ELECTRICITY RESTRUCTURING
WHAT’S GONE RIGHT?
WHAT’S GONE WRONG?
WHY DO WE CARE?

Hans Landsberg Memorial Lecture
Resources For the Future

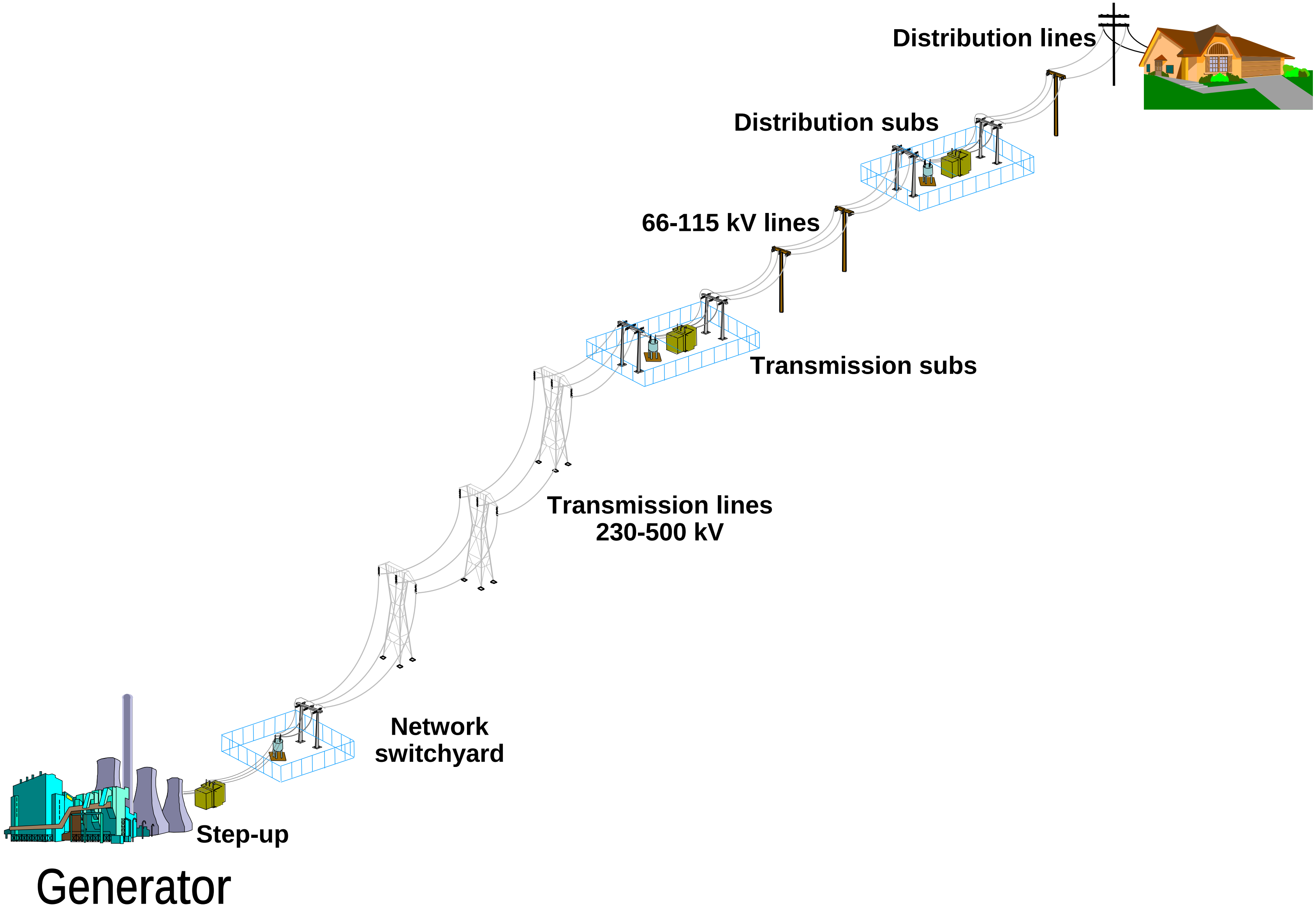
Paul L. Joskow
Alfred P. Sloan Foundation
and
MIT

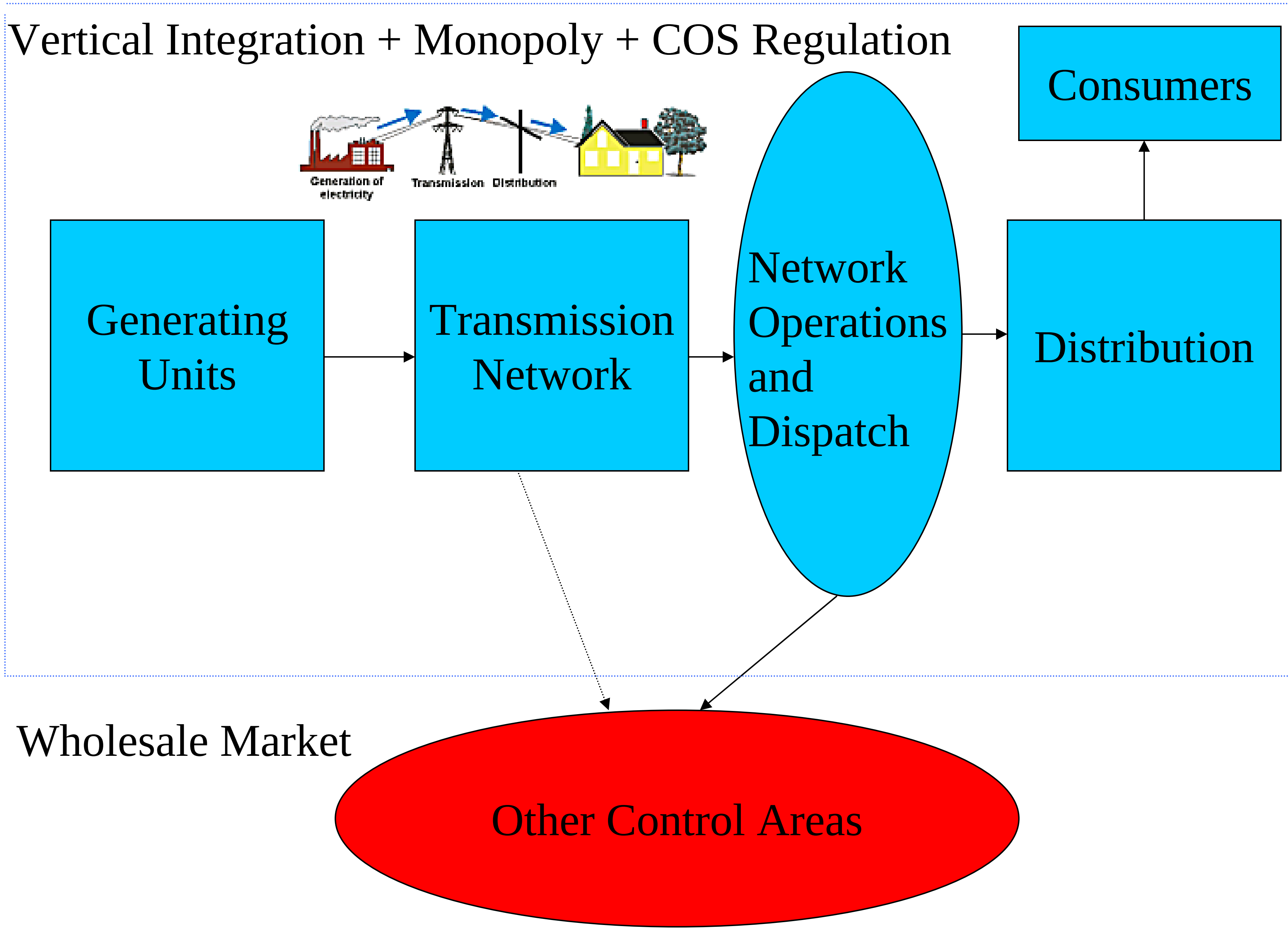
October 1, 2008

The views expressed in this presentation are my own and do not represent the views of the Alfred P. Sloan Foundation or MIT

SOME BASIC FACTS ABOUT ELECTRICITY SECTOR

- Accounts for 42% of primary U.S. energy consumption
- Accounts for 35% of U.S. fossil fuel consumption
- Accounts for 40% of U.S. CO_2 emissions and this share projected to grow in BAU
- Uses almost no petroleum: Oil accounted for 17% of generation in 1973 and only 1.5% today
- Relies primarily on North America for fuel
- Consumption projected to grow faster than total energy consumption

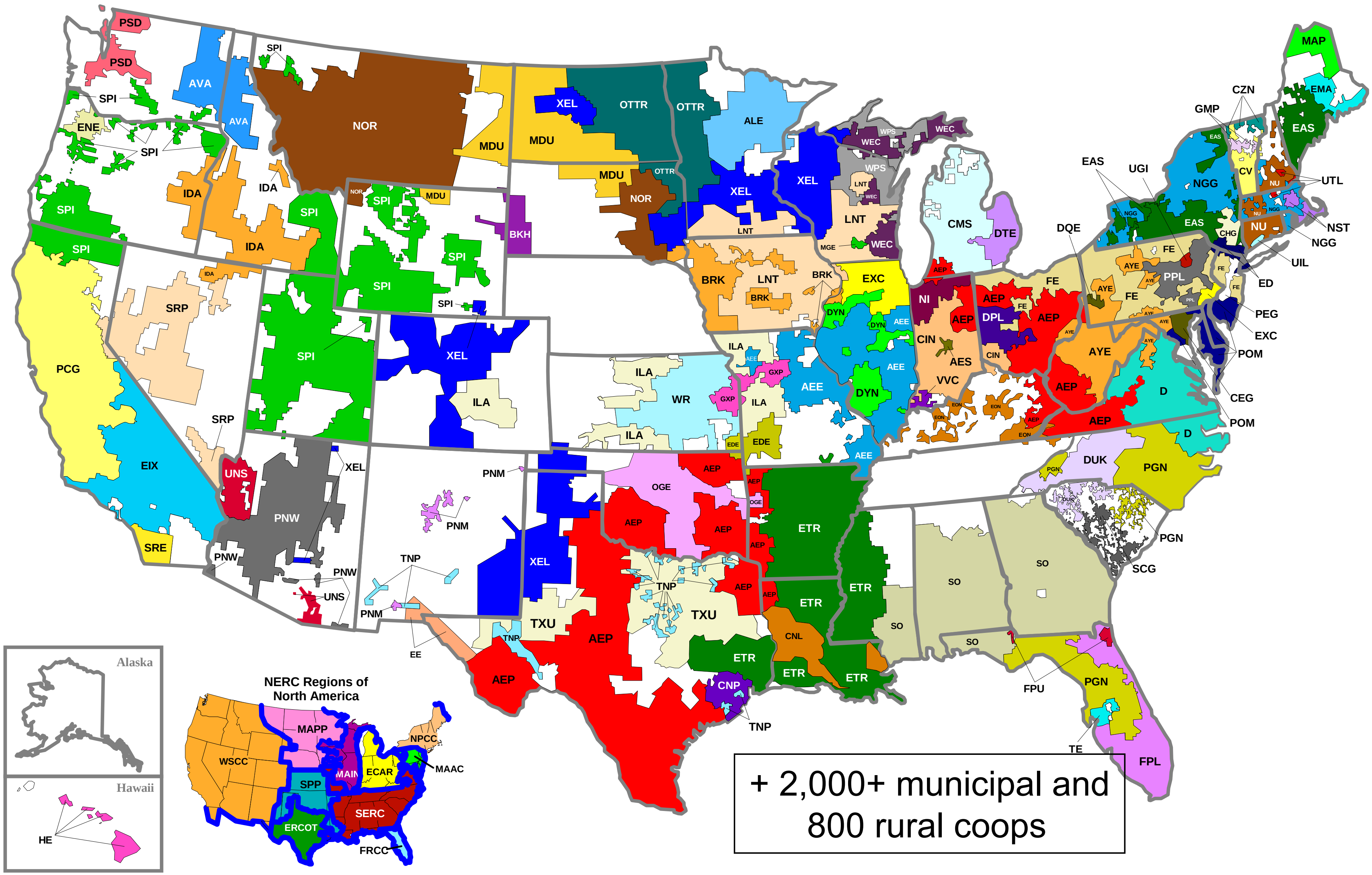

Distribution lines
Distribution subs
66-115 kV lines
Transmission subs
Transmission lines
230-500 kV
Network
switchyard
Step-up
Generator


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

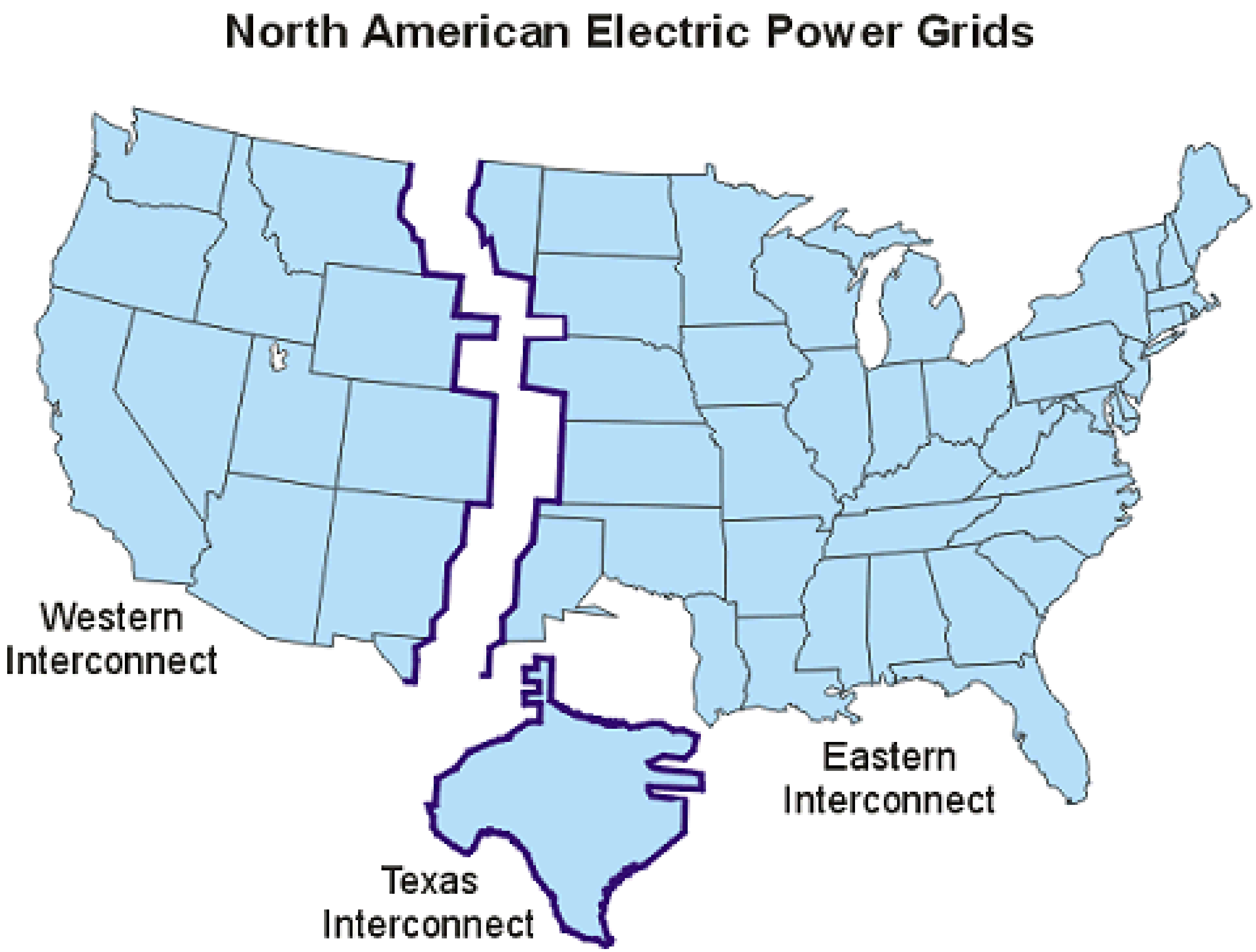
PA Consulting Group

U.S. Investor-Owned Electric Utility Holding Companies

as of January 2004

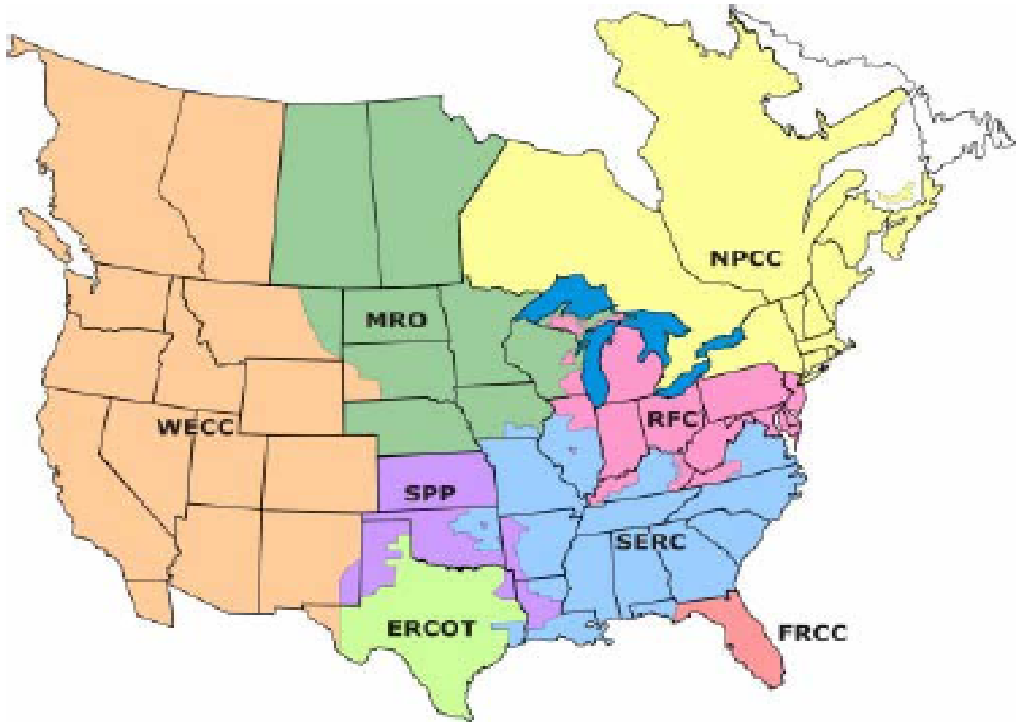


The service boundaries on this map are a general representation of individual utility regions and do not necessarily depict the exact legal boundaries of the regions. Information on this map is believed to be accurate but is not guaranteed.


North American Electric Power Grids
Western Interconnect
Texas Interconnect
Eastern Interconnect

Source: NERC

Figure 1: NERC Regional Reliability Councils as of October 16, 2006



ERCOT
Electric Reliability Council of Texas, Inc.

FRCC
Florida Reliability Coordinating Council

MRO
Midwest Reliability Organization

NPCC
Northeast Power Coordinating Council

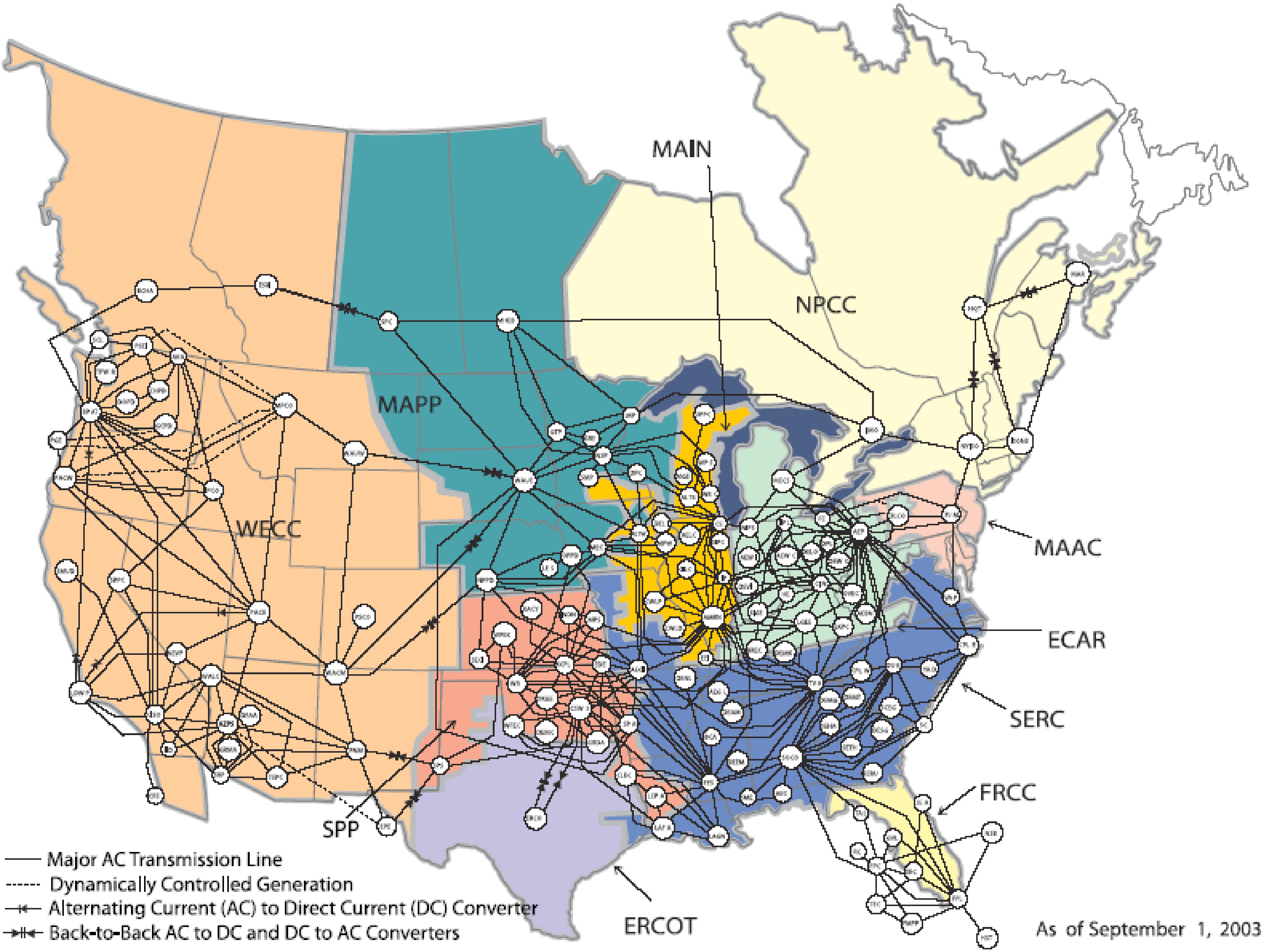
RFC
Reliability*First* Corporation

SERC
SERC Reliability Corporation

SPP
Southwest Power Pool, Inc.

WECC
Western Electricity Coordinating Council

. NERC Regions and Control Areas



Source: North American Electric Reliability Council.

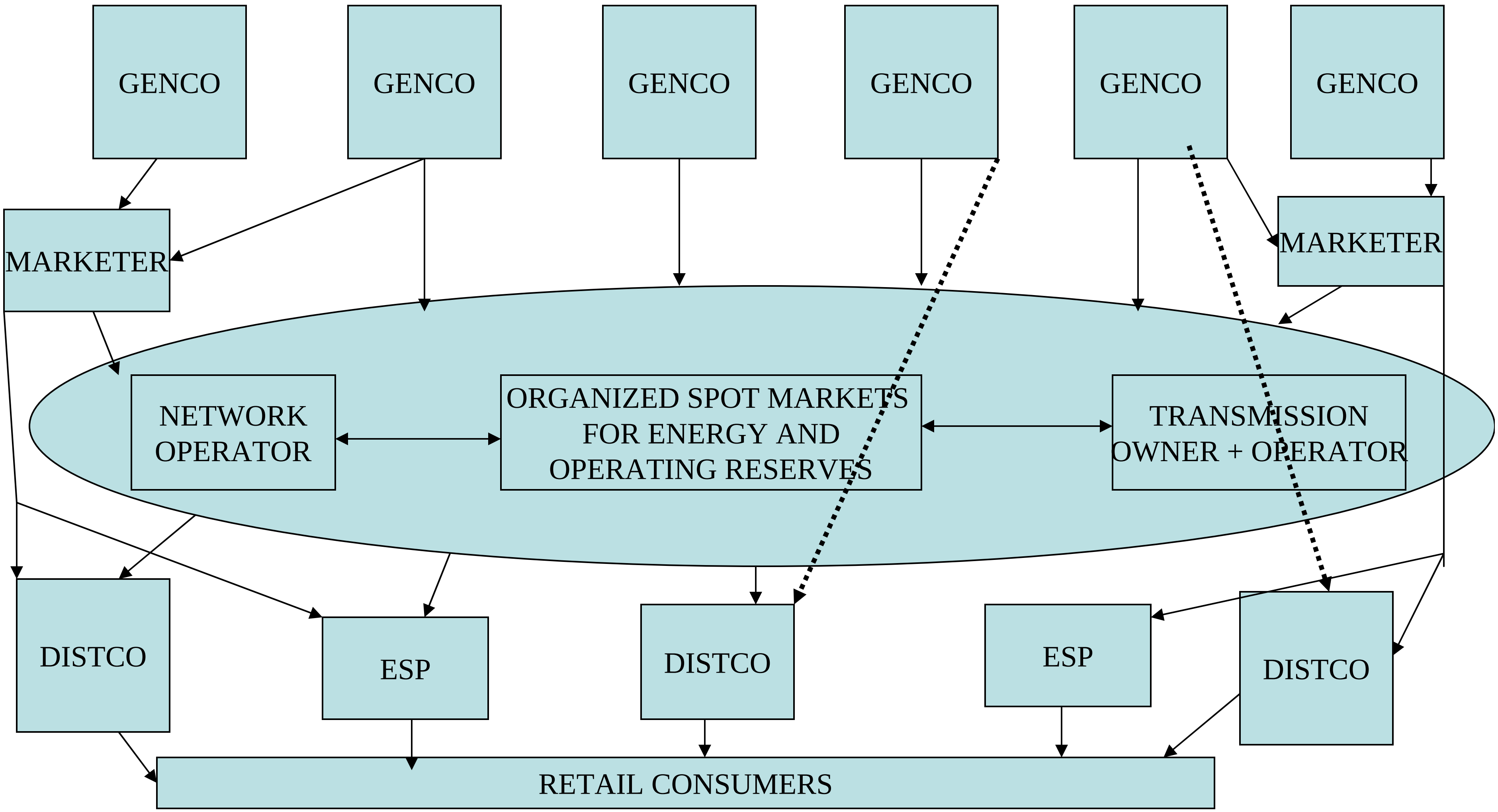
THE GOOD OLD DAYS OF REGULATED MONOPOLY

- Construction cost overruns and poor generating plant operating performance
- Inefficient retail pricing
- Wide price variations within regions
- Costly fragmentation and wide variations in performance
- Productivity and innovation lags
- Growing adverse environmental impacts
- But it worked from the “big picture” perspective and was particularly good at mobilizing capital
- Only energy or infrastructure sector that has escaped mandatory national “liberalization” reforms
- Partially reformed 1935 industrial organization and regulatory framework for a 21st century technology and policy challenges, especially GHG mitigation

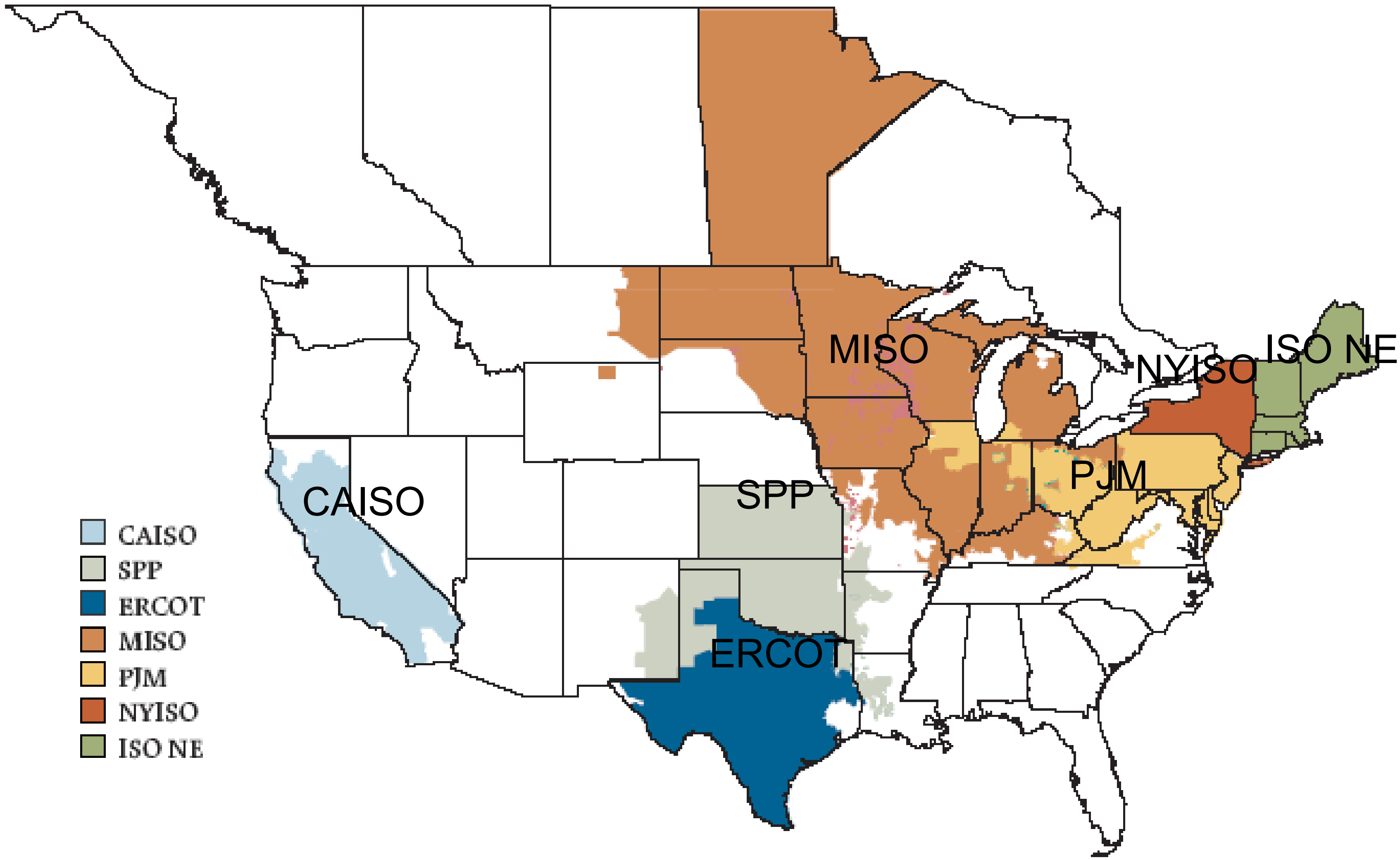
REFORM GOALS

- Efficient and reliable supplies of electricity to support valuable services and economic growth
- Efficient prices that provide good signals for wise use of electricity and sufficient revenues to support efficient operation of and investment in the supply system
- Energy and network security and reliability
- Key platform for meeting GHG mitigation goals
- Stimulate innovation on the supply and demand sides
- Do better than just "work"

VISION FOR COMPREHENSIVE REFORM
COMPETITIVE WHOLESALE + RETAIL MARKETS



ISO/RTOs in the United States 2006



Source: State of the Markets Report 2004, FERC Office of Market Oversight and Investigations (2005, page 53).

Independent System Operators and Organized Wholesale Markets 2006

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 8: RTO Market Characteristics in 2006

■ Existing　□ Projected　♦ Cost-Based　● Other

Services Provided	ISO-NE	NYISO	PJM	MISO	SPP	ERCOT	CAISO
Bilateral transactions	■	■	■	■	■	■	■
Active online physical trading	■		■	■		■	■
Active online financial trading	■	■	■	■			■
Real-time energy market	■	■ [1]	■	■	■ [2]	■	■
Locational energy price	■	■	■	■	■	■	■
Hourly energy price	■	■	■	■	■	■	■
Congestion price	■	■	■	■	■	■	■
Losses price	■	■	□ 07 [3]	■	■ [4]	■	■ [5]
Day-ahead energy market	■	■ [1]	■	■		□ 09	□ 08
Locational energy price	■	■	■	■		□ 09	□ 08
Hourly energy price	■	■	■	■		□ 09 [6]	□ 08
Congestion price	■	■	■	■		□ 09	■ [7]
Losses price	■	■	□ 07 [3]	■			□ 08
Ancillary services market	■	■	■	□ 08	♦	■	■
Regulation service market	■	■	♦ [8]	♦	♦	■	■
Operating reserves market	■	■	■ [9]	♦ [10]	♦	■	■
Reactive power market	● [11]	● [12]	♦	♦	♦	♦	♦
Black start market		♦	♦	♦	♦	● [13]	♦
Financial transmission rights	■	■	■	■		■	■ [7]
Capacity market	■ [14]	■	■			● [15]	♦ [16]
Regional transmission scheduling	■	■	■	■	■	■	■
Regional economic dispatch	■	■	■	■	■	■ [17]	■ [17]
Regional transmission planning	■	■	■	■	■	■	■
Regional interconnection process	■	■	■	■	■	■	■
Independent market monitor	■	■	■	■	■	■	■
Mitigation	■	■	■	■	■		■

Source: FERC *2006 State of the Markets Report*

ATTRIBUTES OF U.S. WHOLESALE MARKET AREAS

Table 7: Wholesale Electric Markets in 2006

■ Existing   □ Projected

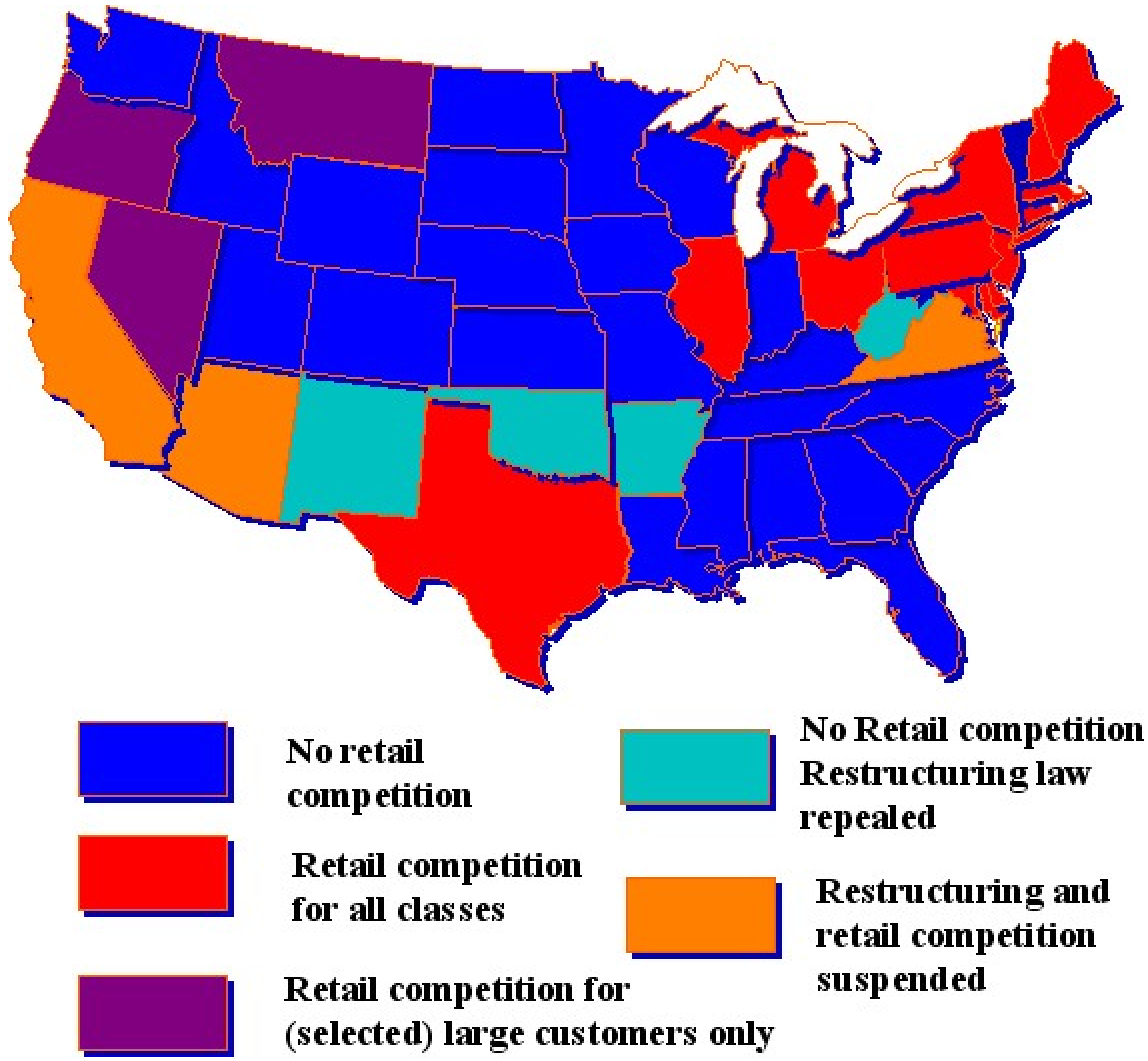
	Real-time market (RTO/ISO)	Real-time market Bilateral	Day-ahead market (RTO/ISO)	Day-ahead market Bilateral	Virtual Bidding (RTO/ISO)	Ancillary services markets (RTO/ISO)	Financial transmission rights (RTO/ISO)	Capacity (UCAP) markets (RTO/ISO)	Associated financial markets
New England	■	■	■	■	■	■	■	■ [1]	■
New York	■	■	■	■	■	■	■	■ [2]	■
PJM	■	■	■	■	■	■	■	■ [3]	■
Midwest	■	■	■	■	■	□ 08	■		■
Southeast		■		■					■
SPP	■	■		■					
ERCOT	■	■	□ 09	■		■	■		
Northwest		■		■					■
Southwest		■		■					■
California	■	■	□ 08	■	□ 09	■	■	[4]	■

[1] Transitioning to a formal capacity market. ISO-NE's installed capacity market was replaced on December 1, 2006, with the transition period for its new Forward Capacity Market.
[2] Locational
[3] Systemwide
[4] California is considering a formal capacity market.

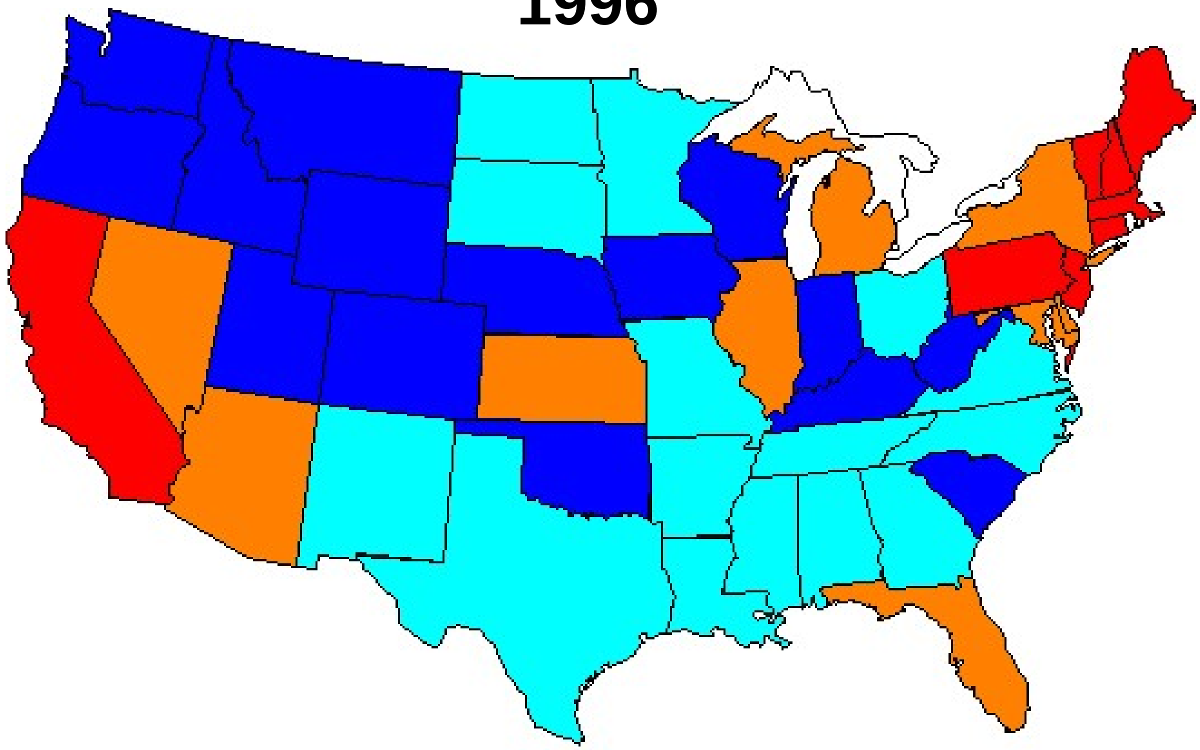
Source: Staff analysis of RTO rules.

Source: FERC *2006 State of the Markets Report*

STATUS OF RETAIL COMPETITION AND RESTRUCTURING REFORMS 2007



AVERAGE PRE-REFORM INDUSTRIAL PRICES
1996



> 5.5 cents/kWh

4.5 - 5.5 cents/kWh

4.0 - 4.5 cents/kWh

< 4.0 cents/kWh

WHAT HAS GONE RIGHT IN WHOLESALE MARKET LIBERALIZATION?

- About 650,000 Mw of U.S. generating capacity in 1996 (75% IOU), almost all of it regulated and integrated with T&D
- 100,000 Mw divested and deregulated by 2004
- 85,000 Mw transferred to unregulated affiliates by 2004
- 200,000 Mw of new generating capacity (80% merchant) added between 2000 and 2004
- Large increase in volume and geographic expanse of wholesale trade.
  - About 35% of electricity is produced by unregulated generators today (45% of IOU generation)
  - Regional wholesale market areas are better integrated economically
- FERC SMD and RTO restructuring spreading slowly but steadily
  - NE, NY, PJM (expanding), MISO
  - California redesign
  - ERCOT redesign

PERFORMANCE OF ORGANIZED WHOLESALE MARKETS

- Short term markets (day-ahead, hour-ahead, balancing) function reasonably well within each ISO/RTO
  - Generator dispatch efficiency has improved
  - 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")
  - Reliability of the network has been maintained
  - Market power is not a significant problem when measured over a reasonable time period except in some load pockets.
  - Forward contracting between suppliers and LSEs has helped, though a growing share of energy is traded in short-term markets
  - Fuel cost adjusted wholesale prices have declined slightly
  - Rising gas and coal prices have "hidden" these increases in efficiency

PERFORMANCE OF ORGANIZED WHOLESALE MARKETS

- Remaining issues to resolve
  - Energy prices do not rise fast enough or high enough during scarcity conditions
    - Capacity obligations and capacity markets are resolving this problem from an investment incentive perpective
  - 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)
  - Demand side participation has been slow to emerge but things are improving

OTHER EFFICIENCY IMPROVEMENTS FROM RESTRUCTURING

- Risk of cost overruns, performance deficiencies, and market volatility are appropriately shifted to producers from consumers
- Availability of deregulated nuclear and fossil plants has improved more than for regulated plants
- Operating costs of deregulated fossil plants have fallen more than for regulated plants
- Prices reflect marginal supply costs and provide better signals to consumers to use electricity widely and to invest in conservation

EVIDENCE

ISO-New England (2008)

- 6.5 million households and businesses; population 14 million
- Over 8,000 miles of high-voltage transmission lines
- 13 interconnections to electricity systems in New York and Canada
- More than 32,000 megawatts (MW) of total supply (includes 1,693 MW of demand-resource capacity)
- All-time peak demand of 28,130 MW, set on August 2, 2006
- More than 300 participants in the marketplace (those who generate, buy, sell, transport, and use wholesale electricity)
- $10 billion annual total energy market value (2007)
- More than $1.0 billion in transmission investment made for reliability since 2002; another $4.0 to $7.0 billion planned over the next 10 years
- Approximately $1.0 to $2.0 billion of economic transmission investment to enable renewable resources under study
- Five major 345-kilovolt projects already in various stages of construction and operation

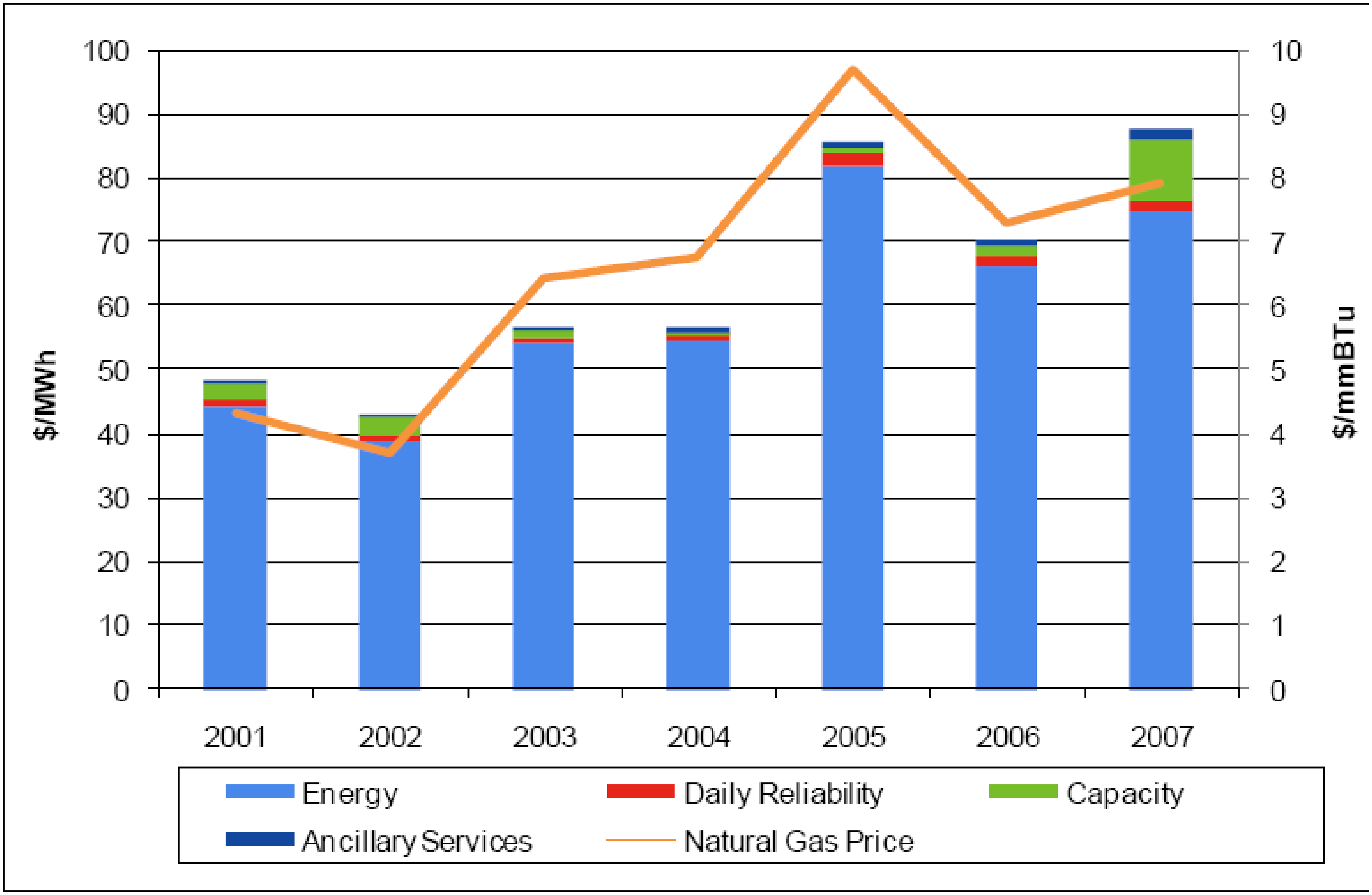


Figure 2-33: New England wholesale electricity market cost metric—electric energy, daily reliability, capacity, and ancillary services, $/MWh, and annual average natural gas prices, $/MMBtu, 2001 to 2007.

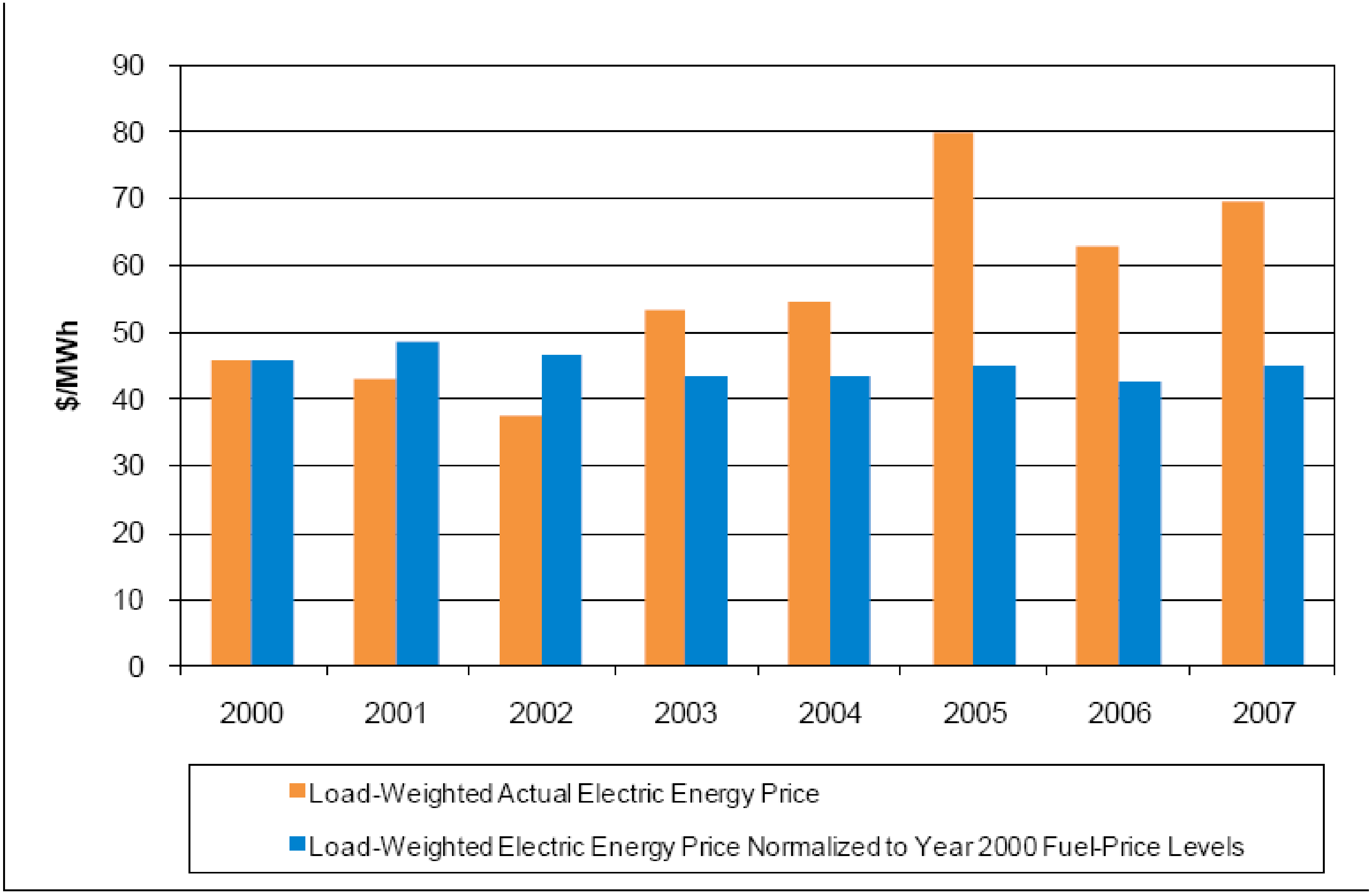


Figure 2-23: Actual and fuel-adjusted average real-time electric energy prices, 2000 to 2007.

ISO-New England (2008)

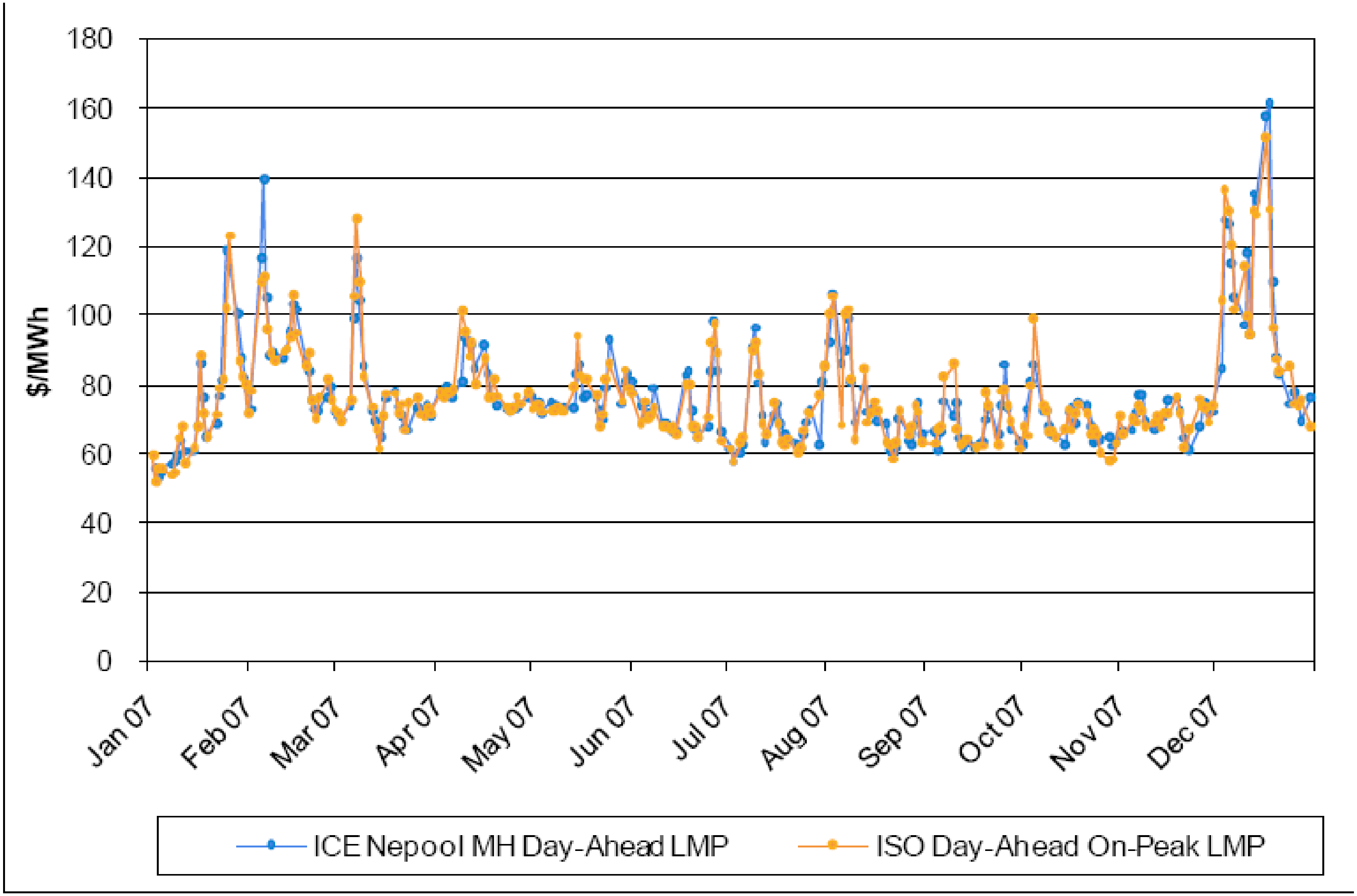


Figure 2-26: Comparison of ISO day-ahead Hub LMPs with ICE day-ahead New England trade prices.

ISO-New England (2008)

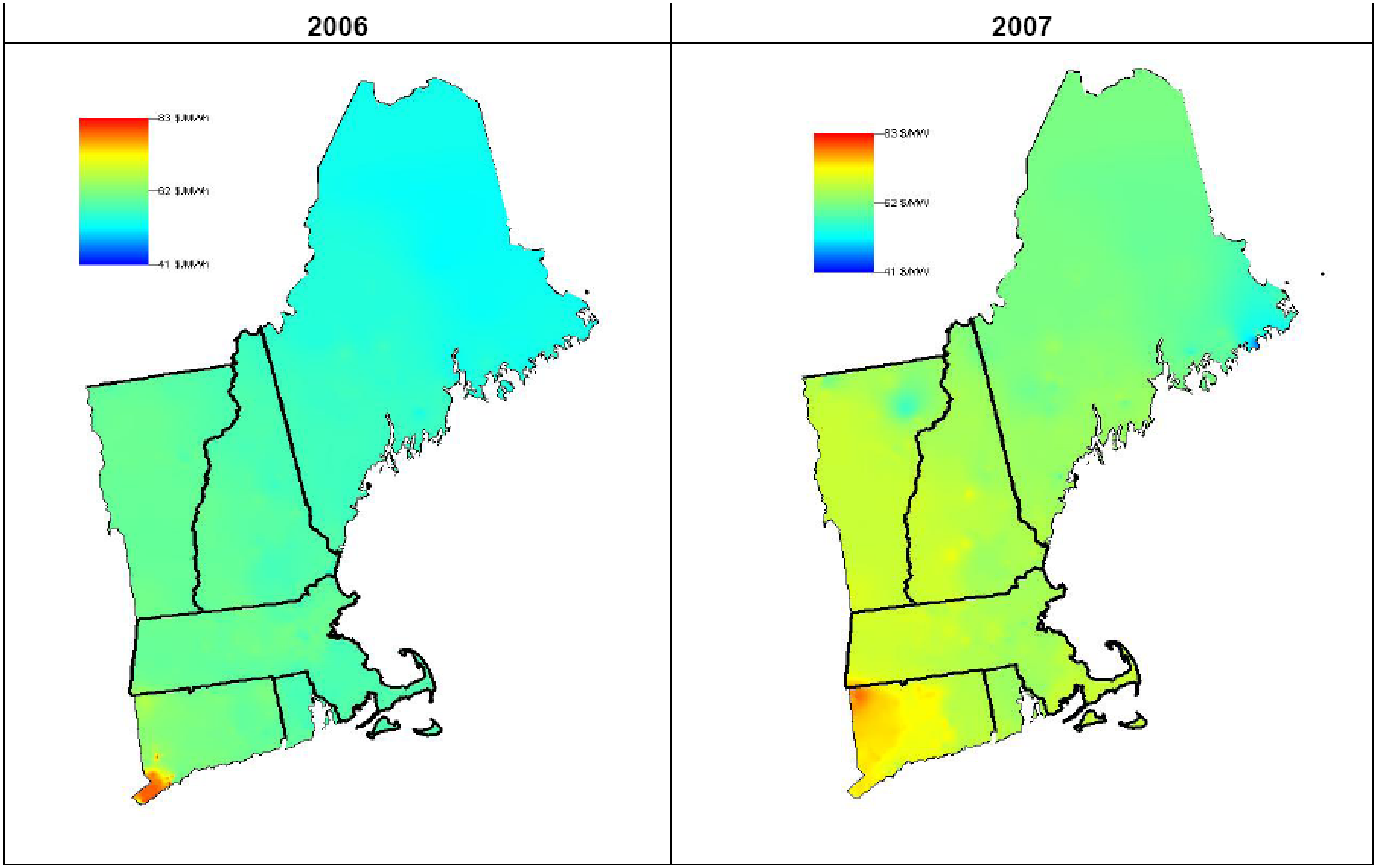
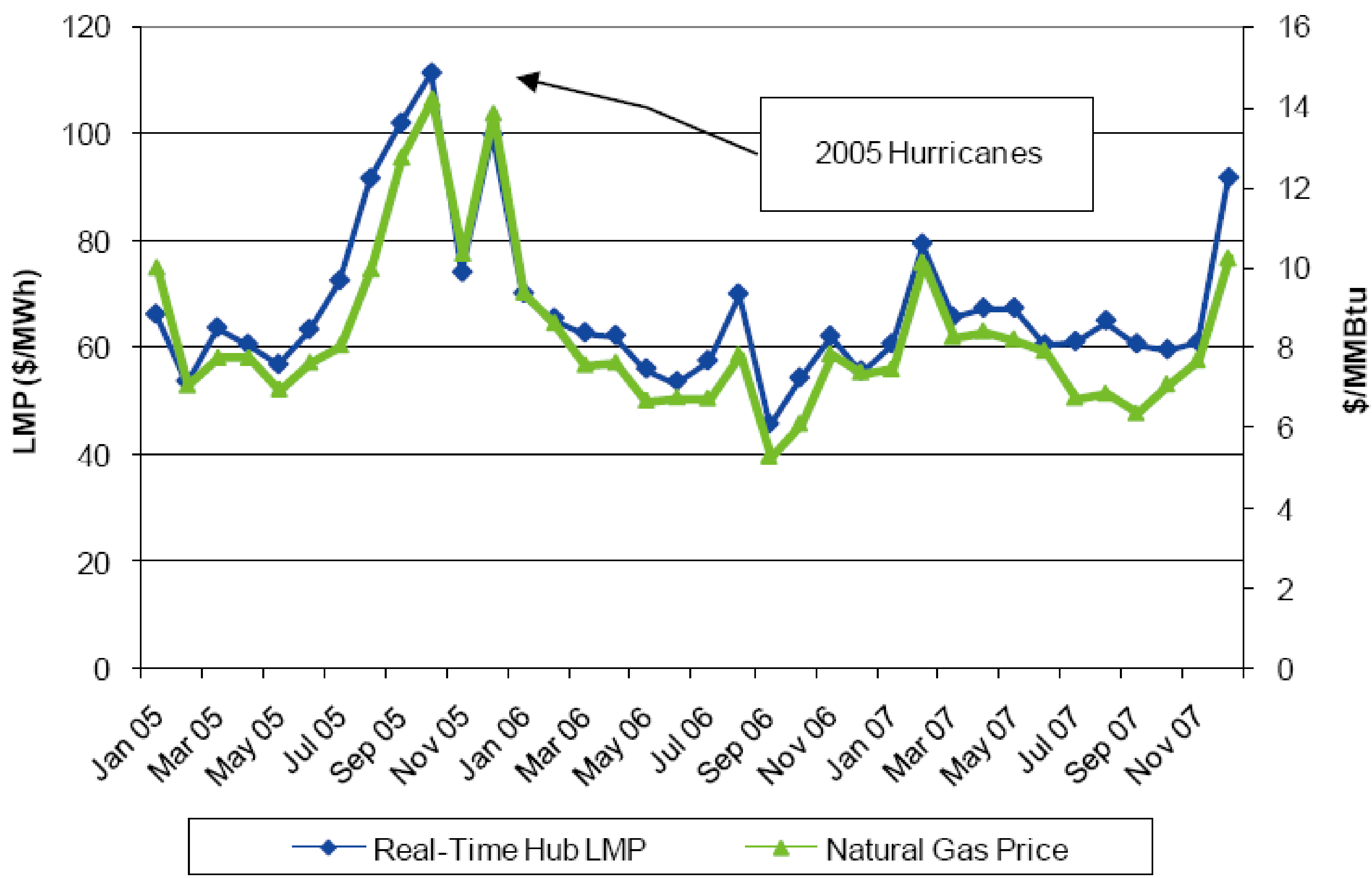


Figure 1-5: Average real-time nodal prices, 2006 and 2007, $/MWh.

ISO-New England (2008)



ISO-New England (2008)

Table 9-7
New England System Weighted Equivalent Availability Factors, %[a]

	1996	1997	1998	1999[b]	2000	2001	2002	2003	2004	2005	2006	2007
System average	75	78	81	81	81	89	88	88	88	89	89	90
Fossil steam[c]	*n/a*	*n/a*	*n/a*	79	78	84	85	87	86	86	88	87
Coal	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	88	84	84	83	88	84	87
Coal/oil	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	86	74	84	88	88	85	79
Oil	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	84	86	84	84	84	89	84
Gas/oil	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	80	84	91	87	84	91	89
Wood/refuse	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	95	94	94	93	93	93	92
Nuclear	*n/a*	*n/a*	*n/a*	82	89	91	91	91	94	89	93	92
Jet engine	*n/a*	*n/a*	*n/a*	70	88	92	94	94	97	95	96	97
Combustion turbine	*n/a*	*n/a*	*n/a*	90	83	89	93	93	97	95	95	94
Combined cycle	*n/a*	*n/a*	*n/a*	83	80	84	90	85	86	86	84	86
Pre-1999 combined cycle	*n/a*	*n/a*	*n/a*	91	89	94	92	91	92	92	92	92
New (installed 1999–2004) combined cycle	*n/a*	*n/a*	*n/a*	47	67	76	90	84	84	86	81	83
Hydro	*n/a*	*n/a*	*n/a*	81	81	95	96	95	94	94	96	96
Pumped storage	*n/a*	*n/a*	*n/a*	86	86	93	87	92	90	92	91	98
Diesel	*n/a*	*n/a*	*n/a*	88	88	98	98	98	95	98	99	97

ISO-New England (2008)

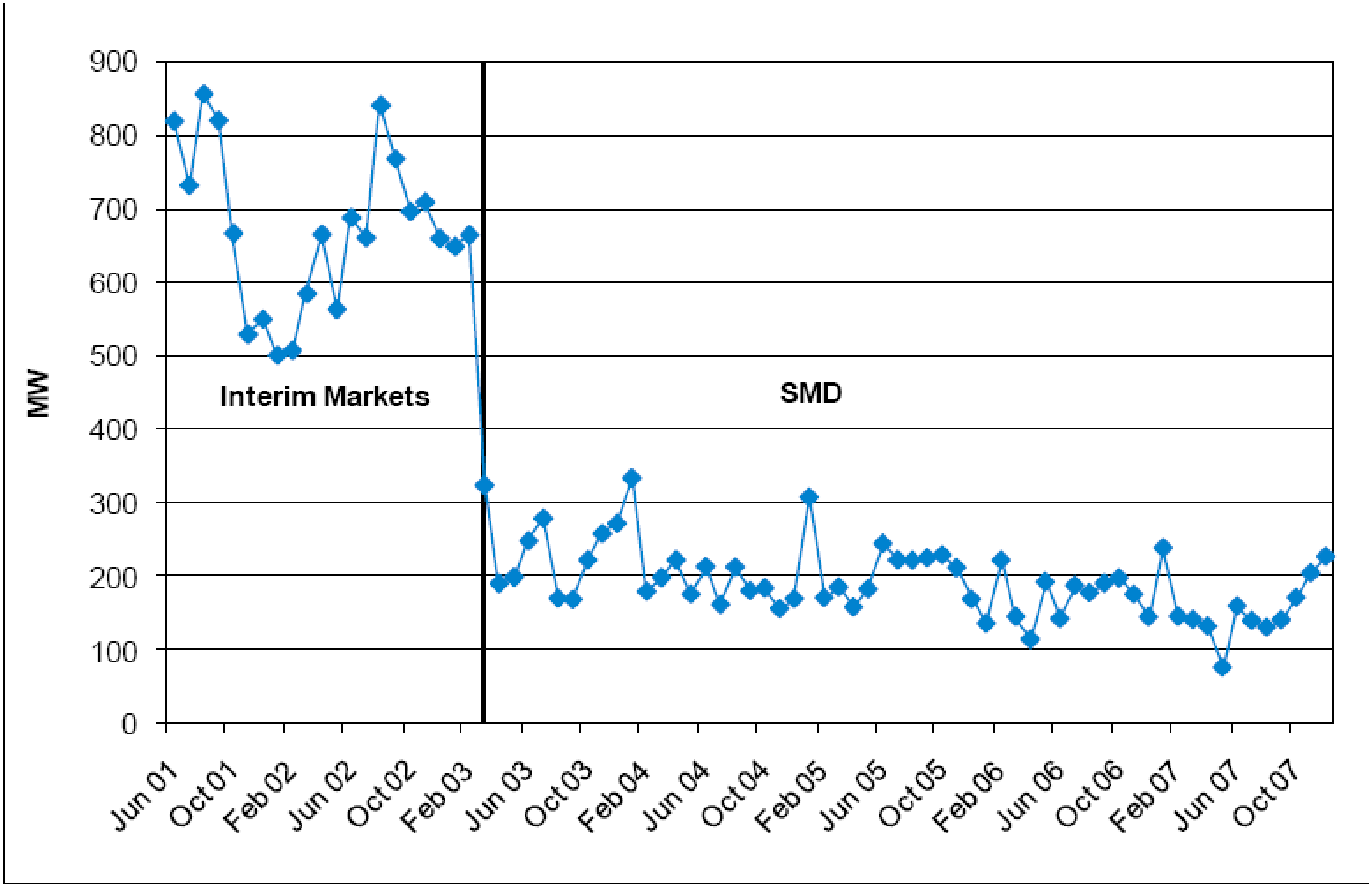
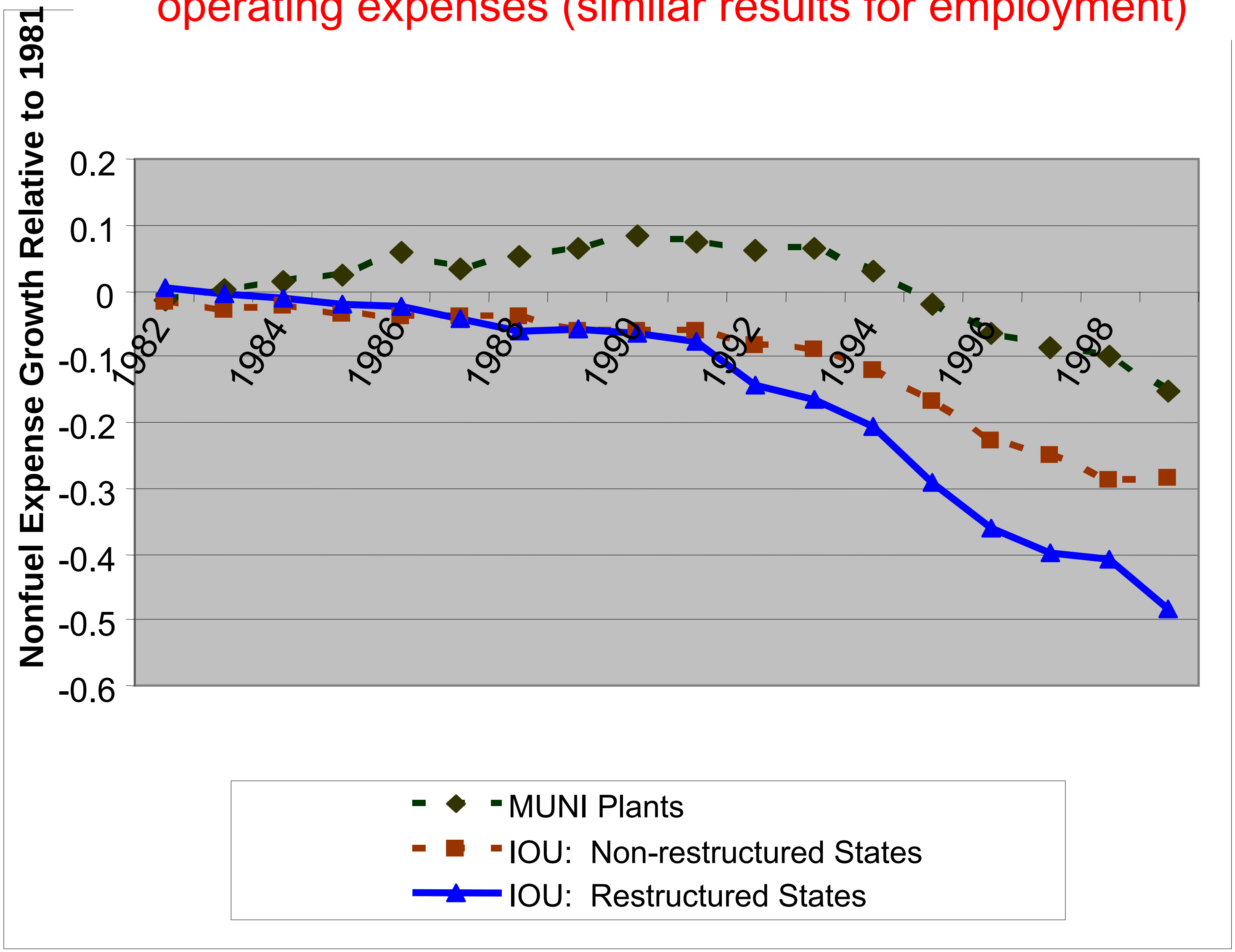


Figure 9-12: Average monthly overnight capacity loss.

ISO-New England (2008)

Plants operated by IOUs in restructuring states experienced the greatest improvement in nonfuel operating expenses (similar results for employment)



Frabrizio, Rose and Wolfram (AER, 2007)

Capacity factors increased for nuclear plants facing restructuring activity (Zhang, 2007)

DOES ELECTRICITY RESTRUCTURING WORK? 413

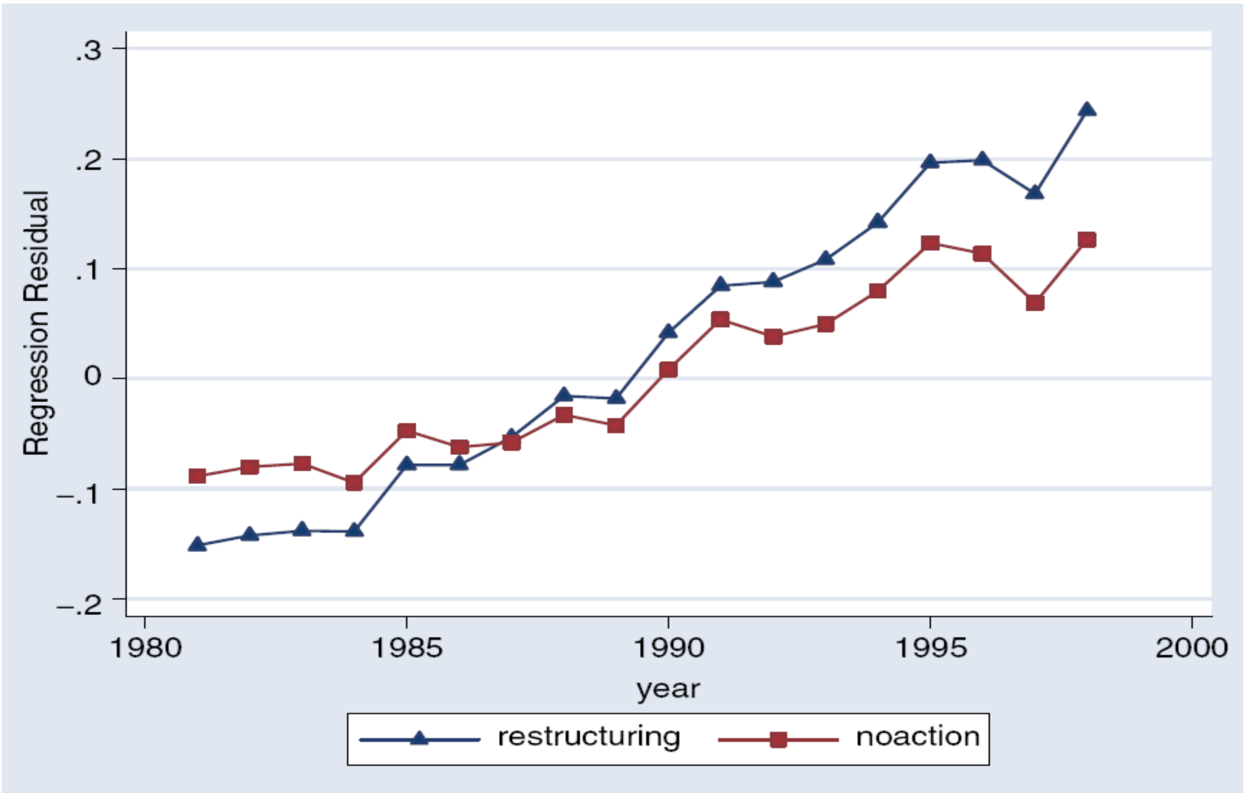
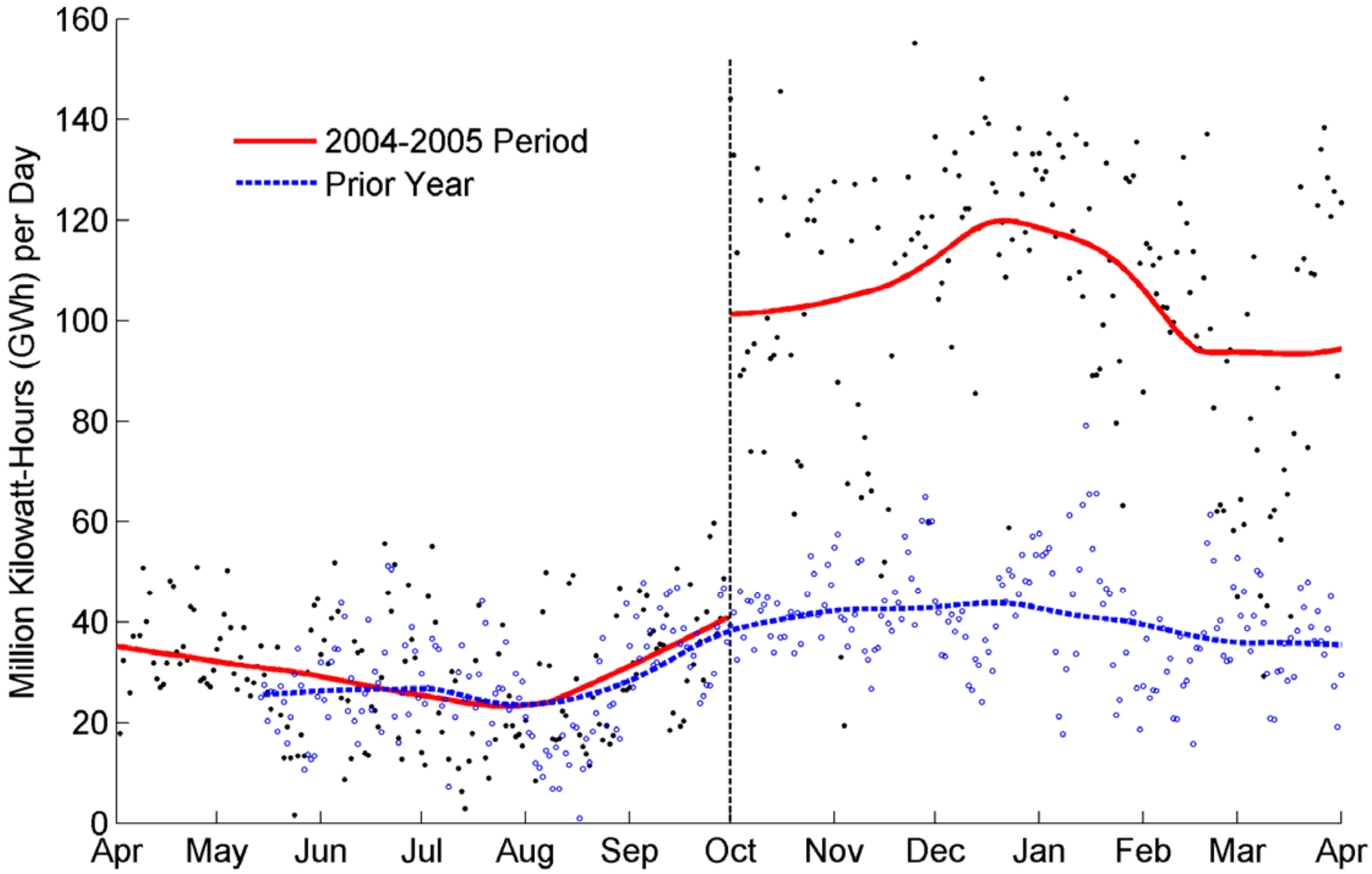


Figure 1
Yearly Capacity Factor (%) Change by Regulatory Status in 1998

Courtesy of Nancy Rose

Quantities traded: Day-ahead net exports, Midwest → East



White and Mansur (2008)

CHALLENGES

- Markets must produce adequate revenues to stimulate efficient investment
  - Capacity obligations
  - Scarcity pricing
- Better integrate demand side with short-term wholesale markets
- Improve efficiencies of interregional trades of power
- Retail competition and retail procurement
- Investment in transmission facilities, especially inter-regional transmission facilities
- Implementing a comprehensive national electricity policy to replace the fragmented system that now exists

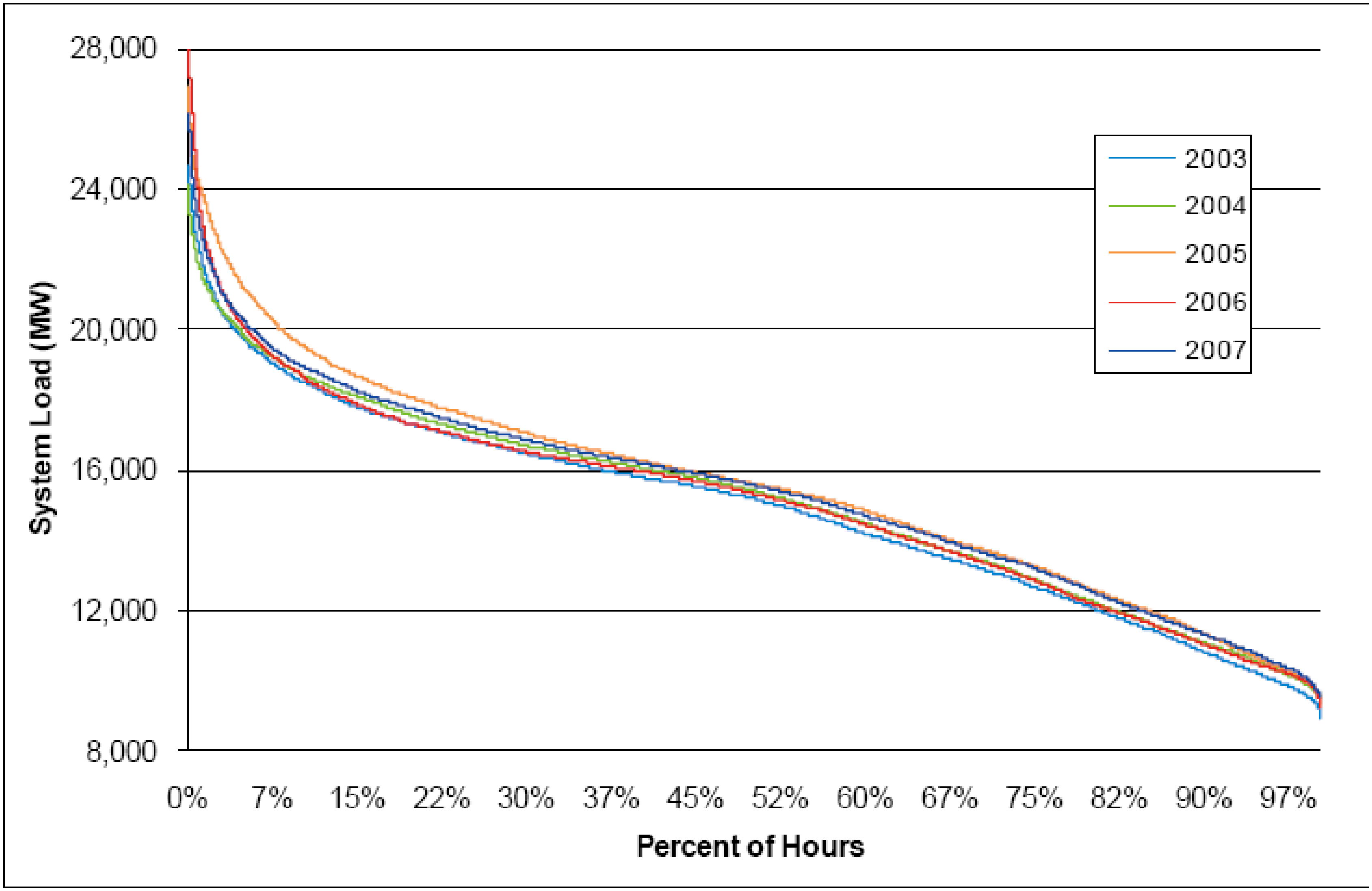


Figure 2-3: New England hourly load-duration curves, 2003 to 2007.

ISO-New England (2008)

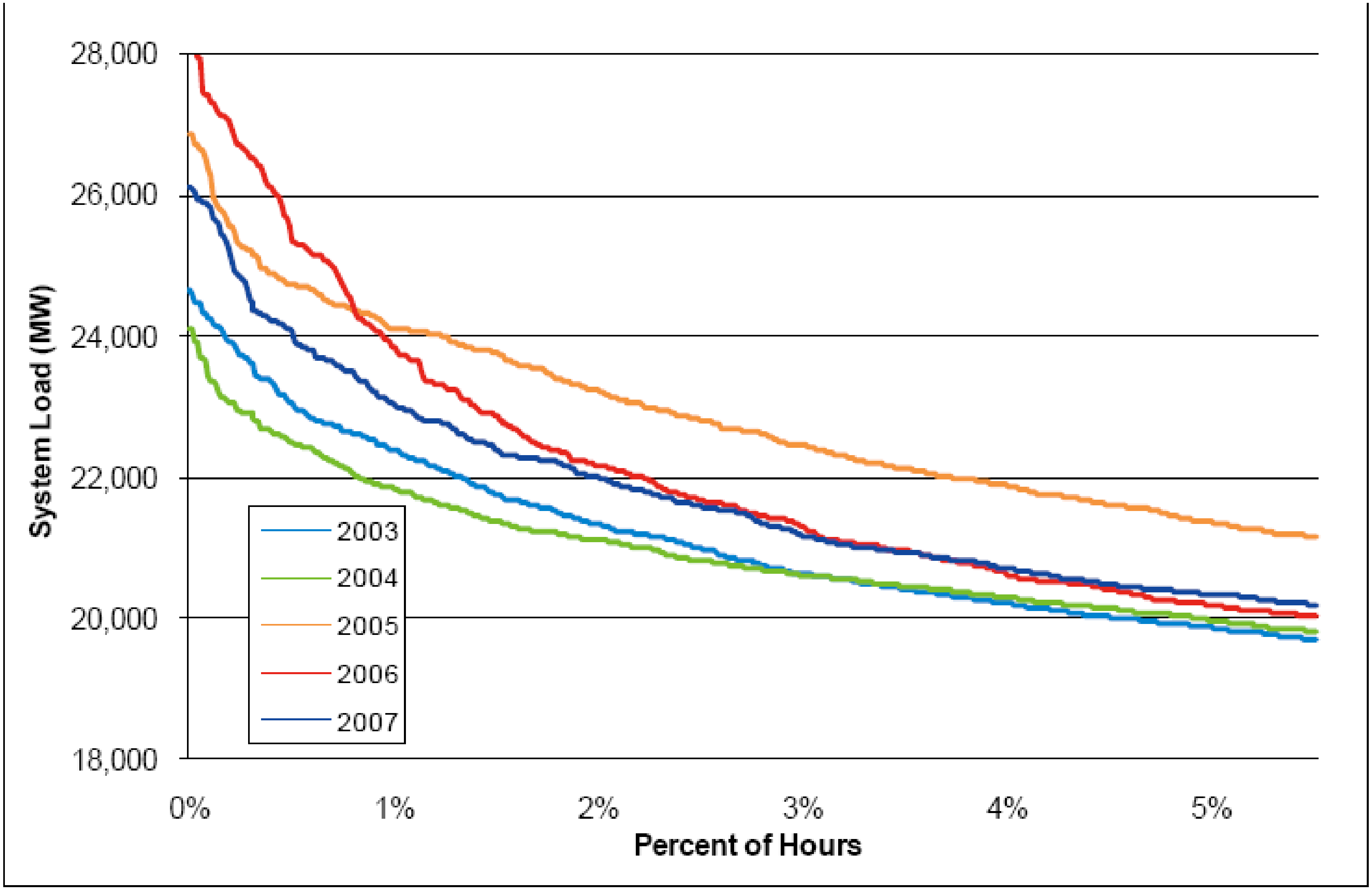
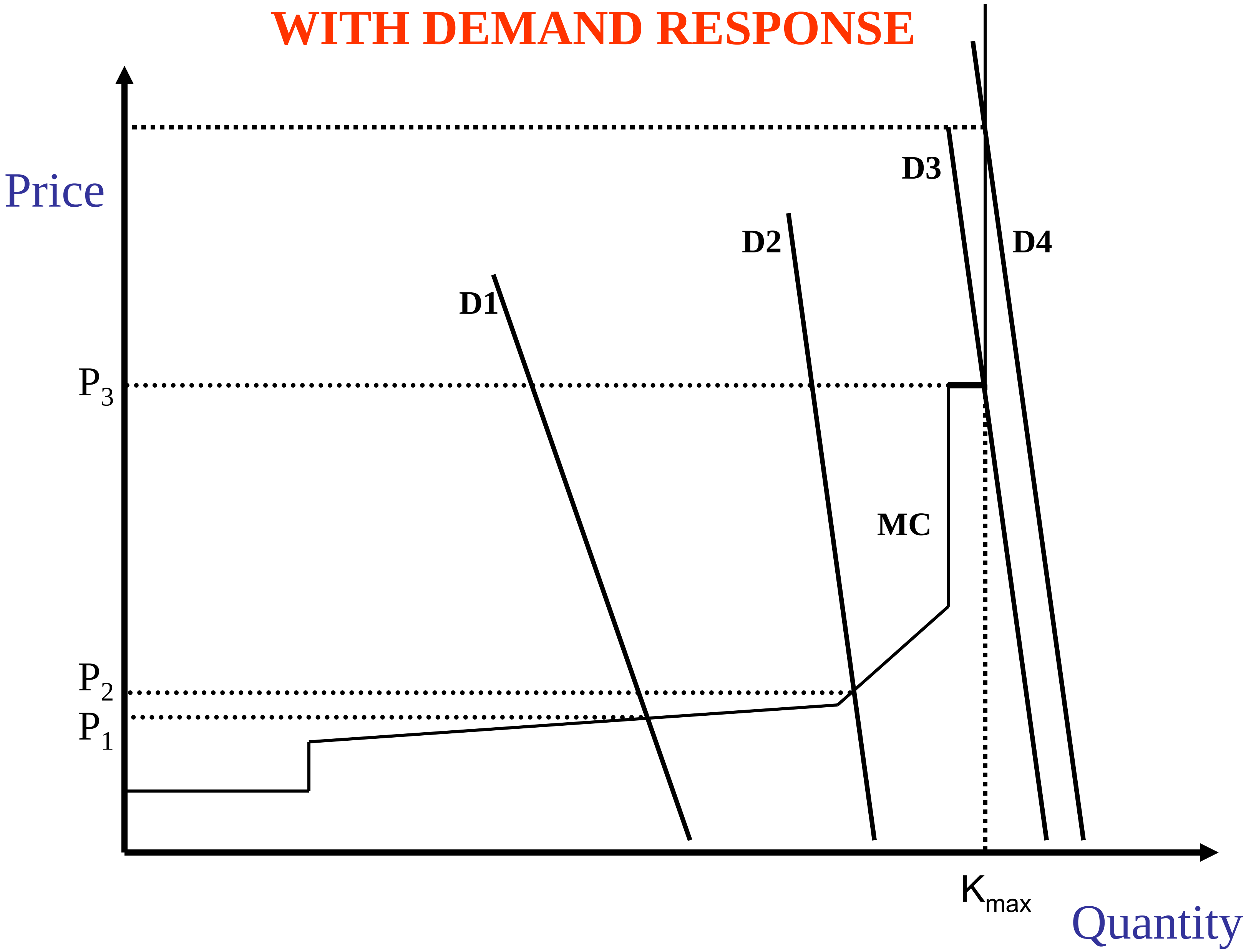
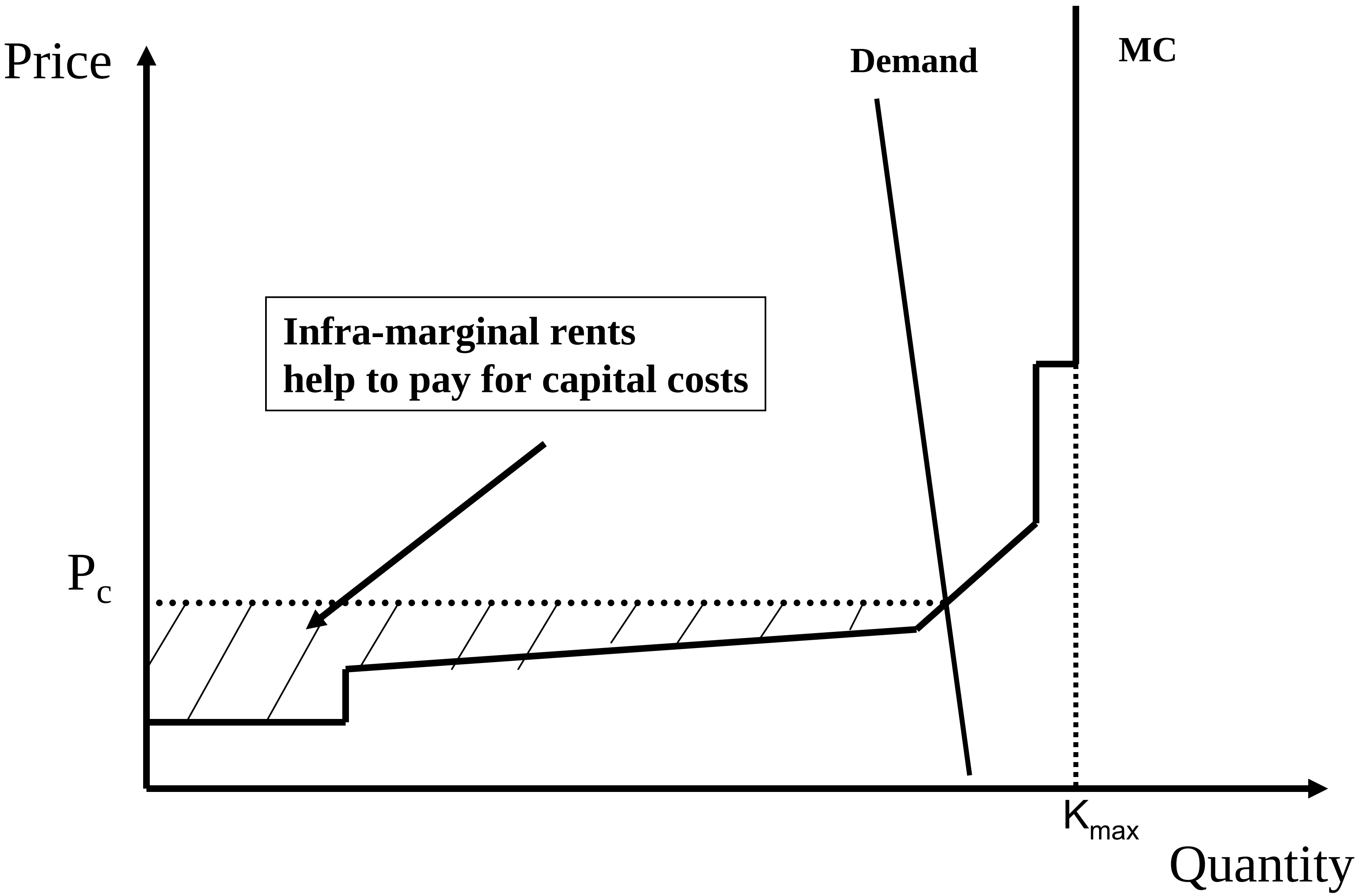


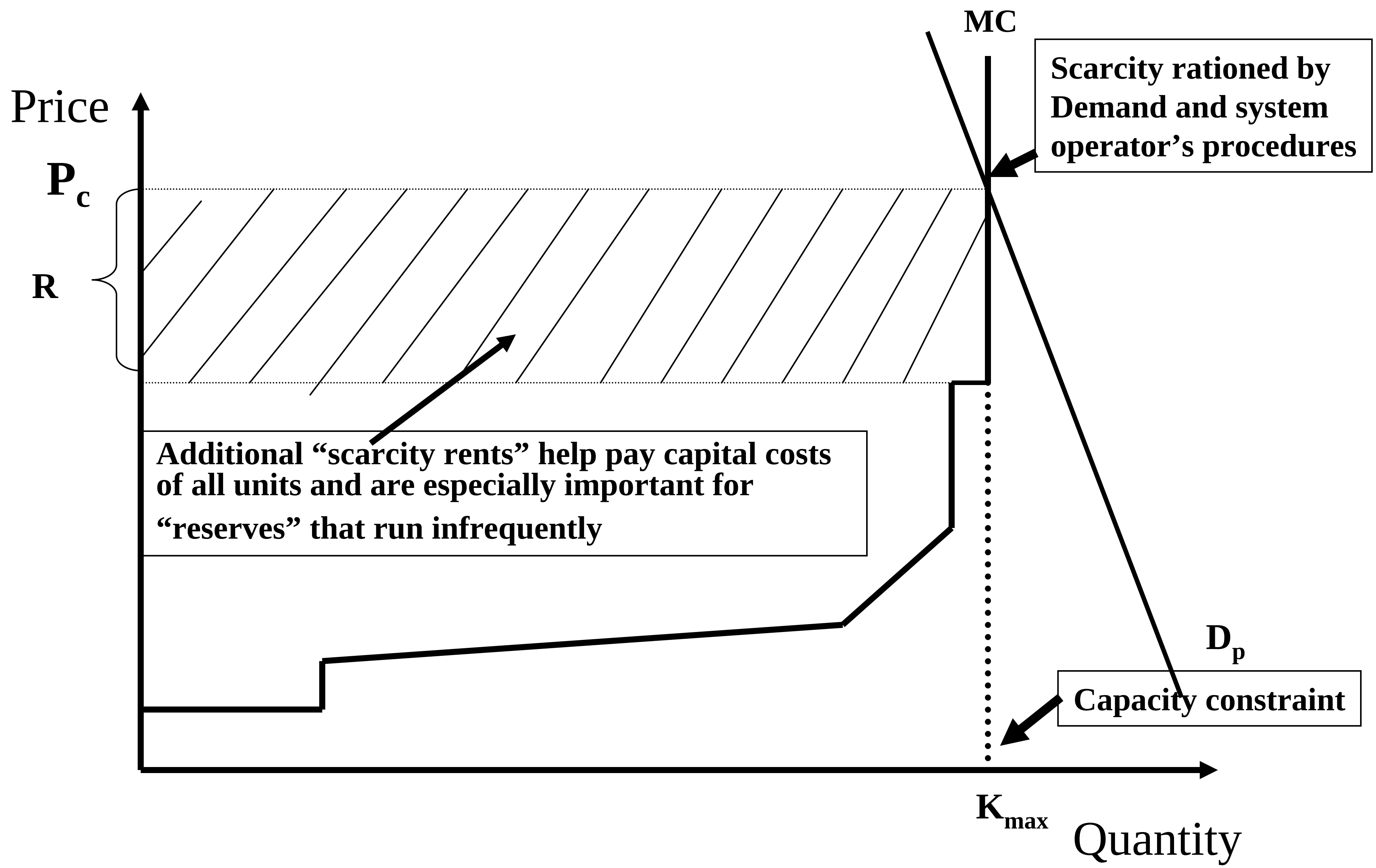
Figure 2-4: New England hourly load-duration curves, top 5% of hours, 2003 to 2007.

ISO-New England (2008)

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

HYPOTHETICAL ELECTRIC GENERATION SYSTEM WITH DEMAND RESPONSE "TECHNOLOGY"

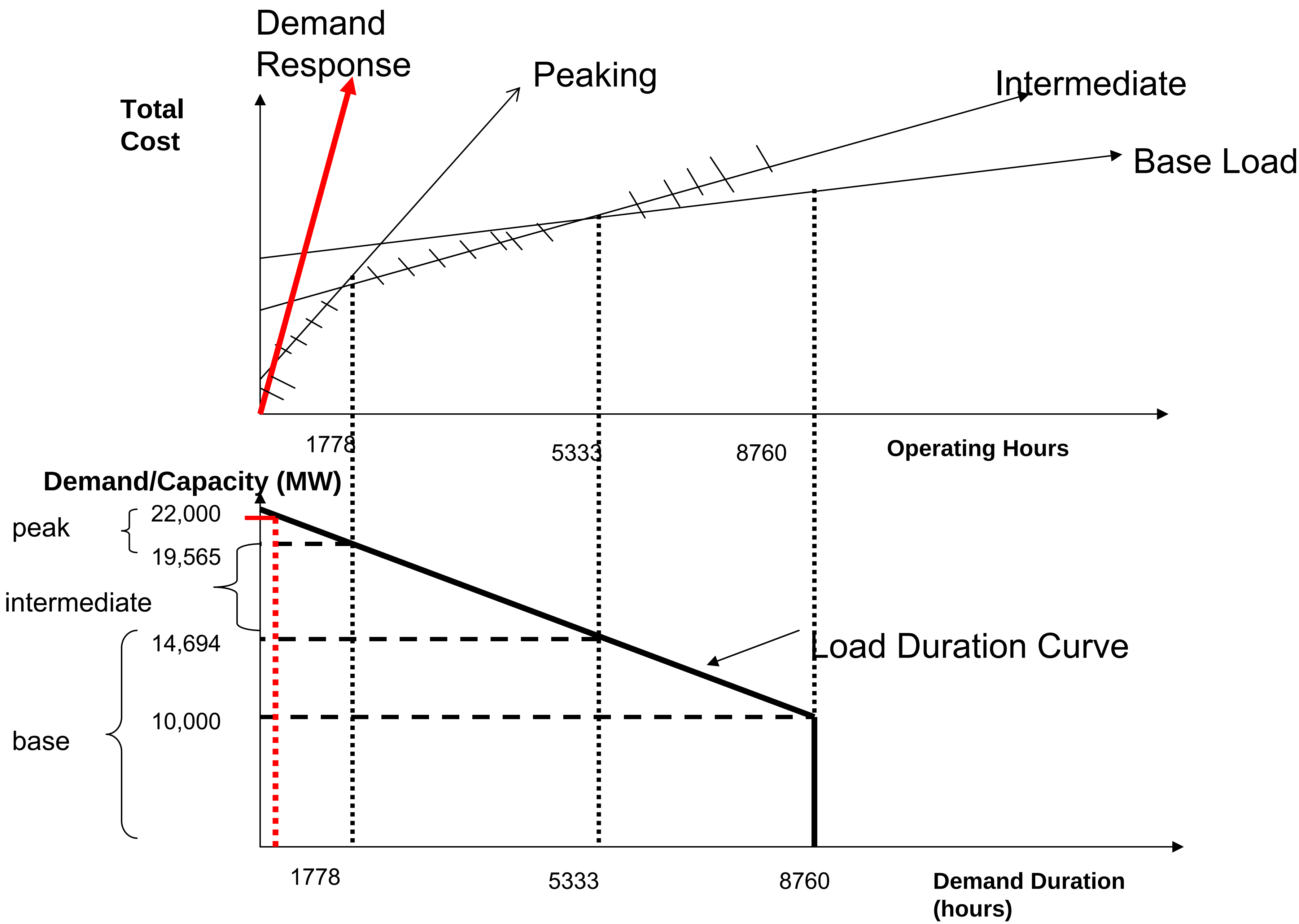
Generation Technology	Annualized Capital Costs $/Mw/Year	Operating Costs $/MWH
Base load	$240,000	$20
Intermediate	$160,000	$35
Peaking	$ 80,000	$80
Demand response (VOLL)	-0-	$4000

Load Duration Curve (See Figure 1)

$$D = 22{,}000 - 1.37H \qquad [0 < H < 8760]$$

D = System load

H = Number of hours system load reaches a level D


Demand Response
Peaking
Intermediate
Base Load
Total Cost
1778
5333
8760
Operating Hours
Demand/Capacity (MW)
peak
22,000
19,565
intermediate
14,694
10,000
base
Load Duration Curve
1778
5333
8760
Demand Duration (hours)

LEAST COST MIX OF GENERATING TECHNOLOGIES AND RUNNING TIMES FOR HYPOTHETICAL SYSTEM WITH DEMAND RESPONSE

Generating Technology	Capacity (Mw)	Running hours	Total Cost ($billions)
Base load	14,694	5333 – 8760	$5.940
Intermediate	4,871	1778 – 5333	$1.385
Peaking	2,407	20.4 – 1778	$0.3657
Demand Response	28	0 – 20.4	$0.0011
TOTAL	22,000		$7.692

SHORT-RUN MARGINAL PRODUCTION COST + SCARCITY PRICING PRICE DURATION SCHEDULE

Marginal Technology	Short-run Marginal Cost/Spot Price $/Mwh	Duration hours
Base load	$20	3427
Intermediate	$35	3556
Peaking	$80	1757
"Scarcity" (Demand Response)	$4000	20

Uniform prices paid to all generation supplies to clear the market at various demand levels

PROFITABILITY OF SHORT-RUN MARGINAL COST + “SCARCITY” PRICING OF ENERGY PRODUCTION FOR LEAST COST SYSTEM

Generating Technology	Revenues ($billions)	Total Cost ($billons)	Shortfall $(billions)	Shortfall $/Mw/Year
Base load	$5.940	$5.940	-0-	-0-
Intermediate	$1.385	$1.385	-0-	-0-
Peaking	$0.366	$0.366	-0-	-0-
Demand Response	$0.0114	$0.0114	-0-	-0-

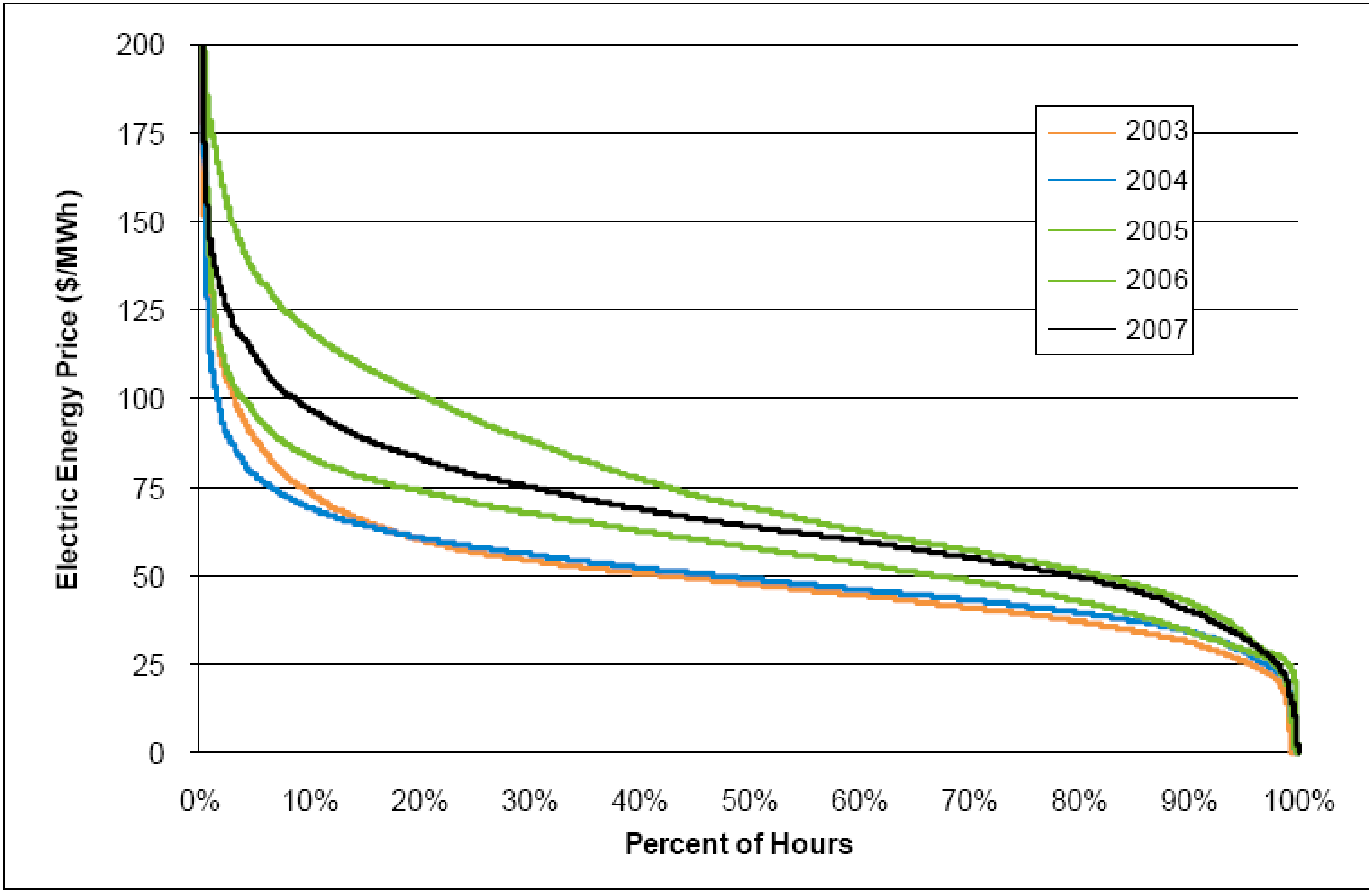


Figure 2-16: System real-time price-duration curves, prices less than $200/MWh, 2003 to 2007.

ISO-New England (2008)

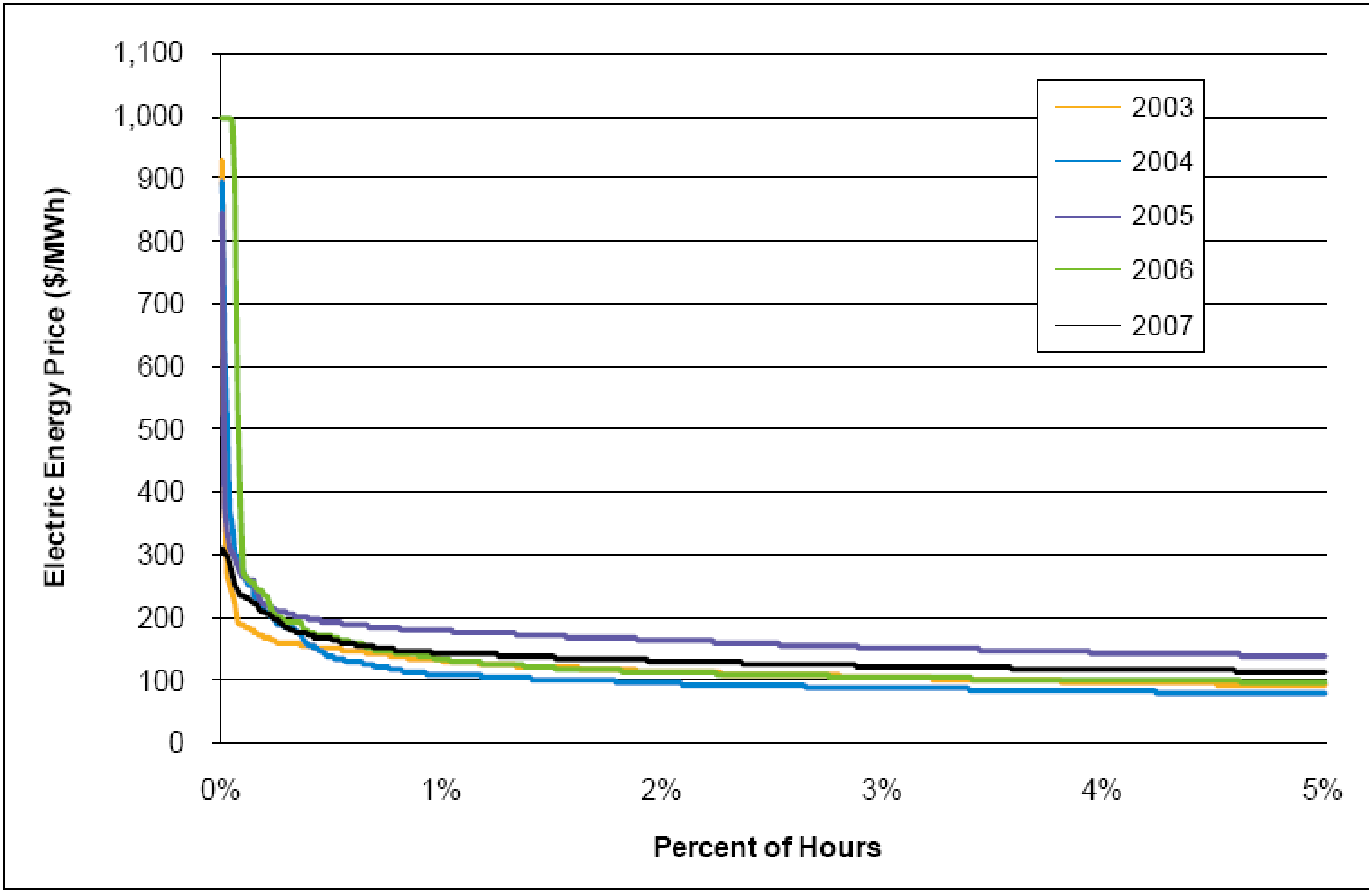


Figure 2-17: System real-time price-duration curves, prices in most expensive 5% of hours. 2003 to 2007.

ISO-New England (2008)

Table 3-22 New entrant 20-year levelized fixed costs (By plant type (Dollars per installed MW-year))

	2005	2006	2007
	20-Year Levelized Fixed Cost	20-Year Levelized Fixed Cost	20-Year Levelized Fixed Cost
CT	$72,207	$80,315	$90,656
CC	$93,549	$99,230	$143,600
CP	$208,247	$267,792	$359,750

PJM (2008)

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)

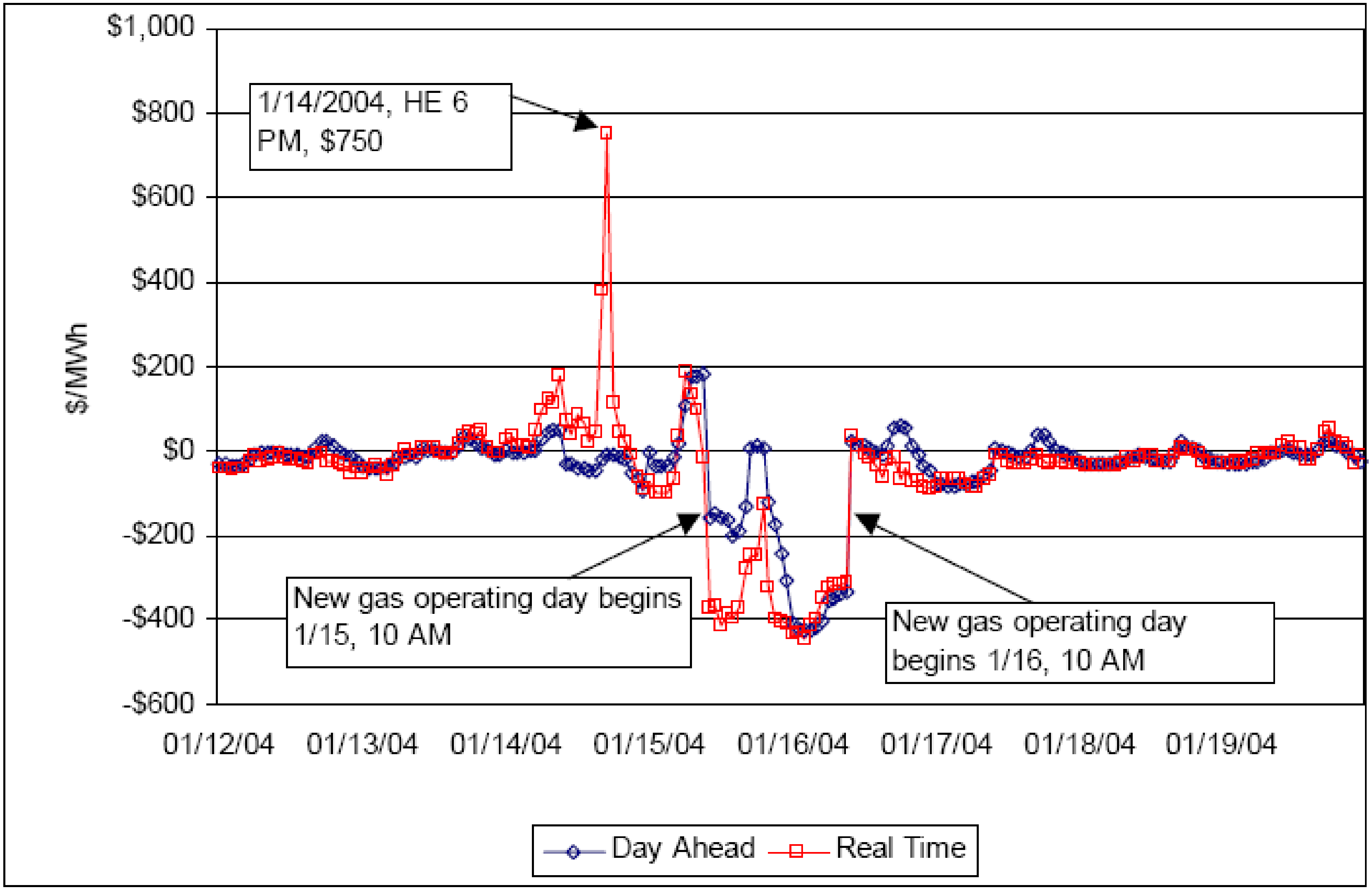
Peaker Fixed-Cost Target: $ $70,000 - $95,000/Mw-year

Table 3-23 CT 20-year levelized fixed cost vs. real-time economic dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2007

	20-Year Levelized Fixed Cost	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$72,207	$74,537	103%
2000	$72,207	$30,946	43%
2001	$72,207	$63,462	88%
2002	$72,207	$28,260	39%
2003	$72,207	$10,566	15%
2004	$72,207	$8,543	12%
2005	$72,207	$10,437	14%
2006	$80,315	$14,948	19%
2007	$90,656	$48,530	54%
Average	$75,158	$32,248	43%

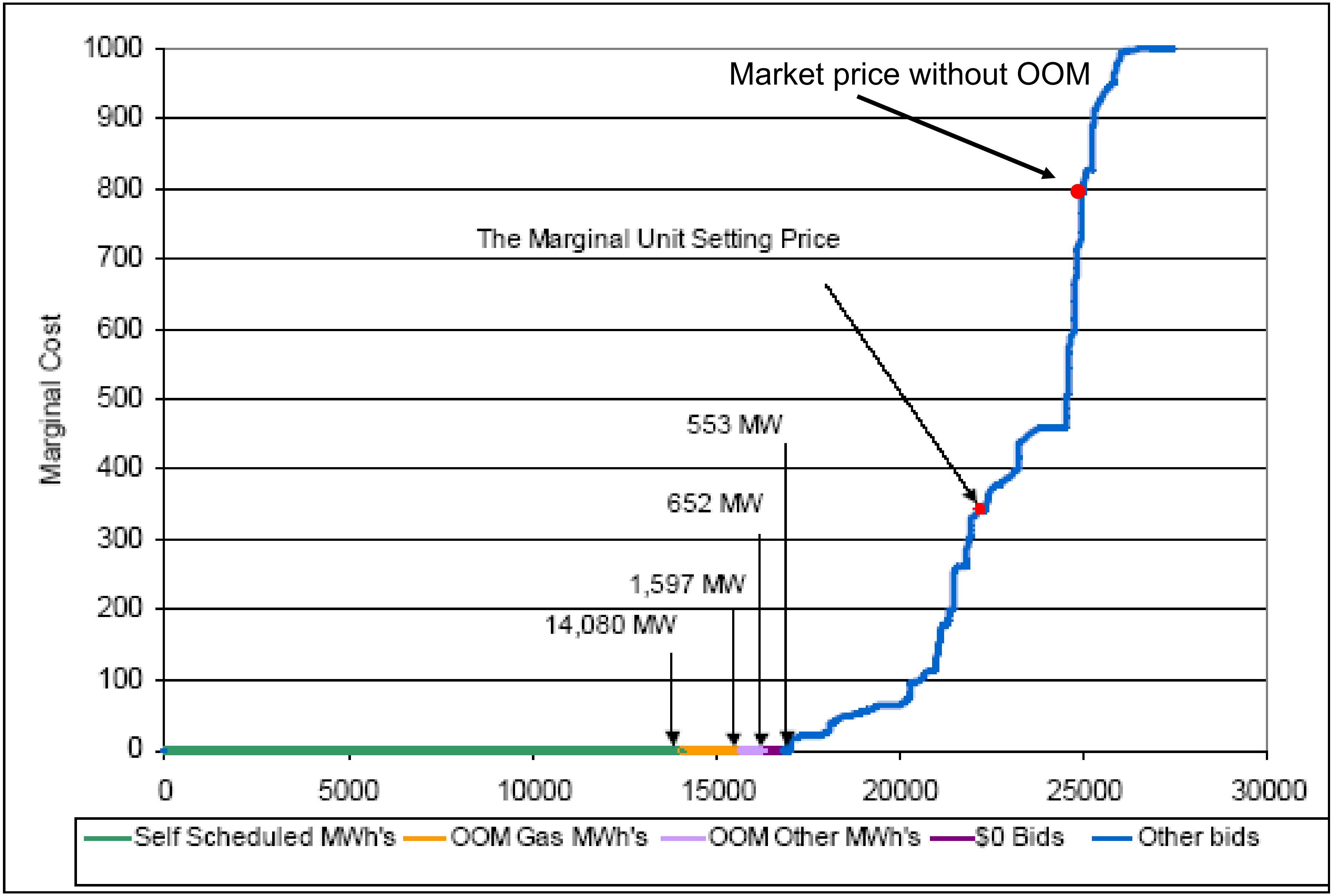
PJM (2008)

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



ISO New England

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



Source: ISO NE

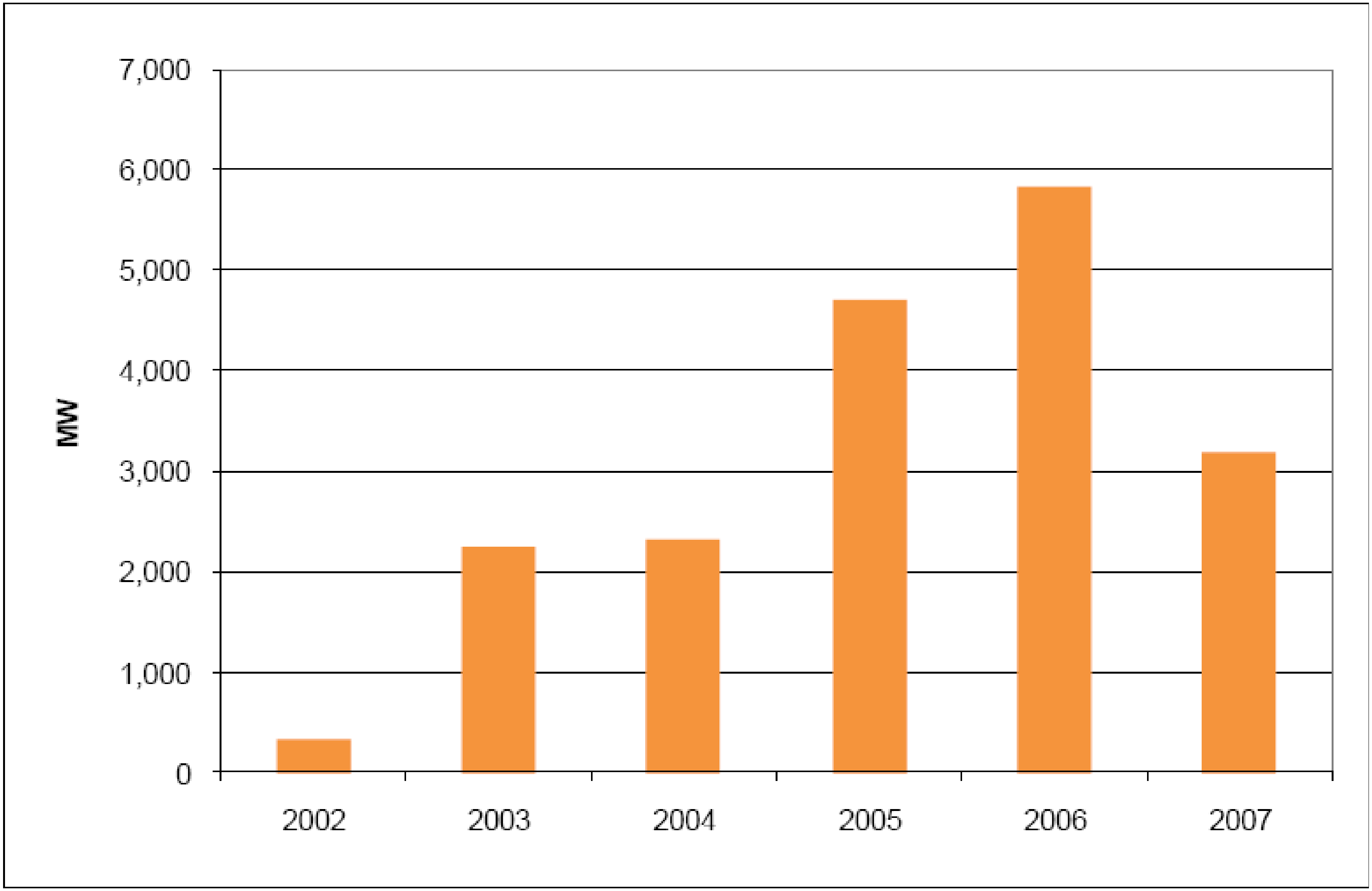


Figure 6-6: Generating capacity with FERC-approved Reliability Agreements.

ISO New England (2008)

3.7 First Forward Capacity Auction

The first FCA for the New England region for the 2010/2011 capability year was successfully concluded on February 6, 2008. The results of that auction were filed with FERC on February 27, 2008.

At the beginning of the auction, a total of 38,105 MW of capacity had been submitted (32,392 MW of existing capacity and 6,102 MW of new capacity minus 389 MW of delisted existing capacity). Compared with the ICR amount of 32,305 MW used in the auction, approximately 18% of the capacity competing in the auction was surplus.

The auction selected approximately 1,813 MW of new supply and demand resources. Of the new resources chosen, 1,188 MW represent new demand projects, and 626 MW represent new supply projects. The auction closed at the administrative floor price of $4.50/kW-month, with 2,047 MW of surplus capacity remaining. Because the auction stopped at the administrative floor price, the price received by capacity remaining in the auction at the close will be prorated. The product of the auction closing price times the ICR amount will be prorated to all remaining capacity. A more detailed examination of the auction and its results will be included in the *2008 Annual Market Report*.

ISO New England (2008)

Table 9-6
Yearly Theoretical Maximum Revenue for Hypothetical Generators
Net of Variable Costs per MW, 2007

Generator	Marginal Cost Formula	Heat Rate (Btu/kWh)	($/MW-Year)			
			2007 Net Energy Revenue	Approximate Capacity Revenue[(a)]	Approximate Ancillary Services Revenue[(b)]	Approximate Theoretical Max. Revenue
Representative combined cycle/ gas fired	(Daily fuel cost x heat rate) + (VOM[(c)] of $1/MWh)	7,000	$119,087	$36,600	$1,437	$157,124
Representative combustion turbine/ gas fired	(Daily fuel cost x heat rate) + (VOM[(c)] of $3/MWh)	10,500	$25,532	$36,600	$31,032	$93,164

ISO New England (2008)

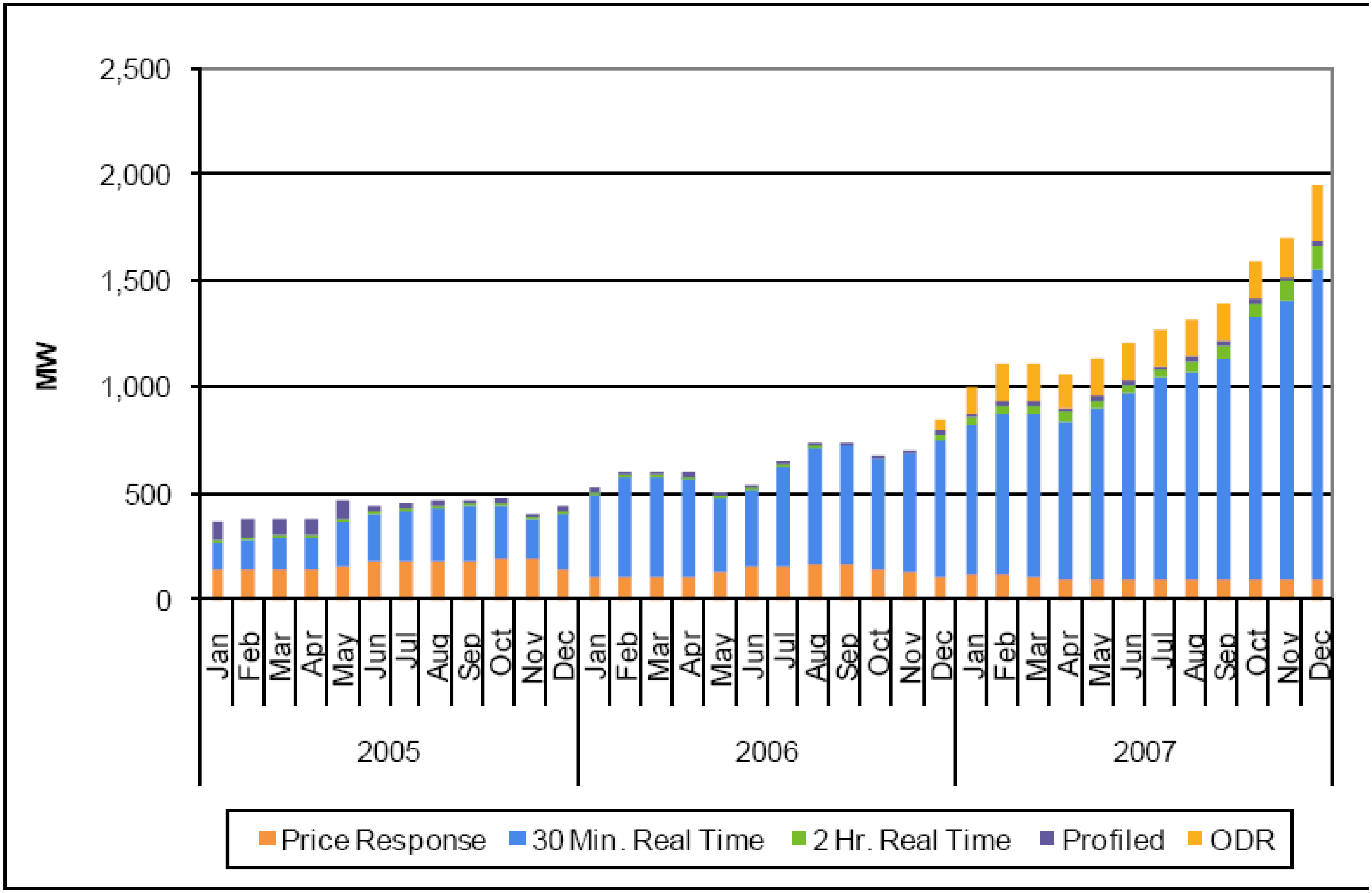


Figure 1-8: Monthly megawatts enrolled in ISO demand-resource programs, 2005 to 2007.

ISO New England (2008)

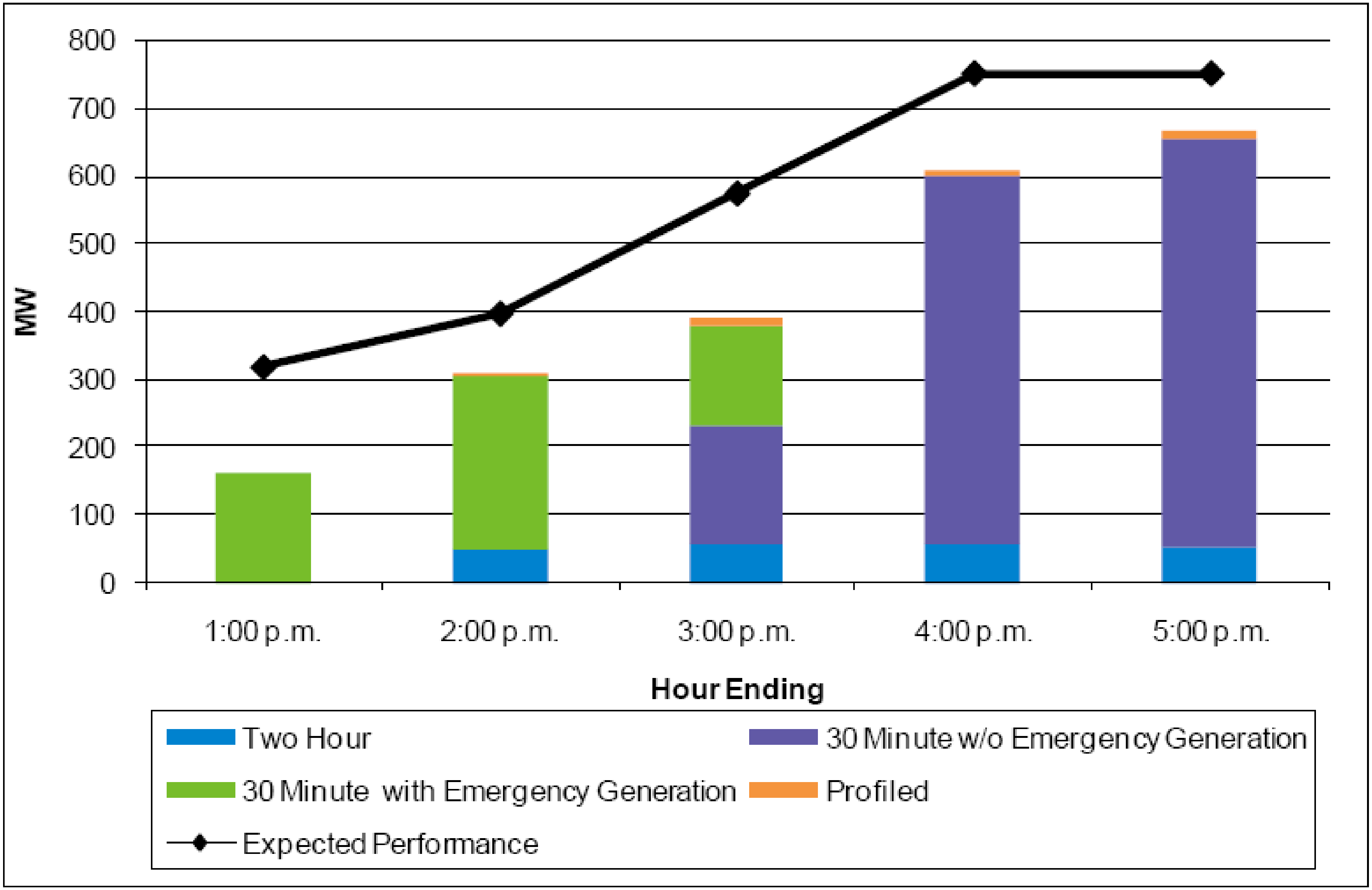


Figure 8-6 Real-time demand-response audit performance, August 15, 2007.

ISO New England (2008)

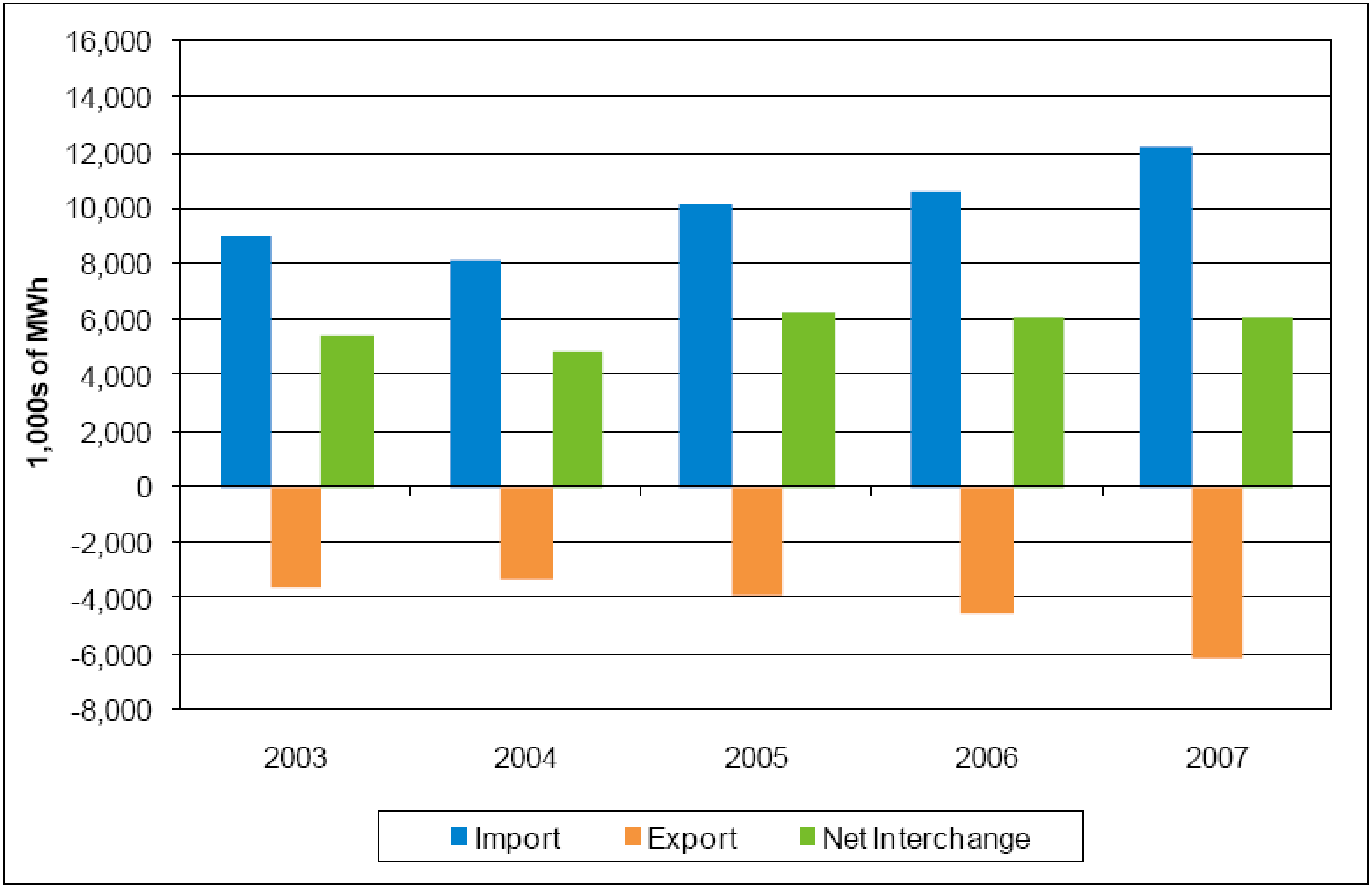
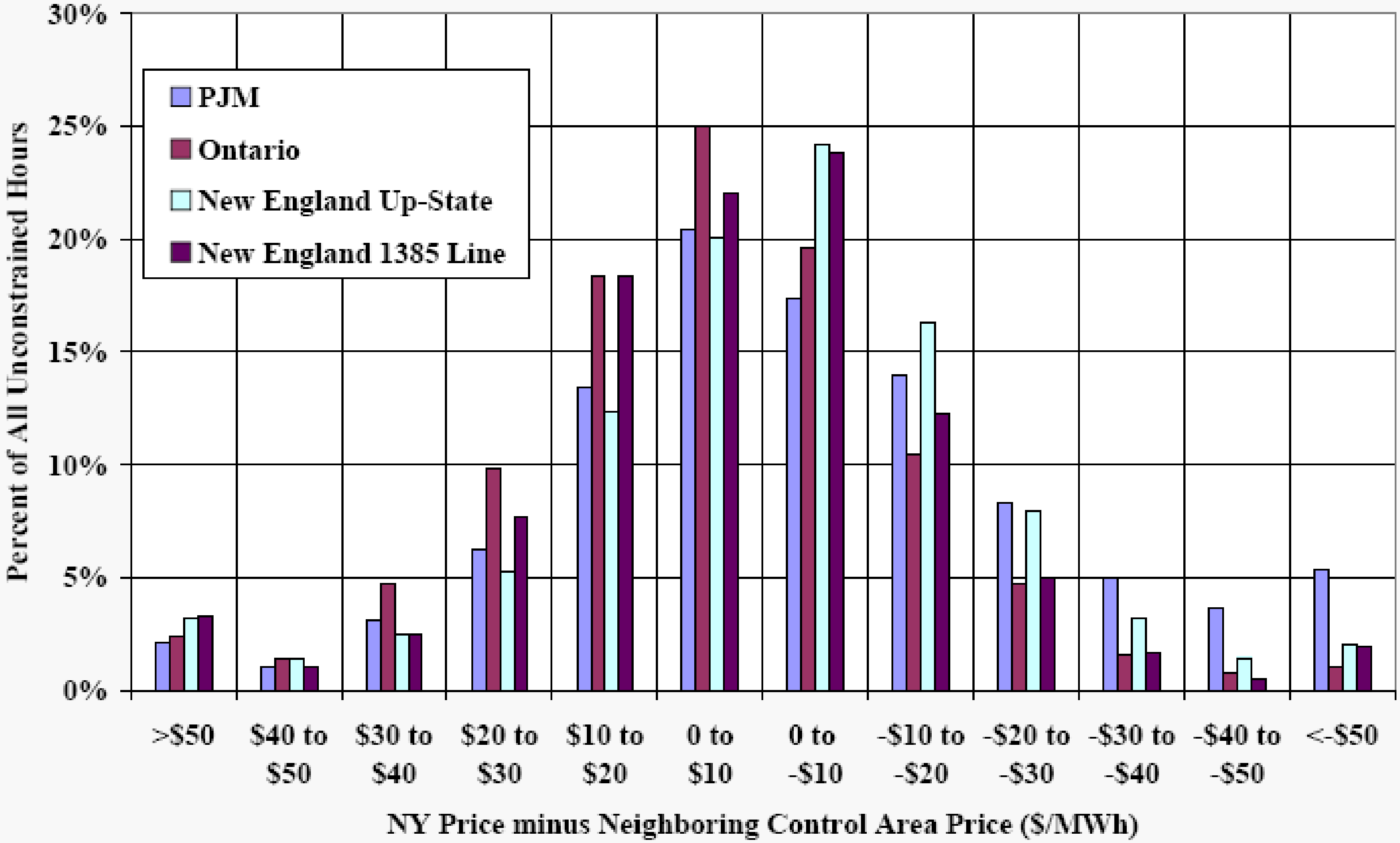


Figure 2-13: New England annual imports, exports, and net interchange, all interfaces.

ISO New England (2008)

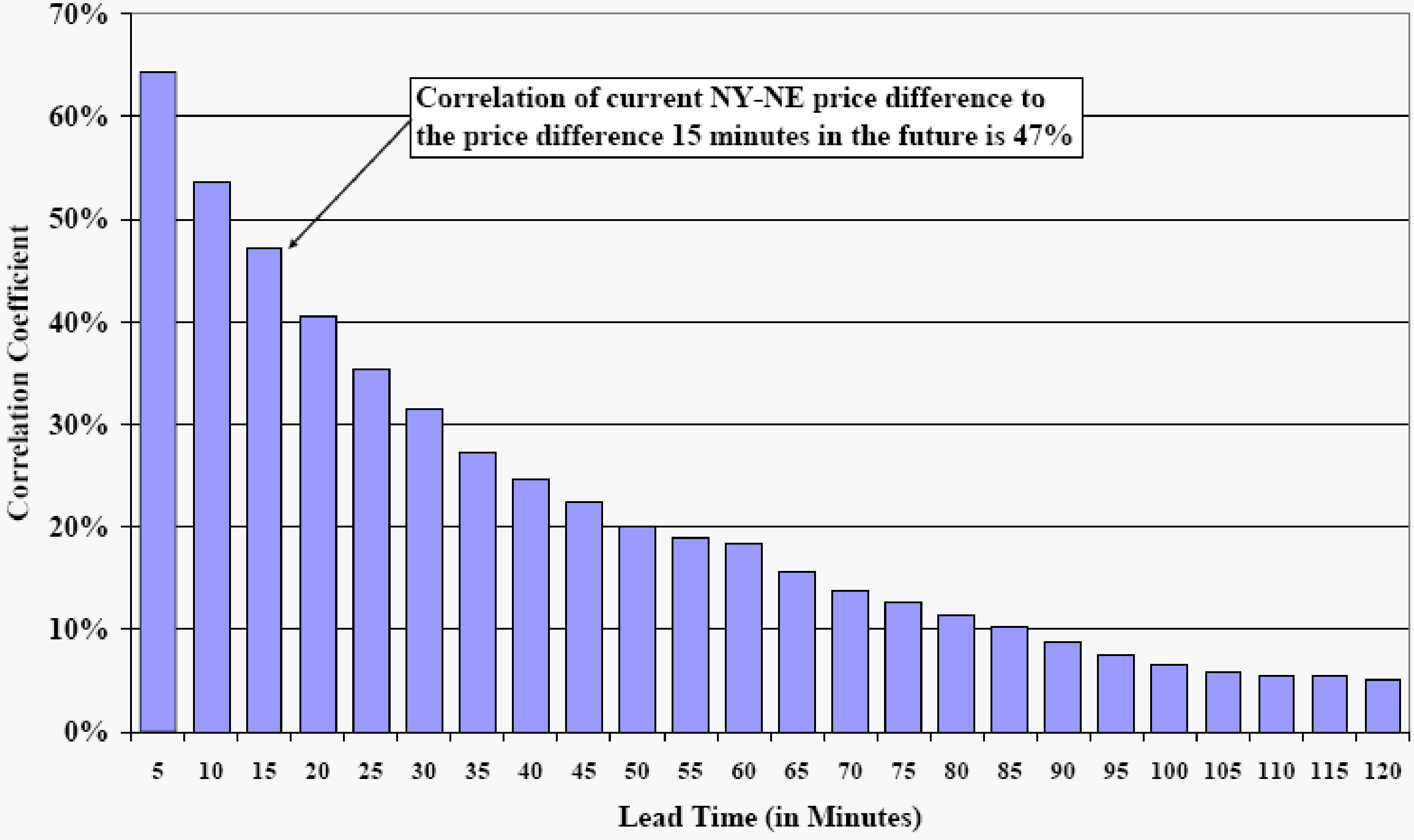
RT Price Convergence Between NY and Adjacent ISO Markets
Unconstrained Hours, 2007



Note: The Neptune and Cross Sound Cable proxy busses are omitted because they depend on a separate system for allocating transmission reservations.

New York ISO (2008)

Efficiency of Reducing Scheduling Lead Time
Correlation of Price Difference to Lead Time
New York – New England Interface, 2007



New York ISO (2008)

Estimated Benefits of Coordinated External Interface Scheduling Up-state Interface with ISO-New England, 2006 & 2007

	2006	2007
Estimated Production Cost Net Savings (in Millions)	$17	$21
Estimated Consumer Net Savings (in Millions):		
New York Customers	$59	$177
New England Customers	$61	$22
Total for New York and New England Customers	$120	$199
During Reserve Shortage Hours	$16	$75

New York ISO (2008)

PERFORMANCE OF RETAIL COMPETITION PROGRAMS

- Fraction of customers “switching” has generally been smaller than hoped for, especially for residential and small commercial customers
  - Regulated default service prices are below market
  - As default arrangements roll off more switching in response to sudden price increases and to mitigate price volatility
- Retail prices have risen rapidly in restructuring states as rising natural gas and coal prices have driven up wholesale and retail prices
- Stranded costs have turned into stranded benefits associated with embedded regulated cost of nuclear and coal
- Diffusion of other value-added services appears to be minimal except for very large customers (not well tracked)
- Poor performance of retail competition has had adverse effects on wholesale markets
  - Real-time pricing and demand elasticity
  - Long-term contracts with generators
- With rising wholesale prices, retail competition has been a tough sell in states that have not already adopted it

RETAIL COMPETITION IN MASSACHUSETTS

Retail Choice Began March 1998
Regulated Basic Charge ended ~ April 2005
Replaced with default wholesale market procurement

Customer Type	% of Load Served by ESPS		
	February 2004	May 2005	May 2008
Residential	2.6	6.1	11.7
Small Commercial	10.8	19.3	33.9
Medium C&I	17.0	22.2	49.8
Large C&I	48.3	63.3	87.3
TOTAL	22.6	34.0	53.0

MA Department of Energy Resources (2008)

EFFECTS OF REGULATED BASIC SERVICE

Percentage of Customers Load (MW) Served By An Alternative Supplier

As Of 7/1/2008

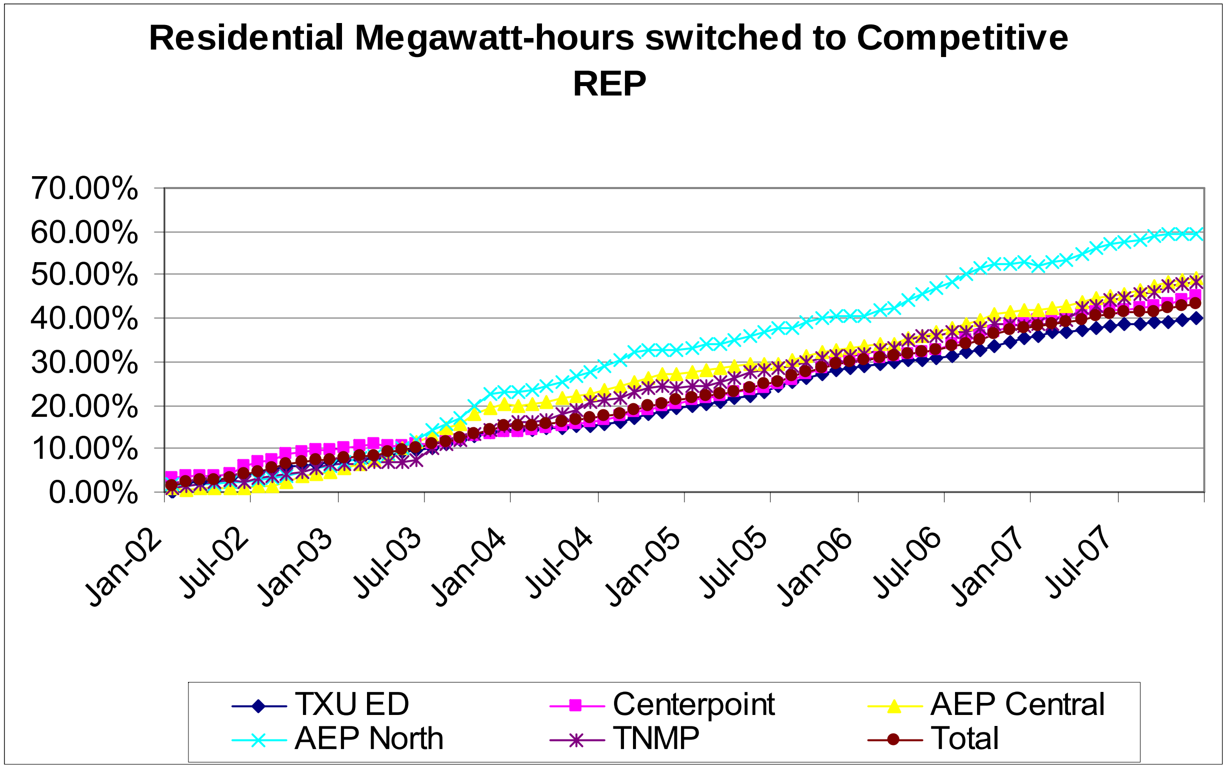
	Residential	Commercial	Industrial	Total
Allegheny Power	0	0	0	0
Duquesne Light	20.5	50.3	88.5	48.8
MetEd/Penelec	0	0	3.9	1
PECO Energy	0.3	7.4	0.1	2.2
Penn Power	6.9	44.9	97.4	53.6
PPL	0	0.1	0.1	0.1
UGI	0	0	0	0

Totals may differ due to rounding.

Pennsylvania Office of Consumer Advocate
7-3-2008

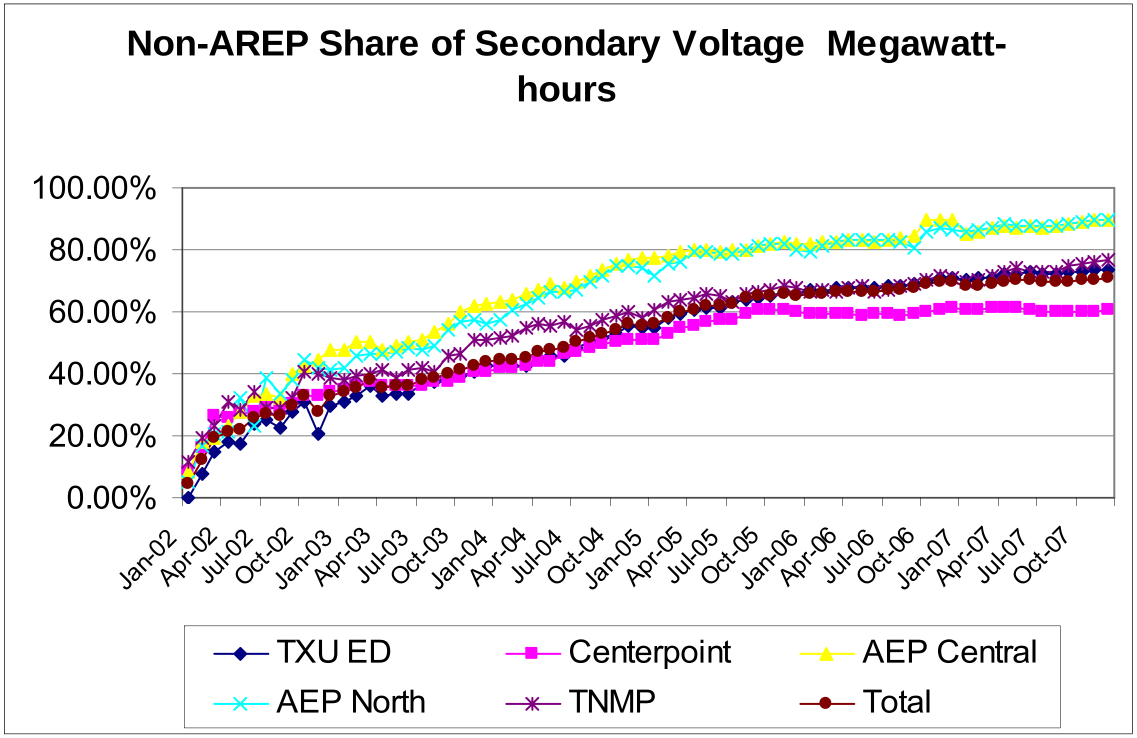
PA Public Advocate (2008)

RETAIL CHOICE IN TEXAS



Texas PUC

RETAIL CHOICE IN TEXAS

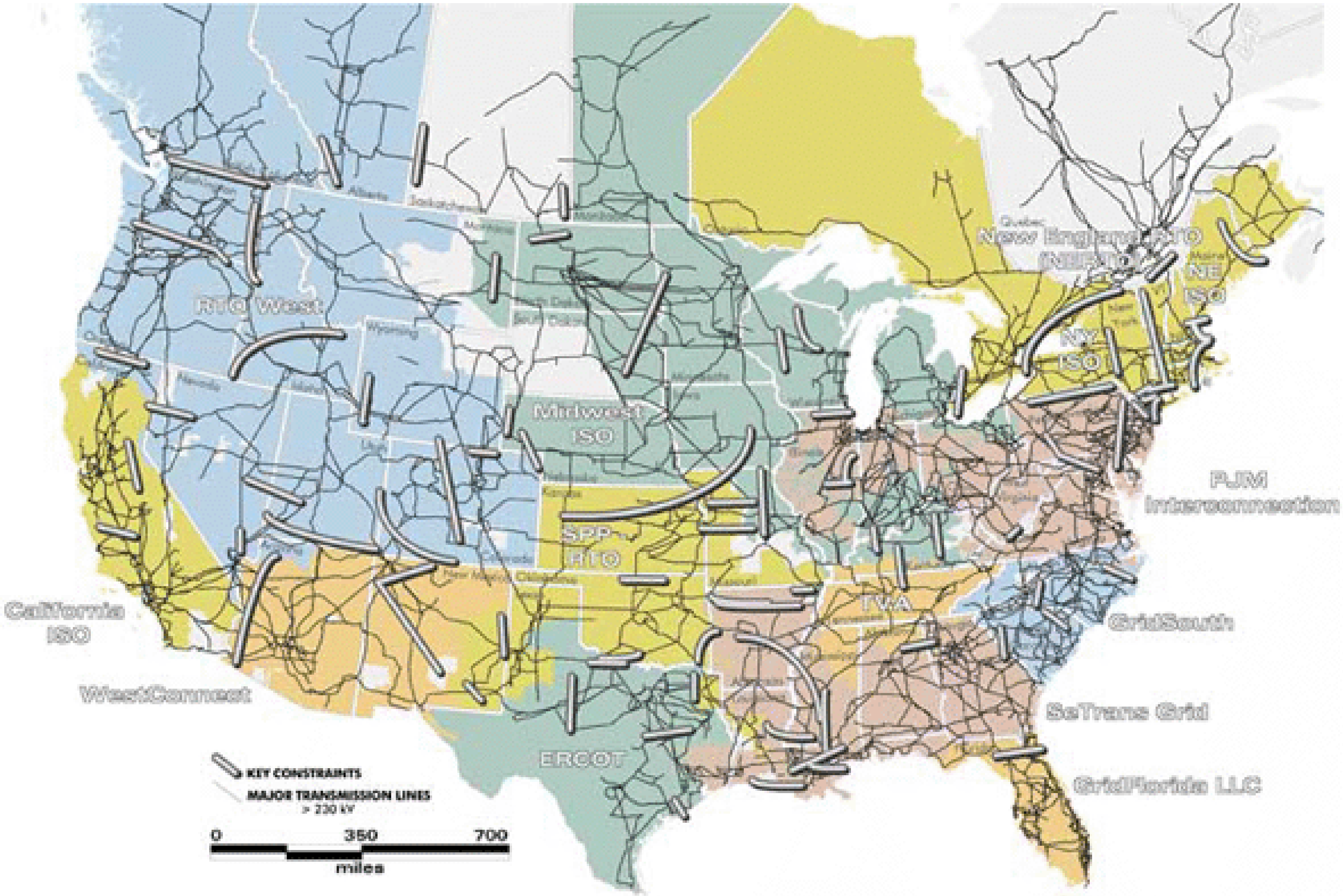


Texas PUC

TRANSMISSION

- 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 increased significantly until 2004
  - 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
- NIMBY is a problem and it is not clear that new federal backstop is helping
- Intra-regional transmission investment situation is improving
- Inter-regional transmission investment situation is not

MAJOR CONGESTED INTERFACES



Source: Platts

CLIMATE CHANGE CHALLENGES

- The electric power sector must play an important role in GHG mitigation
  - Energy efficiency
  - Nuclear Power
  - CCS
  - Renewable energy
- But the industry is in an unstable “partial reform” equilibrium with “regulated,” “deregulated,” and “mixed” states

CLIMATE CHANGE CHALLENGES

- Assume a cap and trade program with primarily free allocation initially
- Assume supplementary renewable energy portfolio standards
- Issues
  - Mobilizing adequate capital in deregulated states
  - Controlling construction costs and getting good operating performance in regulated states
  - Getting the price of CO_2 into retail prices in regulated states to stimulate conservation and energy efficiency
  - Transmission investment to reach most favorable locations for large scale wind and solar initiatives
  - Squabbling over differences in effects between regulated and deregulated states will delay action on climate change
  - Plethora of individual state programs reducing efficiency of a national program with international linkage

MY FEDERAL POWER ACT OF 2009

- Follow the basic restructuring, regulatory reform, and competition model that has worked so successfully for natural gas
- The economic, planning, reliability, and siting regulation of transmission facilities with voltages above let's say 69 kv should be federalized and the prices for service over this network fully unbundled from generation and distribution service and made transparent.
- The key provisions of FERC Order 2000 would be put into law. This would require the creation of RTOs that manage the operation of large regional transmission networks, implement FERC's transmission access, planning and investment regulations, and operate <u>voluntary</u> wholesale markets for electric energy, ancillary services, capacity and transmission rights.
- Vertically integrated utilities should be required to unbundle generation service from distribution service so that their respective costs or prices are transparent. They will also be required to at least move their generation facilities to a separate generation affiliate.
- Existing cost-of-service arrangements governing existing generating capacity can be replicated through properly structure long-term wholesale contracts between distribution and generation affiliates that are regulated by FERC.

MY FEDERAL POWER ACT OF 2009

- The states would be free to decide whether or not they wanted to introduce retail competition for some or all customer classes. Where distribution companies continue to have obligations to serve retail customers, however, they would be required to meet at least their <u>incremental</u> power supply needs through competitive wholesale market solicitations managed by the states using procurement mechanisms that meet reasonably flexible FERC criteria. In states that have already restructured, all generation supplies needed to meet default retail supply obligations would be satisfied through competitive procurement in the wholesale market.
- Any federal loan guarantees available for financing nuclear, CCS, or renewable generation would be available only for "merchant" generating facilities and not to facilities subject to traditional cost-of-service regulation. Generators should get loan guarantees only once, either directly or through cost of service regulation.
- Any free CO_2 allowances allocated to the electric power sector should go to electricity <u>consumers</u> through non-distortionary lump-sum distributions. Generators would be required to buy allowances in the market to cover their emissions. Generators subject to cost-of-service arrangements would be allowed to pass the associated costs through and they would be reflected in retail prices. Consumers would get lump sum "dividend" each month on their bills for the value of the allowances allocated to them. This would then provide better retail price signals on the margin where it matters for stimulating wise consumption decisions.

MY FEDERAL POWER ACT OF 2009

- State regulatory jurisdiction and regulation would continue over distribution facilities, sub-transmission facilities below say 69kv, whether and how retail competition will be permitted, energy efficiency programs, and competitive procurement of generation consistent with FERC procurement criteria. This is no different from the states' jurisdiction in the natural gas industry.