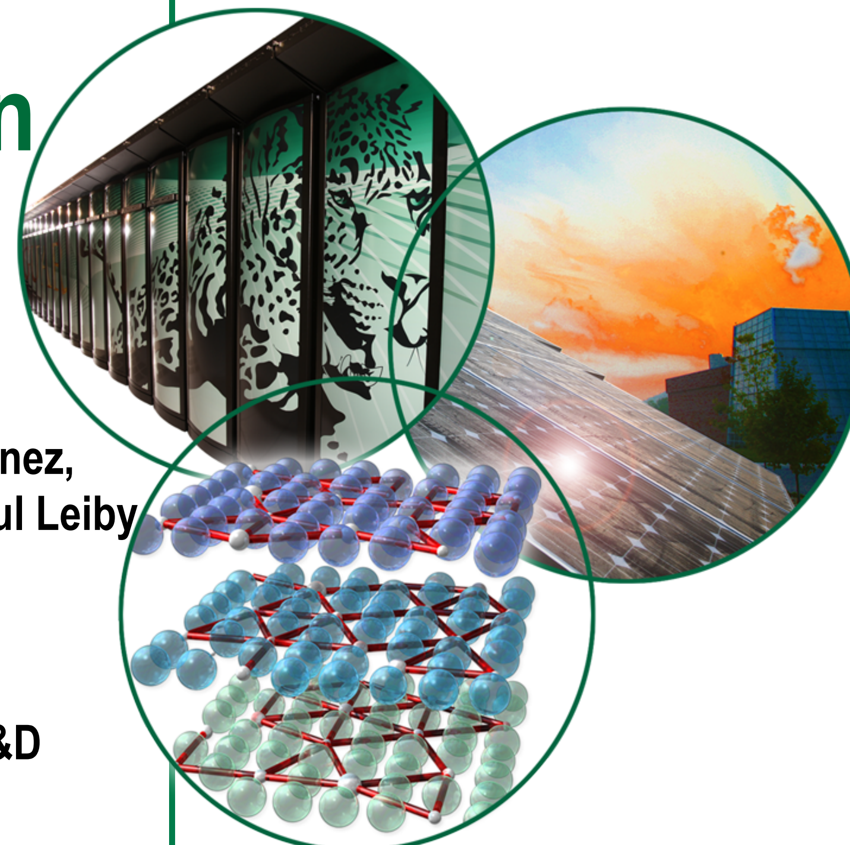
Demand Response Assessment for Eastern Interconnection



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FY12 DOE–CERTS Transmission Reliability R&D
Internal Program Review

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U.S. DEPARTMENT OF ENERGY

OAK RIDGE NATIONAL LABORATORY
MANAGED BY UT-BATTELLE FOR THE DEPARTMENT OF ENERGY

DOE National Laboratory Studies Funded to Support FOA 63

- DOE set aside $20 million from transmission funding for national laboratory studies.
- DOE identified four areas of interest:
  1. Transmission Reliability
  2. Demand Side Issues
  3. Water and Energy
  4. Other Topics
- Argonne, NREL, and ORNL support for EIPC/SSC/EISPC and the EISPC Energy Zone is funded through Area 4.
- Area 2 covers LBNL and NREL work in WECC and ORNL/Georgia Tech studies (DR and EE) for the Eastern Interconnection (EI).

Study Objective and Tasks for Area 2

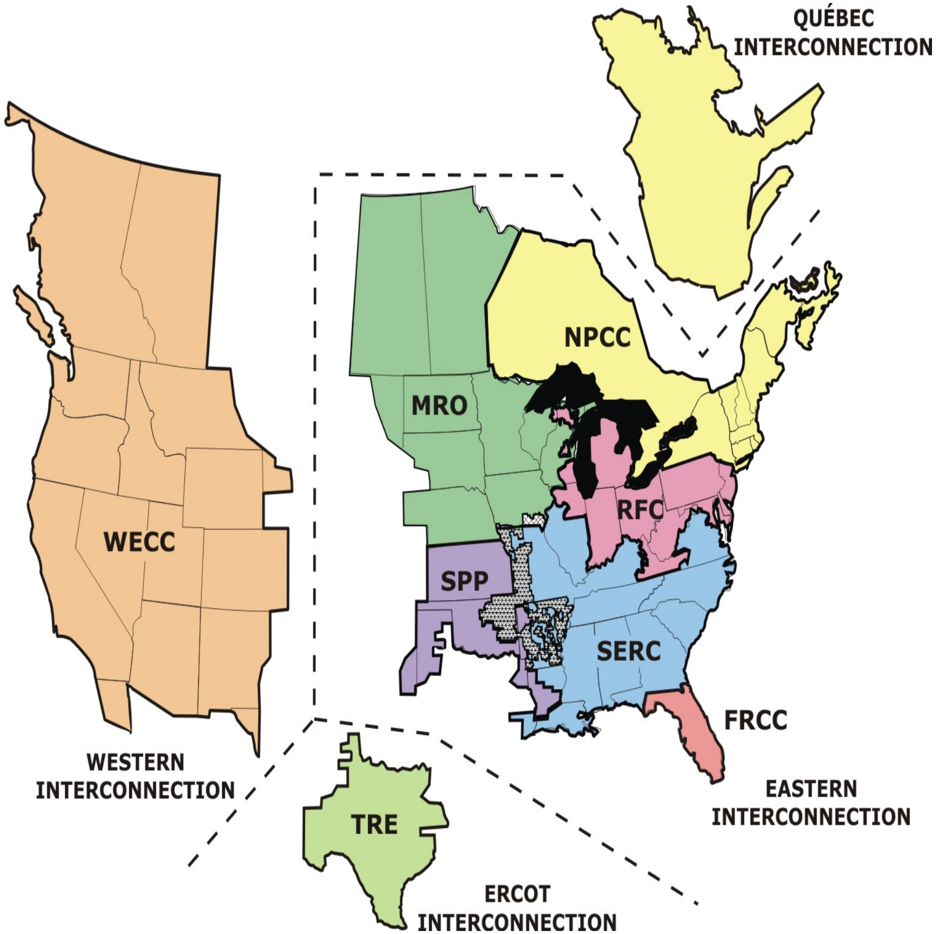
- **Objective: Estimation of Demand Response (DR) potential peak load reductions in EI to inform states and stakeholders for assessment of transmission infrastructure requirements**

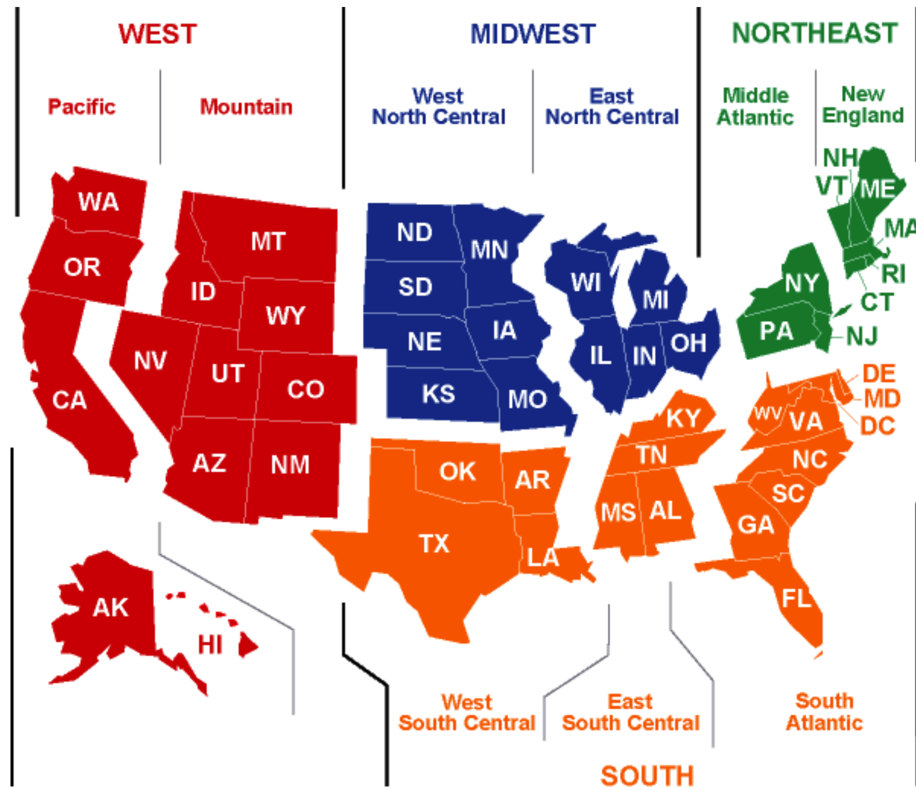
Tasks:

1. Review existing national DR studies and projections
2. Assess EI-DR potential with FERC's NADR model and Monte Carlo technique
3. Estimate costs for DR programs implementation and system impacts/benefits with ORCED model

- Update inputs
- Revise key assumptions and relationships
- Construct scenarios
- Conduct sensitivity analysis and stochastic simulations
- Report DR potential by census division and state

Our Reporting of EI Excludes West and Texas





Coverage of EI on NERC Map

Census Regions and Divisions

FERC's Original Efforts and ORNL's Improvements

- FERC contractors built the National Assessment of Demand Response (NADR) model to estimate DR potential.
  - The NADR model and analysis report were released in 2009.
  - NADR estimates future peak load impacts under DR participation assumptions.
- FERC has conducted bi-annual surveys of Demand Response and Advanced Metering (FERC-731) since 2006.
- ORNL updated the parameters, extended the projection period, and added algorithms to improve NADR.
  - ORNL used 2010 FERC-731 to update some primary parameters.
  - ORNL extrapolated the number of DR customers not reporting to FERC-731 and incorporated that number into NADR.
  - ORNL brought in other data sources (e.g., EIA, Brattle Group).

Types of DR Programs used by ORNL-NADR

- Pricing Programs – Customers are offered time-varying electricity rates on a prior-notice or real-time basis.
  – Rates are typically higher during peak hours.
  – Enabling Technologies, devices that automatically reduce customer load in response to price signals, may be combined with some pricing programs to enhance load impacts.

- Direct Load Control – Customers receive monthly compensation for allowing utilities to control their appliances, such as water heaters and central air conditioners.
  – This requires installation of special controller technologies upon appliances.

Types of DR Programs used by ORNL-NADR (cont.)

- **Interruptible Tariffs – Customers receive a reduced electricity rate or monthly compensation for agreeing to reduce their consumption by specified amounts upon utility's request.**
  - Typically, only medium and large-sized commercial and industrial customers may enroll in these programs.

- **Other – Medium and large-sized commercial and industrial customers are incentivized to reduce their load through various mechanisms.**
  - Examples include Demand Bidding, Capacity Bidding, Aggregator/ Curtailment Service Provider programs, and System Reliability Event programs.

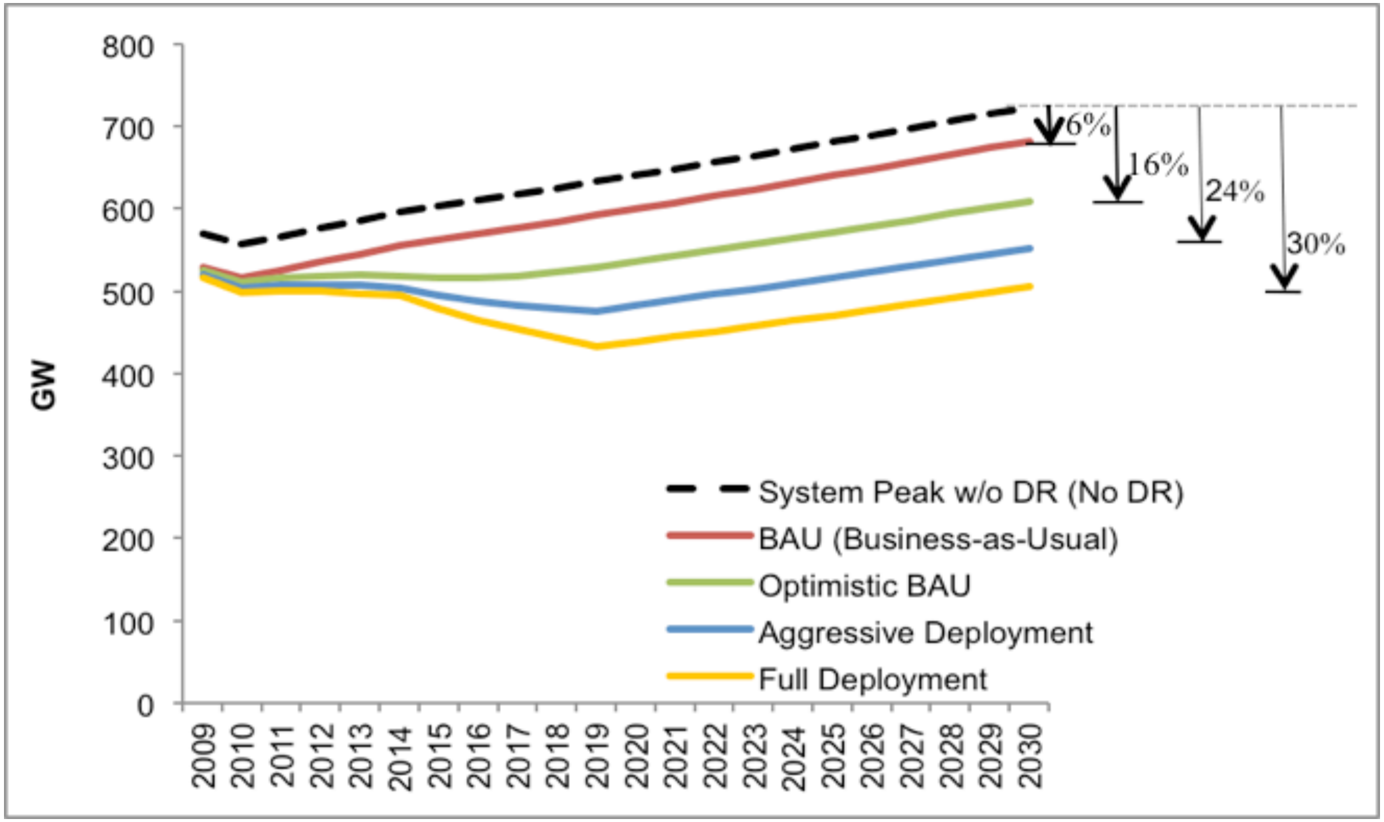
ORNL-NADR Scenarios and Key Factors

	BAU	Optimistic BAU	Aggressive Deployment	Full Deployment
AMI deployment	Partial deployment	Partial deployment	Full deployment	Full deployment
Dynamic pricing participation (of eligible)	Today's level	Voluntary (opt-in); 5%	Default (opt-out): 60 to 70%	Universal (mandatory) 100%
Eligible customers using enabling technology	None	None	57%	100%
Basis for non-pricing participation rate	Baseline level	Best practices estimate	Best practices estimate	Best practices estimate

Optimistic BAU: Impacts from Non-Reporting Entities

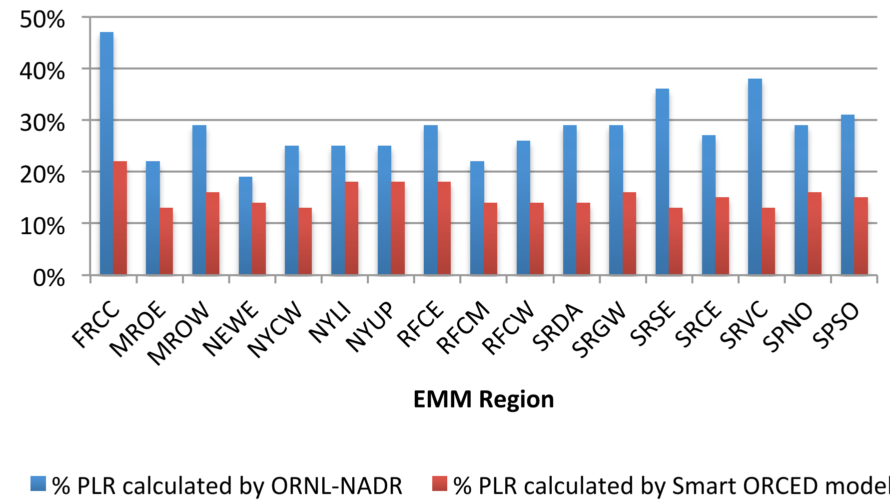
- Only 52% of all utilities returned data to FERC for the 2010 survey.
- Only 16% of all utilities reported DR programs.
- The ORNL conservative scenario (i.e., BAU) assumes that non-reporting utilities have no DR programs.
- The ORNL optimistic scenario assumes that non-reporting utilities have the same level of customer participation in DR as reporting utilities in the same group.
  - ORNL updated participation rates based on regressions using 2008 EIA and 2010 FERC survey data.

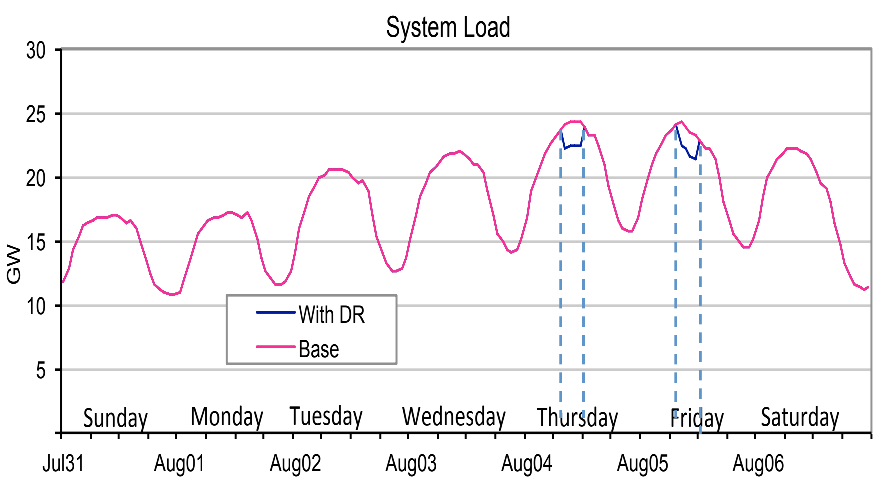
EI Summer Peak Demand Forecast by ORNL-NADR



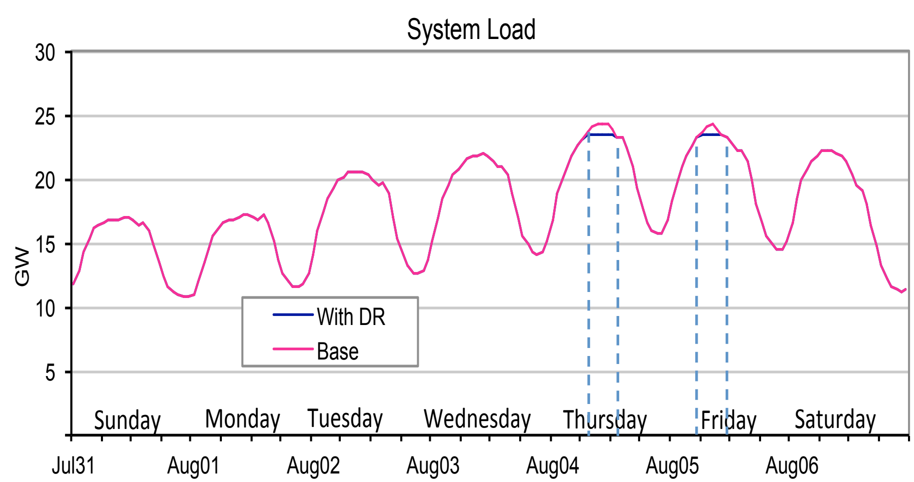
Limited Peak Hours for DR modeling and Possibility of Overestimation

- NADR assumes DR applies to 4 hours for top 15 days (limited 60 hours). At low DR penetration, the assumption works.
- However, at high DR penetration, it is a more realistic modeling to shave the peak load from the top and spread DR impact over more hours to clip peak.
- Therefore, the actual %PLR would be smaller than the %PLR calculated by ORNL-NADR.



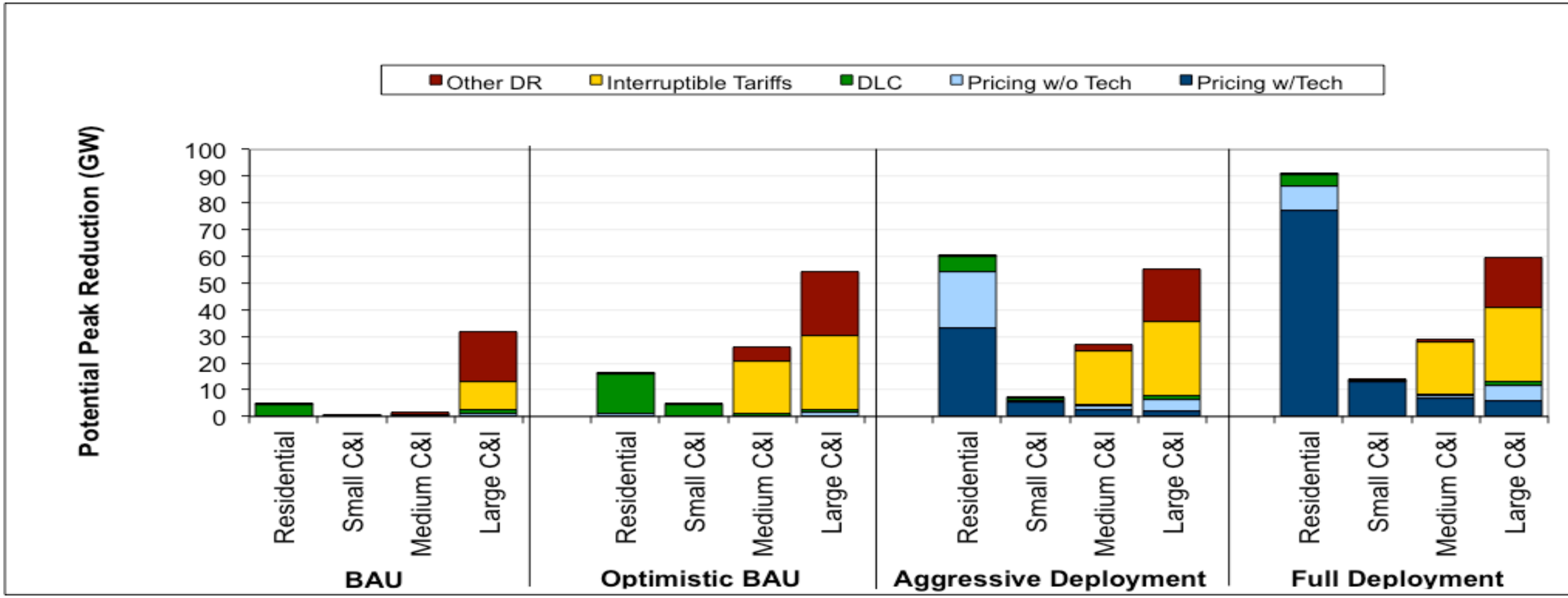


Notch DR modeling (ORNL-NADR)



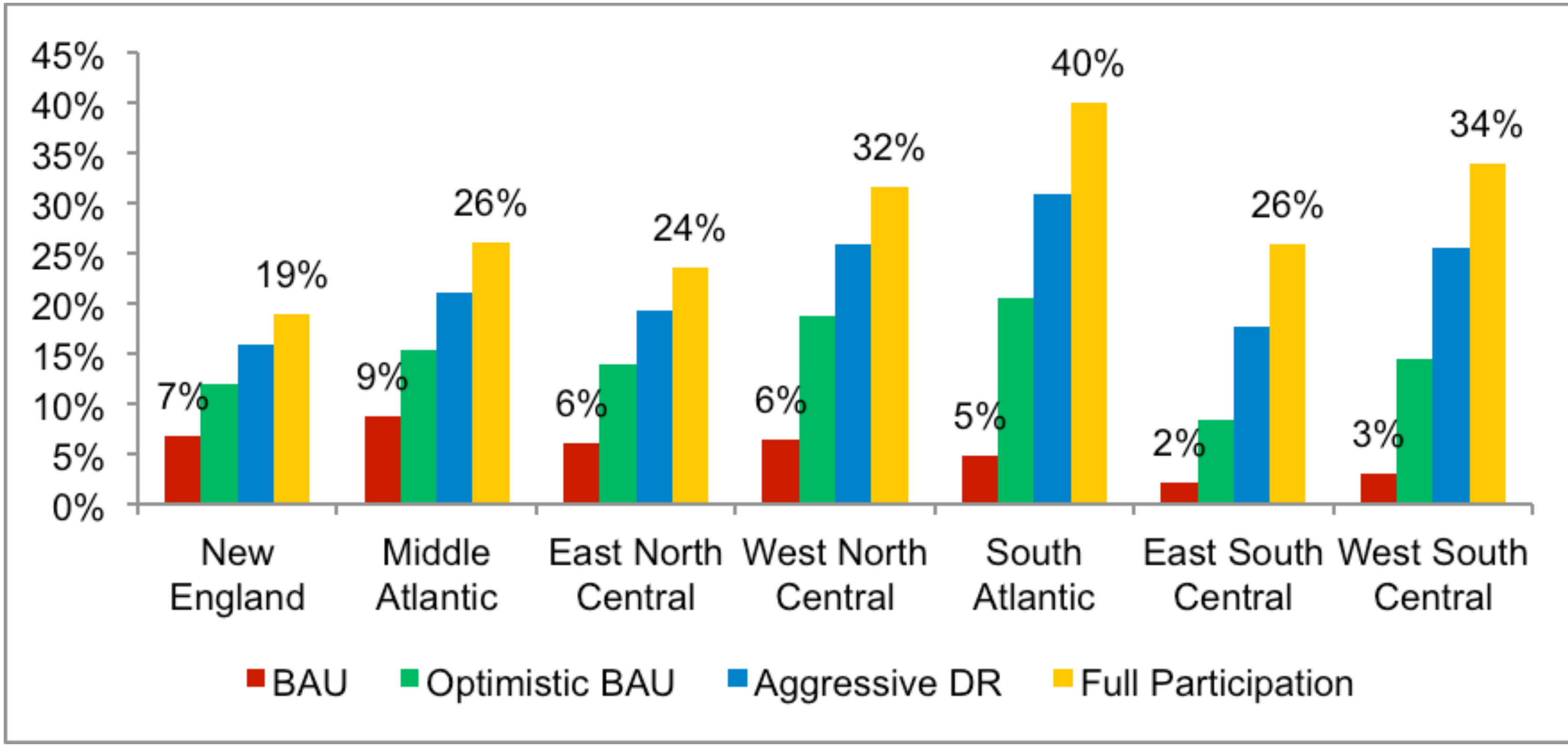
Smart DR modeling (Smart ORCED model)

Potential Peak Reduction from Demand Response in EI, 2030



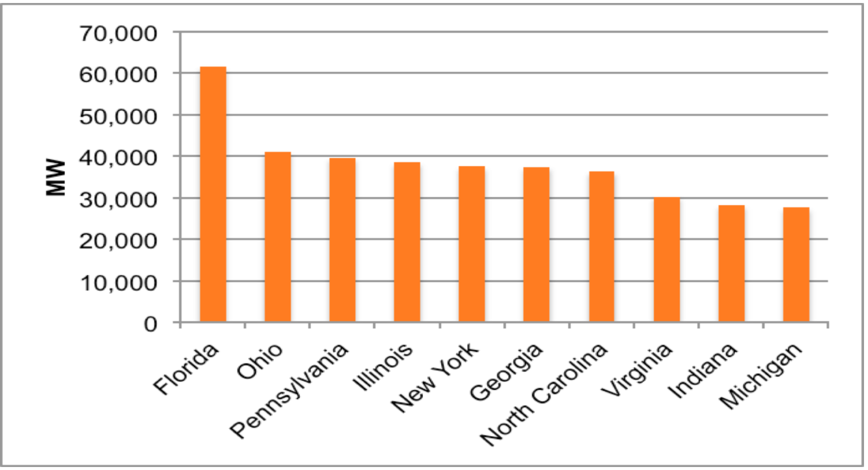
- Under BAU and optimistic BAU, the largest gains through interruptible tariffs and other DR
- A significant growth in pricing programs (with and without enabling technologies) is noticed under the Aggressive and Full Deployment scenarios.
- DLC has a significant impact in the residential and small C&I sectors.
- The majority of DR comes from large C&I customers primarily through interruptible tariffs and capacity and load bidding.
- In the residential sector, most untapped potential for DR comes from the pricing programs.

Demand Response Potential by Census Division and Scenario, 2030

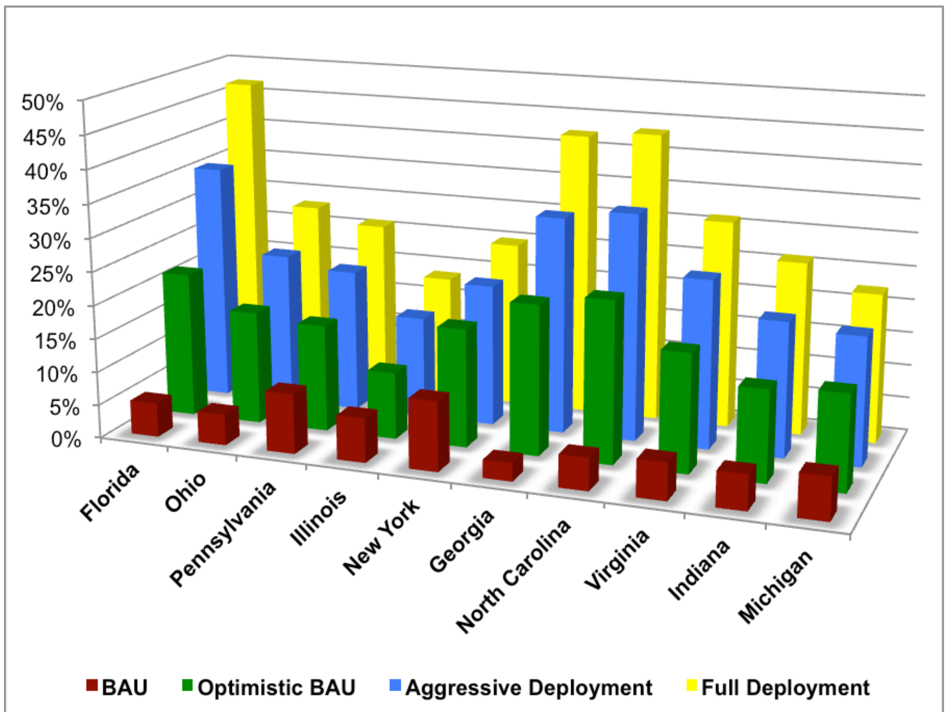


- **The regions show the largest existing (BAU) impacts have both wholesale demand response programs and utility/load serving entity programs.**
- **Central air conditioning saturation plays a key role in determining the magnitude of the Aggressive and Full Deployment demand response potentials.**

Top 10 states in System Peak in 2030



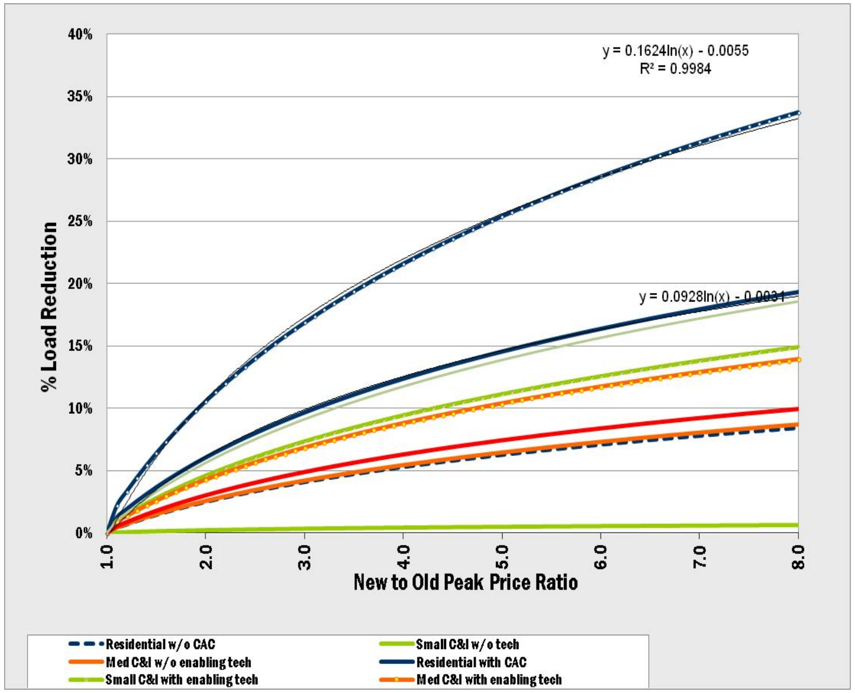
- **FL does not have the highest penetration of demand response, though it is the number-one state in system peak.**
- **PA and NY have actively deployed high levels of demand response to cope with their high system peak demand.**

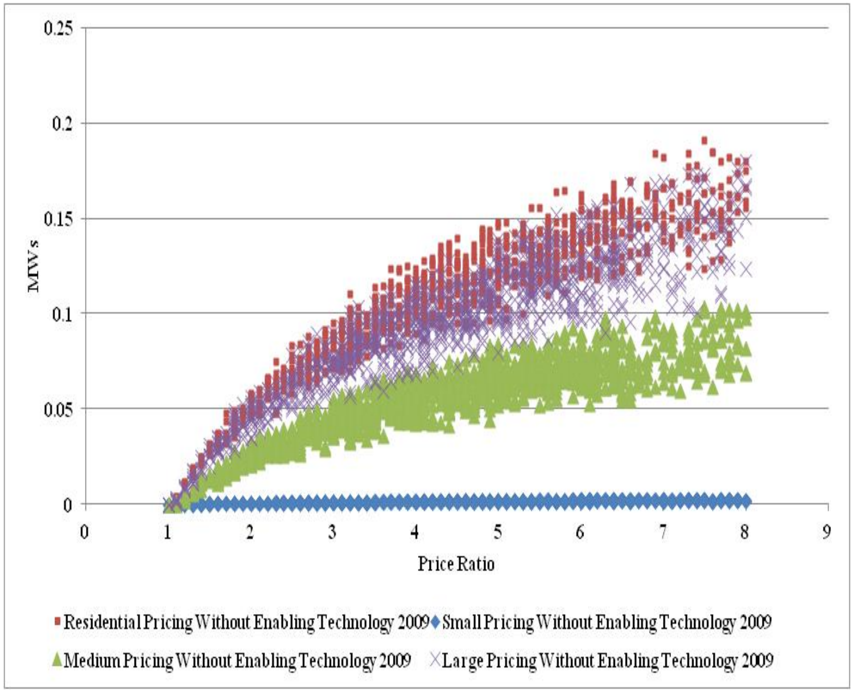


Top 10 States in System Peak (Y-axis: % Peak Load Reduction)

Monte Carlo Simulation for Pricing Programs

- Stochastic simulation for the impact of dynamic pricing programs
  - Allow random variation of previously fixed values for key parameters to improve modeling of peak price elasticity





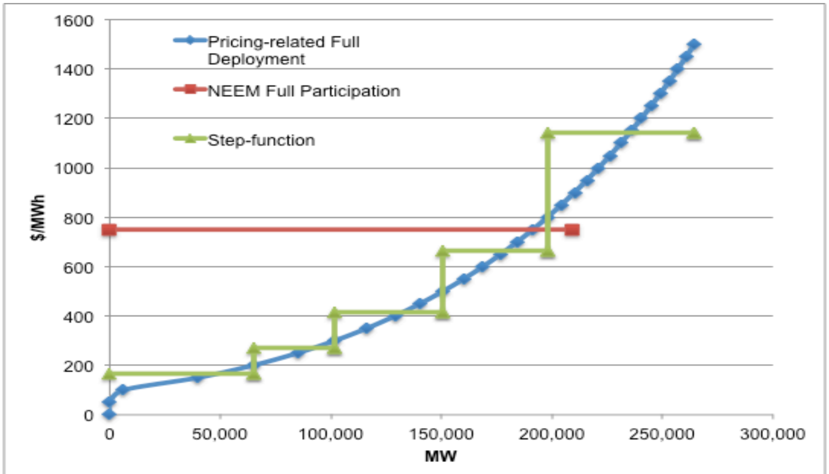
POTENTIAL LOAD REDUCTION FROM DYNAMIC PRICING PROGRAMS (MAINE, 2019) – An example of Monte Carlo simulation results

Monte Carlo Simulation for Pricing Programs (Cont.)

- **An Example Result for Full Deployment Scenario, 2030**

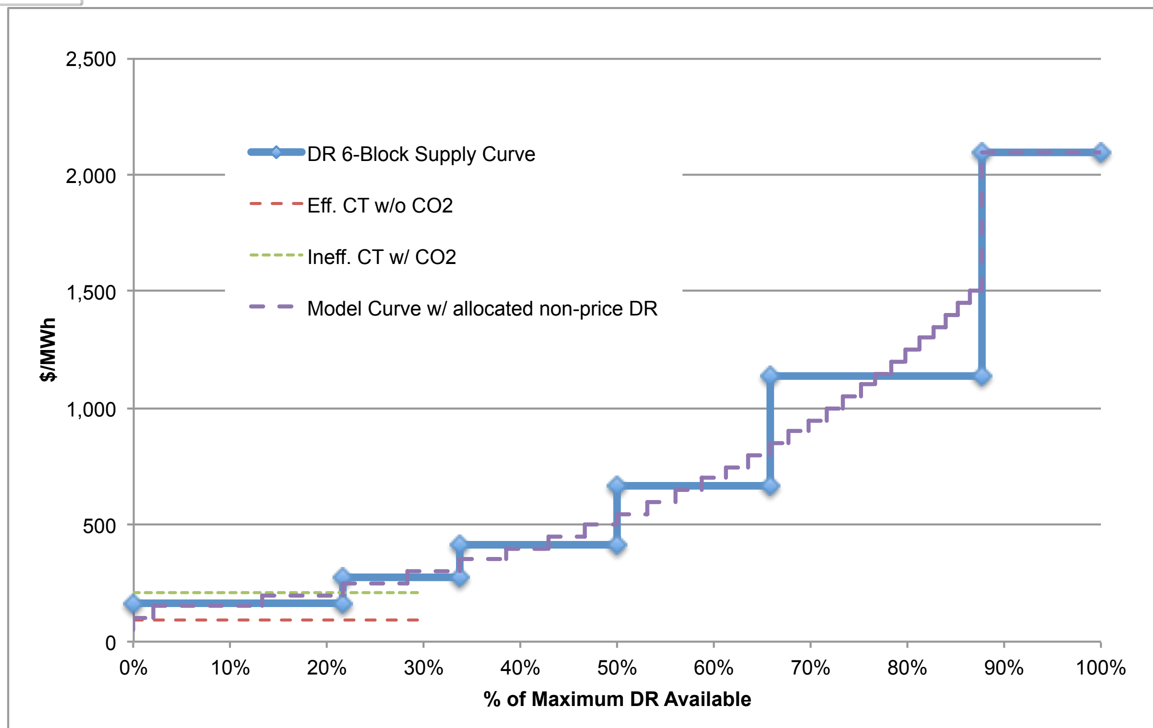
	Ratio of CPP to Ave. Price	Mean (GW)	Lower (GW)	Upper (GW)
Pricing with Enabling Technology	5	52	41	64
	10	78	60	93
	15	94	74	118
Pricing without Enabling Technology	5	33	27	40
	10	49	40	57
	15	59	47	73

Demand Response Supply Curve for EIPC Study



5-Block Supply Curve Only with Pricing Programs in 2030

6-Block Supply Curve and Model Curve with Allocated Non-Pricing DR in 2030



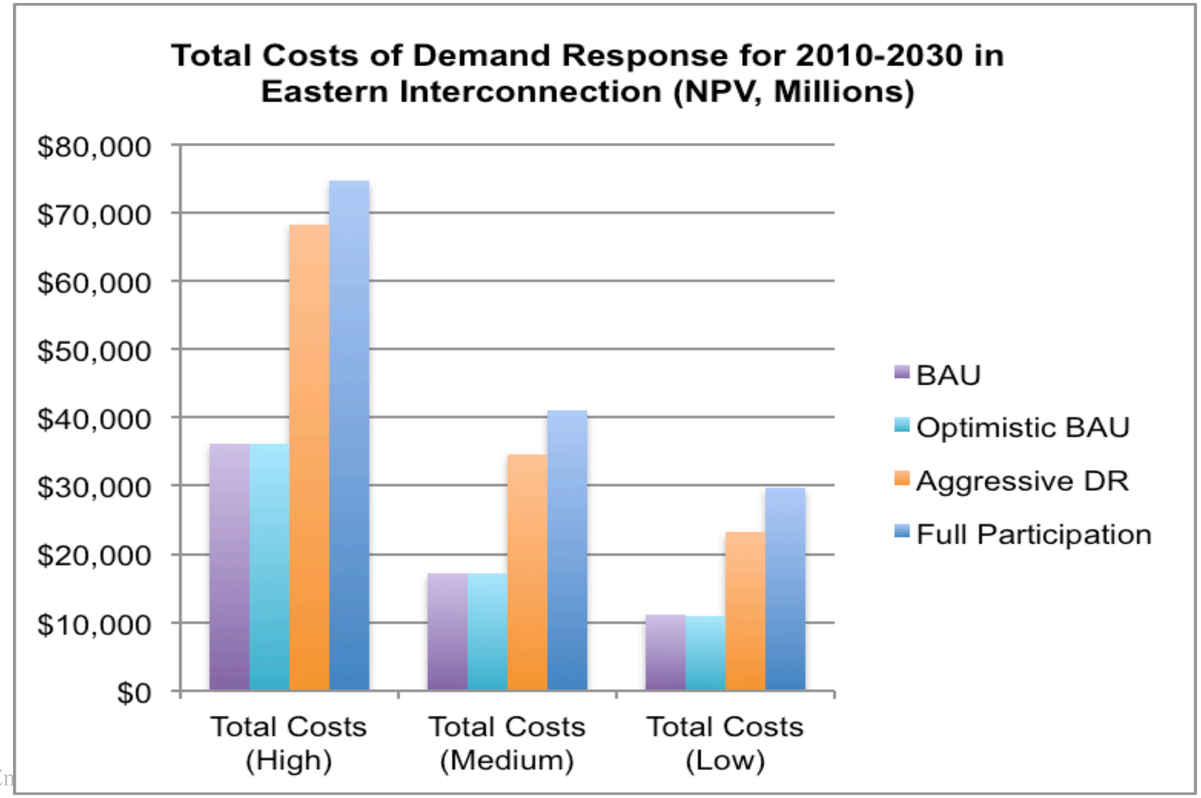
DR Cost Analysis

- DR is tied to Advanced Metering Infrastructure (AMI).
  - AMI is necessary to enable many DR programs.
  - The NADR model uses AMI deployment to proxy DR participation.
- ORNL reviewed data on AMI deployment costs and utility AMI deployment plans
- ORNL incorporated industry learning and economies-of-scale into cost calculations.

Cost Estimates

Estimated Cost-per-Meter of Various AMI System Component ($)

Scenario	Meters	IT Systems	Communications Network	Deployment Management	Annualized AMI O&M
High	243	65	66	81	23
Medium	190	27	43	63	7
Low	129	11	11	28	4

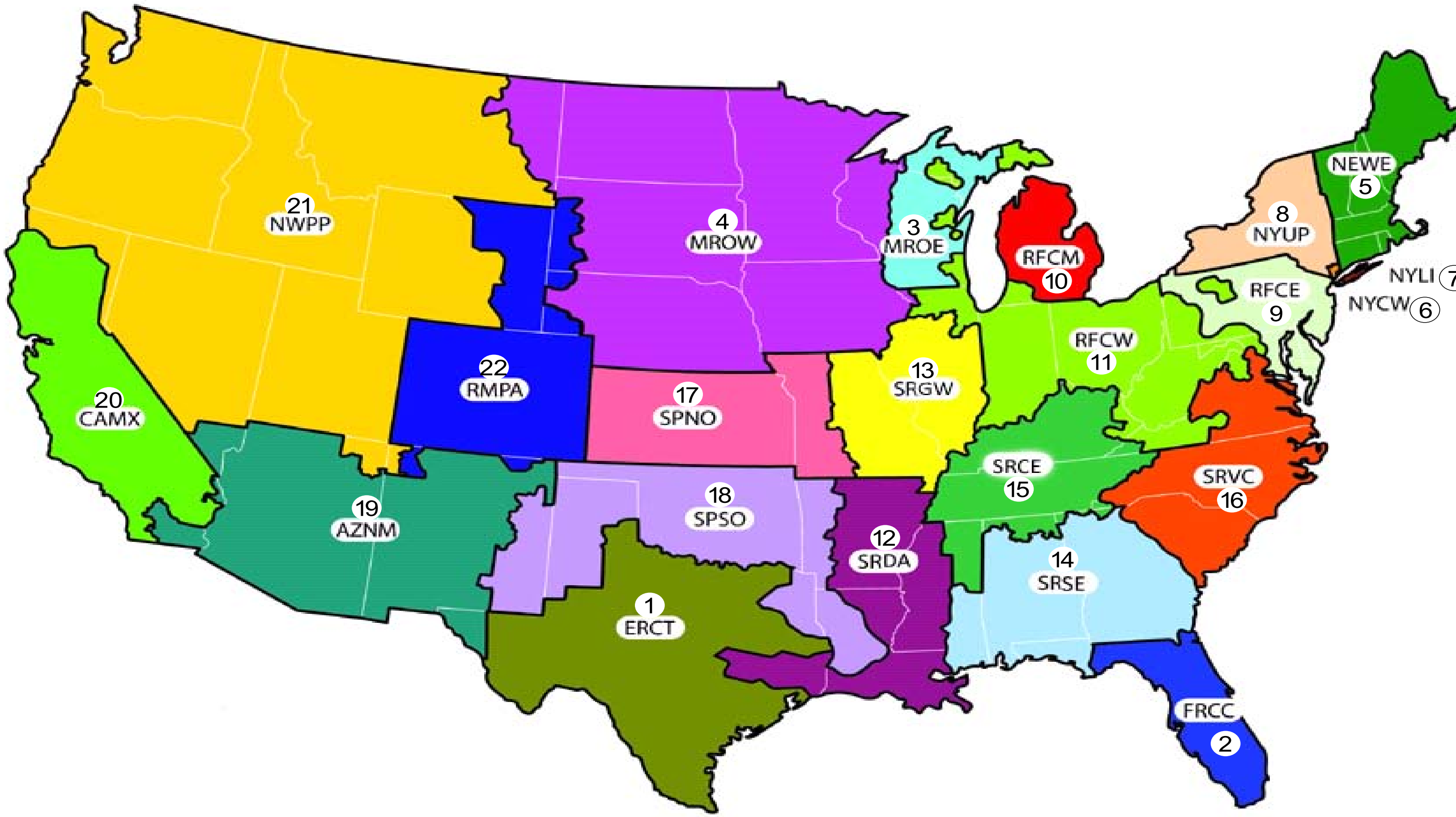


Demand Response (DR) Benefits

- Oak Ridge Competitive Electricity Dispatch (ORCED) model simulates regional dispatch of generation to meet demand.
- With the reductions in demand during peak hours, ORCED calculates changes in generation and unserved energy, price, cost, and greenhouse gas emissions of utilities.
- DR benefits include:
  – System peak impact
  – System reliability impact
  – Reduced system costs
  – Environmental benefits

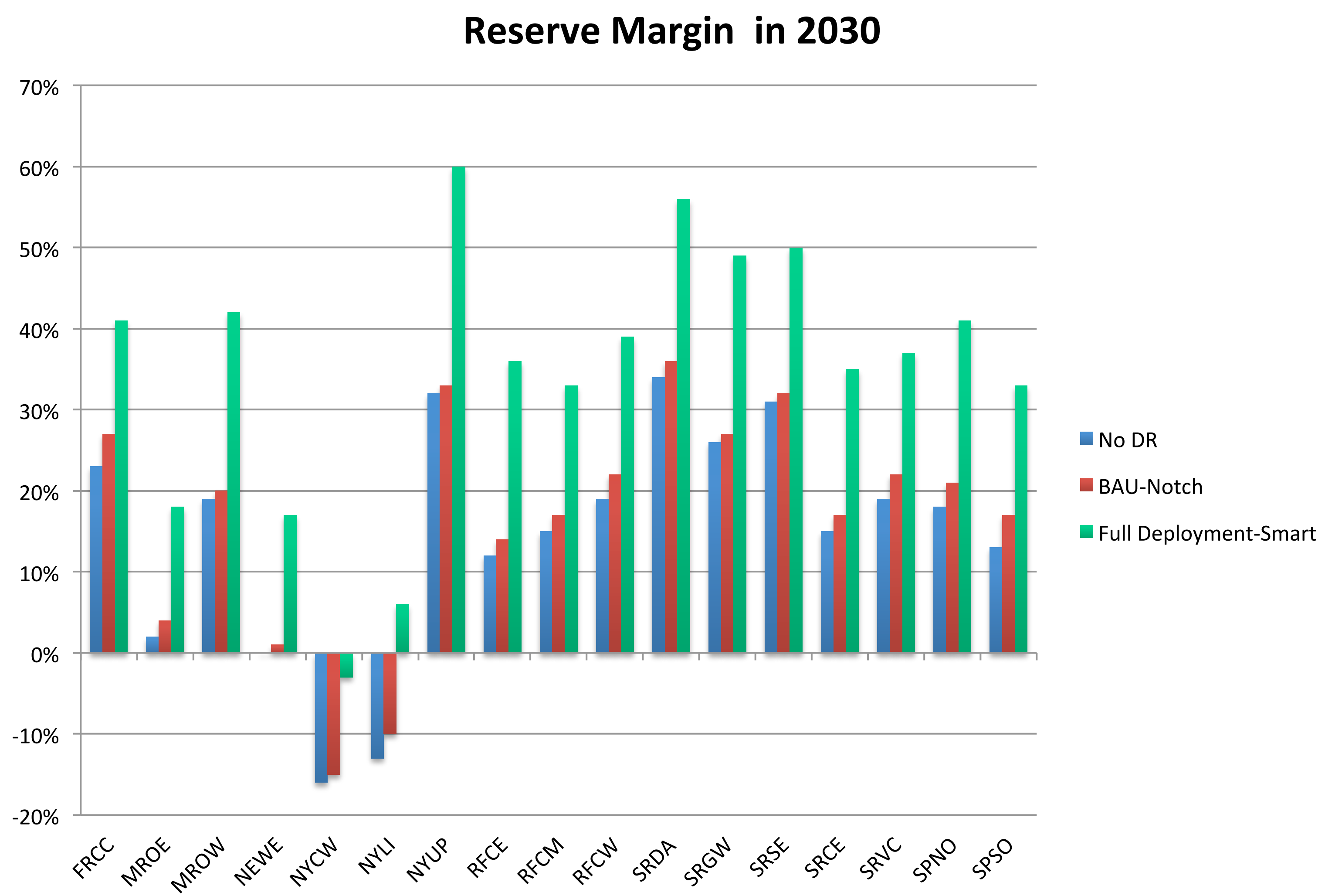
DR Benefit Case	Regional % Peak Load Reduction
No DR (Reference Case)	0%
DR-Notch-BAU	1 – 10% (Ave. 5%)
DR-Smart-BAU	1 – 10% (Ave. 5%)
DR-Smart-Optimistic BAU	8 – 22% (Ave. 15%)
DR-Smart-Aggressive Deployment	16 – 35% (Ave. 23%)
DR-Smart-Full Deployment	19 – 47% (Ave. 30%)

Geographical Classification for Benefits Analysis



EIA's Electricity Market Module Regions

Impact on System Reliability



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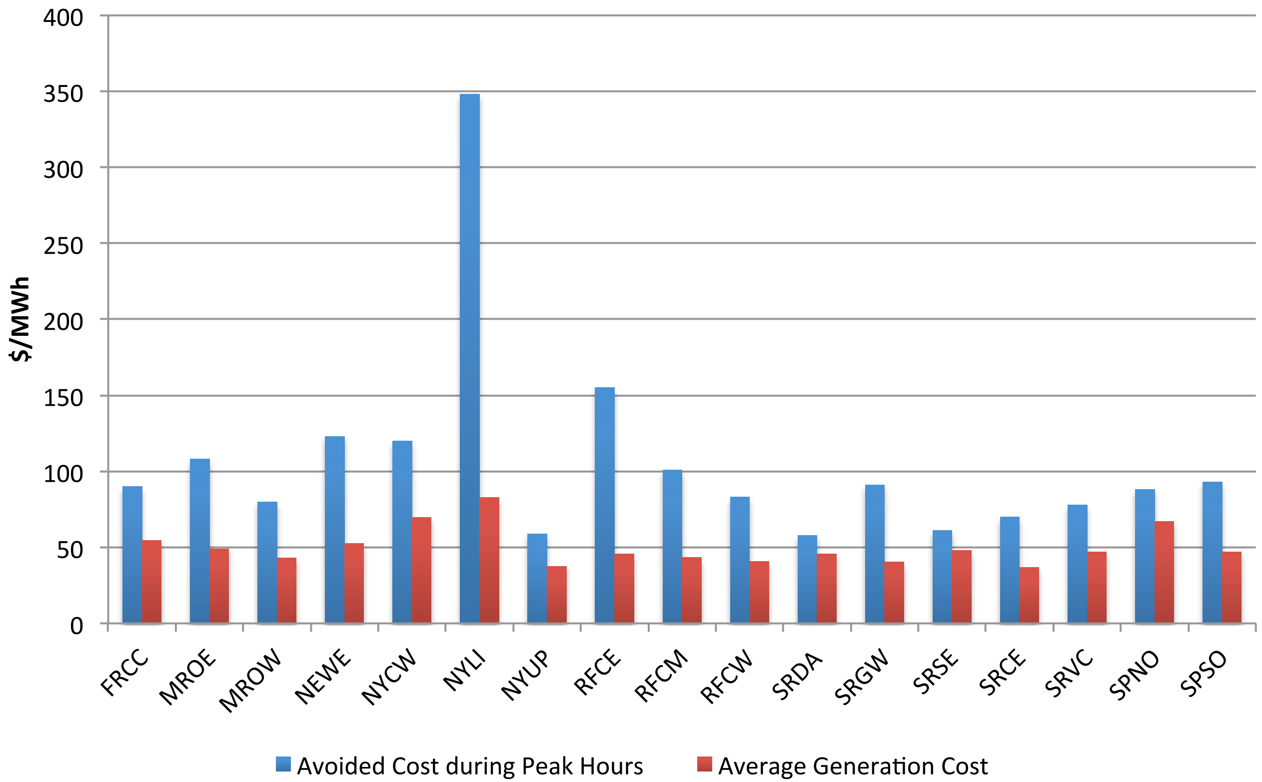
Change in Cost by DR



- **Other factors reported such as change in reserve margins, average cost, and CO_2 emissions**

Future Research Directions

- Revise DR program participation rates
- Investigate demand reduction potential at the program and appliance level
- Update econometric estimation of load profiles for each state and customer type
- Investigate duration and timing of DR programs

Contact information for Further Discussions

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