

Exelon Corporation Investor Meetings

March, 2011



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 2010 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; and (2) 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.

Why Is Exelon a Good Investment?



Largest merchant nuclear fleet in the U.S.

Consistent world-class performance in nuclear operations

Utilities serving two of the largest metropolitan areas in the U.S.

Commitment to investment grade credit ratings and financial discipline

Stable dividend that has yielded ~5% on average over the past year

Exelon is able to execute from a position of strength based on solid fundamentals

2011 Events of Interest



	Q1	Q2	Q3	Q4
	<p>Proposed 316(b) EPA Regulation (by 3/14)</p> <p>Proposed HAP EPA Regulation (by 3/16)</p>	<p>RPM Auction results (5/13)</p> <p>Retirement of Cromby 1 & Eddystone 1 units (5/31)</p> <p>EPA Final Transport Rule (June)</p>		<p>EPA Final HAP Rule (November)</p> <p>Retirement of Cromby 2 unit (12/31)</p>
	<p>ALJ Proposed Order – DST Rate Case (3/31)</p>	<p>Illinois Power Agency RFP (April)</p> <p>DST Rate Case Final Order (by 5/31)</p>		
		<p>Procurement RFP (bids due 5/23; results by 6/23)</p>	<p>Procurement RFP (bids due 9/19; results by 10/19)</p>	

Pursuing Transmission Investment



2023 Revised Conceptual Alternative 2 - 345 kV and 765 kV



RITE Line

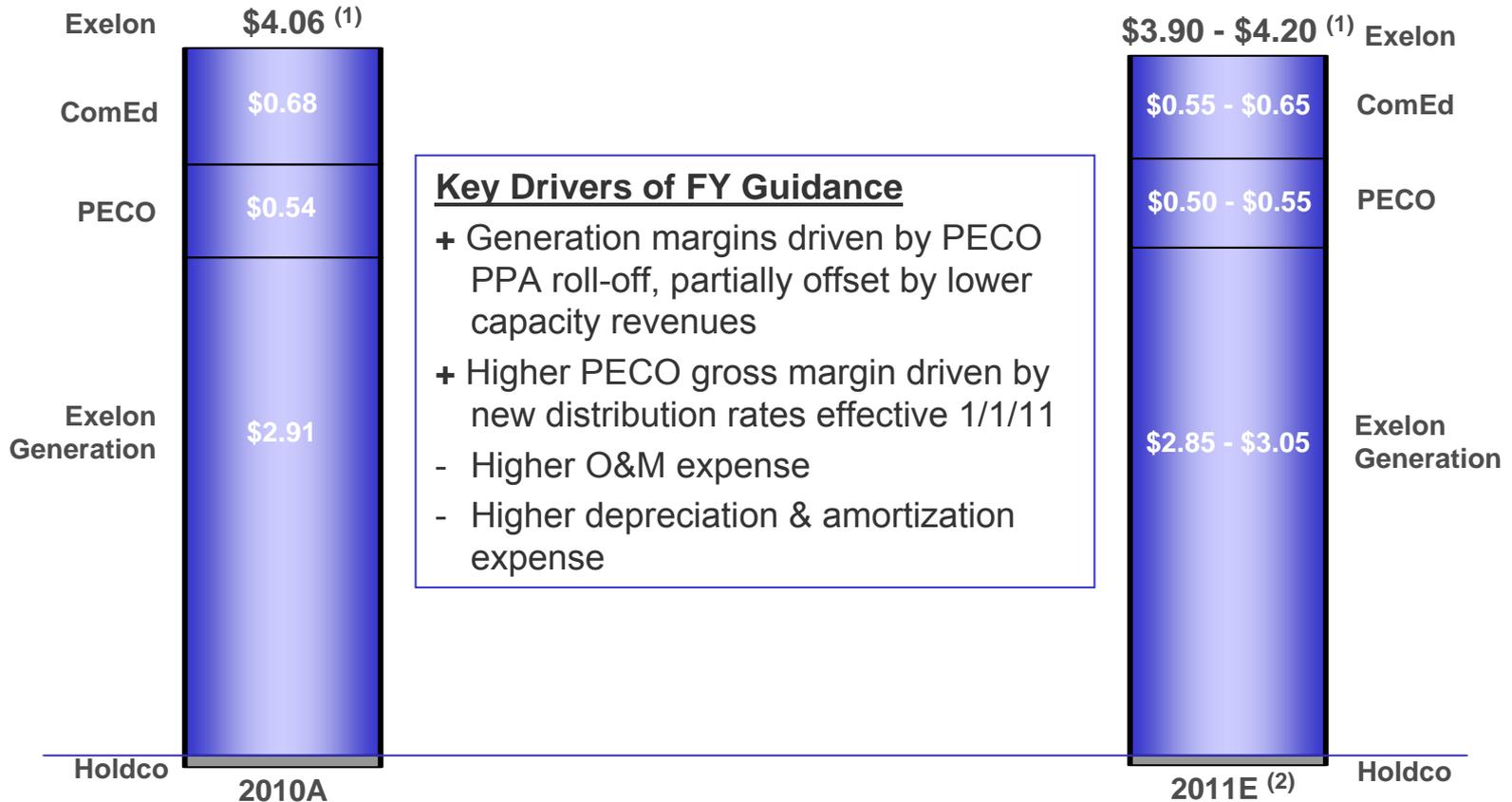
- Moving forward on project planning with partner ETA
- Total Investment ~\$1.6 billion
 - ComEd/Exelon ~\$1.1 billion
- FERC incentive rate joint filing expected late 1Q or early 2Q 2011

West Loop Phase II

- Enhance reliable service to the Chicago central business district
- Estimated cost of ~\$170 million recoverable under ComEd's FERC formula rate
- Expected in-service December 2011

Exelon companies are investing in projects that enhance reliability and support further clean energy development

2011 Operating Earnings Guidance



2011 operating earnings guidance of \$3.90 – \$4.20/share and 1Q 2011 guidance of \$1.00 – \$1.10/share⁽¹⁾

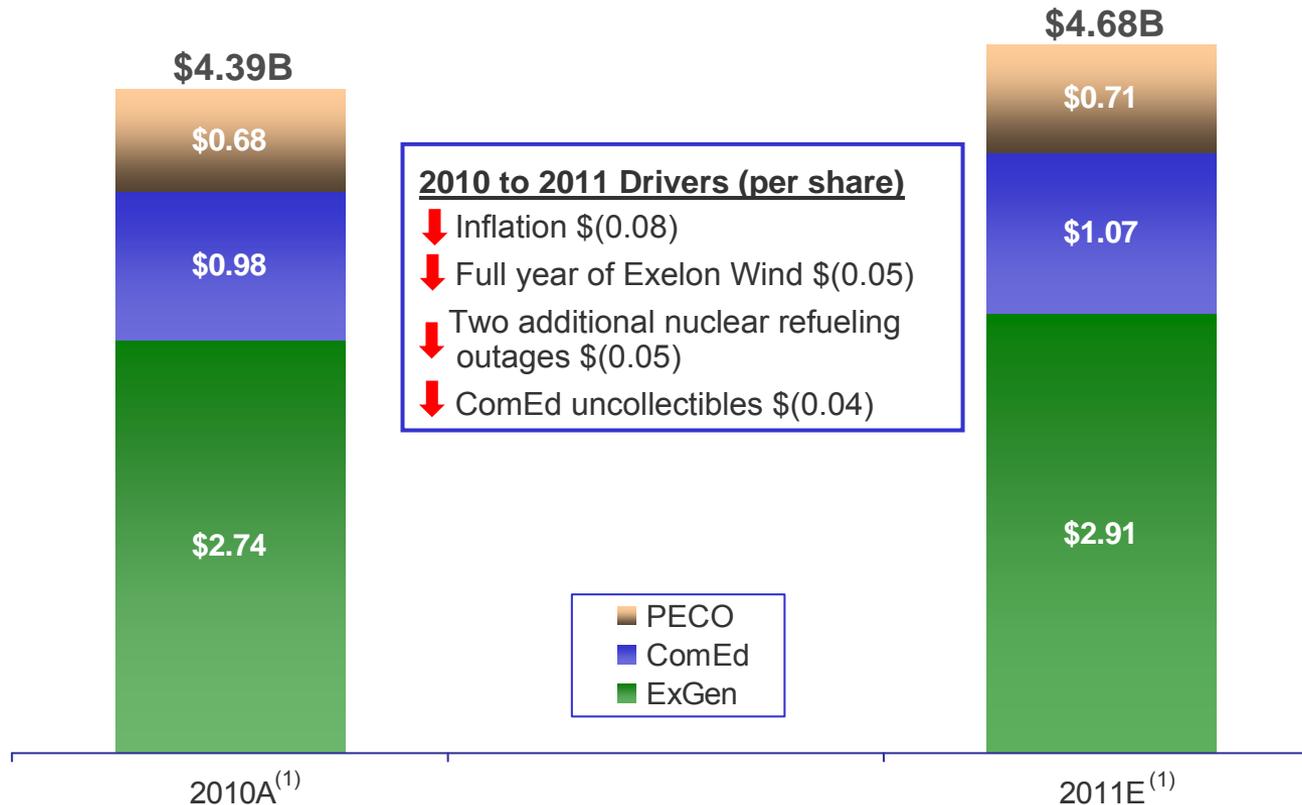
(1) We provided 2011 earnings guidance on January 26, 2011, and we are not updating earnings guidance at this time. Earnings guidance is only reviewed in connection with our quarterly earnings announcements or if we expressly indicate that we are updating the guidance. Refer to slides 45-47 for a reconciliation of adjusted (non-GAAP) operating earnings to GAAP earnings.

(2) Earnings guidance for OpCos may not add up to consolidated EPS guidance.

Operating O&M Outlook



- 2010 Operating O&M below 2008 levels for second consecutive year
- One-time savings in 2010 included executive salary freezes and reduced compensation benefits
- Anticipate annual O&M growth rate of ~2% for 2011-2013



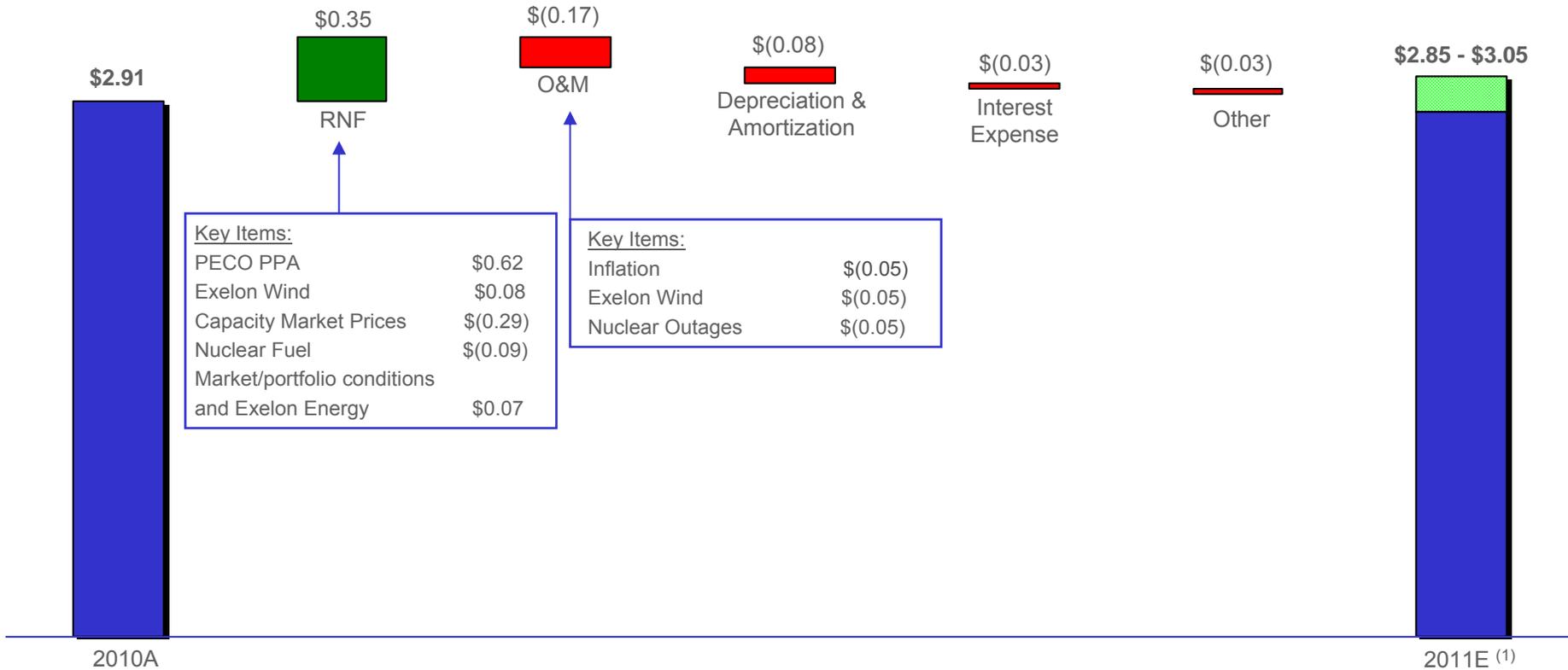
Estimated 2011 O&M represents a new “base” level for operating O&M

(1) Amounts may not add due to rounding. Refer to slide 47 for a reconciliation of GAAP O&M to Operating O&M.

Exelon Generation 2011 EPS Contribution



\$ / Share



Note: Drivers add up to mid-point of 2011 EPS range. We provided 2011 earnings guidance on January 26, 2011, and we are not updating earnings guidance at this time. Earnings guidance is only reviewed in connection with our quarterly earnings announcements or if we expressly indicate that we are updating the guidance. Refer to slides 45-47 for a reconciliation of adjusted (non-GAAP) operating earnings to GAAP earnings.

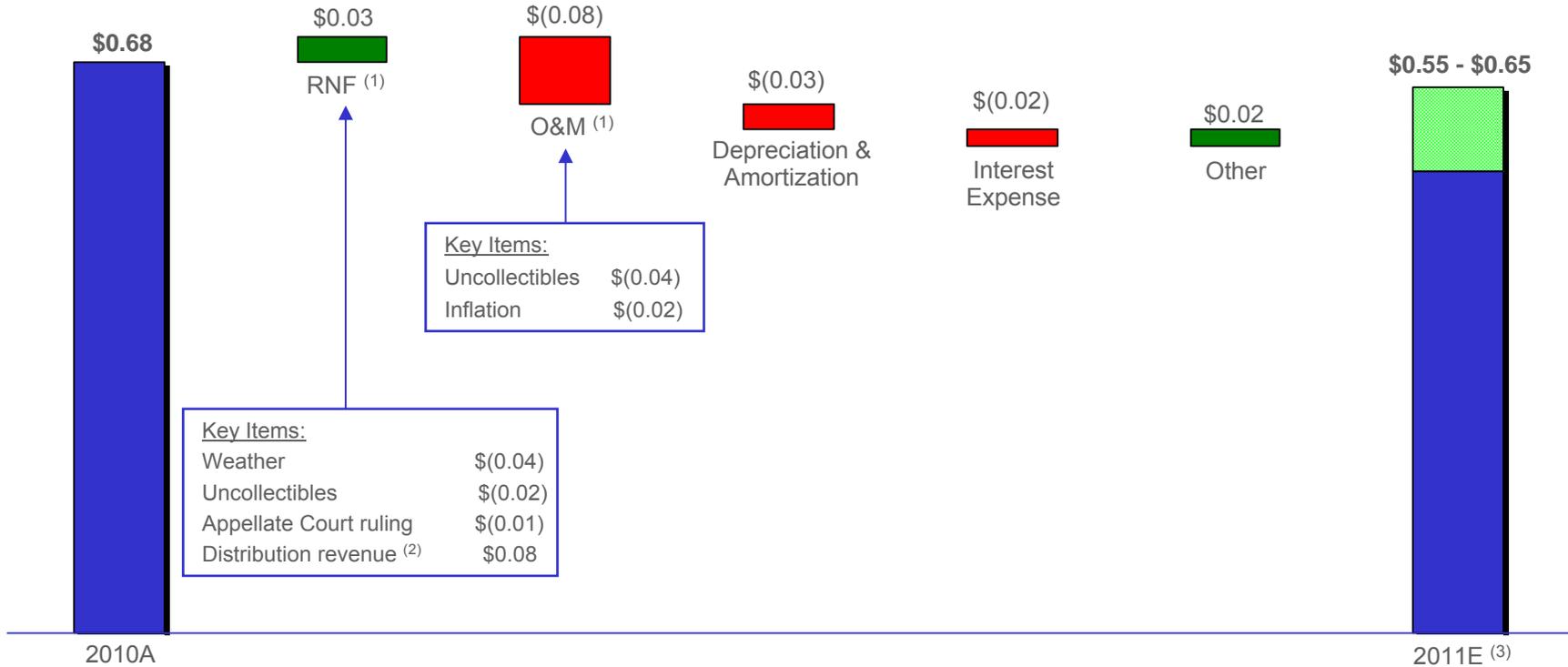
(1) Estimated contribution to Exelon's operating earnings guidance.

RNF = revenue net fuel

ComEd 2011 EPS Contribution



\$ / Share



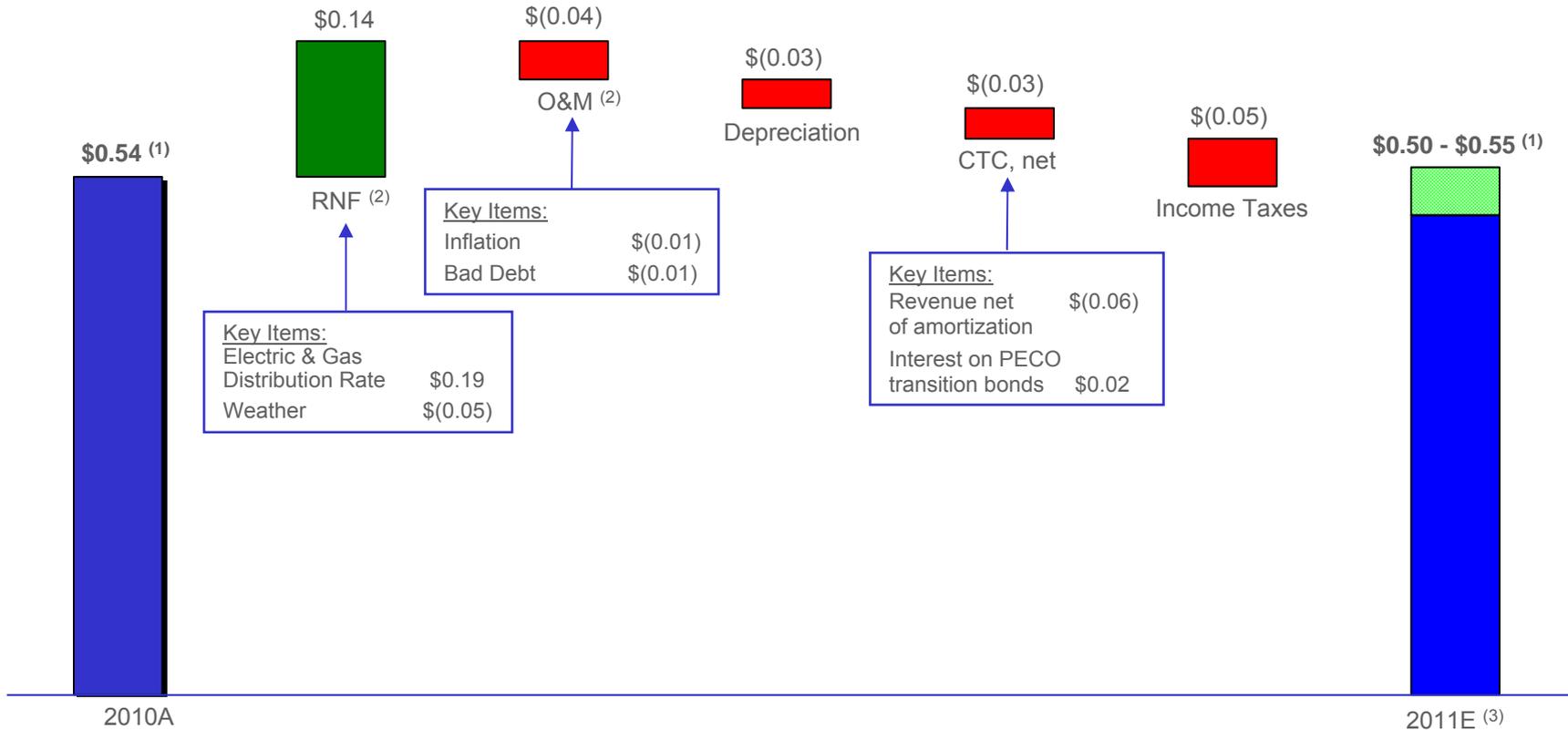
Note: Drivers add up to mid-point of 2011 EPS range. We provided 2011 earnings guidance on January 26, 2011, and we are not updating earnings guidance at this time. Earnings guidance is only reviewed in connection with our quarterly earnings announcements or if we expressly indicate that we are updating the guidance. Refer to slides 45-47 for a reconciliation of adjusted (non-GAAP) operating earnings to GAAP earnings.

- (1) Excludes estimated impact of Rider EDA (Energy Efficiency and Demand Response Adjustment) of +/- \$0.05/share. 2010 net income includes a one-time benefit for collections of under-recovered 2008 and 2009 bad debt costs, as provided by the uncollectible expense rider approved by the ICC in February 2010. Going forward, the rider provides for full recovery of all bad debt costs.
- (2) Distribution rate case currently pending, new rates will be effective in June 2011. Earnings guidance assumes mid-point of ComEd's requested revenue increase.
- (3) Estimated contribution to Exelon's operating earnings guidance.

PECO 2011 EPS Contribution



\$ / Share



Note: Drivers add up to mid-point of 2011 EPS range. We provided 2011 earnings guidance on January 26, 2011, and we are not updating earnings guidance at this time. Earnings guidance is only reviewed in connection with our quarterly earnings announcements or if we expressly indicate that we are updating the guidance. Refer to slides 45-47 for a reconciliation of adjusted (non-GAAP) operating earnings to GAAP earnings.

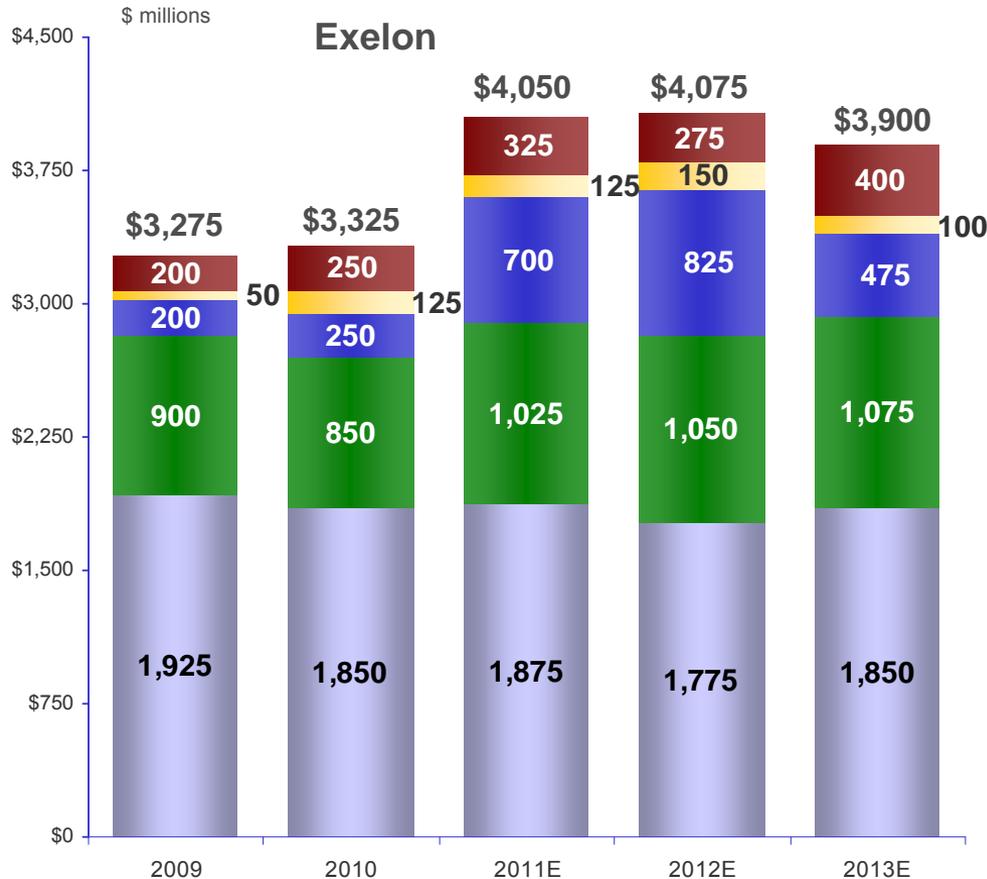
(1) Excludes preferred dividends.

(2) Excludes items that are income statement neutral and estimated impact of energy efficiency and smart meter costs recoverable under a rider of \$0.10/share.

(3) Estimated contribution to Exelon's operating earnings guidance.

CTC = competitive transition charge

Capital Expenditures Expectations



■ Base CapEx ■ Nuclear Fuel
■ Nuclear Uprates and Solar/Wind ■ Smart Grid
■ New Business at Utilities

	2009	2010	2011E	2012E	2013E
Exelon Generation					
Base CapEx	875	775	850	800	775
Nuclear Fuel ⁽¹⁾	900	850	1,025	1,050	1,075
Nuclear Uprates ⁽²⁾	150	250	475	550	475
Solar / Wind ⁽³⁾	50	-	225	275	-
Total ExGen	1,975	1,875	2,575	2,675	2,325
ComEd					
Base CapEx	650	650	700	625	675
Smart Grid/Meter ⁽⁴⁾	50	100	50	100	50
New Business ⁽⁵⁾	150	200	275	225	325
Total ComEd	850	950	1,025	950	1,050
PECO					
Base CapEx	350	475	325	325	375
Smart Grid/Meter	-	25	75	50	50
New Business	50	50	50	50	75
Total PECO	400	550	450	425	500
Corporate ⁽⁶⁾	50	(50)	-	25	25

Note: Data contained on this slide is rounded.

- (1) Nuclear fuel shown at ownership, including Salem.
- (2) Excludes TMI and Clinton EPUs, which are under review.
- (3) Does not include \$900 million related to acquisition of John Deere Renewables.
- (4) ComEd does not plan to move forward with these Smart Grid/Meter investments unless appropriate cost recovery mechanisms are in place.
- (5) Includes transmission growth projects.
- (6) Represents capital projects transferred from Business Services Company (BSC) to Exelon Generation, ComEd and PECO. These projects are shown as capital expenditures at Generation, ComEd and PECO and the capital expenditure is eliminated upon consolidation

2011 Projected Sources and Uses of Cash



(\$ millions)

				Exelon ⁽⁸⁾
Beginning Cash Balance ⁽¹⁾				\$800
Cash Flow from Operations ⁽²⁾	425	775	3,150	4,325
CapEx (excluding Nuclear Fuel, Nuclear Uprates, Exelon Wind, Utility Growth CapEx)	(700)	(325)	(850)	(1,875)
Nuclear Fuel	n/a	n/a	(1,025)	(1,025)
Dividend ⁽³⁾				(1,400)
Nuclear Uprates and Exelon Wind ⁽⁴⁾	n/a	n/a	(700)	(700)
Utility Growth CapEx ⁽⁵⁾	(325)	(125)	n/a	(450)
Net Financing (excluding Dividend):				
Planned Debt Issuances ⁽⁶⁾	1,000	--	--	1,000
Planned Debt Retirements	(350)	(250)	--	(600)
Other ⁽⁷⁾	250	--	--	300
Ending Cash Balance ⁽¹⁾				\$375

(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.

(3) Assumes 2011 dividend of \$2.10/share. Dividends are subject to declaration by the Board of Directors.

(4) Includes \$475 million in Nuclear Uprates and \$225 million for Exelon Wind.

(5) Represents new business, smart grid/smart meter investment and transmission growth projects.

(6) Excludes ComEd's \$191 million of tax-exempt bonds that are backed by letters of credit (LOCs). Excludes PECO's \$225 million Accounts Receivable (A/R) Agreement with Bank of Tokyo. PECO's A/R Agreement was extended in accordance with its terms through September 6, 2011.

(7) "Other" includes proceeds from options and expected changes in short-term debt.

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

Pension and OPEB Expense and Contributions – As of 12/31/10



(\$ in millions)	Assumptions		2010		2011		2012	
	Asset Returns (actual for 2010 and expected for 2011 and 2012)	Discount Rate (used for expense)	Pre-tax expense	Actual contribution	Pre-tax expense	Expected contribution	Pre-tax expense	Expected contribution
Pension	11.9% in 2010 8.0% in 2011 7.5% in 2012	5.83% in 2010 5.26% in 2011 5.48% in 2012	\$240	\$765	\$200	\$2,100 ⁽¹⁾	\$240	\$110
<i>Assets</i>				\$8,860				
<i>Obligations</i>				<u>\$12,525</u>				
<i>Unfunded balance – end of year</i>				\$3,665		\$1,305		\$1,015
OPEB	11.6% in 2010 7.08% in 2011 7.08% in 2012	5.83% in 2010 5.30% in 2011 5.52% in 2012	\$190	\$205	\$210	\$185	\$225	\$210
<i>Assets</i>				\$1,655				
<i>Obligations</i>				<u>\$3,875</u>				
<i>Unfunded balance – end of year</i>				\$2,220		\$2,180		\$2,140

The decrease in pension expense in 2011 is primarily due to the \$2.1 billion pension contribution, partially offset by the effects of lower discount rates and a decrease in EROA

(1) Exelon made a \$2.1B pension contribution on January 31, 2011

(2) Pension expense amounts exclude settlement charges.

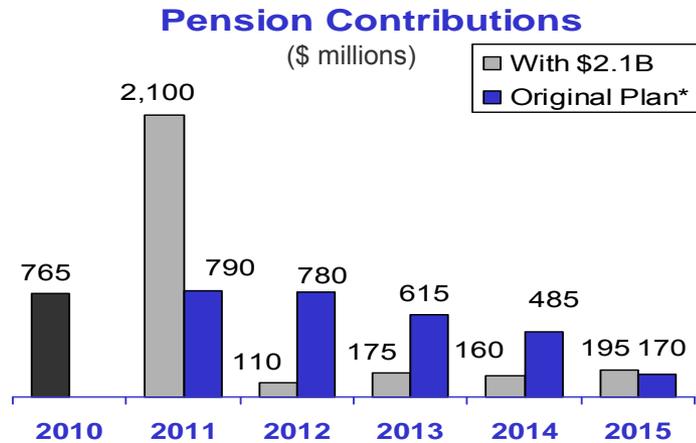
(3) Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006 (the Act), management of the pension obligation and regulatory implications. The Act requires the attainment of certain funding levels to avoid benefit restrictions (such as an inability to pay lump sums or to accrue benefits prospectively), and at-risk status (which triggers higher minimum contribution requirements and participant notification).

Note: Slide provided for illustrative purposes and not intended to represent a forecast of future outcomes. Assumes an ~25% capitalization of pension and OPEB costs.
EROA = earned return on assets

Driving Financial Discipline

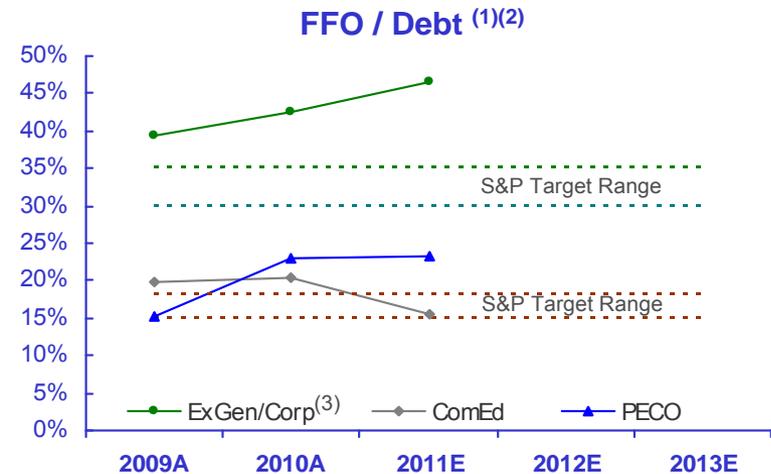


\$2.1B Pension Contribution in 2011



* Original Plan reflects preliminary 2010 underlying assumptions (including discount rate and asset returns).

Continued Strong Balance Sheet



Credit Facilities

- Currently refinancing ExGen, PECO and Corp facilities; expect to close by Q1 2011
 - Three facilities totaling \$6.4B will have 5-year tenor (maturing in March 2016)

(\$ millions)	Generation	PECO	Corporate	ComEd	Total
New Unsecured Revolving Credit Facilities ⁽⁴⁾	\$5,300	\$600	\$500	\$1,000	\$7,400
Expiration date	March 2016	March 2016	March 2016	March 2013	

Maintaining a strong balance sheet and liquidity position

(1) Reflects FFO / Debt as calculated by S&P.

(2) Dashed lines represent S&P Target Ranges (30-35% for ExGen/Corp and 15-18% for ComEd and PECO). See slide 15 for reconciliations to GAAP.

(3) FFO/Debt Target Range reflects ExGen FFO/Debt in addition to the debt obligations of Exelon Corp.

(4) Excludes \$94 million of credit facility agreements arranged with minority and community banks on 10/22/10 that are utilized solely to issue letters of credit.

Metric Calculations 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 / Debt:

$$\frac{FFO}{Adjusted\ Debt^{(2)}}$$

Adjusted Debt:

- LTD
- + STD
- PECO Transition Bond Principal Balance
- + Off-balance sheet debt equivalents ⁽³⁾

= Adjusted Debt

Interest Coverage:

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

Adjusted Interest:

- Net Interest Expense
- PECO Transition Bond Interest Expense
- + AFUDC & Capitalized interest
- + Interest on Present Value (PV) of Operating Leases
- + Interest on Imputed Debt Related to PV of Power Purchase Agreements (PPA)

= Adjusted Interest

Debt / Cap:

$$\frac{Adjusted\ Debt^{(2)}}{Adjusted\ Capitalization}$$

Adjusted Capitalization:

- Total shareholder's equity
- + Preferred Securities of Subsidiaries
- + Adjusted Debt ⁽³⁾

= Adjusted Capitalization

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

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

(3) Metrics are calculated in presentation adjusted for debt equivalents for Present Value of Operating Leases, PPAs, unfunded Pension and OPEB obligations (after-tax) and other minor debt equivalents.

Key Assumptions



	2009 Actual	2010 Actual	2011 Est. ⁽³⁾
Nuclear Capacity Factor (%) ⁽¹⁾	93.6	93.9	93.0
Total Generation Sales Excluding Trading (GWh)	173,065	171,789	168,700
Henry Hub Gas Price (\$/mmBtu)	3.92	4.37	4.56
PJM West Hub ATC Price (\$/MWh)	38.30	45.93	45.45
Tetco M3 Gas Price (\$/mmBtu)	4.64	5.10	5.32
PJM West Hub Implied ATC Heat Rate (mmbtu/MWh)	8.25	9.01	8.54
NI Hub ATC Price (\$/MWh)	28.85	33.09	30.69
Chicago City Gate Gas Price (\$/mmBtu)	3.92	4.46	4.61
NI Hub Implied ATC Heat Rate (mmbtu/MWh)	7.36	7.42	6.66
MAAC Capacity Price (\$/MW-day)	158.48	181.34	136.59
EMAAC Capacity Price (\$/MW-day)	173.73	181.34	136.59
RTO Capacity Price (\$/MW-day)	106.13	144.40	136.59
Electric Delivery Growth (%) ⁽²⁾			
PECO	0.6	0.1	0.0
ComEd	(0.1)	0.2	0.0
Effective Tax Rate - Operating (%)	37.2	36.7	38.1
Exelon Generation	38.3	37.5	37.1
ComEd	37.9	39.7	40.8
PECO	29.5	31.1	38.0

(1) Excludes Salem.

(2) Weather-normalized retail load growth.

(3) Reflects forward market prices as of December 31, 2010; Reflects assumptions used in original 2010 earnings guidance provided on January 26, 2011.

Note: The estimates of planned generation do not represent guidance or a forecast of future results as Exelon has not completed its planning or optimization processes.

Exelon®

Generation

2014/15 PJM Capacity Auction: Expected Changes Since Planning Year 2013/14



Factors Influencing PJM RPM Capacity Auction (Comparison of PY 14/15 and PY 13/14 Price Drivers)	Exelon Price Impact
Cost of Environmental Upgrades ⁽¹⁾	
Higher Net CONE ⁽²⁾	
Higher Net ACRs for Coal Units ⁽³⁾	
Import Transmission Limits and Objectives (muted impact on portfolio revenues due to regional diversification)	
NJ CCGT Proposal / PJM Minimum Offer Price Rules	
Peak Load ⁽⁴⁾	
Demand Response Growth	

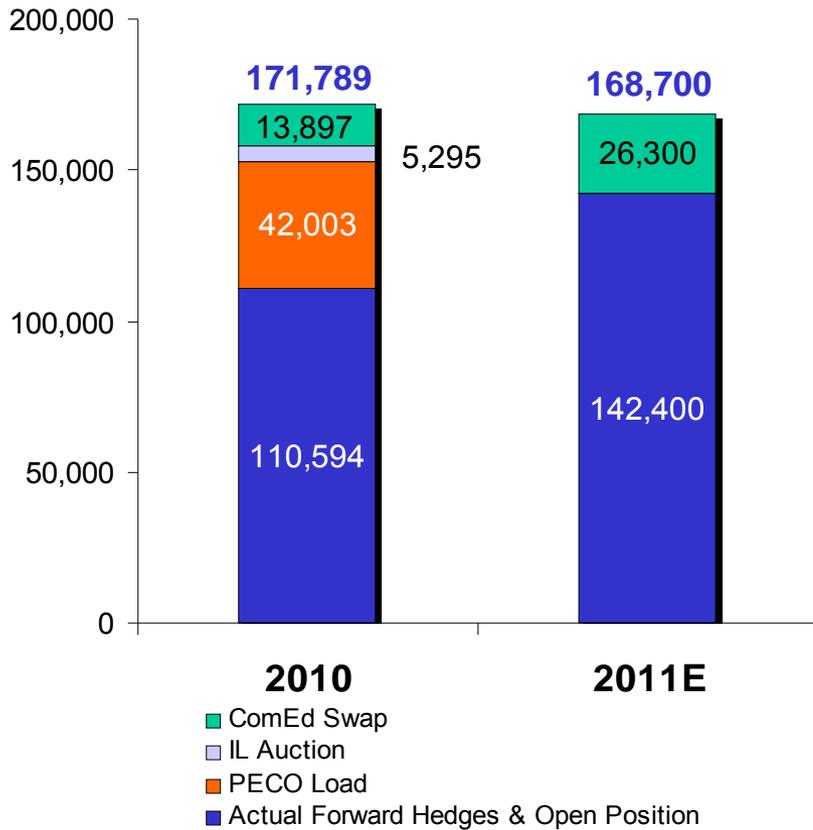
Exelon's capacity position, split almost evenly between the west and the east, dampens the volatility to portfolio revenues from changes to transmission limits while retaining upside across the fleet from upcoming EPA regulations

(1) We expect generators to reflect cost of capital expenditures into their cost based offers at the upcoming auction.
 (2) Cost of new entry (CONE) increased by 7.6% (for RTO) and 5.3% to 6.5% (within Locational Deliverability Areas (LDAs)).
 (3) Replacing 2007 net revenues with significantly lower 2010 revenues in the Net ACR (avoidable cost rate) calculations for coal generators may increase offer caps for certain coal generators in the next auction. However, some coal units may not be affected due to high net revenues compared to avoidable costs.
 (4) Peak load reduced by approx. 1% in RTO (excluding the impact from Duke Ohio integration).
 Note: RPM = Reliability Pricing Model; CCGT = combined cycle gas turbine

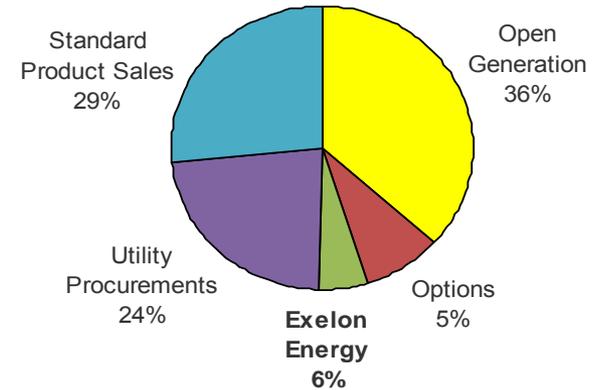
Moving Generation to Market



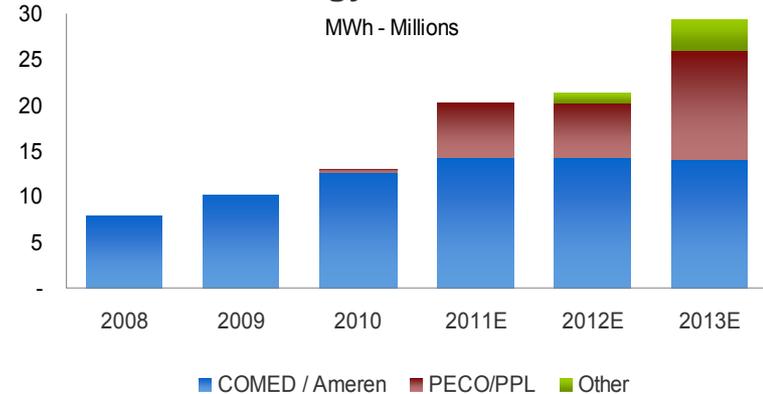
Expected Total Sales (GWh) ⁽¹⁾



2011-2013 Sales as % of Expected Generation ⁽¹⁾



Exelon Energy Electric Volumes



Transition to market at PECO provides additional channels to market for Exelon Generation, including opportunities at Exelon Energy

(1) Represents values as of December 31, 2010.

Growing Our Clean Generation

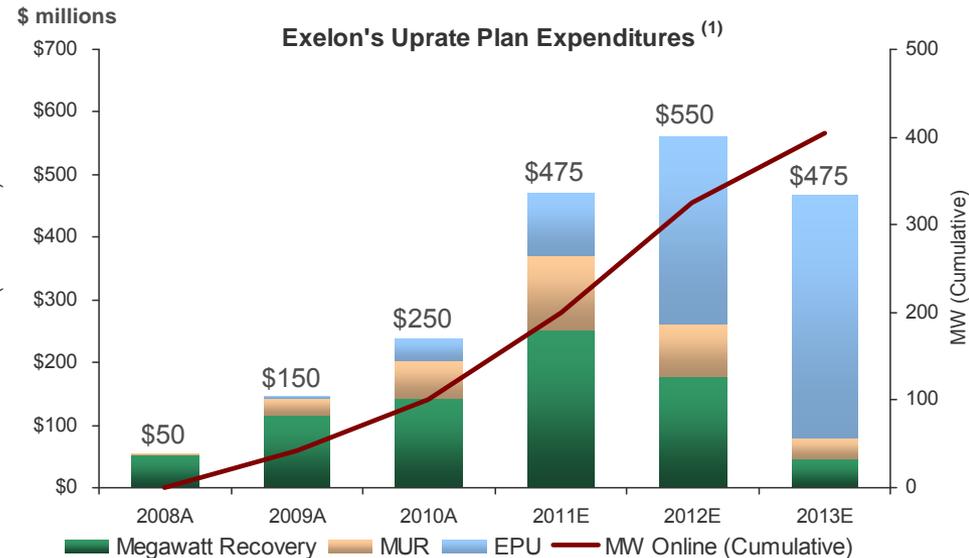
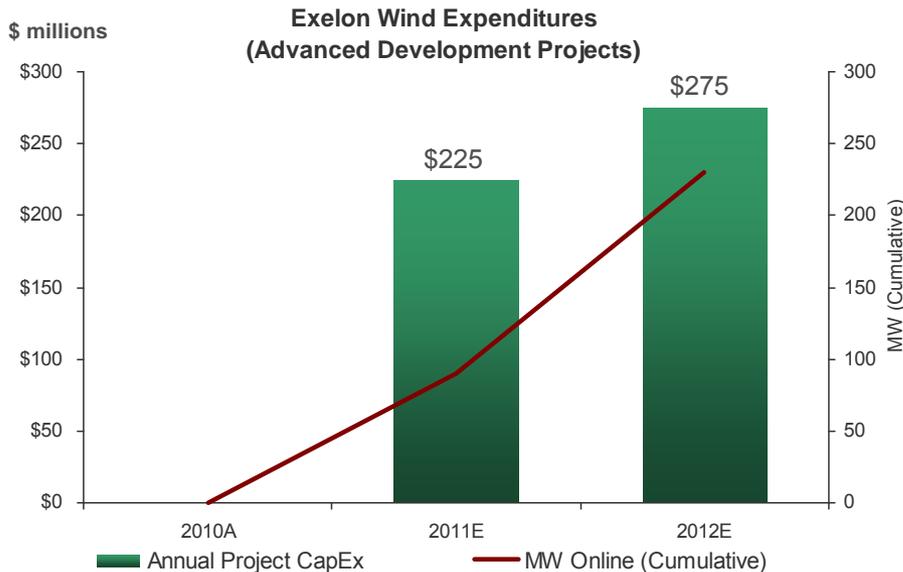


Wind Development Projects

- Attractive economics for both operating and advanced development projects – PPAs already executed
- Provides diversity in geographic presence and generation type

Nuclear Upgrades Program

- Highest return projects are being completed in early years
- Leverages Exelon's substantial experience managing successful uprate projects – 1,100 MW completed from 1999 to 2008, 101 MWs added in 2009-2010



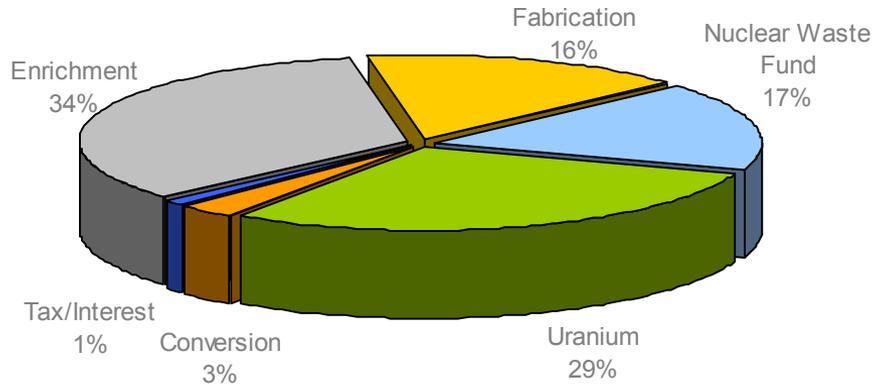
Exelon is positioned as a key player in the US wind market and has the largest size and scale for nuclear uprates

(1) Dollars shown are nominal, reflecting 6% escalation, in millions and exclude TMI and Clinton extended power uprates, which are currently under review. MW shown at ownership. Note: PPA = power purchase agreement; MUR = measurement uncertainty recapture; EPU = extended power uprate. Data contained in this slide is rounded.

Effectively Managing Nuclear Fuel Costs



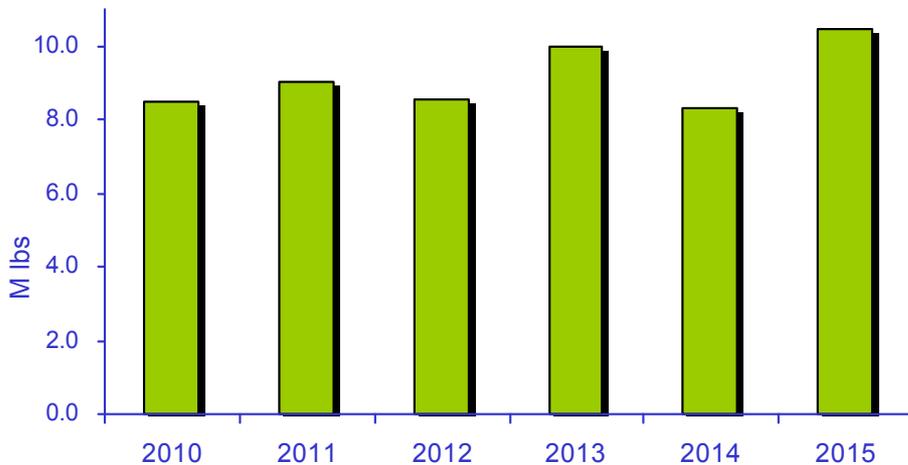
Components of Fuel Expense in 2010



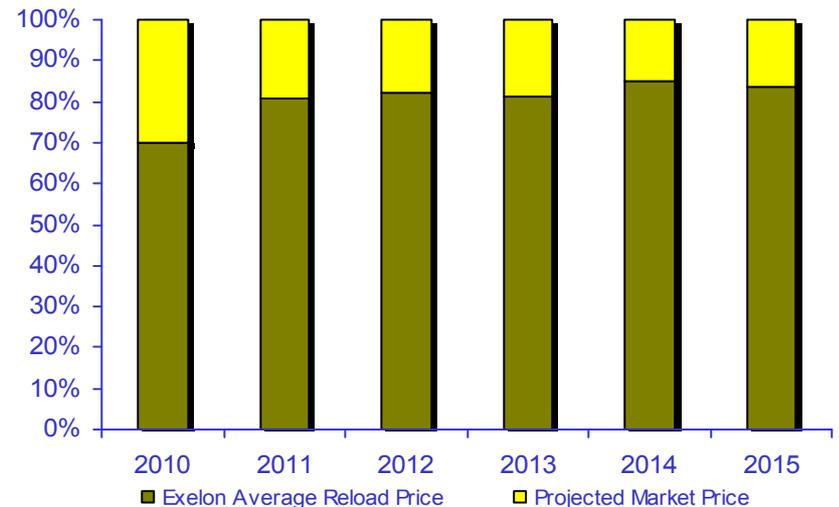
- Exelon Nuclear’s uranium demand is 100% physically hedged for 2010-2015
- Contracted prices continue to be below market prices
- Uranium prices were volatile over last 5 years, but have stabilized in the \$40-\$60/lb range

Projected Exelon Uranium Demand

2010 – 2015: 100% hedged in volume



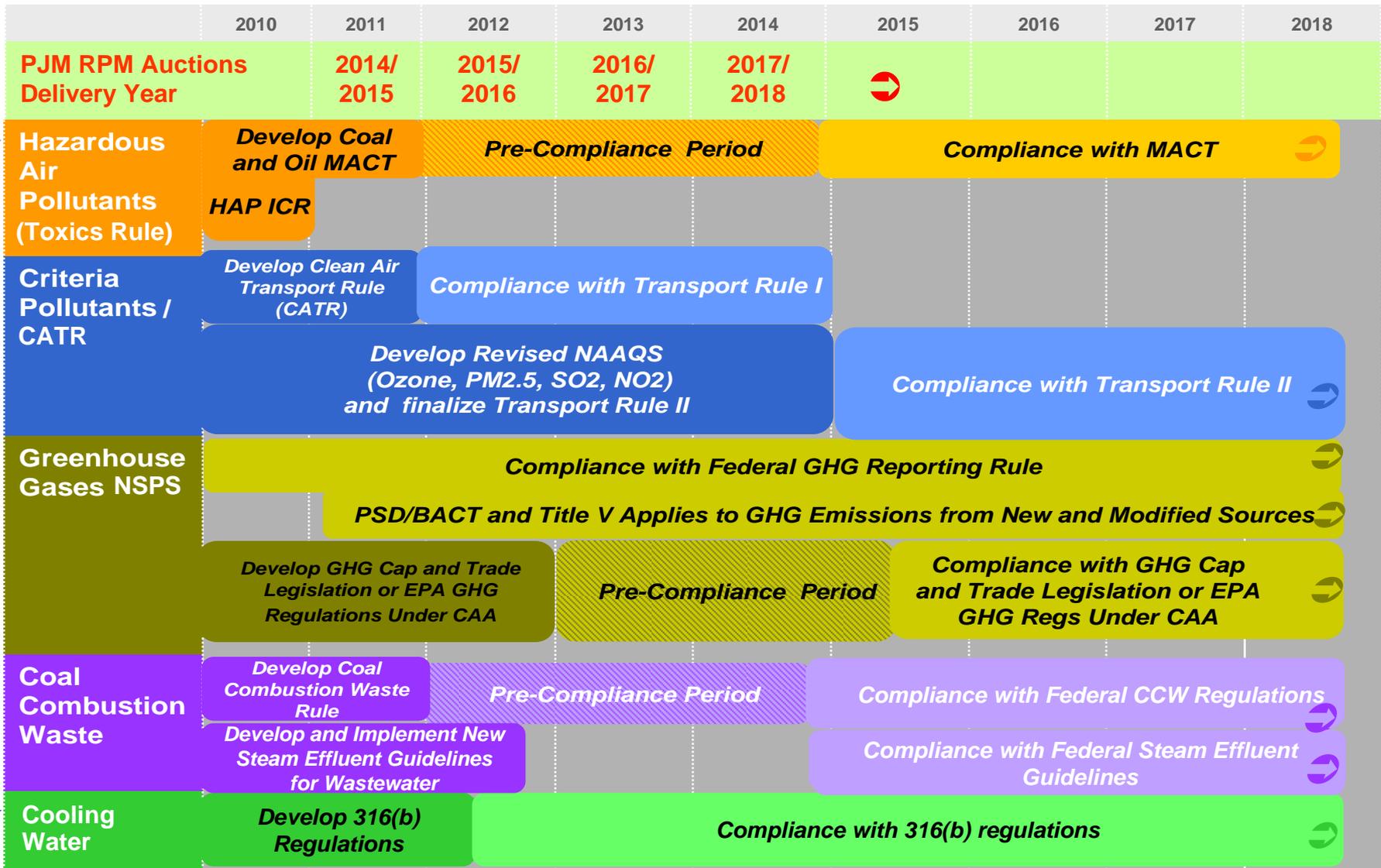
Projected Exelon Average Uranium Cost vs. Market





Environmental

EPA Regulations Will Move Forward in 2011



Note: 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/>).

Exelon's Exposure to EPA Regulations



EPA Regulation	Units Affected	Exelon Investment Needed ⁽¹⁾	Industry Impact ⁽²⁾
Hazardous Air Pollutants (Toxics Rule)	Keystone & Conemaugh ⁽³⁾	~\$10 million	Significant, primarily fossil fuel-fired generation
	Oil-Fired Units >25 MW: ~935 MW	Impact to be determined	
Criteria Pollutants / CATR	Keystone & Conemaugh ⁽³⁾	~\$125 million	Compliance costs of up to \$2.8 billion / year
	Fossil-fuel fired units >25 MW: ~4,000 MW ⁽⁴⁾	None anticipated	
GHG NSPS	Fossil-fuel fired generation ⁽⁵⁾	Minimal due to low carbon position of fossil fleet	Significant, primarily fossil fuel-fired generation
Coal combustion waste	Keystone & Conemaugh ⁽³⁾	Subtitle C: < \$100 million ⁽⁶⁾ Subtitle D: no impact	Compliance costs up to \$20 billion
Cooling Water	Facilities without closed-cycle recirculating systems (e.g. cooling towers) <u>POWER</u> : Schuylkill, Eddystone 3 & 4, Fairless Hills, Mountain Creek, Handley <u>NUCLEAR</u> : Clinton, Dresden, Quad Cities, Peach Bottom, and Salem ⁽⁷⁾	Impact to be determined once rule is promulgated; Cost to retrofit Salem estimated at \$500 million ⁽³⁾	Significant, impacts all fuel types including large base load and intermediate units

(1) These rules are in the proposed or pre-proposed stage and estimates are based on published cost studies used as inputs to IPM modeling.

(2) EPA's estimated costs, where applicable.

(3) Investment needed shown is Exelon's share of the cost. Exelon owns 21% share in Keystone and Conemaugh and 42.59% share in Salem. Keystone & Conemaugh units all have scrubbers and Keystone units have SCRs. Salem investment estimates based on 2006 studies.

(4) Exelon's existing coal-fired units will be retired before this rule will take effect.

(5) This rule applies to new sources or major modifications of existing sources and will establish guidelines for States to incorporate into SIPS for existing sources.

(6) Excludes Eddystone 1 and 2 and Cromby, which are scheduled to retire in 2011 and 2012.

(7) Excludes Oyster Creek due to settlement with NJ DEP that does not require closed cycle cooling.

Why EPA Regulations Will Not Be Delayed



Opposing Argument	Reality	Supporting Facts
<ul style="list-style-type: none"> ➤ Courts will suspend the rules or the President will intervene 	<ul style="list-style-type: none"> ➤ Federal court would have to determine that the rules are inconsistent with applicable law, which is unlikely to occur because the amended rules are aligned with the court's expectations 	<ul style="list-style-type: none"> ➤ Up to 1 year extension by EPA only if necessary for installation of controls ➤ President has only used exemption two times in history (only for national security interests)
<ul style="list-style-type: none"> ➤ Costs are prohibitive for industry and consumer 	<ul style="list-style-type: none"> ➤ Proven technologies are commercially available and have already been installed demonstrating that the costs can be managed ➤ Total savings to consumer, including healthcare impacts 	<ul style="list-style-type: none"> ➤ Well over half of existing units have already installed pollution controls ➤ EPA estimates in 2014 that the proposed Transport Rule will have annual net benefits (in 2006\$) of \$120-290 billion using a 3% discount rate
<ul style="list-style-type: none"> ➤ Timeline is too tight for compliance 	<ul style="list-style-type: none"> ➤ Recent industry trends suggest that it is reasonable to install this quantity of scrubbers according to the proposed timeframe. 	<ul style="list-style-type: none"> ➤ EPA's modeling indicates that only 14 GW of additional capacity would need to be retrofitted with flue gas desulfurization (FGD) for Phase 2 of the Transport rule (2014) ➤ Industry has already demonstrated ability to schedule and sequence outages to comply
<ul style="list-style-type: none"> ➤ Retirements will cause reliability issues on the grid 	<ul style="list-style-type: none"> ➤ Electric system reliability will not be compromised if the industry and its regulators manage the transition 	<ul style="list-style-type: none"> ➤ Each NERC region has excess capacity, totaling over 100 GW nationwide ➤ Between 2001-2003, industry built over 160 GW of new generation – four times what is projected will retire over next 5 years

Opposition will have a voice, but the framework and timetable have been set

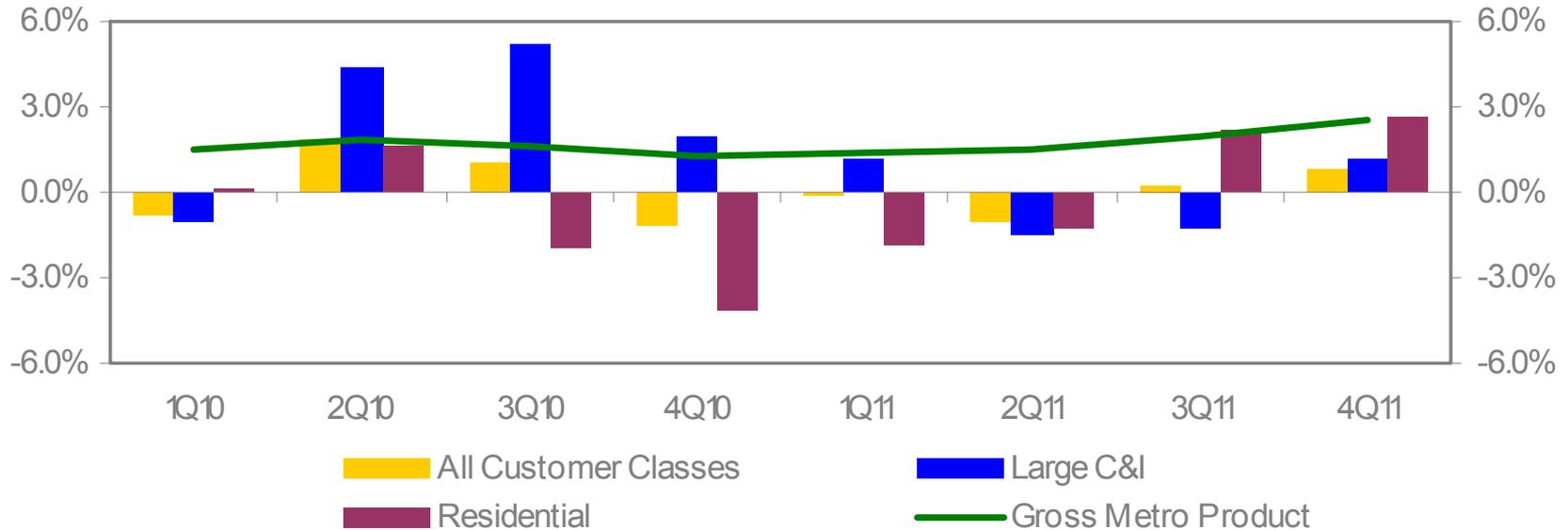
ComEd®

An Exelon Company

ComEd Load Trends



Weather-Normalized Load Year-over-Year



Key Economic Indicators

	Chicago	U.S.
Unemployment rate ⁽¹⁾	9.3%	9.4%
2010 annualized growth in gross domestic/metro product ⁽²⁾	1.6%	2.8%

(1) Source: U.S. Dept. of Labor (December 2010) and Illinois Department of Security (December 2010)

(2) Source: Global Insight December 2010

Weather-Normalized Load

	4Q10	2010	2011E
Average Customer Growth	0.4%	0.2%	0.5%
Average Use-Per-Customer	(4.5)%	(1.4)%	0.0%
Total Residential	(4.1)%	(1.2)%	0.5%
Small C&I	(1.5)%	(0.6)%	(0.3)%
Large C&I	1.9%	2.6%	(0.2)%
All Customer Classes	(1.2)%	0.2%	0.0%

Note: C&I = Commercial & Industrial

ComEd 2010 Rate Case Update



(ICC Docket No. 10-0467)

ComEd Reply Brief (2/23/11)

- \$343M increase requested
- 11.50% ROE / 47.28% equity ratio
- Rate base \$7,349M
- 2009 test year with pro forma plant additions through 6/30/11

ICC Staff Reply Brief Position

- \$113M increase proposed
- 10.00% ROE / 47.11% equity ratio
- Rate base \$6,480M
- Pro forma plant additions and depreciation reserve through 12/31/10

Reconciliation of ComEd Initial Request to Reply Brief

\$ millions	
ComEd Original Request (6/30/10)	\$ 396
Adjustments:	
Bonus Depreciation	(14)
Pro forma plant adds/O&M update	(4)
Errata in Initial Filing	(12)
Reduction to Reg Asset Amortization	(8)
Other Items	(4)
ComEd Rebuttal (11/22/10)	\$ 354
Adjustments:	
New Bonus Depreciation	(22)
Pro forma plant adds/O&M update	(4)
Reduction to AMI/Other	(2)
ComEd Surrebuttal (1/3/2011)	\$ 326
Adjustments:	
IL Business Tax Increase	17
ComEd Reply Brief (2/23/11)	\$ 343*

* ComEd request does not reflect Appellate Court decision relating to depreciation reserve, which ComEd estimates would have a \$85M reduction to revenue requirement.

ComEd – Proposed Infrastructure Investment and Modernization Legislation

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Proposed Grid Modernization Legislation Key Concepts

- ✓ Incremental investment of \$2.6B of capital over 10 years
 - \$1.5B smart grid/smart meter
 - \$1.1B infrastructure improvements
- ✓ Incorporates an annual formula rate proceeding, similar to FERC Transmission rate
 - Protocols clarify treatment of several significant items, including pension costs and pension asset
 - ROE formula based on average 30-year Treasury yield
- ✓ Reduces proceeding timeframe from 11 months to less than 9 months

Proposed Grid Modernization Legislation Customer Benefits

- ✓ Quantifiable benefits to customers of 12 million avoided outages and hundreds of millions in avoided costs
- ✓ Put a smart meter in every home and provide extensive consumer education
- ✓ Significantly improve meter reading
- ✓ Create 2,000 jobs at the peak of the investment cycle
- ✓ Create \$100M in Illinois tax revenues over the life of the program
- ✓ Enhance the economic competitiveness of Illinois; make our state better positioned to attract businesses and jobs

ComEd is driving innovative regulatory and legislative strategy to benefit customers, improve the transparency of the ratemaking process and enable economic development

ComEd Rate Base Growth

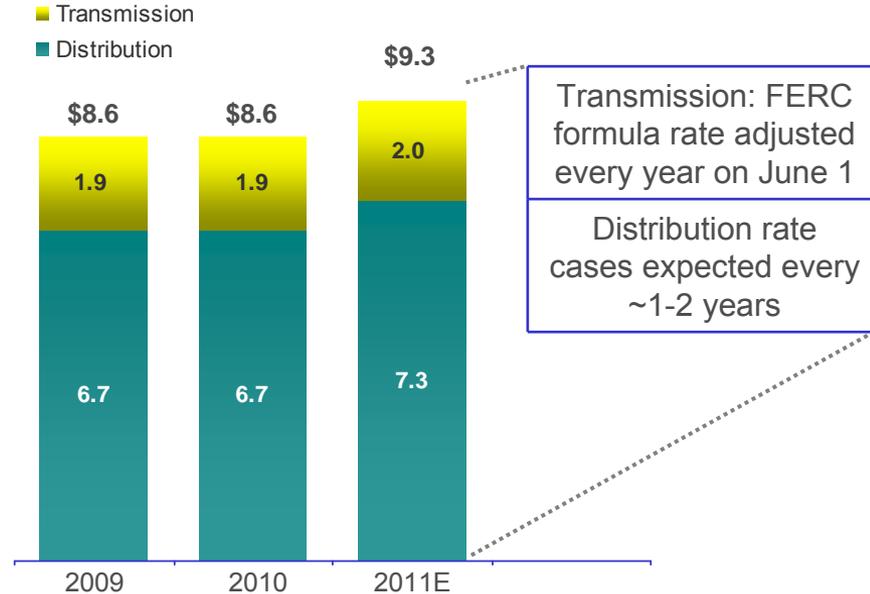


Recent Rate Cases

ELECTRIC DISTRIBUTION	Prior Rate Case	ComEd Surrebuttal 1/3/2011
Rates Effective	October 1, 2008	June 1, 2011
Test Year	2006 pro forma	2009 pro forma
Rate Base	\$6,694 million	\$7,349 million
ROE	10.3%	11.5%
Equity %	45.04%	47.28%

TRANSMISSION	FERC Formula rate
Rates Effective	June 1, 2010
Test Year	2009 pro forma
Rate Base	\$1,949 million
ROE	11.5%
Equity %	56%

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



	2009	2010	Target
Equity	~46%	~45%	~45%
Earned ROE	8.5%	10.6%	≥10%

ComEd executing on regulatory recovery plan

(1) Amounts include pro forma adjustments. On September 30, 2010, the Illinois Appellate Court ruled with regard to ComEd's 2007 distribution rate case and held that the ICC abused its discretion in not reducing ComEd's rate base to account for an additional 18 months of accumulated depreciation while including pro forma plant additions post-test year through that period. The Court remanded the case to the ICC. For the 2007 rate case, the Court's ruling would reduce the \$6,694 million rate base by ~\$500 - \$670 million resulting in a revenue reduction between \$57 and \$77 million. For the current rate case, updating the depreciation and deferred tax reserves to June 2011 would reduce the \$7,349 million rate base by an estimated \$667 million and would reduce the revenue requirement by approximately \$85 million.

Note: Amounts may not add due to rounding.

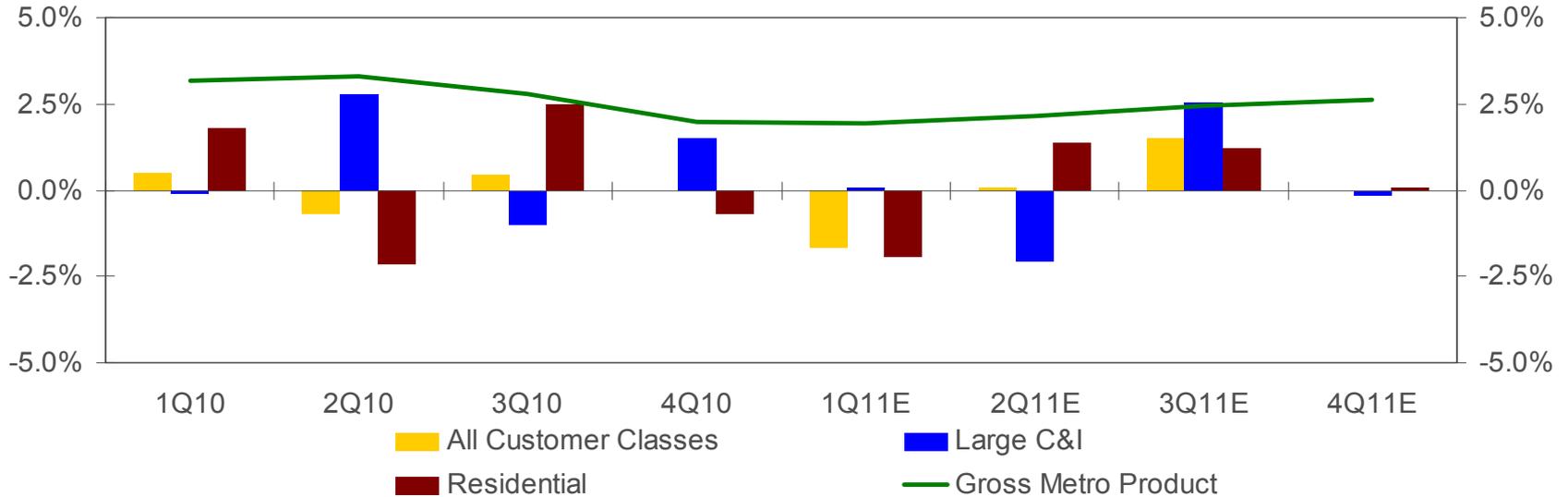


An Exelon Company

PECO Load Trends



Weather-Normalized Load Year-over-Year



Key Economic Indicators

	Philadelphia	U.S.
Unemployment rate ⁽¹⁾	8.4%	9.4%
2010 annualized growth in gross domestic/metro product ⁽²⁾	2.8%	2.8%

(1) Source: U.S Dept. of Labor (PHL – November 2010 preliminary data, US - December 2010)

(2) Source: Global Insight December 2010

Weather-Normalized Load

	4Q10	2010	2011E
Average Customer Growth	0.5%	0.3%	0.4%
Average Use-Per-Customer	(1.2)%	0.3%	(0.3)%
Total Residential	(0.7)%	0.5%	0.1%
Small C&I	(2.0)%	(1.9)%	(0.5)%
Large C&I	1.5%	0.8%	0.1%
All Customer Classes	0.0%	0.1%	0.0%

Note: C&I = Commercial & Industrial

PECO Executing on Transition Plan



Recent Rate Cases ⁽¹⁾

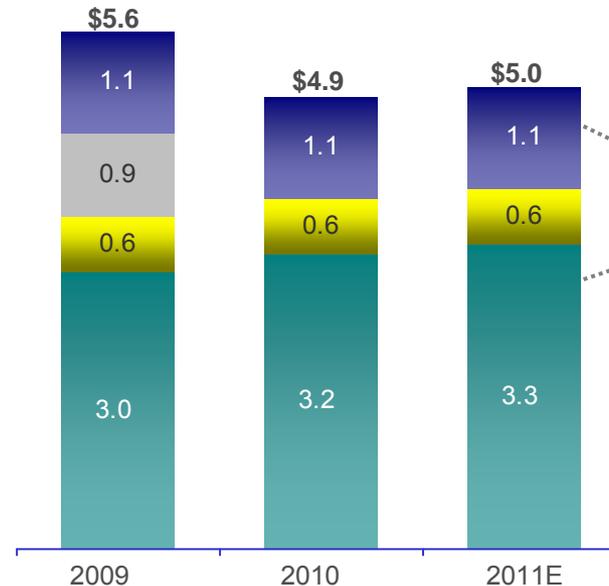
ELECTRIC DISTRIBUTION	Filing 3/31/2010
Rates Effective	January 1, 2011
Test Year	2010
Revenue Increase	\$225 million

GAS DELIVERY	Filing 3/31/2010
Rates Effective	January 1, 2011
Test Year	2010
Revenue Increase	\$20 million

TRANSMISSION	Stated rate; no recent rate cases
---------------------	-----------------------------------

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

■ Electric Distribution ■ Electric Transmission
■ CTC ■ Gas



Periodic rate cases going forward

	2009	2010	2011E
Equity ⁽¹⁾	53%	53%	Target
Earned ROE ⁽²⁾	14.8%	12.9%	≥ 10%

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

(1) As determined for rate-making purposes. Amounts reflect pro forma adjustments that may be made to determine rate base for rate case filing purposes.

(2) Operating Net income basis

Exelon Generation Hedging Disclosures

(as of December 31, 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 December 31, 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.

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Portfolio Management Objective

Align Hedging Activities with Financial Commitments



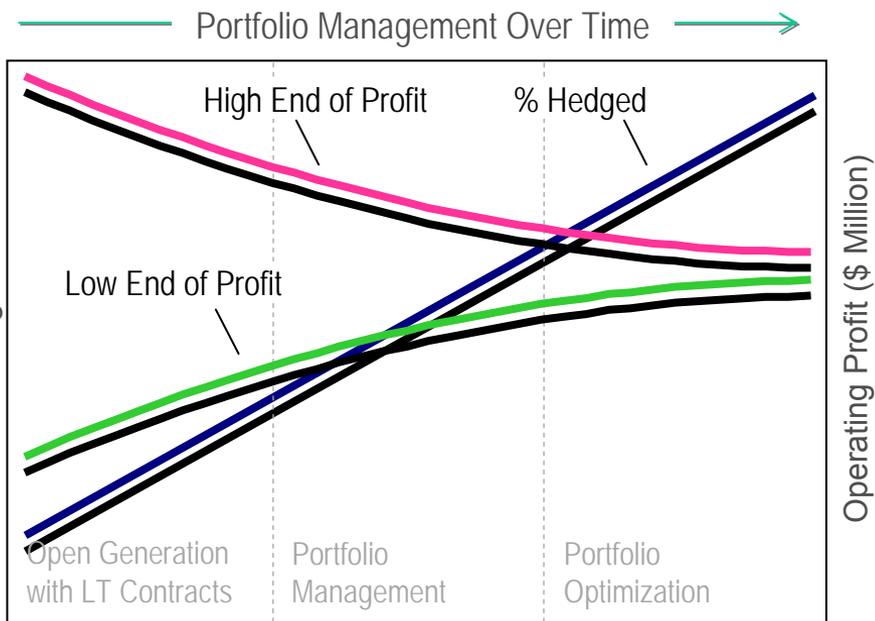
➤ **Exelon’s hedging program is designed to protect the long-term value of our generating fleet and maintain an investment-grade balance sheet**

- 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



	2011	2012	2013
Estimated Open Gross Margin (\$ millions) ⁽¹⁾⁽²⁾⁽³⁾	\$5,200	\$5,050	\$5,700

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

Reference Prices ⁽¹⁾

Henry Hub Natural Gas (\$/MMBtu)	\$4.56	\$5.08	\$5.33
NI-Hub ATC Energy Price (\$/MWh)	\$30.69	\$32.38	\$35.09
PJM-W ATC Energy Price (\$/MWh)	\$45.45	\$46.41	\$48.25
ERCOT North ATC Spark Spread (\$/MWh) ⁽⁴⁾	\$1.12	\$0.82	\$1.84

(1) Based on December 31, 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) As of December 31, 2010 disclosure, Exelon Wind included. Assets in IL, MI and MN are in Midwest region and assets in ID, KS, MO, OR and TX are in South and West region.

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

Generation Profile



	2011	2012	2013
Expected Generation (GWh) ⁽¹⁾	165,900	165,800	163,300
Midwest	99,600	98,500	96,200
Mid-Atlantic	56,800	57,200	56,500
South & West	9,500	10,100	10,600
Percentage of Expected Generation Hedged ⁽²⁾	90-93%	67-70%	32-35%
Midwest	91-94	69-72	31-34
Mid-Atlantic	93-96	67-70	36-39
South & West	70-73	51-54	39-42
Effective Realized Energy Price (\$/MWh) ⁽³⁾			
Midwest	\$43.00	\$41.50	\$43.50
Mid-Atlantic	\$57.00	\$50.50	\$51.50
South & West	\$2.50	\$(1.00)	\$(3.50)

(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 12 refueling outages in 2011 and 10 refueling outages in 2012 and 2013 at Exelon-operated nuclear plants and Salem. Expected generation assumes capacity factors of 93.0%, 93.6% and 93.1% in 2011, 2012 and 2013 at Exelon-operated nuclear plants. These estimates of expected generation in 2012 and 2013 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.

(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.

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Exelon Generation Gross Margin Sensitivities (with Existing Hedges)

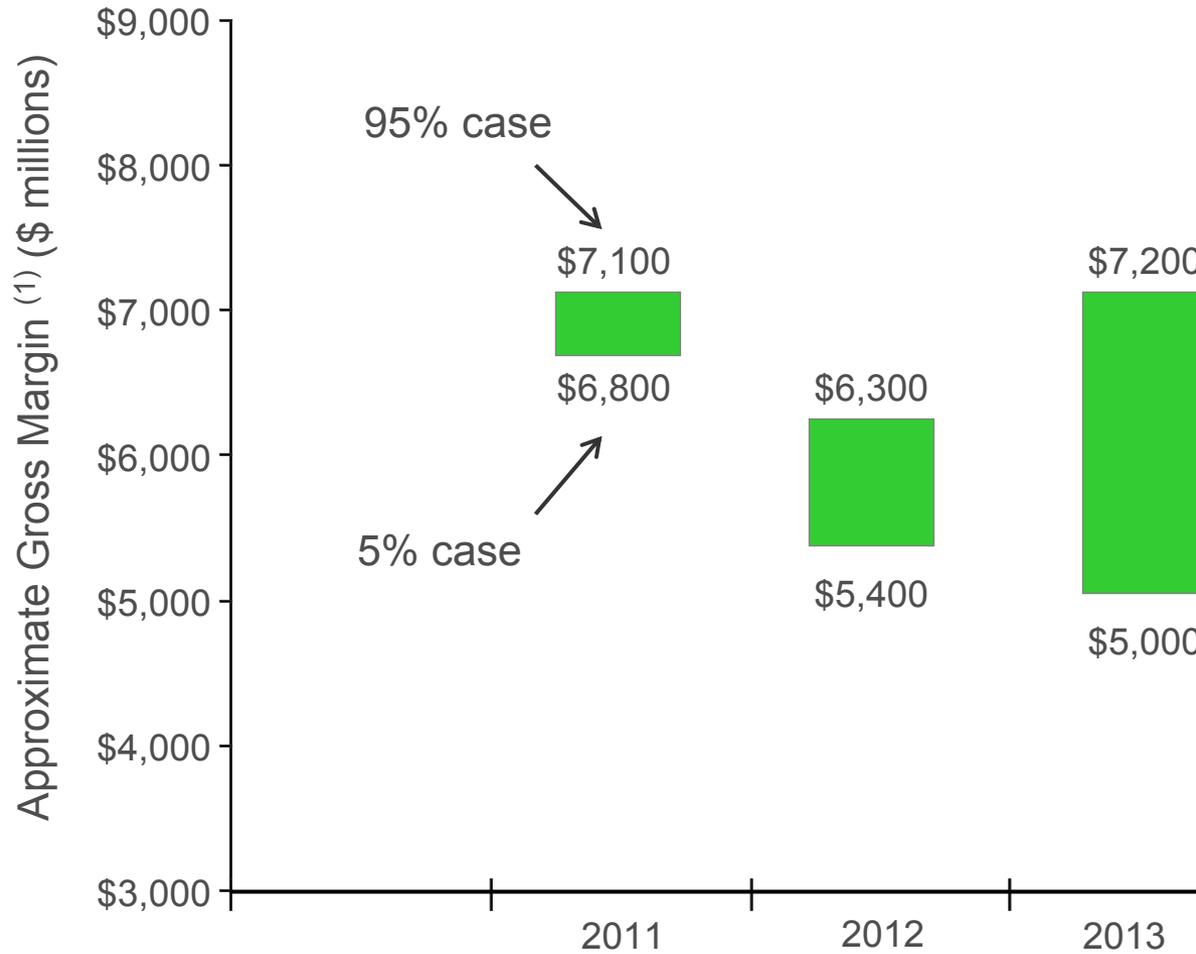


	2011	2012	2013
Gross Margin Sensitivities with Existing Hedges (\$ millions)⁽¹⁾			
Henry Hub Natural Gas			
+ \$1/MMBtu	\$5	\$175	\$495
- \$1/MMBtu	\$(5)	\$(95)	\$(445)
NI-Hub ATC Energy Price			
+\$5/MWH	\$30	\$185	\$340
-\$5/MWH	\$(20)	\$(165)	\$(335)
PJM-W ATC Energy Price			
+\$5/MWH	\$15	\$115	\$200
-\$5/MWH	\$(10)	\$(110)	\$(195)
Nuclear Capacity Factor			
+1% / -1%	+/- \$40	+/- \$45	+/- \$50

(1) Based on December 31, 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.

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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 2012 and 2013 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 December 31, 2010.

Illustrative Example

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of Modeling Exelon Generation 2011 Gross Margin (with Existing Hedges)



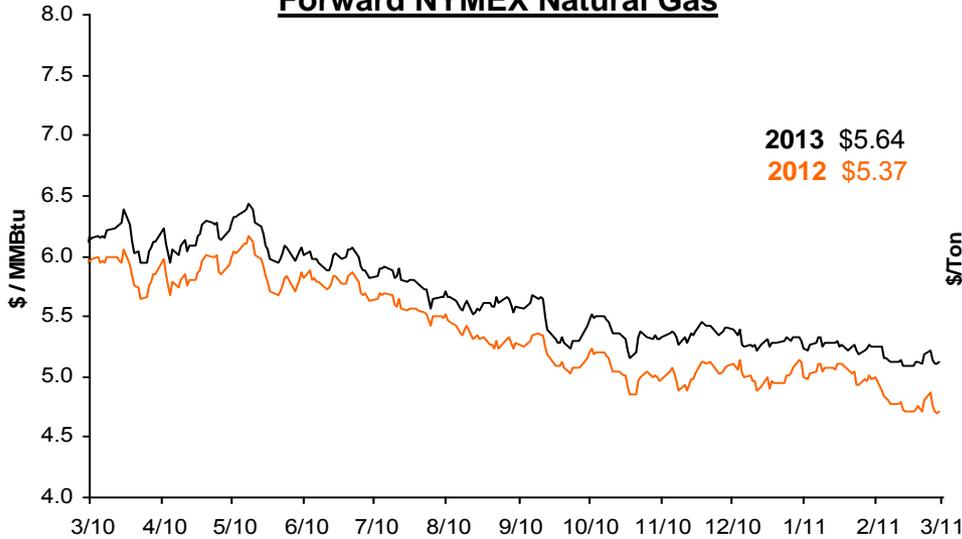
	Midwest	Mid-Atlantic	South & West
Step 1 Start with fleetwide open gross margin	← \$5.20 billion →		
Step 2 Determine the mark-to-market value of energy hedges	99,600GWh * 92% * (\$43.00/MWh-\$30.69MWh) = \$1.13 billion	56,800GWh * 94% * (\$57.00/MWh-\$45.45MWh) = \$0.62 billion	9,500GWh * 71% * (\$2.50/MWh-\$1.12/MWh) = \$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:	\$5.20 billion <u>\$1.13 billion + \$0.62 billion + \$0.01 billion</u> \$6.96 billion	

Market Price Snapshot

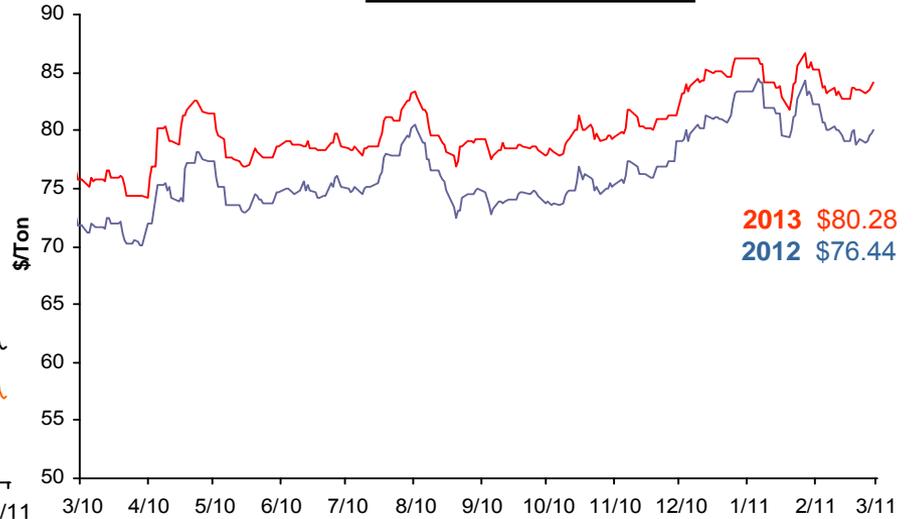
Rolling 12 months, as of March 4th 2011. Source: OTC quotes and electronic trading system. Quotes are daily.



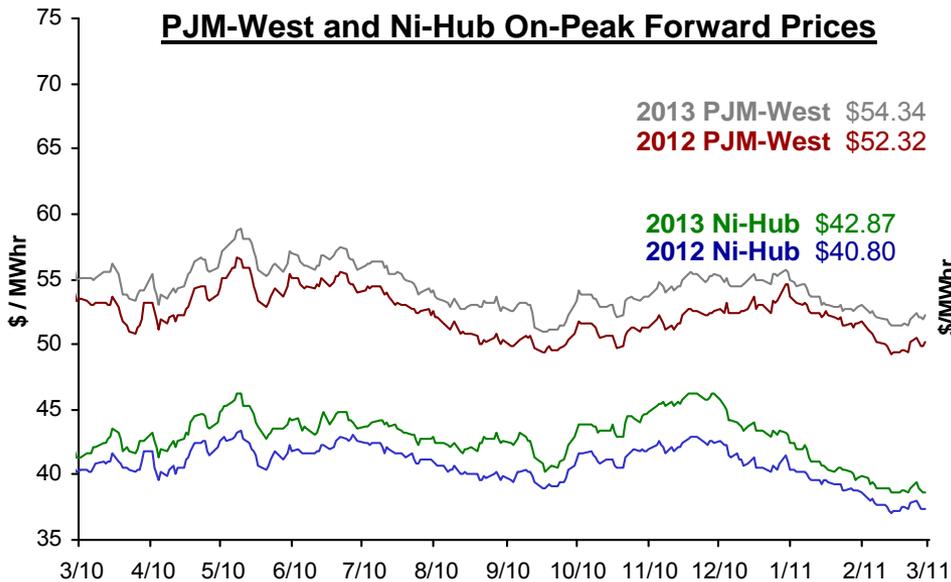
Forward NYMEX Natural Gas



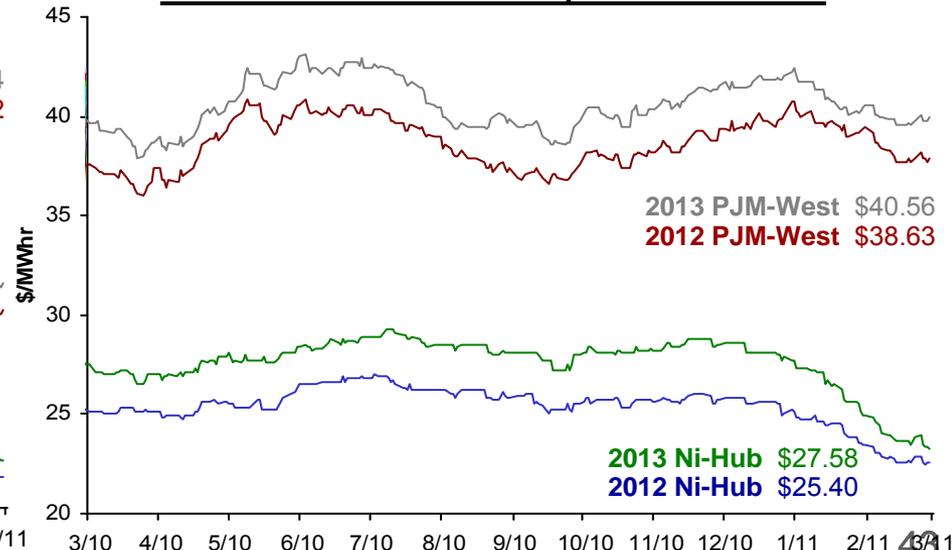
Forward NYMEX Coal



PJM-West and Ni-Hub On-Peak Forward Prices



PJM-West and Ni-Hub Wrap Forward Prices

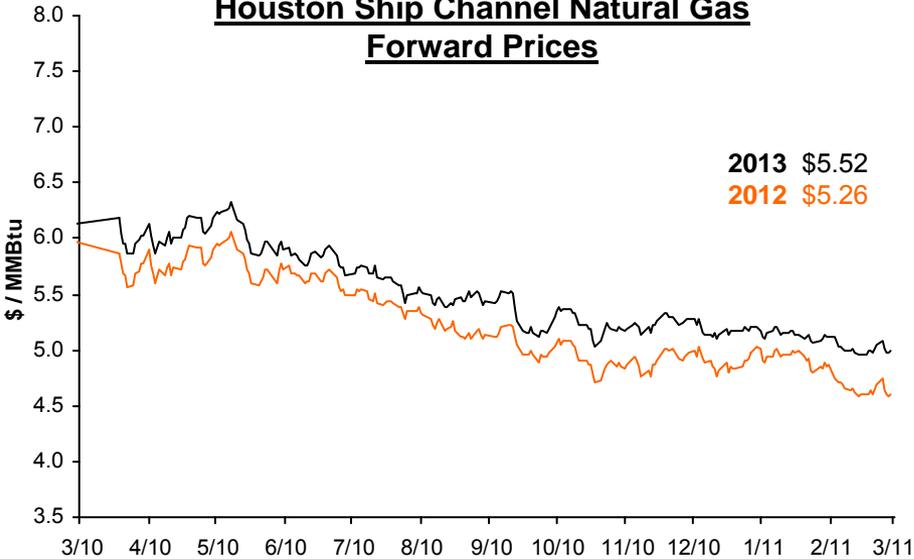


Market Price Snapshot

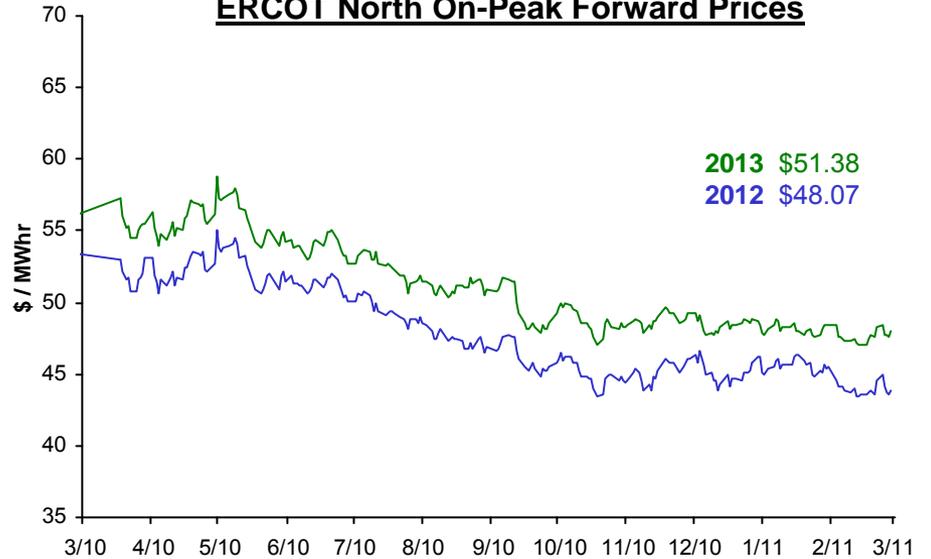
Rolling 12 months, as of March 4th 2011. Source: OTC quotes and electronic trading system. Quotes are daily.



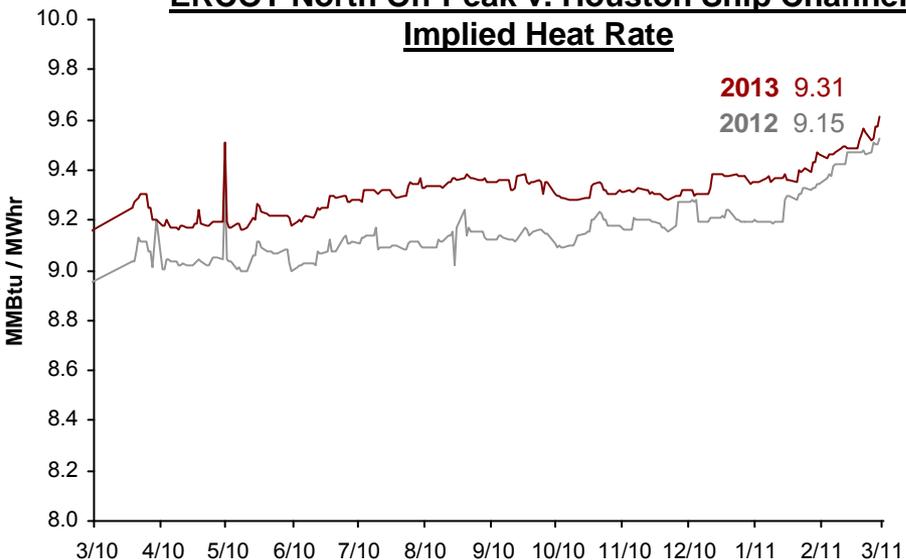
Houston Ship Channel Natural Gas Forward Prices



ERCOT North On-Peak Forward Prices

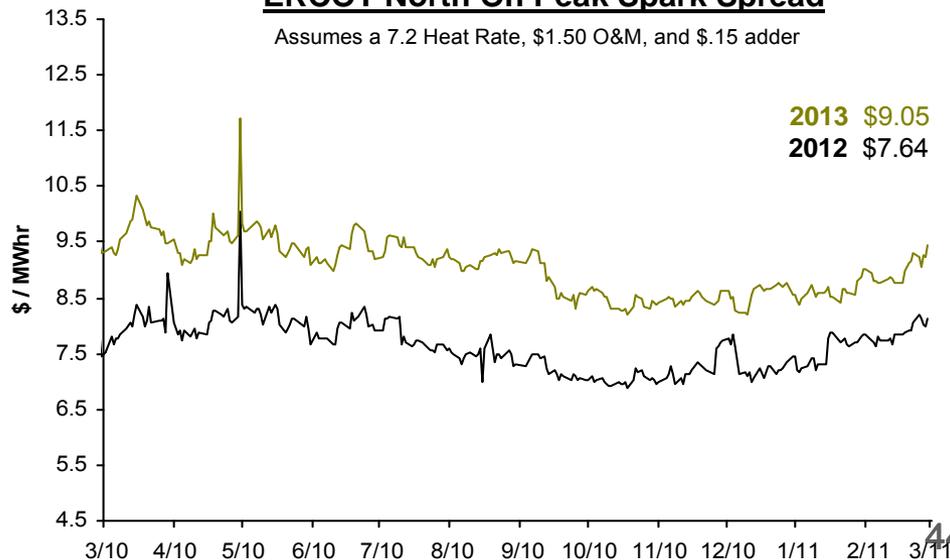


ERCOT North On-Peak v. Houston Ship Channel Implied Heat Rate



ERCOT North On Peak Spark Spread

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



4Q GAAP EPS Reconciliation



<u>Three Months Ended December 31, 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	\$0.66	\$0.16	\$0.12	\$(0.02)	\$0.92
Mark-to-market adjustments from economic hedging activities	0.04	-	-	-	0.04
2007 Illinois electric rate settlement	(0.02)	-	-	-	(0.02)
Unrealized gains related to nuclear decommissioning trust funds	0.02	-	-	-	0.02
City of Chicago settlement with ComEd	-	(0.01)	-	-	(0.01)
Costs associated with early debt retirements	(0.01)	-	-	(0.01)	(0.02)
Retirement of fossil generating units	(0.05)	-	-	-	(0.05)
4Q 2009 GAAP Earnings (Loss) Per Share	\$0.64	\$0.15	\$0.12	\$(0.03)	\$0.88

<u>Three Months Ended December 31, 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	\$0.81	\$0.13	\$0.03	\$(0.01)	\$0.96
Mark-to-market adjustments from economic hedging activities	(0.17)	-	-	-	(0.17)
2007 Illinois electric rate settlement	(0.01)	-	-	-	(0.01)
Unrealized gains related to nuclear decommissioning trust funds	0.04	-	-	-	0.04
Retirements of fossil generation units / plant retirements	(0.03)	-	-	-	(0.03)
John Deere Renewables acquisition costs	(0.01)	-	-	-	(0.01)
Asset Retirement Obligation reduction	-	0.01	-	-	0.01
4Q 2010 GAAP Earnings (Loss) Per Share	\$0.63	\$0.14	\$0.03	\$(0.01)	\$0.79

NOTE: All amounts shown are per Exelon share and represent contributions to Exelon's EPS. Amounts may not add due to rounding.

Full Year GAAP EPS Reconciliation



<u>Twelve Months Ended December 31, 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	\$3.16	\$0.54	\$0.54	\$(0.12)	\$4.12
Mark-to-market adjustments from economic hedging activities	0.16	-	-	-	0.16
2007 Illinois electric rate settlement	(0.09)	(0.01)	-	-	(0.10)
Unrealized gains related to nuclear decommissioning trust funds	0.19	-	-	-	0.19
Nuclear decommissioning obligation reduction	0.05	-	-	-	0.05
City of Chicago settlement with ComEd	-	(0.01)	-	-	(0.01)
NRG acquisition costs	-	-	-	(0.03)	(0.03)
Impairment of certain generating assets	(0.20)	-	-	-	(0.20)
2009 severance charges	(0.01)	(0.02)	(0.00)	-	(0.03)
Non-cash remeasurement of income tax uncertainties and reassessment of state deferred income taxes	0.06	0.06	-	(0.02)	0.10
Costs associated with early debt retirements	(0.07)	-	-	(0.04)	(0.11)
Retirement of fossil generating units	(0.05)	-	-	-	(0.05)
FY 2009 GAAP Earnings (Loss) Per Share	\$3.21	\$0.56	\$0.53	\$(0.21)	\$4.09
<u>Twelve Months Ended December 31, 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	\$2.91	\$0.68	\$0.54	\$(0.07)	\$4.06
Mark-to-market adjustments from economic hedging activities	0.08	-	-	-	0.08
2007 Illinois electric rate settlement	(0.02)	-	-	-	(0.02)
Unrealized gains related to nuclear decommissioning trust funds	0.08	-	-	-	0.08
Asset Retirement Obligation reduction	-	0.01	-	-	0.01
Retirement of fossil generating units	(0.08)	-	-	-	(0.08)
Non-cash remeasurement of income tax uncertainties	0.10	(0.16)	(0.03)	(0.01)	(0.10)
Non-cash charge resulting from health care legislation	(0.04)	(0.02)	(0.02)	(0.02)	(0.10)
Impact of certain emission allowances	(0.05)	-	-	-	(0.05)
John Deere Renewables acquisition costs	(0.01)	-	-	-	(0.01)
FY 2010 GAAP Earnings (Loss) Per Share	\$2.97	\$0.51	\$0.49	\$(0.10)	\$3.87

NOTE: All amounts shown are per Exelon share and represent contributions to Exelon's EPS. Amounts may not add due to rounding.

GAAP to Operating Adjustments



- **Exelon's 2011 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 ComEd's 2007 settlement with the City of Chicago
 - Financial impacts associated with the planned retirement of fossil generating units
 - Other unusual items
 - Significant changes to GAAP

- **Operating earnings guidance assumes normal weather for full year**

- **O&M reconciliation:**

(\$ millions)	2010					2011				
	ExGen	ComEd	PECO	Other	Exelon	ExGen	ComEd	PECO	Other	Exelon
Operating and maintenance (GAAP)	2,812	1,069	733	(14)	4,600	3,010	1,220	820	(10)	5,040
JDR acquisition costs	(11)	-	-	-	(11)	-	-	-	-	-
Retirement of fossil generating units	(3)	-	-	-	(3)	(30)	-	-	-	(30)
Non-cash charge resulting from health care legislation	(4)	(3)	(2)	8	(1)	-	-	-	-	-
Asset retirement obligation reduction	-	10	1	-	11	-	-	-	-	-
Adjusted Non-GAAP O&M	2,794	1,076	732	(6)	4,596	2,980	1,220	820	(10)	5,010
Decommissioning accretion	(57)	-	-	-	(57)	(70)	-	-	-	(70)
Regulatory required programs	-	(94)	(53)	-	(147)	-	(150)	(110)	-	(260)
Operating O&M (as shown on slide 7)	2,737	982	679	(6)	4,392	2,910	1,070	710	(10)	4,680