	-	-	0.01
2007 Illinois electric rate settlement	(0.06)	-	-	-	(0.06)
Unrealized gains related to nuclear decommissioning trust funds	0.05	-	-	-	0.05
NRG acquisition costs	-	-	-	(0.03)	(0.03)
Impairment of certain generating assets	(0.20)	-	-	-	(0.20)
2009 severance charges	(0.02)	(0.02)	-	-	(0.04)
Non-cash remeasurement of income tax uncertainties and reassessment of state deferred income taxes	0.06	0.06	-	(0.02)	0.10
YTD 2009 GAAP Earnings (Loss) Per Share	\$1.58	\$0.35	\$0.28	\$(0.14)	\$2.07

<u>Six Months Ended June 30, 2010</u>	<u>ExGen</u>	<u>ComEd</u>	<u>PECO</u>	<u>Other</u>	<u>Exelon</u>
2010 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$1.35	\$0.37	\$0.31	\$(0.04)	\$1.99
Mark-to-market adjustments from economic hedging activities	0.10	-	-	-	0.10
2007 Illinois electric rate settlement	(0.01)	-	-	-	(0.01)
Unrealized losses related to nuclear decommissioning trust funds	(0.05)	-	-	-	(0.05)
Retirement of fossil generating units	(0.03)	-	-	-	(0.03)
Non-cash remeasurement of income tax uncertainties	0.10	(0.16)	(0.03)	(0.01)	(0.10)
Non-cash charge resulting from healthcare legislation	(0.04)	(0.02)	(0.02)	(0.02)	(0.10)
YTD 2010 GAAP Earnings (Loss) Per Share	\$1.42	\$0.19	\$0.26	\$(0.07)	\$1.80

NOTE: All amounts shown are per Exelon share and represent contributions to Exelon's EPS. Data contained on this slide is rounded.

2010 Earnings Outlook



- **Exelon's 2010 adjusted (non-GAAP) operating earnings outlook excludes the earnings effects of the following:**
 - Mark-to-market adjustments from economic hedging activities
 - Unrealized gains and losses from nuclear decommissioning trust fund investments to the extent not offset by contractual accounting as described in the notes to the consolidated financial statements
 - Significant impairments of assets, including goodwill
 - Changes in decommissioning obligation estimates
 - Costs associated with the 2007 Illinois electric rate settlement agreement
 - Costs associated with ComEd's 2007 settlement with the City of Chicago
 - Costs associated with the retirement of fossil generating units
 - Non-cash charge resulting from passage of Federal health care legislation
 - Non-cash remeasurement of income tax uncertainties
 - Other unusual items
 - Significant future changes to GAAP
- **Operating earnings guidance assumes normal weather for remainder of the year**
- **Operating O&M target excludes the following items:**
 - Exelon Generation: Decommissioning accretion expense
 - ComEd: Impact of riders, primarily Rider EDA (Energy Efficiency and Demand Response Adjustment)
 - PECO: Impact of energy efficiency and smart grid/meter riders