

NARUC Summer Committee Meetings: Electricity and Energy Resources & the Environment Committees

DOE's EPACT Report to Congress on Demand Response in Electricity Markets

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Grid Modernization – A Presidential Priority

“...We have modern interstate grids for our phone lines and our highways. It's time for America to build a modern electricity grid.”

President George W. Bush

April 27, 2005

.... And now also a priority of Congress due to the Energy Policy Act of 2005



EPACT Sec. 1252 Smart Metering [and much more!]

- Nine subsections on demand response, including:
 - Utilities must offer time-based metering & communications;
 - States must investigate DR & time-based metering;
 - Federal assistance, guidance, and encouragement; and,
 - Encourage regional coordination by states



U.S. Congress Demand Response Policy Statement

Federal Encouragement of Demand Response

“It is the policy of the United States that time-based pricing and other forms of demand response....shall be encouraged, the deployment of such technology and devices....shall be facilitated, and unnecessary barriers to demand response participation in energy, capacity and ancillary service markets shall be eliminated.”

– Energy Policy Act of 2005, Sec. 1252(f)



DOE's Informal Demand Response Program Goals

- Customer-friendly instead of engineer-friendly
- Promote both wholesale level demand response and retail level demand response
- Arrest the continuing slide in legacy retail-level demand response program (regulatory incentives?)
- Demand response that includes “long-run demand response” (ie. energy efficiency)
- “Equivalent” treatment in regional and distribution-level planning
- Bottom line: Ensure robust market-oriented demand response capability in U.S. electric markets



EPACT Sec. 1252(d) DOE Demand Response Report to Congress

The Secretary [of Energy] shall be responsible for... not later than 180 days after the date of enactment of the Energy Policy Act of 2005, providing Congress with a report that [1] identifies and quantifies the national benefits of demand response and [2] makes a recommendation on achieving specific levels of such benefits by January 1, 2007.

- www.oe.energy.gov; under “EPACT button”
- FERC also has Report to Congress, but annual report every August



DOE Feb 2006 Report to Congress on Nat'l Benefits of Demand Response

- Identified Demand Response Benefits:
 - Participant financial benefits, market-wide benefits, reliability and market performance benefits
 - DOE reviewed 10 recent studies and concluded:
 - Lack of standardized and accepted analytic methods
 - Preferable to quantify DR benefits at state/regional level (rather than nat'l) because tied directly to local system conditions and market structure
- Made Policy Recommendations in Six Areas:
 - Fostering Price-based Demand Response
 - Improving Incentive-based DR Programs
 - Strengthening DR Analysis and Valuation
 - Integrating DR into Resource Planning
 - Increased Adoption of Enabling Technologies
 - Enhancing Federal Demand Response Actions



Demand Response Definitions Used: Two Categories of DR

■ Price-based Options

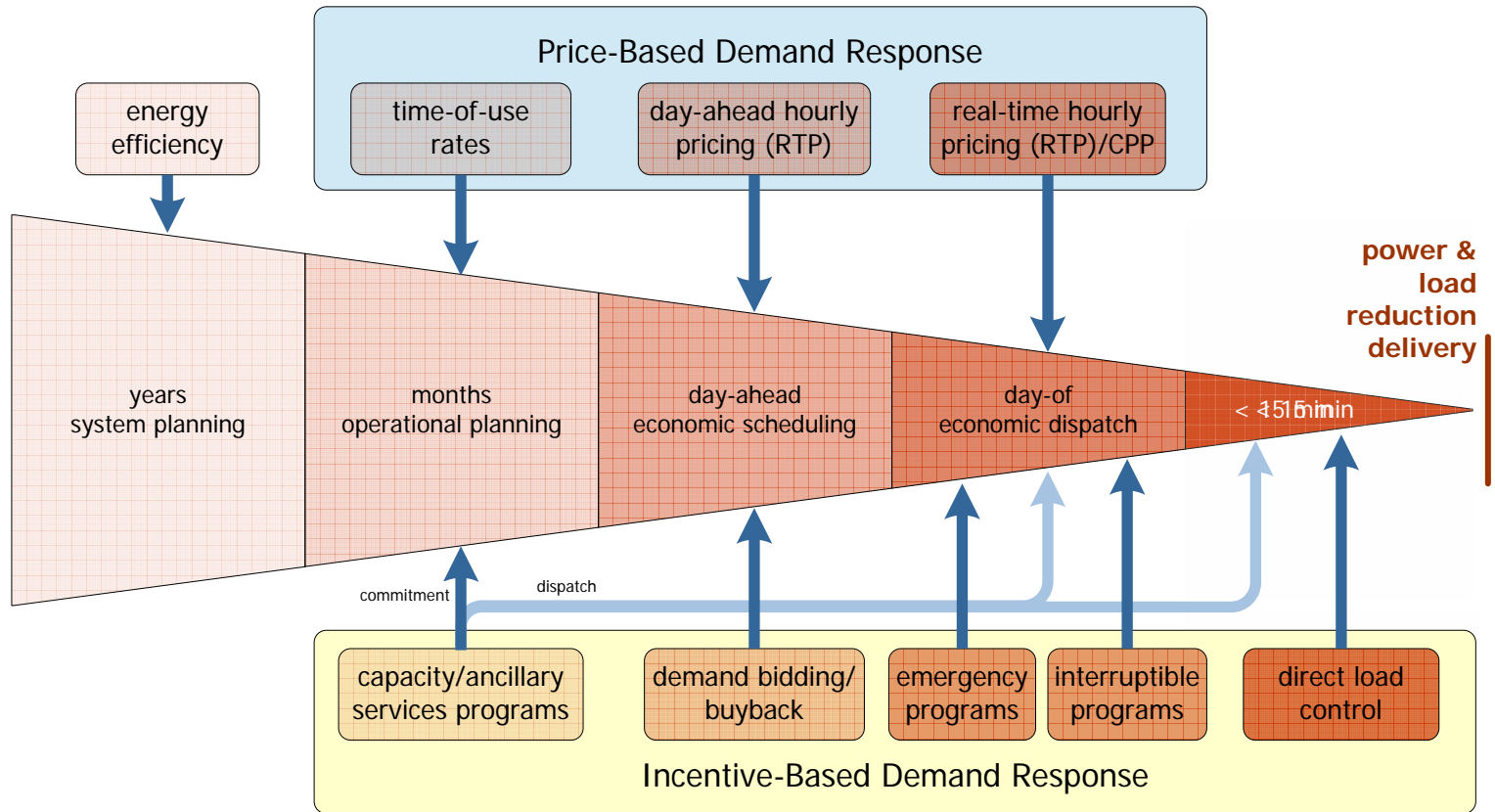
- Real-Time Pricing (RTP)
- Critical Peak Pricing (CPP)
- Time-of-use (TOU) rate

■ Incentive-based DR Programs

- Direct Load Control
- Interruptible/curtailable service
- Emergency DR Programs
- Capacity Market Programs
- Demand Bidding/Buyback programs



Role of Demand Response in Electric Power Systems



- DR options include **price-based DR** (time-varying electricity tariffs) and **incentive-based DR** (programs that pay for load reductions)



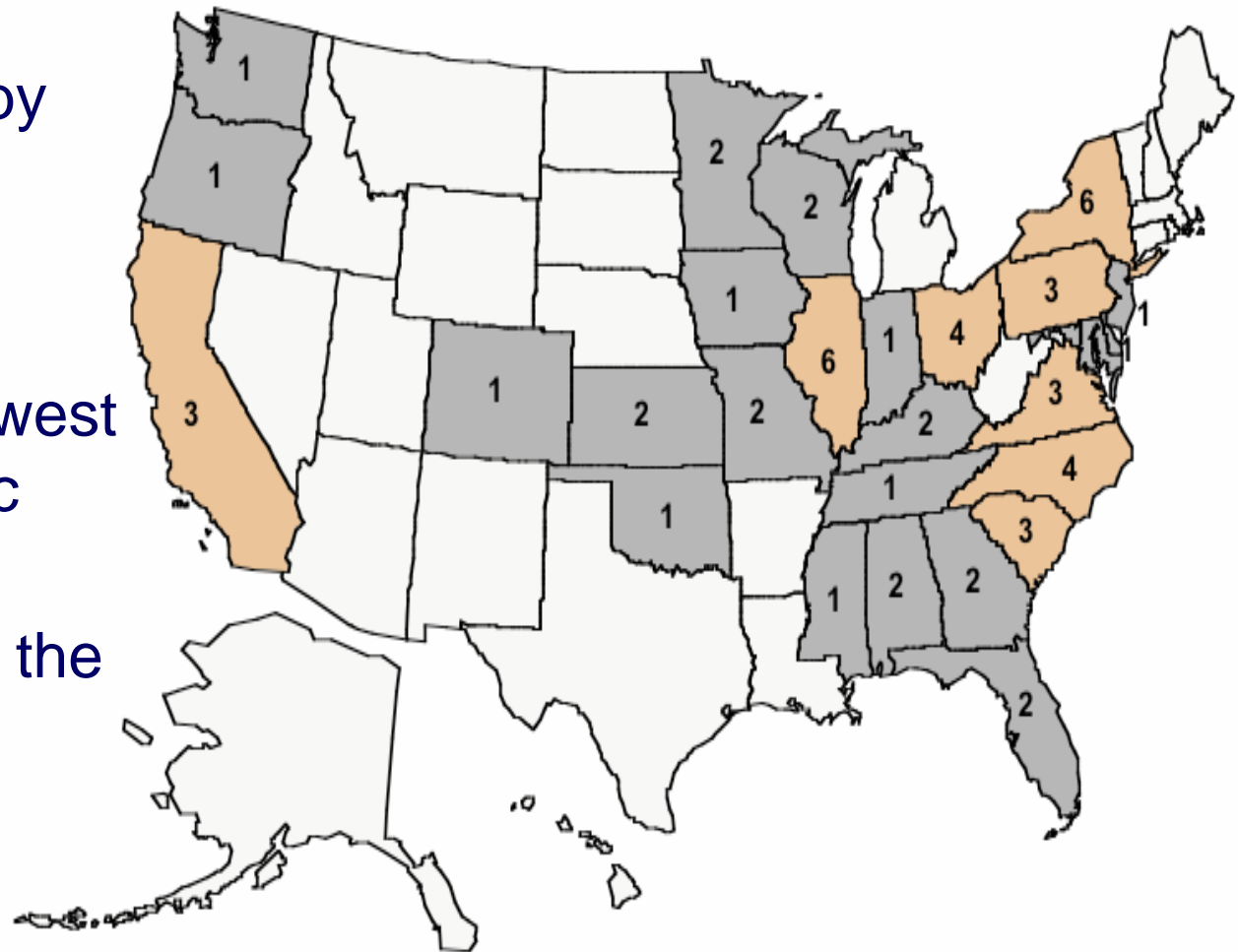
Recommendation #1: Fostering Price-Based Demand Response

- Marginal cost of supplying electricity varies significantly; but nearly all customers face time-averaged, fixed retail rates
- Customers have little or no incentive to adjust their demand to supply-side conditions, which leads to inefficient use of resources
- Policy Issues:
 - What hard evidence is there that RTP or CPP delivers DR?
 - Lack of advanced metering is major barrier to widespread implementation
 - Do state PUCs have political will to aggressively promote price-based DR, given the risks of price volatility?



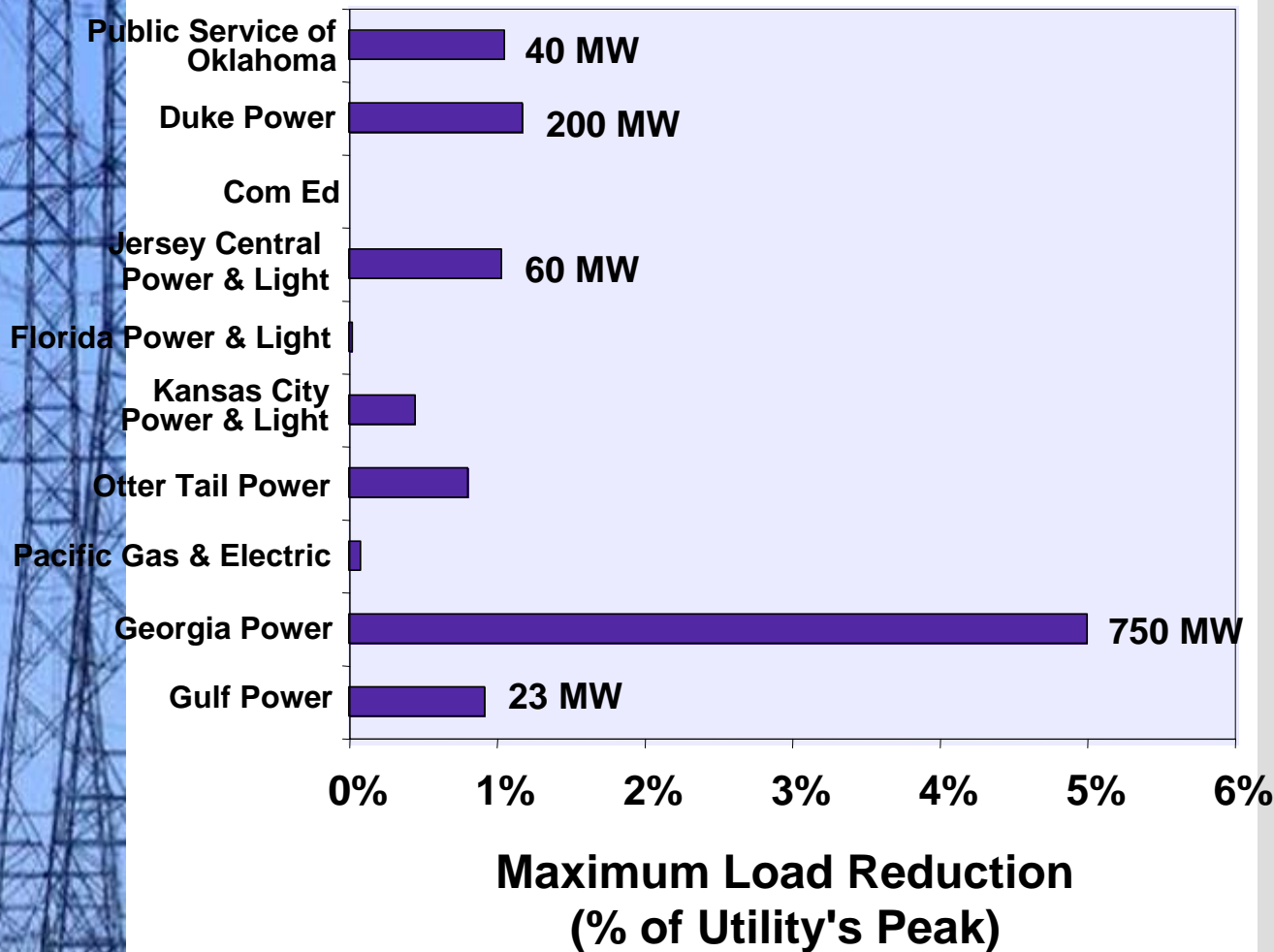
Optional RTP Tariffs: Overview

- RTP offered as Optional Tariff by more than 40 utilities
- Popular in Southeast, Midwest and Mid-Atlantic
- Not offered by many utilities in the West or New England



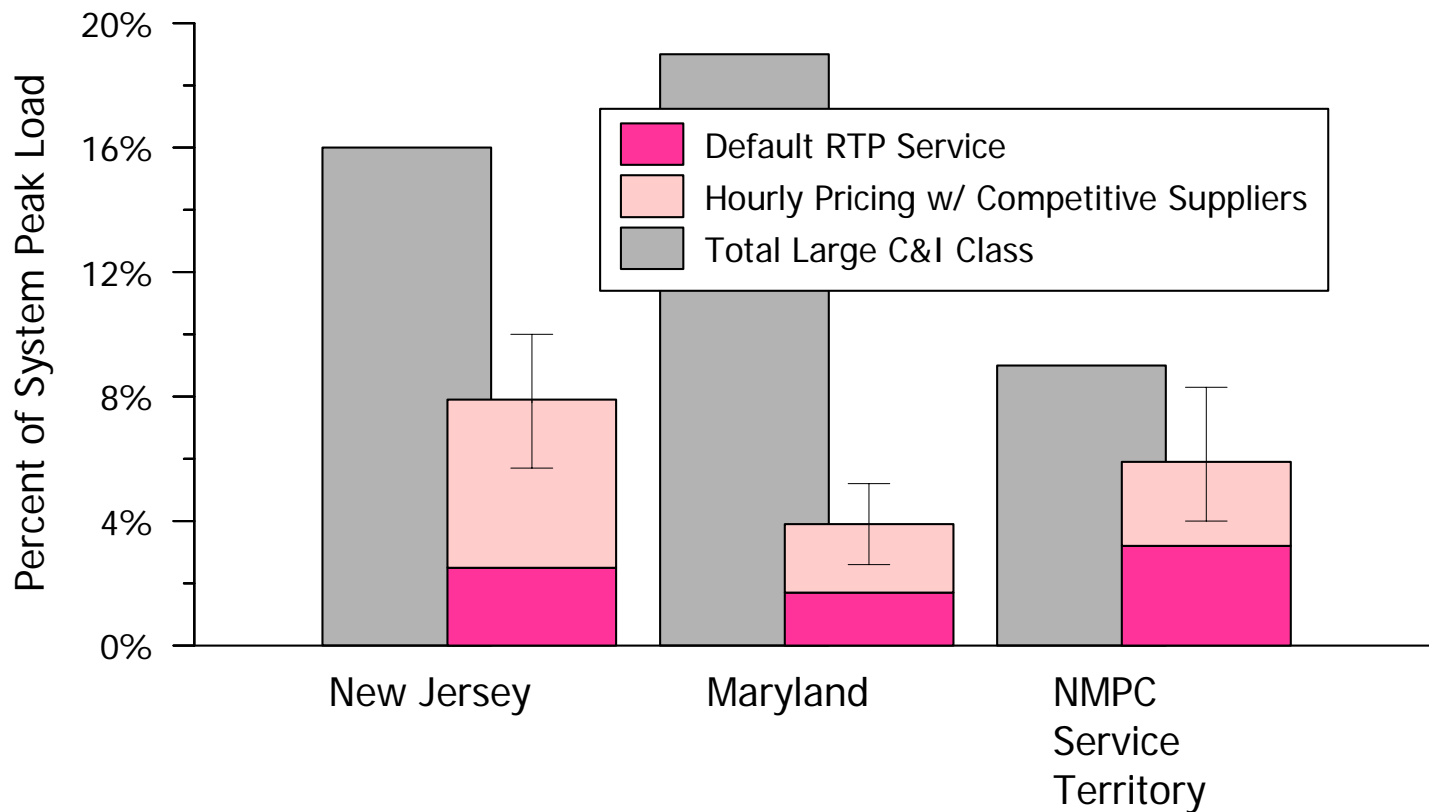


Customer Response to High Prices in RTP Programs



- **RTP programs have reduced utility system peaks by ~1%, except for Georgia Power (5% of utility peak)**

RTP as Default Service: Customers Exposed to Spot Market Prices



- **Customers face spot prices through default RTP and contracts with competitive retailers**
- **Large C/I customers facing spot prices ranges from 4-8% of total system peak load**

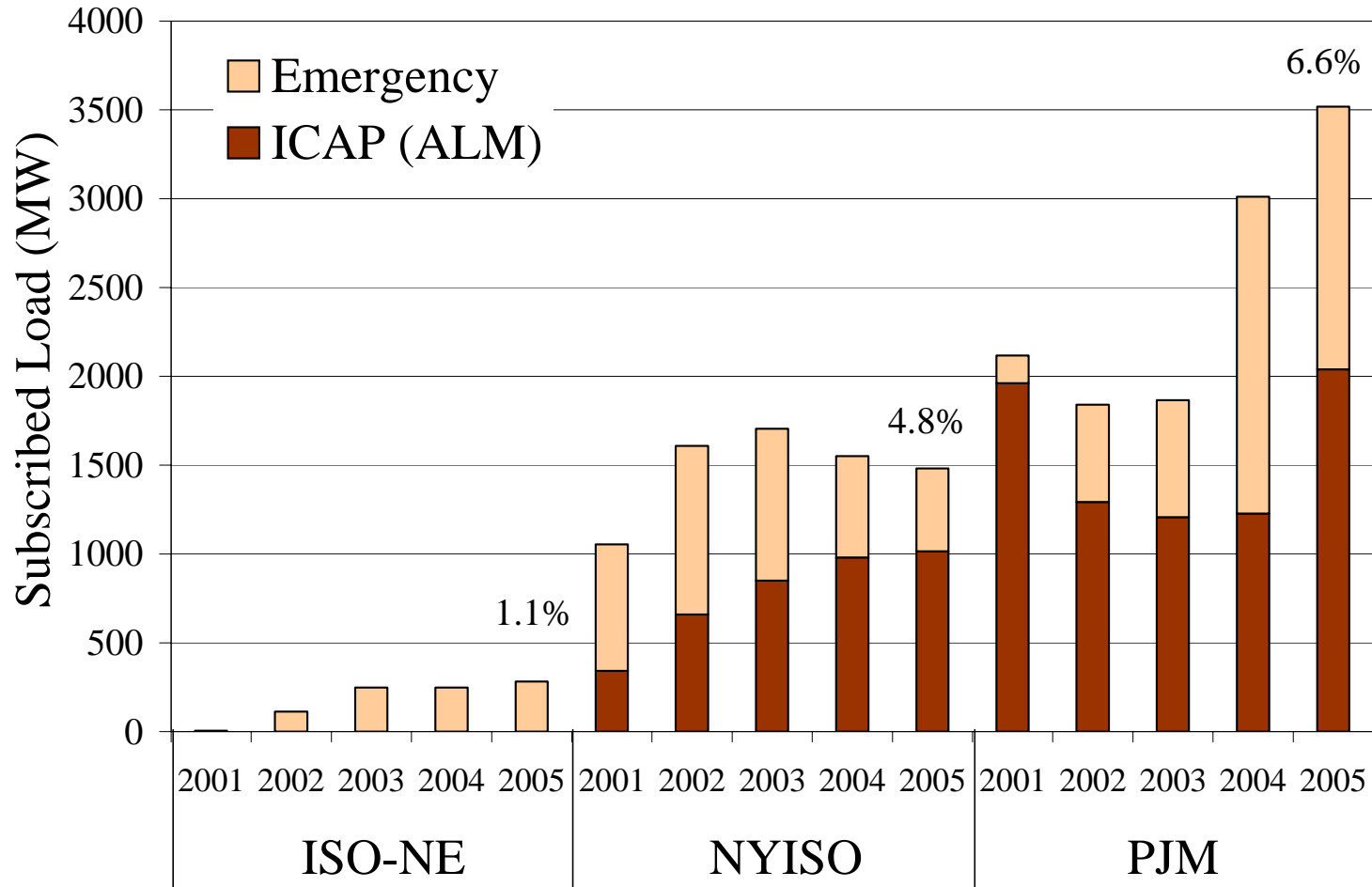


Recommendation #2: Improving Incentive-Based Demand Response Programs

- Trends in ISO DR programs
- Issues:
 - Not all ISOs have integrated DR into their wholesale markets
 - Retail-level traditional load mgmt programs (direct load control and interruptible customers) need to be adapted to new market structures and circumstances



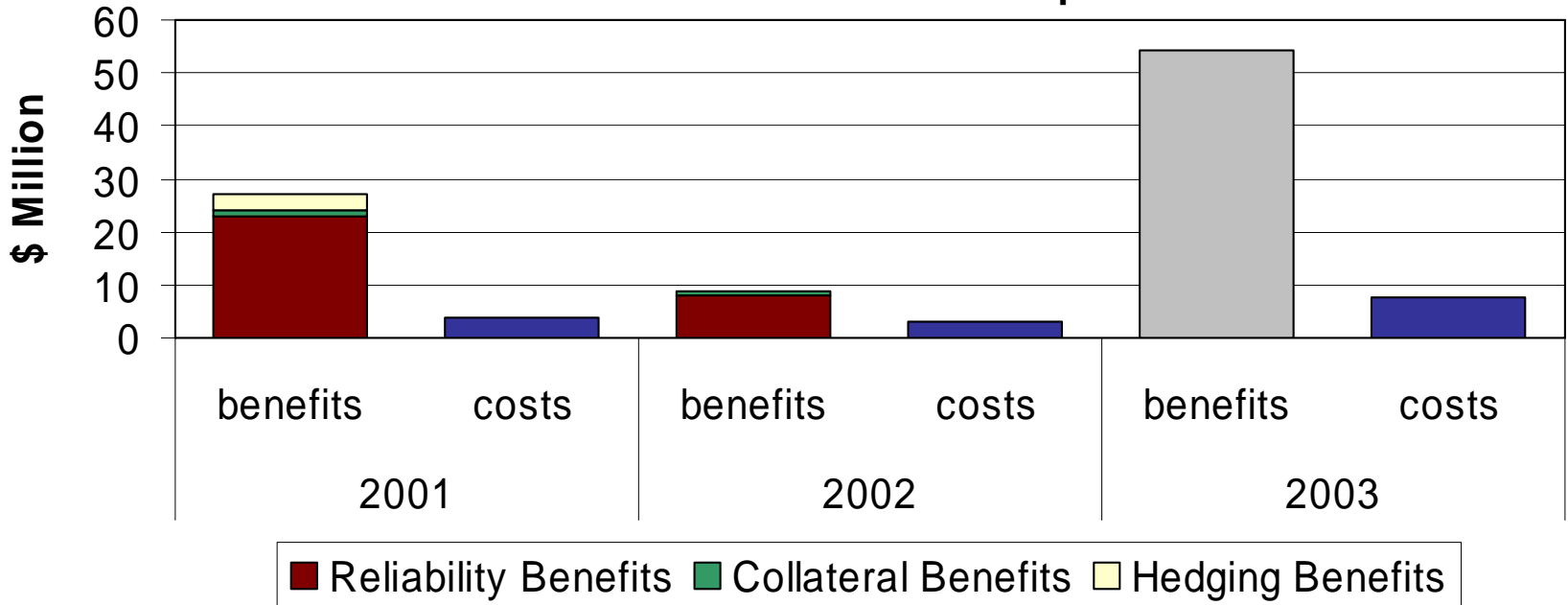
ISO "Reliability-based" DR Programs: Enrollment is increasing





Emergency DR programs can be very cost-effective

NYISO EDRP Cost-Benefit Comparison



Cost-effectiveness driven by:

- number of events
- customer response & program payments
- assumed value of lost load
- “supply curve” flexibility

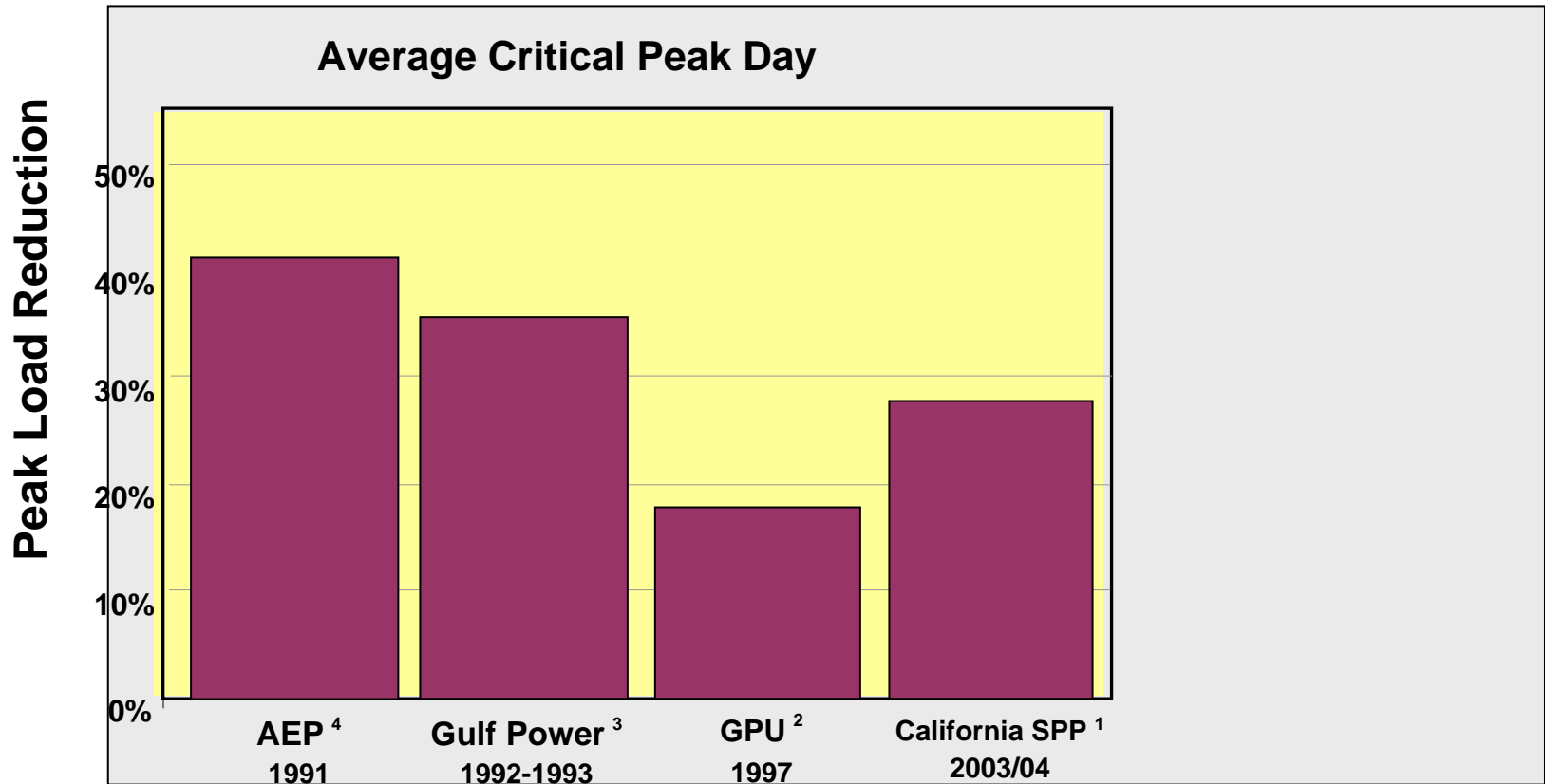


Recommendation #5: Increased Adoption of Enabling Technologies

- Lack of interval metering is significant barrier to deployment of price-based demand response among residential and small C/I customers
- Many large C/I customers do not fully utilize capabilities of automated (EMCS and EIS) systems, advanced HVAC and lighting controls
- Enabling technologies that automate load response provide opportunity to improve persistence of load impacts and increase number of customers willing to curtail loads



Load Response from Critical Peak Pricing and Enabling Technologies: Residential customers



Source:

1. CA Statewide Pricing Pilot CRA 2005
2. Residential TOU pilot study Braithwait 2000.
3. Results of the Pilot Residential Advanced Energy Management System, Gulf Power, November 1994.
4. Levy Associates case study report, July 1994.



Recommendation #3: Strengthening DR Analysis and Valuation

- Challenges in measuring DR Impacts
 - Direct Load Control impacts are reasonably well-characterized, but impacts from price-based DR depend on customer behaviors that are price- or incentive-driven
- Challenges in estimating net benefits of DR
 - Cost reporting issues (participant costs)
 - Value of DR not fully reflected in standard B/C tests
 - Reliability benefits valued differently by customers
 - Other benefits difficult to quantify
- Bottom Line: More comprehensive evaluation framework needed to fully value benefits of DR



Recommendation #4: Integrating DR into Resource Planning

- How much DR is needed for ensuring resource adequacy, given market structures and system conditions?
- Improve characterization of DR in Resource Planning Models
- Organized Markets: ISO/RTO evaluations focus only on short-term impacts and benefits of DR
 - More effort needed to characterize long-term impacts and potential DR benefits, as part of ISO long-range planning studies



Recommendation #6: Enhancing Federal Demand Response Actions

- Federal government can and should lead by example on DR
- DOE should continue to:
 - provide technical assistance on DR to state and regional policymakers, utilities, and ISO/RTOs
 - coordinate with FERC on DR activities
 - through Federal Energy Mgt Program, investigate and evaluate costs/benefits of metering and continue DR audits at Federal facilities
 - Work with EPA to explore efforts to include DR programs in Energy Star programs



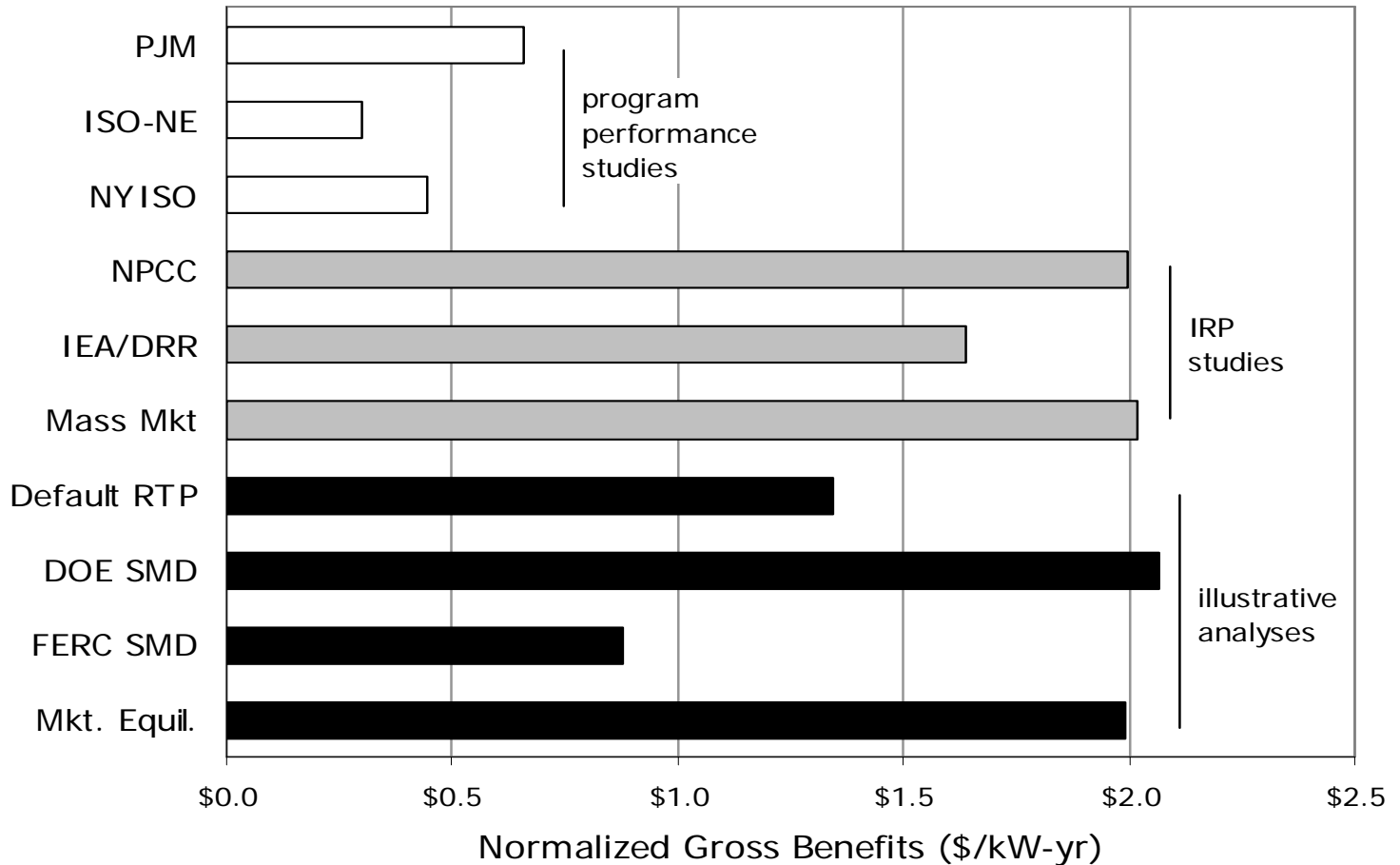
Conclusions on EPACT Effect on DR

- Some may ask: “Is all this wishful thinking”; “what is going on..or is this just one more policy with no teeth?”
- EPACT is the most support for DR that will occur from Congress...don't expect more (due to Federal Power Act)
- What happens next is up to states, regulators, the electric industry, and the supplier industry



Background Slides:

Gross Demand Response Benefits: Normalized Results for 10 studies





Six Main Policy Recommendations

- Fostering Price-Based Demand Response
 - Improving Incentive-Based Demand Response Programs
 - Strengthening DR Analysis and Valuation
 - Integrating DR into Resource Planning
 - Increased Adoption of Enabling Technologies
 - Enhancing Federal Demand Response Actions
-
- Following slides *discuss issues behind* each main recommendation. Note there are 24 sub-recommendations.



DOE DR Rpt to Congress Policy Recommendations

Fostering Price-Based Demand Response

In accordance with EPACT, State regulatory authorities must decide whether their utilities must offer customers time-based rate schedules (i.e., RTP, CPP and TOU rates) and advanced metering and communications technology.

Large Customers

- In states that allow retail competition, state regulatory authorities and electric utilities should consider adopting RTP as their default service option for large customers.
- In states that do not allow retail competition, state regulatory authorities and electric utilities should consider offering RTP to large customers as an optional service.
- Regional entities and collaborative processes, state regulatory authorities, and electric utilities should provide education, outreach, and technical assistance to customers to maximize the effectiveness of RTP tariffs.

Medium and Small Business Customers

- State regulatory authorities and electric utilities should investigate new strategies for segmenting medium and small business customers to identify relatively homogeneous sub-sectors that might make them better candidates for price-based demand response approaches.
- State regulatory authorities and electric utilities should consider conducting business case analysis of CPP for medium and small business customers. Results from existing pilot programs should be carefully evaluated and included in the analysis.
- State regulatory authorities and electric utilities should consider conducting policy or business case analysis of RTP for medium business customers. Results from existing pilot programs should be carefully evaluated and included in the analysis.

Residential Customers

- State regulatory authorities and electric utilities should consider conducting business case analysis of CPP for residential customers. Results from existing pilot programs should be carefully evaluated and included in the analysis.
- State regulatory authorities and electric utilities should investigate the cost-effectiveness of offering technical and/or financial assistance to small business & residential customers to enable their participation in CPP or TOU tariffs and enhance their abilities to reduce demand in response to higher prices.

Improving Incentive-Based Demand Response

- Traditional load management (LM) programs such as direct load control of residential and small commercial equipment and appliances (e.g., ACs, water heaters, and pool pumps) with an established track record of providing cost-effective DR should be maintained/expanded.
- State regulatory authorities and electric utilities should consider offering existing and new participants in these LM programs “pay-for-performance” incentive designs, similar to those implemented by ISOs/RTOs and some utilities, which include a certain level of payment to customers who successfully reduce demand when called upon to do so during events.
- Regional entities, state regulatory authorities, and electric utilities should consider including these emergency DR program features:
 - Payments that are linked to the higher of real-time market prices or an administratively-determined floor payment that exceeds customers’ transaction costs;
 - “Pay-for-performance” approaches that include methods to measure and verify demand reductions;
 - Low entry barriers for DR providers, and in vertically integrated systems, procedures to ensure that customers have access to these programs; &
 - Multi-year commitments from regional entities for emergency DR programs so that customers and aggregators can make decisions about committing time and resources.
- State regulatory authorities should investigate whether it would be cost-effective for default service providers to implement demand response. They should also provide cost recovery for DR investments undertaken by distribution utilities.



DOE DR Rpt to Congress Policy Recommendations (cont)

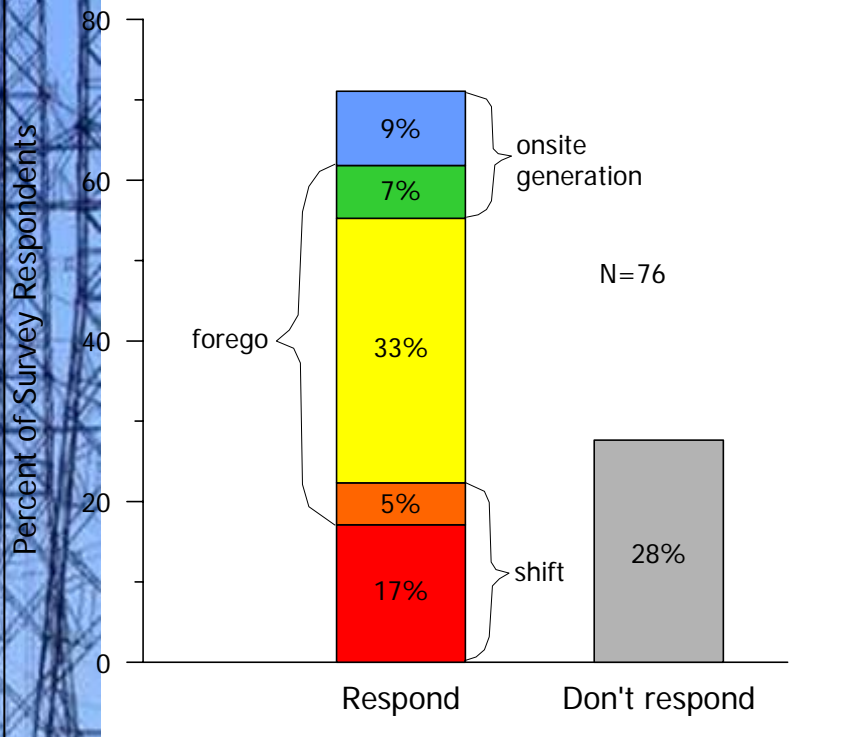
<p>Strengthening Demand Response Analysis and Valuation</p>	<ul style="list-style-type: none"> •A voluntary and coordinated effort should be undertaken to strengthen demand response analysis capabilities. This effort should include participation from regional entities, state regulatory authorities, electric utilities, trade associations, demand response equipment manufacturers and providers, customers, environmental and public interest groups, and technical experts. The goal should be to establish universally applicable methods and practices for quantifying the benefits of demand response.
<p>Integrating Demand Response into Resource Planning</p>	<ul style="list-style-type: none"> •FERC and state regulatory agencies should work with interested ISOs/RTOs, utilities, other market participants and customer groups to examine how much demand response is needed to improve the efficiency and reliability of their wholesale and retail markets. •Resource planning initiatives should review existing demand response characterization methods and improve existing planning models to better incorporate different types of demand response as resource options. •ISOs and RTOs, in conjunction with other stakeholders, should conduct studies to understand demand response benefits under foreseeable future circumstances as part of regional transmission planning and under current market conditions in their demand response performance studies.
<p>Adopting Enabling Technologies</p>	<ul style="list-style-type: none"> •State regulatory authorities and electric utilities should assure that utility consideration of advanced metering systems includes evaluation of their ability to support price-based and reliability-driven demand response, and that the business case analysis includes the potential impacts and benefits of expanded demand response along with the operational benefits to utilities. •State regulatory authorities and electric utilities should evaluate enabling technologies that can enhance the attractiveness and effectiveness of demand response to customers and/or electric utilities, particularly when they can be deployed to leverage advanced metering, communications, and control technologies for maximum value and impact. •State legislatures should consider adopting new codes and standards that do not discourage deployment of cost-effective demand response and enabling technologies in new residential and commercial buildings and multi-building complexes.
<p>Enhancing Federal Actions</p>	<ul style="list-style-type: none"> •DOE, to the extent annual appropriations allow, should continue to provide technical assistance on demand response to states, regions, electric utilities, and the public including activities with stakeholders to enhance information exchange so that lessons learned, best practices, new technologies, barriers, and ways to mitigate the barriers can be identified and discussed. •DOE and FERC should continue to coordinate their respective demand response and related activities. •FERC should continue to encourage demand response in the wholesale markets it oversees. •DOE, through its Federal Energy Management Program, should explore the possibility of conducting demand response audits at Federal facilities. •DOE and the Environmental Protection Agency should explore efforts to include appropriate demand response programs and pricing approaches, where appropriate, in the ENERGY STAR® and other voluntary programs.



Niagara Mohawk: Barriers to RTP

What Customers Told Us

Load Response Strategies



Barriers to Price Response (N=76)

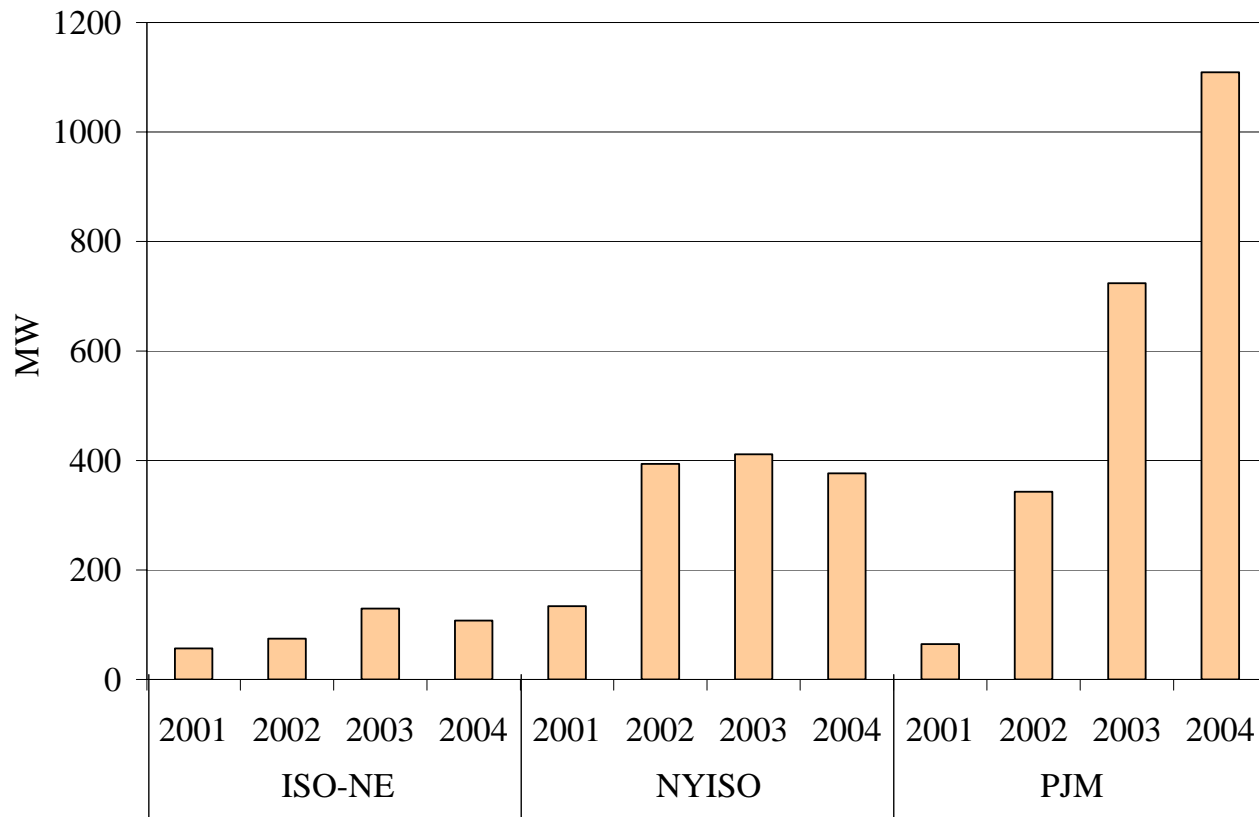
Frequency

No barriers encountered	9
Organization/ Business Practices	
Insufficient time to pay attention to prices	39
Institutional barriers	23
Inflexible labor schedule	16
Inadequate incentives	
Electricity is not a priority	17
Cost/inconvenience outweighs savings	17
Risk averse/ hedged	
Management views price response as too risky	10
Flat rate or time-of-use contract makes responding unimportant	9

- Most customers report multiple barriers to price response; ~15% respond without obstacles



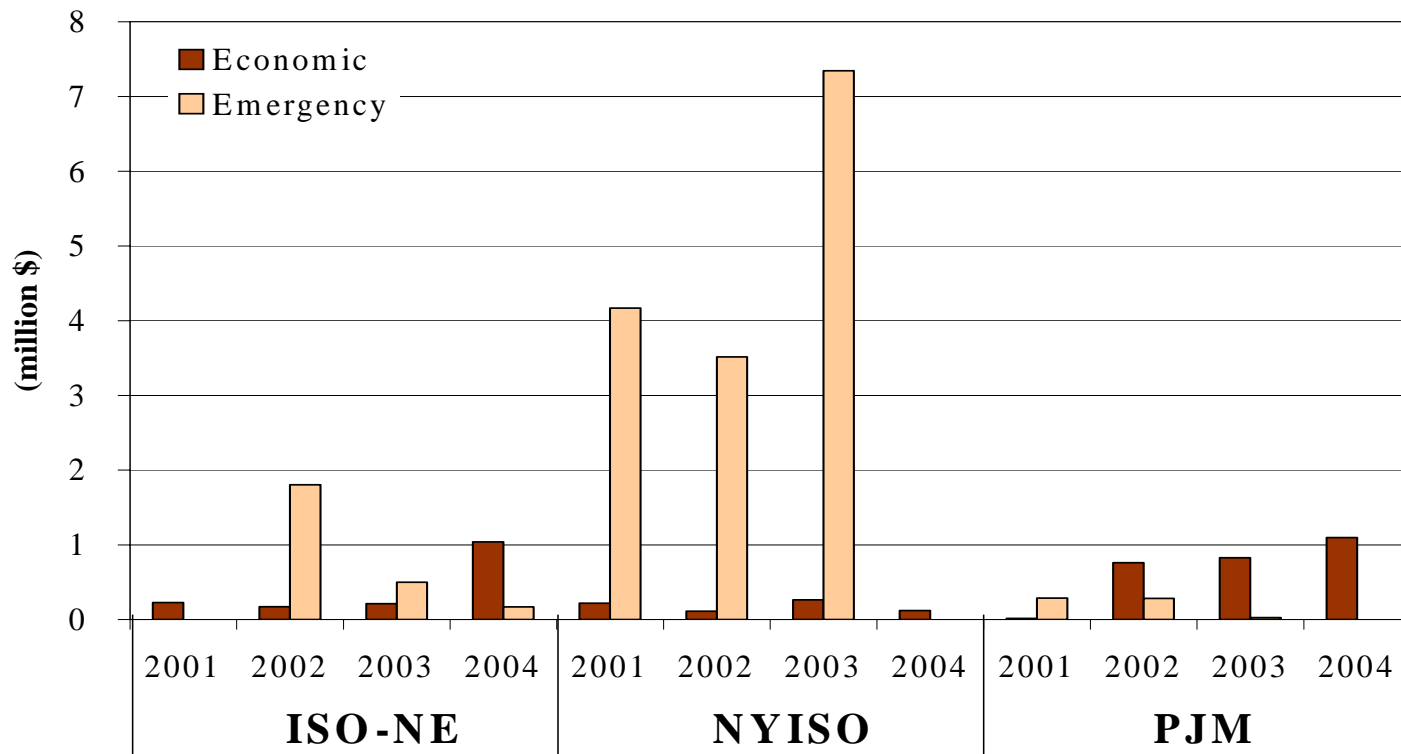
ISO "Economic" DR Programs: Enrollment Increasing - Performance Lags



- **Subscribed load increasing, particularly in PJM**
- **However, scheduled load curtailments are typically low:**
 - **~10-15 MW peak (NYISO day-ahead market and PJM real-time market)**



ISO DR Program Costs and Payments



Cumulative Payments made to participants by 3 ISOs (2001-2004):

- Emergency DR Pgm: \$18.1 M
- Economic DR Pgms: \$5 M



Mid-Atlantic Distributed Resource Initiative (MADRI)

Developing Regional Policies & Market-Enabling Activities to Support Distributed Generation and Demand Response

- Goal: Improve the effectiveness of deployment of distributed resources (distributed generation, demand response, energy efficiency) in the Mid-Atlantic region to improve electric reliability and reduce costs....*driven by the state commissions*
- Objectives:
 - Educate stakeholders (especially state officials) on opportunities, barriers, and solutions
 - Pursue consensus on preferred solutions
- A stakeholder process with open meetings held every 5-6 weeks, with working groups meeting more often
- Focuses on Mid-Atlantic region/“Classic PJM” with input from neighboring states
- Established in June 2004 by State PUC Commissioners, U.S. DOE, U.S. EPA, and PJM Interconnection
- Building on the success of the New England Demand Response Initiative (NEDRI)
- Web site: www.energetics.com/madri



Int'l Energy Agency Demand Response Resources Project

- U.S. is part of this project, DOE is country rep with FERC and DRCC as “country experts”
- Demand Response Coordinating Committee (DRCC) formed to coalesce US industry
- Purpose:
 - Review current demand response practices in each project member countries
 - Develop tools and recommendations for better integrating DR into member country’s electricity markets



IEA DRR Project Subtasks¹

- 2) **Market Characterization** - of demand response products, services and enabling technologies
- 3) **Market Potential of DRR** - methods for assessing the available DR market potential in a given market
- 4) **DRR Valuation** - methods and procedures required to establish the value of DR and to administer them in each country to create a valuation framework to guide development initiatives
- 5) **Role and Value of Technologies** - catalogue that describes the technologies and systems available for use in DR programs both from perspective of system operator and participating customer
- 6) **Market Barriers, DR Solutions and Recommendations** - Identify current DR products and market barriers. Develop recommendations for DR implementations.
- 7) **Communications & Workshops** - web portal and country workshops on DRR methods, technologies, and applications
- 8) **Implementation** - delivery of intellectual property created in the DRR Project to the IEA DSM Programme and the participating countries

¹Green and red text indicate project deliverables that can help a state or utility determine DR market potential or value.



IEA DRR Project Portal

dsm.iea.org/NewDSM/Work/Tasks/13/task13.asp

www.demandresponseresources.com

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WELCOME TO IEA DRR TASK XIII

Danger, Danger, Danger. The computer screen flashes red indicating a severe congestion problem in the northern region. The control room operator jumps into action and activates the local demand response resources (DRR). These resources have been properly trained and well coordinated for several years, so they know just what to do when asked. A few consumers reduce their loads and others turn on a facility generator. As all of this is taking place, the control room operator watches the congestion problem disappear. But they were not really concerned, they've seen the DRR spring into action before.

The International Energy Agency's Demand Side Management Programme (IEA-DSM) established Task XIII to evaluate DRR practices from around the world and develop recommendations on best practices for integrating DRR into regular market activities. Task XIII was formally approved at the DSM Executive Committee meeting on April 15, 2004. Ross Malme (USA), President & CEO of RETX Energy Services Inc. and Chairman of the Peak Load Management Alliance (a USA DRR trade association), was inducted as the Operating Agent for Task XIII.

Demand response is the ability of electricity demand to respond to variations in electricity prices in "market" or "real" time. It can be achieved through load reductions or utilizing alternative onsite generation sources. Inclusion of Demand Response Resources (DRR) in energy markets can take

CONTACT US

Interested in learning more? You can contact the Operating Agent, Ross Malme, at ross.malme@retx.com. Ross is the President and CEO of RETX, an

Done Internet