

Earnings Conference Call 1st Quarter 2015

April 29, 2015



Cautionary Statements Regarding Forward-Looking Information

This presentation contains certain 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 the forward-looking statements made by Exelon Corporation, Commonwealth Edison Company, PECO Energy Company, Baltimore Gas and Electric Company and Exelon Generation Company, LLC (Registrants) include those factors discussed herein, as well as the items discussed in (1) Exelon's 2014 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 22; (2) Exelon's First Quarter 2015 Quarterly Report on Form 10-Q (to be filed on April 29, 2015) 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 17; and (3) other factors discussed in filings with the SEC by the Registrants. 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 Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this presentation.

Policy and Business Priorities



Key Financial Messages

- Delivered adjusted (non-GAAP) operating earnings in Q1 of \$0.71/share exceeding our guidance range of \$0.60-\$0.70/share

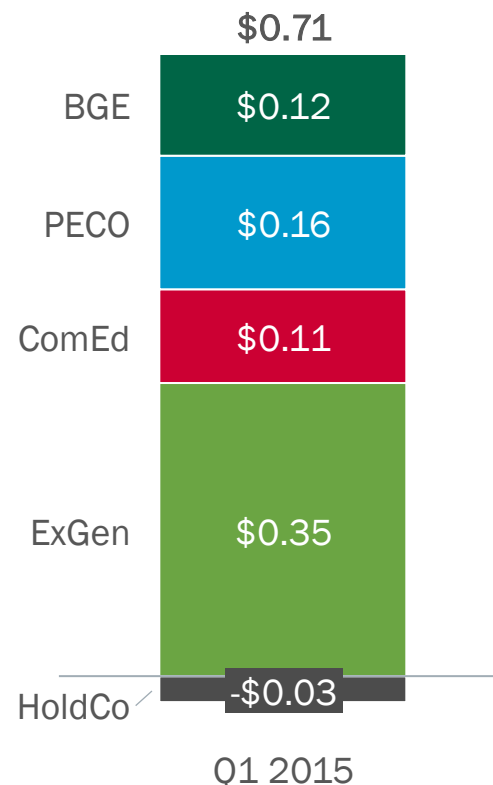
- Utilities

- ↑ Colder than normal winter
- ↑ No severe storms
- ↑ Increased distribution revenues

- ExGen

- ↑ Benefits of generation to load match
- ↑ Higher load serving margins
- ↑ Strong portfolio management
- ↓ Impacts of unplanned nuclear outages

Adjusted Operating EPS Results ^(1,2)



Expect Q2 2015 earnings of \$0.45 - \$0.55/share and re-affirm full-year guidance range of \$2.25 - \$2.55/share^(3,4)

(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) Amounts may not add due to rounding.

(3) ComEd ROE based on 30 Year average Treasury yield of 2.58% as of 3/31/15. 25 basis point move in 30 Year Treasury Rate equates to +/- \$0.01 impact to EPS.

(4) 2015 earnings guidance based on expected average outstanding shares of ~866M. Refer to Appendix for a reconciliation of adjusted non-GAAP operating EPS guidance to GAAP EPS.

Exelon Generation: Gross Margin Update

	March 31, 2015			Change from Dec 31, 2014		
Gross Margin Category (\$M) ⁽¹⁾	2015	2016	2017	2015	2016	2017
Open Gross Margin ⁽³⁾ (including South, West, Canada hedged gross margin)	\$5,600	\$5,900	\$6,050	\$(100)	\$50	\$(50)
Mark-to-Market of Hedges ^(3,4)	\$1,300	\$600	\$350	\$250	\$50	-
Power New Business / To Go	\$250	\$500	\$800	\$(100)	\$(50)	-
Non-Power Margins Executed	\$300	\$150	\$50	\$100	\$50	-
Non-Power New Business / To Go	\$150	\$300	\$400	\$(100)	\$(50)	-
Total Gross Margin⁽²⁾	\$7,600	\$7,450	\$7,650	\$50	\$50	\$(50)

Recent Developments

- Load serving business had a strong quarter driven by our generation to load matching strategy
- Natural gas declined, power prices were relatively flat, and heat rates expanded during the quarter
- Significantly behind ratable in the Midwest reflecting the fundamental upside we see in power prices in 2016 and 2017

1) Gross margin categories rounded to nearest \$50M.

2) Total Gross Margin (Non-GAAP) is defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners, operating services agreement with Fort Calhoun and variable interest entities. Total Gross Margin is also net of direct cost of sales for certain Constellation businesses. See Slide 27 for a Non-GAAP to GAAP reconciliation of Total Gross Margin.

3) Excludes EDF's equity ownership share of the CENG Joint Venture

4) Mark-to-Market of Hedges assumes mid-point of hedge percentages.

2015 Projected Sources and Uses of Cash

Projected Sources & Uses⁽¹⁾

(\$ in millions) ⁽¹⁾	BGE	ComEd	PECO	ExGen	Exelon ⁽³⁾ 2015E	As of 4Q14	Variance
Beginning Cash Balance⁽²⁾					3,575	3,575	–
Adjusted Cash Flow from Operations ⁽⁴⁾	600	2,200	625	3,350	6,700	6,775	(75)
CapEx (excluding other items below):	(675)	(2,025)	(500)	(1,925)	(5,225)	(5,100)	(125)
Nuclear Fuel	n/a	n/a	n/a	(1,125)	(1,125)	(1,125)	–
Dividend ⁽⁵⁾					(1,075)	(1,075)	–
Nuclear Upgrades	n/a	n/a	n/a	(100)	(100)	(100)	–
Wind	n/a	n/a	n/a	(100)	(100)	(100)	–
Solar	n/a	n/a	n/a	(125)	(125)	(125)	–
Upstream	n/a	n/a	n/a	(25)	(25)	(25)	–
Utility Smart Grid/Smart Meter	(25)	(400)	(50)	n/a	(475)	(400)	(75)
Net Financing (excluding Dividend):							
Debt Issuances	250	750	350	750	2,100	2,050	50
Debt Retirements	(75)	(250)	0	(550)	(1,675)	(1,675)	–
Project Finance	n/a	n/a	n/a	75	75	200	(125)
Other Financing ⁽⁶⁾	50	(25)	0	1,100	1,300	1,250	50
Ending Cash Balance⁽²⁾					3,825	4,125	(300)

(1) All amounts rounded to the nearest \$25M.

(2) Does not include collateral.

(3) Includes cash flow activity from Holding Company and other corporate entities.

(4) Adjusted Cash Flow from Operations (non-GAAP) primarily includes net cash flows from operating activities and net cash flows from investing activities excluding capital expenditures at ownership.

(5) Dividends are subject to declaration by the Board of Directors.

(6) "Other Financing" primarily includes expected changes in short-term debt and tax-exempt bond issuance at ExGen.

Key Messages⁽¹⁾

- **Cash from Operations is projected to be \$6,700M vs. 4Q14E of \$6,775M for a (\$75M) variance. This variance is driven by:**
 - (\$75M) MTM pre-issuance interest rate hedges
 - (\$50M) Income taxes and settlements
 - \$25M Working capital favorability
 - \$25M Higher net income at PECO primarily due to favorable weather and volume
- **Cash from Investing activities is projected to be (\$7,175M) vs. 4Q14E of (\$6,975M) for a (\$200M) variance. This variance is driven by:**
 - (\$200M) Grid reliability investments at ComEd
- **Cash from Financing activities is projected to be \$725M vs. 4Q14E of \$750M for a (\$25M) variance. This variance is driven by:**
 - (\$125M) Lower project financing at ExGen
 - \$50M Increased ComEd LTD requirements
 - \$25M Higher commercial paper requirements at ExGen

Exelon Generation Disclosures

March 31, 2015

Portfolio Management Strategy

Strategic Policy Alignment

- Aligns hedging program with financial policies and financial outlook
- Establish minimum hedge targets to meet financial objectives of the company (dividend, credit rating)
- Hedge enough commodity risk to meet future cash requirements under a stress scenario

Three-Year Ratable Hedging

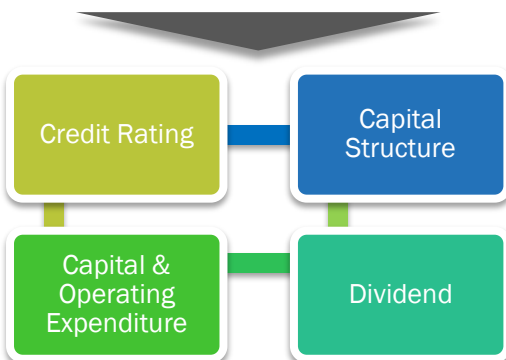
- Ensure stability in near-term cash flows and earnings
- Disciplined approach to hedging
- Tenor aligns with customer preferences and market liquidity
- Multiple channels to market that allow us to maximize margins
- Large open position in outer years to benefit from price upside

Bull / Bear Program

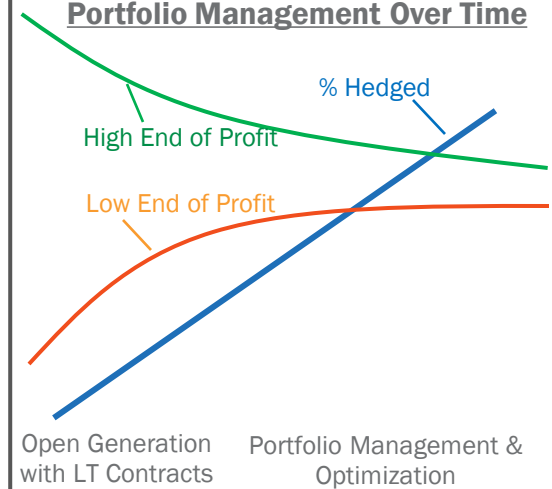
- Ability to exercise fundamental market views to create value within the ratable framework
- Modified timing of hedges versus purely ratable
- Cross-commodity hedging (heat rate positions, options, etc.)
- Delivery locations, regional and zonal spread relationships

Align Hedging & Financials

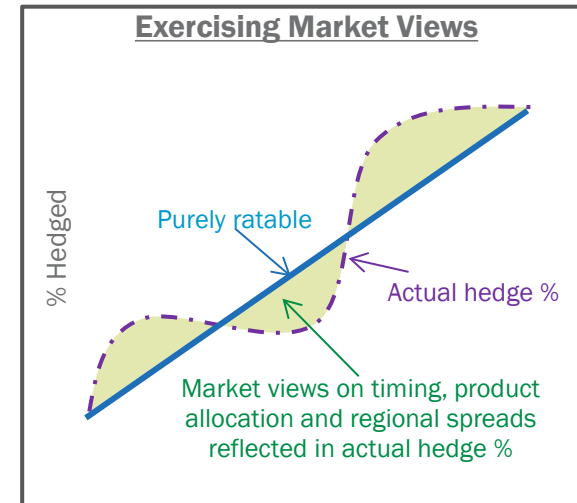
Establishing Minimum Hedge Targets



Portfolio Management Over Time



Exercising Market Views

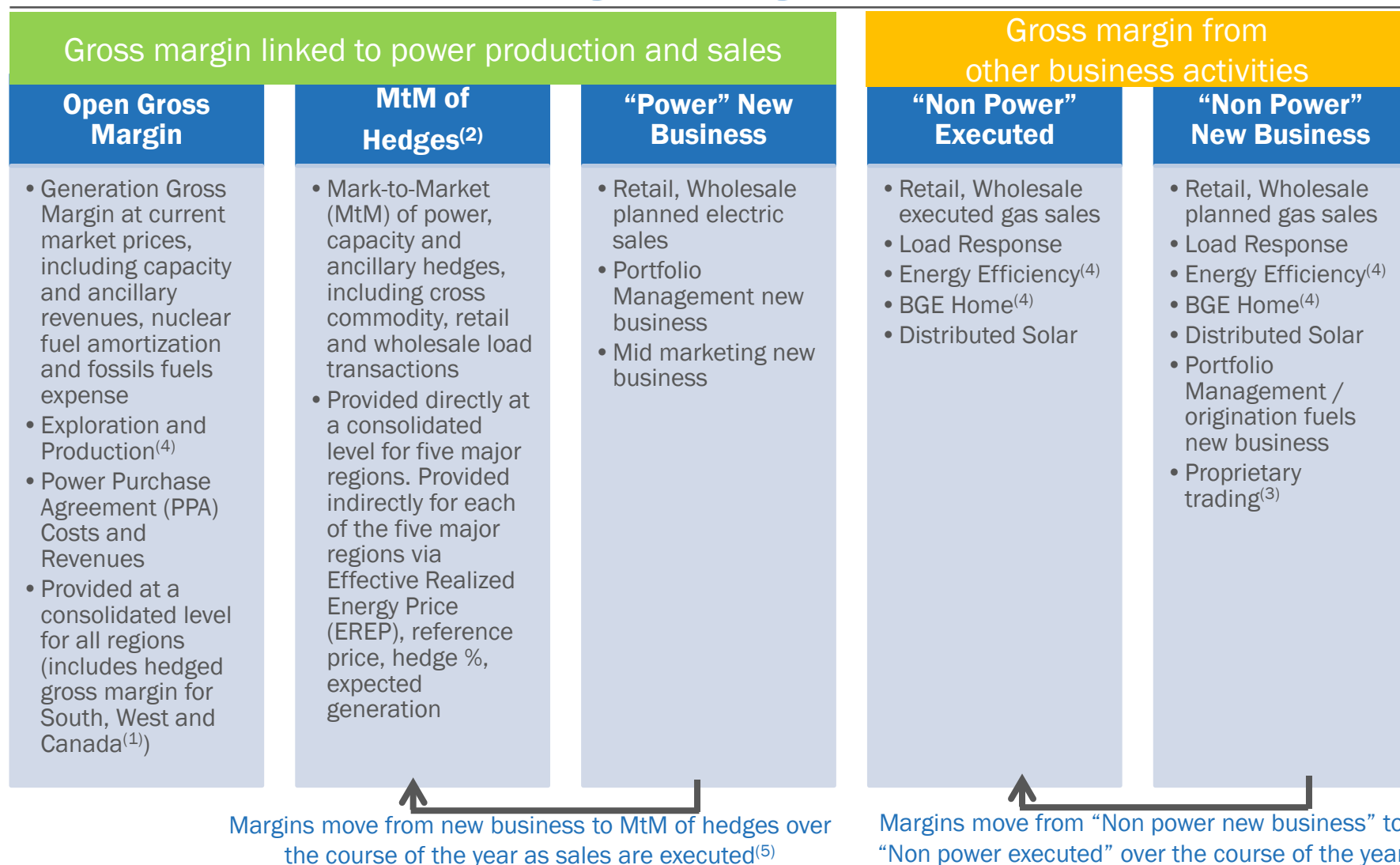


Protect Balance Sheet

Ensure Earnings Stability

Create Value

Components of Gross Margin Categories



(1) Hedged gross margins for South, West & Canada region will be included with Open Gross Margin, and no expected generation, hedge %, EREP or reference prices provided for this region

(2) MtM of hedges provided directly for the five larger regions; MtM of hedges is not provided directly at the regional level but can be easily estimated using EREP, reference price and hedged MWh

(3) Proprietary trading gross margins will generally remain within “Non Power” New Business category and only move to “Non Power” Executed category upon management discretion

(4) Gross margin for these businesses are net of direct “cost of sales”

(5) Margins for South, West & Canada regions and optimization of fuel and PPA activities captured in Open Gross Margin

Gross Margin Category (\$M) ⁽¹⁾	2015	2016	2017
Open Gross Margin (including South, West & Canada hedged GM) ⁽³⁾	\$5,600	\$5,900	\$6,050
Mark-to-Market of Hedges ^(3,4)	\$1,300	\$600	\$350
Power New Business / To Go	\$250	\$500	\$800
Non-Power Margins Executed	\$300	\$150	\$50
Non-Power New Business / To Go	\$150	\$300	\$400
Total Gross Margin⁽²⁾	\$7,600	\$7,450	\$7,650

Reference Prices ⁽⁵⁾	2015	2016	2017
Henry Hub Natural Gas (\$/MMbtu)	\$2.83	\$3.11	\$3.35
Midwest: NiHub ATC prices (\$/MWh)	\$30.74	\$31.06	\$31.23
Mid-Atlantic: PJM-W ATC prices (\$/MWh)	\$39.25	\$38.73	\$38.12
ERCOT-N ATC Spark Spread (\$/MWh) HSC Gas, 7.2HR, \$2.50 VOM	\$4.90	\$4.84	\$4.97
New York: NY Zone A (\$/MWh)	\$35.63	\$36.54	\$35.95
New England: Mass Hub ATC Spark Spread(\$/MWh) ALQN Gas, 7.5HR, \$0.50 VOM	\$7.54	\$9.36	\$10.47

- (1) Gross margin categories rounded to nearest \$50M
- (2) Total Gross Margin (Non-GAAP) is defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners, operating services agreement with Fort Calhoun and variable interest entities. Total Gross Margin is also net of direct cost of sales for certain Constellation businesses. See Slide 27 for a Non-GAAP to GAAP reconciliation of Total Gross Margin
- (3) Excludes EDF's equity ownership share of the CENG Joint Venture

- (4) Mark-to-Market of Hedges assumes mid-point of hedge percentages
- (5) Based on March 31, 2015 market conditions

ExGen Disclosures

Generation and Hedges	2015	2016	2017
<u>Exp. Gen (GWh) ⁽¹⁾</u>	193,000	200,500	205,100
Midwest	96,400	97,400	95,900
Mid-Atlantic ⁽²⁾	61,900	63,200	61,100
ERCOT	15,300	17,400	26,100
New York ⁽²⁾	9,200	9,300	9,300
New England	10,200	13,200	12,700
<u>% of Expected Generation Hedged ⁽³⁾</u>	94%-97%	67%-70%	37%-40%
Midwest	93%-96%	64%-67%	30%-33%
Mid-Atlantic ⁽²⁾	99%-102%	75%-78%	47%-50%
ERCOT	98%-101%	83%-86%	53%-56%
New York ⁽²⁾	82%-85%	57%-60%	35%-38%
New England	77%-80%	37%-40%	16%-19%
<u>Effective Realized Energy Price (\$/MWh) ⁽⁴⁾</u>			
Midwest	\$35.00	\$34.00	\$35.00
Mid-Atlantic ⁽²⁾	\$47.50	\$44.00	\$45.00
ERCOT ⁽⁵⁾	\$14.00	\$9.50	\$8.00
New York ⁽²⁾	\$47.00	\$44.50	\$40.50
New England ⁽⁵⁾	\$32.50	\$17.00	\$12.50

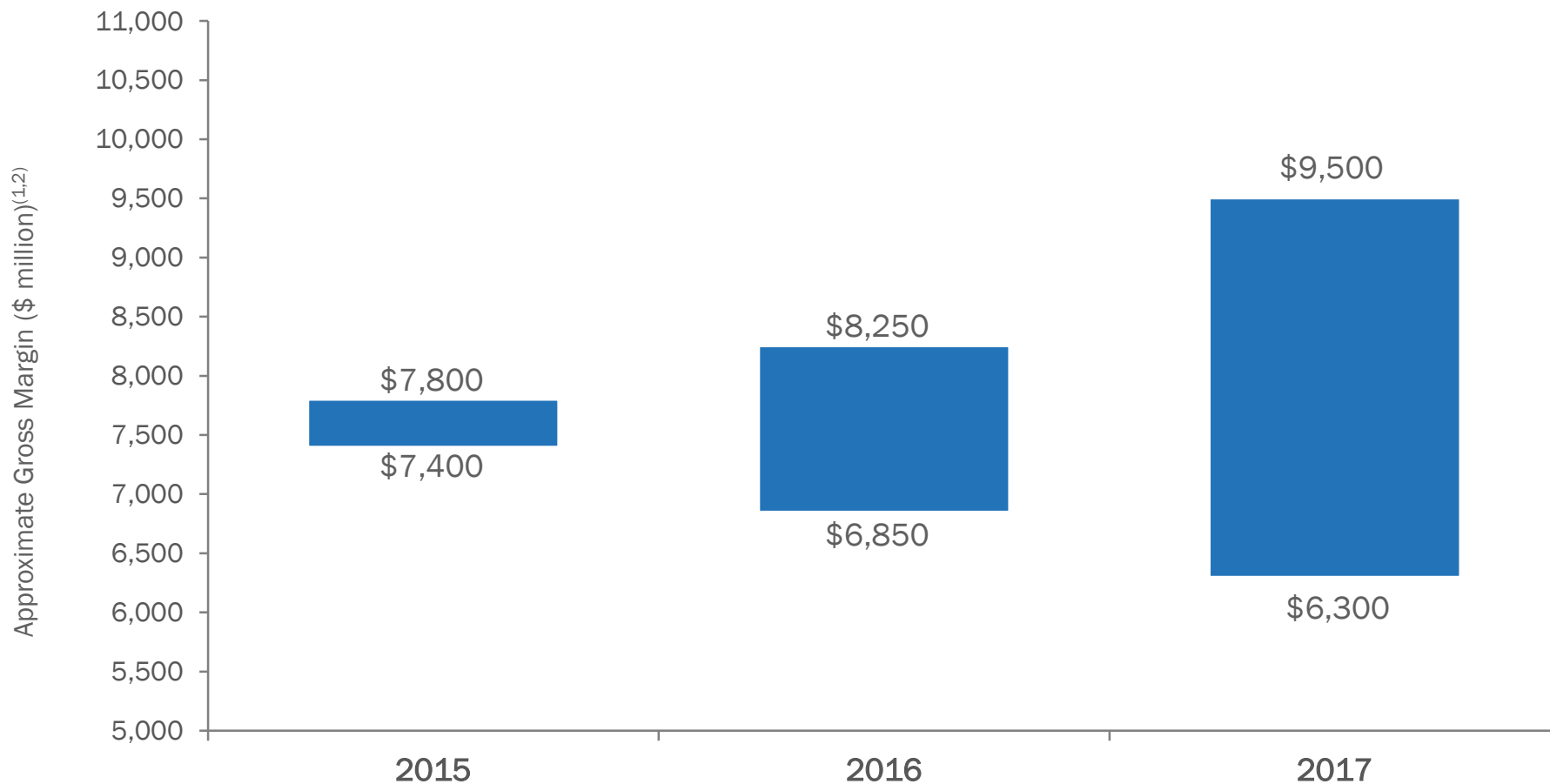
(1) Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Expected generation assumes 14 refueling outages in 2015, 12 in 2016, and 15 in 2017 at Exelon-operated nuclear plants, and Salem. Expected generation assumes capacity factors of 93.0%, 94.1% and 93.4% in 2015, 2016 and 2017 respectively at Exelon-operated nuclear plants, at ownership. These estimates of expected generation in 2016 and 2017 do not represent guidance or a forecast of future results as Exelon has not completed its planning or optimization processes for those years. (2) Excludes EDF's equity ownership share of CENG Joint Venture. (3) Percent of expected generation hedged is the amount of equivalent sales divided by expected generation. Includes all hedging products, such as wholesale and retail sales of power, options and swaps. (4) 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. (5) Spark spreads shown for ERCOT and New England.

ExGen Hedged Gross Margin Sensitivities

Gross Margin Sensitivities (With Existing Hedges) ⁽¹⁾	2015	2016	2017
Henry Hub Natural Gas (\$/Mmbtu)			
+ \$1/Mmbtu	\$(40)	\$240	\$580
- \$1/Mmbtu	\$75	\$(225)	\$(570)
NiHub ATC Energy Price			
+ \$5/MWh	\$20	\$170	\$335
- \$5/MWh	\$(15)	\$(170)	\$(330)
PJM-W ATC Energy Price			
+ \$5/MWh	\$(15)	\$70	\$175
- \$5/MWh	\$15	\$(65)	\$(170)
NYPP Zone A ATC Energy Price			
+ \$5/MWh	\$5	\$10	\$25
- \$5/MWh	\$(10)	\$(15)	\$(30)
Nuclear Capacity Factor			
+/- 1%	+/- \$35	+/- \$45	+/- \$45

(1) Based on March 31, 2015 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; Sensitivities based on commodity exposure which includes open generation and all committed transactions; Excludes EDF's equity share of CENG Joint Venture

ExGen Hedged Gross Margin Upside/Risk



- (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 2016 and 2017 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 March 31, 2015
- (2) Gross Margin Upside/Risk based on commodity exposure which includes open generation and all committed transactions
- (3) Gross Margin (Non-GAAP) is defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners, operating services agreement with Fort Calhoun and variable interest entities. Total Gross Margin is also net of direct cost of sales for certain Constellation businesses. See Slide 27 for a Non-GAAP to GAAP reconciliation of Total Gross Margin Excludes EDF's equity ownership share of the CENG Joint Venture

Illustrative Example of Modeling Exelon Generation 2016 Gross Margin

ZECJ-FIN-21

PUBLIC

Row	Item	Midwest	Mid-Atlantic	ERCOT	New York	New England	South, West & Canada
(A)	Start with fleet-wide open gross margin	<div>← \$5.90 billion →</div>					
(B)	Expected Generation (TWh)	97.4	63.2	17.4	9.3	13.2	
(C)	Hedge % (assuming mid-point of range)	65.5%	76.5%	84.5%	58.5%	38.5%	
(D=B*C)	Hedged Volume (TWh)	63.8	48.3	14.7	5.4	5.1	
(E)	Effective Realized Energy Price (\$/MWh)	34.00	44.00	9.50	44.50	17.00	
(F)	Reference Price (\$/MWh)	31.06	38.73	4.84	36.54	9.36	
(G=E-F)	Difference (\$/MWh)	2.94	5.27	4.66	7.96	7.64	
(H=D*G)	Mark-to-market value of hedges (\$ million) ⁽¹⁾	185	255	70	45	40	
(I=A+H)	Hedged Gross Margin (\$ million)	\$6,500					
(J)	Power New Business / To Go (\$ million)	\$500					
(K)	Non-Power Margins Executed (\$ million)	\$150					
(L)	Non-Power New Business / To Go (\$ million)	\$300					
(N=I+J+K+L)	Total Gross Margin ⁽²⁾	\$7,450 million					

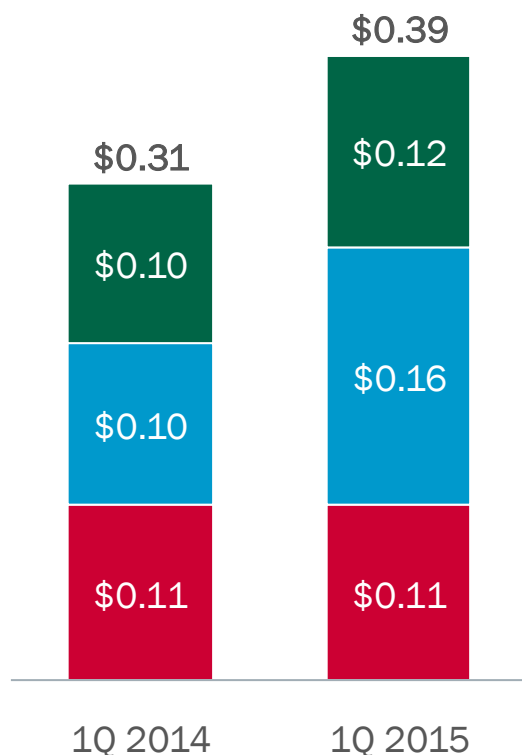
(1) Mark-to-market rounded to the nearest \$5 million

(2) Total Gross Margin (Non-GAAP) is defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners operating services agreement with Fort Calhoun and variable interest entities. Total Gross Margin is also net of direct cost of sales for certain Constellation businesses. See Slide 27 for a Non-GAAP to GAAP reconciliation of Total Gross Margin

Additional Disclosures

Exelon Utilities Adjusted Operating EPS Contribution⁽¹⁾

■ BGE ■ PECO ■ ComEd



Key Drivers – 1Q15 vs. 1Q14:

BGE (+0.02):

- Increased distribution revenue due to rate case: \$0.02

PECO (+0.06):

- Decreased storm costs: \$0.05
- Favorable weather and volume: \$0.01

ComEd (0.00):

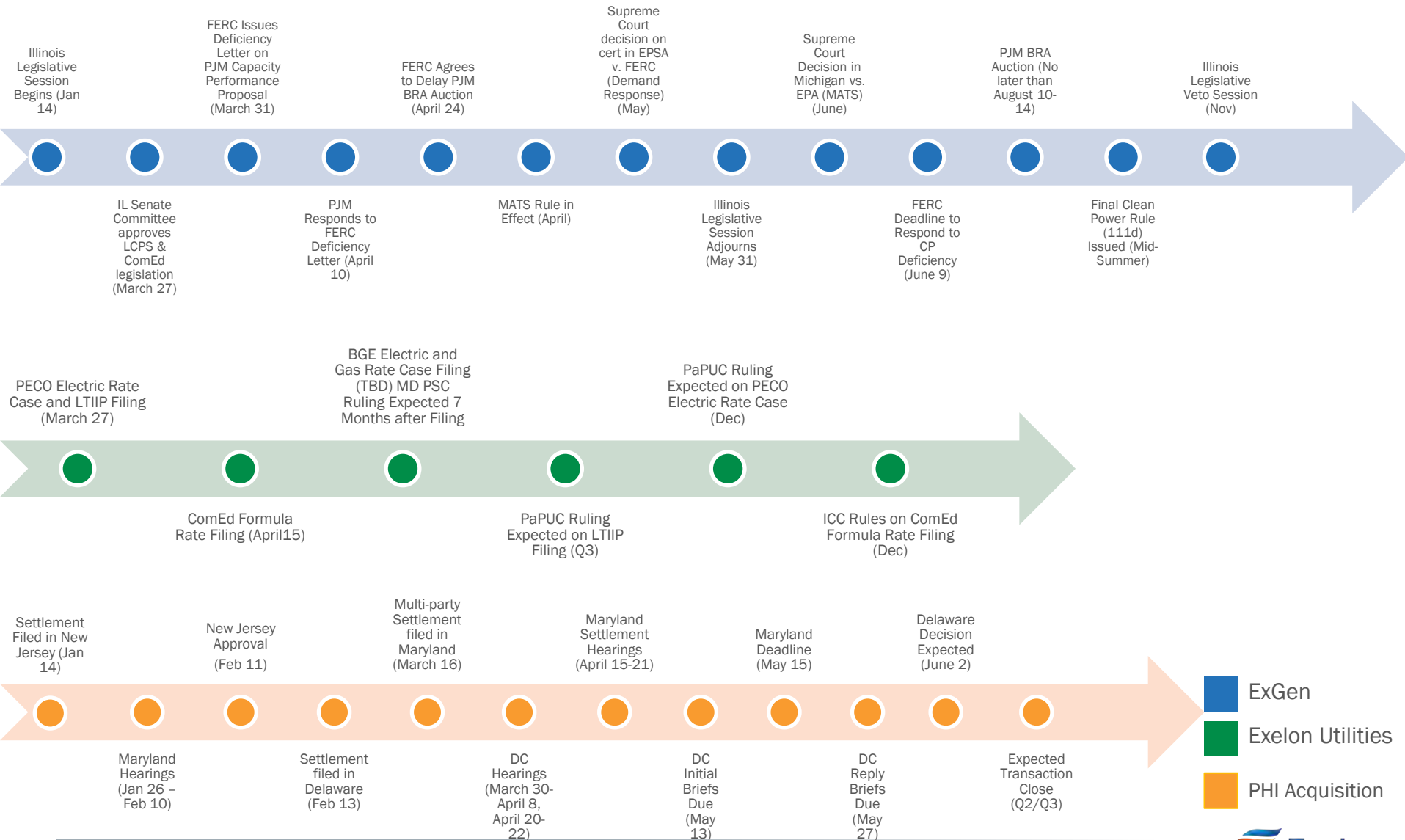
- Unfavorable weather and volume⁽²⁾: \$(0.01)
- Decreased distribution⁽²⁾ earnings due to lower return on common equity: \$(0.01)
- Increased distribution⁽²⁾ earnings due to increased capital investments: \$0.01

Numbers may not add due to rounding.

(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) Due to the distribution formula rate, changes in ComEd's earnings are driven primarily by changes in 30-year U.S. Treasury rates (inclusive of ROE), rate base and capital structure in addition to weather, load and changes in customer mix.

2015 Regulatory and Legislative Timelines



Proposed Low Carbon Portfolio Standard Legislation (HB 3293 / SB1585)

ZECJ-FIN-21

PUBLIC

What is the purpose of the legislation?	Beginning January 1, 2016, the Illinois Power Agency (IPA) must include in electric utilities' procurement plans the procurement of cost-effective low carbon energy credits from low carbon energy resources for all retail customers. This procurement process follows the existing renewable energy resources procurement process.
What is a low carbon energy credit?	A tradable credit that represents the environmental attributes of 1 MW of energy produced from a low carbon energy resource. Low carbon energy credits are created every day that low carbon energy resources are generating power.
What is a low carbon energy, or "LCE", resource?	Energy from a generating unit that does not emit any air pollution, such as sulfur dioxide, nitrogen oxide, or carbon dioxide, including technology fueled by new and existing solar photovoltaic, solar thermal, wind, hydro, nuclear, tidal energy, wave energy or clean coal.
What quantity of LCE resources is being procured?	A maximum of 70% of retail sales per year. Like the renewable energy resources procurement, the LCE procurement is limited by a separate 2.015% rate increase cap and cannot exceed the IPA's benchmarks for renewable energy resources.
Who is purchasing the LCE credits?	Similar to the renewable portfolio standard, electric utilities would purchase the LCE credits. While the renewables procurement includes only eligible retail customers, the LCE procurement covers all retail customers.
How will the utility recover its costs to purchase LCE credits?	Utilities will recover all costs associated with purchasing LCE credits through a rider that adds a charge to each retail customer's bill (consistent with the 2.015% rate cap). Like the renewable portfolio standard, this charge will remain fixed for the duration of the LCPS.
What is the procurement process?	The LCE procurement process relies on the same process the IPA uses to procure renewable energy resources. The key difference is the need to conduct a mid-year procurement. Because the legislation probably will not become law until after the start of the 2015/2016 procurement year on June 1, 2015, the IPA will conduct and complete an initial procurement before January 1, 2016 that will procure the LCE credits needed for the period January 1, 2016 through May 31, 2021, by entering into contracts of 1 to 5 years in length. The IPA may also conduct later procurement processes if it needs to do so.
How long will the new LCE procurement requirements be in effect?	The new LCE procurement requirements will sunset on December 31, 2021, so long as the State has adopted and implemented a plan under Section 111(d) of the federal Clean Air Act. If the State has not completed these actions by that date, then the new requirements will sunset on December 31 of the year in which the State adopts and implements that plan.

Proposed Energy Plan for Illinois' Future Legislation (HB 3328 / SB 1879)

ZECJ-FIN-21

PUBLIC

Legislative Change	Description	Customer Benefits
Expand Energy Efficiency	Allows utilities to invest in voltage optimization to meet energy efficiency goals; spreads costs to customers over 5 years minimizing initial customer impact; shifts all energy efficiency program management to the utilities	<ul style="list-style-type: none"> • More energy efficiency • More customer cost savings for most customers regardless of program participation
Solar Power for the Community	Changes existing net metering law to enable community solar and other meter aggregation programs; provides access to Renewable Energy Resources Fund (RERF) to support development of community and rooftop solar	<ul style="list-style-type: none"> • More customer access to sustainable generation for customers at all income levels and dwelling types (rentals, condos, homes with rooftop limitations, etc.)
Equitable Cost Allocation Through Rate Design Modifications	Implements kilowatt-based rates for all retail customers; breaks-out capacity and transmission charges as separate bill line items; eliminates the requirement that a residential customer who elects real-time pricing remain on that rate for a minimum of a year	<ul style="list-style-type: none"> • Allocates costs of grid more fairly and aligns residential rate design with long-standing C&I rate design • Unbundling charges facilitates comparisons of energy offerings • Adjustment to real-time pricing provides more pricing choices to customers
Additional Financial Assistance for those in need - 2021	Extends access to ComEd shareholder-funded customer assistance dollars for low-income customers, including senior citizens, veterans, small businesses, and community organizations	<ul style="list-style-type: none"> • Provides \$50M in customer assistance benefits
Microgrids for Security and Resiliency	Pilot program to demonstrate how microgrid technology can provide security and resiliency to critical infrastructure	<ul style="list-style-type: none"> • Increased security, resiliency, and reliability for critical infrastructure
Electric Vehicle Charging Stations	Initiates a program to increase the number and accessibility of electric vehicle charging	<ul style="list-style-type: none"> • Supports electrification of transportation sector
Demand Response Facilitation Service	Enables utility to aggregate demand response procurement for retail energy providers in service territory; easing the administrative burden on retail energy providers	<ul style="list-style-type: none"> • Ensures viability of demand response participation in Illinois
Renewable Portfolio Standards Enhancements	Improves access to RERF money which is limited under the current legislation and streamlines administration	<ul style="list-style-type: none"> • Allows for more competitive service for large C&I customers • Increases RECs purchase

ComEd April 2015 Distribution Formula Rate

The 2015 distribution formula rate filing establishes the net revenue requirement used to set the rates that will take effect in January 2016 after the Illinois Commerce Commission's (ICC's) review. There are two components to the annual distribution formula rate filing:

- **Filing Year:** Based on prior year costs (2014) and current year (2015) projected plant additions.
- **Annual Reconciliation:** For the prior calendar year (2014), this amount reconciles the revenue requirement reflected in rates during the prior year (2014) in effect to the actual costs for that year. The annual reconciliation impacts cash flow in the following year (2016) but the earnings impact has been recorded in the prior year (2014) as a regulatory asset.

Docket #	15-0287
Filing Year	2014 Calendar Year Actual Costs and 2015 Projected Net Plant Additions are used to set the rates for calendar year 2016. Rates currently in effect (docket 14-0312) for calendar year 2015 were based on 2013 actual costs and 2014 projected net plant additions
Reconciliation Year	Reconciles Revenue Requirement reflected in rates during 2014 to 2014 Actual Costs Incurred. Revenue requirement for 2014 is based on docket 13-0318 (2012 actual costs and 2013 projected net plant additions) approved in December 2013 and reflects the impacts of PA 98-0015 (SB9)
Common Equity Ratio	~ 46% for both the filing and reconciliation year
ROE	9.14% for the filing year (2014 30-yr Treasury Yield of 3.34% + 580 basis point risk premium) and 9.09% for the reconciliation year (2014 30-yr Treasury Yield of 3.34% + 580 basis point risk premium – 5 basis points performance metrics penalty). For 2015 and 2016, the actual allowed ROE reflected in net income will ultimately be based on the average of the 30-year Treasury Yield during the respective years plus 580 basis point spread, absent any metric penalties
Requested Rate of Return	~ 7% for both the filing and reconciliation years
Rate Base	\$8,286 million – Filing year (represents projected year-end rate base using 2014 actual plus 2015 projected capital additions). 2015 and 2016 earnings will reflect 2015 and 2016 year-end rate base respectively. \$7,095 million - Reconciliation year (represents year-end rate base for 2014)
Revenue Requirement Decrease	\$50M decrease (\$142M decrease due to the 2014 reconciliation offset by a \$92M increase related to the filing year). The 2014 reconciliation impact on net income was recorded in 2014 as a regulatory asset.
Timeline	<ul style="list-style-type: none"> • 04/15/15 Filing Date • 240 Day Proceeding • ICC order expected to be issued by mid-December 2015

Given the retroactive ratemaking provision in the Energy Infrastructure Modernization Act (EIMA) legislation, ComEd net income during the year will be based on actual costs with a regulatory asset/liability recorded to reflect any under/over recovery reflected in rates. Revenue Requirement in rate filings impacts cash flow.

Note: Disallowance of any items in the 2015 distribution formula rate filing could impact 2015 earnings in the form of a regulatory asset adjustment.

PECO Electric Distribution Rate Case

Docket #	R-2015-2468981
Fully Projected Future Test Year	2016
Common Equity Ratio	53%
Requested Return on Equity	10.95%
Overall Rate of Return	8.2%
Proposed Rate Base	\$4.1B
Revenue Requirement Increase Ask	\$190M
System Average Increase as % of overall bill	4.4%
Timeline	<ul style="list-style-type: none"> • 3/27/15 – PECO filed electric distribution rate case with PaPUC • 9 month Proceeding • Increased rates effective on January 1, 2016
Basis for Rate Case	<ul style="list-style-type: none"> • Since last rate case (2010): <ul style="list-style-type: none"> – Electric Distribution Rate base increased by one third (approximately \$1B) – Sales declined by 0.6% – Operating expenses were essentially flat (less than 1% annually) • Proposed investment maintains strong reliability performance with targeted investment to address pockets with reliability issues

First Electric Distribution Rate Case since 2010

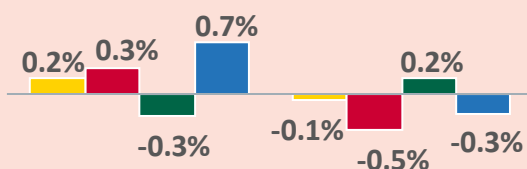
PECO Electric LTIP - System 2020

- PECO filed its Electric Long Term Infrastructure Improvement Plan (“LTIP”) along with its associated recovery mechanism the Distribution System Improvement Charge (“DSIC”) on March 27, 2015 (with Electric Distribution Rate Case)
 - LTIP includes \$275 million in incremental capital spending from 2016-2020 focusing on the following areas:
 - Cable Replacement
 - Storm Hardening Programs
 - Substation replacement and upgrades
 - DSIC mechanism will allow recovery of eligible LTIP spend between rate cases if the electric distribution ROE falls below the DSIC ROE established by PaPUC. The current Electric DSIC ROE is 10.1%.
 - Expected approval in 3Q15
- PECO also proposed the concept of constructing one or more pilot microgrid projects as part of a future LTIP update (\$50-\$100M). The objective is to evaluate and test emerging microgrid technologies that could enhance reliability and resiliency by replacing obsolete infrastructure as an alternative to traditional solutions.

Exelon Utilities Load

■ All Customers ■ Residential ■ Small C&I ■ Large C&I

ComEd



2014

2015E

Chicago GMP

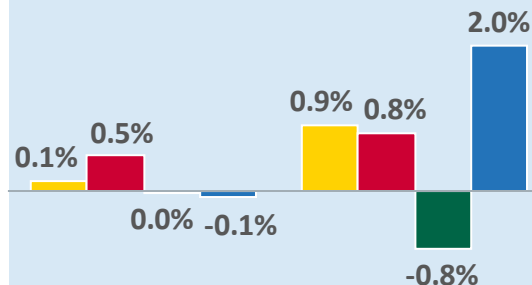
2.4%

Chicago Unemployment

6.1%

2015 load growth is similar to 2014 reflecting slowly improving economy being offset by energy efficiency

PECO



2014

2015E

Philadelphia GMP

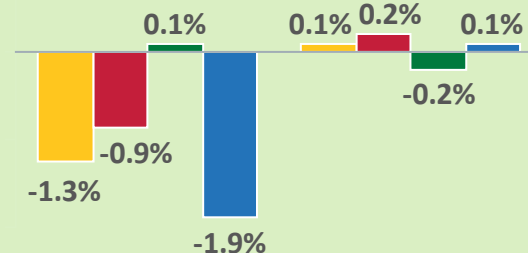
2.0%

Philadelphia Unemployment

6.6%

2015 load growth is driven by modest economic growth coupled with increased shale gas transportation and NGL production, partially offset by energy efficiency.

BGE



2014

2015E

Baltimore GMP

1.6%

Baltimore Unemployment

5.8%

2015 load growth is greater than 2014, attributable to slowly improving economic conditions and moderate customer growth, partially offset by energy efficiency

Notes: Data is not adjusted for leap year. Source of economic outlook data is IHS (February 2015) and Bureau of Economic Analysis. Assumes 2015 GDP of 3.0% and U.S. unemployment of 5.5%. ComEd has the ROE collar as part of the distribution formula rate and BGE is decoupled which mitigates the load risk. QTD and YTD actual data can be found in earnings release tables. BGE amounts have been adjusted for unbilled / true-up load from prior quarters

Appendix

Reconciliation of Non-GAAP Measures

1Q GAAP EPS Reconciliation

Three Months Ended March 31, 2014	<u>ExGen</u>	<u>ComEd</u>	<u>PECO</u>	<u>BGE</u>	<u>Other</u>	<u>Exelon</u>
2014 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$0.30	\$0.11	\$0.10	\$0.10	\$-	\$0.62
Mark-to-market impact of economic hedging activities	(0.52)	-	-	-	-	(0.52)
Unrealized gains related to NDT fund investments	0.01	-	-	-	-	0.01
Merger and integration costs	(0.01)	-	-	-	-	(0.01)
Amortization of commodity contract intangibles	(0.04)	-	-	-	-	(0.04)
Tax settlements	0.04	-	-	-	-	0.04
1Q 2014 GAAP Earnings (Loss) Per Share	\$(0.22)	\$0.11	\$0.10	\$0.10	\$-	\$0.10

Three Months Ended March 31, 2015	<u>ExGen</u>	<u>ComEd</u>	<u>PECO</u>	<u>BGE</u>	<u>Other</u>	<u>Exelon</u>
2015 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$0.35	\$0.11	\$0.16	\$0.12	\$(0.03)	\$0.71
Mark-to-market impact of economic hedging activities	0.11	-	-	-	-	0.11
Unrealized gains related to NDT fund investments	0.03	-	-	-	-	0.03
Merger and integration costs	(0.01)	-	-	-	(0.01)	(0.02)
Mark-to-market impact of PHI merger related interest rate swaps	-	-	-	-	(0.06)	(0.06)
Amortization of commodity contract intangibles	0.03	-	-	-	-	0.03
Midwest Generation bankruptcy recoveries	0.01	-	-	-	-	0.01
CENG Non-Controlling Interest	(0.01)	-	-	-	-	(0.01)
1Q 2015 GAAP Earnings (Loss) Per Share	\$0.51	\$0.11	\$0.16	\$0.12	\$(0.10)	\$0.80

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 2015 adjusted (non-GAAP) operating earnings excludes the earnings effects of the following:**
 - Mark-to-market adjustments from economic hedging activities
 - Unrealized gains and losses from NDT fund investments to the extent not offset by contractual accounting as described in the notes to the consolidated financial statements
 - Certain costs incurred associated with the Integrys and pending Pepco Holdings, Inc. acquisitions
 - Mark-to-market adjustments from forward-starting interest rate swaps related to anticipated financing for the pending PHI acquisition
 - Non-cash amortization of intangible assets, net, related to commodity contracts recorded at fair value at the date of acquisition of Integrys in 2014
 - Generation's non-controlling interest related to CENG exclusion items
 - Other unusual items

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

ExGen Total Gross Margin Reconciliation to GAAP

Total Gross Margin Reconciliation (in \$M) ⁽⁴⁾	2015	2016	2017
Revenue Net of Purchased Power and Fuel Expense⁽¹⁾⁽⁵⁾	\$8,150	\$8,050	\$8,350
Other Revenues ⁽²⁾	\$(250)	\$(250)	\$(250)
Direct cost of sales incurred to generate revenues for certain Constellation businesses ⁽³⁾	\$(300)	\$(350)	\$(450)
Total Gross Margin (Non-GAAP, as shown on slide 5)	\$7,600	\$7,450	\$7,650

- (1) Revenue net of purchased power and fuel expense (RNF), a non-GAAP measure, is calculated as the GAAP measure of operating revenue less the GAAP measure of purchased power and fuel expense. ExGen does not forecast the GAAP components of RNF separately. RNF also includes the RNF of our proportionate ownership share of CENG.
- (2) Reflects revenues from operating services agreement with Fort Calhoun, variable interest entities, funds collected through revenues for decommissioning the former PECO nuclear plants through regulated rates and gross receipts tax revenues.
- (3) Reflects the cost of sales and depreciation expense of certain Constellation businesses of Generation.
- (4) All amounts rounded to the nearest \$50M.
- (5) Excludes the impact of the operating exclusion for mark-to-market due to the volatility and unpredictability of the future changes to power prices.