Demand Response Resources in Pacific Northwest

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Overview

- Typology of DR resources
- Existing DR resource contribution: National Overview
- Existing DR resources in Pacific Northwest
- DR Market Potential: Conceptual approach and some results
- Issues and Next steps

Data Sources

- **FERC DR Survey (*April 2006*)**
  - **Includes time-varying tariffs and DR programs**
- **EIA-861 Survey (*October 2006*)**
  - **DR programs; but unclear if data for time-varying tariffs is included**
- **Literature review**
  - **PUC reports and presentations**
  - **Utility presentations/filings at state PUCs**
  - **Utility Annual Reports**
  - **Journal articles/Technical reports**

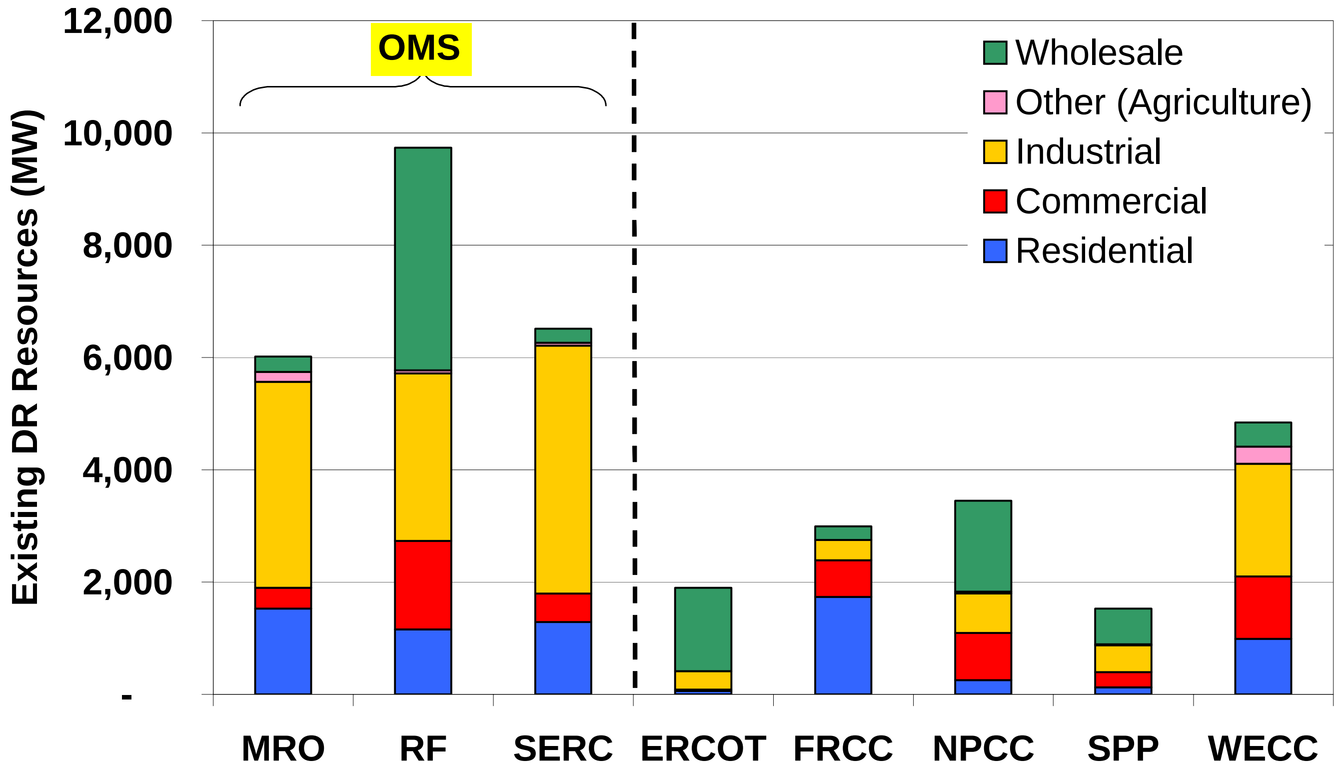
Demand Response Resources

- **Incentive-Based Programs**
  - Direct load control
  - Interruptible / curtailable rates
  - Demand bidding / buyback programs
  - Emergency demand-response programs
  - Capacity-market programs
  - Ancillary-services market programs
- **Time-Based Rates**
  - Time-of-use
  - Critical-peak pricing
  - Real-time pricing

Existing DR Resource Contribution: National Overview

- **DR Resources in 2005: 37,590 MW**
- **Summer 2006 Internal Peak Demand: 743,927 MW**
- **Existing DR resources as percent of U.S. peak demand: 5%**
- **Pacific Northwest utilities are part of WECC**

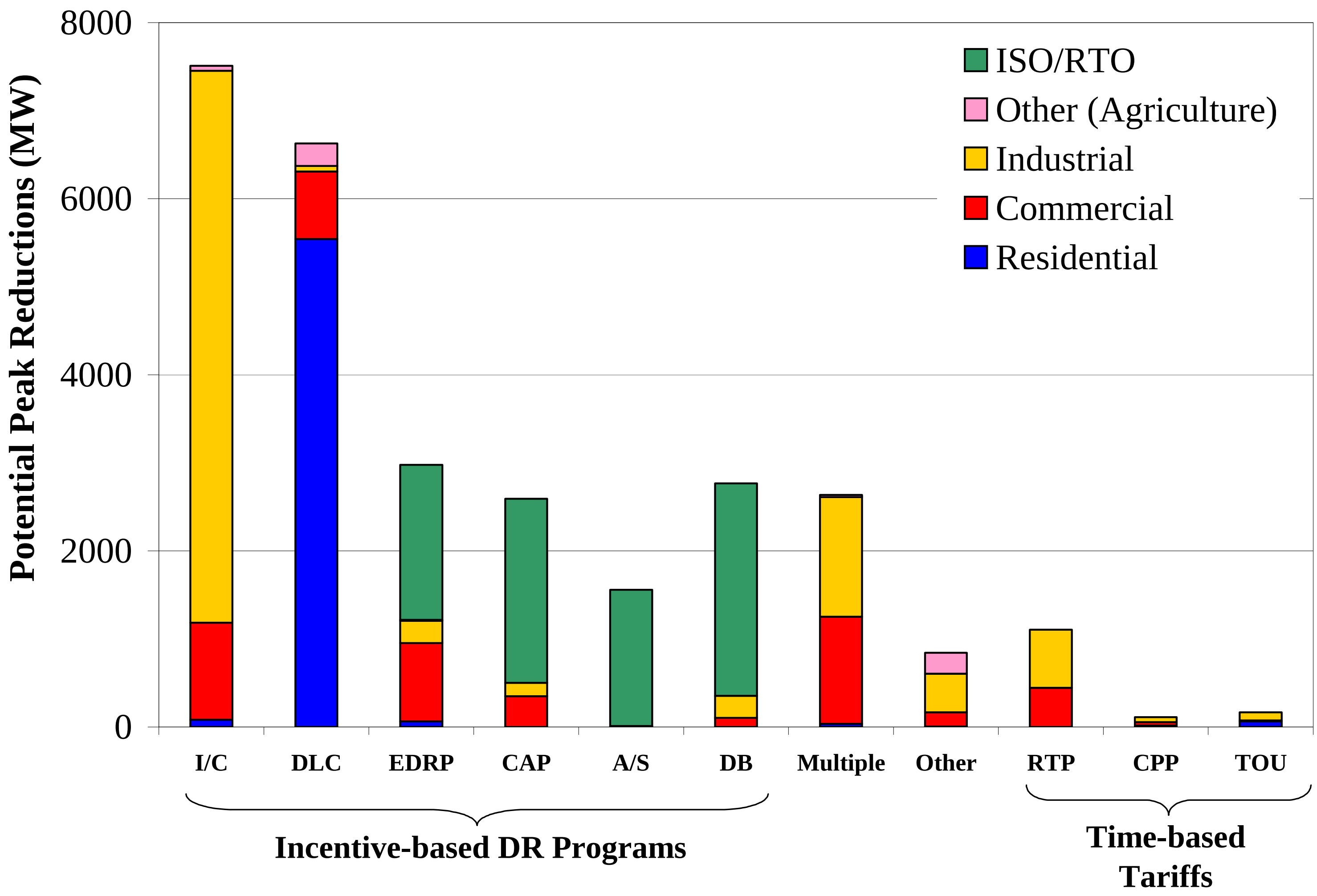
Existing DR Resources in the U.S.



As % of Summer 2006 Demand	MRO	RF	SERC	ERCOT	FRCC	NPCC	SPP	WECC
	20%	4%	4%	3%	7%	6%	4%	4%

Existing DR resources in WECC are close to national average

Existing DR Resources
by Type of Program

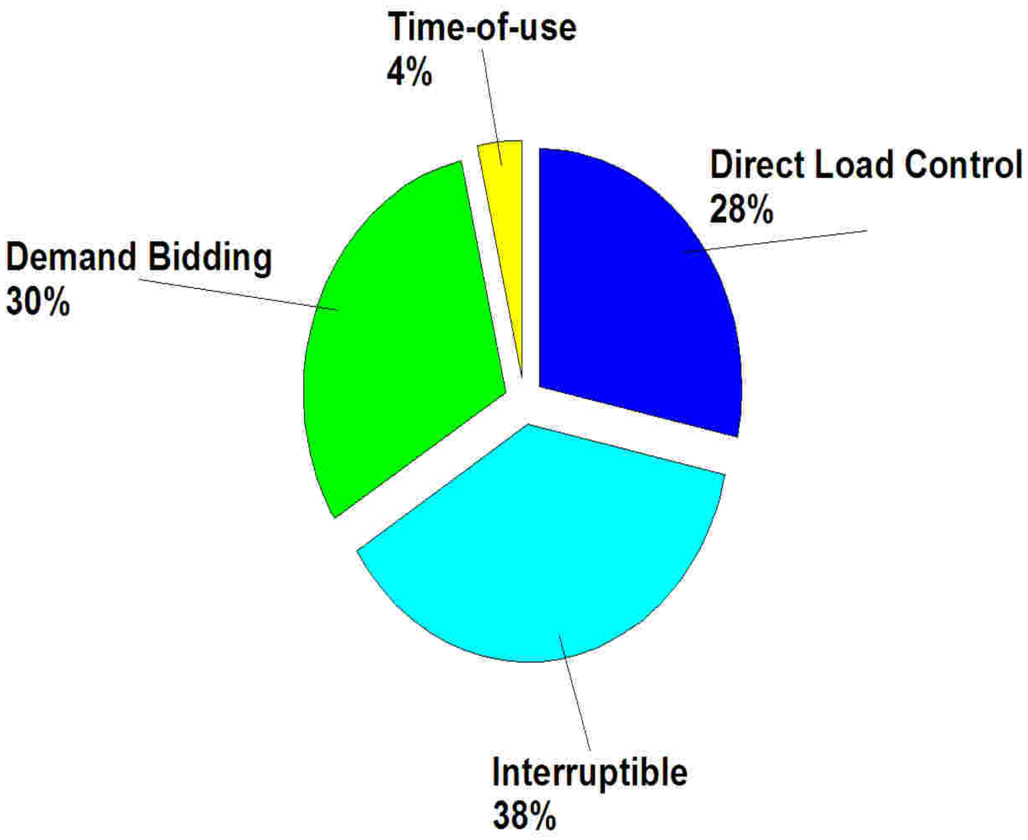


Pacific Northwest: Overview

- Peak Demand = 18,225 MW in 2005
  - 40% Res., 32% Comm., 23% Ind., 4% Irrigation
- Total DR resource ~720 MW
  - 4% of 2005 Peak Demand
- Largest Utility DR Programs:
  - Idaho Power
  - Pacificorp
  - Bonneville Power Authority (BPA)
  - Portland General Electric
  - Puget Sound Energy
- Several pilot programs offered in recent years
  - BPA partnership with Ashland, Olympic Peninsula, etc.

Existing DR Resources in Pac NW

- Direct Load Control ~200 MW
- Interruptible ~265 MW
  - Irrigation Load Control ~208 MW
- Demand Bidding ~214 MW
- Time-of-use ~25 MW
- Resource potential data are not available on several DR programs



Summer 2006 Experience

- PNW is typically a winter-peaking region
  - In 2006, summer peak demand was close to winter peak
- Extreme weather event July 21-24, 2006
  - Coincided with extreme weather in California
- Utilities in PNW managed to reduce between 165-250 MW of load
  - Idaho Power: 32 MW
  - PGE: 29 MW
  - Snohomish PUD: 10 MW
  - Chelan PUD: 10 MW
  - Pacificorp (? MW) – mainly in eastern part of service territory
- Lessons learned

Source: K. Corum, NWPCC (Aug 2006 memo)

Issue #1: Price-based DR often not reported as "resource"

- Utilities often DO NOT collect or provide data on potential reductions from customers enrolled in TOU or RTP tariffs – they report only number of customers enrolled
  - ~54,408 customers are enrolled in RTP, CPP, TOU tariffs (mostly residential)
  - In several cases, utilities report only that a time-varying tariff exists – but no other data
- DR Market Potential for time-varying tariffs can be estimated using several methods

One Approach for Estimating DR Market Potential: LBNL Study

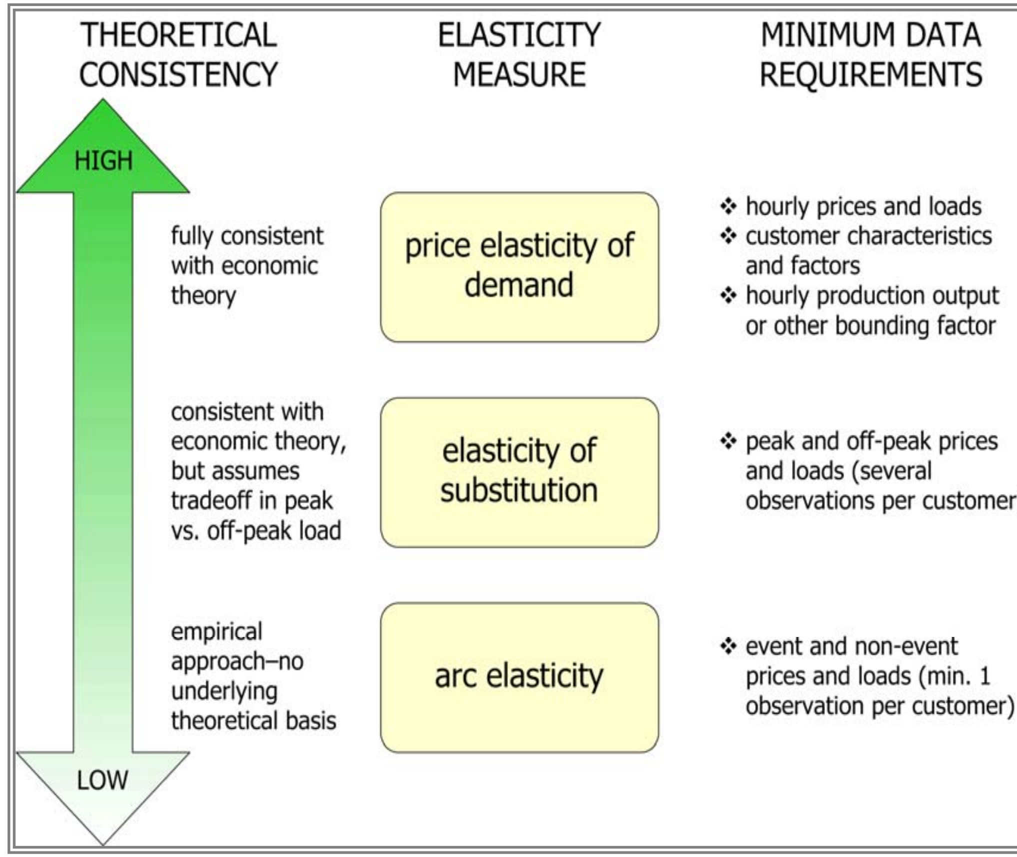
1. Establish study scope—identify target population and types of DR options considered
2. Customer segmentation—identify customer market segments
3. Estimate net program penetration rates—use available data to estimate customer enrollment in voluntary programs and exposure to default pricing programs
4. Estimate price response—develop elasticity estimates for various DR options, customer market segments, and factors found to influence price response
5. Estimate load impacts —use info from steps 2 to 4 to estimate the amount of DR that can be expected from the target customer population at utility at reference price (or incentive level).

DR Options Evaluated

DR Option	Description
Optional Hourly Pricing	Dynamic pricing tariff with bundled charges for delivery and commodity Offered on an optional basis by vertically-integrated utilities (usually) Typical rate design: two-part tariff with customer baseline load (CBL)
Default Hourly Pricing	Dynamic pricing tariff with unbundled distribution and commodity charges Offered as default service tariff in states with retail electric competition Commodity component: Hourly price indexed to a wholesale energy market (day-ahead or real-time)
Short-Notice Emergency Program	DR program that offers financial incentives for curtailing load when called on short notice (i.e., 1-2 hours) in response to system emergencies Customer response is voluntary; no penalties for non-performance
Price-Response Event Program	DR program that pays for measured load reductions when day-ahead wholesale market prices exceed a floor Some programs may include bid requirements and/or penalties
Critical-Peak Pricing	Dynamic-pricing tariff similar to a time-of-use rate, except that on “critical-peak” days a pre-specified higher price is effective for a specific time period

Selecting a Measure of Price Elasticity

- **Most studies of large customer price response estimate substitution or arc elasticities**
- **Substitution elasticity:**
  - **change in peak: off-peak usage in response to a 1% change in peak: off-peak prices**
  - **requires several observations per customer**



- **Arc elasticity:**
  - **% change in usage / percent change in peak price**
  - **Very easy to estimate, but limited explanatory power**

Average Elasticity Values

Customer Market Segment	*Demand Response Option*				
	Optional Hourly Pricing	**Default Hourly Pricing**	**Short-Notice Emergency Program**	**Price-Response Event Program**	**Critical-Peak Pricing**
Commercial/ retail	**0.01**	**0.06**	**-0.03**	**-0.09**	**-0.10**
Government/ education	**0.01**	**0.10**	**-0.02**	**-0.16**	**-0.06**
Healthcare	**0.01**	**0.04**	**-0.04**	**-0.05**	**-0.01**
Manufacturing	**0.26**	**0.16**	**-0.04**	**-0.16**	**-0.05**
Public works	**0.07**	**0.02**	**-0.08**	**-0.22**	**-0.08**

elasticity of substitution

arc elasticity

Participation Rates: Selected Values

Optional hourly pricing	Commercial/retail	*0%*	*2%*
	Gov't/education	*4%*	*25%*
	Manufacturing	*5%*	*25%*
Default hourly pricing	Commercial/retail	*11%*	43%
	Gov't/education	*10%*	42%
	Manufacturing	*8%*	33%
Short-notice emergency program	Commercial/retail	23%	20%
	Gov't/education	5%	9%
	Manufacturing	15%	23%
Price-response event program	Commercial/retail	1%	6%
	Gov't/education	3%	10%
	Manufacturing	10%	30%
Critical-peak pricing	Commercial/retail	3%	4%
	Gov't/education	4%	2%
	Manufacturing	4%	7%

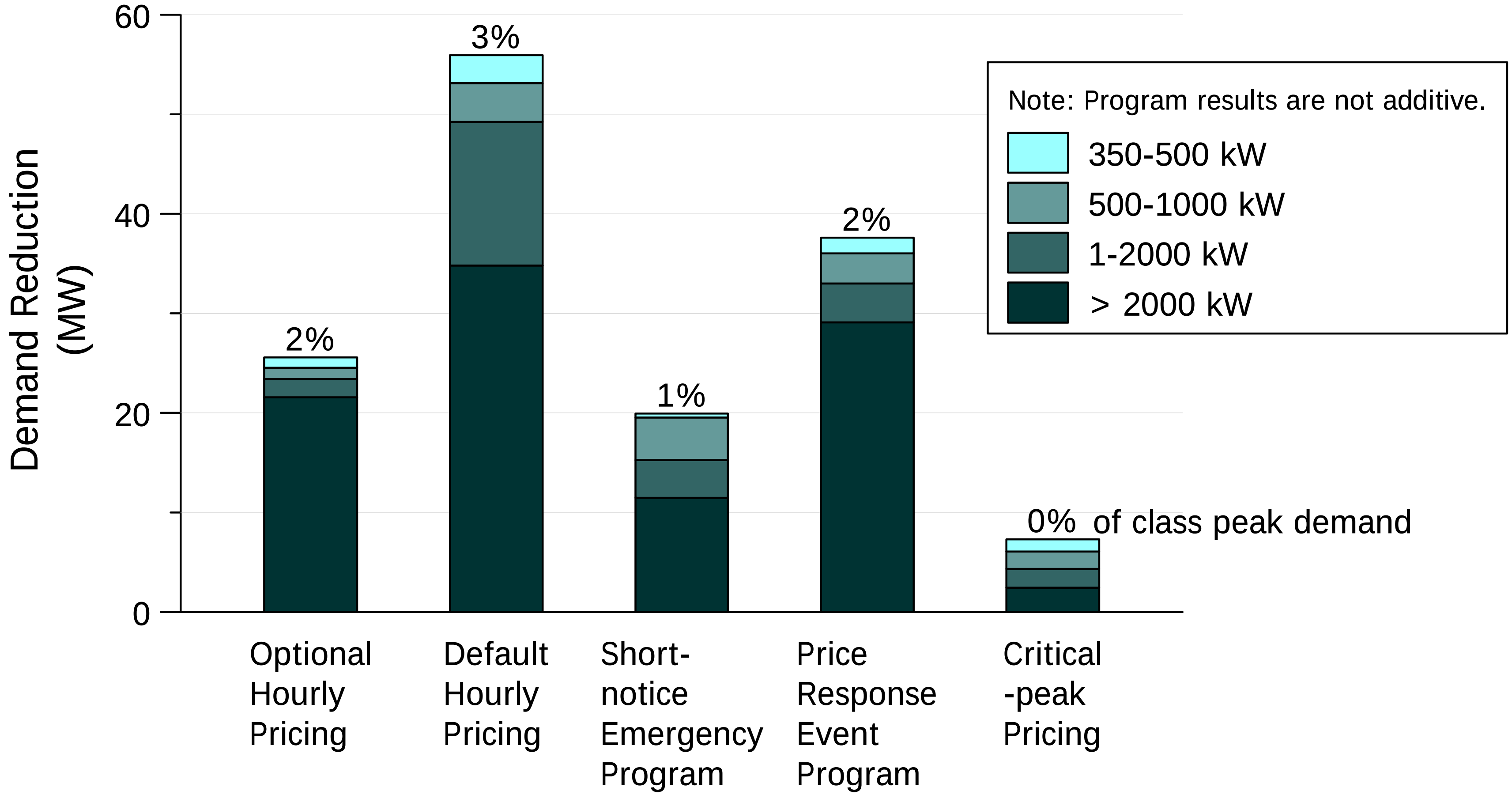
Red italicized values based on expert judgment

- **DR participation =**
  - **enrollment in voluntary programs/tariffs**
  - **retention on default pricing**
- **Participation rates collected for 5 market segments and 4 customer size groups**
- **Some data were not available—used "expert judgment" (red-italicized values)**

Putting it all together: Estimating Market Potential at utility in Northeast

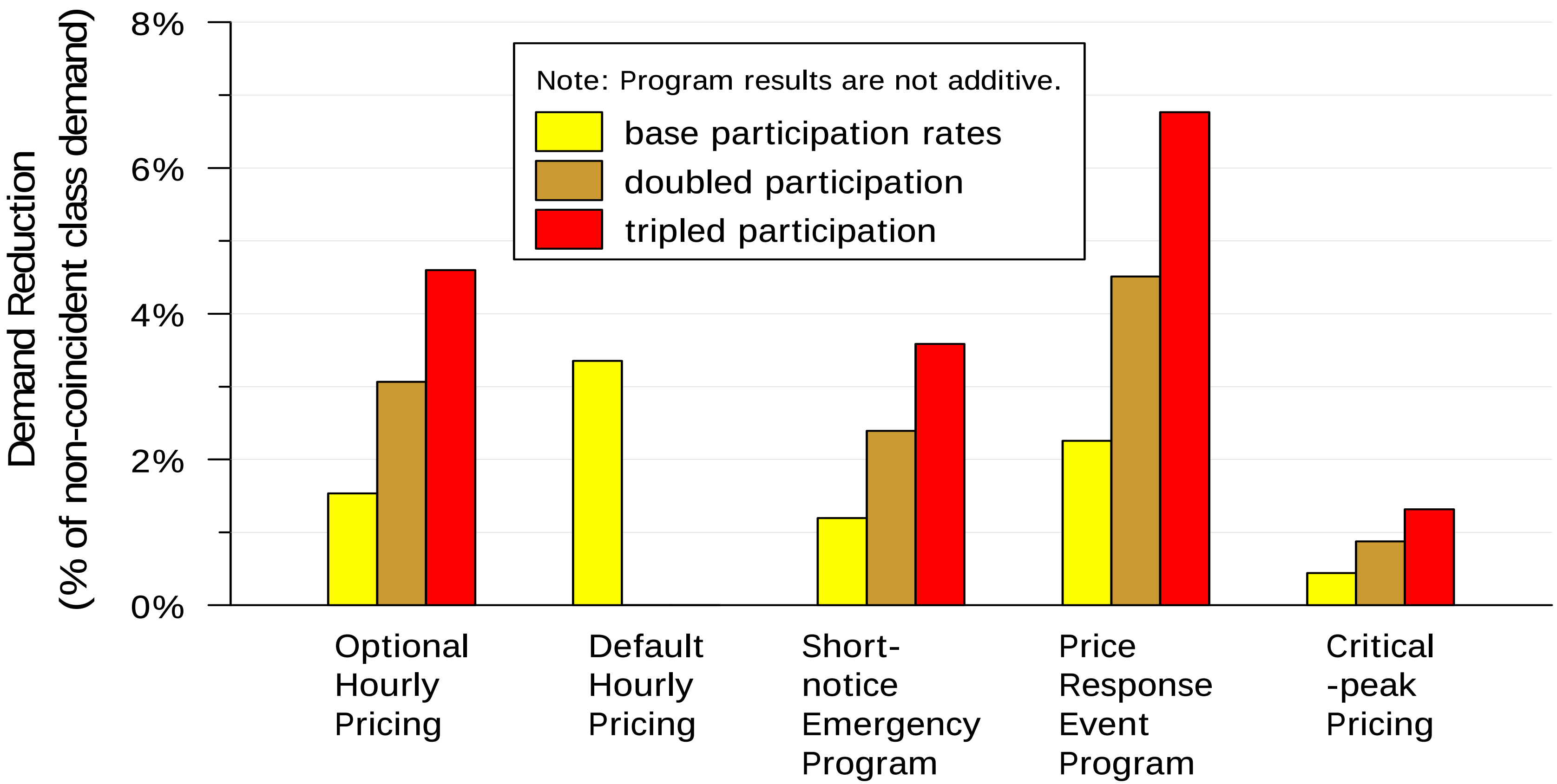
- Simulation: Demonstrate approach by estimating DR market potential at a Northeast utility
- Utility service territory characteristics:
  - Relatively small, urban utility
  - Peak demand of large non-residential customers is ~1700 MW (40% of utility's peak demand)
  - Mostly commercial/retail, gov't/education and healthcare facilities
  - Fewer manufacturing facilities than most suburban or rural areas
- Load impacts estimated assuming that RTP peak and DR "event" prices were $500/MWh
- Estimated DR market potential under several scenarios to illustrate effects of various factors (e.g., high participation rates, customer response at high prices)

Example: Large-customer DR Market Potential at a NE Utility



- **Base case results indicate market potential of up to 3% of class-peak demand for each DR option individually**
- **Largest customers (> 2 MW) provide bulk of load response**
- **Implicit Implication: necessary to target smaller customers too**

Impact of Program Participation Rates on DR Market Potential



- **With very aggressive marketing (i.e., 3x current participation rates), market potential for 3 DR options increases to ~3 to 7% of eligible large customers' peak demand at this utility (or ~75-165 MW)**

Summary of Findings:

- Simulation exercise provides "reasonable range" of DR market potential values of large non-residential customers for DR options
  - Note: load impact results are not additive
- Other analysts can use elasticity values (and participation rates) as starting point for market assessments for these five DR options
- Customer participation rates have largest impact on DR market potential estimates; but represent the largest data uncertainty
  - Need for more info on eligible target population
  - Drivers for participation
- Important to refine and disaggregate elasticity estimates for different groups of customers

Recent LBNL Reports on DR

- Estimating Demand Response Market Potential among Large Commercial and Industrial Customers: A Scoping Study,"

  – Charles Goldman, Nicole Hopper, Ranjit Bharvirkar (LBNL), Bernie Neenan, and Peter Cappers (Utilipoint), LBNL-61498, January 2007.

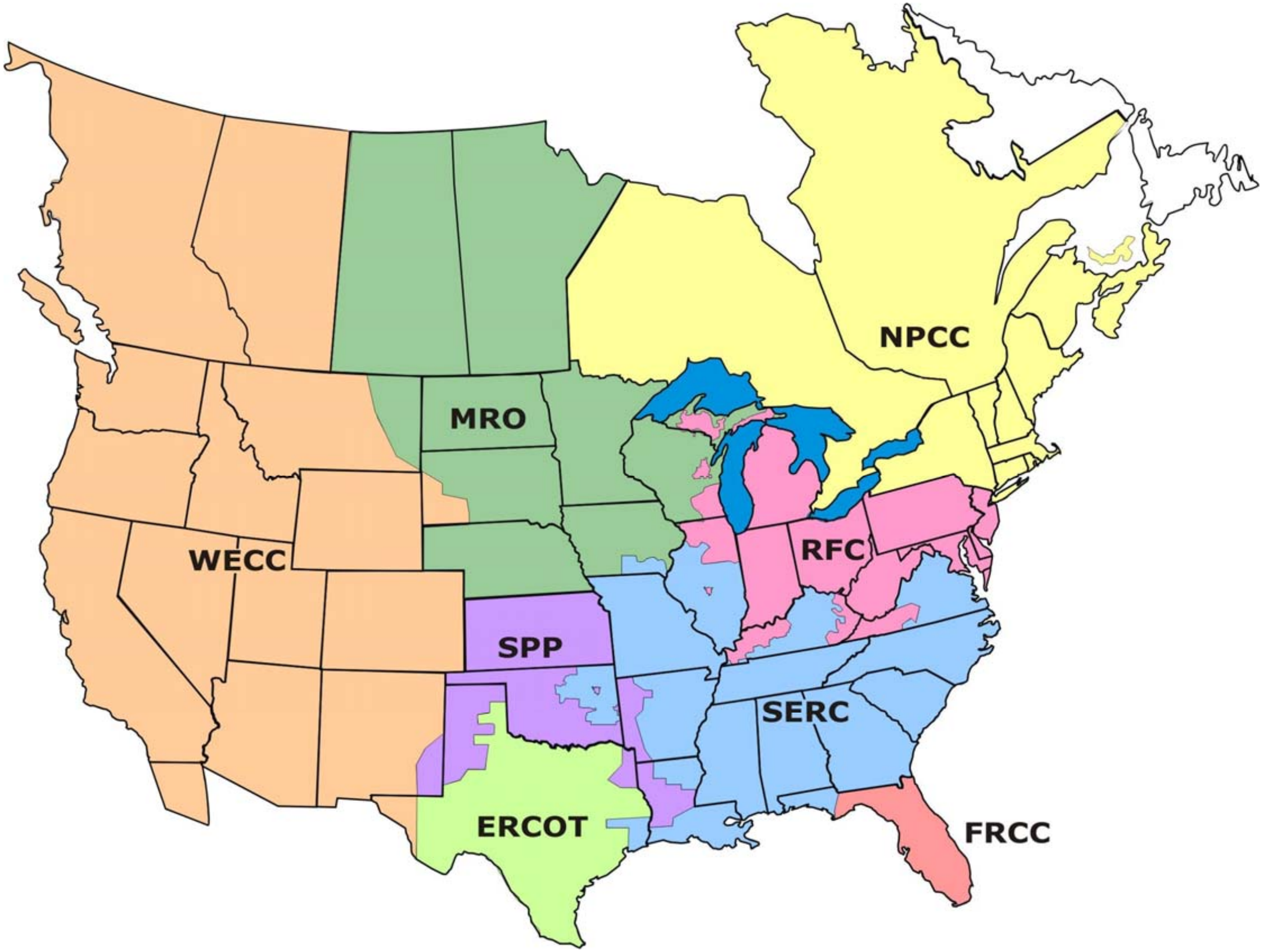
- "Summer of 2006: A Milestone in Ongoing Maturation of Demand Response"

  –N. Hopper, C. Goldman, R. Bharvirkar (LBNL) and D. Engel. *Electricity Journal* June 2007

Reports available at:
http://eetd.lbl.gov/ea/EMS

Background slides

NERC Regions



Idaho Power DR Programs

Program Name (2005 FERC data)	State	Customer Class	Potential Reductions (MW)	Actual Reductions (MW)	Enrolled Customers (Eligible)
A/C Cool Credit (DLC)	ID	Res.	183	3	2,369 (387,000)
Time-of-day Pilot (TOU)	ID	Res.			97 (5,000)
EnergyWatch Pilot (CPP)	ID	Res.		1.58 (average = 1.33)	80 (5,000)
TOU	ID	Ind.			118 (1,131)
Irrigation Peak Rewards	ID, OR	Irrigation	156	39.9 (average = 27.3)	895 service points or 254 customers
TOU	ID	Irrigation			124
TOTAL			339	45	3,042

Pacificorp DR programs

Program Name (2005 FERC data)	State	Customer Class	Enrolled (MW)	Actual Reductions (MW)	Enrolled Customers
Irrigation Load Control (I/C)	ID	Irrigation	52	35	734 pumps (15% of eligible)
Energy Exchange (DB)	ID, OR, WA		100	0-6.4	75
Residential TOU					22,000
TOTAL			152	41.4	809

BPA DR Programs

Program Name	State	Customer Class	Enrolled MW	Actual Reductions (MW)	Enrolled Customers
Olympic Non-Wires Demand Reduction Pilot	WA	Wholesale	27		
Demand Exchange	WA	Wholesale	90		
Ashland DLC	WA	R, C		Summer = 0.12 Winter = 0.25	100
Olympic Peninsula Demand Exchange	WA			22	
Olympic Peninsula DLC	WA		3		1,500
Columbia Basin Irrigation DLC	WA	Irrigation		4.2	
TOTAL			120	26.5	1,600

Portland General Electric DR Programs

Program Name (2005 FERC data)	State	Customer Class	Enrolled MW (Eligible)	Actual Reductions (MW)	Enrolled Customers (Eligible)
Dispatchable Stand-by Generation (I/C)	OR	Large	30		
Demand Exchange (DB)	OR	C&I	20		7
TOU	OR	R, C			1,841
RTP - Pilot	OR	I			87
CAP	OR	I			
Demand Buy-back	OR		3.5		
TOTAL			53.5		1,935

Puget Sound Energy

Program Name	State	Customer Class	Enrolled (MW)	Actual Reductions (MW)	Enrolled Customers
TOU	WA	R, C	25	5-6%	30,000

City of Milton-Freewater

Program Name (2005 FERC data)	State	Customer Class	Enrolled (MW)	Actual Reductions (MW)	Enrolled Customers
Voltage Reduction	OR	R, C	10	2	4,002
Radio Energy Mgmt System	OR	R	1	1	61
TOTAL			11	3	4,063