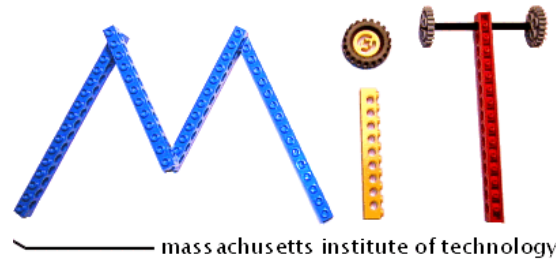


WHOLESALE ELECTRICITY MARKET DEVELOPMENTS IN THE U.S.

Paul L. Joskow



Cambridge, England

July 14, 2004

MIT CEEPR

**Cambridge-MIT Institute
Electricity Project**

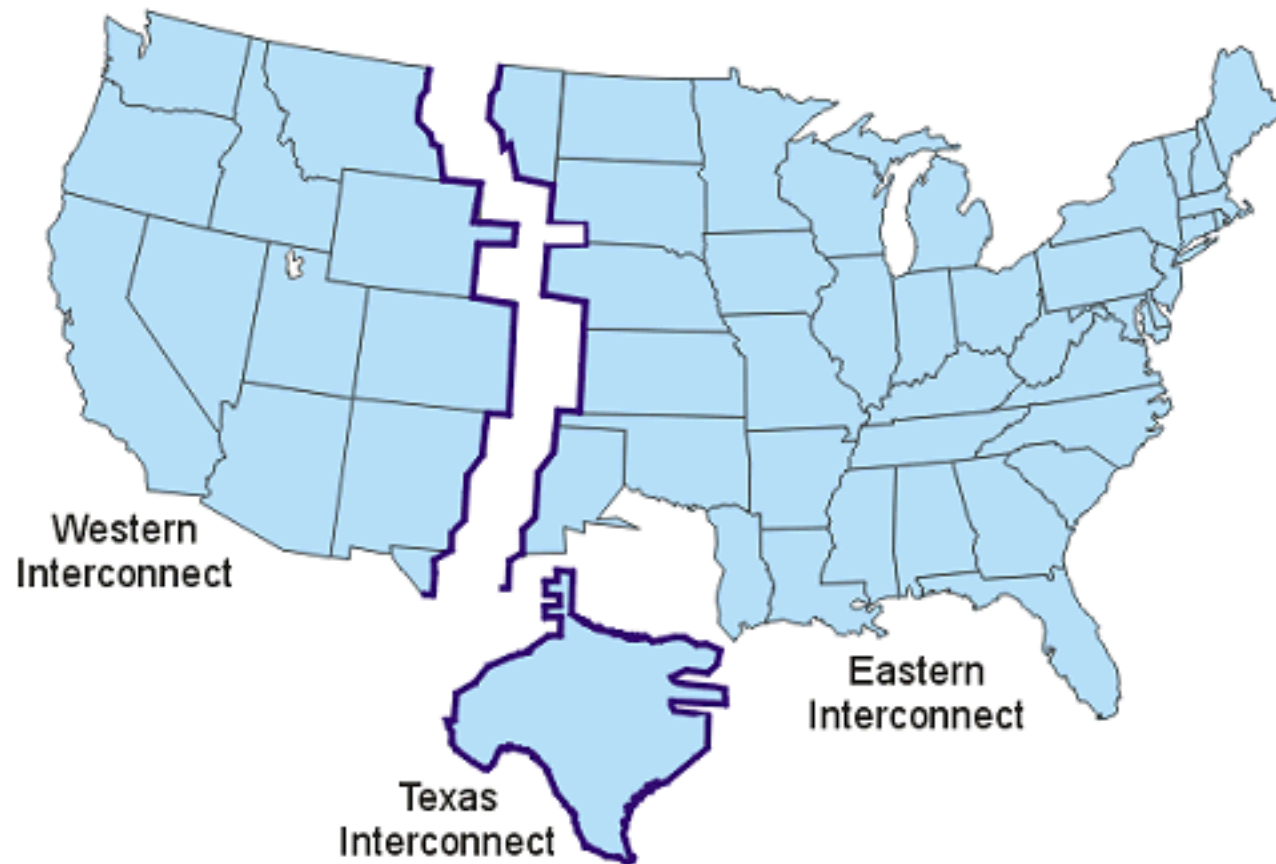
THE UNITED STATES

- Big country
- 50 states
- Diverse energy resources and costs
- Electric power sector organization and regulation was historically primarily the responsibility of the states
- Federal (FERC) historical role very small and its statutory authority modest
- Liberalization involves major increase of federal over state regulatory authority, creating state-federal tensions
- No broad national commitment to liberalization of the electricity sector. Very diverse regional views
- California mess in 2000-2001 slowed down reforms in other states
- August 2003 blackout is being used by opponents of further reform

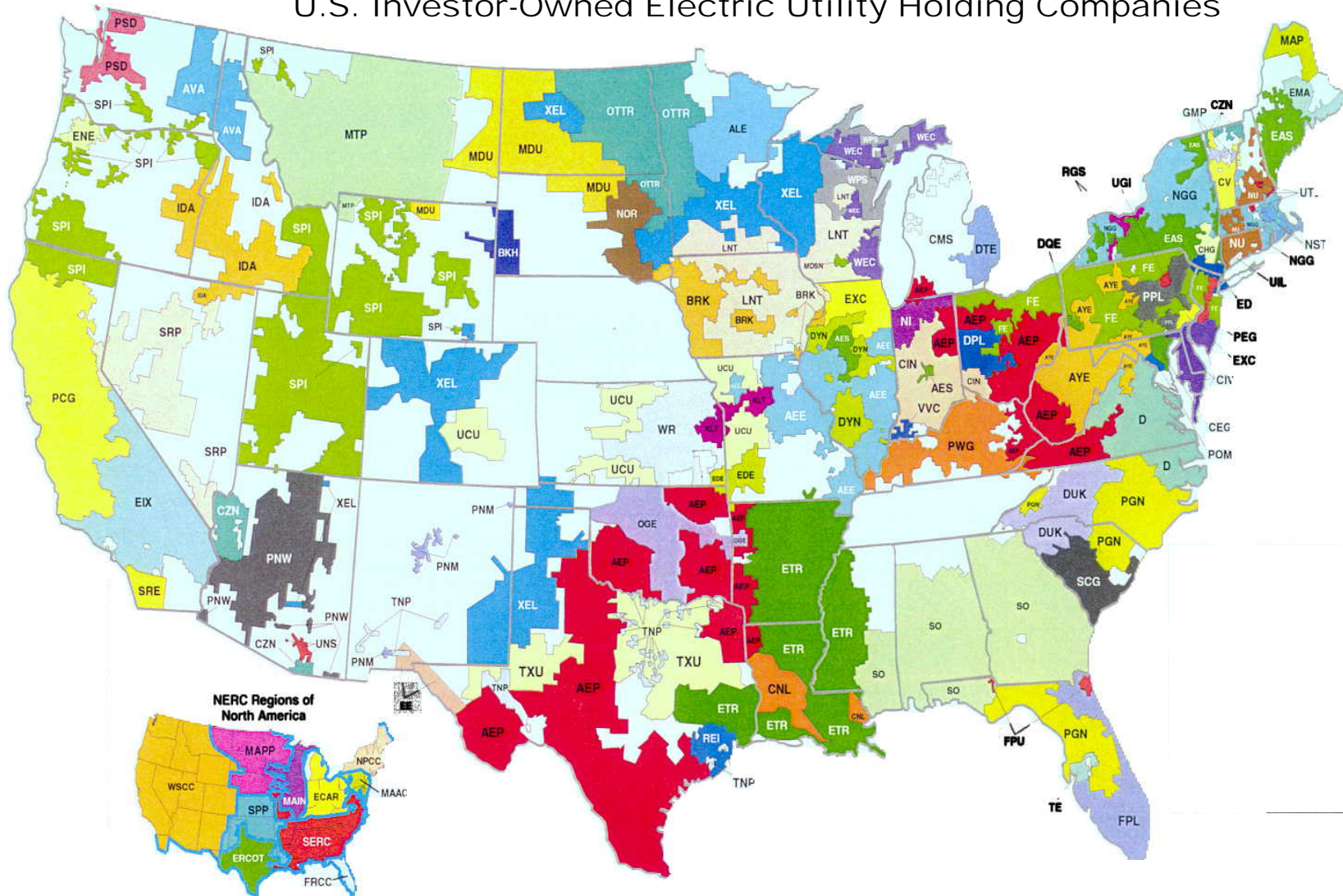
U.S. REGULATORY FRAMEWORK

- Federal: FERC (Federal Power Act of 1935)
 - Wholesale power transactions (not sales to end-users)
 - Interstate “unbundled” transmission access and pricing
 - Utility mergers
 - Market-based pricing authority (under J&R standard)
 - Has used limited statutory authority aggressively
- States: 49 State PUCs (+DC)
 - Local distribution franchises
 - Retail competition/procurement framework
 - Utility organization (Vertical integration)
 - Retail power prices and supporting costs (G +T+G)
 - Transmission investment approvals
 - Full unbundling of T&D for retail sales

North American Electric Power Grids



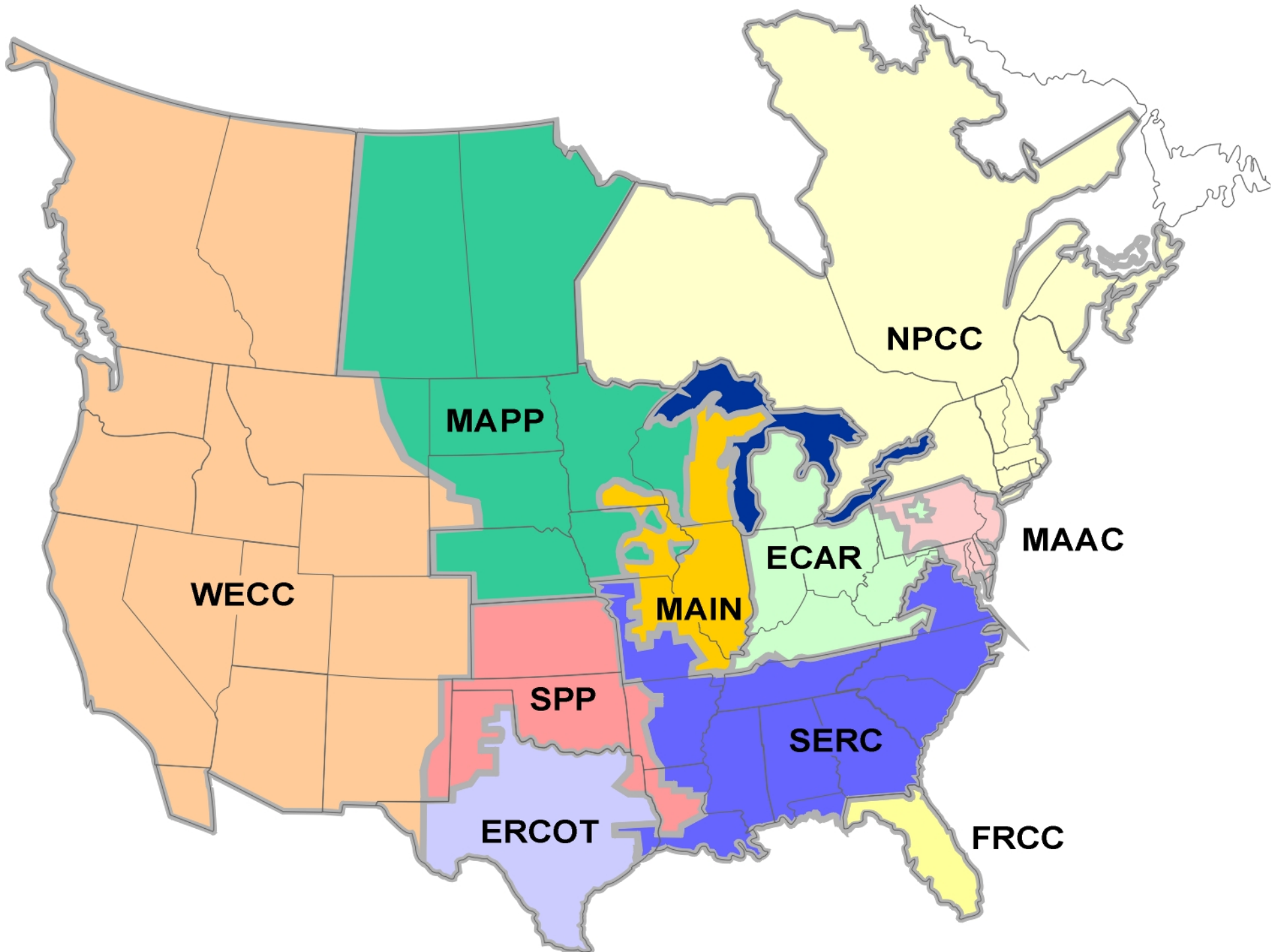
U.S. Investor-Owned Electric Utility Holding Companies



Source: EEI

MAJOR CONTROL AREAS

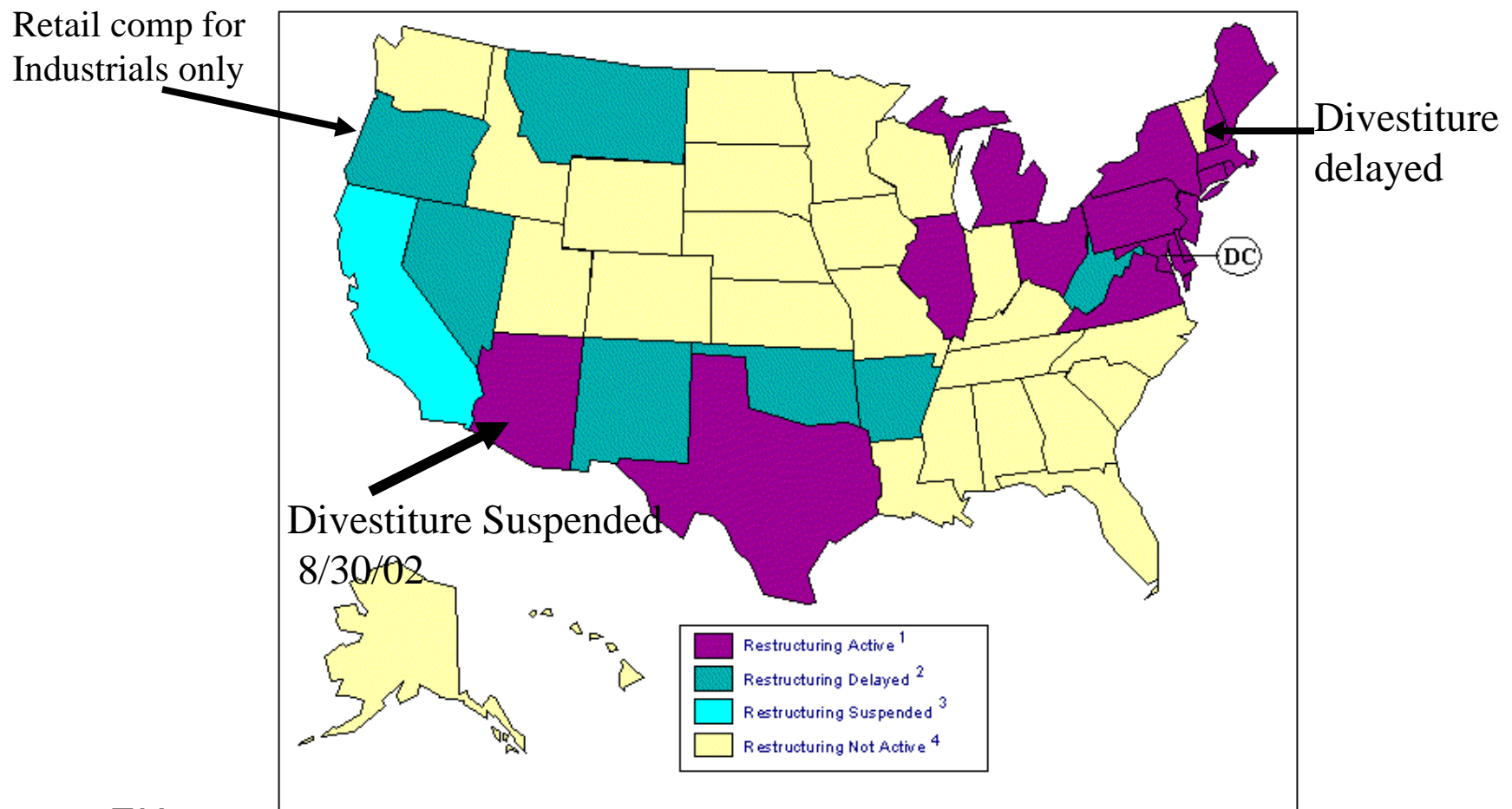




LIBERALIZATION MILESTONES

- Energy Policy Act of 1992
 - FERC authority over transmission service expanded
 - Unregulated generating plants supported (EWG)
- FERC Order 888/889 (1996)
 - Open Access Transmission Tariffs
 - OASIS
- FERC Order 2000 (December 1999)
 - Formation of Regional Transmission Operators (RTOs)
 - Basic Wholesale Market and Transmission Pricing Principles
- Standard Market Design (SMD) Proposal (2002)
 - “PJM” for All
- Wholesale Market Platform White Paper (2003)
 - FERC Backs off SMD and returns to Order 2000
- Generator Interconnection Rules (2003)

STATUS OF COMPREHENSIVE RESTRUCTURING PROGRAMS: STATES

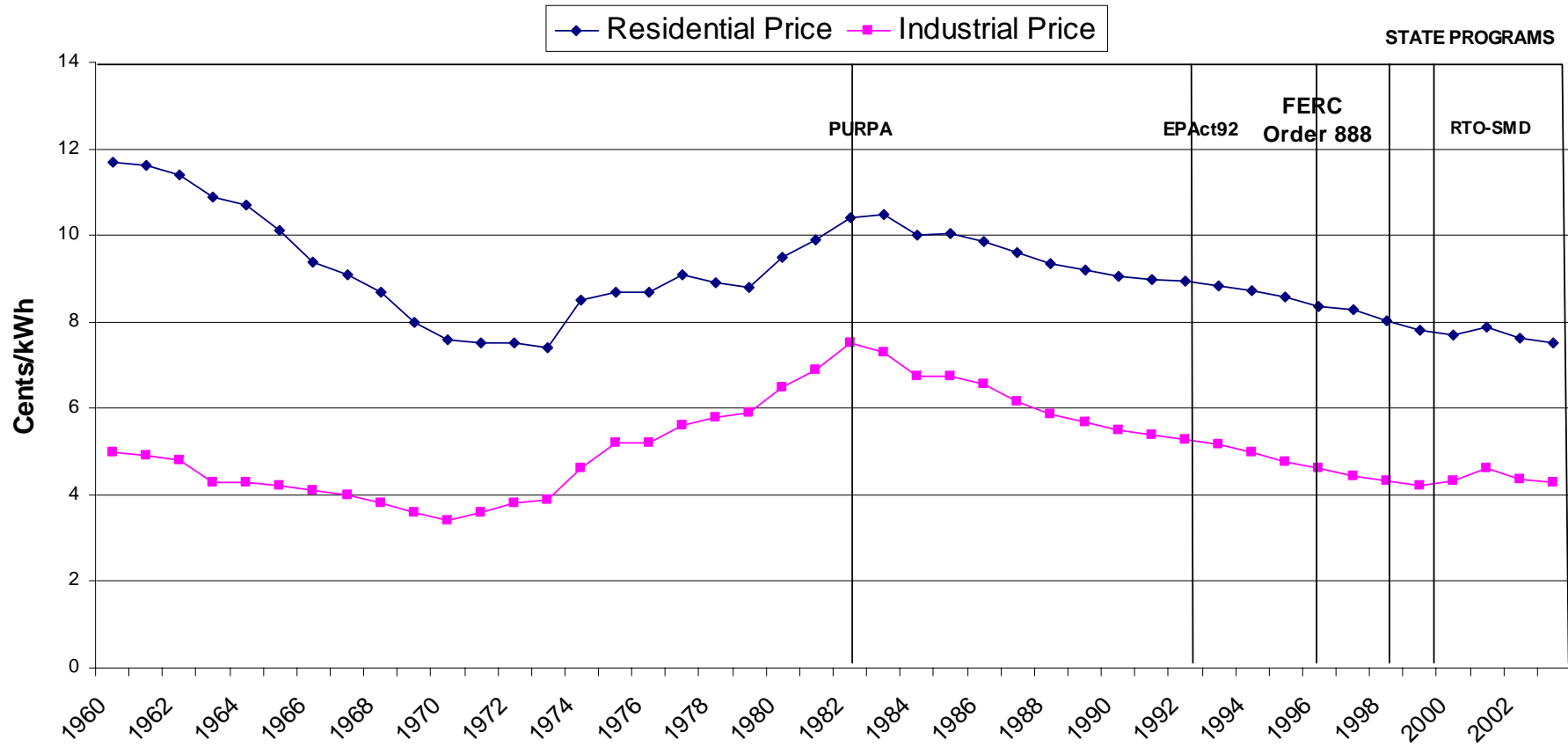


Source: EIA

U.S. WHOLESALE MARKET CHANGES

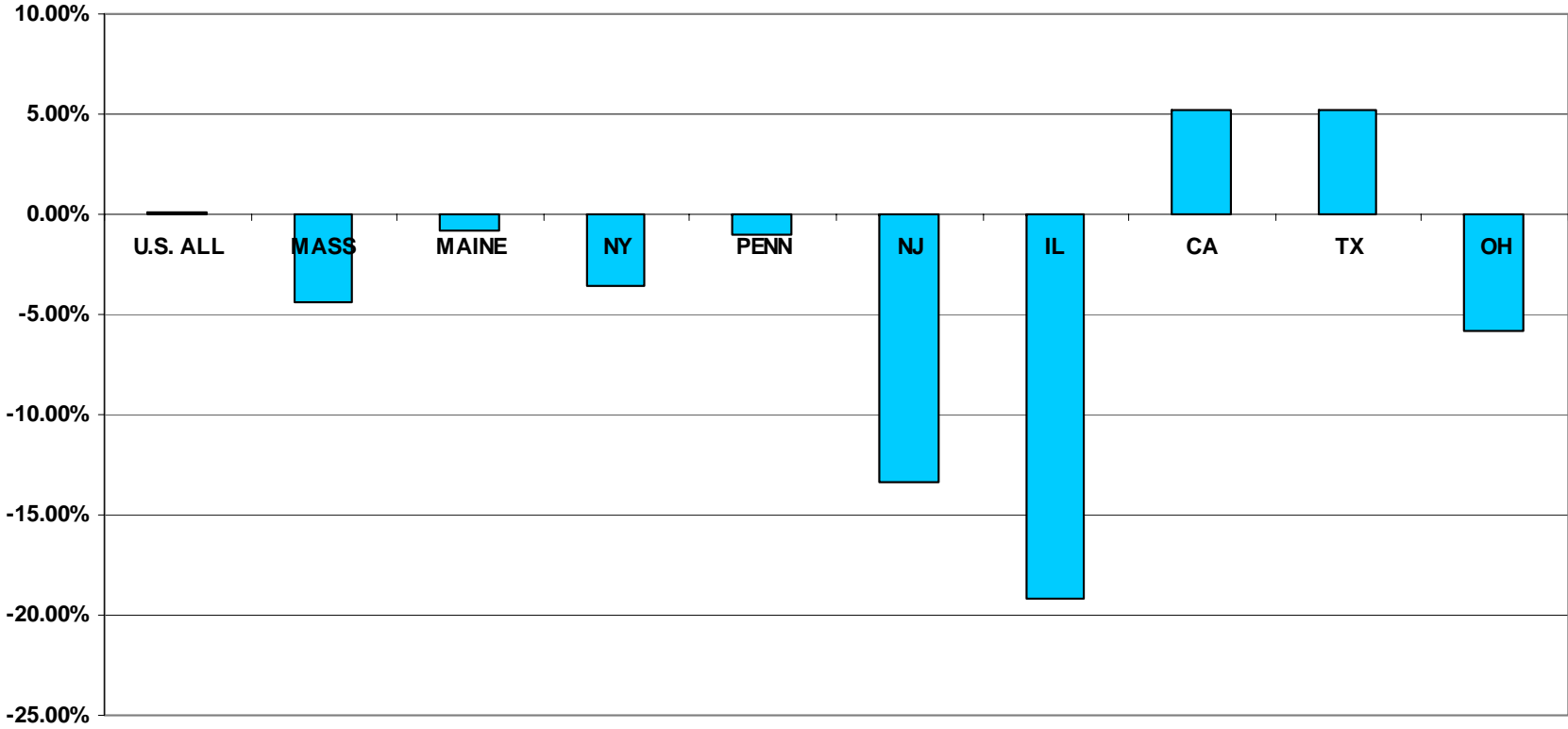
- About 650,000 Mw of U.S. generating capacity in 1996 (75% IOU), almost all of it regulated and integrated with T&D
- 100,000 Mw divested and deregulated by 2003
- 85,000 Mw transferred to unregulated affiliates by 2003
- 175,000 Mw of new generating capacity (80% merchant) added between 2000 and 2003
- Large increase in wholesale trade. About 35% of electricity is produced by unregulated generators today (45% of IOU generation)
- Wholesale market prices have declined after controlling for fuel price changes

Average Electricity Prices 1960-2003 (\$1996)



Source: EIA

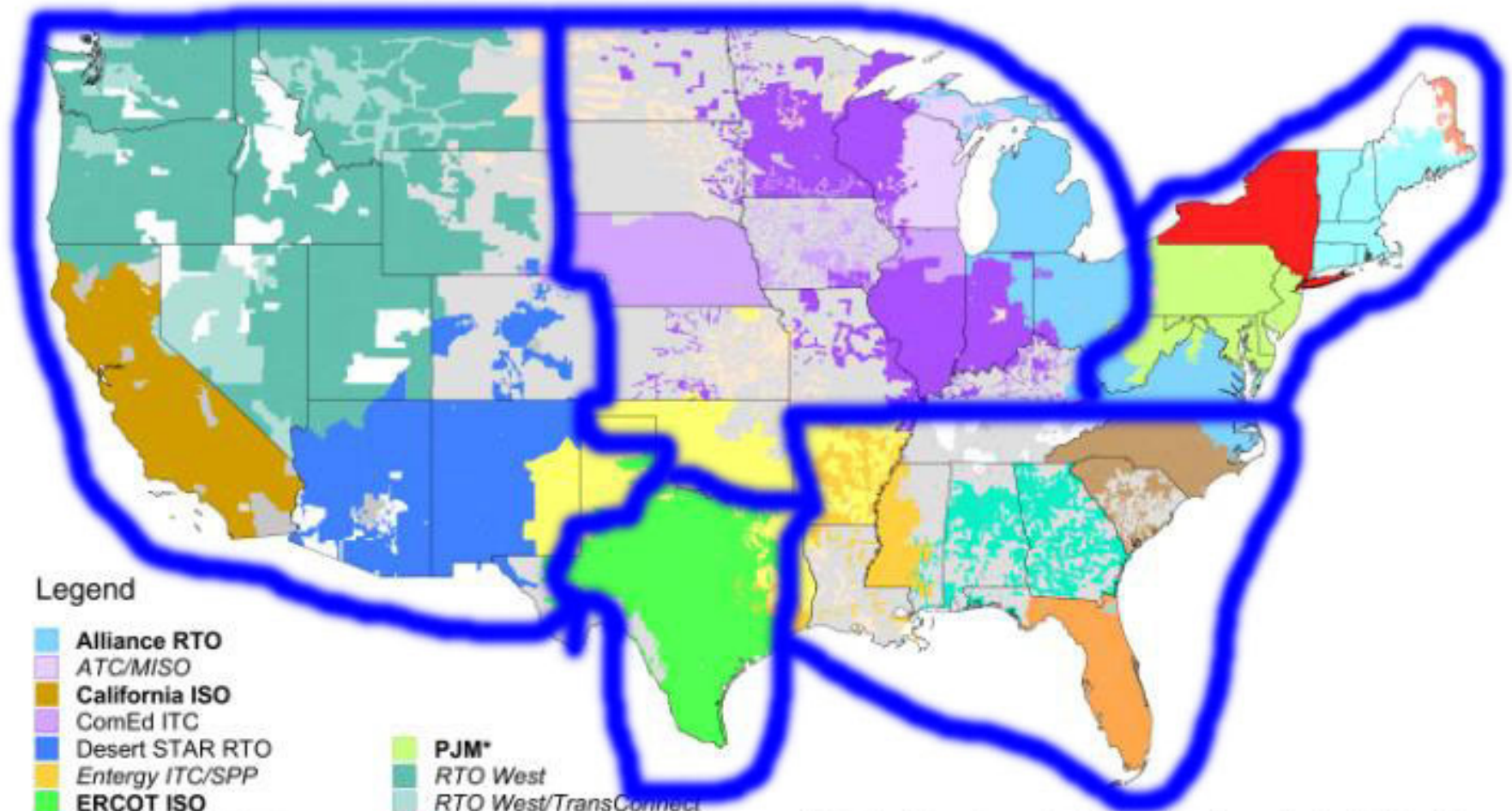
% Change in Nominal Residential Retail Price (1995-2002)



LIBERALIZATION IS NOW MOVING FORWARD SLOWLY

- Restructuring and competition at wholesale and retail levels is still in transition and varies widely from state to state and region to region
- Development of important wholesale market institutions is incomplete in large portions of the country
- No comprehensive Federal restructuring, competition and deregulation initiatives have been passed by Congress
- States have taken their own individual paths with FERC trying to knit together consistent transmission access, pricing and wholesale market rules
- Vertically integrated regulated monopoly model and competitive models are trying to operate simultaneously but very uneasily on the same physical networks
- **Incompatible market and regulatory structures operating on the same physical electric power network creates very significant challenges!**

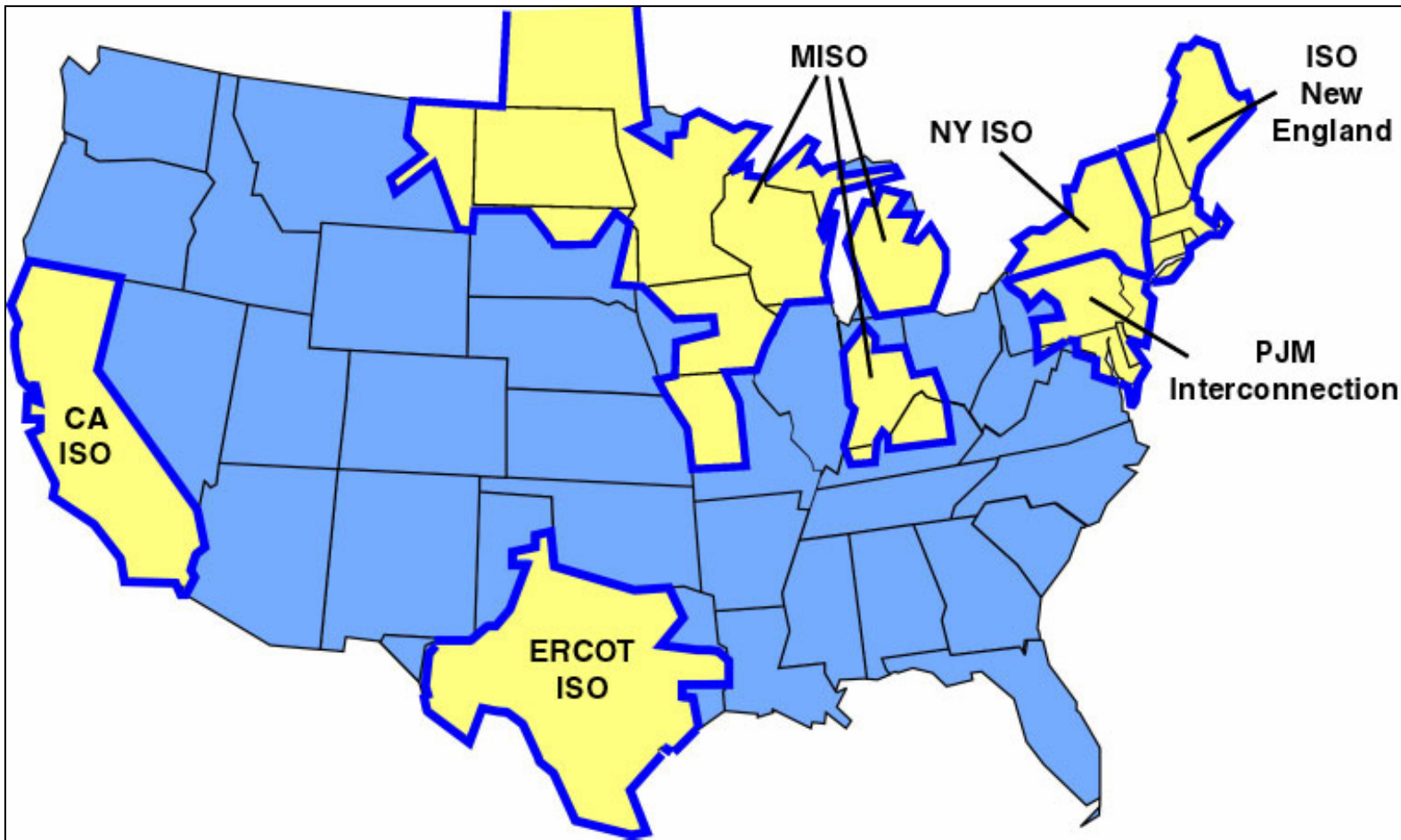
FERC'S INITIAL RTO VISION (2000)



Legend

- | | |
|---------------------|--------------------------------------|
| Alliance RTO | PJM* |
| ATC/MISO | RTO West |
| California ISO | RTO West/TransConnect |
| ComEd ITC | SeTrans Grid Company |
| Desert STAR RTO | SPP RTO |
| Entergy ITC/SPP | Non-participating IOUs |
| ERCOT ISO | Non-participating cooperatives |
| GridFlorida Transco | Non-participating public power |
| GridSouth Transco | Non-utility/no electric service area |
| ISO New England | |
| Midwest ISO | |
| New York ISO | |
| Northern Maine ISA | |

* Allegheny Energy is pursuing joining PJM but has not made a final decision.
 Note: Bold type denotes operational/approved "RTO"s; italics denotes proposed "RTO"s; and plain text denotes "RTO"s under development. Map reflects transmission-owning and TDU-customer member participation in a "RTO".
 Nation-wide, IOU service territories overlap non-IOU service territories.
 Copyright 2000 Edison Electric Institute. Service territory data: POWERmap, 2nd quarter 2000 release, copyright Financial Times Energy.

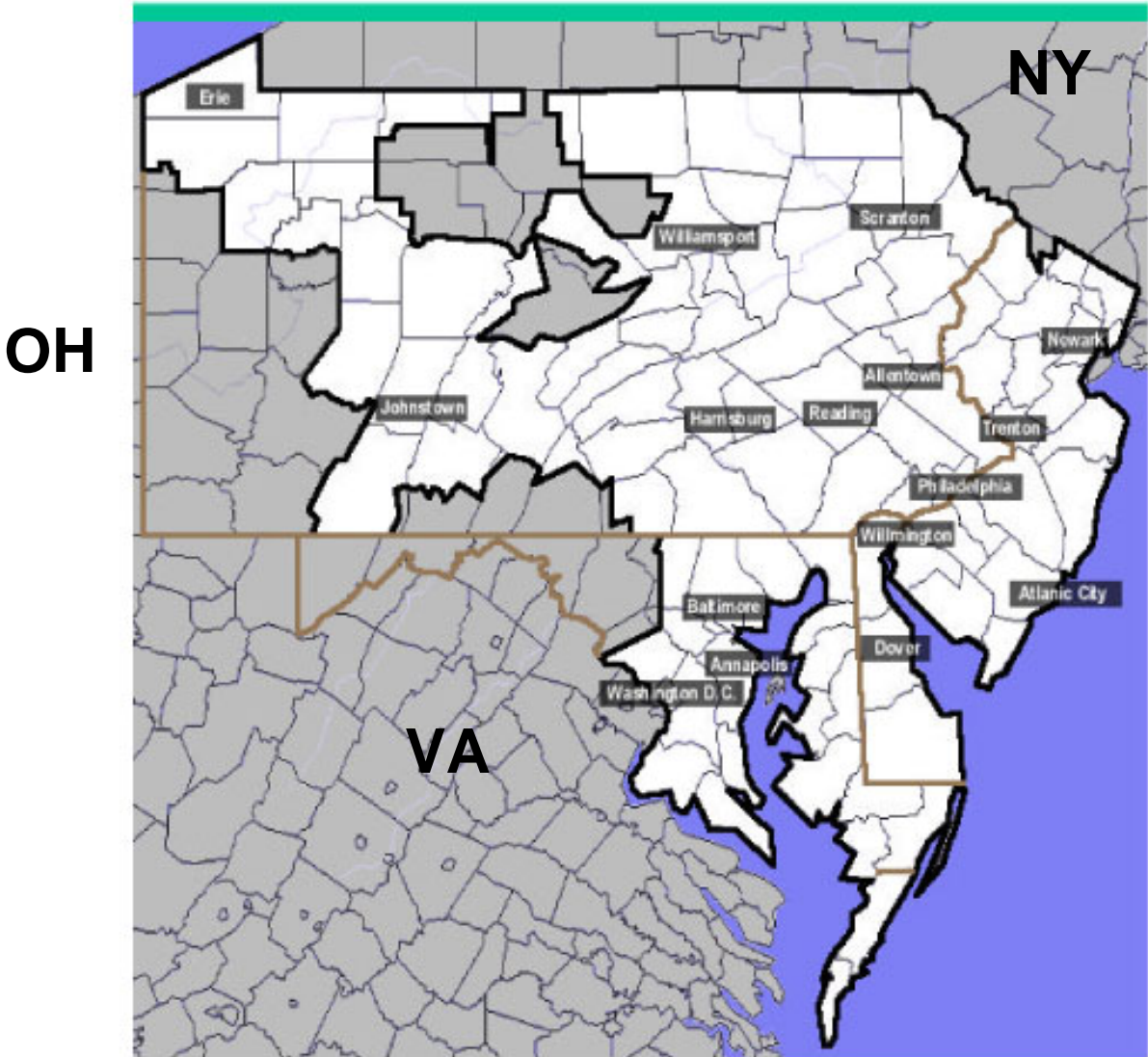


Source: EIA

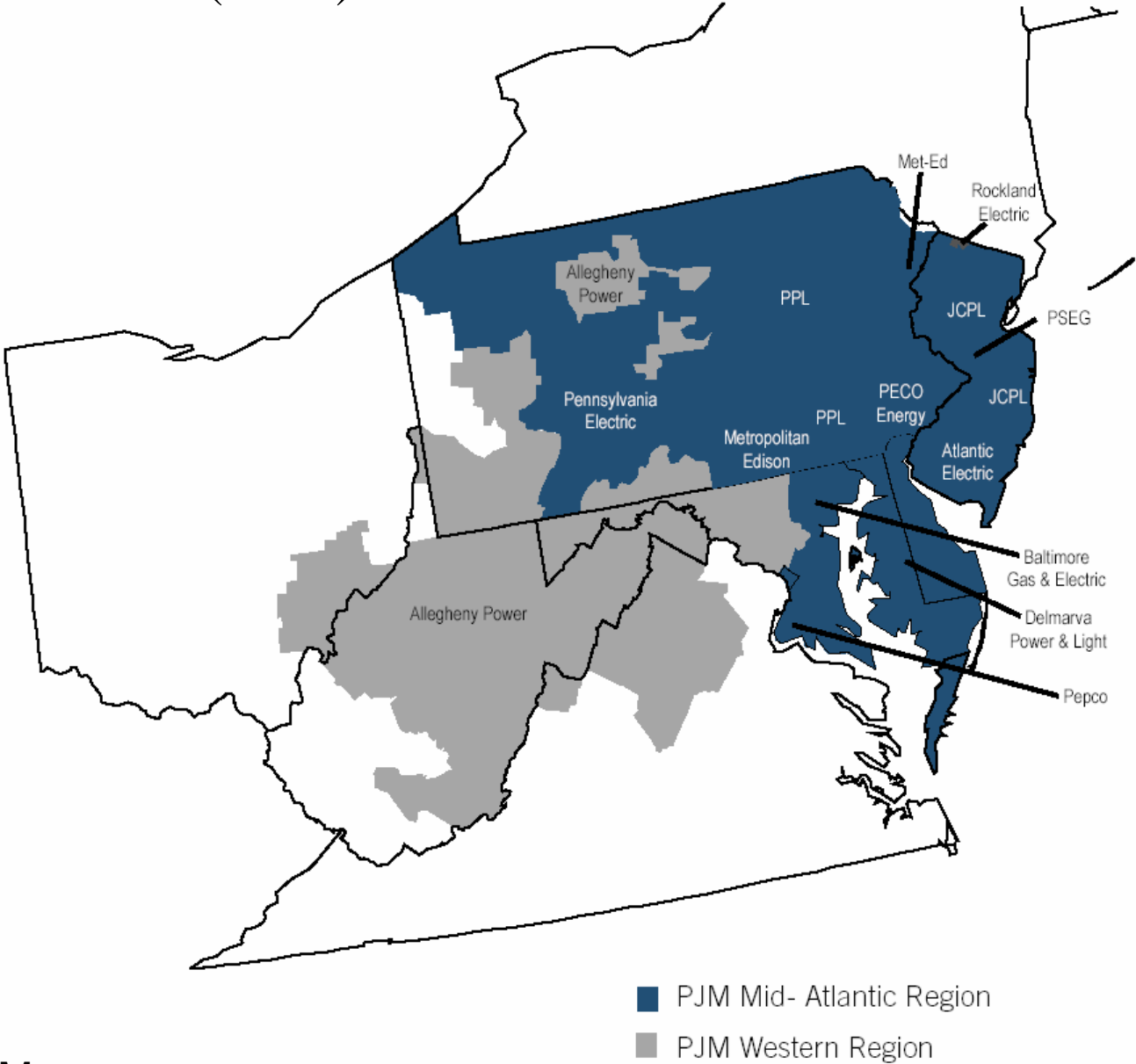
FOCUS ON THE NORTHEASTERN MARKETS

- New England, New York and PJM
- Best articulations of FERC's RTO and SMD visions
- Retail competition in all states but Vermont
- Continued state commitments to restructuring and competition
- Several years of experience
- California and MISO will adopt similar market designs
- PJM expanding West to include portions of Ohio, West Virginia, Indiana, and Virginia as well as Northern Illinois

PJM Control Area 1998

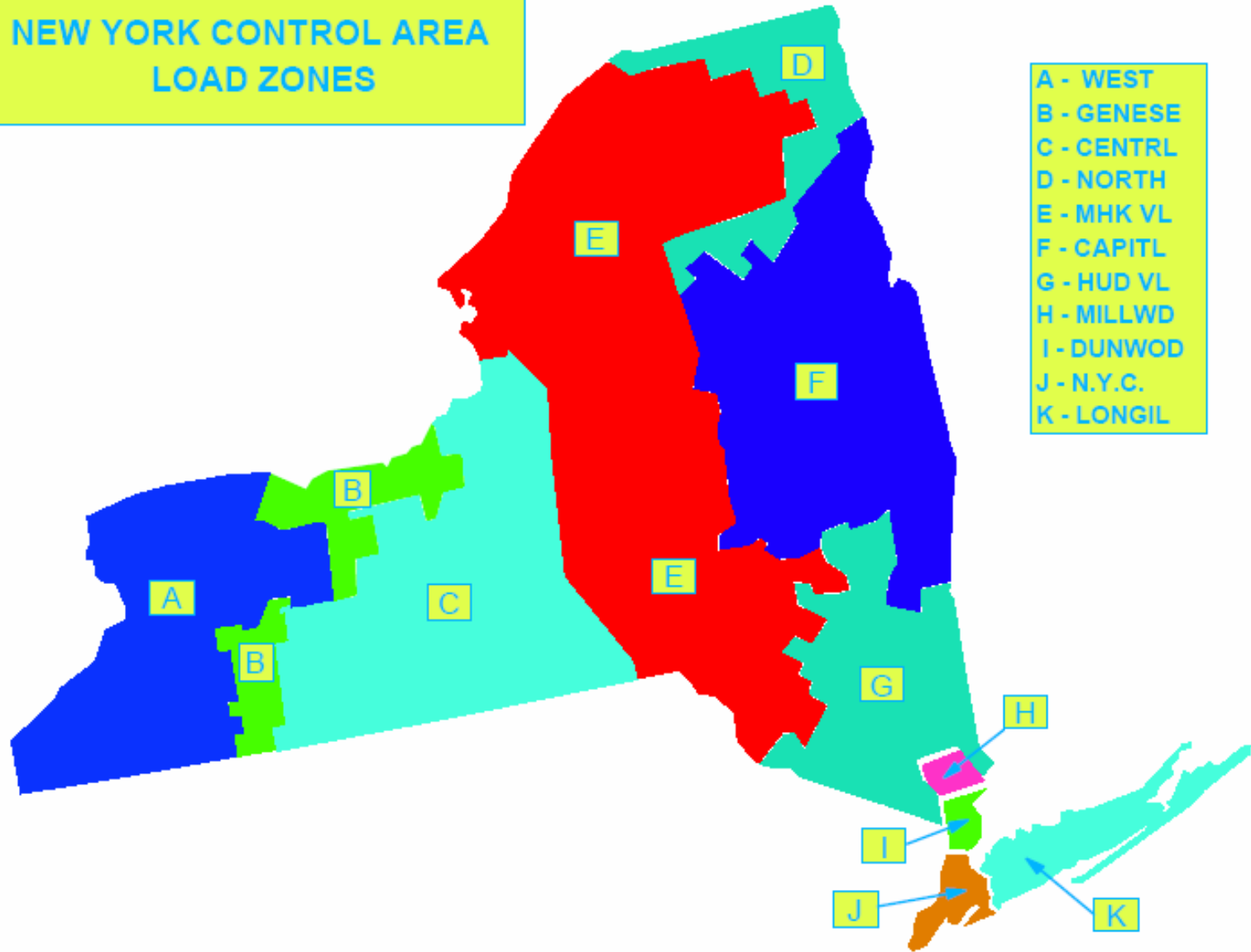


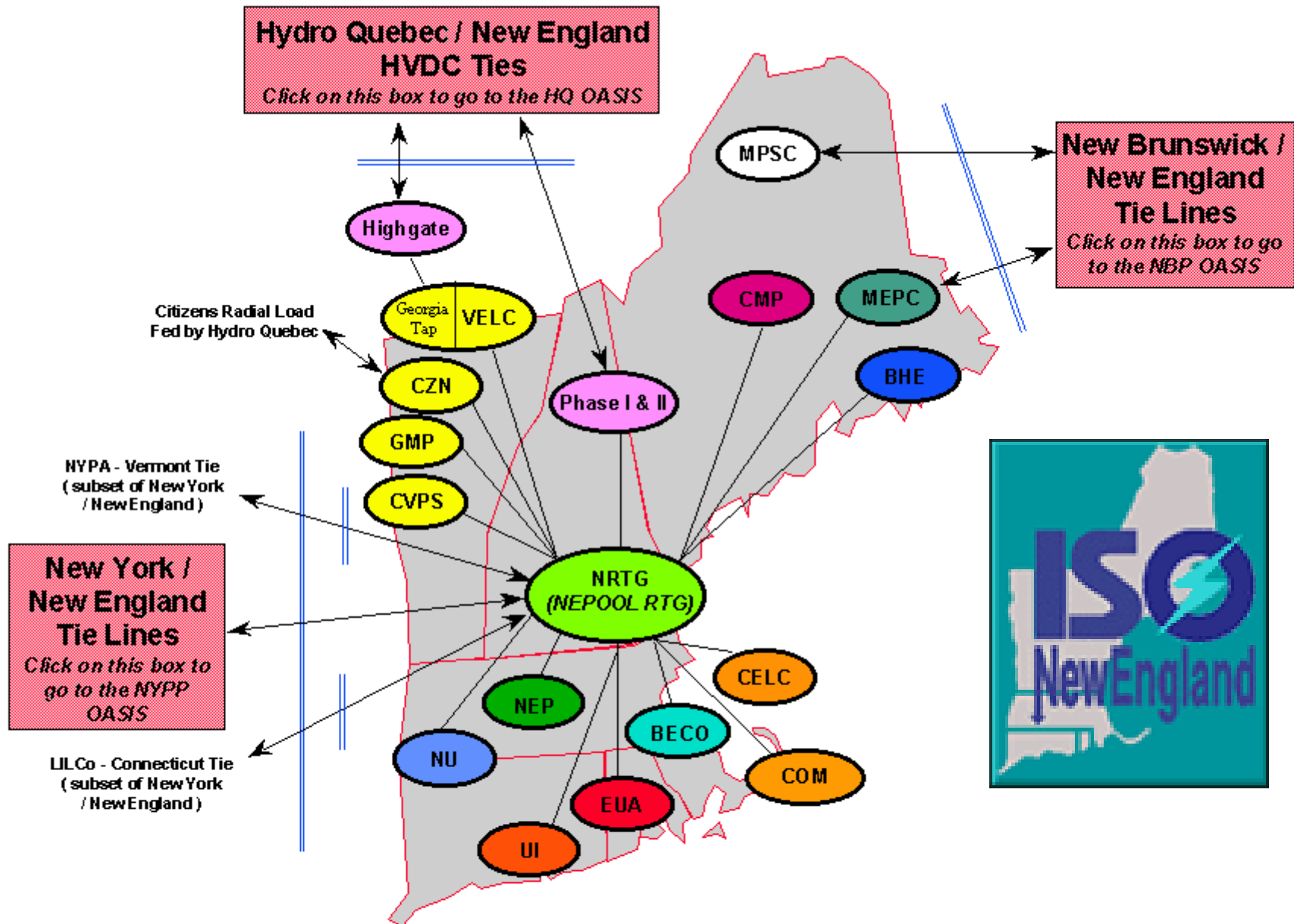
PJM RTO (2003)



Source: PJM

NEW YORK CONTROL AREA
LOAD ZONES





- For Regional Transmission Services, **In To, Out Of or Thru NEPOOL**, click on the NRTG Bubble.
- For Transmission Services between New Brunswick and MEPC and/or MPSC, click on the MEPC or MPSC Transmission Provider Bubbles.
- For Transmission Services between NEPOOL and Hydro Quebec, click on the Phase I & II Bubble.
- For Local Point to Point Transmission Services, click on the individual Transmission Providers bubbles within New England.

BASIC ATTRIBUTES OF NORTHEASTERN RTO/ISOs

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

BASIC FEATURES OF WHOLESALE MARKET DESIGN

- Security constrained bid-based dispatch using state-estimator network model
 - Day-ahead hourly markets
 - Real-time market (adjustments, imbalances, 5-minutes)
 - Self-scheduling permitted subject to imbalance and congestions charges
- Resulting LMPs calculated at each bus
 - Marginal cost of congestion
 - Marginal cost of losses (not yet in PJM)
- Market-based provision of ancillary services integrated with day-ahead and real-time energy markets
- All transmission service customers must pay costs of congestion based on differences in LMPs between source and sink of power transactions
 - Day-ahead
 - Real-time

BASIC FEATURES OF WHOLESALE MARKET

- Financial Transmission Rights (FTRs) allocated (theoretically) consistent with network feasibility constraints
 - Rights to proportionate share of congestion rents
 - Initial allocation based on transmission ownership to serve “native load,” third-party contracts for firm transmission service or investment in new T capacity
 - FTRs are tradable and there are reconfiguration opportunities
 - Auctions (annual, monthly) and Auction Revenue Rights (PJM)
 - Obligation rights, option rights, peak, off-peak rights (PJM)
- Generating capacity (reserve) obligations imposed on LSE (e.g. 18% forward reserve margin)
 - Load reduction capabilities are eligible
 - Capacity resources must meet deliverability criteria (PJM)
 - Designated capacity resources must make energy available to the SO through bids

MARKET MONITORING AND MITIGATION

- \$1000/MWh general bid cap
- Local market power mitigation rules
 - Bid caps
 - RMR contracts
 - Must-offer restrictions
 - Interaction with computation of market prices
- Must offer requirements
- Ex-post bid/price adjustments
- Monitoring of individual market participant behavior and market performance

TRANSMISSION PRICING (PJM)

- Firm Network Integration Service
 - Designed to replicate transmission service available “internally” to vertically integrated LSEs in PJM with their own T networks.
 - LSE’s transmission service price equals average total cost of transmission network per MW of peak load based on cost of transmission facilities in load areas (license plate tariff --- \$15-\$25/KW-year) + network enhancement charges, if any
 - Cost-of-service rate of return regulation determines prices. No PBR for operating costs, availability, outage response (yet)
 - Transmission customers pay congestion charges and losses.
 - Receive FTRs/ARRs for designated sources and sinks
- Firm point-to-point service
 - Imports, exports, transit, internal transactions not otherwise covered by network integration service
 - Term: one day to one year (short-term). One year or more by agreement (long term).
 - Average total cost of transmission system in delivery area (\$15 - \$25/KW-year) or PJM border + enhancement charges
 - Receive FTR/ARR allocation
 - Responsible for congestion charges and allocation of losses

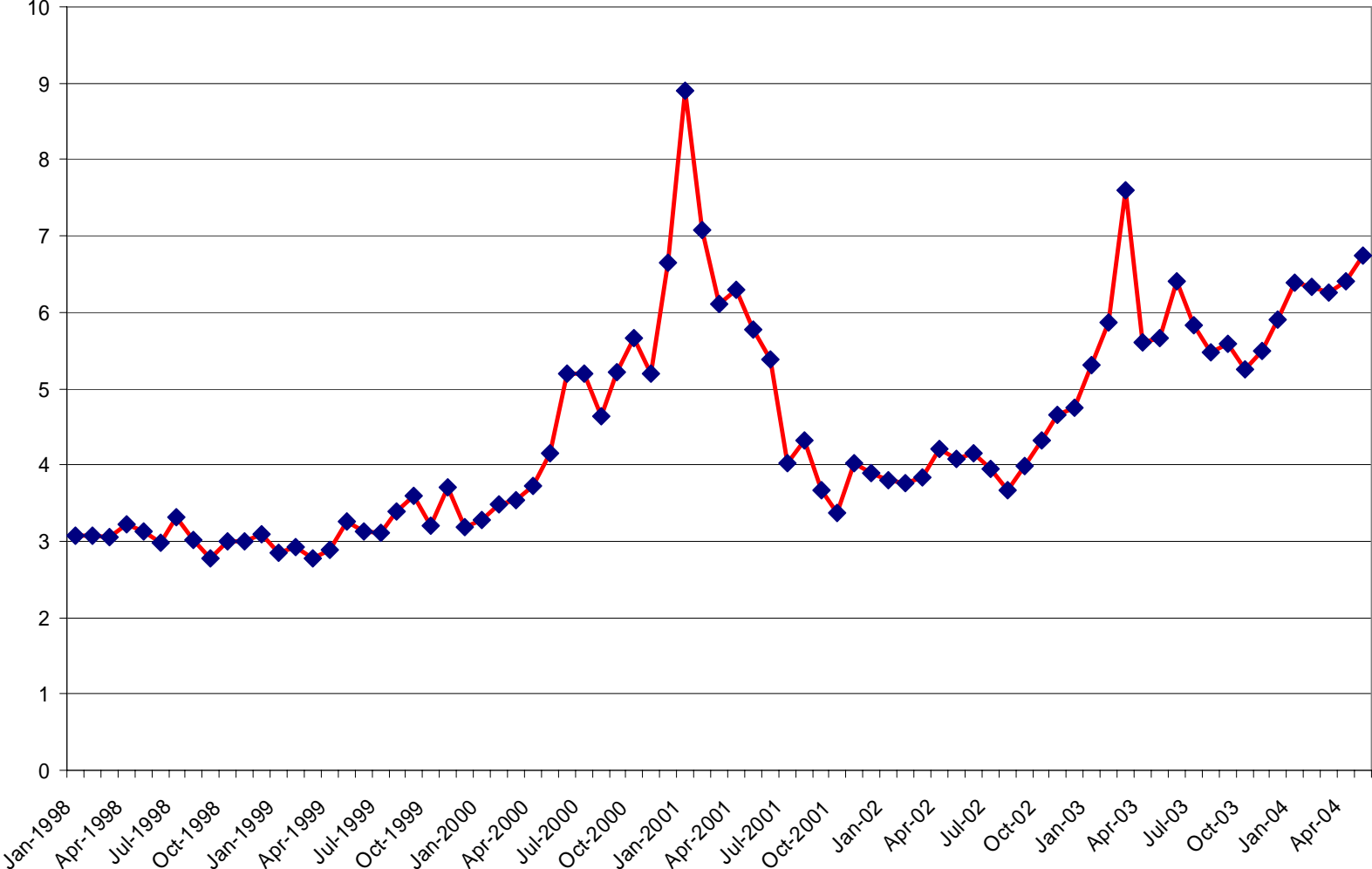
TRANSMISSION PRICING (PJM)

- Non-firm point-to-point service
 - Term: One hour to one-month
 - Curtailed first to relieve congestion with option to pay congestion charges and avoid curtailment
 - Same average total cost-based price per Kw-time as firm but no network enhancement charges (can be discounted)
 - Hourly on-peak transmission service fee averages about \$5/Mwh on peak
 - Loss charges are added
 - No FTRs included

TRANSMISSION PRICING (PJM)

- Transmission charges paid by generators and merchant transmission projects
 - Direct interconnection costs
 - Incremental network upgrade costs to maintain MAAC reliability criteria (incremental FTRs allocated)
 - Sharing protocol for groups of new generators
 - Incremental network upgrade costs to meet MAAC deliverability criteria to be certified as a “capacity resource” (incremental FTRs allocated)
 - Congestion charges and losses only if the generator is also providing supporting transmission service for the transaction or by agreement with buyer (e.g. an export by a merchant generator)

AVERAGE CITY-GATE NATURAL GAS PRICES (1998 -2004) \$/MCF



Source: EIA

Table 2-23 PJM Average Hourly Locational Marginal Prices (in Dollars per MWh)

	Locational Marginal Prices (LMP)			Year-to-Year Percent Change		
	Average	Median	Standard Deviation	Average LMP	Median LMP	Standard Deviation
2003	\$38.27	\$30.79	\$24.71	35.2%	46.0%	10.3%
2002	\$28.30	\$21.08	\$22.40	-12.6%	-8.3%	-50.6%
2001	\$32.38	\$22.98	\$45.30	15.1%	20.3%	76.3%
2000	\$28.14	\$19.11	\$25.69	-0.6%	6.9%	-64.5%
1999	\$28.32	\$17.88	\$72.41	30.4%	7.7%	130.2%
1998	\$21.72	\$16.60	\$31.45			

Source: PJM State of Markets 2003

Table 2-26 PJM Load-Weighted, Fuel-Cost-Adjusted LMP (in Dollars per MWh)

	2003	2002	Percent Change
Average LMP	\$28.60	\$31.60	-9.5%
Median LMP	\$24.40	\$23.41	4.2%
Standard Deviation	\$16.94	\$26.74	-36.6%

Source: PJM State of Markets 2003

Table 2-1 Peak PJM Demand Days: 2001, 2002 and 2003

	22-Aug-03	14-Aug-02	9-Aug-01
Peak Demand (MW)	61,500	63,762	62,232
Maximum Daily LMP (\$ per MWh)	\$95.11	\$445.30	\$932.30
Average PJM LMP (\$ per MWh)	\$58.47	\$88.00	\$387.70
Average Peak PJM LMP (\$ per MWh)	\$65.89	\$122.30	\$559.40
Average Off Peak PJM LMP (\$ per MWh)	\$43.61	\$19.20	\$44.20

Source: PJM State of Markets 2003

Table 2-27 Comparison of Real-Time and Day-Ahead 2003 Market LMP (in Dollars per MWh)

	Day-Ahead	Real-Time	Difference	Difference as Percent Real-Time
Average LMP	\$38.72	\$38.27	-\$0.45	-1.2%
Median LMP	\$35.21	\$30.79	-\$4.43	-14.4%
Standard Deviation	\$20.84	\$24.71	\$3.87	15.7%

Source: PJM State of Markets 2003

Table 2-33 2003 Demand-Side Response Program

PJM Programs	MW Registered
PJM Economic Load-Response Program	724
PJM Emergency Load-Response Program	659
PJM Active Load-Management Resources	1,207
PJM ALM Resources Included in Load-Response Program	(445)
Total PJM Programs	2,145

Source: PJM State of Markets 2003

Table 24 – Quarterly Statistics for Daily All-In Price of Wholesale Electricity (\$/MWh)

Year	Mean Daily Price	Median Daily Price	Max. Daily Price	Min. Daily Price	Std. Dev. Daily Price
1999 Q2	\$39.40	\$29.07	\$232.37	\$23.54	\$42.09
2000 Q2	\$44.31	\$33.45	\$1,219.56	\$20.18	\$107.72
2001 Q2	\$42.31	\$41.96	\$91.41	\$17.11	\$11.59
2002 Q2	\$32.43	\$32.02	\$52.22	\$19.12	\$5.80
2003 Q2	\$52.65	\$46.47	\$150.24	\$34.04	\$18.45

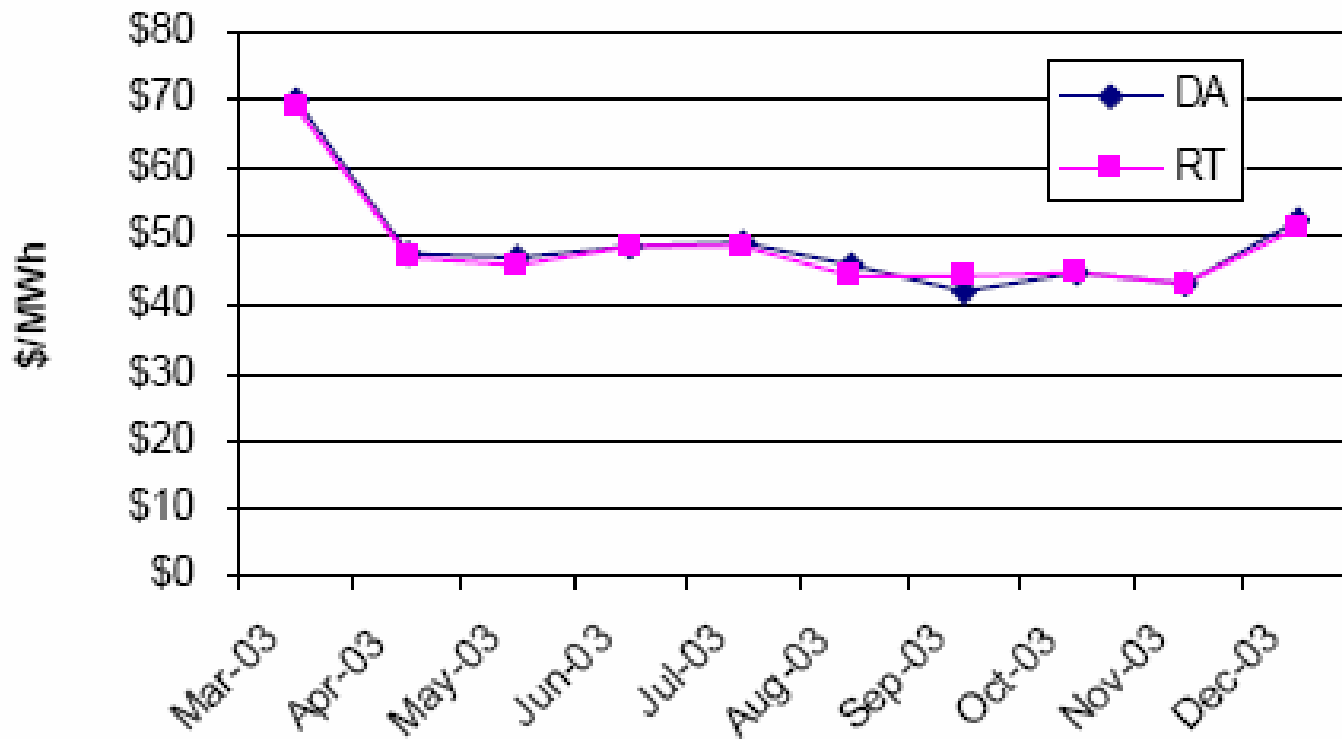
Source: ISO New England

All In Price by Load Zone and System, Month Averages

	MAR2003	APR2003	MAY2003	JUN2003	JUL2003	AUG2003	SEP2003	OCT2003	NOV2003	DEC2003
Maine	\$68.02	\$42.50	\$40.83	\$42.44	\$43.17	\$40.05	\$37.85	\$41.51	\$38.51	\$46.33
New Hampshire	\$68.27	\$46.89	\$43.86	\$46.20	\$47.06	\$43.44	\$40.64	\$43.46	\$40.86	\$49.72
Vermont	\$69.65	\$47.93	\$45.38	\$47.79	\$49.22	\$45.66	\$41.96	\$44.92	\$42.27	\$50.70
Connecticut	\$70.07	\$48.80	\$50.00	\$50.75	\$52.50	\$51.85	\$44.52	\$49.05	\$48.88	\$54.58
Rhode Island	\$67.37	\$45.64	\$45.60	\$46.90	\$46.47	\$44.68	\$40.13	\$43.41	\$41.46	\$50.82
SEMASS	\$67.09	\$45.80	\$45.76	\$46.68	\$46.72	\$43.23	\$39.88	\$43.22	\$41.45	\$49.88
WCMASS	\$69.28	\$46.62	\$46.01	\$47.80	\$48.17	\$44.53	\$41.74	\$44.22	\$42.20	\$51.33
NEMA/Boston	\$71.23	\$48.07	\$47.62	\$49.30	\$49.06	\$46.65	\$43.11	\$46.31	\$43.51	\$51.48
System Overall	\$71.44	\$47.46	\$46.64	\$47.43	\$48.66	\$46.74	\$42.31	\$45.83	\$44.00	\$51.62

Source: ISO New England

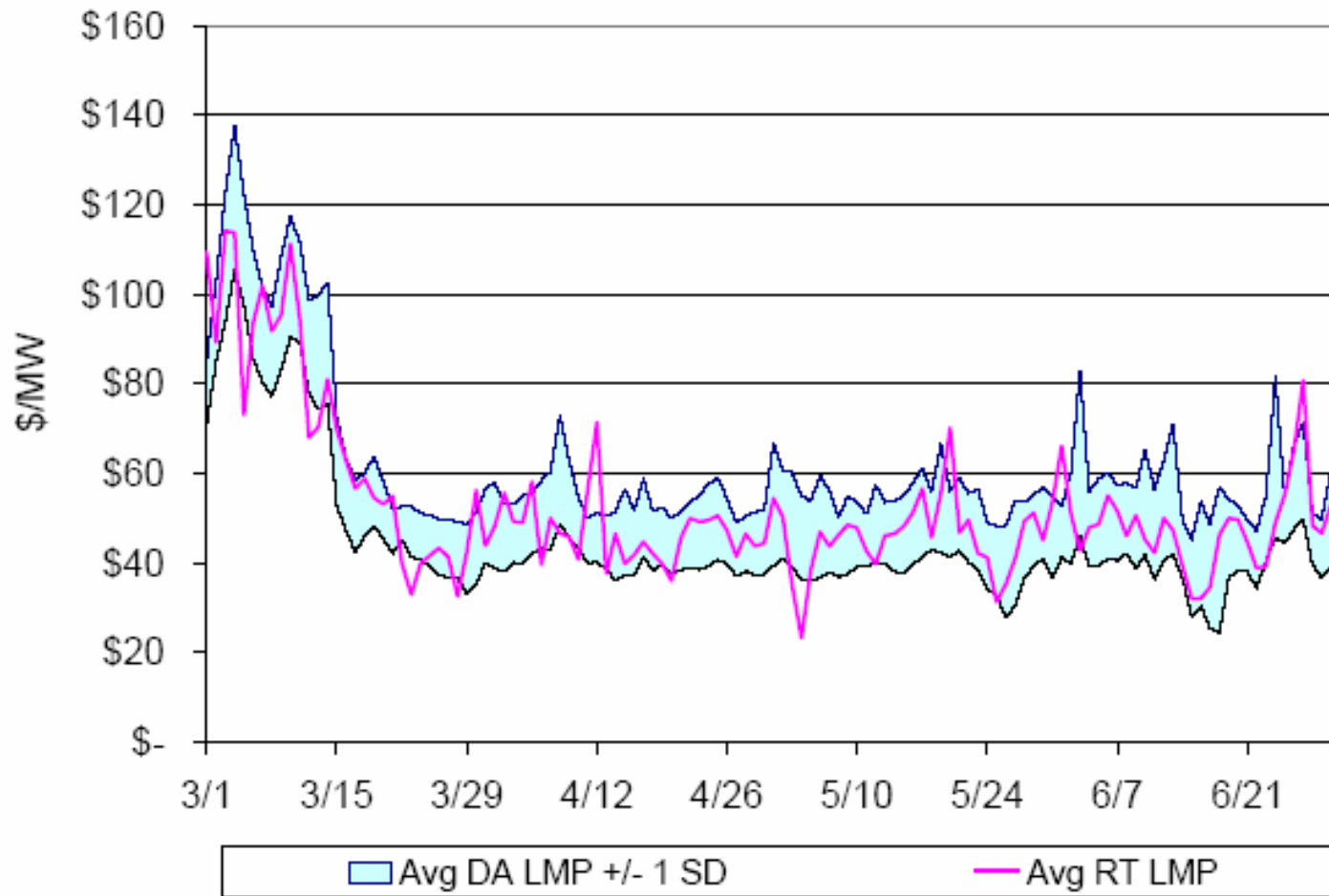
Monthly Average Day-Ahead and Real-Time Hub LMPs
March - December 2003



Source: ISO New England

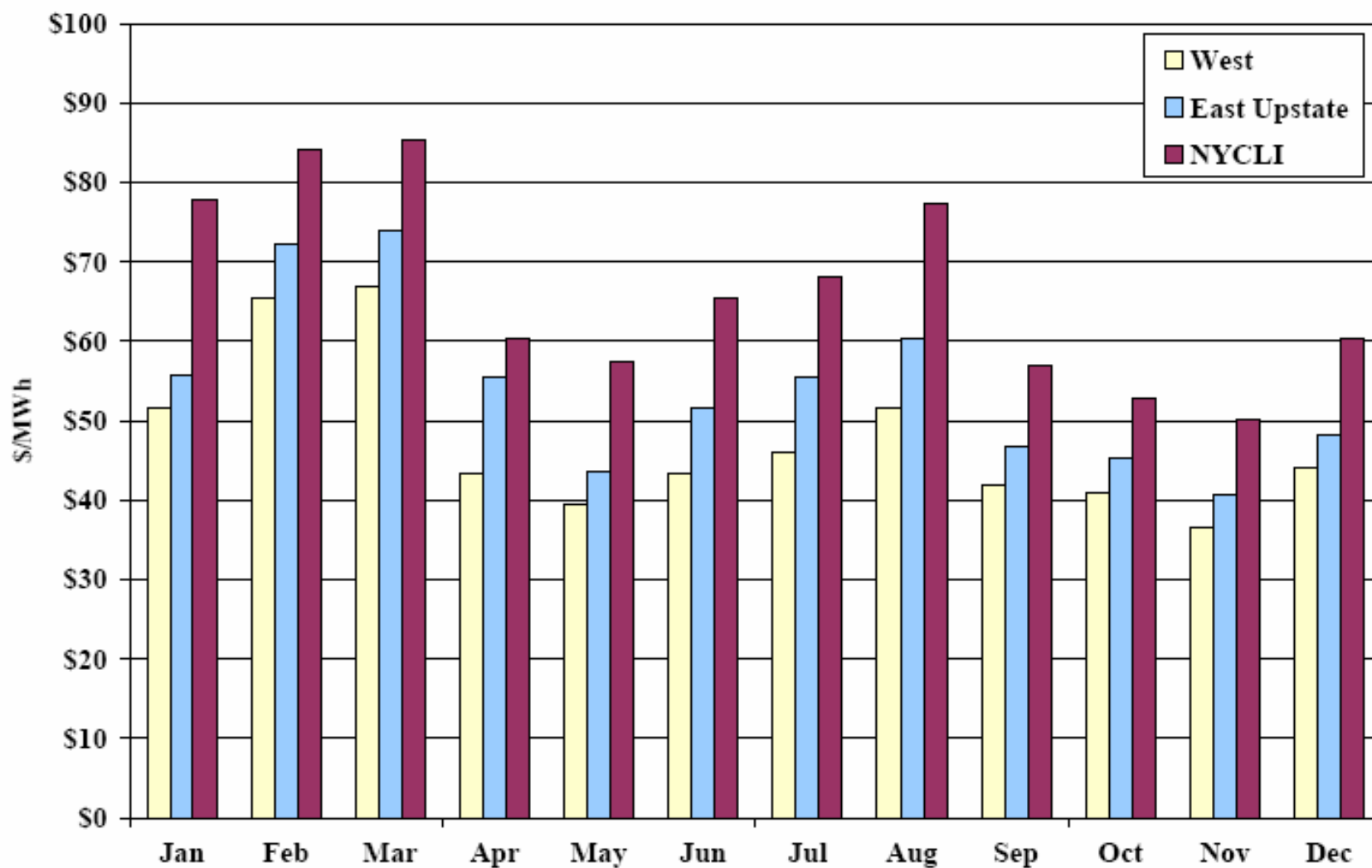
Figure 15 – DA vs. RT LMP Price Convergence at the Hub

March - June 2003



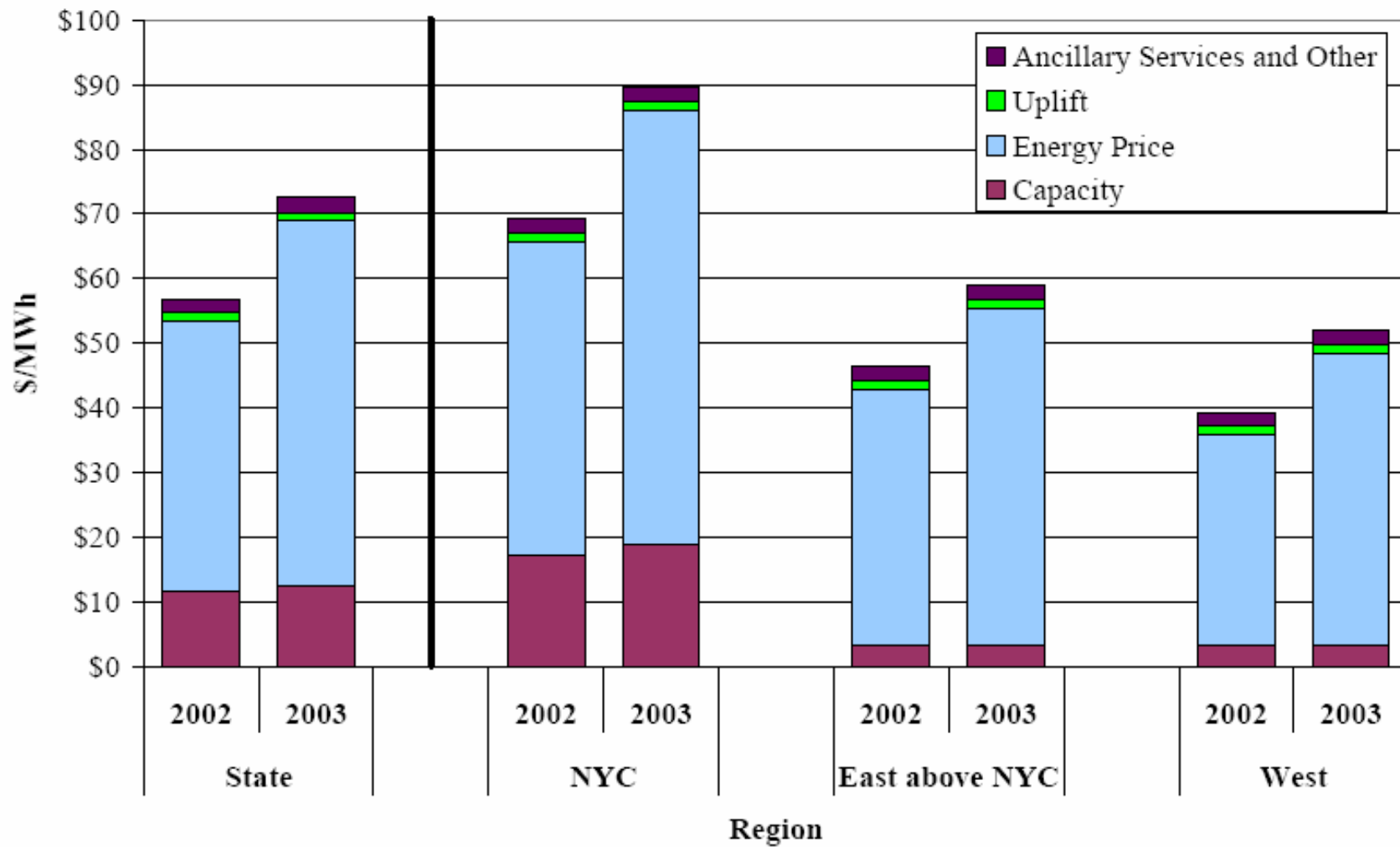
Source: ISO New England

Figure 4: Day-Ahead Energy Prices in 2003

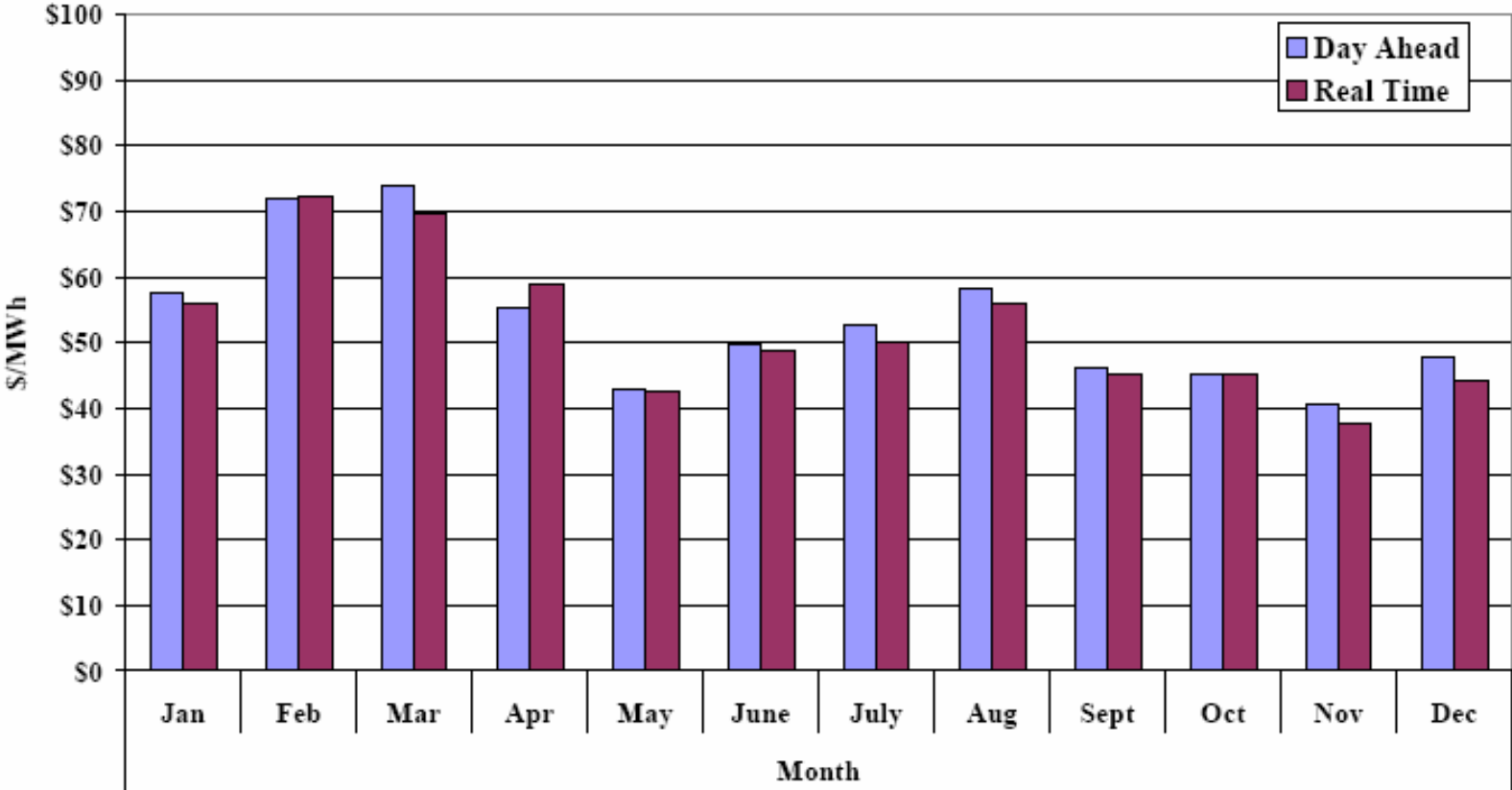


Source: New York ISO (2004)

Figure 7: Average All-In Price in 2002 and 2003

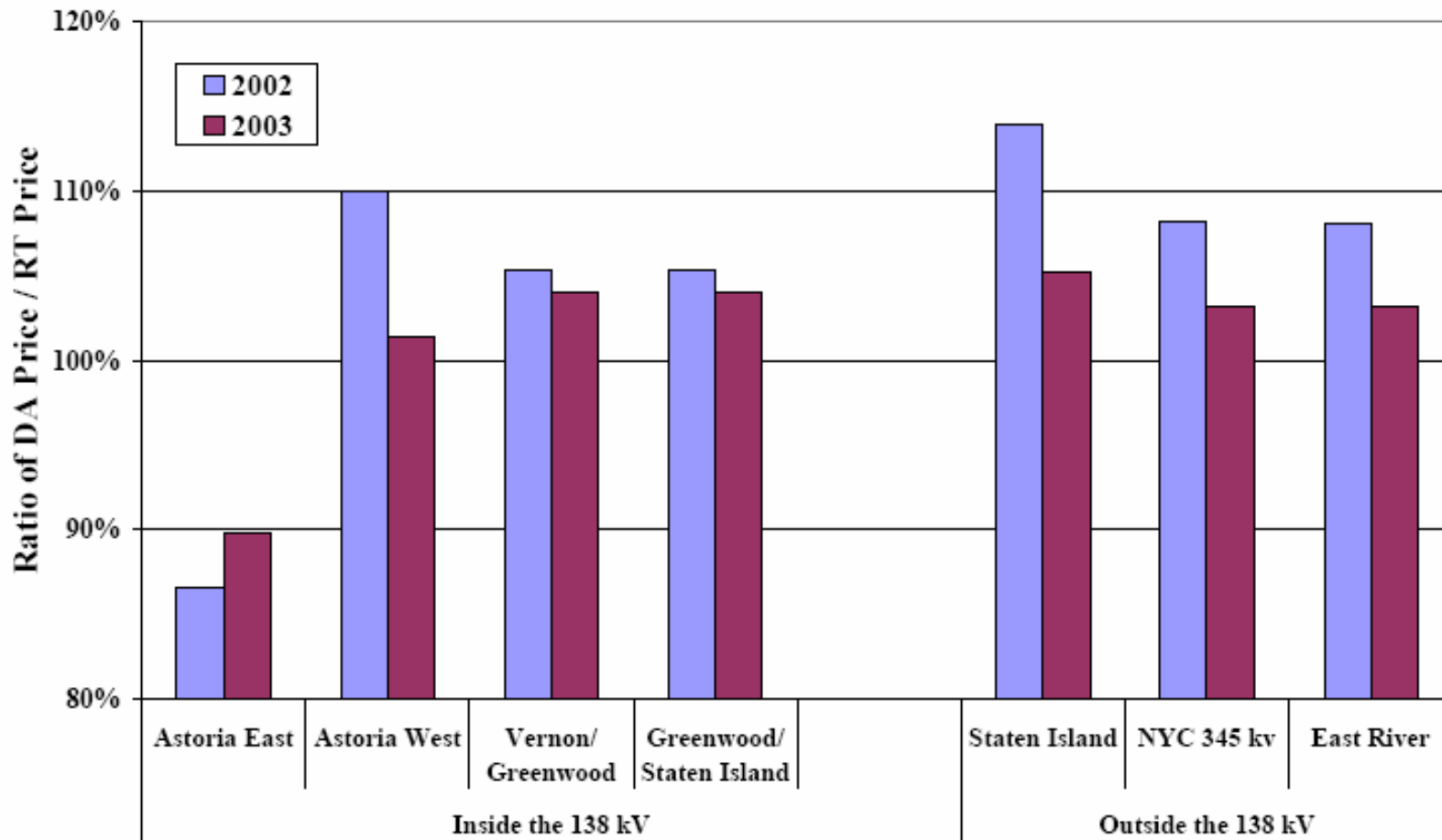


Capital Zone -- 2003

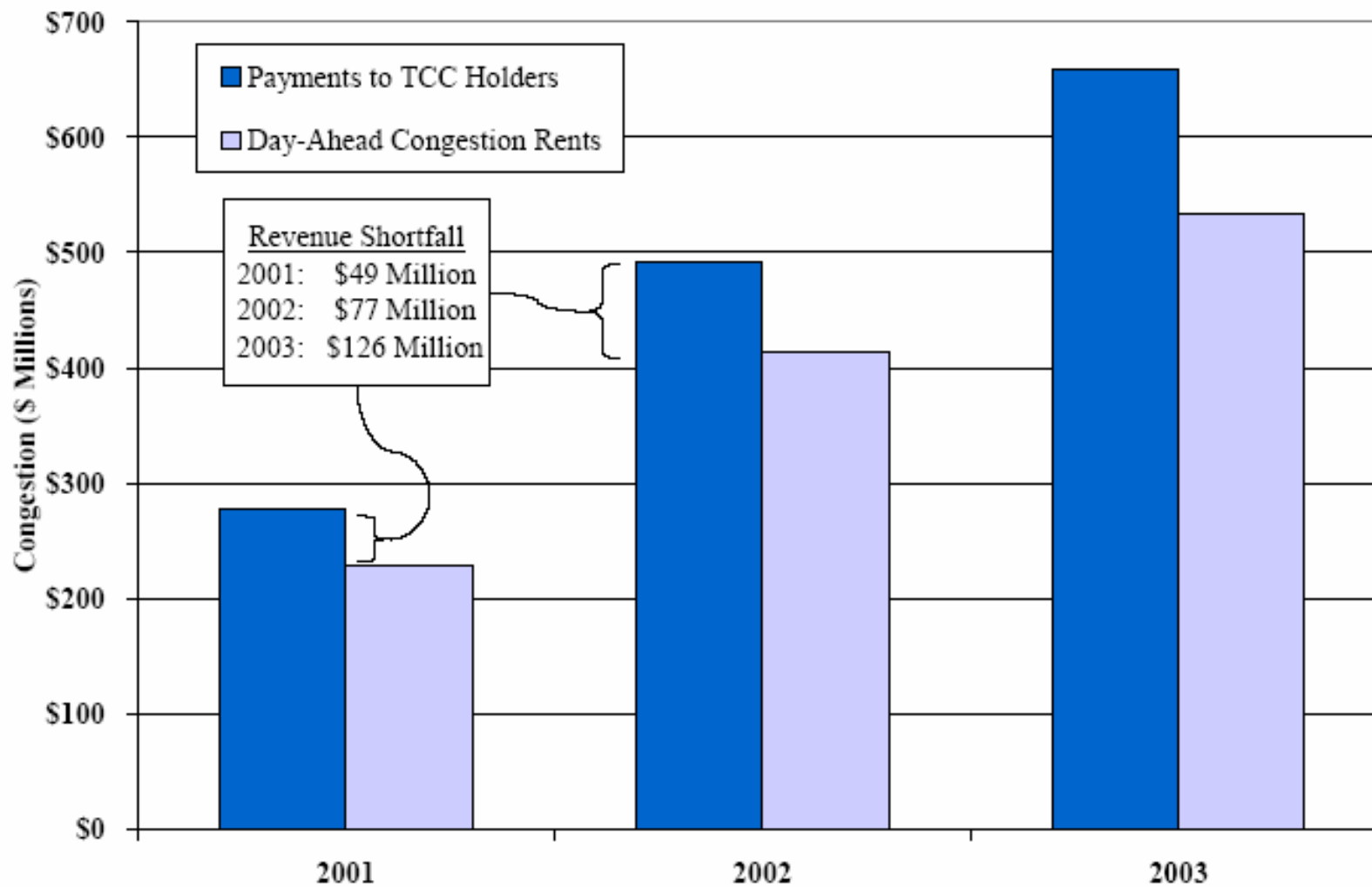


Source: New York ISO

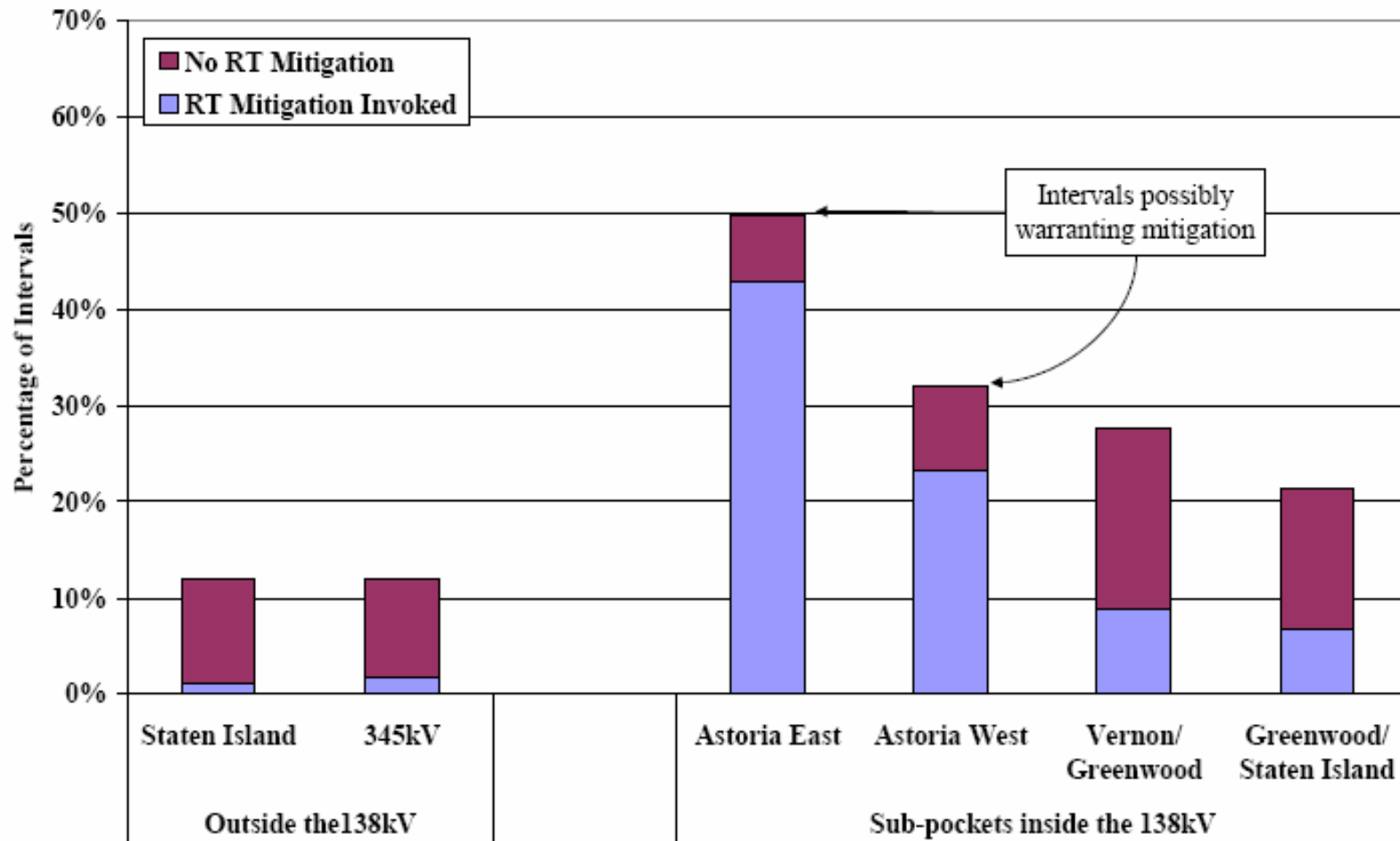
**Figure 11: Day-Ahead and Real-Time Prices in New York City
2002 and 2003**



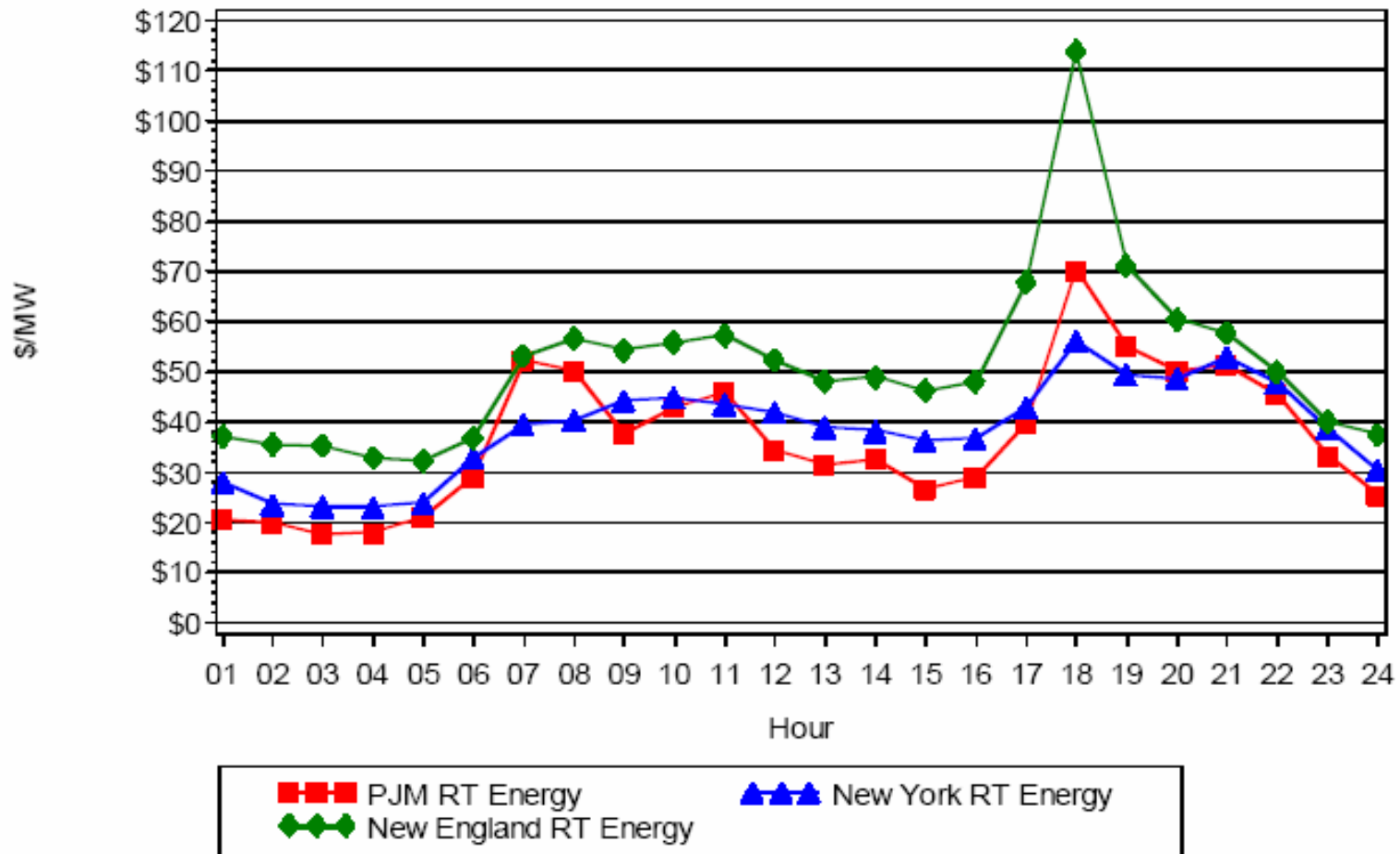
**Figure 27: Day-Ahead Congestion Costs and TCC Payments
2001-2003**



**Figure 13: Frequency of Real-Time Constraints and Mitigation
New York City Load Pockets, 2003**

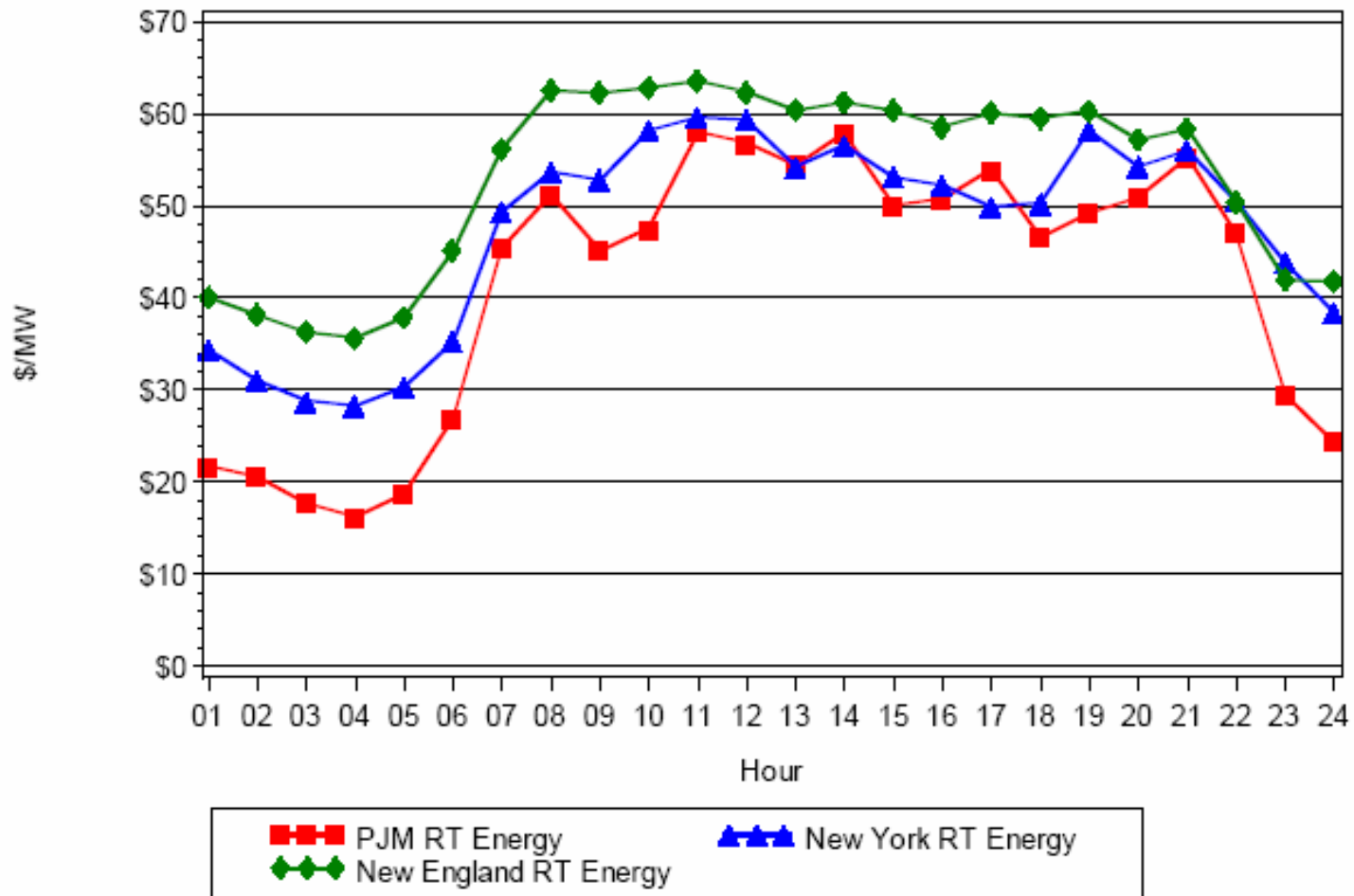


Average Hourly RT Energy Clearing Prices (Weekdays) December 2003



Source: ISO New England

**Figure 20 - Average Hourly RT Energy Prices, NE, NY and PJM
Weekdays, March-June, 2003**



Source: ISO New England

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

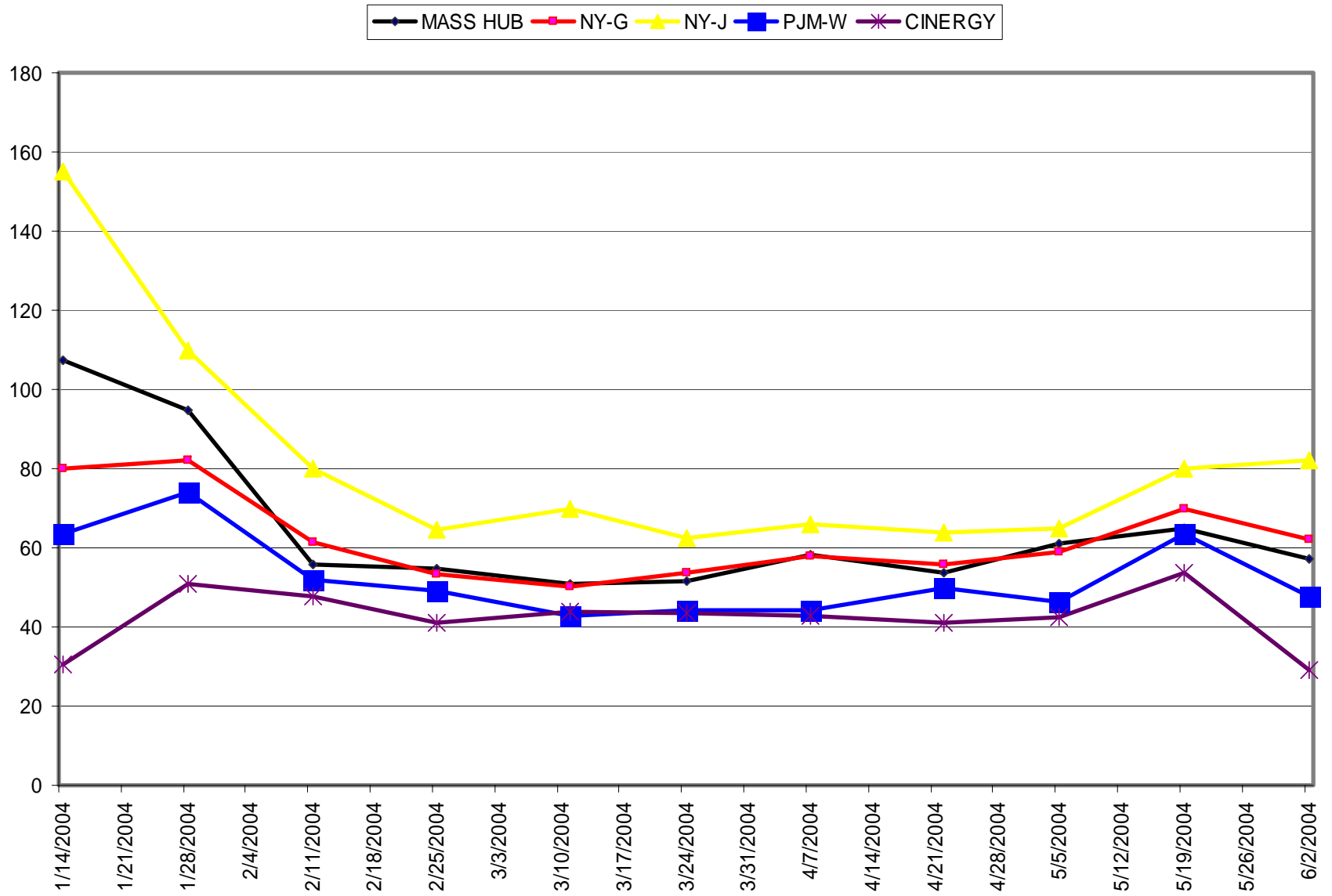
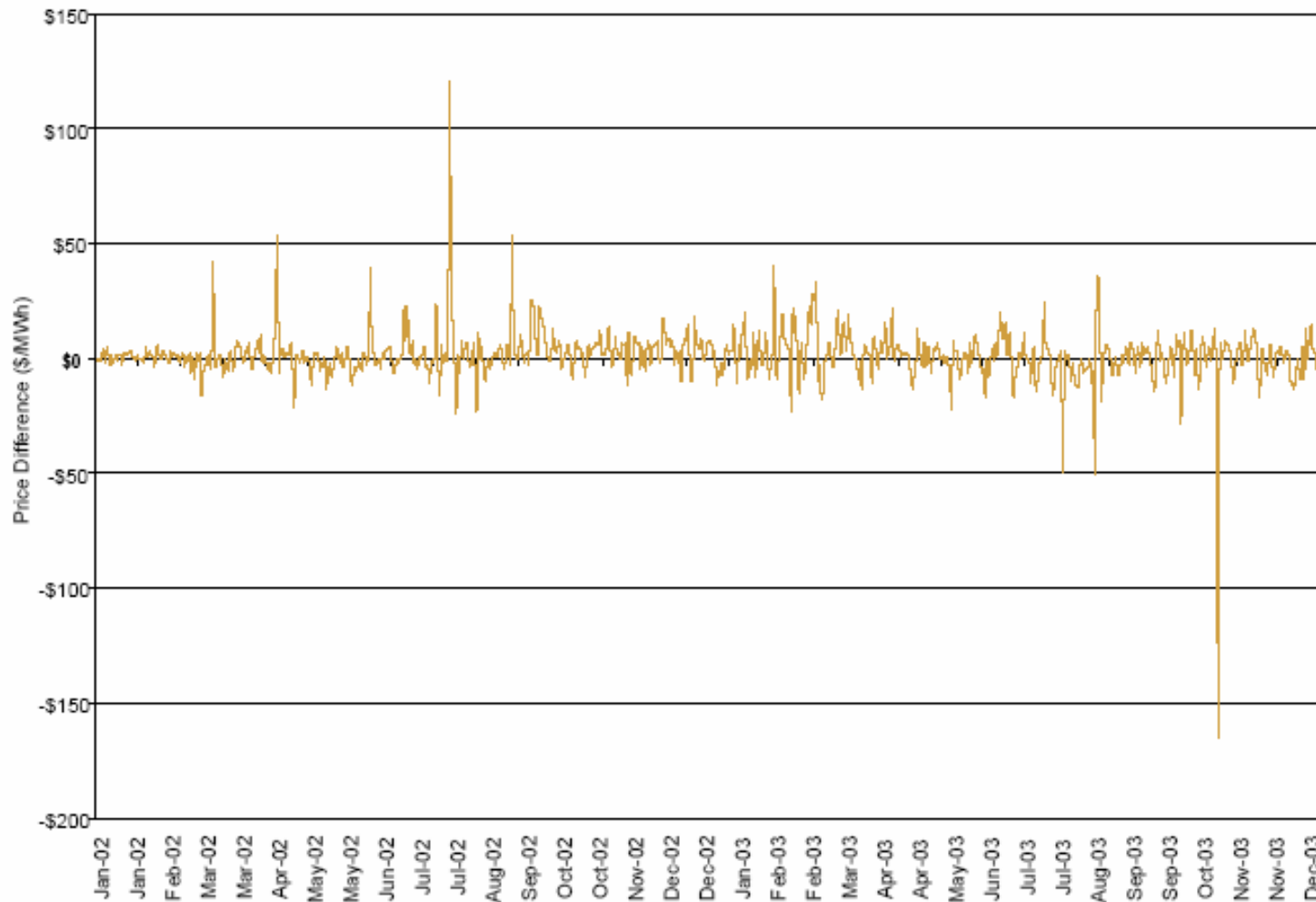


Figure 3-10 Daily Hourly Average Price Difference (NY Proxy - PJM/NYIS)



Source: PJM State of Markets 2003

FORWARD MARKETS

\$/Mwh 6x16 Contract

(June 30, 2004)

<u>Delivery Location</u>	<u>July 04</u>	<u>Aug 04</u>	<u>Q4-04</u>	<u>June 05</u>	<u>Cal 05</u>	<u>Cal 06</u>
MA Hub	70.0	72.0	62.75	61.0	64.75	60.0
NY Zone A	61.25	63.0	-	-	55.75	-
NY Zone G	74.0	76.0	-	-	66.25	-
NY Zone J	99.0	100.0	-	-	83.25	-
PJM West	64.6	67.0	50.25	53.25	52.5	49.75
Cinergy	52.3	54.8	40.8	46.3	45.9	43.0

Source: Platt's *Megawatt Daily*, June 30, 2004

Table 2-17 New Entrant Combustion Turbine and Combined-Cycle Plant Theoretical Net Revenues

Economic Dispatch Generic CT and CC Net Revenue Streams (\$ per Installed MW - Year)								
Gas-Fired								
Year	CT Energy	CC Energy	Capacity	Ancillary	CT Total	CC Total	CT Run Hours	CC Run Hours
2003	\$15,380	\$53,743	\$5,936	\$3,880	\$25,196	\$63,559	964	2,791
2002	\$27,626	\$57,148	\$11,601	\$3,915	\$43,142	\$72,664	1,383	3,206
2001	\$44,481	\$74,831	\$36,700	\$3,823	\$85,004	\$115,354	1,373	3,507
2000	\$19,876	\$45,236	\$23,308	\$4,594	\$47,779	\$73,138	926	2,201
1999	\$73,480	\$97,603	\$20,469	\$3,444	\$97,393	\$121,516	1,415	4,199

Average Net Revenues/MW-year (1999-2003)

	<u>Total</u>	<u>Energy Only</u>
CT:	\$60,000	\$36,000
CC:	\$90,000	\$60,640

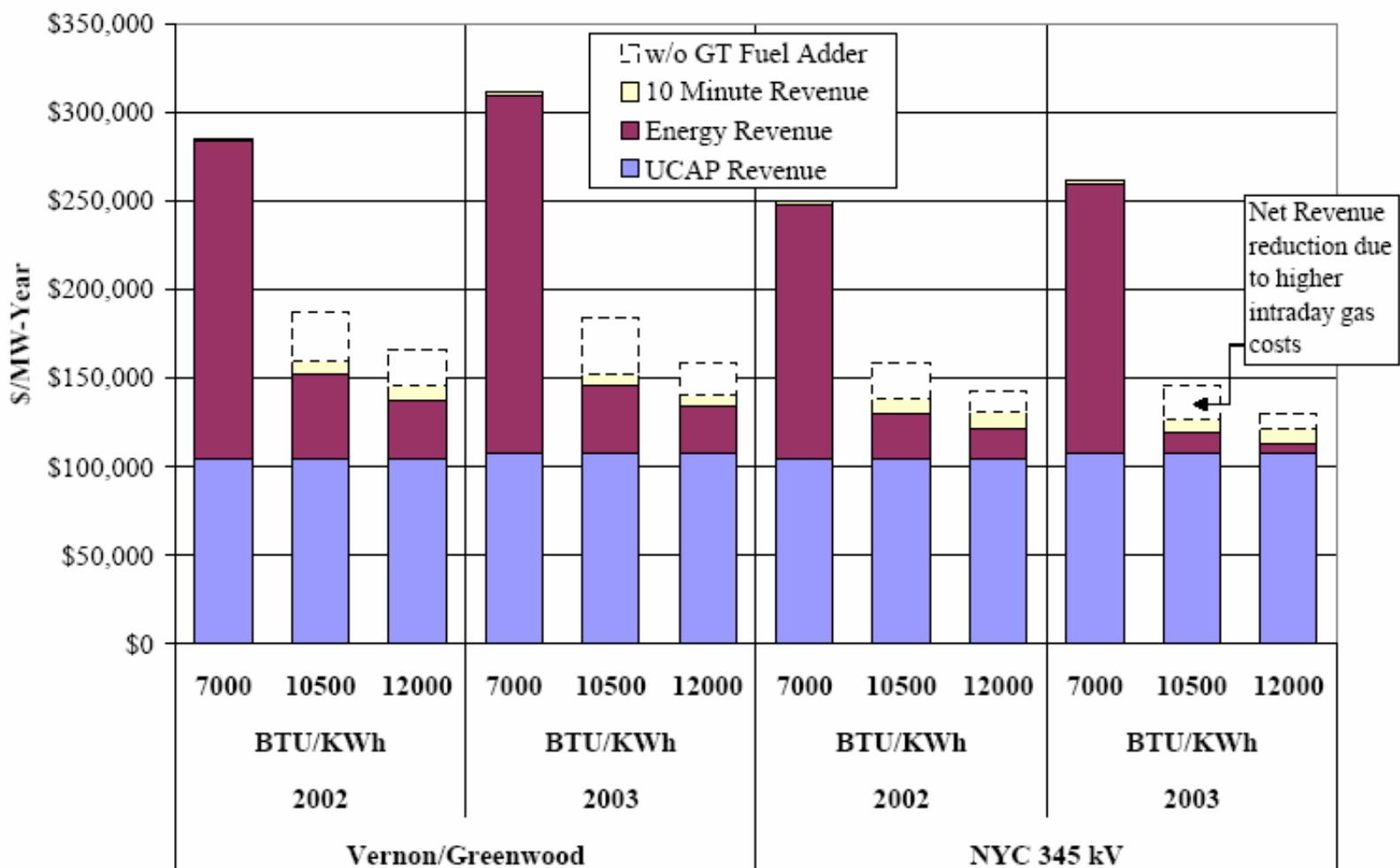
Source: PJM State of Markets 2003

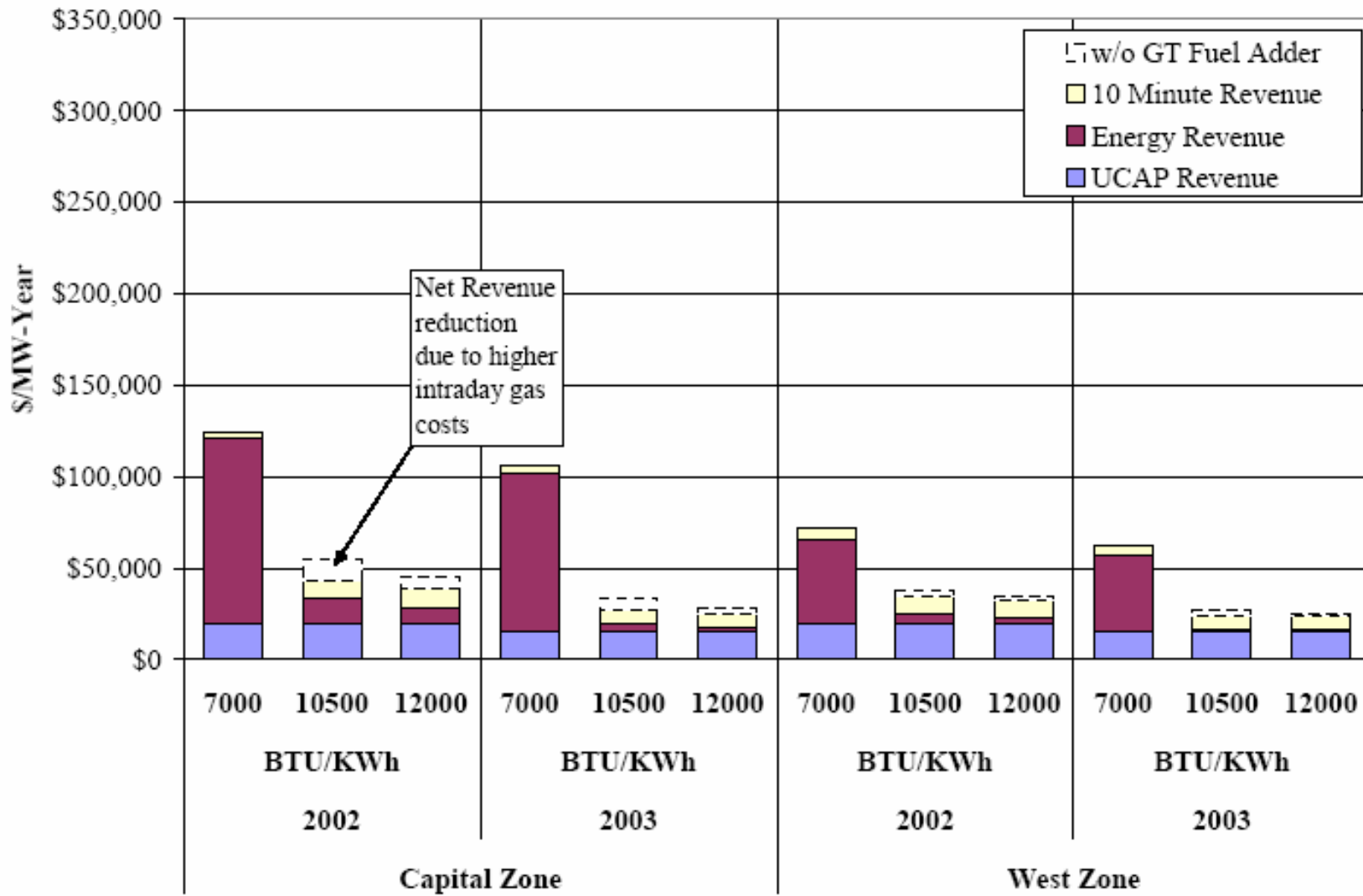
SCARCITY RENTS PRODUCED DURING OP-4 CONDITIONS (\$1000 Price Cap) (\$/Mw-Year)

<u>YEAR</u>	<u>ENERGY</u>		<u>OPERATING</u>	<u>OP-4 HOURS/</u>
	<u>MC=50</u>	<u>MC=100</u>	<u>RESERVES</u>	<u>(Price Cap Hit)</u>
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

**Figure 14: Estimated Net Revenue in the Day-Ahead Market
2002 - 2003**





PJM CONGESTION EVENT HOURS

<u>YEAR</u>	<u>TOTAL</u>	<u>500kv</u>	<u>345kv</u>	<u>230kv</u>
1998	1,244	203	71	588
1999	2,134	189	148	818
2000	6,941	562	14	869
2001	8,435	759	38	744
2002	11,662	1,888	1,084	1,474
2003	9,711	1,985	705	3,016

Source: *PJM State of the Market Report 2002 and 2003*

PJM CONGESTION COSTS (RENTS)

(\$ millions)

1999	53
2000	132
2001	271
2002	430
2003	499

Source: PJM *State of the Market Report 2002 and 2003*

CONGESTION COSTS IN NEW YORK

2001	\$310 million
2002	\$525 million
2003	\$688 million

TRANSMISSION INVESTMENT PJM

- Heavy Influenced by legacy reliability rules and their implementation in the old regime
- Various Categories of investment
 - Direct Interconnection of generators or merchant transmission
 - Interconnection Network Upgrades to restore reliability parameters
 - Deliverability Network Upgrades
 - Other system reliability network upgrades
 - “Economic” upgrades
 - Merchant transmission
- Mediated through regional transmission planning process

TRANSMISSION INVESTMENT

PJM

- MAAC has a complex hierarchy of reliability rules that are applied at the system level and to specific geographic areas (transmission zones)
- Engineering models are used to evaluate the system under various assumptions that bear no relationship to economic dispatch or congestion management
 - e.g. incumbent generators assumed to run to meet peak load and then generator being studied is assumed to run at peak capacity
- Distinctions between “reliability” investments and “economic” investments are quite arbitrary (e.g. generator deliverability)
- A significant fraction of “reliability” investments are really “economic” investments as they are modeled by economists
- New York and New England apply different reliability and economic considerations for transmission investment

PJM (MAAC) RELIABILITY RULES

- Normal system operating conditions
- N-1
- N-2
- Multiple Facility Contingency
- Generator deliverability
- Deliverability to load

TRANSMISSION INVESTMENT

PJM

- TO in affected area designs, owns and operates transmission facilities approved in RTEP except for merchant transmission facilities which TO may also own
- Generators pay regulated cost of service prices for:
 - Direct interconnection facilities
 - Interconnection Network upgrades (incremental FTRs)
 - Deliverability network upgrades (incremental FTRs)
- LSEs shares costs of other reliability mandated network upgrades
- Merchants design, own, operate and pay for new merchant facilities and get FTRs for AC enhancements
- Costs of “economic” planned transmission facilities are shared by LSEs with customers who benefit from upgrades (recent addition still in process)

TRANSMISSION INVESTMENT PLANS

PJM RTEP (11/03)

- Direct interconnection: \$275 million
- Interconnection reliability and deliverability network upgrades: \$214 million
- Other network reliability upgrades: \$197 million
- Economic upgrades: (in process)
- Merchant
 - None completed to date and several proposals withdrawn
 - Most active projects are HVDC interconnects with New York or Long Island (supported by long term contract with LIPA)
 - Three transformer projects (one inside the fence of a refinery and two by incumbent TO) in development

TRANSMISSION INVESTMENT PLANS ISO NEW ENGLAND (11/03)

- Interconnection + Reliability + Economic Benefit: \$1.5 – \$3.0 billion
- Mostly “reliability”
- All regulated projects

NORTHEASTERN MARKET ISSUES

- Seams Issues
 - Better integrate energy and ancillary services markets
 - Framework for expanding interconnections between control areas (merchant is now the only option)
- Local market power problems and solutions
- Incentives for investment in new generating capacity
- Implementation of “resource adequacy” obligations in the presence of retail competition
- Transmission investment framework
- Reliability and markets relationships
- Incentive regulation (PBR) to control transmission operating costs and improve reliability of transmission facilities
- Expand demand-side participation in the wholesale market
 - priority curtailment contracts
 - real time pricing