Creating Value for Investors

FirstEnergy

Company Profile

Forward-Looking Statement

All information contained in this FactBook is as of February 17, 2015 unless otherwise noted.

This FactBook includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements include declarations regarding management's intents, beliefs and current expectations. These statements typically contain, but are not limited to, the terms “anticipate,” “potential,” “expect,” "forecast," "will," "intend," “believe,” "project," “estimate” and similar words. Forward-looking statements involve estimates, assumptions, known and unknown risks, uncertainties and other factors that may cause actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements, which may include the following: the speed and nature of increased competition in the electric utility industry, in general, and the retail sales market in particular; the ability to experience growth in the Regulated Distribution and Regulated Transmission segments and to successfully implement our revised sales strategy for the Competitive Energy Services segment; the accomplishment of our regulatory and operational goals in connection with our transmission investment plan, pending transmission and distribution rate cases and the effectiveness of our repositioning strategy to reflect a more regulated business profile; changes in assumptions regarding economic conditions within our territories, assessment of the reliability of our transmission system, or the availability of capital or other resources supporting identified transmission investment opportunities; the impact of the regulatory process on the pending matters at the federal level and in the various states in which we do business including, but not limited to, matters related to rates and pending rate cases, including the Electric Security Plan IV in Ohio; the impact of the federal regulatory process on the Federal Energy Regulatory Commission (FERC) regulated entities and transactions, in particular FERC regulation of wholesale energy and capacity markets, including PJM Interconnection, L.L.C. (PJM) markets and FERC-jurisdictional wholesale transactions; FERC regulation of cost-of-service rates, including FERC Opinion No. 531’s revised Return on Equity methodology for FERC-jurisdictional wholesale generation and transmission utility service, and FERC’s compliance and enforcement activity, including compliance and enforcement activity related to North American Electric Reliability Corporation’s mandatory reliability standards; the uncertainties of various cost recovery and cost allocation issues resulting from American Transmission Systems, Incorporated's realignment into PJM; economic or weather conditions affecting future sales and margins such as a polar vortex or other significant weather events, and all associated regulatory events or actions; regulatory outcomes associated with storm restoration costs, including but not limited to, Hurricane Sandy, Hurricane Irene and the October snowstorm of 2011; changing energy, capacity and commodity market prices including, but not limited to, coal, natural gas and oil, and their availability and impact on retail margins; the continued ability of our regulated utilities to recover their costs; costs being higher than anticipated and the success of our policies to control costs and to mitigate low energy, capacity and market prices; other legislative and regulatory changes, and revised environmental requirements, including, but not limited to, proposed greenhouse gases emission and water discharge regulations and the effects of the United States Environmental Protection Agency's coal combustion residuals regulations, Cross-State Air Pollution Rule, Mercury and Air Toxics Standards, including our estimated costs of compliance, and Clean Water Act 316(b) water intake regulation; the uncertainty of the timing and amounts of the capital expenditures that may arise in connection with any litigation, including New Source Review litigation, or potential regulatory initiatives or rulemakings (including that such expenditures could result in our decision to deactivate or idle certain generating units); the uncertainties associated with the deactivation of certain older regulated and competitive fossil units, including the impact on vendor commitments, and the timing thereof as they relate to the reliability of the transmission grid; the impact of other future changes to the operational status or availability of our generating units; adverse regulatory or legal decisions and outcomes with respect to our nuclear operations (including, but not limited to the revocation or non-renewal of necessary licenses, approvals or operating permits by the Nuclear Regulatory Commission or as a result of the incident at Japan's Fukushima Daiichi Nuclear Plant); issues arising from the indications of cracking in the shield building at Davis-Besse; the risks and uncertainties associated with litigation, arbitration, mediation and like proceedings, including, but not limited to, any such proceedings related to vendor commitments; the impact of labor disruptions by our unionized workforce; replacement power costs being higher than anticipated or not fully hedged; the ability to comply with applicable state and federal reliability standards and energy efficiency and peak demand reduction mandates; changes in customers' demand for power, including, but not limited to, changes resulting from the implementation of state and federal energy efficiency and peak demand reduction mandates; the ability to accomplish or realize anticipated benefits from strategic and financial goals, including, but not limited to, the ability to continue to reduce costs and to successfully execute our financial plans designed to improve our credit metrics and strengthen our balance sheet through, among other actions, our previously-implemented dividend reduction and our other proposed capital raising initiatives; our ability to improve electric commodity margins and the impact of, among other factors, the increased cost of fuel and fuel transportation on such margins; changing market conditions that could affect the measurement of certain liabilities and the value of assets held in our Nuclear Decommissioning Trusts, pension trusts and other trust funds, and cause us and/or our subsidiaries to make additional contributions sooner, or in amounts that are larger than currently anticipated; the impact of changes to material accounting policies; the ability to access the public securities and other capital and credit markets in accordance with our announced financial plans, the cost of such capital and overall condition of the capital and credit markets affecting us and our subsidiaries; actions that may be taken by credit rating agencies that could negatively affect us and/or our subsidiaries' access to financing, increase the costs thereof, and increase requirements to post additional collateral to support outstanding commodity positions, letters of credit and other financial guarantees; changes in national and regional economic conditions affecting us, our subsidiaries and/or our major industrial and commercial customers, and other counterparties with which we do business, including fuel suppliers; the impact of any changes in tax laws or regulations or adverse tax audit results or rulings; issues concerning the stability of domestic and foreign financial institutions and counterparties with which we do business; the risks associated with cyber-attacks on our electronic data centers that could compromise the information stored on our networks, including proprietary information and customer data; and the risks and other factors discussed from time to time in our United States Securities and Exchange Commission filings, and other similar factors. Dividends declared from time to time on FirstEnergy Corp.‘s common stock during any period may in the aggregate vary from prior periods due to circumstances considered by FirstEnergy Corp.‘s Board of Directors at the time of the actual declarations. A security rating is not a recommendation to buy or hold securities and is subject to revision or withdrawal at any time by the assigning rating agency. Each rating should be evaluated independently of any other rating. The foregoing review of factors should not be construed as exhaustive. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor assess the impact of any such factor on FirstEnergy's business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. FirstEnergy expressly disclaims any current intention to update, except as required by law, any forward-looking statements contained herein as a result of new information, future events or otherwise.

Non-GAAP Financial Matters

All information contained in this FactBook is as of February 17, 2015 unless otherwise noted.

This FactBook contains references to non-GAAP financial measures including, among others, Operating earnings, Adjusted EBITDA, Adjusted Debt, Adjusted Capitalization, Funds from Operations (FFO) and Free Cash Flow. In addition, Basic EPS and Basic EPS-Operating, each calculated on a segment basis, are also non-GAAP financial measures. Generally, a non-GAAP financial measure is a numerical measure of a company's historical or future financial performance, financial position, or cash flows that either excludes or includes amounts that are not normally excluded or included in the most directly comparable measure calculated and presented in accordance with accounting principles generally accepted in the United States (GAAP). Operating earnings are not calculated in accordance with GAAP because they exclude the impact of "special items". Adjusted EBITDA also excludes the impact of special items and represents Operating earnings before interest expense, investment income, taxes, depreciation and amortization. Basic EPS for each segment is calculated by dividing segment net income (loss) on a GAAP basis by the basic weighted average shares outstanding for the period. Basic EPS-Operating for each segment is calculated by dividing segment Operating earnings, which exclude special items as discussed above, by the basic weighted average shares outstanding for the period. Management uses non-GAAP financial measures such as Operating earnings, Adjusted EBITDA, FFO and Free Cash Flow to evaluate the company's performance and manage its operations and frequently references these non-GAAP financial measures in its decision-making, using them to facilitate historical and ongoing performance comparisons. Additionally, management uses Basic EPS and Basic EPS-Operating by segment to further evaluate FirstEnergy's performance by segment and references these non-GAAP financial measures in its decision-making. Management believes that the non-GAAP financial measures of "Operating earnings," "Adjusted EBITDA," "Free Cash Flow," "Basic EPS" and "Basic EPS-Operating" provide consistent and comparable measures of performance of its businesses to help shareholders understand performance trends. Management uses Adjusted Equity, Adjusted Debt and Adjusted Capitalization to calculate and monitor its compliance with the debt to total capitalization financial covenant under the FirstEnergy credit facility and term loan. These financial measures, as calculated in accordance with the FirstEnergy credit facility and term loan, help shareholders understand FirstEnergy's compliance with, and incremental debt capacity under, the debt to total capitalization financial covenant. The financial covenant requires FirstEnergy to maintain a consolidated debt to total capitalization ratio of no more than 65%, measured at the end of each fiscal quarter. All of these non-GAAP financial measures are intended to complement, and are not considered as alternatives to, the most directly comparable GAAP financial measures. Also, the non-GAAP financial measures may not be comparable to similarly titled measures used by other entities.

Pursuant to the requirements of Regulation G, FirstEnergy has provided quantitative reconciliations within the presentation of the non-GAAP financial measures to the most directly comparable GAAP financial measures.

Acronyms

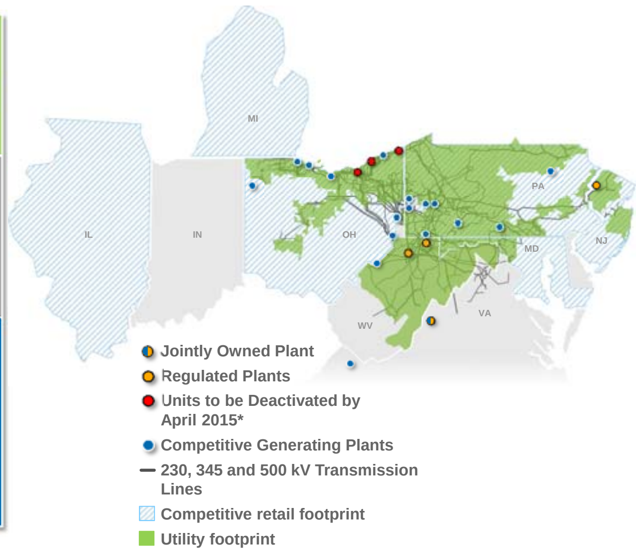
ABO	Accumulated Benefit Obligation
ACI	Activated Carbon Injection
AD	American Electric Power Dayton
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
BGS	Basic Generation Service
BPS	Basis Points
BPU	Board of Public Utilities
BRA	Base Residual Auction
CEMS	Continuous Emissions Monitoring System
CES	Competitive Energy Services
CIS	Customer Information System
COS	Combustion Optimization System
DOE	Department of Energy
DR	Demand Response
DSM	Demand Side Management
DSP	Default Service Plan
EDC	Electric Distribution Company
EE	Energy Efficiency
EHV	Extra High Voltage
EMAAC	EMAAC Locational Deliverability Area in PJM
ENEC	Expanded Net Energy Costs
EPA	United States Environmental Protection Agency
ESP	Electric Security Plan
FERC	Federal Energy Regulatory Commission
FRR	Fixed Resource Requirement
GA	Governmental Aggregation
GWH	Gigawatt-hour
HV	High Voltage
IGCC	Integrated Gasification Combined Cycle
ILB	Illinois Basin
ITC	Investment Tax Credit
kV	Kilovolt
kWh	Kilowatt-hour
LCI	Large Commercial / Industrial Customers
LNB	Low NOx Burners
Lo-S	Low Sulfur Coal
MAAC	MAAC Locational Deliverability Area in PJM
MATS	Mercury and Air Toxics Standards
MCI	Medium Commercial / Industrial Customers
MISO	Midcontinent Independent System Operator
MM	Mass Market
MMBTU	Million British Thermal Unit
MW	Megawatt
MWH	Megawatt-hour
NAPP	Northern Appalachian Coal
NDC	Net Demonstrated Capacity
NDT	Nuclear Decommissioning Trust
NOX	Nitrogen Oxide
NRC	Nuclear Regulatory Commission
OCI	Other Comprehensive Income
OFA	Separated Overfire Air
OPEB	Other Post-Employment Benefits
OVEC	Ohio Valley Electric Corporation
PAPUC	Pennsylvania Public Utility Commission
PBO	Projected Benefit Obligation
PIPP	Percentage of Income Payment Plan
PJM	PJM Interconnection, L.L.C.
POLR	Provider of Last Resort
PPA	Purchase Power Agreement
Precip	Electrostatic Precipitator
PSC	Maryland Public Service Commission
PUCO	Public Utilities Commission of Ohio
PV	Photovoltaic
RD	Recommended Decision
RMR	Reliability Must Run
ROE	Return on Equity
RPM	Reliability Pricing Model
RPS	Renewables Portfolio Standard
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
SCR	Selective Catalytic Reduction
SIP	Stock Investment Plan
SMIP	Smart Meter Technology Procurement and Installation Plan
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SSO	Standard Service Offer
SVC	Static VAR Compensator
VAR	Volt-Ampere Reactive
VVC	Voltage/VAR Control
WFGD	Wet Flue Gas Desulfurization
WV PSC	West Virginia Public Service Commission

Strength in Our Diversity and Scale

Utilities
- Approximately 6M customers
- One of the largest contiguous service territories in the U.S. covering 65,000 square miles

Transmission
- One of the largest transmission systems in PJM
- 24,000+ transmission miles
- Significant opportunity for growth

Competitive Operations
- One of the cleanest, lowest-cost generation fleets in the U.S.
- Long generation vs. sales strategy
- Focused on reducing overall business risk



*See slide 126

2014 Accomplishments

Distribution Utilities

Significant Regulatory Activity
- Rate Case filing in WV
- Rate Case filings in PA
- Filed ESP IV in Ohio; Stipulation filed on December 22, 2014
- 2011 and 2012 storm costs in NJ approved; favorable CTA decision

Transmission Business

Launched "Energizing the Future" Growth Plan
- Initial year spend of $1.4B
- Significant opportunities going forward
- ATSI forward-looking rate approved on December 31, 2014, subject to ROE review by FERC

Competitive Operations

Changed the Character and Operation of the Fleet
- Minimized downside risk and positioned for potential upside
- Sold 527MW of hydro assets
- Adjusted sales strategy; sell no more than we produce
- Advocated market reforms
- Conservation of capital – Modest MATS spend, deferred BV2 steam generator and reactor head replacement

Financial

Focus on Financial Success
- Revised dividend to $1.44 per share; fully supported by regulated businesses
- Extended $6B in credit facilities through March 2019
- Completed inaugural bond issuance at FET; ATSI bond offering to support growth program
- $83M of equity through stock investment/employee benefit plans

As of December 31, 2014

Going Forward … Growth Through Investments in Regulated Operations

… Repositioned Competitive Operations

Grow Regulated Operations …

Competitive Operations

- Reduced size of fleet and changed mix of assets to a much stronger platform of units
- Retain upside potential as markets improve, but limit downside from continued depressed conditions
- Targeting positive cash flow each year, 2015-2018

Regulated Operations

- Increase transmission investments
- Target annual transmission earnings growth of 20%+ at ATSI and TrAILCo
- Grow predictable cash flow
- Seek opportunities in select rate case filings
- Continue to support a strong dividend

Regulated Business targeting 80%+ of EPS

FirstEnergy **Leadership**

FirstEnergy

Charles E. Jones
President and Chief Executive Officer

James F. Pearson
Senior Vice President and Chief Financial Officer

Leila L. Vespoli
Executive Vice President, Markets and Chief Legal Officer

Lynn M. Cavalier
Senior Vice President, Human Resources

James H. Lash
President
FirstEnergy Generation

Donald R. Schneider
President
FirstEnergy Solutions

Steve Strah
Senior Vice President and President of FirstEnergy Utilities

Michael J. Dowling
Senior Vice President, External Affairs

Bennett L. Gaines
Senior Vice President, Corporate Services and Chief Information Officer

Peter P. Sena III
President and Chief Nuclear Officer
FirstEnergy Nuclear Operating Company

John W. Judge
Vice President, Corporate Risk and Chief Risk Officer

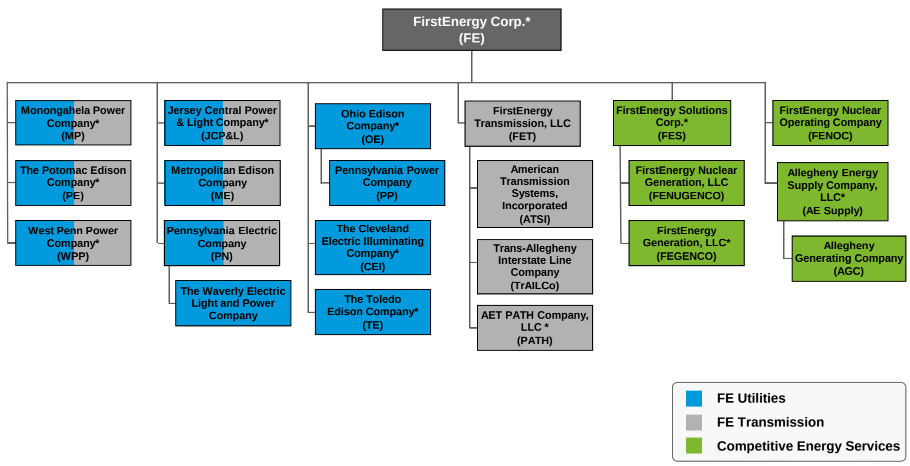
Irene M. Prezelj
Vice President, Investor Relations

Steven R. Staub
Vice President, Treasurer

K. Jon Taylor
Vice President, Controller and Chief Accounting Officer

Summary Organizational Structure

FirstEnergy



*Entity has subsidiaries that are not shown

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FirstEnergy Corp. Segment Descriptions

Regulated Distribution	Comprised of ten distribution companies serving ~6M customers in Ohio, Pennsylvania, New Jersey, West Virginia, Maryland and New York, making this one of the largest contiguous service territories in the U.S. Our regulated generation portfolio consists of 3,790 MW and serves primarily West Virginia. Net plant in-service as of 12/31/2014 was approximately $17.2B.
Regulated Transmission	The FirstEnergy transmission system spans a 65,000 square mile service territory and is one of the largest transmission systems in PJM with over 24,000 transmission miles. The lines are owned by certain distribution companies or FE's transmission companies, ATSI and TrAILCo. ATSI consists of the transmission systems formerly owned by OE, PP, CEI, and TE along with additions constructed by ATSI. TrAILCo consists of TrAIL, a 500-kV transmission line, and other transmission facilities constructed in the service areas of WPP, MP, PE, ME and PN. Net plant in-service as of 12/31/2014 was approximately $5B.
Competitive Energy Services (CES)	FES and AE Supply primarily comprise the Competitive Energy Services segment, which serves customers in the POLR, Governmental Aggregation, and selected large commercial-industrial direct sales channels. FirstEnergy's competitive generating portfolio consists of more than 13,000 MW* of diversified capacity. The segment is long generation versus sales.
Corporate / Other	Corporate/Other contains corporate support and other businesses that are below the quantifiable threshold for separate disclosure as a reportable segment and interest expense on stand-alone holding company debt and corporate income taxes. Additionally, reconciling adjustments for the elimination of inter-segment transactions are included in Corporate/Other.

*Excludes units scheduled to be deactivated by April 2015 (see slide 126)

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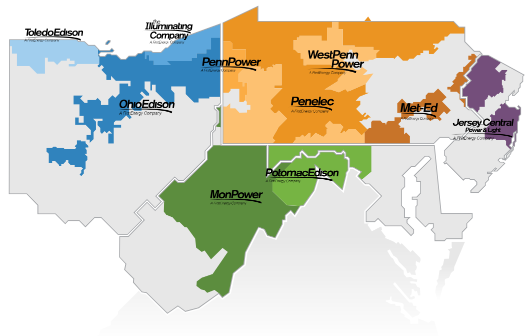
Regulated **Distribution**



State	2014 Customers (in thousands)	2014 Distribution Sales (MWH in thousands)
Ohio	2,089	54,173
Pennsylvania	2,026	52,542
New Jersey	1,103	20,813
West Virginia	527	15,024
Maryland	259	7,001
New York	4	–
Total	**6,008**	**149,553**

As of December 31, 2014

Regulatory **Strategy**

State	Company	Regulatory Activity

New Jersey	JCP&L	• Filed distribution rate case November 30, 2012
		  • ALJ filed initial decision on January 8, 2015
		  • Resolution expected 2015Q1
		• Generic Storm Proceeding stipulation approved March 19, 2014
		• Generic Consolidated Tax Adjustment Proceeding order issued October 22, 2014

West Virginia	MP
	PE – WV
		• MP/PE Rate Case filed April 30, 2014; Amended filing made on June 13, 2014
		  • Rate Case settlement filed with the PSC on November 3, 2014; Hearing held November 7, 2014
		  • Settlement includes $15M increase in base rates and vegetation management surcharge of $48M
		  • Settlement approved without modification by the WVPSC on February 3, 2015
		  • February 25, 2015: effective date of new base rates and vegetation management surcharge
		• ENEC case: Filed August 29, 2014 requesting $65.8M increase based on fuel and purchased power costs; Settlement filed December 2, 2014 with hearing on December 3, 2014; Settlement defers $16.8M for recovery in 2016 and delays the ENEC rate change until February 25, 2015; Settlement approved without modification by the WVPSC on January 29, 2015

Pennsylvania	PP ME PN WPP	• Rate Case filings made for all four companies on August 4, 2014 • Settlements filed on February 3, 2015; PAPUC decision expected in May 2015 • Default Service Plan settlement for June 2015-May 2017 approved by PAPUC
Ohio	OE CEI TE	• Base distribution rate freeze through May 2016 per ESP 3 • ESP IV (Powering Ohio's Progress) filed August 4, 2014. Stipulation filed on December 22, 2014. Evidentiary hearings scheduled to begin April 13, 2015. • Alternative Energy Rider refund ruling appealed to the Supreme Court of Ohio in December 2013
Maryland	PE – MD	• No rate cases currently planned • Continue to monitor potential for Smart Meter and Incremental Investment Riders

Rate Base and Allowed ROEs

State	Company	Rates Effective	Rate Base ($M)	Allowed Debt /Equity	Allowed ROE
Ohio	OE	January 2009	$ 1,251	Debt 51.0% / Equity 49.0%	10.50%
	CEI	May 2009	$ 984	Debt 51.0% / Equity 49.0%	10.50%
	TE	January 2009	$ 414	Debt 51.0% / Equity 49.0%	10.50%
Pennsylvania	PP	May 1988	$ 654	Debt 62.6% / Equity 37.4%	12.90%
	ME	January 2007	$ 969	Debt 51.0% / Equity 49.0%	10.10%
	PN	January 2007	$ 1,068	Debt 51.0% / Equity 49.0%	10.10%
	WPP	December 1994	$ 1,830	Debt 54.5% / Equity 45.5%	11.50%
New Jersey	JCP&L	June 2005	$ 2,080	Debt 54.0% / Equity 46.0%	9.75%
West Virginia*	PE – WV	February 2015	~$ 2,500	Debt 53.5% / Equity 46.5%	
	MP	February 2015	~$ 2,500	Debt 53.5% / Equity 46.5%	
Maryland	PE – MD	February 1993	$ 581	Debt 56.0% / Equity 44.0%	11.90%

As of the most recent rate case approved by respective state commissions. Rate base can include distribution, transmission and generation assets but actual required revenues are adjusted to reflect current rate structure.

* Reflects filed rate base and debt/equity; final settlement/Order do not specifically include rate base or capital structure

Summary of Rate Proceeding Requirements

	Ohio	Pennsylvania	New Jersey	West Virginia	Maryland
General					
Time Limitations Between Cases	No	No	No	No	No
Fuel Clause Renewal Frequency	N/A	N/A	N/A	Annually	N/A
Notice of Intent					
Prior Notice Required	Yes	Yes	No	Yes	Yes
Notice Period (Days)	30	30	N/A	30	30
Case Components					
Base Case Test Year	Hybrid (Historic/ Forecast)	12 Month Historic 12 Month Forecast 12 Month Fully Projected Future Test Year	Hybrid (Historic/ Forecast)	Historic	Hybrid (Historic/ Forecast)
Other					
Requested (but not approved) Rates Effective Subject to Refund	Yes*	Yes	Yes	No	Yes
Approximate number of months after filing to implement rates subject to refund	9 months	9 months	1-9 months	N/A	1-8 months
Default Service					
Term	ESP 3 through May 2016	Current DSP through May 2015	Evergreen	N/A	Standard Offer Service (SOS)–Periodic Filing

* This provision is subject to other requirements including the filing of a bond or letter of credit

Summary of Recovery Mechanisms

Company	Purchased Power[1]/ Fuel Rider	Storm Cost Recovery[2]	Incremental Capital Recovery	Energy Efficiency	Smart Meter / Smart Grid[7]	Alternative Energy[4,8,9]
OE	Annually	Base Rates	Quarterly	Semi Annually	Quarterly[3]	Quarterly
CEI	Annually	Base Rates	Quarterly	Semi Annually	Quarterly[3]	Quarterly
TE	Annually	Base Rates	Quarterly	Semi Annually	Quarterly[3]	Quarterly
PP	Quarterly	Base Rates	No	Annually	Annually	Annually
ME	Quarterly	Base Rates	No	Annually	Annually	Annually
PN	Quarterly	Base Rates	No	Annually	Annually	Annually
WPP	Quarterly	Base Rates	No	Annually	Annually	No-Supplier Obligation[5]
JCP&L	Annually	Base Rates	No	Annually	No	Annually
PE – WV	Annually	Base Rates	No	Annually	No	N/A
MP	Annually	Base Rates	No	Annually	No	N/A
PE – MD	Various[6]	Base Rates	No	Annually	No	No-Supplier Obligation

Notes:
1. Purchased Power is associated with competitive solicitations in all states except West Virginia. Ohio changes annually, reconciled quarterly.
2. Storm Costs that exceed baseline amounts are authorized to be deferred in New Jersey and Ohio. Storm-related vegetation management costs are recovered through a surcharge mechanism in WV. In other states, the company may seek deferral of costs.
3. Smart Meter in Ohio is currently a pilot program with a limited number of meters and equipment; 50% of funding from DOE.
4. Pennsylvania only recovers Solar Renewable Energy Credits. The non-solar obligation remains with the supplier. In Ohio, both solar and non-solar renewable energy credits are recovered.
5. Less existing long-term Tier I Alternative Energy Credits that are recoverable through the Price To Compare.
6. Residential is updated twice a year. Commercial and Small Industrial change quarterly. Large industrial customers have Hourly Pricing Service.
7. Costs in New Jersey and Ohio for the Smart Grid Initiative are recovered through riders; 50% of funding from DOE.
8. New Jersey RPS requirements are the responsibility of the BGS suppliers.
9. West Virginia repealed its Alternative and Renewables Portfolio Act in February 2015.

Net Regulatory Asset Amortization (Deferral)

($ Millions)

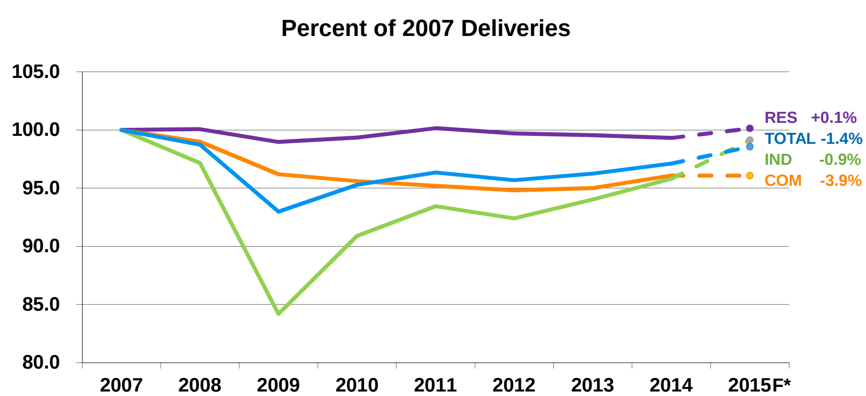
Jurisdiction	2014A	2015F
Ohio	$71	$140
Pennsylvania	($14)	$80
New Jersey	$32	$100
West Virginia / Maryland	($89)	($15)
FERC	$12	$12
Total	**$12**	**$317**

Renewable Energy Requirements

	OH	PA	NJ	MD
Year	2026**	2021	2021	2022
Requirements	12.5%	18.5%	23.85%	20%
Class/Tier I – Non Solar	12.0%	8.0%	17.88%	18%
Solar	0.5%	0.5%	3.47%	2%
Class/Tier II	–	10.0%	2.5%	2.5% until 2018
Default Service RPS Obligations Fulfilled By	▪ 100% Company	▪ Company 100% solar for ME, PN & PP / Suppliers Tier I, Tier II & WPP solar	▪ Suppliers	▪ Suppliers 100% residential & commercial / Company 100% industrial
Procurement Method / Market Incentive (NJ)	▪ RFP & limited spot	▪ RFP	▪ Financing Program / Auction sales to Suppliers	▪ Spot
Solar	▪ Solar PV and Solar Thermal	▪ Solar PV and Solar Thermal	▪ Solar PV and Solar Thermal	▪ Solar PV, Solar Thermal & Solar Water Heating
Class/Tier I/ Renewable Energy Resources	▪ Solar ▪ Wind ▪ Hydro ▪ Geothermal ▪ Solid waste * ▪ Biomass ▪ Fuel cells ▪ Storage * ▪ Distributed generation* ▪ Certain advanced energy resources*	▪ Solar Photovoltaic ▪ Solar Thermal ▪ Wind ▪ Low-impact hydro ▪ Geothermal ▪ Biomass ▪ Methane gas* ▪ Coal-mine methane ▪ Fuel cells ▪ Wood byproducts* ▪ Large-scale hydro*	▪ Solar ▪ Wind ▪ Fuel Cells powered by Renewable fuels ▪ Wave / Tidal ▪ Geothermal technologies ▪ Methane Landfill gas ▪ Anaerobic Digestion ▪ Biomass (sustainable) ▪ In State hydro <3 with in service date >7/23/12	▪ Solar ▪ Wind including Off-Shore* ▪ Biomass ▪ Landfill Gas ▪ Small Hydro ▪ Geothermal Electric ▪ Fuel Cells* ▪ Municipal Solid Waste ▪ Ocean ▪ Poultry litter incineration* ▪ Refuse derived
Class/Tier II Advanced/Alternative Energy Resources	▪ N/A	▪ Waste coal ▪ Distributed generation ▪ DSM ▪ Large hydro ▪ Muni solid waste ▪ Wood byproducts * ▪ IGCC coal ▪ Pumped-storage hydro	▪ Small hydro >3 and <30 ▪ Resource recovery	▪ Hydro (excluding pumped storage) ▪ Waste-to energy ▪ Poultry litter incineration*
Renewable Energy Credit (REC) Life	5 years	3 years	Solar 5 Years, Class I 3 years & Class II 1 year	3 years
Other Provisions	Panel to review the RPS legislation	Quarterly Adjustments to Tier I Non-Solar %	Solar must be in-state	Solar must be in-state

*Additional restrictions and provisions apply
**Changes under SB310 extended RPS requirements from 2024 to 2026 due to freezing requirements barring outcome of panel review of legislation

Regulated Distribution Sales Trends

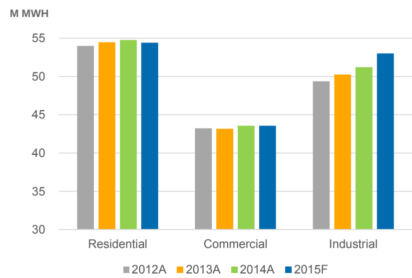


Distribution sales have not fully recovered from 2007 levels, but have shown improvement since 2011

*Assumes normal weather

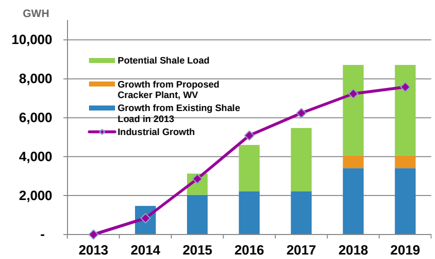
Strengthening Our Utilities
Projected Load Growth

Load Growth by Class
2012 - 2015



- 2015F ~151M MWH vs. 2014A of 149.5M MWH
- Majority of load growth driven by Industrial sector

Load Growth – Industrial Sector
2014A - 2019F

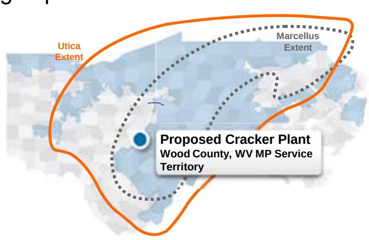


- 2013-2019 Industrial growth ~15%
- Shale accounts for ~50% of Industrial growth

Overall 2015 load growth of 0.9%
Significant 5-year growth projected in shale sector

Leveraging Industrial and Technological Developments in our Region

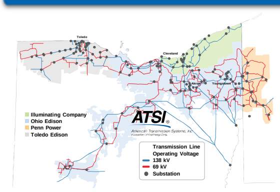
- **FE utility service territory overlays Marcellus and Utica shale region**
- **Although shale is in early stages of development, there are signs of load growth**
  - ~400 MW (Operational 2013 – 2014)
    - ~2.5M – 3.0M MWH of annual load growth
  - ~1,100 MW (2015 – 2019)
    - ~6.5 – 7.5M MWH of additional load growth
- **Shale development also creating other opportunities**
  - Steel and tubing companies benefit from large upstream infrastructure build
  - Midstream companies of substantial size being connected
  - Cracker plants that convert ethane and natural gas are being considered
  - Related supply chains being established



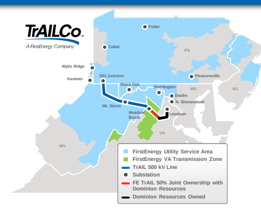
Growing Our Transmission Business
Energizing the Future

- **Regulatory Required: PJM mandated RTEP projects including those that support generation deactivations and shale gas expansion activities**
- **Reliability Enhancement: Projects focused on enhancing customer service, strengthening grid and cyber-security, and adding resiliency and operating flexibility**

Stand Alone Businesses

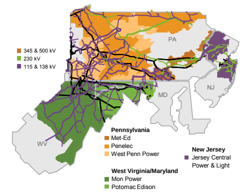


- **Established in 1998**
- **Forward-looking Formula Rate – 12.38% ROE***
- **~7,400 transmission miles**
- **2014 revenues ~$242M**
- **PP&E*** – $1.8B**



- **Established in 2006 – In Service May 2011**
- **Forward-looking Formula Rate 11.7% ROE**
- **~300 transmission miles**
- **2014 revenues ~$214M**
- **PP&E*** – $1.5B**

Utilities

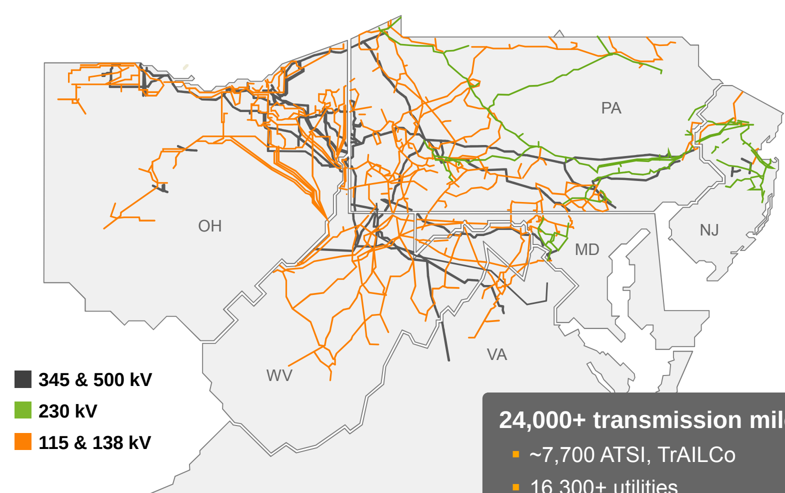


- **Utility Stated Rates**
- **16,300+ transmission miles****
- **2014 revenues ~$300M**
- **PP&E*** – $1.7B**

$4.2B Investment – 2014-2017

*On December 31, 2014 FERC accepted ATSI's rate filing to amend its formula rate to a forward-looking test year effective January 1, 2015. FERC also determined the ROE is subject to inquiry as part of the settlement and hearing proceedings and is subject to refund.
** Includes lines 23kV and above
*** Property, Plant & Equipment (PP&E) in-service net of accumulated depreciation as of December 31, 2014

FirstEnergy Transmission – Overview



24,000+ transmission miles*
- ~7,700 ATSI, TrAILCo
- 16,300+ utilities

*Includes lines 23kV and above

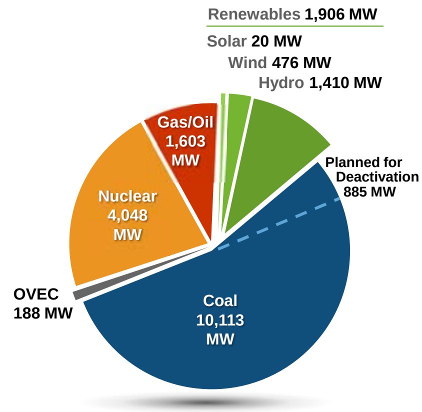
Note: Map does not represent 69kV lines and below

FirstEnergy Generation Portfolio

Nuclear	MW
Beaver Valley 1& 2	1,872
Perry	1,268
Davis-Besse	908
Total	**4,048**

Supercritical Coal	
Mansfield 1-3	2,490
Harrison 1-3 (R)	1,984
Pleasants 1-2	1,300
Sammis 6 & 7	1,200
Fort Martin 1 & 2 (R)	1,098
Total Supercritical Coal	**8,072**

Subcritical Coal	
Sammis 1-5	1,020
Eastlake 1-3 ⬢	396
Bay Shore 1	136
Lake Shore 18 ⬢	245
Ashtabula 5 ⬢	244
Subcritical Coal	**2,041**
OVEC (PR)	188
Regulated: 11 Competitive:177	
Total Subcritical Coal	**2,229**



Total Capacity	17,858 MW	
Competitive	14,068 MW	(79%)
Regulated	3,790 MW	(21%)

■ (R) Fully Regulated or (PR) Partially Regulated units
■ Long-term PPA
⬢ Units scheduled to be deactivated by April 2015 (see slide 126)

Gas/Oil	MW
Springdale 1-5	638
West Lorain 1-6	545
Chambersburg 12 & 13	88
Gans 8 & 9	88
Forked River	86
Hunlock	45
Buchanan	43
Other	70
Total Gas/Oil	**1,603**

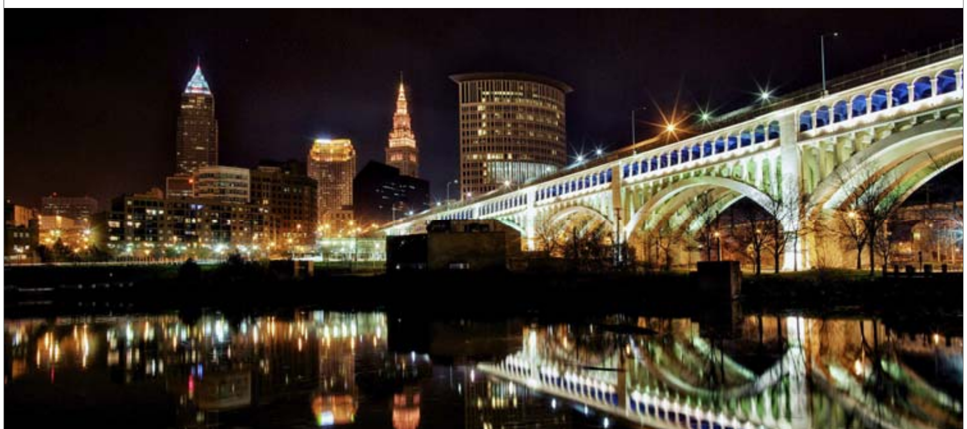
Hydro	
Bath County (PR)	1,200
Regulated: 487 Competitive: 713	
Yards Creek (R)	210
Total Hydro	**1,410**

Wind	
Blue Creek	100
High Trail	99
Allegheny Ridge	80
N. Allegheny Ridge	70
Highland	62
Casselman	35
Meyersdale	30
Total Wind	**476**

Solar	
Maryland Solar	20
Total Solar	**20**

Creating Value for Investors

Ohio Operations

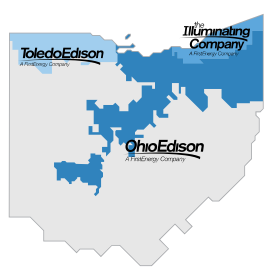


Ohio – Customer Data

2014 Total Customers (thousands)	
Ohio Edison	1,036
The Illuminating Company (CEI)	745
Toledo Edison	308
Total	2,089

Typical Bill Comparison*	
Ohio	$/Month
Ohio Edison	$133.90
The Illuminating Company (CEI)	$131.66
Toledo Edison	$132.39
Statewide Avg. Bill	$139.33

* Typical bills are displayed on 1,000 kWh of residential usage. Billing amounts sourced from the EEI Typical Bills and Average Rates Report as of July 1, 2014. Ohio rates represent POLR bundled residential rates.



Major Metropolitan Areas	Population (thousands)
Cuyahoga County (Cleveland)	1,278
Summit County (Akron)	542
Lucas County (Toledo)	442
Mahoning/Trumbull Counties (Youngstown)	449
Total State of Ohio	11,540

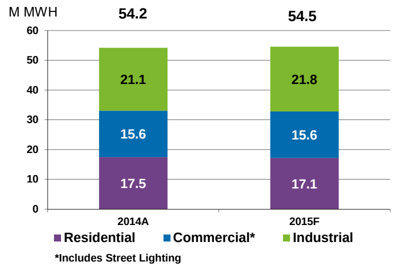
Source: U.S. Census Bureau (2010)

Principal Industries Served**
Primary Fabricated Metals
Automotive
Chemical
Plastic and Rubber
Petroleum

** Based on kWh sales

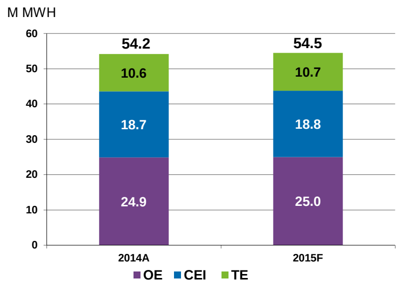
As of December 31, 2014

Ohio – **Distribution Sales**



State Unemployment Rates					
	2007	2011	2012	2013	2014
OH	5.6%	8.7%	7.4%	7.3%	5.8%

Source: Moody's Analytics



Note: Forecasted sales assume normal weather.
Includes forecast for state energy efficiency mandates.
(State mandate 4.2%. Approximately 2.3M MWH)

Gross Domestic Product Annualized Growth (Seasonally Adjusted Annualized Rate)					
	2007	2011	2012	2013	2014
OH	-0.8%	2.6%	3.1%	1.8%	0.3%

Source: Moody's Analytics

Gross Domestic Product, in 2009 dollars ($ billions)					
	2007	2011	2012	2013	2014
OH	$509	$501	$517	$526	$528

Source: Moody's Analytics

Ohio – **Political Landscape**

Governor

Governor	Current Term
John Kasich (R)	Expires in 2019

Public Utilities Commission of Ohio (PUCO)

Commissioners	Current Term
Thomas W. Johnson, Chairman (R)	Expires in 2019
Asim Z. Haque, Vice Chairman (I)	Expires in 2016
Steven D. Lesser (D)	Expires in 2015
Lynn Slaby (R)	Expires in 2017
M. Beth Trombold (I)	Expires in 2018

Ohio – Regulatory Update

Ohio ESP 3

- Approved by the PUCO on July 18, 2012
- Plan covers June 1, 2014, thru May 31, 2016
- Stabilizes pricing by modifying the previous POLR competitive bidding schedule
- Freezes base distribution rates through May 31, 2016
- Continues Delivery Capital Recovery rider to earn a return on and of incremental distribution plant in service since last rate case
  - Up to $405M in revenue for period covered by ESP 3
- Continues collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs
- Extends recovery period for REC costs (with carrying charges) – reducing current monthly charges for non-shopping customers by more than 50%
- Provides PIPP customers with 6% discount off their price-to-compare with wholesale generation supply provided by FE Solutions

Ohio – Regulatory Update

Ohio ESP 3 – Delivery Capital Recovery Rider

Recovery Period	Revenue Cap ($ Millions)
Jan 2012 – Dec 2012	$150
Jan 2013 – Dec 2013	$165
Jan 2014 – May 2014	$75
Jun 2014 – May 2015	$195
Jun 2015 – May 2016	$210

- Individual company revenue caps are determined by the following percentages applied to the total revenue cap
  - **CEI:** up to 70%
  - **OE:** up to 50%
  - **TE:** up to 30%
- Any recovery period shortfall or overage will be applied to the subsequent period

Ohio – **Regulatory Update**

Ohio ESP IV – Powering Ohio's Progress*
Continues to build upon the success of current and prior ESPs

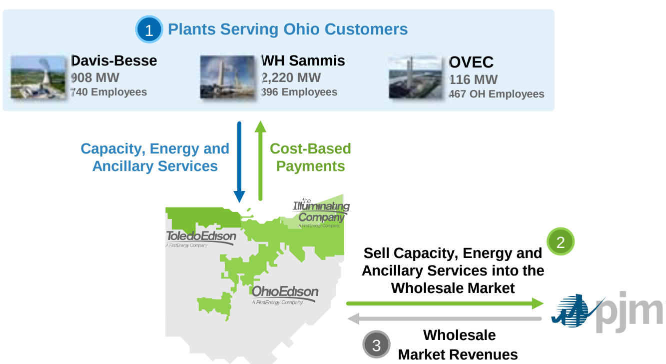
POWERING OHIO'S PROGRESS

- **Filed: August 4, 2014**
- **Term: June 1, 2016 – May 31, 2019**
- **As proposed:**
  - Continues successful competitive bid process for POLR load
  - Freezes base distribution rates through May 31, 2019
  - Continues Delivery Capital Recovery rider with revenue increase caps proposed at $30M per year
  - Continues collection of lost distribution revenue associated with energy efficiency and peak demand reduction programs
  - Includes Economic Stability Program
- **Stipulation with 15 signatory parties filed on December 22, 2014**
  - Accepts the terms of the Ohio Companies' Application except as modified by the Stipulation which includes provisions related to rate design, economic development, energy efficiency, and support for low income customers

* Subject to regulatory approval

Ohio – **Regulatory Update**

POWERING OHIO'S PROGRESS
Economic Stability Program*



1
- FE's Ohio utilities enter into a 15-year purchased power contract with FES
- Purchase power from Davis-Besse, Sammis and a portion of OVEC
- Utilities pay FES a cost-based rate for power

2
- Utilities sell power into wholesale market

3
- When wholesale market revenues exceed cost, customers receive credit
- When wholesale market revenues are less than cost, customers pay charge
- Cost-based arrangement protects all customers from retail price volatility

- Customers projected to save $2B over 15 years

Note:
- Non-shopping customers continue to receive generation from competitive auction process
- All customers retain option to shop for a competitive retail electric supplier

* Subject to regulatory approval

Ohio – Regulatory Update

- **Amended Energy Efficiency Filing**
  - Ohio Senate Bill 310 provides the opportunity to lower customers' costs while continuing to meet the state's energy efficiency requirements for 2015 and 2016
  - On November 20, 2014 the Ohio Companies received approval of their Amended Energy Efficiency Plan to reduce customers' costs while aligning with the state's recent action to freeze energy efficiency mandates for 2015-2016
  - Certain large industrial customers have the ability to opt out of utility-sponsored programs and implement their own energy efficiency initiatives
- **Alternative Energy Rider Case**
  - PUCO issued an Opinion and Order on August 7, 2013, disallowing $43.4M plus carrying costs in Renewable Energy Credit purchases
  - The Ohio Companies and Intervenors filed Applications for Rehearing on September 6, 2013
  - The PUCO granted the Applications for Rehearing for further consideration on September 18, 2013
  - A Second Entry on Rehearing from the PUCO was issued on December 18, 2013, denying the Application for Rehearing filed by the Ohio Companies and Intervenors
  - The Ohio Companies filed an appeal and motion to stay with the Supreme Court of Ohio on December 24, 2013. The stay was granted on February 10, 2014, and went into effect February 14, 2014.

Ohio – **Energy Efficiency**

Mandates and Progress

	Ohio
State Goals	Senate Bill 221*
Energy Efficiency	4.20% in 2015 (2,266 GWH)* 4.20% in 2016 (2,288 GWH)* 5.20% in 2017 (2,832 GWH)*
Demand Response	4.75% in 2015 (552 MW)* 4.75% in 2016 (545 MW)* 5.50% in 2017 (630 MW)*
Smart Meter	No state smart meter requirement

*Senate Bill 310, which became effective September 12, 2014, freezes the 2015 and 2016 energy efficiency and demand response requirements at 4.20% EE, 4.75% DR. The GWH and MW goal estimates shown above are expected to decrease over time as certain C&I customers elect to opt-out of the Companies' Energy Efficiency programs.

Status	
Smart Meter	PUCO approved Phase II pilot DR expansion for total up to 44,000 meters. Opt-in DR Pricing program available to most pilot customers in 2014.
Cost Recovery for Energy Efficiency	In place; semi-annual energy efficiency rider
Compliance	2014 EE & DR targets met based on preliminary data On track to achieve 2015 EE & DR targets

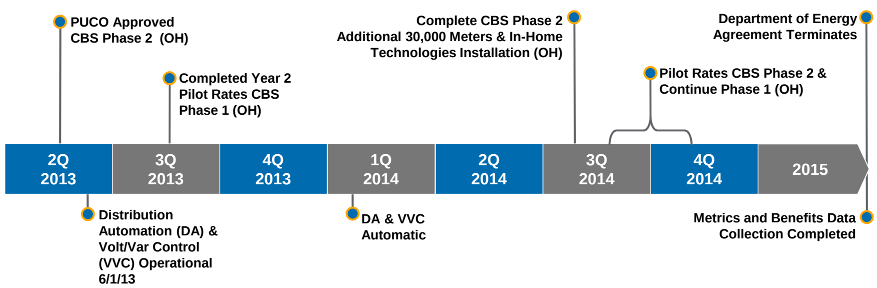
Smart Grid	
Cross-cutting** Technologies/Programs	CEI ($67M)
Distribution Automation	$27
Volt / VAR Control	$10
Consumer Behavior Study	$30

- **Period of performance = 60 months (June 2, 2010 – June 1, 2015)**
- **Implementation of all programs during 2014**
- **All just and reasonable costs are fully reimbursable via federal grant and state approved riders (subject to audit)**

**Cross-cutting describes a project that includes communications and control systems that support more than one component of the smart grid

Ohio – **Smart Grid Modernization Initiative Update**

- **Project Status: 93% Complete**
- **Remaining Work**
  - Consumer Behavior Study (CBS) Final Report
  - Metrics & Benefits Reporting
- **$60M of $67M spent through 4Q 2014**



Ohio – **Procurement Schedule**

Ohio Edison, The Illuminating Company (CEI) and Toledo Edison

ESP 3		Delivery Period		
Auction	Tranches Bid*	June 2013 – May 2014	June 2014 – May 2015	June 2015 – May 2016
Oct-12	17	36 Months $60.90 / MWH		
Jan-13	17	36 Months $59.17 / MWH		
Oct-13	16		12 Months $50.91 / MWH	
	17		24 Months $59.99 / MWH	
Jan-14	16		12 Months $55.83 / MWH	
	17		24 Months $68.31 / MWH	
Oct-14	16			12 Months $73.82 / MWH
Jan-15	16			12 Months $69.18 / MWH

*Each tranche represents 1% of the actual hourly energy and daily capacity required to serve SSO load; tranches are full-requirements products

Ohio – **Long-Term Debt Schedules**

Company	Type	CUSIP	Interest Rate	Maturity	Amount Outstanding
Ohio Edison	First Mortgage Bond	677347CG9	8.25%	10/15/2018	$25,000,000
	Senior Note	677347CE4	6.875%	7/15/2036	$350,000,000
	First Mortgage Bond	677347CF1	8.25%	10/15/2038	$275,000,000
				OE Total	**$650,000,000**
Ohio Edison Funding LLC	Phase-In Recovery Bond	33766QAA5	0.679%	1/15/2017*	$8,025,370
	Phase-In Recovery Bond	33766QAB3	1.726%	1/15/2020*	$10,202,000
	Phase-In Recovery Bond	33766QAC1	3.450%	1/15/2034*	$123,612,000
				OE Funding LLC Total	**$141,839,370**
The Illuminating Company (CEI)	Senior Note	186108CF1	5.7%	4/1/2017	$130,000,000
	Secured Note	186108BU9	7.88%	11/1/2017	$300,000,000
	First Mortgage Bond	186108CH7	8.875%	11/15/2018	$300,000,000
	First Mortgage Bond	186108CJ3	5.5%	8/15/2024	$300,000,000
	Senior Note	186108CE4	5.95%	12/15/2036	$300,000,000
				CEI Total	**$1,330,000,000**

* Expected Final Maturity Date

As of December 31, 2014

Ohio – **Long-Term Debt Schedules**

Company	Type	CUSIP	Interest Rate	Maturity	Amount Outstanding
CEI Funding LLC	Phase-In Recovery Bond	33766QAA5	0.679%	1/15/2017*	$42,387,863
	Phase-In Recovery Bond	33766QAB3	1.726%	1/15/2020*	$56,383,000
	Phase-In Recovery Bond	33766QAC1	3.450%	1/15/2034*	$103,160,000
				CEI Funding LLC Total	**$201,930,863**
Toledo Edison	Senior Secured Notes	889175BE4	7.25%	5/1/2020	$50,000,000
	Senior Secured Notes	889175BD6	6.15%	5/15/2037	$300,000,000
				TE Total	**$350,000,000**
Toledo Edison Funding LLC	Phase-In Recovery Bond	33766QAA5	0.679%	1/15/2017*	$2,796,264
	Phase-In Recovery Bond	33766QAB3	1.726%	1/15/2020*	$3,883,000
	Phase-In Recovery Bond	33766QAC1	3.450%	1/15/2034*	$35,711,000
				TE Funding LLC Total	**$42,390,264**

* Expected Final Maturity Date

As of December 31, 2014

Creating Value for Investors

FirstEnergy

Pennsylvania Operations

Pennsylvania – **Customer Data**

2014 Total Customers (thousands)	
Penelec (Includes NY – 4)	**588**
Met-Ed	**558**
Penn Power	**163**
West Penn Power	**721**
Total	**2,030**

Typical Bill Comparison*	
Pennsylvania	**$/Month**
Penelec	**$142.70**
Met-Ed	**$140.40**
Penn Power	**$122.55**
West Penn Power	**$105.00**
Statewide Avg. Bill	**$142.64**

* Typical bills are based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI Typical Bills and Average Rates Report as of July 1, 2014. Pennsylvania rates represent Default Service Provider bundled residential rates.

Major Metropolitan Areas	Population (thousands)
York County (York)	**436**
Berks County (Reading)	**412**
Westmoreland County (Greensburg)	**365**
Erie County (Erie)	**281**
Total State of Pennsylvania	**12,711**

Source: U.S. Census Bureau (2010)

Principal Industries Served**
Primary and Fabricated Metals
Coal Mining
Chemical
Plastic and Rubber
Non-Metallic Minerals

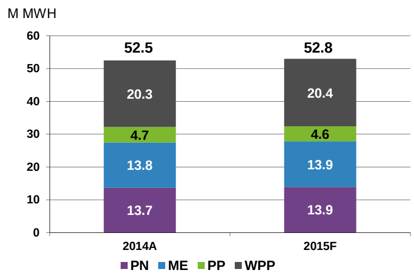
** Based on kWh sales

As of December 31, 2014

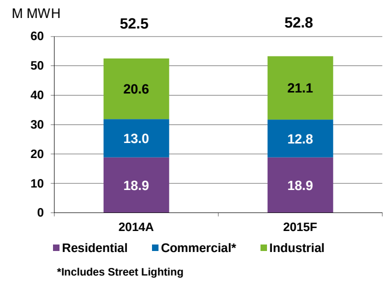
Pennsylvania – **Distribution Sales**

State Unemployment Rates (%)					
	2007	2011	2012	2013	2014
PA	4.4%	8.0%	7.9%	7.4%	5.8%

Source: Moody's Analytics



Note: Forecasted sales assume normal weather.
Includes forecast for state energy efficiency mandates
(State Mandate 3.0% by 5/31/13, ~1.6M MWH. Incrementally ~1.1M MWH by 5/31/16 ~1.1M)



Gross Domestic Product Annualized Growth (Seasonally Adjusted Annualized Rate)					
	2007	2011	2012	2013	2014
PA	1.6%	1.4%	1.2%	0.7%	0.3%

Source: Moody's Analytics

Gross Domestic Product, in 2009 dollars ($ billions)					
	2007	2011	2012	2013	2014
PA	$581	$593	$600	$604	$606

Source: Moody's Analytics

Pennsylvania – **Political Landscape**

Governor

Governor	Current Term
Thomas W. Wolf (D)	Expires in 2019

Pennsylvania Public Utility Commission (PAPUC)

Commissioners	Current Term
Robert F. Powelson, Chairman (R)*	Expires in 2019
John F. Coleman, Jr., Vice Chairman (R)**	Expires in 2017
James H. Cawley (D)	Expires in 2015
Pamela A. Witmer (R)	Expires in 2016
Gladys M. Brown (D)	Expires in 2018

*The Governor-Elect will have up to 120 days from his inauguration to select a new Chair of the PUC. If Chairman Powelson is not retained as Chair, he will continue on the PUC for the remainder of his appointed term as a Commissioner.
** The Vice Chairman is selected by the Commissioners.

Pennsylvania – **Energy Efficiency**

	Pennsylvania
State Goals	**PA Act 129**
Energy Efficiency	**By 5/31/2016 (1,090 GWH) – Phase II of Act 129** – ME +2.3% (338 GWH) – PN +2.2% (319 GWH) – PP +2.0% (96 GWH) – WPP +1.6% (338 GWH)
Demand Response	**No peak demand reduction targets in Phase II, 6/2013 through 5/2016**
Smart Meter	**Smart Meter full deployment** ▪ **Mandatory deployment within 15 year depreciation cycle**
Status	
Smart Meter	**Commission approval received June 5, 2014, on the Revised Smart Meter Deployment Plan** **Deployment began in July 2014 of 170,000 smart meters in PP by the end of 2015 and nearly all PA FE customers by mid-2019.**
Cost Recovery for Energy Efficiency	**In place; annual energy efficiency rider**
Compliance	**On track to achieve 2016 EE targets**

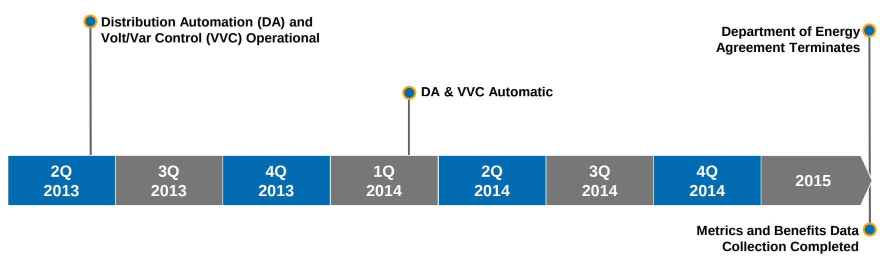
Smart Grid	
Cross-cutting* Technologies/ Programs	**ME ($33M)**
Distribution Automation	**$9**
Volt / VAR Control	**$5**
Integrated Distributed Energy Resource Direct Load Control	**$19**

- **Period of performance = 60 months (June 2, 2010 – June 1, 2015)**
- **Implementation of all programs during 2014**
- **All just and reasonable costs are fully reimbursable via federal grant and state approved riders (subject to audit)**

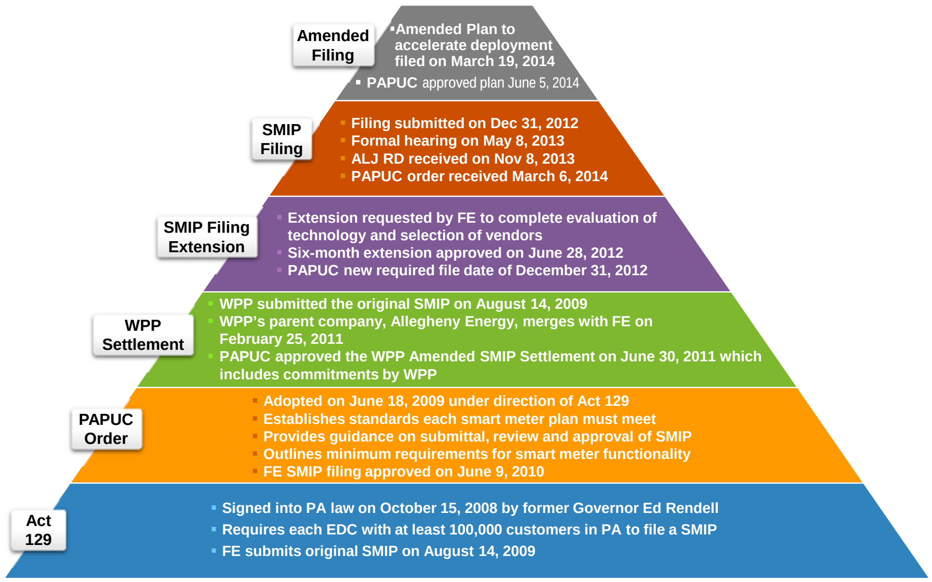
*Cross-cutting describes a project that includes communications and control systems that support more than one component of the smart grid

Pennsylvania – **Smart Grid Modernization Initiative Update**

- **Project Status: 98% Complete**
- **Remaining Work**
  - Metrics & Benefits Reporting
- **$32M of $33M spent through 4Q 2014**



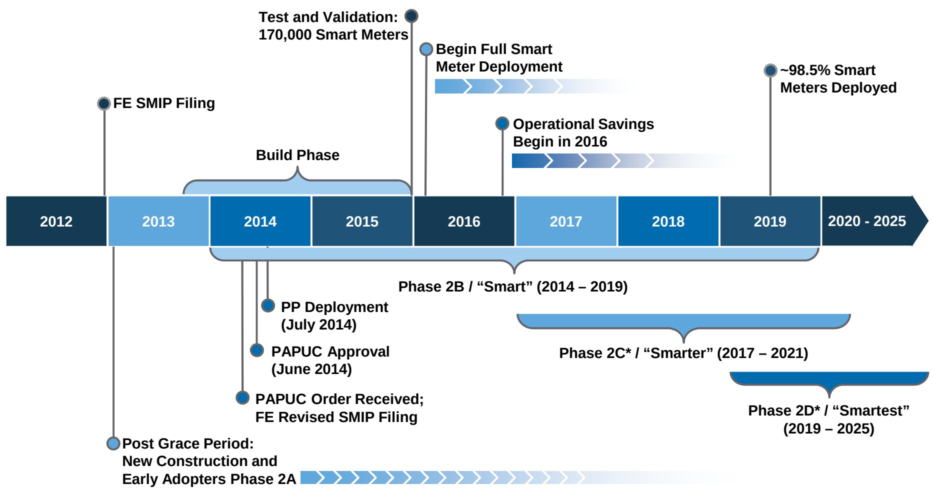
Pennsylvania – **Smart Meter Update**



Pennsylvania – **Smart Meter Update**

- **Commission Approval Received on June 5, 2014**
  - Order approves the Revised Smart Meter Deployment Plan
  - Deployment began in July 2014
  - Approximately 52,000 meters installed by PP through the end of 2014
- **Revised Deployment Plan Timeframe**
  - 2014 - 2015: PP rolls out test program using 170,000 meters
  - 2016 - 2019: Four-year deployment schedule to install approximately two million meters in remaining Pennsylvania Operating Companies
- **Financial Impacts**
  - 20-Year Cost: $1.26B
    - Deployment cost Included in Total Cost: $815M
  - Estimated Operational Savings: $417M
    - Meter Reading: $383M
    - Meter Services: $13M
    - Contact Center: $2M
    - Back Office: $19M
- **Cost Recovery Mechanism: Smart Meter Technologies Charge (SMT-C)**
  - The pending settlements in the base rate cases have established a baseline to measure savings that will result from the deployment of smart meters
  - PAPUC approved 2015 SMT-C rates which became effective January 1, 2015

Pennsylvania – **Smart Meter Update**



*Smarter and Smartest Phases are not included in the Business Case

Pennsylvania – **Settlement Summary[1]**

	Rate Case Settlements Summary[1]			
	Met-Ed	Penelec	Penn Power	West Penn Power
Case Docket #	R-2014-2428745	R-2014-2428743	R-2014-2428744	R-2014-2428742
Capital Structure	50.00% Debt, 50.00% Equity 5.21% Cost of Debt	50.10% Debt, 49.90% Equity 5.72% Cost of Debt	49.90% Debt, 50.10% Equity 6.12% Cost of Debt	49.90% Debt, 50.10% Equity 5.38% Cost of Debt
ROE[2]	Settled	Settled	Settled	Settled
Overall Return[2]	Settled	Settled	Settled	Settled
Percentage Change Over Revenues At Existing Rates[3]	6.8%	6.6%	5.2%	7.0%
($ Thousands)				
Distribution Base Rates	$90,000	$91,300	$17,000	$59,900
USC Rider	–	–	–	29,600
DSS and HPS Riders	(700)	(500)	(1,100)	7,300
Smart Meter	Included in Distribution	Included in Distribution	Included in Distribution	Included in Distribution
Annual Total Revenue Increase	$89,300	$90,800	$15,900	$96,800
Annual Pre-tax Earnings Impact	$56,200	$71,900	$13,000	$64,000

[1] Terms of the settlements; subject to approval by the PaPUC. Orders are expected by May 19, 2015
[2] Settlements did not disclose these specific elements
[3] The percentage was calculated based on total estimated revenue for the fully projected future test year consisting of distribution revenue as well as generation service revenue, with the latter reflecting generation rates equivalent to the Companies' prices for applicable default service.
Settlements and supporting documents filed by ME, PN, PP, and WPP are available at www.puc.state.pa.us

Pennsylvania – **Settlement Summary**[1]

- **WPP Universal Service Rider – makes the WPP Universal Service cost recovery consistent with ME, PN, and PP**
  - Enables WPP to increase expenditures and enhance existing programs in response to changes in economic conditions
  - Rate filed annually on December 1
  - Charged to residential customers only
- **Default Service Support (DSS)/Hourly Pricing Service (HPS) rider changes – Uncollectibles normalized**
  - Update WPP DSS rider to include default service and purchase of receivable-related uncollectible expense
  - Collect industrial default service related uncollectibles through the HPS rider
- **Time-of-Use**
  - Elimination of time-of-use distribution rates (Rate Schedule Residential Time of Day) for ME and PN
  - Creation of Time-of-Use Riders for Residential Price-to-Compare charge for ME and PN
- **Storm Reserve Accounts established for non-extraordinary storms**
  - Enables each Company to defer storm-related expenses for future recovery

[1] Terms of the settlements; subject to approval by the PaPUC. Orders are expected by May 19, 2015.

Pennsylvania – Regulatory Update

- **Met-Ed, Penelec, Penn Power and West Penn Power Default Service Programs for June 2015 – May 2017**
  - Default Service Programs filed on November 3, 2013
  - A settlement was reached with all intervening parties on all but one issue
  - Settlement Documents and Initial Briefs filed March 27, 2014, and Reply Briefs filed April 10, 2014
  - ALJ RD was issued May 7, 2014
  - PAPUC approved settlement July 24, 2014
  - Changes and new rates for Price to Compare Default Service Riders and Default Service Support Riders become effective on June 1, 2015

Pennsylvania – **Procurement Schedule**

ME Default Service Supply Plan • June 1, 2013 to May 31, 2015

Residential Full Requirements Tranche Procurement Schedule*

		Delivery Period							
Auction	**Tranches Bid**	**6/1/13**	**11/30/13**	**12/1/13**	**5/31/14**	**6/1/14**	**11/30/14**	**12/1/14**	**5/31/15**
Jan-13	12	24 months - $67.71 / MWH							
Feb-13	12	12 months - $71.34 / MWH							
Jan-14	12					12 months - $63.24 / MWH			

Commercial Full Requirements Tranche Procurement Schedule

		Delivery Period							
Auction	**Tranches Bid**	**6/1/13**	**11/30/13**	**12/1/13**	**5/31/14**	**6/1/14**	**11/30/14**	**12/1/14**	**5/31/15**
Jan-13	11	6 months - $66.34 / MWH							
Feb-13	12	12 months - $69.16 / MWH							
Sep-13	11			12 months - $63.49 / MWH					
Jan-14	12					12 months - $63.09 / MWH			
Sep-14	11							6 months - $80.23 / MWH	

Hourly Pricing Service Tranche Procurement Schedule

		Delivery Period							
Auction	**Tranches Bid**	**6/1/13**	**11/30/13**	**12/1/13**	**5/31/14**	**6/1/14**	**11/30/14**	**12/1/14**	**5/31/15**
Sep-13	11			18 months - $18.46 / MWH					

* Schedule does not reflect four additional existing fixed block energy only tranches procured during the January 2010 auction which terminate on May 31, 2015

Pennsylvania – **Procurement Schedule**

ME Default Service Supply Plan • June 1, 2015 to May 31, 2017

Residential Full Requirements Tranche Procurement Schedule

Auction Month	Tranches	6/1/15 to 8/31/15	9/1/15 to 11/30/15	12/1/15 to 2/29/16	3/1/16 to 5/31/16	6/1/16 to 8/31/16	9/1/16 to 11/30/16	12/1/16 to 2/28/17	3/1/17 to 5/31/17
October 2014	4	12-Months - $77.89 / MWH							
	4	24-Months - $76.82 / MWH							
January 2015	4	12-Months - $65.74 / MWH							
	4	24-Months - $66.03 / MWH							
April 2015	5	12-Months							
	4	24-Months							
October 2015	4					12-Months			
January 2016	4					12-Months			
April 2016	5					12-Months			

Commercial Full Requirements Tranche Procurement Schedule

Auction Month	Tranches	6/1/15 to 8/31/15	9/1/15 to 11/30/15	12/1/15 to 2/29/16	3/1/16 to 5/31/16	6/1/16 to 8/31/16	9/1/16 to 11/30/16	12/1/16 to 2/28/17	3/1/17 to 5/31/17
October 2014	2	12-Months - $86.56							
	2	24-Months - $89.56							
January 2015	2	12-Months - $66.09 / MWH							
	2	24-Months - $66.53 / MWH							
April 2015	3	3-Months							
	1	12-Months							
	1	24-Months							
June 2015	3		3-Months						
October 2015	3			3-Months					
	2					12-Months			
January 2016	3				3-Months				
	2					12-Months			
April 2016	3					3-Months			
	1					12-Months			
June 2016	3						3-Months		
October 2016	3							3-Months	
January 2017	3								3-Months

Hourly Price Service Tranche Procurement Schedule

Auction Month	Tranches	6/1/15 to 8/31/15	9/1/15 to 11/30/15	12/1/15 to 2/29/16	3/1/16 to 5/31/16	6/1/16 to 8/31/16	9/1/16 to 11/30/16	12/1/16 to 2/28/17	3/1/17 to 5/31/17
January 2015	8	12-Months - $30.50 / MWH							
January 2016	8					12-Months			

Pennsylvania – **Procurement Schedule**

PN Default Service Supply Plan • June 1, 2013 to May 31, 2015

Residential Full Requirements Tranche Procurement Schedule*

		Delivery Period							
Auction	Tranches Bid	6/1/13	11/30/13	12/1/13	5/31/14	6/1/14	11/30/14	12/1/14	5/31/15
Jan-13	9	24 months – $61.14 / MWH							
Feb-13	9	12 months - $64.39 / MWH							
Jan-14	9					12 months - $58.36 / MWH			

Commercial Full Requirements Tranche Procurement Schedule

		Delivery Period							
Auction	Tranches Bid	6/1/13	11/30/13	12/1/13	5/31/14	6/1/14	11/30/14	12/1/14	5/31/15
Jan-13	10	6 months - $63.05 / MWH							
Feb-13	10	12 months – $65.18 / MWH							
Sep-13	10			12 months – $60.89 / MWH					
Jan-14	10					12 months - $60.92 / MWH			
Sep-14	10							6 months - $74.79 / MWH	

Hourly Pricing Service Tranche Procurement Schedule

		Delivery Period							
Auction	Tranches Bid	6/1/13	11/30/13	12/1/13	5/31/14	6/1/14	11/30/14	12/1/14	5/31/15
Sep-13	11			18 months - $12.99 / MWH					

* Schedule does not reflect four additional existing fixed block energy only tranches procured during the January 2010 auction which terminate on May 31, 2015.

Pennsylvania – **Procurement Schedule**

PN Default Service Supply Plan • June 1, 2015 to May 31, 2017

Residential Full Requirements Tranche Procurement Schedule

Auction Month	Tranches	6/1/15 to 8/31/15	9/1/15 to 11/30/15	12/1/15 to 2/29/16	3/1/16 to 5/31/16	6/1/16 to 8/31/16	9/1/16 to 11/30/16	12/1/16 to 2/28/17	3/1/17 to 5/31/17
October 2014	3	12-Months - $73.24 / MWH							
	3	24-Months - $73.61 / MWH							
January 2015	3	12-Months - $63.47 / MWH							
	3	24-Months - $63.75 / MWH							
April 2015	3	12-Months							
	3	24-Months							
October 2015	3					12-Months			
January 2016	3					12-Months			
April 2016	3					12-Months			

Commercial Full Requirements Tranche Procurement Schedule

Auction Month	Tranches	6/1/15 to 8/31/15	9/1/15 to 11/30/15	12/1/15 to 2/29/16	3/1/16 to 5/31/16	6/1/16 to 8/31/16	9/1/16 to 11/30/16	12/1/16 to 2/28/17	3/1/17 to 5/31/17
October 2014	2	12-Months - $86.67							
	2	24-Months - $80.13							
January 2015	2	12-Months - $63.69 / MWH							
	2	24-Months - $64.34 / MWH							
April 2015	5	3-Months							
	1	12-Months							
	1	24-Months							
June 2015	5		3-Months						
October 2015	5			3-Months					
	2					12-Months			
January 2016	5				3-Months				
	2					12-Months			
April 2016	5					3-Months			
	2					12-Months			
June 2016	5						3-Months		
October 2016	5							3-Months	
January 2017	5								3-Months

Hourly Price Service Tranche Procurement Schedule

Auction Month	Tranches	6/1/15 to 8/31/15	9/1/15 to 11/30/15	12/1/15 to 2/29/16	3/1/16 to 5/31/16	6/1/16 to 8/31/16	9/1/16 to 11/30/16	12/1/16 to 2/28/17	3/1/17 to 5/31/17
January 2015	9	12-Months - $17.50 / MWH							
January 2016	9					12-Months			

Pennsylvania – **Procurement Schedule**

PP Default Service Supply Plan • June 1, 2013 to May 31, 2015

Residential Full Requirements Tranche Procurement Schedule*

		Delivery Period							
Auction	Tranches Bid	6/1/13	11/30/13	12/1/13	5/31/14	6/1/14	11/30/14	12/1/14	5/31/15
Jan-13	3	24 months - $52.22 / MWH							
Feb-13	3	12 months - $45.45 / MWH							
Jan-14	3					12 months - $58.04 / MWH			

Commercial Full Requirements Tranche Procurement Schedule

		Delivery Period							
Auction	Tranches Bid	6/1/13	11/30/13	12/1/13	5/31/14	6/1/14	11/30/14	12/1/14	5/31/15
Jan-13	3	6 months - $47.19 / MWH							
Feb-13	4	12 months – $48.19 / MWH							
Sep-13	3			12 months – $55.72 / MWH					
Jan-14	4					12 months - $63.42 / MWH			
Sep-14	3							6 months - $73.73 / MWH	

Hourly Pricing Service Tranche Procurement Schedule

		Delivery Period							
Auction	Tranches Bid	6/1/13	11/30/13	12/1/13	5/31/14	6/1/14	11/30/14	12/1/14	5/31/15
Sep-13	3			18 months - $10.22 / MWH					

* Schedule does not reflect four additional existing fixed block energy only tranches procured during the January 2010 auction which terminate on May 31, 2015

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Pennsylvania – **Procurement Schedule**

PP Default Service Supply Plan • June 1, 2015 to May 31, 2017

Residential Full Requirements Tranche Procurement Schedule

Auction Month	Tranches	6/1/15 to 8/31/15	9/1/15 to 11/30/15	12/1/15 to 2/29/16	3/1/16 to 5/31/16	6/1/16 to 8/31/16	9/1/16 to 11/30/16	12/1/16 to 2/28/17	3/1/17 to 5/31/17
October 2014	1	12-Months - $85.15 / MWH							
	1	24-Months - $78.47 / MWH							
January 2015	1	12-Months - $74.16 / MWH							
	1	24-Months - $72.32 / MWH							
April 2015	1	12-Months							
	1	24-Months							
October 2015	1					12-Months			
January 2016	1					12-Months			
April 2016	1					12-Months			

Commercial Full Requirements Tranche Procurement Schedule

Auction Month	Tranches	6/1/15 to 8/31/15	9/1/15 to 11/30/15	12/1/15 to 2/29/16	3/1/16 to 5/31/16	6/1/16 to 8/31/16	9/1/16 to 11/30/16	12/1/16 to 2/28/17	3/1/17 to 5/31/17
October 2014	1	12-Months - $89.65							
	1	24-Months - $83.19							
January 2015	1	12-Months - $82.87 / MWH							
	1	24-Months - $78.74 / MWH							
April 2015	1	3-Months							
	1	12-Months							
	1	24-Months							
June 2015	1		3-Months						
October 2015	1			3-Months					
	1					12-Months			
January 2016	1				3-Months				
	1					12-Months			
April 2016	1					3-Months			
	1					12-Months			
June 2016	1						3-Months		
October 2016	1							3-Months	
January 2017	1								3-Months

Hourly Price Service Tranche Procurement Schedule

Auction Month	Tranches	6/1/15 to 8/31/15	9/1/15 to 11/30/15	12/1/15 to 2/29/16	3/1/16 to 5/31/16	6/1/16 to 8/31/16	9/1/16 to 11/30/16	12/1/16 to 2/28/17	3/1/17 to 5/31/17
January 2015	2	12-Months - $25.95 / MWH							
January 2016	2					12-Months			

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Pennsylvania – Procurement Schedule

WPP Default Service Supply Plan • June 1, 2013 to May 31, 2015

Residential Full Requirements Tranche Procurement Schedule

		Delivery Period							
Auction	Tranches Bid	6/1/13	11/30/13	12/1/13	5/31/14	6/1/14	11/30/14	12/1/14	5/31/15
Jan-13	15	24 months - $51.04 / MWH							
Feb-13	15	12 months - $46.53 / MWH							
Jan-14	15					12 months - $57.36 / MWH			

Commercial Full Requirements Tranche Procurement Schedule

		Delivery Period							
Auction	Tranches Bid	6/1/13	11/30/13	12/1/13	5/31/14	6/1/14	11/30/14	12/1/14	5/31/15
Jan-13	9	6 months - $45.05 / MWH							
Feb-13	10	12 months - $45.92 / MWH							
Sep-13	9			12 months - $49.46 / MWH					
Jan-14	10					12 months - $57.29 / MWH			
Sep-14	9							6 months - $68.99 / MWH	

Industrial Hourly Pricing Service Tranche Procurement Schedule

		Delivery Period							
Auction	Tranches Bid	6/1/13	11/30/13	12/1/13	5/31/14	6/1/14	11/30/14	12/1/14	5/31/15
Sep-13	12			18 months - $5.68 / MWH					

Pennsylvania – Procurement Schedule

WPP Default Service Supply Plan • June 1, 2015 to May 31, 2017

Residential Full Requirements Tranche Procurement Schedule

Auction Month	Tranches	6/1/15 to 8/31/15	9/1/15 to 11/30/15	12/1/15 to 2/29/16	3/1/16 to 5/31/16	6/1/16 to 8/31/16	9/1/16 to 11/30/16	12/1/16 to 2/28/17	3/1/17 to 5/31/17
October 2014	4	12-Months - $70.22 / MWH							
	4	24-Months - $70.09 / MWH							
January 2015	5	12-Months - $59.05 / MWH							
	5	24-Months - $57.93 / MWH							
April 2015	5	12-Months							
	5	24-Months							
October 2015	4					12-Months			
January 2016	5					12-Months			
April 2016	5					12-Months			

Commercial Full Requirements Tranche Procurement Schedule

Auction Month	Tranches	6/1/15 to 8/31/15	9/1/15 to 11/30/15	12/1/15 to 2/29/16	3/1/16 to 5/31/16	6/1/16 to 8/31/16	9/1/16 to 11/30/16	12/1/16 to 2/28/17	3/1/17 to 5/31/17
October 2014	3	12-Months - $75.73							
	3	24-Months - $74.46							
January 2015	3	12-Months - $60.52 / MWH							
	3	24-Months - $62.00 / MWH							
April 2015	4	3-Months							
	1	12-Months							
	1	24-Months							
June 2015	4		3-Months						
October 2015	4			3-Months					
	2					12-Months			
January 2016	4				3-Months				
	2					12-Months			
April 2016	4					3-Months			
	3					12-Months			
June 2016	4						3-Months		
October 2016	4							3-Months	
January 2017	4								3-Months

Hourly Price Service Tranche Procurement Schedule

Auction Month	Tranches	6/1/15 to 8/31/15	9/1/15 to 11/30/15	12/1/15 to 2/29/16	3/1/16 to 5/31/16	6/1/16 to 8/31/16	9/1/16 to 11/30/16	12/1/16 to 2/28/17	3/1/17 to 5/31/17
January 2015	13	12-Months - $14.75 / MWH							
January 2016	13					12-Months			

Pennsylvania – **Long-Term Debt Schedules**

Company	Type	CUSIP	Interest Rate	Maturity	Amount Outstanding
Penn Power	First Mortgage Bond	Private Placement	9.74%	11/1/2019	$4,903,000
	First Mortgage Bond	Private Placement	6.09%	6/30/2022	$100,000,000
				PP Total	**$104,903,000**
Penelec	Senior Note	708696BU2	6.05%	9/1/2017	$300,000,000
	Senior Note	708696BM0	6.625%	4/1/2019	$125,000,000
	Senior Note	708696BW8	5.2%	4/1/2020	$250,000,000
	Senior Note	708696BX6	4.15%	4/15/2025	$200,000,000
	Senior Note	708696BV0	6.15%	10/1/2038	$250,000,000
				PN Total	**$1,125,000,000**

As of December 31, 2014

Pennsylvania – **Long-Term Debt Schedules**

Company	Type	CUSIP	Interest Rate	Maturity	Amount Outstanding
Met-Ed	Senior Note	591894BX7	7.7%	1/15/2019	$300,000,000
	Senior Note	591894BY5	3.5%	3/15/2023	$300,000,000
	Senior Note	591894CB4	4.0%	4/15/2025	$250,000,000
				ME Total	**$850,000,000**
West Penn Power	First Mortgage Bond	955278BG0	5.875%	8/15/2016	$145,000,000
	First Mortgage Bond	955278BH8	5.95%	12/15/2017	$275,000,000
	First Mortgage Bond	Private Placement	3.34%	4/15/2022	$100,000,000
				WPP Total	**$520,000,000**

As of December 31, 2014

Creating Value for Investors

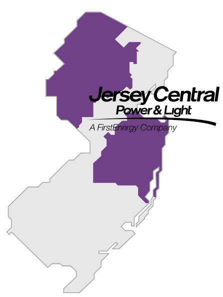
New Jersey Operations

New Jersey – Customer Data

2014 Total Customers (thousands)	
JCP&L	1,103

Typical Bill Comparison*	
New Jersey	$/Month
JCP&L	$136.62
Statewide Avg. Bill	$164.56

* Typical bills are based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI Typical Bills and Average Rates Report as of July 1, 2014. New Jersey rates represent POLR bundled residential rates



Major Metropolitan Areas	Population (thousands)
Monmouth County (Middleton Township)	631
Ocean County (Lakewood Township)	578
Morris County (Parsippany)	493
Somerset County (Franklin Township)	324
Total State of New Jersey	8,804

Source: U.S. Census Bureau (2010)

Principal Industries Served**
Chemical
Primary and Fabricated Metals
Plastic and Rubber

** Based on kWh sales

As of December 31, 2014

New Jersey – **Distribution Sales**

State Unemployment Rates (%)					
	2007	2011	2012	2013	2014
NJ	4.3%	9.3%	9.3%	8.2%	6.7%

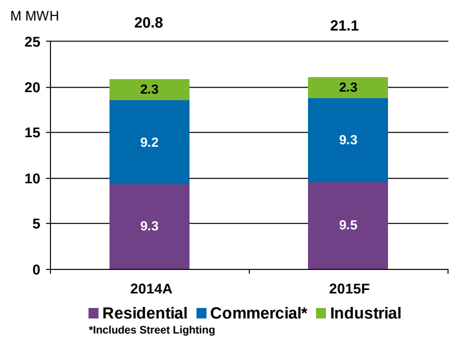
Source: Moody's Analytics

Gross Domestic Product Annualized Growth (Seasonally Adjusted Annualized Rate)					
	2007	2011	2012	2013	2014
NJ	1.3%	-0.5%	2.6%	1.1%	0.3%

Source: Moody's Analytics

Gross Domestic Product, in 2009 dollars ($ billions)					
	2007	2011	2012	2013	2014
NJ	$511	$491	$503	$509	$511

Source: Moody's Analytics



Note: Forecasted sales assume normal weather. Includes forecast for state energy efficiency mandates. (NJ Mandate state goal of 20% usage reduction by 2020).

New Jersey – **Political Landscape**

Governor

Governor	Current Term
Christopher J. Christie (R)	Expires in 2018

New Jersey Board of Public Utilities (BPU)

Commissioners	Current Term
President Richard S. Mroz (R)	Expires in 2015
Dianne Solomon (R)	Expires in 2018
Joseph L. Fiordaliso (D)	Expires in 2019*
Upendra Chivukula (D)	Expires in 2020
Mary-Anna Holden (R)	Expires in 2017

*Pending Senate confirmation

New Jersey – **Regulatory Update**

JCP&L Distribution Rate Case/Regulatory Proceedings

- **November 30, 2012: Distribution Rate Case filed**
- **January 23, 2013: BPU established a generic proceeding to review the consolidated tax adjustment policy**
- **February 22, 2013: Filing updated to include Hurricane Sandy costs**
- **March 20, 2013: BPU established a generic proceeding to review prudency of storm costs for 2011 and 2012**
- **April 4, 2013: JCP&L filed a Motion for Reconsideration to leave storm costs in the base rate case**
- **May 31, 2013: BPU issued "Clarifying Order" stating rate treatment for 2011 Storm costs would be applied in JCP&L's existing rate case. A Phase II of the rate case or some other rate treatment would be utilized relating to the 2012 Storm costs**
- **June 14, 2013: Filed update to incorporate the results of the BPU-Ordered Depreciation Study, the amended Cash Working Capital Testimony, and removed 2012 storm costs and other revisions identified during discovery**
- **August 7, 2013: Rebuttal testimony filed and reflected a revision to the proposed ROE**
- **September 12, 2013: Evidentiary hearings continued through November**
- **January 27, 2014: Briefs submitted by parties**

New Jersey – **Regulatory Update**

JCP&L Distribution Rate Case/Regulatory Proceedings (Continued)

- **February 24, 2014: Reply briefs submitted**
- **February 24, 2014: JCP&L, BPU Staff, Division of Rate Counsel entered into a stipulated agreement in the generic storm proceedings to allow recovery of $736M out of $744M for 2011 and 2012 significant weather events**
  - $156M of 2011 costs to be recovered in the pending JCP&L rate case: $74M Capital, $82M Deferred O&M
  - Recovery mechanism and timing of 2012 costs of $580M is to be determined: $333M Capital, $247M Deferred O&M
- **March 19, 2014: Generic storm proceeding settlement approved**
- **May 5, 2014: JCP&L filed updated schedules to reflect the results of the generic storm cost proceeding and revised the debt rate to 5.93%**
- **June 18, 2014: BPU Staff proposed that the current Consolidated Tax Adjustment (CTA) policy remain in effect except as amended by the following:**
  - Calculation would look back 5 years from the beginning of the test year
  - Allocation of the calculated savings would be 75% to the company and 25% ratepayers; and
  - Transmission assets of the EDCs would not be included in the calculation of the CTA
- **June 30, 2014: ALJ closed record in base rate case**
- **October, 22, 2014: BPU issued an order approving Staff's CTA proposal. Following an initial decision of the Administrative Law Judge (ALJ), the BPU would reopen the record in JCP&L's pending base rate case for the limited purpose of adding a CTA calculation reflecting this modified policy and allow parties the opportunity to comment.**
- **January 8, 2015: ALJ filed the Initial Decision**
- **January 30, 2015: BPU Staff submitted a calculation of the CTA for the rate case, with comments due February 19, 2015**
- **February 5, 2015: Exceptions to ALJ's initial decision filed**
- **February 19, 2015: Reply exceptions due**

New Jersey – **Regulatory Update**

JCP&L Distribution Rate Case/Regulatory Proceedings (Continued)

- **February 11, 2015:** **BPU approved a 45 day extension to render a final decision by April 8, 2015**

	JCP&L November 30, 2012[1]	JCP&L August 7, 2013[1]	JCP&L May 5, 2014[1]	ALJ's Initial Decision January 8, 2015
	Initial Filing	Revised ROE	Revised Debt Rate to 5.93%	
Rate Increase	$31M, 1.4%**	$11M, 0.50%**	$9.1M, 0.40%**	($107.5M), (4.84%)**
Debt/Equity Ratio	46% / 54%	46% / 54%	46% / 54%	50% / 50%
Return on Equity	11.53%	11.00%	11.00%	9.75%
Rate Base	$2.040B	$2.024B	$2.021B	$1.901B

[1]Filing includes 2011 storm costs and does not include a CTA adjustment.

*Excludes June 14, 2013 filing. See slide 64.
**Residential Rate Impact

New Jersey – **Energy Efficiency**

	New Jersey
State Goals	Energy Master Plan (EMP)
Energy Efficiency	2011 modified EMP goal of 20% usage reduction by 2020 (State Goal), subject to modification
Demand Response	17% reduction by 2020 of 2011 PJM Demand Forecast (State Goal)
Smart Grid	Smart Grid DR program 2011. DOE funded circuit automation pilot for 2014
Cost Recovery for Energy Efficiency	In place; annual energy efficiency rider
Compliance	▪ Current EE programs run by the State's Office of Clean Energy

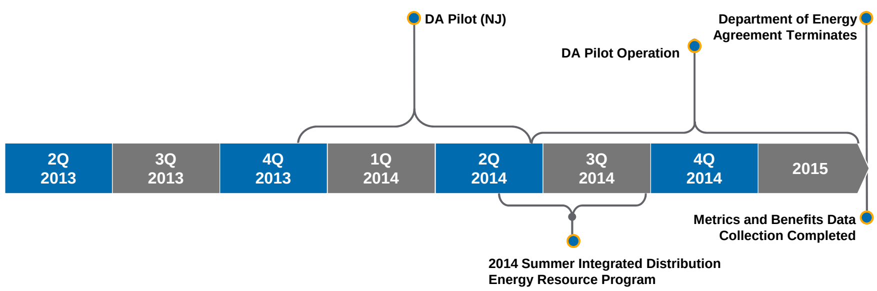
Smart Grid	
Cross-cutting* Technologies/ Programs	JCP&L ($15M)
Distribution Automation	$1
Integrated Distributed Energy Resource Direct Load Control	$14

- Period of performance = 60 months (June 2, 2010 – June 1, 2015)
- Programs were operational during 2014
- All just and reasonable costs are fully reimbursable via federal grant and state approved riders (subject to audit)

*Cross-cutting describes a project that includes communications and control systems that support more than one component of the smart grid

New Jersey – **Smart Grid Modernization Initiative Update**

- **Project Status: 99% Complete**
- **Remaining Work**
  - Distribution Automation (DA) Pilot
  - Metrics & Benefits Reporting
- **$14.8M of $15M spent through 4Q 2014**



New Jersey – **Procurement Schedule**

JCP&L Generation Service Supply Plan
State-wide procurement process

Approximately 33.3% load annually - 100 MW Fixed Price Full Requirements Tranches – Residential & Small Commercial

		Delivery Period					
Auction	Tranches Bid	June 2014	June 2015	June 2016	May 2017	May 2018	May 2019
Feb-14	15	36 months - $84.44 / MWH					
Feb-15	20		36 months - $80.42 / MWH				
Feb-16	18			36 months			

100% load annually - 75 MW Hourly Priced Full Requirements Tranches – Large Commercial Industrial

		Delivery Period		
Auction	Tranches Bid	June 2014 – May 2015	June 2015 – May 2016	June 2016 – May 2017
Feb-14	13	12 months - $254.79 / MW Day		
Feb-15	16		12 months - $248.41 / MW Day	
Feb-16	13			12 months

New Jersey – **Long-Term Debt Schedules**

Company	Type	CUSIP	Interest Rate	Maturity	Amount Outstanding
JCP&L	Senior Note	476556CM5	5.625%	5/1/2016	$300,000,000
	Senior Note	476556CW3	5.65%	6/1/2017	$250,000,000
	Senior Note	476556CK9	4.8%	6/15/2018	$150,000,000
	Senior Note	476556DA0	7.35%	2/1/2019	$300,000,000
	Senior Note	476556DB8	4.7%	4/1/2024	$500,000,000
	Senior Note	476556CP8	6.4%	5/15/2036	$200,000,000
	Senior Note	476556CT0	6.15%	6/1/2037	$300,000,000
				JCP&L Total	**$2,000,000,000**
JCP&L Transition Funding LLC	Transition Bond	47214TAD1	6.16%	6/5/2017*	$72,485,803
	Transition Bond	47215BAC1	5.52%	6/5/2018*	$44,801,179
	Transition Bond	47215BAD9	5.61%	6/5/2021*	$51,139,000
				JCP&L Transition Funding LLC Total	**$168,452,982**

* Expected Final Maturity Date

As of December 31, 2014

Creating Value for Investors

FirstEnergy

West Virginia/Maryland Operations

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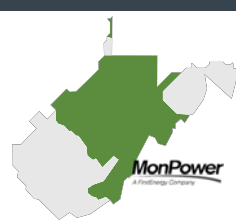
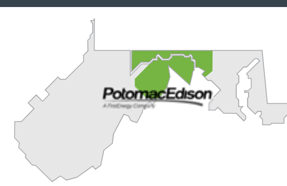
West Virginia/Maryland – **Customer Data**

2014 Total Customers (thousands)	
MP	389
PE	397
Total	786

Typical Bill Comparison*	
West Virginia/Maryland	$/Month
MP/PE-WV	$92.62
PE-MD	$107.03
WV Statewide Avg. Bill	$93.20
MD Statewide Avg. Bill	$132.17

* Typical bills are based on 1,000 kWh of residential usage. Billing amounts sourced from the EEI Typical Bills and Average Rates Report as of July 1, 2014. MD/WV rates represent POLR bundled residential rates





Principal Industries Served**
Chemical
Coal Mining
Non-Metallic Minerals
Primary and Fabricated Metals
Oil and Gas Extractions

** Based on kWh sales

Major Metropolitan Areas	Population (thousands)
Berkeley County (Martinsburg)	105
Monongalia County (Morgantown)	97
Wood County (Parkersburg)	87
Total State of West Virginia	1,854

Major Metropolitan Areas	Population (thousands)
Frederick County	234
Washington County (Hagerstown)	148
Allegany County (Cumberland)	75
Total State of Maryland	5,788

Source: U.S. Census Bureau (2010)

As of December 31, 2014

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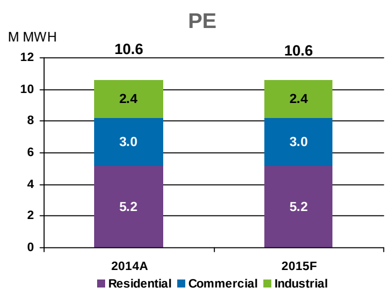
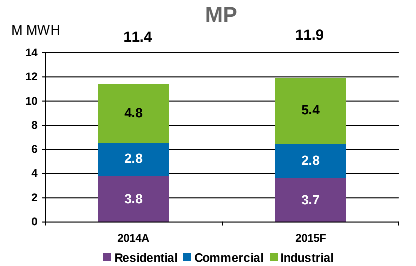
West Virginia/Maryland – **Distribution Sales**

State Unemployment Rates					
	2007	2011	2012	2013	2014
WV	4.2%	7.9%	7.3%	6.5%	6.3%
MD	3.4%	7.3%	6.9%	6.6%	5.9%

Source: Moody's Analytics



Note: Forecasted sales assume normal weather. Includes forecast for state energy efficiency mandates. (MD Mandate 10% per capita by 12/31/15, ~0.4M MWH)



Note: Forecasted sales assume normal weather. Includes forecast for state energy efficiency mandates. (WV Mandate 0.5% of 2009 sales by 12/31/16, ~0.1M MWH. Plus incremental 0.5% of 2013 Sales by May 2018)

Gross Domestic Product Annualized Growth (Seasonally Adjusted Annualized Rate)					
	2007	2011	2012	2013	2014
WV	-0.4%	2.5%	-1.4%	5.1%	-0.2%
MD	1.6%	1.7%	1.2%	0.0%	1.1%

Source: Moody's Analytics

Gross Domestic Product, in 2009 dollars ($ billions)					
	2007	2011	2012	2013	2014
WV	$62	$66	$65	$69	$68
MD	$303	$318	$322	$322	$326

Source: Moody's Analytics

West Virginia/Maryland – **Political Landscape**

West Virginia

Governor

Governor	Current Term
Earl Ray Tomblin (D)	Expires in 2017

Public Service Commission of West Virginia (WV PSC)

Commissioners	Current Term
Michael A. Albert, Chairman (R)	Expires in 2019
Brooks F. McCabe (D)	Expires in 2015
Vacant	Expires in 2015

Maryland

Governor

Governor	Current Term
Lawrence J. Hogan (R)	Expires in 2019

Maryland Public Service Commission (PSC)

Commissioners	Current Term
W. Kevin Hughes, Chairman (D)	Expires in 2018
Harold D. Williams (D)	Expires in 2017
Lawrence Brenner (D)	Expires in 2015
Kelly Speakes-Backman (D)	Until Reappointed or Replaced
Anne E. Hoskins (D)	Expires in 2016

West Virginia – **Regulatory Update**

Rate Case

- **April 30, 2014: Base Rate Case Filed (Case # 14-0702-E-42T)**
  - $95.7M (9.27%) base rate increase (2013 historic test year), inclusive of depreciation rate increase
    - $144.1M (14.0%) overall increase including vegetation management plan surcharge
  - 11% return on equity
  - Depreciation case filed concurrently ($17M reflected in overall increase)
- **June 13, 2014: Amendment to Base Rate Case**
  - Amendment filed due to WV PSC order requiring MP and PE-WV to begin reading customer meters on a monthly basis no later than July 1, 2015 (i.e., convert bimonthly meter reads to monthly meter reads)
  - Annual incremental increase of $7.5M
  - Amended rate impact: $103.2M (9.99%) base rate increase, inclusive of depreciation rate increase
    - $151.6M (14.7%) overall increase including vegetation management program and monthly meter reading
- **November 3, 2014: Joint Settlement filed with the WV PSC**
  - Hearing on the joint settlement held on November 7, 2014
  - Joint settlement includes:
    - $15M (1.43%) base rate increase, includes moving Harrison surcharge into base rates
    - Vegetation Management Surcharge of $48M (4.52%) in 2015
    - Vegetation Management Surcharge along with the base rate increase results in an overall increase of $63M (5.95%)
    - Collection of $46M of 2012 storm costs, amortized over 5 years
    - Depreciation rates remain unchanged from current value
    - Delay in ENEC rate change until Feb 25, 2015
    - Deferral of 2016-2017 MATS capital costs
    - Black box settlement does not provide ROE and income tax rate in base rates
- **February 3, 2015: WVPSC approved joint settlement without modification**
- **February 25, 2015: Effective date of new rates and surcharge**

Base Rate Change	**$ 124.3M**
Elimination of Harrison Surcharge	**$ (109.3)**
Vegetation Management Surcharge	**$ 47.6**
Total Settlement Increase	**$ 62.6M**

West Virginia – **Regulatory Update**

West Virginia Vegetation Maintenance Program & MATS Compliance

- **Vegetation Management Surcharge**
  - Permits timely recovery of cycle-based, end-to-end vegetation management plan approved by the WV PSC on April 14, 2014
  - Reconcilable surcharge to recover 100% of vegetation management O&M and capital costs between base rate cases
  - Deferral of incremental O&M costs (incurred from April 14, 2014 PSC order date through February 25, 2015 effective date of new rates) to be included in September 2015 reconciliation filing for rates effective January 1, 2016
  - Includes $15M O&M previously in base rates
- **MATS Compliance Capital Recovery**
  - New base rates include collection of MATS compliance capital projects placed in service by December 31, 2015
  - Establishes regulatory asset for MATS compliance capital projects placed in service during 2016-2017
  - Recovery of the regulatory asset expected in the next base rate case

Maryland – **Procurement Schedule**

			Delivery Period **		
Load Type	Tranches Bid *	Auction Date	June 2014 - May 2015	June 2015 - May 2016	June 2016 - May 2017
Residential	1	October 2013	12 Months		
	1		24 Months		
Residential	2	January 2014	12 Months		
	2		24 Months		
Residential	1	April 2014		12 Months	
	1			24 Months	
Residential	1	June 2014		12 Months	
	1			24 Months	

			Delivery Period **
Load Type	Tranches Bid *	Auction Date	June 2014 - May 2016
Small C&I	1	October 2013	24 Months
Small C&I	1	January 2014	24 Months

			Delivery Period **			
Load Type	Tranches Bid *	Auction Date	Dec 2013 – Feb 2014	March 2014 – May 2014	June 2014 – Aug 2014	Sept 2014 – Nov 2014
Medium C&I	3	October 2013	3 Months			
Medium C&I	3	January 2014		3 Months		
Medium C&I	3	April 2014			3 Months	
Medium C&I	3	June 2014				3 Months

*All tranches are for full requirements service.
**The Maryland PSC does not release bid or winning prices. However, a list of bidders who submitted bids and a list of winning bidders can be found at https://www.firstenergycorp.com/content/fecorp/upp/md/power_procurements/2014sosrfp/archive.html

Maryland/West Virginia – **Energy Efficiency**

	Maryland	West Virginia
State Goals	**EmPower MD**	**Base Rate Case and Merger Settlements**
Energy Efficiency	10.0% per capita by 12/31/2015 (415 GWH)[1]	0.5% of 2009 Sales by 12/31/2016 (67 GWH) Plus incremental 0.5% of 2013 Sales by May 2018 (71 GWH)
Demand Response	15.0% per capita by 12/31/2015 (21 MW)	0.5% of 2009 Demand by 12/31/2016 (14 MW)
Smart Meter	No state smart meter requirement	No state smart meter requirement
Cost Recovery for Energy Efficiency	In place – 5 year amortization schedule with carrying costs and annual reconciliation	In place – annual energy efficiency rider
Compliance	On track to achieve EE/DR 2015 targets	On track to achieve EE/DR 2016 targets

[1]On 9/30/14, PE filed a 2015-2017 EE/PDR Plan that was approved by the MD PSC on 12/23/14. The Plan projects to achieve 178 GWHs cumulative energy savings for 2015-2017.

West Virginia/Maryland – **Long-Term Debt Schedules**

Company	Type	CUSIP	Interest Rate	Maturity	Amount Outstanding
Mon Power	Pollution Control Note*	41524CAU8	5.5%	10/15/2037	$73,500,000
	First Mortgage Bond	610202BK8	5.375%	10/15/2015	$70,000,000
	First Mortgage Bond	610202BL6	5.7%	3/15/2017	$150,000,000
	First Mortgage Bond	610202BN2	4.1%	4/15/2024	$400,000,000
	First Mortgage Bond	610202BP7	5.4%	12/15/2043	$600,000,000
				MP Total	$1,293,500,000
Mon Power Environmental Funding LLC	Environmental Control Bond	553214AB3	5.233%	7/15/2019**	$75,427,062
	Environmental Control Bond	553214AC1	5.463%	7/15/2026**	$153,250,000
	Environmental Control Bond	553214AD9	5.523%	7/15/2027**	$29,025,000
	Environmental Control Bond	553214AE7	5.127%	1/15/2031**	$64,380,000
				Mon Power Environmental Funding LLC Total	$322,082,062

*Mon Power assumed primary liability for this note from AE Supply in connection with the Harrison transfer
** Expected Final Maturity Date

As of December 31, 2014

West Virginia/Maryland – **Long-Term Debt Schedules**

Company	Type	CUSIP	Interest Rate	Maturity	Amount Outstanding
Potomac Edison	First Mortgage Bond	737662BR6	5.125%	8/15/2015	$145,000,000
	First Mortgage Bond	737662BS4	5.8%	10/15/2016	$100,000,000
	First Mortgage Bond	Private Placement	4.44%	11/15/2044	$200,000,000
				PE Total	$445,000,000
Potomac Edison Environmental Funding LLC	Environmental Control Bond	69336NAB5	5.233%	7/15/2019*	$25,328,396
	Environmental Control Bond	69336NAC3	5.463%	7/15/2026*	$50,700,000
	Environmental Control Bond	69336NAD1	5.523%	7/15/2027*	$9,975,000
	Environmental Control Bond	69336NAE9	5.127%	1/15/2031*	$21,510,000
				Potomac Edison Environmental Funding LLC Total	$107,513,396

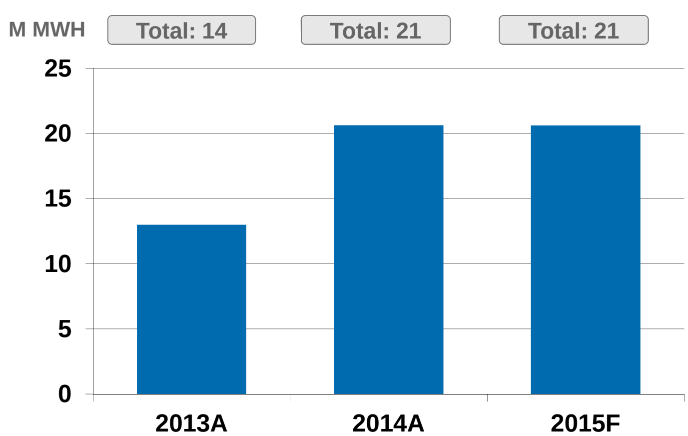
* Expected Final Maturity Date

As of December 31, 2014

Creating Value for Investors

Regulated Generation

Regulated Generation – **2013 - 2015 Output**



Increase in 2013A and 2014A reflects Harrison/Pleasants asset transfer, which occurred in October 2013

Regulated Generation

Fuel

	Plants	Units	Total Fleet – Coal Sources: NAPP	Western	ILB
Supercritical Units	Harrison	1-3	✓		
	Fort Martin	1-2	✓	✓	✓

Fossil Environmental Controls

Supercritical	Plant	NDC	NOx Controls: SCR	SNCR	LNB	OFA	SO_2 Controls: Scrubbers[1]	Lo-S Fuel	Particulate: Electro/Other[2]	Cooling Towers
	Harrison 1-3	1,984	✓		✓		✓		✓	✓
	Fort Martin 1 & 2	1,098		✓	✓	✓	✓	✓	✓	✓
	Sub-total	3,082								

[1]Scrubbed coal units have FGD (Flue Gas Desulfurization - equipment to remove sulfur from flue gas after combustion)
[2]Particulate Controls can include Venturi Scrubber or Electrostatic Precipitator

Regulated Generation – **Plant Deactivations**

- **660 MW deactivated as of September 1, 2012**

Regulated	NDC MW	2012 M MWH	2012 Capacity Factor (%)	Deactivation Date
Albright	292	0.2	10	9/1/2012
Rivesville	126	0.0	0	9/1/2012
Willow Island	242	0.0	1	9/1/2012
Total	660	0.2		

Regulated Generation – **MATS Overview**

- **MATS**
  - Total cost estimate of $192M, of which $77M has been spent through 2014.

Plant	Technologies
Harrison 1-3	**Precip Changes, FGD changes, SCR Catalyst, Duct Repairs, CEMS**
Fort Martin 1 & 2	**GORE Mercury Control System, Duct Repairs, CEMS**

Regulated Generation – **Plant Details**

Plant	PJM Zone	State	Utility	Fuel Type	Units	Net Maximum Capacity (MW)	Year Plant Commissioned
Bath County	Rest of RTO	VA	MP	Hydro	6	487*	1985
Fort Martin	Rest of RTO	WV	MP	Coal	2	1,098	1967
Harrison	Rest of RTO	WV	MP	Coal	3	1,984	1972
OVEC	Rest of RTO	Multiple	MP	Coal	Multiple	11**	
	Rest of RTO Total					**3,580**	
Yards Creek	EMAAC	NJ	JCP&L	Hydro	3	210	1965
	EMAAC Total					**210**	
	Regulated Generation Total					**3,790**	

*Represents MP's approximate 41% shareholder interest in AGC, which owns a 40% interest in Bath County, a pumped-storage hydroelectric station. The station is operated by 60% owner Virginia Electric and Power Company
**Represents MP's 0.49% entitlement based on its participation in OVEC

Creating Value for Investors

FirstEnergy

Transmission

Transmission – **Enhancing** Transmission Reliability for Customers

"Energizing the Future"

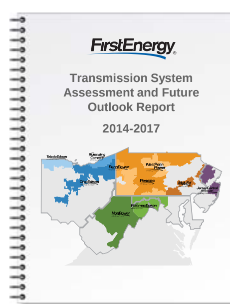
- **FirstEnergy's overall transmission program**
- **Includes all investments in ATSI, TrAILCo and other utility operating companies within the FirstEnergy footprint**

2014-2017 Growth Program

- **$4.2B plan initially focused primarily in ATSI and extending east over time**

Benefits

- **Focused on smaller-scale projects with near-term completion dates**
  - Majority of projects located in the ATSI region, target 69kV lines, and outside of the RTEP approval process
  - Construction to occur on land where most rights-of-way are already secured
- **Enhanced system reliability and customer service**
- **Older equipment replaced with updated technology**
- **Decreased maintenance costs by converting to condition-based maintenance program that allows for equipment replacement using real-time data**
- **Local employment opportunities for ~1,100 contractors annually**



2018 and Beyond

- **$15B in incremental opportunities for reliability enhancement**

Transmission – Energizing the Future

Energizing the FUTURE

To increase system reliability and capacity for existing and new customers

Reliability Enhancements	**$1.6B**	▪ **Upgrade condition / health of the system** ▪ **Increase operating flexibility/margin** • Outage scheduling • System/storm restoration • Load serving capability for existing and new customers ▪ **Increase system performance/reliability** • Decrease exposure to outages • Decrease outage time ▪ **Increase automation and communication within the system** ▪ **Improve dynamic performance** ▪ **Reduce future transmission investment costs**
Regulatory Required	**$2.6B**	▪ **Preserves the reliability of PJM's transmission system** ▪ **Formula rate recoverable in both ATSI and TrAILCo** ▪ **RTEP approved projects (PJM requested to support grid reliability)** ▪ **Generator deactivation projects** ▪ **Enables future markets** ▪ **Emerging shale gas projects**

$4.2B plan initially focused primarily in ATSI and extending east over time

Transmission – **Formula Rate Summary**

	ATSI	TrAILCo
Jurisdiction	FERC	FERC
Filing Month	November	May
FERC approved ROE	**12.38% *****	**12.70% TrAIL the Line & Black Oak SVC** **11.70% All other projects**
Rate Base	**$1.8B***	**$1.2B****
Transmission system locations	**OE, PP, CEI, and TE**	**WPP, MP, and PE. Also some portions of JCP&L, ME, and PN**
Term	January – December	June – Following May
Test Year	**Forward-Looking:** Projects rate base and expenses for the calendar year; Network Service Peak Load updated effective January 1***	**Forward-Looking**: Utilizes prior year plant-in-service from FERC Form 1 and adds capital additions projected to be in service within current calendar year
True-up Mechanism	Yes	Yes
Calculation	Revenue Requirement used to calculate an Annual Network Rate and Point-to-Point rates	Revenue Requirement by project: ▪ TrAIL the Line ▪ Individual RTEP projects

* Represents projected rate base from its 2015 Projected Transmission Revenue Requirement effective January 1, 2015, through December 31, 2015.
** Represents projected rate base from its annual update on May 15, 2014 for rates effective June 1, 2014
*** On December 31, 2014 FERC accepted ATSI's rate filing to amend its formula rate to a forward-looking test year effective January 1, 2015. FERC also determined the ROE is subject to inquiry as part of the settlement and hearing proceedings and is subject to refund.

Transmission – **Enhancing** Transmission Reliability for Customers

- **$4.2B over 2014-2017: Majority of near-term projects in ATSI**
- **Funding Strategy: FET up to 65% Debt, ATSI & TrAILCo up to 40% Debt**

2014

ATSI and TrAILCo

JCP&L, ME, PN

2017

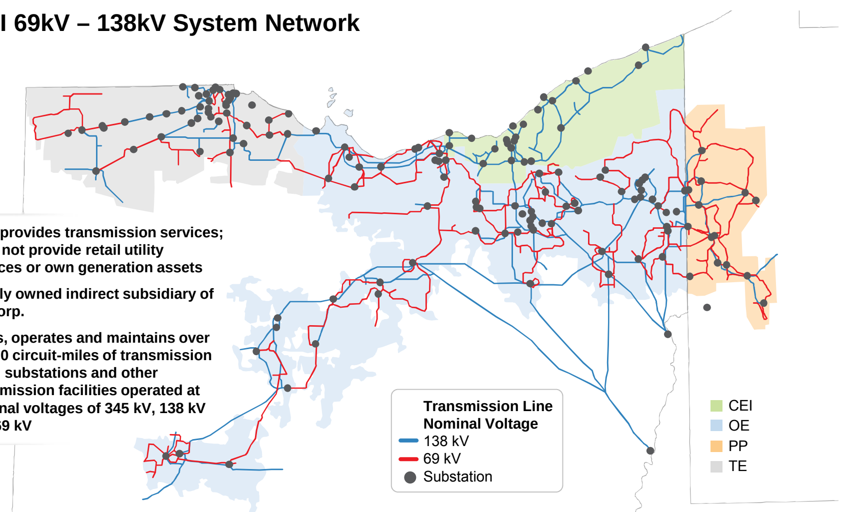
MP, WPP, PE

Future

Transition from ATSI … to TrAILCo … then east to utility operating companies over time

Transmission – **Enhancing** Transmission Reliability for Customers

ATSI 69kV – 138kV System Network



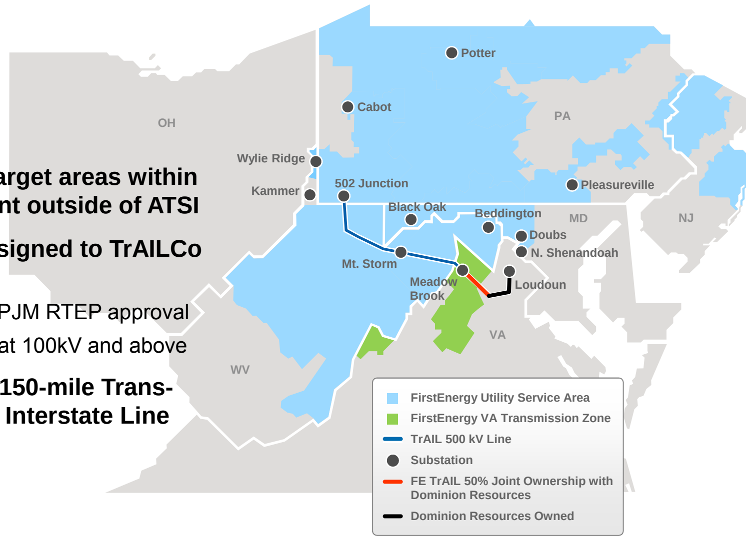
- **Only provides transmission services; does not provide retail utility services or own generation assets**
- **Wholly owned indirect subsidiary of FE Corp.**
- **Owns, operates and maintains over ~7,400 circuit-miles of transmission lines, substations and other transmission facilities operated at nominal voltages of 345 kV, 138 kV and 69 kV**

Near-term projects planned within ATSI

Transmission – **TrAILCo** Footprint

TrAILCo
A FirstEnergy Company

- **Projects target areas within FE footprint outside of ATSI**
- **Assets assigned to TrAILCo must:**
  - Receive PJM RTEP approval
  - Operate at 100kV and above
- **Owns the 150-mile Trans-Allegheny Interstate Line (TrAIL)**



Transmission – **Enhancing** Transmission Reliability for Customers

Energizing the Future Capital Program	2014A*	2015F	2016F	2017F
Formula Rate Recoverable Projects designed to upgrade and enhance system conditions, performance, capacity and reliability. Receive ATSI or TrAILCo formula rates.	$1,177M	$805M	$810M	$725M
Baseline Planned capital projects at operating companies (JCP&L, ME, MP, PN, PE, and WPP).	$246M	$165M	$185M	$125M
Total	$1,423M	$970M	$995M	$850M

Expected ATSI & TrAILCo annual earnings growth of 20+%

* Includes $38M associated with the capital component of the Pension/OPEB mark-to-market adjustment

Transmission – **Upgrade Condition of the System**

- **Replace oil, single-pressure and two-pressure, gas-insulated circuit breakers with new single-pressure, gas-insulated circuit breakers due to deteriorating condition. New EHV circuit breakers will also include on-line diagnostic systems with capabilities to provide data to the new Asset Health System**
- **Replace power transformers due to deterioration of internal insulation with new transformers that include on-line diagnostic systems with capabilities to provide data to the new Asset Health System**
- **Evaluate and rebuild aging EHV and HV transmission lines (~2,500 circuit miles of 69kV and ~5,000 circuit miles of 138kV and 345kV)**
- **Based on the initial reliability review, anticipate rebuilding approximately 50% of the 69kV and 20% of the 138kV lines; however these percentages may increase as overall condition assessment of the ATSI transmission system is completed**

Oil pressure gas insulated circuit breaker (on left), replaced by gas-insulated circuit breaker (on right)

New transformers will provide data to the Asset Health System

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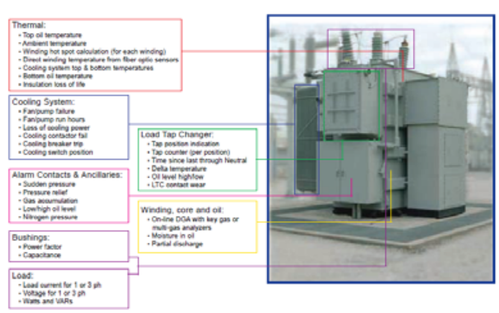
Transmission – Enhance System Performance

- **Implement an Asset Health System**
  - Provide situational awareness through real-time, consolidated data on asset condition
  - Reduce maintenance by enabling real-time data event analysis and condition assessment
- **Physical Security Enhancements**
  - Replace existing chain link perimeter fencing with no cut /no climb product where necessary
  - Expand use of perimeter video, thermal imaging and virtual inspection
- **Expand FirstEnergy's fiber and core network to critical transmission facilities**
  - Reduce/eliminate dependence on unreliable third-party communication assets
  - Increased capacity enables diagnostic data to provide proactive monitoring and improved reliability of critical equipment



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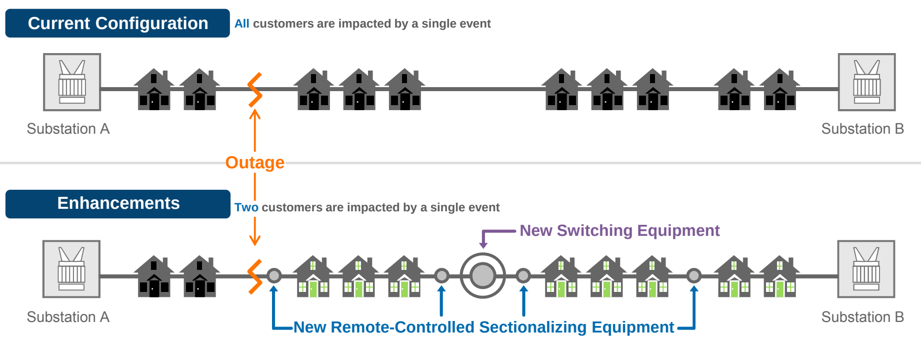
Transmission – **Add Operating Flexibility and Capacity**

- **Rebuild existing single-circuit transmission lines as double-circuit transmission lines**
- **Build line segments to create parallel paths (loop feeds) to existing substations**
- **Reconfigure longer transmission lines with high customer loads to decrease the number of customers impacted by a single operational event**

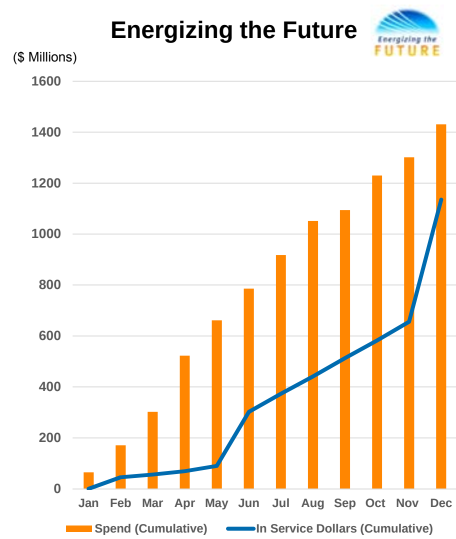


Transmission Program Status

- **Burns & McDonnell hired to support engineering, procurement, construction and completion of capital portfolio created for Energizing the Future**
  - Design engineering continues, with several local Ohio firms supplementing Burns & McDonnell
  - A four-year project list has been established (construction complete or underway on numerous projects), and coordination of future outages and construction is in progress
- **Quanta Services augmenting physical labor (linemen and substation electricians) required to perform reliability-based work**
- **Manufacturer production and deliveries to support construction activities through 2014 and 2015; Equipment includes:**
  - 750 HV circuit breakers
  - 60 HV power transformers
  - 25 EHV power transformers

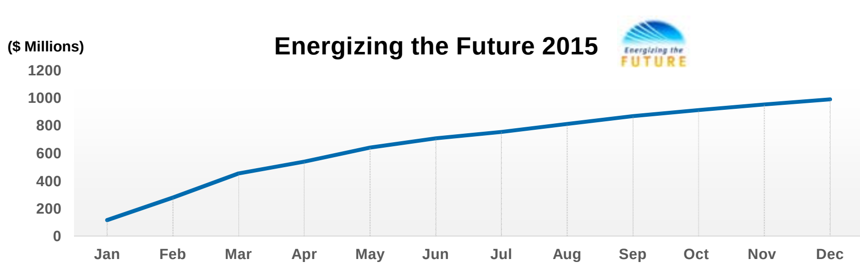
2014 Accomplishments

- **Completed Projects**
  - Approximately:
    - 960 pieces of substation equipment replaced
    - 140 miles of Transmission line rebuild projects completed
    - 70 miles of Transmission line capacity upgrade projects completed
  - Physical Security Upgrade projects completed at approximately 50 Substations
  - One Synchronous Condenser conversion and three Static Var Compensators (SVC) projects in-service
    - Provides ~1,900 MVAR of support
  - Approximately 70 Communication Upgrade projects completed



Transmission Program Status

- **2015 Projects**
  - Over 1,000 pieces of substation equipment slated for replacement/upgrades including:
    - 60+ transformers, 17 capacitor banks, 80+ breakers
  - Approximately 300 miles of Transmission line projects
  - Telecom/IT projects
  - 7 SVC Projects
  - 1 Synchronous Condenser conversion project in 2015



Transmission – **Political Landscape**

Federal Energy Regulatory Commission (FERC)

Commissioners	Current Term
Cheryl A. LaFleur (D)- Chairman*	Expires in 2019
Philip D. Moeller (R)	Expires in 2015
Tony Clark (R)	Expires in 2016
Colette D. Honorable (D)	Expires in 2017
Norman C. Bay (D)*	Expires in 2018

*Commissioner Bay will become Chairman of the FERC on April 15, 2015. Chairman LaFleur has announced that she will step down from Chair, but will remain as a Commissioner through the end of her term in 2019.

Transmission – **Long-Term Debt Schedules**

Company	Type	CUSIP	Interest Rate	Maturity	Amount Outstanding
FET	Senior Note	33767BAB5	4.35%	1/15/2025	$600,000,000
	Senior Note	33767BAA7	5.45%	7/15/2044	$400,000,000
				FET Total	$1,000,000,000
ATSI	Senior Note	030288AA2	5.25%	1/15/2022	$400,000,000
	Senior Note	030288AB0	5.00%	9/1/2044	$400,000,000
				ATSI Total	$800,000,000
TrAILCo	Senior Note	893045AE4	3.85%	6/1/2025	$550,000,000

As of December 31, 2014

Creating Value for Investors

FirstEnergy

Competitive Operations

Taking Our Generation to the Competitive Market

Taking Our Generation to the Competitive Market

- Utilize strong competitive knowledge
- Take advantage of flexibility given current committed position

Effectively hedge generation

- Flexibility to continue POLR, Governmental Aggregation, and selected large commercial-industrial sales
- Enables the use of retail margin uplift to hedge during periods of low wholesale prices
- Employ a variety of hedging tools, including existing retail sales commitments, traditional forward wholesale sales and potentially Utility PPAs
- Strong focus on portfolio optimization and risk management

- Leverage clean, efficient generation portfolio
- Mitigate risk
- Maximize margins

"Long" generating strategy

Annual generation resources of 80-85M MWH

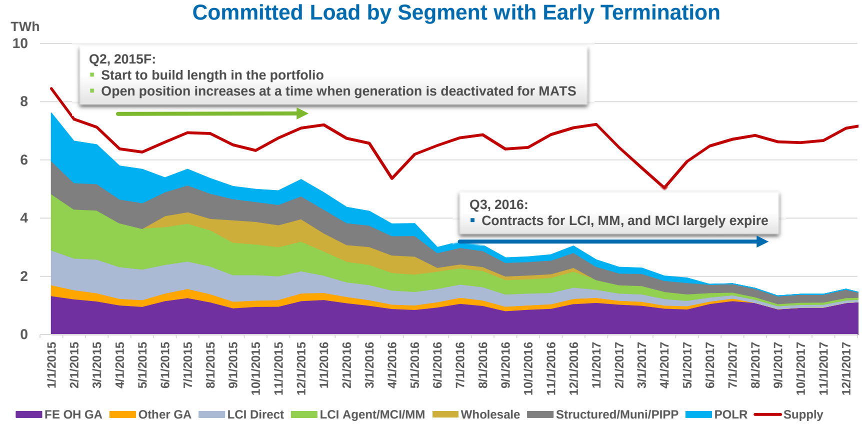
- Benefit from established baseline of higher margin Governmental Aggregation load (13M MWH) and natural attrition of selected channels through 2019
- Reserve 10-20M MWH to protect weather-sensitive loads and to take advantage of opportunities resulting from scarcity pricing
- Target 10-45M MWH annually through POLR, Governmental Aggregation and selected large commercial-industrial sales
- Balance remainder of portfolio for sales in the wholesale market and potentially Utility PPAs

Adapt Competitive Operations to changing market dynamics

Existing Committed Sales

- **Retain POLR, GA, and selected large commercial-industrial contracts**
- **Exit MCI, MM and certain LCI contracts by natural attrition**

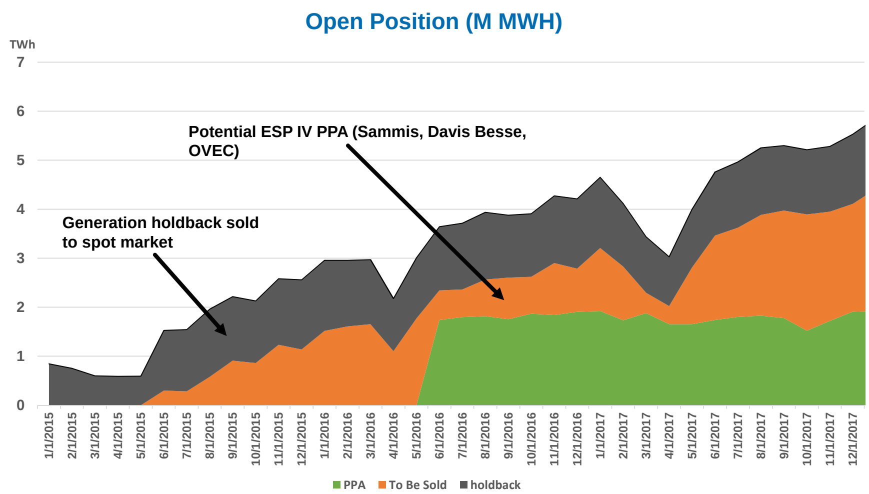
Committed Load by Segment with Early Termination



Expected significant level of uncommitted sales beginning mid-2015 provides flexibility

As of February 2, 2015

Flexible Hedging Platform to Bring Our Generation to Market



Significant level of committed sales through mid-2015

As of February 2, 2015

Optionality and Variety of Hedging Resources

Channel	Description	Value
Wholesale Sales	Sales in forward power markets made to hedge generation	Provides flexibility in volume and timing of hedge
GA	Buying group formed by communities which choose electric supplier for all members in the group. Pricing is fixed or is a percentage discount off the price to compare, which is determined through utility default service auctions. Current contracts run through 2019.	Higher margin load, pricing of majority of sales moves with market, minimal acquisition cost, minimizes risk of POLR
POLR	Tranches of non-shopping load that is won through utilities' default service auctions	Higher margin load, minimal acquisition cost and flexibility of participation
Structured	Includes municipality sales, co-operative sales, bilateral sales, and unique transactions	Higher margin wholesale transactions made for strategic purposes
LCI	Selected/strategic direct sales to large commercial and industrial customers	Higher load factors, less weather sensitive, flexibility of term; a wholesale-type load with better margins
Utility PPA	Dedicated plant output (MW) to distribution utilities through PPA	Cost-based recovery; provides more revenue certainty
Spot Market Sales	Sales in day-ahead or real-time to take advantage of market volatility/scarcity pricing	Having a reserve dedicated to spot provides flexibility to manage weather sensitive loads and take advantage of market volatility
MCI and MM Sales	No new sales. Small Commercial and Residential customers. Contracts expire naturally through 2018.	High cost to acquire and support customers; highly weather sensitive

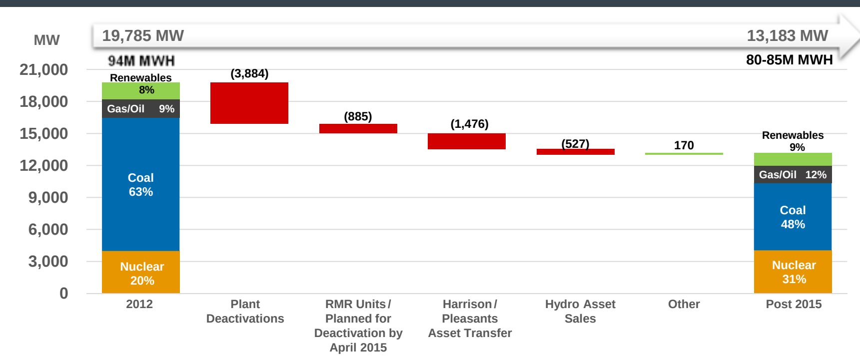
Target Portfolio Mix

Weather Sensitive		Annual Load (M MWH)
✓	GA	10-15
✓	POLR	0-10
✓ / ✗	LCI Direct*	0-20
✗	Block Wholesale	10-20
✗	Spot Wholesale	10-20

Annual Generation Resources = 80-85M MWH

*LCI Direct is less weather sensitive than GA and POLR

Repositioning our Competitive Fleet Over Time



Current generation output of 75-80M MWH; additional resources of 0-5M MWH (includes Wind/Solar/OVEC)

The character and operation of our fleet has changed over the past several years

- 3,884 MW deactivated
- 885 MW additional deactivations by April 2015*
- Changed operating status of Sammis to cold storage for a period of 4 months in 2012
- 1,833 MW includes asset transfer and sales and other actions including net uprates (110 MW), additional wind and solar PPA agreements (120 MW), less deactivation of Mad River plant (60 MW)

In 2015, the competitive generation portfolio will operate similar to a natural gas portfolio in that ~100% of the power generated will come from low or non-emitting sources yet also offer a diverse platform of resources

Generation output of 75-80M MWH; additional resources of 0-5M MWH (includes Wind/Solar/OVEC)
*See slide 126

2015F CES Adjusted EBITDA

	Closed			Open			Total		
	M MWH	Rate	$M	M MWH	Rate	$M	M MWH	Rate	$M
Sales:									
LCI/MCI/MM	27.1	$57	$1,530				27.1	$57	$1,530
GA & POLR	25.7	$64	$1,655				25.7	$64	$1,655
Structured & Muni	9.9	$45	$450				9.9	$45	$450
Wholesale	4.3	$38	$165	14.8	$34.55	$510	19.1	$35.45	$675
Other	2.9						2.9		
Capacity Revenue - BRA			$890						$890
Total Revenues	69.9		$4,690	14.8	$34.55	$510	84.7		$5,200
Expenses:									
Capacity & Delivery Expenses			($1,230)			($50)			($1,280)
Purchased Power	6.2	($45)	($280)				6.2	($45)	($280)
Nuclear Fuel	30.9	($7.00)	($215)				30.9	($7.00)	($215)
Fossil Fuel	32.8	($27.45)	($900)	14.8	($27.45)	($405)	47.6	($27.45)	($1,305)
Total Expenses	69.9		($2,625)	14.8		($455)	84.7		($3,080)
Commodity Margin			$2,065			$55			$2,120
Commodity Margin (excl. Capacity Revenue)		~$17	$1,175		~$4	$55		~$15	$1,230

Closed Contribution	+	Open Contribution	=	CES Adjusted EBITDA[1] – 2015F
$820-$895		$55		$875 -$950

Please see slide 113 for additional notes describing "Sales" and "Expenses"

[1] Total CES 2015F Adjusted EBITDA, a non-GAAP financial measure, is reconciled to 2015F CES Net Income on slide 142, and is based on market prices as of February 2, 2015. The "Closed contribution" to Adjusted EBITDA is based on committed sales whereas the "Open contribution" to Adjusted EBITDA is based on currently uncommitted sales that are assumed to be sold in the wholesale market assuming market prices as of February 2, 2015. The purpose of the table above is to summarize the impact on Adjusted EBITDA of changes in market prices on currently uncommitted sales.

2016F CES Adjusted EBITDA

	Closed			Open			Total		
	M MWH	Rate	$M	M MWH	Rate	$M	M MWH	Rate	$M
Sales:									
LCI/MCI/MM	12.1	$58	$700				12.1	$58	$700
GA & POLR	16.7	$65	$1,095				16.7	$65	$1,095
Structured & Muni	7.2	$44	$315				7.2	$44	$315
Wholesale	4.1	$40	$165	40.1	$37.15	$1,490	44.2	$37.40	$1,655
Other	2.6						2.6		
Capacity Revenue			$670						$670
Total Revenues	42.7		$2,945	40.1	$37.15	$1.490	82.8		$4,435
Expenses:									
Capacity & Delivery Expenses			($630)			($125)			($755)
Purchased Power	4.9	($45)	($220)				4.9	($45)	($220)
Nuclear Fuel	32.3	($7.15)	($230)				32.3	($7.15)	($230)
Fossil Fuel	5.5	($27.60)	($150)	40.1	($27.60)	($1,110)	45.6	($27.60)	($1,260)
Total Expenses	42.7		($1,230)	40.1		($1,235)	82.8		($2,465)
Commodity Margin			$1,715			$255			$1,970
Commodity Margin (excl. Capacity Revenue)		~$25	$1,045		~$6	$255		~$16	$1,300

Closed Contribution	+	Open Contribution	=	CES Adjusted EBITDA[1] – 2016F
$495-$595		$255		$750 -$850

Please see slide 114 for additional notes describing "Sales" and "Expenses"

[1] Total CES 2016F Adjusted EBITDA, a non-GAAP financial measure, is reconciled to 2016F CES Net Income on slide 142, and is based on market prices as of February 2, 2015. The "Closed contribution" to Adjusted EBITDA is based on committed sales whereas the "Open contribution" to Adjusted EBITDA is based on currently uncommitted sales that are assumed to be sold in the wholesale market assuming market prices as of February 2, 2015. The purpose of the table above is to summarize the impact on Adjusted EBITDA of changes in market prices on currently uncommitted sales.

2015 CES Adjusted EBITDA Notes

- **Sales:**
  - Volume in all channels, with the exception of wholesale, is subject to fluctuations due to weather and customer behavior.
  - When wholesale volumes are committed they will be categorized as "Closed" and moved to the appropriate channel. Additional retail channel sales could include an operating margin of ~$2 to $3 per MWH.
  - Wholesale "Open" rate is the weighted average of generation length based on forward market prices at AD Hub as of February 2, 2015. The "Closed" position represents physical and financial transactions executed to reduce market price risk.
  - "Other" sales include distribution losses and pumping for Hydro units.
- **Expenses:**
  - Capacity expense is the cost associated with serving load, net of incremental capacity auctions and bilateral transactions and credits associated with serving load, Capacity Transfer Rights or CTRs.
  - Delivery expenses, net of delivery revenues, include congestion, losses, ancillaries, Network Integration Transmission Service and the cost of Financial Transmission Rights. Can vary based on delivery location, channel and market conditions.
    - A delivery expense of ~$2 – $4/MWH is incurred to serve wholesale load
    - A delivery expense of ~$3 – $6/MWH is incurred to serve retail load
  - Generation volume is committed in the following order: (1) Purchased Power, which includes Renewables/OVEC of ~2M MWH and additional Bilateral/Spot Purchases, (2) Nuclear, and (3) Fossil.
  - Fossil Fuel expense includes Coal, Gas, and Hydro.
  - Nuclear Fuel expense reflects the suspension of the DOE nuclear fuel disposal fee.
  - Total Adjusted EBITDA includes other operating expenses such as, O&M, Non Income Taxes, as well as variability (+/- ~$37M) in other revenues and expenses such as, customer usage, weather, planned generation output, and spot purchases.

2016 CES Adjusted EBITDA Notes

- **Sales:**
  - Volume in all channels, with the exception of wholesale, is subject to fluctuations due to weather and customer behavior.
  - When wholesale volumes are committed they will be categorized as "Closed" and moved to the appropriate channel. Additional retail channel sales could include an operating margin of ~$2 to $3 per MWH.
  - Wholesale "Open" rate is the weighted average of generation length based on forward market prices at AD Hub as of February 2, 2015. The "Closed" position represents physical and financial transactions executed to reduce market price risk.
  - "Other" sales include distribution losses and pumping for Hydro units.
  - Capacity Revenue includes revenues from the BRA as well as the results of incremental capacity auctions, bilateral transactions and credits associated with serving load (CTRs).
- **Expenses:**
  - Capacity expense is the cost associated with serving load.
  - Delivery expenses, net of delivery revenues, include congestion, losses, ancillaries, Network Integration Transmission Service and the cost of Financial Transmission Rights. Can vary based on delivery location, channel and market conditions.
    - A delivery expense of ~$2 – $4/MWH is incurred to serve wholesale load
    - A delivery expense of ~$3 – $6/MWH is incurred to serve retail load
  - Generation volume is committed in the following order: (1) Purchased Power, which includes Renewables/OVEC of ~2M MWH and additional Bilateral/Spot Purchases, (2) Nuclear, and (3) Fossil.
  - Fossil Fuel expense includes Coal, Gas, and Hydro.
  - Nuclear Fuel expense reflects the suspension of the DOE nuclear fuel disposal fee.
  - Total Adjusted EBITDA includes other operating expenses such as, O&M, Non Income Taxes, as well as variability (+/- $50M) in other revenues and expenses such as, customer usage, weather, planned generation output, and spot purchases.

CES Commodity Margin Current Assumptions

		2015*	2016
Energy Prices	**AD Hub Forwards** (On-peak/Off-peak $/MWH)	$38 / $26	$40 / $29
	PJM West Forwards (On-peak/Off-peak $/MWH)	$41 / $28	$44 / $31
	Ind Hub (On-peak/Off-peak $/MWH)	$36 / $25	$39 / $28
Fuel Prices	**Henry Hub Natural Gas** ($/MMBTU)	$2.82	$3.24
	Dominion South Natural Gas ($/MMBTU)	$1.87	$2.13

*March-December market forwards

	Impact to Commodity Margin/Adjusted EBITDA	
Sensitivities**	**2015**	**2016**
+ / - $5/MWH RTC Energy Prices	+ / - $75M	+ / - $200M
Fuel Cost Exposure		
+ / - $1/MMBTU Natural Gas	- / + $11M	- / + $28M
+ / - $5/Ton Eastern Coal	- / + $10M	- / + $41M
+ / - $5/Ton Western Coal	- / + $2M	- / + $2M

**RTC energy price sensitivities relate to the impact of the change in prices on CES' open position.
Gas and coal sensitivities relate to the impact of the change in prices on CES' open gas and coal position.

As of February 2, 2015

Committed Sales by Zone

Calendar Year	2013A			2014A			2015F			2016F		
Committed Sales	M MWH	$ M	$/MWH	M MWH	$ M	$/MWH	M MWH	$ M	$/MWH	M MWH	$ M	$/MWH
ATSI	40	$2,155	$54	33	$1,910	$57	27	$1,640	$61	20	$1,205	$60
Rest of RTO	49	2,450	50	46	2,345	51	29	1,500	52	16	825	51
MAAC	12	755	65	11	730	67	6	405	66	3	180	68
EMAAC	2	160	75	2	175	75	1	90	74	<1	25	77
MISO	6	285	47	7	305	47	4	165	45	1	40	50
Total Committed Sales	109	$5,805	$53	99	$5,465	$55	67	$3,800	$57	40	$2,275	$57

Planning Year	PY 13/14A			PY 14/15F			PY 15/16F			PY 16/17F		
Committed Sales	M MWH	$ M	$/MWH	M MWH	$ M	$/MWH	M MWH	$ M	$/MWH	M MWH	$ M	$/MWH
ATSI	39	$2,120	$54	29	$1,710	$60	26	$1,610	$61	16	$935	$60
Rest of RTO	49	2,485	50	40	2,060	52	23	1,160	51	12	610	51
MAAC	11	760	67	10	620	65	4	275	68	2	130	67
EMAAC	2	180	75	2	150	74	1	50	75	<1	15	77
MISO	7	305	46	5	250	46	2	110	46	1	30	52
Total Committed Sales	109	$5,850	$54	85	$4,790	$56	56	$3,205	$57	30	$1,720	$57

Numbers may not foot due to rounding

Beginning June 2016 FE Ohio GA rate has been forecasted based on projected PTC

As of February 2, 2015

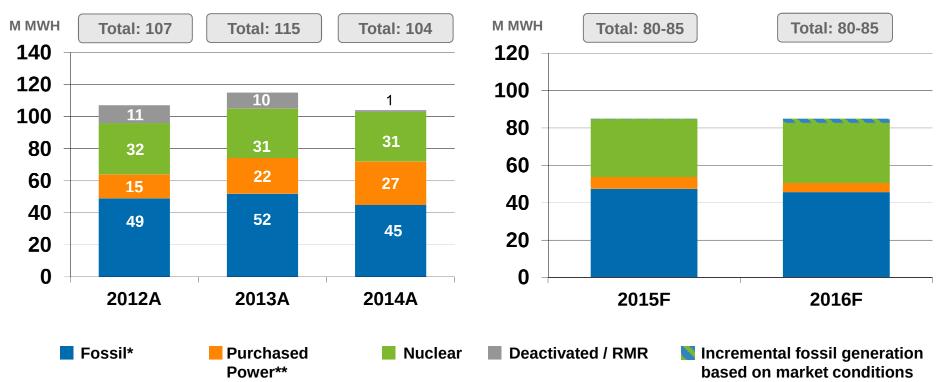
Committed Sales by Channel

Calendar Year	2014A			2015F			2016F		
Committed Sales	M MWH	$ M	$/MWH	M MWH	$ M	$/MWH	M MWH	$ M	$/MWH
MM	7	$450	$67	4	$285	$68	2	$155	$69
MCI	4	225	64	2	120	64	1	70	63
LCI	40	2,135	53	21	1,125	53	9	475	54
GA	20	1,190	61	16	1,055	68	13	855	66
POLR	16	900	57	10	600	59	4	240	64
Structured	13	565	44	10	450	45	7	315	44
Wholesale	-	-	-	4	165	38	4	165	40
Total Committed Sales	99	$5,465	$55	67	$3,800	$57	40	$2,275	$57

Planning Year	PY 14/15F						PY 15/16F						PY 16/17F					
	Jun - Dec 14			Jan - May 15			Jun - Dec 15			Jan - May 16			Jun - Dec 16			Jan - May 17		
Committed Sales	M MWH	$ M	$/MWH	M MWH	$ M	$/MWH	M MWH	$ M	$/MWH	M MWH	$ M	$/MWH	M MWH	$ M	$/MWH	M MWH	$ M	$/MWH
MM	4	$245	$67	2	$145	$67	2	$140	$69	1	$75	$69	1	$80	$70	<1	$25	$73
MCI	2	125	65	1	60	65	1	60	64	<1	30	63	1	40	62	<1	20	61
LCI	21	1,105	52	10	555	53	11	570	53	4	225	55	5	250	54	2	95	54
GA	11	705	65	7	425	63	9	630	72	6	385	68	7	470	64	5	320	61
POLR	9	505	59	7	375	56	3	225	66	2	155	64	2	85	64	1	60	64
Structured	8	350	45	4	195	44	6	255	46	4	170	45	3	145	41	2	85	42
Wholesale	-	-	-	-	-	-	4	165	38	3	120	39	1	45	45	-	-	-
Total Committed Sales	54	$3,035	$56	31	$1,755	$56	36	$2,045	$57	20	$1,160	$57	20	$1,115	$56	10	$605	$57

Numbers may not foot due to rounding   Beginning June 2016 FE Ohio GA rate has been forecasted based on projected PTC   As of February 2, 2015

CES Generation Portfolio



Planned ongoing generation resources of 80- 85M MWH annually

* Fossil includes Coal, Gas, and Hydro excluding pumping; excludes deactivated and RMR units
** Purchased Power includes Renewables/OVEC and additional Bilateral/Spot Purchases

Competitive Fuel Sources

	2013A*	2014A*	2015F	2016F
Fossil (M MWH)	52	45	48	46
Nuclear (M MWH)	31	31	31	32
Total	83	76	79	78
Hedged Fossil			90%-95%	80%-85%
Hedged Nuclear			100%	100%
Fossil $/MWH	$26.69	$27.16	~$27.50	~$28.00
Nuclear $/MWH	$7.79	$7.45	~$7.00**	~$7.00**
Total Competitive Fleet $/MWH	$19.61	$19. 07	~$19.00	~$19.00

			2015F Total Fleet–Coal Sources		
	Plants	Units	NAPP	Western	Petcoke
Supercritical Units	Mansfield	1-3	✓		
	Pleasants	1-2	✓		
	Sammis	6-7	✓	✓	
Subcritical Units	Sammis	1-5	✓	✓	
	Bay Shore	1			✓

*Fossil includes Coal, Gas, and Hydro excluding pumping; excludes deactivated and RMR units

**Adjusted for suspension of the DOE spent nuclear fuel fee

Reliability Pricing Model Capacity

Auction Results
Price Per Megawatt-Day

		RTO		MAAC	EMAAC
		ATSI	Rest of RTO		
2011 – 2012	FRR Integration Auction	$108.89	–	–	–
2012 – 2013	FRR Integration Auction	$20.46	–	–	–
2010-2011	BRA	N/A	$174.29	$174.29	$174.29
2011-2012	BRA	N/A	$110.00	$110.00	$110.00
2012-2013	BRA	N/A	$16.46	$133.37	$139.73
2013-2014	BRA	$27.73	$27.73	$226.15	$245.00
2014-2015	BRA	$125.99	$125.99	$136.50	$136.50
2015-2016	BRA	$357.00	$136.00	$167.46	$167.46
2016-2017	BRA	$114.23	$59.37	$119.13	$119.13
2017 - 2018	BRA	$120.00	$120.00	$120.00	$120.00

Future Capacity Auctions

	Base Residual	First Incremental	Second Incremental	Third Incremental
2015 - 2016	–	–	–	February 23, 2015
2016 - 2017	–	–	July 2015	February 2016
2017 - 2018	–	September 2015	July 2016	February 2017
2018 - 2019	May 2015	September 2016	July 2017	February 2018

- **First Incremental Auction for 2016-2017 held in September 2014**
  - 500 MW of FE Competitive Generation cleared at ~$100/MWD

This schedule does not incorporate any potential changes from PJM's proposed capacity and energy market reforms currently pending before FERC.

PJM Capacity Revenues

BRA Cleared/Current Available MW

	13/14	14/15	15/16	16/17		17/18	
	Cleared	Cleared	Cleared	Cleared	Available	Cleared	Available
ATSI	6,830	5,645	7,070	3,845	2,490	4,285	2,455
RTO	5,670	4,720	5,040	3,460	275	4,515	-
MAAC	85	85	80	80	-	75	-
EMAAC	55	55	55	55	-	55	-
TOTAL – CLEARED/AVAILABLE	12,640	10,505	12,245	7,440	2,765	8,930	2,455
Total Capacity Revenue ($M)	$140	$485	$1,185	$240		$390	

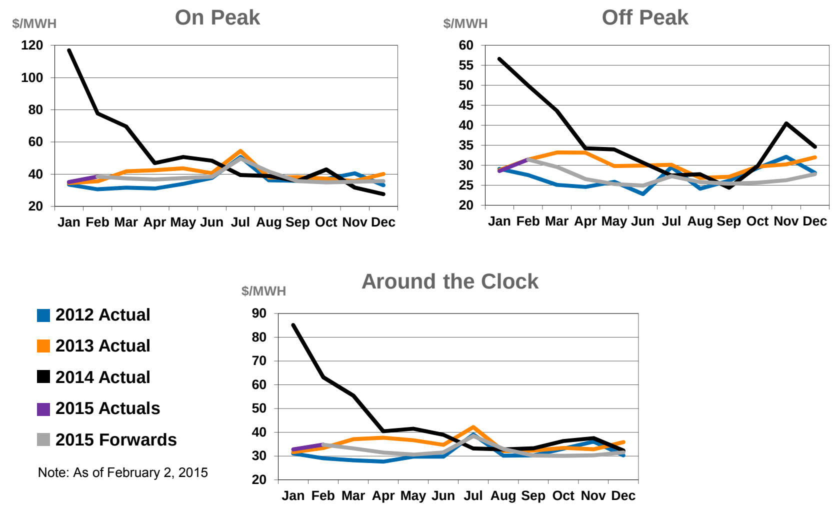
PJM BRA Capacity Revenues ($ Millions)

	2014	2015	2016	2017
ATSI	$180	$645	$480	$175
RTO	$150	$235	$145	$145
MAAC	$5	$5	$5	$5
EMAAC	$5	$5	$5	$5
Total Cleared Revenue	$340	$890	$635	$330

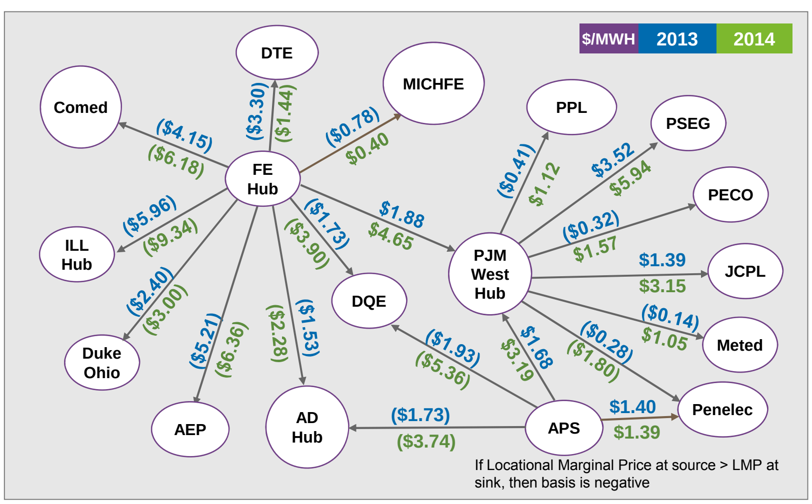
- **The "Cleared" MW and Revenues above reflect only results from the PJM Base Residual Auction**
- **Units that have been deactivated are included for years in which they cleared as their capacity obligations will be met with sources that did not clear or with purchased replacement capacity**
- **Units that have been sold/transferred are excluded from MW and capacity revenues**
- **PY 14/15 includes:**
  - MW and revenues from the portion of Pleasants transferred to CES
  - RMR unit revenues
- **"Available" MW:**
  - Include MW that did not clear the BRA or incremental auctions and can be offered into future incremental auctions
  - If "Available" MW cleared at $50/MWD in incremental auctions, would produce additional ~$50M in revenues for PY 16/17, ~$45M in revenues for PY 17/18

Power Price Trends

AD Hub



Commodity Operations – **Basis Risk**



- Basis risk mitigated by limiting geographic scope of sales obligation
- Basis risk hedged with basis and financial swaps as well as power transactions at the zones
- Values shown are around-the-clock, day-ahead average basis values

As of December 31, 2014

Commodity Operations – **Annual Historical Basis Values**

A negative value means the Locational Marginal Price (LMP)* at the source is greater than the LMP at the sink

Source	Sink	2012 ($/MWH)	2013 ($/MWH)	2014 ($/MWH)
FE Hub	Ill Hub	(5.04)	(5.96)	(9.34)
FE Hub	Comed	(3.31)	(4.15)	(6.18)
FE Hub	DTE	(1.33)	(3.30)	(1.44)
FE Hub	MichFE	(0.57)	(0.78)	0.40
FE Hub	PJM West Hub	1.78	1.88	4.65
FE Hub	DQE	(0.58)	(1.73)	(3.90)
FE Hub	AD Hub	(0.88)	(1.53)	(2.28)
FE Hub	AEP	(4.39)	(5.21)	(6.36)
FE Hub	Duke Ohio	(1.56)	(2.40)	(3.00)
APS	AD Hub	(1.60)	(1.73)	(3.74)
APS	DQE	(1.29)	(1.93)	(5.36)
APS	PJM West Hub	1.07	1.68	3.19
APS	Penelec	0.59	1.40	1.39
PJM West Hub	PPL	(0.70)	(0.41)	1.12
PJM West Hub	PSEG	0.86	3.52	5.94
PJM West Hub	PECO	0.12	(0.32)	1.57
PJM West Hub	JCP&L	0.35	1.39	3.15
PJM West Hub	Met-Ed	(0.21)	(0.14)	1.05
PJM West Hub	Penelec	(0.48)	(0.28)	(1.80)

*Values shown are around-the-clock, day-ahead average basis values

As of December 31, 2014

Repositioning Our Competitive Generation Portfolio
2012 - 2015

Deactivations

Competitive	NDC MW	RMR/Planned Deactivation MW	2012 M MWH	2012 Capacity Factor (%)	Deactivation Date
Eastlake 1-5	1,233	396 (1-3)	4.5	53	9/1/2012 (4-5); 4/15/2015 (1-3)*
Bay Shore 2-4	495	–	0.4	12	9/1/2012
Armstrong	356	–	0.3	16	9/1/2012
Lake Shore 18	245	245	0.2	9	4/15/2015*
Ashtabula 5	244	244	0.2	12	Under RMR status until 4/15/2015
R. Paul Smith 3-4	116	–	0.1	12	9/1/2012
Hatfield 1-3	1,710	–	9.7	64	10/9/2013
Mitchell 2-3	370	–	1.2	47	10/9/2013
Total	4,769	885	16.6		

*Units were under RMR status until September 15, 2014 and are now included in CES Generation and planned to be deactivated by April 15, 2015

Transfers and Sales

Competitive	NDC MW	Date
Harrison / Pleasants Asset Transfer	1,476	10/9/2013
Hydro Asset Sales	527	2/12/2014
Total	2,003	

Competitive Generation – **Plant Details**

Plant Name	PJM Zone	State	Fuel Type	Units	Net Maximum Capacity (MW)	Year Plant Commissioned
Ashtabula	ATSI	OH	Coal	1	244	1958
Bay Shore	ATSI	OH	Coal, Oil	2	153	1955
Davis-Besse	ATSI	OH	Nuclear	1	908	1977
Eastlake	ATSI	OH	Coal, Oil	4	425	1953
Lake Shore	ATSI	OH	Coal, Oil	2	249	1962
Mansfield	ATSI	PA	Coal	3	2,490	1976
Perry	ATSI	OH	Nuclear	1	1,268	1987
R.E. Burger	ATSI	OH	Oil	1	7	1972
Sammis	ATSI	OH	Coal, Oil	8	2,233	1959
West Lorain	ATSI	OH	Natural Gas, Oil	2	545	1973
Total ATSI Zone Generation					**8,522**	
Forked River*	EMAAC	NJ	Natural Gas		86	
Total EMAAC Zone Generation					**86**	

*Long-term PPA

Competitive Generation – **Plant Details** (Continued)

Plant Name	PJM Zone	State	Fuel Type	Units	Net Maximum Capacity (MW)	Year Plant Commissioned
Hunlock	MAAC	PA	Natural Gas	1	45	2000
Wind Farms*	MAAC	Multiple	Wind	Multiple	277	
Total MAAC Zone Generation					**322**	
Bath County	Rest of RTO	VA	Hydro	6	713**	1985
Beaver Valley	Rest of RTO	PA	Nuclear	2	1,872	1976
Buchanan	Rest of RTO	VA	Natural Gas	1	43	2002
Chambersburg	Rest of RTO	PA	Natural Gas	1	88	2001
Gans	Rest of RTO	PA	Natural Gas	1	88	2000
Maryland Solar*	Rest of RTO	MD	Solar	Multiple	20	
OVEC*	Rest of RTO	Multiple	Coal	Multiple	177***	
Pleasants	Rest of RTO	WV	Coal	2	1,300	1979
Springdale	Rest of RTO	PA	Natural Gas	5	638	1999
Wind Farms*	Rest of RTO	Multiple	Wind	Multiple	199	
Total Rest of RTO Generation					**5,138**	
Total Competitive Generation					**14,068**	

*Long-term PPA
** Represents AES entitlement
***Represents FES' 4.85% and AE Supply's 3.01% entitlement

Fossil **Environmental Controls**

	Plant	NDC	NOx Controls					SO_2 Controls		Particulate		Cooling Towers
			SCR	SNCR	COS	LNB	OFA	Scrubbers[1]	Lo-S Fuel	Baghouse	Electro/Other[2]	
Supercritical	Mansfield 1-3	2,490	✓		✓	✓	✓	✓			✓	✓
	Pleasants 1-2	1,300	✓			✓		✓			✓	✓
	Sammis 6 & 7	1,200	✓	✓	✓	✓	✓	✓			✓	
	Sub-total	4,990										
Subcritical	Sammis 1 - 4	720		✓	✓	✓	✓	✓		✓		
	Sammis 5	300		✓	✓	✓	✓	✓			✓	
	Bay Shore 1 (CFB [3])	136				3		3		✓		
	Sub-total	1,156										
RMR/Planned Deactivations[4]	Ashtabula 5	244				✓					✓	
	Eastlake 1	132				✓	✓				✓	
	Eastlake 2	132				✓	✓				✓	
	Eastlake 3	132				✓	✓				✓	
	Lake Shore 18	245							✓		✓	
	Sub-total	885										

[1]Scrubbed coal units have FGD (Flue Gas Desulfurization - equipment to remove sulfur from flue gas after combustion)
[2]Particulate Controls can include Venturi Scrubber or Electrostatic Precipitator
[3]CFB (Circulating Fluidized Bed) Boiler is inherently low emitting for NOx and SO_2
[4]See slide 126

In 2015, nearly 100% of the power the competitive portfolio generates is expected to come from low- or non-emitting sources, including nuclear, natural gas, scrubbed coal and renewable energy

Coal Combustion Residuals Impoundments

- **FE operates coal combustion residuals (CCR) impoundments and wastewater ponds in accordance with federal, state, and local regulatory requirements**
  - Requirements address design, construction, material placement, structural inspections, environmental monitoring, and final closure of facilities
- **Majority of FE CCRs are handled as dry material**
  - Typically sites consist of geotextile liners and or clay soil
  - Leachate and/or runoff is collected and treated
  - Wet CCR impoundments exist at Pleasants and Mansfield - Little Blue Run (LBR)
- **FE periodically removes CCR material from active wastewater ponds for placement in dry landfills**
  - All inactive CCR wastewater treatment ponds at retired plants have been stabilized and will be closed in accordance with state regulation
- **Closure permit issued by PA Department of Environmental Protection for LBR**
  - Site will stop receiving CCRs on December 31, 2016, and complete closure over a 12-year-period
  - A 30-year period of post closure monitoring will follow
  - Bonded closure cost is ~$170M
- **Pleasants impoundment is estimated to reach full capacity no sooner than 2021**
  - Closure plan to be developed and submitted to WV Department of Environmental Protection 1-2 years prior to closure

MATS Overview

- **MATS**
  - Total cost estimate of $178M, of which $56M has been spent through 2014.

Plant	Technologies
Bay Shore 1*	Baghouse Fabric Filter changes, Mini ACI system, CEMS
Sammis 1-7*	Precip Controls, CEMS
Mansfield 1-3	WFGD Changes, SCR Changes, CEMS
Pleasants 1&2	Precip Changes, FGD Changes, SCR Catalyst, Duct Repairs, CEMS

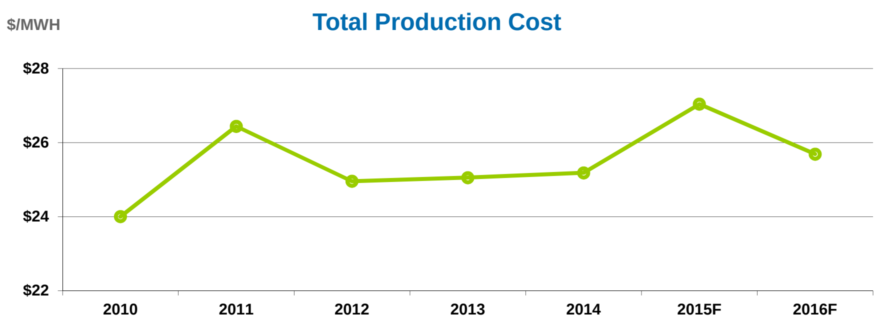
*Nearly all spending for Bay Shore and Sammis has been completed through 2014.

Nuclear **Key Events**

Key Events	Beaver Valley 1 (939 MW)	Beaver Valley 2 (933 MW)	Davis-Besse (908 MW)	Perry (1,268 MW)
License Expiration	2036	2047	2017*	2026**
2013	▪ **Completed planned outage**	▪ **Completed fuel pool rerack**	▪ **Relicensing process** – NRC issued final Safety Evaluation Report (SER) in license renewal process	▪ **Completed planned outage** ▪ **Supplemental NRC inspection (95002) completed satisfactorily**
2014	▪ **Implement dry fuel storage**	▪ **Planned outage** – Refueling	▪ **Completed planned outage** – Refueling – Steam generator replacement	▪ **Prepare for License Renewal Application submittal**
2015	▪ **Planned outage** – Refueling	▪ **Planned outage** – Refueling	▪ **Relicensing process** – NRC scheduled to issue final Supplemental Environmental Impact Statement (SEIS)	▪ **Submit License Renewal Application** ▪ **Planned outage** – Refueling
2016	▪ **Planned outage** – Refueling		▪ **Planned outage** – Refueling	
2017		▪ **Planned outage** – Refueling	▪ **Implement dry fuel storage**	▪ **Planned outage** – Refueling

*License Renewal Application submitted in 2010 **Submit License Renewal Application in 2015

Nuclear **Operating Costs**



FENOC	2010	2011	2012	2013	2014	2015F	2016F
O&M ($/MWH)	$17				$18	$20	$19
Fuel ($/MWH)	$7				$7	$7	$7
Generation (M MWH)	30.9	29.8	31.8	30.9	31.0	30.9	32.3

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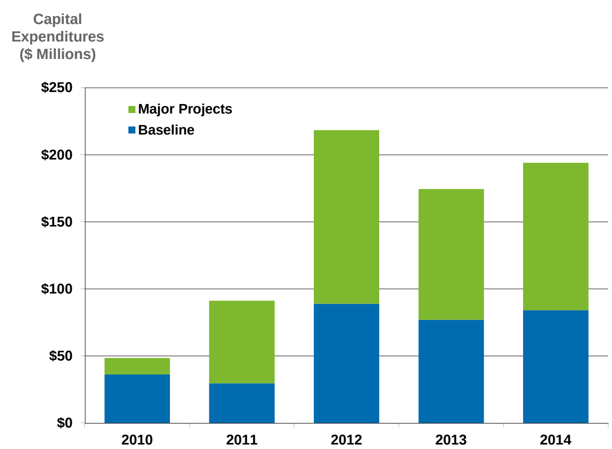
Beaver Valley



Major projects include:

- Steam Generator Replacement
- Low-Pressure Turbine Rotor Replacement
- Reactor Vessel Head Replacement

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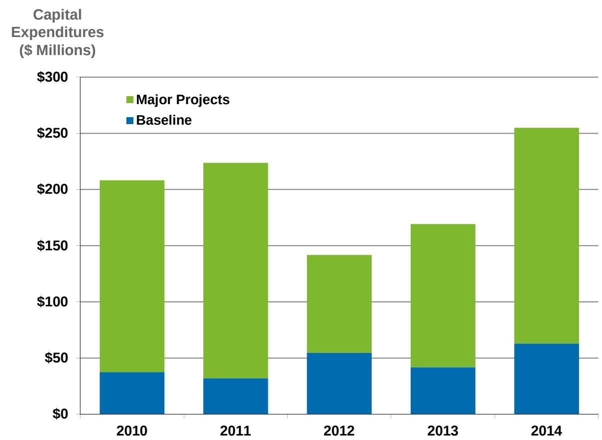
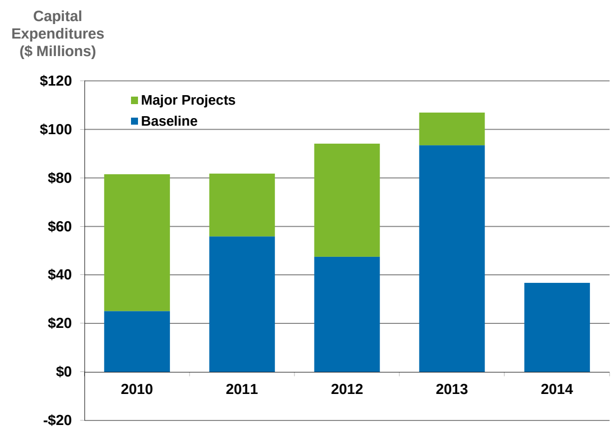
Davis-Besse



Major projects include:

- Reactor Vessel Head Replacement
- Steam Generator Replacement
- Main Generator Rewind
- Alloy 600 Mitigation

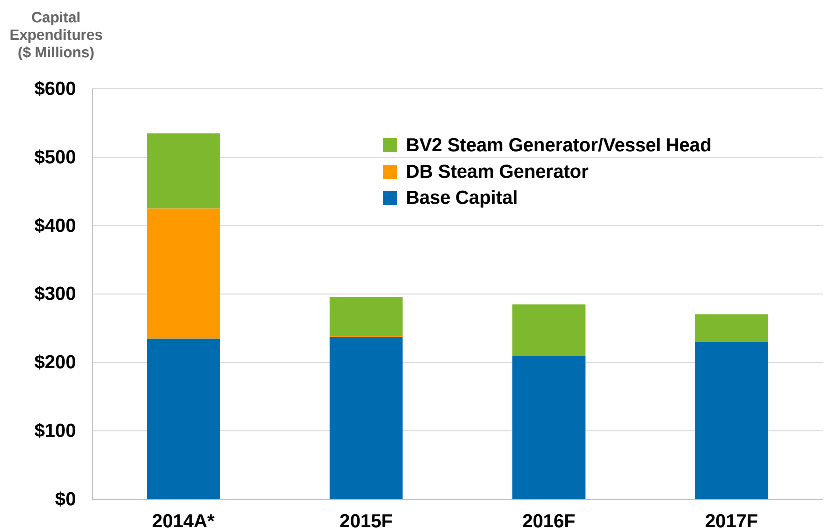
Perry



Major projects include:

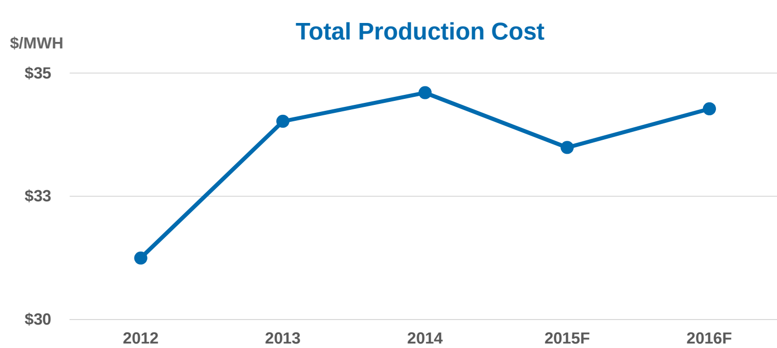
- Low-Pressure Turbine Rotor Replacement
- Main Generator Rewind
- Alternate Decay Heat Removal System Replacement

Nuclear **Fleet Capital**



*Includes $8M associated with the capital component of the Pension/OPEB mark-to-market adjustment

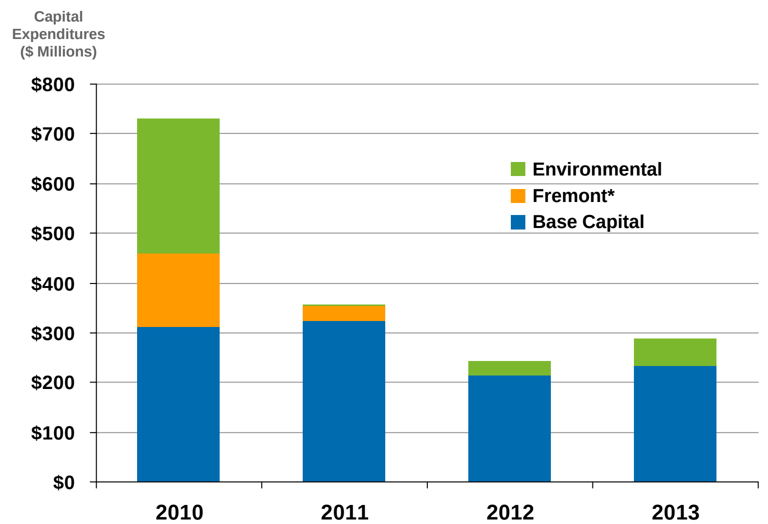
Fossil **Operating Costs**



Fossil	2012*	2013*	2014*	2015F*	2016F
O&M ($/MWH)	$6	$6	$7	$6	$7
Fuel ($/MWH)	$26	$28	$28	$27	$28
Generation (M MWH)	64.7	61.1	45.4	47.6	45.6

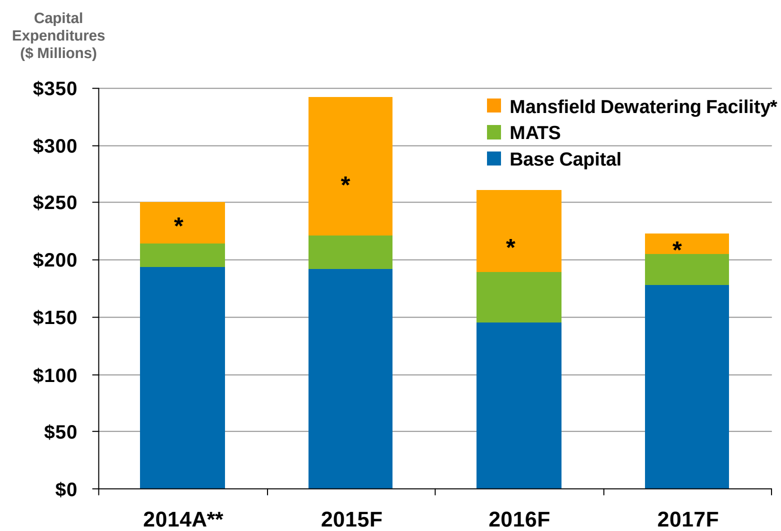
* Includes deactivated units and units planned to be deactivated by April 15, 2015

Fossil **Fleet Capital**



*Fremont was sold in July 2011

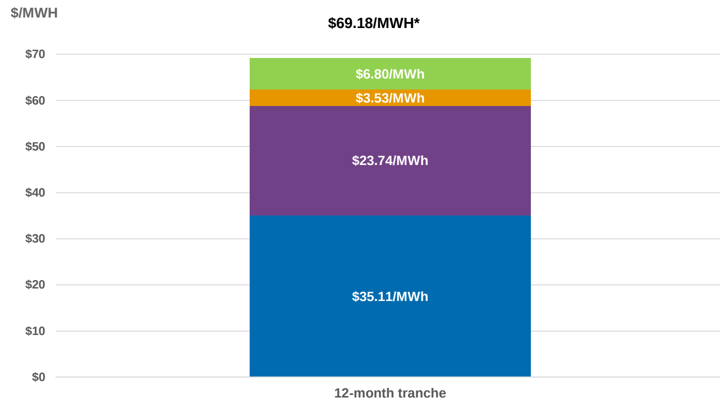
Fossil **Fleet Capital**



*Final spending to be determined. Due to closure of LBR by end of December 2016, Mansfield's CCBs must be converted to a dry product for disposal.
**Includes $11M associated with the capital component of the Pension/OPEB mark-to-market adjustment

Illustration of POLR Components

January 2015 FE Ohio POLR Auction Results



The following components are estimated and for illustrative purposes only:

- **Energy:** Energy price at AD Hub for FE Ohio slice of system load shape
- **Capacity:** RPM Capacity expense for product
- **Delivery:** Contains all non-energy; non-capacity RTO expenses. In OH, Network Integration Transmission Service is excluded.
- **Risk Premium:** Contains margin and risk premiums associated with load shape and price volatility

*Represents the actual OH POLR Clearing Price

Competitive Operations
Net Income (Loss) to Adjusted EBITDA* Reconciliation

($ Millions)	2014A	2015F	2016F
Net Income (Loss) – GAAP	$(337)	$135 – $175	$35 – $145
Special Items (after tax)*	436	55	40 – 30
Operating Earnings	$99	$190- $230	$75 - $175
Income Taxes**	47	100 – 145	45 – 100
Interest Expense, Net	152	160 – 155	165 – 150
Depreciation	387	410 – 405	430 – 415
Amortization***	66	65	70 – 65
Investment Income	(98)	(50)	(35) – (55)
Adjusted EBITDA*	$653	$875– $950	$750 – $850

* Adjusted EBITDA represents GAAP net income adjusted for the special items listed on slide 143 and the addition of Income Taxes; Interest Expense, net; Depreciation, Amortization and Investment Income.

** Includes income taxes on continued operations and discounted operations.

*** Amortization expense included in Other Operating Expenses on the Consolidated Statements of Income. Primarily relates to amortization of customer contract intangible assets, as disclosed in Note 7 - Intangible Assets, and amortization of deferred costs on sale leaseback transaction, net, as disclosed in the Consolidated Statements of Cash Flows. Does not include nuclear fuel amortization of approximately $220M, $215M and $230M, in 2014, 2015, and 2016, respectively.

Competitive Operations – **Special Items**

($ Millions)	2014A	2015F	2016F
Pre-tax items			
Trust Securities Impairment	$33	$ –	$ –
Merger Accounting – Commodity Contracts	42	40 – 45	40 – 45
Non-Core Asset Sales/Impairments	(122)	15	10 – 20
Plant Closing Costs	206	–	–
Loss on Debt Redemptions	8	–	–
Regulatory Charges	4	–	–
Mark to Market Adjustments			
Pension/OPEB actuarial assumption	327	–	–
Other	74	–	–
Retail Repositioning Charges	70	30	–
Subtotal	$642	$85 - $90	$50 - $65
Income Taxes	(206)	(30) – (35)	(20) – (25)
After Tax Effect – Special Items	$436	$55	$30 – $40

Competitive Operations – **Long-Term Debt Schedules**

Company	Type	CUSIP	Interest Rate	Maturity	Amount Outstanding
FEGENCO	Pollution Control Note	677660UC4	Variable*	10/1/2018	$2,805,000
	Pollution Control Note	677525UZ8	Variable*	10/1/2018	$2,985,000
	Pollution Control Note	074876HE6	Variable*	10/1/2047	$46,300,000
	Pollution Control Note	708686DX5	Variable*	6/1/2028	$15,000,000
	Pollution Control Note	074876HK2	Variable*	6/1/2028	$25,000,000
	Pollution Control Note	677525VK0	3.75%**	12/1/2023	$234,520,000
	Pollution Control Note	708686DA5	3.375%**	12/1/2040	$43,000,000
	Pollution Control Note	677660UE0	2.25%**	8/1/2029	$6,450,000
	Pollution Control Note	677525VB0	2.25%**	8/1/2029	$100,000,000
	Pollution Control Note	074876HF3	2.15%**	3/1/2017	$28,525,000
	Pollution Control Note	074876HJ5	2.5%**	12/1/2041	$129,610,000
	Pollution Control Note	677525TF4	5.625%	6/1/2018	$141,260,000
	Pollution Control Note	708686DB3	2.55%**	11/1/2041	$26,000,000

* Subject to mandatory redemption upon expiration of associated letter of credit; may later be remarketed, subject to market and other conditions
** Currently a fixed rate subject to mandatory put prior to maturity; may later be remarketed, subject to market and other conditions
Note: FES' debt obligations are guaranteed by its subsidiaries, FEGENCO and FENUGENCO, and FES guarantees the debt obligations of FEGENCO and FENUGENCO

As of December 31, 2014

Competitive Operations – **Long-Term Debt Schedules**

Company	Type	CUSIP	Interest Rate	Maturity	Amount Outstanding
FEGENCO	Pollution Control Note	074876HL0	3.5%**	11/1/2041	$56,600,000
	Pollution Control Note	677525TK3	5.7%	8/1/2020	$177,000,000
	Pollution Control Note	677525VP9	3.1%**	3/1/2023	$50,000,000
	Pollution Control Note	677660UL4	3.0%	5/15/2019	$90,140,000
				FEGENCO Total	$1,175,195,000
FENUGENCO	Pollution Control Note	677525VR5	3.625%**	10/1/2033	$9,100,000
	Pollution Control Note	677660UM2	3.625%**	10/1/2033	$20,450,000
	Pollution Control Note	677660UN0	3.95%**	11/1/2032	$33,000,000
	Pollution Control Note	677525VS3	3.95%**	11/1/2032	$23,000,000
	Pollution Control Note	677660UJ9	4.0%**	12/1/2033	$135,550,000
	Pollution Control Note	677660UK6	4.0%**	6/1/2033	$46,500,000
	Pollution Control Note	677525TY3	3.375%**	7/1/2033	$8,000,000

** Currently a fixed rate subject to mandatory put prior to maturity; may later be remarketed, subject to market and other conditions
Note: FES' debt obligations are guaranteed by its subsidiaries, FEGENCO and FENUGENCO, and FES guarantees the debt obligations of FEGENCO and FENUGENCO

As of December 31, 2014

Competitive Operations – **Long-Term Debt Schedules**

Company	Type	CUSIP	Interest Rate	Maturity	Amount Outstanding
FENUGENCO	Pollution Control Note	677660TV4	3.375%**	7/1/2033	$99,100,000
	Pollution Control Note	677525TZ0	3.375%**	1/1/2034	$7,200,000
	Pollution Control Note	677660TU6	3.375%**	1/1/2034	$82,800,000
	Pollution Control Note	074876GX5	3.375%**	1/1/2035	$72,650,000
	Pollution Control Note	677660TP7	5.875%**	6/1/2033	$107,500,000
	Pollution Control Note	677525TE7	5.75%**	6/1/2033	$62,500,000
	Pollution Control Note	677660UF7	2.2%**	6/1/2033	$54,600,000
	Pollution Control Note	677525VQ7	3.625%**	12/1/2033	$15,500,000
	Pollution Control Note	074876HG1	2.2%**	1/1/2035	$60,000,000
	Pollution Control Note	074876HH9	2.7%**	4/1/2035	$98,900,000
	Pollution Control Note	074876HM8	3.5%**	12/1/2035	$163,965,000

** Currently a fixed rate subject to mandatory put prior to maturity; may later be remarketed, subject to market and other conditions
Note: FES' debt obligations are guaranteed by its subsidiaries, FEGENCO and FENUGENCO, and FES guarantees the debt obligations of FEGENCO and FENUGENCO

As of December 31, 2014

Competitive Operations – **Long-Term Debt Schedules**

Company	Type	CUSIP	Interest Rate	Maturity	Amount Outstanding
FENUGENCO	Collateralized Lease Bonds	N/A	9.12%	5/30/2016	$14,140,000
	Collateralized Lease Bonds	N/A	8.83%	5/30/2016	$6,500,000
	Collateralized Lease Bonds	N/A	9.0%	6/1/2017	$17,054,000
	Collateralized Lease Bonds	N/A	12.0%	6/1/2017	$425,604
	Collateralized Lease Bonds	N/A	8.89%	6/1/2017	$60,048,000
	Collateralized Lease Bonds	N/A	8.68%	6/1/2017	$8,668,000
				FENUGENCO Total	$1,207,150,604

As of December 31, 2014

Competitive Operations – **Long-Term Debt Schedules**

Company	Type	CUSIP	Interest Rate	Maturity	Amount Outstanding
FES	Senior Note	33766JAD5	6.05%	8/15/2021	$332,305,000
	Senior Note	33766JAF0	6.8%	8/15/2039	$363,281,000
	Term Note*	N/A	5.15%	7/1/2015	$17,480,986
				FES Total	$713,066,986
AE Supply	Pollution Control Note	41524CAU8	5.5%	10/15/2037	$73,500,000**
	Pollution Control Note	728896CF6	5.25%	10/15/2037	$142,000,000
	Senior Note	017363AK8	5.75%	10/15/2019	$155,532,000
	Senior Note	017363AM4	6.75%	10/15/2039	$150,034,000
				AE Supply Total	$521,066,000
AGC	Senior Note	Private Placement	5.06%	7/15/2021	$100,000,000
				AGC Total	$100,000,000

*Paid in full on February 5, 2015
**Mon Power assumed primary liability for this Note in connection with the Harrison transfer
Note: FES' debt obligations are guaranteed by its subsidiaries, FEGENCO and FENUGENCO, and FES guarantees the debt obligations of FEGENCO and FENUGENCO

As of December 31, 2014

Creating Value for Investors

FirstEnergy

Financial

Financial – Liquidity

Available Liquidity

($ Millions)

	CES	FET	FEU	FE Corp.	FE Consolidated
Revolving Credit Facility	**$ 1,500**	**$ 1,000**	**$ 3,500**		**$ 6,000**
Short-term borrowings	(6)	–	–	(2, 025)	**(2,031)**
Letters of Credit (LOC)	(59)	–	–	(6)	**(65)**
Total Utilization	**$ (65)**	–	**$ (2,031)**		**$ (2,096)**
Available External Credit Capacity	**$ 1,435**	**$ 1,000**	**$1,469**		**$ 3,904**
Cash & Investments	–	54	–	4	**58**
Available Liquidity	**$ 1,435**	**$ 1,054**	**$1,473**		**$ 3,962**

As of January 31, 2015

Financial – **Parental Guarantees**

	FirstEnergy Corp. Parent					
	Competitive		Regulated		Corp/Other	
	$M	Expiration	$M	Expiration	$M	Expiration
Energy Related Contracts	$46	2020-2030	–	–	–	–
Fuel Related Contracts	$33	2021-2031	–	–	–	–
Retail Contracts	$99	2015-2016	–	–	–	–
Benefit Related Programs	$135	–	$173	–	$214	–
Other	$5	2015	$4	2030	$3	–
Total FE Guarantee on behalf of subsidiaries	**$318**		**$177**		**$217**	

As of December 31, 2104

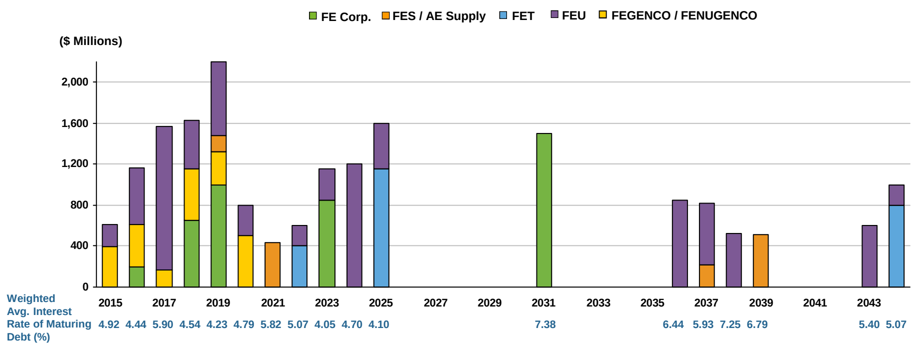
Financial –
Collateral Dependent on Investment Grade Rating

($ Millions)

Collateral Provisions As of December 31, 2014	FES* (tied to FE Corp. rating)	FES* (tied to FES rating)	Utilities	Total
Split Rating (One Rating Agency below investment grade)	**$180****	**$429**	**$48**	**$657**
Non-Investment Grade Ratings (All Rating Agencies at or below BB+/Ba1)	**$186**	**$463**	**$48**	**$697**
Total Exposure from Contractual Obligations	**$297**	**$661**	**$86**	**$1,044**

*Includes AE Supply
**Exists due to FE Corp's current Unsecured Rating of BB+ by Standard & Poors

Consolidated Long-Term Debt Maturities



Excludes variable rate tax-exempt debt and securitization bonds

As of December 31, 2104

Outstanding Debt by Legal Entity

Hold Co. At 12/31/2014	FE Hold Co.
Short-term Debt	1,901
Long-term Debt	4,200
Securitization Bonds	-
Debt Subtotal	**6,101**
Discounts/Premiums	23
Purchase Accounting	-
Capital Leases	-
Total Balance Sheet Debt	**6,124**

Utilities At 12/31/2014	Ohio Edison	Cleveland Electric	Toledo Edison	Penn Power	Metropolitan Edison	Pennsylvania Electric	Jersey Central	Mon Power	Potomac Edison	West Penn Power
Short-term Debt	-	124	99	37	33	-	233	11	4	89
Long-term Debt	650	1,330	350	105	850	1,125	2,000	1,294	445	520
Securitization Bonds	142	202	42	-	-	-	168	322	108	-
Debt Subtotal	**792**	**1,656**	**491**	**142**	**883**	**1,125**	**2,401**	**1,626**	**557**	**609**
Discounts/Premiums	(9)	(2)	(1)	-	(1)	(2)	(7)	(1)	-	-
Purchase Accounting	-	-	-	-	-	-	-	22	10	18
Capital Leases	25	20	11	5	20	30	-	8	7	13
Total Balance Sheet Debt	**808**	**1,674**	**502**	**147**	**902**	**1,152**	**2,394**	**1,655**	**575**	**639**

Transmission At 12/31/2014	FET Hold Co.	ATSI	TrAIL
Short-term Debt	-	-	101
Long-term Debt	1,000	800	550
Securitization Bonds	-	-	-
Debt Subtotal	**1,000**	**800**	**651**
Discounts/Premiums	(2)	(4)	(0)
Purchase Accounting	-	-	-
Capital Leases	-	-	-
Total Balance Sheet Debt	**998**	**796**	**650**

Generation At 12/31/2014	FES Hold Co.	FE Generation	FE Nuclear Generation	Allegheny Energy Supply	Allegheny Generating
Short-term Debt	92	330	27	62	12
Long-term Debt	713	1,177	1,207	521	100
Securitization Bonds	-	-	-	-	-
Debt Subtotal	**805**	**1,507**	**1,235**	**583**	**112**
Discounts/Premiums	(1)	-	-	-	-
Purchase Accounting	-	-	-	(29)	-
Capital Leases	-	17	-	0	-
Total Balance Sheet Debt	**804**	**1,524**	**1,235**	**553**	**112**

As of December 31, 2104

Financial – **Debt Targets**

Segment	FirstEnergy Utilities (FEU)	FirstEnergy Transmission (FET)		Competitive Energy Services (CES)
		HoldCo	OpCo	
Target Adjusted Debt Ratios*	**55%**	**65%**	**40%**	**≤40%**

FEU = OE, PP, CEI, TE, JCP&L, ME, PN, MP, PE, WPP

FET = FET, ATSI, TrAILCo

CES = FES, AE Supply

Outstanding debt at FE Corp is not reflected above

*Calculated per rating agency view shown on slide 177

Financial – **FirstEnergy Corp. Long-Term Debt Schedules**

Company	Type	CUSIP	Interest Rate	Maturity	Amount Outstanding
FirstEnergy Corp.	Term Loan	N/A	Variable	12/31/2016	$200,000,000
	Term Loan	N/A	Variable	3/31/2019	$1,000,000,000
	Unsecured Notes	337932AE7	2.75%	3/15/2018	$650,000,000
	Unsecured Notes	337932AF4	4.25%	3/15/2023	$850,000,000
	Unsecured Notes	337932AC1	7.375%	11/15/2031	$1,500,000,000
				FirstEnergy Corp. Total	**$4,200,000,000**

As of December 31, 2014

Financial – **Credit Ratings**

As of 12/31/2014	Corporate Credit Rating (S&P) / Issuer Rating (Moody's) / Issuer Default (Fitch)			Senior Secured			Senior Unsecured			Outlook		
	S&P	Moodys	Fitch	S&P	Moodys	Fitch	S&P	Moodys	Fitch	S&P	Moodys	Fitch
FirstEnergy Corp.	BBB-	Baa3	BB+	-	-	-	BB+	Baa3	BB+	stable	stable	stable
FirstEnergy Solutions	BBB-	Baa3	-	-	-	-	BBB-	Baa3	-	stable	stable	-
Allegheny Energy Supply	BBB-	Baa3	-	-	-	-	BBB-	Baa3	-	stable	stable	-
Allegheny Generating Co.	BBB-	Baa3	-	-	-	-	BBB-	Baa3	-	stable	stable	-
American Transmission Systems Inc.	BBB-	Baa2	-	-	-	-	BBB-	Baa2	-	stable	stable	-
Cleveland Electric Illuminating	BBB-	Baa3	-	BBB+	Baa1	-	BBB-	Baa3	-	stable	stable	-
FirstEnergy Transmission	BBB-	Baa3	-	-	-	-	BB+	Baa3	-	stable	stable	-
Jersey Central Power & Light	BBB-	Baa2	-	-	-	-	BBB-	Baa2	-	stable	negative	-
Metropolitan Edison	BBB-	Baa1	-	-	-	-	BBB-	Baa1	-	stable	stable	-
Monongahela Power	BBB-	Baa2	-	BBB+	A3	-	-	-	-	stable	stable	-
Ohio Edison Co.	BBB-	Baa1	-	BBB+	A2	-	BBB-	Baa1	-	stable	stable	-
Pennsylvania Electric Co.	BBB-	Baa2	-	-	-	-	BBB-	Baa2	-	stable	stable	-
Pennsylvania Power Co.	BBB-	Baa1	-	BBB+	A2	-	-	-	-	stable	stable	-
Potomac Edison Co.	BBB-	Baa2	-	BBB+	A3	-	-	-	-	stable	stable	-
Toledo Edison Co.	BBB-	Baa3	-	BBB	Baa1	-	-	-	-	stable	stable	-
Trans-Allegheny Interstate Line Co.	BBB-	A3	-	-	-	-	BBB-	A3	-	stable	stable	-
West Penn Power Co.	BBB-	Baa1	-	BBB+	A2	-	-	-	-	stable	stable	-

Financial – 2015 Financial Plan

Committed to maintain investment grade metrics at each business unit and improve metrics at FE Corp. over time consistent with business profile

- **Focus on FE Transmission growth**
  - Long-term financings to support growth*
- **Target positive cash flow in 2015 at CES**
  - Refinancing of maturing debt*
  - Focus on cost control in low power price environment
- **Continued focus on strengthening FE Utilities balance sheets**
  - Refinancing of maturing debt at certain utilities*
  - Reduce short-term borrowings through refinancings*
- **Issue equity through stock investment/employee benefit plans, as available – program targets ~$100M****

*Subject to market and other conditions. ** Varies based on participation and market conditions

Financial – 2014 Financial Accomplishments

- **Revised annual dividend level of $1.44 per share**
  - Dividend level aligned with FE's targeted business mix (80+% regulated, <20% competitive)
  - Fully supported by earnings and cash flows from regulated businesses
  - Provides balance sheet capacity to invest in transmission reliability projects
- **Focus on FE Transmission growth**
  - Issued long-term debt to support transmission reliability program
    - $1B at FET HoldCo
    - $400M at ATSI
    - $550M at TrAIL ($450M refinanced)
- **Focus on strengthening FES/AE Supply balance sheets**
  - $394M sale of hydro assets completed on February 12, 2014
  - Refinanced certain debt at FEGENCO and FENUGENCO
- **Focus on strengthening FE Utilities balance sheets**
  - Refinanced maturing debt at certain utilities
  - Reduced short-term borrowings through refinancings
- **Improved liquidity by restructuring existing credit facilities**
  - Extended maturity of facilities by one year to March 2019
  - Upsized FE Corp/FEU facility to $3.5B while reducing FES/AE Supply facility to $1.5B
  - FE Corp. entered into a new $1B 5-year term loan
- **Issued equity – ~$83M in 2014 through stock investment/employee benefit plans**

As of December 31, 2014

Financial – **Credit Providers**

31 financial institutions provide ~$7.5B aggregate credit commitment

($ Millions)	
Revolving Credit Facilities	**$6,000**
Term Loans	**1,200**
SUB-TOTAL	**$7,200**
Letters of Credit (LOC)	**93**
Vehicle Leases	**208**
Sale Leaseback LOC	**28**
TOTAL	**$7,529**

Bank of America	JP Morgan Chase
Bank of New York Mellon	Keybank
Bank of Nova Scotia	Mizuho
Barclays Bank	Morgan Stanley
BBVA	National Cooperative Services
BNP Paribas	PNC
CIBC	Regions Bank
Citibank	Royal Bank of Canada
CoBank	Royal Bank of Scotland
Credit Agricole	Santander
Credit Suisse	Sumitomo Mitsui
Fifth Third Bank	TD Bank
First National Bank	Union Bank/Bank of Tokyo Mitsubishi
G.E. Capital	US Bank
Goldman Sachs	Wells Fargo
Huntington National Bank	

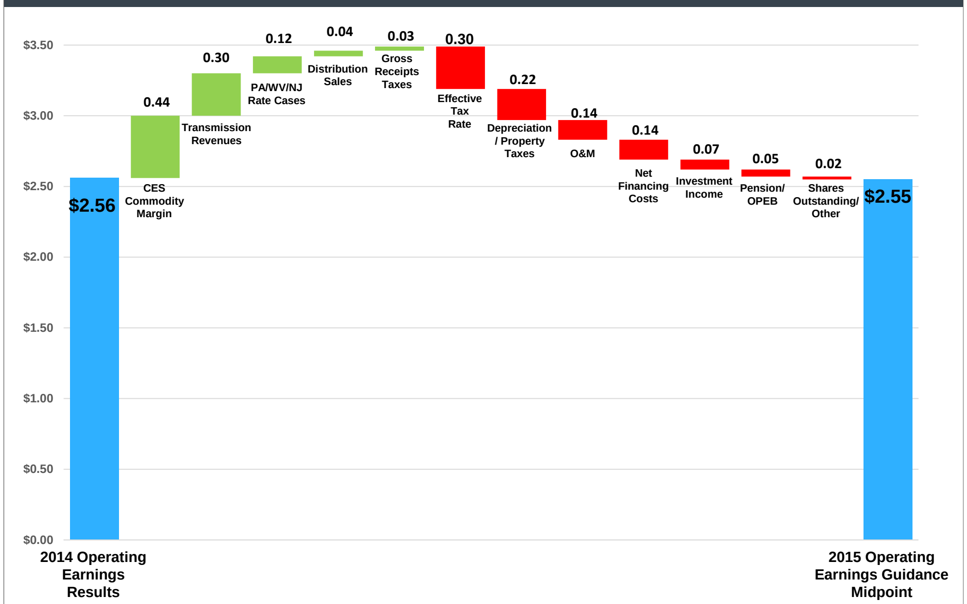
As of December 31, 2014

Financial – **Operating Earnings**[1] by Segment

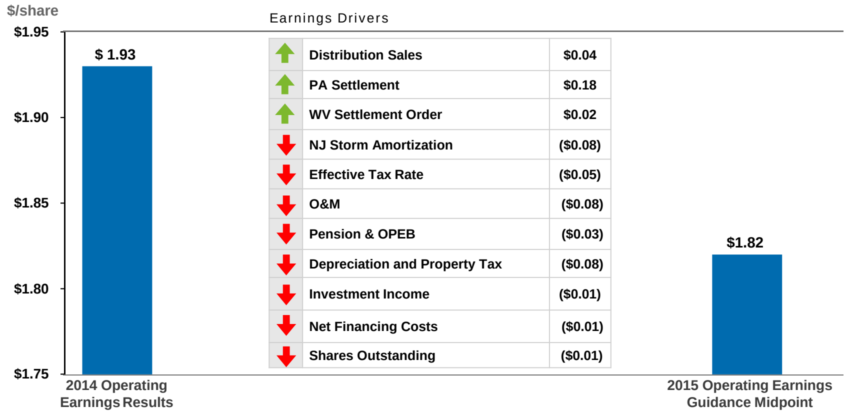
Operating EPS[1] – Basic	2014A	2015 Guidance
Regulated Distribution	$1.93	$1.74 - $1.90
Regulated Transmission	0.54	0.63 - 0.67
Sub-total	$2.47	$2.37 – $2.57
Competitive Energy Services	0.23	0.45 – 0.55
Corporate / Other	(0.14)	(0.42)
FirstEnergy Consolidated	$2.56	$2.40 - $2.70

[1]See GAAP to Operating earnings reconciliation on slides 167 and 168

FE Consolidated – 2014 to 2015 Earnings



Regulated Distribution – 2014 to 2015



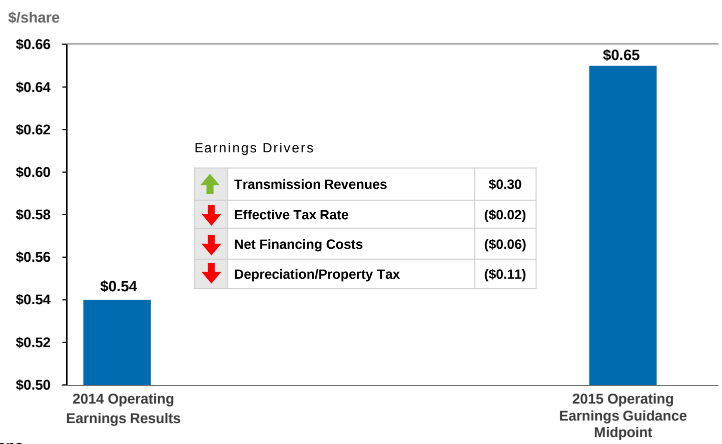
Earnings Drivers

↑	Distribution Sales	$0.04
↑	PA Settlement	$0.18
↑	WV Settlement Order	$0.02
↓	NJ Storm Amortization	($0.08)
↓	Effective Tax Rate	($0.05)
↓	O&M	($0.08)
↓	Pension & OPEB	($0.03)
↓	Depreciation and Property Tax	($0.08)
↓	Investment Income	($0.01)
↓	Net Financing Costs	($0.01)
↓	Shares Outstanding	($0.01)

Assumptions

- **Distribution Sales –** Forecasted sales of ~151M MWH in 2015 versus 149.5M MWH in 2014
- **PA** – $120M pre-tax earnings benefit effective May 2015 per settlements; annual pre-tax earnings benefit of $205M
- **WV** – Pre-tax earnings impact of $13M per rate case settlement order, effective February 25, 2015
- **NJ** – Assumes 2015 revenues neutral to 2014; ($0.08) for 2011 & 2012 storm amortization, effective March 1, 2015
- **Effective Tax Rate** – 35.2% in 2014 vs. 36.9% in 2015
- **O&M –** Higher Distribution O&M expenses ($0.05), primarily in PA, and higher generation O&M for regulated plants ($0.03)
- **Pension & OPEB –** Higher expense due to lower amortization of prior service credits along with annual updates to actuarial assumptions
- **Depreciation & Property Tax –** Results primarily from higher rate base
- **Investment Income** – Lower interest and dividend income
- **Net Financing Costs –** Related to new debt issuances, partially offset by lower short-term interest costs
- **Shares Outstanding –** ~420M shares in 2014 to ~422M in 2015

Regulated Transmission – 2014 to 2015



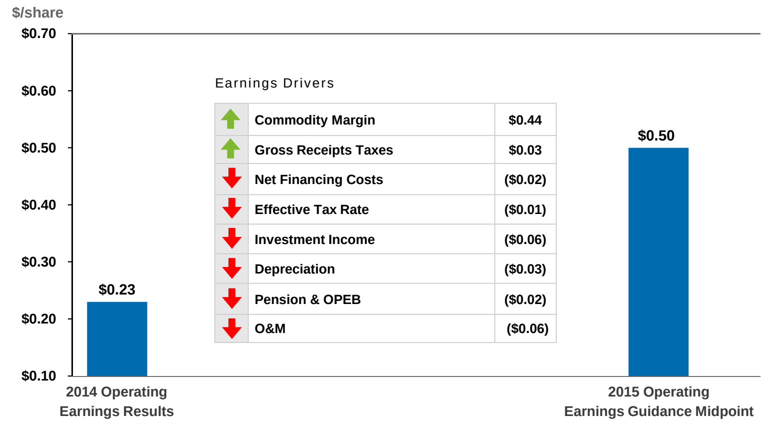
Earnings Drivers

↑	Transmission Revenues	$0.30
↓	Effective Tax Rate	($0.02)
↓	Net Financing Costs	($0.06)
↓	Depreciation/Property Tax	($0.11)

Assumptions

- **Transmission Revenue** – Assumes impact of ATSI forward looking rate filing with 1/1/15 effective date and higher rate base at ATSI / TrAILCo
- **Effective Tax Rate** – 35.2% in 2014 vs. 36.9% in 2015
- **Net Financing Costs** – Reflects full year impact of debt issuances at FET Hold Co ($1,000M) and ATSI ($400M) and lower average CWIP balance resulting in decreased AFUDC-equity earnings
- **Depreciation / Property Tax** – Increased expenses resulting from higher asset base

Competitive Energy Services – 2014 to 2015



Earnings Drivers

↑	Commodity Margin	$0.44
↑	Gross Receipts Taxes	$0.03
↓	Net Financing Costs	($0.02)
↓	Effective Tax Rate	($0.01)
↓	Investment Income	($0.06)
↓	Depreciation	($0.03)
↓	Pension & OPEB	($0.02)
↓	O&M	($0.06)

Assumptions

- **Commodity Margin**
  - Lower spot purchased power
  - Higher capacity revenue from increased prices
  - Lower delivery expense costs
  - Lower fuel rates from fossil and nuclear
- **Gross Receipts Taxes** – Lower gross receipts taxes due to lower retail sales volumes
- **Net Financing Costs**– Refinancing of PCRB's
- **Effective Tax Rate** – 35.2% in 2014 vs. 36.9% in 2015
- **Investment Income** – Lower other income from realized gains in 2014
- **Depreciation** – Increased expenses due to full year of DB steam generator and higher asset base
- **Pension & OPEB**- Higher expense due to lower amortization of prior service credits along with updates to actuarial assumptions
- **O&M** – 3 nuclear outages in 2015 vs 2 in 2014

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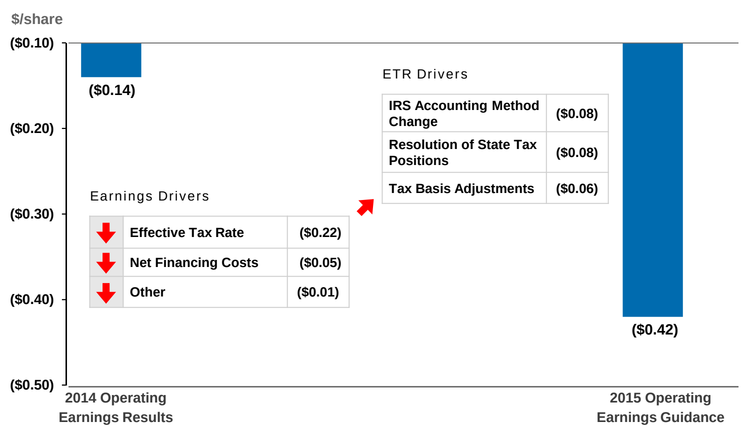
Corporate / Other – 2014 to 2015



ETR Drivers

IRS Accounting Method Change	($0.08)
Resolution of State Tax Positions	($0.08)
Tax Basis Adjustments	($0.06)

Earnings Drivers

↓	Effective Tax Rate	($0.22)
↓	Net Financing Costs	($0.05)
↓	Other	($0.01)

Assumptions

- **Effective Tax Rate** – 2014 consolidated ETR of 29% vs. 37% - 38% in 2015
- **Net Financing Costs**
  - Increased rate on $1B in variable rate debt in March 2014
  - Higher short-term interest expense

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Financial – 2015 GAAP to Operating Earnings[1] Reconciliation

(In Millions, except per share amounts)	FirstEnergy Consolidated 2015F	Regulated Distribution 2015F	Regulated Transmission 2015F	Competitive Energy Services 2015F	Corporate/ Other 2015F
Net Income (Loss) – GAAP	$935M - $1,060M	$710M - $780M	$265M - $280M	$135M - $175M	($175M)
Basic EPS (average shares outstanding 423M)	$2.21 - $2.51	$1.68 - $1.84	$0.63 - $0.67	$0.32 - $0.42	($0.42)
Excluding Special Items[2]:					
Regulatory Charges	$0.06	$0.06	-	-	-
Non-core Asset Sales/Impairments	$0.02	-	-	$0.02	-
Retail Repositioning Charges	$0.04	-	-	$0.04	-
Merger Accounting – Commodity Contracts	$0.07	-	-	$0.07	-
Total Special Items[2]	$0.19	$0.06	$0.00	$0.13	$0.00
Basic EPS – Operating (Non-GAAP) (average shares outstanding 422M)	$2.40 - $2.70	$1.74 - $1.90	$0.63 - $0.67	$0.45 - $0.55	($0.42)

[1]Operating earnings exclude special items as described in the reconciliation table above and is a non-GAAP financial measure
[2]Per share amounts for the special items above are based on the after tax effect of each item divided by the weighted average shares outstanding for the period

Financial – 2014 GAAP to Operating Earnings[1] Reconciliation

(In Millions, except per share amounts)	FirstEnergy Consolidated 2014A	Regulated Distribution 2014A	Regulated Transmission 2014A	Competitive Energy Services 2014A	Corporate/ Other 2014A
Net Income (Loss) – GAAP	$299M	$465M	$223M	($337M)	($52M)
Basic EPS (average shares outstanding 420M)	$0.71	$1.11	$0.53	($0.80)	($0.13)
Excluding Special Items[2]:					
Mark-to-market Adjustments					
Pension/OPEB actuarial assumptions	1.23	0.74	0.01	0.48	–
Other	0.11	–	–	0.11	–
Plant Deactivation Costs	0.34	–	–	0.34	–
Trust Securities Impairment	0.06	0.01	–	0.05	–
Regulatory Charges	0.08	0.07	–	0.01	–
Litigation Resolution	(0.01)	–	–	–	(0.01)
Loss on Debt Redemptions	0.01	–	–	0.01	–
Merger Accounting – Commodity Contracts	0.07	–	–	0.07	–
Non-core Asset Sales/Impairments	(0.15)	–	–	(0.15)	–
Retail Repositioning Charges	0.11	–	–	0.11	–
Total Special Items[2]	$1.85	$0.82	$0.01	$1.03	($0.01)
Basic EPS – Operating (Non-GAAP) (average shares outstanding 420M)	$2.56	$1.93	$0.54	$0.23	($0.14)

[1]Operating earnings exclude special items as described in the reconciliation table above and is a non-GAAP financial measure
[2]Per share amounts for the special items above are based on the after tax effect of each item divided by the weighted average shares outstanding for the period

Financial – 2014A Capital Expenditures

Capital Expenditures ($ Millions)	Regulated Distribution	Regulated Transmission	CES[1]	Corporate/ Other	FirstEnergy Consolidated[2]
Baseline Capital	$869	$192	$436	$84	$1,581
Formula Rate Recoverable	413	1,177	–	–	1,590
Major Projects					
Generation Projects	–	–	336	–	336
MATS	31	–	20	–	51
JCP&L LITE	4	52	–	–	56
Storms	69	2	–	–	71
Total	$1,386	$1,423	$792	$84	$3,685

[1] Excludes nuclear fuel of $233M
[2] Total includes $387M associated with the capital component of the Pension and OPEB mark-to-market adjustment.

Financial – 2015F Capital Expenditures

Capital Expenditures ($ Millions)	Regulated Distribution	Regulated Transmission	CES[1]	Corporate/ Other	FirstEnergy Consolidated
Baseline Capital	$720	$125	$440	$115	$1,400
Formula Rate Recoverable	375	805	–	–	1,180
Major Projects					
Generation Projects	–	–	180	–	180
MATS	65	–	30	–	95
JCP&L LITE	5	40	–	–	45
Storms	40	–	–	–	40
Total	$1,205	$970	$650	$115	$2,940

[1] Excludes nuclear fuel of $205M

2014 Free Cash Flow

($ Millions)	FirstEnergy Consolidated
Funds From Operations (FFO)[1]	**$2,493**
Capital Expenditures[2]	(3,298)
Nuclear Fuel	(233)
Cash Before Other Items	**($1,038)**
Hydro Asset Sales	394
Collateral	(54)
Working Capital/Other	4
Cash Before Dividends and Equity	**($694)**
Dividends @ $1.44/share	(604)
Equity (SIP and other employee benefit plans)	83
Free Cash Flow [3]	**($1,215)**

[1] Non-GAAP measure; See GAAP to FFO reconciliation on slide 172
[2] Excludes capital component of Pension/OPEB mark-to-market adjustment
[3] Excludes cash items related to financing activity

Financial – **Funds** from **Operations Reconciliation**

FirstEnergy Consolidated ($ Millions)	2014A
Net Income – GAAP	**$299**
Depreciation	1,220
Amortization of Regulatory Assets, net	12
Nuclear Fuel Amortization(1)	220
Deferred Taxes and ITC(2)	107
Deferred Purchased Power and Other Costs(3)	(115)
Pension and OPEB MTM	835
NDT Impairments and Gains(4)	(27)
Loss on Debt Redemptions	8
Gain on Asset Sale, pre-tax	(142)
Other(5)	76
Funds from Operations (FFO)	**$2,493**

[1] Included in fuel expense
[2] See Combined Notes to Consolidated Financial Statements - Note 5,Taxes. Includes deferred taxes from continuing and discontinued operations
[3] Included in consolidated statement of cash flows
[4] Includes investment impairments and gain on investment securities held in trust in consolidated statement of cash flows
[5] Primarily includes securitized debt principal payments and non-cash items such as unrealized gain and losses on derivative contracts and AFUDC

2015F Free Cash Flow

($ Millions)	FirstEnergy Consolidated
Funds From Operations (FFO)[1]	**$3,165 - $3,365**
Capital Expenditures	(2,942)
Nuclear Fuel	(205)
Cash Before Other Items	**$18 - $218**
Pension Contribution	(143)
Working Capital/Other	125
Cash Before Dividends and Equity	**$0 - $200**
Dividends @ $1.44/share	(610)
Equity (SIP and other employee benefit plans)	105
Free Cash Flow [2]	**($505) - ($305)**

[1] Non-GAAP measure; See GAAP to FFO reconciliation on slide 174. Amount shown reflects the midpoint
[2] Excludes cash items related to financing activity

Financial – **Funds** from **Operations Reconciliation**

FirstEnergy Consolidated ($ Millions)	2015F
Net Income – GAAP	**$935 - $1,060**
Depreciation	1,345
Amortization of Regulatory Assets, net	317
Nuclear Fuel Amortization	215
Deferred Taxes and ITC	510
Deferred Purchased Power and Other Costs	(40)
Retirement Benefits	25
Other[(1)]	(142) – (67)
Funds from Operations (FFO)	**$3,165 - $3,365**

[1] Primarily includes securitized debt principal payments and non-cash items such as unrealized gain and losses on derivative contracts and AFUDC

Financial – Qualified Pension Status Overview

Pension Plan ($ Millions)	2013	2014	2015 Assumptions
Assumptions* - Pension Costs			
Expected Return on Assets	7.75%	7.75%	7.75%
Previous Year-End Discount Rate	4.25%	5.00%	4.25%
Pension Funding (Year End)			
Plan Assets	$6,171	$5,811	
ABO Liability	$7,554	$8,412	
ABO Funding Ratio	82%	69%	

($ Millions)	2013	2014	2015F
Contributions during the year	$ -	$ -	$ 143

- **Projected Benefit Obligation (PBO) Liability as of December 2014 was $8,882M**
  - A 25 bps increase in the discount rate decreases the PBO liability by ~$220-250M
- **At December 31, 2014, the annual Pension and OPEB mark-to-market adjustment was $1.2B of which $835M, or $1.23 per share, was recorded in operating expenses and $387M was included as a capital cost. The mark-to-market adjustment primarily reflects a discount rate of 4.25% (4.00% on OPEB), lower mortality rates, and other actuarial changes.**

* Assumptions relate to net periodic pension costs as opposed to the pension benefit obligation. Year-end liabilities are valued based on the end-of-year discount rate.

2016 vs. 2015 Earnings Drivers

Regulated Distribution	
Distribution Revenue	↑
O&M	↔
Depreciation	↓
Interest	↓
Effective Tax Rate	↔

Regulated Transmission	
Transmission Revenue	↑
Depreciation	↓
General Tax	↓
Interest	↓
Effective Tax Rate	↔

Competitive Energy Services	
Commodity Margin	↓
Sales Revenue	↓
Capacity Revenue	↓
Capacity Expense	↑
Purchased Power	↑
Fuel	↔
O&M	↑
General Taxes	↑
Depreciation	↓
Effective Tax Rate	↔

Financial – **Credit Metrics Calculations**

FFO Calculation

Net Income
- Adjustments for non-cash items:
  - Depreciation, amortization (incl. nuclear fuel, Pension/OPEB MTM adjustment and lease amortization), and deferral of regulatory assets
  - Deferred purchased power and other costs
  - Deferred income taxes and investment tax credits
  - Investment impairments
  - Retirement benefits
  - Loss on debt redemptions
  - Gain on Asset Sale
  - Other

= Funds from Operations (FFO)

FFO Interest Coverage

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

Adjusted Interest:
+ Interest Expense (before AFUDC)
+ Interest portion of leases
– Securitization bond interest expense

= Adjusted Interest

Debt / Capitalization Ratio

Rating Agency View	*Covenant View*
Debt: Long-term debt + Short-term borrowings + Operating lease debt equivalent* + Post-retirement benefit obligations** + Other debt – Securitization debt	Debt: Long-term debt + Short-term borrowings – Securitization debt + Guarantees of Indebtedness + Reimbursement Obligations
= Adjusted Debt	= Adjusted Debt
Capitalization: + Adjusted debt + Total equity	Capitalization: + Adjusted Debt + Total Equity – Accumulated OCI + Non-cash charges***
= Adjusted Capitalization	= Adjusted Capitalization

FFO-to-Debt Ratio

$$= \frac{\text{FFO}}{\text{Adjusted Debt}}$$

Adjusted debt:
+ Short-term borrowings
+ Long-term debt
+ Operating lease debt equivalent*
+ Post-retirement benefit obligations**
+ Other debt
– Securitization debt

= Adjusted Debt

* Net Present Value of future lease payments using discount rate of 7%
** After-tax unfunded Pension/OPEB obligation
*** Includes historical (2012-2014) and forward-looking non-cash charges

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