# DESIGNING WHOLESALE ELECTRICITY MARKETS

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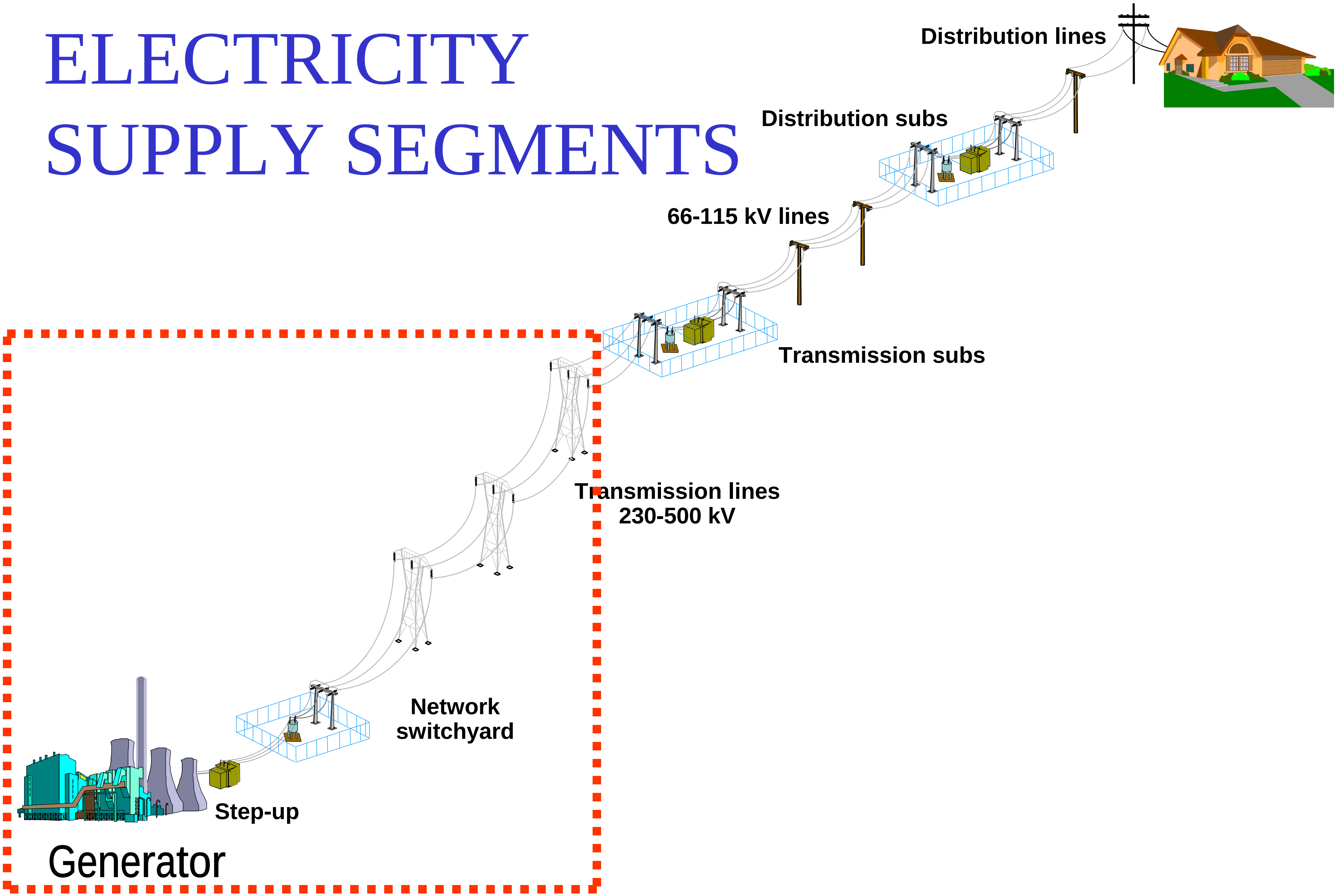
# OUTLINE

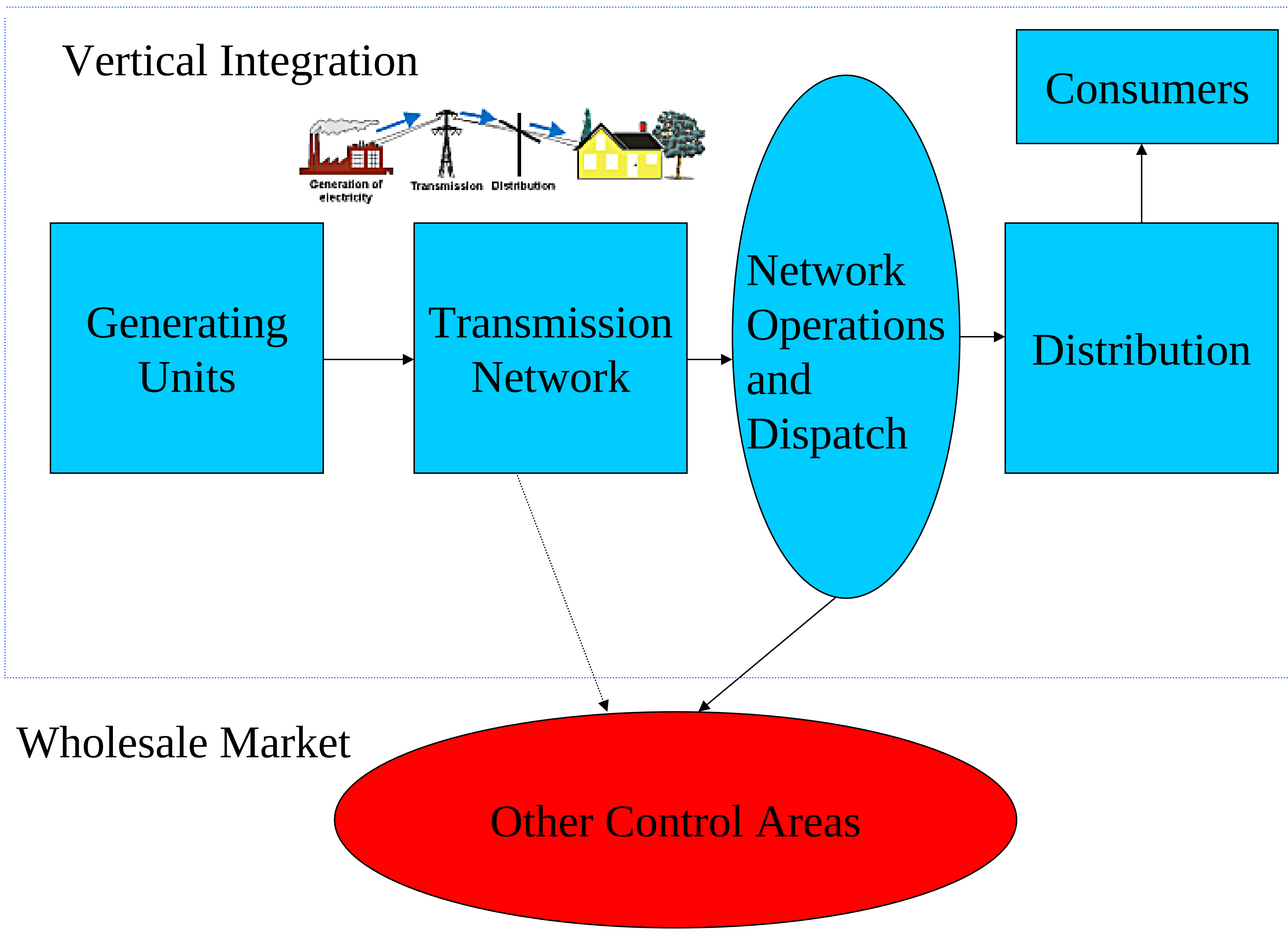
- Background goals and challenges for liberalization (restructuring, competition and regulatory reform)
- Short-term wholesale market design objectives and principles
- U.S. standard market design
  - Short-term performance
  - Long-run investment incentives
- Transmission network investment issues

# ELECTRICITY SUPPLY SEGMENTS



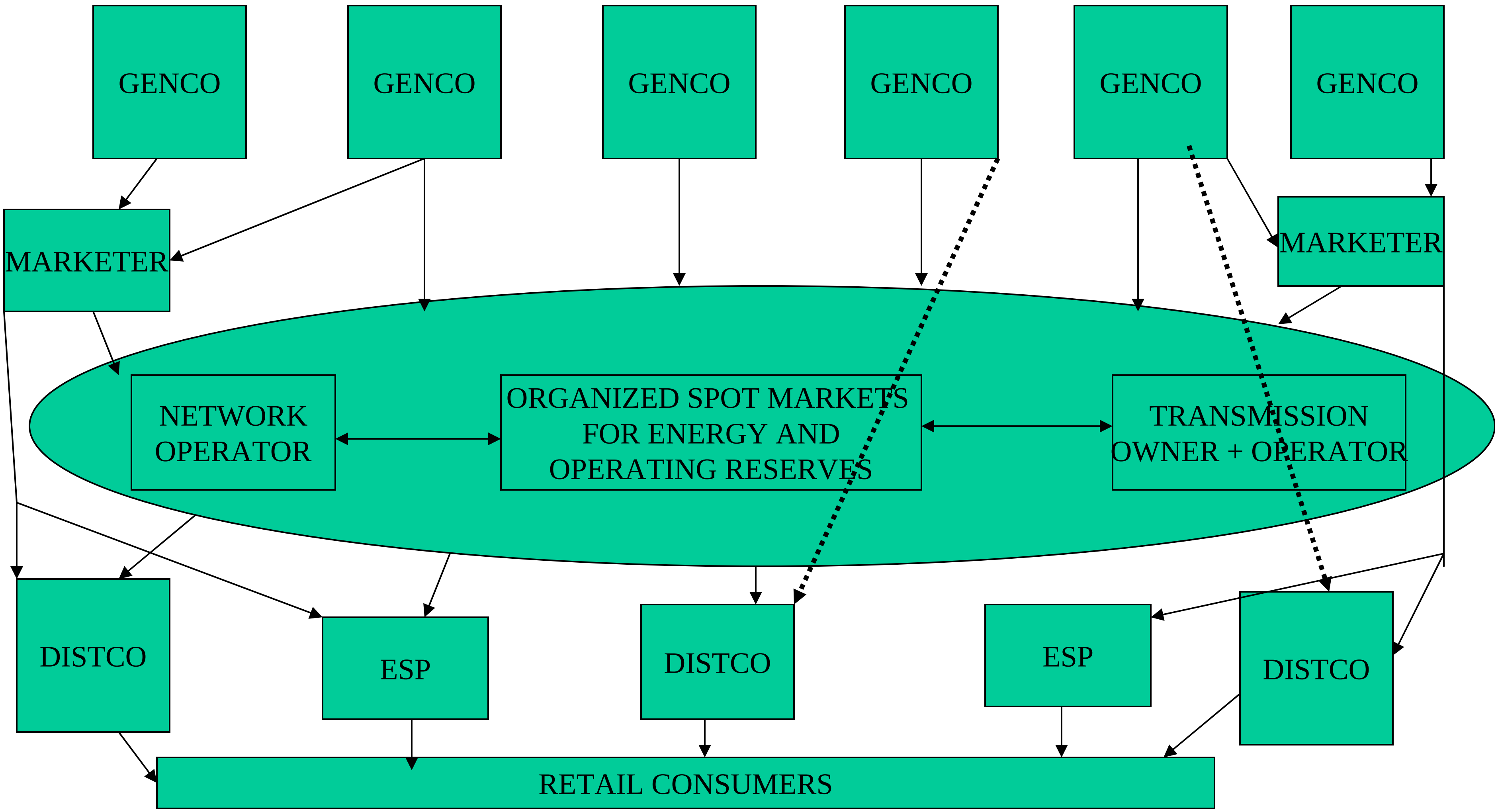
# GOALS FOR WHOLESALE (G&T) ELECTRIC POWER SYSTEMS

- Efficient and reliable system operation
  - Balance supply and demand in real time
  - Maintain network's physical parameters (*e.g.*, frequency)
  - Low probability of "non-price" rationing (e.g. rolling blackouts)
  - Avoid adverse impacts on interconnected networks
  - Rapid system restoration
  - Minimize cost of achieving these goals
  - Provide efficient price signals to consumers
- Efficient investment consistent with reliability and environmental standards
  - Minimize long-run bulk power supply costs (G&T) consistent with reliability and environmental goals



Vertical Integration
Generation of electricity
Transmission
Distribution
Consumers
Generating Units
Transmission Network
Network Operations and Dispatch
Distribution
Wholesale Market
Other Control Areas

# COMPREHENSIVE VISION FOR LIBERALIZATION



# WHY WHOLESALE AND RETAIL COMPETITION?

- Goal is to provide long run net benefits to society
- Provide better incentives for controlling capital and operating costs of new and existing generating capacity
- Encourage innovation in power supply technologies
- Shift risks of "mistakes" to suppliers and away from consumers
- Support retail prices that reflect marginal production cost including the costs of congestion, losses, and scarcity
- Provide enhanced array of retail service products, risk management, demand management, and opportunities for service quality differentiation based on individual consumer preferences
- Facilitate better regulation of residual monopoly services to enhance efficiency incentives and reduce T&D costs (broadly defined)
- Consistent with environmental and reliability policy goals using market-compatible mechanisms (green taxes or cap-and-trade)

# CREATING COMPETITIVE WHOLESALE AND RETAIL MARKETS

- Easy to do badly and difficult to do well.
- Electricity has unusual physical and economic attributes that make wholesale and retail market design a significant technical and institutional challenge
- Major institutional changes are required
  - Industry Restructuring- vertical and horizontal
  - New market institutions
  - New regulatory institutions
  - Re-evaluation and adaptation of engineering reliability rules
- A strong political commitment to making competitive markets work is important because it's a long difficult process with gainers and losers

# RESTRUCTURING FOR COMPETITION

- New market and institutional structures are necessary for successful liberalization (good market design cannot fix a bad market structure)
  - Vertical separation and unbundling of competitive segments from regulated monopoly segments
  - Horizontal decentralization to support competition in generation and retail supply
  - Horizontal integration of transmission ownership and operations to internalize network externalities
  - New wholesale market institutions to replace central economic dispatch and network management
  - New regulatory institutions for T&D networks
  - Harmonization of market and regulatory institutions between network control areas to facilitate efficient trading, enhance competition, and support investment in transmission capacity over large geographic regions
  - Compatible retail market institutions (prices, demand response)

# WHOLESALE MARKET DESIGN SHORT-TERM OPERATIONS

- Replace internal behavioral protocols used by vertically integrated system operators with transparent decentralized market mechanisms
  - Efficient scheduling generation and load to balance supply and demand continuously
  - Efficient generator dispatch
  - Efficient provision of frequency regulation and operating reserves
  - Efficient allocation of scarce transmission capacity
  - Coordination with neighboring systems to support trade and reliability
  - Manage operating reserve emergencies and unplanned outages of G&T consistent with appropriate reliability criteria using market mechanisms

# INVESTMENT INCENTIVES

- Well functioning short-term wholesale (and retail) markets are necessary to provide appropriate incentives for investment in and retirement of generating capacity
- Well functioning wholesale markets provide necessary signals for evaluating both regulated and merchant transmission investments
- Several revenue streams
  - energy revenues
  - ancillary services or “operating reserves” revenues
  - capacity revenues (if any)
- Other factors are also important
  - congestion management and locational pricing
  - contract regime (spot, longer term)
  - transmission interconnection and transit rules and prices
  - engineering reliability rules

# INVESTMENT INCENTIVE ISSUES

- Investment incentives for new generation
  - Do “energy-only” markets provide adequate incentives to stimulate generation investment consistent with reliability criteria
  - Do we get the right “mix” of generating capacity?
  - Are capacity obligations and capacity markets necessary?
- How should investment in transmission capacity be governed?
  - Intra-network for reliability
  - Intra-network to reduce congestion
  - Inter-network connections (“interconnectors”)
  - Regulated, merchant, a mixture?

# WHOLESALE MARKET DESIGN FEATURES

- Wholesale electricity markets do not design themselves
- Organized day-ahead, intra-day adjustment and real time balancing markets for energy
  - Efficient unit commitment and dispatch
  - Efficient wholesale prices
- Organized day-ahead and adjustment markets for ancillary services
  - How are requirements defined? (public goods?)
  - Integration with energy markets
  - Efficient (arbitraged) prices
- Transmission congestion and loss management
  - Integration of allocation of transmission with energy markets
  - Efficient prices for congestion and losses
  - Over large geographic areas
  - Minimize "seams" problems between control areas
- Capacity obligations, capacity prices, capacity markets?

# WHOLESALE MARKET DESIGN FEATURES

- Accommodating “self-scheduling” to support bilateral contracts
  - Consistent and transparent congestion and loss prices
  - Consistent and transparent imbalance prices
- Integration with engineering reliability rules and criteria
  - Where do they come from?
- Demand-side responses
  - Real time pricing
  - Controllable loads
  - Non-price rationing
- Price formation during “scarcity conditions”

# U.S. STANDARD MARKET DESIGN

- The basic standard wholesale market design (SMD) in operation in the U.S. Northeast and Midwest works reasonably well from a short run operating cost and reliability perspective
- New England, New York, PJM, MISO (CAISO and ERCOT Soon)
- The SMD has evolved over time and its performance has improved based on experience
- Primary deficiencies relate to investment incentives for new generation and transmission
- T&D regulatory frameworks and industry restructuring have not kept up with wholesale market design improvements in the U.S. (unlike UK, etc.)
- Imperfections in competitive retail markets have adverse effects on wholesale market performance

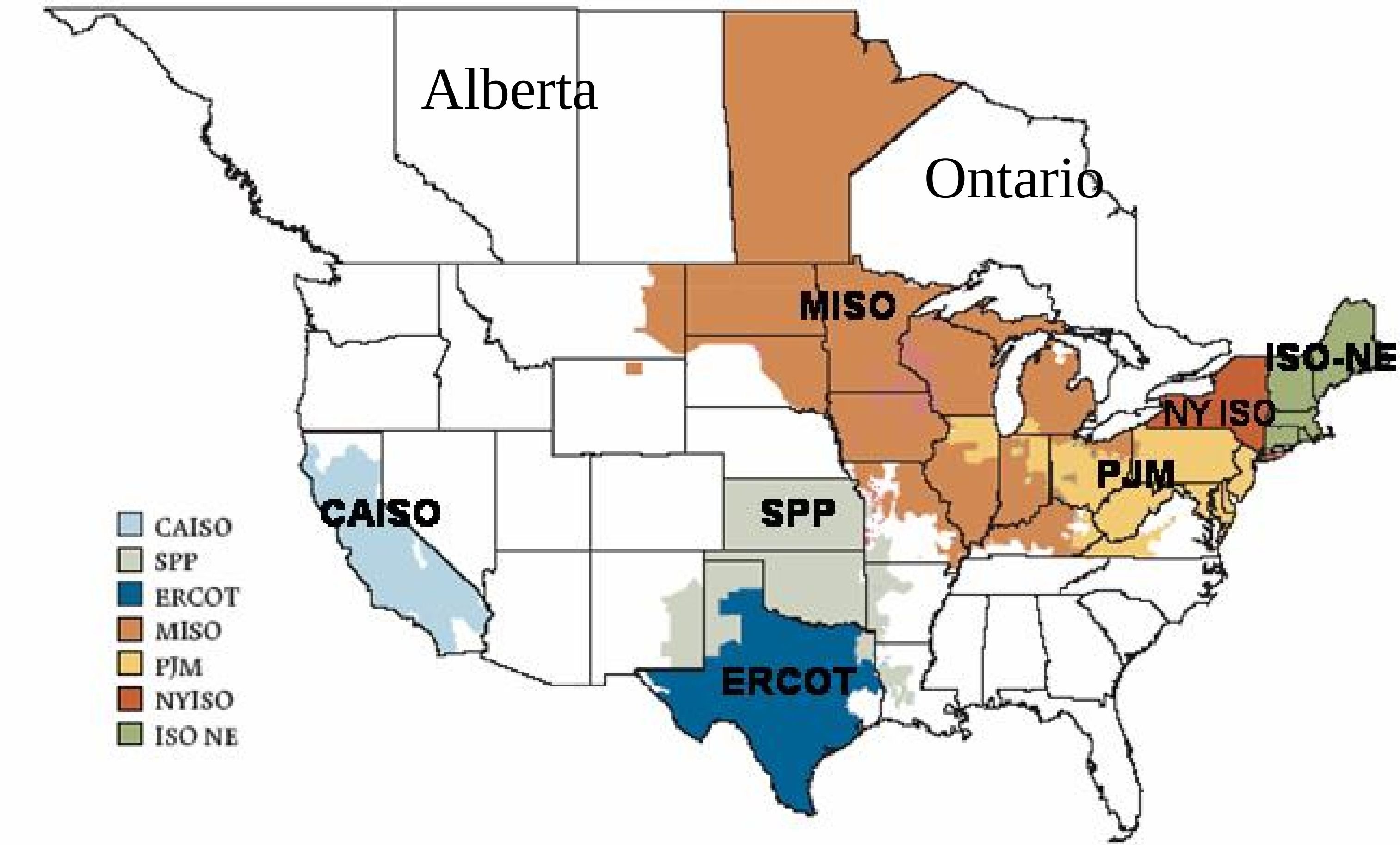

Alberta
Ontario
MISO
ISO-NE
NY ISO
PJM
SPP
CAISO
ERCOT
CAISO
SPP
ERCOT
MISO
PJM
NYISO
ISO NE

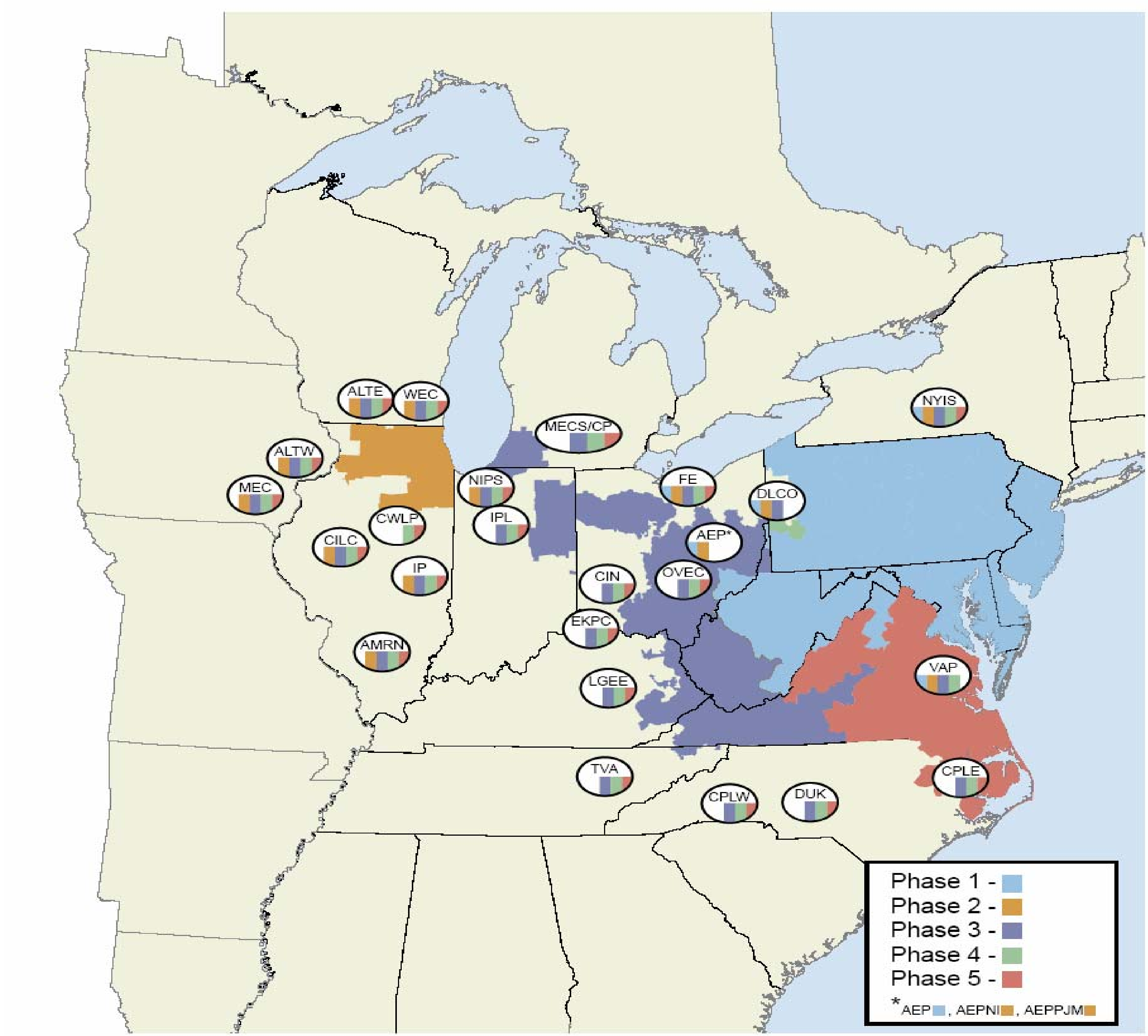
**Table 1. Independent System Operators and Organized Wholesale Markets 2005**

| System Operator | Generating Capacity (MW) |
|---|---|
| ISO-New England (RTO) | 31,000 |
| New York ISO | 37,000 |
| PJM (expanded) (RTO) | 164,000 |
| Midwest ISO (MISO) | 130,000 |
| California ISO | 52,000 |
| ERCOT (Texas) | 78,000 |
| Southwest Power Pool (RTO)[1] | 60,000 |
| ISO/RTO Total | 552,000 |
| Total U.S. Generating Capacity | 970,000 |

[1] Organized markets being developed

*Table 2-4 - Actual PJM footprint summer peak loads: From 1999 to 2005*

| | Date | EPT Hour Ending | PJM Load (MW) | Difference (MW) |
|---|---|---|---|---|
| 1999 | 06-Jul-99 | 1400 | 59,365 | NA |
| 2000 | 26-Jun-00 | 1600 | 56,727 | (2,638) |
| 2001 | 09-Aug-01 | 1500 | 54,015 | (2,712) |
| 2002 | 14-Aug-02 | 1600 | 63,762 | 9,747 |
| 2003 | 22-Aug-03 | 1600 | 61,500 | (2,262) |
| 2004 | 03-Aug-04 | 1700 | 77,887 | 16,387 |
| 2005 | 26-Jul-05 | 1600 | 133,763 | 55,876 |


ALTE
WEC
MECS/CP
NYIS
ALTW
MEC
NIPS
FE
DLCO
CWLP
IPL
AEP*
CILC
IP
CIN
OVEC
EKPC
AMRN
LGEE
VAP
TVA
CPLE
CPLW
DUK
Phase 1 -
Phase 2 -
Phase 3 -
Phase 4 -
Phase 5 -
*AEP, AEPNI, AEPPJM

# BASIC ATTRIBUTES OF U.S. WHOLESALE (SMD) MARKETS

- **Independent System Operator (ISO)**
  - Non-profit entity (effectively) that does not own transmission assets
  - Responsible for operating reliability of network
  - Control area operator (SO)
  - Manages Open Access Transmission Tariff and OASIS
  - Manages voluntary wholesale spot markets for power and ancillary services
  - Manages requests for transmission service, allocation of scarce transmission capacity and network expansions
  - Regional Transmission Expansion Planning process
  - Supports market monitoring and mitigation programs
  - Coordination with neighboring control areas, including imports/exports (cross-border trade)
- **Regulated Incumbent Transmission Owners (TOs)**
  - Functional separation rules due to G&T vertical integration
  - Opportunities/obligations for both regulated and merchant projects

# BASIC FEATURES OF WHOLESALE MARKET DESIGN

- Security constrained bid-based dispatch using state-estimator network model
  - Day-ahead hourly markets
  - Intra-day adjustment and balancing markets (adjustments, imbalances, 5-minutes)
  - Self-scheduling and bilateral contracts permitted subject to imbalance and congestions charges
- Resulting LMPs calculated at each bus
  - Marginal cost of congestion
  - Marginal cost of losses (NE, NY, not yet in PJM)
  - Internalizes network externalities into prices
  - Allocates scarce transmission capacity efficiently
- Market-based provision of operating reserves integrated with day-ahead and real-time energy markets

# BASIC FEATURES OF WHOLESALE MARKET

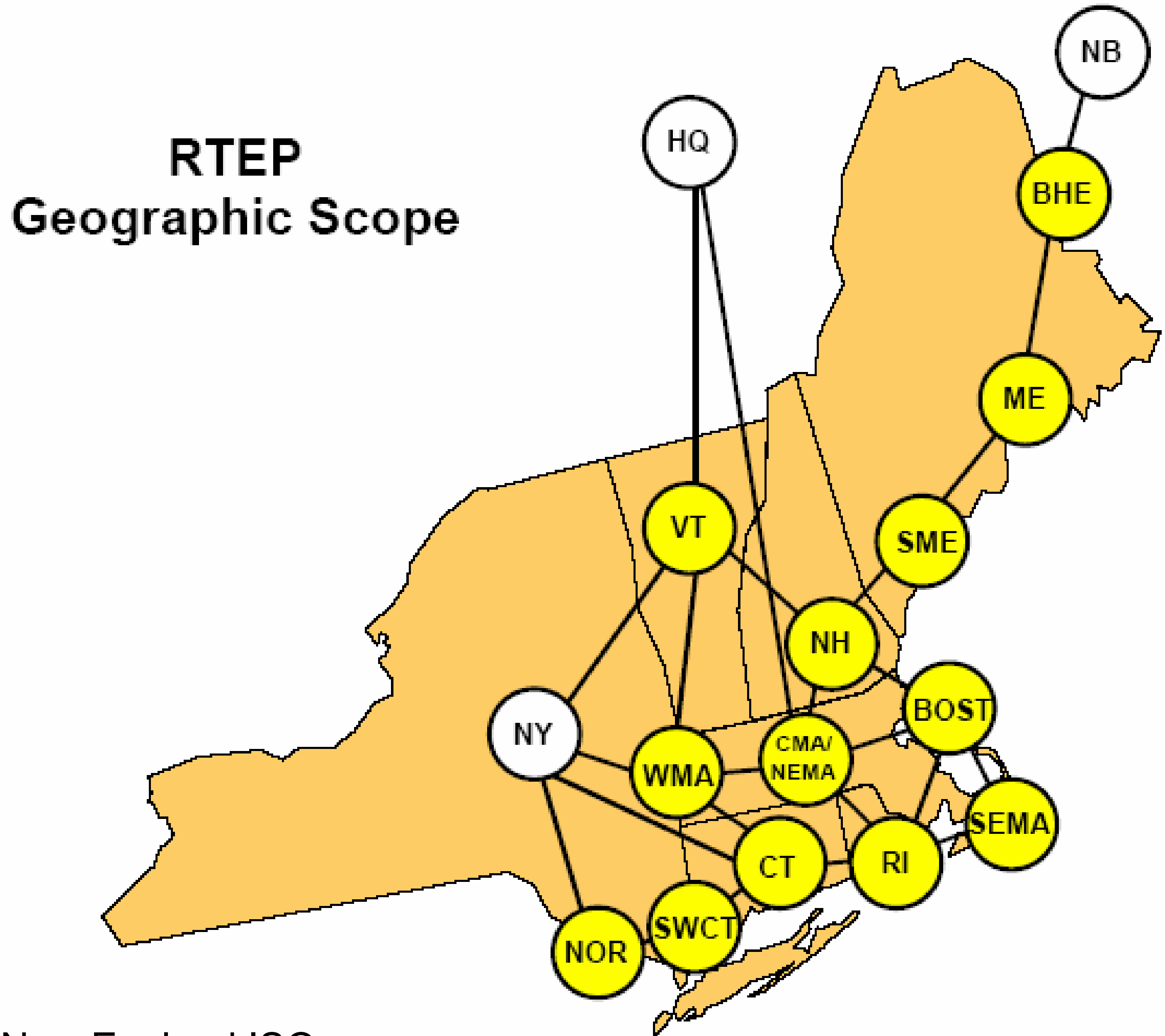
- Financial Transmission Rights (FTRs) are auctioned and traded to provide congestion price hedges
- Also provide property rights to support new merchant transmission investment
- Generating capacity (reserve) obligations imposed on suppliers (e.g. 18% forward reserve margin) and associated "capacity markets" and capacity prices
  - Uniform reserve obligation on all retail suppliers (LSEs)
  - Annual and monthly auctions for "capacity"
  - "Reserve Capacity demand curve" in New York
  - 4-year forward reserve capacity obligation for LSEs agreed in NE and proposed in PJM

# MARKET MONITORING AND MARKET POWER MITIGATION

- $1000/MWh general bid cap on spot energy and capacity markets
- Local market power mitigation rules (e.g. NYC, Boston)
  - Bid caps
  - RMR contracts
  - Must-offer restrictions
  - Interaction with computation of market prices
- Must offer requirements during tight supply conditions
- Ex-post bid/price adjustments
- Monitoring of individual market participant behavior and market performance

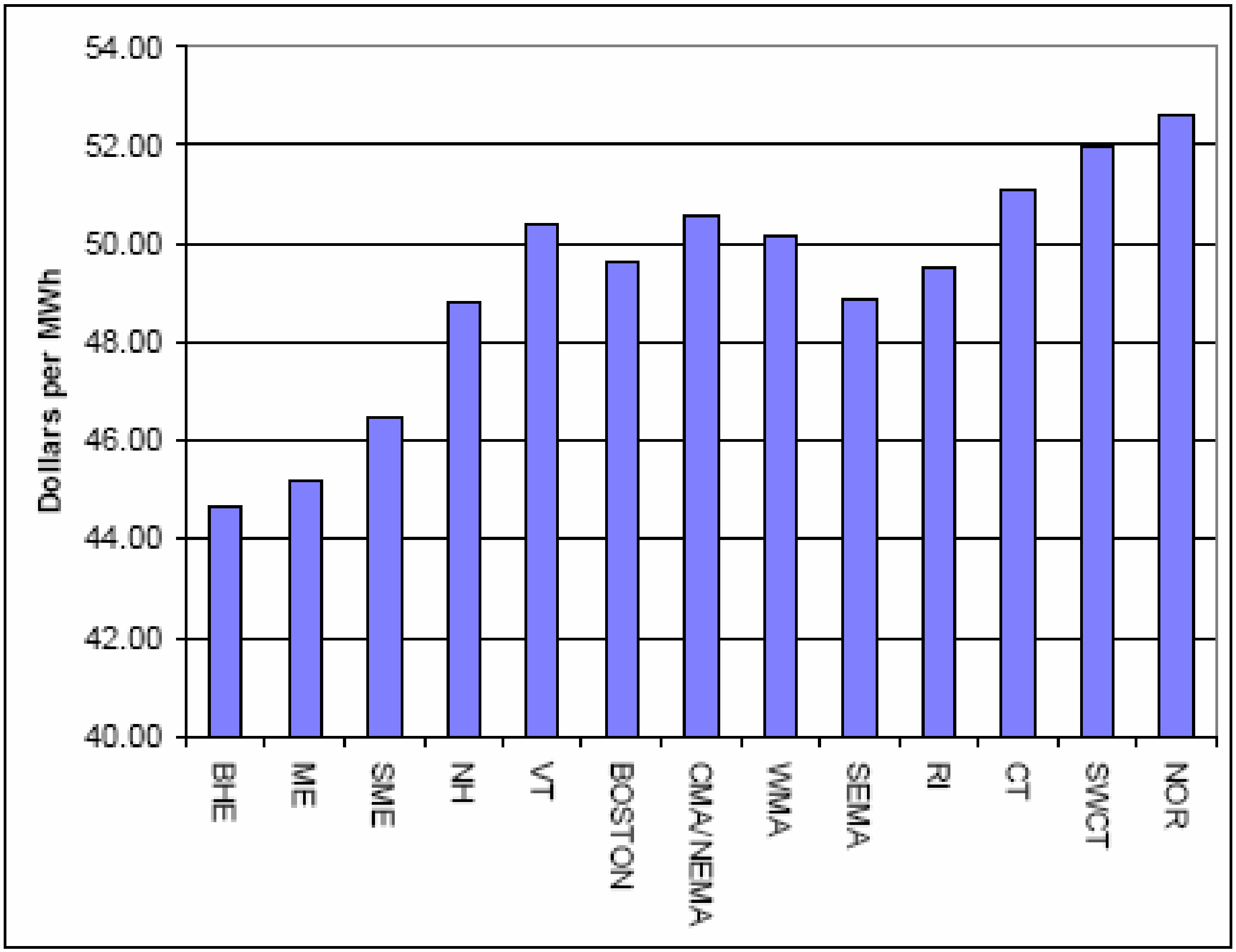
# PERFORMANCE OF SHORT-TERM SMD WHOLESALE MARKETS

- **Short term markets (day-ahead, intra-day adjustment, balancing) function reasonably well within each ISO/RTO**
  - Efficient generator dispatch and higher generator availability
  - Real fuel-price adjusted wholesale prices have declined slightly along with average heat rate of dispatched units since 2000
  - Scarce transmission capacity is allocated efficiently
  - Locational price differences reflect congestion (and marginal losses in NE and NY)
  - Day-ahead, hour-ahead and real time markets are reasonably well arbitraged, but some "gaming" in constrained-on areas ("load pockets")
  - Operating reserves and energy markets are generally well integrated
  - Market power is not a significant problem when measured over a reasonable time period except in load pockets
  - Market redesign has improved performance but also created uncertainty for investors

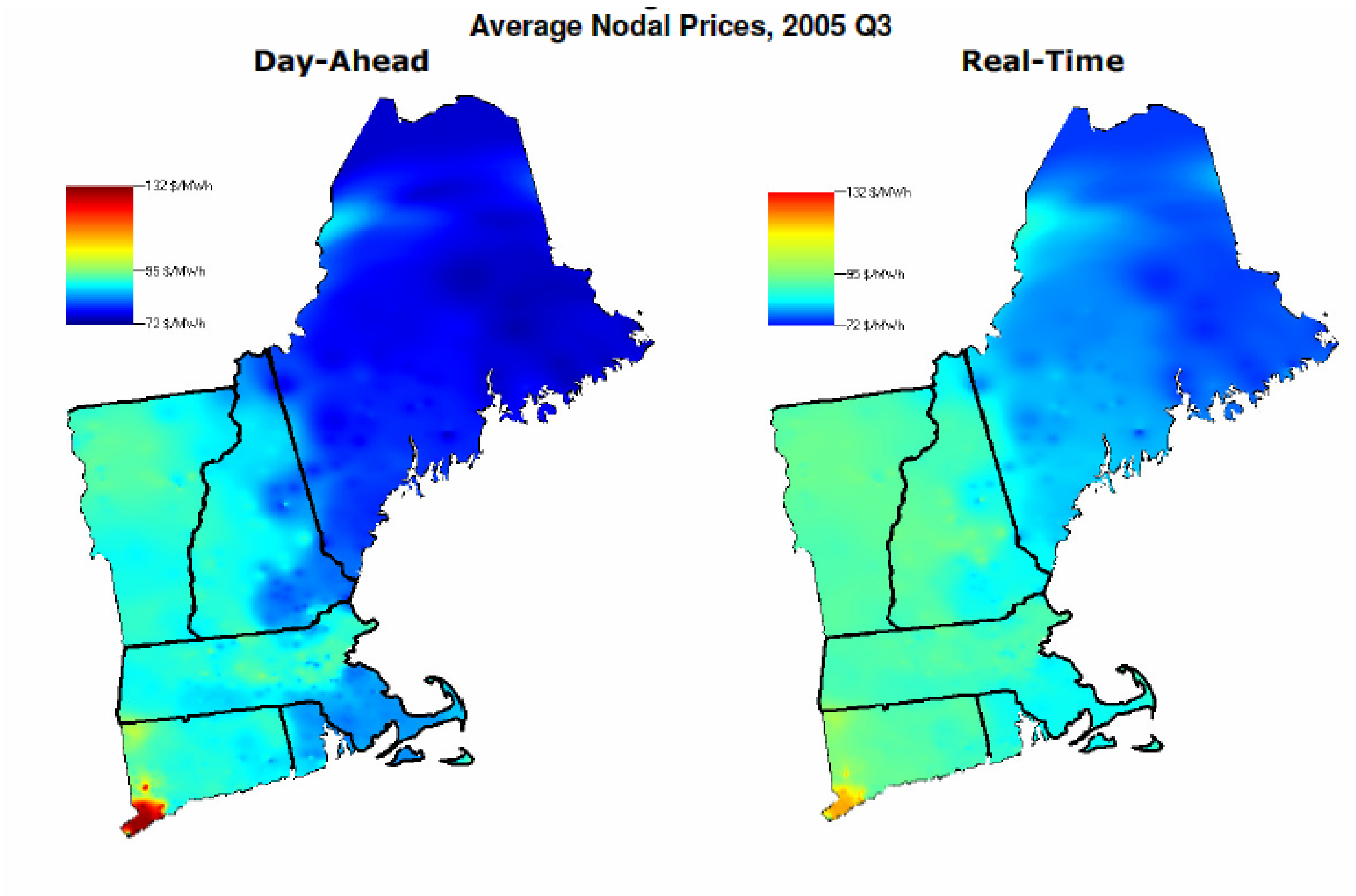



Source:  New England ISO

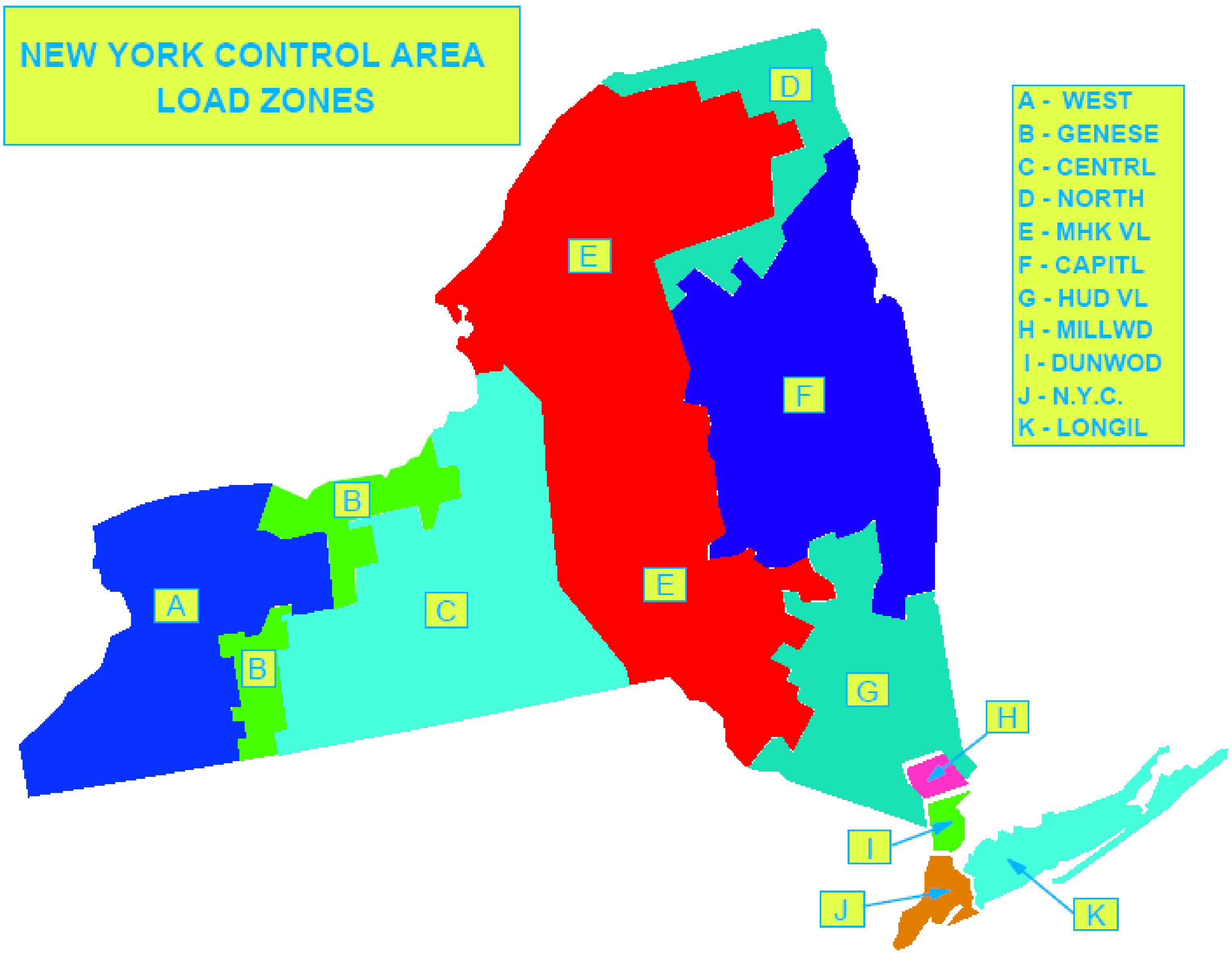
**Figure 10.2**
**Average Locational Marginal Price**
**RTEP Sub-areas, March 2003 to February 2004**



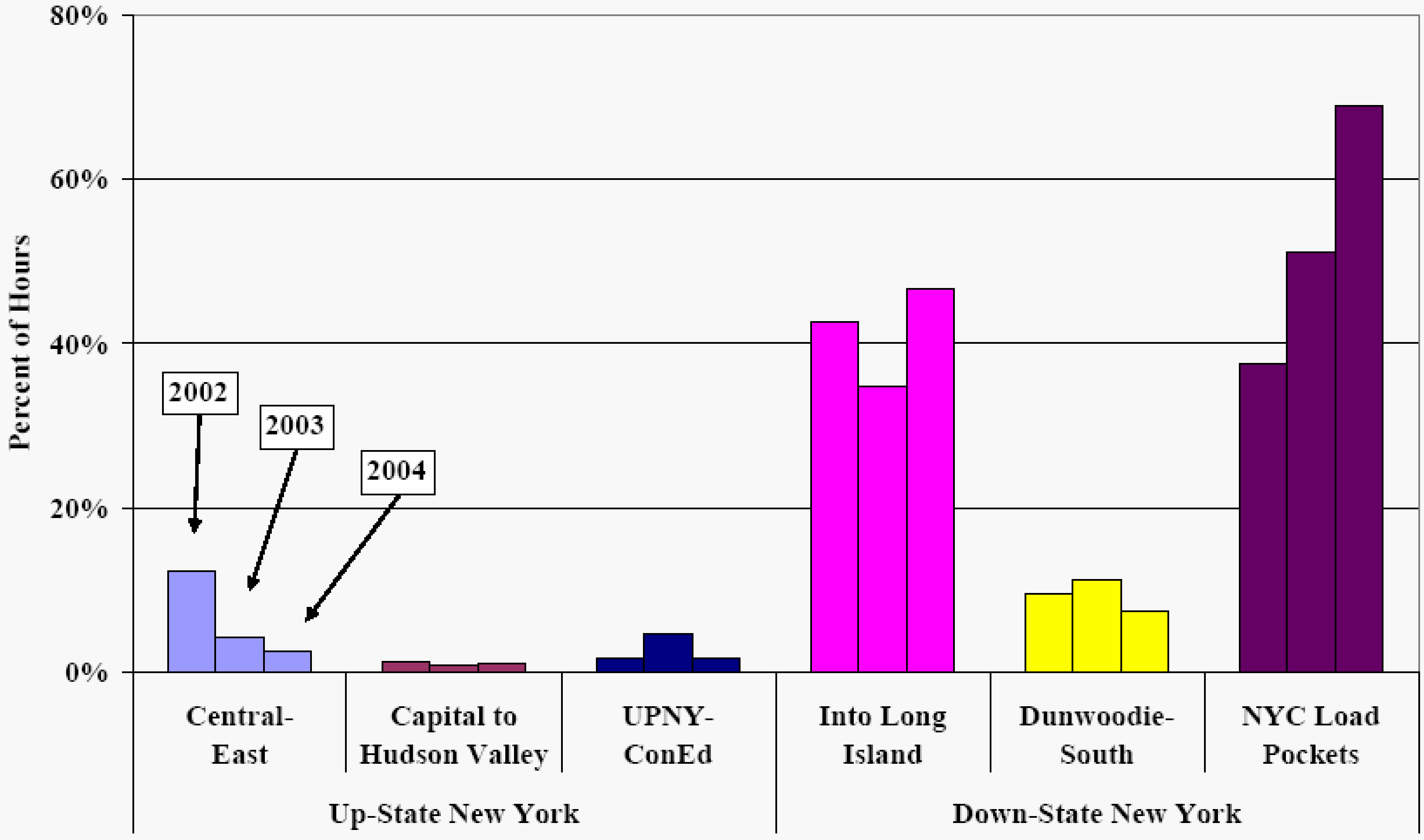

Source: New England ISO


Average Nodal Prices, 2005 Q3
Day-Ahead
Real-Time
132 $/MWh
95 $/MWh
72 $/MWh
132 $/MWh
95 $/MWh
72 $/MWh

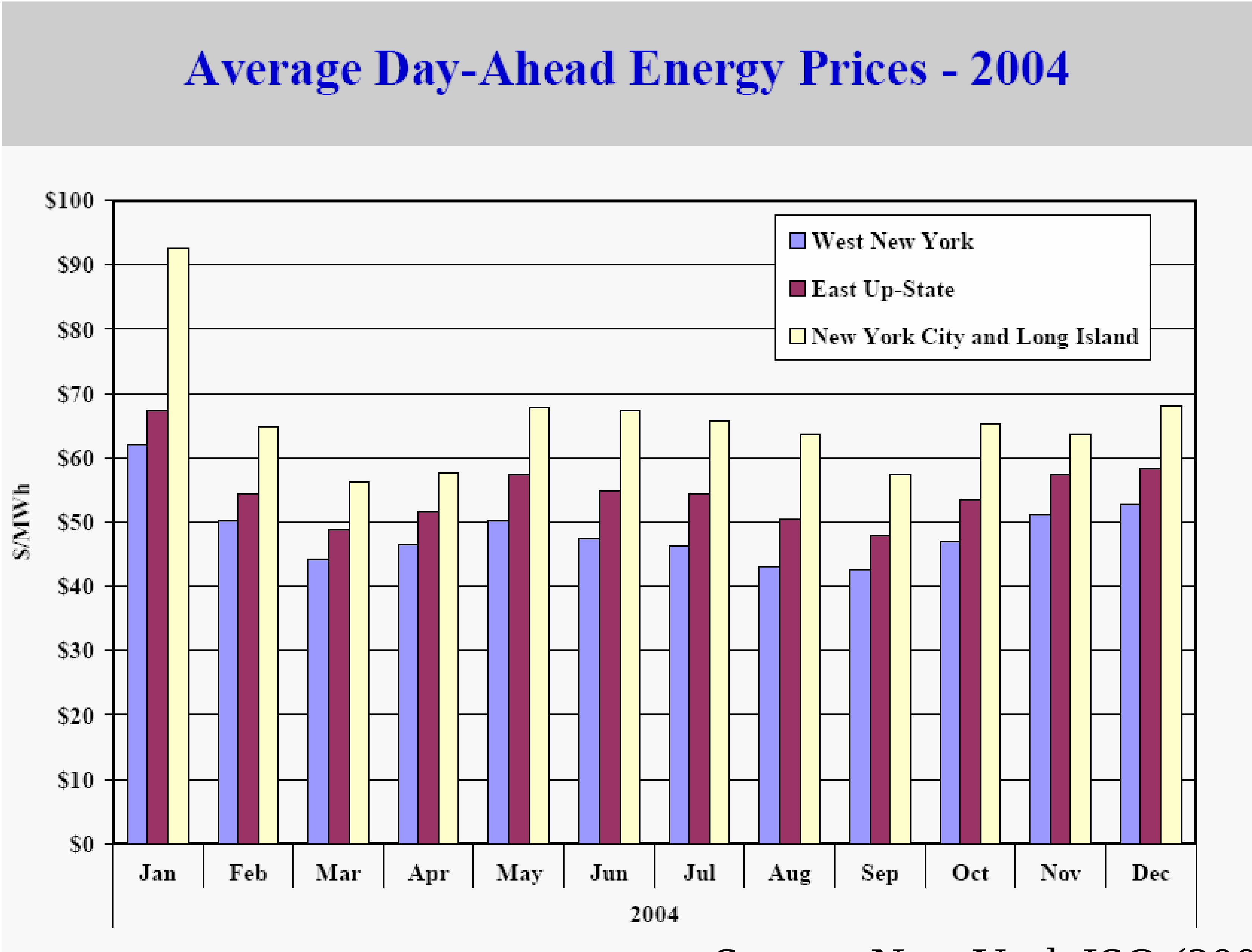
ISO-NE (2006)


NEW YORK CONTROL AREA
LOAD ZONES
A - WEST
B - GENESE
C - CENTRL
D - NORTH
E - MHK VL
F - CAPITL
G - HUD VL
H - MILLWD
I - DUNWOD
J - N.Y.C.
K - LONGIL
A
B
B
C
D
E
E
F
G
H
I
J
K

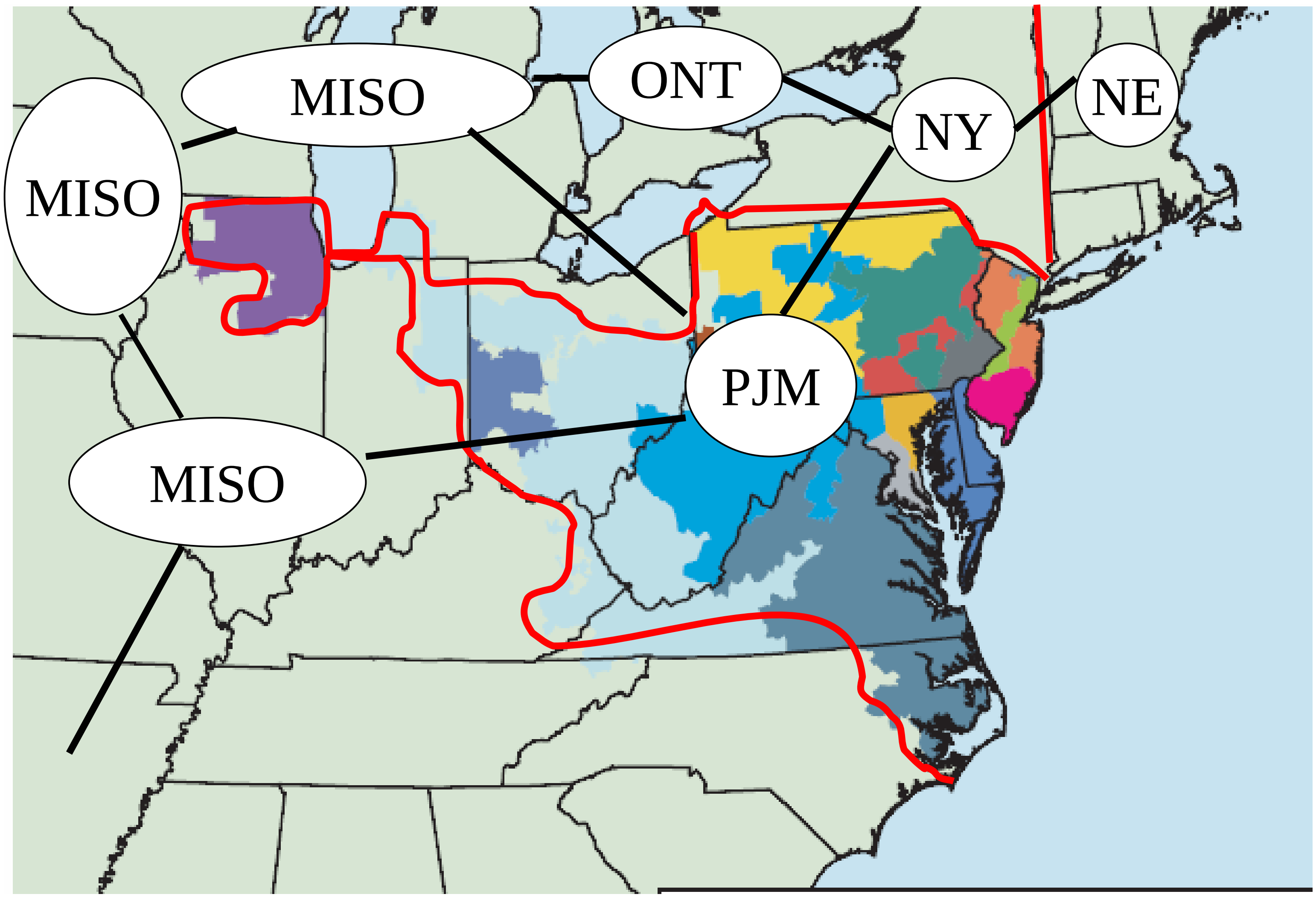
# Frequency of Real-Time Congestion on Major Interfaces 2002 – 2004



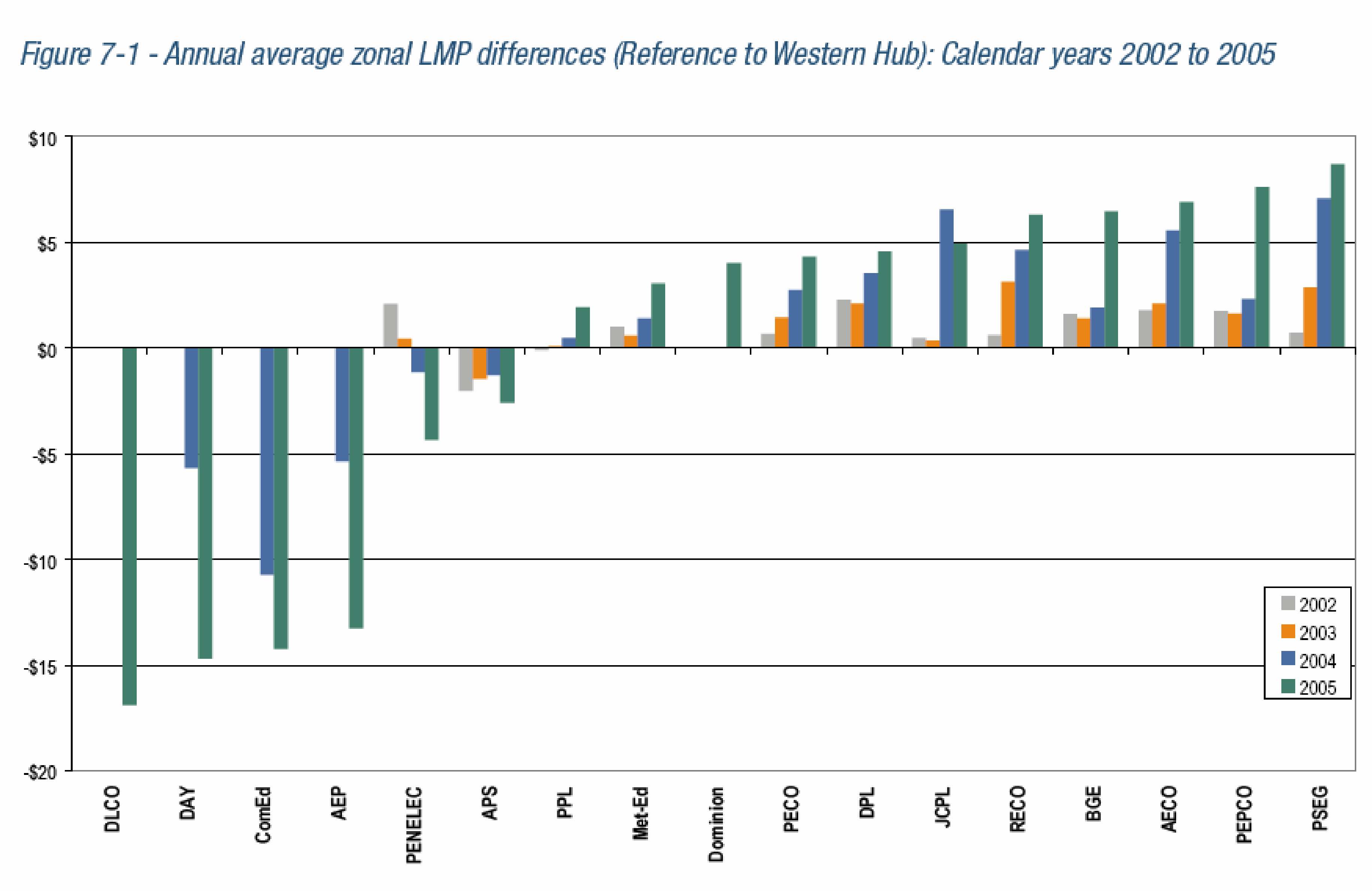

Source: New York ISO (2005)



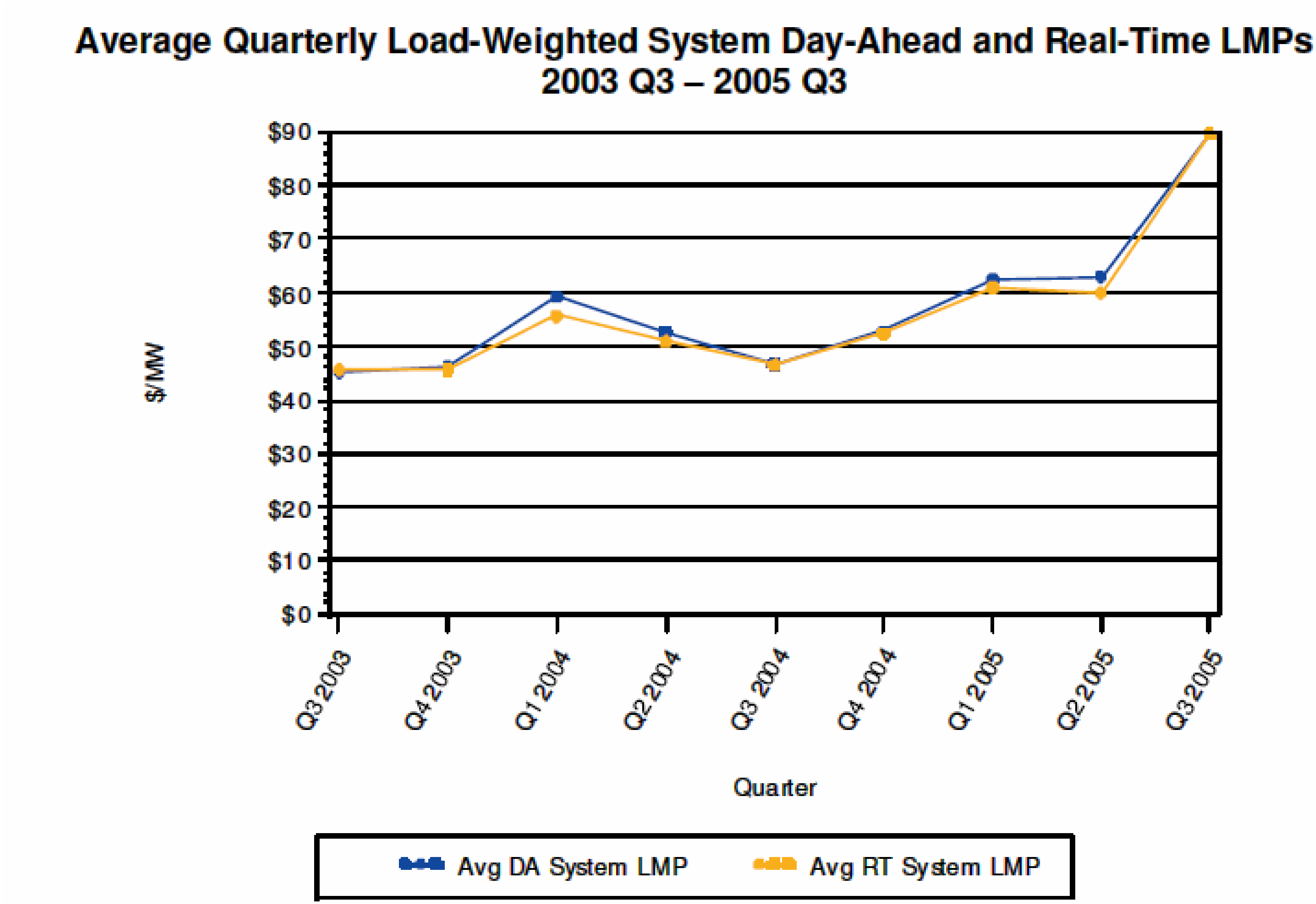

Source: New York ISO (2005)



MISO
MISO
ONT
NY
NE
PJM
MISO

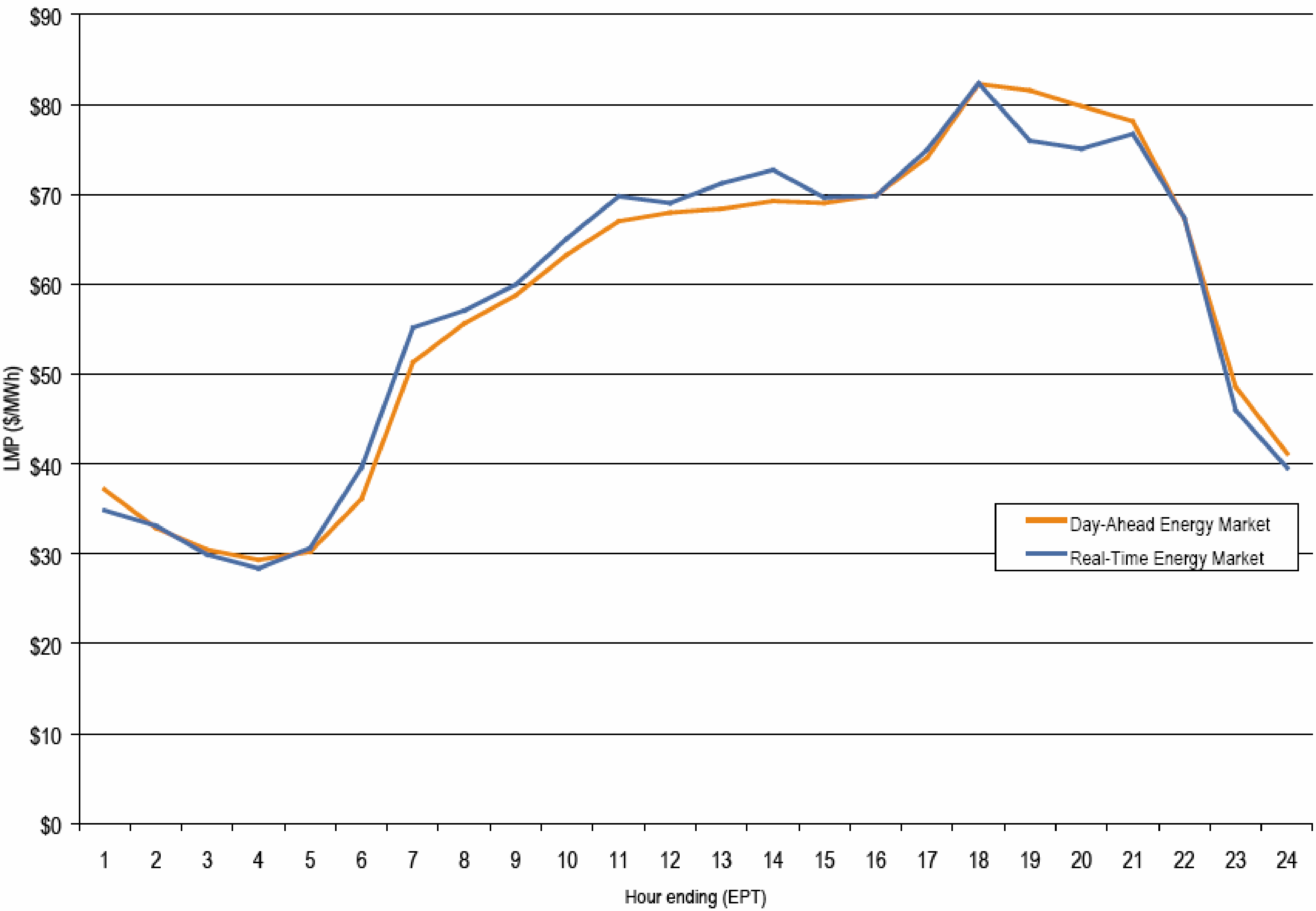


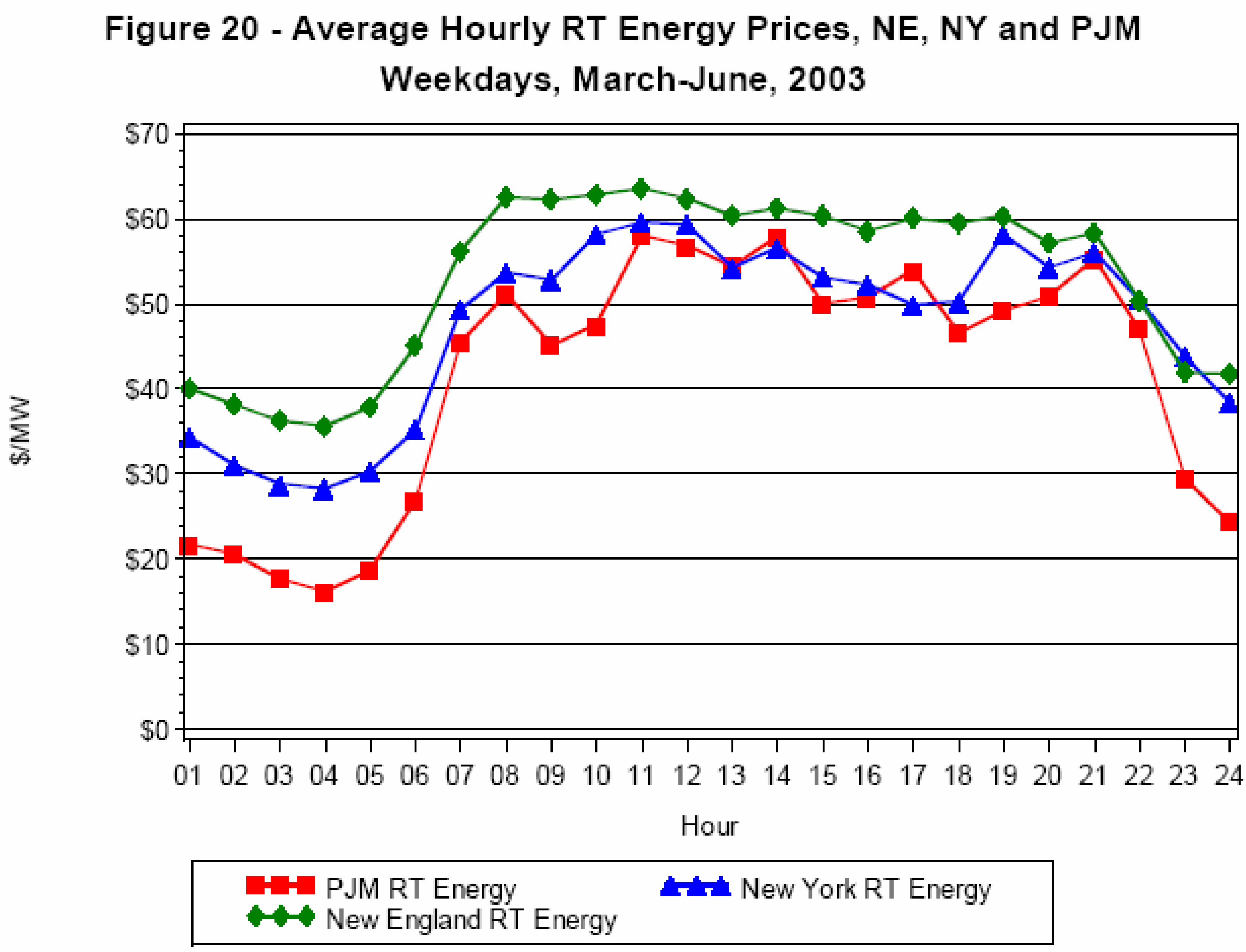

Source: PJM (2006)




SOURCE: ISO-NE (2006)

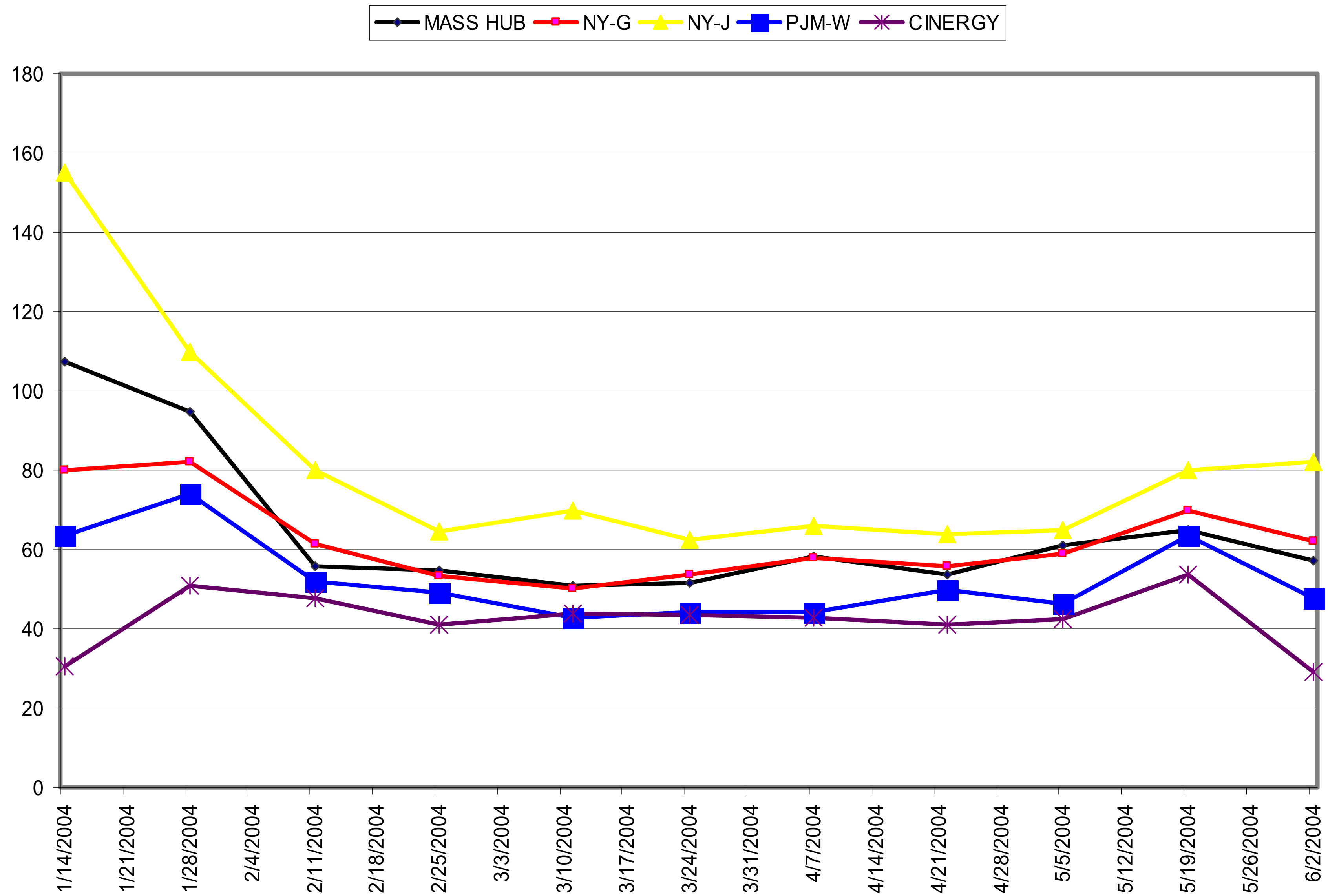
*Figure 2-21 - PJM hourly system average LMP: Calendar year 2005*






Source: ISO New England

# DAY-AHEAD PEAK PRICES (2004) $/MWH



# FUEL PRICE EFFECTS

- Large increases in natural gas prices have led to large increases in wholesale prices in many regions
  - New England market clears on gas and oil fueled generation 85% of the hours
- Makes it difficult for consumers and policymakers to see performance improvements
- Price increases are creating significant political problems now

# U.S. NATURAL GAS WELLHEAD PRICES
# (1998-2005)

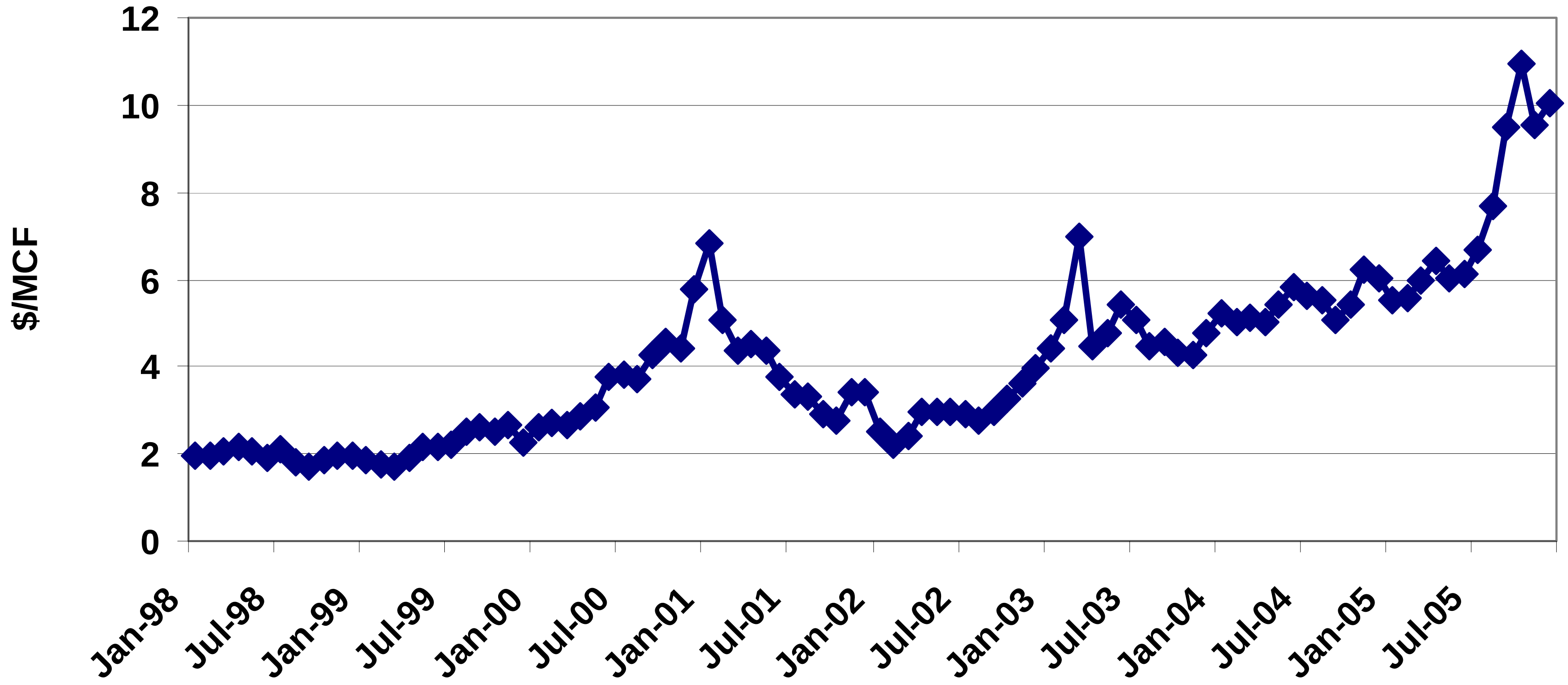


*Table 2-32 - PJM average hourly LMP (Dollars per MWh): Calendar years 1998 through 2005*

| | Locational Marginal Prices (LMPs) | | | Year-to-Year Changes | | |
|---|---|---|---|---|---|---|
| | Average | Median | Standard Deviation | Average | Median | Standard Deviation |
| 1998 | $21.72 | $16.60 | $31.45 | NA | NA | NA |
| 1999 | $28.32 | $17.88 | $72.42 | 30.4% | 7.7% | 130.3% |
| 2000 | $28.14 | $19.11 | $25.69 | (0.6%) | 6.9% | (64.5%) |
| 2001 | $32.38 | $22.98 | $45.03 | 15.1% | 20.3% | 75.3% |
| 2002 | $28.30 | $21.08 | $22.40 | (12.6%) | (8.3%) | (50.3%) |
| 2003 | $38.27 | $30.79 | $24.71 | 35.2% | 46.1% | 10.3% |
| 2004 | $42.40 | $38.30 | $21.12 | 10.8% | 24.4% | (14.5%) |
| 2005 | $58.08 | $47.18 | $35.91 | 37.0% | 23.2% | 70.0% |

Source: PJM (2006)

# OPERATING EFFICIENCIES

- Nuclear units
  - Availability has improved
  - Non-fuel O&M has declined
- Fossil units
  - Availability has improved
  - Heat rates have improved
  - Non-fuel O&M has declined
- Distribution
  - O&M costs have declined
- Transmission congestion has increased

# PERFORMANCE PROBLEMS WITH SHORT-TERM SMD WHOLESALE MARKETS

- Problems with short term SMD markets
  - Energy prices do not rise fast enough or high enough during scarcity conditions
  - System operators need more “products” to maintain reliability without undermining market performance (OOM)
  - “Seams” issues are slowly being resolved through better integration of markets between RTO/ISOs or by internalization (PJM expansions)
  - Discrimination by vertically integrated transmission owners and incomplete unbundling is a continuing problem in some areas
  - Demand side participation has been slow to emerge
  - Market power in load pockets is a continuing problem
  - Liquidity in forward markets is being restored slowly

# LONGER TERM SMD MARKET PERFORMANCE ISSUES

- Policymakers are worried about “shortages” resulting from inadequate investment in generation and transmission
- Energy-only markets do not provide adequate incentives for new investment consistent with reliability rules
- Existing capacity obligations/markets provide partial but inadequate safety valve and are being redesigned
- Transmission planning and investment mechanisms have been slow to evolve and have been side-tracked by FERC’s initial focus on “market driven” transmission investment
  - Congestion has increased significantly since 1998
  - Better transmission planning and investment frameworks have been adopted in NE, PJM and MISO
- Reliability planning and investment rules have not been harmonized with market mechanisms and incentives

# NEW U.S. GENERATING CAPACITY

| YEAR | CAPACITY ADDED (MW) |
|---|---|
| 1997 | 4,000 |
| 1998 | 6,500 |
| 1999 | 10,500 |
| 2000 | 23,500 |
| 2001 | 48,000 |
| 2002 | 55,000 |
| 2003 | 50,000 |
| 2004 | 20,000 |
| 2005 | 15,000 |
| | 230,000 Mw |

Source: EIA

# GENERATING CAPACITY UNDER CONSTRUCTION
## January 2005

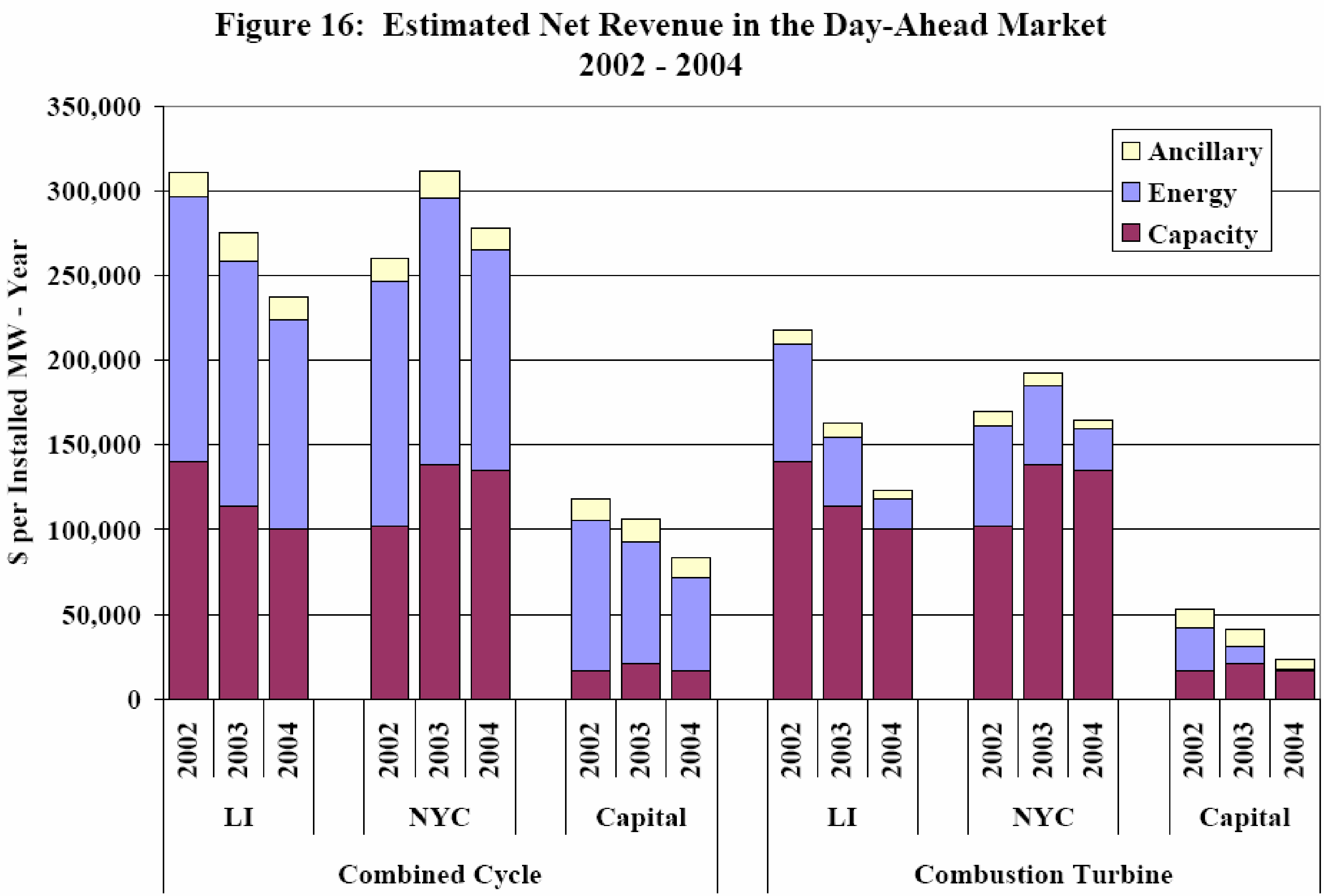
| | |
|---|---|
| ISO-NE | 3 Mw |
| NY-ISO | 3,700 Mw |
| PJM (traditional) | 1,800 Mw |

Source: Argus

**Theoretical Net Energy and Ancillary Services Revenue For A New Combustion Turbine Peaking Plant (PJM) $/MW- Year**

| Year | ***Net* Energy and Ancillary Services Revenue** |
|---|---:|
| 1999 | $64,445 |
| 2000 | 18,866 |
| 2001 | 41,659 |
| 2002 | 25,622 |
| 2003 | 14,544 |
| 2004 | 10,453 |
| 2005 | 18,000 |
| Average | $27,700 |

Annualized 20-year Fixed Cost ~ $70,000/Mw/year



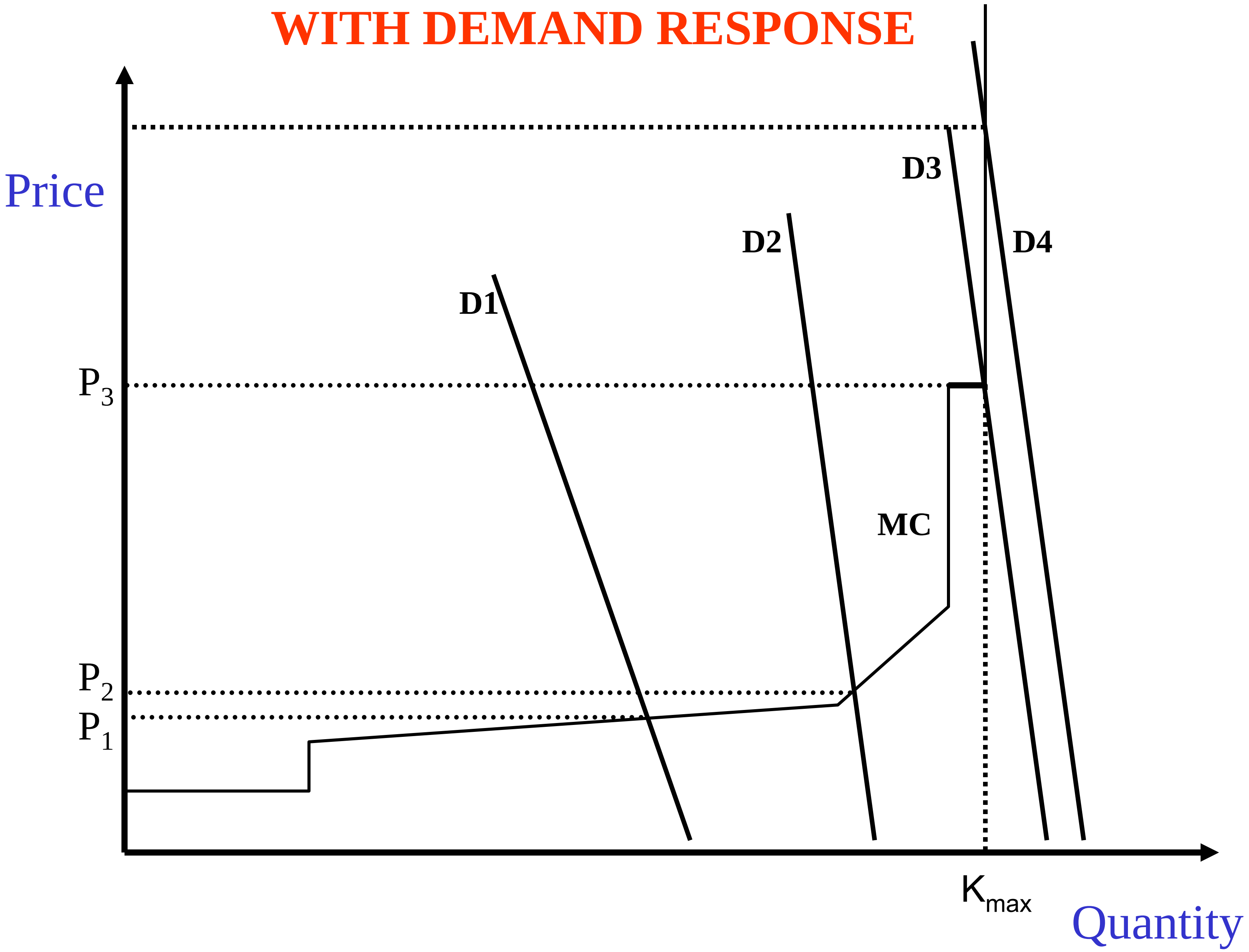

New York ISO (2005)

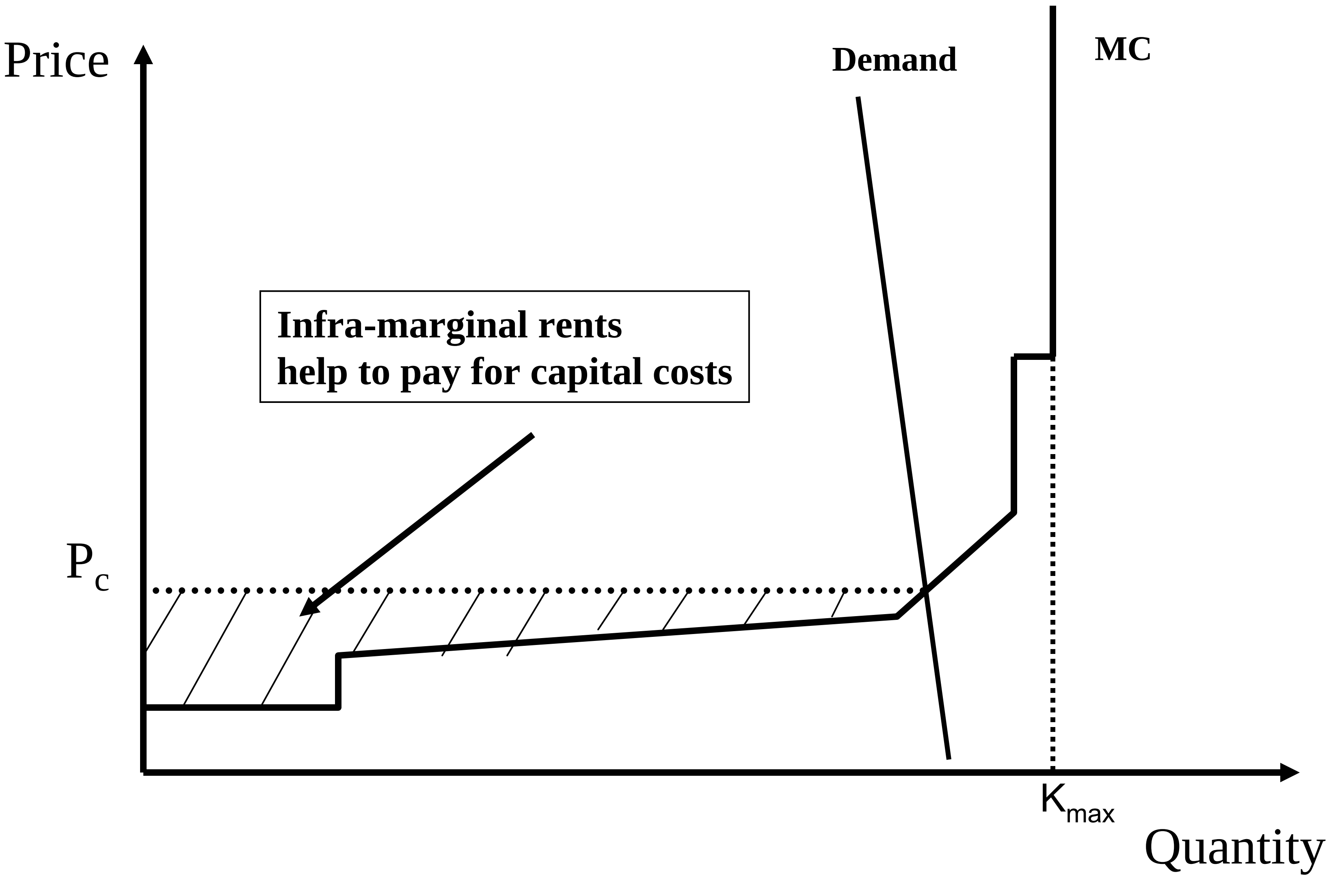
# SCARCITY RENTS PRODUCED DURING OP-4 CONDITIONS ($1000 Price Cap) ($/Mw-Year)

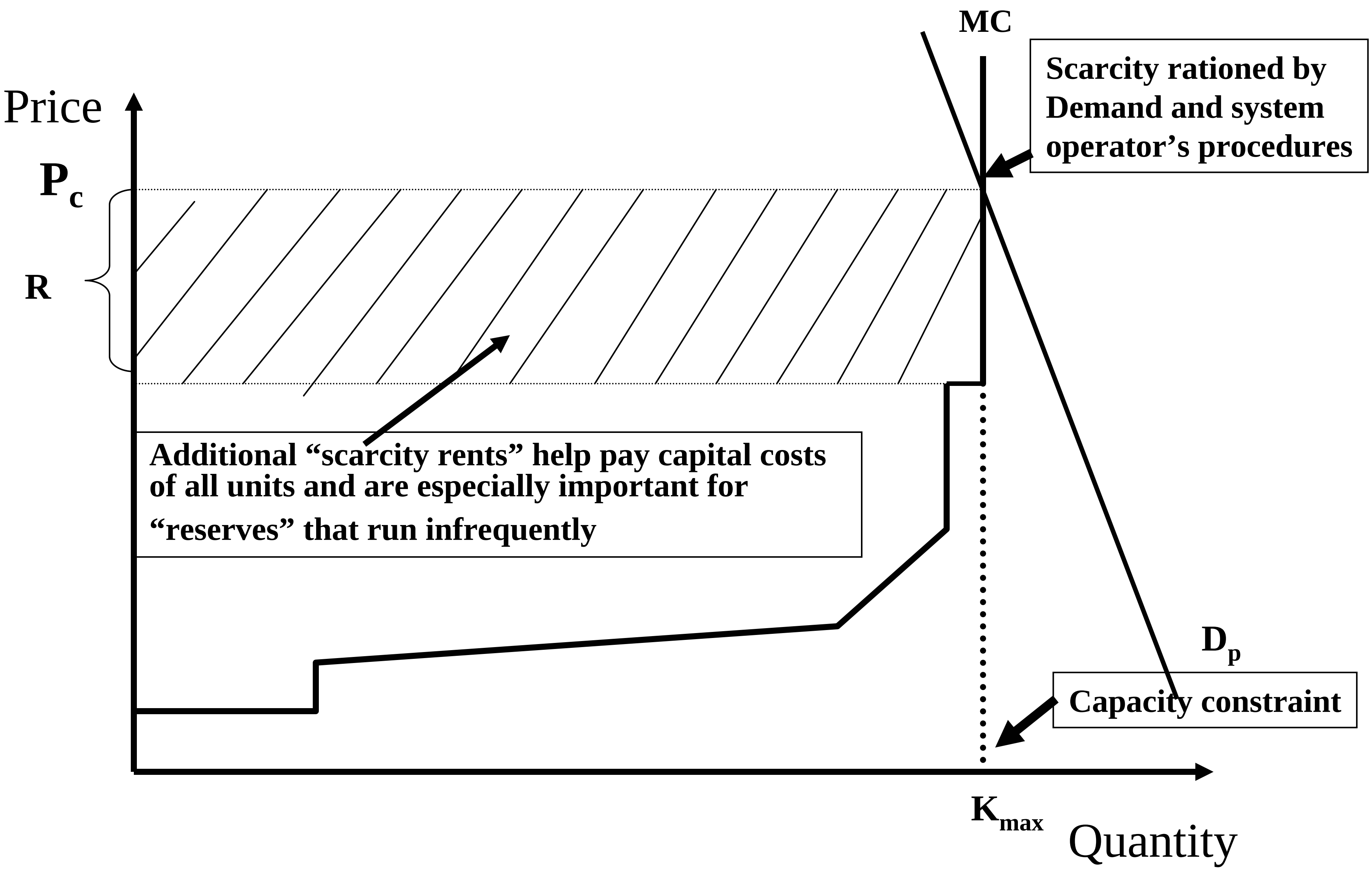
| YEAR | ENERGY MC=50 | ENERGY MC=100 | OPERATING RESERVES | OP-4 HOURS/ (Price Cap Hit) |
|---|---|---|---|---|
| 2002 | $ 5,070 | $ 4,153 | $ 4,723 | 21 (3) |
| 2001 | $15,818 | $14,147 | $11,411 | 41 (15) |
| 2000 | $ 6,528 | $ 4,241 | $ 4,894 | 25 (5) |
| 1999 | $18,874 | $14,741 | $19,839 | 98 (1) |
| Mean | $ 11,573 | $ 9,574 | $10,217 | 46 (6) |

Peaker Fixed-Cost Target: $60,000 - $70,000/Mw-year

# IDEALIZED WHOLESALE ELECTRICITY MARKET WITH DEMAND RESPONSE

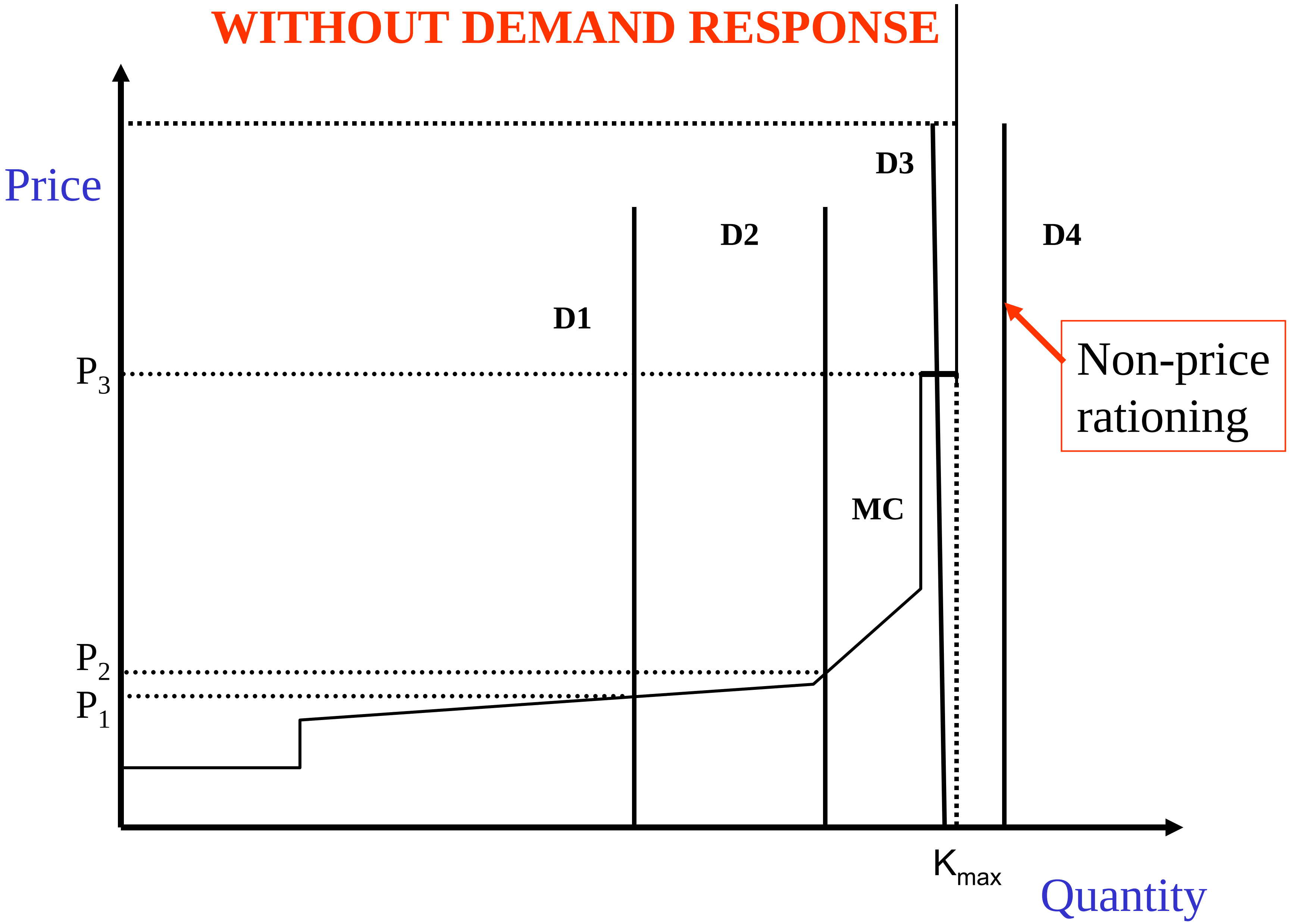



Price
Demand
MC
Infra-marginal rents
help to pay for capital costs
$P_c$
$K_{max}$
Quantity

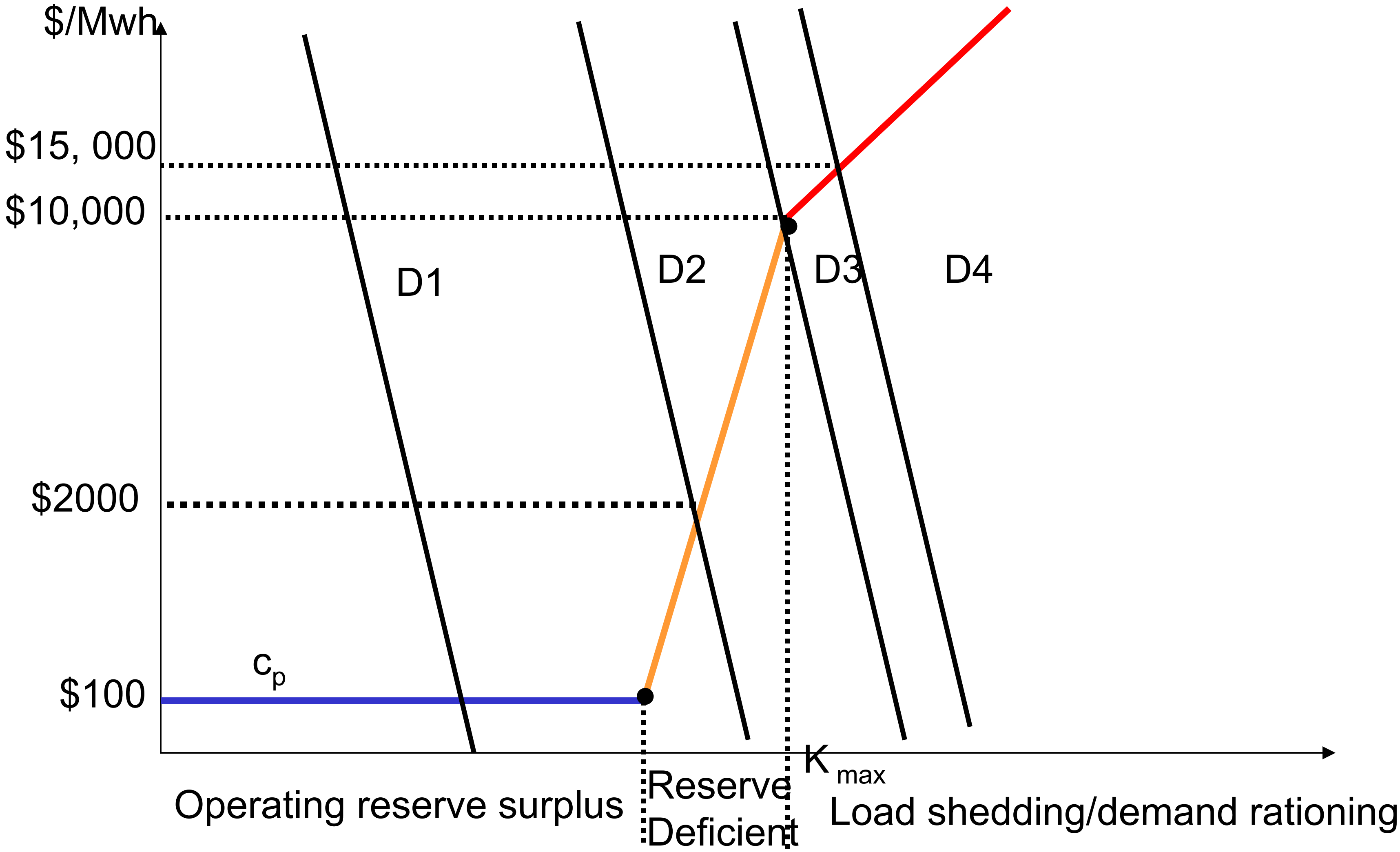


MC
Scarcity rationed by Demand and system operator's procedures
Price
$P_c$
R
Additional "scarcity rents" help pay capital costs of all units and are especially important for "reserves" that run infrequently
$D_p$
Capacity constraint
$K_{max}$
Quantity

# WHOLESALE ELECTRICITY MARKET WITHOUT DEMAND RESPONSE



# IDEALIZED "PEAK PERIOD" WHOLESALE MARKET PRICE PATTERNS




Joskow-Tirole (2005c)

## 2004 NERC-Reported Demand Response

| | Estimated Peak Demand Response (MW) | Actual Peak Demand (MW) | Estimated Demand Response as Share of Peak Demand | Peak Demand Reponse Growth from 2003 (MW) |
|---|---|---|---|---|
| ECAR | 2,643 | 95,300 | 3% | -313 |
| ERCOT | 892 | 58,531 | 2% | 173 |
| FRCC | 2,822 | 42,243 | 7% | 27 |
| MAAC | 1,082 | 52,049 | 2% | -191 |
| MAIN | 3,191 | 53,348 | 6% | -18 |
| MRO | 544 | 34,852 | 2% | -1,052 |
| NPCC | 2,115 | 98,454 | 2% | 2,115 |
| SERC | 5,781 | 157,678 | 4% | 221 |
| SPP | 990 | 39,893 | 2% | -430 |
| WECC | 2,561 | 141,100 | 2% | 740 |
| **TOTAL NERC** | **22,621** | **773,448** | **3%** | **1,272** |

Source: Derived from NERC Summer Assessments for 2003, 2004, and 2005. Note: "Estimated peak demand response" includes interruptible demand and direct-control, demand-side management.

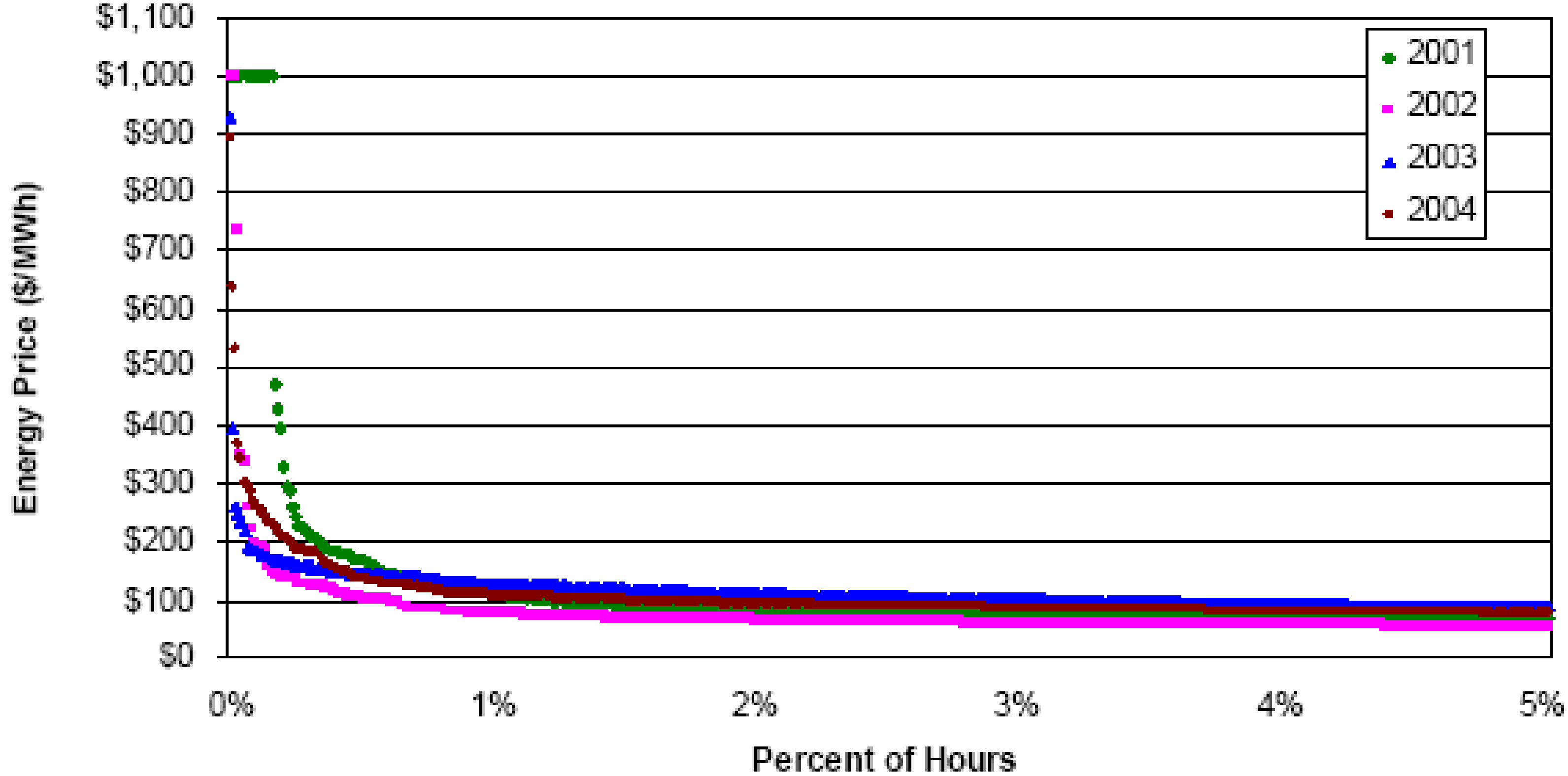
FERC (2005)

# WHY DON'T "ENERGY-ONLY" MARKETS PROVIDE ADEQUATE PRICE SIGNALS?

- **Several factors "truncate" the upper tail of the distribution of spot energy prices**
  - Price caps and other market power mitigation mechanisms
    - Where did $1000/Mwh come from?
  - Prices are too low during operating reserve deficiency conditions for a variety of challenging implementation problems
  - Administrative rationing of scarcity rather than demand/price rationing of scarcity depresses prices
  - "Reliability" actions ahead of market price response keep prices low
  - SO dispatch decisions that are not properly reflected in market prices (OOM; too few "products" to manage the network?)
- **Consumer valuations may be inconsistent with traditional reliability criteria**
  - The implicit value of lost load associated with "one-day of a single firm load curtailment event in ten-year" criterion is very high and inconsistent with reliability of the distribution system (NPCC ~ $150,000/Mwh)
  - Administrative rationing increases the cost of outages to consumers

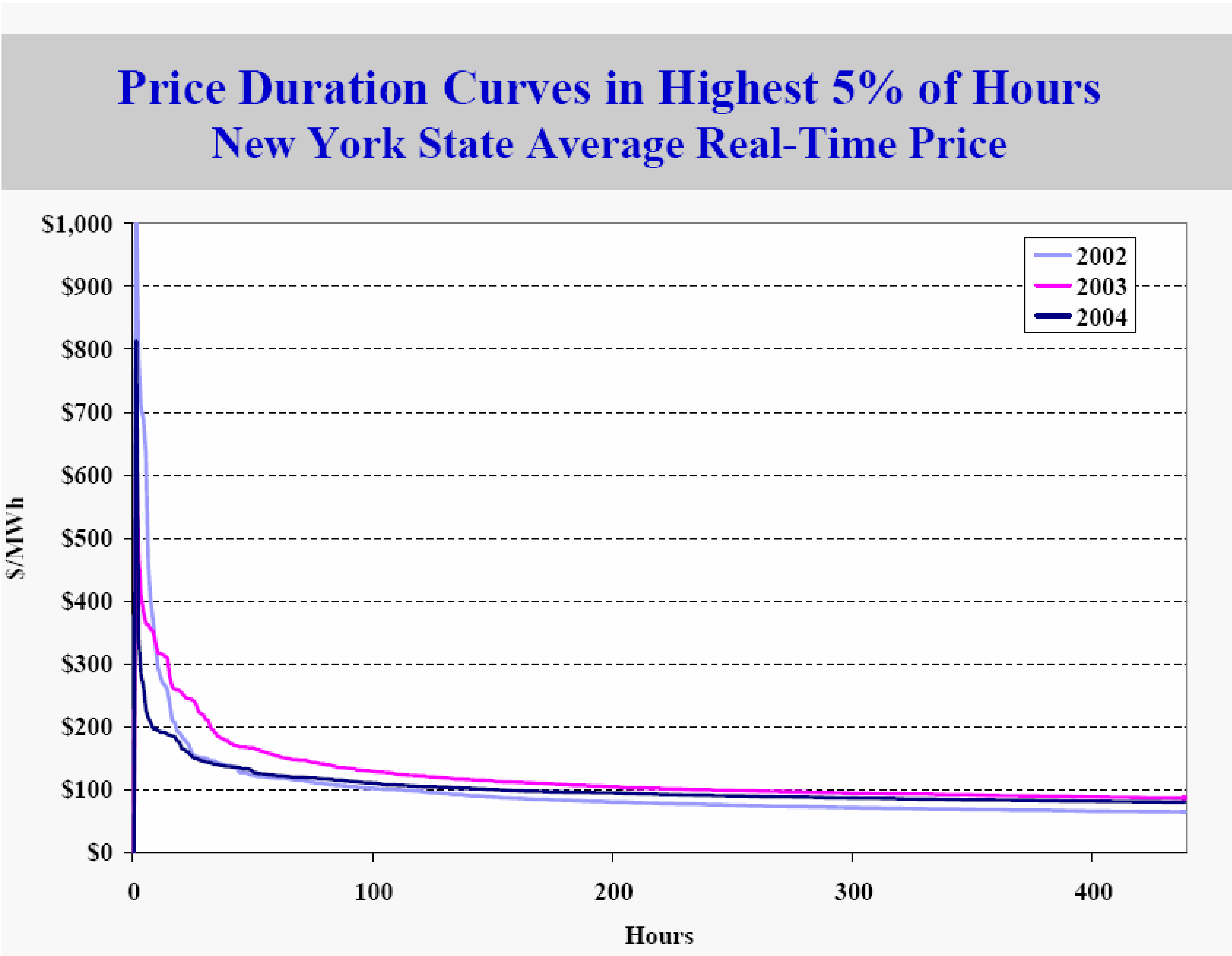
**Figure 18**

**System Price Duration Curves, Prices in Most Expensive 5% of Hours 2001-2004**



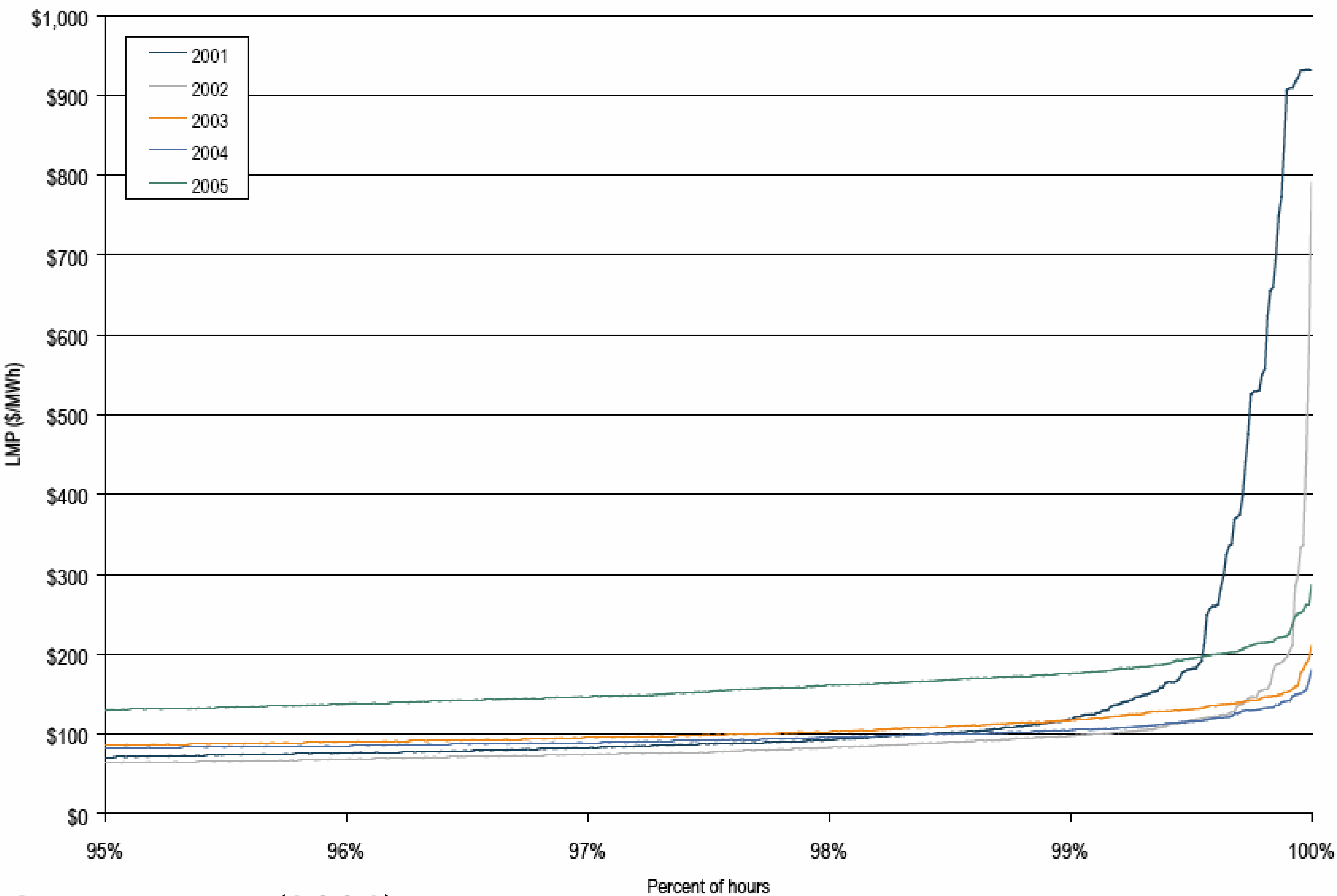

System Price is single Energy-Clearing Price for Interim Market Period ending Feb. 28, 2003, and load-weighted Real-Time Energy Market LMPs for Mar. 2003 - Dec. 2004.

Sorce: ISO New England (2005)



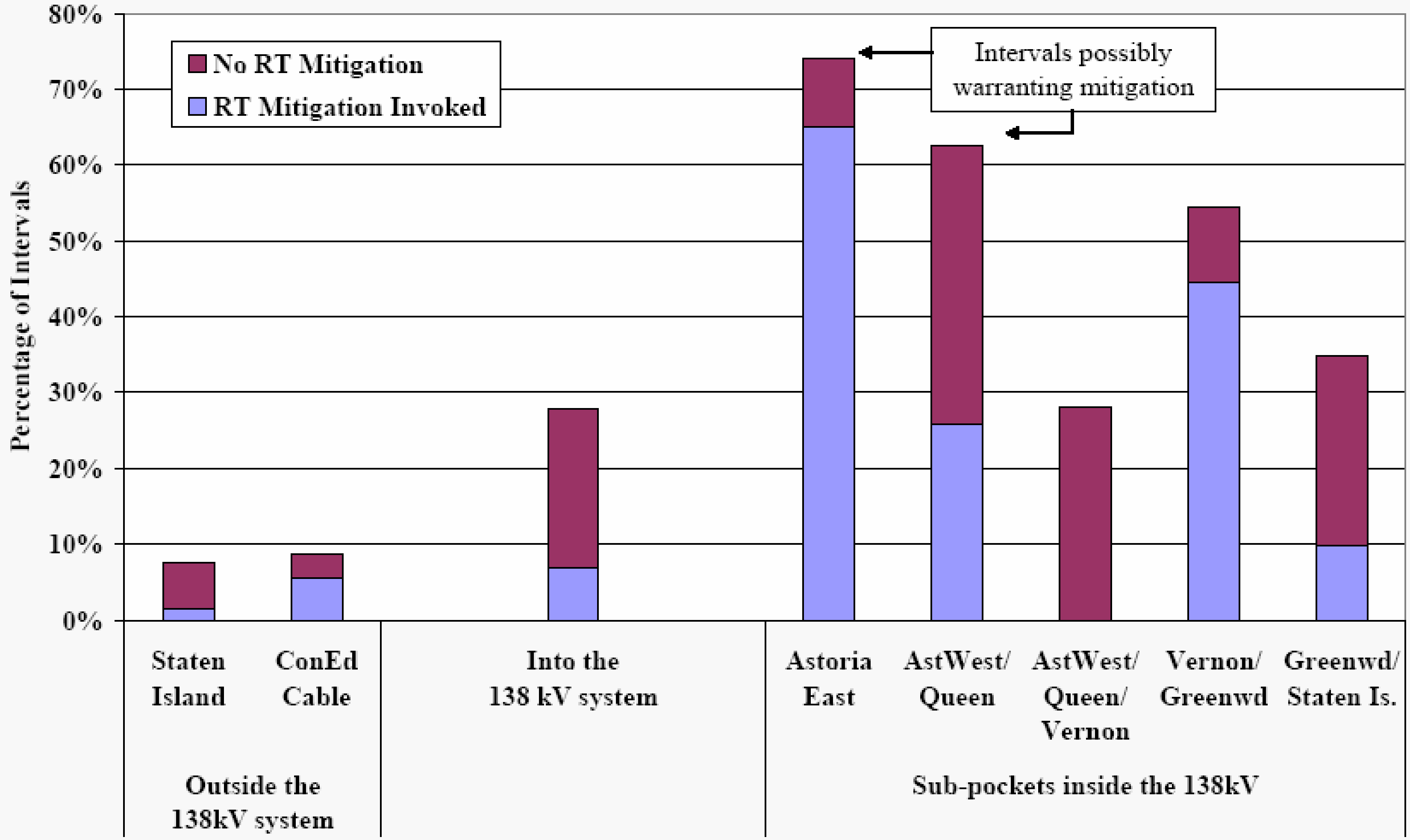

Source: NYISO (2005)

*Figure 2-17 - Price duration curves for the PJM Real-Time Energy Market during hours above the 95th Percentile: Calendar years 2001 through 2005*




Source: PJM (2006)

# Frequency of Real-Time Constraints and Mitigation
## New York City Load Pockets in 2004




Source: NYISO (2005)

Figure 12 - Day-Ahead and Real-Time Spark Spreads for a Gas-Fired Unit with an 8MMBtu/MWh Heat Rate, January 12 - January 19, 2004

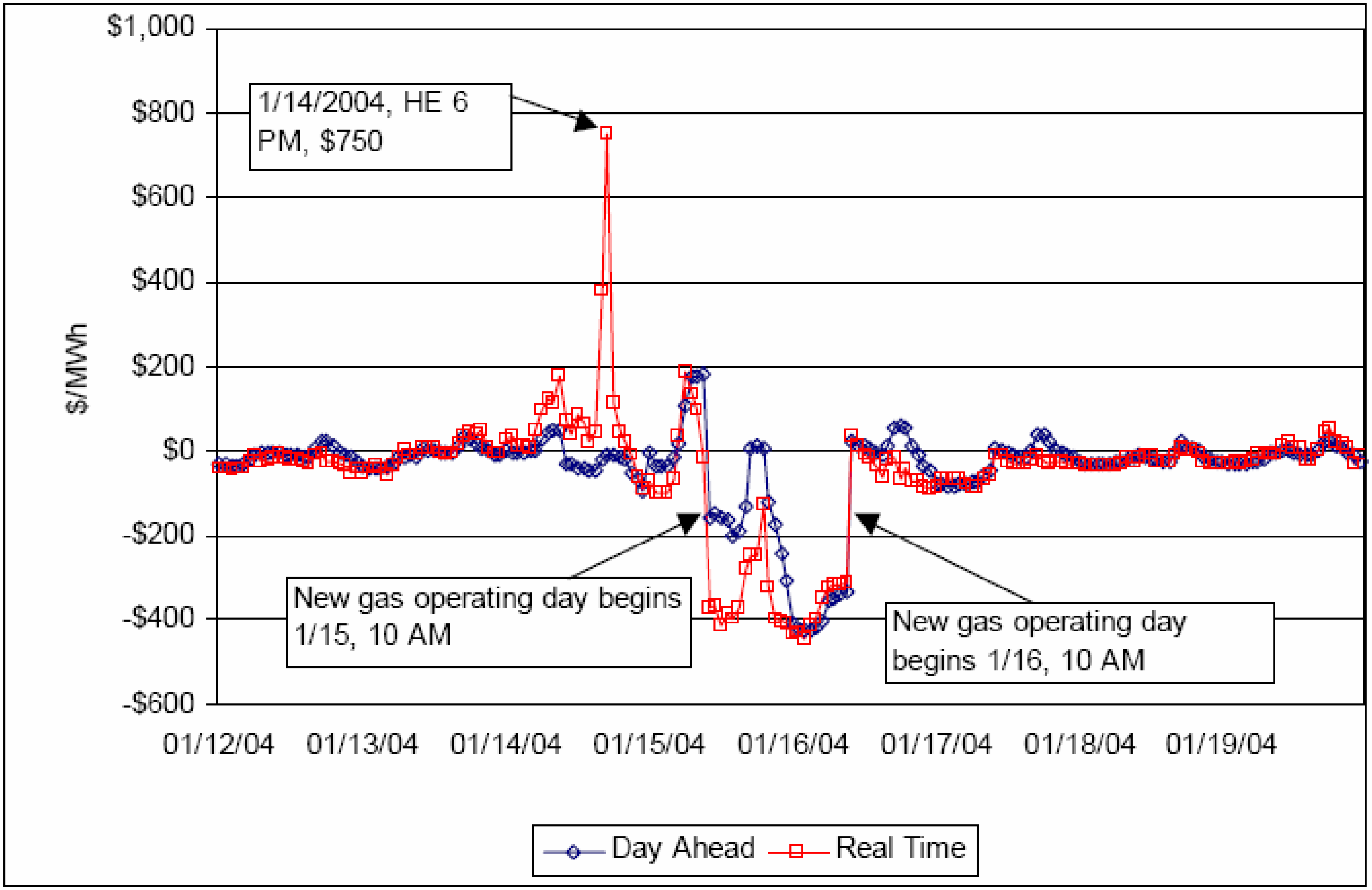
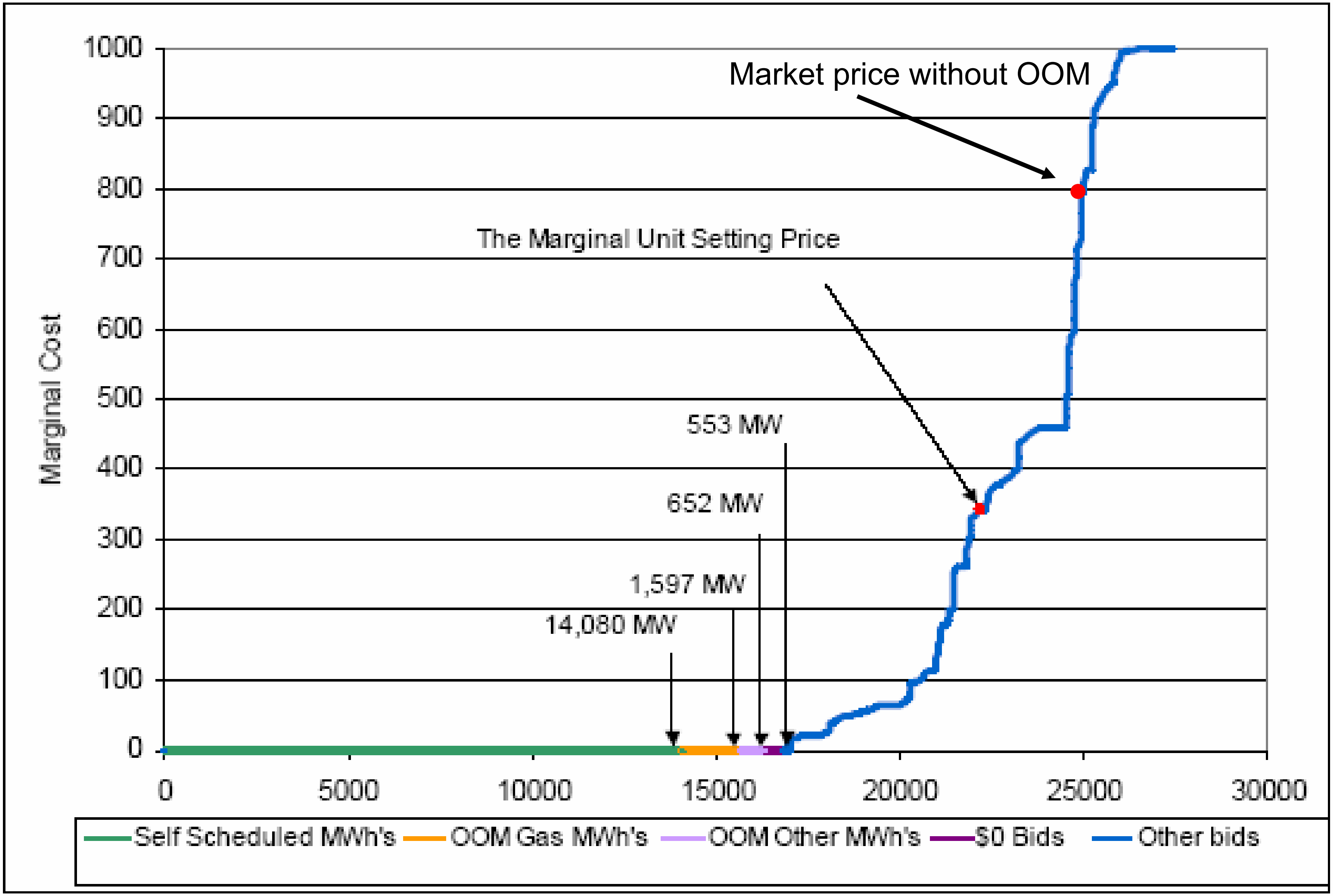
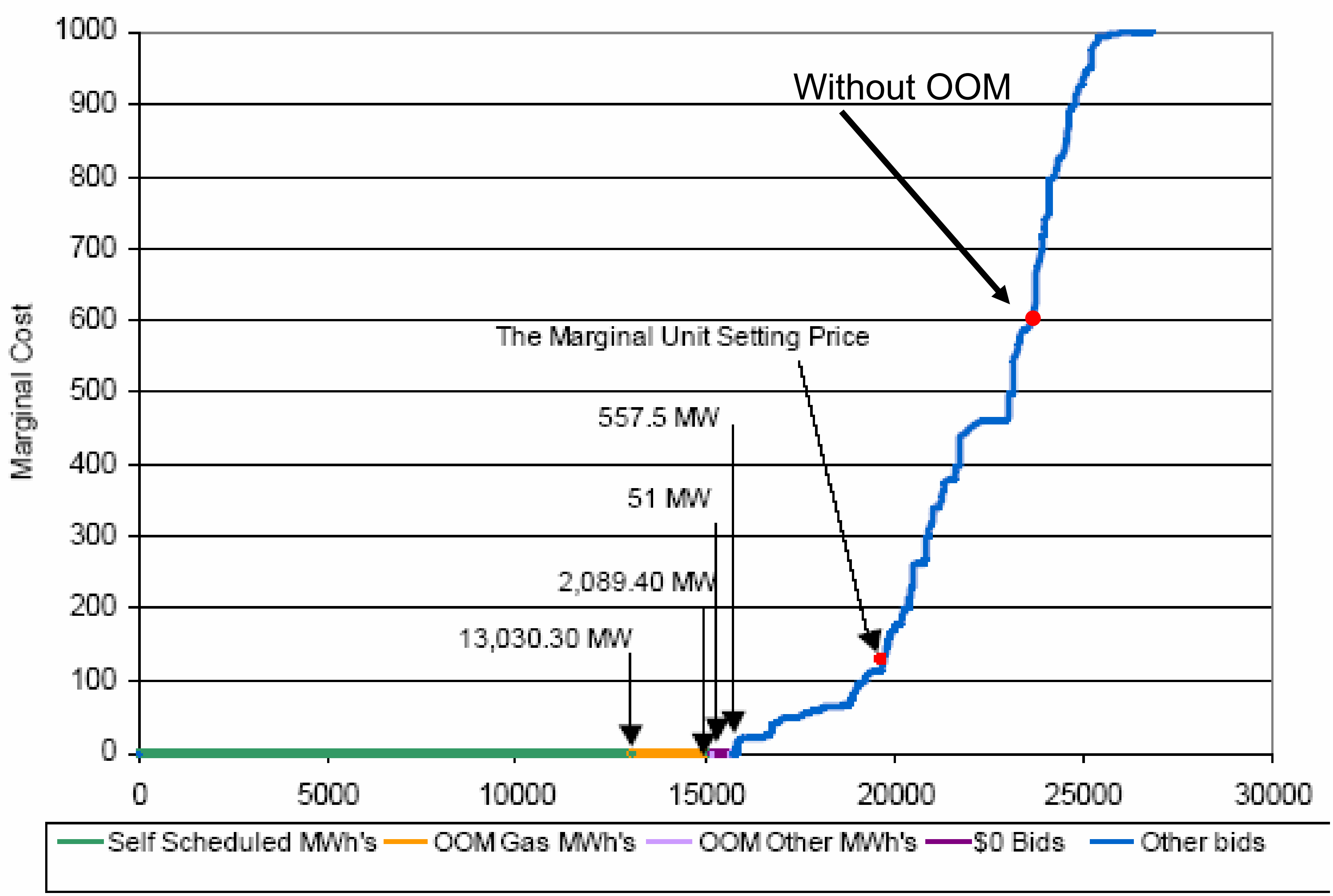


Figure 30 - Supply Stack for 1 SPD Run, January 15, Hour Ending 7 p.m.




Source: ISO NE

**Figure 29 - Supply Stack for 1 SPD run, January 15, Hour Ending 2:00 p.m.**



# VOLTAGE REDUCTIONS

- SOs use voltage reductions as a last resort before going to rolling blackouts
- Voltage reductions reduce demand and spot prices in the short run
- Voltage reductions are not free
  - Consumers bear costs that are widely disperse
  - The probability of a network collapse increases
- Prices fall while marginal costs rise
- Price signals are distorted

# WHAT TO DO ON WHOLESALE MARKET REFORM?

- Continue to improve the performance of the spot markets for energy and operating reserves
  - Raise the price caps to reflect reasonable estimates of VOLL
  - Allow prices to rise faster and higher under operating reserve deficiency conditions
  - Minimize use of OOM or define a wider array of wholesale market products that are fully integrated with markets for related products (e.g. NE Forward reserve market for 10 minute and 30 minute non-spinning reserves)
  - Continue efforts to bring active demand side into the spot market for energy and reserves
  - Increase harmonization of markets separated by "seams"
  - Reform inter-area spot transmission pricing rules
  - Re-evaluate reliability criteria to better reflect consumer valuations

# WHAT TO DO ON WHOLESALE MARKET REFORM?

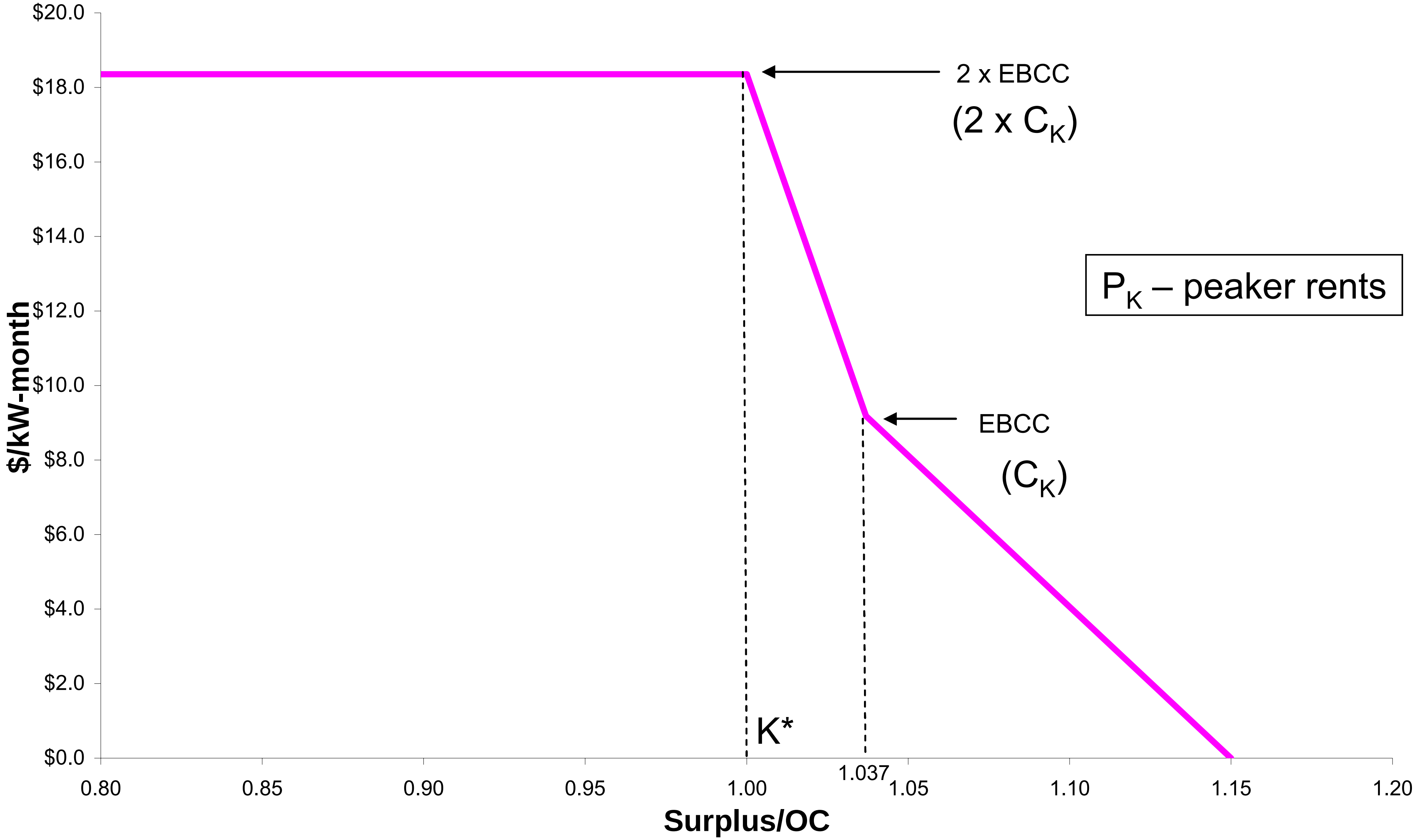
- Implement improved “capacity price” or “capacity obligation” mechanisms as a “safety valve” to produce adequate net revenues to support investment consistent with reliability criteria (target reserve margin and associated capacity)
  - PJM
  - NY-ISO
  - NE-ISO
  - California-ISO (in process)
- These reforms should mitigate generator investment incentive problems

*Table 3-5 - New entrant gas-fired CT (Dollars per installed MW-year): Theoretical net revenue for calendar years 1999 to 2005*

| | Energy | Capacity | Spin | Regulation | Reactive | Total |
|---|---|---|---|---|---|---|
| 1999 | $62,065 | $16,677 | $0 | $0 | $2,248 | $80,990 |
| 2000 | $16,476 | $20,200 | $0 | $0 | $2,248 | $38,924 |
| 2001 | $39,269 | $30,960 | $0 | $0 | $2,248 | $72,477 |
| 2002 | $23,232 | $11,516 | $0 | $0 | $2,248 | $36,996 |
| 2003 | $12,154 | $5,554 | $0 | $0 | $2,248 | $19,956 |
| 2004 | $8,063 | $5,376 | $0 | $0 | $2,248 | $15,687 |
| 2005 | $15,741 | $2,048 | $0 | $0 | $2,248 | $20,037 |

Source: PJM (2006)

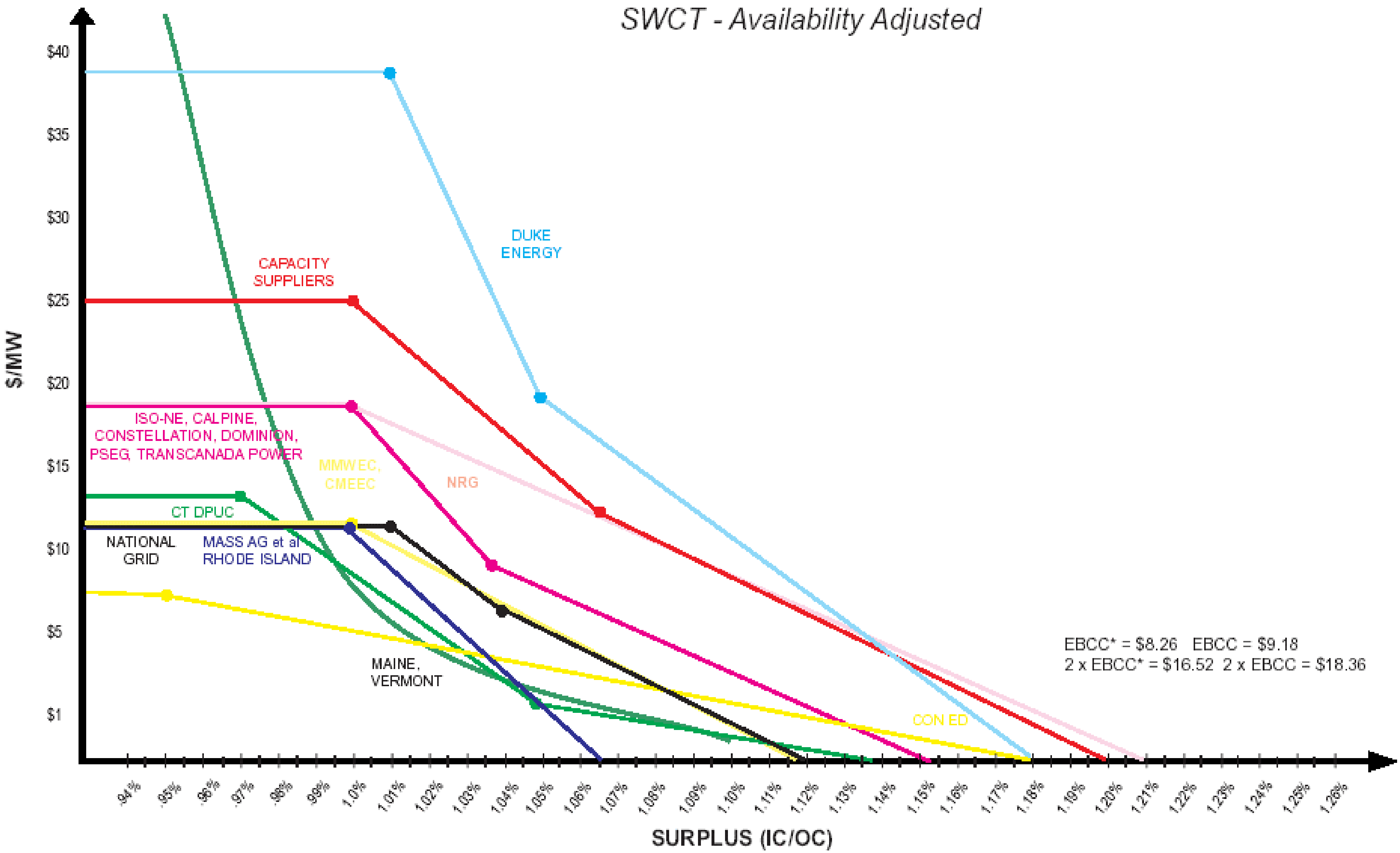
# ISO NEW ENGLAND PROPOSED "CAPACITY" DEMAND CURVE




Source: NSTAR

# DEMAND CURVE PROPOSALS

*SWCT - Availability Adjusted*

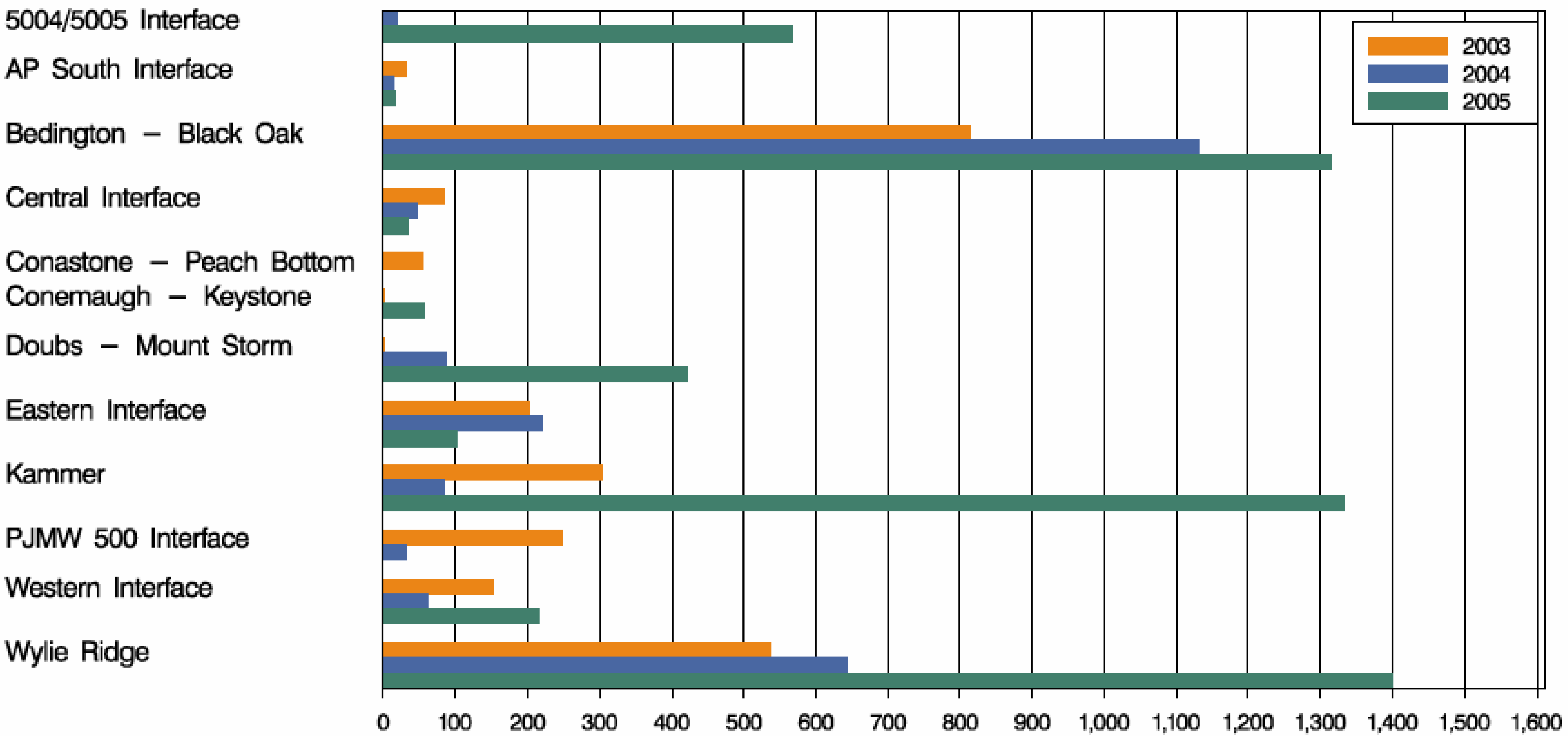



Source: NSTAR

# TRANSMISSION INVESTMENT

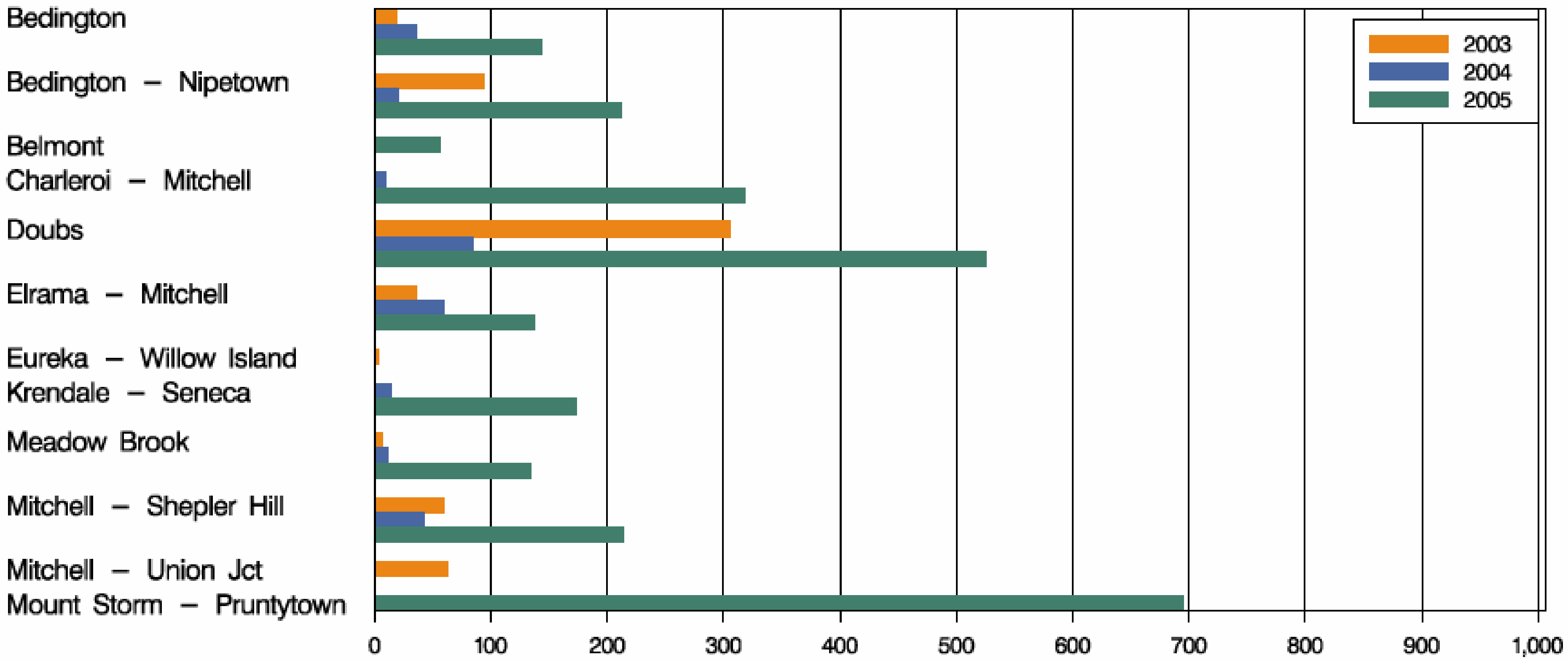
- **Well functioning wholesale markets need a "robust" transmission network**
  - Wholesale market performance
  - Entry of new generation
  - Market power mitigation
- **Assume that transmission investment will be mediated primarily through regulated monopoly TO/SOs**
  - Define clear investment criteria
  - Implement a consistent transparent "wide area" planning process
  - Apply a consistent, credible incentive regulation program that makes desired transmission investment profitable
  - Apply clear principles for "who pays" that provide good locational incentives and do not distort short-run generation and trading decisions
  - Harmonization and coordination between SO/TO areas evaluation of contingencies, rating of interfaces, planning, investment and cost-sharing
- **Merchant investment should be an option but not the foundation for expanding the transmission grid**

*Figure 7-6 - 500 kV zone congestion-event hours (By facility): Calendar years 2003 to 2005*

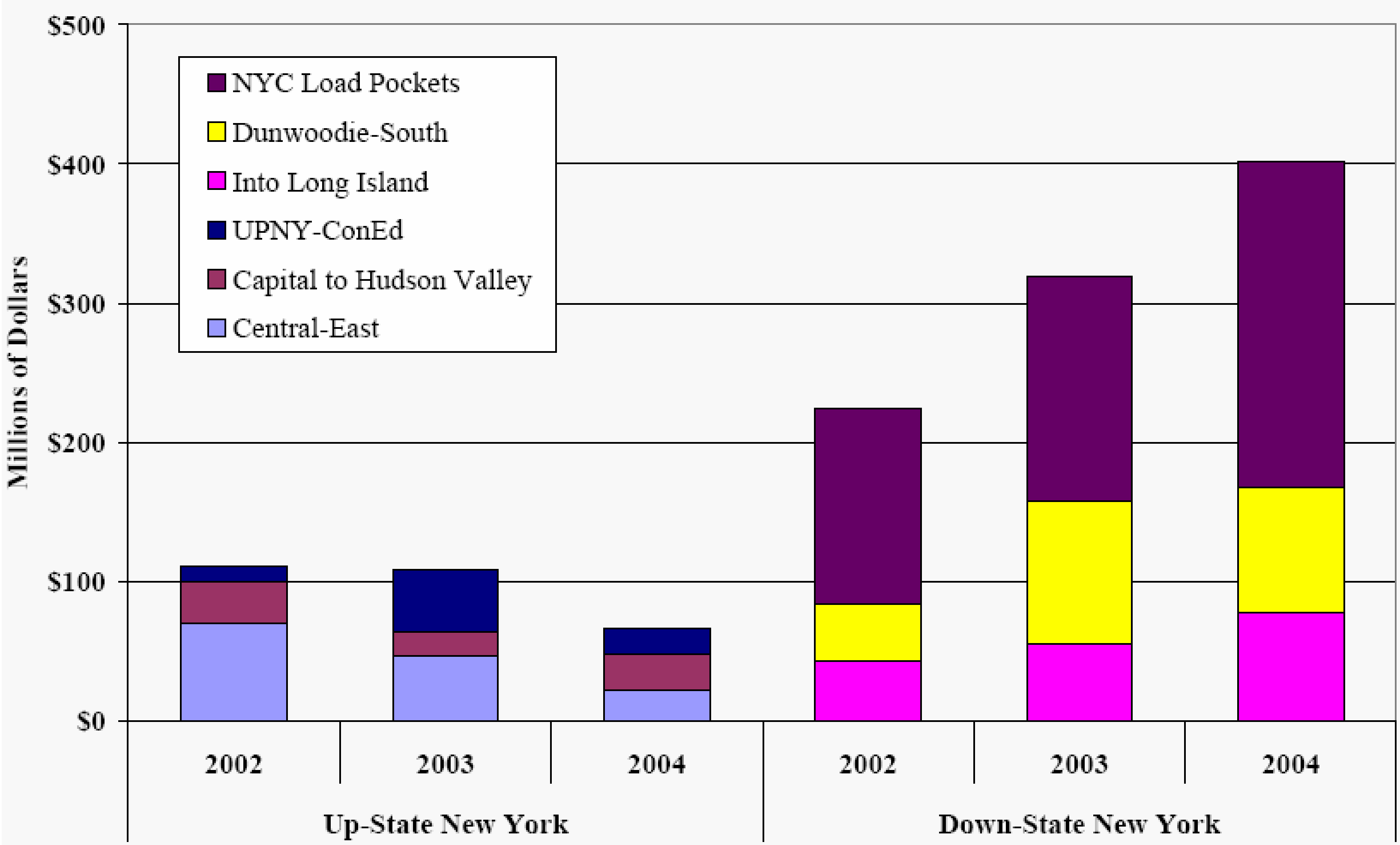



Source: PJM (2006)

*Figure 7-31 - AP Control Zone congestion-event hours (By facility): Calendar years 2003 to 2005*



# Value of Real-Time Congestion on Major Interfaces 2002 – 2004

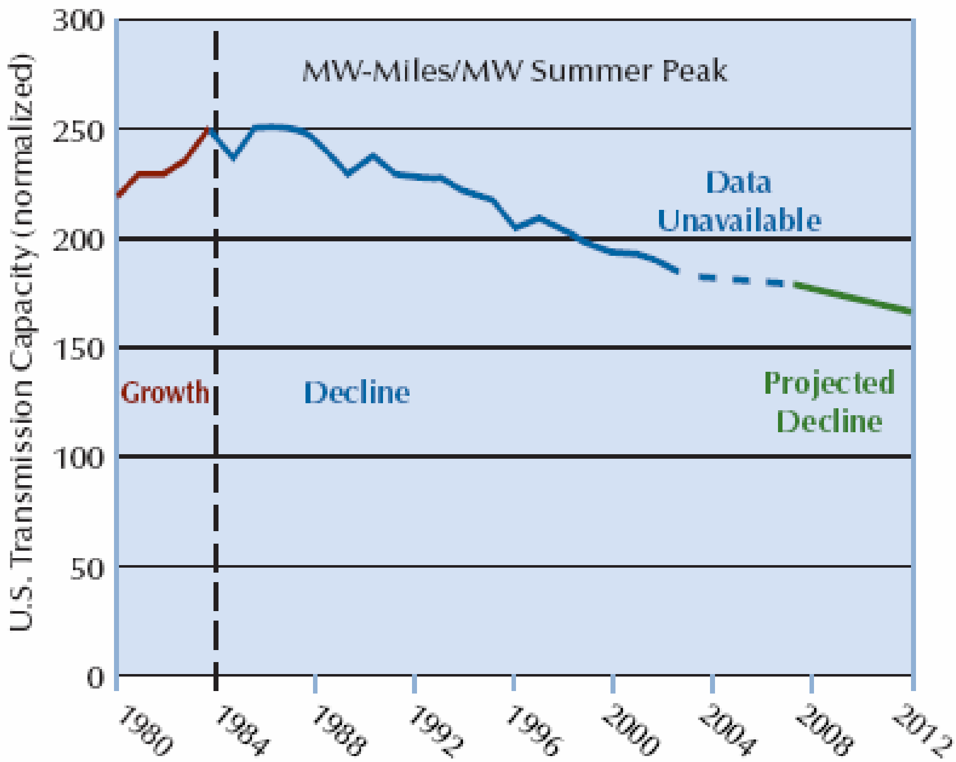



Source: New York ISO (2005)

Figure 5-3

## Transmission Capacity versus Peak Electricity Demand

U.S. transmission capacity per megawatt of summer peak demand has been steadily declining since the 1980s and is expected to continue to decline.




U.S. Transmission Capacity Normalized by Summer Peak Demand.

Hirst, 2004

Source: NCEP (2005)

# TRANSMISSION INVESTMENT

- The "market driven" merchant model based on differences in LMPs and allocation of FTRs (property rights) has not worked as a general framework for stimulating transmission investment
  - Economic issues (e.g. lumpiness)
  - Inconsistent with implementation of reliability rules
  - Inconsistent with market power mitigation rules
  - Does not take account of increased difficulties of relying on wholesale market mechanisms when there is a lot of congestion (OOM, RMR, etc.)
  - Leads to too little investment to support efficient wholesale markets consistent with reliability criteria
  - But opportunity for merchant investment is an important safety valve for organizational and regulatory imperfections

# TRANSMISSION INVESTMENT

- Transmission investment problems are compounded in the U.S.
  - Balkanized ownership of transmission
  - Separation of TO and SO functions
  - Inconsistencies between federal and state regulation of transmission prices and siting permits
  - Lack of clear transmission investment criteria, planning processes and credible supporting incentive regulation mechanisms
  - Inconsistent policies regarding pricing of transmission service and "who pays" for new investment
  - NIMBY impediments

# 2005 U.S. ENERGY POLICY ACT

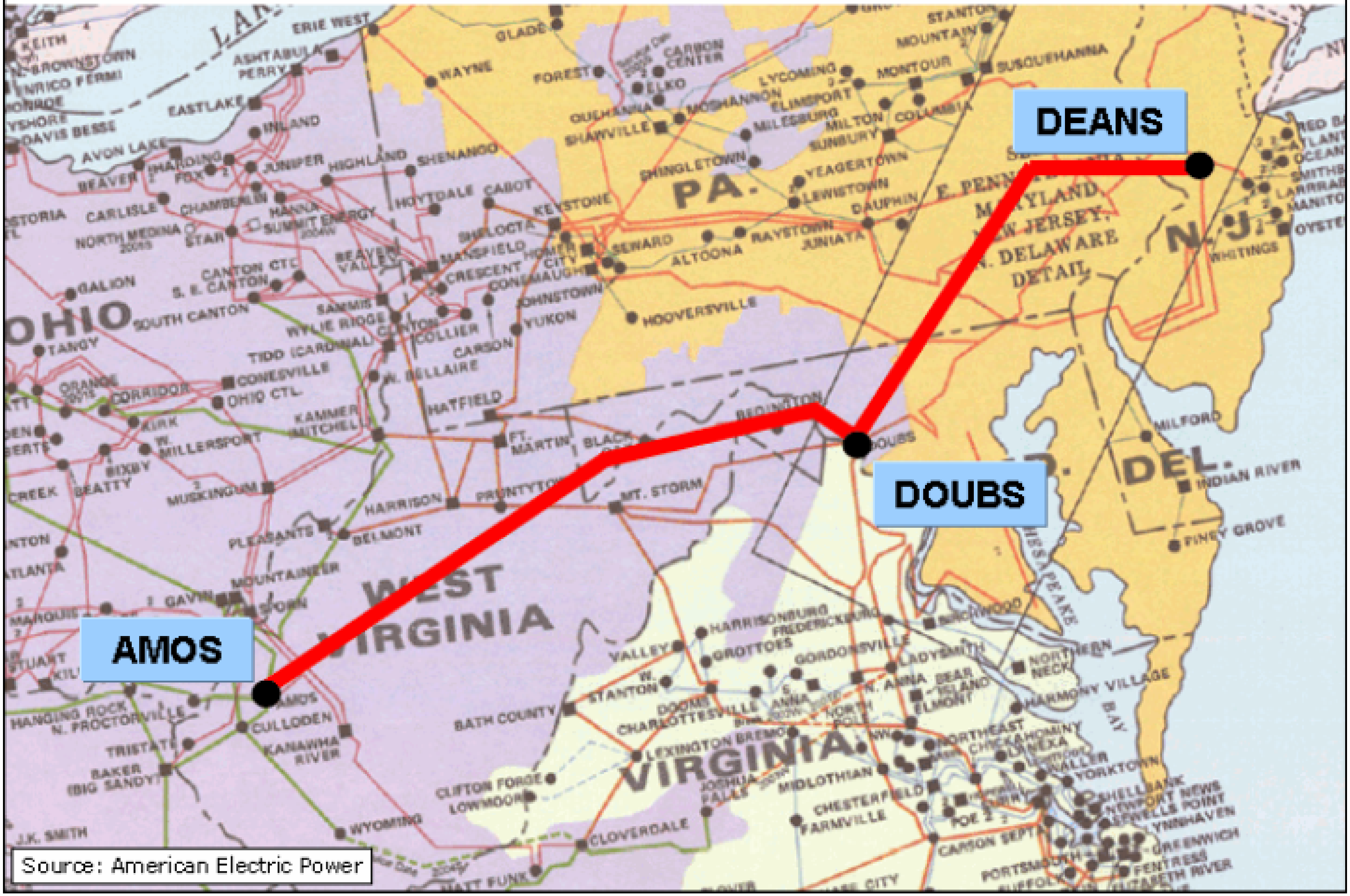
- Creates new federal government authority to grant permits for “critical” transmission facilities
- Provides more attractive tax treatment for investments in new transmission facilities
- Directs FERC to provide “incentive prices” to encourage transmission investment
- Creates tax incentives to divest transmission facilities

# REACTIONS

- At least two major new interregional transmission facilities have been proposed so far in 2006
  - AEP: 550 mile long 765kv link from West Virginia to New Jersey
  - AE: 330 mile long 500kv link from West Virginia to Maryland
- Several major links between Alberta, Wyoming and California under consideration

## Map of the Proposed AEP Interstate Project 765 kV Transmission Line Route

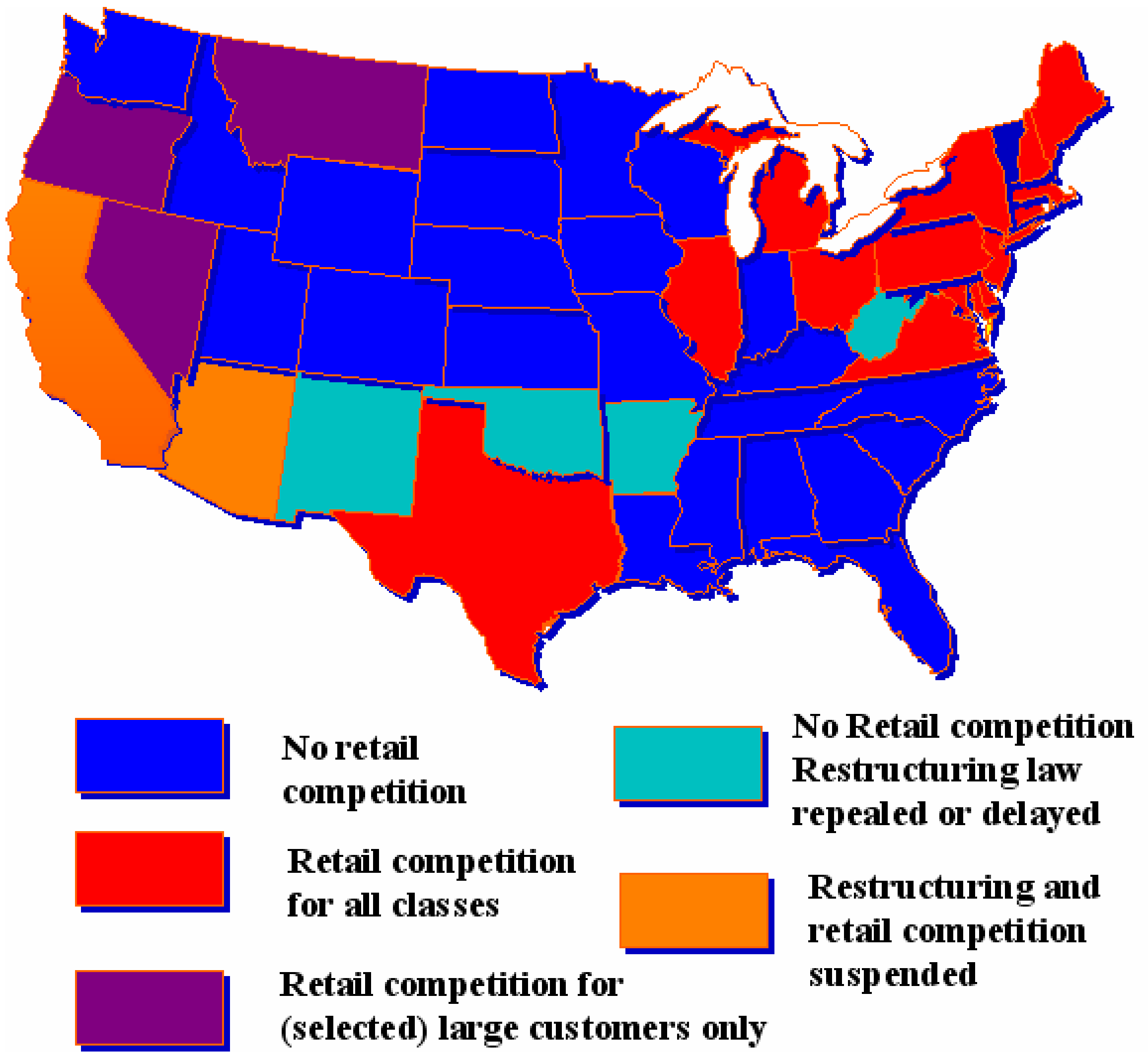
(Line route is conceptual and subject to change in regulatory and PJM Regional Transmission Expansion Plan processes)



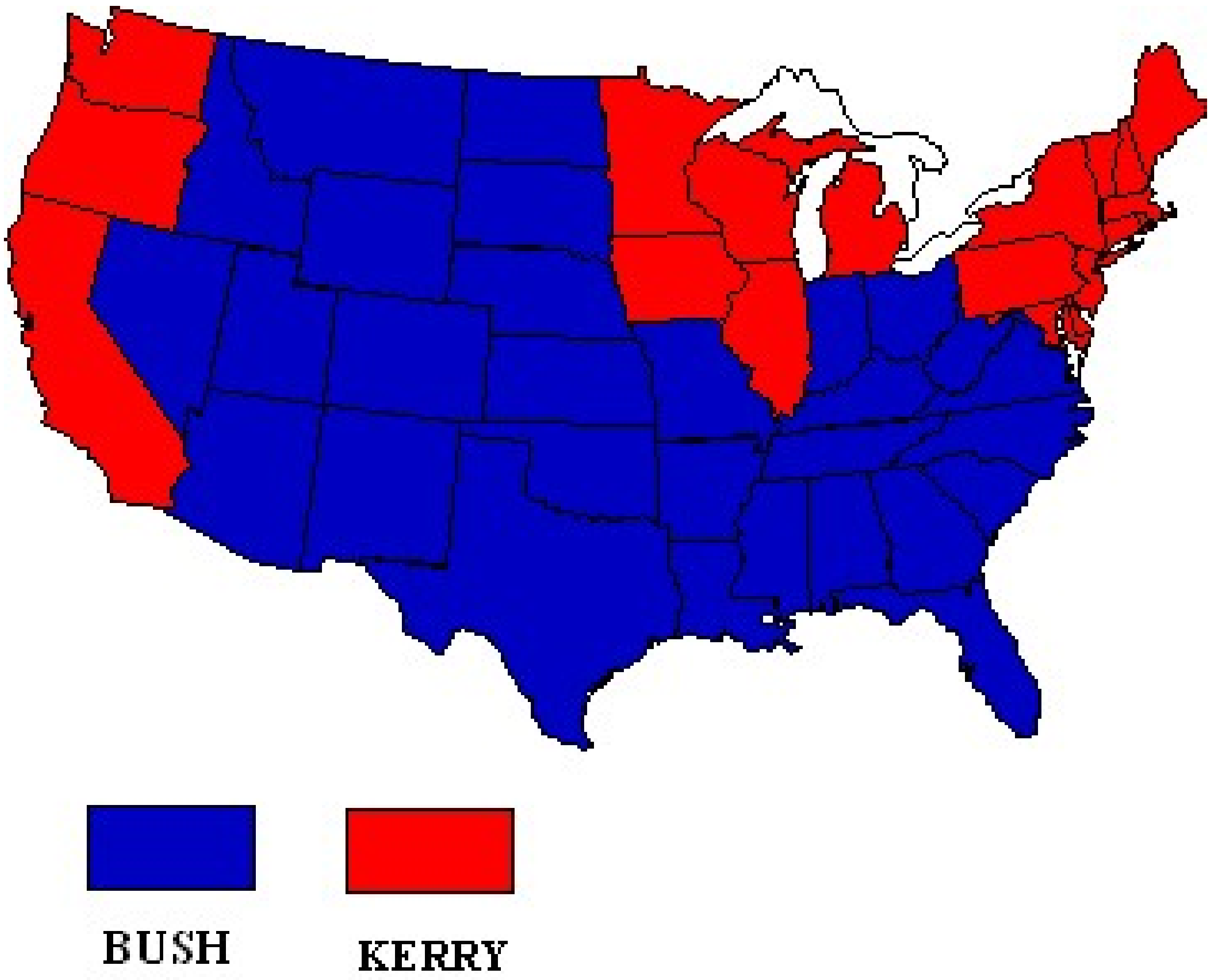

Source: American Electric Power

# BACKGROUND MATERIAL ON RETAIL COMPETITION IN THE U.S.

# STATUS OF RETAIL COMPETITION AND RESTRUCTURING REFORMS 2004



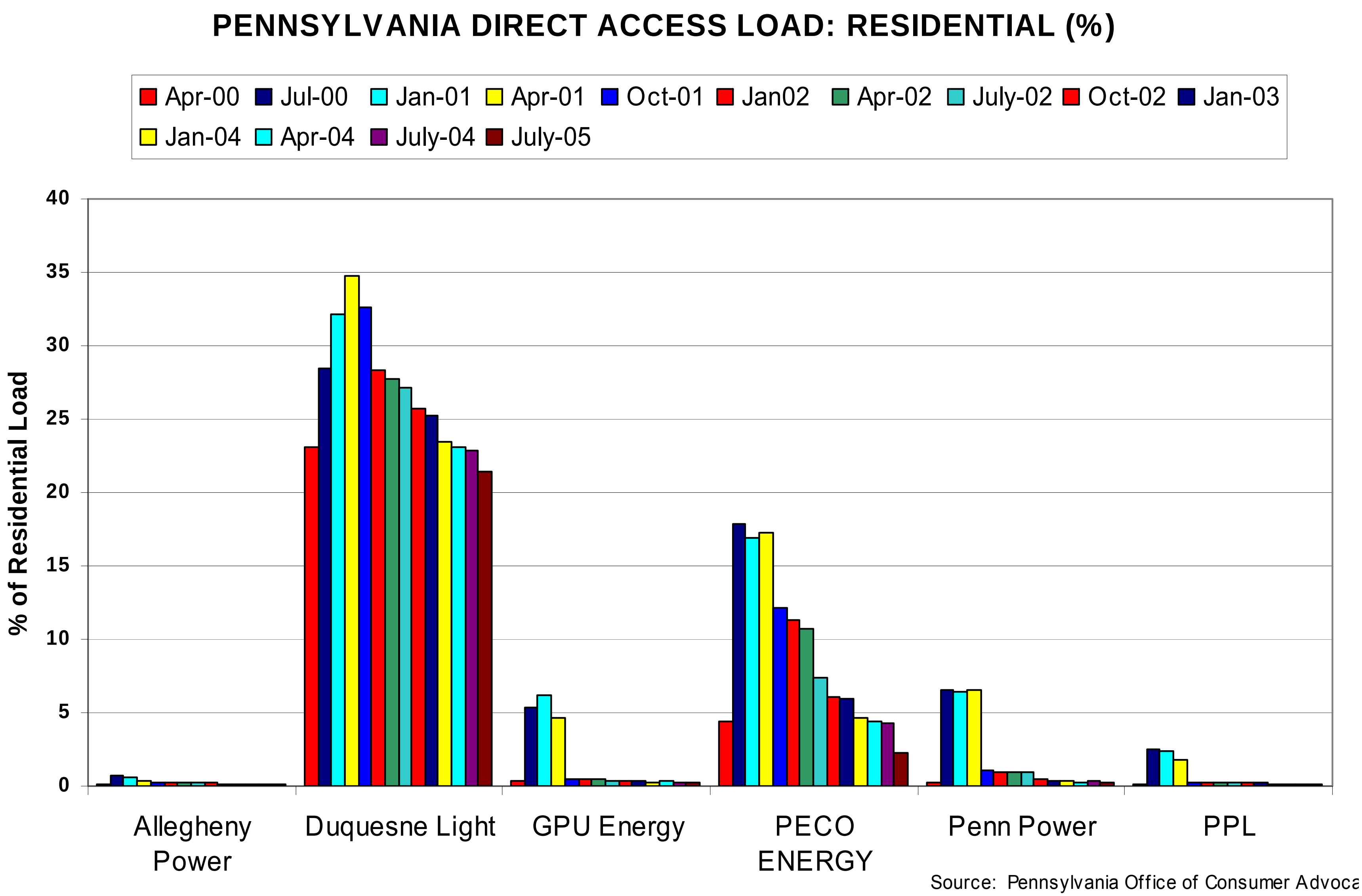
# BUSH V. KERRY 2004



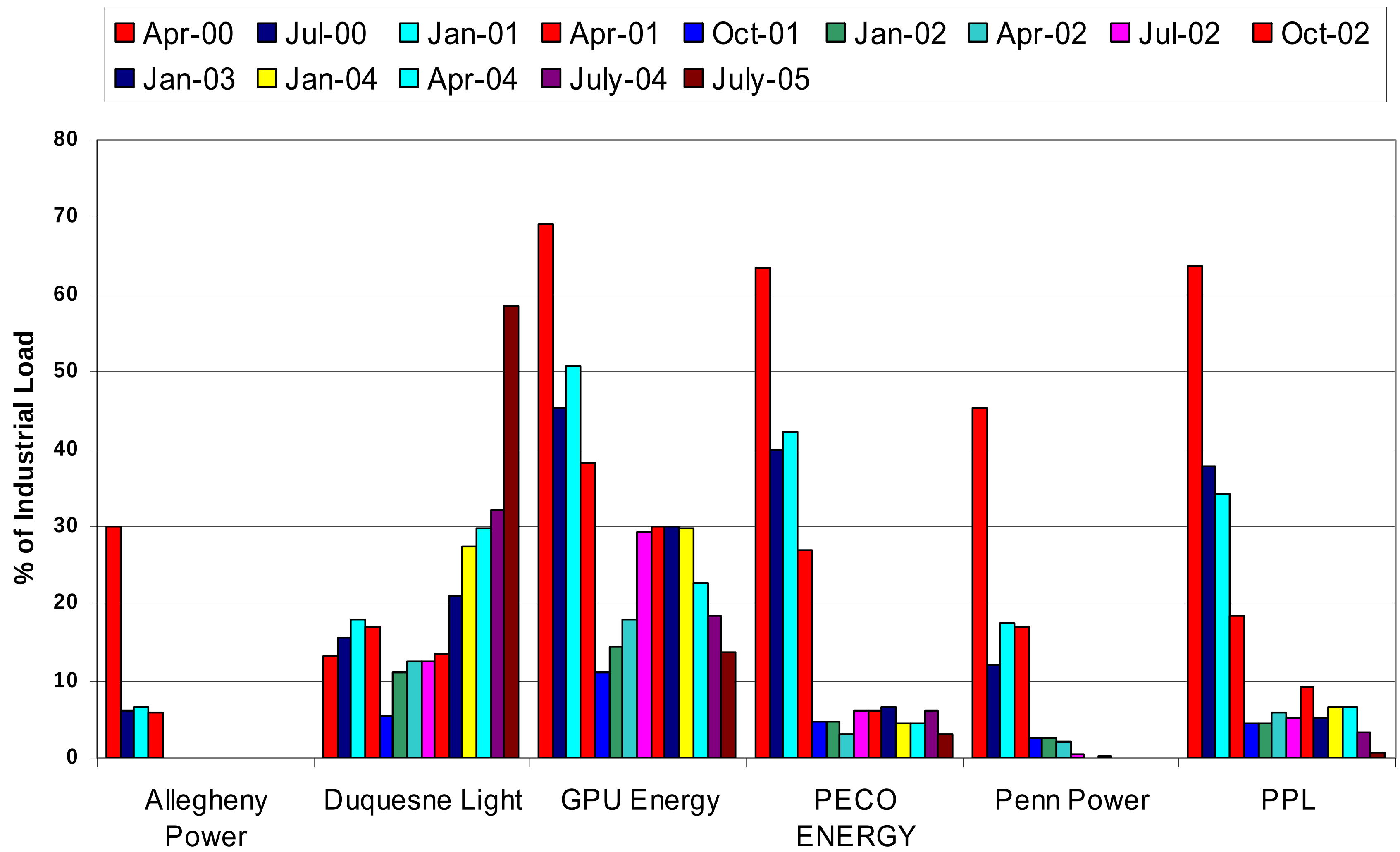
**Retail Competition in Massachusetts**
**February 2004 and January 2006**

Retail Choice Began March 1998

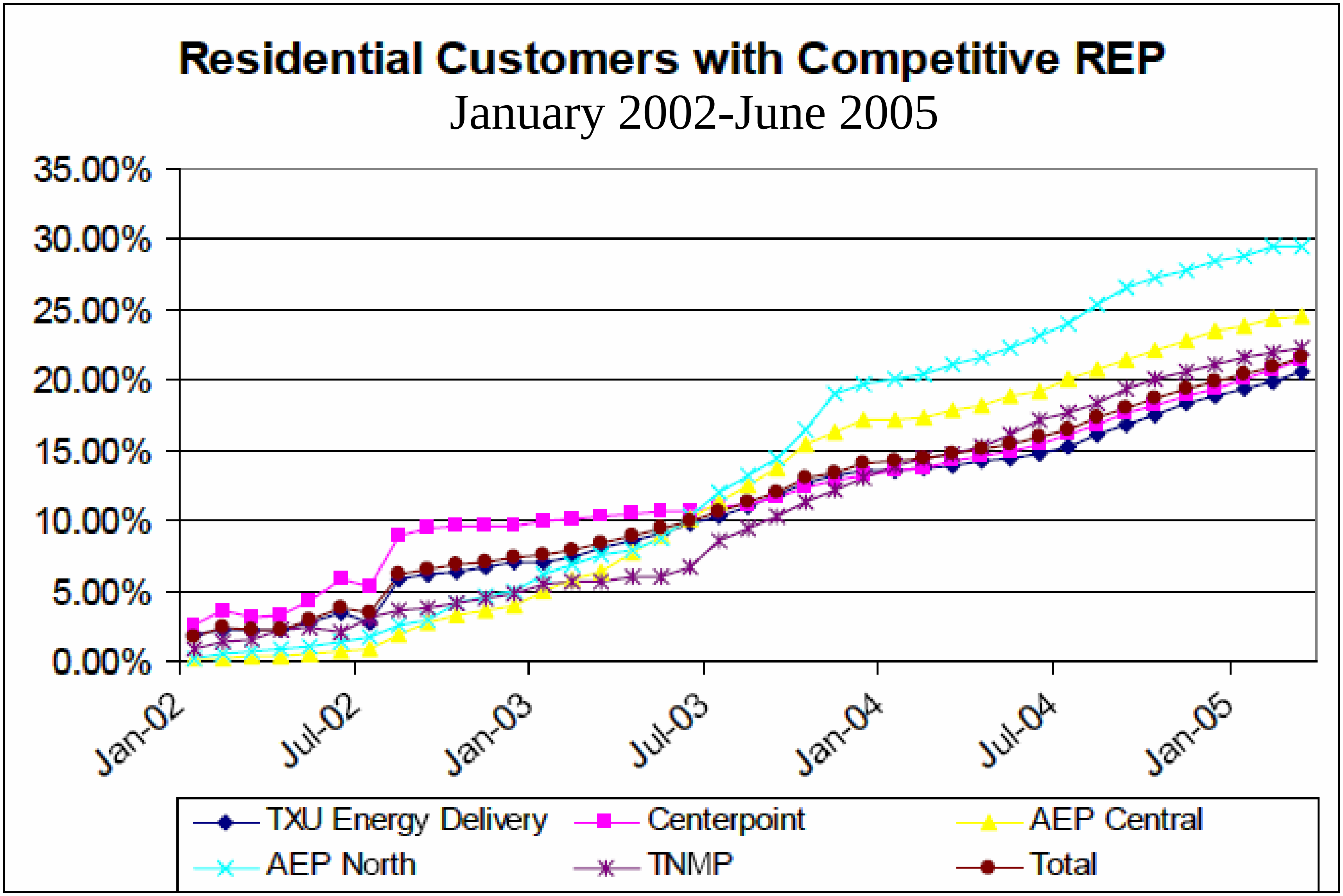
| **Customer Type** | **% of Load Served by ESP's** | |
|---|---|---|
| | February 2004 | January 2006 |
| Residential | 2.6 | 7.4 |
| Small Commercial/Industrial | 10.8 | 21.2 |
| Medium Commercial/Industrial | 17.0 | 24.3 |
| Large Commercial/Industrial | 48.3 | 59.5 |
| Total | 22.6 | 31.0 |


PENNSYLVANIA DIRECT ACCESS LOAD: RESIDENTIAL (%)
Apr-00
Jul-00
Jan-01
Apr-01
Oct-01
Jan02
Apr-02
July-02
Oct-02
Jan-03
Jan-04
Apr-04
July-04
July-05
% of Residential Load
0
5
10
15
20
25
30
35
40
Allegheny Power
Duquesne Light
GPU Energy
PECO ENERGY
Penn Power
PPL
Source: Pennsylvania Office of Consumer Advoca

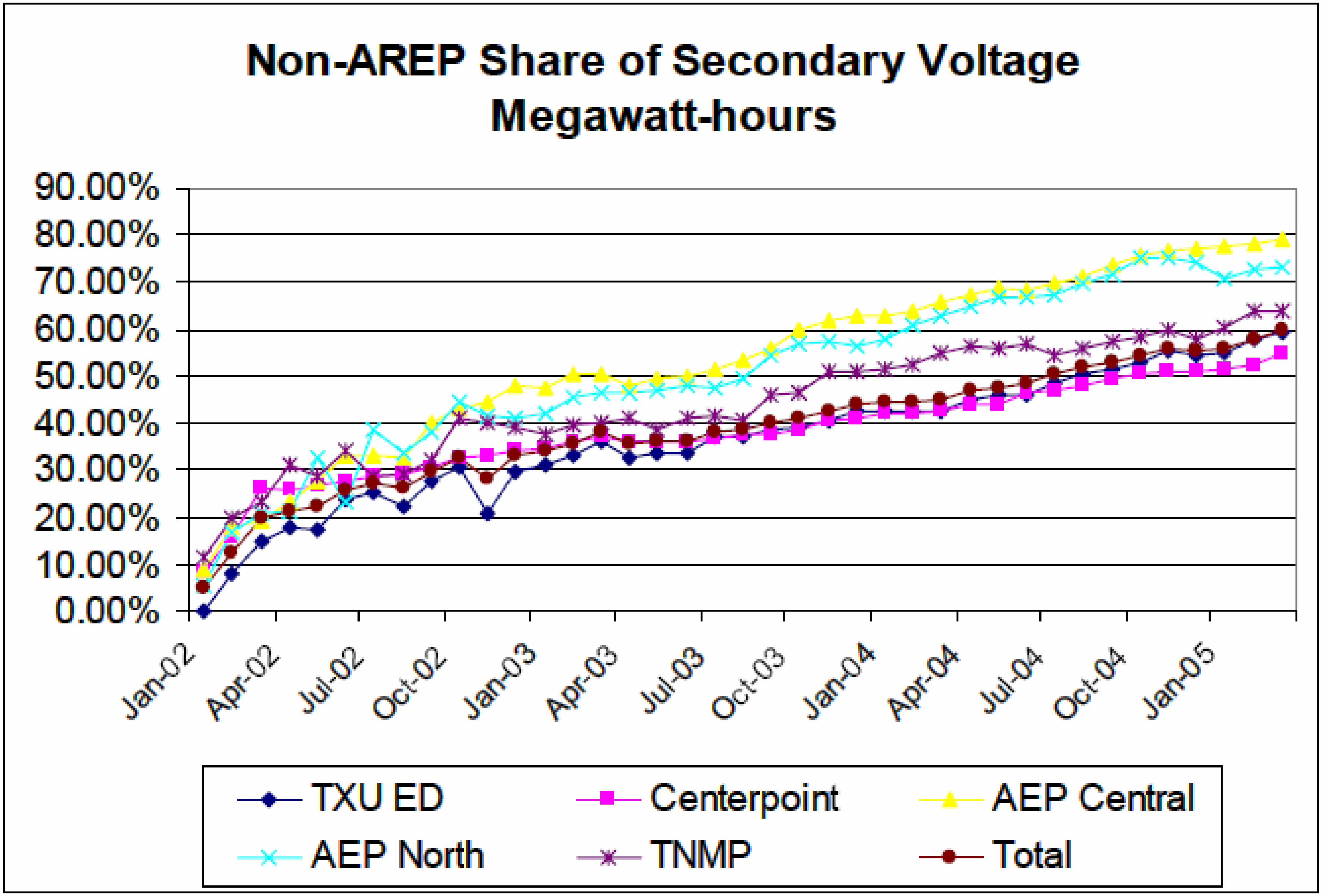
# PENNSYLVANIA DIRECT ACCESS LOAD: INDUSTRIAL (%)




Source: Pennsylvania Office of Consumer Advoca




Source: Public Utility Commission of Texas




Source: Public Utility Commission of Texas

| TDSP | # of REPs serving Residential Customers (incl. AREP) | # of Residential products (incl. PTB) | # of Renewable Products |
|---|---|---|---|
| TXU ED | 13 | 21 | 5 |
| CenterPoint | 12 | 19 | 5 |
| AEP Central (CPL) | 13 | 19 | 5 |
| TNMP | 11 | 17 | 5 |
| AEP North (WTU) | 9 | 13 | 1 |

Source: Public Utility Commission of Texas