UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of the
Securities Exchange Act of 1934

June 7, 2012
Date of Report (Date of earliest event reported)

Commission File Number	Exact Name of Registrant as Specified in Its Charter; State of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	**EXELON CORPORATION** **(a Pennsylvania corporation)** 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379 (312) 394-7398	23-2990190
333-85496	**EXELON GENERATION COMPANY, LLC** **(a Pennsylvania limited liability company)** 300 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219
1-1839	**COMMONWEALTH EDISON COMPANY** **(an Illinois corporation)** 440 South LaSalle Street Chicago, Illinois 60605-1028 (312) 394-4321	36-0938600
000-16844	**PECO ENERGY COMPANY** **(a Pennsylvania corporation)** P.O. Box 8699 2301 Market Street Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
1-1910	**BALTIMORE GAS AND ELECTRIC COMPANY** (a Maryland corporation) 2 Center Plaza 110 West Fayette Street Baltimore, Maryland 21201 (410) 234-5000	52-0280210

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Section 7 — Regulation FD

Item 7.01. Regulation FD Disclosure.

On June 7, 2012, Exelon Corporation (Exelon) will host the 2012 Analyst Meeting. Attached as Exhibit 99.1 to this Current Report on Form 8-K are the presentation slides to be used at the conference.

Section 9 – Financial Statements and Exhibits

Item 9.01. Financial Statements and Exhibits.

(d) *Exhibits*.

Exhibit No.	Description
99.1	Presentation Slides

* * * * *

This combined Form 8-K is being furnished separately by Exelon, Exelon Generation Company, LLC, Commonwealth Edison Company, PECO Energy Company, and Baltimore Gas and Electric Company (Registrants). Information contained herein relating to any individual Registrant has been furnished by such Registrant on its own behalf. No Registrant makes any representation as to information relating to any other Registrant.

This Current Report 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 2011 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) Constellation Energy Group's 2011 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 12; (3) the Registrant's First Quarter 2012 Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors and (b) Part I, Financial Information, ITEM 1. Financial Statements: Note 15; and (4) 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 Current Report. 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 Current Report.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, each Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

EXELON CORPORATION

/s/ Jonathan W. Thayer
Jonathan W. Thayer
Executive Vice President and Chief Financial Officer
Exelon Corporation

EXELON GENERATION COMPANY, LLC

/s/ Andrew L. Good
Andrew L. Good
Senior Vice President and Chief Financial Officer Exelon Generation Company, LLC

COMMONWEALTH EDISON COMPANY

/s/ Joseph R. Trpik, Jr.
Joseph R. Trpik, Jr.
Senior Vice President, Chief Financial Officer and Treasurer
Commonwealth Edison Company

PECO ENERGY COMPANY

/s/ Phillip S. Barnett
Phillip S. Barnett
Senior Vice President, Chief Financial Officer and Treasurer
PECO Energy Company

BALTIMORE GAS AND ELECTRIC COMPANY

/s/ CarimV. Khouzami
CarimV. Khouzami
Vice President, Chief Financial Officer and Treasurer
Baltimore Gas and Electric Company

June 7, 2012

EXHIBIT INDEX

Exhibit No.	Description
99.1	Presentation Slides

Exhibit 99.1

Exelon

Performance that Drives Progress

Analyst Meeting

June 7, 2012

Welcome

JaCee Burnes

Vice President, Investor Relations

Exelon.

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 2011 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) Constellation Energy Group's 2011 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 12; (3) the Registrant's First Quarter 2012 Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors and (b) Part I, Financial Information, ITEM 1. Financial Statements: Note 15; and (4) 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.

Exelon.

Agenda

Time (ET)	Presentation Topic	Presenter	Total Time
9:00 – 9:10	Welcome & Introductions	JaCee Burnes	10 minutes
9:10 – 9:30	Exelon Overview	Chris Crane	20 minutes
9:30 – 9:45	Financial Update	Jack Thayer	15 minutes
9:45 – 10:15	Constellation	Ken Cornew	30 minutes
10:15 – 10:25	Competitive Markets	Bill Von Hoene	10 minutes
10:25 – 10:55	Q&A	Panel Q&A(1)	30 minutes
10:55 – 11:15	BREAK		20 minutes
11:15 – 11:30	Exelon Utilities	Denis O’Brien	15 minutes
11:30 – 11:40	Power Generation	Chip Pardee	10 minutes
11:40 – 11:55	Q&A	Panel Q&A(2)	15 minutes
11:55 – 12:00	Closing	Chris Crane	5 minutes
12:00 – 1:30	RECEPTION/LUNCH		90 minutes

(1) First panel for Q&A to include Chris Crane, Bill Von Hoene, Ken Cornew, Jack Thayer, Joe Glace.
(2) Second panel for Q&A to include Denis O’Brien, Chip Pardee, Anne Pramaggiore, Craig Adams, Ken DeFontes, Jack Thayer.

Exelon Overview

Chris Crane
President & Chief Executive Officer

Exelon

Exelon Overview

Exelon Generation		Exelon Utilities
Power Generation	Constellation	ComEd, PECO & BGE



Power Generation

- Largest merchant fleet in the nation (~35 GW of capacity), with unparalleled upside
- One of the largest and best managed nuclear fleets in the world (~19 GW)
- Significant gas generation capacity (~10 GW)
- Renewable portfolio (~1 GW), mostly contracted

Constellation

- Leading competitive energy provider in the U.S.
- Customer-facing business, with ~1.1 M competitive customers and large wholesale business
- Top-notch portfolio and risk management capabilities
- Extensive suite of products including Load Response, RECs, Distributed Solar

ComEd, PECO & BGE

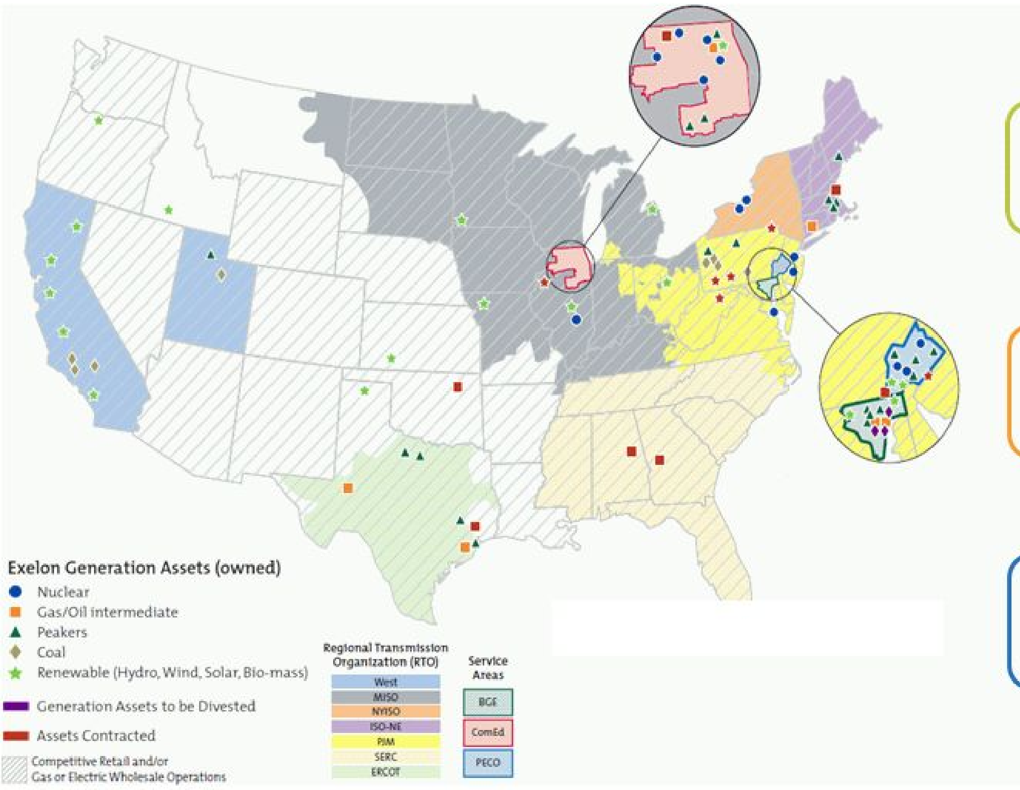
- One of the largest electric and gas distribution companies in the nation ~6.6 M customers
- Diversified across three utility jurisdictions – Illinois, Maryland and Pennsylvania
- Significant investments in Smart Grid technologies
- Transmission infrastructure improvement at utilities

Competitive Business | Regulated Business

Exelon is the largest competitive integrated energy company in the U.S.

National Scope

National presence gives us a unique platform to perform and grow



Power Generation

Operations in seven RTOs, with strong positions across PJM, ERCOT & New England

Constellation

Serves more than 2/3rds of the Fortune 100 companies in the U.S.

Exelon Utilities

Large urban presence with operations in three states – IL, PA and MD

Coast-to-coast presence with operations in 47 states and Canada

Exelon.

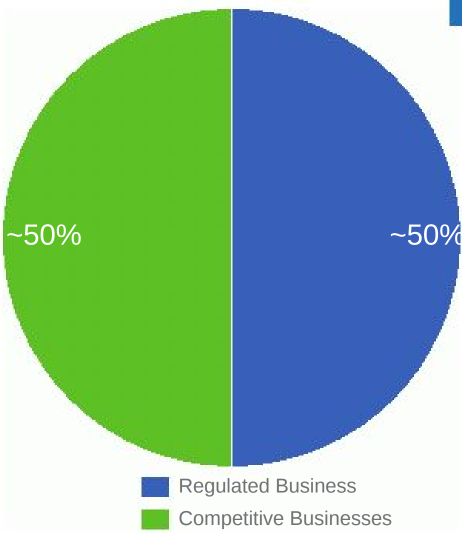
Diversified Platform and Revenue Growth

Exelon's portfolio is well diversified and positioned for long-term growth

Balanced EBITDA Contribution[1]

Competitive Business

- Upside from tightening power markets from significant amount of coal retirements
- Strong pipeline of organic generation growth opportunities, including nuclear uprates, wind & solar
- Leverage Constellation brand, network and relationships to grow customer-facing business across the country
- Low-risk investment through contracted renewables fleet and load matched with generation
- Investment grade credit ratings to support operations and growth



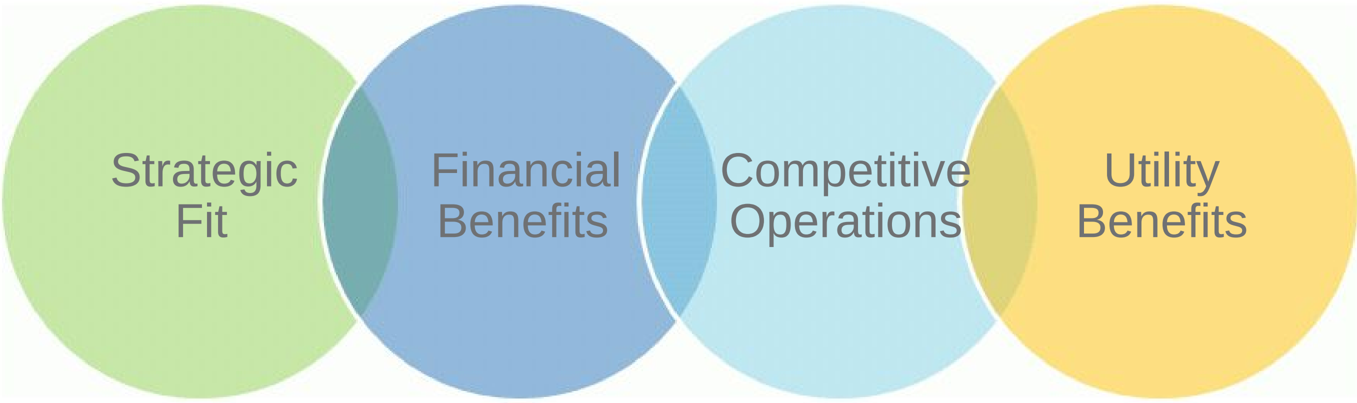
Regulated Business

- Stable income and cash flow from utility operations
- Significant investment in infrastructure upgrades, including next generation technology enhancements (Smart Grid)
- Diversification across three utility jurisdictions
- Leverage utility structure to drive best practices
- Investments to improve reliability and operations

Diversification of revenue, earnings and cash flows

(1) Based on 2012 thru 2014 average operating EBITDA estimate as of 4/30/2012 and adjusting for ComEd rate order.

Multiple Merger Benefits



- Matches Exelon's clean generation fleet with Constellation's customer-facing leading retail and wholesale platform
- Creates economies of scale through expansion across the value chain

- Earnings and cash flow accretive
- Stronger balance sheet than standalone financials
- Significant cost synergies and gross margin expansion

- Regional and technological diversification
- Maintain clean generation profile
- More competitive product offerings and enhanced margins
- Scalable commercial platform

- Maintains a regulated earnings profile
- Enables operational enhancements from sharing best practices

This merger creates incremental strategic and financial value

Exelon.

Exelon's Transformation

Exelon Pre Merger		Exelon Post Merger
	Financials	
$55.1 billion	Assets[1]	$74.5 billion
$18.9 billion	Revenues[1]	$32.7 billion
$26.4 billion	Market Capitalization[2]	$33.9 billion
	Power Generation[3]	
~26 GW	Total Capacity[4]	~35 GW
175 TWh	Expected Generation[5]	220 TWh
~4 GW	Natural Gas Capacity[5]	~10 GW
	Constellation[3]	
~40 TWh / 50 BCF	Competitive Load & Gas[6]	~170 TWh / 465 BCF
3,500	Customer Count	More than 1 million
Minimal Load Response	Load Response Portfolio	~2,000 MW
No projects	Energy Efficiency Projects	Over 4,000 projects across U.S.
	Exelon Utilities[3]	
5.4 million	Customers	6.6 million
$13 billion	2011 Combined Rate Base	$17 billion

The merger enhances scale, scope and flexibility across the value chain

(1) Represents 2011 actuals.
(2) As of 3/12/2012.
(3) 2012 estimate as of 4/30/2012.
(4) Represents owned capacity, net of mitigation (~2,648 MW).
(5) Represents owned or contracted capacity, net of mitigation.
(6) Represents fixed price or indexed load, including retail and wholesale.

Generation and Load Match

Benefits of a well-matched generation and load footprint are realized across the board

Strategic Benefits

- Competitive pricing that enables volume and/or margin growth
- Improved risk profile, with asset-backed hedging of load position
- Natural hedge between what we own and what we sell

Financial Benefits

- Lower collateral costs with reduction in size of liquidity facilities and collateral postings
- Savings on transaction costs with less need for Over-the-Counter hedging

Customer Benefits

- Lower energy costs reflected in prices paid by customers
- Expanded set of products and services backed by a large, diverse portfolio of generation assets, including several low carbon options

Strategic, financial and customer value from combining generation and load portfolios

Exelon.

Committed to Making the Merger Successful

Clearly defined plans to make this merger successful

Tasks Accomplished

- ✓ Closed the merger in less than a year
- ✓ Effective integration planning and execution for seamless day 1 operations
- ✓ Appointed leadership and management teams

Ongoing Focus

- Employ Exelon's management model to enhance profitability by realizing efficiencies and reducing costs
- Enterprise-wide synergy realization (O&M, CapEx)
- Efficient and optimal use of capital to pursue highest value projects and opportunities
- Grow and diversify our business in a deliberate and sustainable manner
- Focus on both process and innovation to protect and grow the business

Merger Checklist / Scorecard

Item	Target
Cost Synergies	$500 million run rate(1)
Liquidity Reduction	$4.2 billion year-end 2012
Gross Margin Opportunities	$100 million run rate(2)
Asset Sales Process	Complete by August 2012
Commercial Load Volume Growth	~6% CAGR on volumes(3)
BGE	File rate case in 2nd half of 2012

Confident in ability to achieve or exceed targets in a timely and efficient manner

We are well on our way to realizing the value from this merger

(1) Run rate target for O&M synergies from 2014 onwards.
(2) Gross Margin opportunities on a run rate basis from 2014 onwards from combining the two commercial portfolios.
(3) Represents Compounded Annual Growth Rate (CAGR) until 2014 using 2011 as the base year.

Exelon.

Financial Discipline

Strategic Policy Alignment

- Align commodity hedging program to financial policies, including dividend and investment grade credit rating
- Hedge enough commodity risk to meet future cash requirements

Cost Containment

- Achieve or exceed synergy targets (O&M, CapEx)
- Eliminate inefficiencies and contain costs

Investment Grade Rating

- Committed to maintain investment grade credit rating
- Rigorous and comprehensive capital allocation process among competing uses and growth projects

Enterprise Risk Management

- Holistic view on company-wide risk, recognition of natural hedges and offsets as part of decision making process
- Small, well-managed proprietary trading function

Continue to execute a well-aligned financial policy framework and maintain dividend

Exelon: Vision, Strategy, Values and Goals

VISION – Performance that Drives Progress

STRATEGIC DIRECTION – Sustainable Growth

VALUES

- We are dedicated to safety
- We actively pursue excellence
- We innovate to better serve our customers
- We act with integrity and are accountable to each other, our communities, and the environment
- We succeed as a diverse and inclusive team

GOALS

- Keep the lights on and the gas flowing
- Run generation fleet at world class levels
- Foster a work environment that is safe, productive, learning-focused and engaging
- Capitalize on clean energy as a competitive advantage
- Build sustained value through disciplined financial management
- Be a top-tier competitor in our key markets
- Advance competitive markets

Strategic Direction: Sustainable Growth

Key focus areas as we diversify and grow our business

Operational Excellence
We capitalize on reliability and efficiency in our operations as a competitive advantage

Financial Discipline
We are committed to investment grade ratings and maintaining the dividend

Drive Competition & Choice
We champion competitive energy markets

Advance Clean Energy
We believe clean energy creates value

Sustainable Growth –Focused on creating value for our shareholders by leveraging our strength in operations and financial management to grow our business

Exelon.

Financial Update

Jack Thayer, EVP & Chief Financial Officer

Exelon.

2012 Earnings Guidance

- Expect to deliver full-year 2012 adjusted (non-GAAP) operating EPS within guidance range of $2.55 - $2.85/share (1)
  - Guidance includes CEG earnings from merger close date
  - ExGen guidance reflects gross margins for combined company portfolio
  - Lower PJM capacity revenues as expected
  - ComEd earnings reflect impact from recent ICC formula rate order
  - Merger cost synergies of $0.12/share
  - Purchase accounting adjustments largely excluded from operating earnings

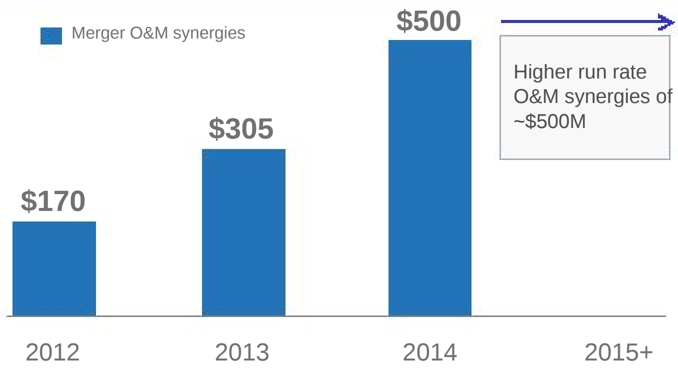
Confident of achieving earnings within range of $2.55 - $2.85/share

(1) 2012 guidance includes Constellation Energy and BGE earnings for March 12 – December 31. Based on expected 2012 average outstanding shares of 819M. Earnings guidance for OpCos may not add up to consolidated EPS guidance.

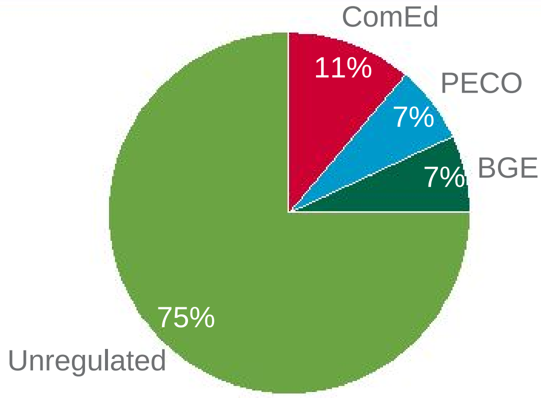
Exelon.

Achievable Merger Synergies

O&M Savings(1) ($M)



Run Rate O&M Synergies Breakdown



Gross Margin Opportunities ($M)

- Run rate gross margin opportunities of $100M(2) starting in 2014
  - Matching load and generation
  - Retail growth opportunities
  - Portfolio optimization

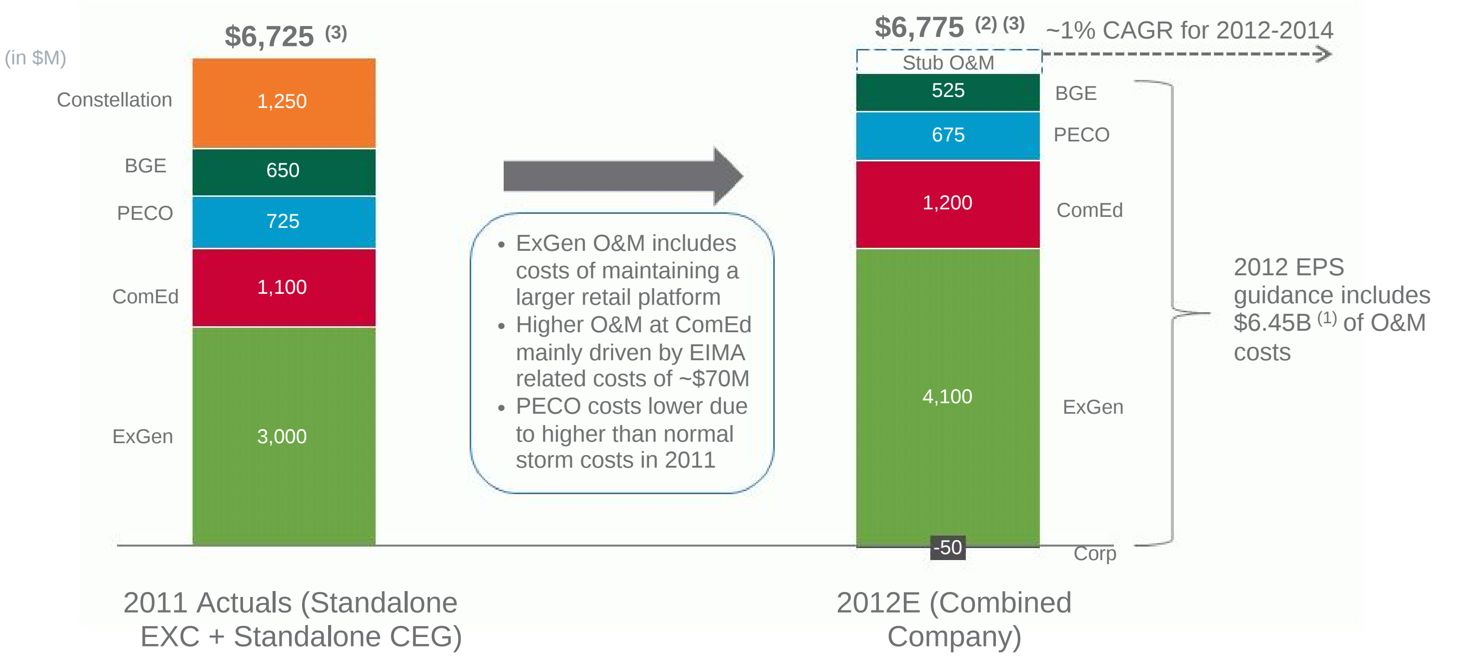
- Key Drivers of run rate O&M synergies include
  - Labor savings from corporate and commercial consolidations
  - Reduced collateral requirements
  - IT systems consolidation
  - Supply chain savings
  - Other non-labor corporate synergies

(1) O&M synergies include cost savings of ~$40M from lower liquidity requirements.
(2) Gross margin opportunities included in Total Gross Margin shown on slide 45.

Fully committed to achieving merger synergies

Operating O&M Forecast Lower than Inflation

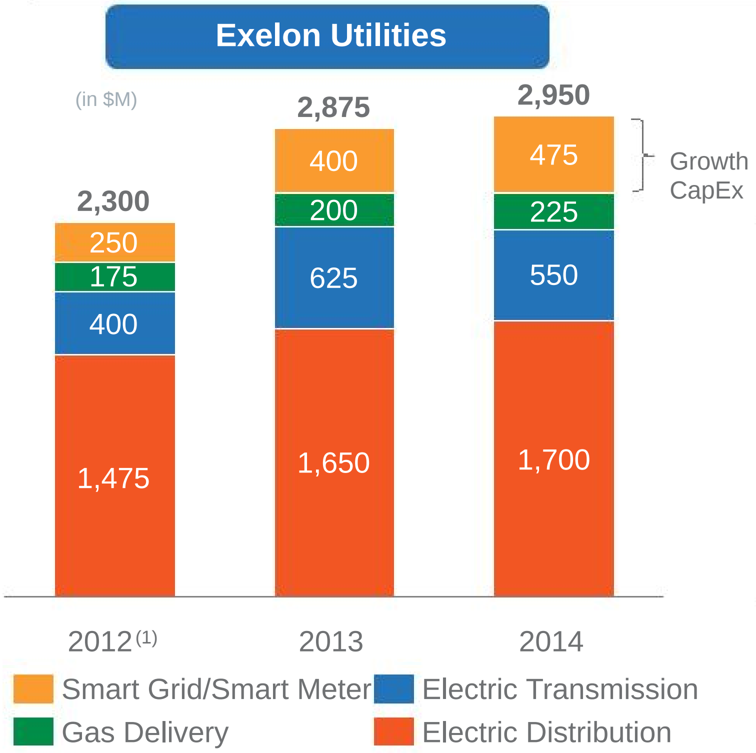
- 2012 O&M forecast of $6.45B[1]
  - Includes merger synergies of $170M for ~9.5 months
  - Excludes costs to achieve which are considered non-operating
- Maintain O&M CAGR of ~1%[2] for 2012-2014

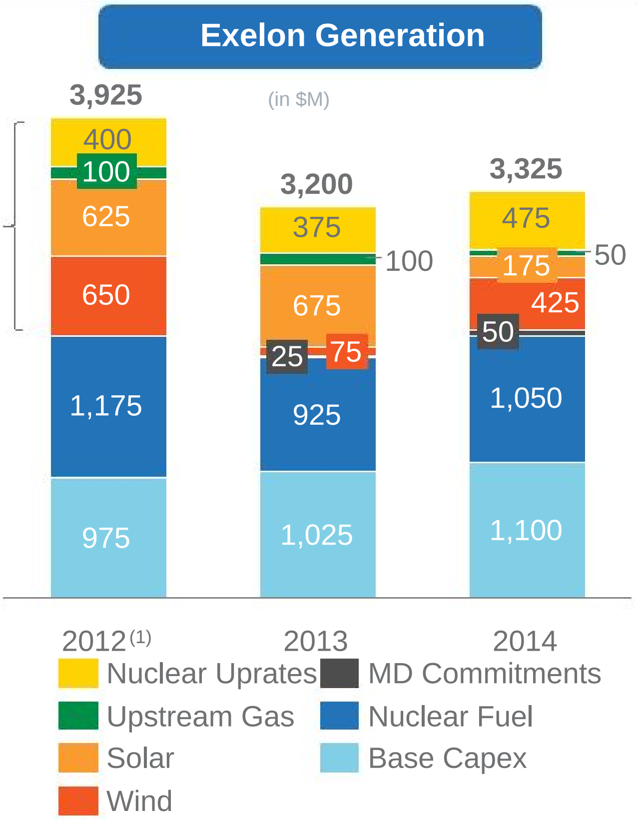


(1) O&M included in 2012 EPS guidance includes CEG and BGE costs from merger close date.
(2) O&M Compound Annual Growth Rate (CAGR) calculated after normalizing 2012 O&M to include CEG and BGE costs for 12 months.
(3) O&M for utilities excludes regulatory O&M that are P&L neutral. ExGen O&M excludes decommissioning costs.
EIMA = Energy Infrastructure Modernization Act

Exelon.

Capital Expenditure Expectations





(1) 2012 CapEx includes CEG and BGE from merger close date.

Diversified balance of utility capex recoverable through rates and generation growth capex that are largely contracted

Exelon.

2012 Projected Sources and Uses of Cash

($ in Millions)	BGE	ComEd	PECO	Exelon Generation	Exelon[7]
Beginning Cash Balance [1]					$550
Cash acquired from Constellation[2]	150	n/a	n/a	1,375	1,650
Cash Flow from Operations[3]	300	1,425	825	3,600	5,925
CapEx (excluding other items below):	(475)	(1,225)	(350)	(975)	(3,100)
Nuclear Fuel	n/a	n/a	n/a	(1,175)	(1,175)
Dividend[4]					(1,725)
Nuclear Uprates	n/a	n/a	n/a	(400)	(400)
Wind	n/a	n/a	n/a	(650)	(650)
Solar	n/a	n/a	n/a	(625)	(625)
Upstream	n/a	n/a	n/a	(100)	(100)
Utility Smart Grid/Smart Meter	(75)	(100)	(75)	n/a	(250)
Net Financing (excluding Dividend):					
Planned Debt Issuances[5]	300	--	250	775	1,325
Planned Debt Retirements	(175)	(450)	(375)	(75)	(1,075)
Project Finance/Federal Financing Bank Loan	n/a	n/a	n/a	350	350
Other[6]	--	225	--	--	175
Ending Cash Balance[1]					$875

(1) Exelon beginning cash balance as of 12/31/11. Excludes counterparty collateral activity.
(2) Includes $675 million of Constellation net collateral paid to counterparties prior to merger completion.
(3) Cash Flow from Operations primarily includes net cash flows provided by operating activities, estimated proceeds from Maryland clean coal fleet divestitures and net cash flows used in investing activities other than capital expenditures.
(4) Dividends are subject to declaration by the Board of Directors.
(5) 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 August 31, 2012.
(6) "Other" includes proceeds from options and expected changes in short-term debt.
(7) Includes cash flow activity from Holding Company, eliminations, and other corporate entities. Represents Constellation cash flows from merger close through December 31, 2012.

Credit Metrics Support Investment-Grade Ratings

- Committed to maintaining investment-grade ratings
- 2012-2016 credit metrics for Exelon Generation/HoldCo at or above target range
  — S&P target of 25-27% for Exelon Generation/HoldCo based on current market conditions

	Moody's Credit Ratings(1)(2)	S&P Credit Ratings(1)(2)	Fitch Credit Ratings(1)(2)	FFO / Debt Target Range
Exelon Corp	Baa2	BBB-	BBB+	
ComEd	A3	A-	BBB+	15-18%
PECO	A1	A-	A	15-18%
BGE	Baa1	BBB+	BBB+	15-18%
Generation	Baa1	BBB	BBB+	25-27%(3)

(1) Current senior unsecured ratings for Exelon, Exelon Generation and BGE and senior secured ratings for ComEd and PECO as of April 16, 2012.

(2) Moody's downgraded Exelon and Generation and upgraded BGE upon completion of the merger with Constellation Energy. Moody's currently has Exelon and Generation on Negative Outlook. S&P and Fitch affirmed ratings of Exelon and subsidiaries upon completion of the merger.

(3) FFO/Debt Target Range reflects Generation FFO/Debt in addition to the debt obligations of Exelon Corp. Range represents FFO/Debt to maintain current ratings at current business risk.

Metrics sufficient to maintain investment-grade rating in 5-year financial plan

Levers Provide Additional Flexibility

	Lever	Summary
Operational Efficiencies	Cost Management	• Identify additional cost management opportunities within the combined company
Financial Tools	Project Financing	• Use project financing for renewable opportunities as deemed fit
	Defer Growth Projects	• Maintain flexibility on timing of generation growth projects — LaSalle EPU 2-year deferral provides additional cash flow headroom and maintains ability to add 303 - 336 MWs by 2017/18

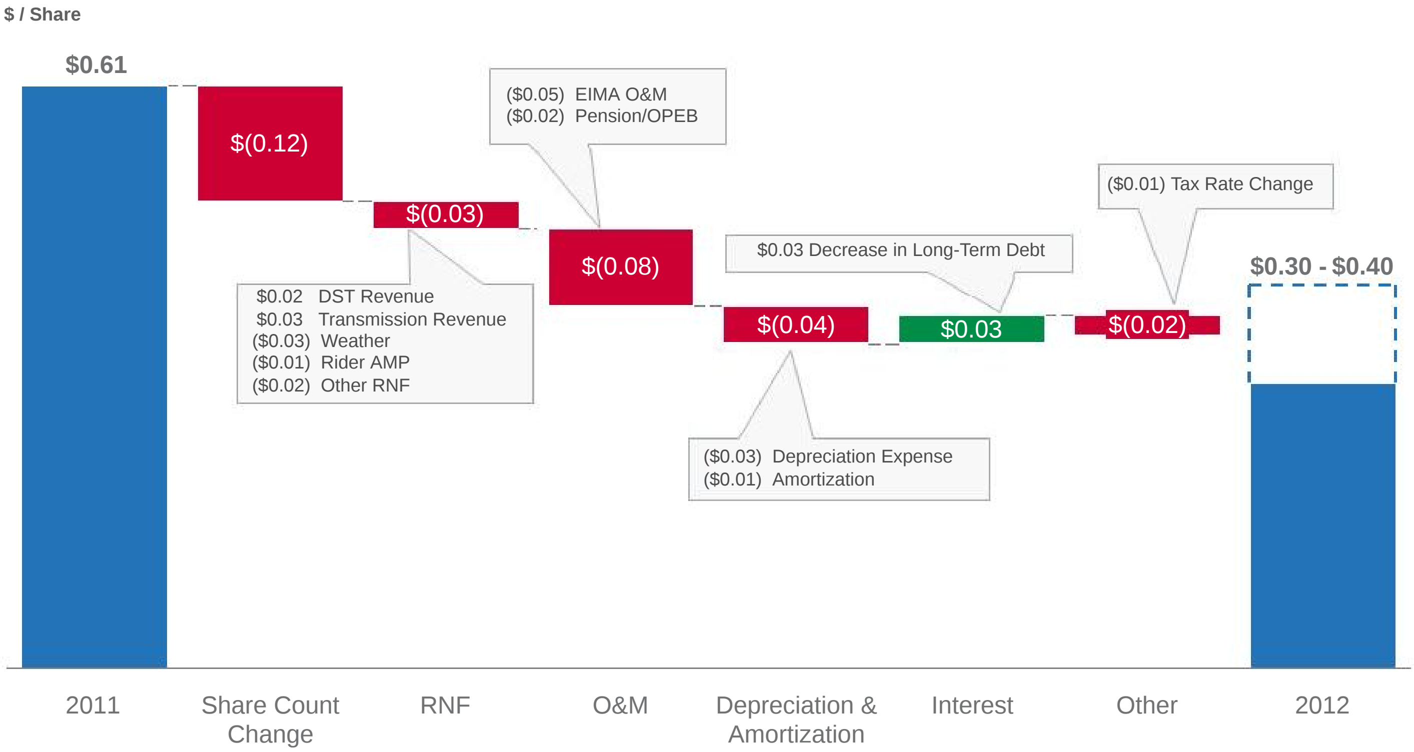
Exelon has levers available to maintain balance sheet strength, sustain the dividend and maintain investment-grade ratings

EPU = Extended Power Uprate

Exelon.

Appendix

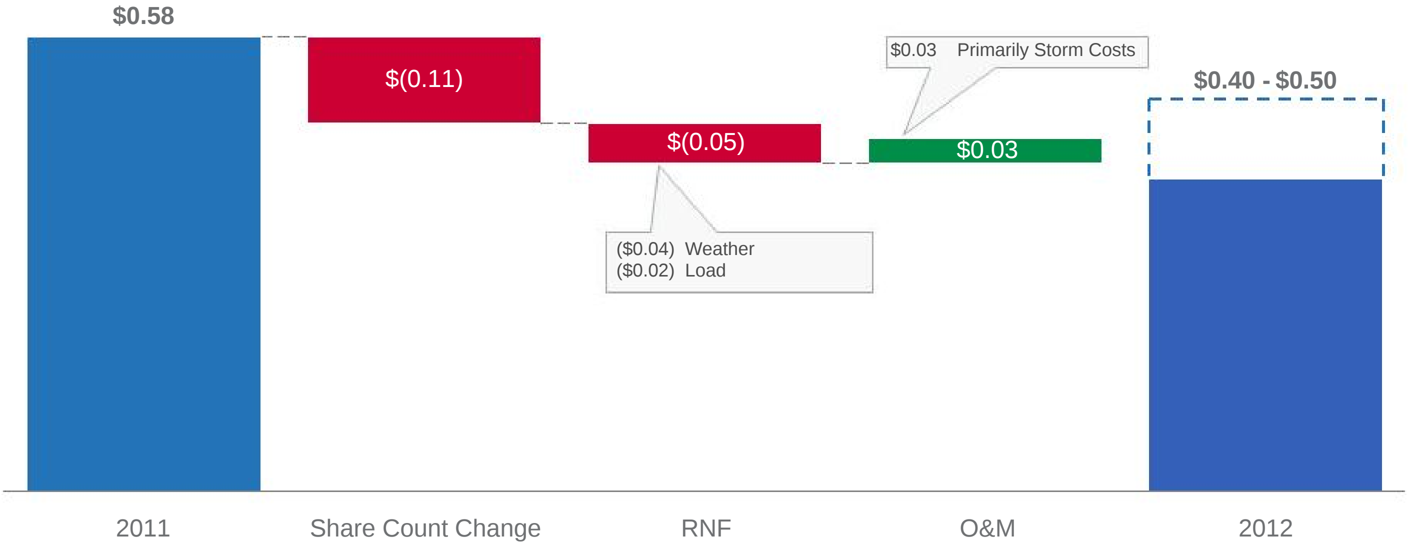
ComEd Operating EPS Bridge



Note: Drivers add up to mid-point of 2012 EPS range.
AMP = Advanced Metering Program
RNF = Revenue Net Fuel

(1) O&M for utilities excludes regulatory O&M that are P&L neutral.

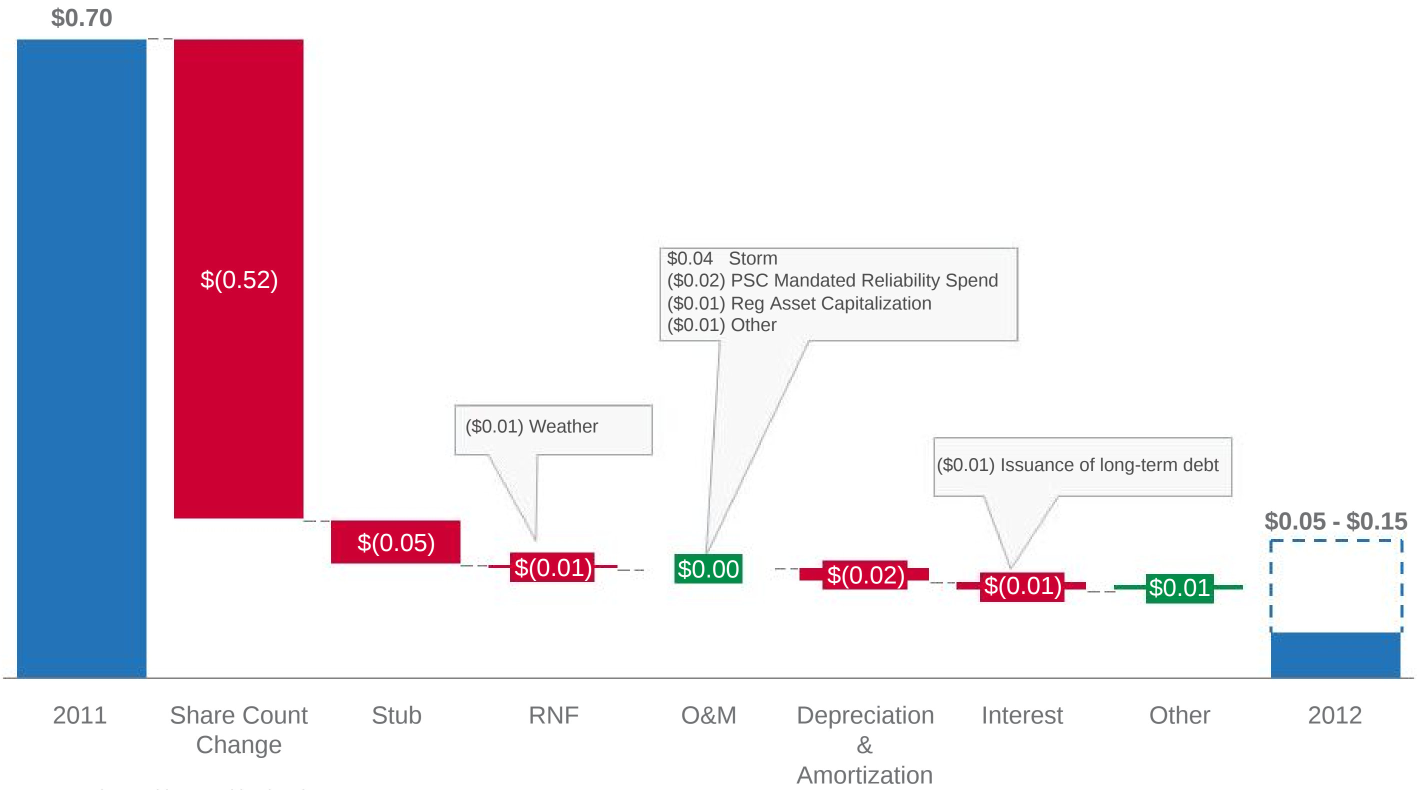
PECO Operating EPS Bridge



Note: Drivers add up to mid-point of 2012 EPS range
RNF = Revenue Net Fuel

(1) O&M for utilities excludes regulatory O&M that are P&L neutral.

BGE Operating EPS Bridge



Note: Drivers add up to mid-point of 2012 EPS range.
RNF = Revenue Net Fuel

(1) O&M for utilities excludes regulatory O&M that are P&L neutral.

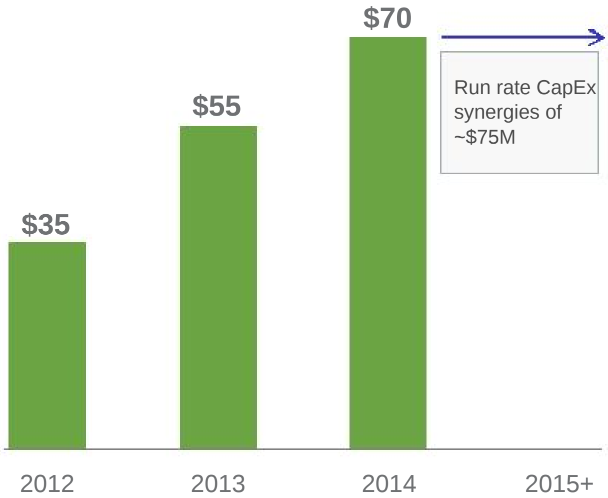
Credit Facility Update

- Constellation liquidity facilities (excluding BGE) of $4.2B to be eliminated by end of year 2012
  - Reduced Constellation $2.5B revolver by $1.0B at merger close and plan to eliminate balance revolver by end of 2012
  - End state liquidity capacity of $6.1B starting in 2013

Expect to realize $40M in annual cost savings beginning in 2013

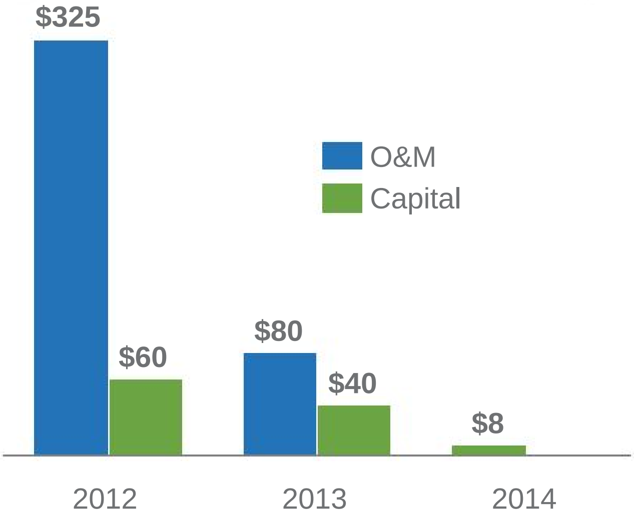
Merger CapEx Synergies & Costs To Achieve

CapEx Synergies ($M)



- Run rate CapEx synergies mainly driven by:
  - Information Technology (IT) systems consolidation
  - Supply Chain capital synergies

Costs to Achieve ($M)



- Costs to achieve excluded from operating earnings
- Key areas of costs to achieve:
  - IT systems consolidation
  - Transaction costs (banker, legal costs, etc.)
  - Employee-related costs

Exelon.

Merger Purchase Accounting P&L Impacts

Preliminary Exelon Generation Pre-Tax GAAP P&L Impacts[1] ($M)

	2012								
Item	**Q1**	**Q2**	**Q3**	**Q4**	**Total**	**2013**	**2014**	**Description**	**Earnings Treatment**
Unamortized energy contracts, net (Revenue net Fuel)	~($125)	~($450)	(~$275)	~($300)	~($1,150)	~($475)	~($100)	Non-cash amortization of intangible assets, net, for acquired power supply and fuel contracts recognized at fair value at the merger date.	Excluded from operating earnings in 2012-14
Depreciation & Amortization	~($1)	~($6)	~($6)	~($6)	~($20)	~($30)	~($30)	Net incremental depreciation and amortization based on fair value of generation station and upstream assets, trade name, and retail relationships. Excludes plant divestitures.	Included in operating earnings
Amortization of adjustment to recognize the unregulated long-term debt at fair value (Interest Expense)	~$3	~$8	~$8	~$8	~$28	~$25	~$15	Non-cash amortization of fair value adjustment for long-term debt.	Included in operating earnings except for $17M and $12M hybrid amortization in 2012-13, respectively[2]

(1) Amounts shown in table above are based on the preliminary valuation underlying the disclosures in the first quarter Form 10-Q. These amounts are subject to revision and any changes could be material. Numbers represent increase / (decrease) to GAAP earnings. This list of purchase accounting adjustments is not all inclusive. Other minor adjustments have minimal impact on earnings.

(2) Exclusion from operating earnings for amortization related to hybrid instrument expected to be retired in 2013.

Pension and OPEB for Combined Company

Plan Design and Funding Strategy:

- Exelon is evaluating benefit plan design changes for the combined company, but does not anticipate merging the Exelon and Constellation plans until 2013 at the earliest
- Exelon and Constellation plans will maintain their stand-alone funding strategies in 2012; the funding strategy for the combined company will be reevaluated once the future state plan design is established
  - Both companies' pension funding strategy is to contribute the minimum amounts required under ERISA, including amounts necessary to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006
  - Unlike qualified pension plans, OPEB plans are not subject to regulatory minimum contribution requirements and are, therefore, voluntary. The contribution strategy for Exelon's OPEB plans is determined based on benefit claims paid and regulatory implications (amounts deemed prudent to meet regulator expectations and best assure continued recovery), while Constellation's plans are unfunded

Current Forecast:

- The table below provides the combined company's 2012 and forecasted 2013 pension and OPEB expense and contributions assuming 2012 asset returns of 7.50% and 6.68% (after-tax) for pension and OPEB, respectively, a projected 12/31/12 pension discount rate of 4.70% and 4.52% for Exelon and Constellation, respectively, and a projected 12/31/12 OPEB discount rate of 4.78% and 4.53% for Exelon and Constellation, respectively

	2012		2013	
(in $M)	Pre-Tax Expense(1)	Contributions(2)	Pre-Tax Expense(1)	Contributions(2)
Pension	$350	$160	$350	$150
OPEB	$240	$320	$235	$305
Total	$590	$480	$585	$455

(1) Pension and OPEB expenses assume a 27.0% and 27.6% capitalization rate for 2012 and 2013, respectively.
(2) Contributions shown in the table above are based on the current contribution policy for Exelon and Constellation plans.

Exelon.

2013 Pension and OPEB Sensitivities

- Tables below provide sensitivities for the combined company's 2013 pension and OPEB expense and contributions[1] under various discount rate and S&P 500 asset return scenarios

	2013 Pension Sensitivity[2] (in $M)					
	S&P Returns in Q2 - Q4 2012[3]					
	10%		0%		-10%	
Discount Rate at 12/31/12	Pre-Tax Expense[1]	Contributions[2]	Pre-Tax Expense[1]	Contributions[2]	Pre-Tax Expense[1]	Contributions[2]
Baseline Discount Rate[4]	$340	$145	$360	$155	$375	$160
+50 bps	$310	$150	$325	$155	$345	$160
- 50bps	$375	$90	$390	$150	$410	$160

	2013 OPEB Sensitivity[2] (in $M)					
	S&P Returns in Q2 - Q4 2012[3]					
	10%		0%		-10%	
Discount Rate at 12/31/12	Pre-Tax Expense[1]	Contributions[2]	Pre-Tax Expense[1]	Contributions[2]	Pre-Tax Expense[1]	Contributions[2]
Baseline Discount Rate[4]	$220	$285	$230	$300	$245	$320
+50 bps	$200	$260	$210	$275	$225	$290
- 50bps	$240	$315	$255	$335	$270	$355

(1) Contributions shown in the table above are based on the current contribution policy for Exelon and Constellation plans.

(2) Pension and OPEB expenses assume a 27.6% capitalization rate.

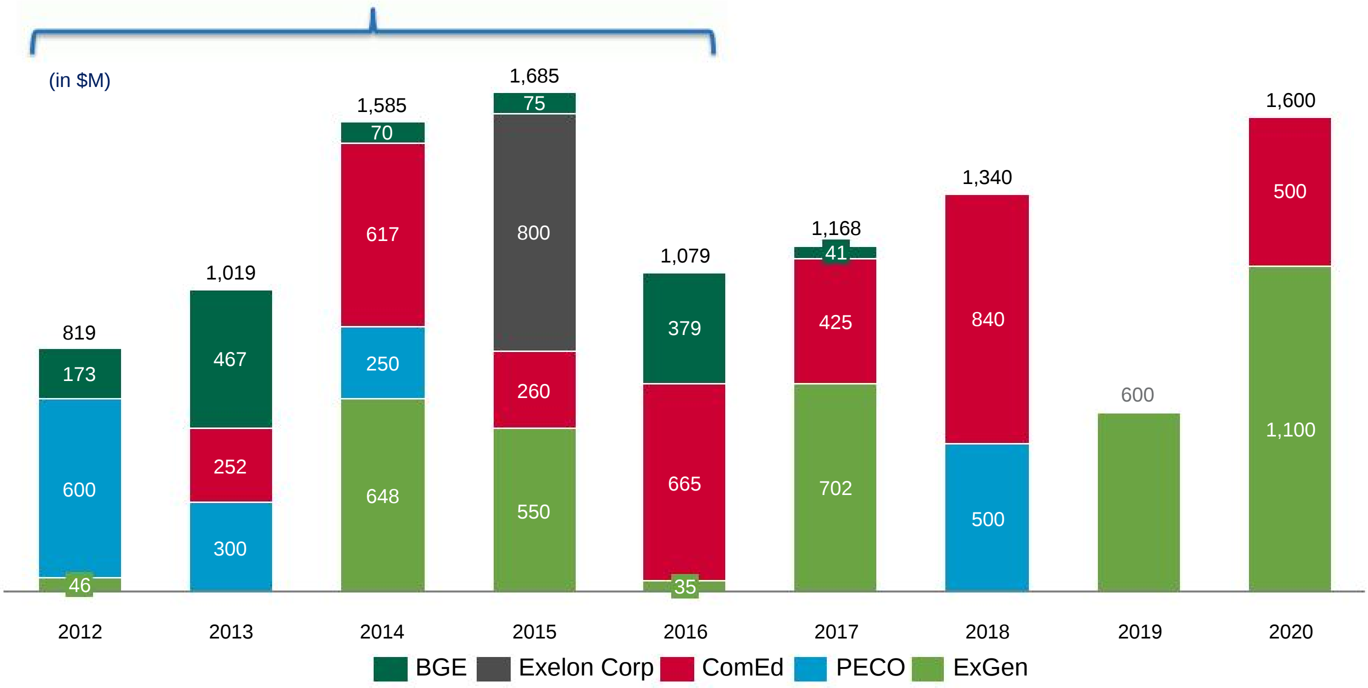
(3) Final 2012 asset return for pension and OPEB will depend in part on overall equity market returns from Q2 – Q4 2012 as proxied by the S&P 500. The amounts above reflect YTD S&P returns through March 31, 2012.

(4) The baseline discount rates reflect a projected 12/31/12 pension discount rate of 4.70% and 4.52% for Exelon and Constellation, respectively, and OPEB discount rate of 4.78% and 4.53% for Exelon and Constellation, respectively.

Debt Maturity Schedule

Debt Maturity Profile (2012-2020)

~66% of 2012 – 2016 debt maturities consist of regulated utility debt



2012 Key Assumptions

Generation Statistics	2012 Estimate[2]
Nuclear Capacity Factor (%)[1]	93.5%
Total Expected Generation(GWh)	219,900
Henry Hub Natural Gas ($/MMbtu)	$2.47
Midwest: NiHub ATC Price	$26.71
Mid-Atlantic: PJM-W ATC Price	$32.70
ERCOT-N ATC Spark Spread	$11.10
New York: NY Zone A ATC Price	$26.99
New England: Mass Hub Spark Spread	$5.98
Effective Tax Rate (%) - Operating	37.1%

Utility Statistics	2012 Estimate
Electric Delivery Growth (%)[3]	
ComEd	(0.3)%
PECO	(3.3)%
BGE	0.7%
Effective Tax Rate -Operating (%)	
ComEd	39.6%
PECO	33.6%
BGE	37.8%
Exelon	37.4%

2012 O&M[4] Reconciliation (in $M)	ExGen	ComEd	PECO	BGE	Other	Exelon
GAAP O&M	**$4,725**	**$1,350**	**$700**	**$575**	**$175**	**$7,525**
Decommissioning accretion	$(75)	-	-	-	-	$(75)
Retirement of Fossil Plants	$(25)	-	-	-	-	$(25)
FERC Settlement	$(200)	-	-	-	-	$(200)
Regulatory O&M	-	$(150)	$(25)	-	-	$(175)
Merger/Integration costs	$(325)	-	-	$(50)	$(225)	$(600)
Operating O&M (as shown on slide 18)	**$4,100**	**$1,200**	**$675**	**$525**	**$(50)**	**$6,450**

(1) Excludes Salem and CENG.
(2) Reflects forward market prices as of April 30, 2012.
(3) Weather-normalized load growth.
(4) O&M rounded to the nearest $25M.

Exelon.

GAAP to Operating Adjustments

- Exelon's 2012 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
  - Financial impacts associated with the planned retirement of fossil generating units
  - Certain costs related to the Constellation merger and integration initiatives
  - Costs incurred as part of Maryland commitments in connection with the merger
  - Non-cash amortization of intangible assets, net, related to commodity contracts recorded at fair value at the merger date
  - Costs incurred as part of a March 2012 settlement with the Federal Energy Regulatory Commission (FERC) related to Constellation's prior period hedging and risk management transactions
  - Revenues and operating expenses related to three generation facilities required to be sold within 180 days of the merger
  - Non-cash benefit associated with a change in state deferred tax rates resulting from a reassessment of anticipated apportionment of Exelon's deferred taxes as a result of the merger
  - Certain costs incurred associated with other acquisitions
  - Significant impairments of assets, including goodwill
  - Other unusual items
  - Significant changes to GAAP
- Operating earnings guidance assumes normal weather for remainder of the year

Three Months Ended March 31, 2012	ExGen[1]	ComEd	PECO	BGE[1]	Other[1]	Exelon[1]
2012 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	**$0.58**	**$0.13**	**$0.14**	**$0.02**	**$(0.02)**	**$0.85**
Mark-to-market adjustments from economic hedging activities	0.05	-	-	-	0.01	0.06
Unrealized gains related to nuclear decommissioning trust funds	0.05	-	-	-	-	0.05
Retirements of fossil generation units	(0.01)	-	-	-	-	(0.01)
Constellation merger and integration costs	(0.06)	(0.00)	(0.01)	(0.00)	(0.09)	(0.16)
Maryland commitments	(0.03)	-	-	(0.12)	(0.17)	(0.32)
Amortization of commodity contract intangibles	(0.11)	-	-	-	-	(0.11)
FERC settlement	(0.25)	-	-	-	-	(0.25)
Plant divestitures	(0.00)	-	-	-	-	(0.00)
Reassessment of state deferred income taxes	0.02	-	-	-	0.15	0.17
Other acquisition costs	(0.00)	-	-	-	-	(0.00)
1Q 2012 GAAP Earnings (Loss) Per Share	**$0.24**	**$0.13**	**$0.14**	**$(0.09)**	**$(0.12)**	**$0.28**

(1) For the three months ended March 31, 2012, includes financial results for Constellation and BGE beginning on March 12, 2012, the date the merger was completed.

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

Exelon.

Constellation

Ken Cornew

EVP and Chief Commercial Officer of Exelon and President and CEO of Constellation

Exelon.

Commercial Business Overview

Scale, Scope and Flexibility Across the Energy Value Chain

Development and exploration of natural gas and liquids properties

11 assets in seven states

~295 BCFe of proved Reserves[1]

Largest merchant power generation portfolio in the U.S.

~35 GW of owned generation capacity[2]

Clean portfolio, well positioned for evolving regulatory requirements

Industry-leading wholesale and retail sales and marketing platform

~170 TWh of load and ~465 BCF of gas delivered[3]

~ 1 million residential and 100,000 business and public sector customers

One of the largest and most experienced Energy Management providers

~2,000 MW of Load Response under contract[4]

Over 4,000 energy savings projects implemented across the U.S.

Benefiting from scale, scope and flexibility across the value chain

(1) Estimated proved reserves as of 12/31/2011. Includes Natural Gas (NG), NG Liquids (NGL) and Oil. NGL and Oil are converted to BCFe at a ratio of 6:1.
(2) Total owned generation capacity as of 4/30/2012, net of physical market mitigation (Brandon Shores, C.P. Crane and H.A. Wagner ~2,648 MW).
(3) Expected for 2012 as of 4/30/2012. Electric load and gas includes fixed price and indexed products. No stub period adjustment for legacy Constellation contribution.
(4) Load Response estimate as of 4/30/2012.

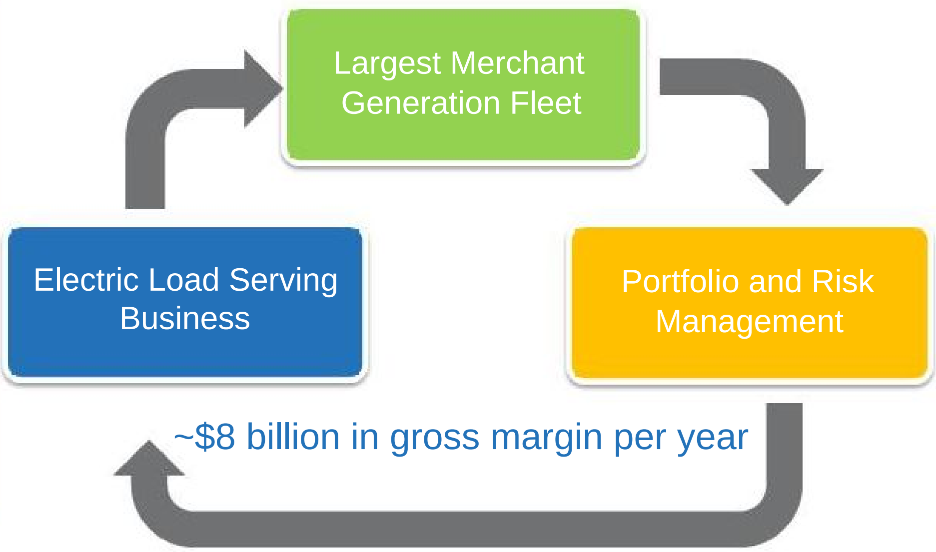
Commercial Business Transformation

PJM, wholesale marketing focus > National, customer-facing business

Low-cost, geographically and technologically diverse generation fleet

Unparalleled upside to tightening energy and capacity markets

- Expand into new markets
- Cross sell new products and services
- Benefit from matching generation and load
- Capital and collateral efficiency



- Optimize generation assets/value added forward hedges
- Leverage relationships with large wholesale customers
- Monetize risk management expertise

Industry-leading retail platform and portfolio management expertise, combined with one of the lowest cost and best managed generation fleets

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

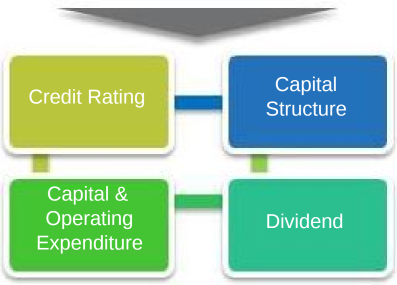
- Ensure stability in near-term cash flows and earnings
  - Disciplined approach to hedging
  - Tenor aligns with customer preferences and market liquidity
  - Multiple channels to market that allow us to maximize margins
  - Large open position in outer years to benefit from price upside

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

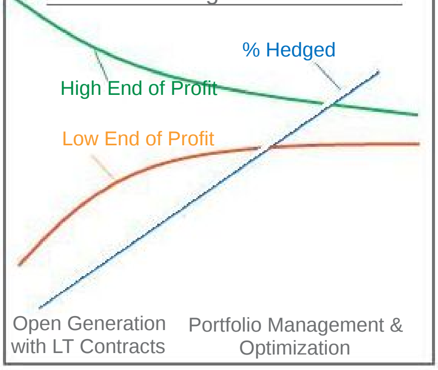
Align Hedging & Financials

Establishing Minimum Hedge Targets



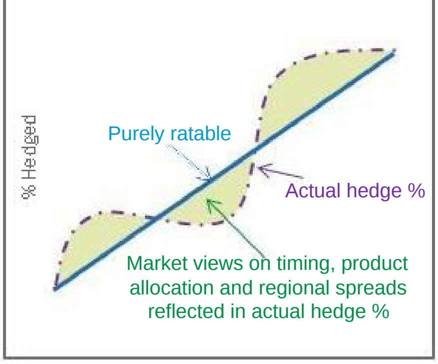
Protect Balance Sheet

Portfolio Management Over Time



Ensure Earnings Stability

Exercising Market Views

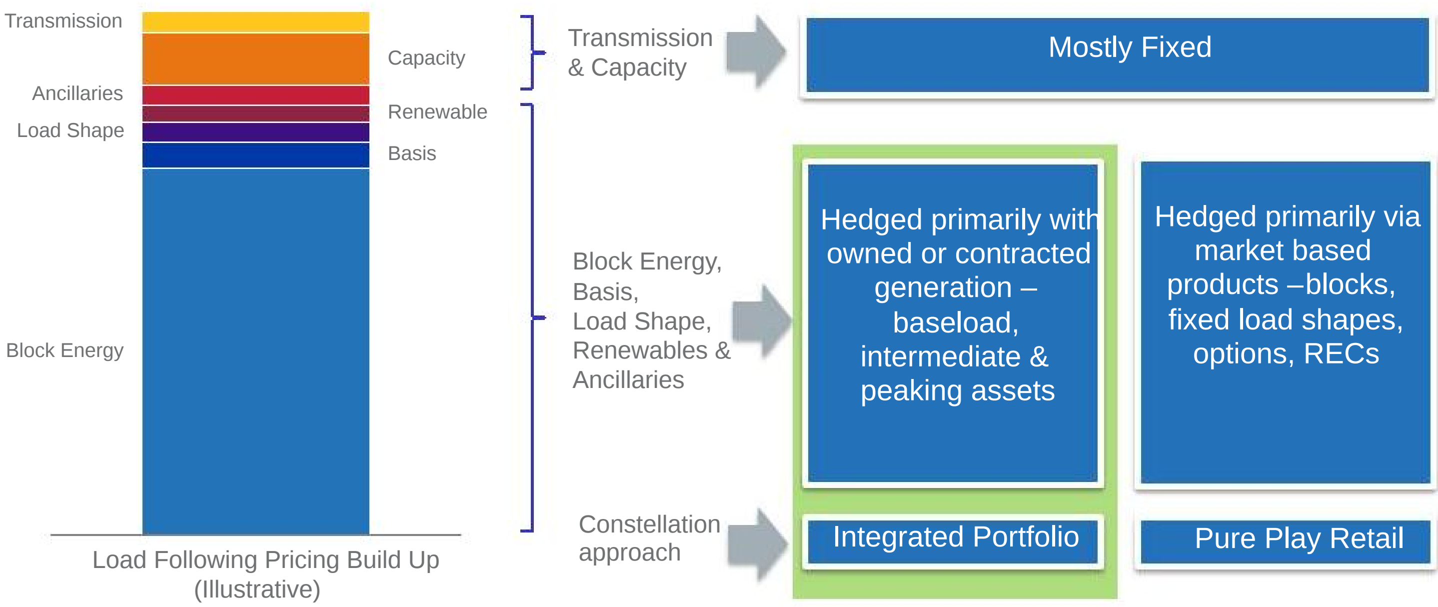


Create Value

Portfolio Management Approach

Full Requirements Components(1)

Pricing and Portfolio Management Approach

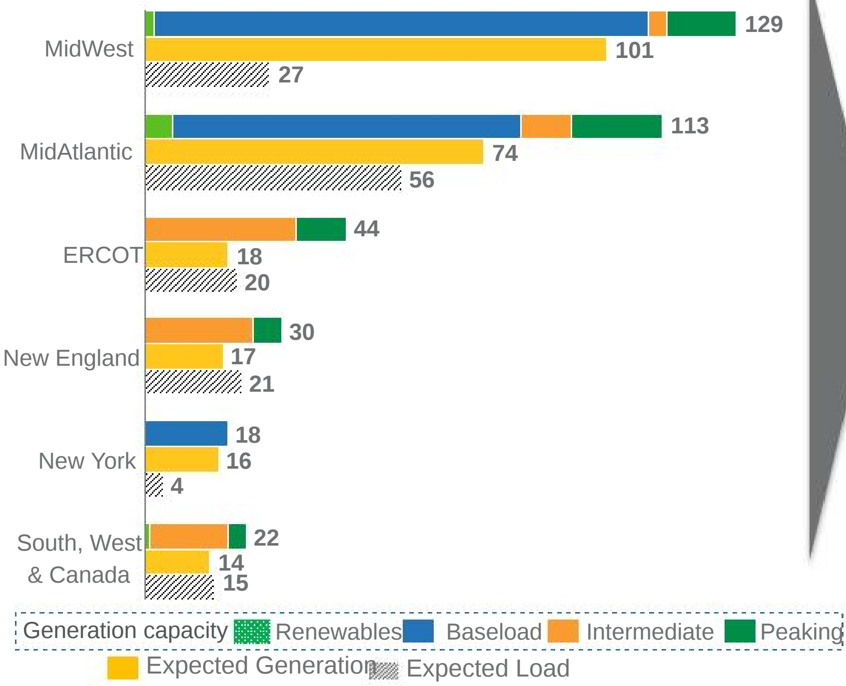


Constellation's model will be an integrated approach to load management, selling the products that closely tie to its asset portfolio

(1) Full requirements pricing build up is for illustrative purpose and not reflective of any one particular product or zone. Margins are not reflected in the build up.

Generation and Load Match

Generation Capacity, Expected Generation and Expected Load 2012 in TWh[1,2]



Generation & Load Match: Competitive Advantage

Our generation portfolio is low cost, flexible and diverse

Generation and load positions are well balanced across multiple regions

Adequate intermediate and peaking capacity within the portfolio for managing peaking load

Continue to buy or sell length from market to manage portfolio needs

The combination establishes an industry-leading platform with regional diversification of the generation fleet and customer-facing load business

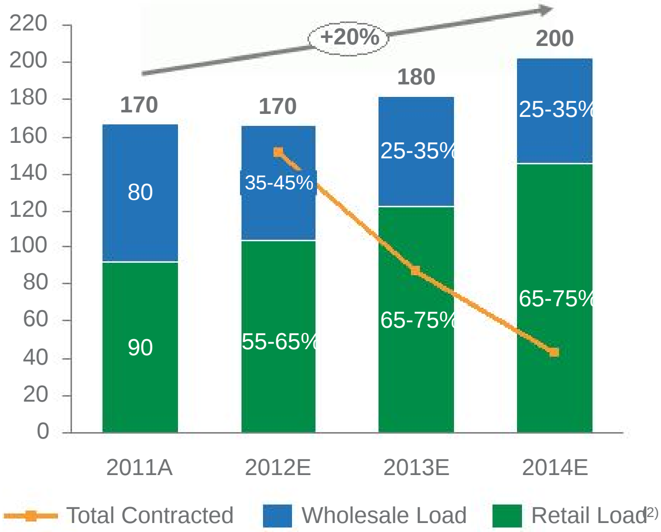
(1) Owned and contracted generation capacity converted from MW to MWh assuming 100% capacity factor for all technology types, except for renewable capacity which is shown at estimated capacity factor.

(2) Expected generation and load shown in the chart above will not tie out with load volume and ExGen disclosures. Load shown above does not include indexed products and generation reflects a net owned and contracted position. Estimates as of 4/30/2012.

Electric Load Serving Business: Growth Target

Commercial Load[1]

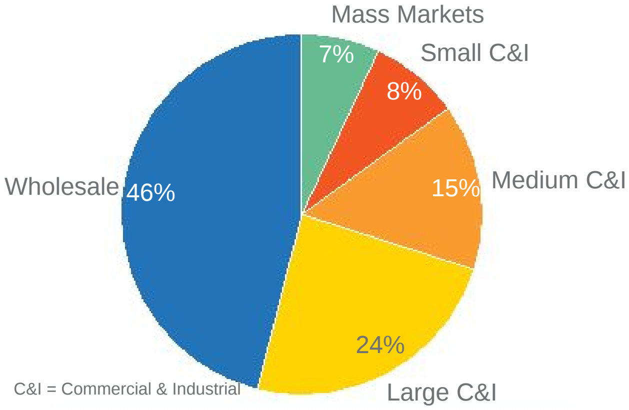
2011 – 2014 TWh



(1) Numbers and percentages are rounded to the nearest 5
(2) Index load expected to be 20% to 30% of total forecasted retail load

Load Split by Customer Class

(2011 TWh)



Customer Type	Load Size
Mass Markets	<1,000 MWhs per year
Small C&I	1,001-5,000 MWhs per year
Medium C&I	5,001-25,000 MWhs per year
Large C&I	>25,000 MWhs per year

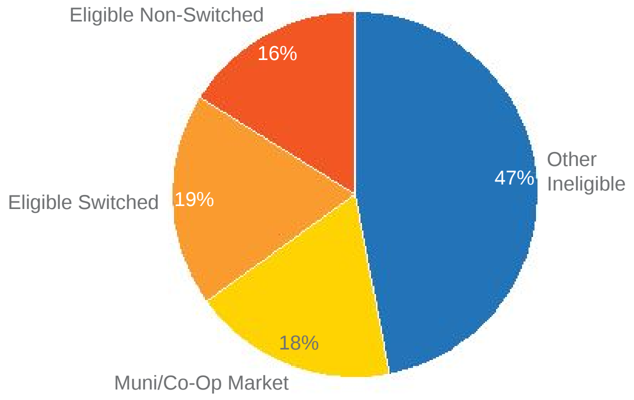
Well positioned for growth in volumes and margins on the back of a sustainable platform and new opportunities

A diverse set of customers enhances margin opportunities from a sales and portfolio management standpoint

Electric Load Serving Business: Strategy

Total U.S. Power Market in 2012

Estimated Load ~ 3,700 TWh[1]



Through retail and wholesale channels, Constellation currently serves 170 TWhs, or approximately 5%, of total U.S. power demand

Expected Total Competitive Market Growth

- Underlying load growth
  - More than 1% annual load growth across the U.S.
- Switched market expected to grow by approximately 11% in C&I from 2011 to 2014
  - Existing markets: PA and OH
  - New markets: MI and AZ
- Switched market expected to grow by approximately 15% in residential from 2011 to 2014

Strategy to Grow

- As existing markets grow and new markets open, serve new customers
- Improve market share in existing markets
- Cross sell suite of products to existing customers
  - Create more value with customers
  - Utilize data and technology to expand product offerings
  - Achieve higher renewal rates
  - Distinguish our brand
- Leverage operational efficiency

Constellation is well positioned in a U.S. market where capacity available for competitive supply has room to grow

(1) Source: EIA, KEMA and internal estimates.

Exelon.

ExGen Disclosure Overview

Continue to provide transparency in our ExGen disclosures with a modified and expanded framework that incorporates new business lines and regions

- **Maintain ability to value generation fleet on an open and hedged basis**
  - Continue to provide open gross margins, expected generation, hedge %, reference prices and effective realized energy prices (EREP)
  - Also provide Mark-to Market (MtM) value of all hedges on a consolidated basis
- **No separate gross margins for commercial load, but will disclose volume targets and sales execution**
  - Consider retail and wholesale load to be an alternate channel to market our generation. As such, executed sales are regarded as a hedge and thus flow into MtM, EREP and hedge percentage
  - Provide volume targets and track sales execution versus targets on an annual basis
- **Introduction of new gross margin categories**
  - In addition to Open Gross Margin and MtM of hedges, gross margins will be provided for the following categories -
    - Power New Business: Gross margins from future hedging activity via retail, wholesale or structured transaction/mid-marketing activities. Once power sales are executed, these flow into MtM via EREP
    - Non Power New Business: Gross margins from planned sales from business activities not related to hedging power production, such as Load Response, Energy Efficiency, Retail and Wholesale Gas, Proprietary Trading(1) etc. Once sales are executed, gross margins will flow to "Non Power Executed" category.
    - Non Power Executed: Contracted gross margin associated with business activities not directly linked to production or sale of power
- **Introduction of new regions**
  - To reflect our expanded national presence, New England, New York, and South, West & Canada regions have been added to Midwest, Mid-Atlantic and ERCOT
  - Hedged gross margins for South, West & Canada will be included within the consolidated "Open Gross Margin" estimate
  - The other five regions will have corresponding expected generation, hedge %, reference prices and EREP

(1) Proprietary trading gross margins will remain within "Non Power" New Business category and not move to "Non power" executed category.

Exelon

Components of Gross Margin Categories

Gross margin linked to power production and sales			Gross margin from other business activities	
Open Gross Margin	**MtM of Hedges[2]**	**"Power" New Business**	**"Non Power" Executed**	**"Non Power" New Business**
•Generation Gross Margin at current market prices, including capacity & ancillary revenues •Exploration and Production •PPA Costs & Revenues •Provided at a consolidated level for all regions (includes hedged gross margin for South, West & Canada[1])	•MtM of power, capacity and ancillary hedges, including cross commodity, retail and wholesale load transactions •Provided directly at a consolidated level for five major regions. Provided indirectly for each of the five major regions via EREP, reference price, hedge %, expected generation	•Retail, Wholesale planned electric sales •Portfolio Management new business •Mid marketing new business	•Retail, Wholesale executed gas sales •Load Response •Energy Efficiency •BGE Home •Distributed Solar	•Retail, Wholesale planned gas sales •Load Response •Energy Efficiency •BGE Home •Distributed Solar •Portfolio Management / origination fuels new business •Proprietary trading [3]

Margins move from new business to MtM of hedges over the course of the year as sales are executed

Margins move from "Non power new business" to "Non power executed" over the course of the year

(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 remain within "Non Power" New Business category andnot move to "Non power" executed category.

Exelon

ExGen Disclosures

Gross Margin Category ($ MM)	2012 (1)	2013	2014
Open Gross Margin(2,3) (including South, West, Canada hedged gross margin)	$4,300	$5,800	$6,250
Mark-to-Market of Hedges	$3,150	$1,400	$500
Power New Business / To Go	$200	$550	$850
Non-Power Margins Executed	$200	$100	$50
Non-Power New Business / To Go	$200	$500	$550
Total Gross Margin	**$8,050**	**$8,350**	**$8,200**

Reference Prices (ATC -$/MWh) (5)	2012	2013	2014
Henry Hub Natural Gas ($/MMbtu)	$2.47	$3.45	$3.87
Midwest: NiHub	$26.71	$30.28	$32.45
Mid-Atlantic: PJM-W	$32.70	$37.93	$40.37
ERCOT-N ATC Spark Spread	$11.10	$9.19	$8.50
New York: NY Zone A	$26.99	$31.40	$33.46
New England: Mass Hub Spark Spread	$5.98	$4.66	$3.50

Generation and Hedges	2012 (1)	2013	2014
Exp. Gen (GWh)	**219,900**	**218,400**	**210,200**
Midwest	101,800	97,900	97,800
Mid-Atlantic(2,3)	71,300	74,100	72,000
ERCOT	19,900	18,800	16,100
New York(3)	13,400	13,400	10,500
New England	13,500	14,200	13,800
% of Expected Generation Hedged	**97-100%**	**73-76%**	**41-44%**
Midwest	94-97%	77-80%	44-47%
Mid-Atlantic(2,3)	105-108%	74-77%	45-48%
ERCOT(4)	89-92%	56-59%	34-37%
New York(3)	91-94%	69-72%	20-23%
New England(4)	94-97%	66-69%	27-30%
Effective Realized Energy Price ($/MWh)			
Midwest	$41.00	$39.50	$37.00
Mid-Atlantic(2,3)	$53.00	$49.00	$49.00
ERCOT(4)	$8.50	$6.00	$3.00
New York(3)	$45.00	$37.00	$37.50
New England(4)	$8.00	$8.50	$3.50

(1) Stub period was calculated by excluding Jan 2012 thru mid-March 2012 for Constellation only.
(2) Excludes Maryland assets to be divested.
(3) Includes Constellation Energy Nuclear Group (CENG) Joint Venture.
(4) Spark spreads shown for Texas and New England.
(5) Based on April 30, 2012 market conditions.

Closing Remarks

- RPM PY 2015/2016 Auction Results
  - Results were in line with internal expectations of pricing improvement vs. last year's auction
  - Moderate growth in cleared Demand Response (DR) signals continued DR bidding discipline
- Best Positioned Merchant Generation Portfolio
  - Continue to believe the upside associated with net retirements and higher operational costs in the range of $3-5/MWh in PJM, with a large portion not currently reflected in energy prices
- Effective Risk Management
  - Well established criteria and effective oversight to manage and monitor risk
  - Small proprietary trading function and contribution to gross margin
- Nation's Number One Energy Marketer
  - Best positioned to capture additional load as new markets open and existing markets mature
  - Matching generation to load, and an extensive suite of products and services, provides us with a competitive advantage

We are well positioned to expand our business across many fronts and deliver on overall commercial business growth

Appendix

Generation Capacity Market Positions

		2011/2012	2012/2013	2013/2014	2014/2015	2015/2016
PJM(1)						
RTO	*Capacity*	27,400	12,800	11,500	11,500	11,500
	Price	$110	$16	$28	$126	$136
EMAAC	*Capacity(2)*		9,200	9,200	9,200	9,200
	Price		$140	$245	$137	$168
MAAC	*Capacity*		2,600	2,700	2,700	2,700
	Price		$133	$226	$137	$168
SWMAAC	*Capacity(3)*		1,900	1,900	1,900	1,900
	Price		$133	$226	$137	$168
New England(4)						
NEMA	*Capacity*	2,100	2,100	2,100	2,100	2,100
	Price	$104 (5)	$85 (5)	$85 (5)	$107	$114
SEMA	Capacity	35	35	35	35	35
	Price	$104 (5)	$85 (5)	$85 (5)	$95 (5)	$104 (5)
Rest of Pool	*Capacity*	700	700	700	700	700
	Price	$104 (5)	$85 (5)	$85 (5)	$95 (5)	$104 (5)
NYISO(6)						
Rest of Pool	*Capacity*	1,100	1,100	1,100	1,100	1,100
MISO(7)						
AMIL	*Capacity*	1,100	1,100	1,100	1,100	1,100

RTO = Regional Transmission Organization, MAAC = Mid-Atlantic Area Council, EMAAC = Eastern Mid-Atlantic Area Council, SWMAAC = South West Mid-Atlantic Area Council, NEMA = North East Massachusetts; SEMA = North East Massachusetts, AMIL = Ameren Illinois.

(1) Reflects owned and contracted generation installed capacity (ICAP) adjusted for mid – year PPA roll offs.
(2) ICAP is net of Eddystone 1&2, Cromby 1&2 (total ~ 933 MW), which are not included PY 11/12 onwards reflecting decision in December 2009 to permanently retire these units.
(3) ICAP for all years beginning PY 11/12 excludes capacity for units to be divested (Brandon Shores, Wagner & Crane ~2,648 MW). Constellation offered these units in PY11/12 - PY 15/16 auctions.
(4) Reflects Qualified Summer Capacity including owned and contracted units.
(5) Price is pro-rated for auctions that clear at the floor price and there is more capacity procured than suggested by the reliability requirement.
(6) Reflects 50.01% ownership in CENG; (7) Does not include wind under PPA.

Capacity Market Background

PJM Reliability Pricing Model (RPM)

- Base Residual Auction is held 3 years in advance for 1-year term
  - 97.5% of Reliability Requirement is targeted to be procured
  - Demand curve based approach to procurement
- Three Incremental Auctions are held prior to delivery
  - 2.5% of Reliability Requirement is targeted to be procured

ISO-NE Forward Capacity Market (FCM)

- Forward Capacity Auction is held 3 years in advance for 1-year term
  - 100% of Installed Capacity Requirement is procured
  - Descending clock auction with administrative floor price
- Three Reconfiguration Auctions are held prior to delivery and Monthly Spot Auctions are held during the delivery year

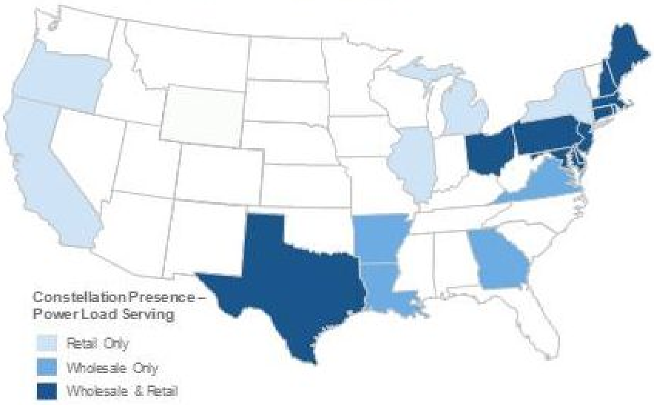
NYISO Capacity Auctions

- Annual procurement for prompt planning year
  - Split into summer and winter seasonal auctions
  - Demand curve based approach to procurement
- Monthly and spot auctions are held during the delivery year

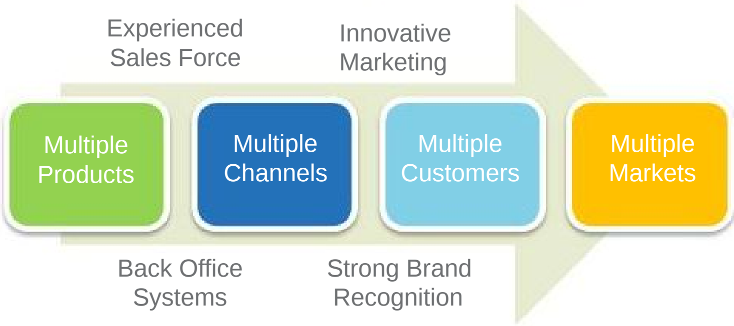
Exelon.

Electric Load Serving Business: Background

National Presence



Multiple Avenues & Scalable Platform



- #1 retail C&I power provider with 17% share of the switched commercial and industrial market [(1)]
- Top 10 provider of residential power
- Active in all U.S. power markets and products and serving over 2/3rds of Fortune 100 companies

Constellation is the leading power supplier in the U.S. with coast to coast presence and a large suite of product offerings

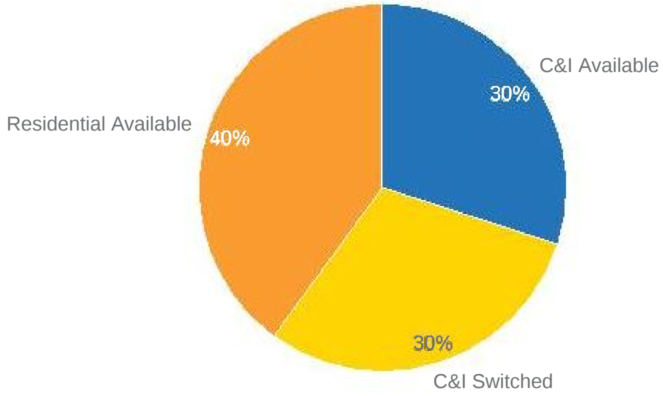
(1) Exelon and Constellation combined retail businesses. Source: KEMA, "The Retailer Yearbook", December 2011.

Exelon.

Load Response

National Presence

Estimated Total
Available Market = 100 GW(1)



Portfolio Size

- Approximately 2 GW of load response under contract

Market Potential

- Roughly 100 GW total market potential of which 30 GW is located in active ISO Demand Response markets

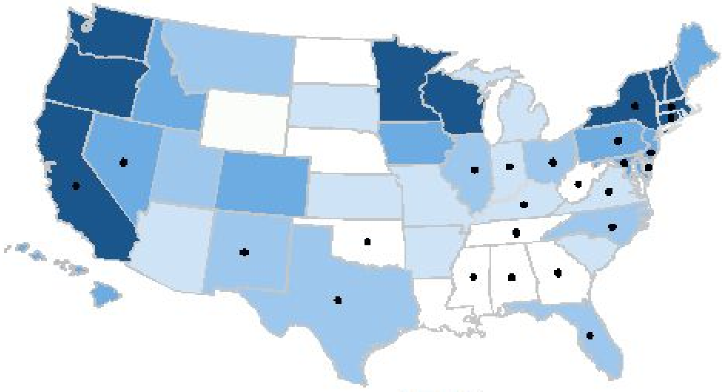
Growth Strategy and Objectives

- Share capture in maturing formal ISO demand response capacity programs
- Focus on growth opportunities in economics and reserve programs

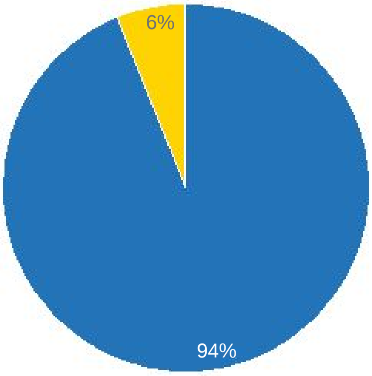
(1) Source: FERC/McKinsey. Customer class as % of total market. Not including municipals, cooperatives and utility driven DR programs.

Energy Efficiency

National Presence



Estimated Total Available Market = 20 GW(1)



Portfolio Size

- Over 4,000 energy savings projects have been implemented to date

Market Potential

- $5 billion to $6 billion in annualized revenue
- Approx. 40% located in non-competitive markets allowing growth beyond key traditional power markets

Growth Strategy and Objectives

- Focus on government, education, healthcare and multi-family housing sectors
- Combined product offering primarily focuses on commercial and industrial customers

(1) Source: EPRI/McKinsey. Customer class as % of total market.

Distributed Solar

Portfolio Size

- Of the company's 345 MW of solar installations owned or under construction (all expected to be operational by 2013), approximately 59 MW are non-utility scale installations for our commercial, industrial and public sector customers

Market Potential(2)

- Unsubsidized economic potential for distributed residential and commercial solar PV in the U.S. likely to reach 10 to 12 GW by the end of 2012

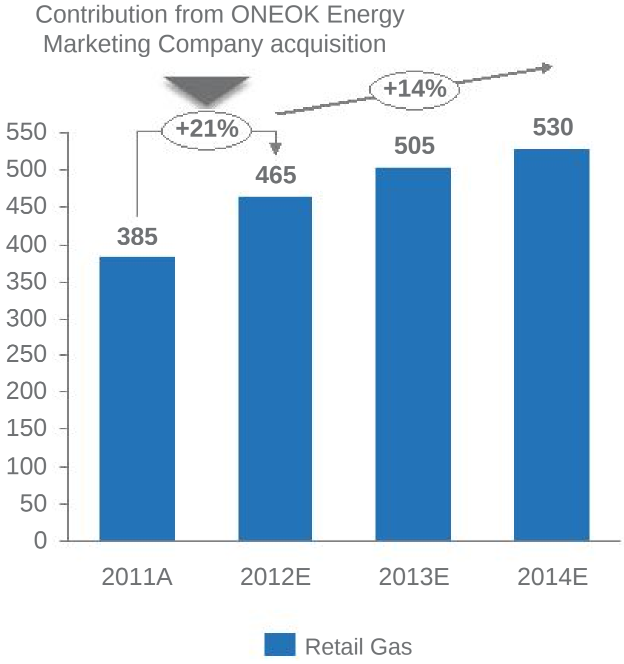
Growth Strategy and Objectives

- Focus on states with established incentives markets in place – MD, NJ, MA and CA – and where there is potential for new incentive markets – CT and NY
- Pursue opportunities in non-Solar REC markets – CO, AZ and NM – where there is increased interest in solar

(1) Excludes Antelope Valley Solar Ranch One (230 MW), Sacramento Municipal Utility District (30 MW), City Solar Project (10 MW) and Maryland Generating Clean Horizons (16 MW).
(2) Source: McKinsey, "Solar Power: Darkest Before Dawn" published April 2012.

Retail and Wholesale Gas

Retail Gas[1]
(2011 – 2014 Bcf)



(1) Estimate as of 4/30/2012.

Retail Gas

Portfolio Size
- 465 Bcf expected to be served in 2012
- Month by month renewals, with high renewal rates

Market Potential
- All states are competitive markets with an estimated total market size of 15,000 Bcf, of which 7,000 Bcf is currently switched

Growth Strategy and Objectives
- Looking to grow Northeast gas markets as well as recently acquired ONEOK territories

Wholesale Gas

Portfolio Size
- 5 Bcf wholesale storage
- 300,000 MMBtu's per day of term transport
- Over 1 Bcf/day of plant supply

Growth Strategy and Objectives
- Expand wholesale presence to complement power assets

Exelon.

ExGen Disclosures

April 30, 2012

ExGen Disclosures

Gross Margin Category ($ MM)(1)	2012 (2)	2013	2014
Open Gross Margin (including South, West & Canada hedged GM)(3,4)	$4,300	$5,800	$6,250
Mark to Market of Hedges(5)	$3,150	$1,450	$550
Power New Business / To Go	$200	$550	$850
Non-Power Margins Executed	$200	$100	$50
Non-Power New Business / To Go	$200	$500	$550
Total Gross Margin	**$8,050**	**$8,350**	**$8,200**

Reference Prices (6)	2012	2013	2014
Henry Hub Natural Gas ($/MMbtu)	$2.47	$3.45	$3.87
Midwest: NiHub ATC prices ($/MWh)	$26.71	$30.28	$32.45
Mid-Atlantic: PJM-W ATC prices ($/MWh)	$32.70	$37.93	$40.37
ERCOT-N ATC Spark Spread ($/MWh) *HSC Gas, 7.2HR, $2.50 VOM*	$11.10	$9.19	$8.50
New York: NY Zone A ($/MWh)	$26.99	$31.40	$33.46
New England: Mass Hub ATC Spark Spread($/MWh) *ALQN Gas, 7.5HR, $0.50 VOM*	$5.98	$4.66	$3.50

(1) Gross margin rounded to nearest $50M.
(2) Stub period calculated by excluding Jan 2012 thru mid-March 2012 for Constellation only.
(3) Excludes Maryland assets to be divested.
(4) Includes CENG Joint Venture.
(5) Mark to Market of Hedges assumes mid-point of hedge percentages.
(6) Based on April 30, 2012 market conditions.

ExGen Disclosures

Generation and Hedges	2012 (1)	2013	2014
Exp. Gen (GWh)(4)	219,900	218,400	210,200
Midwest	101,800	97,900	97,800
Mid-Atlantic(2,3)	71,300	74,100	72,000
ERCOT	19,900	18,800	16,100
New York(3)	13,400	13,400	10,500
New England	13,500	14,200	13,800
% of Expected Generation Hedged(5)	97-100%	73-76%	41-44%
Midwest	94-97%	77-80%	44-47%
Mid-Atlantic(2,3)	105-108%	74-77%	45-48%
ERCOT	89-92%	56-59%	34-37%
New York(3)	91-94%	69-72%	20-23%
New England	94-97%	66-69%	27-30%
Effective Realized Energy Price ($/MWh)(6)			
Midwest	$41.00	$39.50	$37.00
Mid-Atlantic(2,3)	$53.00	$49.00	$49.00
ERCOT(7)	$8.50	$6.00	$3.00
New York(3)	$45.00	$37.00	$37.50
New England(7)	$8.00	$8.50	$3.50

(1) Stub period calculated by excluding Jan 2012 thru mid-March 2012 for Constellation only. (2) Excludes Maryland assets to be divested (3) Includes CENG Joint Venture. (4) 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 2012 and 2013 and 11 refueling outages in 2014 at Exelon-operated nuclear plants and Salem but excludes CENG. Expected generation assumes capacity factors of 93.5%, 93.3% and 93.8% in 2012, 2013 and 2014 at Exelon-operated nuclear plants excluding Salem and CENG. These estimates of expected generation in 2012, 2013 and 2014 do not represent guidance or a forecast of future results as Exelon has not completed its planning or optimization processes for those years. (5) 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. Uses expected value on options. (6) 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. (7) Spark spreads shown for ERCOT and New England.

Exelon.

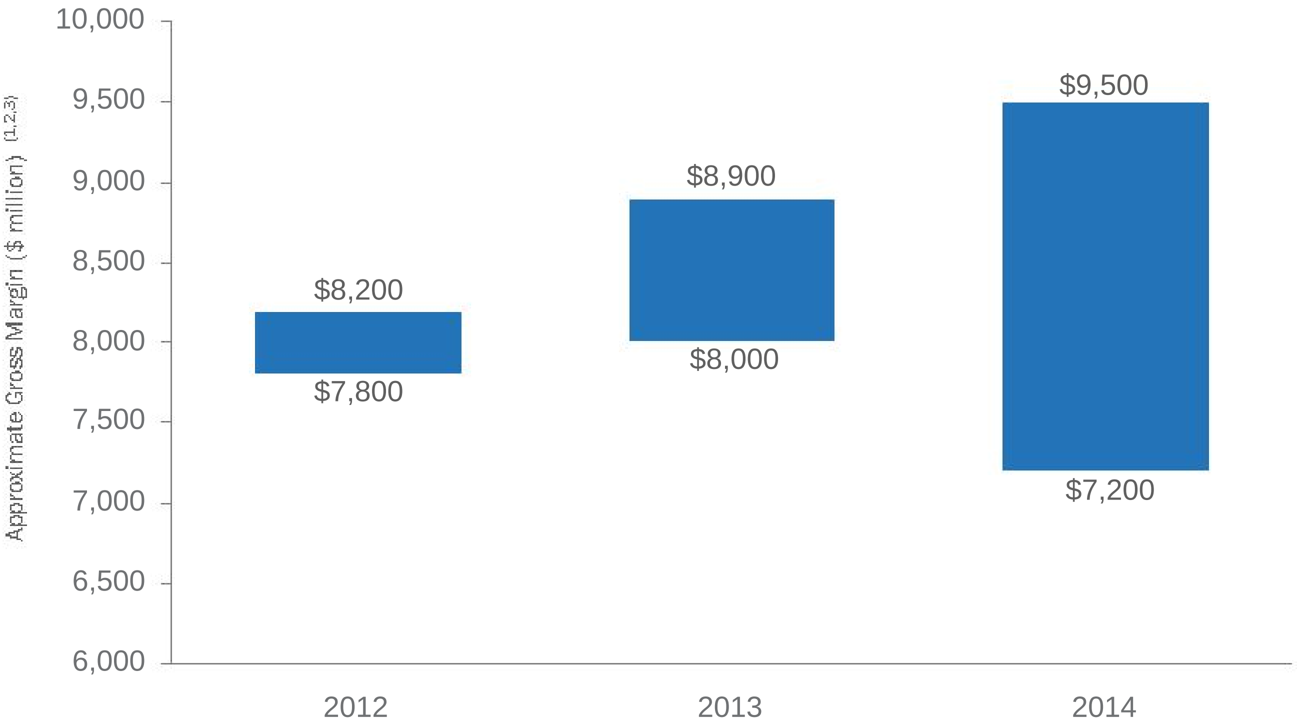
ExGen Hedged Gross Margin Sensitivities

Gross Margin Sensitivities (With Existing Hedges) [1, 4]	2012	2013	2014
Henry Hub Natural Gas ($/MMbtu) [2]			
+ $1/Mmbtu	$(70)	$155	$570
- $1/Mmbtu	$85	$(130)	$(505)
NiHub ATC Energy Price			
+ $5/MWh	$20	$105	$295
- $5/MWh	$(10)	$(105)	$(290)
PJM-W ATC Energy Price [2]			
+ $5/MWh	$(20)	$90	$205
- $5/MWh	$25	$(90)	$(200)
NYPP Zone A ATC Energy Price			
+ $5/MWh	$10	$25	$45
- $5/MWh	$(10)	$(25)	$(45)
Nuclear Capacity Factor [3]			
+/- 1%	+/- $25	+/- $40	+/- $40

(1) Based on April 30, 2012 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. (2) Excludes Maryland assets to be divested. (3) Includes CENG Joint Venture (4) Sensitivities based on commodity exposure which includes open generation and all committed transactions.

Exelon

Exelon Generation 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 2013 and 2014 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 April 30, 2012
(2) Gross Margin Upside/Risk based on commodity exposure which includes open generation and all committed transactions. (3) Excludes Maryland assets to be divested.

Upstream E&P Assets

- Current Portfolio of Investments
  - Mississippi lime (OK)
  - Hunton dewatering (OK)
  - Woodford shale (OK)
  - Eagle Ford shale (TX)
  - Fayetteville shale (AR)
  - Haynesville shale (LA)
  - Floyd shale (AL)
  - Ohio shale (OH)
  - Trenton Black River (MI)

Estimated Net Proved Reserves (as of 12/31/11)	Average Net Daily Production (Q1 2012)
295 Bcfe	67 MMcfe

Forecasted Production

	2012	2013	2014
Net Daily Prod (MMcfe / day)	55 - 70	55 - 70	60 - 75

(1) Oil/NGL conversion to gas is 6:1.
(2) Constellation does not operate any of its properties.

ExGen Disclosures Guide

ExGen Disclosure Overview

Continue to provide transparency in our ExGen disclosures with a modified and expanded framework that incorporates new business lines and regions

- **Maintain ability to value generation fleet on an open and hedged basis**
  - Continue to provide open gross margins, expected generation, hedge %, reference prices and effective realized energy prices (EREP)
  - Also provide Mark-to Market (MtM) value of all hedges on a consolidated basis
- **No separate gross margins for commercial load, but will disclose volume targets and sales execution**
  - Consider retail and wholesale load to be an alternate channel to market our generation. As such, executed sales are regarded as a hedge and thus flow into MtM, EREP and hedge percentage
  - Provide volume targets and track sales execution versus targets on an annual basis
- **Introduction of new gross margin categories**
  - In addition to Open Gross Margin and MtM of hedges, gross margins will be provided for the following categories -
    - Power New Business: Gross margins from future hedging activity via retail, wholesale or structured transaction/mid-marketing activities. Once power sales are executed, these flow into MtM via EREP
    - Non Power New Business: Gross margins from planned sales from business activities not related to hedging power production, such as Load Response, Energy Efficiency, Retail and Wholesale Gas, Proprietary Trading(1) etc. Once sales are executed, gross margins will flow to "Non Power Executed" category.
    - Non Power Executed: Contracted gross margin associated with business activities not directly linked to production or sale of power
- **Introduction of new regions**
  - To reflect our expanded national presence, New England, New York, and South, West & Canada regions have been added to Midwest, Mid-Atlantic and ERCOT
  - Hedged gross margins for South, West & Canada will be included within the consolidated "Open Gross Margin" estimate
  - The other five regions will have corresponding expected generation, hedge %, reference prices and EREP

(1) Proprietary trading gross margins will remain within "Non Power" New Business category and not move to "Non power" executed category.

ExGen Disclosure Overview

Gross Margin Categories ($ MM) For all regions, three years forward	General Description
Open Gross Margin	Value of generation at current market prices, excluding the impact of any near-term hedges
Mark to Market of Hedges	Mark-to-market value of transactions associated with hedging open generation position (power or fuel hedges, including executed retail/wholesale electric load)
Power New Business / To Go	New category of gross margins for future hedging activity via retail, wholesale or structured transaction / mid marketing activities.
Non-Power Margins Executed	New category for contracted gross margin associated with business activities not directly linked to production or sale of power
Non-Power New Business / To Go	New category for gross margins from planned sales from business activities not related to hedging power production
Total Gross Margin	Sum total of each of the five gross margin categories

Generation & Hedges	General Description
Expected Generation (GWh)	Anticipated output from owned or contracted generating capacity
% of Expected Generation Hedged	Physical or financial hedges against power output
Effective Realized Energy Price	Close proxy for the hedged power price or spark, and when used in conjunction with the reference price and hedged MWh yields the MtM of hedges.

Retail & Wholesale Volumes	General Description
Electric load target & contracted volumes	Estimate of load sales target and sales executed from all load channels
Retail gas target	Estimate of gas sales target

Exelon

Components of Gross Margin Categories

Gross margin linked to power production and sales

Gross margin from other business activities

Open Gross Margin	MtM of Hedges[2]	"Power" New Business	"Non Power" Executed	"Non Power" New Business
•Generation Gross Margin at current market prices, including capacity & ancillary revenues •Exploration and Production •PPA Costs & Revenues •Provided at a consolidated level for all regions (includes hedged gross margin for South, West & Canada[1])	•MtM of power, capacity and ancillary hedges, including cross commodity, retail and wholesale load transactions •Provided directly at a consolidated level for five major regions. Provided indirectly for each of the five major regions via EREP, reference price, hedge %, expected generation	•Retail, Wholesale planned electric sales •Portfolio Management new business •Mid marketing new business	•Retail, Wholesale executed gas sales •Load Response •Energy Efficiency •BGE Home •Distributed Solar	•Retail, Wholesale planned gas sales •Load Response •Energy Efficiency •BGE Home •Distributed Solar •Portfolio Management / origination fuels new business •Proprietary trading [3]

Margins move from new business to MtM of hedges over the course of the year as sales are executed

Margins move from "Non power new business" to "Non power executed" over the course of the year

(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 remain within "Non Power" New Business category and not move to "Non power" executed category.

Exelon

Illustrative Example of Modeling Exelon Generation 2013 Gross Margin

Row	Item	Midwest	Mid-Atlantic	ERCOT	New England	New York	South, West & Canada
(A)	Start with fleet-wide open gross margin	$5.8 billion					
(B)	Expected Generation (TWh)	97.9	74.1	18.8	13.4	14.2	
(C)	Hedge % (assuming mid-point of range)	78.5%	75.5%	57.5%	70.5%	67.5%	
(D=B*C)	Hedged Volume (TWh)	76.9	55.9	10.8	9.4	9.6	
(E)	Effective Realized Energy Price ($/MWh)	$39.50	$49.00	$6.00	$37.00	$8.50	
(F)	Reference Price ($/MWh)	$30.28	$37.93	$9.19	$31.40	$4.66	
(G=E-F)	Difference ($/MWh)	$9.22	$11.07	($3.19)	$5.60	$3.84	
(H=D*G)	Mark-to-market value of hedges ($ million) (1)	$715 million	$625 million	($35) million	$55 million	$40 million	
(I=A+H)	Hedged Gross Margin ($ million)	$7,200 million					
(J)	Power New Business / To Go ($ million)	$550 million					
(K)	Non-Power Margins Executed ($ million)	$100 million					
(L)	Non-Power New Business / To Go ($ million)	$500 million					
(N=I+J+K+L)	Total Gross Margin	$8,350 million					

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

Exelon.

Constellation Energy Nuclear Group (CENG) Background

As a result of Exelon's equity interest in CENG, PPA contracts between CENG and 3rd parties and the PPA between CENG and ExGen, some background on CENG and how CENG gross margins and earnings are reflected in ExGen disclosures and other financial statements.

	Calvert 1&2	NMP 1	NMP 2 (1)	Ginna(2)	
Ownership Interest					
Total Plant Capacity	1, 750 MW	620 MW	1,138 MW	581 MW	
Ownership Split	100% CENG	100% CENG	82% CENG / 18% LIPA	100% CENG	
ExGen Ownership (50.01% of CENG)	875 MW	310 MW	466.5 MW	290.5 MW	
PPA structure (% output)					
CENG Legacy PPA with Utilities	-	-	See footnote 1	90% < June 2014	0% > June 2014
CENG PPA with Parents	100%	100%	100%	10% < June 2014	100% > June 2014

CENG PPA with Parents				
5 year contract extendable at end of each year for additional year - Market based pricing and monthly, rolling 3 year hedge profile (100%, 60%, 30%)				
	2012	**2013**	**2014**	**2015**
(% of uncommitted output)				
EDF Trading	15	15	15	N.A.
ExGen	85	85	85	N.A.

(1) Nine Mile Point 2 (NMP) has a revenue sharing agreement (via a call option type contract) on 80% of the output.
(2) Ginna Legacy PPA at $44/MWh; CENG PPA with parents (ExGen, EDF) at close to market prices and designed to maintain a monthly ratable profile for CENG.

Constellation Energy Nuclear Group (CENG) Background

ExGen Disclosures
Forward Estimates

- ExGen forward disclosures reflect the gross position that accrues to ExGen from ownership interest in CENG and PPA with CENG as of a certain date
- Open Gross Margin: Reflects proportionate share of CENG revenues and fuel costs, market value of PPA less PPA costs paid by ExGen to CENG
- MtM of Hedges: Reflects MtM of any hedges placed by ExGen for managing position arising from ownership interests or PPAs with CENG
- Expected Generation: Reflects proportionate ownership in CENG and generation associated with PPA between CENG and ExGen.
- Hedge Percentage: Reflects hedges placed by ExGen to hedge exposure arising from CENG position (owned or contracted)
- Effective Realized Energy Price: Reflects MtM and hedges from CENG position (owned or contracted)

Financial Statements
(10-Q, 10-K, Earnings Release tables)
Actuals

- ExGen actuals reflect equity method accounting treatment for ownership interest in CENG and regular treatment for PPA between ExGen and CENG.
- RnF: Includes net PPA gross margin (revenues less costs) between ExGen and CENG. CENG earnings or gross margin are not included, and are instead shown under "CENG equity earnings" on the income statement.
- Total Supply: Includes only the generation corresponding to the PPA between ExGen and CENG.
- Average Margins ($/MWh): Includes only margins corresponding to PPA between ExGen and CENG as well as any hedges placed by ExGen

Competitive Markets

Bill Von Hoene
Senior EVP & Chief Strategy Officer

Exelon.

Drive Competition and Choice

We believe in the value competitive energy markets bring to our customers via choice, innovation and savings

Retail Markets	Wholesale Markets
Perfect Core Markets Support continued growth of competitive retail choice for energy and services in restructured states	Support Transparent Pricing Mechanisms Promote the establishment of market rules that provide transparent price signals for energy and capacity and allow a level playing field for all providers to compete
Defend Open Markets Oppose and defeat efforts to limit competitive retail choice for energy and services	Defend Well Functioning Wholesale Markets Oppose government mandates to subsidize unneeded, uneconomic generation. Challenge illegalities of legislative or regulatory construct and strengthen mitigation measures via FERC (e.g. MOPR)
Expand into Restricted or Closed Markets Enable competitive retail choice for energy & services in states that limit or are closed to competition	

We champion competitive energy markets to empower our customers and enhance value for our shareholders

Exelon.

Perfecting Existing Retail Energy Markets

Illinois

- Opportunity to offer savings for residential class continues to support switching
  - 56% of eligible Illinois load is served by competitive suppliers
  - Over 200 communities approved ballot measures to allow municipal aggregation
  - Increased consumer protection encourages residential consumers to pursue retail supply

Pennsylvania

- PAPUC moving steadily toward a fully competitive end state
  - 60% of eligible Pennsylvania load is served by competitive suppliers
  - Retail markets assessment targeting improvements to retail market
  - Reforms of default service likely to stimulate retail shopping

Maryland

- Exelon looking to build partnership with Maryland energy stakeholders
  - 56% of eligible Maryland load is served by competitive suppliers
  - Web portal for residential electricity price comparison

Texas

- Steadfast commitment to retail competition
  - Market volatility creates opportunities for risk management and enhanced products and services
  - High penetration of smart meter installation and state-wide, standardized customer data interface creates opportunities for increased products and services

Core retail markets are adopting continuous improvements to enhance shopping and expand customer experience

Note: PAPUC = Pennsylvania Public Utility Commission; AMI = Advanced Metering Infrastructure.

Exelon

Defense of Competitive Markets

Our regulatory advocacy efforts are designed to improve the functioning of competitive markets where they exist and protect against attempts to undermine price signals

- We participate in, or if necessary initiate, proceedings at FERC and at state commissions to protect the efficient functioning of wholesale and retail markets and thwart attempts to undermine price signals
  - A current example is our efforts to defend forward capacity markets in PJM from the exercise of buyer market power by states and load interests
- A key component of energy market regulation is the principle of comparability; all resources, whether existing, new, renewable, fossil or nuclear, should have a level playing field and the ability to compete on a best price basis. Supply and demand resources should be expected to meet the same performance criteria if they receive the same compensation
- Transmission is a critical element of wholesale market liquidity, so we seek to develop or facilitate the development of transmission upgrades that reduce congestion around our assets
- We utilize public messaging and are active in coalitions such as COMPETE to inform consumers of the value of competition

We actively seek opportunities to preserve the integrity of competitive markets

Opportunities to Expand Competitive Retail Energy Markets

Arizona

- Considering opening the market to retail choice
  - Customer/supplier advocacy efforts to encourage policymakers and commission to take action to re-open retail shopping
  - Recent rate case settlement includes pilot shopping program

California

- Increase existing Direct Access Cap
  - Existing program fully subscribed
  - Incremental shopping eligibility fills within seconds
  - Exit fees remain a challenge
  - Community Choice Aggregation still an option

Michigan

- Increase or remove existing 10% electric choice cap and enable more customers to select their provider of choice
  - Current program is fully subscribed
  - Legislation introduced to raise shopping cap to 19% to accommodate current waiting list

Ohio

- Significant improvement in retail competition with the changes in the Electric Security Plan to phase-in competition but there is room for further enhancements
  - 50% of eligible Ohio load is served by competitive suppliers
  - Outlook suggests competitive solicitations for utility standard service offer
  - Utilities moving assets to participate in PJM RPM market

There is a growing interest to open or expand competition in markets with restricted or non-existent retail choice

Exelon.

Asset Divestiture Update

Brandon Shores

- 1,273 MW capacity
- 2 unit coal plant

H.A. Wagner

- 976 MW capacity
- 5 unit coal/oil/gas plant

C.P. Crane

- 399 MW capacity
- 3 unit coal/oil plant

- Maryland assets to be divested are an attractive investment for potential buyers
  - Plants are well-positioned to comply with Air Toxics Standards and Cross-State Air Pollution Rule (CSAPR)
  - Located in Southwestern MAAC region, an attractive region within PJM
  - Near major urban centers with stable demand

Executed purchase and sale agreement expected by August 2012

Exelon.

Exelon Utilities

Denis O’Brien
Senior EVP of Exelon and
CEO of Exelon Utilities

Exelon Utilities – Leveraging Operational Expertise

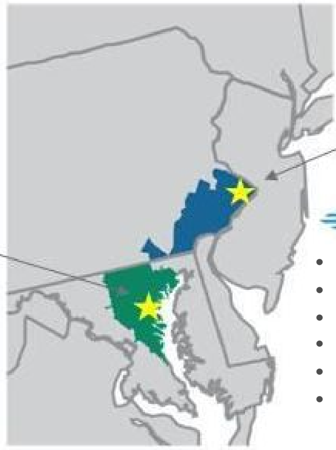
Achieving best-in-class performance:
- Set a strategic direction to be among the best
- Ensure that each utility performs to the highest standards
- Drive for standardization and sharing of best practices
- Realize merger synergies across the utilities

Chicago, Illinois

ComEd
- 2011 Revenues: $6.1B
- Employees: ~5,800
- Electric customers: 3.8 million
- Service Territory: 11,300 square miles
- All-Time Peak Load: 23,753 MW

BGE
- 2011 Revenues: $3.0B
- Employees: ~3,400
- Electric customers: 1.2 million
- Gas customers: 0.7 million
- Service Territory: 2,300 square miles
- All-Time Peak Load: 7,616 MW

Baltimore, Maryland



Philadelphia, Pennsylvania

PECO
- 2011 Revenues: $3.7B
- Employees: ~2,400
- Electric customers: 1.6 million
- Gas customers: 0.5 million
- Service Territory: 2,100 square miles
- All-Time Peak Load: 8,983 MW

Exelon Utilities will deliver best-in-class operational and financial performance, creating greater value for our stakeholders

Exelon

ComEd –Growth through Investment that Benefits Customers

Energy Infrastructure Modernization Act (EIMA)

- Driving investment in electricity infrastructure and smart meter/smart grid
  - $2.6B over 10 years
- Making investments that benefit customers
  - Smart meters
  - Distributed automation
  - Storm hardening
- Monitoring performance standards and metrics
- Providing for returns on investment
  - Performance-based distribution formula rate recovery

Formula Rate Process

Distribution:

- Nov. 2011 initial filing (2010 calendar year + 2011 net plant additions) proposed $59M decrease in revenue requirement
  - 10.05% ROE (12-month average of the 30-year US Treasury yield plus 580 basis point risk premium)
  - May 2012 ICC ordered $168M decrease
- April 2012 first annual update (2011 calendar year + 2012 net plant additions) and 2011 reconciliation filing; rates effective following January

Transmission:

- Latest annual formula rate update filed in May 2012, increased revenue requirement ~$23M
- Rates effective June 2012
- FERC approved 11.50% ROE

Economic Development Initiatives

- Illinois Economic Development Corporation Act introduced to form public-private partnership supporting business expansion and creating jobs
- ComEd's Economic Development team targeting new facilities in northern Illinois, including expansion of data centers, warehouses and manufacturing

Transmission Growth

- Several upgrade projects planned
  - Burnham to Taylor lines will reinforce transmission system and increase capacity to reliably serve the Chicago southern business district
  - Capital spend estimated at ~$150M
  - In-service date planned for June 2014

Driving innovative legislative and regulatory policy to benefit customers, improve ratemaking process transparency and enable economic development

Note: ICC = Illinois Commerce Commission; FERC = Federal Energy Regulatory Commission

Exelon.

PECO – Competitive Market Initiatives

Alternative Ratemaking

- Newly enacted Act 11 (HB 1294) provides a distribution system improvement charge (DSIC) to support electric and gas infrastructure investment
  - Provision for use of fully projected future test year in rate cases
  - Requires submission of long-term infrastructure improvement plan
  - DSIC capped at 5% of distribution rates
  - PAPUC DSIC rulemaking underway

Rate Case Update

Distribution:

- In Dec. 2010, PAPUC approved settlement of electric and gas rate cases; no allowed ROE specified
- Increase in annual service revenue of $225M for electric and $20M for gas effective 1/1/11
- No rate cases currently planned; timing of future filings will depend on load and expense forecasts and implementation of DSIC

Electricity Supply Procurement

- PAPUC-approved Default Service Plan (DSP) Program has 29-mo. term that ends 5/31/13
- PECO filed second DSP outlining plan from 6/1/13 through 5/31/15
- As of May 2012, ~28% of total retail customers purchased energy from alternative suppliers, representing ~60% of load
- PAPUC evaluating alternative default service models to enhance competition

Growth Initiatives

- Executing $650M Smart Grid investment plan with surcharge recovery for AMI costs
- Support potential sales and repurposing of oil refineries
- Convert oil and propane usage to natural gas
- Enhance economic development outreach

Supporting competitive procurement markets and evaluating longer-term opportunities of Act 11

Note: PAPUC = Pennsylvania Public Utility Commission; AMI = Advanced Metering Infrastructure

Exelon.

BGE –Fulfilling Commitments

Commitments to Maryland

- Reinforced ring fencing
- Maintaining employment and minimum O&M/capital spending levels for 2 years
- Rate credit of $100 per residential customer provided in May/June 2012
- $113.5M customer investment fund
  - First contribution to fund within 90 days from merger close
  - MD Public Service Commission (MDPSC) set June 15 deadline for parties to submit preliminary proposals for allocating fund

Rate Case Update

Distribution:

- Last electric and gas rate cases filed 5/7/10
- MDPSC approved $31M electric revenue increase with 9.86% ROE and $10M gas increase with 9.56% ROE
- New rates effective December 2010
- Plan to file electric and gas cases in 2nd half of 2012 with rates effective no more than 210 days after filing

Transmission:

- Latest annual formula rate update filed in April 2012, increased revenue requirement ~$18M
- Rates effective June 2012
- FERC approved 11.3% ROE

MDPSC Service Quality and Reliability Regulations

- Effective regulations establish standards in a variety of service quality and reliability areas
- Actions expected to add incremental costs beginning in 2012 to achieve compliance and enhance system reliability and customer satisfaction

Transmission Growth

- Transmission-related capital spend expected to total ~$690M through 2016
  - Majority of spend (~$450M) related to RTEP-mandated projects for system upgrades and enhancements

Fulfilling commitments to stakeholders with continued focus on safety and reliability

Note: RTEP = PJM's Regional Transmission Expansion Plan

Smart Meter / Smart Grid Update

ComEd will invest ~$1.3B over the next 10 years

- Installation of nearly 4M smart electric meters to begin Q4 2012
- Smart Grid program to include distribution automation device installations and substation modernization upgrades
- ComEd Innovation Corridor will provide a "Test Bed" for smart grid technologies to be demonstrated within a utility scale environment
- Investment recovered through formula rate beginning with May 2012 filing

PECO will invest up to $650M through 2014

- Installation of more than 1.8M smart electric meters began Q1 2012
- Plans to file request with PAPUC to accelerate deployment completion by 2014
- Awarded $200M under the DOE program[1], lowering net cost to customers to ~$450M
- Investment recovered through surcharge mechanism with 10% ROE

BGE will invest up to $500M through 2015

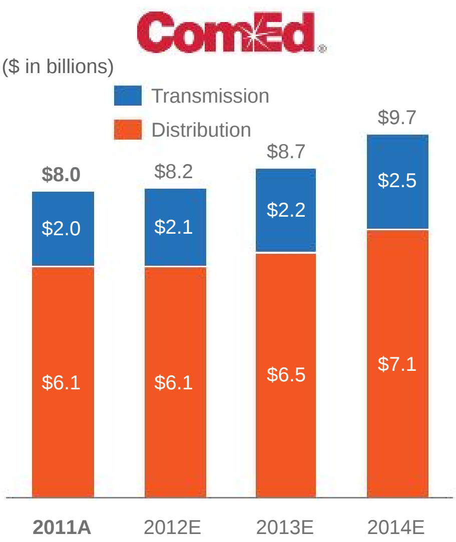
- Installation of 2M smart electric and gas meters began in April 2012
- A customer web portal and dynamic pricing (Peak Time Rebates) as the default tariff
- Awarded $200M under the DOE program[1], lowering net cost to customers to ~$300M
- Cost recovery on project pending until cost-effectiveness showing at the end of deployment

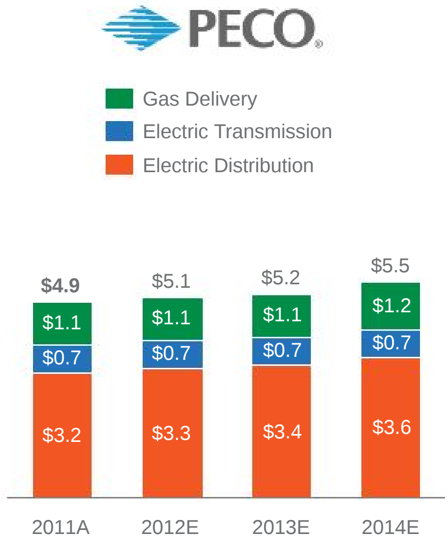
Investments will provide customer operational and reliability benefits

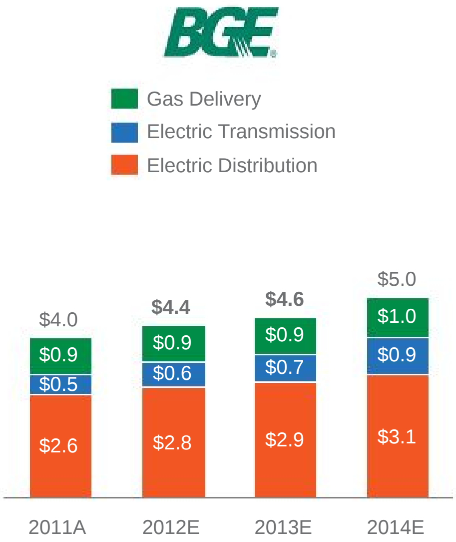
(1) The $200M DOE grant was the maximum allowable under the Smart Grid Investment Grant Program.
Note: ComEd program may be reevaluated given recent ICC rate order.

Rate Base and ROE Targets

($ in billions)







	2012E	Long-Term Target
Equity Ratio	~45%	~53%(1)
Earned ROE	6 - 7%	Based on 30-yr. US Treasury(2)

	2012E	Long-Term Target
Equity Ratio	~56%	~53%
Earned ROE	11 - 12%	≥ 10%

	2012E	Long-Term Target
Equity Ratio	~48%	~53%(3)
Earned ROE	5 - 6%	≥10%

Smart meter and smart grid investment will be a key driver of rate base growth

(1) Equity component for distribution rates will be the actual capital structure adjusted for goodwill.
(2) Earned ROE will reflect the weighted average of 11.5% allowed transmission ROE and distribution ROE resulting from 30-year Treasury plus 580 basis points for each calendar year.
(3) Per MDPSC merger commitment, BGE is precluded from paying dividends through 2014. Per MDPSC orders, BGE cannot pay out a dividend to its parent company if said dividend would cause BGE's equity ratio to fall below 48%.
Note: ComEd distribution rate base represents an average and transmission rate base represents end of year; PECO rate base represents end-of-year; and BGE rate base represents a trailing 13-month average. Numbers may not add due to rounding.

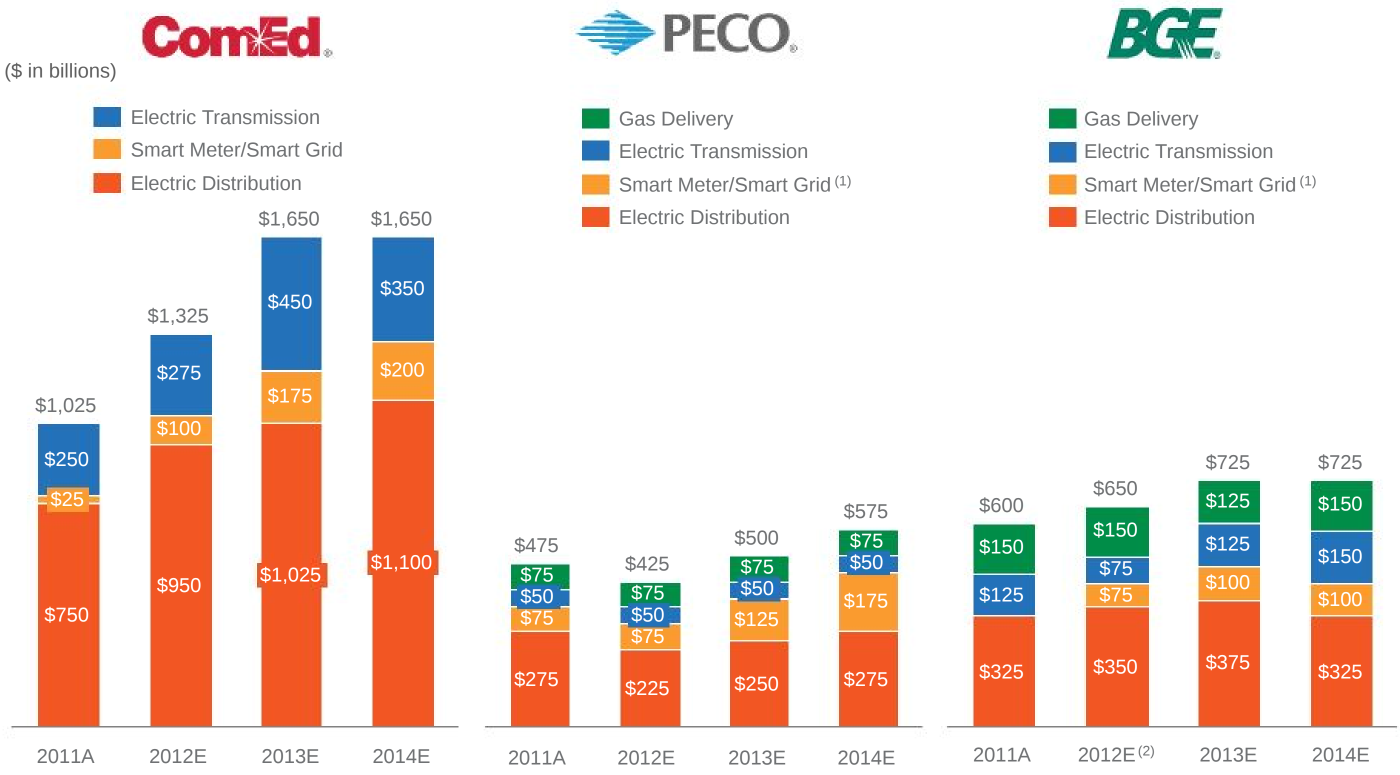
Exelon Utilities

- Operational Excellence
  - Achieve top decile safety and top quartile reliability performance
  - Enhance customer satisfaction experience
  - Drive continuous cost management and productivity focus
- Regulatory and Legislative Stewardship
  - Support competitive supply procurements
  - Invest in smart meter/smart grid infrastructure
  - Secure constructive rate recovery
- Financial Discipline
  - Maintain strong investment grade credit ratings
  - Obtain appropriate allowed ROEs
  - Target long-term earned ROEs close to allowed

Exelon Utilities will provide opportunities to leverage scale and expertise to achieve improved operational and financial results

Appendix

Capital Expenditures

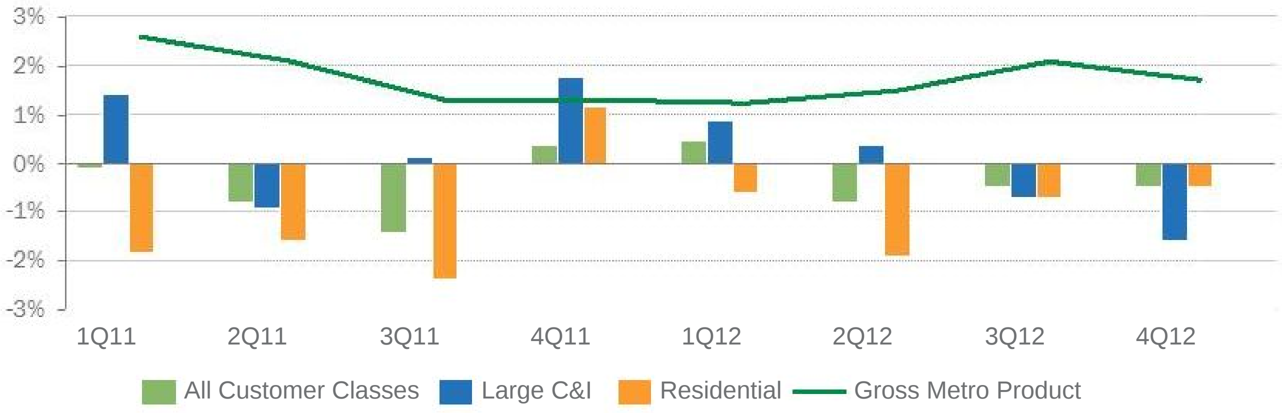


(1) Smart Meter/Smart Grid CapEx net of proceeds from U.S. Department of Energy (DOE) grant. For BGE, includes CapEx from Smart Energy Savers program of ~$10M per year.
(2) Represents 2012 full year CapEx; estimated 2012 CapEx from merger close date totals $550M.

Exelon.

ComEd Load Trends

Weather-Normalized Electric Load Year-over-Year



Key Economic Indicators

	Chicago	U.S.
Unemployment rate[1]	8.6%	8.1%
2012 annualized growth in gross domestic/metro product[2]	1.6%	2.1%

(1) Source: US Dept. of Labor (April 2012) and Illinois Department of Security (April 2012)
(2) Source: Global Insight (February 2012)
(3) Not adjusted for leap year

Weather-Normalized Electric Load

	2011	1Q12	2012E[3]
Average Customer Growth	0.4%	0.3%	0.4%
Average Use-Per-Customer	(1.7)%	(0.9)%	(1.3)%
Total Residential	(1.3)%	(0.6)%	(0.9)%
Small C&I	(0.8)%	1.1%	(0.1)%
Large C&I	0.6%	0.9%	(0.3)%
All Customer Classes	(0.5)%	0.5%	(0.3)%

Note: C&I = Commercial & Industrial

Exelon.

ComEd Distribution Formula Rate Plan

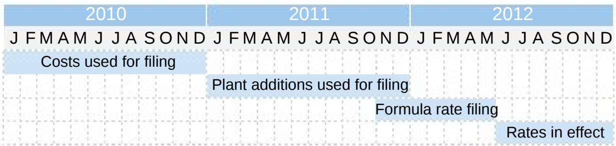
Summary of Filings

2011 Formula Rate Filing (Docket # 11-0721 filed 11/8/11; rates eff. June 2012):

- Based on 2010 calendar year costs and 2011 net plant additions
- Supported $59M distribution revenue requirement reduction
- 10.05% ROE (2010 Treasury yield of 4.25% + 580 basis point risk premium)

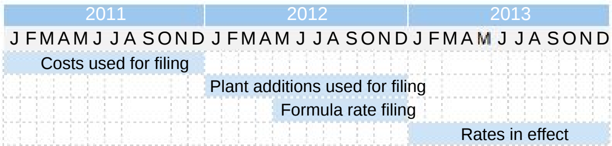
ICC Final Order (issued 5/30/12):

- $168 revenue requirement reduction; incremental reduction includes:
  - ~$50M related to costs ICC determined should be recovered through alternative rate recovery tariffs or reflected in reconciliation proceeding; primarily delays timing of cash flows
  - ~$35M reflects disallowance of return on pension asset
  - ~$10M reflects incentive compensation related adjustments
  - ~$15M reflects various adjustments for cash working capital, operating reserves and other technical items



2012 Formula Rate Filing (Docket # 12-0321 filed 4/30/12)

- 2012 plan year based on 2011 actual costs and 2012 net plant additions
  - 9.71% ROE (2011 Treasury yield of 3.91% + 580 basis point risk premium)
- Reconciled 2011 revenue requirements in effect to 2011 actual costs incurred
  - 9.81% ROE (3.91% plus 590 basis point risk premium)(1)
- Supported $106M distribution revenue requirement increase relative to Dec. 2012 rates as ComEd initially proposed (Revenue requirement and relative increase will be updated to reflect 11-0721 rate order)
- ICC order by year end; rates effective January 2013



Financial Statement Impacts of Formula Rate Process

Income Statement:

- Revenues are based on forecasted calendar year revenue requirement and are accrued and recorded monthly

Cash Flow:

- Rate adjustments become effective two years after costs are incurred (one year for net plant additions and depreciation expense)
  - Rate adjustment intended to reconcile revenue requirement and actual costs incurred
  - Adjustment for 2011 costs incurred (April 30, 2012 filing) will take effect January 2013
  - Adjustment for 2012 costs incurred (Spring 2013 filing) will take effect January 2014

Balance Sheet:

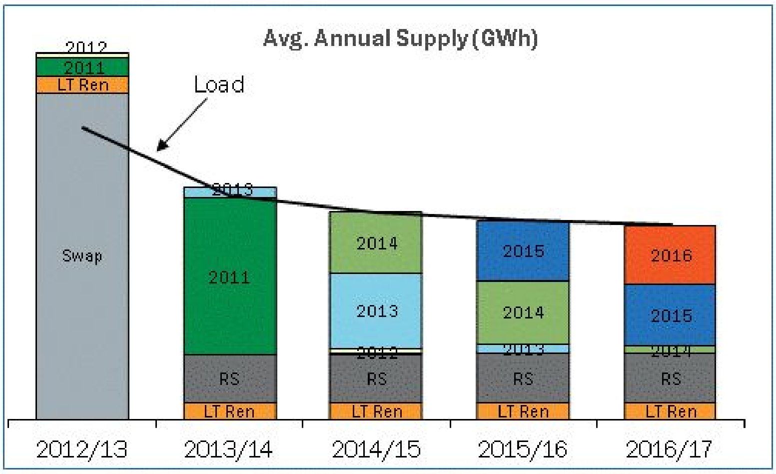
- A regulatory asset is recorded (with interest) to reflect the difference between revenue recognized and revenue billed

(1) 590 basis point premium applies only to 2011 revenue reconciliation. All subsequent revenue reconciliations will assume a 580 basis point premium.

Exelon.

Illinois Power Agency (IPA) RFP Procurement

- Results of Rate Stability Standard Product Procurements held February 2012:
  - Effective ATC of $32.57/MWh for 3 winning Standard Product suppliers for the 2013-14 plan-year.
  - Prices increase 2.5% annually beginning 6/1/14
  - Contracts are for 450MW ATC through 12/31/17
- Results of REC Rate Stability Procurement held February 2012:
  - Procured 2.7M RECs through December 2017
  - Included solar, wind and other qualified renewables
  - Average price = $1.67/REC
- Results of Spring Standard Product Procurement held April 2012:
  - 4 winning Standard Product suppliers for modest volumes within the 2012/13 and 2014/15 plan-years
- Results of Spring REC Procurement held May 2012:
  - Procured 1.3M RECs
  - Included wind and other qualified renewables
  - Average price = $0.88/REC



Note: Chart is for illustrative purposes only.
ATC = around-the-clock; REC = renewable energy credit; LT Ren = long-term renewable energy; RS = rate stability

Financial Swap Agreement with ExGen

(ATC baseload energy -notional quantity 3,000 MW)

Term	Fixed Price ($/MWh)
1/1/12-12/31/12	$52.37
1/1/13-5/31/13	$53.48

	Volume procured in 2011 IPA Procurement (GWh)	
Delivery Period	Peak	Off-Peak
June 2011 - May 2012	5,118	4,001
June 2012 - May 2013	1,129	358
June 2013 - May 2014	6,494	6,062

	Volume procured in Spring 2012 IPA Procurement (GWh)	
Delivery Period	Peak	Off-Peak
June 2012 - May 2013	235	176
June 2013 - May 2014	0	0
June 2014 - May 2015	308	60

Exelon.

PECO Load Trends

Weather-Normalized Electric Load Year-over-Year

Key Economic Indicators

	Philadelphia	U.S.
Unemployment rate(1)	8.1%	8.1%
2012 annualized growth in gross domestic/metro product(2)	1.6%	2.1%

(1) Source: US Dept. of Labor data (April 2012) – US
US Dept. of Labor prelim. data (March 2012) – Philadelphia
(2) Source: Global Insight (February 2012)
(3) Not adjusted for leap year

Weather-Normalized Electric Load

	2011	1Q12	2012E(3)
Average Customer Growth	0.3%	0.5%	0.6%
Average Use-Per-Customer	1.3%	(2.9)%	(2.5)%
Total Residential	1.7%	(2.5)%	(1.9)%
Small C&I	(0.7)%	(4.9)%	(2.7)%
Large C&I	(3.3)%	(1.8)%	(5.6)%
All Customer Classes	(0.9)%	(2.7)%	(3.3)%

Note: C&I = Commercial & Industrial

Oil refinery closing estimated direct impact to reduce Large C&I and total load in 2012 by 4.9% and 2.0%, respectively

PECO – Default Service Plan Filing (DSP II)

- On 1/13/12, PECO filed a new Default Service Plan with the PAPUC, which outlines how PECO will purchase electricity for customers not purchasing from a competitive generation supplier from 6/1/13 through 5/31/15
- A PAPUC order on the filing is expected in mid-October 2012

	Proposed Procurement Mix	
Class	DSP I (1/1/11 – 5/31/13)	DSP II (6/1/13 – 5/31/15)
Large C&I Current load retained: 4%	• 100% spot-priced FR[1] products • 2011 opt-in FPFR[2] product	• 100% of supply procured directly from the PJM spot market
Medium Commercial Current load retained: 18%	• 85% 1-year FPFR products, 15% spot-priced FR products	• 100% 6-month FPFR products
Small Commercial Current load retained: 44%	• 70% 1-year FPFR products, 20% 2-year FPFR products, 10% spot-priced FR products	• 100% 1-year FPFR products
Residential Current load retained: 73%	• 45% 2-year FPFR products; 30% 1-year FPFR products; targeted 20% block products of 1-yr, 2-yr, 5-yr and seasonal terms; targeted 5% spot market purchases	• As block products expire, block and spot is replaced by FPFR products with terms ending 5/31/15 (end of DSP II period) • Remainder of portfolio is a mix of 2-yr and 1-yr FPFR products, with delivery periods overlapping on a semi-annual basis

Incorporates Retail Market Enhancements suggested by PAPUC Order issued 12/15/11:

- Offers a 6-month opt-in auction program with price at least 5% less than PECO's expected Price to Compare (PTC) as of 6/1/13
- Establishes a residential customer referral program for 1-year, fixed price at least 7% below PECO PTC
- Provides customer information and referral programs for various products; "seamless" moves between properties

(1) FR = Full Requirements;
(2) FPFR = Fixed-Price Full Requirements
Retention as of: May 22, 2012

BGE Load Trends

Weather-Normalized Electric Load Year-over-Year

Key Economic Indicators

	Baltimore	U.S.
Unemployment rate(1)	7.1%	8.1%
2012 annualized growth in gross domestic/metro product(2)	1.6%	2.1%

(1) Source: US Dept. of Labor data (April 2012) – US
US Dept. of Labor prelim. data (March 2012) – Baltimore
(2) Source: Global Insight (February 2012) – US
Moody's Analytics (February 2012) – Baltimore
(3) Not adjusted for leap year

Weather-Normalized Electric Load

	2011	1Q12	2012E(3)
Average Customer Growth	0.2%	0.0%	0.4%
Average Use-Per-Customer	(4.4)%	0.4%	0.0%
Total Residential	(4.3)%	0.4%	0.3%
Small C&I	0.8%	(8.3)%	(0.7)%
Large C&I	2.0%	(0.5)%	0.9%
All Customer Classes	(1.1)%	0.3%	0.7%

Note: C&I = Commercial & Industrial

Note: As approved by the MDPSC, BGE records a monthly adjustment to residential and the majority of its commercial and industrial customers to eliminate the effect of abnormal weather and usage patterns per customer on distribution volumes, thereby recovering a specified dollar amount of distribution revenues per customer, by customer class, regardless of changes in consumption levels. Therefore, while these revenues are affected by customer growth, they will not be affected by actual weather or usage conditions.

BGE –Standard Offer Service

- BGE provides Standard Offer Service (SOS) as fixed seasonal rates for those electric customers who are not shopping. The costs of providing this service are recovered from customers via an Administrative Charge included in the SOS rate. The Administrative Charge and the Energy & Transmission components of the SOS Rate are subject to periodic true-ups. BGE procures the majority of energy for this product via Full Requirements load auctions as ordered by the MDPSC. See table below:

	Procurement Mix	
Class	6/1/11 – 5/31/12	6/1/12 – 5/31/13
Large C&I (Hourly) Current load retained: 5%	• 100% of supply procured directly from the PJM spot market	• 100% of supply procured directly from the PJM spot market
Medium Commercial (Type II) Current load retained: 28%	• 100% 3-month FPFR[1] products • Auction Apr '11 for Jun '11 –Aug '11 • Auction Jun '11 for Sep '11 –Nov '11 • Auction Oct '11 for Dec '11 –Feb '12 • Auction Jan '12 for Mar '12 –May '12	• 100% 3-month FPFR products • Auction Apr '12 for Jun '12 –Aug '12 • Auction Jun '12 for Sep '12 –Nov '12 • Auction Oct '12 for Dec '12 –Feb '13 • Auction Jan '13 for Mar '13 –May '13
Small Commercial (Type I) Current load retained: 63%	• 25% 2-year FPFR products • Auction Apr '09 for Oct '09 –Sep '11 • Auction Oct '09 for Jun '10 –May '12 • Auction Apr '10 for Oct '10 –Sep '12 • Auction Oct '10 for Jun '11 –May '13 • Auction Apr '11 for Oct '11 –Sep '13	• 25% 2-year FPFR products • Auction Apr '10 for Oct '10 –Sep '12 • Auction Oct '10 for Jun '11 –May '13 • Auction Apr '11 for Oct '11 –Sep '13 • Auction Oct '11 for Jun '12 –May '14 • Auction Apr '12 for Oct '12 –Sep '14
Residential Current load retained: 75%	• 25% 2-year FPFR products • Auction Apr '09 for Oct '09 –Sep '11 • Auction Oct '09 for Jun '10 –May '12 • Auction Apr '10 for Oct '10 –Sep '12 • Auction Oct '10 for Jun '11 –May '13 • Auction Apr '11 for Oct '11 –Sep '13	• 25% 2-year FPFR products • Auction Apr '10 for Oct '10 –Sep '12 • Auction Oct '10 for Jun '11 –May '13 • Auction Apr '11 for Oct '11 –Sep '13 • Auction Oct '11 for Jun '12 –May '14 • Auction Apr '12 for Oct '12 –Sep '14

(1) FPFR = Fixed-Price Full Requirements
Retention as of: February 2012

Regulatory Schedule

2012	Q1	Q2	Q3	Q4	2013
ComEd Distribution Formula Rate		Proposed order for initial filing (5/1); Final order (issued 5/30); rates effective June thru Dec. First annual update and reconciliation filing (4/30)		Final order (by 12/27)	Rates effective Jan. thru Dec.
Illinois Power Agency Procurement	Procurements for ATC supply and RECs for 6/1/13-12/31/17 (Feb.)	Regular annual procurement event (April)			
ComEd Transmission Rate Update		Annual update filing with FERC (5/15); rates effective June 2012 thru May 2013			
PECO Supply Procurement		Procure DSP I residential block supply (April)	Procure DSP I residential block supply (September)	Final DSP II order (mid-October)	
PECO DSIC Filing					DSIC filing (tentative)
BGE Distribution Rates			File case with MDPSC (2^{nd} half of 2012)		MDPSC order due 210 days after filing
BGE Transmission Rate Update		Annual update filing with FERC (4/24); rates effective June 2012 thru May 2013			
BGE Supply Procurement		Regular procurement event (April & June)		Regular procurement event (October)	

Exelon.

Energy Efficiency Progress

ComEd – Illinois

- Annual savings requirement 0.8% of energy deliveries for year ended 5/31/12; increases annually to 2.0% beginning 6/1/15 and each year thereafter, subject to spending cap of ~2% of revenues
- EIMA created process that would allow spending above cap for incremental cost-effective EE approved by the IPA and ICC
- Achieved annual savings goal in each of the first three years and is projected to achieve goal in year four
- Recovery of EE/DR program costs approved by ICC

PECO – Pennsylvania

- Electric consumption required to be reduced by 1% and 3% by 5/31/11 and 5/31/13, respectively (vs. 6/09–5/10 baseline)
- Exceeded 1% energy use reduction target and is projected to achieve 3% goal in Q4 2012
- Since program inception, more than 1 million MWh energy reduced and less than 50% of budget target spent
- Recovery of EE/DR program costs approved by PAPUC

BGE – Maryland

- EmPOWER MD statute 15% by 2015 (vs. 2007 baseline); most ambitious targets of any state
- Making good progress to achieving demand reduction and toward energy targets, with further potential from smart grid and recent program filings
- Revenue decoupling mechanism implemented to mitigate impact of declines in customer consumption
- Recovery of EE/DR program costs approved by MDPSC

Note: EE = energy efficiency; DR = demand response

Generation Overview

Chip Pardee

SVP and Chief Operating Officer of Exelon Generation

Exelon Generation Fleet

National Scope

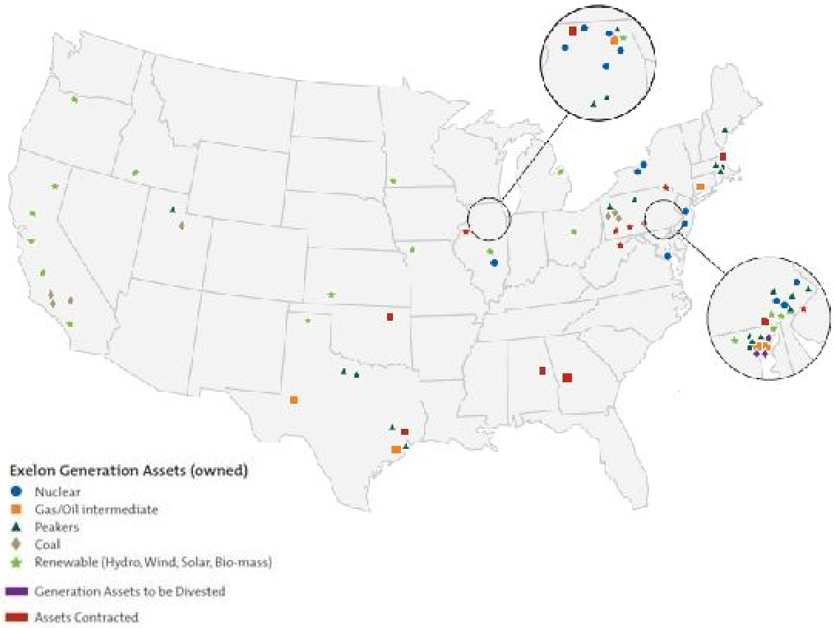
- Power generation assets in 20 states and Canada

Large and Diverse

- 35 GW of diverse generation[1]
  - 19 GW of Nuclear
  - 10 GW of Gas
  - 2 GW of Hydro
  - 2 GW of Oil
  - 1 GW of Coal
  - 1 GW of Wind/Solar/Other

Clean

- One of nation's cleanest fleets as measured by CO2, SO2 and NOx intensity



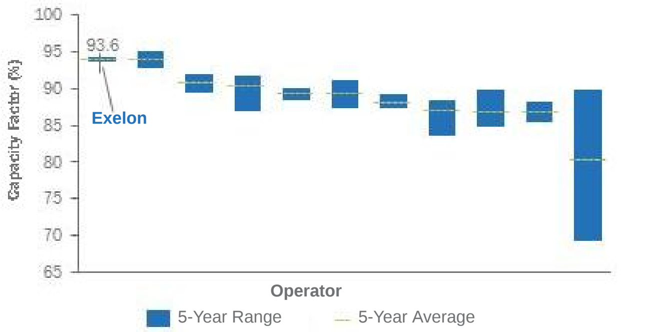
Generation fleet uniquely diversified across regions and technologies

(1) Total owned generation capacity as of 4/30/2012 for legacy Exelon and legacy Constellation combined, net of physical market mitigation assumed to be 2,648 MW. Nuclear capacity reflects EXC ownership of CENG and Salem. Coal capacity shown does not include Eddystone 2 (309 MW) retired on 6/1/2012.

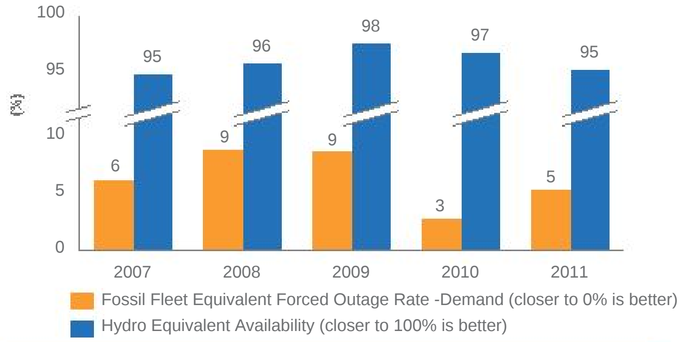
Operational Excellence

Continue tradition of operational excellence and continuous improvement

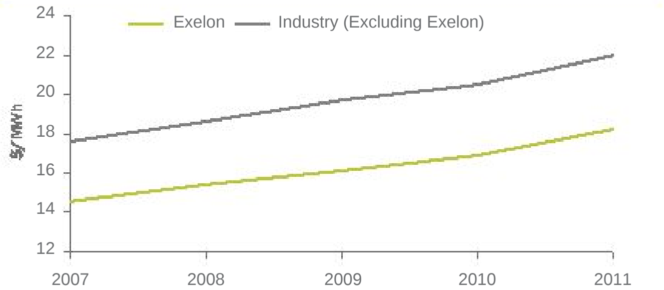
Range of Nuclear Fleet 2-Yr Avg Capacity Factor (2007-2011) (1)



Fossil and Hydro Fleet Availability (2)



Nuclear 2-Yr Production Cost ($/MWh) (3)



Industry Leading Refueling Outage Duration (4)

(1) Source: Platts Nuclear News, Nuclear Energy Institute and Energy Information Administration (Department of Energy). Exelon metrics exclude CENG & Salem.
(2) Excludes legacy Constellation asset performance.
(3) Source: 2011 Electric Utility Cost Group (EUCG) survey. Includes Fuel Cost plus Direct O&M divided by net generation. Exelon metrics exclude CENG & Salem.
(4) Exelon data excludes Salem & CENG. Exelon's 2009 average includes 23 days of TMI outage that extended into 2010 for a steam generator replacement.

NRC Fukushima Related Orders

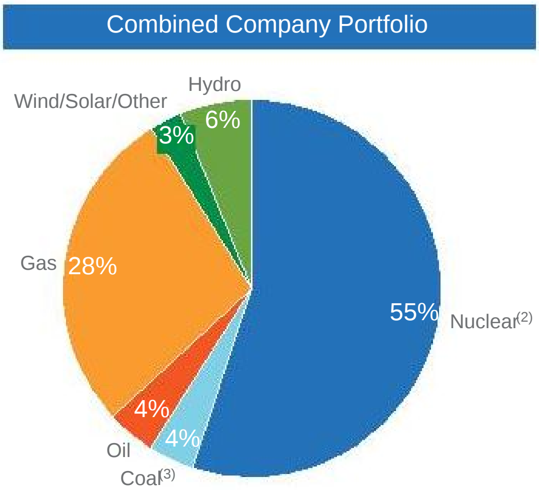
Working collaboratively with NRC and U.S. Nuclear Industry to invest in long term enhancements resulting from lessons learned

Tier 1 Staff Requirements

- Mitigating Strategies:
  - Additional portable equipment purchased to enhance mitigation capability for beyond-design-basis events
  - Integrated Plan to be submitted to NRC by February 2013
  - All actions will be implemented across the Exelon fleet by the end of 2016
- Hardened Vents for Mark I and Mark II Containments:
  - Conceptual design for Mark II containments is in progress and conceptual design for Mark I containments to begin in August 2012
  - Integrated Plan to be submitted to NRC by February 2013
  - All actions will be implemented across the Exelon fleet by the end of 2016
- Spent Fuel Pool (SFP) Instrumentation:
  - Conceptual design for upgraded SFP instrumentation is in progress
  - Integrated Plan to be submitted to NRC by February 2013
  - All actions will be implemented across the Exelon fleet by the end of 2016

Exelon expects the costs to comply with NRC requirements to be manageabl

Well Positioned for Clean Air Rules



Total Generation Capacity (1): ~ 34,660 MW

- Largest clean merchant generation portfolio in the nation
- Less than 5% of combined generation capacity will require capital expenditures to comply with Air Toxic rules
  - Approx. $200 million of CapEx, majority of which is at Conemaugh (Exelon ownership share ~31%)
- Low-cost generation capacity provides unparalleled leverage to rising commodity prices

A clean and diverse portfolio that is well positioned for environmental upside from EPA regulations

(1) Total owned generation capacity as of 4/30/2012 for legacy Exelon and legacy Constellation combined, net of physical market mitigation assumed to be 2,648 MW.
(2) Nuclear capacity shown above reflects EXC ownership of CENG and Salem.
(3) Coal capacity shown above does not include Eddystone 2 (309 MW) retired on 6/1/2012.

Executing on Growth Projects

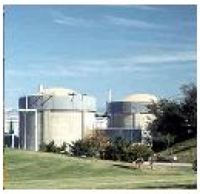
Wind

- Constructing 404 MWs of wind projects in 2012
- May develop or acquire 500 MWs to 1,000 MWs over the next five years
- Future wind development to be backed by PPA and tax benefits

Solar

- Antelope Valley Solar Ranch One Project adding 80 MW by year end 2012 and 150 MW in 2013 – investment recovered by 2015
- Adding 21 MWs through non-utility scale projects in 2012[1]

Uprates



- Value driven uprate program has added 247 MWs through the end of 2011
- Adding 85 MWs in 2012 and 850 MWs over the next six years

Exelon adding material amount of new generation over planning horizon with safe returns

(1) Includes projects signed as of 4/30/12.

Appendix

Exelon Generation Fleet Overview(1)

Plant	Location	Owned Capacity (MW)	LDA	Hub/Zone	Region for Disclosure Mapping
Nuclear					
Braidwood	Braidwood, IL	2,348	Rest of RTO	NiHub	Midwest
Byron	Byron, IL	2,323	Rest of RTO	NiHub	Midwest
Calvert Cliffs I and II	Calvert Co, MD	853	SWMAAC	BGE	Mid-Atlantic
Clinton	Clinton, IL	1,067	n/a	Indiana Hub	Midwest
Dresden	Morris, IL	1,753	Rest of RTO	NiHub	Midwest
LaSalle	Seneca, IL	2,316	Rest of RTO	NiHub	Midwest
Limerick	Limerick Twp., PA	2,312	EMAAC	PECO Zone	Mid-Atlantic
Nine Mile Point I and II	Scriba, NY	782	NYPP	Zone C	New York
Oyster Creek	Forked River, NJ	625	EMAAC	PECO Zone	Mid-Atlantic
Peach Bottom	Peach Bottom Twp., PA	1,150	EMAAC	PECO Zone	Mid-Atlantic
Quad Cities	Cordova, IL	1,380	Rest of RTO	NiHub	Midwest
R.E. Ginna	Ontario, NY	291	NYPP	Zone B	New York
Salem	Hancock's Bridge, NJ	1,004	EMAAC	PECO Zone	Mid-Atlantic
Three Mile Island	Londonderry Twp, PA	837	MAAC	Whub/MetEd Zone	Mid-Atlantic
Coal(2)					
ACE	Trona, CA	32		n/a	Other
Conemaugh	New Florence, PA	533	MAAC	Whub/Penelec Zone	Mid-Atlantic
Jasmin	Kern Co, CA	18		n/a	Other
Keystone	Shelocta, PA	716	MAAC	Whub/Penelec Zone	Mid-Atlantic
POSO	Kern Co, CA	18		n/a	Other
Gas					
Colorado Bend	Wharton, TX	550		Houston	ERCOT
Eddystone 3, 4	Eddystone, PA	760	EMAAC	PECO Zone	Mid-Atlantic
Fore River	North Weymouth, MA	688	ROP-NE	Hub	New England
Gould Street	Baltimore City, MD	97	SWMAAC	BGE	Mid-Atlantic
Grande Prairie	Alberta, Canada	93		n/a	Other
Handley 3, 4, 5	Fort Worth, TX	1,265		ERCOT N	ERCOT
Handsome Lake	Rockland Twp, PA	268	MAAC	Whub/Penelec Zone	Mid-Atlantic
Hillabee Energy	Alexander City, Alabama	740		GTC	Other
LaPorte	Laporte, TX	152		ERCOT	ERCOT
Medway	West Medway, MA	105	ISO-NE	Mass Hub	New England
Mountain Creek 6, 7, 8	Dallas, TX	805		ERCOT N	ERCOT
Mystic 7	Charlestown, MA	560	ROP-NE	Hub	New England
Mystic 8,9	Charlestown, MA	1,398	NEMA	Hub	New England
Notch Cliff	Baltimore Co, MD	101	SWMAAC	BGE	Mid-Atlantic
Perryman -Gas	Harford Co, MD	147	SWMAAC	BGE	Mid-Atlantic
Quail Run Energy	Odessa, TX	550		West	ERCOT
Riverside -Gas	Baltimore Co, MD	189	SWMAAC	BGE	Mid-Atlantic
Southeast Chicago	Chicago, IL	296	Rest of RTO	NiHub	Midwest
West Valley	Salt Lake City, UT	200		n/a	Other
Westport	Baltimore Co, MD	116	SWMAAC	BGE	Mid-Atlantic
Wolf Hollow 1, 2, 3	Granbury, TX	705		ERCOT N	ERCOT
Oil					
Chester	Chester, PA	39	EMAAC	PECO Zone	Mid-Atlantic
Conemaugh	New Florence, PA	2	MAAC	Whub/Penelec Zone	Mid-Atlantic
Croydon	Bristol Twp., PA	391	EMAAC	PECO Zone	Mid-Atlantic
Delaware	Philadelphia, PA	56	EMAAC	PECO Zone	Mid-Atlantic
Eddystone	Eddystone, PA	60	EMAAC	PECO Zone	Mid-Atlantic
Falls	Falls Twp., PA	51	EMAAC	PECO Zone	Mid-Atlantic
Framingham	Framingham, MA	28	ISO-NE	Mass Hub	New England
Keystone	Shelocta, PA	2	MAAC	Whub/Penelec Zone	Mid-Atlantic
Moser	Lower Pottsgrove Twp., PA	51	EMAAC	PECO Zone	Mid-Atlantic
Mystic Jet	Charlestown, MA	9	ROP-NE	Hub	New England
New Boston	South Boston, MA	12	ISO-NE	Mass Hub	New England
Perryman -Oil	Harford Co, MD	200	SWMAAC	BGE	Mid-Atlantic
Philadelphia Road	Baltimore Co, MD	61	SWMAAC	BGE	Mid-Atlantic
Richmond	Philadelphia, PA	98	EMAAC	PECO Zone	Mid-Atlantic
Riverside -Oil	Baltimore Co, MD	39	SWMAAC	BGE	Mid-Atlantic
Salem	Hancock's Bridge, NJ	16	EMAAC	PECO Zone	Mid-Atlantic
Schuylkill	Philadelphia, PA	199	EMAAC	PECO Zone	Mid-Atlantic
Southwark	Philadelphia, PA	52	EMAAC	PECO Zone	Mid-Atlantic
Wyman	Yarmouth, ME	36	ISO-NE	Maine Zone	New England
Hydro					
Conowingo	Harford Co., MD	572	EMAAC	PECO Zone	Mid-Atlantic
Malacha	Muck Valley, CA	16		n/a	Other
Muddy Run	Lancaster, PA	1,070	EMAAC	PECO Zone	Mid-Atlantic
Safe Harbor	Safe Harbor, PA	278	MAAC	Whub	Mid-Atlantic
Wind					
AgriWind	Bureau Co., IL	8		IL Hub/Indiana Hub	Midwest
Blue Breezes	Faribault Co., MN	3		MinnHub	Midwest
Bluegrass Ridge	Gentry Co., MO	56		SERC	Other
Brewster	Jackson Co., MN	6		MinnHub	Midwest
Cassia	Twin Falls Co., ID	29		WECC/Mid-C	Other
Cisco	Jackson Co., MN	8		MinnHub	Midwest
Conception	Nodaway Co., MO	50		SERC	Other
Cow Branch	Atchinson Co., MO	50		SERC	Other
Cowell	Pipestone Co., MN	2		MinnHub	Midwest
CP Windfarm	Faribault Co., MN	4		MinnHub	Midwest
Criterion	Oakland, MD	70		Whub	Mid-Atlantic
Echo 1	Umatilla Co., OR	34		WECC/Mid-C	Other
Echo 2,3	Morrow Co., OR	30		WECC/Mid-C	Other
Ewington	Jackson Co., MN	20		MinnHub	Midwest
Exelon Wind 1-11	Various Counties, TX	180		SPP	Other
Greensburg	Kiowa Co., KS	13		SPP	Other
Harvest	Huron Co., MI	53		MichHub	Midwest

(1) Total owned generation capacity as of 4/30/2012 for legacy Exelon and legacy Constellation combined, net of physical market mitigation assumed to be 2,648 MW.
(2) Coal capacity shown does not include Eddystone 2 (309 MW) retired on 6/1/2012.

Exelon

Exelon Generation Fleet Overview (cont'd)[1]

Plant	Location	Owned Capacity (MW)	LDA	Hub/Zone	Region for Disclosure Mapping
Wind (cont'd)					
High Plains	Moore Co., TX	10		SPP	Other
Loess Hills	Atchinson Co., MO	5		SERC	Other
Marshall	Lyon Co., MN	19		MinnHub	Midwest
Michigan Wind 1 and 2	Bingham Twp., MI	159		MichHub	Midwest
Mountain Home	Elmore Co., ID	40		WECC/Mid-C	Other
Norgaard	Lincoln Co., MN	9		MinnHub	Midwest
Threemile Canyon	Morrow Co., OR	10		WECC/Mid-C	Other
Tuana Springs	Twin Falls Co. ID	17		WECC	Other
Wolf	Nobles Co., MN	6		n/a	Midwest
Solar					
City Solar	Chicago, IL	10	Rest of RTO	NiHub	Midwest
Constellation Solar	Various	84		n/a	Other
SEGS IV-VI	Kramer Junction, CA	8		n/a	Other
Biomass					
Chinese Station	Jamestown, CA	10		n/a	Other
Fresno	Fresno, CA	12		n/a	Other
Rocklin	Placer Co, CA	12		n/a	Other
Landfill Gas					
Fairless Hills	Falls Twp, PA	60	EMAAC	PECO Zone	Mid-Atlantic
Pennsbury	Falls Twp., PA	6	EMAAC	PECO Zone	Mid-Atlantic
Waste Coal					
Colver	Colver Township, PA	26		n/a	Mid-Atlantic
Panther Creek	Nesquehoning, PA	40		n/a	Mid-Atlantic
Sunnyside	Sunnyside, UT	26		n/a	Other
Total, Net of Physical Mitigation[1]		34,662			
Physical Market Mitigation					
Brandon Shores	Anne Arundel Co, MD	1,273	SWMAAC	BGE	Mid-Atlantic
H. A. Wagner	Anne Arundel Co, MD	976	SWMAAC	BGE	Mid-Atlantic
C. P. Crane	Anne Arundel Co, MD	399	SWMAAC	BGE	Mid-Atlantic

(1) Total owned generation capacity as of 4/30/2012 for legacy Exelon and legacy Constellation combined, net of physical market mitigation assumed to be 2,648 MW.

Post Fukushima: NRC Requirements and Anticipated Implications

- In March, NRC issued its final Tier 1 requirements based on NRC task force and staff recommendations

Tier 1 Staff Requirements

Requirement	EXC Actions Required	Proactive Steps Taken
Mitigating strategies for beyond-design-basis events	• Develop procedures and plant modifications to implement additional requirements for mitigation of beyond design basis events	• Validated existing strategies • Performed preliminary analysis to identify strategy improvements • Purchased additional portable equipment
Reliable hardened vents for Mark I and Mark II containment	• Install new hardened vents for Mark II containments, upgrade existing Mark I hardened containment vents	• Validated existing venting procedures • Began conceptual design for installation of Mark II containment vents
Spent Fuel Pool (SFP) instruments	• Upgrade existing SFP monitoring capability to meet new requirements	• Additional controls established for SFP cooling equipment monitoring and equipment availability

- Significant activity is in progress in preparation for seismic and external flooding walkdowns which are required under additional NRC requests for information and are scheduled to be completed by the end of November 2012

Exelon's actions and commitments are aligned with coordination that is taking place across the U.S. nuclear industry

Growing Clean Generation with Uprates

Nuclear Uprate Program Summary[1]

	Estimated IRR	Overnight Cost[2]	Approval Process	Project Duration
Megawatt Recovery & Component Upgrades	11-14%	$860 M	Not required	3-4 Years
MUR (Measurement Uncertainty Recapture)	12-16%	$340 M	Straight forward approval process	2-3 Years
EPU (Extended Power Uprate)	9-13%	$2,260 M	Straight forward approval process	3-6 Years

Station	Base Case MW [3]	Max Potential MW [3]	MW Online to Date	Year of Full Operation by Unit [1]
MW Recovery & Component Upgrades:				
Quad Cities	99	99	99	2011 / 2010
Dresden	3	3		2013 / 2012
Peach Bottom	29	30	15	2011 / 2012
Dresden	106	110	62	2011 / 2013
Limerick	6	6	3	2012 / 2013
Peach Bottom	2	2		2014 / 2015
MUR:				
LaSalle	39	39	39	2010 / 2011
Limerick	30	30	30	2011 / 2011
Braidwood	34	42		2012 / 2012
Byron	34	42		2012 / 2012
Quad Cities	21	23		2014 / 2014
Dresden	28	31		2014 / 2015
TMI	12	15		2014
EPU:				
Clinton	2	2	2	2010
Peach Bottom	130	137		2015 / 2016
LaSalle	303	336		2018 / 2017
Limerick	306	340		2016 / 2017
Total	1,184	1,287	250	

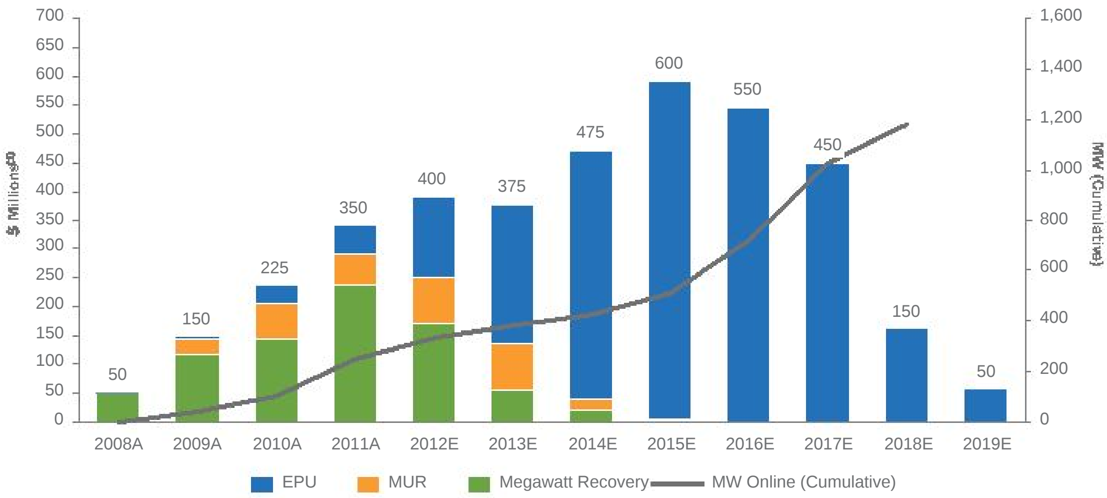
Executing uprate projects across our geographically diverse nuclear fleet – planned to add 85 MW's in 2012

(1) Includes deferral of LaSalle EPU.
(2) In 2012 dollars. Overnight costs do not include financing costs or cost escalation.
(3) Adjusted for actual MW's achieved.

Phased Execution Lowers Risk

- Highest return projects are being completed in the early years
- Leverages Exelon's substantial experience managing successful uprate projects – 1,100 MW completed prior to 2008

Exelon's Uprate Plan Expenditures[2]



Approximately 134 MWs scheduled to be completed in 2012 and 2013
Total expenditures expected to be $3,825 million from 2008 – 2019 (1)

(1) Dollars shown are nominal in millions (excludes capitalized interest).
(2) Values shown are rounded and at ownership. Data includes deferral of LaSalle EPU.

Exelon.

Exelon's Uprate Program Is a Pragmatic Approach to Nuclear Growth

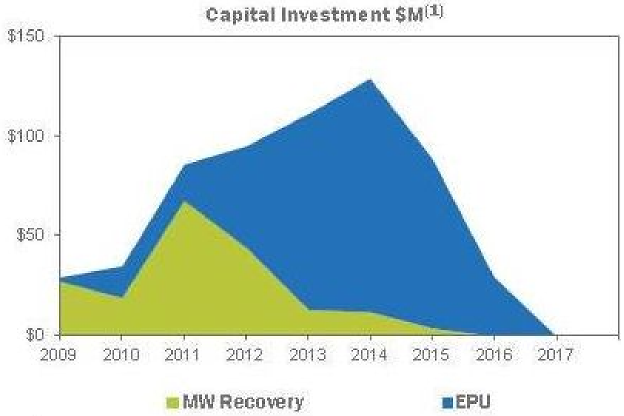
Key Considerations	Exelon Uprate Program[2]	New Merchant Nuclear[3]
Overnight cost[1]	$2,700 - $2,900 / KW	$4,500 - $6,200 / KW
Time to market	2 - 6 years	At least 9 years
O&M cost	No additional O&M cost	$11 - $15 / MWh
Ancillary costs – NDT, maintenance capital, etc	Minimal ancillary costs	$ 2 - $3 / MWh
Asset diversification	Operational risk spread amongst several assets	Operational risk concentrated to single asset
Market diversification	Diversify revenue source amongst several power markets / regions	Market risk concentrated to one location
Market timing risk	Lower risk due to phased execution	Risk of hitting low commodity cycle
Regulatory approval	1 - 2 years review period	3 - year minimum review period
Financing Source	Leverage balance sheet strength	Loan guarantees needed
Development flexibility	Ability to respond to changing market / financial conditions	Much less flexibility to cancel

Exelon's uprate program is a proven approach to add clean generation to the portfolio, and it provides flexibility to respond to changing economic and market conditions

(1) In 2012 dollars. Overnight costs do not include financing costs or cost escalation.
(2) Includes deferral of LaSalle EPU.
(3) Cost estimates are based on Exelon's internal projections for new merchant nuclear.

Exelon.

Peach Bottom Uprate Program



- MW Recovery
  - Low Pressure Turbine Retrofit in progress with installation complete for Unit 3 and completion for Unit 2 planned in 2012
  - Replacement of Reactor Recirculation Pump Motor Generator sets with energy efficient Adjustable Speed Drives in 2014 and 2015
- EPU
  - Funding approved for design work
  - Full project authorization currently in progress

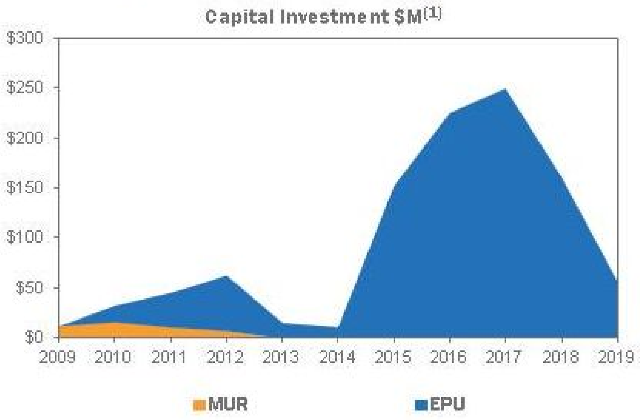
	Unit 2		Unit 3		
Uprate Project	MW Increase(1)	Online Date	MW Increase(1)	Online Date	Status
MW Recovery Low Pressure Turbine Retrofit	14	4Q 2012	15	4Q 2011	Unit 3 complete Unit 2 in progress
MW Recovery Adjustable Speed Drives	2	4Q 2014	2	4Q 2015	Scheduled to start in 2012
EPU	65	1Q 2015	65	1Q 2016	Design phase in progress

(1) Capital investment and MW uprate numbers represent Exelon's 50% ownership stake in Peach Bottom Station. $'s used in chart are nominal (excludes capitalized interest).

Peach Bottom Uprate Projects are underway –15 additional MWs came online in 2011 and the remaining will come online between 2012 and 2016

Exelon.

LaSalle Uprate Program



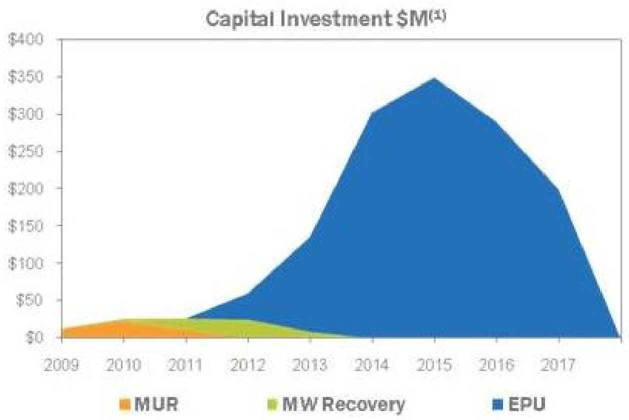
- MUR
  – Completed in 2010 and 2011
- EPU
  – Funding approved for design work
  – Project completion has been moved from 2015/2016 to 2017/2018

Uprate Project	Unit 1 MW Increase	Unit 1 Online Date	Unit 2 MW Increase	Unit 2 Online Date	Status
MUR	19	2010	20	2011	Complete
EPU	151	3Q 2018	151	3Q 2017	Design phase in progress, Project completion moved from 2015 / 2016 to 2017 / 2018

(1) $'s used in chart are nominal (excludes capitalized interest).

LaSalle Uprate Projects are underway –39 additional MWs came online through 2011 and the remaining will come online between 2017 and 2018

Limerick Uprate Program



- MW Recovery
  - Replacement of Reactor Recirculation Pump Motor Generator sets with energy efficient Adjustable Speed Drives completed for Unit 1 in 2012 and planned for Unit 2 in 2013
- MUR
  - Completed in 2011
- EPU
  - Funding approved for initial studies
  - Will review in 3Q 2012 before authorizing start of design work

	Unit 1		Unit 2		
Uprate Project	MW Increase	Online Date	MW Increase	Online Date	Status
MUR	15	2010	15	2011	Complete
MW Recovery Adjustable Speed Drives	3	1Q 2012	3	2Q 2013	Unit 1 complete Unit 2 in progress
EPU	153	3Q 2016	153	3Q 2017	Initial studies in progress

(1) $'s used in chart are nominal (excludes capitalized interest).

Limerick Uprate Projects are underway –33 additional MWs came online through 2012 and the remaining will come online between 2013 and 2017

Exelon.

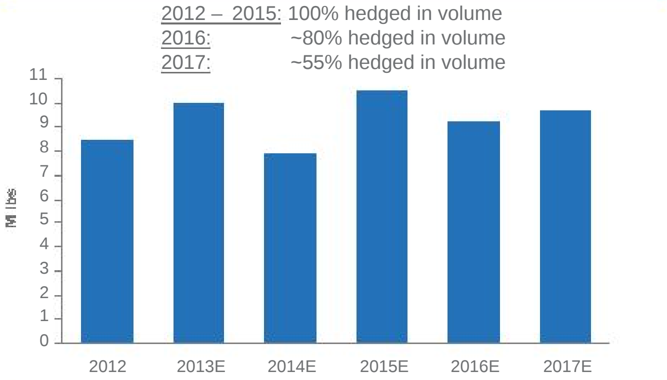
Exelon Nuclear Fleet Overview (including CENG and Salem)

Region	Plant Location	Type/ Containment	Water Body	License Extension Status / License Expiration[1]	Ownership	Spent Fuel Storage/ Date to lose full core discharge capacity[2]
Midwest	Braidwood, IL (Units 1 and 2)	PWR Concrete/Steel Lined	Kankakee River	Expect to file application in 2013 / 2026, 2027	100%	Dry Cask
Midwest	Byron, IL (Units 1 and 2)	PWR Concrete/Steel Lined	Rock River	Expect to file application in 2013 / 2024, 2026	100%	Dry Cask
Midwest	Clinton, IL (Unit 1)	BWR Concrete/Steel Lined / Mark III	Clinton Lake	2026	100%	2018
Midwest	Dresden, IL (Units 2 and 3)	BWR Steel Vessel / Mark I	Kankakee River	Renewed / 2029, 2031	100%	Dry Cask
Midwest	LaSalle, IL (Units 1 and 2)	BWR Concrete/Steel Lined / Mark II	Illinois River	2022, 2023	100%	Dry Cask
Midwest	Quad Cities, IL (Units 1 and 2)	BWR Steel Vessel / Mark I	Mississippi River	Renewed / 2032	75% Exelon, 25% Mid-American Holdings	Dry Cask
Mid-Atlantic	Calvert Cliffs, MD (Units 1and 2)	PWR Concrete/Steel Lined	Chesapeake Bay	Renewed / 2034, 2036	100% CENG[4]	Dry Cask
Mid-Atlantic	R.E. Ginna, NY (Unit 1)	PWR Concrete/Steel Lined	Lake Ontario	Renewed / 2029	100% CENG[4]	Dry Cask
Mid-Atlantic	Limerick, PA (Units 1 and 2)	BWR Concrete/Steel Lined / Mark II	Schuylkill River	Filed application in June 2011 (decision expected in 2013) / 2024, 2029	100%	Dry Cask
Mid-Atlantic	Nine Mile Point, NY (Units 1 and 2)	BWR Concrete/Steel Vessel / Mark I / Concrete/Steel Vessel/ Mark II	Lake Ontario	Renewed / 2029, 2046	100% CENG[4] / 82% CENG[4], 18% Long Island Power Authority	Dry Cask (Summer 2012)
Mid-Atlantic	Oyster Creek, NJ (Unit 1)	BWR Steel Vessel / Mark I	Barnegat Bay	Renewed / 2029[3]	100%	Dry Cask
Mid-Atlantic	Peach Bottom, PA (Units 2 and 3)	BWR Steel Vessel / Mark I	Susquehanna River	Renewed / 2033, 2034	50% Exelon, 50% PSEG	Dry Cask
Mid-Atlantic	TMI, PA (Unit 1)	PWR Concrete/Steel Lined	Susquehanna River	Renewed / 2034	100%	2023
Mid-Atlantic	Salem, NJ (Units 1 and 2)	PWR Concrete/Steel Lined	Delaware River	Renewed / 2036, 2040	42.6% Exelon, 57.4% PSEG	Dry Cask

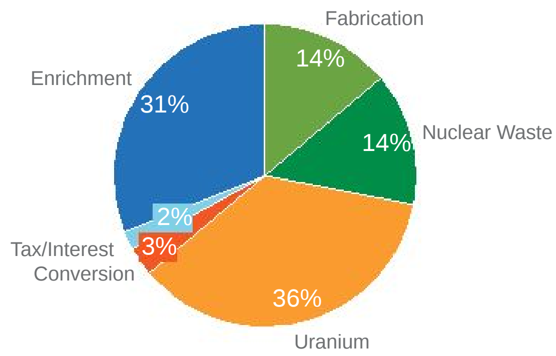
(1) Operating license renewal process takes approximately 4-5 years from commencement until completion of NRC review.
(2) The date for loss of full core reserve identifies when the on-site storage pool will no longer have sufficient space to receive a full complement of fuel from the reactor core. Dry cask storage will be in operation at those sites prior to losing full core discharge capacity in their on-site storage pools.
(3) On December 8, 2010, Exelon announced that it will permanently cease generation operations at Oyster Creek by December 31, 2019. Oyster Creek's current NRC license expires in 2029.
(4) Exelon Generation has a 50.01% ownership interest in CENG (Constellation Energy Nuclear Group, LLC). Electricite de France SA (EDF) has a 49.99% ownership interest in CENG.

Effectively Managing Nuclear Fuel Costs(1)

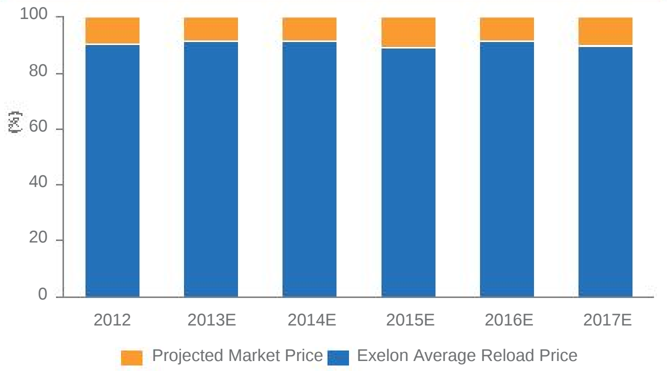
Projected Exelon (100%) Uranium Demand



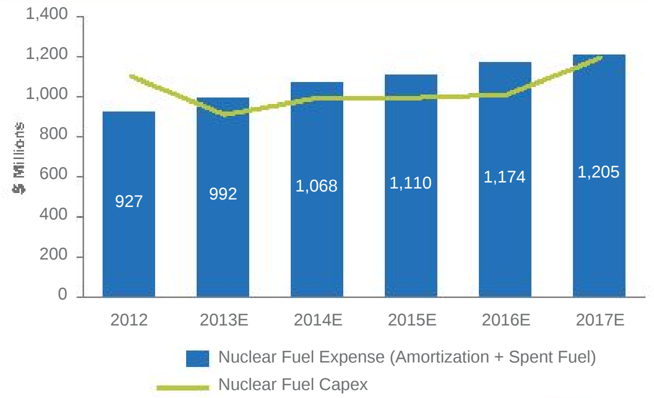
Components of Fuel Expense in 2012



Projected Exelon Average Uranium Cost vs. Market



Projected Total Nuclear Fuel Spend(2)



(1) All charts exclude Salem and CENG.
(2) At ownership, excluding Salem and CENG. Excludes costs reimbursed under the settlement agreement with the DOE. Data assumes LaSalle's deferral of EPU.

Q&A

Exelon Value Proposition

- Right strategy, right platform, right set of assets and right leadership team

- Merger will be successful

- Right time to own Exelon stock given robust dividend yield and unparalleled upside to market recovery

- Confident in ability to achieve 2012 earnings in range of $2.55 - $2.85 per share

- Commitment to existing dividend[1] rate of $2.10 per share

(1) Dividends are subject to declaration by the Exelon board of directors on a quarterly basis.

Exelon Investor Relations Contacts

Exelon Investor Relations
10 South Dearborn Street
Chicago, Illinois 60603
312-394-2345
312-394-4082 (Fax)

For copies of other presentations, annual/quarterly reports, or to be added to our email distribution list please contact:

Martha Chavez, Executive Admin Coordinator
312-394-4069
Martha.Chavez@ExelonCorp.com

Investor Relations Contacts:

JaCee Burnes, Vice President
312-394-2948
jacee.burnes@exeloncorp.com

Melissa Sherrod, Director
312-394-8351
melissa.sherrod@exeloncorp.com

Ishaan Kapoor, Manager
312-394-3657
ishaan.kapoor@exeloncorp.com

Sandeep Menon, Principal Analyst
312-394-7279
sandeep.menon@exeloncorp.com