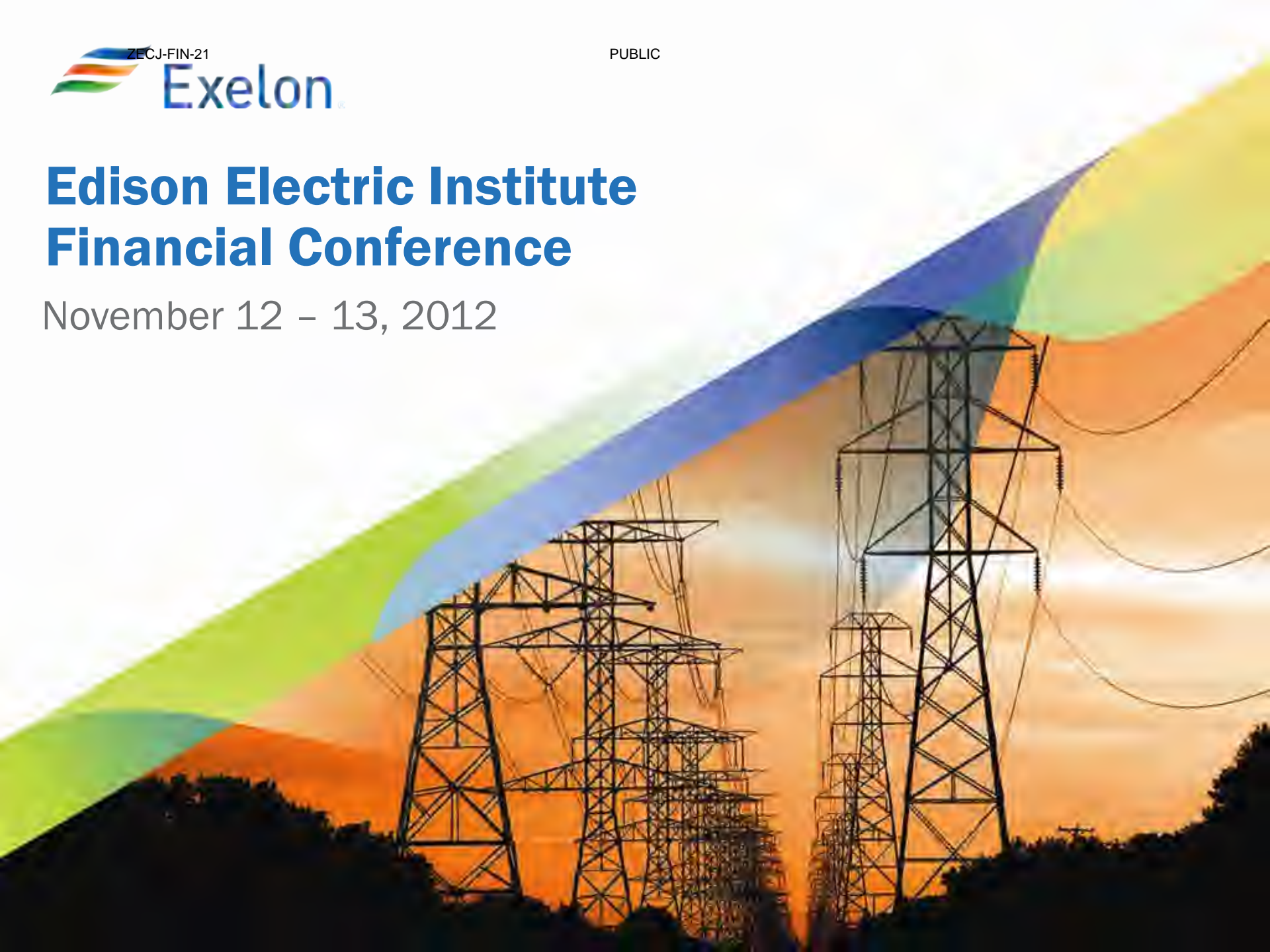


# **Edison Electric Institute Financial Conference**

November 12 – 13, 2012



# Cautionary Statements Regarding Forward-Looking Information

ZECJ-FIN-21

PUBLIC

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 Third Quarter 2012 Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors; (b) Part 1, Financial Information, ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 16; 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.

# Financial Discipline & Flexibility

	Financial Action	Summary
Operational Efficiencies	Cost Management	<ul style="list-style-type: none"> <li>Identified additional cost savings of \$50 million per year beginning in 2014, in addition to \$500 million merger run rate synergies <sup>(1)</sup></li> </ul>
Financial Tools	Financial Flexibility	<ul style="list-style-type: none"> <li>Optimized nuclear fuel inventory expenditures for cash savings of \$400 million from 2013-2016 <sup>(2)</sup> (<i>incorporated in 2012 Analyst Day CapEx schedule</i>)</li> <li>Investments in upstream gas business and utility scale solar will be funded off-credit where possible</li> <li>Evaluating project financing options for Exelon Wind portfolio</li> </ul>
	Defer Growth Projects	<ul style="list-style-type: none"> <li>Deferred ~\$1.0B of nuclear uprate spend to align with expected market recovery               <ul style="list-style-type: none"> <li>LaSalle EPU 4-year deferral (additional two years since 2012 Analyst Day announcement)</li> <li>Limerick EPU 4-year deferral</li> </ul> </li> <li>Eliminated undesigned renewable spend of ~\$1.3 billion in 2013-2015</li> </ul>

**Maintaining investment grade credit rating and dividend are our top priorities**

(1) Run rate target for O&M synergies from 2014 onwards.  
Note: EPU = Extended Power Uprate.

(2) Includes reduction in nuclear fuel capital expenditures related to the 4 year deferral of LaSalle and Limerick EPU projects.

# Merger Checklist Update

Item	Target	Status	Highlights
O&M Synergies	\$500 million run rate beginning in 2014 <sup>(1)</sup>	✓	<ul style="list-style-type: none"> <li>On track to meet \$170 million 2012 target and \$550 <sup>(2)</sup> million run rate synergy target for 2014</li> <li>Unregulated business comprises ~75% of target</li> </ul>
Liquidity Reduction	\$4.2 billion year-end 2012	✓	<ul style="list-style-type: none"> <li>On track to eliminate legacy CEG credit facilities of \$4.2 billion, with \$2.7 billion reduced year to date<sup>(3)</sup></li> <li>Amended and extended existing \$7 billion in credit facilities across all OpCos until 2017</li> </ul>
Gross Margin Opportunities	\$100 million run rate <sup>(4)</sup>	✓	<ul style="list-style-type: none"> <li>On track to meet \$100 million run rate synergies starting in 2014</li> </ul>
Asset Sales Process	Execute sales agreement by August 2012	✓	<ul style="list-style-type: none"> <li>Executed sales agreement on August 9<sup>th</sup> for ~\$400 million, plus tax benefits of \$225 million; expect to close transaction in 4Q 2012</li> </ul>
BGE	File rate case in 2 <sup>nd</sup> half of 2012	✓	<ul style="list-style-type: none"> <li>Filed rate case on July 27<sup>th</sup>, 2012 and expect order from MD PSC by February 2013</li> <li>Filing reflects a \$176M increase in revenue requirements for both electric and gas</li> </ul>
Commercial Load Growth	~20% growth in volumes from 2011 - 2014		<ul style="list-style-type: none"> <li>Lower volume growth as a consequence of significant competition but disciplined pricing</li> </ul>

**We are successfully executing on the merger**

(1) Run rate target for O&M synergies from 2014 onwards.

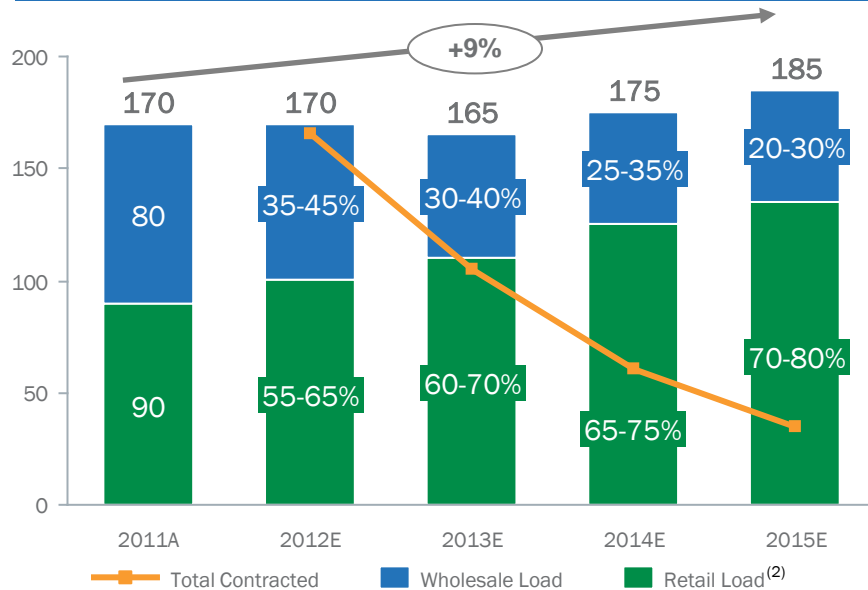
(2) Includes additional \$50M run rate cost savings disclosed in 3Q12 earnings materials.

(3) As of 9/30/2012.

(4) Gross Margin opportunities on a run rate basis from 2014 onwards from combining the two commercial portfolios.

# Exelon Generation: Load Serving Update

## Retail & Wholesale Load (TWh)<sup>(1)</sup>



(1) Numbers and percentages are rounded to the nearest 5.

(2) Index load expected to be 20% to 30% of total forecasted retail load.

## Strategy

- Serve new customers as existing markets grow and new markets open
  - Retail expected to grow at ~11% CAGR for 2011-2015
  - Wholesale expected to remain static starting in 2013
- Improve market share in existing markets
- Cross sell suite of products to existing customers to create higher retention
- Leverage operational efficiency and national footprint

## Retail Landscape

- Expected load growth of 1% across the U.S.
- Switched market expected to grow by approximately 11% in C&I from 2011 to 2015
- Switched market expected to grow by approximately 22% in residential from 2011 to 2015

## Execution

- Recently, the market has been impacted by increased competition and aggressive pricing
- Our disciplined approach to pricing has led to a reduction in expected volumes and margins
- Various channels to market are available to optimize our generation

# Exelon Generation: Regulatory Priorities

---

- **PJM – Restructured Minimum Offer Price Rules (MOPR)**
  - Proposed modifications will enhance clarity and appropriately apply minimum offer rule to subsidized projects
  - Modifications positioned to be implemented in advance of May 2013 PJM capacity auction
  
- **ERCOT – Market Redesign**
  - Forward capacity market remains a long-term option to assure resource adequacy
  - In October, the PUCT voted to increase price caps (as an “interim” step) from \$4,500/MWh to:
    - \$5,000/MWh (beginning June 1, 2013)
    - \$7,000/MWh (beginning June 1, 2014)
    - \$9,000/MWh (beginning June 1, 2015)

**Exelon is heavily engaged in advocating positions that enhance the integrity of competitive markets and shareholder value**

# Executing Plan for Stronger Future

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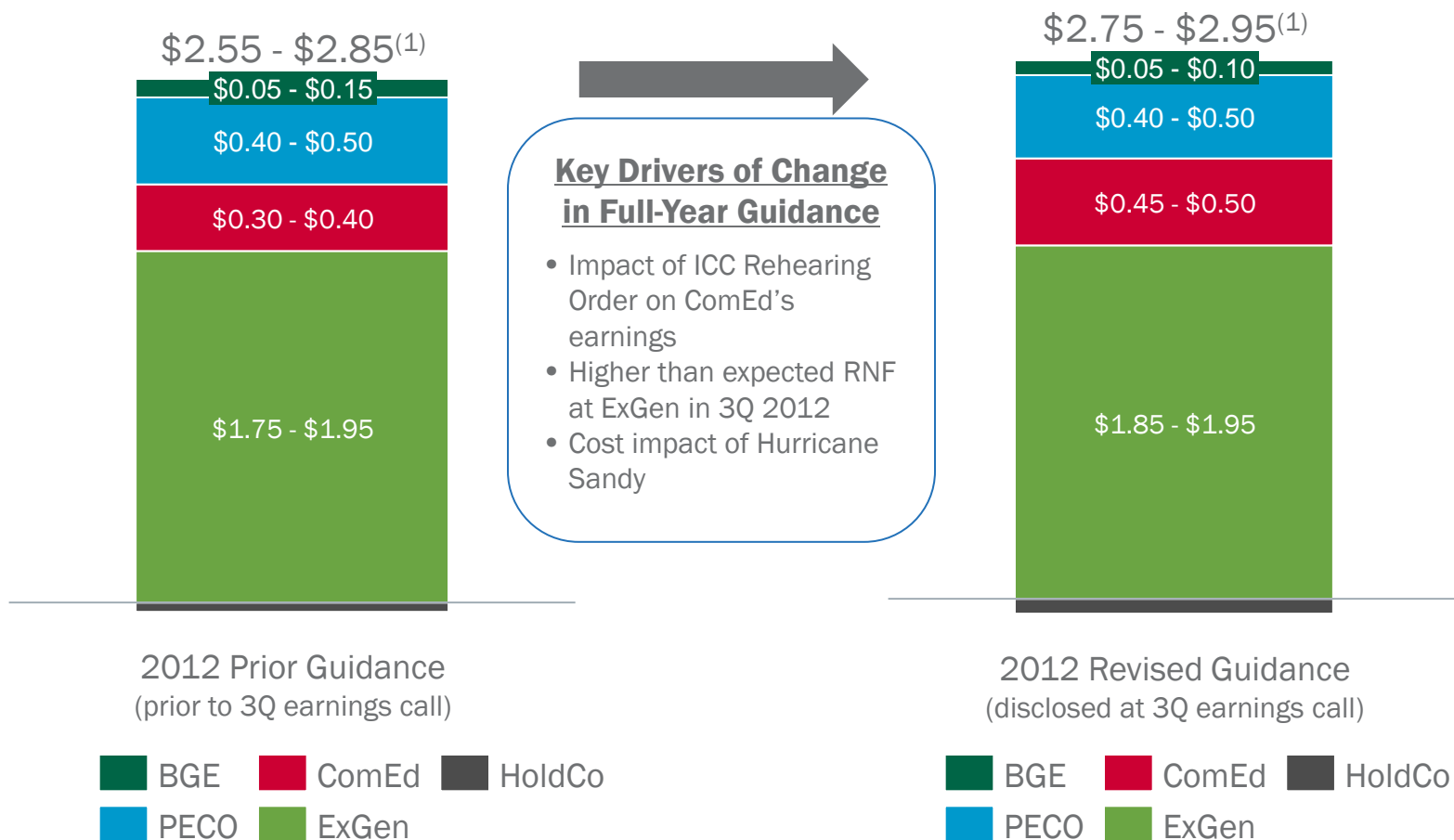
- Strong financial performance in 2012
- Successfully executing on the merger and meeting commitments
- Growing utility rate base in a prudent manner
- Expecting \$3 - \$6/MWh upside in forward power prices as a result of plant retirements, higher operating costs for compliance and a disconnect between heat rates and gas prices
- Extracting value out of load serving business in a tough, competitive pricing environment
- Anticipating positive enhancements in the regulatory arena, particularly with the PJM MOPR
- Prioritizing capital allocation in order to maintain investment grade ratings and provide time for a power market recovery to support the dividend



# Financial Update



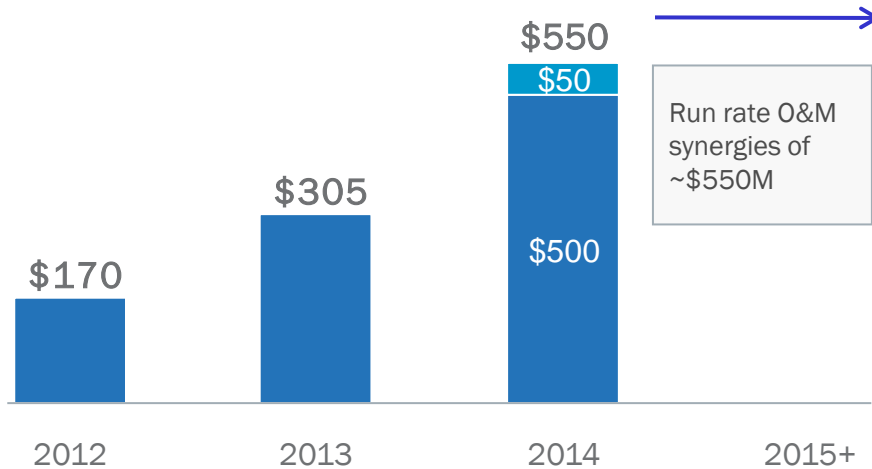
# 2012 Earnings Guidance



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

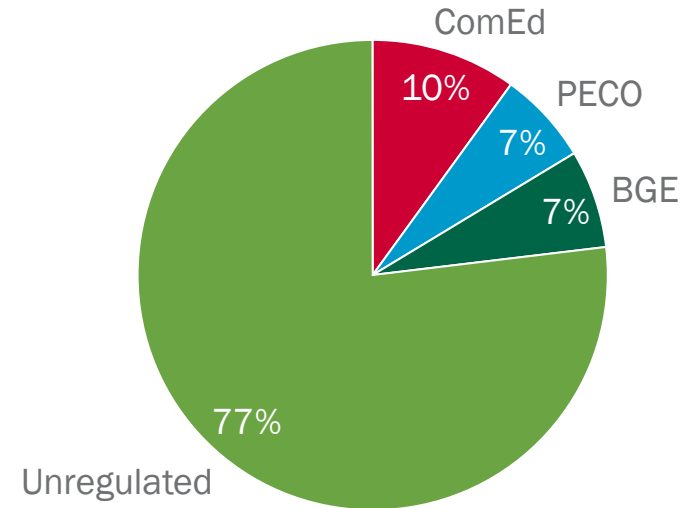
# Cost Synergies Update

## O&M Savings<sup>(1)</sup> (\$M)



- On track to meet \$170M O&M synergies target for 2012
- Completed activities to enable \$275M of the \$550M run-rate synergies to date

## Run Rate O&M Synergies Breakdown



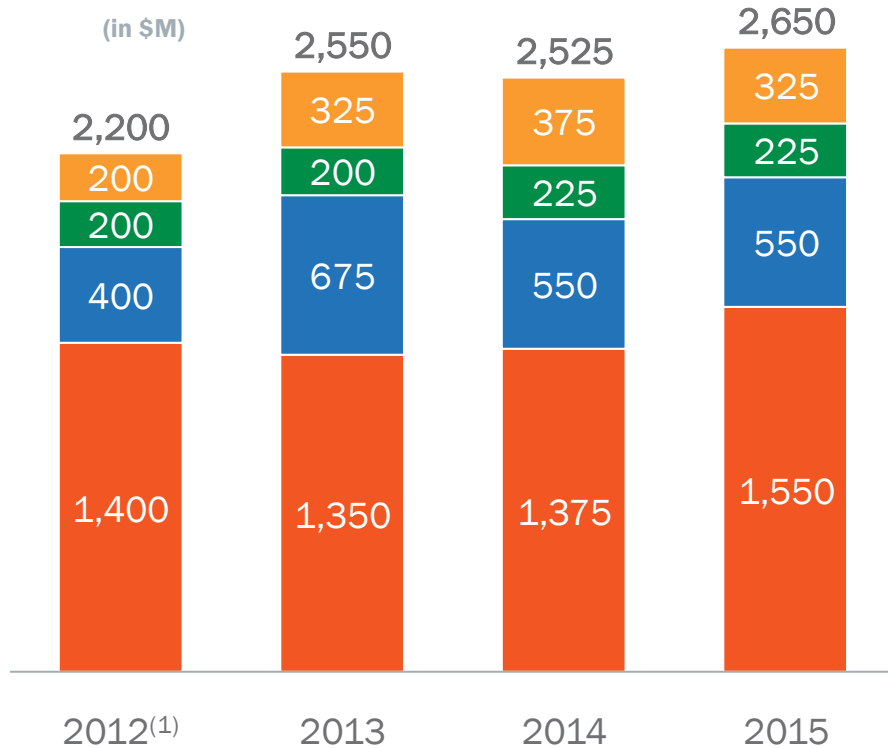
- Key Drivers of run rate O&M synergies include
  - Labor savings from corporate and commercial consolidations
  - Reduced collateral requirements
  - IT systems consolidation
  - Supply chain savings
  - Other non-labor corporate synergies

**On track to achieving merger synergies**

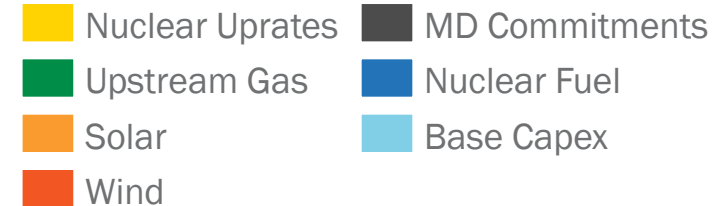
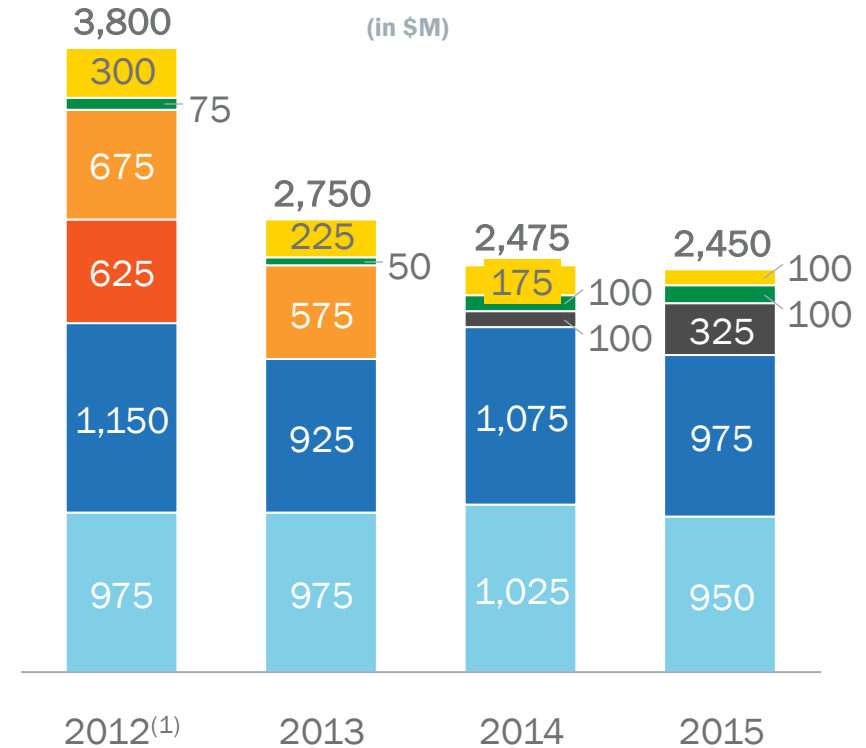
(1) O&M synergies include cost savings of ~\$40M from lower liquidity requirements.

# Capital Expenditure Expectations

## Exelon Utilities



## Exelon Generation



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

# 2012 Projected Sources and Uses of Cash

(\$ in Millions)

ComEd



PECO

Exelon<sup>(7)</sup>

<b>Beginning Cash Balance<sup>(4)</sup></b>					<b>\$550</b>
Cash acquired from Constellation <sup>(2)</sup>	150	n/a	n/a	1,375	1,650
Cash Flow from Operations <sup>(3)</sup>	250	1,175	900	3,475	5,825
CapEx (excluding other items below):	(425)	(1,225)	(350)	(975)	(3,050)
Nuclear Fuel	n/a	n/a	n/a	(1,150)	(1,150)
Dividend <sup>(4)</sup>					(1,725)
Nuclear Upgrades	n/a	n/a	n/a	(300)	(300)
Wind	n/a	n/a	n/a	(625)	(625)
Solar	n/a	n/a	n/a	(675)	(675)
Upstream	n/a	n/a	n/a	(75)	(75)
Utility Smart Grid/Smart Meter	(75)	(50)	(75)	n/a	(200)
Net Financing (excluding Dividend):					
Debt Issuances <sup>(5)</sup>	250	350	350	775	1,725
Debt Retirements	(175)	(450)	(375)	(125)	(1,125)
Project Finance/Federal Financing Bank Loan	n/a	n/a	n/a	375	375
Other <sup>(6)</sup>	--	25	(25)	--	(100)
<b>Ending Cash Balance<sup>(4)</sup></b>					<b>\$1,100</b>

(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 30, 2013.

(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
- 2012-2015 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

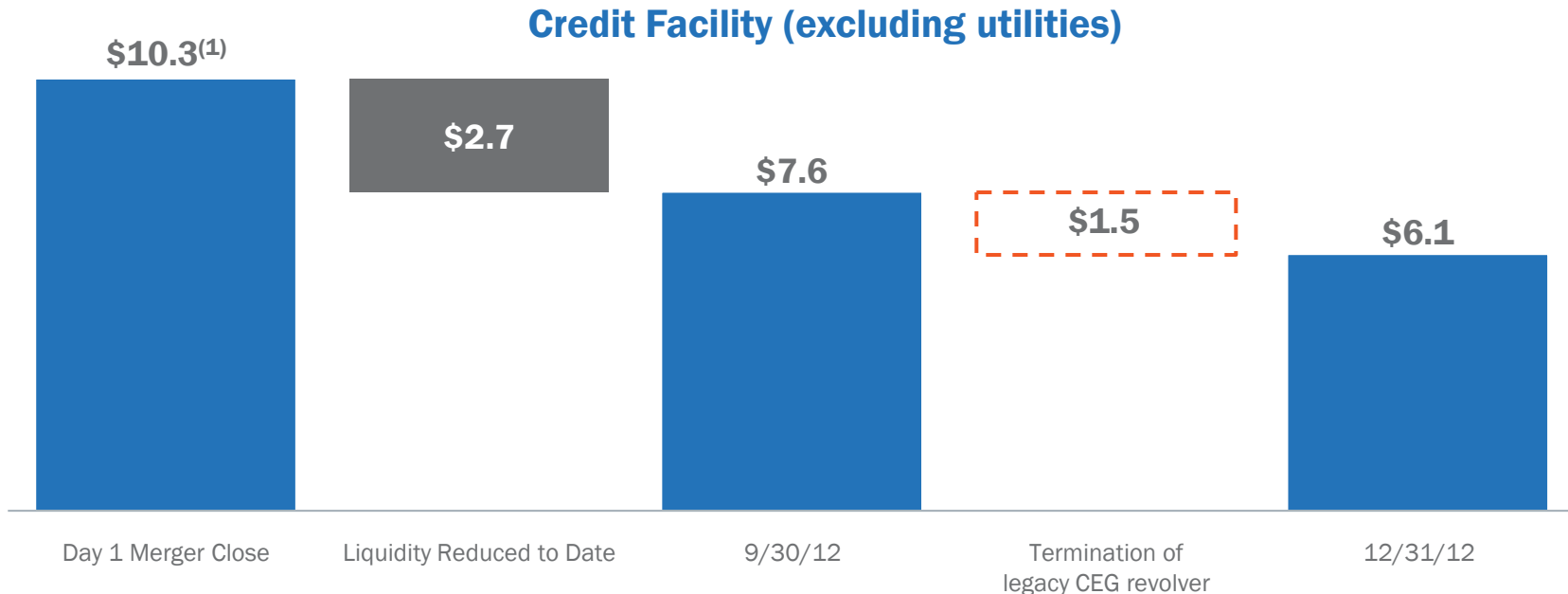
	Moody's Credit Ratings <sup>(1)(2)</sup>	S&P Credit Ratings <sup>(1)(2)</sup>	Fitch Credit Ratings <sup>(1)(2)</sup>	FFO / Debt Target Range
Exelon Corp	Baa2	BBB-	BBB+	
ComEd	A3	A-	BBB+	15-18%
PECO	A1	A-	A	15-18%
BGE	Baa1	BBB+	BBB+	15-18%
Generation	Baa1	BBB	BBB+	25-27% <sup>(3)</sup>

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

- (1) Current senior unsecured ratings for Exelon, Exelon Generation and BGE and senior secured ratings for ComEd and PECO as of November 8, 2012.
- (2) On November 8, 2012 Moody's affirmed the ratings of Exelon and Generation with a negative outlook, concluding their review for a possible downgrade. ComEd, PECO and BGE ratings have a stable outlook at Moody's. All ratings at S&P and Fitch have a stable outlook.
- (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.

# Credit Facility Update

- Achieving targeted facility reductions and associated synergies
  - \$4.2B reduction in legacy CEG facilities (excluding BGE) on track by 12/31/12
  - \$40M in annual cost savings beginning in 2013 (\$35 million in 2012)
- Amended and extended existing \$7 billion in credit facilities for Exelon Corp, ExGen, PECO and BGE
  - Anticipate ~\$20M in savings over life of credit facilities



**Liquidity sizing supports commercial trading platform and provides ongoing access to substantial liquidity**

<sup>(1)</sup> Includes Exelon Generation \$5.3B revolver, legacy CEG \$2.5B revolver, legacy CEG bilateral agreements of \$1.7B, Exelon Corp \$0.5B revolver and Exelon Generation \$0.3B bilateral agreement

# Pension and OPEB for Combined Company

## Plan Design and Funding Strategy:

- Plan funding strategies are summarized as follows:
  - For pension, 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. For Exelon's largest pension plan, Exelon expects to contribute the greater of \$250M or the minimum amounts required under ERISA beginning annually in 2013.
  - OPEB plans are not subject to regulatory minimum contribution requirements. 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 legacy plans are unfunded.
- In July 2012, legislation was passed that provides pension funding relief for certain plans in the near term; the impact of this legislation is included in the forecast and sensitivities.
- During the third quarter of 2012, Exelon announced certain plan design changes for its post-retirement benefit plans. The changes are effective beginning in 2014 and their impact has been incorporated in the forecast below.

## Current Forecast:

- The table below provides the combined company's forecasted 2013 and 2014 pension and OPEB expense and contributions.

	2013		2014	
(in \$M)	Pre-Tax Expense <sup>(1)</sup>	Contributions <sup>(2)</sup>	Pre-Tax Expense <sup>(1)</sup>	Contributions <sup>(2)</sup>
Pension <sup>(3)(4)</sup>	\$430	\$265	\$455	\$280
OPEB <sup>(3)(4)</sup>	\$240	\$305	\$225	\$285
Total	\$670	\$570	\$680	\$565

(1) Pension and OPEB expenses assume an ~ 24% capitalization rate.

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

(3) Expected return on assets for pension is 7.50% (2013) and 7.0% (2014). Expected return on assets for 2013 - 2014 for OPEB is 6.68%. Amounts above assume Exelon achieves its expected return on assets for pension and OPEB in 2012 of 7.50% and 6.68%, respectively.

(4) Projected 12/31/12 pension discount rate is 3.87% (Exelon) and 3.67% (Constellation). Projected 12/31/12 OPEB discount rate is 3.96% (Exelon) and 3.69% (Constellation).



# 2013 Pension and OPEB Sensitivities

- Tables below provide sensitivities for the combined company's 2013 pension and OPEB expense and contributions<sup>(1)</sup> under various discount rate and S&P 500 asset return scenarios

2013 Pension Sensitivity <sup>(2)</sup> (in \$M)						
S&P Returns in Q4 2012 <sup>(3)</sup>						
10%		0%		-10%		
Discount Rate at 12/31/12	Pre-Tax Expense <sup>(1)</sup>	Contributions <sup>(2)</sup>	Pre-Tax Expense <sup>(1)</sup>	Contributions <sup>(2)</sup>	Pre-Tax Expense <sup>(1)</sup>	Contributions <sup>(2)</sup>
Baseline Discount Rate <sup>(4)</sup>	\$400	\$265	\$420	\$265	\$440	\$265
+50 bps	\$365	\$265	\$385	\$265	\$405	\$265
- 50bps	\$445	\$265	\$465	\$265	\$485	\$265

2013 OPEB Sensitivity <sup>(2)</sup> (in \$M)						
S&P Returns in Q4 2012 <sup>(3)</sup>						
10%		0%		-10%		
Discount Rate at 12/31/12	Pre-Tax Expense <sup>(1)</sup>	Contributions <sup>(2)</sup>	Pre-Tax Expense <sup>(1)</sup>	Contributions <sup>(2)</sup>	Pre-Tax Expense <sup>(1)</sup>	Contributions <sup>(2)</sup>
Baseline Discount Rate <sup>(4)</sup>	\$220	\$275	\$235	\$295	\$250	\$315
+50 bps	\$185	\$235	\$200	\$255	\$215	\$275
- 50bps	\$255	\$320	\$270	\$340	\$285	\$360

(1) Contributions shown in the table above are based on the current contribution policy for Exelon and Constellation plans and include the impact of pension funding relief.

(2) Pension and OPEB expenses assume an ~ 24% capitalization rate in 2013.

(3) Final 2012 asset return for pension and OPEB will depend in part on overall equity market returns for Q4 2012 as proxied by the S&P 500. The amounts above reflect YTD S&P returns through September 30, 2012.

(4) The baseline discount rates reflect a projected 12/31/12 pension discount rate of 3.87% and 3.67% for Exelon and Constellation, respectively, and OPEB discount rate of 3.96% and 3.69% for Exelon and Constellation, respectively.

# Additional 2012 ExGen and CENG Modeling

P&L Item	2012 Stub <sup>(1)</sup> Estimate	2012 Full-Year <sup>(2)</sup> Estimate
<b>ExGen Model Inputs <sup>(3)</sup></b>		
O&M <sup>(4)</sup>	\$4,000M	\$4,250M
Taxes Other Than Income (TOTI)	\$300M	\$300M
Depreciation & Amortization <sup>(5)</sup>	\$700M	\$750M
Interest Expense	\$300M	\$350M
<b>CENG Model Inputs</b>		
Gross Margin	Included in ExGen Disclosures	
O&M <sup>(6)</sup>	\$350M	\$450M
Depreciation & Amortization <sup>(7)</sup>	\$100M	\$100M

(1) Stub period represents estimates for March 12 – December 31, 2012 and is reflected as part of ExGen's 2012 earnings guidance.

(2) Full-year estimates provided for modeling purposes.

(3) ExGen amounts for O&M, TOTI and Depreciation & Amortization exclude the impacts of CENG. CENG impact is reflected in "Equity earnings of unconsolidated affiliates" in the Income Statement.

(4) ExGen O&M excludes decommissioning costs and the impact from O&M related to entities consolidated solely as a result of the application of FIN 46R.

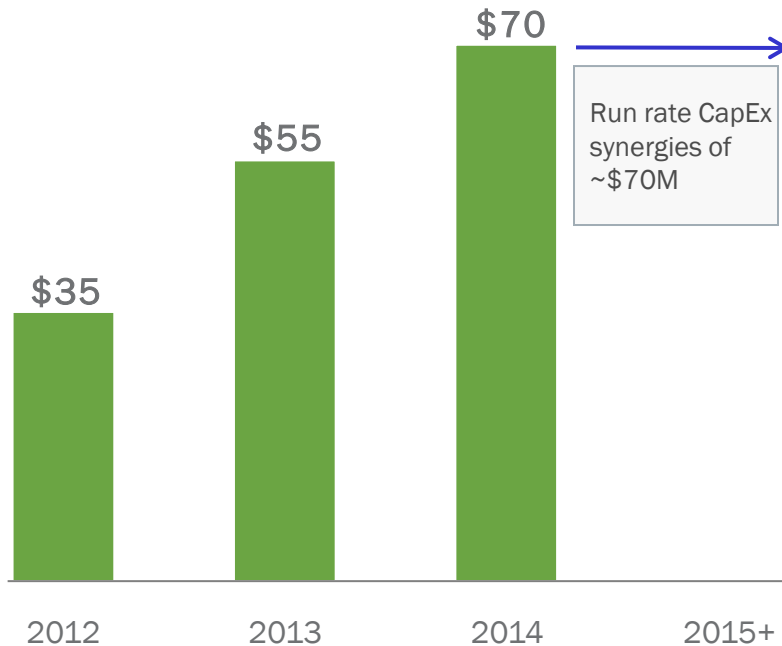
(5) ExGen Depreciation & Amortization excludes the impact of decommissioning.

(6) CENG O&M includes TOTI of \$20M for stub estimate and \$25M for full-year estimate.

(7) CENG Depreciation & Amortization includes accretion expense.

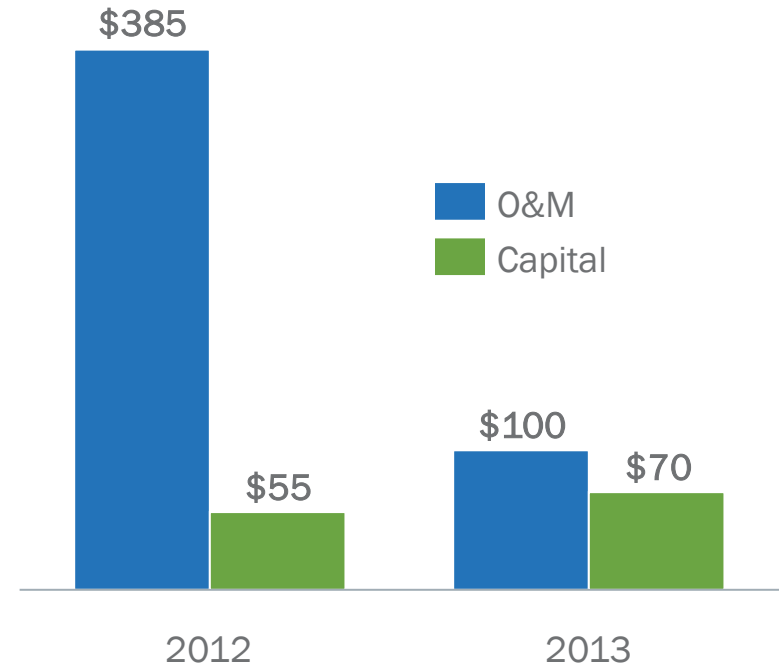
# Merger CapEx Synergies & Costs To Achieve

CapEx Synergies (\$M)



- On track to achieve CapEx synergies in 2012 and beyond
- Run rate CapEx synergies mainly driven by:
  - Information Technology (IT) systems consolidation
  - Supply Chain capital synergies

Costs to Achieve (\$M)

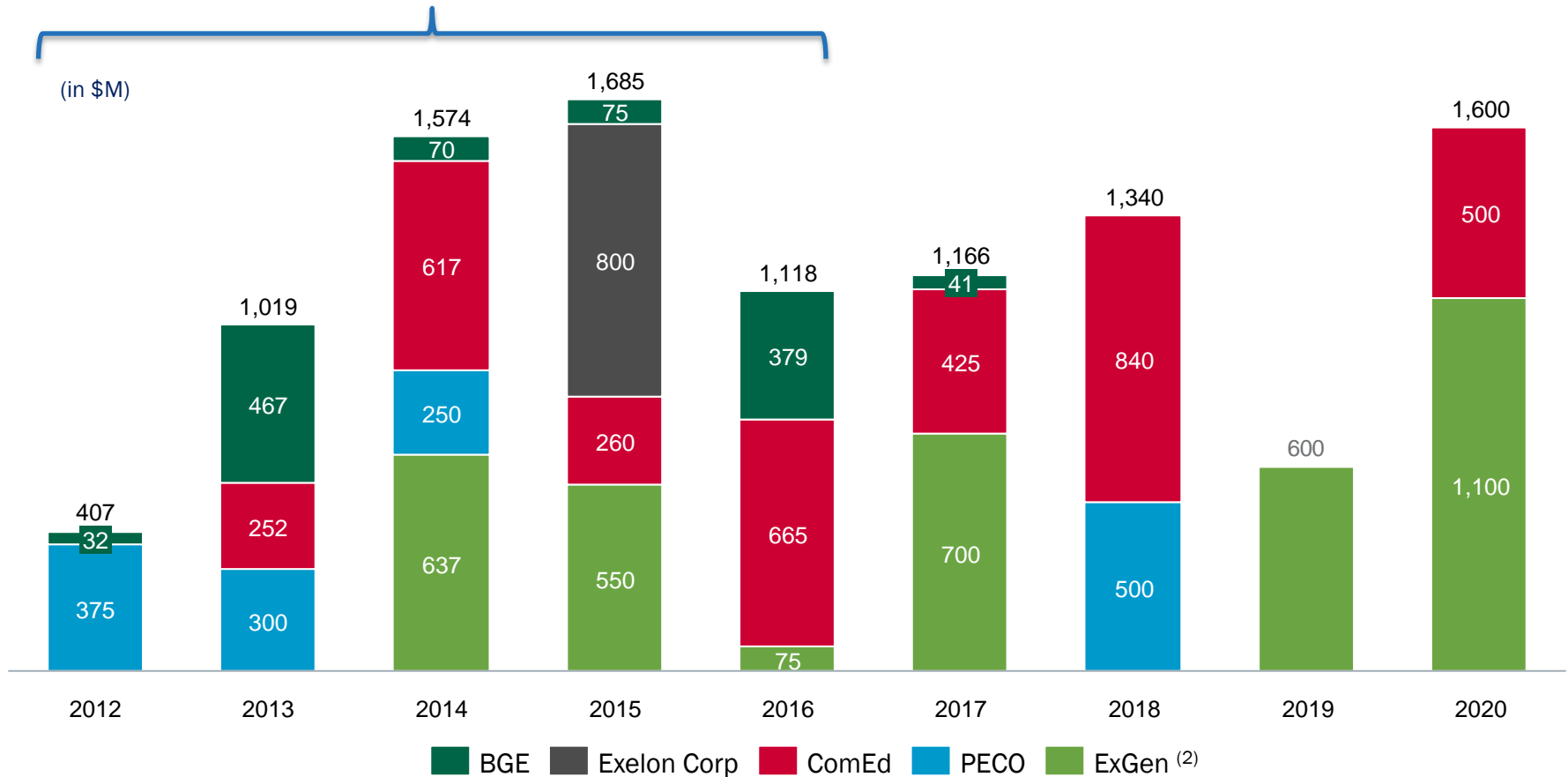


- Costs to achieve excluded from operating earnings
- Key areas of costs to achieve:
  - IT systems consolidation
  - Transaction costs (banker, legal costs, etc.)
  - Employee-related costs

# Debt Maturity Schedule

## Debt Maturity Profile<sup>(1)</sup> (2012-2020)

~64% of 2012 – 2016 debt maturities consist of regulated utility debt



(1) As of 9/30/12

(2) Includes \$550M in 2015 and 2020 of inter-company loan agreements between Exelon and Exelon Generation that mirror the terms and amounts of the third party obligations of Exelon.

# GAAP to Operating Adjustments

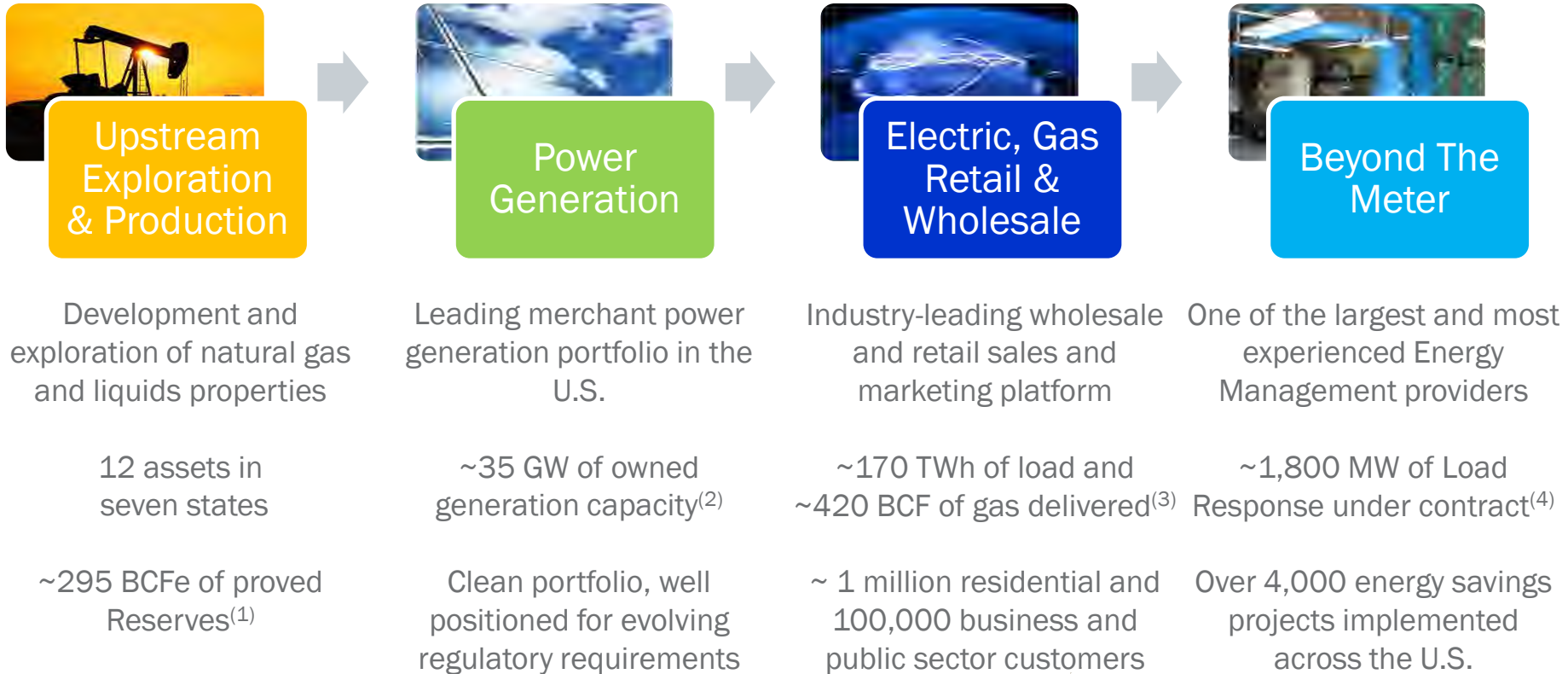
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- **Exelon's 2012 adjusted (non-GAAP) operating earnings outlook excludes the earnings effects of the following:**
  - Mark-to-market adjustments from economic hedging activities
  - Unrealized gains and losses from nuclear decommissioning trust fund 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 and the expected sale in the fourth quarter of 2012 of three generating stations as required by the merger
  - Changes in decommissioning obligation estimates
  - Certain costs incurred 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
  - Changes in state deferred tax rates resulting from a reassessment of anticipated apportionment of Exelon's deferred taxes as a result of the merger
  - Non-cash amortization of certain debt recorded at fair value at the merger date expected to be retired in 2013
  - 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**



# Commercial Business Overview

## Scale, Scope and Flexibility Across the Energy Value Chain



**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 9/30/2012, net of physical market mitigation (Brandon Shores, C.P. Crane and H.A. Wagner ~2,648 MW).

(3) Expected for 2012 as of 9/30/2012. Electric load and gas includes fixed price and indexed products. No stub period adjustment for legacy Constellation contribution.

(4) Load Response estimate as of 9/30/2012.



# 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

**Leading Merchant  
Generation Fleet**

**Electric Load Serving  
Business**

**Portfolio and Risk  
Management**

**~\$8 billion in gross margin per year**

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

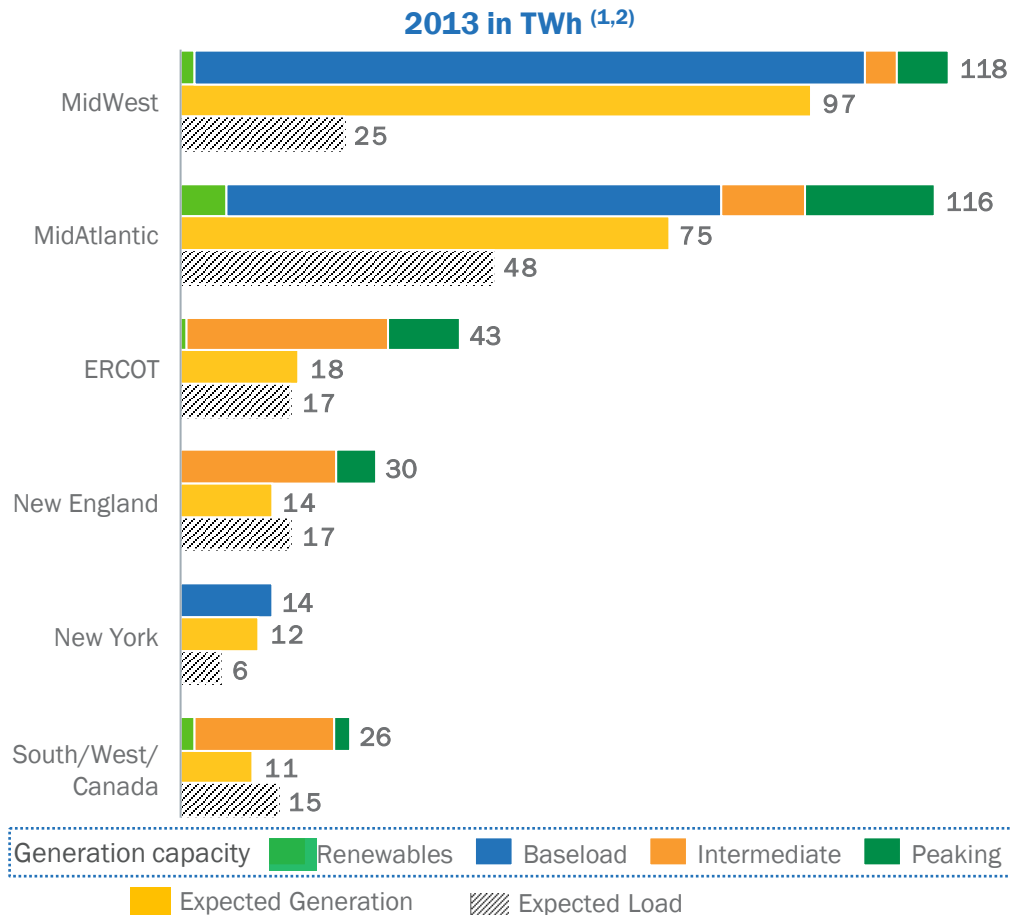
Leverage  
relationships  
with large  
wholesale  
customers

Monetize risk  
management  
expertise

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

# Generation and Load Match

## Generation Capacity, Expected Generation and Expected Load



## Generation & Load Match: Competitive Advantage

We have already seen benefits across the portfolio this summer:

- Took advantage of large moves in summer heat rates in ERCOT
  - Sold excess peaking generation at pre-summer higher forward contract prices
  - Bought back below the cost of our units when actual market heat rates dropped through delivery
- Sold load following products against our PJM portfolio through our retail and wholesale load channels
  - Now able to sell closer to our generation locations reducing risk associated with locational pricing
  - Generation dispatched due to high summer delivered heat rates and helped serve higher loads from the hot weather

**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 9/30/2012.

# Minimum Offer Price Rules (MOPR) Update

## PJM is proposing modifications to the MOPR to ensure uneconomic generation does not distort market

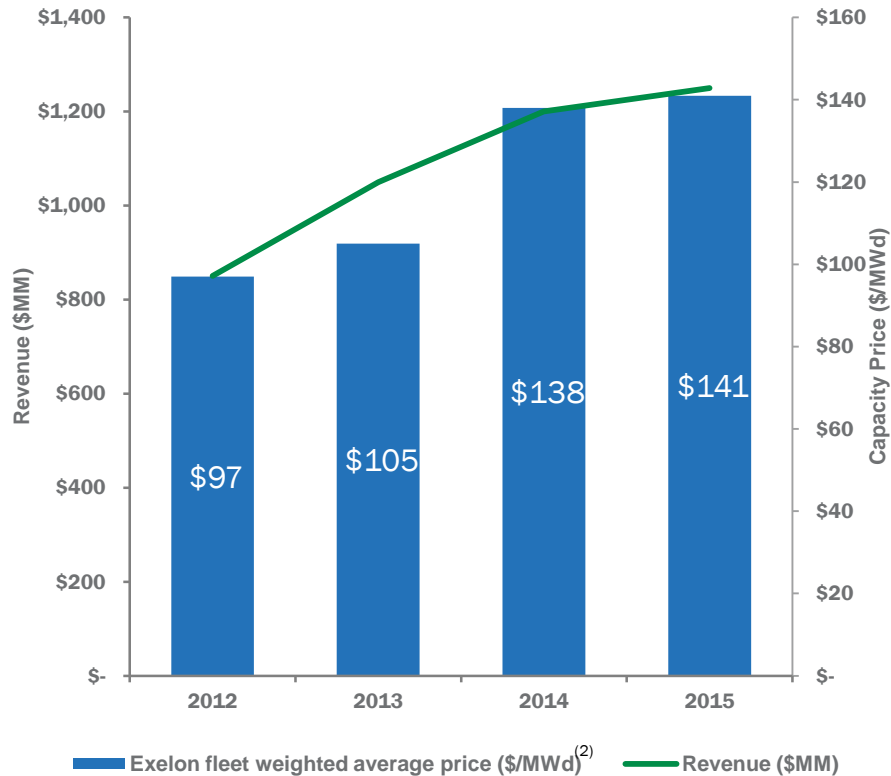
- Restructured MOPR
  - MOPR to apply to all new gas-fired and IGCC units in PJM, with limited exceptions
  - MOPR exemption to be available only to self-supply entities and competitive market entrants
  - MOPR floor to apply for three years, set at 100% of the net cost of new entry
- Implementation/Timing
  - PJM currently reviewing restructured MOPR with all stakeholders
  - PJM expected to file for FERC approval by November 30, 2012
  - Exelon, other generators, and other stakeholders to support PJM's filing
  - FERC approval expected in early February, 2013



Note: IGCC = Integrated Gasification Combined Cycle. FERC = Federal Energy Regulatory Commission. RPM= Reliability Pricing Model.

# Capacity Markets

**PJM RPM Capacity Revenues<sup>(1)</sup>**



	2011/ 2012	2012/ 2013	2013/ 2014	2014/ 2015	2015/ 2016
--	---------------	---------------	---------------	---------------	---------------

<b>PJM<sup>(3,8)</sup></b>					
<b>RTO</b>	<i>Capacity</i>	27,400	12,800	11,500	11,500
	<i>Price</i>	\$110	\$16	\$28	\$126
<b>EMAAC</b>	<i>Capacity<sup>(4)</sup></i>		9,100	9,100	9,100
	<i>Price</i>		\$140	\$245	\$168
<b>MAAC</b>	<i>Capacity</i>		2,600	2,700	2,700
	<i>Price</i>		\$133	\$226	\$168
<b>SWMAAC</b>	<i>Capacity<sup>(5)</sup></i>		1,800	1,800	1,800
	<i>Price</i>		\$133	\$226	\$168
<b>Average Exelon</b>		\$110	\$78	\$142	\$153
<b>New England<sup>(6)</sup></b>					
<b>NEMA</b>	<i>Capacity</i>	2,100	2,100	2,100	2,100
	<i>Price</i>	\$104 <sup>(7)</sup>	\$85 <sup>(7)</sup>	\$85 <sup>(7)</sup>	\$107
<b>SEMA</b>	<i>Capacity</i>	35	35	35	35
	<i>Price</i>	\$104 <sup>(7)</sup>	\$85 <sup>(7)</sup>	\$85 <sup>(7)</sup>	\$95 <sup>(7)</sup>
<b>Rest of Pool</b>	<i>Capacity</i>	700	700	700	700
	<i>Price</i>	\$104 <sup>(7)</sup>	\$85 <sup>(7)</sup>	\$85 <sup>(7)</sup>	\$95 <sup>(7)</sup>
<b>NYISO<sup>(8)</sup></b>					
<b>Rest of Pool</b>	<i>Capacity</i>	1,100	1,100	1,100	1,100
<b>MISO<sup>(9)</sup></b>					
<b>AMIL</b>	<i>Capacity</i>	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.

(6) Reflects Qualified Summer Capacity including owned and contracted units.

(7) Price is pro-rated for auctions that clear at the floor price and there is more capacity procured than suggested by the reliability requirement.

(8) Reflects 50.01% ownership in CENG.

(9) Does not include wind under PPA.

(1) Revenues reflect capacity cleared in base and incremental auctions and are for calendar years. Revenue rounded to nearest \$50M.

(2) Weighted average \$/MW-Day would apply if all owned generation cleared.

(3) Reflects owned and contracted generation Installed Capacity (ICAP) adjusted for mid-year PPA roll offs.

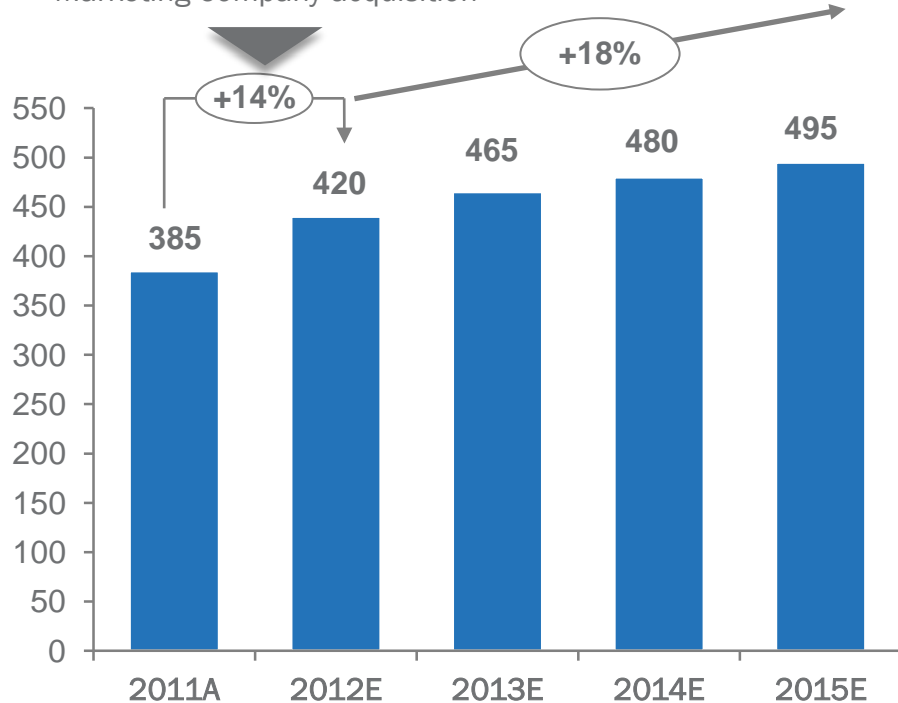
(4) ICAP is net of Eddystone 1&2, Cromby 1&2 and Schuylkill 1 (total ~ 1,100 MW).

(5) ICAP is net of units to be divested (Brandon Shores, Wagner & Crane ~2,648 MW; Constellation offered these units in PY11/12 - PY 15/16 auctions) and Riverside 6 CT (~115MW).

# Retail and Wholesale Gas

## Retail Gas<sup>(1)</sup> (2011 – 2015 Bcf)

Contribution from ONEOK Energy  
Marketing Company acquisition



(1) Estimate as of 9/30/2012.

### Retail Gas

#### Portfolio Size:

- 420 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

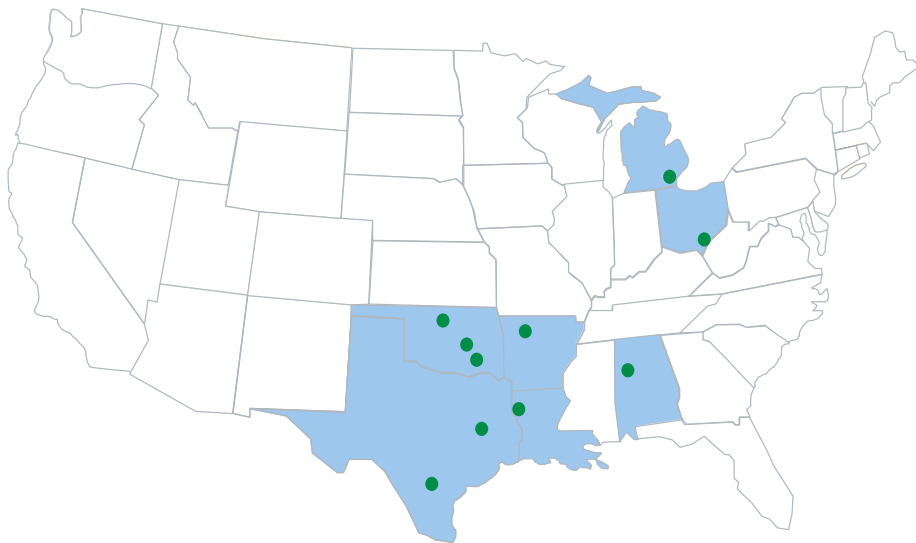
#### Portfolio Size:

- 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
- Increase market knowledge of regional and basis transport information to assist power forecasting

# Upstream E&P Assets



## Current Portfolio Of Investments

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

## Investment Thesis

- Our Upstream Gas business achieves strong returns (>12% IRR)
- \$150m (~50% utilized) Reserve Based Lending (RBL) facility in place
  - Receives off-balance sheet treatment from S&P
- Provides valuable market intelligence in complex natural gas markets

## Forecasted Production

	<u>2012</u>	<u>2013</u>	<u>2014</u>	<u>2015</u>
Net Daily Prod (MMcfe / day)	55 - 70	55 - 70	60 - 75	60 - 75

Estimated Net Proved  
Reserves  
(as of 12/31/11)

295 Bcfe

Average Net Daily  
Production  
(Q2 2012)

60.3 MMcfe

(1) Oil/NGL conversion to gas is 6:1.

(2) Constellation does not operate any of its properties.

Note: E&P = Exploration and Production

# **Exelon Generation Disclosures**

**September 30, 2012**

**(As disclosed in Third Quarter 2012 Earnings materials)**



# 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, investment-grade credit rating)
- Hedge enough commodity risk to meet future cash requirements under a stress scenario

## Three-Year Ratable Hedging

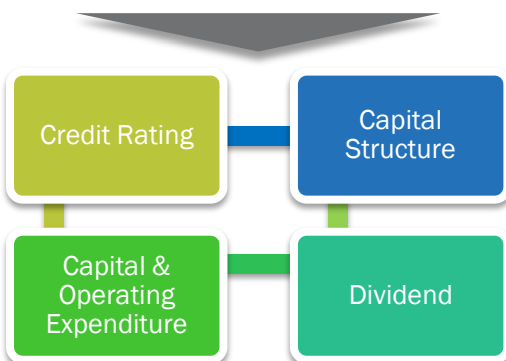
- Ensure stability in near-term cash flows and earnings
  - Disciplined approach to hedging
  - Tenor aligns with customer preferences and market liquidity
  - Multiple channels to market that allow us to maximize margins
  - Large open position in outer years to benefit from price upside

## Bull / Bear Program

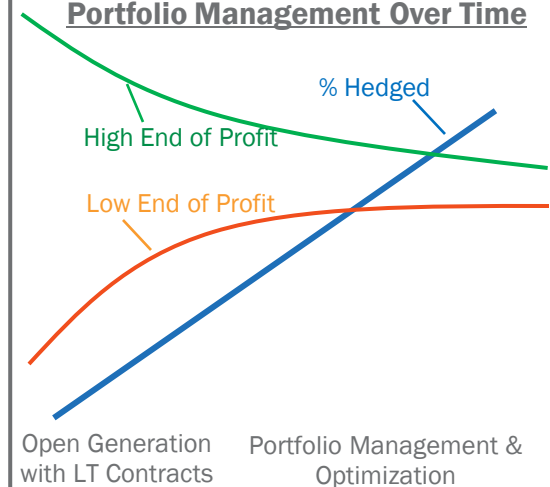
- Ability to exercise fundamental market views to create value within the ratable framework
  - Modified timing of hedges versus purely ratable
  - Cross-commodity hedging (heat rate positions, options, etc.)
  - Delivery locations, regional and zonal spread relationships

## Align Hedging & Financials

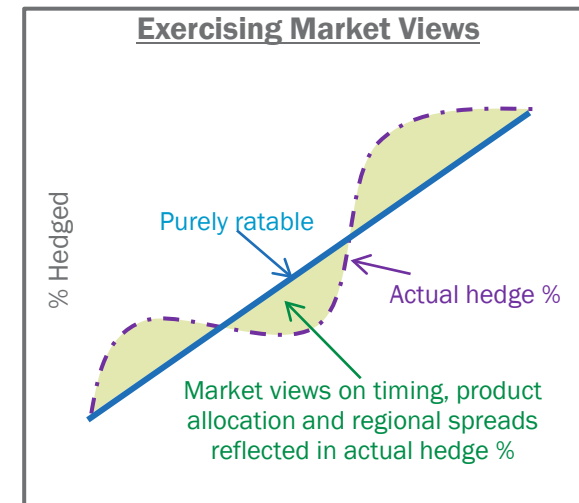
### Establishing Minimum Hedge Targets



## Portfolio Management Over Time



## Exercising Market Views

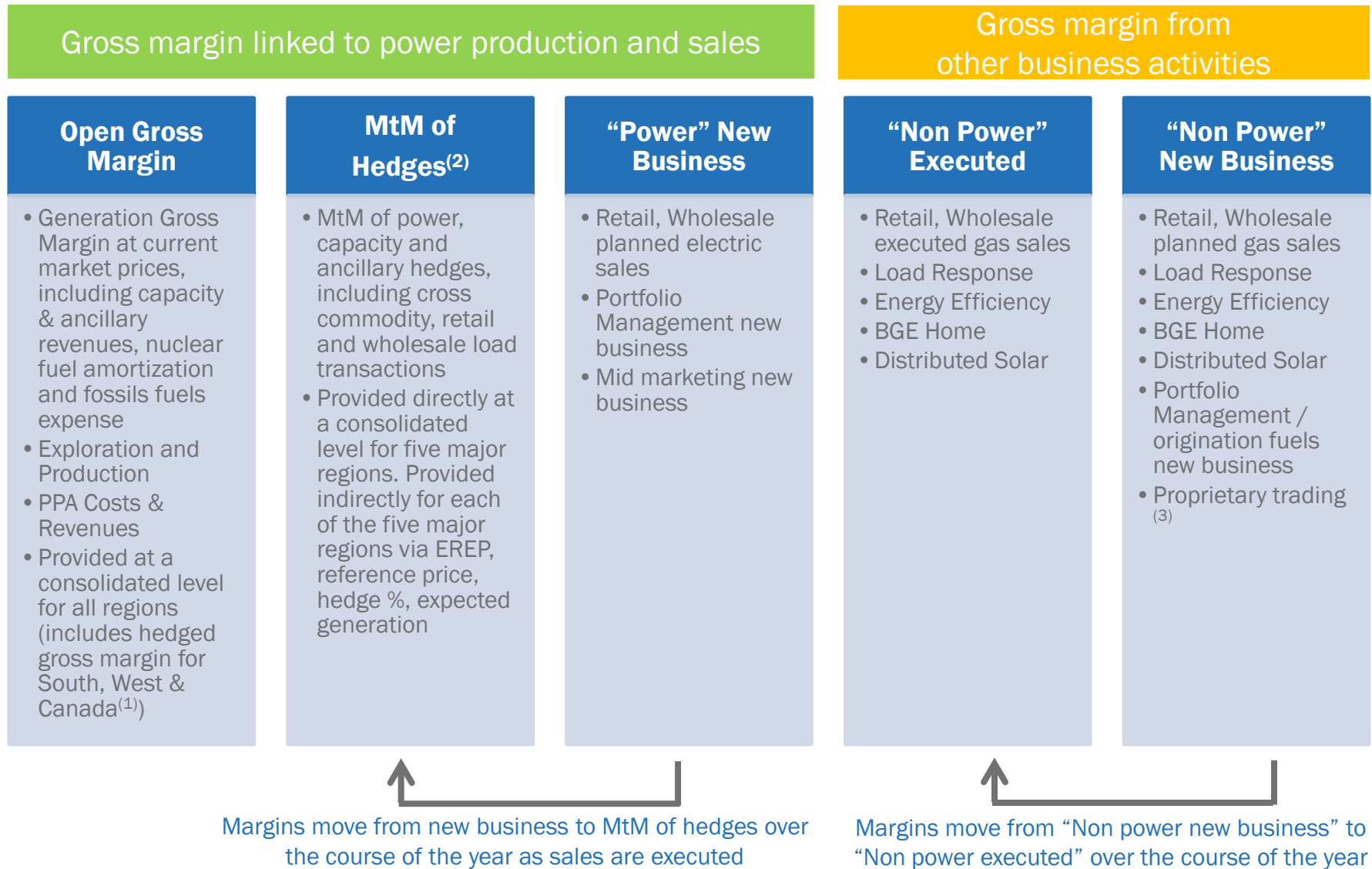


**Protect Balance Sheet**

**Ensure Earnings Stability**

**Create Value**

# Components of Gross Margin Categories



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

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

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

# ExGen Disclosures

Gross Margin Category (\$M) <sup>(1,2)</sup>	2012 <sup>(3)</sup>	2013	2014	2015
Open Gross Margin (including South, West & Canada hedged GM) <sup>(4,5)</sup>	\$4,500	\$5,750	\$6,050	\$6,200
Mark to Market of Hedges <sup>(5,6)</sup>	\$3,200	\$1,350	\$500	\$250
Power New Business / To Go	\$50	\$500	\$750	\$950
Non-Power Margins Executed	\$300	\$150	\$100	\$50
Non-Power New Business / To Go	\$100	\$450	\$500	\$550
<b>Total Gross Margin</b>	<b>\$8,150</b>	<b>\$8,200</b>	<b>\$7,900</b>	<b>\$8,000</b>

Reference Prices <sup>(7)</sup>	2012	2013	2014	2015
Henry Hub Natural Gas (\$/MMbtu)	\$2.77	\$3.84	\$4.18	\$4.37
Midwest: NiHub ATC prices (\$/MWh)	\$28.95	\$30.59	\$31.34	\$32.32
Mid-Atlantic: PJM-W ATC prices (\$/MWh)	\$33.93	\$38.24	\$39.44	\$40.77
ERCOT-N ATC Spark Spread (\$/MWh) <i>HSC Gas, 7.2HR, \$2.50 VOM</i>	\$3.67	\$8.37	\$8.30	\$7.15
New York: NY Zone A (\$/MWh)	\$30.85	\$35.19	\$35.98	\$36.55
New England: Mass Hub ATC Spark Spread(\$/MWh) <i>ALQN Gas, 7.5HR, \$0.50 VOM</i>	\$6.72	\$4.42	\$3.79	\$4.07

(1) Gross margin does not include revenue related to decommissioning, Exelon Nuclear Partners and entities consolidated solely as a result of the application of FIN 46R.

(2) Gross margin rounded to nearest \$50M.

(3) Stub period calculated by excluding Jan 2012 through mid-March 2012 for Constellation only.

(4) Excludes Maryland assets to be divested.

(5) Includes CENG Joint Venture.

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

(7) Based on September 30, 2012 market conditions.

# ExGen Disclosures

Generation and Hedges	2012 <sup>(1)</sup>	2013	2014	2015
<u>Exp. Gen (GWh) <sup>(4)</sup></u>	<b>219,500</b>	<b>218,700</b>	<b>211,400</b>	<b>209,800</b>
Midwest	100,700	97,400	97,500	99,000
Mid-Atlantic <sup>(2,3)</sup>	71,800	75,000	72,200	71,800
ERCOT	19,900	18,500	16,900	15,800
New York <sup>(3)</sup>	13,000	13,800	10,900	9,300
New England	14,100	14,000	13,900	13,900
<u>% of Expected Generation Hedged <sup>(5)</sup></u>	<b>99-102%</b>	<b>88-91%</b>	<b>56-59%</b>	<b>21-24%</b>
Midwest	99-102%	89-92%	56-59%	20-23%
Mid-Atlantic <sup>(2,3)</sup>	99-102%	88-91%	57-60%	24-27%
ERCOT	96-99%	78-81%	53-56%	28-31%
New York <sup>(3)</sup>	98-101%	92-95%	61-64%	15-18%
New England	97-100%	89-92%	51-54%	11-14%
<u>Effective Realized Energy Price (\$/MWh) <sup>(6)</sup></u>				
Midwest	\$42.00	\$38.00	\$35.00	\$34.50
Mid-Atlantic <sup>(2,3)</sup>	\$56.00	\$48.00	\$47.50	\$50.50
ERCOT <sup>7</sup>	\$9.00	\$7.50	\$5.00	\$5.00
New York <sup>(3)</sup>	\$44.00	\$36.00	\$35.00	\$52.00
New England <sup>(7)</sup>	\$8.00	\$7.00	\$4.00	\$5.00

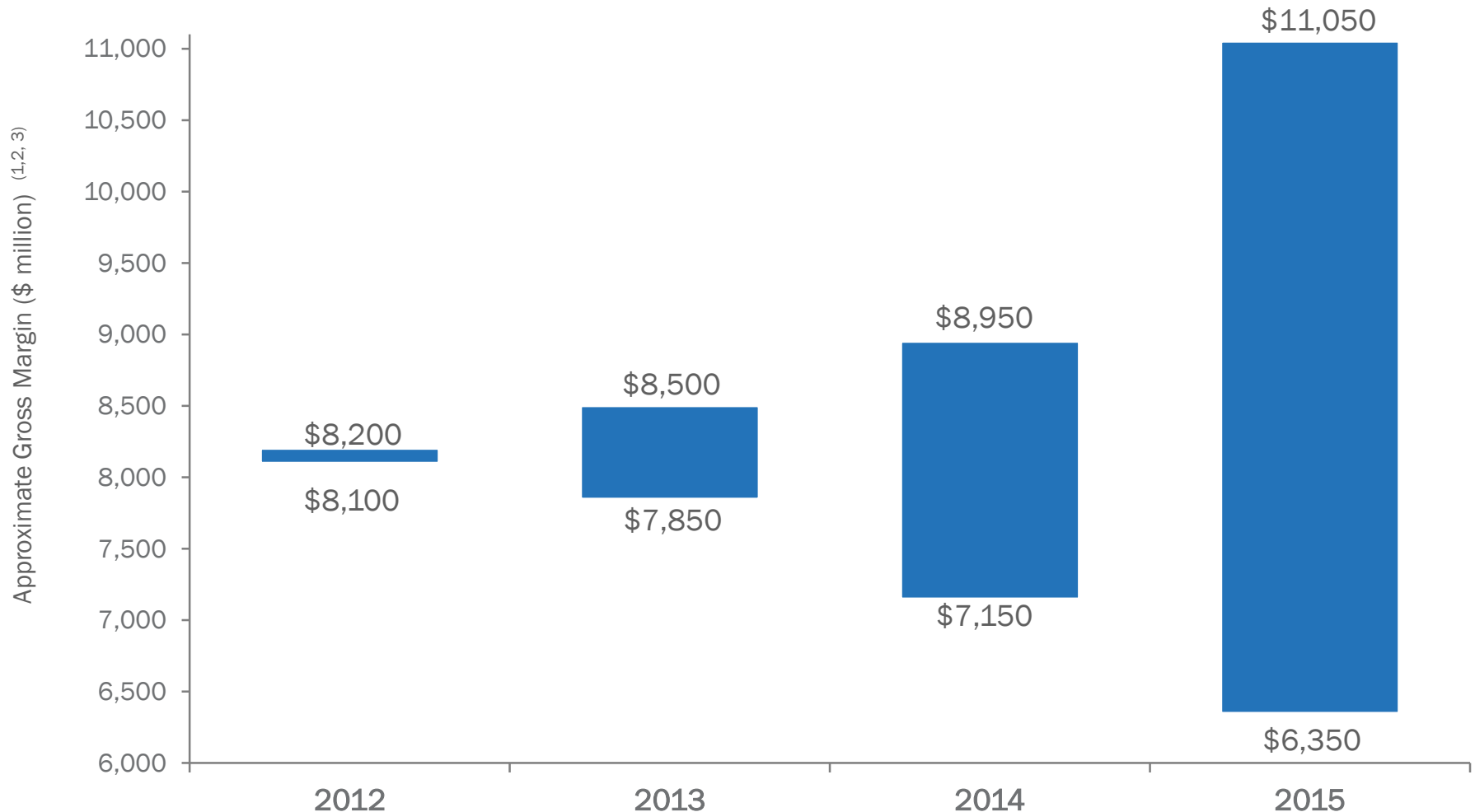
(1) Stub period calculated by excluding Jan 2012 thru mid-March 2012 for Constellation only. (2) Excludes Maryland assets to be divested (3) Includes CENG Joint Venture. (4) Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted for capacity. 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 and 2015 at Exelon-operated nuclear plants and Salem but excludes CENG. Expected generation assumes capacity factors of 92.8%, 93.5%, 93.8%, and 93.3% in 2012, 2013, 2014 and 2015 at Exelon-operated nuclear plants excluding Salem and CENG. These estimates of expected generation in 2012, 2013, 2014 and 2015 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.

# ExGen Hedged Gross Margin Sensitivities

Gross Margin Sensitivities (With Existing Hedges) <sup>(1, 4)</sup>	2012	2013	2014	2015
Henry Hub Natural Gas (\$/MMbtu) <sup>(2)</sup>				
+ \$1/MMbtu	\$(5)	\$55	\$400	\$780
- \$1/MMbtu	\$25	\$(15)	\$(325)	\$(700)
NiHub ATC Energy Price				
+ \$5/MWh	\$(5)	\$40	\$230	\$390
- \$5/MWh	\$5	\$(35)	\$(230)	\$(385)
PJM-W ATC Energy Price <sup>(2)</sup>				
+ \$5/MWh	\$(5)	\$50	\$165	\$295
- \$5/MWh	\$5	\$(40)	\$(160)	\$(285)
NYPP Zone A ATC Energy Price				
+ \$5/MWh	\$5	\$15	\$35	\$45
- \$5/MWh	\$(5)	\$(15)	\$(35)	\$(45)
Nuclear Capacity Factor <sup>(3)</sup>				
+/- 1%	+/- \$10	+/- \$40	+/- \$45	+/- \$45

(1) Based on September 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 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, 2014 and 2015 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 September 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.

# Illustrative Example of Modeling Exelon Generation 2013 Gross Margin

ZECJ-FIN-21

PUBLIC

Row	Item	Midwest	Mid-Atlantic	ERCOT	New England	New York	South, West & Canada
(A)	Start with fleet-wide open gross margin	<div> <div></div> <div>\$5.75 billion</div> <div></div> </div>					
(B)	Expected Generation (TWh)	97.4	75.0	18.5	14.0	13.8	
(C)	Hedge % (assuming mid-point of range)	90.5%	89.5%	79.5%	90.5%	93.5%	
(D=B*C)	Hedged Volume (TWh)	88.2	67.1	14.7	12.7	12.9	
(E)	Effective Realized Energy Price (\$/MWh)	\$38.00	\$48.00	\$7.50	\$7.00	\$36.00	
(F)	Reference Price (\$/MWh)	\$30.59	\$38.24	\$8.37	\$4.42	\$35.19	
(G=E-F)	Difference (\$/MWh)	\$7.41	\$9.76	(\$0.87)	\$2.58	\$0.81	
(H=D*G)	Mark-to-market value of hedges (\$ million) <sup>(1)</sup>	\$655 million	\$655 million	(\$15) million	\$35 million	\$10 million	
(I=A+H)	Hedged Gross Margin (\$ million)	\$7,100 million					
(J)	Power New Business / To Go (\$ million)	\$500 million					
(K)	Non-Power Margins Executed (\$ million)	\$150 million					
(L)	Non- Power New Business / To Go (\$ million)	\$450 million					
(N=I+J+K+L)	Total Gross Margin	\$8,200 million					

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



# Constellation Energy Nuclear Group (CENG) Background

As a result of Exelon's equity interest in CENG, CENG gross margins and earnings are reflected in ExGen disclosures and other financial statements. The following is information related to PPA contracts between CENG and 3<sup>rd</sup> parties and the PPA between CENG and its equity parents.

	<u>Calvert 1&amp;2</u>	<u>NMP 1</u>	<u>NMP 2 <sup>(1)</sup></u>	<u>Ginna<sup>(2)</sup></u>	
<u>Ownership Interest</u>					
Total Plant Capacity	1,705 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)	852.5 MW	310 MW	466.5 MW	290.5 MW	
<u>PPA structure (% output)</u>					
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

<b><u>CENG PPA with Parents</u></b>				
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%)				
	<u>2012</u>	<u>2013</u>	<u>2014</u>	<u>2015</u>
(% 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

# Exelon Utilities



# ComEd Distribution Rate Case Overview

## Summary of Filings

### 2011 Formula Rate Filing (Docket # 11-0721 filed 11/8/11; 2010 test year costs, 2011 plant additions, rates eff. June 2012 – Dec 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):

- \$168M reduction to revenue requirement; 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

ICC Re-hearing Order (issued 10/3/12) on pension asset, interest rate on reconciliation and average rate base

- Granted \$35M of prior disallowance related to pension, reflecting an updated total reduction to revenue requirement of \$133M
  - Upheld the average rate base decision
  - Order also revised the decision on interest on reconciliation balances, granting a rate equal to the short term debt rate
- ComEd filed a notice of appeal with the First Appellate Court on 10/4/12 and a motion to expedite on 10/10/12. The motion to expedite was denied, therefore, initial briefs are due on 12/13/12.

### 2012 Formula Rate Filing (Docket # 12-0321 filed 4/30/12, 2011 test year costs, 2012 projected plant additions, rates eff. Jan 2013 – December 2013)

- 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)<sup>(1)</sup>
- When factoring in 5/30/12 Order and 10/3/12 Re-hearing Order for #11-0721, ComEd proposes a \$74M increase to distribution revenue requirement
- Received staff and intervener direct testimony on 7/17/12 and rebuttal testimony on 9/11/12
- ICC order by 12/26/12; rates effective January 2013

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

# BGE Rate Case (Updated to reflect 10/22/12 filing)

Rate Case Request <sup>(1)</sup>	Electric	Gas
Docket #	9299	
Test Year	October 2011 – September 2012	
Common Equity Ratio	48.4%	
Requested Returns	ROE: 10.5%; ROR: 7.96%	
Rate Base	\$2.7B	\$1B
Revenue Requirement Increase	\$131M	\$45M
Proposed Distribution Price Increase as % of overall bill	4%	6%

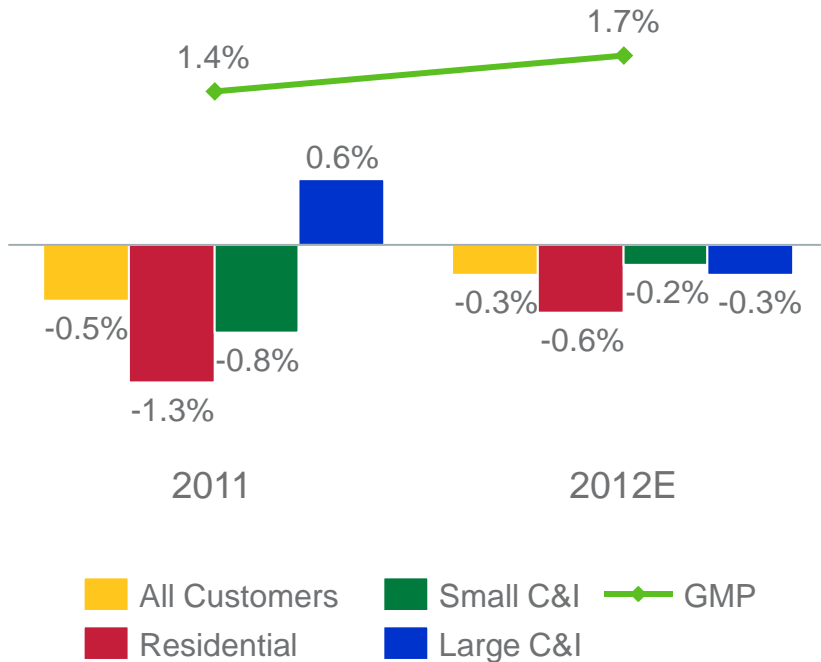
## Timeline

- 10/22/12: Update 8 months actual/4 month estimated test period data with actuals for last 4 months (June-Sept. 2012)
- 11/9/12: BGE and staff/intervenors file rebuttal testimony
- 11/20/12: Staff/Intervenors and BGE file surrebuttal testimony
- 12/3/12 – 12/18/12: Hearings
- 1/11/13: Initial Briefs
- 1/23/13: Reply Briefs
- 2/23/13: Decision
- New rates are in effect shortly after the decision

(1) Initial filing on 7/27/12 used 8 months of actuals and 4 months of projections for October 2011 – September 2012 time period and requested an ROR of 8.02%, electric revenue increase of \$151M and gas revenue increase of \$53M. Rate base, equity ratio and ROE have not changed materially since the 7/27/12 filing.

# ComEd Load

## Weather-Normalized Load YoY Growth



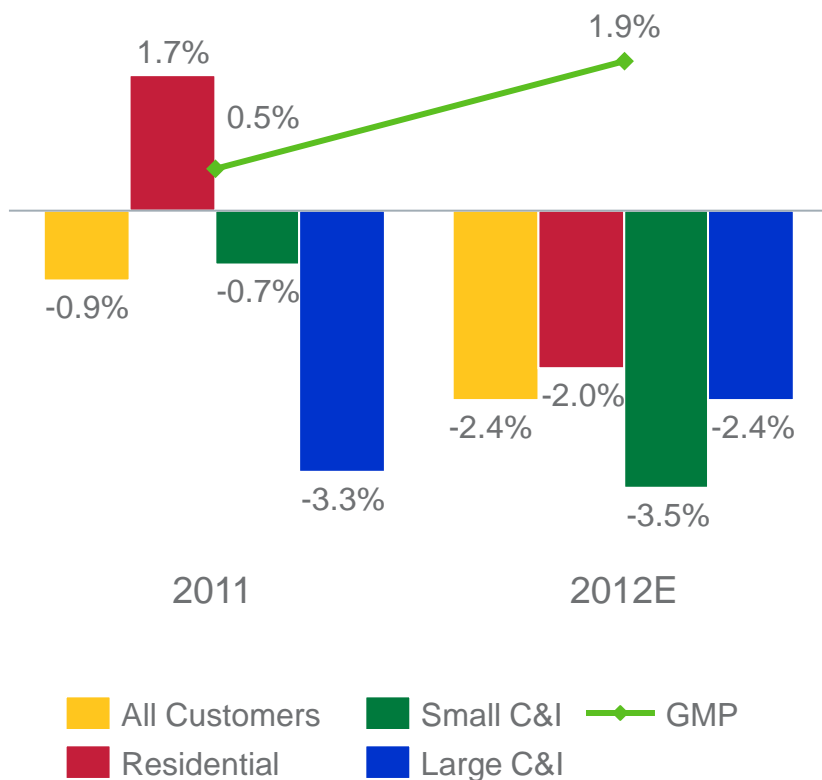
## Economic Forecast of Drivers that Influence Load

Driver or Indicator	2013 Outlook
Gross Metro Product (GMP)	1.5% growth in GMP, which reflects a slow growth economy
Employment	1.3% increase in total employment is expected for 2013.
Manufacturing	Manufacturing employment is expected to grow 2.0% in 2013, which is consistent with the growth in 2011 and 2012.
Households	Household formations is expected to increase 0.4% in 2013. This is slightly better than the 0.3% growth expected for 2012.
Energy Efficiency	Continued expansion of EE programs with ~ 1% reduction in usage in 2013.

**Slow growth economy and energy efficiency initiatives will continue to impact load growth**

Notes: 2012 data is not adjusted for leap year. Source of 2013 economic outlook data is Global Insight (July 2012).

## Weather-Normalized Load YoY Growth



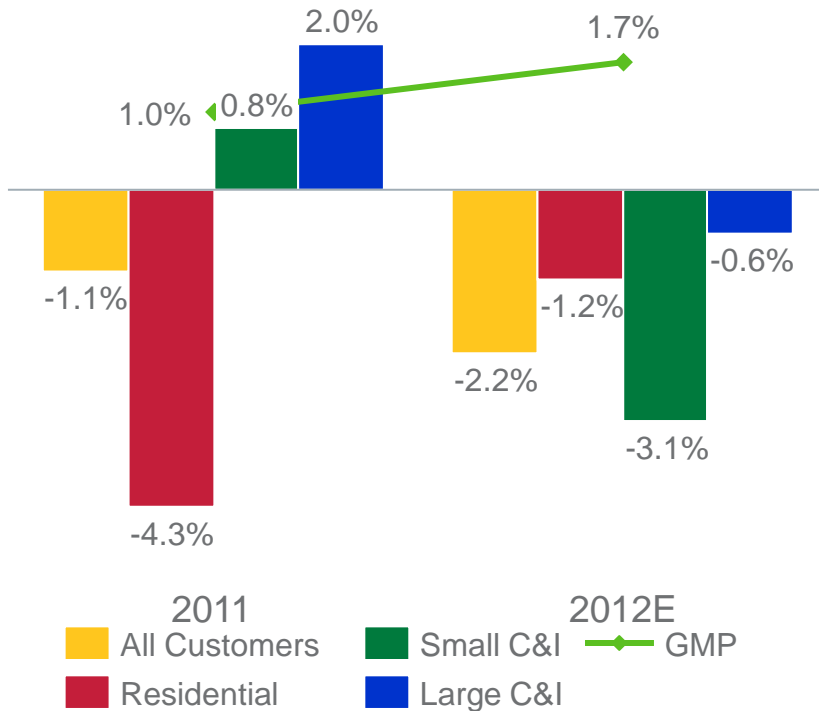
## Economic Forecast of Drivers that Influence Load

Driver or Indicator	2013 Outlook
Gross Metro Product (GMP)	GMP projected to grow at 1.8% for 2013, vs. pre-recession average of 2.5%
Employment	Resident Employment outlook is 1.3% in 2013 vs. 1.0% in 2012
Manufacturing	Manufacturing employment is expected to grow at 1.0%. Philadelphia has had negative growth from 2000 to 2011.
Households	Household growth is expected to be 0.3%, the same as the last three years.
Energy Efficiency	Energy Efficiency impact forecasted to be ~1% reduction in usage in 2013.

**Improvements at oil refineries will be partially offset by on-going energy efficiency initiatives**

Notes: 2012 data is not adjusted for leap year. Source of 2013 economic outlook data is Global Insight (July 2012).

## Weather-Normalized Load YoY Growth



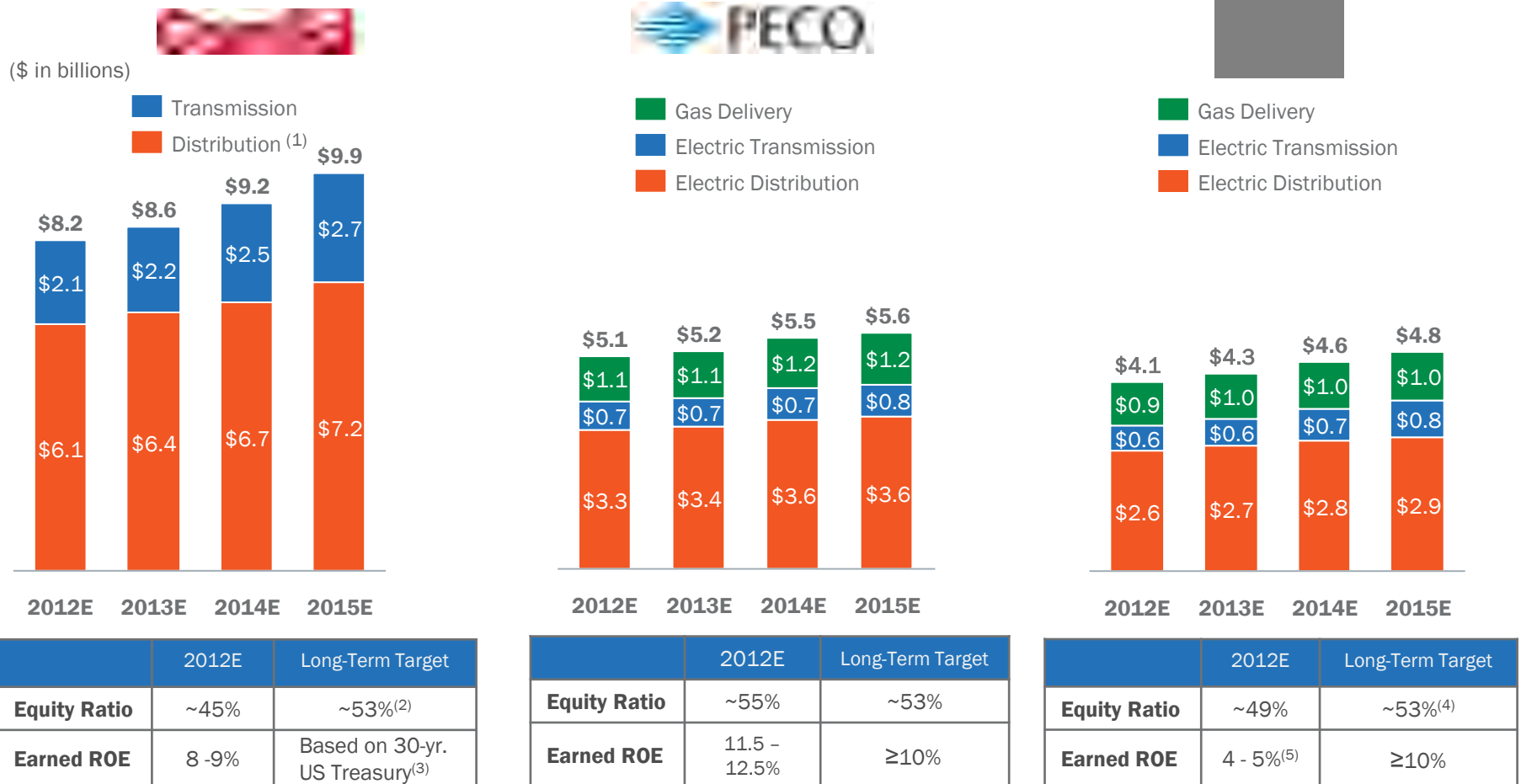
## Economic Forecast of Drivers that Influence Load

Driver or Indicator	2013 Outlook
Gross Metro Product (GMP)	GMP is projected to grow at 1.5% for 2013.
Employment	1.0% growth projected. BGE's decoupled non-rate case revenue growth is primarily driven by customer growth. The main driver for customer growth is employment.
Manufacturing	Manufacturing employment is expected to be fairly flat to 2012 levels in 2013
Personal Income	Projected to grow at 1.7%
Energy Efficiency	Continued expansion of EE programs will offset any growth seen due to improvements in economic conditions.

**2013 is expected to be another transition year for the Baltimore economy with continued slow growth projected combined with the shutdown of RG Steel**



# Exelon Utilities: Rate Base and ROE Targets



## Continued investment in Utilities will provide stable earnings growth

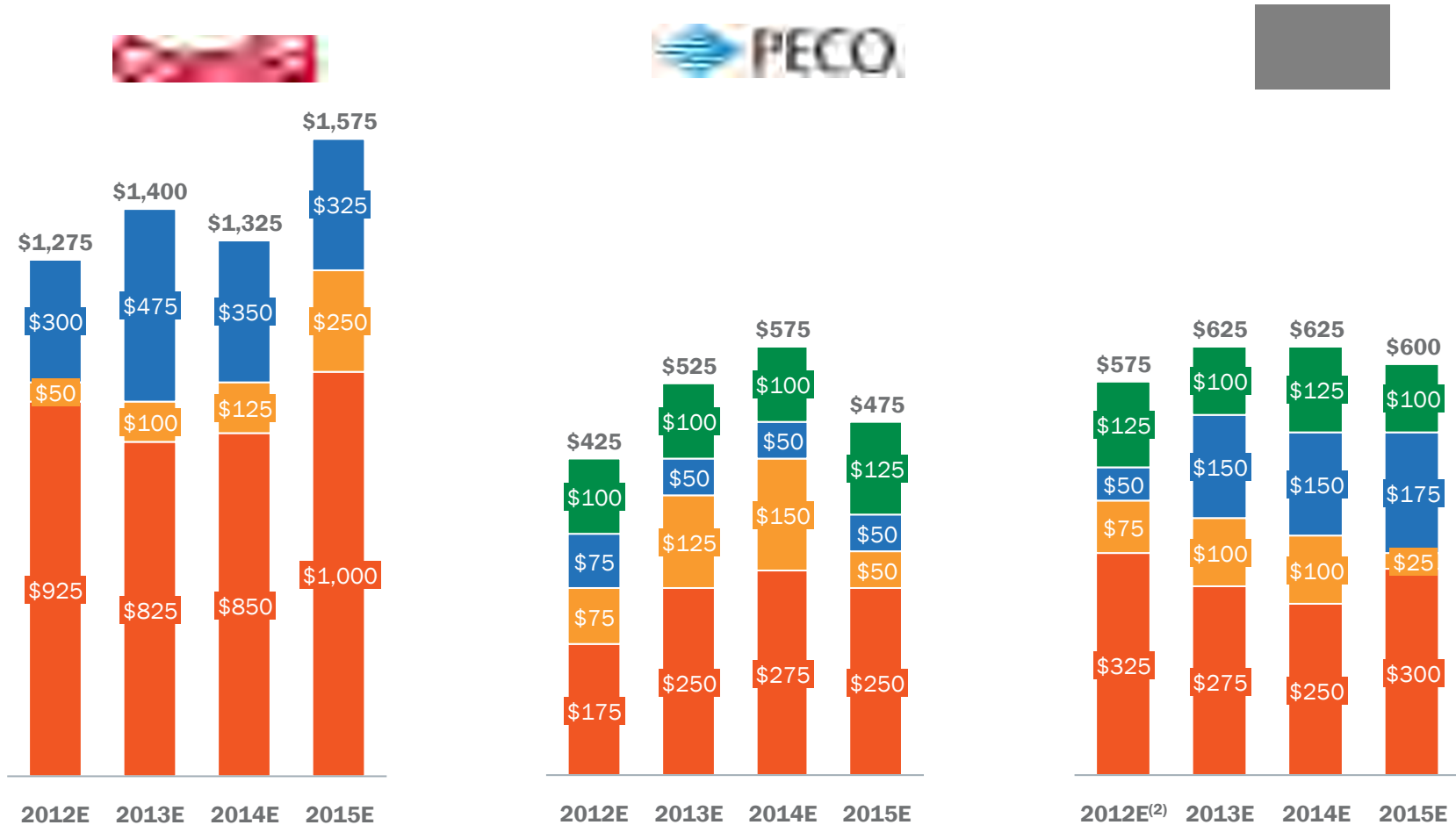
- (1) ComEd distribution rate base represents an average and transmission rate base represents end of year; PECO rate base represents end-of-year; and BGE rate base represents a trailing 13-month average. Numbers may not add due to rounding.
- (2) Equity component for distribution rates will be the actual capital structure adjusted for goodwill.
- (3) 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.

- (4) 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%.
- (5) ROE represents full year of 2012 earnings and therefore includes activity prior to the merger close in March 2012.

# Capital Expenditures

(\$ in millions)

■ Gas Delivery 
 ■ Electric Transmission 
 ■ Smart Meter/Smart Grid<sup>(1)</sup>
■ Electric Distribution



(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 \$500M.

# Smart Meter / Smart Grid Update

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

- Installation of nearly 4M smart electric meters delayed to Q1 2015 pending order on rehearing
- 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 distribution formula rate

## 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<sup>(1)</sup>, 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<sup>(1)</sup>, 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.

# 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
- PA PUC entered an Opinion and Order on October 12, 2012

	Proposed Procurement Mix	
Class	DSP I (1/1/11 – 5/31/13)	DSP II (6/1/13 – 5/31/15)
<b>Large C&amp;I</b> Current load retained: 3%	<ul style="list-style-type: none"> <li>100% spot-priced FR<sup>(1)</sup> products</li> <li>2011 opt-in FPFR<sup>(2)</sup> product</li> </ul>	<ul style="list-style-type: none"> <li>100% spot-priced FR products</li> </ul>
<b>Medium Commercial</b> Current load retained: 17%	<ul style="list-style-type: none"> <li>85% 1-year FPFR products, 15% spot-priced FR products</li> </ul>	<ul style="list-style-type: none"> <li>100% 6-month FPFR products</li> </ul>
<b>Small Commercial</b> Current load retained: 42%	<ul style="list-style-type: none"> <li>70% 1-year FPFR products, 20% 2-year FPFR products, 10% spot-priced FR products</li> </ul>	<ul style="list-style-type: none"> <li>100% 1-year FPFR products</li> </ul>
<b>Residential</b> Current load retained: 70%	<ul style="list-style-type: none"> <li>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</li> </ul>	<ul style="list-style-type: none"> <li>As block products expire, block and spot is replaced by FPFR products with terms ending 5/31/15 (end of DSP II period)</li> <li>Remainder of portfolio is a mix of 2-yr and 1-yr FPFR products, with delivery periods overlapping on a semi-annual basis</li> </ul>

## PA PUC order:

- Directs PECO to develop a plan by 1/1/14 to allow Customer Assistance Program (CAP) customers to select an Electric Generation Supplier (EGS)
- Provides for some changes to PECO's Retail Market Enhancements (Opt-In and Customer Referral programs)
- Directs PECO, EGSs, and interested parties to submit a plan within 60 days to address how participating EGSs will pay for Retail Market Enhancements

(1) FR = Full Requirements; (2) FPFR = Fixed-Price Full Requirements  
 Retention as of: October 9, 2012

# 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	6/1/12 – 5/31/13	6/1/13 – 5/31/14
<b>Large C&amp;I (Hourly)</b> Current load retained: 7%	<ul style="list-style-type: none"> <li>100% of supply procured directly from the PJM spot market</li> </ul>	<ul style="list-style-type: none"> <li>100% of supply procured directly from the PJM spot market</li> </ul>
<b>Medium Commercial (Type II)</b> Current load retained: 38%	<ul style="list-style-type: none"> <li>100% 3-month FPFR<sup>(1)</sup> products               <ul style="list-style-type: none"> <li>Auction Apr '12 for Jun '12 – Aug '12</li> <li>Auction Jun '12 for Sep '12 – Nov '12</li> <li>Auction Oct '12 for Dec '12 – Feb '13</li> <li>Auction Jan '13 for Mar '13 – May '13</li> </ul> </li> </ul>	<ul style="list-style-type: none"> <li>100% 3-month FPFR products               <ul style="list-style-type: none"> <li>Auction Apr '13 for Jun '13 – Aug '13</li> <li>Auction Jun '13 for Sep '13 – Nov '13</li> <li>Auction Oct '13 for Dec '13 – Feb '14</li> <li>Auction Jan '14 for Mar '14 – May '14</li> </ul> </li> </ul>
<b>Small Commercial (Type I)</b> Current load retained: 63%	<ul style="list-style-type: none"> <li>25% 2-year FPFR products               <ul style="list-style-type: none"> <li>Auction Apr '10 for Oct '10 – Sep '12</li> <li>Auction Oct '10 for Jun '11 – May '13</li> <li>Auction Apr '11 for Oct '11 – Sep '13</li> <li>Auction Oct '11 for Jun '12 – May '14</li> <li>Auction Apr '12 for Oct '12 – Sep '14</li> </ul> </li> </ul>	<ul style="list-style-type: none"> <li>25% 2-year FPFR products               <ul style="list-style-type: none"> <li>Auction Apr '11 for Oct '11 – Sep '13</li> <li>Auction Oct '11 for Jun '12 – May '14</li> <li>Auction Apr '12 for Oct '12 – Sep '14</li> <li>Auction Oct '12 for Jun '13 – May '15</li> <li>Auction Apr '13 for Oct '13 – Sep '15</li> </ul> </li> </ul>
<b>Residential</b> Current load retained: 74%	<ul style="list-style-type: none"> <li>25% 2-year FPFR products               <ul style="list-style-type: none"> <li>Auction Apr '10 for Oct '10 – Sep '12</li> <li>Auction Oct '10 for Jun '11 – May '13</li> <li>Auction Apr '11 for Oct '11 – Sep '13</li> <li>Auction Oct '11 for Jun '12 – May '14</li> <li>Auction Apr '12 for Oct '12 – Sep '14</li> </ul> </li> </ul>	<ul style="list-style-type: none"> <li>25% 2-year FPFR products               <ul style="list-style-type: none"> <li>Auction Apr '11 for Oct '11 – Sep '13</li> <li>Auction Oct '11 for Jun '12 – May '14</li> <li>Auction Apr '12 for Oct '12 – Sep '14</li> <li>Auction Oct '12 for Jun '13 – May '15</li> <li>Auction Apr '13 for Oct '13 – Sep '15</li> </ul> </li> </ul>

(1) FPFR = Fixed-Price Full Requirements  
 Retention as of: September 30, 2012

# Regulatory Schedule

	4Q12	1Q13	2Q13	3Q13	4Q13
<b>ComEd Distribution Formula Rate</b>	12-0321 final order (by 12/26); rates effective 1/2/13 – 1/1/14		2013 formula rate case filing (by 5/1/13)		2013 formula rate case filing final order (by 12/27/13); rates effective 1/2/14 – 1/1/15
<b>Illinois Power Agency Procurement</b>		No procurement events scheduled for 2013			
<b>ComEd Transmission Rate Update</b>			2013 formula rate case filing (by 5/1); rates effective June 2013 thru May 2014		
<b>PECO Supply Procurement</b>	DSP II Procurement (December)	DSP II Procurement (February)			DSP II Procurement (October)
<b>PECO Distribution Filing</b>	Act 129 Part II Energy Efficiency Plan Filing (11/2012)				
<b>BGE Distribution Rates</b>		MDPSC Order expected February 23, 2013			
<b>BGE Transmission Rate Update</b>			2013 formula rate case filing (by 5/15/13); rates effective June 2013 thru May 2014		
<b>BGE Supply Procurement</b>	Regular procurement event (October)	Regular procurement event (January)	Regular procurement event (April and June)		Regular procurement event (October)

# Generation



# Exelon Generation Fleet

## National Scope

- Power generation assets in 20 states and Canada
- Low-cost generation capacity provides unparalleled leverage to rising commodity prices

## Large and Diverse

- 35 GW of diverse generation<sup>(1)</sup>
  - 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 CO<sub>2</sub>, SO<sub>2</sub> and NO<sub>x</sub> intensity
- Less than 5% of combined generation capacity will require capital expenditures to comply with Air Toxic rules



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

(1) Total owned generation capacity as of 9/30/2012 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.



# Executing on Renewable Development Projects

## Solar

- Antelope Valley Solar Ranch Project One
  - Large scale solar project that will be 230 MW once fully operational
    - On track to add 80 MW by year-end 2012
    - 150 MW online by Fall 2013
  - Initial investment fully recovered by 2015
  - 25-year PPA for entire output with Pacific Gas & Electric
  - Cashflow and EPS accretive in 2013



## Wind

- Six projects completed or to be completed by the end of 2012
  - Adding 404 MW
  - Diverse geographic representation:
    - Idaho
    - Kansas
    - Michigan
    - New Mexico
    - Texas
- All projects done under long-term PPAs with anticipated payback in approximately 10 years



**Existing renewable projects will expand the renewable portfolio by more than 600 MW by 2013**

# Nuclear Uprates

## Nuclear Uprate Program Summary<sup>(1)</sup>

	Estimated IRR <sup>(4)</sup>	Overnight Cost <sup>(2)</sup>	Approval Process	Project Duration
Megawatt Recovery & Component Upgrades	11 - 13%	\$890 M	Not required	3-4 Years
MUR (Measurement Uncertainty Recapture)	12 - 16%	\$300 M	Straight forward approval process	2-3 Years
EPU (Extended Power Uprate)	8 - 13%	\$2,240 M	Straight forward approval process	3-6 Years

**Uprate projects enhance Exelon's geographically diverse nuclear fleet – approximately 18 MW to come on line in 2012 and an additional 230 MW through 2015**

Station	Base Case MW <sup>(3)</sup>	Max Potential MW <sup>(3)</sup>	MW Online to Date	Year of Full Operation by Unit <sup>(1)</sup>
<b>MW Recovery &amp; Component Upgrades:</b>				
Quad Cities	99	99	99	2011 / 2010
Dresden	3	3		2013 / 2012
Peach Bottom	29	30	15	2012 / 2011
Dresden	106	110	62	2011 / 2013
Limerick	6	6	3	2012 / 2013
Peach Bottom	2	2		2014 / 2015
<b>MUR:</b>				
LaSalle	39	39	39	2010 / 2011
Limerick	30	30	30	2011 / 2011
Braidwood	34	42		2013 / 2013
Byron	34	42		2013 / 2013
Quad Cities	20	21		2014 / 2014
Dresden	26	28		2014 / 2015
TMI	0	0		Deleted
<b>EPU:</b>				
Clinton	2	2	2	2010
Peach Bottom	130	137		2015 / 2016
LaSalle	297	313		2020 / 2019
Limerick	270	284		2021 / 2021
Total	1,127	1,188	250	

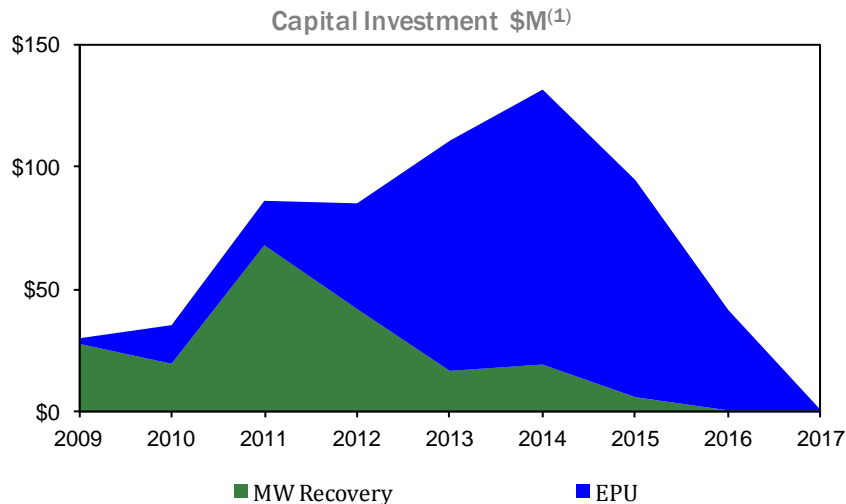
(1) Includes deletion of TMI MUR from the uprate program and deferral of Limerick and LaSalle EPU's.

(2) In 2013 dollars. Overnight costs do not include financing costs or cost escalation.

(3) Adjusted for actual MW's achieved.

(4) Total project returns.

# Peach Bottom Uprate Program



- MW Recovery
  - Low Pressure Turbine Retrofit installation complete for both Unit 2 and Unit 3
  - Replacement of Reactor Recirculation Pump Motor Generator sets with energy efficient Adjustable Speed Drives in 2014 and 2015
- EPU
  - Funding approved for installation work

	Unit 2		Unit 3		
Uprate Project	MW Increase <sup>(1)</sup>	Online Date	MW Increase <sup>(1)</sup>	Online Date	Status
MW Recovery - Low Pressure Turbine Retrofit	14	4Q 2012	15	4Q 2011	Complete
MW Recovery - Adjustable Speed Drives	1	4Q 2014	1	4Q 2015	Initial studies in progress
EPU	65	1Q 2015	65	1Q 2016	Installation 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 late 2012 and 2016**

# Exelon Nuclear Fleet Overview (including CENG and Salem)

	Plant Location	Type/ Containment	Water Body	License Extension Status / License Expiration <sup>(1)</sup>	Ownership	Spent Fuel Storage/ Date to lose full core discharge capacity <sup>(2)</sup>
Midwest	Braidwood, IL (Units 1 and 2)	PWR Concrete/Steel Lined	Kankakee River	Expect to file application in 2013 / 2026, 2027	100%	Dry Cask
	Byron, IL (Units 1 and 2)	PWR Concrete/Steel Lined	Rock River	Expect to file application in 2013 / 2024, 2026	100%	Dry Cask
	Clinton, IL (Unit 1)	BWR Concrete/Steel Lined / Mark III	Clinton Lake	2026	100%	Dry Cask (2017)
	Dresden, IL (Units 2 and 3)	BWR Steel Vessel / Mark I	Kankakee River	Renewed / 2029, 2031	100%	Dry Cask
	LaSalle, IL (Units 1 and 2)	BWR Concrete/Steel Lined / Mark II	Illinois River	2022, 2023	100%	Dry Cask
	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 1 and 2)	PWR Concrete/Steel Lined	Chesapeake Bay	Renewed / 2034, 2036	100% CENG <sup>(4)</sup>	Dry Cask
	R.E. Ginna, NY (Unit 1)	PWR Concrete/Steel Lined	Lake Ontario	Renewed / 2029	100% CENG <sup>(4)</sup>	Dry Cask
	Limerick, PA (Units 1 and 2)	BWR Concrete/Steel Lined / Mark II	Schuylkill River	Filed application in June 2011 (decision expected in 2015) / 2024, 2029	100%	Dry Cask
	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 <sup>(4)</sup> / 82% CENG <sup>(4)</sup> , 18% Long Island Power Authority	Dry Cask
	Oyster Creek, NJ (Unit 1)	BWR Steel Vessel / Mark I	Barnegat Bay	Renewed / 2029 <sup>(3)</sup>	100%	Dry Cask
	Peach Bottom, PA (Units 2 and 3)	BWR Steel Vessel / Mark I	Susquehanna River	Renewed / 2033, 2034	50% Exelon, 50% PSEG	Dry Cask
	TMI, PA (Unit 1)	PWR Concrete/Steel Lined	Susquehanna River	Renewed / 2034	100%	2023
	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.

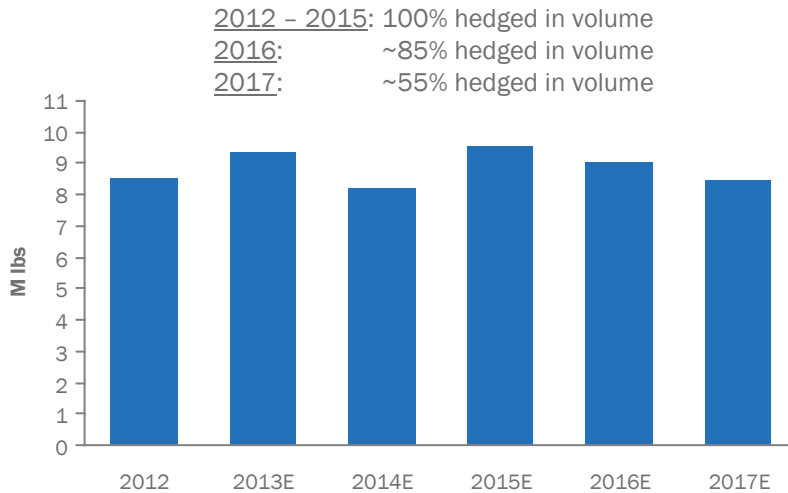
(2) The date for loss of full core reserve identifies when the on-site storage pool will no longer have sufficient space to receive a full complement of fuel from the reactor core. Dry cask storage will be in operation at those sites prior to losing full core discharge capacity in their on-site storage 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.

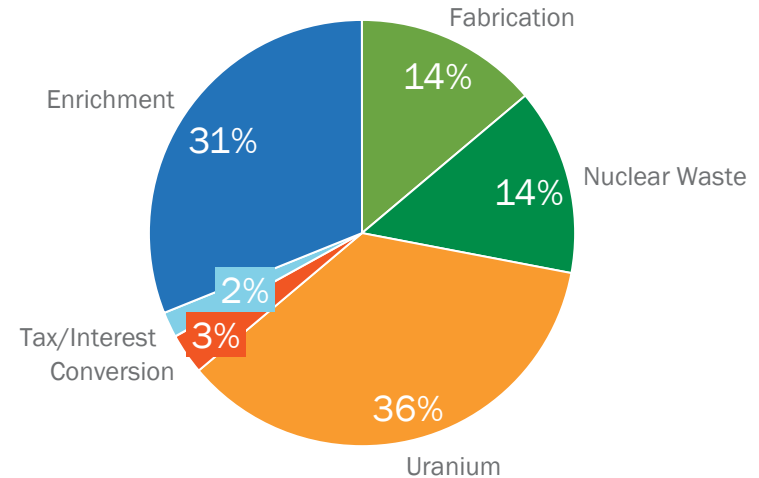
(4) Exelon Generation has a 50.01% ownership interest in CENG (Constellation Energy Nuclear Group, LLC). Electricite de France SA (EDF) has a 49.99% ownership interest in CENG.

# Effectively Managing Nuclear Fuel Costs<sup>(1)</sup>

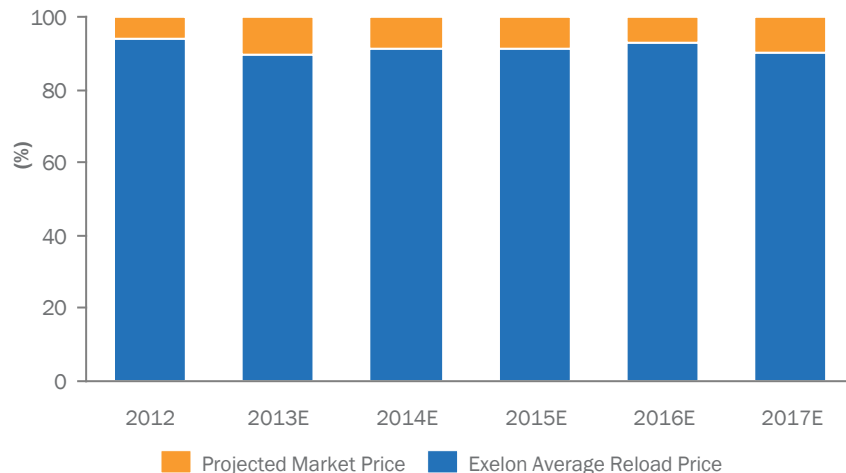
## Projected Exelon (100%) Uranium Demand



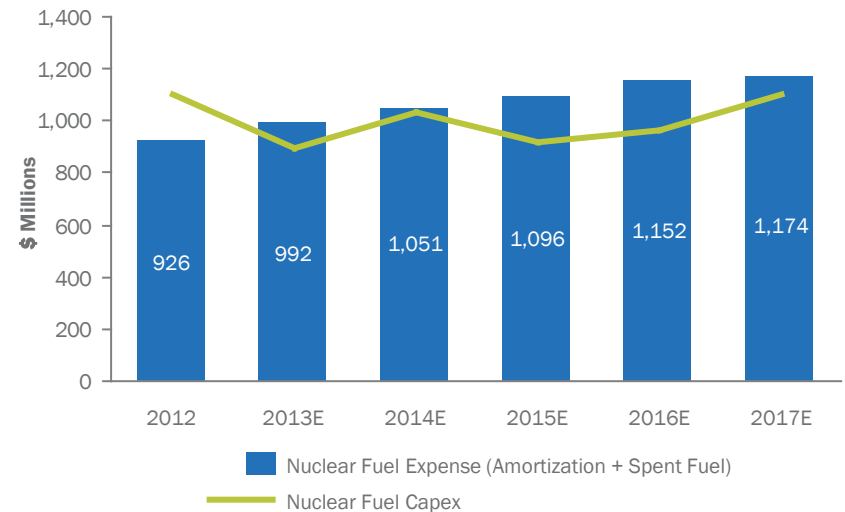
## Components of Nuclear Fuel in 2012



## Projected Exelon Average Uranium Cost vs. Market



## Projected Total Nuclear Fuel Spend<sup>(2)</sup>

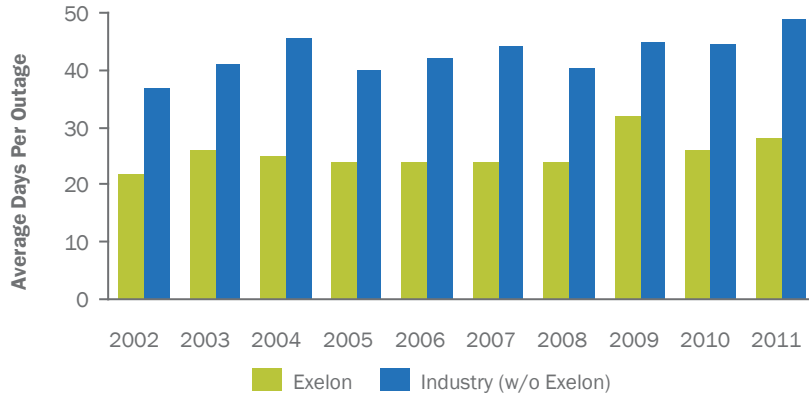


(1) All charts exclude Salem and CENG.

(2) At ownership, excluding Salem and CENG. Excludes costs reimbursed under the settlement agreement with the DOE.

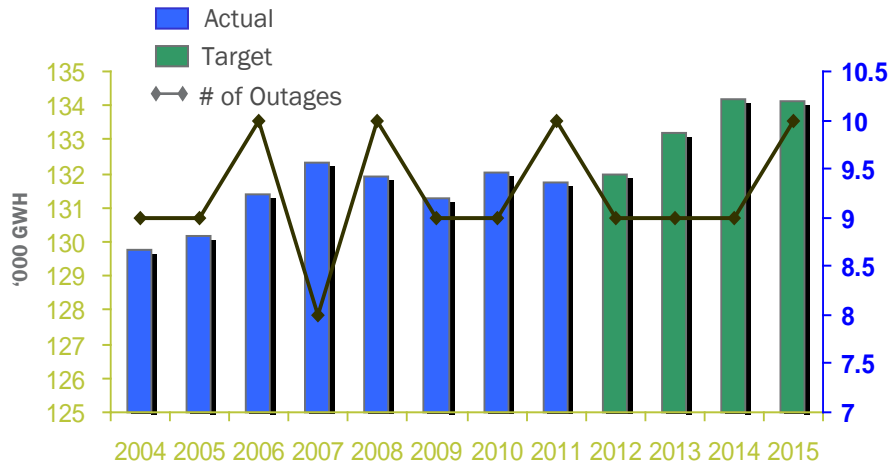
# Impact of Refueling Outages

## Refueling Outage Duration



Note: Exelon data excludes Salem & CENG. Exelon's 2009 average includes 23 days of TMI outage that extended into 2010 for a steam generator replacement.

## Nuclear Output<sup>(1)</sup>



Note: Net nuclear generation data at ownership excluding Salem and CENG.

## Nuclear Refueling Cycle

- All Exelon owned units on a 24 month cycle except for Braidwood U1/U2, Byron U1/U2 and Salem U1/U2, which are on 18 month cycles
- Average Outage Duration (2010-11): ~27 days

## 2012 Refueling Outage Impact

- 10 planned refueling outages, including 1 at Salem
- Exelon completed 4 refueling outages in the Spring with an average duration of 30 days
- 5 Exelon planned Fall refueling outages (Byron 1, Peach Bottom 2, Braidwood 2, Oyster Creek, and Dresden 3)
- 1 Salem planned Fall refueling outage

## 2013 Refueling Outage Impact

- 10 planned refueling outages, including 1 at Salem
- 4 Exelon planned Spring refueling outages and 5 planned Fall refueling outages
- 1 Salem planned Spring refueling outage