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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549
FORM 8-K

CURRENT REPORT

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

August 6, 2003
(Date of earliest
event reported)

Commission File Number	Name of Registrant; State of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	EXELON CORPORATION (a Pennsylvania corporation) 10 South Dearborn Street – 37th Floor P.O. Box 805379 Chicago, Illinois 60680-5379 (312) 394-7398	23-2990190
1-1839	COMMONWEALTH EDISON COMPANY (an Illinois corporation) 10 South Dearborn Street – 37th Floor P.O. Box 805379 Chicago, Illinois 60680-5379 (312) 394-4321	36-0938600
1-1401	PECO ENERGY COMPANY (a Pennsylvania corporation) P.O. Box 8699 2301 Market Street Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
333-85496	EXELON GENERATION COMPANY, LLC (a Pennsylvania limited liability company) 300 Exelon Way Kennett Square, Pennsylvania 19348 (610) 765-6900	23-3064219

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Item 5. Other Events

On August 6, 2003, Exelon Corporation (Exelon) issued a news release reaffirming 2003 guidance and announcing workforce reductions related to The Exelon Way. The news release is attached as Exhibit 99.1.

Item 9. Regulation FD Disclosure

On August 6, 2003, Exelon held an investor conference in New York City. The slides and handouts used in the presentation are attached as Exhibits 99.2 and 99.3.

Exhibit Index

Exhibit No.	Description
99.1	News Release
99.2	Slide Presentations
99.3	Various Handouts

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

Except for the historical information contained herein, certain of the matters discussed in this Report are forward-looking statements, within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by a registrant include those factors discussed herein, as well as the items discussed in (a) the Registrants' 2002 Annual Report on Form 10-K — ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Business Outlook and the Challenges in Managing Our Business for each of Exelon, ComEd, PECO and Generation, (b) the Registrants' 2002 Annual Report on Form 10-K — ITEM 8. Financial Statements and Supplementary Data: Exelon — Note 19, ComEd – Note 16, PECO – Note 18 and Generation – Note 13 and (c) other factors discussed in filings with the United States Securities and Exchange Commission (SEC) by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Report.

SIGNATURES

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

EXELON CORPORATION
COMMONWEALTH EDISON COMPANY
PECO ENERGY COMPANY
EXELON GENERATION COMPANY, LLC

/s/ Robert S. Shapard

Robert S. Shapard
Executive Vice President and
Chief Financial Officer
Exelon Corporation

August 6, 2003

Exhibit 99.1

News Release

From: Exelon Corporation
Corporate Communications
P.O. Box 805379
Chicago, IL 60680-5379

For Immediate Release

Contact: Linda Marsicano
312.394.3099

Exelon Corporation Reaffirms 2003 Guidance; Targets to Reduce Workforce 10 percent By 2006

CHICAGO (August 6, 2003) — Senior executives with Exelon Corporation met with investors and analysts today in New York City to update the financial community on progress of The Exelon Way, the company's program aimed to improve cash flow by $300 — $600 million in cash savings annually by focusing on operational excellence, simplifying procedures and standardizing processes.

Exelon reaffirmed its guidance for 2003 of earnings per share at the upper end of a range of $4.80 to $5.00 and provided guidance of between $5.15 and $5.45 per share for 2004.

As part of The Exelon Way, approximately 1,200 positions are targeted for elimination by 2004, and another 700 by 2006. Positions identified for elimination in 2003 will be complete by November. The majority of the reductions will come from professional and management employees. Overall, Exelon targets to reduce its workforce by about 1900 positions — or 10 percent — by 2006.

"Exelon is committed to treating its employees fairly and will facilitate voluntary separation agreements wherever possible, " says Chairman and CEO John Rowe. "To that end, we are providing an updated and improved severance package for all affected employees."

Eliminating redundancies in job functions is only one aspect of The Exelon Way. The program also focuses on streamlining operations, realigning our supply chain and information technology structure, and realizing opportunities for process improvements throughout the organization.

###

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Exelon — Note 19, ComEd — Note 16, PECO — Note 18 and Generation — Note 13 and (c) other factors discussed in filings with the United States Securities and Exchange Commission (SEC) by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this release. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this release.

###

Exelon Corporation is one of the nation's largest electric utilities with approximately 5 million customers and more than $15 billion in annual revenues. The company has one of the industry's largest portfolios of electricity generation capacity, with a nationwide reach and strong positions in the Midwest and Mid-Atlantic. Exelon distributes electricity to approximately 5 million customers in Illinois and Pennsylvania and gas to more than 440,000 customers in the Philadelphia area. The company also has holdings in such competitive businesses as energy, infrastructure services, energy services and telecommunications. Exelon is headquartered in Chicago and trades on the NYSE under the ticker EXC.

Exhibit 99.2

Exelon Investor Conference
August 6, 2003
The Waldorf=Astoria
New York City

Building Value – The Exelon Way
Agenda

7:30 a.m.–8:00 a.m	Registration and Continental Breakfast (Astor Salon, 3rd Floor)
Conference Program	(Jade Room, 3rd Floor)
8:00 a.m.–8:30 a.m	John W. Rowe – Introduction and Strategic Overview
8:30 a.m.–9:00 a.m	Oliver D. Kingsley, Jr. – Operating Overview
9:00 a.m.–9:15 a.m	Michael B. Bemis – Energy Delivery Regulatory Overview
9:15 a.m.–9:30 a.m	John W. Rowe – Evolving Regulatory Framework
9:30 a.m.–10:00 a.m	Break (Astor Salon)
10:00 a.m.–10:20 a.m	John F. Young – Generation Strategy
10:20 a.m.–10:40 a.m	Ian P. McLean – Portfolio Optimization and Risk Management
10:40 a.m.–11:10 a.m	Robert S. Shapard – Financial Overview
11:10 a.m.–12:00 p.m	John W. Rowe – Wrap-up/Q&A

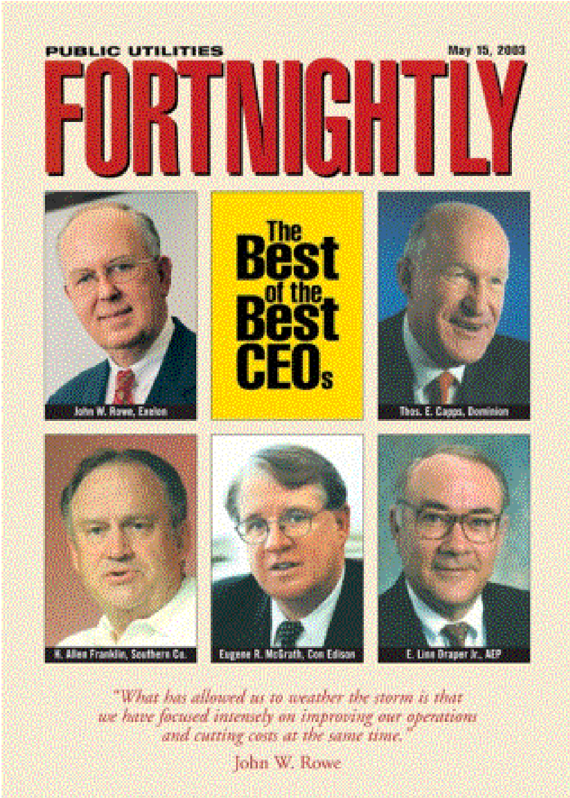
Exelon Corporation
Building Value – The Exelon Way

John W. Rowe
Chairman & Chief Executive Officer

Exelon Investor Conference
New York City
August 6, 2003

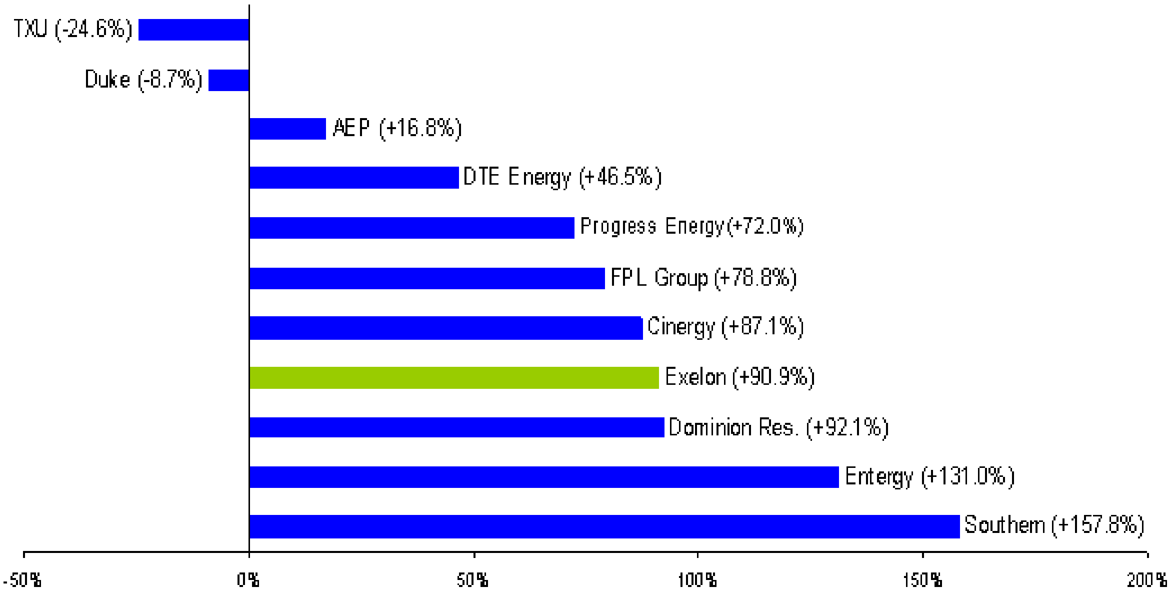
Forward-Looking Statements

This presentation contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by a registrant include those discussed herein as well as those discussed in Exelon Corporation's 2002 Annual Report on Form 10-K in (a) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Business Outlook and the Challenges in Managing Our Business for Exelon, ComEd, PECO and Generation and (b) ITEM 8. Financial Statements and Supplementary Data: Exelon—Note 19, ComEd—Note 16, PECO—Note 18 and Generation—Note 13, and (c) other factors discussed in filings with the Securities and Exchange Commission (SEC) by Exelon Corporation, Commonwealth Edison Company, PECO Energy Company and Exelon Generation Company, LLC (Registrants). Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this presentation. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this presentation.


PUBLIC UTILITIES
May 15, 2003
FORTNIGHTLY
The Best of the Best CEOs
John W. Rowe, Exelon
Thos. E. Capps, Dominion
H. Allen Franklin, Southern Co.
Eugene R. McGrath, Con Edison
E. Linn Draper Jr., AEP
"What has allowed us to weather the storm is that we have focused intensely on improving our operations and cutting costs at the same time."
John W. Rowe

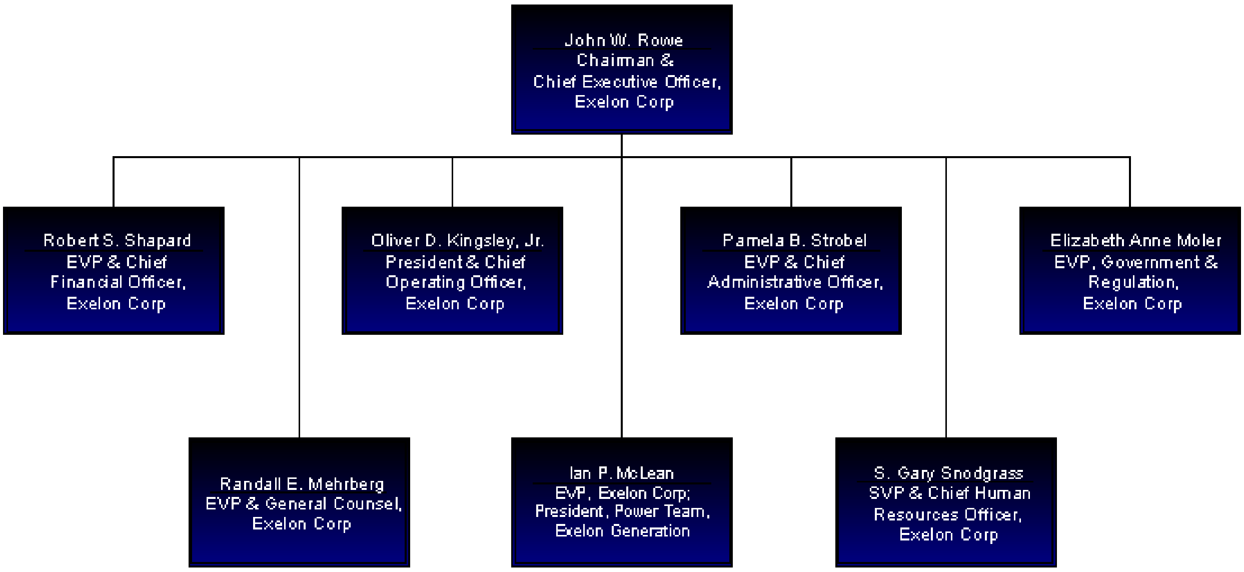
Total Return Comparisons

1/1/00 – 6/30/03



Source: Bloomberg

The Exelon Way Team



Exelon One Company, One Vision

Exelon strives to build exceptional value — by becoming the best and most consistently profitable electricity and gas company in the United States.

To succeed, we must...

Live up to our commitments

- Keep the lights on.
- Perform safely — especially in nuclear operations.
- Constantly improve our environmental performance.
- Act honorably and treat everyone with respect, decency and integrity.
- Continue building a high performance culture that reflects the diversity of our communities.
- Report our results, opportunities and problems honestly and reliably.

Perform at world-class levels

- Relentlessly pursue top quartile performance levels in productivity, quality, safety and customer satisfaction.
- Adopt a common business model, core operating processes and best practices across the enterprise.
- Ensure effective integration across businesses and optimize the whole.
- Promote and implement policies that build effective markets.
- Adapt rapidly to changing markets, politics, economics, and technology to meet our customers' needs.

Build value through disciplined financial management

- Maximize the earnings and cash flow from our assets and businesses and sell those that do not meet our goals.
- Prioritize acquisition opportunities based upon synergies and value creation potential, balance sheet integrity, and consistency with our model for serving customers and meeting regulatory obligations.
- Return cash generated by the company to investors when higher returns are not available from other investment opportunities.

Building on Success

- Low-cost generation portfolio
- Large, stable retail customer base
- No material trading or international exposure
- Strong balance sheet
- Positioned to deliver 5% annual earnings growth
- Experienced management to take Exelon to the next level of excellence – The Exelon Way

Today's Agenda

Building Value – The Exelon Way

8:00 a.m.–8:30 a.m.	John W. Rowe – Introduction and Strategic Overview
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Operating Overview

Oliver D. Kingsley, Jr.
President & Chief Operating Officer

Exelon Investor Conference
New York City
August 6, 2003

Generation Portfolio

Total: 40,764 MW (1)
28,003 MW Operating
12,761 MW Contracted

MAIN:
20,164 MW Total
11,028 MW Operating
9,136 MW Contracted

NPCC:
4,066 MW Operating

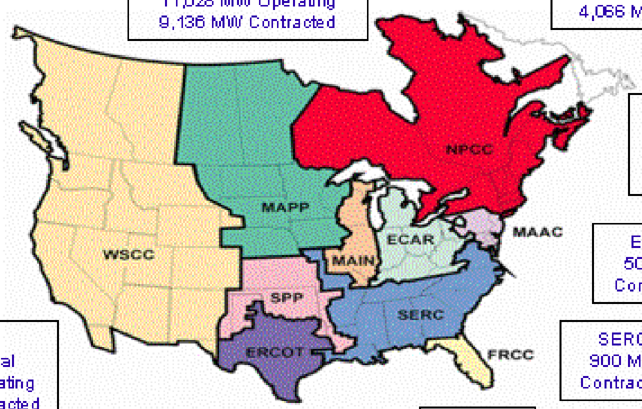
MAAC:
10,665 MW Total
10,415 MW Operating
250 MW Contracted

ECAR:
500 MW
Contracted

SERC:
900 MW
Contracted

SPP:
795 MW
Contracted

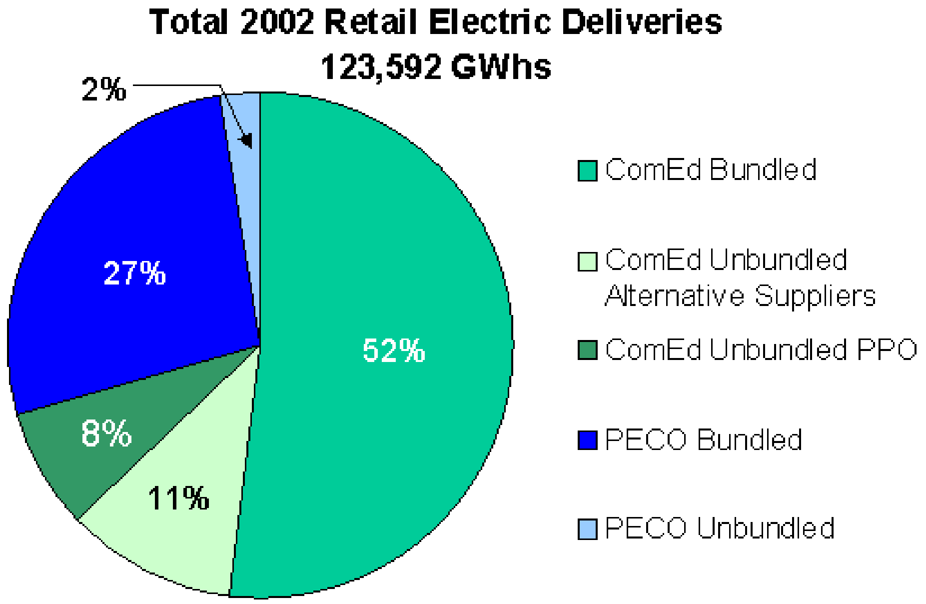
ERCOT:
3,674 MW Total
2,494 MW Operating
1,180 MW Contracted



(1) Based on Exelon Generation's ownership and long-term contracts at 7/31/03, including AmerGen Energy Company, LLC; excludes investment in Sithe Energies, Inc.

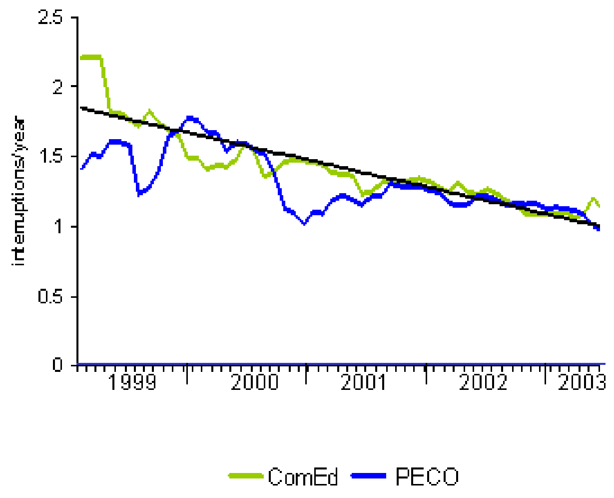
Largest U.S. Electric Customer Base

Total electric customers – 5.1 million

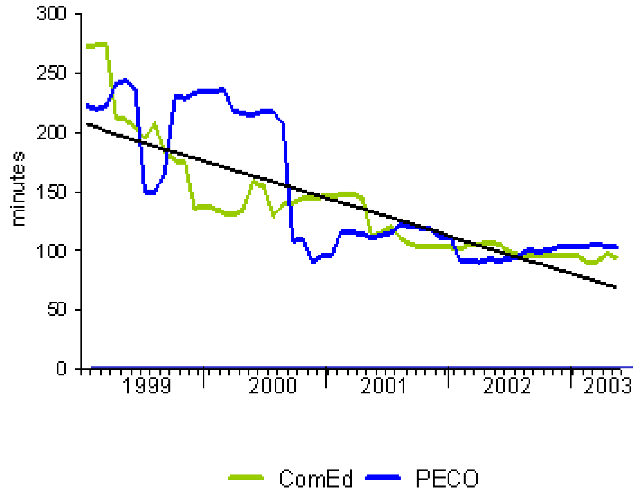


Improved Energy Delivery Operations

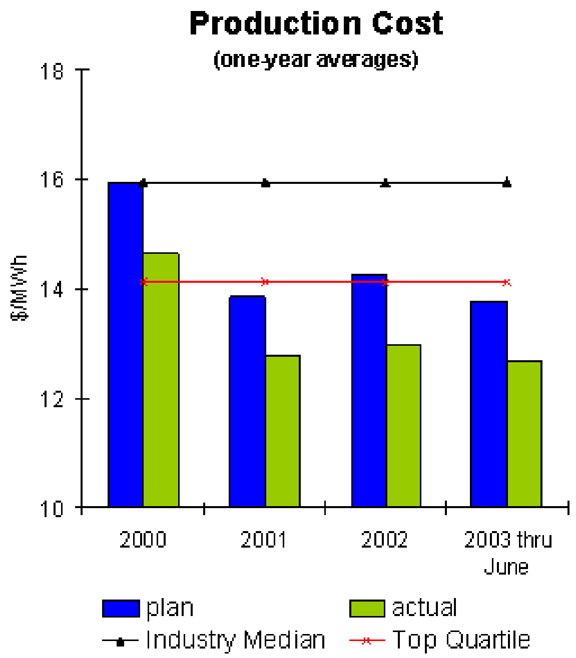
Fewer Interruptions

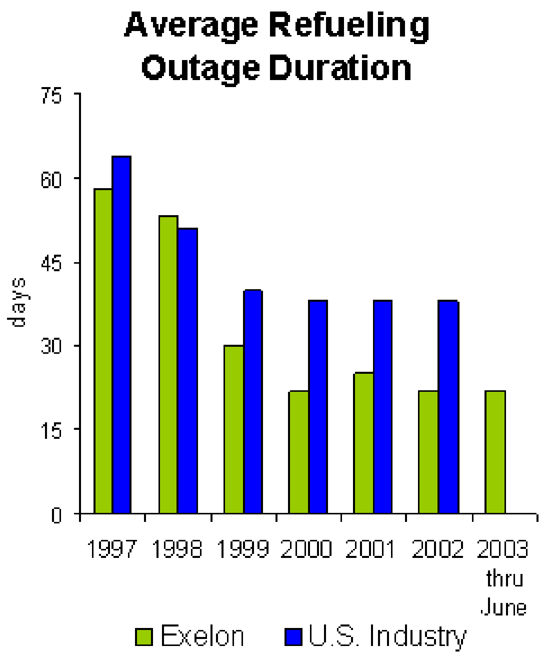


Shorter Interruptions

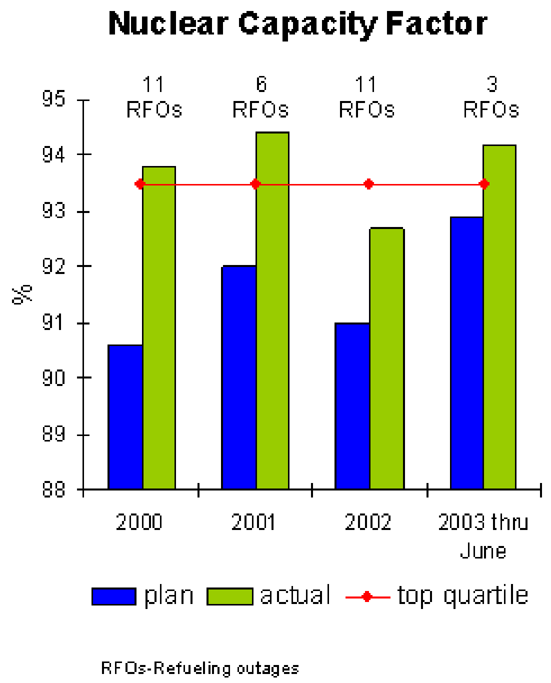


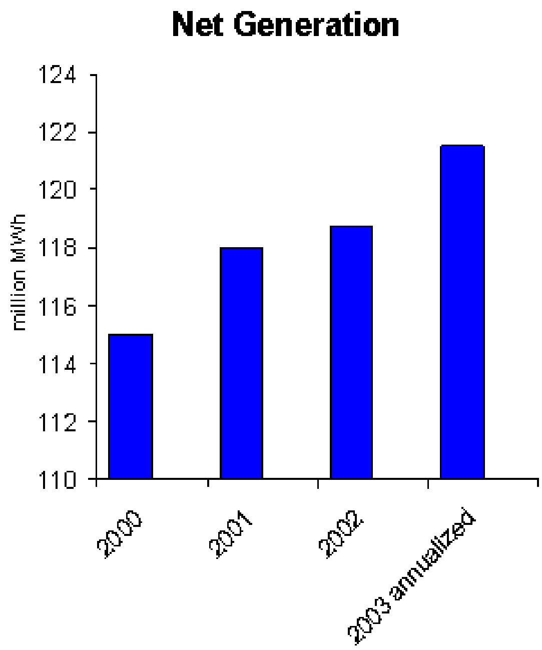
World-Class Nuclear Operations



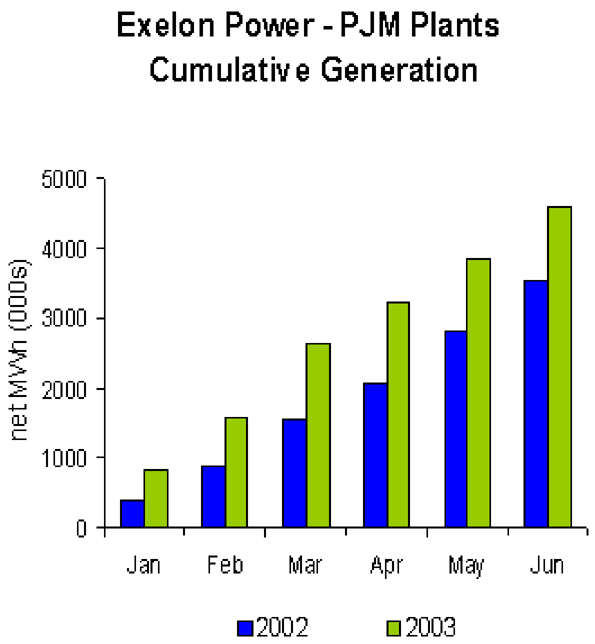


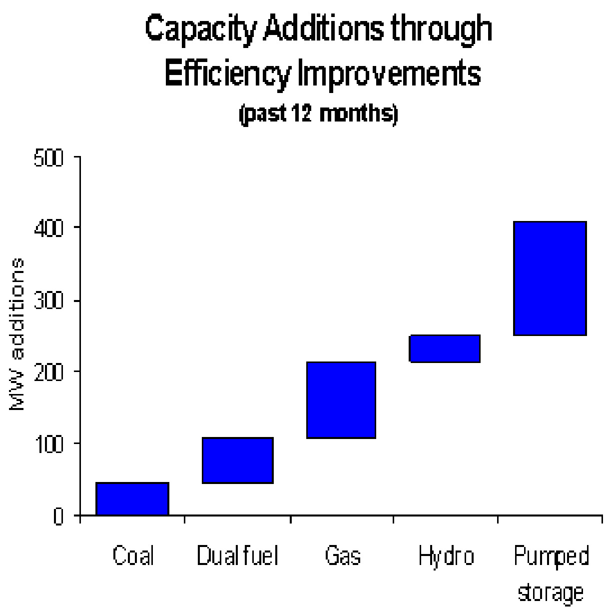
Focus on Operational Excellence



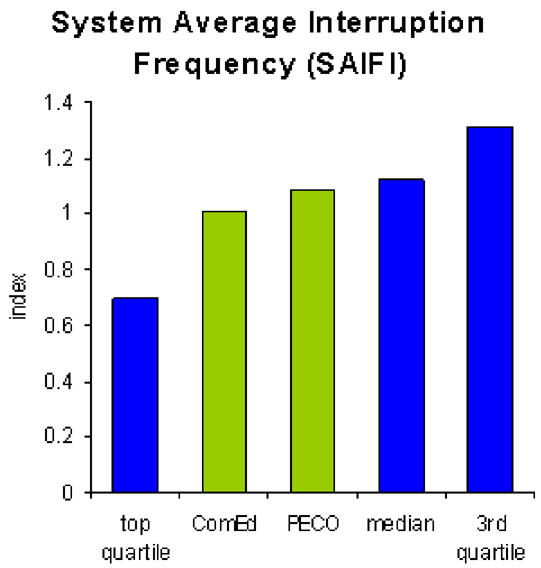


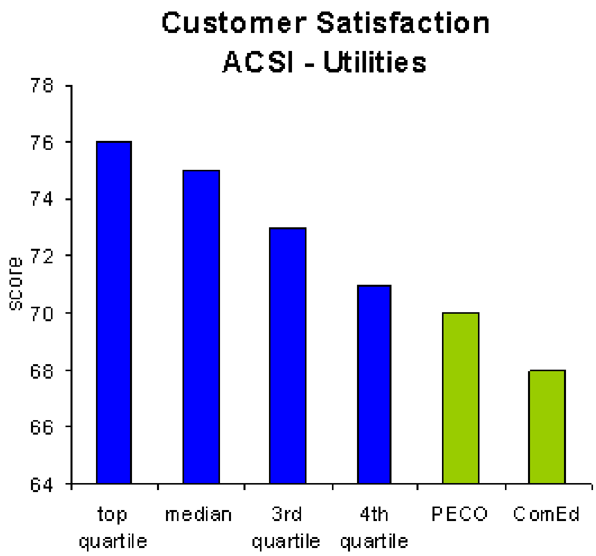
Improvement in Exelon Power





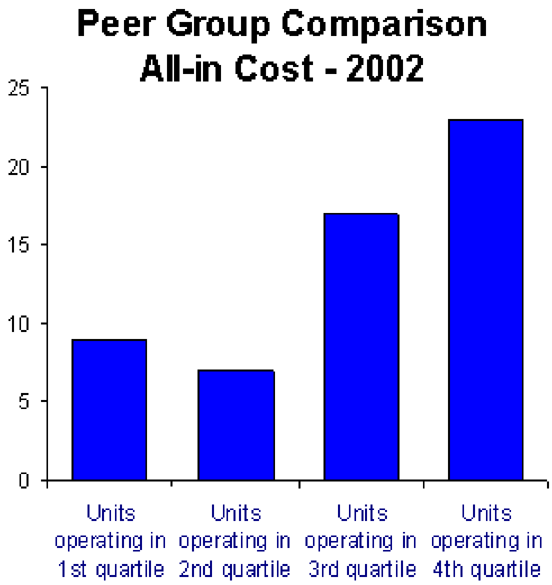
Opportunity for Additional Improvement – Energy Delivery





SAIFI – 2001 industry actuals; 2002 Exelon actuals
American Customer Satisfaction Index (ACSI) – 2002 actuals

Opportunity for Improvement – Exelon Power

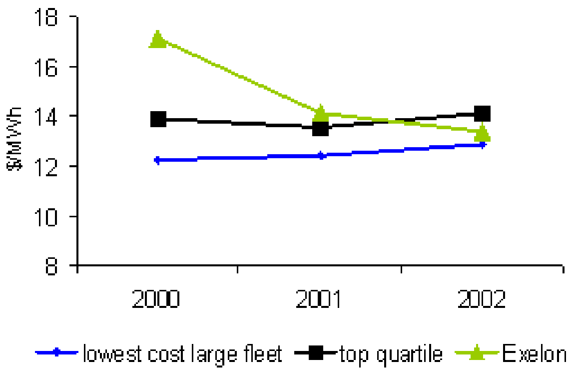


Data: GKS (Generation Knowledge System) benchmarking community

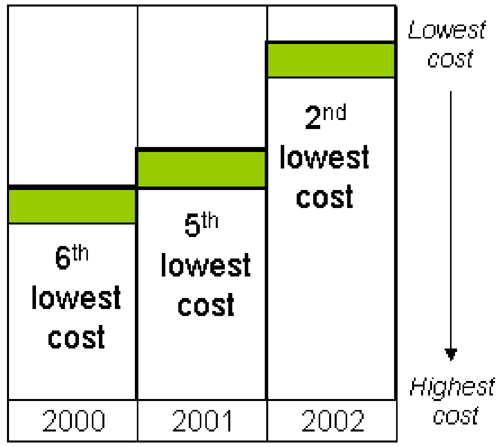
- Exelon Power units are not consistently top quartile in their peer groups
- Actions:
  - Fleet-wide material condition assessment completed
  - Human performance initiatives
  - Standard programs, processes
  - Asset-by-asset portfolio review underway

Opportunity for Improvement – Exelon Nuclear

Nuclear Production Cost
(2-year average, U.S. plants)



Of the 11 large nuclear fleet operators, Exelon Nuclear was:



- Exelon Nuclear is closing the production cost gap to top performance compared with other major operators
- Continued focus on refueling outage execution, forced loss rate, operational excellence

Data: Electric Utility Cost Group

The Exelon Way

Goals

- Achieve top-quartile operating and financial performance excellence as measured by industry metrics
- Deliver at least $300 million in annual cash flow improvement from O&M and Cap Ex by 2004
  - Grow to more than $600 million in annual cash flow improvement by 2006

Strategy

- Reshape the Exelon business model to maximize consolidation and integration synergies
- Create a high-performance organization and culture of excellence
- Standardize, simplify and strengthen underlying business management processes
- Put the management in place to make it happen
- Aggressively pursue significant and sustainable cash flow improvement

The New Play Book

- Standard best programs and processes
  - Reduce resource requirements, duplication; capture synergies
- Effective process management
  - Enable sustained and replicable good performance
- Rigorous performance management
  - Focus on productivity improvement
- Operational improvement and organizational alignment is driving sustainable cost reduction

It's working in Nuclear.
It's producing results in Power.
It's being defined & implemented in Energy Delivery.
The Exelon Way is driving it company-wide.

Genco Operations and Alignment – What's Different?

- Nuclear – Continued focus on top performance
- Power – Optimization and execution
- Power/Power Team market alignment
  - Regional asset rationalization
- Sales and Marketing
  - Enhanced marketing focus and leadership in all regions

EED Operations and Alignment – What's Different?

- EED will complete the merger
  - $500 million uncaptured savings potential in O&M and capital
- EED is developing and implementing the model
  - Consolidated organization structure with clear accountabilities
  - Focus on the basics: events, errors, fundamental standards
- Leadership team and 18 process teams are driving business/organization integration

Corporate Support and Alignment – What's Different?

Supply Chain:

- > $2 billion total non-fuel spend in 2002
  - ~ 750 full-time employees
  - ~ $80 million operating costs
- Integrated supply chain organization will deliver increased value
  - Eliminate redundancy
  - Strategic sourcing and category management
  - Inventory management
  - Vehicle fleet management
  - e-Business payment channel
  - Headcount reductions
- Sustainable savings opportunities 2004–2006: $120-180 million

Corporate Support and Alignment – What's Different?

Information Technology:

- ~ $500 million Exelon IT spend in 2002
  - ~ 1,200 Exelon and contractor resources
- New structure consolidates IT, eliminates redundancies
  - Re-prioritize, manage IT project spend
  - Consolidate and reduce headcount
  - Standardize infrastructure and processes
  - Leverage the right outsourcing opportunities
  - Strengthen governance
  - Manage demand
- Sustainable savings opportunities 2004–2006: $50-70 million

Exelon Energy Delivery
Regulatory Overview

Michael B. Bemis
President, Exelon Energy Delivery

Exelon Investor Conference
New York City
August 6, 2003

Current Regulatory Structure

ComEd

- The Illinois Electric Service Customer Choice and Rate Relief Law of 1997
- Transition period through 2006
- Last pre-restructuring rate case – 1994 test year

PECO Energy

- Electricity Generation Customer Choice and Competition Act – 1996
- Restructuring Settlement Agreement – 1998
- Transition period through 2010
- Last pre-restructuring electric rate case – 3/90 test year
- Last gas rate case – 1988

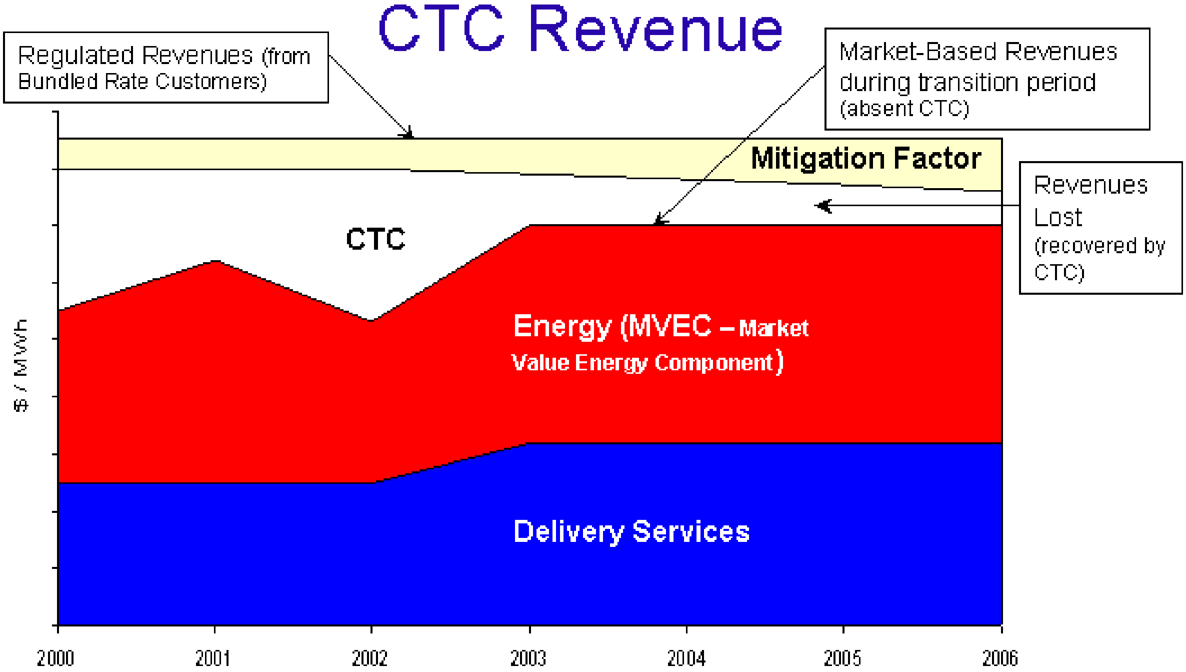
PECO Transition Structure

- Generation rate cap expires January 1, 2011
- Distribution rate cap expires January 1, 2007
- $5.26 billion of stranded investment collected on 12-year amortization schedule with 10.75% return
- Annual reconciliation of Competitive Transition Charge (CTC)
- Stranded investment is not recomputed
- Returns (net income) decrease over time: $137 million in 2003 to $3 million in 2010

ComEd Transition Structure

- Established a "transition period" through 2006
- Provided an *opportunity* to recover stranded costs, but did not predetermine the amount
- Recovery mechanisms included:
  - Bundled Rate freeze though 2004 (later extended to 2006)
  - Collection of CTCs from shopping customers using "revenues lost" approach
  - Flexibility to restructure and transfer assets
  - Ability to issue transition bonds securitized by the total regulated revenue stream
- Established ROE cap with earnings-sharing mechanism

"Revenues Lost" Approach Determines CTC Revenue



Note: Regulated Revenues represent the average residential revenue/MWh for 2003, which was used for all periods. Other data represents actual averages for historical periods and hypothetical averages for future periods, based on assumption that current factors will not change. Hypothetical data are used for illustrative purposes only and they do not represent Exelon's projections for future rates.

2003 ComEd Regulatory Settlement

Addressed major issues awaiting regulatory action:

- Constructively concluded ComEd Residential Delivery Services rate case
- Modified calculation of CTC revenue for shopping customers
- Facilitated extension of full-requirements PPA between ComEd and Generation through 2006
- Facilitated continued collection of decommissioning charge revenue through 2006
- Supported Provider of Last Resort (POLR) provisions
- Provided funding for energy-related programs in Illinois

Evolving Regulatory Framework

John W. Rowe
Chairman & Chief Executive Officer

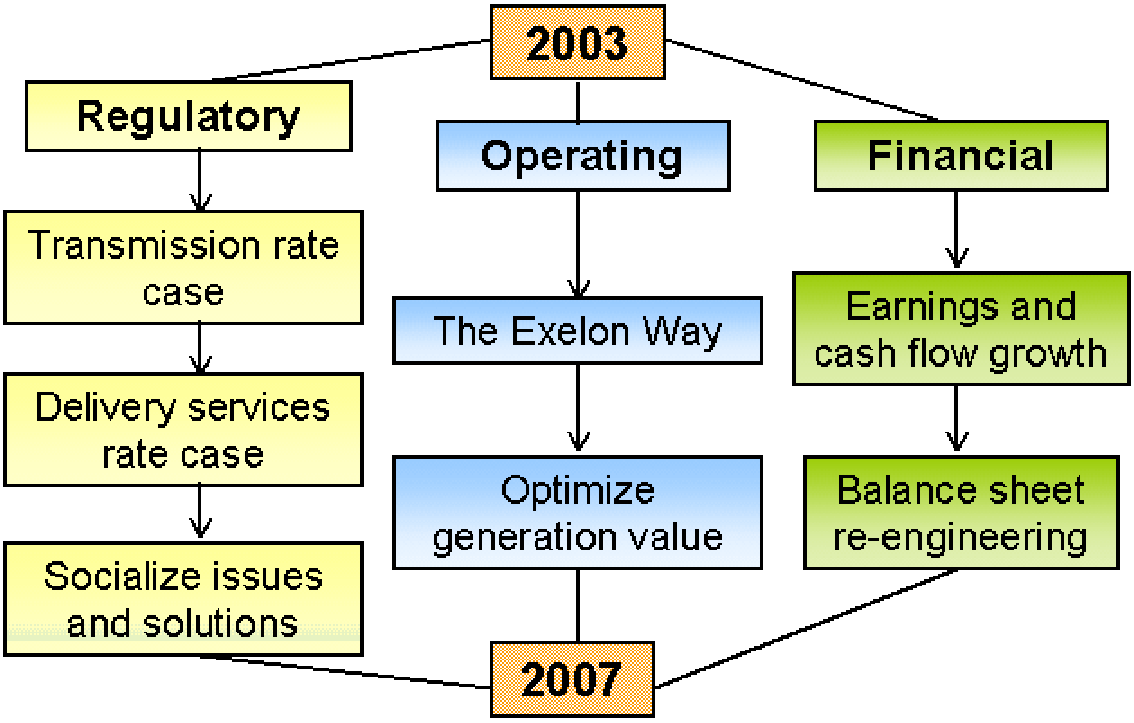
Exelon Investor Conference
New York City
August 6, 2003

Exelon

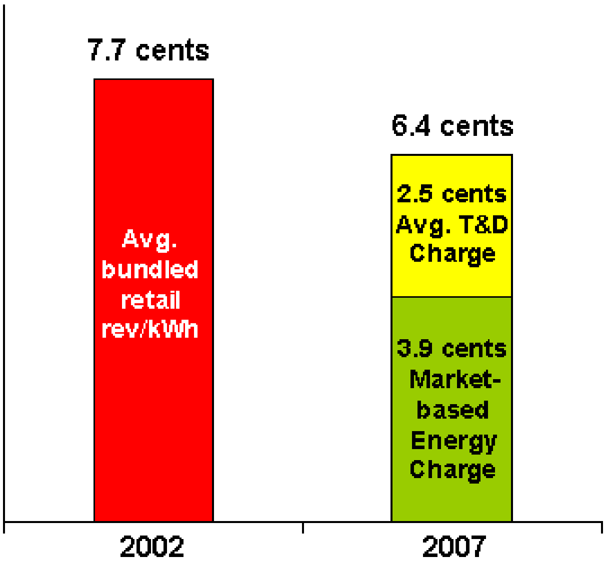
Electric Industry Ratemaking Evolution

Traditional	Transition	Post Transition
All electric services bundled	Separation of regulated and competitive businesses	Regulated T&D rates
Rates based on assets owned	Hybrid of traditional ratemaking and market pricing	Market-based commodity pricing
AFUDC	Stranded investment recovery	Rates based on services provided
Used and useful	CTC	Retail risk management adder
Prudency review	MVEC	Energy procurement charge
	Shopping credit	Customer switching premium
	Mitigation factor	A new bundled rate agreement

Post-Transition Strategy



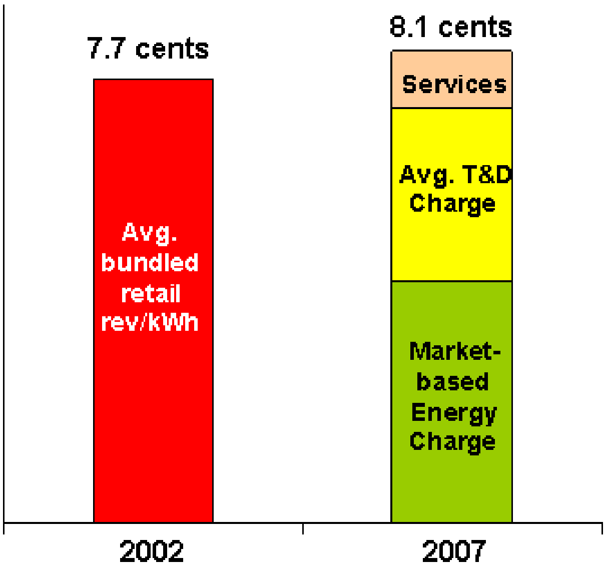
The “Status Quo” Scenario



- Lack of full recovery on T&D service
- No long-term risk management services
- High risk for customers (no rate certainty)

Note: Numbers represent actual average data for historical periods and hypothetical data for future periods, based on assumption that current factors will not change. Hypothetical numbers are used for illustrative purposes only and they do not represent Exelon's projections for future rates.

The "Full-Value Recognition" Scenario



- Average bundled rate below inflation-adjusted 1996 level
- Full recovery of T&D costs
- Market-based energy price
- Compensation for risk management services

Note: Numbers represent actual average data for historical periods and hypothetical data for future periods. Hypothetical numbers are used for illustrative purposes only and they do not represent Exelon's projections for future rates.

Building Value – The Exelon Way

Generation Strategy

John F. Young
President, Exelon Power

Exelon Investor Conference
New York City
August 6, 2003

Exelon Generation: An Overview

Exelon Generation

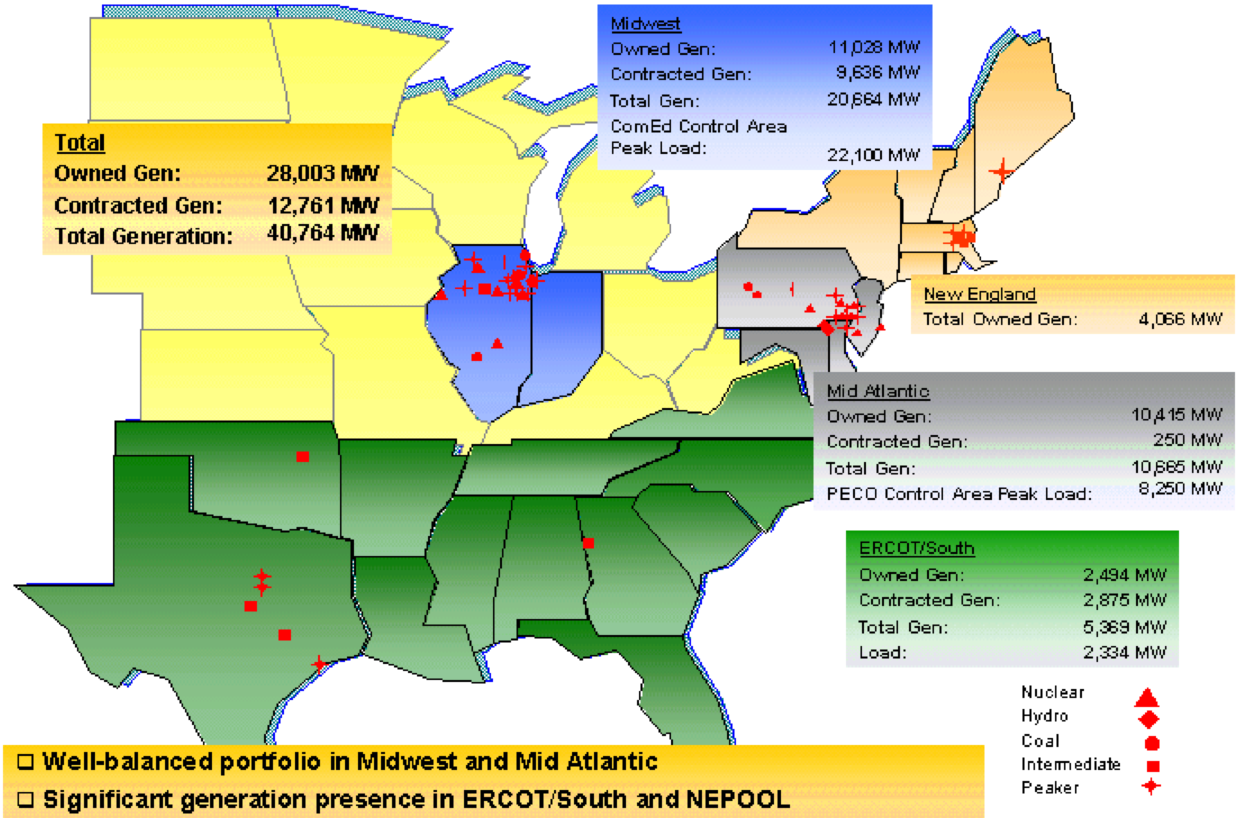
Competitive energy business of Exelon

Exelon Nuclear	Exelon Power	Power Team
President: John L. Skolds	President: John F. Young	President: Ian P. McLean
Operates and maintains Exelon's nuclear assets	Operates and maintains Exelon's fossil and hydro units	Manages Exelon Generation's portfolio risk and optimizes near-term margins
Nuclear Capacity: 15,788 MW	Fossil Capacity: 10,631 MW Hydro Capacity: 1,584 MW	Contracts under management: 12,761 MW

Exelon Generation:

- A world-class operator of nuclear power generation
- A broad based portfolio of gas, oil, coal, wind and hydro generation
- A experienced leader in wholesale power marketing and risk management

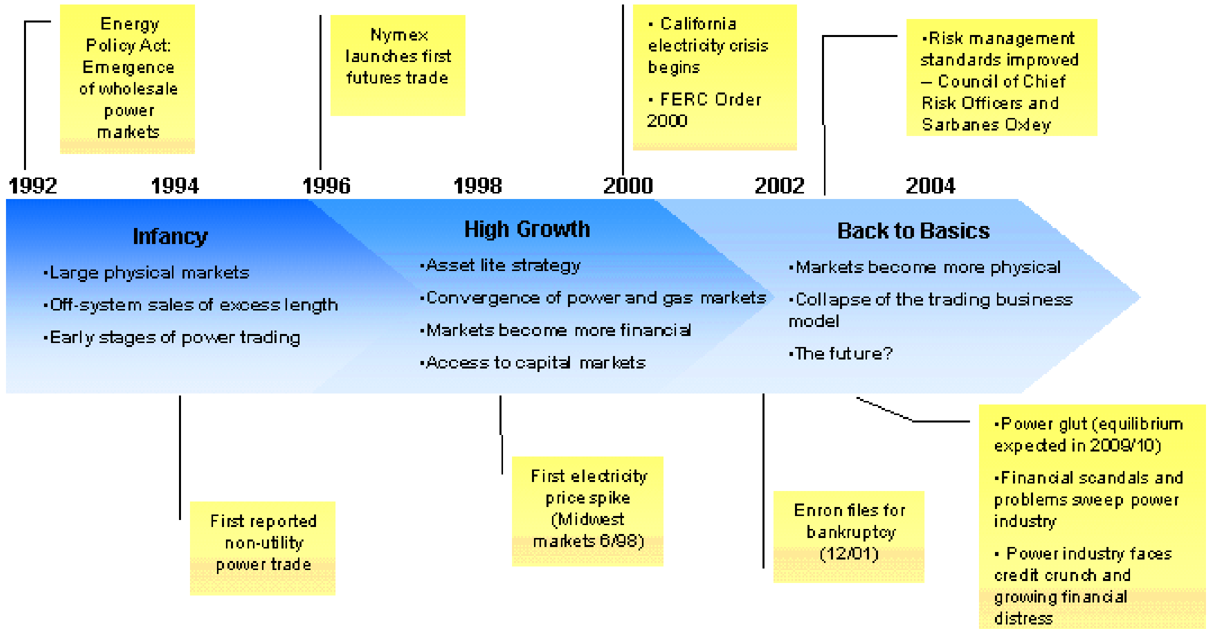
Regional Summary



- ❑ **Well-balanced portfolio in Midwest and Mid Atlantic**
- ❑ **Significant generation presence in ERCOT/South and NEPOOL**

Owned generation includes Exelon's share of AmerGen and excludes Sithe assets.

Evolving Power Markets



Exelon Generation – Consistent over Time:

- ❑ Balancing power generation with load and wholesale trading
- ❑ Asset-led physical strategy and added balance through financial markets
- ❑ Financial results - What you see is what you get

Exelon Generation's Strategy

Exelon's Vision

To become the best and the most consistently profitable electric and gas company in the United States

Business Strategy

Exelon Generation's Strategy

- Create value through proven world class operational excellence and superior market based commercial experience

Goals and Objectives

Goals and Objectives

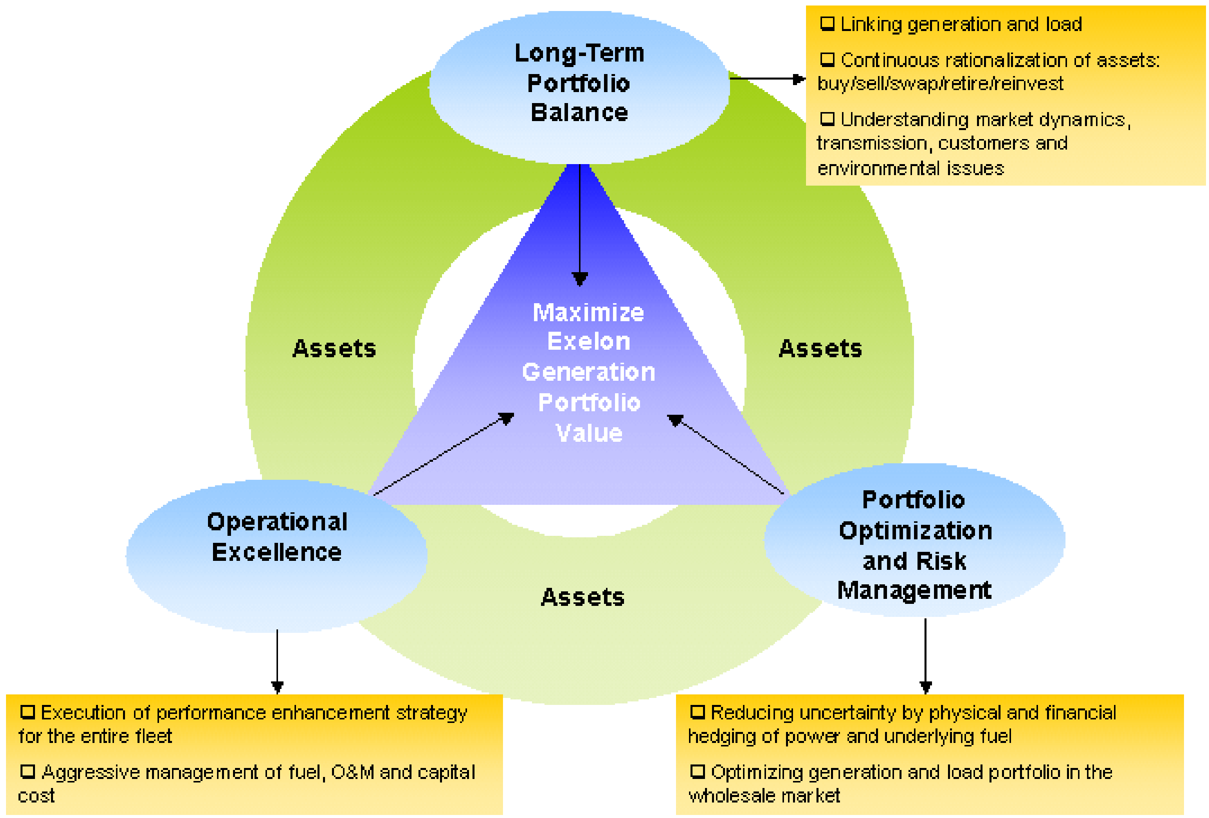
- Generate electricity reliably and at a lower cost than our competitors
- Achieve top quartile operating performance on a sustained basis
- Optimize investment in assets consistent with market environment
- Leverage our commercial expertise to optimize our portfolio and mitigate risk

Key Skills

Key Skills

- World class nuclear operations
- Demonstrated ability to extract value from fossil and hydro assets
- Financial valuation skills across commodities and products
- Knowledge of both power and fuels markets

Generation: Value Creation

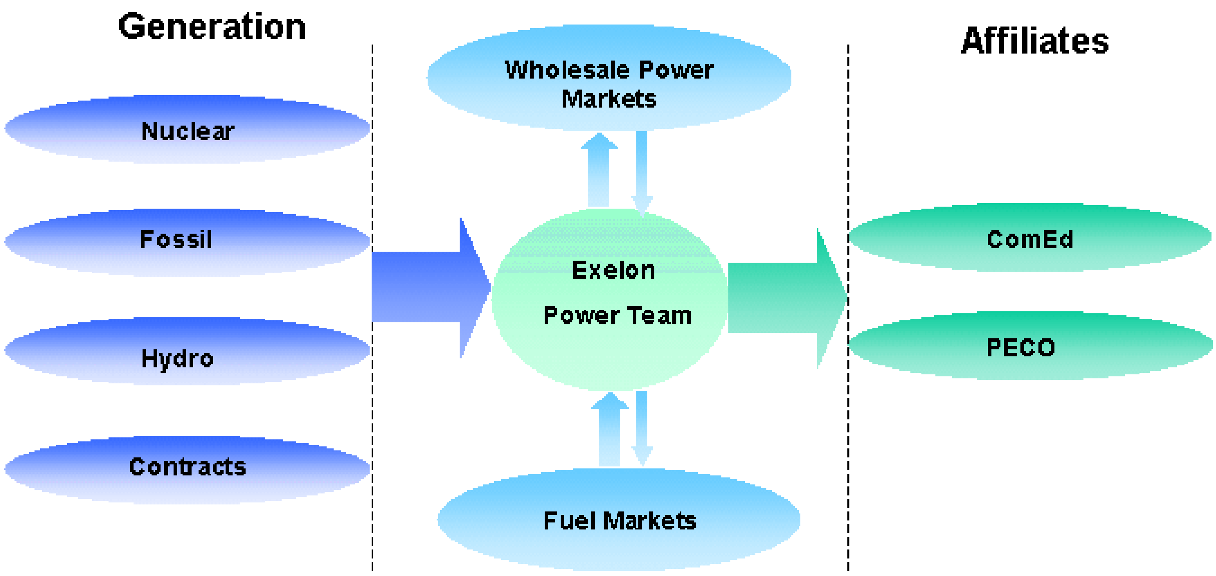


Portfolio Optimization and Risk Management

Ian P. McLean
President, Power Team

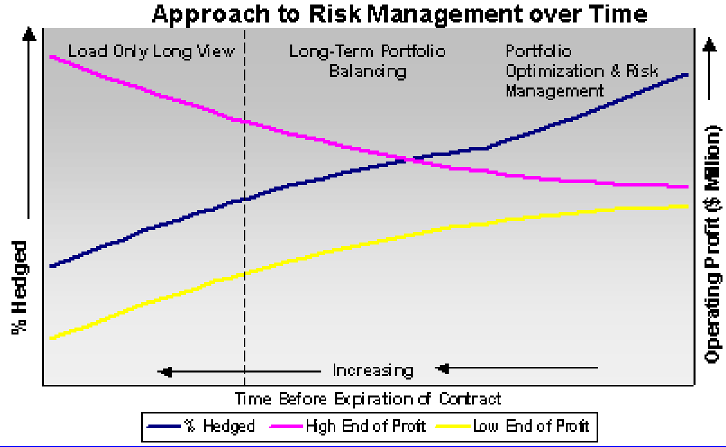
Exelon Investor Conference
New York City
August 6, 2003

Value Added Intermediary



Power Team manages the interaction between the generation portfolio and the wholesale customers in order to reduce risk and optimize Exelon Generation profitability in the near term.

Risk Management Framework Exelon



There are three distinct time horizons from which to view risk management.

Approach To Managing Volatility And Optimizing Value

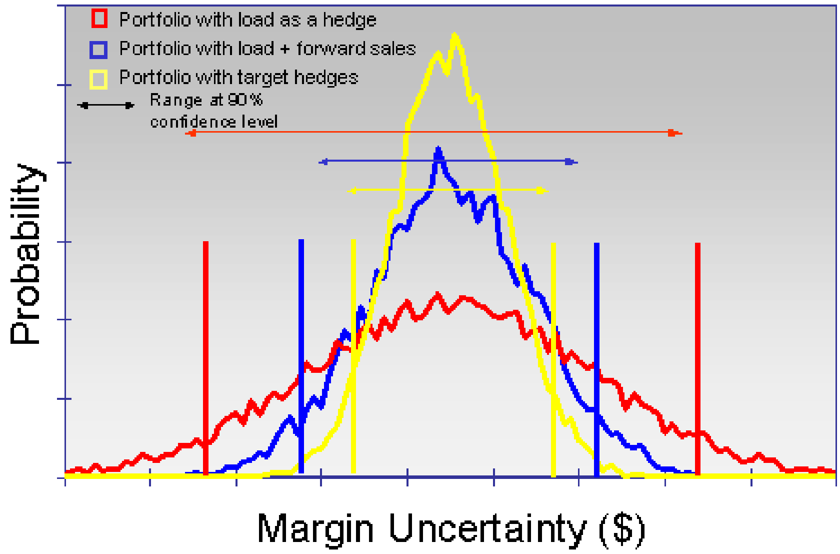
In 2003:

- ❑ Established hedge ratio goal of 80% or more
- ❑ Grew hedge position to 90+% on average for year

For 2004:

- ❑ Establish portfolio and regional hedge book limits based on earnings-at-risk proxy and considering:
  - ❑ Market liquidity and depth
  - ❑ Internal hedges
  - ❑ Risk appetite
  - ❑ Load uncertainty
- ❑ Sell forward or utilize options to stay within limits
- ❑ Optimize positions to provide flexibility and maximize earnings while staying within limits (leave some energy to spot)
- ❑ Increase hedge ratio in short run
- ❑ Do not over hedge in any region
- ❑ Purchase underlying fuel for any forward sales

Risk Management



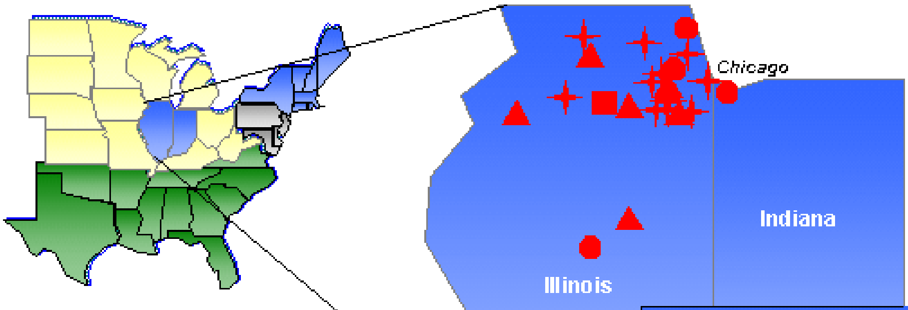
Portfolio Characteristics

- Generally long – to address full requirements PPAs
- Internal load provides 50% fixed price hedge
- Internal ComEd CTC hedge and Texas PPAs provide additional protection

Risk Issues

- Reliability – Meeting load obligations in ComEd, PECO
- Financial (All Regions) –
  - Power Prices & Volatility
  - Fuel Prices & Volatility
  - Load & Volatility
  - Credit Issues

Midwest Portfolio



Plant	2003 Capacity (MW)	Avg. Variable Cost ($/MWh)
Nuclear	10,678	$4.50
Coal	5,134**	$16.00
Intermediate	1,084	$33.00
Peakers*	3,768	$60.00
Total Capacity	20,664	$21.50
Demand		
Annual GWh (2004)	74,500	
Peak Load (MW)	18,350	

* Assuming $5/MMBtu gas price

** Excludes recent decision to terminate 578 MW of coal options

Market Dynamics

The Midwest portfolio is in MAIN and ECAR.

- Predominantly a bilateral market
- Significant transmission constraints
- ComEd integration into PJM (est. 11/03) expected to increase volume of transactions
- MAIN: 25% reserve margin, 57,000-MW peak demand, coal = 33% of total capacity
- ECAR: 30% reserve margin, 100,000-MW peak demand, coal = 50% of total capacity
- Supply/demand equilibrium not expected until 2009/2010

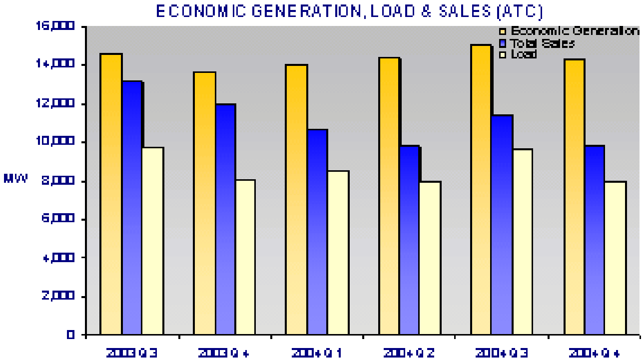
Midwest: Key Elements

Exelon

Commodity	Impact	Comments
Natural Gas		• Substantial base-load capacity → Long gas position • Gas increasingly on the margin
Oil		• Oil not significantly on the margin in the region
Gas Spark		• Relatively insignificant spark capacity as compared to base-load length
Oil Spark		• Minimal oil capacity in the portfolio

Significant Insignificant

ECONOMIC GENERATION, LOAD & SALES (ATC)



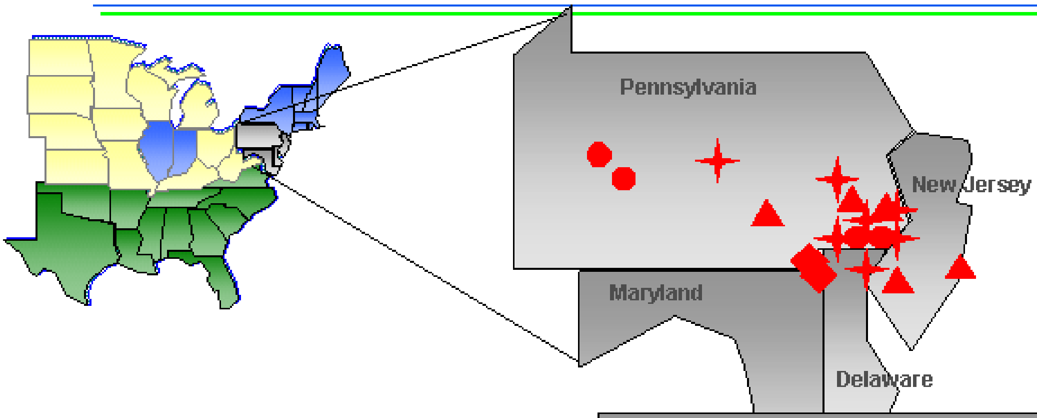
Risk Management 2003
Portfolio around 90% sold forward for 2003 and the underlying fuel purchased
Put in place option strategies to mitigate weather and power/gas price risks
Given significant base-load capacity, region still exposed to power price movements

Risk Management 2004
Portfolio around 75% sold forward for 2004 and the underlying fuel purchased – limited ability to sell forward in financial markets
Mitigated off-peak length by releasing 578 MW of high-priced Midwest Generation coal contracts
Acquire intermediate products to complement existing asset portfolio
Actively balancing generation and load through bilateral markets

2003: +/- $1/MWh ATC power	**$ 10 M**
2004: +/- $1/MWh ATC power	**$ 28 M**

ATC – Around the clock

Mid-Atlantic Portfolio



Market Dynamics
All the Mid-Atlantic portfolio assets are in the PJM region.
▪ Centrally dispatched power pool
▪ 23% reserve margin, 63,800-MW peak demand (PJM and PJM West)
▪ Coal = 28% of total capacity
▪ Combined-cycle gas turbines (CCGTs) are on the margin a majority of on-peak hours and many summer off-peak hours
▪ Supply/demand equilibrium not expected until 2009/2010

Plant	2003 Capacity (MW)	Avg. Variable Cost ($/MWh)
▲ Nuclear	5,110	$5.00
◆ Hydro	1,584	NA
● Coal	1,434	$20.00
■ Intermediate & Wind	250	$40.00
✦ Peakers*	2,287	$80.00
Total Capacity	10,665	
Demand		
Annual GWh (2004)	34,000	
PPA Peak Load (MW)	6,858	

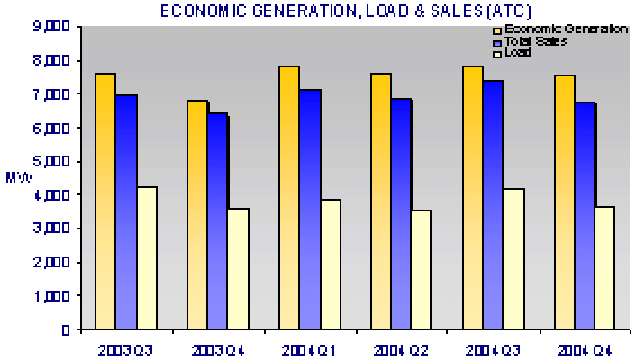
* Assuming $5/MMBtu gas price

Mid-Atlantic: Key Elements

Commodity	Impact	Comments
Natural Gas		• Substantial base-load capacity and oil-fired generation → Long gas position • Gas increasingly on the margin
Oil		• Oil on the margin a significant proportion of the time
Gas Spark		• Relatively insignificant spark capacity as compared to base-load length
Oil Spark		• Significant oil-based capacity in the portfolio

Significant Insignificant

ECONOMIC GENERATION, LOAD & SALES (ATC)

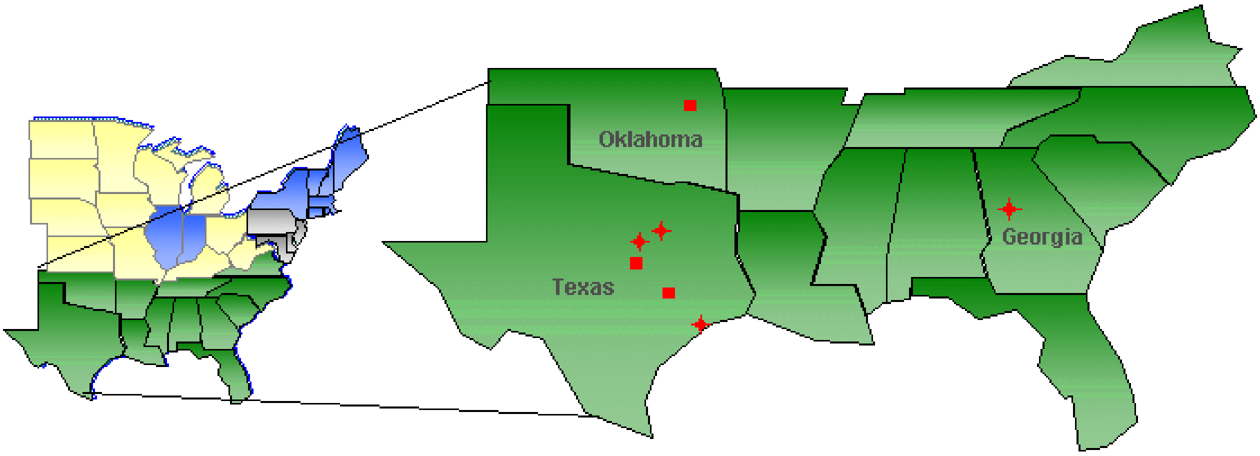


Risk Management 2003
Over 95% power sold forward and underlying fuel purchased
Higher than expected native load required buyback of forward sales
Upside and downside protection through options
Risk Management 2004
Portfolio in 2004 fairly well hedged
Acquire intermediate products to complement existing asset portfolio
Further hedging limited to upside and downside protection through option strategies

2003: +/- $1/MWh ATC power	**$ 2 M**
2004: +/- $1/MWh ATC power	**$ 6 M**

ERCOT/South Portfolio

Exelon



Market Dynamics

The portfolio assets are in the ERCOT, SPP and Southern Company (SoCo) regions.

- ERCOT: Centrally dispatched power pool, 56% reserve margin, 57,629-MW peak, gas on the margin during peak hours, supply/demand equilibrium expected 2014
- SPP & SoCo: Bilateral markets only, 43,000-MW peak (SPP), 48,000-MW peak (SoCo), reserve margins 21% (SPP), 28% (SoCo); gas on the margin during peak months, supply/demand equilibrium expected 2009/2010

Plant	Capacity	Avg. Variable Cost ($/MWh)
Combined Cycle*	1,975 MW	$40.00
Peakers*	3,394 MW	$60.00
Total Capacity	5,369 MW	
Load**	2,334 MW	

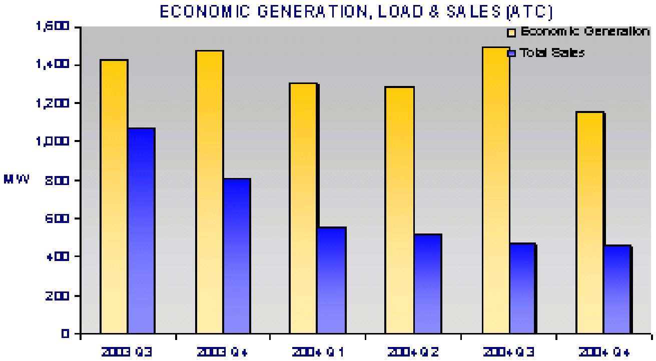
* Assuming $5/MMBtu gas price

** TXU tolling deal totaling 2,334 MW

ERCOT/South: Key Elements

Commodity	Impact	Comments
Natural Gas		• Gas on the margin a significant proportion of the time (over 80% of the hours); however, spark determines regional profit
Oil		• Oil not on the margin in the region
Gas Spark	Significant	• The entire portfolio is spark based; 40% are high-efficiency combined-cycle units
Oil Spark	Insignificant	• Minimal oil capacity

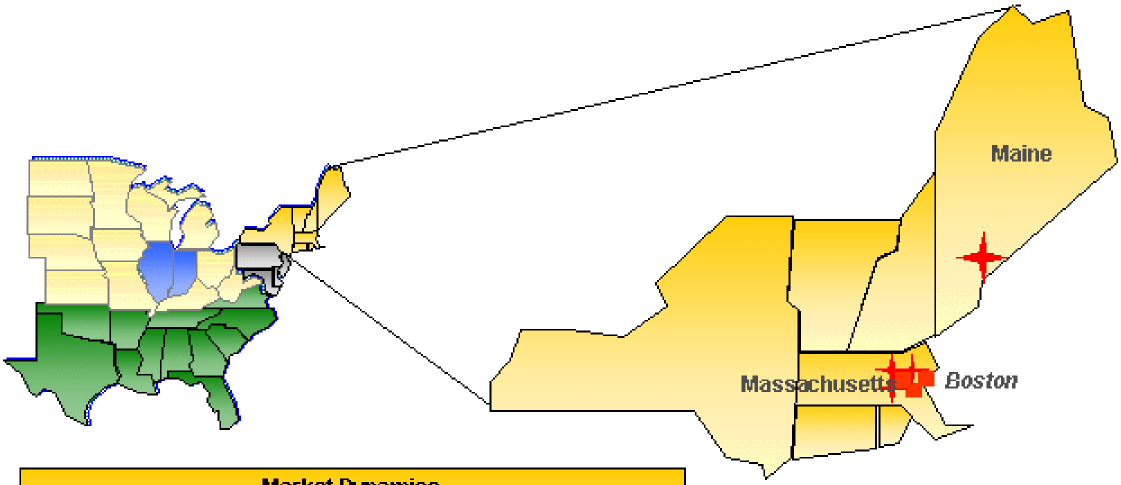
Significant Insignificant



Risk Management 2003
Portfolio over 80% sold in Q3 and the underlying fuel purchased; however, portfolio exposed to market risks in Q4 as only 60% sold forward
Wolf Hollow not yet commercial; will sell forward over 70% of generation once commercial
Risk Management 2004
Portfolio largely unsold in 2004; currently, only 45% sold (excludes toll to TXU) – limited ability to sell forward in financial markets
In the process of selling generation and purchasing underlying gas for 2004 through bilateral markets – targeting a hedge ratio of around 80%

2003: +/- $1/MWh ATC spark	$ 2 M
2004: +/- $1/MWh ATC spark	$ 7 M

New England Portfolio



Market Dynamics

All of the New England portfolio assets are in the NEPOOL region.

- Centrally dispatched pool with locational pricing
- 30% reserve margin in 2003, equilibrium expected in 2009/2010
- Generation mix is predominately new CCGTs and old dual fuel units
- Majority of load served through competitive auctions
- NEPOOL governance weighted towards transmission and load interests

Plant	Capacity	Avg. Variable Cost ($/MWh)
Base-load*	2,421 MW	$40.00
Peakers*	1,645 MW	$60.00
Total Capacity	4,066 MW	

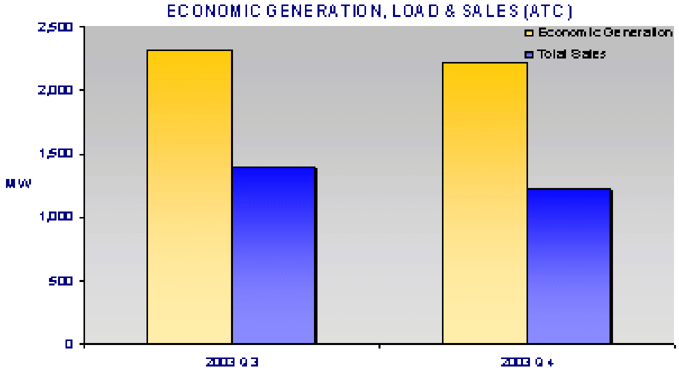
* Assuming $5/MMBtu gas price

New England: Key Elements

Commodity	Impact	Comments
Natural Gas		• Gas increasingly on the margin (over 50% of the on-peak hours)
Oil		• Over time the importance of oil in the region decreases • Oil on the margin a significant proportion of the time (around 45%)
Gas Spark		• Significant proportion of portfolio is gas based
Oil Spark		• Oil-based capacity in the portfolio is insignificant

Significant Insignificant

ECONOMIC GENERATION, LOAD & SALES (ATC)



Risk Management 2003
Around 60% of generation sold forward and underlying fuel purchased
Fore River not sold forward due to uncertainty around commercial operation date
Continuing to evaluate forward sales in light of bank financing issues

2003: +/- $1/MWh ATC spark $4 M

In Summary…

* *Real assets, real financial results*
* *Linked load and generation strategy*
* *Focused risk management and short-term value creation*

Financial Overview

Robert S. Shapard
Executive Vice President & Chief Financial Officer

Exelon Investor Conference
New York City
August 6, 2003

The Exelon Way

Baseline and Goals
Reporting and Timeline

O&M and CapEx Targets ($ millions)

	2004 Annual Impact			2006 Annual Impact		
	O&M*	CapEx	Total	O&M*	CapEx	Total
GenCo	$ 80	$ 65	$145	$115	$125	$240
EED	130	135	265	215	295	510
Total	$210	$200	$410	$330	$420	$750

* Pre-tax

Cash Flow Summary

	2004 Impacts			2006 Impacts		
	O&M	CapEx	Total	O&M	CapEx	Total
GenCo	$ 50	$ 65	$115	$ 71	$125	$196
EED	81	135	216	133	295	428
Total	$131	$200	$331	$204	$420	$624

Key Points

- Severance costs expected to occur in 3Q/4Q 2003 and most likely recur in late 2004/early 2005 for second stage reductions
- Anticipated staffing reduction target of ~1,200 by 2004 and 1,900 by 2006
- Beyond severance, overall costs-to-achieve associated with information technology, facilities and third-party costs are not expected to be significant
- Savings targets are net of costs-to-achieve other than severance

Total Spend Baseline

Business Unit	2003 Cost Baseline ($ millions) Total O&M*	CapEx	Total Spend
GenCo	$ 1,200	$ 850	$ 2,050
EED	1,050	975	2,025
Enterprises	775	–	775
Corporate/BSC	1,050	125	1,175
Total	$ 4,075	$1,950	$ 6,025

* Pre-tax

Considerations

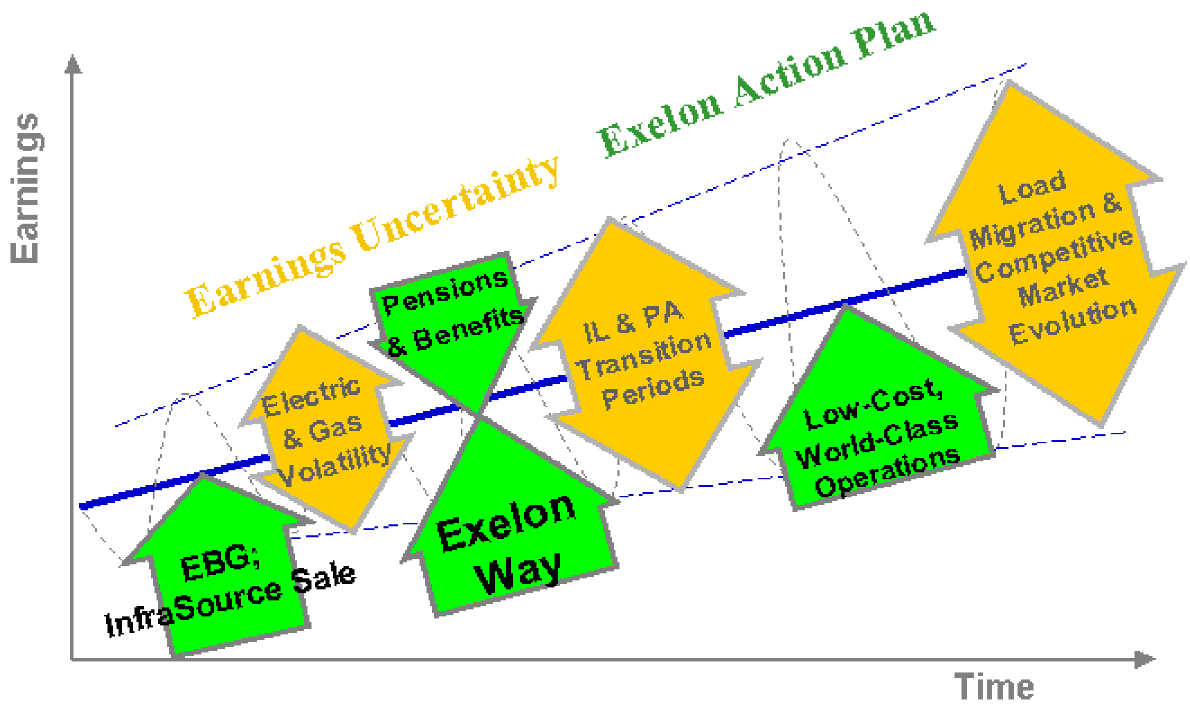
- Based upon 2003 year-end targets
- Total Exelon O&M and CapEx to be addressed
- Approximately 50% of total O&M spend is labor related
- Enterprises largely addressed through divestment program

High-Level Timeline

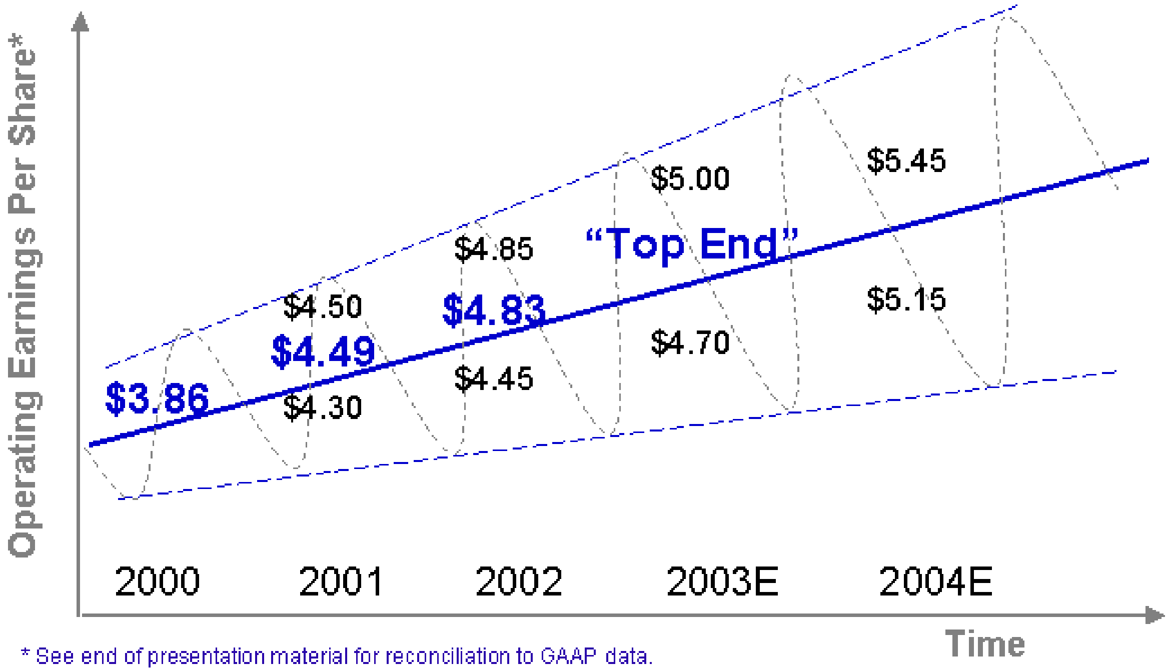
Key Activities	Calendar
• High-level organizational models defined • First-cut targets affirmed by Teams • New GenCo and EED high-level organizations announced	**May/June**
• Operating process identified • Savings initiative tracking in place for "quick hits"	**July**
• Finalize detailed functional and Business Unit organization structures • Complete 2004 opportunity assessments • Prepare implementation plans for 2004 savings	**August/September**
• Staffing reduction (for 2004 targets) to be completed by mid-November • Process redesign and implementation continuing	**October – December**

Financial Outlook

Build Value through Consistent Profitability



Build Value through Consistent Profitability



* See end of presentation material for reconciliation to GAAP data.
Note: Current 2003E operating EPS guidance is $4.80 to $5.00.

Exelon Consolidated Key Assumptions

	2002A	2003E	2004E
Nuclear Capacity Factor (%)	92.7	94.3	92.0
Total Genco Sales Ex Trading (GWhs)	212,578	199,875	197,700
Total Genco Sales to Intercompany (GWhs)	129,013	115,000	112,600
Total Market Sales (GWhs)	83,565	84,875	85,100
Volume Retention (%)			
PECO	92	91	90
ComEd	85	82	77
Delivery Growth Assumptions (%)*			
PECO	1.6	1.4	1.0
ComEd	(0.7)	1.3	1.5
Elec. Wholesale Mkt. ATC Price ($/MWh)			
MAIN	24.00	30.00	28.00
PJM	27.50	41.00	36.00
Effective Tax Rate (%)	37.4	37.4	37.4

A = Actual; E = Estimate; ATC = Around the clock
* Weather normalized

EED Financial Outlook

($ billions)	2002A	2003E Low		2003E High	2004E Low		2004E High
Revenues	10.5	10.2	-	10.4	10.2	-	10.4
Gross Margin (Rev. Net Fuel)	5.9	5.6	-	5.7	5.4	-	5.7
EBIT	2.9	2.7	-	2.8	2.7	-	3.0
Operating Net Income	1.3	1.2	-	1.3	1.2	-	1.3
Avg. Shares - Diluted (millions)	325	327	-	328	329	-	330
Operating EPS ($)	3.91	3.65	-	3.85	3.80	-	4.00
Cash From Operations*	2.9	1.6	-	1.7	1.8	-	1.8
CapEx	(1.0)	(0.9)	-	(0.9)	(0.9)	-	(0.8)
Transition Debt	(0.7)	(0.6)	-	(0.6)	(0.6)	-	(0.6)
Cash for Investment/Dividends	1.2	0.1	-	0.2	0.3	-	0.4

A = Actual; E = Estimated

*2003 Cash from Operations declines due to increased other post-retirement benefits contribution, EED parent receivable reclassification, and delayed 2002 year-end Genco/EED receivable into 2003.

Note: See end of presentation material for reconciliation to GAAP data.

Genco Financial Outlook

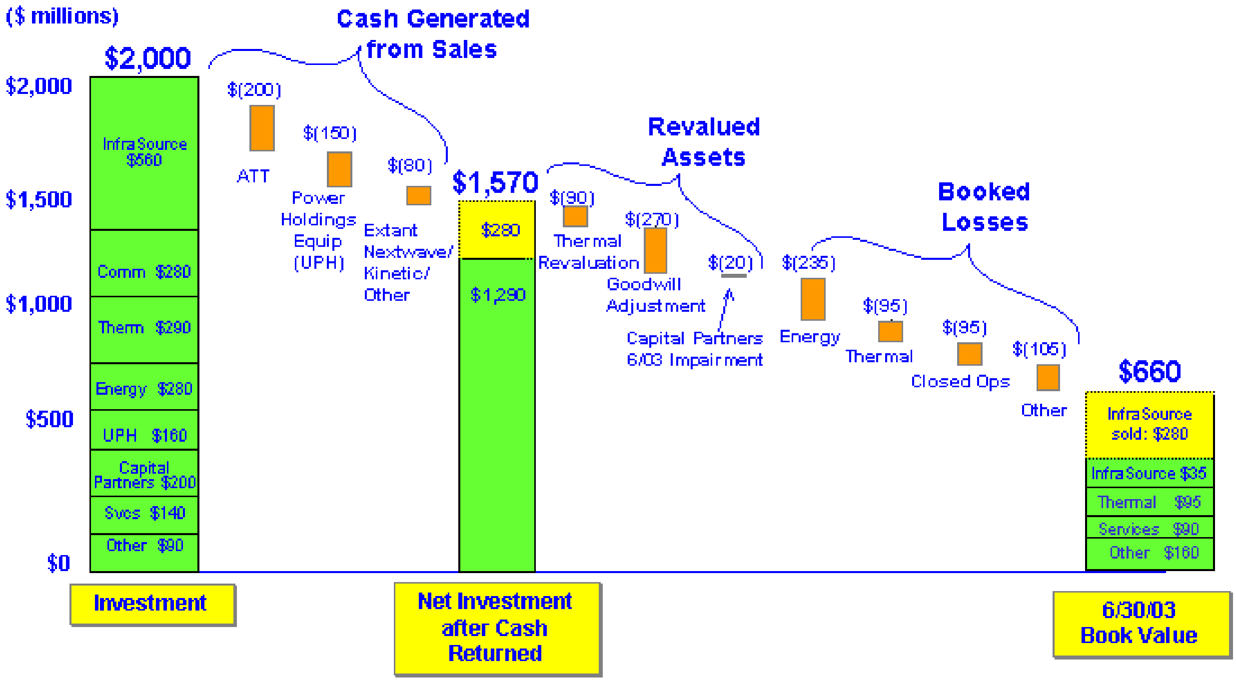
($ billions)	2002A	2003E Low		2003E High	2004E* Low		2004E* High
Revenues	6.9	6.6	-	8.0	6.1	-	6.7
Gross Margin (Rev. Net Fuel)	2.6	2.9	-	3.0	2.8	-	3.0
EBIT	0.5	0.5	-	0.8	0.9	-	1.0
Operating Net Income	0.4	0.4	-	0.5	0.5	-	0.6
Avg. Shares - Diluted (millions)	325	327	-	328	329	-	330
Operating EPS ($)	1.23	1.30	-	1.45	1.50	-	1.70
Cash From Operations	1.1	1.4	-	1.5	1.5	-	1.6
Decommissioning Trusts	(0.1)	(0.1)	-	(0.1)	(0.1)	-	(0.1)
Available Cash From Operations	1.0	1.3	-	1.4	1.4	-	1.5
CapEx	(0.6)	(0.4)	-	(0.5)	(0.4)	-	(0.4)
Investment in Nuclear Fuel	(0.4)	(0.4)	-	(0.4)	(0.4)	-	(0.4)
Cash for Investment/Dividends	0.0	0.5	-	0.5	0.6	-	0.7

A = Actual; E = Estimated

*Excludes Exelon Boston Generating

Note: See end of presentation material for reconciliation to GAAP data.

Revaluation of Enterprises' Assets



NOTE: Signed agreements to sell InfraSource businesses are expected to generate $280 million in cash.

Exelon Consolidated Financial Outlook

($ billions)	2002A	2003E Low		2003E High	2004E Low		2004E High
Revenues	15.0	14.4	-	15.8	14.1	-	15.0
Gross Margin (Rev. Net Fuel)	9.7	9.3	-	9.6	9.5	-	9.8
EBIT	3.3	3.1	-	3.3	3.5	-	3.9
Operating Net Income	1.5	1.5	-	1.6	1.7	-	1.8
Avg. Shares - Diluted (millions)	325	327	-	328	329	-	330
Operating EPS ($)	4.83	4.80	-	5.00	5.15	-	5.45
Cash From Operations	3.6	3.1	-	3.2	3.4	-	3.5
Decommissioning Trusts	(0.1)	(0.2)	-	(0.2)	(0.1)	-	(0.1)
Available Cash From Operations	3.5	2.9	-	3.0	3.3	-	3.4
CapEx	(2.0)	(1.7)	-	(1.7)	(1.7)	-	(1.7)
Transition Debt	(0.7)	(0.6)	-	(0.6)	(0.6)	-	(0.6)
Cash for Investment/Dividends	0.8	0.6	-	0.7	1.0	-	1.1
Common Dividends Paid	0.6	0.6		0.6	0.7		0.7

A = Actual; E = Estimated

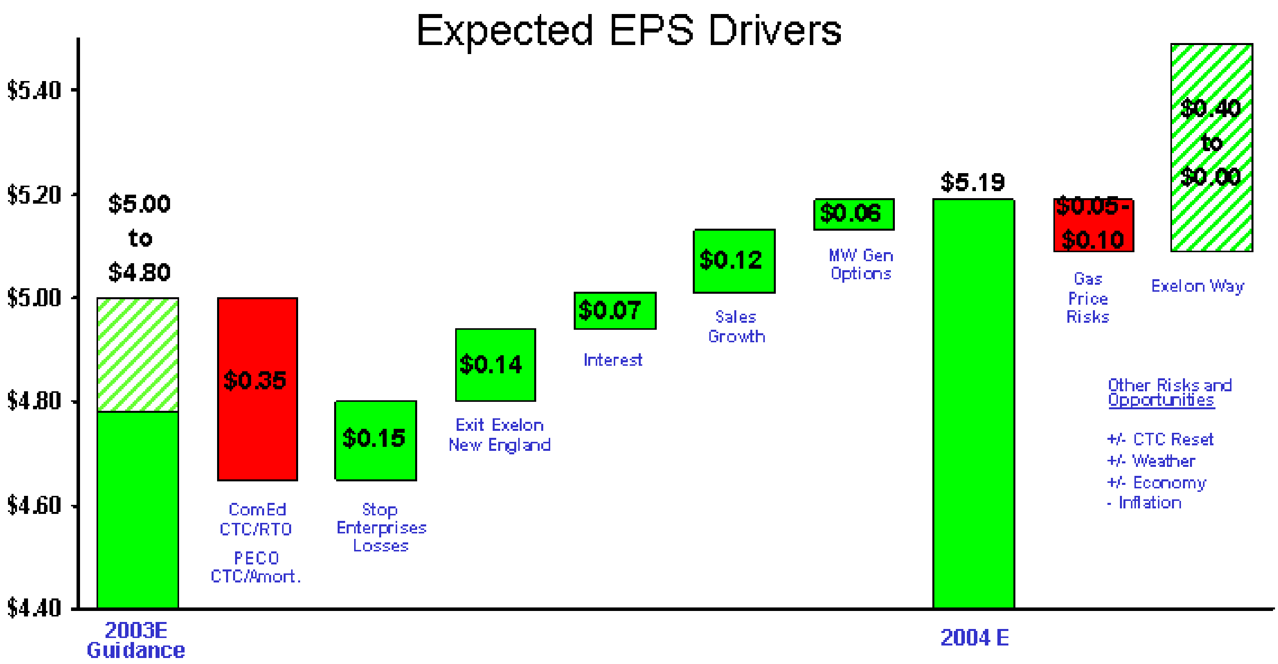
Note: See end of presentation material for reconciliation to GAAP data.

Exelon Consolidated Balance Sheet

($ billions)	2002A	2004E
Long-Term Debt	8.8	8.7
Transition Bonds	6.3	5.1
Total Long-Term Debt, Incl. Current Portion	15.1	13.8
Commercial Paper	0.7	0.3
Total Debt	15.8	14.1
Preferred Securities of Subsidiaries	0.6	0.6
Total Shareholders' Equity	7.8	8.7
Total Capitalization	24.2	23.4
Total Debt to Total Capital	65%	60%
Debt Ex Transition Bonds to Total Capital	53%	49%

A = Actual; E = Estimate

2004 EPS Guidance: $5.15 - $5.45



Conference Wrap-up

John W. Rowe
Chairman & Chief Executive Officer

Exelon Investor Conference
New York City
August 6, 2003

Valuation Measures

	P/E	Earnings per Share		Dividends	Yield
	2004E (X)	2-Yr CAGR 2000-2002A (%)	2-Yr CAGR 2002A-2004E (%)	5-Yr CAGR 1997-2002A (%)	(%)
Exelon	**11.0**	**11.9**	**4.2**	**2.2**	**3.5**
Entergy	12.6	10.5	4.6	-5.5	3.5
FPL Group	12.1	4.7	3.1	3.8	3.9
Dominion Res.	11.9	20.4	2.4	0	4.3
Southern	14.7	10.6	2.1	0.8	4.9
Cinergy	12.3	1.3	1.5	0.1	5.4
Progress Energy	10.6	12.5	0.3	3.0	5.5
DTE Energy	9.5	7.4	-1.1	0	5.8
AEP	12.2	3.5	-11.0	0	5.0
Duke Energy	12.4	-5.4	-14.6	0.2	6.3
Average	**11.9**	**7.7**	**-0.9***	**0.5**	**4.8**

* 2.1% CAGR excluding AEP and Duke
Sources: Thomson First Call, Bloomberg
Note: P/E and yield statistics as of 7/31/03
A=Actual; E=Estimate; CAGR=Compound annual growth rate

Building Value – The Exelon Way

Exhibit 99.3

Exelon

Reconciliation of GAAP Reported and Operating Earnings per Share

2000 Reported EPS	**$ 2.87**
Change in common shares	(1.06)
Extraordinary items	(0.07)
Cumulative effect of accounting change	0.01
Unicom pre-merger results	1.58
Merger-related costs	0.68
Pro forma merger accounting adjustments	(0.15)
2000 Pro Forma Operating EPS	**$ 3.86**
2001 Reported EPS	**$ 4.43**
Cumulative effect of adopting SFAS 133	(0.04)
Employee severance cost	0.09
Litigation reserves	0.03
Net loss on investments	0.02
CTC prepayment	(0.02)
Wholesale rate settlement	(0.01)
Settlement of transition bond swap	(0.01)
2001 Pro Forma Operating EPS	**$ 4.49**
2002 Reported EPS	**$ 4.44**
Transition loss on implementation of FAS 141 and 142	0.71
Gain on sale of AT&T Wireless	(0.36)
Employee severance costs	0.04
2002 Pro Forma Operating EPS	**$ 4.83**

Exelon Energy Delivery
Consolidated Statement of Income
(unaudited)
(in millions, except per share data)

	Six Months Ended June 30, 2003		
	GAAP (a)	Pro Forma Adjustments	Pro Forma
Operating revenues	$4,964	$ —	$4,964
Operating expenses			
Purchased power	1,918	—	1,918
Fuel	257	—	257
Operating and maintenance	744	(41)(b)	703
Depreciation and amortization	427	—	427
Taxes other than income	258	—	258
Total operating expenses	3,604	(41)	3,563
Operating income	1,360	41	1,401
Other income and deductions			
Interest expense	(383)	—	(383)
Distributions on preferred securities of subsidiaries	(22)	—	(22)
Equity in earnings of unconsolidated affiliates	—	—	—
Other, net	43	(12)(b)	31
Total other income and deductions	(362)	(12)	(374)
Income before income taxes and cumulative effect of changes in accounting principles	998	29	1,027
Income taxes	382	12	394
Income before cumulative effect of changes in accounting principles	616	17	633
Cumulative effect of changes in accounting principles, net of income taxes	5	(5)(c)	—
Net income	$ 621	$ 12	$ 633

Effect of pro forma adjustments on earnings per Exelon Corporation's average diluted common share recorded in accordance with GAAP:	
March 3 ComEd Settlement Agreement	$(0.05)
Cumulative effect of adopting SFAS No. 143	(0.02)
Total pro forma adjustments	$(0.07)

(a) Results reported in accordance with accounting principles generally accepted in the United States (GAAP).

(b) Pro forma adjustment for the March 3 ComEd Settlement Agreement.

(c) Pro forma adjustment for the cumulative effect of adopting SFAS No. 143.

Exelon Generation Company, LLC
Consolidated Statement of Income
(unaudited)
(in millions, except per share data)

	Six Months Ended June 30, 2003		
	GAAP (a)	Pro Forma Adjustments	Pro Forma
Operating revenues	$3,765	$ —	$3,765
Operating expenses			
Purchased power	1,642	—	1,642
Fuel	706	—	706
Operating and maintenance	943	—	943
Depreciation and amortization	91	—	91
Taxes other than income	88	—	88
Total operating expenses	3,470	—	3,470
Operating income	295	—	295
Other income and deductions			
Interest expense	(38)	—	(38)
Distributions on preferred securities of subsidiaries	—	—	—
Equity in earnings of unconsolidated affiliates	37	—	37
Other, net	(134)	200(b)	66
Total other income and deductions	(135)	200	65
Income before income taxes and cumulative effect of changes in accounting principles	160	200	360
Income taxes	71	70	141
Income before cumulative effect of changes in accounting principles	89	130	219
Cumulative effect of changes in accounting principles, net of income taxes	108	(108)(c)	—
Net income	$ 197	$ 22	$ 219

Effect of pro forma adjustments on earnings per Exelon Corporation's average diluted common share recorded in accordance with GAAP:	
Impairment of Exelon's investment in Sithe Energies, Inc.	$(0.40)
Cumulative effect of adopting SFAS No. 143	0.33
Total pro forma adjustments	$(0.07)

(a) Results reported in accordance with accounting principles generally accepted in the United States (GAAP).

(b) Pro forma adjustment for the impairment of Exelon's investment in Sithe Energies, Inc.

(c) Pro forma adjustment for the cumulative effect of adopting SFAS No. 143.

Exelon New England Plants

Station	Status	Capacity (MWs)	Fuel	Heat Rate (Btu/kWh)	2003 Projected Capacity Factor
Fore River (Base-load)	Construction	807	Gas/Oil	6,850	> 50%
Total Merchant Under Constr.		**807**			
Framingham 1 (Peaking)	Operating	13	Oil	13,500	< 5%
Framingham 2 (Peaking)	Operating	11	Oil	13,500	< 5%
Framingham 3 (Peaking)	Operating	13	Oil	13,500	< 5%
Mystic 4 (Intermediate)	Operating	135	Oil	9,900	< 5%
Mystic 5 (Intermediate)	Operating	130	Oil	10,200	< 5%
Mystic 6 (Intermediate)	Operating	138	Oil	10,300	< 5%
Mystic 7 (Intermediate)	Operating	592	Gas/Oil	10,400	30-40%
Mystic 8 (Base-load)	Operating	807	Gas	6,850	> 70%
Mystic 9 (Base-load)	Operating	807	Gas	6,850	> 70%
Mystic CT (Peaking)	Operating	12	Oil	13,500	< 5%
New Boston 1 (Peaking)	Operating	380	Gas/Oil	N/A	
New Boston 3 (Peaking)	Operating	20	Oil	N/A	
West Medway 1 (Peaking)	Operating	55	Gas/Oil	13,500	< 5%
West Medway 2 (Peaking)	Operating	55	Gas/Oil	13,500	< 5%
West Medway 3 (Peaking)	Operating	55	Gas/Oil	13,500	< 5%
Wyman 4 (Peaking)	Operating	36	Oil	10,400	< 5%
Total Merchant in Operation		**3,259**			
	Total MWs	**4,066**			

June 10, 2003

Sithe Energies Assets

The following table shows Sithe's principal assets as of December 31, 2002:

Type of Plant	Station	Location	No. of Units	Fuel	Dispatch Type	Net Generation Capacity (MW)
Merchant Plants	Batavia	New York	1	Gas	Intermediate	51
	Massena	New York	1	Gas/Oil	Intermediate	68
	Ogdensburg	New York	1	Gas/Oil	Intermediate	71
	Cardinal	Canada	1	Gas	Base-load	157
			4			347
Qualifying Facilities	Allegheny 5, 6, 8, 9	Pennsylvania	4	Hydro	Intermediate	50
	Bypass	Idaho	1	Hydro	Base-load	10
	Elk Creek	Idaho	1	Hydro	Base-load	2
	Greeley	Colorado	1	Gas	Base-load	49
	Hazelton	Idaho	1	Hydro	Base-load	9
	Independence	New York	1	Gas	Base-load	617
	Ivy River	North Carolina	1	Hydro	Base-load	1
	Kenilworth	New Jersey	1	Gas	Base-load	26
	Montgomery Creek	California	1	Hydro	Base-load	3
	Naval Station	California	1	Gas/Oil	Base-load	47
	Naval Training Center	California	1	Gas/Oil	Base-load	22
	North Island	California	1	Gas/Oil	Base-load	34
	Oxnard	California	1	Gas	Base-load	48
	Rock Creek	California	1	Hydro	Base-load	4
	Sterling	New York	1	Gas	Intermediate	55
			18			977
Under Construction	TEG 1, 2	Mexico	2	Coke	Base-load	228
Total			24			1,552

Midwest Generation PPA Options

In 2002, we released 4,411 MWs of options; in 2003, we have 3,043 MWs of options to exercise or release for 2004. We released 578 MWs on 6/24/03 and will decide on remaining 1,778 MWs by early October.

	Coal PPA (MWs)		Collins PPA (MWs)	Peakers PPA (MWs)	Total (MWs)
	Non-option	**Option**			
2002 Capacity	**5,645**		**2,698**	**807**	**9,150**
2002 Decision	1,696	3,949	Released 1,614	Released 113	Released 4,411
	Released 2,684				
2003 Capacity	**2,961**		**1,084**	**694**	**4,739**
Pending 2003 Decision	1,696	1,265	May release up to 1,084	May release up to 694	May release up to 1,778 (remaining options)
	Released 578				
Projected 2004 Capacity	**2,383**		**0 – 1,084**	**0 – 694**	**2,383 – 4,161**

Note: All Midwest Gen contracts expire after 2004.

Political & Regulatory Environment – IL

Illinois Commerce Commission

- New Chairman and two new Commissioners
- Three Democrats, one Republican, one Independent

Legislature (a new day in Springfield)

- First Democratic Governor in 26 years
- Democratically controlled House and Senate
- Only one Republican Constitutional Officer (Treasurer)

ComEd Restructuring Legislation
Enacted Dec. 1997

Rate Reductions

- Residential - 15% effective 1/1/98 ~ $400 million
  5% effective 10/1/2001 ~ $100 million

Direct Access Phase-In Schedule

- Residential
  5/1/2002 100% of residential customers have supplier choice.

- Commercial and Industrial, Governmental

All C&I customers had supplier choice effective 12/31/00.

Transition Cost Recovery Provisions

1) Bundled rates are frozen through 2006 (originally 2004) at 1996 levels after taking the residential rate reductions described above.

2) Unbundled delivery service rates apply to customers who choose an alternate supplier or the market rate for energy (ComEd PPO).

- Utilities recover transition costs via a Competitive Transition Charge (CTC) from customers who select an alternate supplier. The CTC will apply through 2006 for all classes. The CTC will be calculated based on the following formula:

CTC = Tariff/contract revenues *minus*
Delivery service revenue *minus*
Market value of electricity *minus*
Mitigation factor

(See current and proposed delivery rate schedules attached.)

Mitigation Factor

The mitigation factor is a credit averaging 0.5 cents/kWh offered by the utility to delivery service only customers.

- The mitigation factor for commercial and industrial customers is:

10/1/99-12/31/02	0.5 cents per kWh or 8%
2003-2004	0.5 cents per kWh or 10%
2005	0.6 cents per kWh or 11%
2006	0.9 cents per kWh or 12%

- The mitigation factor for residential customers is calculated as a percentage of base rates after the rate reductions are in effect. The applicable percentages are as follows:

2002	6% of base rates after rate reductions
2003-2004	7% of base rates after rate reductions
2005	8% of base rates after rate reductions
2006	10% of base rates after rate reductions

Transition Period Provision

During the transition period utilities will be able to recognize, sell or assign assets; retire or remove plants from service; unbundle or restructure tariffs on a revenue neutral basis (with impact limitations described in Earnings and Viability below); accelerate depreciation or amortization or assets without ICC approval. The ICC could intercede if it believed the transaction jeopardized reliable service.

Earnings and Viability

The maximum allowable rate of return will be pegged to the 30-year T-Bond rate, plus 8.5%. If earnings exceed the allowed rate of return by more than 1.5%, 50% of the excess earnings would be shared with customers. If the rate of return is below the T-bond Rate, the utilities can apply to the ICC for a rate increase.

Securitization

Utilities are allowed to utilize securitization of transition period revenues as a means to mitigate stranded costs. The proceeds primarily are to be used to retire debt and equity, and to repay or retire fuel obligations if the Commission finds such use is the public interest.

Amount allowable for securitization is capped by 50% of capitalization. In December 1998, ComEd securitized $3.4 billion.

ComEd CTC Calculation

Bundled Base Rate	Average rate by customer class, frozen through 2006 per 1997 Illinois legislation
DST Rate	Average rate for distribution and transmission services per published tariff
Mitigation Factor	Guaranteed savings for customers, currently the greater of 10% of the bundled rate or $0.005/kWh
MVEC	Market value energy component adjusted annually on June 1
CTC	Competitive transition charge for recovery of investments made prior to restructuring

100-400 kW Avg. Demand	Cents/kWh	
Bundled Rate	7.428	
– DST Rate	1.520	→ Per published tariff by demand class
– Mitigation	0.743	→ Per 1997 Illinois legislation
– MVEC	3.896	→ Avg. 12-month forward energy prices of trade and bid/ask data from 2/24-3/21/03
= CTC	**1.269**	

ComEd MVEC – How It Works

Changes in MVEC cause inverse change to CTC (100-400 kW avg. demand):

	June 2001	March 2002	June 2002	March 2003	June 2003
Bundled	7.428	Energy Prices ↘	7.428	Energy Prices ↗	7.428
DST	1.368		1.368		1.520
Mitigation	0.594		0.594		0.743
MVEC	5.053		2.660		3.896
CTC	0.413		2.806		1.269

Customer Impact

- Switching (retail electric suppliers (RES) only) as a percent of total 2002 GWh:
  - Small C&I – 17%
  - Large C&I – 35%
  - Total – 15%
- Potential reduction in CTC revenue beginning 6/03 from customers who buy energy from alternate suppliers
- Creates potential switching opportunity for other customers

ComEd ROE Cap – Earnings Sharing Formula

- Applies through the end of the transition period (Dec. 31, 2006)
- Index Calculation: 12-month simple average of "Monthly Treasury Long-Term Average Rates"

  Plus: 7% Index Adder

  Plus: 1.5% Index Margin
- ComEd's two-year average ROE must exceed the two-year average of this index for the same two years before invoking a 50% earnings sharing provision
- Only the incremental earnings contributing to the percentage in excess of the index is subject to sharing
- Goodwill is included as equity for purposes of calculating ComEd's ROE

Commonwealth Edison Company
Determination of Nonresidential Customer Transition Charge (Summary Page)
Based on Market Value Defined in Rider PPO — Power Purchase Option (Market Index) Applicable Period A (June 2003 — May 2004)
(All units are in cents per kilowatt-hour)

	Base Rate Revenue (1)(2)	**Delivery Service Revenue(1)(3)**	**Market Value (4)**	**Mitigation Amount (5)**	**June 2003 - May 2004 CTC(6)(7)**
	(A)	**(B)**	**(C)**	**(D)**	**(E)=(A)-(B)-(C)-(D)**
Customer Transition Charge Customer Class					
Nonresidential Delivery Service Customers					
With Only Watt-hour Only Meters	11.258	3.756	4.028	1.126	**2.348**
0 kW to and including 25 kW Demand	9.288	2.161	3.954	0.929	**2.244**
Over 25 kW to and including 100 kW Demand	8.344	1.908	3.944	0.834	**1.658**
Over 100 kW to and including 400 kW Demand	7.428	1.520	3.896	0.743	**1.269**
Fixture-included Lighting Nonresidential Delivery Service Customers	13.554	9.754	3.059	1.355	**0.000**
Street Lighting Delivery Service Customers — Dusk to Dawn	3.852	1.801	3.047	0.500	**0.000**
Street Lighting Delivery Service Customers — All Other Lighting	7.172	1.794	3.514	0.717	**1.147**
Railroads Delivery Service Customers (8)					
Pumping Delivery Service Customers	6.465	1.418	3.684	0.647	**0.716**

Notes:

(1) Transfer from Column (H) and Column (M) of Determination of Customer Transition Charge, on Pages 5 to 12 of attached work papers.

(2) Base rate revenues consist of customer, demand, and energy charges. Base rate revenues do not include facility, meter, or other equipment rentals, franchise fees or other franchise cost additions, fuel adjustment clause charges, decommissioning expense adjustment clause charges, taxes, local government compliance clause charges, compensation for energy generated by a person or entity other than ComEd, or Renewable Energy Resources and Coal Technology Development Assistance Charge and Energy Assistance Charge for the Supplemental Low-Income Energy Assistance Fund.

(3) The amount of revenue that the Company would receive under Rate RCDS — Retail Customer Delivery Service (Rate RCDS) and Rider ISS — Interim Supply Service (Rider ISS) for standard delivery of energy to customers in the CTC Customer Class.

(4) The Market Value for a CTC Customer Class has the same value as the per kilowatt-hour Load Weighted Average Market Value (LWAMV) as defined in Rider PPO — Power Purchase Option (Market Index) for the applicable customer class for Applicable Period A.

(5) The mitigation amount as defined in Rate CTC is the greater of 0.5 cents per kilowatt-hour or 10% of the base rate revenue for the calendar years 2003 and 2004.

(6) This Applicable Period A Customer Transition Charge (CTC) is not applicable if you are taking service under a multi-year CTC option under Rider CTC — MY — Customer Transition Charges — Multi-Year (Rider CTC-MY). Applicable CTCs under a multi-year CTC option are provided on pages 2 through 4.

(7) CTCs are subject to change without specific notice if one of the components used in the determination of the CTC, as described in Rate CTC, is modified. If the CTC is equal to zero, this account will not be eligible for service under Rider PPO — Power Purchase Option (Market Index) (Rider PPO).

(8) There are two customers in the Railroads class and each customer will have a Customer-specific CTC.

Commonwealth Edison Company
Determination of Residential Customer Transition Charge (Class Summary Page)
Based on Market Value Defined in Rider PPO — Power Purchase Option (Market Index) Applicable Period A (June 2003 — May 2004)
(All units are in cents per kilowatt-hour)

	Base Rate Revenue (1)(2)	Delivery Service Revenue (3)	Market Value (4)	Mitigation Amount (5)	June 2003 - May 2004 CTC
	(A)	(B)	(C)	(D)	(E)=(A)-(B)-(C)-(D)
Customer Transition Charge Customer Class					
Residential Delivery Service Customers					
Single Family Without Space Heat	8.715	3.355	3.911	0.610	0.839
Multi Family Without Space Heat	8.961	4.404	4.057	0.627	0.000
Single Family With Space Heat	5.836	2.279	3.750	0.409	0.000
Multi Family With Space Heat	6.169	2.881	3.818	0.432	0.000
Fixture-included Lighting Residential Delivery Service Customers	8.655	9.853	3.080	0.606	0.000

Notes:

(1) Based on three years of residential historical data ending January 2002 and residential rates in effect beginning October 1, 2001.

(2) Base rate revenues consist of customer service and energy charges. Base rate revenues do not include facility, meter, or other equipment rentals, franchise fees or other franchise cost additions, fuel adjustment clause charges, decommissioning expense adjustment clause charges, taxes, local government compliance class charges, compensation for energy generated by a person or entity other than ComEd, or Renewable Energy Resources and Coal Technology Development Assistance Charge and Energy Assistance Charge for the Supplemental Low-Income Energy Assistance Fund.

(3) The amount of revenue that the Company would receive under Rate RCDS — Retail Customer Delivery Service (Rate RCDS) and Rider ISS — Interim Supply Service (Rider ISS) for standard delivery of energy to customers in the CTC Customer Class.

(4) The Market Value for a CTC Customer Class has the same value as the per kilowatt-hour Load Weighted Average Market Value (LWAMV) as defined in Rider PPO — Power Purchase Option (Market Index) for the applicable delivery service customer class.

(5) The residential mitigation amount as defined in Rate CTC is 7% of the base rate revenue for the calendar years of 2003 and 2004.

Exelon.

Political & Regulatory Environment – PA

- Five PUC Commissioners – four Republicans, one Democrat (recently appointed)
- Five-year staggered terms, expiring March 31 of each year
- Commissioner Fitzpatrick just appointed as Chairman (term expires 3/31/04), replacing Glen Thomas
- Governor Rendell (D) appointed Wendell Holland (D) as replacement for Commissioner Wilson (R)
- 2002 legislation allows no more than three Commissioners from the Governor's party

PECO ENERGY

Restructuring Settlement

This summary of the major elements of the 1998 settlement reflects amendments made in 2000 following announcement of the PECO Unicom merger.

- Recovery of $5.26 billion of stranded costs over a 12-year transition period beginning January 1, 1999 and ending December 31, 2010, with a return of 10.75 percent.
- Rate caps will vary over the transition period. (See Table on Page 2.)
- On January 1, 1999 PECO unbundled rates into three components:
  - a transmission and distribution rate of 2.98 cents per kWh.
  - a competitive transition charge (CTC) designed to recover the $5.26 billion of stranded costs. Revenue collected through the CTC will be reconciled annually based on actual sales.
  - a shopping credit initially set at 4.46 cents per kWh on a system-wide basis.
- Authorization for PECO to securitize up to $5 billion of stranded costs. (PECO has securitized fully to its $5B limit.) The intangible transition charges associated with transition bonds terminate no later than December 31, 2010.
- Flexible pricing, within a specified range, for residential default customers.
- Customer choice phased in between January 1, 1999 and January 2, 2000.
- Authorization for PECO to transfer its generation assets to a separate entity.
- Ability of electric generation suppliers (EGS) to provide metering and billing services to retail customers who have direct access.
- As required by law, on January 1, 2001 the provider of default service for 20 percent of residential customers was bid competitively.
- If 35 percent and 50 percent of all customers are not shopping by 2001 and 2003, respectively, a number of customers sufficient to equal those trigger points shall be randomly selected and assigned to licensed suppliers by a PUC-determined process.
- PLR Requirement: PECO is PLR through 2010.

Schedule of System Average Rates
¢/kWh

Effective Date	Transmission[a] (1)	Distribution (2)	T&D Rate Cap[b] (3)	CTC/ITC (4)	Credit for Delivery Service Only (5)	Generation Rate Cap[c] (6)
January 1, 2002	0.45	2.35	2.80	2.51	4.47	6.98
January 1, 2003	0.45	2.35	2.80	2.47	4.51	6.98
January 1, 2004	0.45	2.41	2.86	2.43	4.55	6.98
January 1, 2005	0.45	2.41	2.86	2.40	4.58	6.98
January 1, 2006	0.45	2.53	2.98	2.66	4.85	7.51
January 1, 2007	N/A	N/A	N/A	2.66	5.35	8.01
January 1, 2008	N/A	N/A	N/A	2.66	5.35	8.01
January 1, 2009	N/A	N/A	N/A	2.66	5.35	8.01
January 1, 2010	N/A	N/A	N/A	2.66	5.35	8.01

(a) Transmission prices listed are for illustration only. The PUC does not regulate rates for transmission Service.

(b) T&D Rate Cap (column 3) = sum of columns (1)+(2).

(c) Generation Rate Cap (column 6) = sum of columns (4)+(5).

Notes:

- Average figures for CTC/ITC from 2002-2010 in column 4 are fixed, subject to reconciliation for actual sales levels.
- The credit (paid to delivery-service-only-customers) figures in column 5 will be adjusted to reflect changes due to the CTC/ITC reconciliation.
- Average transmission and distribution service rates will not exceed the figures in column 3.
- The generation portion of bills for customers who remain with regulated PECO generation supply will not, on average, exceed figures in column 6.
- Calculation of average rates for 2002: 9.96¢/kWh (existing rate cap) — 1.8 percent reduction = 9.78¢/kWh 9.78¢/kWh = 2.80 (column 3) + 2.51 (column 4) + 4.47 (column 5)

PECO ENERGY
CTC Amortization

Annual Stranded Cost
Amortization and Return[a]

Year	Annual Sales	CTC	Revenue, excluding Gross Receipts Tax		
			Total	Return @ 10.75%	Amortization
	MWh	¢/kWh	($000)	($000)	($000)
2002	34,381,485	2.51	825,004	516,869	308,135
2003	34,656,537	2.47	818,352	482,401	335,951
2004	34,933,789	2.43	811,540	444,798	366,742
2005	35,213,260	2.40	807,933	403,555	404,378
2006	35,494,966	2.66	902,623	353,070	549,553
2007	35,778,925	2.66	909,844	290,627	619,217
2008	36,065,157	2.66	917,123	220,312	696,811
2009	36,353,678	2.66	924,459	141,229	783,231
2010	36,644,507	2.66	931,855	52,381	879,474

(a) Subject to reconciliation of actual sales and collections. Under the settlement, sales are estimated to increase 0.8 percent per year.

Other Features

- The transmission & distribution rate cap of 2.98 cents per kWh includes .01 cent for a sustainable energy and economic development fund during the rate cap period.
- PECO is permitted to transfer ownership and operation of its generating facilities to a separate corporate entity. The generating facilities will be valued at book value at the time of the transfer.
- Twenty percent of residential customers will be assigned to a provider of last resort (PLR), other than PECO, on January 1, 2001. The PLR will be selected on the basis of a PUC-approved energy and capacity market price bidding process. PECO-affiliated suppliers will be prohibited from bidding for this block of customers.
- As of January 1, 2001, PECO (as PLR) will price its service to residential customers within a specified range.
- A Qualified Rate Order authorizing securitization of up to $4 billion is included (subsequently increased to $5 billion).

Exelon Maturity Schedule — 2003
(Includes issues called to date)

	Refinancing						New Issue				
	Company	**Type**	**Amount ($M)**	**Coupon**	**Maturity Date**	**Actual Call Date**	**Type**	**Maturity Date**	**Amount ($M)**	**Coupon**	**Pricing Date**
Jan	ComEd	FMB	200.0	7.375%	9/15/02						
	ComEd	FMB	200.0	8.375%	9/15/22	9/16/02					
	ComEd	Notes	200.0	Variable	9/30/02		FMB	2008	350.0	3.70%	1/14/03
	ComEd	Notes	100.0	9.170%	10/15/02		FMB	2033	350.0	5.875%	1/14/03
Mar	ComEd	Trust Pfd Sec	200.0	8.48%	9/30/35	3/20/03	Trust Pfd Sec	2033	200.0	6.35%	3/10/03
Mar	ComEd	FMB	236.0	8.375%	2/15/23	3/18/03					
	ComEd	FMB	160.0	8.000%	4/15/23	4/15/03	FMB	2015	395.0	4.70%	3/31/03
Apr	PECO	FMB	250.0	6.625%	3/1/03						
	PECO	FMB	200.0	6.500%	5/1/03		FMB	2008	450.0	3.50%	4/21/03
May	ComEd	Pollution control bonds	40.0	5.875%	5/15/07	5/15/03	Pollution Control bonds	2017	40.0	Variable*	5/8/03
June	PECO	Pfd Stock	50.0	7.48%	—	6/11/03	Trust Pfd Sec	2033	100.0	5.75%	6/17/03
		Trust Pfd Sec	50.0	8.00%	6/5/37	6/24/03					

Remaining Maturities

Aug	ComED	FMB	100.0	6.625%	7/15/03	(new issue pending)
Sep	ComED	Notes	250.0	Variable	9/30/03	

* The initial 35-day pricing rate is 1.13%.

Exelon Corporation

Transitional Bond Summary

($ in millions)	Dec-00	Dec-01	Dec-02	Dec-03	Dec-04	Dec-05	Dec-06	Dec-07	Dec-08	Dec-09	Dec-10
ComEd											
Year End Principal Balance	$2,720	$2,380	$2,040	$1,700	$1,360	$1,020	$ 680	$ 340	$ —	$ —	$ —
Principal Payments		$ 340	$ 340	$ 340	$ 340	$ 340	$ 340	$ 340	$ 340	$ —	$ —
PECO											
Year End Principal Balance	$4,838	$4,582	$4,255	$4,015	$3,725	$3,295	$2,775	$2,135	$1,505	$805	$ —
Principal Payments		$ 256	$ 327	$ 240	$ 290	$ 430	$ 520	$ 640	$ 630	$700	$805
Total											
Year End Principal Balance	$7,558	$6,962	$6,295	$5,715	$5,085	$4,315	$3,455	$2,475	$1,505	$805	$ —
Principal Payments		$ 596	$ 667	$ 580	$ 630	$ 770	$ 860	$ 980	$ 970	$700	$805

Securities Ratings for Exelon and its Subsidiary Companies

	Securities	Moody's Investors Service	Standard & Poors Corporation	Fitch Investors Service, Inc.
Exelon	Senior unsecured debt	Baa2	BBB+	BBB+
	Commercial paper	P2	A2	F2
ComEd	Senior secured debt	A3	A-	A-
	Commercial paper	P2	A2	F2
PECO	Senior secured debt	A2	A	A
	Commercial paper	P1	A2	F1
Generation	Senior unsecured debt	Baa1	A-	BBB+
	Commercial paper	P2	A2	F2