ORNL/TM-2012/303

Eastern Interconnection Demand Response Potential

November 2012

Prepared by

Youngsun Baek[1]
Stanton W. Hadley[1]
Rocío Uría-Martínez[2]
Gbadebo Oladosu[2]
Alexander M. Smith[1]
Fangxing Li[1]
Paul N. Leiby[2]
Russell Lee[2]

[1] Power and Energy Systems Group, Oak Ridge National Laboratory
[2] Energy Analysis Group, Oak Ridge National Laboratory

ORNL/TM-2012/303

Power and Energy Systems Group

EASTERN INTERCONNECTION DEMAND RESPONSE POTENTIAL

Young Sun Baek
Stanton W. Hadley
Rocio Uria-Martinez
Gbadebo Oladosu
Alexander M. Smith
Fangxing Li
Paul N. Leiby
Russell Lee

Date Published: November 2012

Prepared by
OAK RIDGE NATIONAL LABORATORY
Oak Ridge, Tennessee 37831-6283
managed by
UT-BATTELLE, LLC
for the
U.S. DEPARTMENT OF ENERGY
under contract DE-AC05-00OR22725

CONTENTS

Page

LIST OF FIGURES

Figure **Page**

LIST OF TABLES

Table **Page**

GLOSSARY

AEO	Annual Energy Outlook
AGC	Automatic Generation Control
AMI	Advance Meter Infrastructure
AMR	Automated Meter Reading
AD	Aggressive Deployment (ORNL-NADR Scenario)
AP	Achievable Participation (Original NADR Scenario)
BAU	Business As Usual
C&I	Commercial and Industrial
CAC	Central Air-Conditioning
CES	Constant Elasticity of Substitution
CIS	Customer Information System
CPP	Critical Peak Price
CT	Combustion Turbine
CPUC	California Public Utilities Commission
DADS	Demand Response Availability Data System
DLC	Direct Load Control
DOE	Department of Energy
DR	Demand Response
EBAU	Expanded Business As Usual (Original NADR Scenario)
OBAU	Optimistic Business As Usual (ORNL-NADR Scenario)
EE	Energy Efficiency
EI	Eastern Interconnection
EIPC	Eastern Interconnection Planning Collaborative
EISA	Energy Independence and Security Act
EISPC	Eastern Interconnection State Planning Council
ELCON	Electricity Consumer Resource Council
EMM	Electricity Market Module
EPRG	Electric Policy Research Group
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FD	Full Deployment (ORNL-NADR Scenario)
FP	Full Participation (Original NADR Scenario)
GIS	Geographic Information System
GW	Giga-Watt
ISO	Independent System Operator
IOU	Investor-Owned Utility
LDC	Load Duration Curve
LMP	Locational Marginal Price
LOLP	Loss of Load Probability
LSE	Load-Serving Entity
LTRA	Long Term Reliability Assessment
MDMS	Meter Data Management Systems
MISO	Midwest Independent System Operator

MW	Mega-Watt
MWG	Modeling Working Group
NADR	National Assessment of Demand Response (model)
NEEM	North American Electricity and Environment Model
NEMS	National Energy Modeling System
NERC	North American Electric Reliability Corporation
NPV	Net Present Value
NPVRR	Net Present Value revenue Requirements
ORCED	Oak Ridge Competitive Electricity Dispatch (model)
ORNL	Oak Ridge National Laboratory
PCT	Programmable Communicating Thermostat
PG&E	Pacific Gas & Electric
PLC	Power Line Carrier
PLMA	Peak Load Management Alliance
PLR	Peak Load Reductions
PMO	Program Management Office
PRISM	Pricing Impact Simulation Model
REC	Rural Electric Cooperative
RF	Radio Frequency
RTO	Regional Transmission Operator
RTP	Real Time Pricing
SGIC	Smart Grid Information Clearinghouse
SGIG	Smart Grid Investment Grant
SSC	Stakeholder Steering Committee
TOU	Time of Use
TRC	Total Resource Cost
TWh	Tera-Watt Hours

ACKNOWLEDGMENTS

Funding for this research was provided by the Department of Energy (DOE) under the direction of David Meyer. The sponsorship is greatly appreciated.

Bob Pauley of Eastern Interconnection States Planning Council (EISPC) contributed meaningfully to the communications with EISPC and Navigant and the completion of this report.

Valuable comments on earlier drafts of this report were received from Greg Wikler (EnerNOC), Andy Satchwell (Lawrence Berkeley National Laboratory) and Nasr Alkadi (ORNL).

The authors are grateful for the willingness of these individuals to engage in a dialogue about the potential to expand demand-response resources in the Eastern Interconnection Area. Any errors that survived this review process are strictly the responsibility of the authors.

EXECUTIVE SUMMARY

Demand response (DR), one of the key components in the Smart Grid initiative, has received increasing interest in recent years among power utilities, independent system operators, and policy makers. With this surge of interest in DR, in April 2010 the Department of Energy (DOE) issued a research call to provide technical support to the interconnection-level electric infrastructure planning projects they had issued earlier in the year. In Area of Interest 2, they identified a need/purpose: "The Eastern Interconnection States' Planning Council (EISPC) seeks to significantly improve the knowledge base and modeling capabilities of demand-side resources for purposes of transmission planning." In response to the research call, Oak Ridge National Laboratory (ORNL) conducted a research project to estimate the DR potential peak load reductions in the Eastern Interconnection area over the next two decades until 2030, as well as analyzed costs and benefits occurring out of the DR resources. This final report is the outcome of the study by a team of ORNL researchers with diverse backgrounds in engineering, economics, and public policy.

Ahead of quantitative analyses, an extensive review of existing DR assessments and projections from various sources was conducted. Then, four different DR deployment scenarios were developed: 1) Business-As-Usual (BAU), 2) Optimistic BAU, 3) Aggressive Deployment, and 4) Full Deployment. These scenarios varied in program participation rate, percentage of eligible customers, and scale of Advance Metering Infrastructure (AMI). The DR programs were classified into four different categories: pricing programs, direct load control (DLC), interruptible tariffs, and other DR programs. Based on the National Assessment of Demand Response (NADR) model developed by Federal Energy Regulatory Commission (FERC), the system peak demand by state and census division was forecasted. Key inputs and assumptions were updated with the latest data collected by FERC, Brattle Group, Energy Information Administration (EIA), and North American Electric Reliability Corporation (NERC). In addition, new equations considering the stochastic characteristic of the demand response programs were developed as an extension of the NADR model and the updated model was named ORNL-NADR. The detailed ORNL-NADR specifications and scenario definitions are presented in Chapter 4.1.

Regional and state-level results of demand response potentials within the EI system are presented and analyzed in this report.[3] Further, this report presents the analyses and results of the costs and benefits associated with demand response programs. The Oak Ridge Competitive Economic Dispatch (ORCED) model was used for the benefit analysis.

The unique contributions of this report can be summarized as follows:

1. Latest data from DR program surveys are used for this study;

2. Regression analysis is employed to address the issues related to the non-responding utilities in FERC's DR-AMI survey;

3. Monte Carlo simulation is employed to analyze the stochastic nature of the dynamic pricing program in terms of consumers' responsiveness to changes in peak to off-peak price ratios; and

4. Full-scale analyses of DR costs and benefits are conducted in this study.

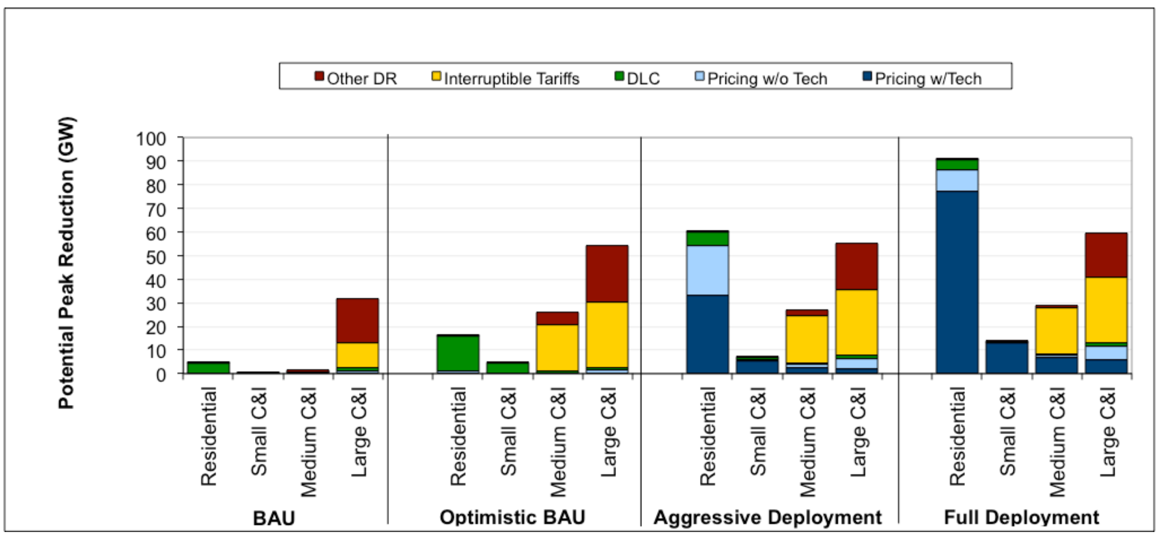
[3] For detailed information, regional analysis is presented in Chapter 5.4 (Regional Result Profiles) and State-by-state results are provided in Appendix B.

The major findings for EI are:

- System peak demand of EI begins at 569 GW in 2009 and grows at an average annual growth rate of 1.2%, reaching 724 GW by 2030 under no DR assumption. Peak demand under BAU grows at a very similar rate overall. The reduction in peak demand under BAU, relative to the No DR forecast is 41 GW by 2030 representing a 6% of peak demand. The Optimistic BAU scenario results in a further reduction in peak demand of 114 GW (16%). The Aggressive Deployment scenario produces reduces the peak demand in 2030 by 24% (171 GW). The Full Deployment scenario produces the largest reduction of 219 GW (30%) in 2030.

- The DR reduction amounts are limited in the number of hours they are available over a year, according to FERC's NADR model. At higher DR penetration rates, the system peak load reduction will be smaller than the percentages shown because the DR resource will be spread over more hours rather than concentrated at pre-fixed peak hours.

- According to 2030 DR potential analysis by scenario, program type, and end-use sector, under BAU and Optimistic BAU, the largest gains come 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 commercial and industrial (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.



Potential Peak Reduction from Demand Response in EI, 2030

- Regionally, Middle Atlantic (9%) and New England (7%) have the highest estimates in terms of percentage peak load reduction under the BAU scenario in 2030. On the other hand, regions in the South such as East South Central (2%) and West South Central (3%) show relatively small existing programs possibly because they have historically had few DR programs.

- Central air conditioning saturation plays a key role in determining the magnitude of the Aggressive and Full Deployment demand response potentials. Regions that have hotter climate requiring high central air conditioning systems (such as the South Atlantic, East South Central, and West South Central Divisions) could achieve greater average-per-customer impacts from DLC and dynamic pricing programs. As a result, these regions tend to have larger overall potential under the Aggressive and Full Deployment scenarios where pricing programs play a more significant role than in the BAU and Optimistic BAU scenarios.

- Our Monte Carlo simulation varied the peak to off-peak price ratios for dynamic pricing programs. Table 6 in Chapter 5.2 presents the summary statistics from these simulations for three price ratios (5, 10 and 15). The contribution from dynamic pricing to the peak load reduction without enabling technology varies substantially in the range between 27 and 73 GW in the Aggressive Deployment scenario. The contributions from dynamic pricing without technology in the Full Deployment scenario are about half those in the Aggressive Deployment scenario. The results for pricing with technology programs show that the demand response are similar to those from the case without technology program under the Aggressive Deployment scenario (41 GW to 118 GW), but much larger under the Full Deployment scenario (101 GW to 276 GW).

- Using total resource cost test framework, we estimated the net present value (NPV) of DR costs for 20 years (2010 – 2030) at a 3 percent discount rate. DR costs are assumed to primarily consist of the costs of advanced metering infrastructure (AMI) systems and load-controlling technologies (enabling technologies) such as DLC devices and Programmable Communicating Thermostats. The NPV of total DR costs ranges between $13 billion (Low, Optimistic BAU) and $77 billion (High, Full Deployment).

- We classified the system benefits into four categories: of 1) system peak impact, 2) system reliability impact, 3) avoided generation cost, and 4) environmental impact. DR significantly contributes to increasing the system reliability. The regional reserve margin increases by 13 (BAU) – 28 (Full Deployment) percentage points in 2030. On the other hand, the impacts on reduction in average generation cost and total CO_2 emissions are not noticeable. This is because DR addresses only the peak hours (60 hours on average), which last less that 1% of a year.

The results in this report may serve as a decision-support information source for Eastern Interconnection States Planning Council (EISPC) and individual state representatives for transmission expansion planning.

1. INTRODUCTION/OBJECTIVES

Historically, long-term planning within the electric sector was most concerned with providing sufficient generation and transmission resources to meet expected customer demand. The demands on the system were considered fixed and outside of the control of utilities. Small amounts of capacity were available through demand side management but these were not widely considered during long-term transmission planning. With the advent of increased demand response (DR) resources being made available to utilities through "smart grid" initiatives, less costly DR supplies, and greater difficulty in adding supply-side capacity, it has become increasingly necessary for planning to take into account these resources.

The extent of demand response (DR) penetration over the next two decades is one of many aspects to consider in estimating long-term transmission requirements. How do different volumes and types of DR change the requirements for new generation and transmission? Does DR reduce total energy use and emissions and by how much? What is the most efficient mix of resources (generation, DR, energy efficiency, energy storage, smart grid, distributed generation) to accomplish the overarching goals of reliable, affordable and clean electricity?

In April 2010 the U.S. Department of Energy (DOE) issued a research call to provide technical support to the interconnection-level electric infrastructure planning projects they had issued earlier in the year. In Area of Interest 2 they identified a need/purpose: "The Eastern Interconnection States' Planning Council (EISPC) seeks to significantly improve the knowledge base and modeling capabilities of demand-side resources, among other things, for purposes of transmission planning. These improvements are critical to the credibility of transmission expansion study work and the value of such work in formulating state and provincial policies." (DOE 2010)

The scope of the project is "to accurately estimate the demand-side resource technical and economic potential in the power system of the Eastern Interconnection." It lists a number of possible topics that may be studied, including estimating energy efficiency, demand response, and distributed generation potentials for use by the EISPC and Eastern Interconnection Planning Collaborative (EIPC) in their studies, potential impacts of energy efficiency programs and policies, and technical assistance to these groups regarding demand resources.

A number of these activities were completed through ORNL work with the EIPC Stakeholder Steering Committee (SSC). These included working with various sub-groups of the Modeling Working Group to develop estimates of existing and possible energy efficiency amounts, demand response capacities, and distributed generation growth from photovoltaic solar installation. These projections were used in Phase I and Phase II of the EIPC long-term transmission study.

Another facet of the project is an analysis of the potential for energy efficiency across the Eastern Interconnection. This is being conducted by Georgia Institute of Technology under sub-contract to ORNL. They are using the EIA National Energy Modeling System (NEMS) to estimate the impact of carrying out different energy efficiency policies in the industrial, commercial, and residential sectors.

The work summarized in this report is in response to the DOE-requested topic "Updating the Federal Energy Regulatory Commission (FERC)'s *A National Assessment of Demand Response Potential* for derivation of demand response resource potential in load forecasts 10-years and 20-years in the future." This report summarizes the work done by ORNL in assessing DR potential, costs and system impact for the Eastern Interconnection. The ORNL team has conducted the following tasks as part of this assessment:

- Reviewing/contrasting existing assessments of DR potential in Eastern Interconnection region in terms of results and methodologies

- Updating values and refining methodology to construct estimates of DR potential and system benefits for Eastern Interconnection

- Estimating implementation costs for different types of DR programs

- Estimating system benefits of DR programs

Besides extending and enhancing the FERC model, the report includes a survey of existing smart grid and demand response programs and studies for the cost estimates for future DR programs. It also conducts a benefits study of different types and levels of DR with regard to electric system operations, costs, and emissions.

Chapter 2 defines and classifies the different types of DR. Chapter 3 reviews various assessments to date. Chapter 4 describes the modifications to the NADR model definitions, inputs, and stochastic simulation. Chapter 5 presents results for the Eastern Interconnection regions. Chapter 6 covers our analysis of DR costs. Chapter 7 covers our analysis of the system benefits from DR using the ORCED model. Chapters 8, 9, and 10 cover challenges to DR implementation, future possible R&D, and references.

We hope that this report and associated model development will provide a valuable resource to states, planners, and other stakeholders in the electricity system.

2. DEMAND RESPONSE DEFINITIONS AND CLASSIFICATIONS

FERC defines demand response as "the changes in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized (FERC, 2009)." DR tariffs and incentive programs are offered by utility companies, system operators, utility companies, electricity cooperatives, municipal power agencies, and other load-serving entities, and they incentivize consumers to reduce their electricity consumption over a specific period of time (Isser 2009, FERC 2009, PLMA 2002). DR programs are quite diverse in the means through which they offer energy-consumption-reduction incentives.

Typical classifications of demand response programs include:

- **Administered by utilities (retail) vs. administered by ISOs/RTOs (wholesale)**

In competitive wholesale markets, there are two layers in DR provision. The system operator is required to match load and generation on a continuous basis but cannot provide balancing services directly. Instead, ISOs/RTOs design DR programs at the wholesale level. Demand response providers or curtailment service providers may function as intermediaries between the ISO and the end-use customers in the implementation of these programs. Demand response providers aggregate from multiple end customers the minimum load (e.g., 100kW in CAISO) required to participate in the wholesale market from multiple end-use customers. Demand response providers and curtailment service providers can be utilities or other entities.

- **Emergency vs. economic programs**

Emergency Programs – These programs are only engaged during conditions that threaten grid stability. Customers who reduce loads are offered compensation based on a high minimum price (e.g. $500/MWh) and an added rate that varies with the Locational Marginal Price (LMP) of their electricity (PLMA 2002).

Economic Programs – These programs involve day-ahead markets, in which electricity is purchased at least one day before it is consumed. Suppliers may offer hourly rates for electricity consumption in the future, and customers voluntarily reduce their electricity consumption based upon these future rates. Alternatively, customers may "bid" future electricity consumption volume reductions in return for customer-specified compensation levels; suppliers may then choose to purchase the optimal electricity consumption reductions from among customer offers. These programs require interval metering (PLMA 2002, FERC 2009).

- **Dispatchable vs. non-dispatchable**

Dispatchable programs allow the system operators to call upon DR resources to modify demand based on the status of the system. Non-dispatchable systems have pre-set signals on demand modification and so are under less control by operators.

Curtailable Load Programs – Large commercial and industrial customers (e.g. factories, retail stores) enter into contracts with their electricity suppliers to reduce their load on command from the supplier. Suppliers (e.g. a utility company) notify the customer between 30 minutes to one hour in advance of a requested load reduction. The customer is free to decide how to reduce its own load, and is compensated by the supplier at an agreed-upon rate (usually in the form of rebates to the customer's electricity bill). The customer and electricity supplier agree to perform these reductions a certain number of times per year (or per season) and with a certain frequency (e.g. 5 reductions, once every two months). Customer's reductions are measured with respect to a "baseline consumption level," i.e. the consumption that would normally occur without the customer's reduction efforts. This level is developed through energy modeling of the customer's consumption and is part of the contract established between the customer and the supplier. Interval Meters are used to monitor the customer's electricity consumption during the requested load reduction (PLMA 2002, FERC 2009).

Interruptible Load Programs – These programs are similar to Curtailable Load Programs, except that customers must be able to reduce most or all their load. Customers must be able to reduce a minimum (e.g. 1000kWh) to qualify for these programs, which usually offer larger compensations than curtailable load programs (PLMA 2002).

Direct Load Control – These programs target residential and small industrial customers. The agreements made between customers and suppliers of electricity are similar to those found in Curtailable Load Programs; instead of the customer being free to choose how to reduce his or her load, however, the supplier directly controls the deactivation of specific appliances (e.g. cycling the air conditioning on and off). Special infrastructure is required for this, which may include additional lines for telecommunication being connected to the customer's location or special voltage-signaling devices being installed at the supplier's location (PLMA 2002).

Pricing Programs – These programs require advanced metering technologies to communicate real-time changes (hourly or more frequently) to customers. RTP categorizes further into three major sub-classes:

- "Real Time Pricing:" The supplier and the participating customer develop the customer's baseline electricity consumption profile through energy modeling. If the customer consumes more than the baseline during a particular hour of the year, it pays a tariff to the supplier for that hour; if the customer consumes less than the baseline for a particular hour during the year, it receives a premium payment from the supplier for that hour.
- "One-Part Tariffs:" Spot prices for retail electricity are provided on the hour (or more frequently) to the customer. The customer then voluntarily reduces electricity consumption to save money. These retail spot prices reflect aggregate supply and demand conditions in the wholesale market. One-Part Tariffs do not require baseline consumption estimates.
- "Super-Peak", "Critical Peak" or "Coincident Peak" Pricing: The customer simply agrees to be charged a higher price for certain hours of the year and to receive a discount on all other hours. Suppliers notify customers a day in advance of what the high-price hours will be, so that the customer can decide how best to manage its power demand (PLMA 2002, FERC 2009).
- Peak Time Rebate programs: Customers get a rebate for consuming less than its predetermined baseline usage during planned or emergency events for which they receive notification.
- Time-of-Use Rates (TOU) – These programs target all customers. Like RTP programs, TOU programs offer hourly rates to customers that induce voluntary electricity consumption reductions by the customers; unlike RTP programs, however, TOU hourly rates are fixed throughout the year so customers know well in advance what they will pay for electricity. (PLMA 2002, FERC 2009)

Pricing programs typically result in non-dispatchable DR resources since decisions on when and how much to modify the consumption profile relative to the baseline are made by the customer. Critical peak pricing with controlling technology is an exception. On the other hand, curtailable loads, interruptible loads and appliances with direct load control are DR resources whose dispatch is, to some degree, controlled by the system operator.

3. REVIEW OF DEMAND RESPONSE ASSESSMENTS

The ORNL team conducted extensive review of existing assessments and projections as a first step in assessing electricity demand response potential to support EIPC's planning efforts for transmission grid expansion in the Eastern Interconnection. The studies and assessments that were reviewed are:

a) National level DR assessments conducted by FERC and EPRI (see Appendix A for a summary)
b) DR projections by ISOs/RTOs
c) DR projections by NERC and regional reliability councils
d) Utility-administered DR programs as reported in EIA Form 861
e) Other literature sources

Among these sources, some assess DR potential (source a), some project DR levels (sources b and c) and others calculate existing levels (source d).

Review of national level assessments

In Section 529 of the Energy Independence and Security Act (EISA), Congress mandated FERC to develop a process that would direct the nation towards achievement of its demand response potential. In particular, EISA required FERC to prepare a National Assessment of Demand Response Potential and a National Action Plan. The former, submitted to Congress in June 2009, evaluated state-level DR potential in 5 and 10 year horizons and identified barriers to implementation and policies that could bring down those barriers. Meanwhile, the Action Plan identifies tools to communicate with States, utilities and customers and to assist them in implementing demand response programs. The FERC assessment presents results for 4 scenarios: *business as usual (BAU), expanded business as usual (EBAU), achievable participation (AP) and full participation (FP)*. Table 1 shows the main attributes of those 4 scenarios. Four customer groups (residential, small C&I, medium C&I and large C&I) and five program types (direct load control, interruptible demand, dynamic pricing with enabling technology, dynamic pricing without enabling technology, other) are considered.[4]

Table 1: Key Differences in FERC's Assessment Scenario Assumptions

	Business-as- usual	Expanded business-as-usual	Achievable participation	Full participation
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): 60-75%	Universal (mandatory): 100%
Eligible customers offered enabling tech	None	None	95%	100%
Eligible customers accepting enabling tech	None	None	60%	100%
Basis for non-pricing participation rate	Today's level	"Best practices" estimate	"Best practices" estimate	"Best practices" estimate

[4] Enabling technology refers to devices that automatically reduce consumption during high-priced hours. In the case of residential and small C&I customers, it would typically be a programmable communicating thermostat. For large C&I customers, it refers to automated demand response systems. The "Other DR Programs" category includes programs primarily available to medium and large C&I customers such as capacity bidding and demand bidding. Residential direct load control refers exclusively to air conditioning appliances due to state-level saturation data for other candidate appliances (e.g., water heaters, pool pumps). Time-of-use rates are not included in the portfolio of DR programs captured in this assessment.

The EPRI study evaluates both energy efficiency and demand response potentials. It considers a 20-year time horizon (2010-2030) and presents results at the Census Region level. Based on the concepts of technical potential and economic potential, this study provides results for two scenarios: *maximum achievable potential* (economic potential * market acceptance rate) and *realistic achievable potential* (maximum achievable potential * program implementation factor that reflects utility budget constraints and regulatory or political barriers/incentives in different regions). DR programs considered in this analysis include direct load control (for all sectors), dynamic pricing programs (for all sectors) and interruptible demand (for commercial and industrial sectors). No distinction is made between dynamic pricing with/without enabling technology. Moreover, commercial and industrial customers are considered as different groups with no distinction made by their size.

Figure 1 compares potential summer peak demand reductions for the years and scenarios highlighted in the FERC and EPRI studies. Results from the two studies are not directly comparable because of different programs, customer classifications, modeling horizon and other assumptions but it is still informative in that it reveals a much more optimistic assessment from the FERC study. Since the two studies use different summer peak demand baselines, the potential reductions shown in Figure 1 are expressed in absolute terms rather than as a percentage reduction relative to the baseline without DR. The FERC study uses as baseline the summer peak demand forecast from the NERC 2008 Long Term Reliability Assessment, which excludes the effects of demand response but includes the effect of energy efficiency and implies an average annual growth rate of 1.7%. The EPRI study constructs its baseline starting from the AEO2008 Reference Case and assuming an average annual growth rate of 1.5%.

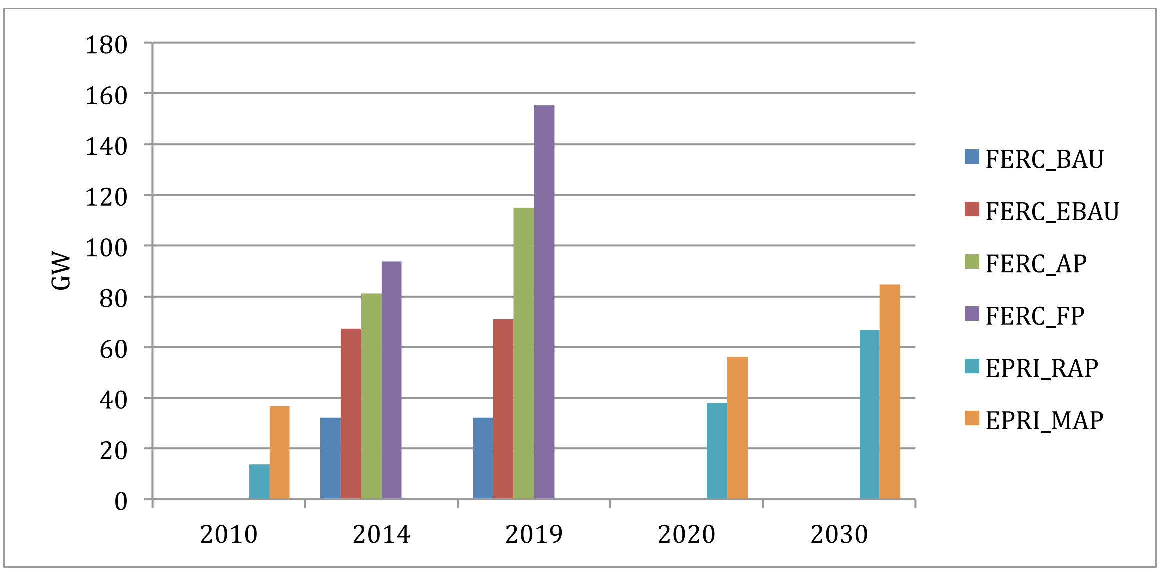


Figure 1: Potential Reduction in Summer Peak Demand from Demand Response Programs in Eastern Interconnection (GW)[5]

The estimates from these two assessments differ significantly in potential summer peak demand reductions obtained from DR. However, both agree in that DR potential in the Eastern Interconnection represents between 80% and 90% of the U.S. total. In the FERC study the DR potential exceeded 100GW barrier by 2019 in the *achievable participation* and *full participation* scenarios, but not in any of the

[5] The figures in this graph correspond to a proxy of the Eastern Interconnection area defined as the Lower 48 minus Census Divisions 8 and 9.
FERC_BAU (FERC's Business-As-Usual Scenario); FERC_EBAU (FERC's Expanded BAU Scenario); FERC_AP (FERC's Achievable Participation Scenario); FERC_FP (FERC's Full Participation Scenario); E

scenarios presented in the EPRI assessment. Achieving a 60 GW reduction in the Eastern Interconnection's peak demand by 2014 would only require small modifications to current program offerings (i.e., transitioning to the expanded business-as-usual scenario) in the FERC analysis while it is not within the boundaries of realistic potential by 2020 under EPRI's assumptions.

Combining projection data to produce aggregate, useful estimates

A complete DR projection that would be useful to EIPC transmission planning efforts should distinguish between dispatchable and non-dispatchable resources.[6] It should include ISO and utility-administered programs. It should cover the entire Eastern Interconnection territory and be disaggregated into the same spatial units as the electric system model in which demand response projections are going to be used. Sources b) through e) provide projections, but not in a form that could be directly used to estimate DR potential:

- Source b) does not account for utility-administered programs and a portion of the Eastern Interconnection is not within any ISO or RTO service territory
- Source c) covers the entire Eastern Interconnection territory but does not account for non-dispatchable DR resources
- Source d) only provides an aggregate potential peak demand reduction for each utility with no clear way to disentangle dispatchable and non-dispatchable DR from that aggregate number
- Source d) only provides historical data
- Sources b), c) and d) are all updated on an annual basis

Figure 2 summarizes dispatchable DR as compiled from electric reliability council websites in the Eastern Interconnection for the 2010-2019 period (source b in the list presented at the beginning of this chapter). Reliability councils must report to NERC every year on peak demand **forecasts** for the next ten years. Reliability councils collect data from utilities and/or ISOs in their respective service territories. Reliability council reports to NERC contain *total* versus *net internal demand* projections. The difference between those two magnitudes is demand response. However, NERC's purview is electric reliability so that only DR that could be directed by the system operator or balancing authority in case of emergency is considered in these reports. This estimate would be comparable to the dispatchable portion of the business as usual scenario in FERC's DR assessment.

[6] Dispatchability is a necessary attribute for DR to count as a resource in meeting reliability standards.

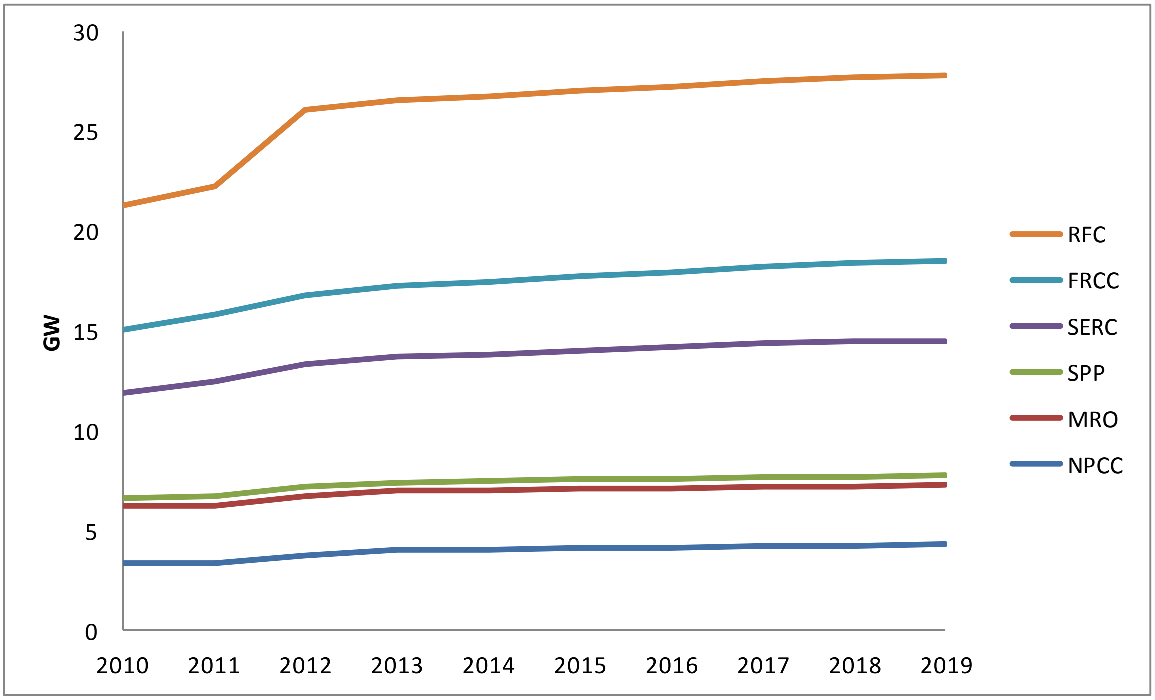


Figure 2: Dispatchable DR in Eastern Interconnection's Reliability Councils/NERC Regions (2009-2019)

Since there are no organized wholesale markets in their territories, FRCC, SERC and SPP numbers correspond exclusively to utility-administered programs. MRO numbers combine both utility administered and ISO-administered programs. RFC and NPCC numbers coincide with those reported by their corresponding ISOs.

According to these projections, the 30% increase in dispatchable DR (curtailable load + interruptible load + direct control load) projected from 2010 to 2019 would happen mostly in the first two years and mostly in the RFC region. NERC (2010) cautions that, in most cases, actual forecasting of DR is not done and projected numbers are based on the amount of capacity contracted in the current commitment period (generally 1 to 3 years forward). Such behavior is consistent with the very flat curves displayed in Figure 2.

Previous studies have estimated potential peak demand reductions from DR at the NERC region level. One example is Cappers, Goldman, and Kathan (2009). Results from that study, summarized in Figure 3, differ significantly from the ones discussed above because they include dispatchable and non-dispatchable DR resources. Figure 3 reveals that existing demand response programs can reduce between 3% and 9% of peak summer electricity demands for most RTO and ISO regions, with the exception of the Midwest Reliability Region where demand response programs can reduce up to 20% of peak electricity demand. Some of the factors that help explaining regional differences in DR potential are central air conditioning penetration rates, customer type mix and cost effectiveness of enabling technology.

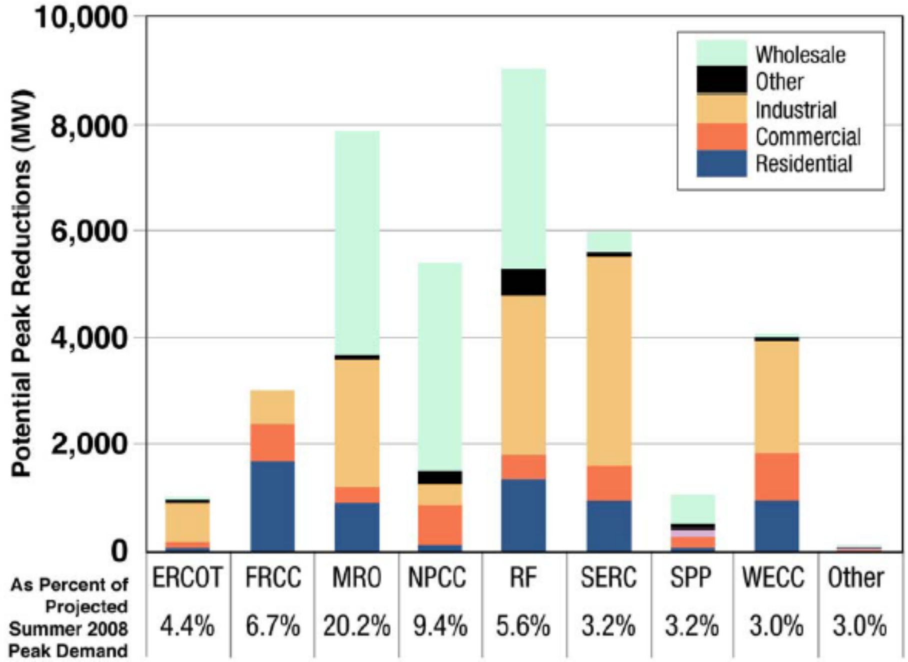


Figure 3: Attainable Reductions in Summer Peak Demands by Region and Customer Type for Demand Response Programs (as of 2008) (FERC 2008)

Table 2 combines information from reliability councils and EIA Form 861 (utility-administered DR programs) to estimate dispatchable and non-dispatchable DR portions at the NERC region level.

Table 2: Potential Peak Reduction from Utility-Administered Load Management Programs vs Reliability Council Assessments (GW)[7]

	EIA Form 861_Total (2009)	EIA Form 861_utilities with no incentive payments (2009)	Reliability council assessments (2010)	Estimated total dispatchable (2010)
NPCC	0.43	0.07	3.32	3.68
RFC	5.11	2.30	6.20	9.01
MRO	4.58	2.46	2.90	5.02
SPP	1.17	0.83	0.42	0.76
SERC	5.15	2.54	5.26	5.26
FRCC	3.04	0.25	3.19	3.19
Total	19.48	8.45	21.29	26.92

Sources: EIA Form 861 (2009), Reliability Council Regions LTRAs (2010)

For FRCC and SERC, the reliability council numbers are very close to those in EIA's Form 861 (the difference could be entirely due to the different years of reporting from both sources). This is consistent with the fact that in those two regions, DR is done entirely at the utility level because there are no ISOs/RTOs.

For SPP, the difference between the two numbers can be attributed to utility level programs not accounted by the reliability council.

[7] This is the potential given the existing number of customers, AMI devices and so forth.

For MRO, the difference should be mostly explained by non-dispatchable programs provided by utilities in that area. Bharvirkar et al. (2008) studied the DR resources available within the Midwest Independent System Operator (MISO) service territory, finding a total of 4,727 MW of demand response resources available of which 90% were administered by utility companies.

For NPCC and RFC, the reliability council assessment accounts for the wholesale component of DR while the EIA Form accounts for the utility component.

The missing piece in estimating a total peak demand reduction number for the Eastern Interconnection from combining the information sources described at the beginning of this chapter would be to figure out what fraction of the utility-level programs reported in EIA Form 861 are non-dispatchable resources. There is no direct, accurate way of finding out that fraction with only the Form 861 information. However, an upper bound can be computed using information about whether a utility reports or not incentive payments since those normally correspond to dispatchable programs. The "estimated total dispatchable DR" for 2010 in Table 2 was computed as the sum of the reliability council assessment and EIA Form 861 net of the proxy for non-dispatchable resources. For SERC and FRCC, however, the reliability council assessment number is taken directly as the total dispatchable.

An upper bound to estimated total DR availability in the Eastern Interconnection in 2010 is approximately 35GW (see Table 2). How does this compare to the levels attributed by FERC and EPRI to Eastern Interconnection regions? It is close to the *maximum achievable potential* identified in the EPRI report for 2010. Dispatchable DR reported by reliability regions (21.29 GW), far outstrips EPRI's *realistic achievable potential* (13.84 GW). On the other hand, it is higher than FERC's *business as usual* estimate for 2010 (30.8 GW).

Need to refine assessment of peak demand reductions from non-dispatchable, price-based DR programs

Demand reduction potential from dynamic pricing programs is more difficult to estimate than that from dispatchable DR programs. The largest divergence between estimates from FERC's *achievable participation* scenario in 2019 and estimates from EPRI's *realistic achievable potential* scenario in 2020 comes from estimated potential reductions attributed to dynamic pricing programs in both studies. Peak demand reductions from dynamic pricing depend largely on modeling assumptions about key parameters such as customer price elasticity and customer participation rates.

One of the first estimates of customer price elasticity in the context of a critical peak pricing program was developed by Charles River Associates with data from the California Statewide Pricing Pilot from 2500 residential and commercial customers distributed throughout the state participated in this pricing pilot study in 2003 and 2004. For residential customers, the critical peak price reduced demand on critical peak days by more than 14%. Demand reductions were lower for small commercial (between 6% and 9%) and medium commercial (between 8% and 10%) customers. The daily price elasticity estimated for the residential sector was -0.041 while the elasticity of substitution was -0.086 (Charles Rivers Associates, 2005).

In a survey of utility companies providing real-time pricing programs, Barbose et al. (2004) found that such demand response programs effectively reduce 12%-33% of participating customers' peak demand in aggregate. Threshold prices at which customers in these programs start to reduce peak loads ranged from \$0.12/kWh to \$6.50/kWh, although the high end of that range is shown to be an outlier in Figure 4. Most reductions came in the range of 10%-25% of aggregate peak demand and less than \$1.75 per kWh. The relationship between maximum load reduction and price of electricity appears to be inverse, but this is likely due to system-specific phenomena affecting the customers of the utility companies that were surveyed (Barbose et al. 2004).

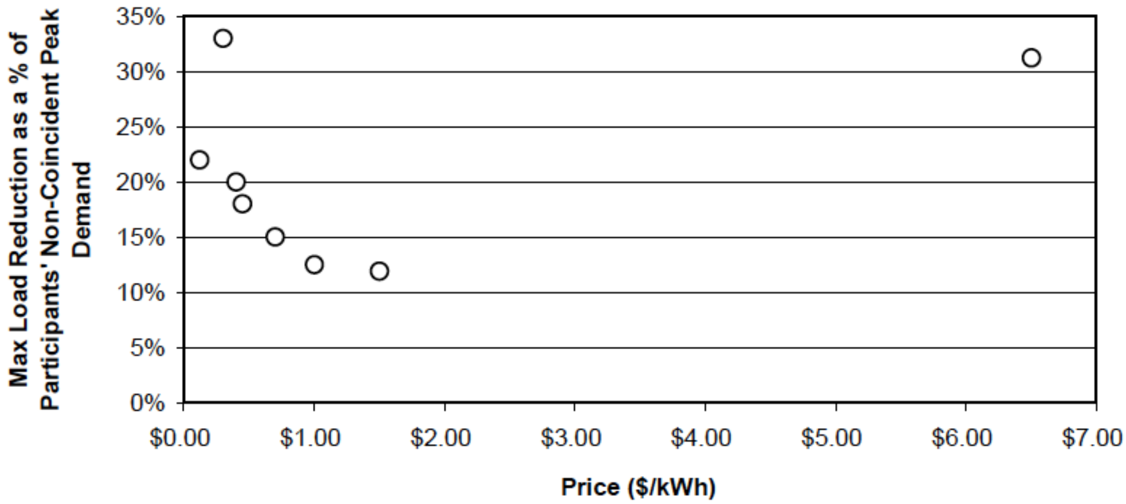


Figure 4: Maximum Aggregate Peak Demand Reductions Achieved Through Real-Time Pricing Programs for Eight Utility Companies Surveyed (Barbose, Goldman, and Neenan 2004)

Further data on dynamic pricing program performance will be key in sharpening the understanding of customer behavior under that type of DR programs. Two initiatives to gather this kind of data are currently in place: Smart Grid Investment Grant (SGIG) Consumer Behavior Studies and NERC's Demand Response Availability Data System (DADS). In this report, the uncertainty in peak load reduction from dynamic pricing programs is acknowledged by offering a range of results based on Monte Carlo simulations.

Dealing with discrepancy in spatial units for assessment and system impact analyses

FERC's assessment produced state-level data. NERC and ISO projections refer to their respective service territories. On the other hand, EIPC production cost and transmission planning analysis is performed using the North American Electricity and Environment Model (NEEM), which has a different regional disaggregation. Finally, for policy coordination among state representatives at EISPC, it is desirable to talk about DR potentials and system impacts at the state level.

These different regional classification requirements reveal the need to have a flexible way to move across different spatial aggregation levels. To achieve such flexibility, the ORNL team constructed proportioning matrices that allow transitioning between the various spatial units.

As discussed earlier, model used for FERC's National Assessment of Demand Response (NADR) has the capability to analyze state-by-state DR potential. The raw data of some inputs to NADR, however, are arranged by NERC region. Thus, a NERC-to-state proportioning method is required to break down NERC-level data into state. NERC region boundaries are not same as state boundaries, whereas census regions are collections of states. To address this issue, proportioning matrices are developed. They treat all these different spatial units as sets of counties and calculate weights based on county level variables such as population, number of households, or value of shipments.

The mapping methodology used here involves four steps:

- Using Geographic Information System (GIS), approximate NERC regional boundaries are depicted with county boundaries.
- Identify each county as one of eight NERC regions.

- Using county FIPS codes as identifiers, combine geographic location with county-level socioeconomic and energy information.
- The set of attribute information are used to disaggregate NERC-level data into state. The candidate proxy variables to implement this disaggregation are displayed in Table 3.

Table 3: Proxy variables for Disaggregation of NERC region data into state-level data

Data	Attributes	Source
NERC Identification	NERC region, FIPS code, County name, State name	The Energy-Water Connection
Socioeconomic/ Energy	Pop1990, Pop2000, Pop1990 per square mile, Households, Female, Male, Race, Population by Age, Marriage Status etc.	GIS-based data
	Population estimate 2009	U.S. Census Bureau, Population Estimates data, 2000-2009
	Residential population 2010, Housing units 2010, Households 2005-2009, Per capita income 2010, Median household income 2010, Personal income 2010, Employment in all industries 2010, Number of firms 2010, Total value of manufacturing shipments	U.S. Census Bureau, State & County QuickFacts data, 2010
	Sum of plant nameplate capacity (MW) by county	eGRID Plant, Boiler, and Generator Data, 2007

The amount of peak load reduction by state is calculated using the fraction of each NERC region to the state. A matrix is developed to contain the conversion factors between NERC and state. Similar steps are conducted to translate results between state or NERC and NEEM regions. Figure 5 and Figure 6 show the geographic borders of the two regional definitions.

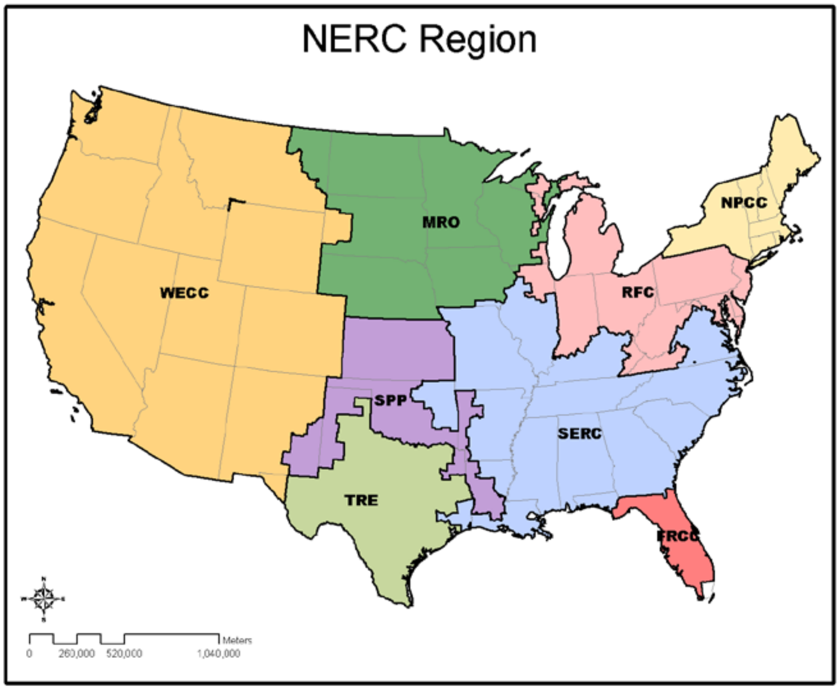


Figure 5: Map of NERC regions

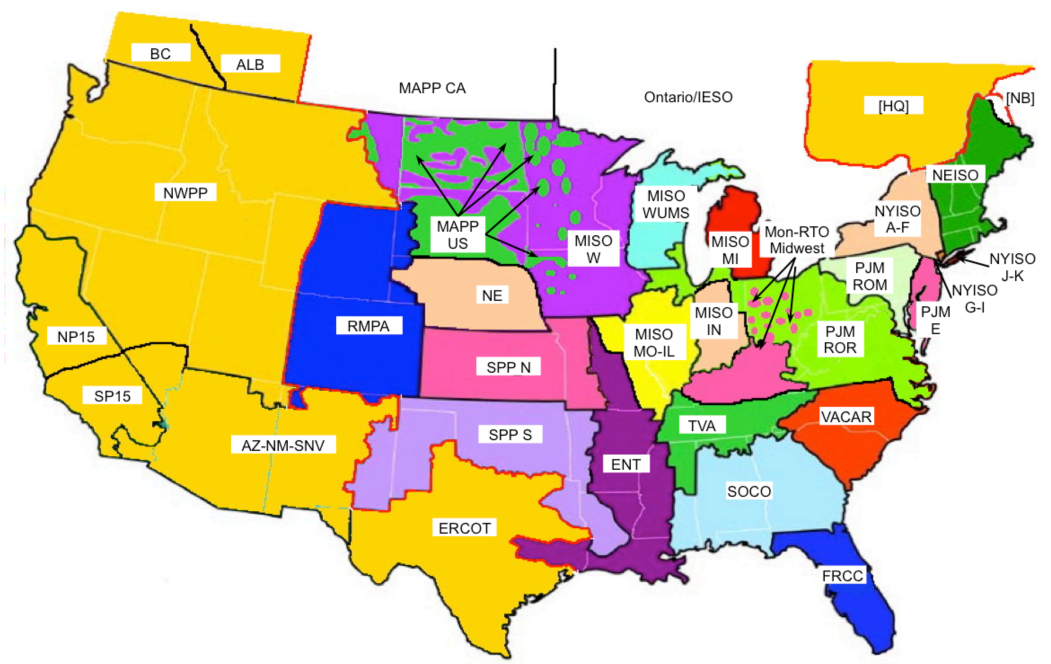


Figure 6: Map of NEEM regions

4. DEMAND RESPONSE ASSESSMENT UPDATES AND ORNL-NADR ANALYSIS

FERC's assessment of DR potential is supported by two modeling tools. First, the NADR model uses information to determine DR potential by state and customer type. Second, the DRIVE model looks at system impacts that different DR mixes and total volumes would have on load profiles, plant utilization profiles, marginal prices, capacity additions, CO2 emissions and total system costs.

The current round of EISPC scenario analysis has used DR resource estimates from the original NADR model version. Taking advantage of its open spreadsheet nature, the ORNL team has modified NADR in order to derive updated, refined DR resource potential estimates for the Eastern Interconnection from 2009 to 2030. Those updated estimates were subsequently used as inputs to Oak Ridge Competitive Electricity Dispatch (ORCED) in order to assess DR system impacts.

Proposed steps for updating/refining NADR

Figure 7 summarizes the three key components for DR impact estimation in NADR. First, baseline loads must be defined that will convey, for each customer type and region, peak demand in absence of demand response. Second, the percentage reduction enabled by each type of program (by customer type and region) is estimated. Third, in order to translate average reductions per customer into system aggregate amounts, participation rates for each program and customer type are required. In order to distinguish the updated NADR from the original NADR model, we named the newly updated model ORNL-NADR.

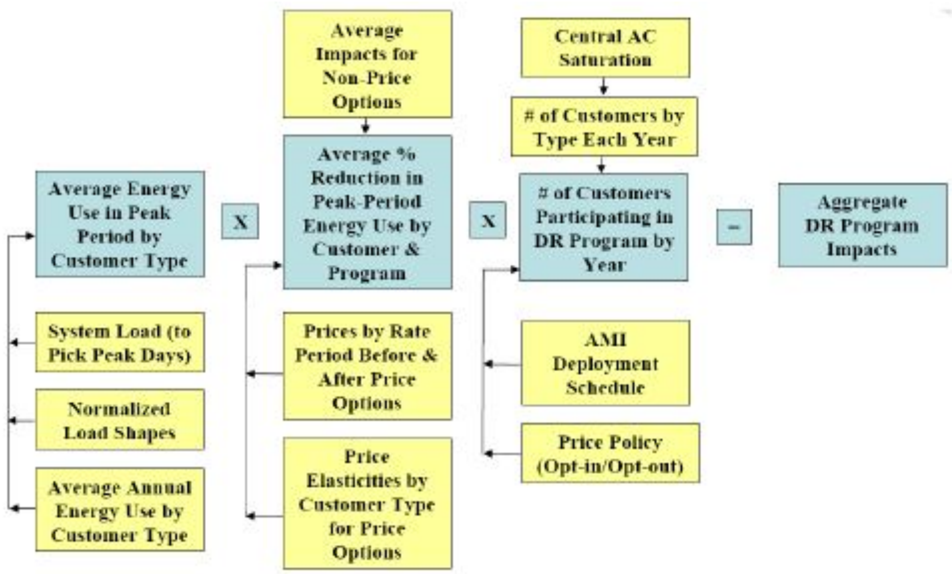


Figure 7: Key Building Blocks for Demand Response Impact Estimation in NADR (FERC 2009)

4.1 UPDATED DEFINITIONS IN ORNL-NADR

Planning horizon

The updated ORNL-NADR has an expanded planning horizon (2009-2030) relative to the original NADR (2009-2019). This adjustment has been made to suit the needs of EISPC whose transmission planning analysis is conducted with a 20-year horizon.

Included Demand Response Programs

The following programs, whose names correspond to those in the 2010 FERC Assessment on Demand Response and Advanced Metering, have been included in the ORNL-NADR version.[8]

- Direct load control
- Interruptible tariffs
- Pricing programs
    - critical peak pricing
    - critical peak pricing with load control
    - time-of-use
    - peak time rebate
    - real time pricing
- Other DR programs
    - demand bidding and buyback
    - emergency demand response
    - load as capacity resource
    - system peak transmission tariff
    - other

The main difference relative to the original NADR version is the inclusion of time-of-use rates within the pricing programs category.

ORNL-NADR Scenario definitions

The ORNL team developed four scenarios to assess the potential DR impact on system peak load reduction in the Eastern Interconnection area. The four ORNL-NADR scenarios are defined as follows:

Business-as-Usual (BAU) Scenario considers the amount of demand response that would take place if existing and currently planned demand response programs continued unchanged over until 2030.

Optimistic BAU Scenario is the BAU scenario with the inclusion of statistically imputed participation rates for non-reporting utilities. It assumes that non-reporting utilities to FERC 731 survey have the same level of enrolled customers as the reporting entities in the same level of revenue, summer peak, sector, and region.

Aggressive Deployment Scenario is an estimate of how much demand response would take place if 1) advanced metering infrastructure were universally deployed; 2) a dynamic pricing tariff were the default; and 3) other demand response programs, such as direct load control, were available to those who decide to opt out of dynamic pricing. It also assumes that 60 to 70 percent of eligible customers stay on dynamic pricing rates. In addition, 57 percent of the eligible customers use enabling technologies in states where programmable communicating thermostats are cost-effective.

Full Deployment Scenario is an estimate of how much cost-effective demand response would take place if 1) advanced metering infrastructure were universally deployed, 2) dynamic pricing were made the default tariff and offered with proven enabling technologies, and 3) all utilities were mandated to report their customers' DR participation rates to FERC. It assumes that all customers remain on the dynamic

[8] It should be noted that NADR focuses on estimating DR potential as a percentage of summer peak demand. DR resources that were reported in the FERC survey as dedicated to the provision of ancillary services were not included in our assessment.

pricing tariff and use enabling technology where it is cost-effective.

Table 4 lists key factors that differentiate the scenarios.

Table 4: 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*

As in the original NADR, these four scenarios have been designed such that the expected load reduction potential is smallest in the BAU case and largest in the rightmost column case. The BAU case is very conservative in that it does not expect any additional load reductions from DR programs beyond the ones already available in the baseline year. The Optimistic BAU case attains higher load reduction potential from non-pricing programs by adopting an upper bound on the participation rates in this kind of programs (entities that did not respond to the FERC survey are assumed to have the same penetration rates as the reporting entities with the same level of revenue, summer peak, sector and region rather than zero penetration) yet it still has barely no participation in dynamic pricing programs. The aggressive and Full Deployment scenarios assume, on top of the load reduction potential in the Optimistic BAU case, that advanced metering infrastructure is deployed for every customer in the country. The difference between them is that the Aggressive Deployment scenario models dynamic pricing programs as opt-out programs while in the Full Deployment scenario they become mandatory. Moreover, in the Full Deployment scenario, the 100% deployment figure refers not only to advanced metering infrastructure but also to enabling technology.

Imputation method for baseline participation rates in non-pricing programs

Data from EIA 861(2008) survey were merged with data from FERC Form 731 (2010) to estimate the DR enrollment status assuming that non-reported entities have the same level of participation as those entities who responded to the FERC survey (FERC 731 reports the results from that survey) if they were the same type of entity, collected similar amount of revenue, were located in the same state and had the same summer peak load.[9] The econometric estimation of the participation rates assumed a logistic functional form.

The penetration rates resulting from this econometric estimation are used as inputs in the baseline year (2009) of the ORNL-NADR model. Penetration rates based on expert opinion as published in Faruqui and Mitarotonda (2009) are assumed for year 2020 except when the baseline percentage is higher or when the combination of DR program and customer type is not considered in the Faruqui and Mitarotonda report. In the former case, the baseline percentage is assumed to stay constant. In the latter case, the higher of the estimated baseline percentage or the maximum penetration rate in the original NADR is used.

[9] The entity types are classified into cooperatively-owned utility, curtailment service provider, Federal utility, investor-owned utility, municipal power agency, municipally-owned utility, political subdivision, retail power marketer and state utility.

4.1 INPUT UPDATING

The NADR model was first released in 2009. It was conceived as a flexible tool in which inputs could be updated as better/most recent information became available. This section details all updates to the NADR input database conducted by the ORNL team.

4.1.1 Baseline System Peak Load and Customer Population

Baseline system peak load forecast: Figure 8 contrasts NADR's baseline system peak load, obtained from NERC's 2008 Long Term Reliability Assessment (LTRA), with subsequent versions of that same assessment. NERC revised its system peak load forecast downward in its 2009 and 2010 editions. The average annual growth rate went from 1.7% in the 2008 forecast to a 1.4% in the 2010 and 2011 versions. The system peak load in the updated ORNL-NADR version is based on the LTRA 2010 forecast. The method used to allocate the U.S. total system peak across states was the same as in the original NADR (i.e., it is based on the percentage of total electric sales for each state, except for Alaska, Hawaii and New York).[10]

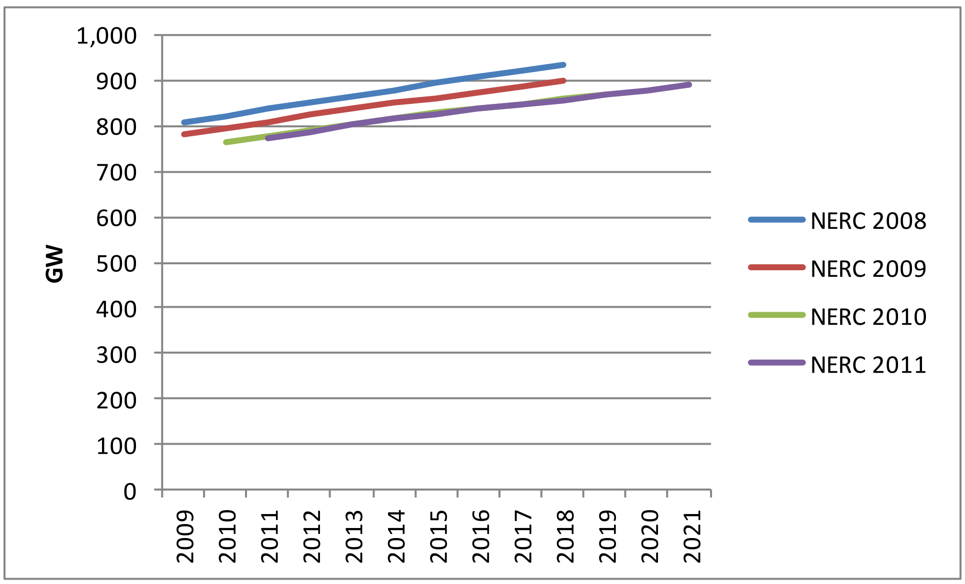


Figure 8: U.S. summer electricity summer system peak load update

Starting customer population: Updated values were obtained from http://www.eia.gov/electricity/data/state/ (number of retail customers by state by sector, based on information from EIA-Form 861, 2009)

4.1.2 Load and Population Growth Rates

Population growth rate: For residential customers, the source of the updated values is the U.S. Census Bureau (http://www.census.gov/population/www/projections/stproj.html). The latest state projections by age and sex were based on Census 2000 and released in 2005. Thus, there has been no update to the numbers used in the original NADR. For C&I customers, the source are Supplemental Tables to

[10] NERC system peak load does not include Alaska and Hawaii so the estimates for these two states were based on EIA-Form 861 reported utility peak values for those two states. Also, since NERC reports a system peak load value for New York, that value was taken instead of relying on the allocation process for that state.

AEO2012 (projections on commercial square feet by Census Division). [These tables were obtained via an email request to EIA].

<u>*Annual consumption growth rate*</u>: These rates were updated using the supplementary tables for AEO2010. These tables provide values for residential, commercial and industrial sectors. Commercial and industrial consumption projections were added up into a C&I category whose growth rates are applied to the small, medium and large C&I customer types in NADR.

<u>*Annual critical peak load growth*</u>: The updated rate was estimated using the following relationship

Peak load by rate class= critical peak load per account * number of accounts

Assuming peak load by rate class grows at the same rate as the NERC system peak, which is important to maintain consistency between the top down and bottom up growth rates used in the model:

1. Growth in number of accounts: Table D-1 from FERC (2009) is used in the original NADR to allocate total C&I accounts among the small, medium and large categories. Those weights are applied to more updated information on number of accounts, taken from EIA Form 861 (2009).
2. Annual values for peak load by rate class are calculated by applying the system peak load growth rate to the baseline rate class peak load.
3. Annual values for number of accounts are obtained applying the % growth rate in customer population to the baseline number of accounts computed in (1)
4. Annual critical peak load per customer is solved for by combining (2) & (3).
5. Growth rate in annual critical peak load per customer is calculated.

4.1.3 Critical Peak Average Hourly Load

Load profile data by customer type is the starting point to calculate the average energy use in peak period by customer type (baseline, without demand response). However, utilities do not publish this kind of data. Thus, the original NADR version estimates baseline loads with an econometric model estimated using the limited available sample. The explanatory variables are dummy variables indicative of month of the year, day of the week and hour of the day, temperature and central air conditioning saturation.

The estimated model equation is as follows:

$$
\begin{aligned}
normalizedkW_{x,t} \\
&= a_x + \sum_{i=5}^{9} b_i * Month_i + \sum_{k=1}^{7} c_k * Dayofweek_k + \\
&+ \sum_{j=1}^{24} d_j * Hour_J + \sum_{j=1}^{24} e_j * Hour_j * Wkndholiday + \sum_{j=1}^{24} f_j * Hour_j * MondayFriday \\
&+ + \sum_{j=1}^{24} g_j * Hour_j * CoolingDegreeHours * CACpenetration + U_{xt}
\end{aligned}
$$

where:

normalizedkW is the normalized hourly load for state *x* in period *t*
x= state or utility
t= period (hour)
i= month of the year
j= hour of the day
CoolingDegreeHours is the difference between observed temperature and 65 degrees Fahrenheit if observed temperature is above 65; otherwise, it takes a zero value.
CACpenetration refers to the percentage of residential customers with central air conditioning in state x

MondayFriday takes the value 1 on Mondays and Fridays and zero otherwise
Wkndholiday takes the value 1 on weekends or holidays and zero otherwise

System load information is used to identify the 15 days with the largest peak loads. Then, the equation is used to estimate load for the 2 to 6 pm timeframe on those 15 days. The average of the resulting 60 point estimates is the desired input variable (average energy use in peak period per customer type).

No new data were available to update the estimation of the load profiles for each state and customer type so that the estimated values from the original NADR were used. Baseline load profiles are an important ingredient in any DR analysis so further research in this area would be valuable. To ensure consistency between the system peak load based on NERC data and the critical peak average hourly load (calculated from the bottom up as number of participants * load per participant) were adjusted by the same percentage difference between the original and updated system peak load. For instance, since the updated system peak load in Alabama in 2009 was 2.7% lower than in the original NADR, the critical peak load for all customer types in Alabama was also adjusted by that same percentage.

4.1.4 Participation Rates in Non-Pricing Programs

To update baseline year participation rates, the responses from the FERC Survey on Demand Response and Advanced Metering conducted in 2010 (FERC 2011b) were a key source. Specifically, responses from the following two survey questions were used.

Question 8: "Provide the following information (program type, number of customers, maximum demand of customers, potential peak reduction…) for each DR program and time-based rate/tariff your entity *offered directly to retail customers* during calendar year 2009, by customer, sector and state."

Question 9: "Provide the following information (program type, potential peak reduction, minimum reduction required for participation) for each DR program your *entity offered to wholesale customers and curtailment service providers* during calendar year 2009, by state.

Adjustments were necessary to avoid double counting retail and wholesale potential peak load reductions from DR programs using information from the FERC 2010 DR and AMI survey. The basis for adjusting for double counting is shown in Figure 9. Utilities offer retail programs to their customers. Part of the peak load reduction that results from these utility programs is enrolled into ISO/RTO wholesale programs. These amounts are reported in the survey and were therefore subtracted from the total peak load reduction potential reported by utilities and RTO/ISO combined. For the entire U.S., this amounted to 4.6GW out of the total 28GW of peak reduction potential coming from retail programs.

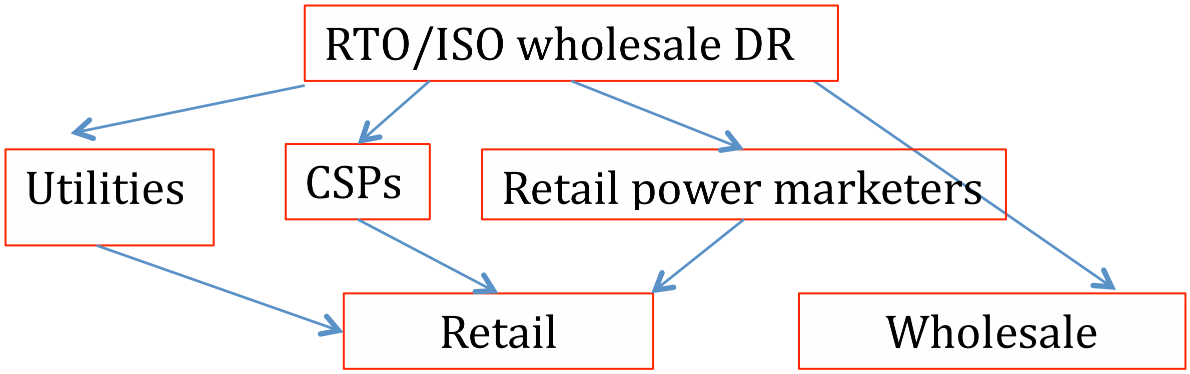


Figure 9: Relationships between DR providers[11]

As for the curtailment service providers and retail power marketers, these entities can offer DR programs to either retail or wholesale customers but, in any case, we assumed that they enroll 100% of the associated MW of potential peak load reduction into ISO/RTO programs. Thus, potential load reductions from these two types of entities were assumed to be entirely included within the potential peak load reductions reported by ISO/RTOs. An additional issue is that potential load reductions (in MWs) from a given utility program may be enrolled into an ISO/RTO program that falls under a different category. When that was the case, the adjustment was made to the "Other DR" category in the wholesale programs, since that is where the majority of DR activity by ISO/RTOs takes place.

Thus, the procedure used to avoid double counting of retail and wholesale DR programs is as follows. We have information on:

1. DR programs offered by utilities to retail customers
    a. Amount of potential peak load reduction from these programs that is enrolled into RTOs/ISOs
2. DR programs offered by retail power marketers and curtailment service providers to retail customers
3. DR programs offered by retail power marketers and curtailment service providers to wholesale customers
4. DR resources enrolled in RTOs/ISOs (participants can include utilities, retail power marketers, curtailment service providers and wholesale customers (large C&I))

Total amount of DR brought into ORNL-NADR = 1+4-1a

The evolution of participation rates is mainly governed by two parameters: maximum percentage enrolled or notified in each DR type and years required to reach the maximum penetration.[12] For non-pricing programs, the gap between current and maximum penetration is allocated over the allowed deployment

[11] The relationship between DR providers varies from market to market. For example, for NYISO: "The NYISO has four Demand Response programs: the Emergency Demand Response Program (EDRP), the ICAP Special Case Resources (SCR) program, the Day Ahead Demand Response Program (DADRP) and the Demand Side Ancillary Services Program (DSASP)" (http://www.nyiso.com/public/markets_operations/market_data/demand_response/index.jsp). However, for California, "Currently, demand response programs are administered by California's three regulated investor-owned utilities: PG&E, SCE, and SDG&E. Most of the utility demand response programs target large commercial and industrial customers that are equipped with meters that are capable of measuring and reporting energy usage in one hour intervals or less" (http://www.cpuc.ca.gov/PUC/energy/wholesale/01a_cawholesale/MRTU/06_demandresponse.htm).

[12] It must be noted that neither direct load control for large C&I customers nor interruptible contracts for residential or small C&I customers are considered. As in the original NADR, the baseline penetration rates for those combinations of program and customer type are assumed to be 0%.

period (5-10 years) using an inverse normal distribution. Next, a list of all the variables regarding participation rates in non-pricing programs and if/how they were updated is presented:

Direct load control market penetration in baseline year (% of customers)

For business as usual scenario, market penetration is based on number of customers enrolled (from the 2010 FERC survey on Demand Response and Advanced Metering, (FERC 2011)) and total number of customers for each state and type from EIA Form 861.

Problem: not all utilities report the number of customers enrolled in a given program and there are no data on number of customers enrolled in wholesale program so this will likely be an underestimation. For the rest of scenarios, imputation of participation rates to non-responding utilities to the FERC survey. The imputation is based on a regression, as described at the beginning of chapter 4.

Direct load control maximum penetration of program (% of customers): Based on high-case numbers from Faruqui and Mitarotonda (2011).

Years required to achieve maximum penetration in direct load control programs: 10 because the numbers in Faruqui and Mitarotonda represent projections for 2020.

Interruptible tariffs market penetration in baseline year (% of customers): For business as usual scenario, market penetration is based on number of customers enrolled (from the 2010 FERC survey on Demand Response and Advanced Metering, FERC(2011)) and total number of customers for each state and type from EIA Form 861.

Interruptible tariffs market penetration in baseline year (% of MW): NADR only allows medium and large C&I customers to participate in interruptible tariffs. The assumption that the largest customers within these customer categories would be enrolled first leads to small percentages of participation accounting for higher percentages of load. The following assumptions were made:

- if penetration rate as percentage of customers is less than 10%, the penetration rates as percentage of load is 2*percentage of customers enrolled
- if penetration rate as percentage of customers is between 10% and 20%, the penetration rates as percentage of load is 1.5*percentage of customers enrolled
- if penetration rate as percentage of customers is between 20% and 30%, the penetration rates as percentage of load is 1.2*percentage of customers enrolled
- if penetration rate as percentage of customers is larger than 10%, the penetration rates as percentage of load is equal to the percentage of customers enrolled

These assumptions are not backed for empirical data. Utility data on the size distribution of their customers would help refine this relationship but is not publicly available.

Interruptible tariffs maximum penetration (% of customers in segment): Based on figures from Faruqui and Mitarotonda (2011) for C&I customers. For residential customers, they do not consider this program type and, therefore, the numbers from the original NADR were used instead.

Interruptible tariffs maximum penetration (% of MW): Same method and comments as for interruptible tariffs market penetration in baseline year (% of MW)

Years required to achieve maximum penetration in interruptible tariffs: 5 for residential (because that is the number in the original NADR), 10 for C&I customers (because projections in Faruqui and Mitarotonda are for 2020)

Other DR programs penetration in baseline year (% of customers): For business as usual scenario, market penetration is based on number of customers enrolled (from the 2010 FERC survey on Demand Response and Advanced Metering, FERC(2011)) and total number of customers for each state and type from EIA Form 861.

Problem: no data on number of customers enrolled in wholesale program so this will likely be an underestimation (particularly important for this program category because most of these programs are wholesale). For the rest of scenarios, imputation of participation rates to non-responding utilities to the FERC survey. The imputation is based on a regression.

Other DR programs penetration in baseline year (% of MW): Same method and comments as for interruptible tariffs market penetration in baseline year (% of MW)

Other DR programs maximum penetration (% of customers in segment): Based on values for Faruqui and Mitarotonda (2011) for C&I customers. Their expert survey did not consider the Other DR program category for residential customers so the original numbers for NADR were kept there.

Other DR programs maximum penetration (% of MW): Same method and comments as for interruptible tariffs market penetration in baseline year (% of MW)

Years required to achieve maximum penetration in other DR programs: 5 years for residential customers (since that is the number in the original NADR) and 10 years for C&I customers (since projections in Faruqui and Mitarotonda are for 2020).

4.1.5 Participation Rates in Pricing Programs

Participation in dynamic pricing programs is largely driven by the pace of AMI deployment. Advanced metering is a necessary infrastructure component for supporting mass-market pricing programs. However, as will be further explained in chapter 6, it is not a sufficient condition for implementing price-responsive DR. A utility also needs a meter data management system and billing system that will support price-responsive DR options (FERC,2009). AMI penetration rates in the NADR model combined information from multiple sources up to 2008. Updated estimates have become available since then which can be used to revise the baseline (year 2009) penetration rates and the subsequent deployment schedule. The ORNL team pulled information from the following sources:

- FERC 2010 Assessment of Demand Response and Advanced Metering. This survey was sent to all utilities in the country and elicited a response rate of 52.1%.
- EIA Form 861 (file 8), which contains information on the numbers of automatic meter reading (AMR) and AMI devices for all utilities.
- EIA Form 826 “Monthly Electric Utility Sales/Revenue Data”, which started reporting AMI information in year 2011 for a sample of utilities.
- Smart Grid Information Clearinghouse (SGIC) (http://www.sgiclearinghouse.org/)
- Recovery Act Smart Grid Programs (http://www.smartgrid.gov/)

Figure 10 compares NADR 2009 AMI deployment rates with those estimated in the most recent FERC AMI survey.

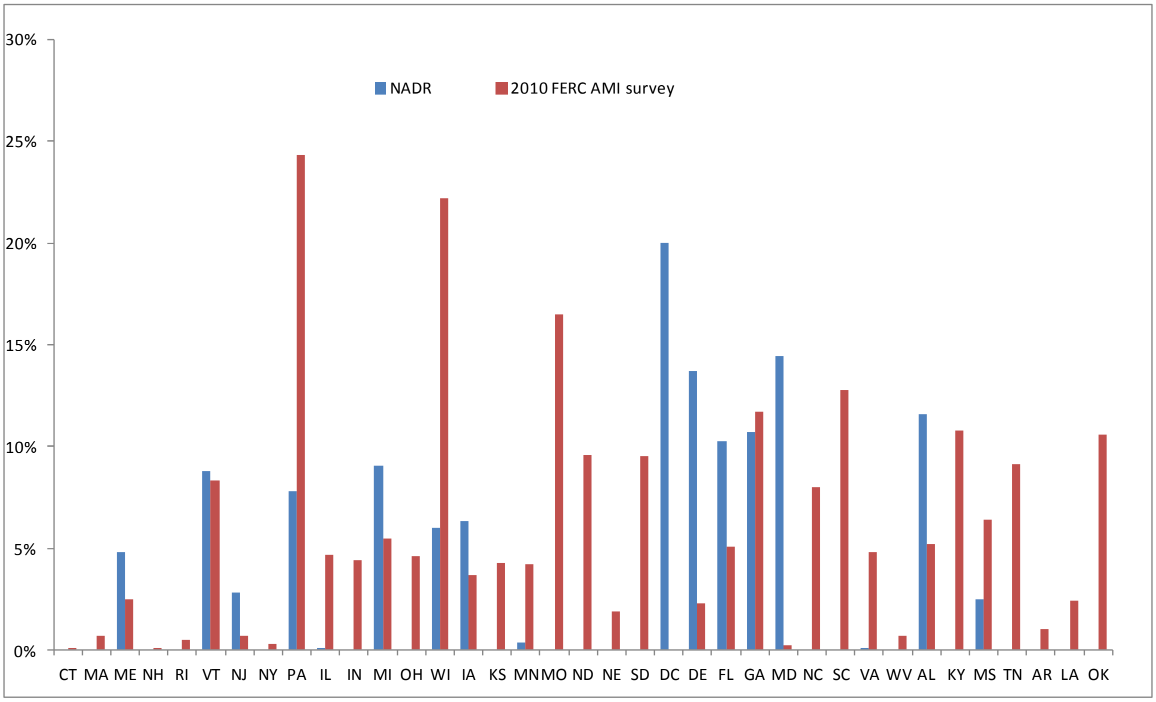


Figure 10: 2009 AMI Deployment Estimates for States in Eastern Interconnection

For those states in which the 2010 FERC AMI Survey estimate is larger than the NADR estimate (CT, NH, RI, NY, PA, IL, IN, WI, KS, MN, MO, ND, NE, SD, GA,NC, SC,VA, WV, KY, MS, TN, AR, LA, OK), the difference reflects more recent installation numbers. For the rest, the smaller number of meters in the more recent survey reflects the more restrictive definition of AMI that has emerged in the last few years. According to the 2010 FERC AMI Survey, advanced meters are those that "measure and record usage data at hourly intervals or more frequently and provide usage data to both consumers and energy companies at least once daily".

NADR assumes a piecewise linear AMI deployment path which varies by state and scenario but not across customer types. That assumption was maintained in the updated ORNL-NADR runs.[13] The information from SGIG projects provides a good window into expected deployments in the next few years. Penetration rates for 2014 can be derived from those data. As for the target penetration rates by the end of its planning period (2019), same as in NADR are used with 100% AMI deployment achieved in every state in the *Aggressive Deployment* and *Full Deployment* scenarios. For the rest of scenarios, the penetration rate assigned to each utility is based on its size, on whether it already had AMR infrastructure and on whether it has committed to AMI deployment (BAU and expanded BAU scenarios). Thus, resulting penetration rates in each state depend on the composition of utilities in each of them.

Figure 11 shows an example of the revised deployment paths, based on updated 2009 and 2014 estimates.

[13] Amongst the utilities that reported having installed any AMI devices in the FERC 2010 AMI Survey, the average penetration rate was 64% for residential customers and 44% for C&I customers

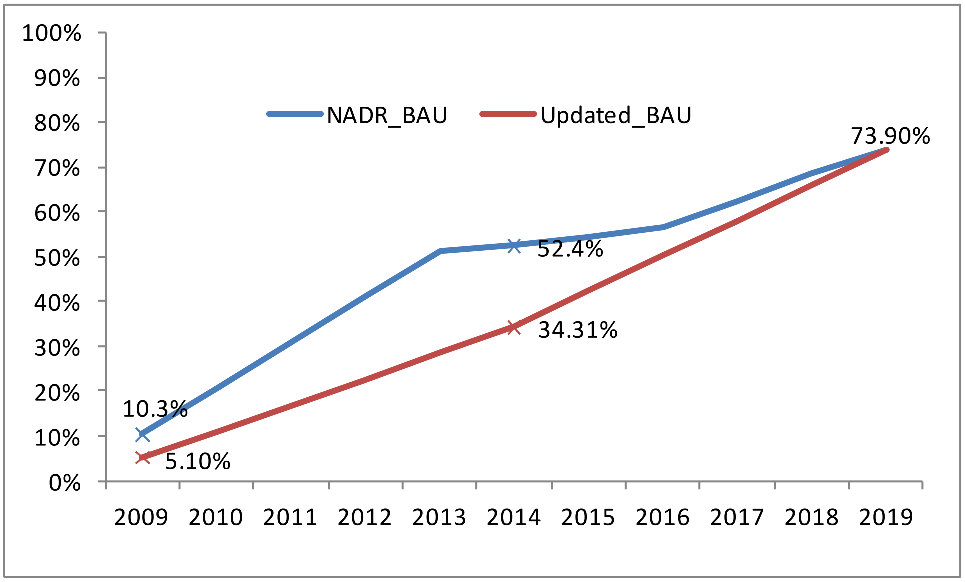


Figure 11: AMI Penetration Rates (Florida, BAU)

The *Aggressive Deployment* and *Full Deployment* scenarios assume a 100% participation rate by 2020 for pricing programs. It supposes that all utilities will have AMI meters in place for all customers, along with the MDMS and billing systems required to support price-based DR, by 2020. The *BAU* and *Optimistic BAU* scenarios assume partial deployment by 2020 that would stay constant out to 2030. It supposes that AMI deployment plans for each state would be based largely on a continuation of current trends. It assumes participation increases from utilities that already have or are currently deploying AMI systems and other utilities that, based on a variety of data sources, have expressed interest in or believed to have a higher probability of installing these systems.

These two alternative scenarios should not be interpreted as forecasts of actual AMI meter and system deployment. The Full Deployment scenario is based on the assumption that all customers will have smart meters and that enrolling in dynamic pricing programs will be mandatory by 2020. This assumption is combined with a variety of information and assumptions that drive the likely sequence of installation across utilities in a state and across states. The partial deployment scenario is probably closer to what might actually occur, but it is not a true forecast either, since a true forecast would require conducting business cases for each load serving entity and an assessment of the likely barriers to deployment in each state. Such work was beyond the scope of this analysis.

4.1.6 Load Reductions per Participant

For non-pricing DR programs, the percentage load reduction must be based on understanding the particular devices that the system operator can curtail and which fraction of each customer's load these represent or on the contractually set demand reductions. Currently, NADR focuses on direct load control devices for air conditioning appliances. Since no new data were available, the updated ORNL-NADR maintains the same estimates of load reduction per participant in direct load control, interruptible tariffs and other DR programs.

For dynamic pricing programs, assessing load reductions requires estimates of elasticities and peak to off-peak price spreads, and other consumer characteristics. The original NADR model uses impact multipliers that reflect the enhanced response by customers with enabling technology and the impact of humidity to fine tune baseline percentage reduction estimates.[14] These multipliers are given as percentage load reductions for each new-to-old price ratio (where "old" refers to a flat price) from 1 to 8 in increments of 0.1 as shown in Figure 12. also shows that the relationship between the percentage load reductions and price ratios can be approximated with a log-linear function.

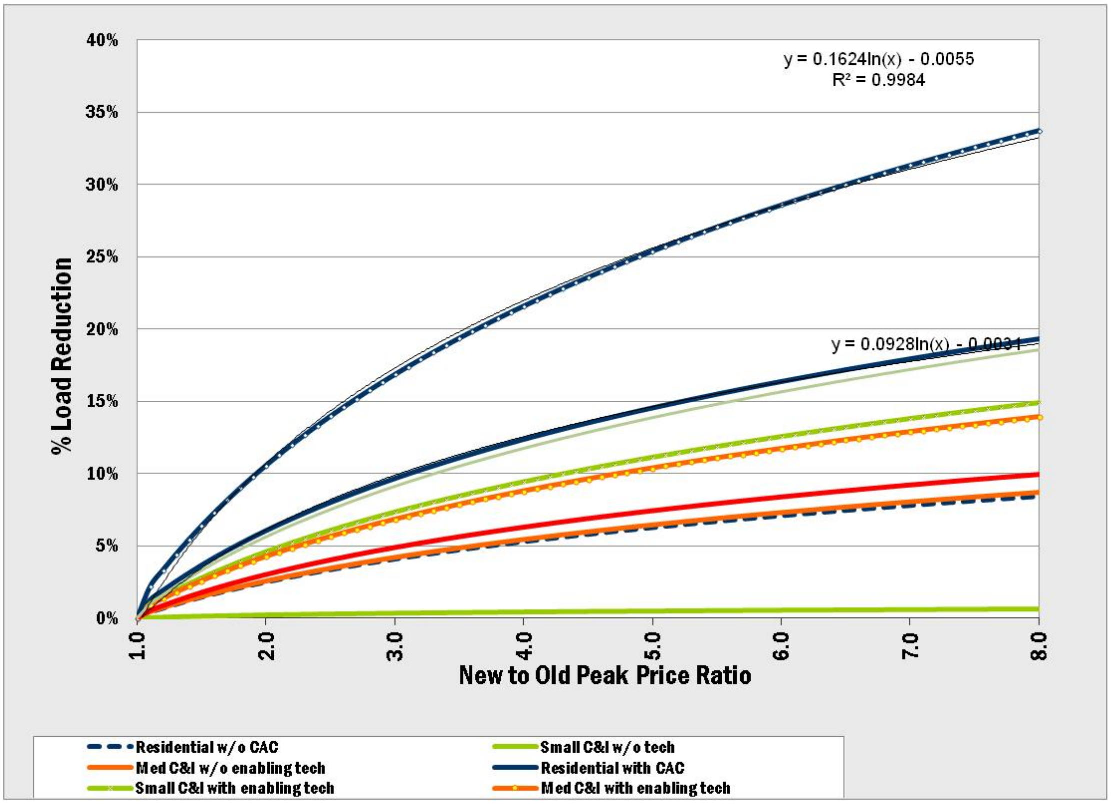


Figure 12: Percent Peak Load Reduction under Dynamic Pricing by Customer Type

Recognizing that load reduction percentages from dynamic pricing are key and depend on highly uncertain parameters led the ORNL team to select them as target for stochastic simulations. This involved substantial modifications to modeling of load reduction from dynamic pricing in the NADR model. That effort will be described in the next subsection.

4.2 STOCHASTIC SIMULATION

4.2.1 Initial Sensitivity Analysis with the Original NADR Model

Initial "uncertainty" analysis was conducted based on the results of FERC's *achievable participation* scenario to identify those parameter categories that are key drivers of DR potential. Refinement of those crucial parameters should subsequently receive the most time and effort. The selected variables for which the sensitivity analysis was conducted and the range of impacts are shown in Figure 13.

[14] NADR currently assumes that 40% of the large C&I customers and at least 70% of the small and medium C&I customers are eligible for enabling technology. There is wide variation in these percentages for the residential sector ranging from 2.5% in Alaska to 87.5% in Georgia.

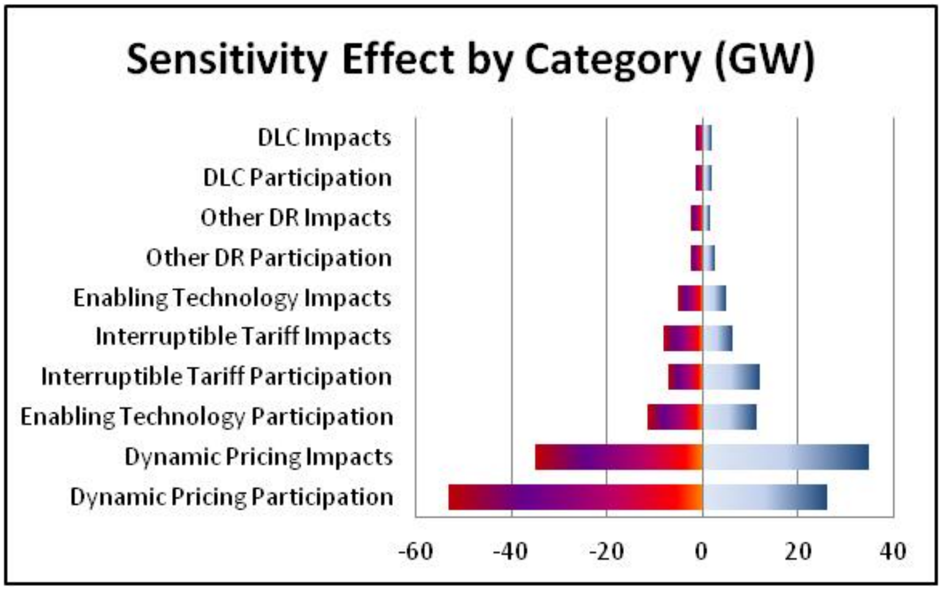


Figure 13: Sensitivity of Demand Response Potential to Selected Parameter Categories

The nominal impacts displayed in Figure 13 are transformed into elasticities in Figure 14 after identifying the range of values considered for each variable and the base DR potential under the *achievable participation* scenario.

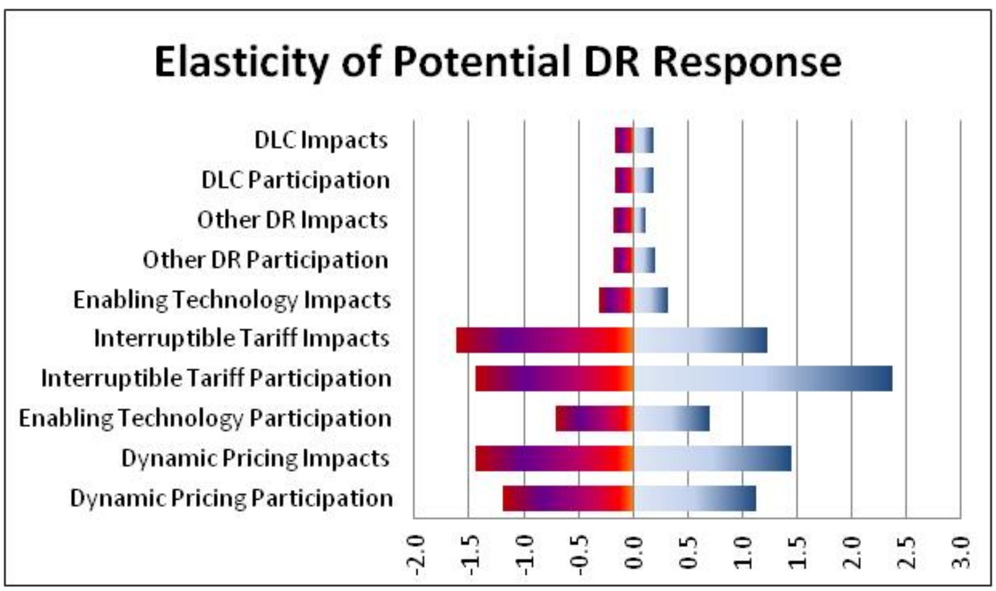


Figure 14: Elasticity of Demand Response Potential with respect to Selected Parameter Categories

Participation rates and impacts due to dynamic pricing and interruptible tariff programs are, by far, the main drivers of the DR potential that could be attained under the achievable participation scenario. Dynamic pricing impact was selected for further investigation using Monte Carlo simulation. Simulations were performed to demonstrate the effect of parameter changes on the distribution of demand response under dynamic pricing. This was done by in the original NADR model by replacing the price impact table with the functions fitted to this data as shown in Figure 12. Coefficients were specified as triangular distributions with lower and upper bounds assumed to be 70% and 130% of the estimated coefficients in

Figure 12. Figure 15 displays the resulting distribution of demand response and shows that the variation under dynamic pricing can be substantial.

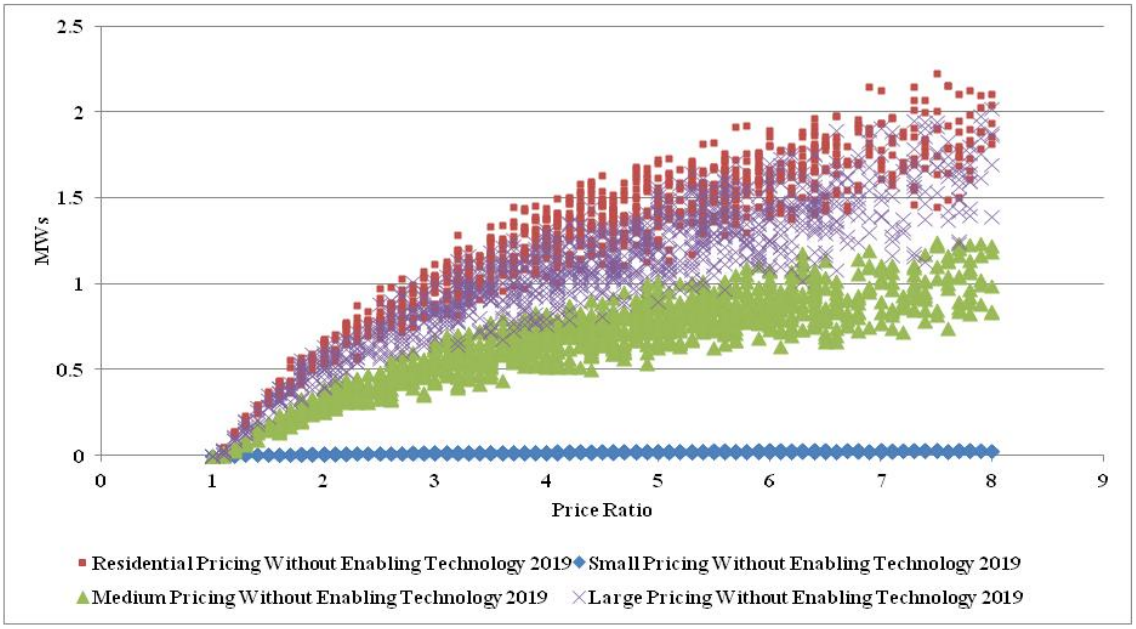


Figure 15: Relationship between Peak Load Reduction and Peak/Off-Peak Price Ratio (Maine, 2019)

4.2.2 Dynamic Pricing Demand Response Specification in the Updated NADR Model

The peak load reduction multipliers in the original NADR model were generated from results of simulations with PRISM (Pricing Impact Simulation Model). Percentage load reductions in PRISM are calculated using Constant Elasticity of Substitution (CES) functions. The CES function is given by Faruqui and Sergici (2010):

$$\ln\left(\frac{Q_p}{Q_{op}}\right) = \alpha + \sum_{i=1}^{n} \theta_i * D_i + \sigma * \ln\left(\frac{P_p}{P_{op}}\right) + \delta * \left(CDH_p - CDH_{op}\right) + \gamma * \left(CDH_p - CDH_{op}\right) * \ln\left(\frac{P_p}{P_{op}}\right) + \rho * CAC_i * \ln\left(\frac{P_p}{P_{op}}\right)$$

and implies an elasticity of substitution given as:

$$ES = \sigma + \gamma * \left(CDH_p - CDH_{op}\right) + \rho * (CAC)$$

where
Q_p, Q_{op} = Peak and Off-peak period average energy use per hour;
P_p, P_{op} = Peak and Off-peak period average energy use per hour
ES = Elasticity of substitution between peak and off-peak periods
D_i is a fixed effects variable that takes the value 1 for customer *i* and zero otherwise
CDH_p, CDH_{op} are cooling degree hours on peak and off-peak days
CAC_i is a dummy variable that takes the value 1 when a customer has central air conditioning

The ORNL team implemented the PRISM CES function directly in NADR to calculate peak load reductions on critical peak days. This enables more flexibility in investigating the determinants of customer demand response to price changes such as different elasticities, and accounts for changes in total domestic (or off-peak) customer load.

The elasticities used in the PRISM simulations to generate the impact multipliers in the original NADR model are shown in Table 5, and were also used for the CES function in this study. These parameters are based heavily on data collected from the California Pilot Survey on critical peak pricing and might not be an accurate representation of customer behavior in the Eastern Interconnection. Thus, further research that explores regional differences on the behavior of customers participating in dynamic pricing programs is needed.

Table 5: Daily and Substitution Elasticities for Simulating Dynamic Pricing Demand Response

	Residential			**Small C&I**		**Medium C&I**		**Large C&I**
	w/o CAC	with CAC	with tech.	w/o tech.	with tech.	w/o techn.	with tech.	w/o tech.
Critical Day Substitution Elasticity	-0.0472	-0.1383	-0.3523	-0.0010	-0.0892	-0.0412	-0.0815	-0.0500
Critical Day Daily Elasticity	-0.0330	-0.0487	-0.0677	-0.0010	-0.0250	-0.0250	-0.0250	-0.0200

In addition, state level average electricity price for 2011 were estimated for residential and C&I customers from EIA data (derived from Form EIA-826). This provides the data for the off-peak, and initial peak prices used in estimating demand response from dynamic pricing.

4.2.3 Monte Carlo Simulation of Demand Response under Dynamic Pricing

In addition to implementing the CES function, the ORNL team made additional changes to the NADR model to enable a Monte Carlo simulation of dynamic pricing programs. The main steps of the Monte Carlo analysis are:

1. Triangular distributions were attached to critical day substitution and daily elasticity parameters with the mean values set as in Table 5. Upper and lower bounds were specified as 30% and 200% of the mean levels, respectively. In the absence of information on the empirical distribution of each of these parameters or their correlation across customer categories all the parameters were driven by a single random variable in the Monte Carlo simulation. Thus, the distribution of these parameters are assumed to be perfectly correlated, so that they change in the same direction and by the same percentage on each draw. Variations in the critical price or critical price to off-peak price ratio were also specified as triangular distributions. A separate option was also implemented to simulate a fixed sequence of prices or price ratios. The simulations in this report are based on the latter option.
2. A Monte Carlo simulation consisting of 1000 simulations for each combination of state and scenario was performed. This consisted of five critical to off-peak price ratios (2, 5, 10, 15 and 20) and 200 draws of the elasticity parameters. There were a total of 148,000 replications for the 37 states of the Eastern Interconnection.

Summary statistics of the Monte Carlo simulation results at the national and regional levels are presented in the next sections. A table of summary statistics is also included in each state's profile in Appendix B.

5. EASTERN INTERCONNECTION DEMAND RESPONSE SCENARIO ANALYSIS RESULTS FROM UPDATED ORNL-NADR

This chapter summarizes the key findings and results from the ORNL-NADR assessment for the eastern interconnection. The demand response potentials are presented across scenarios, program types, customer classes, and regions and states. The state-by-state result summaries are in Appendix B.

5.1 EASTERN INTERCONNECTION (EI) RESULTS

Figure 16 illustrates the potential impact of demand response on peak demand over the analysis horizon.[15] The black dashed line represents an EI peak demand forecast that does not include any demand response, as provided by the North American Electric Reliability Corporation (NERC).[16] System peak demand begins at 569 GW in 2009 and grows at an average annual growth rate of 1.2%, reaching 724 GW by 2030. Peak demand under BAU grows at a very similar rate overall. The reduction in peak demand under BAU, relative to the No DR forecast is 41 GW by 2030 representing a 6% reduction in peak demand.[17] The Optimistic BAU scenario results in a further reduction in peak demand of 114 GW (16%). The Aggressive Deployment scenario produces even larger reduction in peak demand and reduces the peak demand in 2030 by 24% (171 GW). The Full Deployment scenario produces the largest reduction of 219 GW (30%) in 2030. The peak demand estimates under the Aggressive Deployment and Full Deployment scenarios show a dip between 2019 and 2020, after the reductions increase at constant rates. The pattern is a result of assumed market penetration schedule of new demand response programs and an Aggressive Deployment of AMI provided by the SGIG. The aggressive AMI deployment directly affects the growth of dynamic pricing programs over time. At higher DR penetration rates, the actual system peak will not be reduced by the full DR amount because the resource will be spread over more hours rather than concentrated at the system peak. Detailed discussions about the relationship between percentage peak load reduction and DR-effective hours are presented in Chapter 7.4.

---

[15] 2009 is considered to be the base year because the majority of input data were collected and updated from the year. 2030 is the end year of the analysis horizon.

[16] The No DR baseline is derived from 2010 NERC data for total summer demand, which excludes the effects of demand response but includes the effects of energy efficiency. The results from 2010 Long Term Reliability Assessment were inputted for updating system peak levels (Source: http://www.nerc.com/files/2010%20LTRA.pdf).

[17] The DR potential estimate under the ORNL's BAU scenario was comparable to the result of the assessment of demand response and energy efficiency potential released by Global Energy Partners in 2010 (Global Energy Partners 2010).

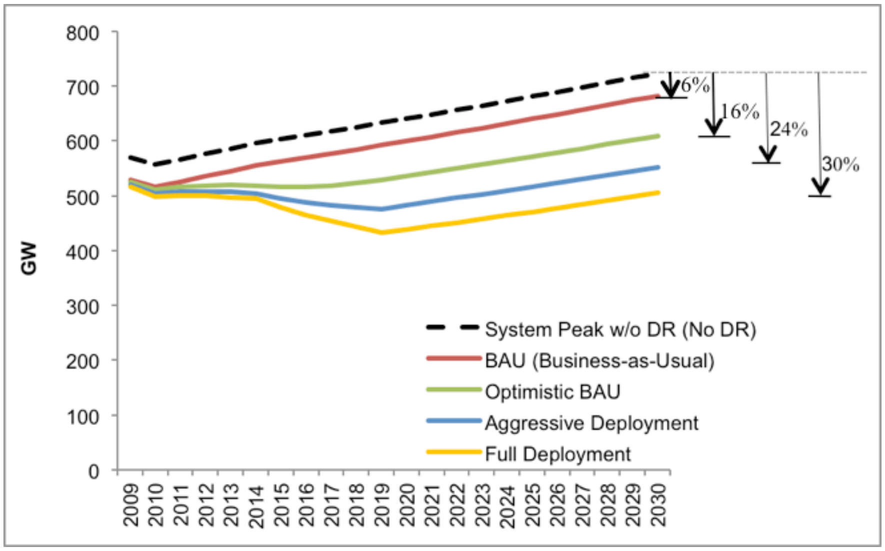


Figure 16: EI Summer Peak Demand Forecast by Scenario

The results of the four scenarios in ORNL-NADR are in fact estimates of potential, rather than projections of what is likely to occur. The numbers reported in this study should be interpreted as the amount of demand response that could potentially be achieved under a variety of assumptions about the types of programs pursued and the overall cost-effectiveness and penetration of the programs (FERC, 2009). By quantifying potential opportunities that exist in each state and region, these estimates can serve as a reference for understanding the various pathways for pursuing increased levels of demand response. As with any model-based analysis in economics, the estimates in this assessment are subject to a number of contingencies, most of them arising from limitations in the data that are used to estimate the model parameters (FERC, 2009).

Further, we must point out that the peak reductions due to DR in Figure 16 are based on the total amount of DR available. Most DR resources are only available for a limited number of hours over the year. As a consequence, not all DR will be called upon at the same time, especially if the DR represents a large fraction of demand. The full system peak may only fall by one half to two thirds of the DR depending on the load shape for the region and the time available for individual DR resources. This is described in more detail in Chapter 7.

The difference in peak load reduction between BAU and Optimistic BAU is 10 percent points in 2030. As explained earlier in chapter 4, the main difference in assumption is that how the FERC 731 survey represents the actual participation in demand response programs. The difference is how the potential for aggressively pursuing non-pricing programs is treated for the utilities that did not reported any existing participation to FERC. The Optimist BAU, Aggressive and Full Deployment scenarios use the imputed participation rates for non-reported utilities to FERC 731 survey. An econometric analysis was conducted for estimating the participation rate for non-reported utilities with the variables of summer peak, revenue, region, and program type. Under BAU and Optimistic BAU, the largest gains in demand response impacts can be made through interruptible tariffs and other demand response programs (Figure 17). On the other hand, a significant growth in pricing programs (with and without enabling technologies) is noticed under the Aggressive and Full Deployment scenarios. As different scenarios show their potentials in various degrees, so do the customer segments. DLC is the option that has a significant impact on the residential and small C&I sectors. The majority of demand response comes from large commercial and industrial customers primarily through interruptible tariffs and capacity and load bidding programs. However, in the residential sector, most untapped potential for demand response comes from the pricing programs. As seen below, the impacts from the residential class drives the major differences across the demand response potential scenarios.

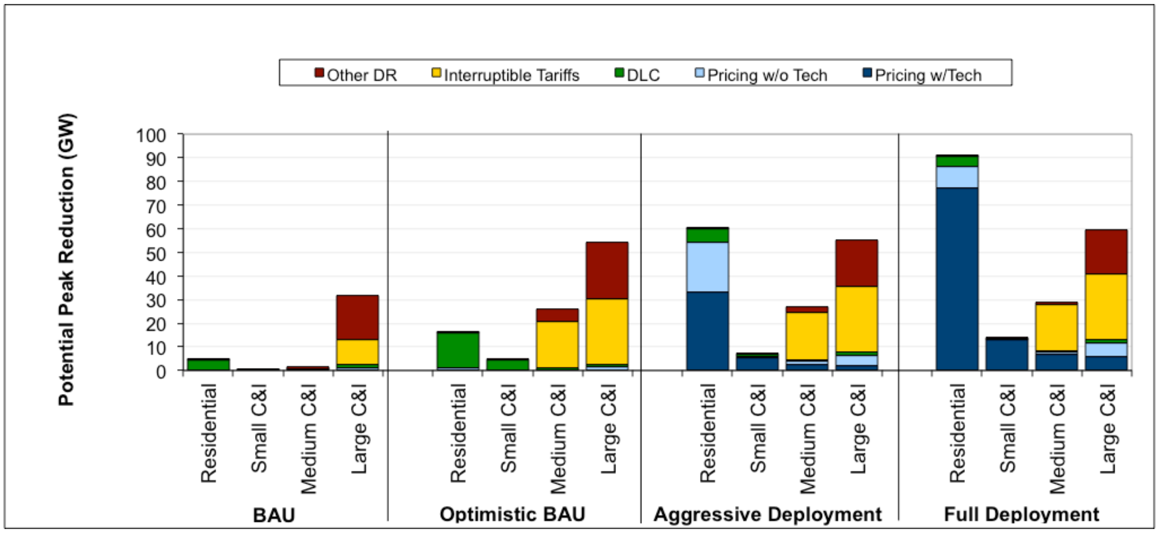


Figure 17: Potential Peak Reduction from Demand Response in EI, 2030

5.2 SUMMARY OF MONTE CARLO SIMULATION RESULTS AT EI LEVEL

The uncertainty in the estimates of demand response from pricing programs is investigated with a Monte Carlo simulation varying the critical-peak to off-peak price ratios, and the price response parameters in the CES function used to model dynamic pricing programs in the ORNL-NADR model. Table 6 presents the summary statistics from these simulations for the entire Eastern Interconnection for three price ratios (5, 10 and 15). It shows that under the BAU scenario pricing programs contribute only 3 GW to the total estimated DR in 2030 (41 GW), and all of these were from dynamic pricing without enabling technology. Under the Optimistic BAU scenario, the contribution from dynamic pricing slightly increased from 5 to 8 GW in 2030. The contribution of dynamic pricing without enabling technology increased substantially from 27 to 73 GW in the Aggressive Deployment scenario. Table 6 shows that contributions of dynamic pricing without technology in the Full Deployment scenario are about half of those in the Aggressive Deployment scenario. The results for pricing with technology programs show that the demand response are similar to those from the without technology program under the Aggressive Deployment scenario (41 GW to 118 GW), but much larger under the Full Deployment scenario (101 GW to 276 GW).

Table 6: Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in EI by Scenario, Pricing Program and Price, and Price Ratio (GW)

	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	3	3	3	3	3	3	3	3	3	3	3	3
10	3	3	3	3	3	3	3	3	3	3	3	3
15	3	3	3	3	3	3	3	3	3	3	3	3
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	4	4	4	5	4	5	5	4	5	5	4	5
10	5	4	5	6	5	6	6	5	7	6	5	7
15	5	4	6	6	5	7	7	6	8	7	6	8
Aggressive Deployment												
Pricing with Technology												
5	20	15	26	47	37	57	50	39	60	52	41	64
10	30	22	37	70	54	83	74	57	88	78	60	93
15	36	27	46	84	67	105	89	70	111	94	74	118
Pricing without Technology												
5	15	12	18	31	25	36	32	26	38	33	27	40
8	21	17	25	45	36	52	47	38	54	49	40	57
15	25	19	31	53	43	66	56	45	69	59	47	73
Full Deployment												
Pricing with Technology												
5	49	39	61	114	91	137	120	96	145	127	101	154
10	73	53	90	169	129	201	178	135	212	188	141	223
15	87	66	109	202	163	247	212	171	261	224	179	276
Pricing without Technology												
5	9	7	11	17	14	20	17	14	21	18	15	22
10	12	10	15	24	20	29	25	21	30	26	22	31
15	14	11	17	29	23	34	30	24	35	31	25	36

5.3 REGIONAL DISTRIBUTION OF DEMAND RESPONSE

Figure 18 shows the coverage of the Eastern Interconnection on the NERC map. In this study, the results were broken down at the level of census divisions to identify regional differences in demand response potential. Out of nine census divisions in the US, seven divisions such as the New England, Middle Atlantic, East North Central, West North Central, South Atlantic, East South Central, and West South Central census divisions are defined as the Eastern Interconnection area (Figure 19). Regional differences in demand response potential are driven by many factors including customer mix, market penetration of central air conditioning equipment, cost-effectiveness of new demand response programs, per-customer impacts from existing programs, participation in existing programs, and AMI deployment plans (FERC, 2009).

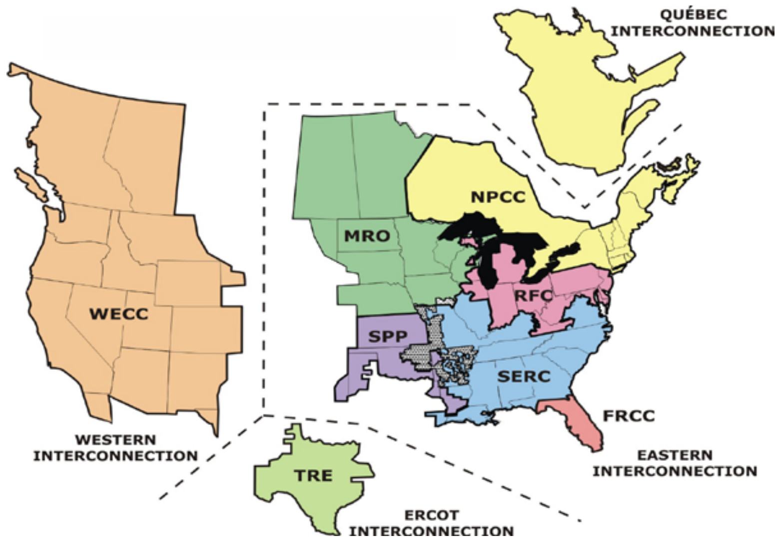


Figure 18: Coverage of EI on NERC Map (ERCOT 2012)

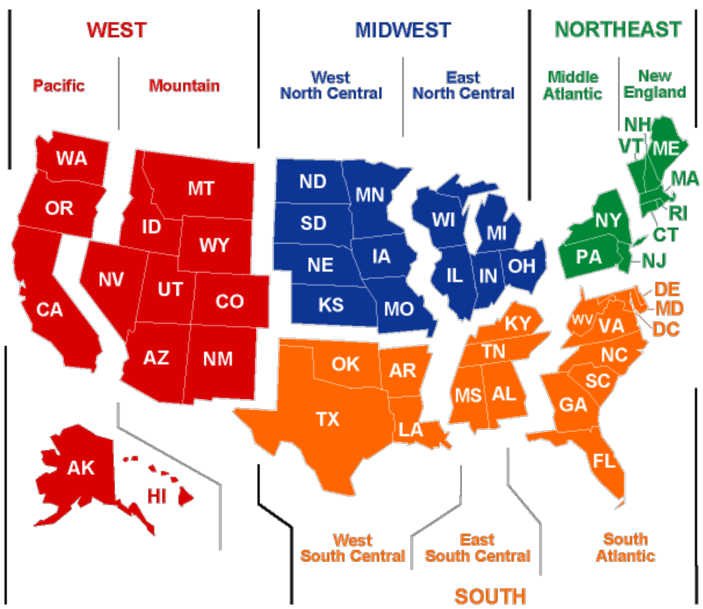


Figure 19: Census Regions and Divisions

A summary of the regional demand response potential estimates by scenario is provided in Figure 20. The regions show the largest existing (BAU) impacts have both wholesale demand response programs and utility/load serving entity programs. Thus, Middle Atlantic (9%) and New England (7%) have the highest estimates for the BAU scenario. On the other hand, regions in the South such as East South Central (2%) and West South Central (3%) show relatively small existing programs due to the deficiency of wholesale-organized markets. Central air conditioning saturation plays a key role in determining the magnitude of the Aggressive and Full Deployment demand response potentials. Regions have hotter climate that requires high central air conditioning systems such as the South Atlantic, East South Central, and West South Central Divisions could achieve greater average-per-customer impacts from DLC and dynamic pricing programs (FERC, 2009). As a result, these regions in the South tend to have larger overall potential under the Aggressive and Full Deployment scenarios where dynamic pricing plays a more significant role than in the BAU and Optimistic BAU scenarios.

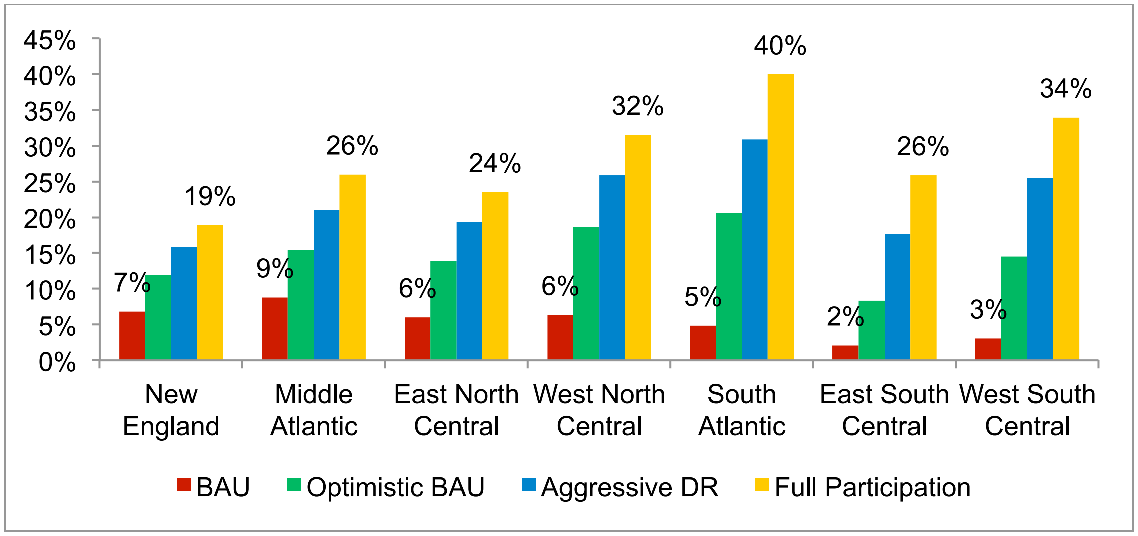


Figure 20: Demand Response Potential by Census Division and Scenario, 2030

At the most granular level, demand response potential was estimated for each 37 states[18] in the Eastern Interconnection Area. Florida does not have the highest penetration of demand response, though they are the number-one state in system peak (Figure 21 and Figure 22). However, Pennsylvania and New York have actively deployed high levels of demand response to cope with their high system peak demand.

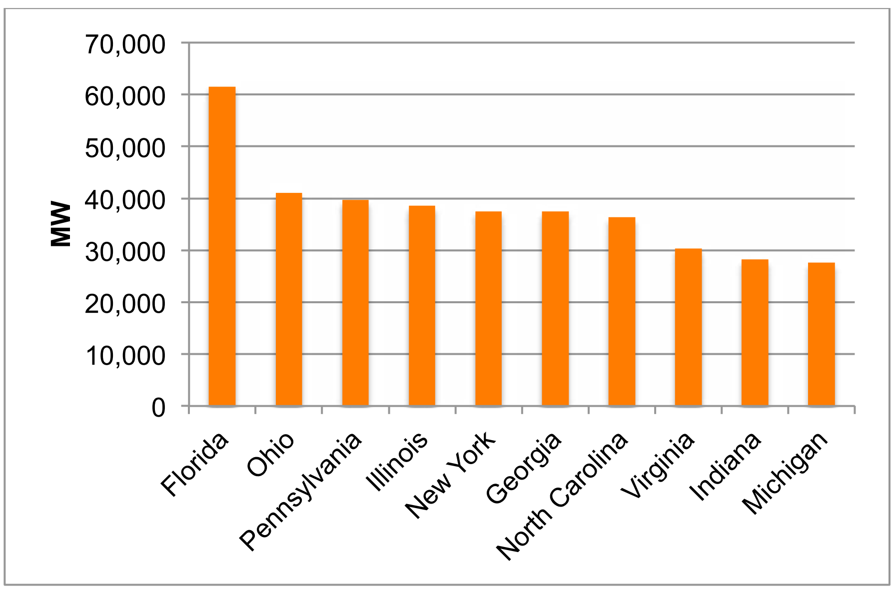


Figure 21: System Peak by State

[18] This study includes 37 states in the Eastern Interconnection: Alabama, Arkansas, Connecticut, DC, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Nebraska, New Hampshire, New Jersey, New York, North Carolina, North Dakota, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Vermont, West Virginia, and Wisconsin.

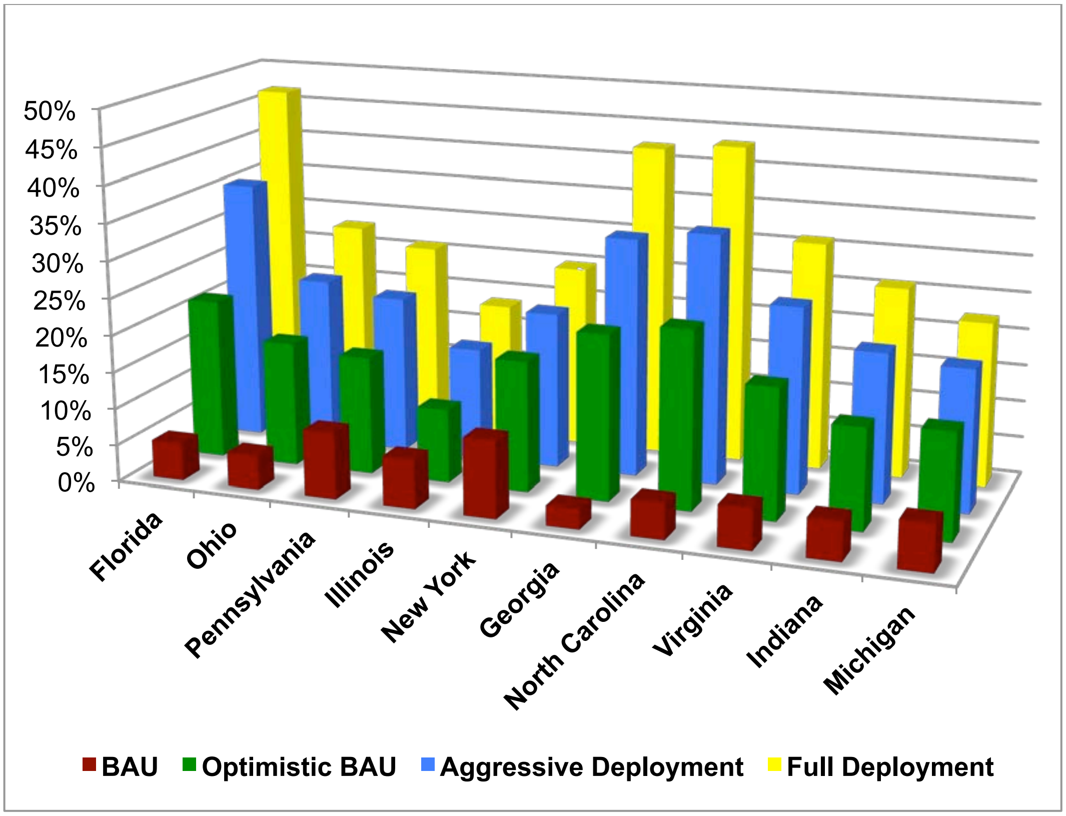


Figure 22: Top 10 States in System Peak (Y-axis: % Peak Load Reduction)

Figure 23 shows top 10 states in the demand response potential under BAU. Maine shows a 15% peak load reduction already under BAU. Because the already untapped amount of demand response is large under BAU, its growth of demand response is relatively small in the Full Deployment scenario. Oklahoma, Iowa, and Arkansas have a high level of demand response under BAU and have a great potential to grow as well thanks to the high CAC saturation rate and interruptible load resources.

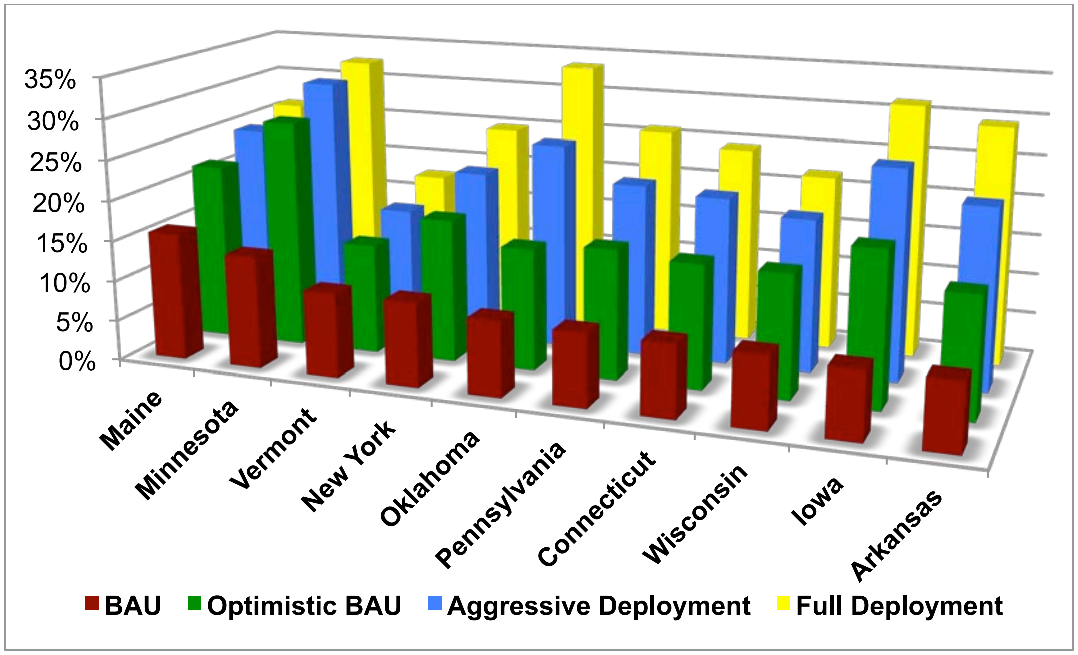


Figure 23: Top 10 States in Demand Response Potential under BAU (Y-axis: % Peak Load Reduction)

Under the Full deployment scenario, a significant growth in % peak load reduction is anticipated in the southern states, because of the high level of CAC saturation and relatively large untapped demand response potentials today (Figure 24).

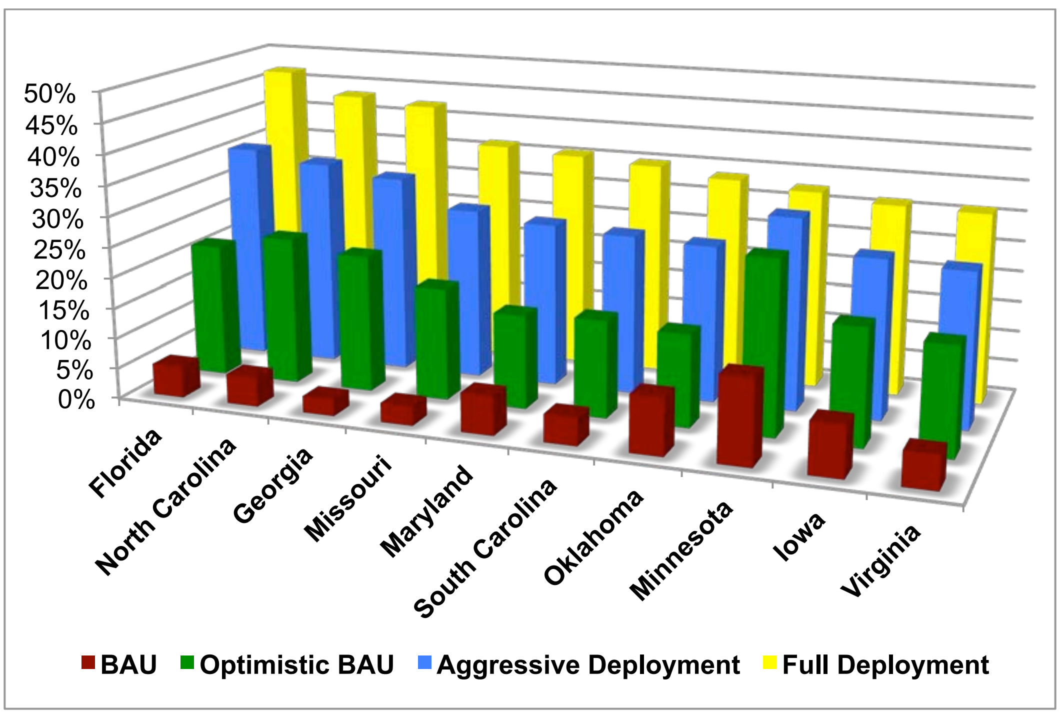


Figure 24: Top 10 States in DR Potential under Full Deployment (Y-axis: Peak Load Reduction)

5.4 REGIONAL RESULT PROFILES

New England Census Division Profile

The New England census division is comprised of Maine, New Hampshire, Vermont, Massachusetts, Connecticut, and Rhode Island. The summer peak of the division is 24 GW and the winter peak is 19 GW. The division has a 1% AMI penetration rate and a 17% CAC penetration rate.

In the year 2030, the system peak without DR would be 33 GW, the DR potential peak load reduction will be 2 GW (7%) under BAU, 4 GW (12%) under Optimistic BAU, 5 GW (16%) under Aggressive Deployment, and 6 GW (19%) under Full Deployment (Figure 25).

Key drivers of New England's demand response potential include Other DR such as capacity bidding and interruptible tariffs. The potential from pricing programs grows under Aggressive Deployment and Full Deployment scenarios. Many large C&I customers participate in New England RTO's Forward Capacity Market, a market for bidding demand reductions. This participation is captured in the Other DR program category, which is the primary source of the strong peak load reductions under the BAU and all other scenarios. Low CAC saturation in this division restricts residential participation (Figure 26).

Table 7 provides summary statistics of the Monte Carlo simulation for dynamic pricing programs in the New England census division. Demand response from the pricing without technology program was about 91 MW under the BAU scenario, and increased slightly under the Optimistic BAU scenario to a range of 109 to 177 MW in 2030. In the Aggressive and Full Deployment scenarios the range of demand response is 352 to 2044 MW in 2030. Demand response from the pricing with technology program are zero in the first two scenarios, but are 197 to 1494 MW and 536 to 3581 MW under the Aggressive and Full Deployment scenarios, respectively.

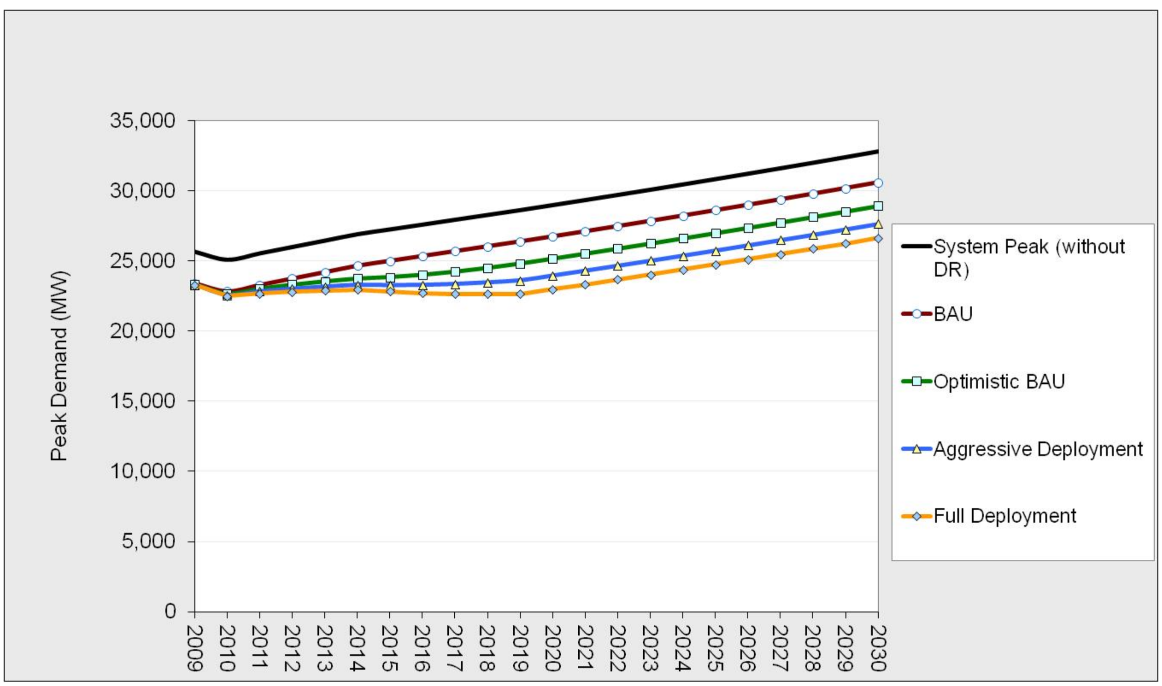


Figure 25: New England Division System Peak Demand Forecasts by Scenario

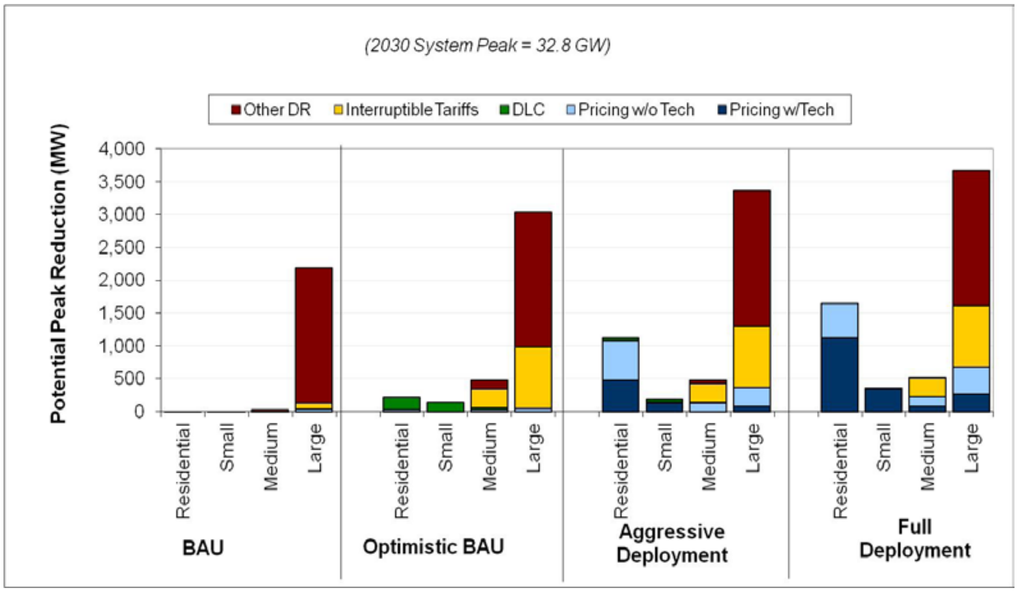


Figure 26: New England Division DR Potential in 2030, by Scenario

Table 7: Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in New England by Scenario, Pricing Program, and Price Ratio (MW)

	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	91	91	91	91	91	91	91	91	91	91	91	91
10	91	91	91	91	91	91	91	91	91	91	91	91
15	91	91	91	91	91	91	91	91	91	91	91	91
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	118	102	130	123	108	137	124	109	138	125	109	139
10	130	109	146	138	115	157	139	116	158	140	116	160
15	136	107	159	147	113	173	148	114	175	149	114	177
Aggressive Deployment												
Pricing with Technology												
5	248	83	366	553	187	824	566	192	842	579	197	861
10	365	152	555	813	360	1253	831	370	1281	851	380	1311
15	443	180	653	985	402	1429	1007	412	1461	1031	423	1494
Pricing without Technology												
5	400	234	528	733	340	1021	750	346	1044	766	352	1068
8	560	331	753	1067	605	1529	1092	621	1565	1118	637	1601
15	668	345	955	1294	711	1798	1324	729	1840	1355	748	1884
Full Deployment												
Pricing with Technology												
5	591	220	896	1337	509	1994	1369	522	2039	1401	536	2084
10	896	370	1345	2002	847	3021	2048	871	3090	2096	895	3161
15	1013	381	1593	2290	886	3425	2343	907	3502	2398	928	3581
Pricing without Technology												
5	415	228	552	782	374	1085	801	383	1112	820	393	1139
10	593	321	833	1155	653	1611	1183	669	1651	1213	685	1691
15	679	370	964	1338	693	1947	1371	710	1995	1405	728	2044

Middle Atlantic Census Division Profile

The Middle Atlantic census division is comprised of New Jersey, New York, and Pennsylvania. The summer peak of the division is 85 GW and the winter peak is 66 GW. The division has a 9% AMI penetration rate and a 41% CAC penetration rate.

In the year 2030, the system peak without DR would be 98 GW, the DR potential peak load reduction will be 9 GW (9%) under BAU, 15 GW (15%) under Optimistic BAU, 21 GW (21%) under Aggressive Deployment, and 26 GW (26%) under Full Deployment (Figure 27).

Similar to New England states, the Middle Atlantic states experience high levels of participation in DR programs offered through organized markets. New Jersey, New York, and Pennsylvania currently have high levels of Large C&I participation in PJM and NYISO capacity market DR programs, and these levels remain high throughout all four scenarios. New Jersey and Pennsylvania experience high levels of growth in pricing programs with enabling technologies under the Aggressive Deployment and Full Deployment scenarios, thanks to the moderate (~50%) rates of CAC saturation in each state. Significant AMI deployment is projected in the next few years through SGIG (Smart Grid Investment Grant)-funded projects under American Recovery and Reinvestment Act of 2009 (Figure 28).

Table 8 provides summary statistics of the Monte Carlo simulation for dynamic pricing programs in the Middle Atlantic census division. Demand response from the pricing without technology program was about 68 MW under the BAU scenario, and increased slightly under the Optimistic BAU scenario to a range of 120 to 439 MW in 2030. In the Aggressive and Full Deployment scenarios the range of demand response is 642 to 5930 MW in 2030. Demand response from the pricing with technology program are zero in the first two scenarios, but are 1582 to 9552 MW and 3831 to 21177 MW under the Aggressive and Full Deployment scenarios, respectively.

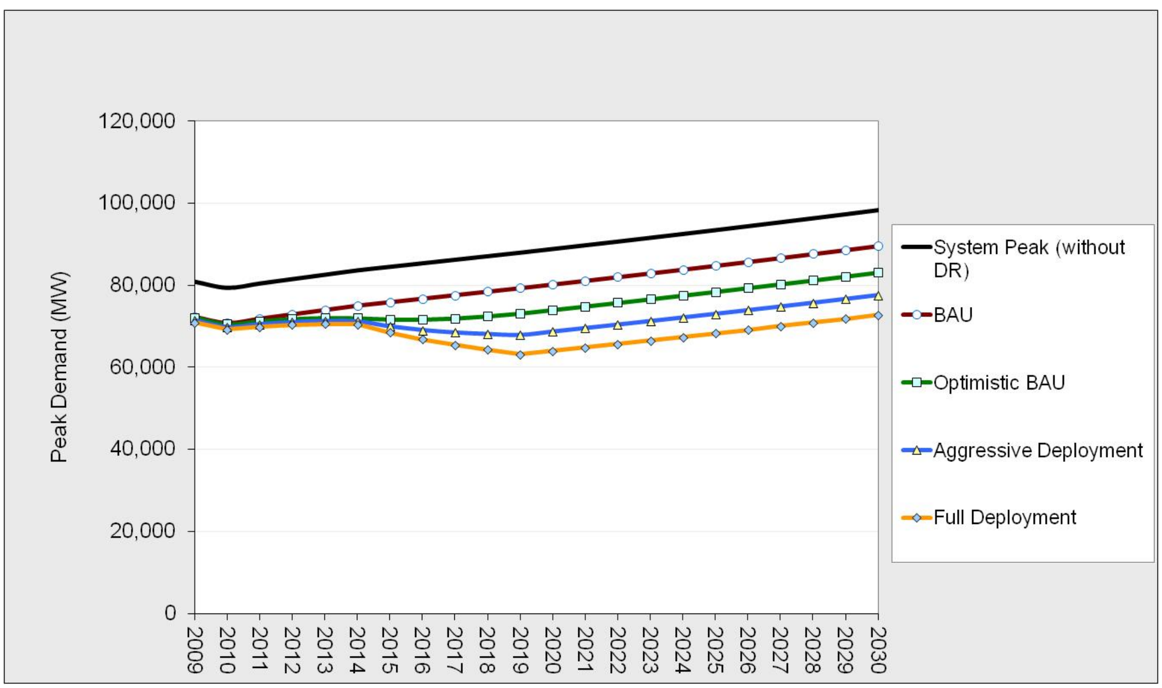


Figure 27: Middle Atlantic Division System Peak Demand Forecasts by Scenario

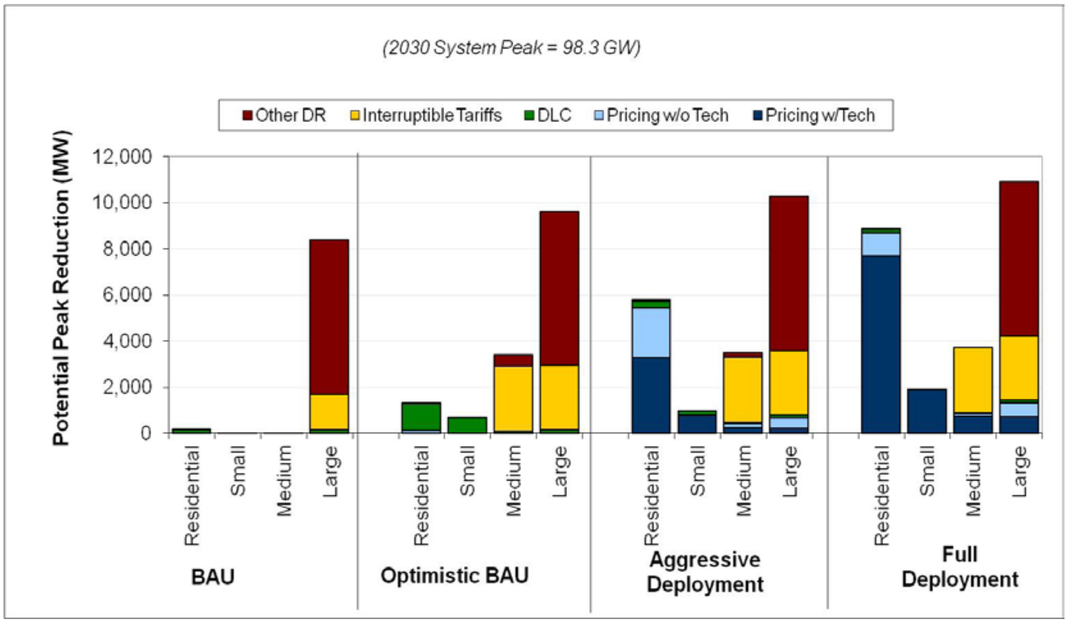


Figure 28: Middle Atlantic Division DR Potential in 2030, by Scenario

Table 8: Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in Middle Atlantic by Scenario, Pricing, and Price Ratio (MW)

	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	68	68	68	68	68	68	68	68	68	68	68	68
10	68	68	68	68	68	68	68	68	68	68	68	68
15	68	68	68	68	68	68	68	68	68	68	68	68
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	120	86	142	198	118	254	200	119	257	203	120	261
10	142	97	185	258	160	364	261	162	369	264	163	374
15	159	99	212	303	157	427	307	159	433	311	160	439
Aggressive Deployment												
Pricing with Technology												
5	1076	423	1654	3436	1533	5244	3495	1558	5335	3556	1582	5428
10	1625	555	2391	5190	1930	7662	5279	1962	7795	5370	1994	7932
15	1908	664	2926	6091	2310	9236	6197	2347	9393	6304	2386	9552
Pricing without Technology												
5	698	311	1042	2106	1015	3200	2138	1028	3248	2172	1042	3298
8	1035	393	1503	3211	1260	4729	3260	1278	4803	3311	1296	4878
15	1210	463	1836	3771	1516	5755	3829	1537	5841	3888	1558	5930
Full Deployment												
Pricing with Technology												
5	2588	1026	3970	8235	3711	12495	8377	3770	12708	8522	3831	12926
10	3764	1440	5679	12021	5123	17501	12230	5206	17791	12444	5290	18087
15	4652	2030	6713	14758	7003	20500	15013	7113	20835	15273	7225	21177
Pricing without Technology												
5	438	218	644	1301	625	1974	1320	633	2003	1340	642	2033
10	618	286	932	1889	926	2874	1918	943	2916	1947	960	2959
15	763	323	1116	2353	986	3429	2389	1004	3479	2424	1022	3529

East North Central Census Division Profile

The East North Central census division is comprised of Michigan, Wisconsin, Ohio, Indiana, and Illinois. The summer peak of the division is 200 GW and the winter peak is 161 GW. The division has a 6% AMI penetration rate and a 61% CAC penetration rate.

In the year of 2030, the system peak without DR would be 154 GW, the DR potential peak load reduction will be 9 GW (6%) under BAU, 21 GW (14%) under Optimistic BAU, 30 GW (19%) under Aggressive Deployment, and 36 GW (24%) under Full Deployment (Figure 29).

Heavy and energy-intensive industries are prevalent in this division. Michigan's interruptible tariff program is one of the largest in the country in terms of MW reduction. At the same time, this division exhibits a great potential for DR, particularly in pricing programs due to the above-average CAC saturations in three of its largest states (Wisconsin, Ohio, and Indiana). Throughout all four scenarios, Illinois and Michigan maintain high levels of C&I participation in Other DR and Interruptible Tariffs. The East North Central census division shows a very similar participation pattern to the Eastern Interconnection overall (Figure 30).

Table 9 provides summary statistics of the Monte Carlo simulation for dynamic pricing programs in the East North Central census division. Demand response from the pricing without technology program was about 176 MW under the BAU scenario, and increased to a range of 302 to 704 MW in 2030 under the Optimistic BAU scenario. In the Aggressive and Full Deployment scenarios the range of demand response is 2424 to 12370 MW in 2030. Demand response from the pricing with technology program are zero in the first two scenarios, but are 1447 to 9342 MW and 3517 to 22350 MW under the Aggressive and Full Deployment scenarios, respectively.

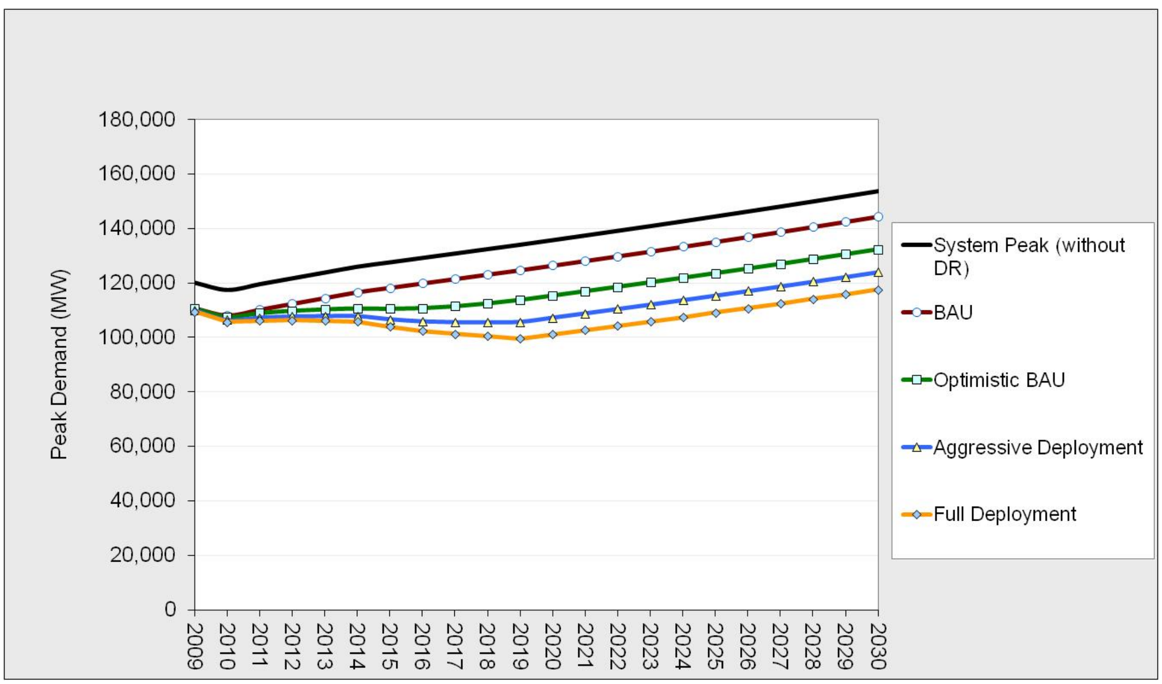


Figure 29: East North Central Division System Peak Demand Forecasts by Scenario

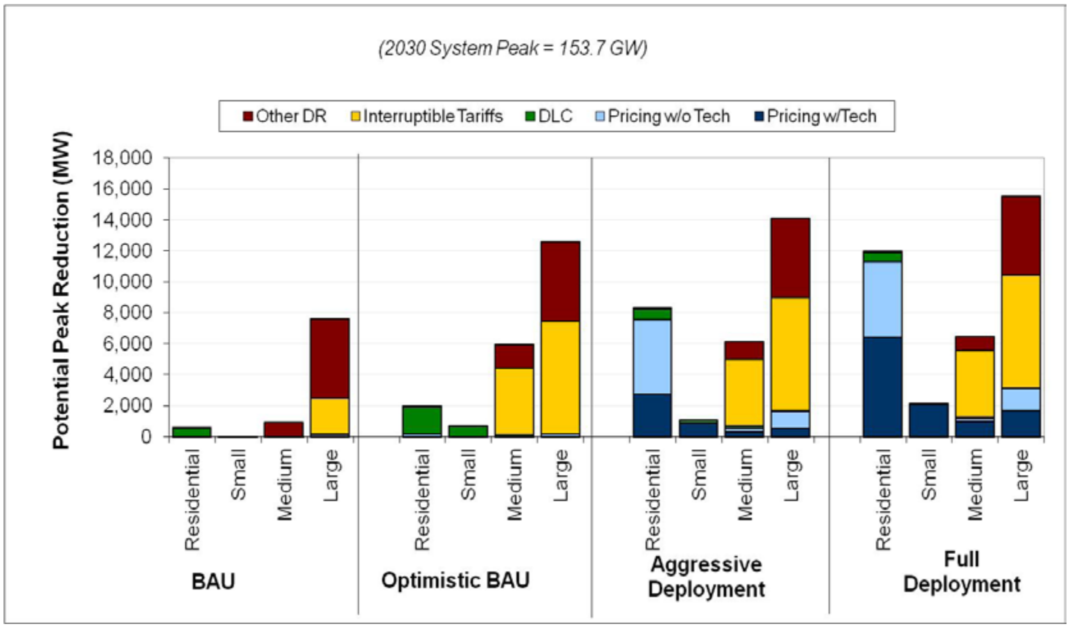


Figure 30: East North Central Division DR Potential in 2030, by Scenario

Table 9: Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in East North Central by Scenario, Pricing Program, and Price Ratio (MW)

	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	176	176	176	176	176	176	176	176	176	176	176	176
10	176	176	176	176	176	176	176	176	176	176	176	176
15	176	176	176	176	176	176	176	176	176	176	176	176
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	321	250	388	375	297	464	380	300	470	384	302	476
10	392	255	507	473	297	618	479	300	627	486	302	636
15	438	290	555	538	343	682	546	346	693	553	350	704
Aggressive Deployment												
Pricing with Technology												
5	1450	651	1988	3436	1372	4788	3512	1409	4887	3590	1447	4989
10	2096	926	2967	4960	2036	7115	5070	2091	7262	5183	2148	7415
15	2590	1126	3655	6133	2401	8961	6268	2465	9148	6407	2531	9342
Pricing without Technology												
5	2317	1279	3209	4651	2546	6344	4741	2586	6471	4833	2628	6602
8	3367	1569	4890	6838	3426	9801	6973	3492	9995	7111	3559	10193
15	4061	2272	5753	8314	4953	11494	8479	5050	11725	8648	5148	11962
Full Deployment												
Pricing with Technology												
5	3568	1662	5353	8313	3332	12632	8503	3423	12913	8699	3517	13203
10	5306	2637	7546	12388	5684	18006	12670	5848	18394	12962	6019	18794
15	6316	3345	9077	14824	7237	21420	15162	7451	21878	15512	7672	22350
Pricing without Technology												
5	2521	1215	3532	4807	2321	6738	4909	2372	6881	5013	2424	7028
10	3700	1749	5319	7209	3555	10543	7363	3641	10770	7523	3730	11003
15	4361	2414	6189	8502	4482	11868	8686	4582	12116	8875	4684	12370

West North Central Census Division Profile

The West North Central census division is comprised of North Dakota, Minnesota, South Dakota, Iowa, Nebraska, Kansas, and Missouri. The summer peak of the division is 92 GW and the winter peak is 79 GW. The division has a 9 % AMI penetration rate and a 71% CAC penetration rate.

In the year of 2030, the system peak without DR would be 78 GW, the DR potential peak load reduction will be 5 GW (6%) under BAU, 15 GW (19%) under Optimistic BAU, 20 GW (26%) under Aggressive Deployment, and 25 GW (32%) under Full Deployment (Figure 31).

Due to high levels of CAC saturation in its western-most states and large Interruptible Tariff programs in Iowa, Nebraska, and Minnesota, the West North Central census division develops a very well-rounded DR program portfolio under scenarios of higher participation; Interruptible Tariff programs for large C&I customers maintain high levels of participation, and pricing programs grow tremendously under Aggressive and Full Deployment scenarios. Enabling technologies are not cost-effective for many customers in this division (e.g., Minnesota), however, resulting in higher-than-usual levels of DLC and Pricing without Tech program participation. This division shows a good combination of multiple programs (Figure 32).

Table 10 provides summary statistics of the Monte Carlo simulation for dynamic pricing programs in the West North Central census division. Demand response from the pricing without technology program was about 631 MW under the BAU scenario, and increased to a range of 675 to 900 MW in 2030 under the Optimistic BAU scenario. In the Aggressive and Full Deployment scenarios the range of demand response is 1227 to 6655 MW in 2030. Demand response from the pricing with technology program are zero in the first two scenarios, but are 1616 to 8834 MW and 4336 to 21778 MW under the Aggressive and Full Deployment scenarios, respectively.

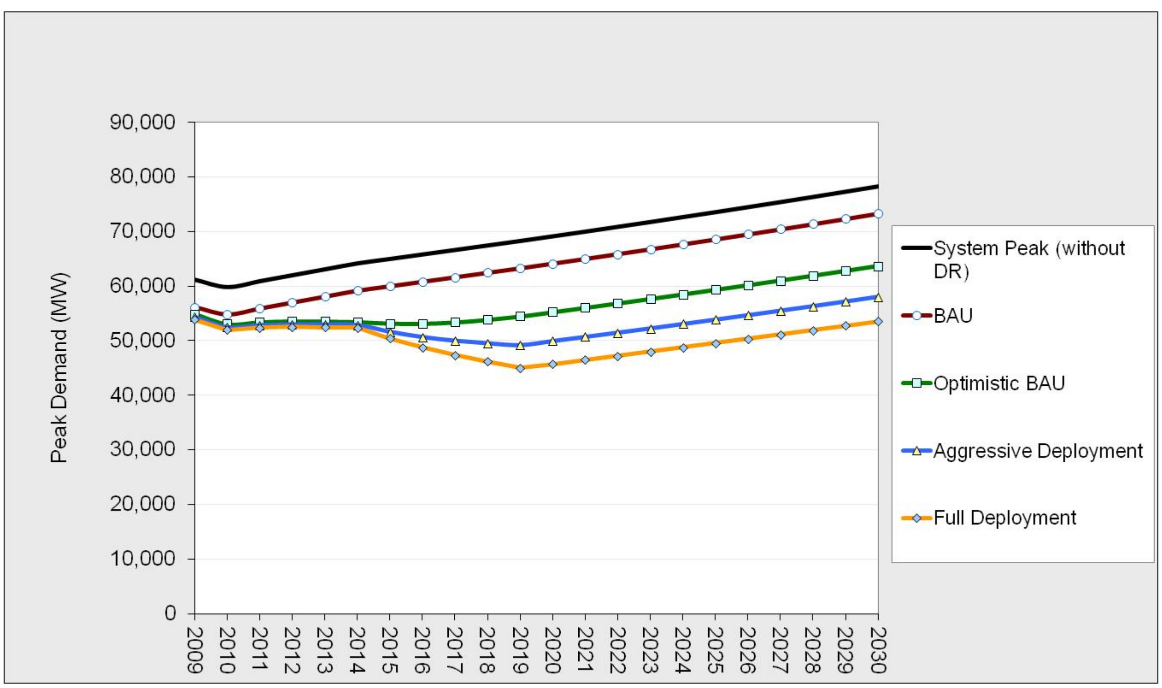


Figure 31: West North Central Division System Peak Demand Forecasts by Scenario

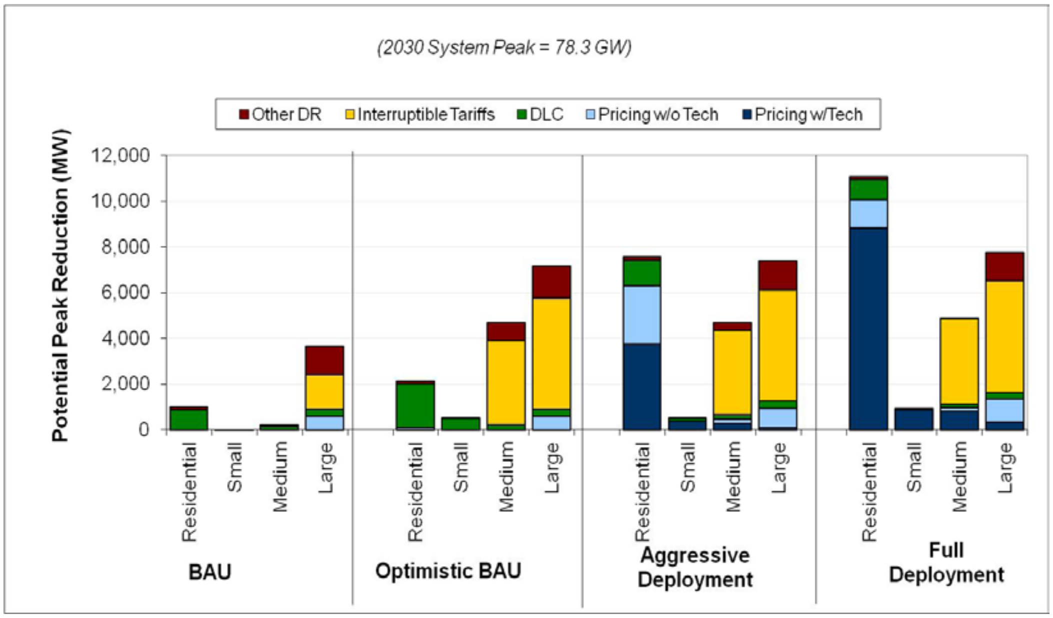


Figure 32: West North Central Division DR Potential in 2030, by Scenario

Table 10: Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in West North Central by Scenario, Pricing Program, and Price Ratio (MW)

	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	631	631	631	631	631	631	631	631	631	631	631	631
10	631	631	631	631	631	631	631	631	631	631	631	631
15	631	631	631	631	631	631	631	631	631	631	631	631
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	674	651	689	733	673	769	736	674	773	739	675	777
10	694	659	720	783	697	848	787	699	855	792	701	862
15	706	674	733	814	735	884	819	738	892	825	741	900
Aggressive Deployment												
Pricing with Technology												
5	967	440	1363	3334	1527	4641	3423	1571	4764	3515	1616	4891
10	1456	673	2026	5021	2464	7005	5156	2536	7191	5295	2609	7382
15	1674	782	2440	5788	2700	8386	5944	2777	8607	6104	2857	8834
Pricing without Technology												
5	1201	901	1436	2756	1674	3654	2824	1706	3753	2895	1739	3858
8	1496	1091	1845	3860	2411	5207	3966	2465	5361	4075	2520	5520
15	1642	1158	2128	4426	2507	6280	4550	2563	6464	4679	2621	6655
Full Deployment												
Pricing with Technology												
5	2310	1155	3256	7951	4105	11228	8167	4219	11526	8389	4336	11833
10	3454	1525	5082	11907	5479	17307	12229	5630	17769	12559	5787	18244
15	4049	2128	6078	13929	7410	20662	14307	7612	21212	14696	7820	21778
Pricing without Technology												
5	914	769	1057	1814	1178	2438	1864	1200	2516	1916	1227	2597
10	1050	815	1246	2409	1396	3263	2484	1431	3373	2563	1467	3488
15	1141	830	1393	2807	1528	3888	2900	1568	4042	2997	1609	4202

South Atlantic Census Division Profile

The South Atlantic census division is comprised of Delaware, Maryland, DC, West Virginia, Virginia, North Carolina, South Carolina, Georgia, Florida. The summer peak of the division is 210 GW and the winter peak is 211 GW. The division has a 6% AMI penetration rate and 78% CAC penetration rate.

In the year of 2030, the system peak without DR would be 220 GW, the DR potential peak load reduction will be 11 GW (5%) under BAU, 45 GW (21%) under Optimistic BAU, 68 GW (31%) under Aggressive Deployment, and 88 GW (40%) under Full Deployment (Figure 33).

Under the Aggressive Deployment and Full Deployment scenarios, all states in the South Atlantic division experience large growth in residential pricing programs (except for Washington, DC, for which enabling technologies are not cost-effective) due to the medium-to-high-levels of CAC saturation in the division. Certain states, such as Maryland and West Virginia, also maintain high participation from Large C&I customers in Other DR and Interruptible Tariffs. Most states in the South Atlantic currently exhibit small DR activities (as reflected in the BAU), making the South Atlantic a high potential division for DR (Figure 34).

Table 11 provides summary statistics of the Monte Carlo simulation for dynamic pricing programs in the South Atlantic census division. Demand response from the pricing without technology program was about 190 MW under the BAU scenario, and increased to a range of 561 to 2026 MW in 2030 under the Optimistic BAU scenario. In the Aggressive and Full Deployment scenarios the range of demand response is 1231 to 21713 MW in 2030. Demand response from the pricing with technology program are zero in the first two scenarios, but are 9567 to 43761 MW and 17331 to 104944 MW under the Aggressive and Full Deployment scenarios, respectively.

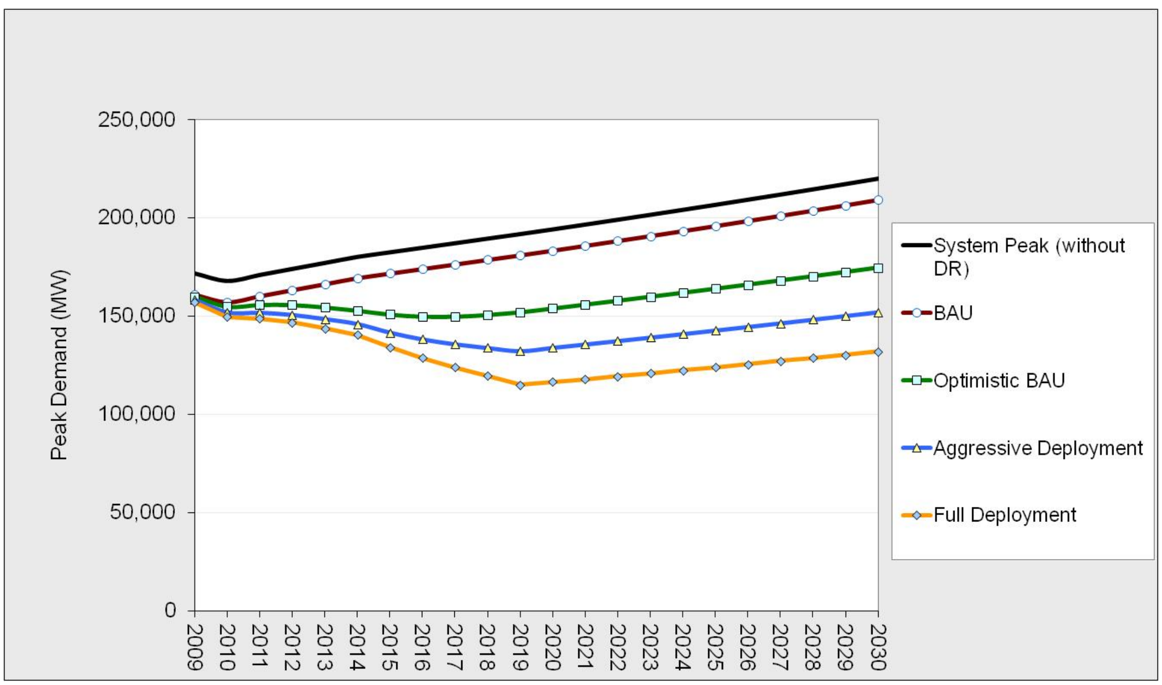


Figure 33: South Atlantic Division System Peak Demand Forecasts by Scenario

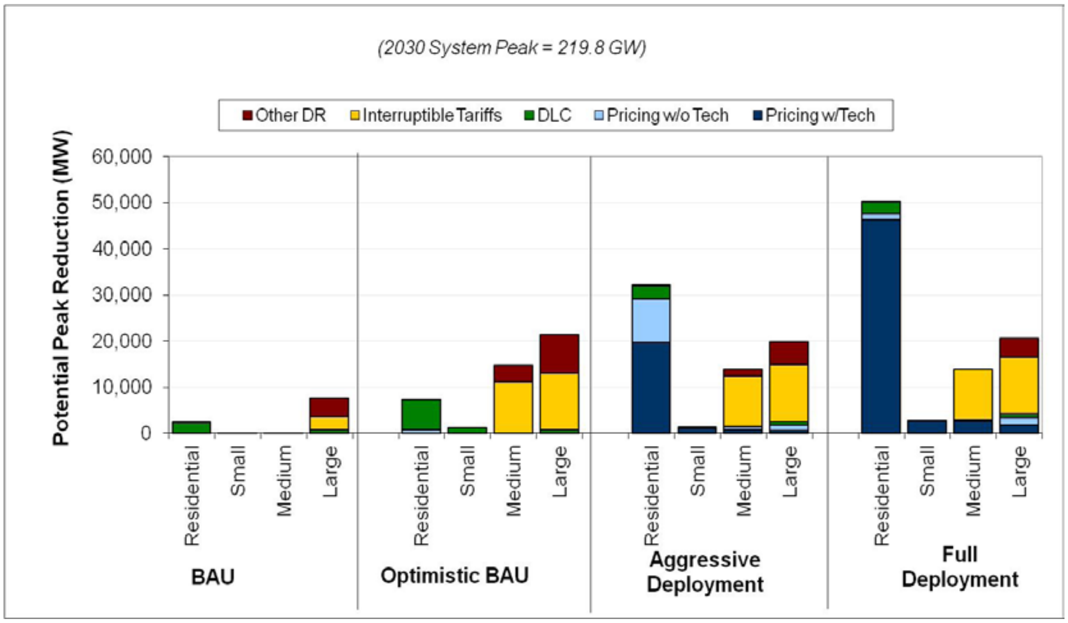


Figure 34: South Atlantic Division DR Potential in 2030, by Scenario

Table 11: Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in South Atlantic by Scenario, Pricing Program, and Price Ratio (MW)

	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	190	190	190	190	190	190	190	190	190	190	190	190
10	190	190	190	190	190	190	190	190	190	190	190	190
15	190	190	190	190	190	190	190	190	190	190	190	190
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	547	381	718	805	514	1075	854	537	1147	908	561	1225
10	728	454	972	1099	654	1501	1170	687	1606	1247	722	1719
15	852	553	1093	1315	796	1763	1403	839	1890	1499	886	2026
Aggressive Deployment												
Pricing with Technology												
5	6544	3407	8884	14781	8422	20288	15868	8974	21835	17043	9567	23510
10	9736	5775	13486	21946	11860	29839	23559	12649	32128	25301	13495	34606
15	11844	7196	16728	26657	16394	37802	28622	17493	40664	30744	18671	43761
Pricing without Technology												
5	3388	1899	4507	7423	4424	10095	7951	4697	10844	8522	4990	11654
8	4993	3076	6787	11032	6303	15001	11821	6704	16118	12671	7133	17326
15	6059	3834	8427	13419	8262	18820	14380	8801	20210	15418	9378	21713
Full Deployment												
Pricing with Technology												
5	15808	6442	22627	35687	15297	50760	38312	16278	54539	41148	17331	58626
10	23254	13068	31966	52618	30130	72770	56502	32139	78250	60700	34294	84181
15	28036	16627	40482	63218	35619	90903	67869	37969	97508	72893	40490	104944
Pricing without Technology												
5	1081	614	1436	2147	1119	2983	2278	1173	3170	2418	1231	3370
10	1551	984	2006	3164	2068	4178	3358	2187	4442	3566	2314	4724
15	1873	1211	2690	3842	2389	5581	4078	2521	5926	4330	2663	6295

East South Central Census Division Profile

The East South Central census division is comprised of Kentucky, Tennessee, Mississippi, and Alabama. The summer peak of the division is 104 GW and the winter peak is 102 GW. The division has a 8% AMI penetration rate and a 81% CAC penetration rate.

In the year of 2030, the system peak without DR would be 90 GW, the DR potential peak load reduction will be 2 GW (2%) under BAU, 7 GW (8%) under Optimistic BAU, 16 GW (18%) under Aggressive Deployment, and 23 GW (26%) under Full Deployment (Figure 35).

The Growth in DR peak load reduction is largely driven by the Residential pricing programs. The high levels of CAC saturation in this division drive this growth in DR activity. Also, most states in the East South Central division do not currently maintain high levels of DR participation. Alabama, which maintains high participation by Large C&I in Interruptible Tariffs programs, is a notable exception (Figure 36).

Table 12 provides summary statistics of the Monte Carlo simulation for dynamic pricing programs in the East South Central census division. Demand response from the pricing without technology program was about 140 MW under the BAU scenario, and increased to a range of 193 to 512 MW in 2030 under the Optimistic BAU scenario. In the Aggressive and Full Deployment scenarios the range of demand response is 501 to 7311 MW in 2030. Demand response from the pricing with technology program are zero in the first two scenarios, but are 3322 to 15003 MW and 7228 to 35326 MW under the Aggressive and Full Deployment scenarios, respectively.

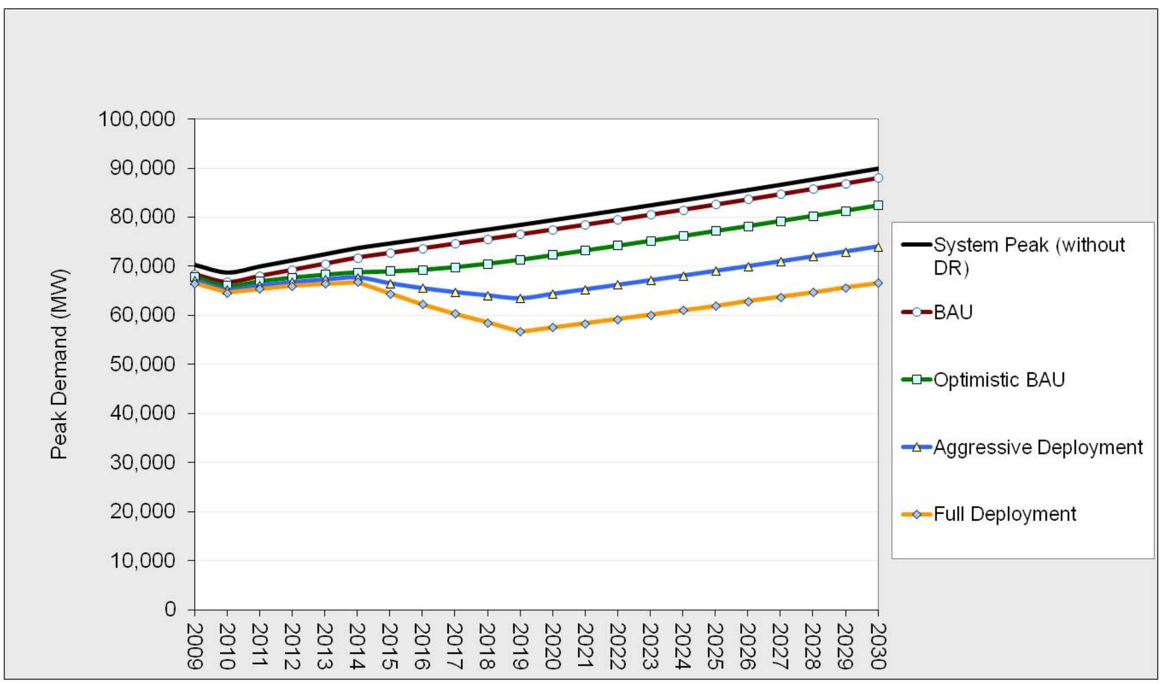


Figure 35: East South Central Division System Peak Demand Forecasts by Scenario

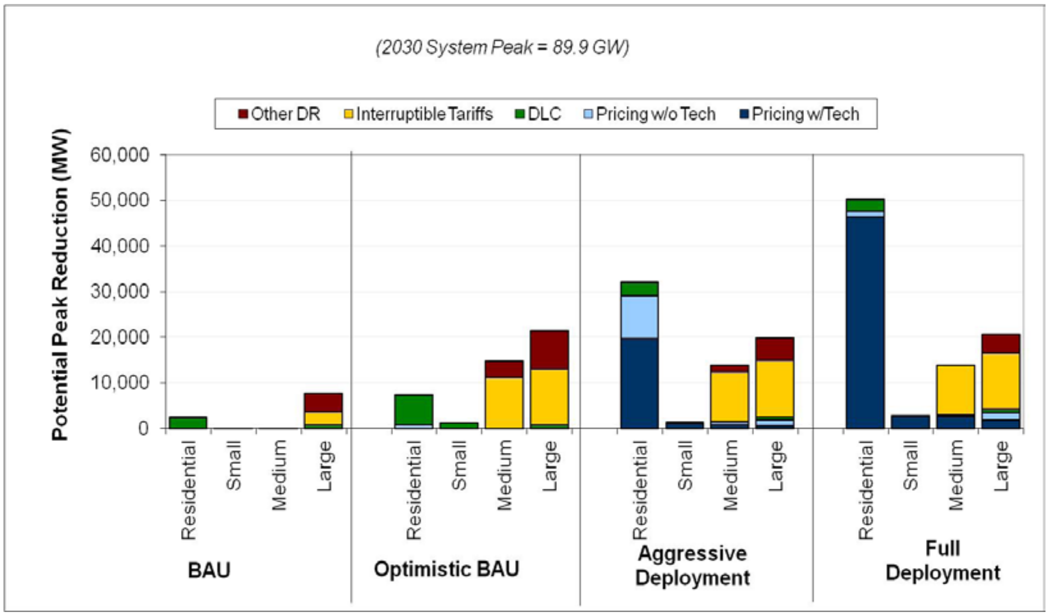


Figure 36: East South Central Division DR Potential in 2030, by Scenario

Table 12: Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in East South Central by Scenario, Pricing Program, and Price Ratio (MW)

	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	140	140	140	140	140	140	140	140	140	140	140	140
10	140	140	140	140	140	140	140	140	140	140	140	140
15	140	140	140	140	140	140	140	140	140	140	140	140
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	189	164	210	260	190	317	264	192	322	268	193	328
10	215	171	251	329	219	428	334	222	437	341	225	446
15	233	174	277	372	233	490	379	235	501	386	238	512
Aggressive Deployment												
Pricing with Technology												
5	1668	960	2348	5606	3137	7866	5790	3228	8130	5980	3322	8403
10	2473	1073	3524	8262	3607	11991	8532	3712	12384	8812	3821	12792
15	2848	1578	4175	9574	5330	14071	9884	5480	14528	10206	5635	15003
Pricing without Technology												
5	848	533	1162	2718	1562	3796	2805	1607	3921	2896	1654	4050
8	1228	583	1722	4024	1786	5811	4153	1838	5998	4287	1891	6193
15	1415	817	2051	4679	2658	6864	4827	2731	7084	4981	2807	7311
Full Deployment												
Pricing with Technology												
5	3882	2190	5621	13035	6821	19196	13464	7021	19848	13910	7228	20527
10	5929	3183	8236	19914	9758	28184	20575	10046	29132	21263	10345	30119
15	6809	2843	9773	22813	9442	33119	23561	9745	34201	24339	10060	35326
Pricing without Technology												
5	307	204	419	937	465	1329	973	482	1381	1011	501	1435
10	443	262	592	1427	760	1974	1483	791	2051	1542	823	2133
15	511	250	719	1663	622	2404	1729	648	2498	1797	674	2597

West South Central Census Division Profile

The West South Central census division is comprised of Oklahoma, Arkansas, Louisiana, and Texas. The summer peak of the division is 47 GW and the winter peak is 41 GW. The division has a 5% AMI penetration rate and a 76% CAC penetration rate.

In the year of 2030, the system peak without DR would be -- GW, the DR potential peak load reduction will be 4 GW (3%) under BAU, 21 GW (15%) under Optimistic BAU, 37 GW (26%) under Aggressive Deployment, and 50 GW (34%) under Full Deployment (Figure 37).

In a manner similar to that of the East South Central division, the West South Central division experiences its largest growth in Residential pricing programs thanks to high CAC saturation rates in its states (Figure 38). Arkansas is noteworthy for also experiencing high growth in participation from Large C&I customers in Other DR and Interruptible Tariff programs. Arkansas also maintains significant amounts of DLC throughout all four scenarios for its Residential and Small C&I customers.

Table 13 provides summary statistics of the Monte Carlo simulation for dynamic pricing programs in the West South Central census division. Demand response from the pricing without technology program was about 930 MW under the BAU scenario, and increased to a range of 1076 to 2184 MW in 2030 under the Optimistic BAU scenario. In the Aggressive and Full Deployment scenarios the range of demand response is 1482 to 15414 MW in 2030. Demand response from the pricing with technology program are zero in the first two scenarios, but are 4216 to 28014 MW and 9872 to 70162 MW under the Aggressive and Full Deployment scenarios, respectively.

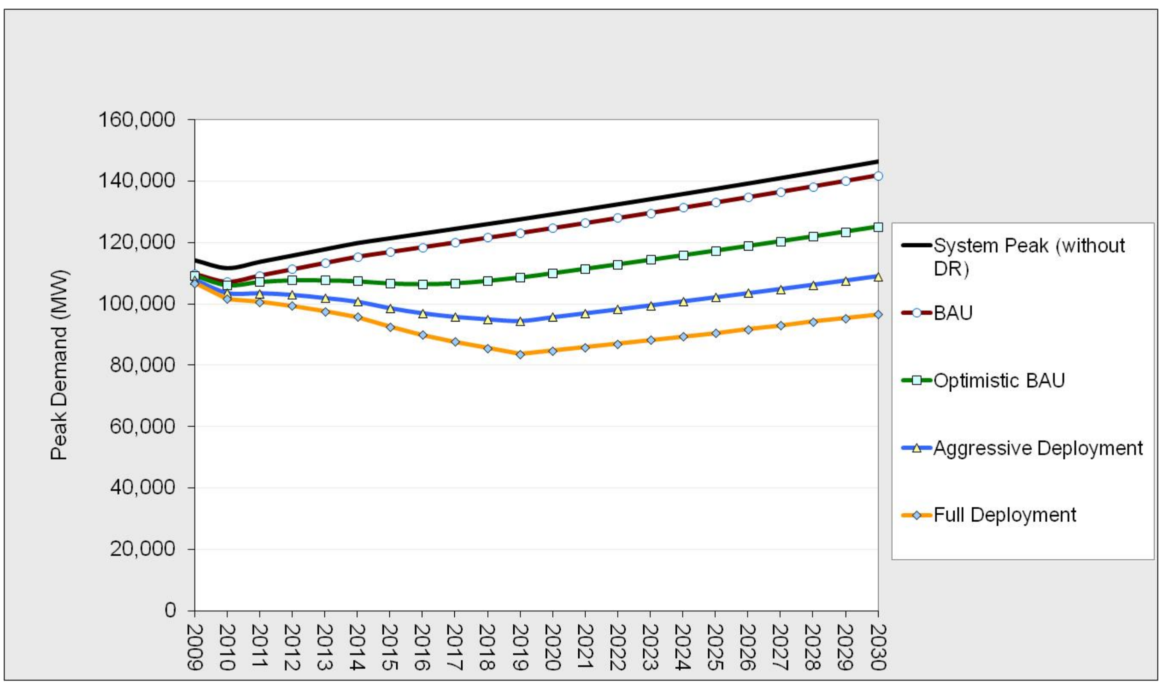


Figure 37: West South Central Division System Peak Demand Forecasts by Scenario

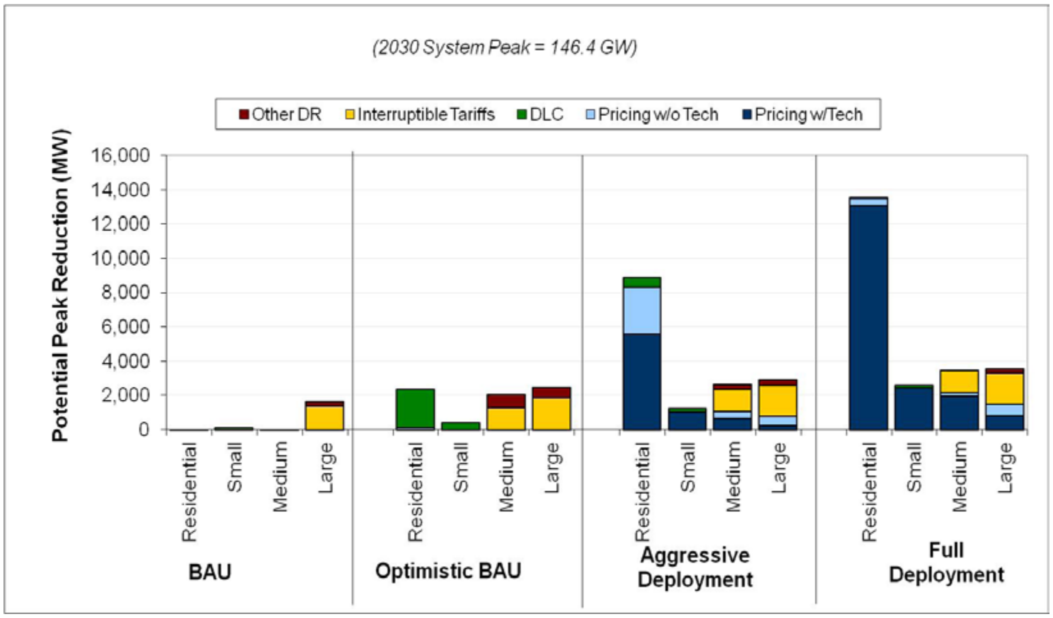


Figure 38: West South Central Division DR Potential in 2030, by Scenario

Table 13: Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in West South Central by Scenario, Pricing Program, and Price Ratio (MW)

	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	930	930	930	930	930	930	930	930	930	930	930	930
10	930	930	930	930	930	930	930	930	930	930	930	930
15	930	930	930	930	930	930	930	930	930	930	930	930
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	1229	1027	1397	1323	1059	1540	1351	1067	1582	1380	1076	1628
10	1391	1086	1647	1533	1142	1866	1574	1154	1930	1619	1167	1998
15	1494	1109	1773	1667	1167	2027	1717	1182	2102	1771	1199	2184
Aggressive Deployment												
Pricing with Technology												
5	4956	1878	7662	9152	3804	13965	9708	4003	14833	10304	4216	15762
10	7177	2734	11227	13328	5616	20398	14130	5905	21668	14989	6213	23029
15	9174	3232	13562	16827	6584	24825	17864	6928	26364	18975	7295	28014
Pricing without Technology												
5	3461	1857	4867	5562	2758	8038	5846	2855	8487	6151	2959	8967
8	4620	2300	6754	7736	3715	11393	8151	3859	12044	8596	4012	12741
15	5683	2556	7986	9595	4226	13756	10134	4407	14557	10711	4600	15414
Full Deployment												
Pricing with Technology												
5	12023	4455	18262	22180	8912	33337	23529	9377	35418	24973	9872	37649
10	18085	7330	27181	33221	15021	49497	35252	15754	52566	37428	16536	55856
15	21565	8407	33809	39591	17558	62312	42014	18441	66102	44610	19383	70162
Pricing without Technology												
5	1667	1174	2084	2271	1424	3025	2356	1452	3159	2447	1482	3302
10	2060	1321	2646	3009	1736	3986	3140	1782	4180	3280	1831	4386
15	2290	1390	3075	3452	1927	4970	3611	1991	5220	3780	2058	5485

5.5 DEMAND RESPONSE SUPPLY CURVE FOR EIPC STUDY

EIPC's modeling working group (MWG) has modeled demand response as Pseudo generators in the NEEM model. The model does not limit DR to maximum length of run or total amount of operation over year and uses price as a lever so that DR is dispatched semi-realistically. In Phase I of the modeling, the amount of DR was calculated based on NADR's default ratio of critical peak price (CPP) to old price (average price) of 8. With the default ratio of CPP to average price and a rough estimate of average retail electricity price, the average price of DR was set at $750/MWh. The estimated DR price was applied to the dispatch process in NEEM. However, because it applied a single price to the entire DR available and the average DR price of $750/MWh was too high to be called on, a more realistic DR supply curve was needed. Therefore, the MWG decided to use a tiered pricing arrangement for DR in the second phase of the study with GE MAPS model, which has 6 different DR price blocks and still keeps the average price of DR at $ 750/MWh.

In response to the MWG's request, we created a national stepwise DR supply curve in 2030 based on ORNL-NADR. Under the Full Deployment scenario of ORNL-NADR, we ran multiple cases to see how system peak load would respond to changes in CPP. We ran 30 different cases with a variation of CPP ranging from $50 to $1,500/MWh (Figure 39).

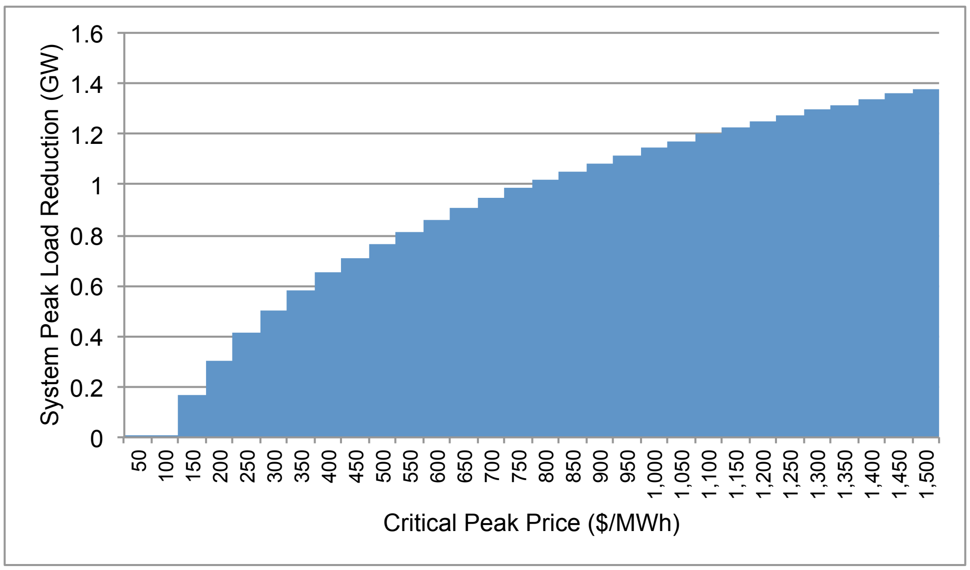


Figure 39: ORNL-NADR Runs with Variation in Critical Peak Price

Figure 40 illustrates a supply curve for pricing-related full DR deployment and its 5-block supply curve in comparison with the supply curve used in the NEEM for phase I (red line). The red line was driven based on the FERC's 2009 NADR results and shows the maximum DR available in 2030 is 209 GW.

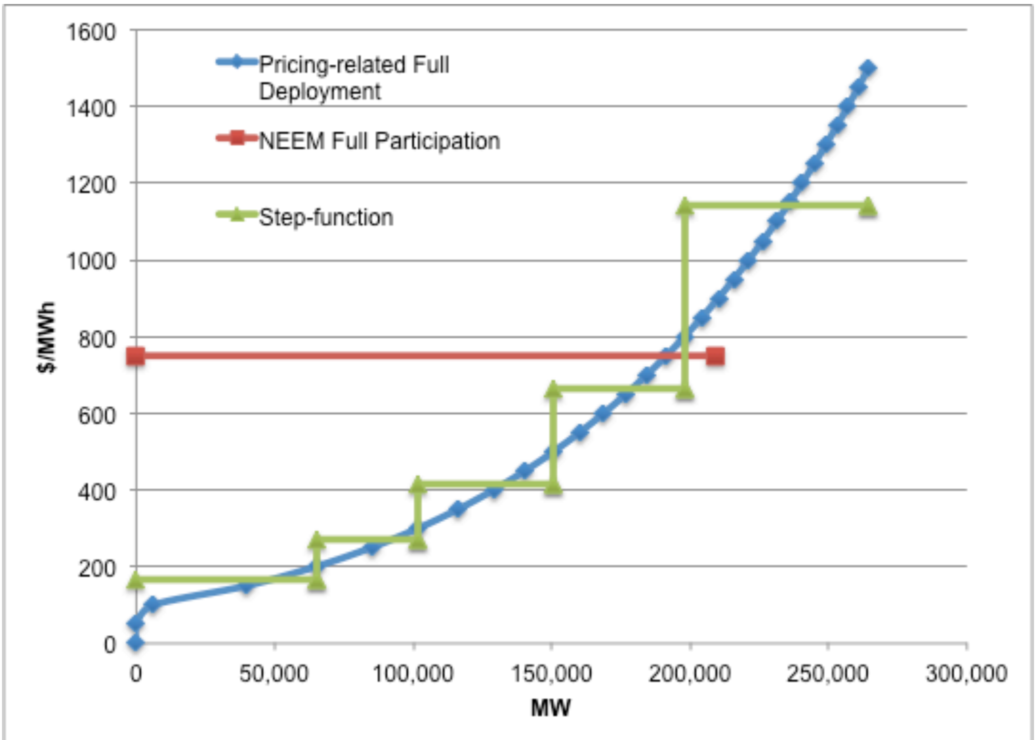


Figure 40: 5-Block Supply Curve Only with Pricing Programs in 2030

Actual DR would have a mixture of programs that dispatchers call upon. Some programs have no specific price but have time or frequency limits. Some allow customers to vary their response at different price points. In addition, the variation in CPP addresses only the impact from pricing programs (Figure 39 and Figure 40). To reflect such DR supply from non-pricing programs, we chose to allocate non-pricing DR amount into each block proportionally (Figure 41). A 70% of peak load reductions (PLR) came from non-pricing DR was distributed into the first five price blocks, and the rest 30% of PLR was allocated to a new 6th price block. The price for this last block was set so that the weighted average of DR price stayed at $750/MWh. A 22% of maximum DR available could be supplied at the first price block of $165/MWh and possibly replace advanced-combustion turbine (CT) options as pseudo-generators in the dispatch process. The last price block represents exceptionally expensive DR options such as rotational blackout that involve high societal costs but are not included in the typical DR program categories.

The resulting six blocks with both their price and the fraction of total DR, as used in the EIPC Phase 2 study, are shown in Table 14. Each region's total DR potential for the scenario in question was multiplied by the fractions from the table and priced at the amount shown. This simplified the supply curve for modeling each region's DR amounts for the purpose of the analysis. The results can be seen in the final report from the EIPC when it is published.

Table 14. DR Supply Curve as Proportion of Total DR Available in Region for EIPC Study

Block	Price $/MWh	% of Total Capacity	
		Incremental	Cumulative
1	165	22%	22%
2	273	12%	34%
3	418	16%	50%
4	665	16%	66%
5	1,142	22%	88%
6	2,100	12%	100%

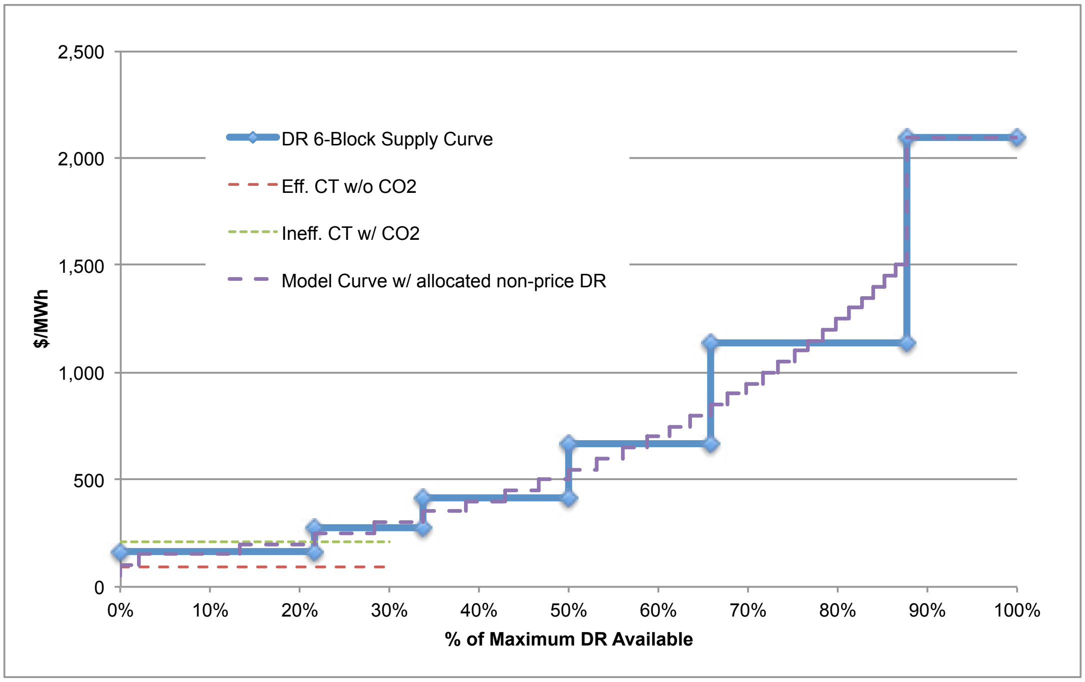


Figure 41: 6-Block Supply Curve and Model Curve with Allocated Non-Price DR in 2030

6. DEMAND RESPONSE COSTS

6.1 INTRODUCTION

Although Demand Response (DR) has many applications in electricity markets, other alternatives exist for any given application. While DR can reduce reserve requirements, enable greater participation in capacity bidding programs, provide grid relief during emergency conditions, and reduce the overall capital and operating costs of electric power systems, other alternatives exist to serve these applications.[19]

Because many technological alternatives exist for a given electricity market application, cost estimates become valuable tools for comparing across alternatives. This chapter provides cost estimates for the DR deployed in the Eastern Interconnection forecast in this report. The scope of the chapter is limited to the costs of DR, and costs of alternative technologies will not be described. Readers should carefully note the framework and assumptions used in this analysis, especially when using this analysis to compare DR to alternatives.

6.2 SUMMARY

This chapter presents estimates of DR program costs under the Total Resource Cost Test (TRC) framework of benefit-cost analysis. DR costs are assumed to primarily consist of the costs of advanced metering infrastructure (AMI) systems and load-controlling technologies ("Enabling Technologies"), an assumption well-supported by DR literature. Costs-per-unit of AMI and Enabling Technology are estimated from a review of literature and public utility regulatory commission dockets containing AMI business cases filed by electric utility companies. These costs-per-unit are applied to AMI and Enabling Technology deployment data from the ORNL-NADR, using further assumptions about AMI and ET deployment practices garnered from the reviewed AMI business cases. The resulting costs are forecast for each state, sector, and year of the ORNL-NADR model. Costs are aggregated into census regions and provided for the EI. These results are compared to other studies of AMI costs and discussed with respect to the literature reviewed.

6.3 FINDINGS FROM PRIOR STUDIES OF DEMAND RESPONSE

Demand Response Cost Drivers

The primary costs associated with DR programs are the costs of deploying AMI and Enabling Technologies (Gellings et al. 2011, Chupka et al. 2008). AMI is necessary to enable many DR programs that require interval metering to measure peak load reduction and/or communication of price signals. AMI is also useful for load profiling, which helps define parameters of customer-utility DR contracts. Supporting the interconnectedness of AMI and DR, utility companies applying to deploy AMI have portrayed DR benefits as attributable to AMI investments (Heffner 2010). Utility companies such as Pacific Gas and Electric and Centerpoint Energy Houston Electric have used benefits from forecasted DR load reductions to cost-justify AMI investments (Agerter and Ouborg 2005, Standish 2008).

While AMI investments can yield great energy savings benefits from DR programs, DR is not necessarily the strongest driver behind AMI investment. Utility companies can achieve significant net benefits

---

[19] Energy efficiency can reduce reserve requirements, distributed generation can enable greater capacity bidding, improved sensor systems can help avert emergency conditions altogether, and improved generation technologies can reduce capital and operating costs, to name a small subset of technologies capable of performing DR functions.

through deploying AMI because AMI reduces the operating costs of utility metering systems. For many utilities, it is less expensive to deploy and operate AMI systems than to employ a metering-reading labor force, even if that labor force uses Automated Meter Reading (AMR) technologies. AMI can also reduce revenue losses by improving estimation and validation processes, and AMI can help utilities prevent electricity theft via improved tampering protection and remote disconnection features (Maters, et al. 2010; McIndoo 2008; Haney, Jamasb, and Pollitt 2009).

Conversely, some DR programs do not require AMI to achieve significant energy reductions. Programs that involve utility control of customer devices or that require large C&I customers to reduce load in a manner of their choosing in response to utility phone calls have existed in previous decades and do not require AMI. While AMI can help enhance the load impacts of these programs by improving the accuracy of customer load reduction measurement and verification, certain DR programs are perfectly functional without AMI investment (Federal Energy Regulatory Commission 2009).

While some DR programs function without AMI investment, such programs may require investment in Enabling Technologies. Enabling Technologies are necessary for specific DR programs that provide a reduced rate or monthly bill rebate to customers in exchange for utility control of customer loads. Enabling Technologies are devices that enable a utility to unilaterally limit customer loads. Among residential customers, for example, utilities may control the loads from central air conditioning (CAC) and water heating through Enabling Technologies (Federal Energy Regulatory Commission 2008, 2009).

Other monetized costs to utilities and customers arise from DR programs. The cost to utilities of compensating customers for participating in DR programs is one example of a monetized cost of DR. This monetized cost to the utility is a direct, monetized benefit to the customers participating in the DR program (Heffner 2010).

Non-monetized costs also arise from DR programs and can be even more significant than monetized costs in shaping DR program deployment. One example of non-monetized DR costs is cost to consumers of behavioral changes, such as the inconvenience to residential customers of shifting laundry activities from on-peak periods to off-peak periods. The impacts of such non-monetized costs can be observed in features of DR contracts such as duration and frequency limits on DR events and overall participation in DR programs.

Costs of Advanced Metering Infrastructure and Enabling Technologies

“Estimating the Costs and Benefits of the Smart Grid,” a report published in 2011 by the Electric Power Research Institute (EPRI), provides estimates of per-unit costs of AMI and its technological sub-components as well as forecasts of AMI costs from 2010 to 2030 for the entire United States. Assuming an 83% average market saturation of smart meters across all customer types and all states in the US, EPRI concluded that AMI investment between 2010 and 2030 would range from $15 to $42 billion. By contrast, EPRI estimated that between $338 and $476 billion of investment would be necessary to thoroughly modernize the entire U.S. electricity grid by 2030 (Gellings et al. 2011).

To form its unit cost estimates, EPRI gathered information from electric utility companies that were deploying the first wave of Smart Grid Infrastructure Grant (SGIG)-funded AMI projects. These utilities included FirstEnergy, Dayton Power and Light, Idaho Power Company, Southern California Edison, and San Diego Gas & Electric. The unit cost estimates formed from this information represent an estimate of actual costs to be incurred by utilities deploying AMI From this analysis, EPRI assumed four separate per-unit costs for AMI deployment: lower-bound estimates of $77 per unit for residential customers and $140 per unit for commercial and industrial (C&I) customers, and upper-bound estimates of $165 per unit for residential customers and $565 per unit for C&I customers (Gellings et al. 2011, pp. 6-13 to 6-14).

The Brattle Group's "Transforming America's Power Industry: The Investment Challenge 2010-2030" provides a cursory estimate of AMI costs for the 2010 to 2030 period. Assuming AMI saturation rates of 30% among residential customers and 50% among commercial and industrial (C&I) customers reached by 2030, the Brattle Group calculated a total cost of $27 billion for AMI system deployments from 2010 to 2030. Assuming 12% residential, 20% C&I AMI saturation rates reached by 2030, the Brattle Group calculated a total cost of $19 billion for AMI system deployments from 2010 to 2030. Through review of California shareholder filings for AMI budget approval, the Brattle Group estimated the cost of an AMI system per residential customer to be $300 and per C&I customer to be $1,500. The Brattle Group estimated that approximately $880 billion of investment would be necessary for modernizing the U.S. electricity grid by 2030 (Chupka et al. 2008).

A 2009 publication from Cambridge University's Electricity Policy Research Group (EPRG) titled "Smart Metering and Electricity Demand: Technology, Economics, and International Experience" provides a review of international experience with AMI deployment. The EPRG finds that advanced meters frequently have useful lives of 15 years, in contrast to the 20-year useful lives held by traditional electromechanical meters. The EPRG also finds that large-scale, centrally-managed deployments of AMI may have greater potential to reduce the costs-per-advanced meter of the deployment than small-scale, de-centralized deployments due to economies of scale. Economies of scale can also lower marginal costs if AMI deployments are accelerated rather than phased-in. The EPRG finds that radio-frequency (RF) communications technologies are more cost-effective for sending signals to advanced meters located in more densely-populated areas than are power-line-carrier (PLC) communications technologies (Haney, Jamasb, and Pollitt 2009).

AMI deployments have been observed to be subject to industrial learning effects, which is to say that the marginal cost of a product decreases as cumulative production increases. Navigant Energy Consulting studied many cases of AMI deployments funded by the Department of Energy's Smart Grid Investment Grants, finding that the costs per AMI meter deployed declined as utility companies deployed a greater cumulative number of advanced meters (Chan et al 2011).

The Federal Energy Regulatory Commission (FERC)'s 2009 National Assessment of Demand Response provides estimates of unit costs for Enabling Technologies. The FERC assesses two particular kinds of Enabling Technologies – Direct Load Control (DLC) switches and Programmable Communicating Thermostats (PCTs). DLC switches are used by utility companies administering DLC programs to remotely control a customer's load devices, while PCTs are used to control CAC units via price signals from a utility. Table 15 below provides the unit costs of DLC devices and PCTs estimated by FERC (these unit costs were used in the original NADR and thus the customers sectors match those in the ORNL-NADR) (Federal Energy Regulatory Commission 2009). An earlier study of Enabling Technology costs by the California Energy Commission's Public Interest Energy Research supports the costs estimated by FERC (Nancy, Haiad, et al. 2005).

Table 15: Unit Costs for Enabling Technologies

	Programmable Communicating Thermostat	Direct Load Control Switch
Residential	$200.00	$200.00
Small C&I	$350.00	$350.00
Med. C&I	$1,050	$1,050
Large C&I	$13,500	$1,050[20]

Insights into the Next Wave of Advanced Metering Infrastructure Deployment

Recent insights into the AMI market show that rural electric cooperatives (RECs) and municipally-owned electricity systems ("Munis") are likely to be the next major deployers of AMI systems. GreenTech Media's Zach Pollock states that most U.S. investor-owned utilities (IOUs) have already deployed AMI or are in the process of deploying AMI systems (Pollock and Clavenna 2012). RECs led the U.S. in AMI deployments in 2010; according to a FERC study published in 2011, 25% of REC meters were advanced while only approximately 8% of meters nationwide were advanced (Federal Energy Regulatory Commission 2011). RECs have particularly strong incentives to deploy AMI due to the large metering costs intrinsic to rural areas (Roche 2011).

Review of AMI Business Cases

For detailed data on AMI deployment costs, twenty separate AMI business cases were reviewed and analyzed. These business cases were filed by utility companies in support of applications to public utility regulatory commissions for approval of AMI deployment. Each business case describes the costs of the AMI system that the utility company expects to incur and for which the utility company requests revenue recovery. As such, these expected costs of AMI deployment are passed on to ratepayers instead of the actual costs incurred by the utility from the AMI deployment.

The AMI business cases provide examples of the scale (i.e. number of meters) of AMI deployments, the timing of AMI deployments, various technological features of AMI deployments, and the costs of AMI deployments. While estimating exact costs for future AMI system deployments over a twenty-year period is impossible, these examples of AMI system cost forecasts provide sufficient information for estimating a reasonable range of AMI deployment costs for a twenty-year future.

6.4 METHODOLOGY

6.4.1 Assumptions

Total Resource Cost Test Framework

This analysis presents the costs of DR under the TRC framework, which is intended to evaluate a utility's investment decisions from the perspective of all society (including the utility and its customers). The TRC framework considers three categories of cost for an energy program: Installation Costs, Overhead Costs, and Incremental Costs (Environmental Protection Agency 2008). These categories may be respectively described as:

[20] The FERC did not estimate unit costs for Large C&I DLC switches because no Large C&I participating in DLC programs were forecast in their 2009 analysis. The ORNL-NADR forecasts a small number of Large C&I participants in DLC programs, however, so the unit costs for Medium C&I DLC switches has been assumed for Large C&I DLC switches.

Installation costs – the costs necessary to acquire equipment, install equipment at customer sites, acquire and setup infrastructure to support program, acquire and setup/integrate necessary utility systems to manage program, and the management/labor costs of these acquisitions, installations, and setups.

Overhead costs – the costs of operating the program, such as maintaining the equipment and infrastructure, fees associated with software or service licensing/contracts, and payments to personnel for operating and administering program.

Incremental costs – these are installation costs that occur in the operation phase of the program, i.e. after deployment and the associated installation costs have already taken place. These can include equipment replacement (in the case of failure or end-of-life), equipment upgrades, and incremental expansion of the program due to new enrollees.

Alternative benefit-cost frameworks and the variables they consider are presented in Appendix C.

Monetized costs of DR programs that are incurred as costs by one party in a DR program but incurred as monetized benefits by another party in a DR program are ignored by the TRC. A utility's cost of compensating customers participating DR is a direct benefit to the customers being compensated, for example, and this cost is therefore ignored by the TRC. The Program Administrator Cost Test, Ratepayer Impact Measure, and Participant Cost Tests account for monetized costs ignored by the TRC (see Appendix C for more detail).

Non-monetized costs are considered by the TRC framework, but are not captured by this analysis. The non-monetized welfare impacts of DR can vary widely due to the variety of programs through which DR can be implemented; the valuation made by utility firms upon peak load relief, lost sales, and load loss; and the distribution of valuations of electricity consumption by different customer sectors and within each customer sector. A separate study would be appropriate in scale and scope for characterizing the non-monetized welfare impacts of DR[21].

6.4.2 Analysis of AMI Business Cases in Societal Cost Test Framework

The costs presented in the AMI business cases were analyzed within the framework of the TRC. The AMI systems reviewed had four key categories of Installation Costs:

- Meters – the costs incurred through procurement of advanced meter hardware, such as advanced meters and communication modules, and installation of advanced meter hardware at customer sites.
- Information Technology Systems – costs incurred through the procurement of hardware and software necessary to receive and manage data from the installed advanced meters. Such systems frequently involve Meter Data Management Systems (MDMS), customer information systems (CIS), and billing systems that are capable of handling interval data (i.e. consumption data collected on the hour or more frequently).

[21] A calculation of consumer welfare change resulting from the DR programs modeled in this study was prepared but ultimately discarded due to lack of data for a complimentary calculation of producer welfare changes. Readers interested in the consumer welfare calculation are encouraged to contact the authors for more information.

- Communications Networks – costs incurred through procurement of telecommunications technologies necessary for carrying data between utilities' Information Technology Systems and advanced meters. Technologies frequently used to form Communications Networks include:

    - Power-line carrier (PLC) networks – these networks convey voltage-based signals between utilities and advanced meters through existing power distribution lines. PLC networks are reported to be the most cost-effective option for rural areas (Greer, Bates, et al. 2008).

    - Wi-Max networks – these networks use extant wireless radio frequency telecommunications towers to gather data from nearby advanced meters via wireless signaling. This type of network is also referred to as "point-multipoint" and "Radio-Frequency-star."

    - Radio-frequency (RF) Mesh – these networks use each advanced meter as a communications relay to send data from the advanced meter to the utility through wireless signaling. RF Mesh networks are reported to be the most cost-effective option for urban areas (PECO Energy Company 2009).

- Deployment Management – costs incurred through the additional human resources necessary to deploy the AMI system. These costs include the installation and programming costs for Information Technology Systems and Communications Networks and costs attributable to Project Management Offices (PMOs).

AMI systems also incur Overhead Costs through the human resources used to manage the Information Technology Systems and Communications Networks; human resources used to maintain the advanced meters, Information Technology Systems, and Communications Networks; and any on-going software, hardware, or frequency spectrum licenses that the utility may need to pay on a recurring basis. The DLC and PCT devices used to enable DLC DR programs and enhance dynamic pricing DR programs also contribute to the Installation Costs of DR programs, though not to the costs of AMI. While some utilities have deployed DLC devices and PCTs in conjunction with AMI systems, DLC devices and PCTs were not found to be essential components of AMI systems in the review of AMI business cases. As such, these devices are treated separately from AMI systems in the cost analysis.

To develop a range of estimates for the costs of AMI systems, the Deployment Costs and Operating Costs per advanced meter deployed were calculated along each cost category for each AMI business case reviewed. This necessitated converting all values reported in the AMI business cases into nominal values. Though most AMI business cases reported costs in this manner, two cases reported Net Present Value (NPV) costs and another reported Net Present Value Revenue Requirements (NPVRR). Annuity calculations using discount and tax rates provided in the AMI business cases under the assumption that the AMI systems would be deployed over a five year period were made to convert the NPVs and NPVRRs into NFVs. The assumption that the AMI deployments would be achieved within five years is supported by an average five-year deployment period among the AMI plans reviewed. Additionally, certain utility firms didn't disaggregate their reported costs sufficiently to fit into the cost categories used in this study. To facilitate calculation of a cost-per-unit for all cost categories, 11 out of the 100 values used were fixed as the average of all utilities who had reported disaggregated costs suitable for categorization. The category most sensitive to this approximation was Deployment Management, for which 6 of the 20 values were fixed as the mean of utilities who had reported Deployment Management costs.

These cost-per-meter estimates were broken into quartiles to form a high cost estimate, a medium cost estimate, and a low cost estimate for each cost category. From these estimates, three different cost scenarios were calculated – one in which the high cost estimate was used for all categories ("High cost scenario"), one in which the medium cost estimate was used for all categories ("Medium cost scenario"), and one in which the low cost estimate was used for all categories ("Low cost scenario"). Table 16 below provides the cost per advanced meter deployed for each cost scenario and each cost category.

Table 16: Estimated Cost-per-Meter of Various AMI System Component

Scenario	Meters	IT Systems	Communications Network	Deployment Management	Annualized AMI O&M
High	$243.43	$64.58	$66.33	$81.19	$22.74
Medium	$189.98	$27.07	$42.76	$63.00	$7.32
Low	$128.61	$10.73	$11.47	$27.67	$4.74

These cost-per-meter estimates were applied to the AMI deployment forecasts of the ORNL-NADR model to calculate high, medium, and low total AMI cost estimates.

The ORNL-NADR forecasts system ramp-up deployment periods to 2020. Growth in AMI after 2020 represents the addition of customers who are new to the utility altogether, referred to as "meter growth." Meter growth consists of new customers having new meters installed at their point of consumption, such as newly-constructed homes or business facilities. The new meters are supported by Information Technology Systems and Communications Networks deployed in 2010-2020. In other words, no new Information Technology Systems and Communications Networks are deployed in 2020-2030.

Cost-per-meter estimates for Information Technology Systems, Communications Networks, and Labor and Management were not applied after 2020 due to the assumption that Information Technology Systems and Communications Networks would be deployed only during deployment ramp-up periods. As such, the Deployment Management costs associated with these activities are also applied only during the 2010-2020 deployment ramp-up period.

Unit costs of DLC devices and PCTs were applied to the ORNL-NADR's forecasts of the number of customers using DLC devices and PCTs to produce total costs of DLC devices and PCTs for the EI to 2030.

Net present values were calculated using a 3% discount rate from the costs calculated for each cost component and year in the 2010–2030 analysis period. The discount rate was chosen on the basis of guidance from The Office of Management and Budget's Circular A-4, which prescribes a discount rate of 3% for projects of significant relevance to societal welfare (Office of Management and Budget 2003)..

6.5 RESULTS AND DISCUSSION[22]:

The total costs of DR for the EI for each deployment scenario and cost scenario are displayed in Figure 42. Figure 43 displays the number of AMI meters deployed in each deployment scenario. Appendix D contains estimates for all census regions.

[22] Further results and calculations are available upon request to the authors

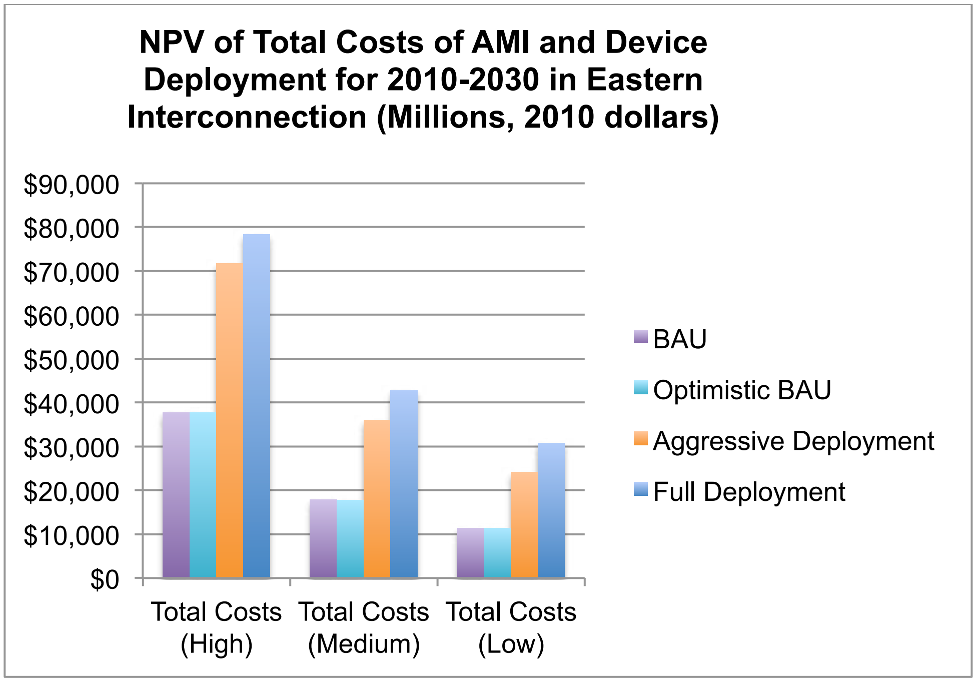


Figure 42: Total Costs of Demand Response for 2010-2030 in Eastern Interconnection (NPV, Millions)

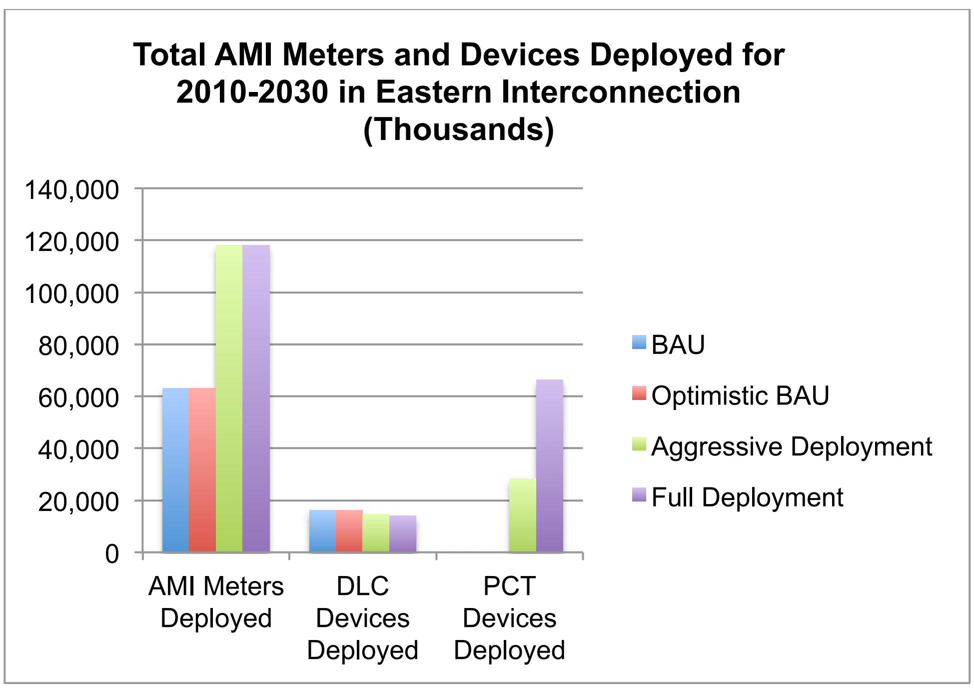


Figure 43: Total AMI Meters and Devices Deployed for 2010-2030 in Eastern Interconnection (Thousands)

Analysis of the total cost results shows strong sensitivity of the overall results toward the unit cost for the Meters and Annual O&M categories, as well as the timing with which advanced meters are deployed throughout the EI. The total costs of Meters and Annual O&M through 2030 together compose over 70% of the costs of AMI systems for most states, and AMI systems are greater than 90% of the costs of DR for most states.

The general dominance of the Annual O&M cost category is due to the fact that Annual O&M costs grow with the cumulative number of meters deployed. Even if no new advanced meters are deployed, the existing advanced meter stocks still incurs Annual O&M expenses as part of the TRC test's "Overhead Cost" category. Meters, Information Technology Systems, Communications Networks, and Deployment Management costs all grow with the annual incremental number of meters deployed, i.e. new meter deployments in each year. If no new meters are deployed, no costs within these categories are incurred and the relative portion of total cost contributed by these categories diminishes.

Given the dependence of Annual O&M costs on cumulative advanced meter deployment, earlier deployment schedules lead to greater total costs over a fixed period than do later deployment schedules. Because the ORNL-NADR assumes that the AMI penetration rate for each state reaches its 2030 level in 2020, greater costs are incurred than would be if deployments were linear through 2030 or delayed to a later period. This is an artifice of the ORNL-NADR's deployment period being fixed, however, as Annual O&M costs would be incurred for the lifetime of all AMI. Postponing deployments of cost-effective AMI systems would have no benefit to society.

The cost-dominance of Meters is primarily due to the large unit costs of advanced meters assumed in this study. As demonstrated in Table X4, unit costs assumed for Information Technology Systems, Communications Networks, and Deployment Management are an order of magnitude less than the unit costs of advance meters assumed in this study.

DLC switches and PCT costs are the least contributive to overall DR costs. These devices can function independently of the AMI system, and therefore only contribute the unit costs of deploying the devices themselves. This amounts to less than 10% of DR costs for most states.

6.5.1 Brattle Group Comparison

For comparison to prior studies by the Brattle Group and EPRI, which each analyze the costs of only AMI, the costs of AMI produced by the ORNL analysis are displayed in Figure 44 below.

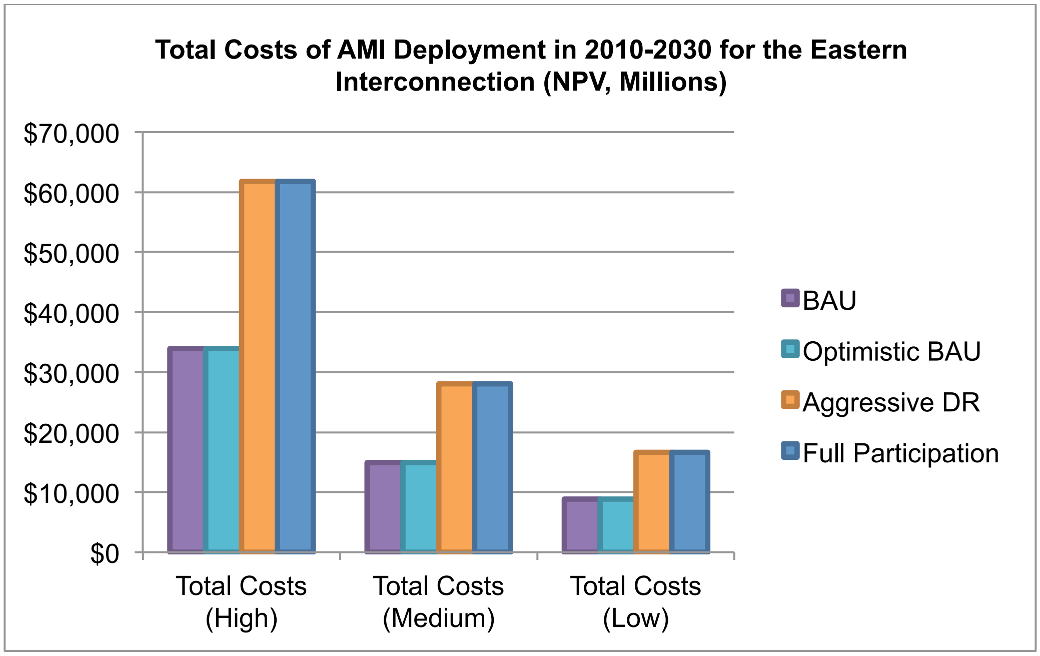


Figure 44: Total Costs of AMI Deployment in 2010-2030 for the Eastern Interconnection (NPV, Millions)

Comparison of the ORNL results with Brattle and EPRI results also necessitates applying the deployment assumptions used in each study. The effects of deployment assumptions upon total costs of AMI systems are highly significant, as it is reasonable to assume that larger assumed deployments will lead to larger total cost. As the deployment assumptions vary between the ORNL-NADR study, EPRI's study, and the Brattle Group's study, the deployment assumptions used in the EPRI study and in the Brattle Group study were applied to the ORNL-NADR analysis to produce more comparable results.

Table 17 displays the percent differences from the High and Low estimates by the Brattle Group produced by the ORNL-NADR analysis when Brattle Group deployment assumptions are applied. In Table 17, positive values represent the percent by which the Brattle Group's results exceeded the results of the ORNL-NADR analysis under the Brattle Group's deployment assumptions.

Since all values in Table 17 are positive and greater than 20%, the comparison reveals the strong influence of the Brattle Group's assumed costs-per-unit of AMI deployment. While the Brattle Group assumed per-unit costs of AMI systems for residential customers that differed little from the assumed per-unit costs of the ORNL-NADR study, the Brattle Group assumed per-unit costs of AMI systems for commercial and industrial customers that are an order of magnitude above those assumed in the ORNL-NADR study. This leads the Brattle Group analysis to forecast total AMI costs well in excess of the ORNL-NADR analysis, even when deployment assumptions from the Brattle Group analysis are applied to both.

Table 17: Percent Differences between Brattle Group Estimates and ORNL-NADR analysis estimates using Brattle Group Deployment Assumptions

Assumptions	$27 billion			$19 billion		
	Total Costs (High)	**Total Costs (Medium)**	**Total Costs (Low)**	**Total Costs (High)**	**Total Costs (Medium)**	**Total Costs (Low)**
BAU	73%	85%	91%	61%	79%	87%
Optimistic BAU	73%	85%	91%	61%	79%	87%
Aggressive DR	53%	75%	84%	33%	64%	77%
Full Participation	53%	75%	84%	33%	64%	77%

The Brattle Group's assumption of $1500 per unit of AMI deployed to C&I customers may be unrepresentative of the costs of AMI due to the source of the estimate, namely California utility shareholder filings in support of AMI deployments. California utilities were first-movers in large-scale AMI deployment, being the first utilities in the nation to deploy AMI to the entirety of their respective customer bases. This first-mover status may have led the utilities to over-estimate their costs due to uncertainty and lack of industry experience with AMI technology at such large scales. California utilities are also some of the largest in the U.S. and serve some of the highest-income ratepayers in the U.S., which allows them to bear investment costs that most other utilities could not afford. The tendency toward aggressive, innovative business strategies among California utilities may have led to AMI deployment costs that were inflated beyond what a small, conservative utility company would have borne. Overall, it is difficult to argue that California utility companies and their AMI deployment characteristics are representative of utility companies around the nation, which is one reason that the ORNL-NADR cost analysis examined AMI business cases beyond (but including) those of California utilities. Given that the Brattle Group's study of AMI costs was made in 2008, however, it is unlikely that alternative sources of information were available when the Brattle Group formed its estimates of per-unit AMI costs.

6.5.2 EPRI Comparison

To facilitate comparison to the EPRI study, the deployment assumptions made by EPRI were applied to the ORNL-NADR analysis. Application of EPRI deployment assumptions reveals that the differences between the results of the EPRI analysis and the ORNL-NADR analysis are driven by factors other than the costs-per-unit assumptions in each. Table 18 displays the percent differences between the EPRI High and Low estimates and the results of the ORNL-NADR analysis using EPRI deployment assumptions. Under these assumptions, the High cost scenario produces results that are approximately equal to those of the EPRI High estimate; the Medium cost scenario produces results that are approximately equal to the EPRI Low estimate.

Table 18: Percent Differences between Brattle Group Estimates and ORNL-NADR analysis estimates using EPRI Deployment Assumptions

	$42 billion			$19 billion		
	Total Costs (High)	**Total Costs (Medium)**	**Total Costs (Low)**	**Total Costs (High)**	**Total Costs (Medium)**	**Total Costs (Low)**
BAU	15%	57%	73%	-138%	-20%	25%
Optimistic BAU	15%	57%	73%	-138%	-20%	25%
Aggressive DR	15%	57%	73%	-138%	-20%	25%
Full Participation	15%	57%	73%	-138%	-20%	25%

Two factors largely explain the differences between the EPRI results and the ORNL-NADR results: the 20% difference in maximum residential AMI penetration rates, and the assumed timing of AMI deployments. The 100% residential AMI deployment rate assumed in the ORNL-NADR's Aggressive DR and Full Participation deployment scenarios yields total cost estimates in the High cost scenario that are almost twice the EPRI High estimate - $62 billion. As mentioned in the review of studies, however, EPRI uses lower costs-per-unit for residential AMI deployment than does ORNL-NADR. When the maximum residential AMI deployment in ORNL-NADR is brought from 100% down to the 80% assumed by EPRI, the EPRI results exceed the ORNL-NADR results. Therefore the deployment to the remaining 20% of customers not captured by the EPRI deployment assumptions significantly increases the total costs of AMI deployment, a conclusion supported by the dominant proportion of electric power customers that fall into the residential classification.

The timing of AMI deployment influences the total cost of AMI through discounting factors and Annualized O&M costs. The EPRI analysis assumes a linear deployment schedule, such that $1/20^{th}$ of AMI deployments achieved in 2030 are deployed in each year between 2010 and 2030. Conversely, the ORNL-NADR analysis assumes a ramp-up period during which AMI deployment rates increase drastically between 2010 and 2020 and after which AMI deployment rates remain constant. This leads to AMI deployments occurring later in the EPRI analysis and earlier in the ORNL-NADR analysis. Net present value analysis leads costs incurred earlier to be greater than costs incurred later, thus increasing the costs of the ORNL-NADR AMI deployments beyond the costs of the EPRI AMI deployments *ceteris paribus*.

The Annualized O&M costs applied to AMI systems also bring greater costs to earlier schedules of AMI deployment. Because Annualized O&M costs are applied every year to cumulative AMI deployment, greater total O&M costs will be brought upon AMI systems that deploy earlier in a modeled timeframe. This is an artifice of the respective modeling frameworks used in the EPRI study and the ORNL-NADR study, as AMI systems deployed at different schedules would incur similar lifetime costs. The costs of the AMI system deployed later simply lag the costs of the AMI system deployed earlier. Because the ORNL-NADR analysis and the EPRI analysis both the same fixed time period, however, the earlier schedule of AMI deployment in the EPRI analysis significantly reduces the estimated costs of AMI relative to the ORNL-NADR estimated costs of AMI.

6.5.3 Discussion of Results according to Other Literature Findings

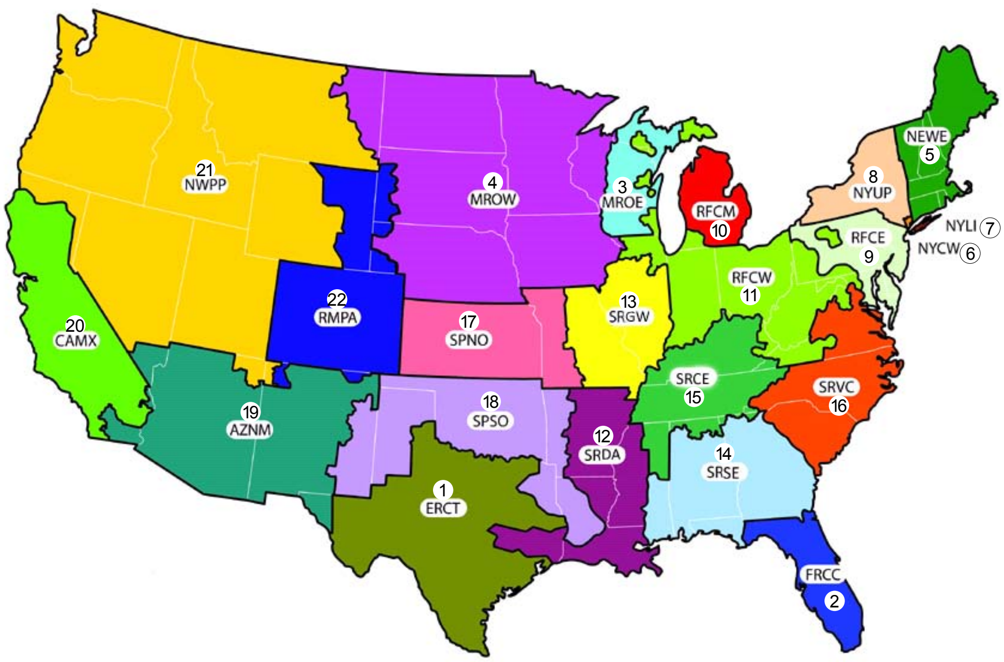
The literature findings discussed above provide multiple reasons to expect the results of this analysis to overestimate the future TRC-test costs of DR in the EI. The cost-reducing learning effects of cumulative deployment found by Navigant are not captured in this study, and large deployments of AMI in the EI are likely to yield such unit cost reductions through learning (Navigant 2011). A coordinated AMI deployment across multiple utilities could reduce costs relative to the costs of independent AMI deployments, such as those from which the cost assumptions for the ORNL-NADR analysis were drawn (Haney et al. 2009). RECs and Muni's may be the next major market for AMI deployments, in which case the cost forecasts would likely be lower and more accurate than those forecast by IOUs according to Roger Levy. Finally, utilities deploying AMI may capitalize on existing AMR meter hardware and communications infrastructure to reduce costs in ways not observed during the review of AMI business cases in the ORNL-NADR analysis. These unaccounted-for effects could reduce the costs of DR encountered by utilities, and could lead to rate reductions for customers that would decrease the costs of DR under the TRC framework.

The literature findings discussed above also provide multiple reasons to expect the results of this analysis to underestimate the future TRC-test costs of DR in the EI. Certain monetized costs of DR programs that are not related to AMI, PCTs, or DLC switches, such as costs of consumer education and costs of submitting rate cases to utility regulators, are not captured in this analysis. The non-monetized welfare losses that will certainly affect the extent to which DR is deployed are also not captured by this analysis. If retail customers become less price-elastic toward bulk electric power, as will likely be the case during further transition in the United States toward a digital economy, the costs of DR in terms of welfare lost through consumer behavioral change may contribute significantly to DR costs. More research in this area is desirable.

Given the extent of empirical review used in forming the cost assumptions for this analysis, however, the estimates produced remain reasonable. The DR cost drivers described above should be considered by electric utility companies and electric utility regulators as opportunities for mitigating DR costs. Regulators seeking greater DR in their territories should examine how to improve the influence of the cost-reducing factors and mitigate the influence of the cost-increasing factors mentioned above; for example, a regulator might organize a coordinated AMI deployment in her territory or encourage distributed generation in his territory to increase bulk power price elasticity among retail customers. This analysis upholds the finding of the FERC that regulators have great influence over both the deployment of DR and its costs (FERC 2009).

7. SYSTEM BENEFITS OF DEMAND RESPONSE

Changes in demand caused by demand response programs would affect not only the dispatch of existing plants but also the additions of advanced generation technologies, the retirements of old coal-firing plants, and the finances of the market. We analyzed the impact of the demand response programs on the grid in 2030 and the consequent level of benefits in terms of reduction in electricity price and green house gas (CO_2) emissions, reserve margin, loss of load probability (LOLP), avoided electricity generation, and consequently avoided cost. To find the new market equilibrium after the deployment of demand response programs, we used the Oak Ridge Competitive Electricity Dispatch Model (ORCED) developed to simulate the operations and costs of regional power markets depending on various factors including fuel prices, initial mix of generation capacity, and customer response to electricity prices (Hadley 2008; Hadley 1998; Hirst and Hadley 1999). In ORCED, over 19,000 plant units in the nation are aggregated into up to 200 plant groups per region. Then, ORCED dispatches the power plant groups in each region to meet the electricity demands for a given year. In our analysis, we show various demand, supply, and dispatch patterns affected by demand response across the Eastern Interconnection area classified by EIA's Electricity Market Module (EMM) regions (see Figure 45). Out of 22 EMM regions, 17 regions are assumed as the Eastern Interconnection area.[23]



Source: Annual Energy Outlook 2011, EIA

Figure 45: EIA's Electricity Market Module Regions

7.1 BENEFIT CASES FROM DEMAND RESPONSE

To see how demand response influences the electricity grid in 2030, we developed seven different cases depending on % peak load reduction (%PLR) and time period when the savings happen. The range of %

[23] Regions from 2 to 18 are defined as the Eastern Interconnection area in this analysis. 2 FRCC (FRCC All); 3 MORE (MRO East), 4 MROW (MRO West); 5 NEWE (NPCC New England); 6 NYCW (NPCC NYC/Westchester); 7 NYLI (NPCC Long Island); 8 NYUP (NPCC Upstate NY); 9 RFCE (RFC East); 10 RFCM (RFC Michigan); 11 RFCW (RFC West); 12 SRDA (SERC Delta); 13 SRGW (SERC Gateway); 14 SRSE (SERC Southeastern); 15 SRCE (SERC Central); 16 SRVC (SERC VACAR); 17 SPNO (SPP North); 18 SPSO (SPP South).

PLR for each scenario was set according to the ORNL-NADR results discussed in Chapter 5. Table 19 shows the regional amount of capacity savings as a percentage of peak demand. The four levels of DR represent the BAU scenario, the Optimistic BAU scenario, the Aggressive Deployment of DR, and Full Deployment in DR programs.

Table 19. Regional DR as Percentage of Peak Demand in 2030 under various scenarios

	BAU	Optimistic BAU	Aggressive Deployment	Full Deployment
FRCC	5%	22%	35%	47%
MROE	9%	15%	19%	22%
MROW	9%	20%	26%	29%
NEWE	7%	12%	16%	19%
NYCW	10%	18%	21%	25%
NYLI	10%	18%	21%	25%
NYUP	10%	18%	21%	25%
RFCE	7%	15%	22%	29%
RFCM	6%	14%	19%	22%
RFCW	6%	15%	21%	26%
SRDA	4%	12%	21%	29%
SRGW	4%	15%	23%	29%
SRSE	3%	18%	27%	36%
SRCE	1%	8%	18%	27%
SRVC	5%	20%	30%	38%
SPNO	2%	12%	21%	29%
SPSO	6%	13%	23%	31%

Three demand response cases were developed to analyze various demand response benefit cases.

No DR case: This case considers a situation before demand response programs are deployed. It is used as a reference case. Figure 46 shows the hourly load curve for one week out of the representative year studied for New England, one of the regions.

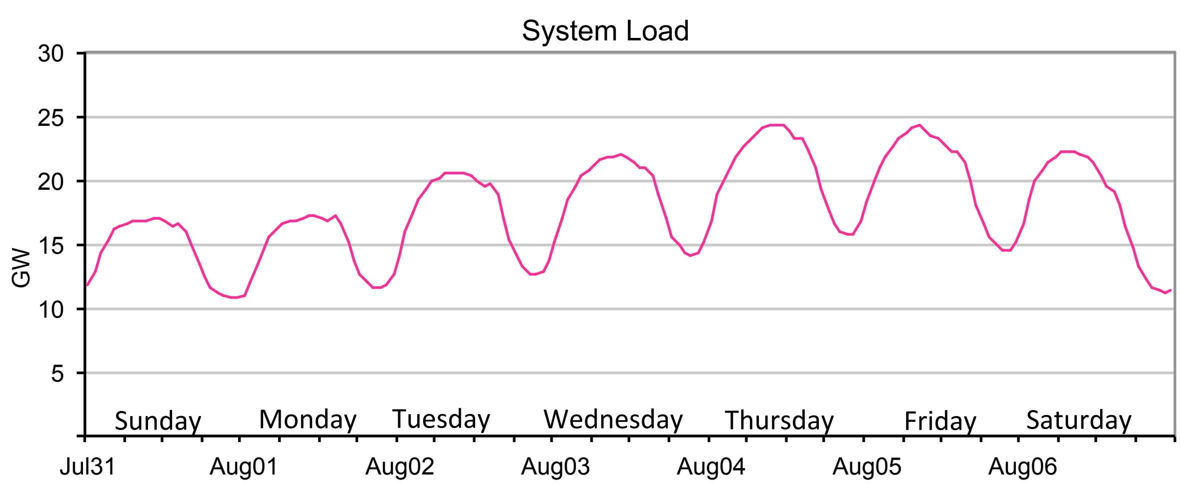


Figure 46: Energy Load Shape under No DR Case (NEWE region, August1-August6)

DR-Notch case: This case assumes that the peak demand declines consistently by a certain percentage only during the pre-specified peak hours. This case refers to specific time periods representing when DR has a high probability of being used. The “peak hours” on a “typical event day” is defined as hours between 2 and 6 pm on the top 15 system load days (60 hours a year) (FERC 2009). This definition from FERC is simplified from the variety of programs currently existing. Regional % PLR is applied to define the scale of DR impact in each region. This scenario does not consider load shifting between peak and off-peak hours. This “Notch” was on only applied to the BAU scenario because under a high DR penetration it was unrealistic that all DR would be used only during the specific four hours on the fifteen highest summer days. Figure 47 shows the same week as above but with the DR applied in the two highest days since those two days are among the 15 days with highest demands.

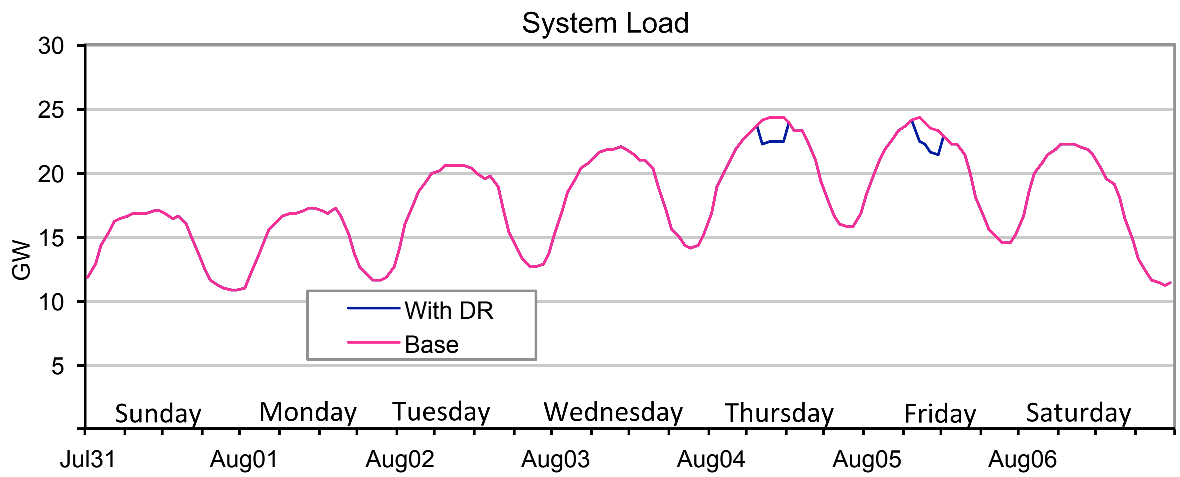


Figure 47: Energy Load Shape under DR-Notch Case (NEWE region, August1 – August6)

DR-Smart case: This case assumes that DR is designed and implemented to meet a certain target-power level (P) over a year. First, we estimated the energy-avoided by the forecasted ORNL-NADR peak load impacts by assuming it to be equivalent to that in the DR-Notch case. We calculated a peak demand level (P) that makes the amount of avoided energy from the Smart case the same as that from the Notch case. In other words, the peak demands above P are clipped throughout the year while the total energy saved is the same as in the notch definition. DR may be applied more times than the notch’s fifteen days and in more hours than just 2 pm to 6 pm, but the total energy over the year is equal. Figure 48 shows the impact on the same week as the other two graphs above. Less DR is used on these days, but the DR is applied to other days such that total demand is never above the new peak amount, in this case 23.5 GW.

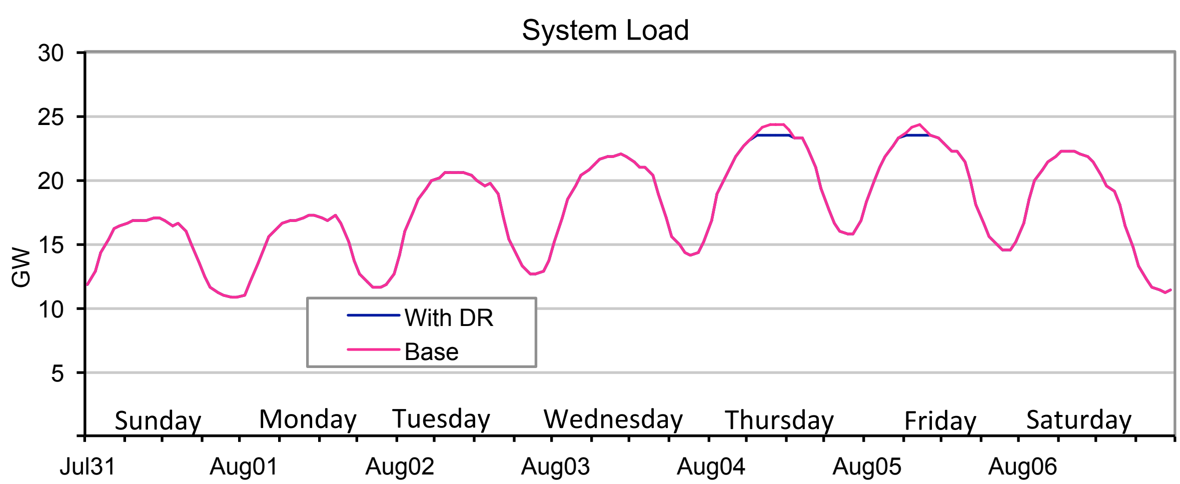


Figure 48: Energy Load Shape under DR-Smart Case (NEWE region, August 1 – August 6)

In practical terms, the actual response of DR will be more complex than either of these methods. The notch method does not capture peaks outside of its summertime block, such as winter mornings or high demands after 6 pm. The smart DR assumes that DR resources are flexible enough to precisely shave the peak demands, and in some hours calls on more capacity reductions than are available. (To examine this, we added a "constrained" BAU scenario where the DR in any hour cannot exceed the NADR-calculated amount, even if it is only called upon for a few hours. The other DR scenarios are not affected by this problem.) In none of the cases are the DR resources adjusted based on supply changes such as outages from power plants.

7.2 DATA AND PROJECTIONS

This benefit analysis uses two publicly available data sources to set the supply and demand levels. The Annual Electric Balancing Authority Area and Planning Area Report of the Federal Energy Regulatory Commission (FERC Form 714) was used to update Load Duration Curves (LDCs) of the demand module. FERC Form 714 contains hourly load by utilities or their regional system operators. Data was also retrieved from regional transmission operators where available. Daylight saving time by utilities was adjusted to have a consistent time format across regions. Hourly load graphs for several days before and after the spring and fall shift were compared to ensure consistency. Because the data on the hourly imports and exports are not available in FERC Form 714, the total net energy load as compared to the net generation for a region in AEO 2011 was used to adjust the load reflecting imports and exports of electricity of the region.

The input data for the supply module is updated by 2011 input data for the Electricity Market Module (EMM) of EIA's National Energy Modeling System (NEMS). AEO 2011 re-classifies the old 13 EMM regions into 22 subregions. Input file Pltf860.txt in NEMS provided information of summer/ winter capacity, heat rate, emission rates of NO_X and SO_X of 18,570 existing and planned plants. This study also used the cumulative unplanned additions forecast of AEO2011 to consider not only the existing and planned plants but also 525 unplanned (but expected) plant additions by 2030.

7.3 METHODOLOGY

This study used the ORCED model to simulate the operations and costs of regional power markets depending on various factors including fuel prices, initial mix of generation capacity, and customer response to electricity prices. ORCED consists of three modules of supply, demand, and dispatch.

Demand Module: The year 2030 hourly loads were retrieved from all utilities that submitted data to the FERC Form 714 database, as well from regional transmission organizations. These were converted to Load Duration Curves, rearranging the demands from highest to lowest. The typical shape of LDC is the navy-color curve in Figure 49. These were consolidated into the 22 EMM regions and escalated to match the 2030 demands based on the AEO2011 reference case. The demand module then consolidated the 8,760 hours of demands into three LDCs, one each for summer, winter, and off-peak seasons.

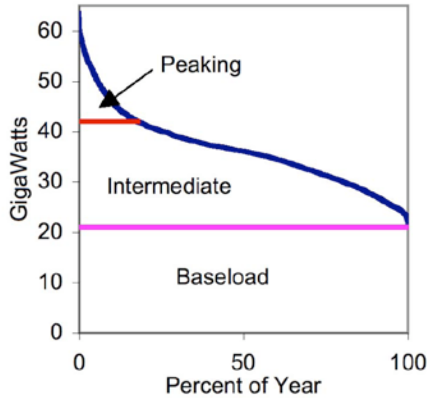


Figure 49: Load Duration Curves and Power Plant Type Dispatch Order

Supply Module: The list of units for each region that are operating in 2030 were consolidated into up to 200 power plant groups based on their technology, fuel type, and operating cost. For each season, the 200 plants from the supply module were sorted in order of increasing variable costs. The order may be different in each season because some costs (e.g., NO_X emission credits) might only be added to the summer season, depending on the scenario. The power capacities are adjusted by season for planned and forced outages.

Dispatch Module: This module dispatched the 200 plant groups created in the supply module to meet the demand. The steps began with altering the LDCs for hydro and pumped storage production. It then proceeded to dispatch the plants for each season using a modified Balleriaux-Booth procedure for unserved energy calculations (Vardi and Avi-Ithak 1981). Figure 49 shows an example of the LDC for a region along with the types of pants that are used to fulfill those demands. Some plants are most effective at providing power essentially all the time, or "baseload" power. They typically have low variable costs but may have high fixed costs. Intermediate or "load-following" plants are called on to meet the demand of a significant fraction of the year, but still cycle on and off. Peaking plants are called on least frequently, during high demand times only to meet capacity emergencies. They have the highest marginal costs but typically have low fixed costs either because of their low-cost technology or because they are old, fully depreciated plants. The amount of generation by each plant was then calculated. Lastly, time-dependent prices and costs were calculated. ORCED has the capability for a plant to use a price other than its variable cost for its bid price into the market. By default, ORCED sets the price of "must-run" and intermittent plants to zero so that they are always called upon; intermittent plants have high outage rates to simulate their variable output. The seasonal results are then combined for a yearly result. Emissions and other financial parameters are last to be calculated. Since demand fluctuates over the year, some plants are called on more often than others in the electricity supply portfolio.

7.4 RESULTS

We ran 7 benefit cases for 17 EMM regions separately with ORCED, as listed in Table 20. A comprehensive benefit analysis for the Eastern Interconnection is presented in this section. Four different types of benefits were examined: 1) system peak reduction, 2) system reliability improvement, 3) cost reduction,and 4) emissions reduction.

Table 20: Demand Response Scenarios used for Benefit Analysis

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%)
Energy Efficiency[24]	A 5%-point decrease across both peak and off-peak hours

7.4.1 System Peak Impact

The most direct impact of DR was the reduction in system peak demand. Earlier chapters describe how the NADR model calculated the amount of DR potentially available in MW as compared to the peak demand in the region, as listed in Table 19. In ORCED, this DR was made available as a resource either during the "notch" hours or as a peak clipping mechanism, but with the limit of 60 hours total per DR resource. Each region was modeled; Figure 50 shows the resulting annual LDCs for each of the scenarios for the region SRGW (SERC Gateway, including eastern Missouri and southern Illinois). This region was selected for graphing since its percentage reductions from DR are close to the average for all regions and all of its demand reductions are in the summer season.

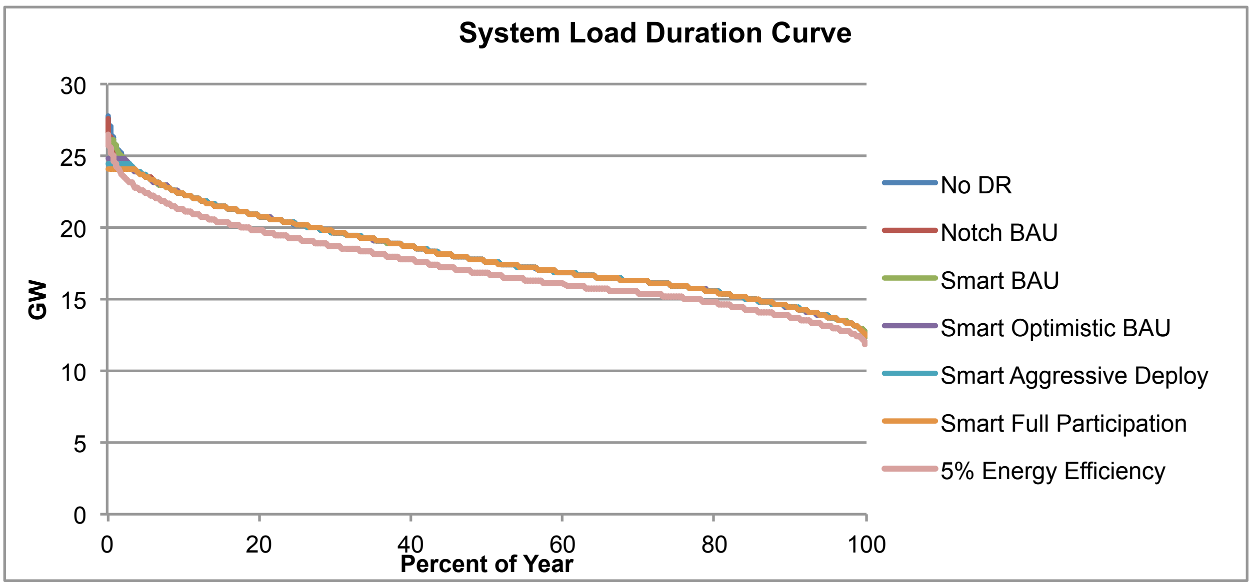


Figure 50: Annual Load Duration Curves under different scenarios (SRGW)

Figure 51 is a magnification of Load Duration Curve (LDC) showing the top 4% of the year. The Notch scenario reduced demand by roughly 950 MW for 60 hours, but these were not necessarily during the peak hours, so there were some discontinuities where peak hours had no reduction. An additional curve has been added labeled Constrained BAU that is the Smart-BAU with the DR amount constrained so that the amount dispatched was never more than the 950 MW calculated by NADR. The peak was reduced by 950 MW in the peak hours and then declined so that the peak flattened at 25.9 GW. The three Smart

[24] We developed Energy Efficiency case for a comparison purpose.

scenarios have clipped peaks at 26.1 GW (BAU), 24.9 GW (Optimistic BAU), 24.4 GW (Aggressive Deploy) and 24.1 GW (Full Participation).

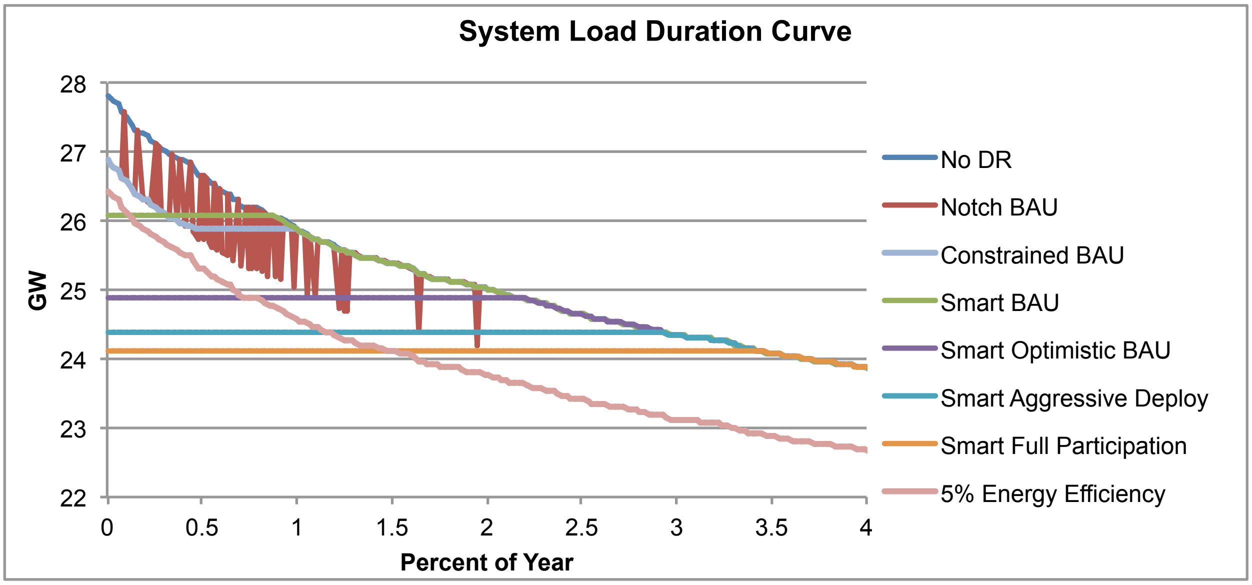


Figure 51: Peak Portion of Load Duration Curve of SRGW

A number of insights can be derived from these figures. First, the three BAU cases (Notch, Smart, and Constrained) all had the same amount of energy reduction but had very different impacts on the LDC. The Notch was applied to a four-hour block on the fifteen highest days, but that block may not result in a true flattening of the peak. As a consequence, DR was applied in some lower demand hours, which were further to the right on the LDC and so dissipated the impact of DR. The peak demand in the Notch case was 27.6 GW, a decrease of only 260 MW. Contrarily, the Smart BAU flattened the peak at 26.1 GW and reduced demand during all of the 76 highest hours. Some hours had more DR called upon (up to 1,700 MW) while others less, but the total energy reduction was the same as in the Notch scenario. The third BAU scenario shown, Constrained, still limited the DR impact to only 950 MW but applied these to the highest demands so the system peak dropped the full 950 MW to 26.9 GW.

Another key insight was that in high penetration scenarios the final peak system load was reduced by much less than the DR percentage. For example, in the FP scenario the DR amounted to 29% of peak demand (Table 19), but reduced the peak by just 16% or 3.7 GW.

Theoretically, all of the DR could be called upon during the top 60 hours, but then they would drop demand 29% for only those hours but have no impact on hours 61 and beyond. Instead, it is “smarter” to spread the DR around; this ends up with it being used in 303 hours (3.5% of the year) in the FP scenario. Only some participants were called upon during each occasion so that their annual participation was still only 60 hours or less. Table 21 shows the DR available as a percentage of peak demand (from Table 19) along with the actual system peak reduction as DR is spread to flatten the peaks (in the Smart scenarios) or misses some peaks out of the 2-6pm target in the Notch scenario.

Note how even with large increases in DR percentage from the Optimistic BAU to Full Participation, the actual system peak was not heavily impacted in most regions. In SRGW for example, the DR % rose from 15% to 29% between these two scenarios, but the system peak reduction only changed from 12% to 16%. The DR became energy-limited rather than capacity-limited. Much of any additional DR had to be spread over more hours so had less effect on the system peak.

Table 21. System Peak Reductions with Increasing DR Penetration

	DR-BAU				DR-Optimistic BAU		DR-Aggressive Deployment		DR-Full Deployment	
		System Peak Reduced								
	DR	Notch	Constrained	Smart	DR	System Peak Reduced	DR	System Peak Reduced	DR	System Peak Reduced
FRCC	5%	0%	5%	15%	22%	19%	35%	21%	47%	22%
MROE	9%	2%	9%	10%	15%	12%	19%	13%	22%	13%
MROW	9%	0%	9%	11%	20%	14%	26%	16%	29%	16%
NEWE	7%	0%	7%	10%	12%	12%	16%	13%	19%	14%
NYCW	10%	1%	10%	10%	18%	12%	21%	13%	25%	13%
NYLI	10%	3%	10%	14%	18%	17%	21%	17%	25%	18%
NYUP	10%	1%	10%	13%	18%	16%	21%	17%	25%	18%
RFCE	7%	2%	7%	11%	15%	14%	22%	16%	29%	18%
RFCM	6%	2%	6%	8%	14%	11%	19%	13%	22%	14%
RFCW	6%	2%	6%	8%	15%	12%	21%	13%	26%	14%
SRDA	4%	2%	4%	8%	12%	11%	21%	13%	29%	14%
SRGW	4%	1%	4%	7%	15%	12%	23%	14%	29%	16%
SRSE	3%	1%	3%	5%	18%	10%	27%	11%	36%	13%
SRCE	1%	1%	1%	6%	8%	11%	18%	13%	27%	15%
SRVC	5%	0%	5%	6%	20%	10%	30%	12%	38%	13%
SPNO	2%	2%	2%	5%	12%	12%	21%	15%	29%	16%
SPSO	6%	4%	6%	9%	13%	11%	23%	14%	31%	15%

Lastly, Figure 50 shows how small an impact DR had on the total energy demand. It had an effect on less than 4% of the year's demand, while energy efficiency can have a much more extensive effect. The area between the base and other curves represent the amount of energy saved. The LDC with a 5% reduction over all hours has much more total space between the two curves than any of the DR scenarios. This is quantified later in this report. Energy efficiency programs are discussed in more detail in the companion study From Georgia Institute of Technology *Estimating the Energy-Efficiency Potential in the Eastern Interconnection* (Brown, et al, 2012). This "smart" use of DR resources clips the peak at 24,100 MW.

7.4.2 System Reliability Impact

Related to the reduction in peak demand is the second type of benefit, improved system reliability. Our modeling did not include reducing the amount of generating capacity, which means that the reserve margin would increase as system peaks declined. We found that the DR programs significantly contribute to increasing the reserve margin in each region (see Table 22). The reserve margin in this analysis is defined as follows:

$$Regional\ Reserve\ Margin = \frac{(Total\ Generation\ Capacity - 85\%\ of\ Wind\ Capacity)}{(Regional\ Demand - DR\ Load\ Impact)}$$

This equation reduces regional capacity by 85% of the wind capacity in the region to represent the variable nature of wind. This value is roughly in alignment with what is used in various reliability regions. Secondly, this equation does not incorporate the impact of exports or imports into a region. Those regions planning on exports will have a higher reserve margin in this table, while those that heavily utilize imports will have a low or negative reserve margin.

For example, both NYCW and NYLI show negative values of reserve margin. This result can be explained by the fact that NYCW and NYLI highly depend on electricity from upstate New York or

RFCE region to meet their regional demand. MROE and NEWE show positive but relatively low levels in reserve margin. MROE imports electricity from the neighboring MROW, and NEWE internationally imports electricity from Canada.[25] In addition to reserve margin, we checked changes in LOLP to validate the changes in system reliability under different scenarios. The LOLP decreases below 1 day per 10 year in most of the regions with the addition of DR. NYCW region showed one of the highest impacts on LOLP and its LOLP dropped from 6.8 (under BAU) to 0.4 (under Full Deployment–Smart).

Table 22: Reserve Margin in 2030[26]

	No DR	BAU-Notch	BAU-Smart	Optimist BAU-Smart	Aggressive Deployment -Smart	Full Deployment -Smart
FRCC	23%	27%	29%	36%	39%	41%
MROE	2%	4%	13%	15%	17%	18%
MROW	19%	20%	34%	39%	41%	42%
NEWE	0%	1%	12%	14	16%	17%
NYCW	-16%	-15%	-7%	-5%	-4%	-3%
NYLI	-13%	-10%	1%	4%	5%	6%
NYUP	32%	33%	52%	57%	58%	60%
RFCE	12%	14%	26%	31%	33%	36%
RFCM	15%	17%	25%	29%	32%	33%
RFCW	19%	22%	30%	35%	38%	39%
SRDA	34%	36%	46%	51%	54%	56%
SRGW	26%	27%	36%	43%	47%	49%
SRSE	31%	32%	38%	46%	48%	50%
SRCE	15%	17%	23%	29%	33%	35%
SRVC	19%	22%	26%	33%	35%	37%
SPNO	18%	21%	25%	34%	38%	41%
SPSO	13%	17%	24%	27%	31%	33%

Of course, any region may choose to retire, deactivate, or mothball old capacity, or not build new capacity if they use the DR resources available in their region. However, attempting to determine how many and which plants to deactivate was beyond the scope of this study.

7.4.3 Generation Cost Impact

The third type of benefit from the demand response programs is reduction in production cost. Table 23 shows the reduction in average cost per MWh under different scenarios. It indicates that the average costs are not significantly affected by the penetration of demand response programs even under the Full deployment scenario. Regionally, NYLI and NEWE regions in Full Deployment-Smart scenario show the highest impact of 2% reduction in average cost.

Whereas the impact on the average production cost is small, the demand response programs significantly contribute to subduing the cost during the peak hours. Table 24 shows the cost of avoided electricity by DR during the peak hours. In general, the per-MWh avoided cost under the BAU-Smart scenario is the greatest during peak hours. It is because the scenario addresses the actual peak hours rather than the pre-specified time slots and targets the tiptop of the peak loads. Since relatively expensive generation options

[25] The international import is not captured by NEMS supply data that we used for setting the supply module of ORCED.

[26] The input dataset for the supply module in ORCED was updated by NEMS for AEO 2011 and LDCs in the demand module were generated based on FERC's 714 data. The difference in data source might cause an inaccurate estimate of LOLP and reserve margin that are calculated in the dispatch module where the supply and the demand meet. Furthermore, the model used calculates a relative LOLP that only treats a fraction of the plants as stochastic.

are involved to meet peak demand in general, demand response programs are able subdue the increase in price by shaving off the peak loads.

Table 23: Average Cost of Generation in 2030 ($/MWh)

($/MWh)	No DR	BAU-Notch	BAU-Smart	Optimist BAU-Smart	Aggressive Deployment-Smart	Full Deployment-Smart
FRCC	54.9	54.9	54.9	54.8	54.7	54.7
MROE	49.2	49.1	49.1	49.0	49.0	49.0
MROW	43.1	43.0	43.0	43.0	43.0	43.0
NEWE	52.7	52.6	52.6	52.6	52.5	52.5
NYCW	70.2	70.0	70.0	69.9	69.9	69.8
NYLI	84.5	83.8	83.7	83.2	83.0	82.8
NYUP	37.5	37.5	37.5	37.5	37.5	37.4
RFCE	46.1	46.0	45.9	45.8	45.8	45.8
RFCM	43.6	43.5	43.5	43.5	43.4	43.4
RFCW	40.8	40.7	40.7	40.7	40.7	40.7
SRDA	45.6	45.6	45.6	45.6	45.6	45.6
SRGW	40.7	40.6	40.6	40.6	40.6	40.5
SRSE	48.0	48.0	48.0	48.0	48.0	47.9
SRCE	36.9	36.9	36.9	36.8	36.8	36.8
SRVC	47.2	47.2	47.2	47.2	47.1	47.1
SPNO	66.9	66.9	66.9	66.9	66.8	66.9
SPSO	47.2	47.1	47.1	47.1	47.0	47.0

Table 24: Avoided Cost of Electricity Generation during the Peak Hours in 2030 ($/MWh)

	BAU-Notch	BAU-Smart	Optimist BAU-Smart	Aggressive Deployment-Smart	Full Deployment-Smart
FRCC	87	134	98	96	90
MROE	114	117	111	109	108
MROW	83	101	86	82	80
NEWE	140	184	141	128	123
NYCW	126	155	131	127	120
NYLI	345	387	368	356	348
NYUP	48	16	31	45	59
RFCE	224	297	216	179	155
RFCM	107	117	107	105	101
RFCW	99	112	97	86	83
SRDA	62	74	62	60	58
SRGW	84	106	98	92	91
SRSE	57	62	62	61	61
SRCE	72	73	84	73	70
SRVC	83	105	84	79	78
SPNO	90	117	107	98	88
SPSO	118	117	101	93	93

7.4.4 Environmental Impact

In addition to the cost reduction and the improved system reliability, DR also results in environmental benefits. In general, the amount of green house gas emissions is proportional to the electricity generation. The total amount of reduction in electricity generation by DR in the Eastern Interconnection is 2~11 TWh by scenario in 2030. Table 25 shows that, compared to the energy efficiency, the impact of DR on reduction in total electricity generation is small. It is because energy efficiency shifts down the absolute levels of electricity demand across the entire year, DR addresses only the peak hours that occupy less than 1% of a year. Decreases in CO_2 emissions by scenario and region are shown in Table 26. In the Eastern Interconnection area, 5~25 million tons of CO_2 could be avoided by DR in 2030. Some regions where the peak demand is served by a variety of other generation options that are cleaner than fossil fuels might not be able to expect a significant reduction in GHG emission from DR.

Table 25: Change in Generation Volumes in 2030 due to DR program deployment (TWh)

(TWh)	BAU-Notch	BAU-Smart	Optimist BAU-Smart	Aggressive Deployment-Smart	Full Deploymen t-Smart	5% Energy Efficiency
FRCC	-0.15	-0.15	-0.67	-1.06	-1.43	-11.97
MROE	-0.04	-0.04	-0.06	-0.08	-0.09	-1.69
MROW	-0.21	-0.21	-0.48	-0.62	-0.69	-11.86
NEWE	-0.08	-0.06	-0.13	-0.20	-0.25	-6.78
NYCW	-0.07	-0.06	-0.12	-0.14	-0.16	-1.21
NYLI	-0.03	-0.03	-0.06	-0.07	-0.08	-0.62
NYUP	-0.10	-0.10	-0.18	-0.21	-0.25	-5.11
RFCE	-0.25	-0.24	-0.54	-0.79	-1.05	-16.07
RFCM	-0.08	-0.08	-0.18	-0.25	-0.29	-5.73
RFCW	-0.39	-0.39	-0.98	-1.38	-1.70	-33.64
SRDA	-0.07	-0.07	-0.20	-0.34	-0.47	-7.11
SRGW	-0.05	-0.05	-0.20	-0.31	-0.39	-7.95
SRSE	-0.09	-0.09	-0.56	-0.83	-1.11	-14.38
SRCE	-0.03	-0.03	-0.22	-0.49	-0.74	-12.24
SRVC	-0.20	-0.20	-0.80	-1.21	-1.53	-16.12
SPNO	-0.02	-0.02	-0.11	-0.20	-0.27	-3.73
SPSO	-0.09	-0.09	-0.22	-0.40	-0.54	-7.41
EI Total	**-1.95**	**-1.92**	**-5.71**	**-8.57**	**-11.05**	**-163.62**

Table 26: Change in CO2 emissions in 2030 due to DR program deployment

(Million tons)	**BAU-Notch**	**BAU-Smart**	**Optimist BAU-Smart**	**Aggressive Deployment-Smart**	**Full Deployment-Smart**
MROE	-0.10	-0.10	-0.17	-0.21	-0.25
FRCC	-0.35	-0.44	-1.65	-2.45	-3.18
MROW	-0.63	-0.53	-1.24	-1.60	-1.80
NEWE	-0.23	-0.28	-0.52	-0.66	-0.75
NYCW	-0.18	-0.20	-0.34	-0.39	-0.45
NYLI	-0.13	-0.13	-0.24	-0.27	-0.32
NYUP	-0.17	-0.18	-0.31	-0.35	-0.42
RFCE	-0.87	-0.93	-1.79	-2.38	-2.80
RFCM	-0.22	-0.23	-0.47	-0.59	-0.71
RFCW	-0.93	-0.98	-2.28	-3.17	-3.77
SRDA	-0.12	-0.13	-0.33	-0.59	-0.81
SRGW	-0.14	-0.14	-0.50	-0.75	-1.01
SRSE	-0.25	-0.14	-1.03	-1.45	-1.90
SRCE	-0.13	-0.08	-0.44	-1.02	-1.36
SRVC	-0.25	-0.48	-1.54	-2.21	-2.58
SPNO	-0.06	-0.07	-0.31	-0.52	-0.67
SPSO	-0.20	-0.24	-0.55	-0.95	-1.28
EI Total	**-4.96**	**-5.28**	**-13.72**	**-19.58**	**-24.04**

On balance, the results from the ORCED benefits analysis show that DR programs are able to significantly increase the system reliability in the Eastern Interconnection area by increasing the reserve margin and reducing LOLP days. By avoiding the peak period, customers will benefit from the subdued electricity prices. While both energy efficiency and demand response are expected to influence the electricity market in general and contribute to curtailing the fossil fuel consumption for electricity generation, the time periods when the savings happen and the magnitude of the impacts vary tremendously. The impact of EE was distributed across the entire year, whereas that of DR was focused on the peak periods. As a consequence, DR is beneficial to emergency controls and grid reliability and is anticipated to contribute to controlling the supplies and prices during the peak hours. This result is explained by the fact that DR is originally designed to cope with supply-deficiency situations during the peak hours.

8. CHALLENGES TO DEMAND RESPONSE IMPLEMENTATION

Assessing Costs and Benefits of Demand Response

Difficulty in assessing some of the costs and benefits of DR programs obstructs wider program implementation. In declaring cost-effectiveness estimation protocols for DR programs administered by utility companies in California, for example, the California Public Utilities Commission (CPUC) explicitly stated that certain costs and benefits are "difficult, if not impossible, to calculate" (CPUC 2010). The CPUC's protocols require utilities to provide estimates of these uncertain costs and benefits using either "a reasonable and transparent method" or a qualitative discussion of the likelihood and extent of [such costs and benefits]" (CPUC 2010). The CPUC (2010) lists the following benefits and costs of DR programs as particularly challenging to assess:

<u>*Environmental Benefits*</u> – Through inducing reductions in electricity consumption, DR programs simultaneously reduce the emissions associated with electricity generation. As with all pollution reductions, the benefits are difficult to assess because they are spread over such a large population and monetary values have not yet been well-mapped to particular pollutants. A more-certain benefit that DR programs provide is avoiding the additional costs of meeting environmental regulations during construction of new power plants; these costs are already accounted for in the avoided generation benefits of demand response, however (CPUC 2008).

<u>*Market Benefits*</u> – Mitigating electricity price volatility is a chief benefit of DR programs; other similar benefits include increasing the reliability of the electricity grid and increasing market efficiency. Although the ultimate form of these benefits is both quantifiable and monetary (e.g. consumers and producers should have more wealth in a more efficient market), mapping these benefits to DR programs is difficult because of the nature of electricity price volatility, market efficiency, and grid reliability as dependent upon aggregate supply and aggregate demand. It is always challenging to assign particular features of the aggregate market to specific individual actors, such as attributing a certain percent reduction in electricity price volatility to a specific DR program (CPUC 2008).

<u>*Transaction Costs and Value of Service Lost*</u> – These costs are highly dependent upon the customer's own preferences and valuations. The transaction costs may include time spent learning about available DR programs, time spent completing an application for a DR program, and time spent performing energy audits. To know these costs, the customer's valuation of each of these quantities of time is necessary. Value of Service Lost refers to the gains from electricity use that would have been realized had the customer not reduced electricity use at all. These frequently include productivity values (e.g. the output produced with a given amount of electricity) and comfort values (e.g. the greater amount of satisfaction one feels from a hot shower instead of a warm shower). Both of these costs would require customers to self-identify (in honesty) what these amounts of comfort, productivity, or time are worth in monetary terms (CPUC 2008).

The CPUC protocols released in 2010 are the culmination of several preliminary studies, stakeholder feedback sessions, and utility surveys that began with the reporting of internal cost-effectiveness protocols by three large California utilities: Pacific Gas & Electric, San Diego Gas & Electric, and Consolidated Edison (CPUC 2005a; CPUC 2005b; CPUC 2005c; Barkovich, Ellis, Jordan, et al. 2007; CPUC 2008; CPUC 2010). The Total Resource Cost (TRC) test calculates costs and benefits for society, understood as the LSE and its customers and it is the most commonly applied test by utilities trying to justify their DR programs in front of their public utility commissions.

Another helpful methodological guide is the one published by EPRI in 2010 regarding the approach to quantify benefits and costs of smart grid demonstration projects. Like in the case of DR programs, smart grid programs generate benefits and costs to participant customers, non-participant customers, utilities and society as a whole. Benefits in this handbook are classified in 4 main categories: economic, reliability and power quality, environmental and security and safety.

Regulatory issues

Discriminatory treatment to non-generation resources: Since the approval of FERC Order 890 in 2007, RTOs and ISOs are required to evaluate non-generation resources, such as DR and storage, on a comparable basis to services provided by generation resources in meeting mandatory reliability standards, providing ancillary services and planning expansion of the transmission grid. Before this ruling, much of the potential value of DR resources was not being realized as, in many cases, DR was not allowed to provide ancillary services and could not be counted as capacity for reliability planning purposes.

Discriminatory treatment to fast-response resources: FERC Order 755, published in November 2011, will matter for DR resources providing frequency regulation service in organized wholesale electric markets. It establishes that resources participating in regulation markets should receive compensation with two elements: a capacity element that includes the opportunity cost of the marginal unit providing the service during each hour and a payment for performance. This second payment is a dollar amount per MW up or down of regulation service provided such that those resources that can respond very fast and accurately to the automatic generation control (AGC) signal (e.g., flywheels, batteries, fast hydro and DR) get paid more than slower units.

Compensation: Another challenging issue for implementation of DR programs is determining fair compensation to program participants. As described above, programs such as Curtailing Load and Interruptible Load involve paying participating customers to compensate them for the value of electricity service they lose when making their demand reductions. This issue was the subject of debate after FERC distributed a Notice of Proposed Rulemaking (NOPR RM10-17) stating that it would soon set a standard compensation rate to be paid by all electricity suppliers to customers participating in DR programs (Boshar 2010). Certain members of FERC as well as consumer advocates argued in favor of paying DR participants the Locational Marginal Price (LMP) in return for their demand reductions, while electricity supplier advocates argued for payments below the LMP.

The argument in favor of the LMP centered on treating DR resources as avoided capacity expansions. Since the LMP is used to cover the costs of capacity expansions (including additional transmission infrastructure and distribution costs), it seems reasonable to pay DR participants the LMP for helping suppliers to avoid the costs that suppliers would need to recover through the LMP (Boshar 2010, FERC 2011). Additionally, consumer advocacy group Electricity Consumer Resource Council (ELCON) argued that the LMP would help compensate DR participants for the shared benefits their demand reductions created, such as increased grid stability and market efficiency (Boshar 2010).

The counterargument offered by the Electricity Power Supply Association and other supply-side advocates stated that paying the LMP to DR participants would exacerbate the economic inefficiencies of the electricity market. Supply advocates, with the support of economist William Hogan from Harvard's Kennedy School of Government, argued that only a select few DR customers needed to be compensated at all for their reductions and that no compensation should be equal to or greater than the LMP (FERC 2011, Boshar 2010). Hogan's work on this issue concludes that only customers who do not pay the LMP for their electricity should be compensated for their demand reductions. Hogan and fellow critics argued that the LMP would be an overcompensating amount to pay to DR participants (Boshar 2010).

On March 24, 2011, The FERC issued its final rule on DR compensation. The FERC ultimately chose to make payment of the LMP the policy to which all DR program providers (i.e. electricity suppliers) must subscribe:

> "…We find, based on the record here that, when a demand response resource has the capability to balance supply and demand as an alternative to a generation resource, and when dispatching and paying LMP to that demand response resource is shown to be cost-effective as determined by the net benefits test described herein, payment by an RTO or ISO of compensation other than the LMP is unjust and unreasonable. When these conditions are met, we find that payment of LMP to these resources will result in just and reasonable rates for ratepayers. As stated in the NOPR, we believe paying demand response resources the LMP will compensate those resources in a manner that reflects the marginal value of the resource to each RTO and ISO." (FERC 2011, paragraph 47)

While FERC's decision may have temporarily abated the DR program compensation debate, many of the challenges to DR implementation remain unanswered. Further research is necessary to establish the costs of DR programs and their consumption-curtailing effectiveness.

9. POSSIBLE NADR RESEARCH ENHANCEMENTS

A) Revising participation hierarchy

Modeling tools designed to assess demand response potential in a given region typically assume no overlaps in demand response participation (i.e.,if a customer enrolls in a particular kind of program is automatically taken out of the pool of available customers for the rest of program). Therefore, the order in which customers are selected is important.

Since no additional information regarding this aspect of DR program design is available, the ORNL team has maintained the participation hierarchy from the original NADR. First, interruptible tariffs customers are chosen. Second the remaining customers are used as the available pool for applying participation rates related to dynamic pricing programs. Third, dynamic pricing non-participants with central AC are the pool eligible for direct load control programs. Lastly, remaining non-participants in any of the above programs are the eligible population for enrolling in Other DR programs.

The chosen participation hierarchy used explains some apparently odd results in the scenario analysis. For instance, for D.C., the load reduction potential under the "Optimistic BAU" scenario is higher than in the "Full Deployment" scenario, which given the additive nature of these scenarios, should not be the case. The explanation is that the increase in load reduction associated with universal participation in dynamic pricing is more than offset by reductions in load reduction from C&I customers that were enrolled in different programs in other scenarios.

B) Representation of DR program penetration rates

Currently, NADR takes a simple, linear interpolation approach to represent the transition from current market penetration to maximum market penetration in a pre-specified number of years, where those 3 parameters are program specific.

Alternative, more sophisticated approaches to estimate rates of adoption and attrition have been used in particular case studies. For instance, Brattle Group has forecasted enrollment on non-residential DR programs by one particular utility (PG&E) from 2011 to 2021 (see Wharton and Palmer, 2011). In this analysis, probabilities of enrolment in mutually exclusive programs are obtained using a multilogit choice model (and portfolio analysis to account for instances of dual enrollment). Then, the evolution of enrolment rates over time is characterized using a Markov chain.

C) Investigating demand reduction potential at the appliance level

NADR provides aggregate percentage load reduction from each program type rather than considering separately the reduction potential from specific types of appliances. Starke et al.(2011) discuss differences in the DR value of different residential sector appliances. Some of the key attributes to consider are whether a load can be ramped to different consumption levels, has thermal storage capabilities or would need supplementary add-on devices or retrofitting is crucial in capturing a load's DR value. Water heaters, refrigerators and HVAC units have the potential to provide the most demand reduction. Another reason why having appliance-level data is important is to model rebound effects associated with DR dispatch. Black et al. (2008) highlight the importance of distinguishing between instantaneous loads like lighting which, if dispatched as DR, would not have an associated rebound effect and deferrable or thermal demand which would shift to later hours. The current version of NADR does not account at all for possible rebound effects.

D) Update econometric estimation of load profile curves for each state and customer type

Several issues are worth noting regarding the current set of econometric estimates for load profile curves.

- The equation estimation is based on data from 2008 or earlier. As indicated in Figure 8 for the NERC system peak load, electricity consumption fell significantly due to the recession that, officially, started in December 2007. For the analysis summarized in this report, an adjustment factor was applied to the critical peak load for each state. However, it does not distinguish across customer types despite it being likely that the impact of the weakened macroeconomic conditions was different for a large industrial customer than for a residential customer. To capture those changes, a re-estimation of the load profile curves with more recent data would be advisable.
- The equation estimation is based on a data panel with significant <u>geographical gaps</u>. No data are available for many states in the Eastern Interconnection (Wisconsin, North Dakota, South Dakota, Minnesota, Iowa, Nebraska, Kansas, West Virginia, Virginia, Florida, Georgia, Kentucky, Tennessee, Alabama, Mississippi, Arkansas, Louisiana, Oklahoma). Were there any idiosyncrasies in load profiles in Census Divisions 4 or 6, they would not be captured by the above equation. The ORNL team is looking for ways to refine estimation of baseline peak loads.
- This approach assumes that <u>only the summer peaks are important</u> for demand response. The equation only looks at load profile during months 5 through 9 (i.e., May through September) and focuses on the interaction between temperatures and central air conditioning.
- This approach is geared towards examining the impacts of one particular dynamic pricing program: <u>critical peak pricing.</u>

E) Investigate duration and timing of DR programs

While the amount of potential DR can be calculated to be a rather large percentage of the peak demand, the limited hours that it is available will reduce the overall impact on peaks, as shown in Chapter 7. Our assumption, consistent with the FERC NADR study, was that an individual DR resource could be called upon a maximum of 60 hours over a year. Actual DR programs may have more or fewer hours of availability, depending on the type and end-user preferences. With increasing DR penetration, this could have a large impact on the ultimate change in peak demand. While some work has been done in this area through FERC's DRIVE (Demand Response Impact and Value Estimation) model, further research is needed to find the range of availabilities of different DR programs and their impact on overall peak levels over the year.

10. REFERENCES

Agerter, L. L., & Ouborg, P. (2005). Preliminary AMI Business Case Analysis of Pacific Gas and Electric Company (U 39-E). Analysis. San Francisco, California. Retrieved from http://sites.energetics.com/MADRI/toolbox/pdfs/business_cases/pge_businesscase.pdf

Barbose, G.; Goldman, C.; and Neenan, B. (2004) A survey of utility experience with real time pricing. Retrieved June 13, 2011 from http://eetd.lbl.gov/ea/EMS/EMS_pubs.html

Barkovich, B.; Ellis, J.; Jordan, L.H.; et al. (2007) *Joint coments of California Large Energy Consumers Association, Comverge, Inc., Division of Ratepayer Advocates, Energyconnect, Inc., Enernoc, Inc., Ice Energy, Inc., Pacific Gas and Electric Company (U 39-M), San Diego Gas & Electric company (U 902-E), Southern California Edison Company (U 338-E) and the Utility Reform Network recommending a demand response cost effectiveness evaluation framework: R.07-01-041* Retrieved June 11, 2011 from http://www.nwcouncil.org/energy/dr/meetings/2008_01/ConsensusCADRCEEvaluationFramework111907.pdf

Bharvirkar, R.; Goldman, C.; Heffner, G.; and Sedano, R. (2008) Coordination of retail demand response with Midwest ISO wholesale markets. Retrieved June 13, 2011 from http://eetd.lbl.gov/ea/EMS/EMS_pubs.html

Boshar, G. (2010) ELCON, EPSA, and Harvard's Hogan face off over demand response compensation rules. *SNL Energy Power Daily*. May 17, 2010. Retrieved June 5, 2011 from http://proquest.umi.com/pqdweb?did=2353266341&Fmt=3&clientId=30287&RQT=309&VName=PDQ

Brown, Marilyn and Yu Wang (2012) *Estimating the Energy-Efficiency Potential in the Eastern Interconnection*, ORNL/TM-2012/568, prepared by Georgia Institute of Technology for Oak Ridge National Laboratory, November.

Buckner, David E. (2009) Direct Testimony of David E. Buckner on behalf of Mississippi Power Company before the Mississippi Public Service Commission. Mississippi Public Service Commission Docket No. '09-UA-398

Cappers, P.; Goldman, C.; and Kathan, D. (2009) Demand response in U.S. electricity markets: Empirical evidence. Retrieved June 13, 2011 from http://eetd.lbl.gov/ea/EMS/EMS_pubs.html

Casady, S. (2008). September 2008 AMI Plan Biannual Report, Decsion No. 68112, Docket No. E-01345A-03-0775 and E-01345A-04-0657. Paragraph. Phoenix, Arizona. Retrieved from http://images.edocket.azcc.gov/docketpdf/0000088550.pdf

Cawley, J. H., Christy, T. J., Pizzingrilli, K., Gardner, W. E., & Powelson, R. F. (2009). Smart Meter Procurement and Installation: Implementation Order. Harrisburg, Pennsylvania. Retrieved from www.puc.state.pa.us/electric/Act129/Smart_Meter_Technology.aspx

Chan, M., et al. (2011) Preliminary US DOE Smart Grid Investment Grant Program Advanced Metering Infrastructure Asset Costs: A comparison to costs published by the EPRI and the Brattle Group. Navigant Energy Consulting for the US Association of Energy Economics, October 8-11, 2011.

Charles Rivers Associates (2005). Impact Evaluation of the California Statewide Pricing Pilot, Marc 16.

Downloadable from http://www.calmac.org/publications/2005-03-24_SPP_FINAL_REP.pdf

Chupka, M. W., Earle, R., Fox-penner, P., & Hledik, R. (2008). Transforming America's Power Industry: The Investment Challenge 2010-2030. Prism. Retrieved from http://www.eei.org/ourissues/finance/Documents/Transforming_Americas_Power_Industry.pdf

Clavenna, Scott; Pollock, Zach. (2012) Can the smart meter and AMI market continue its meteoric growth? (Audiorecording/Interview/Podcast). Available at http://www.greentechmedia.com/articles/read/podcast-the-smart-grid-ami-market-q1-20121/

Connecticut Light and Power Company (2010) Plan-it-Wise Recommendations. Connecticut Department of Public Utility Control Docket No. 05-10-03RE01.

CPUC (2005a) Audit report: Pacific Gas & Electric Company interruptible load management program for years 2001, 2002, and 2003. Retrieved June 7, 2011 from http://docs.cpuc.ca.gov/published/Report/46797.PDF

CPUC (2005b) Audit report: San Diego Gas & Electric interruptible load management program for years 2001, 2002, and 2003. Retrieved June 7, 2011 from http://docs.cpuc.ca.gov/published/Report/46796.PDF

CPUC (2005c) Audit report: Southern California Edison Company interruptible load management program for years 2001, 2002, and 2003. Retrieved June 7, 2011 from http://docs.cpuc.ca.gov/published/Report/46798.PDF

CPUC (2008) *Attachment A: Draft demand response cost effectiveness protocols: R.07-01-041*. Retrieved June 11, 2011 from http://docs.cpuc.ca.gov/efile/RULINGS/80858.pdf

CPUC (2010) *Attachment 1: 2010 demand response cost effectiveness protocols*. Retrieved June 11, 2011 from http://docs.cpuc.ca.gov/WORD_PDF/AGENDA_DECISION/128212.pdf

Curry, Kimberly A., et al. (2009) Application of Baltimore Gas and Electric Company for Authorization to Deploy a Smart Grid Initiative and to Establish a Surcharge Mechanism for the Recovery of Costs. Public Service Commission of Maryland Md. E-6: Rider 30, Md. G-9: Rider 13. Baltimore, Maryland.

Dayton Power and Light Company (2007) AMI Costs & Benefits: Public Utilities Commission of Ohio AMI Workshop #5. Public Utility Commission of Ohio Case No. 07-646-EL-UNC.

Energy Information Administration. (2011). Form 861 Data: 2010. Retrieved from http://205.254.135.24/cneaf/electricity/page/eia861.html

Environmental Protection Agency (2008) Understanding Cost-effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers. Available at www.epa.gov/eeactionplan

EPRI (2010). *Methodological approach for estimating the benefits and costs of smart grid demonstration projects*. Report number 1020342.

EPRI (2009). Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S. Report number 1016987.

EPRI (2009). *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.* Report number 1016987.

EPRI (2009). Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S. Report number 1016987.

ERCOT Image Source: http://www.ercot.com/content/news/mediakit/maps/NERC_Interconnections_color.jpg

Farmer, L., Hatch-Miller, J., Mundell, W. A., Spitzer, M., Gleason, M., & Mayes, K. K. (2005). In the Matter of the Application of Arizona Public Service Company for a Declaratory Order Regarding Bill Estimation Procedures. Direct. Phoenix, Arizona. Retrieved from http://images.edocket.azcc.gov/docketpdf/0000028339.pdf

Faruqui, A. and D. Mitarotonda (2011). "Energy efficiency and demand response in 2020- a survey of expert opinion". Available at http://www.brattle.com/_documents/UploadLibrary/Upload990.pdf

Faruqui,A. and S. Sergici (2010). "Household response to dynamic pricing of electricity: a survey of 15 experiments". *Journal of Regulatory Economics* 38: 193-225.

Federal Energy Regulatory Commission (FERC) (2008). *Assessment of demand response and advanced metering, staff report*. Retrieved May 20, 2011 from http://www.ferc.gov/legal/staff-reports/12-08-demand-response.pdf

FERC (2009) *A National Assessment of Demand Response Potential NADR* prepared by the Brattle Group, Freeman, Sullivan & Co, Global Energy Partners, LLC.. Retrieved May 20, 2011 from http://www.ferc.goc/legal/staff-reports/06-09-demand-response.pdf

FERC (2010). *National Action Plan on Demand Response*. Available at http://www.ferc.gov/legal/staff-reports/06-17-10-demand-response.pdf

FERC (2011) Demand response compensation in organized wholesale electricity markets: Final rule. *Federal Register*, 76(57), 16658-16682

FERC(2011b). *Assessment of Demand Response and Advanced Metering. Staff Report*. Available at http://www.ferc.gov/legal/staff-reports/2010-dr-report.pdf

FirstEnergy (2007) Public Utilities Commission of Ohio Smart Metering Workshop: Ohio Edison Company, The Cleveland Electric Illuminating Company, And The Toledo Edison Company. Public Utilities Commission of Ohio Case No. 07-646-EL-COI.

Gellings, C. (2011). Estimating the Costs and Benefits of the Smart Grid. Power. Palo Alto, California. Retrieved from http://www.rmi.org/Content/Files/EstimatingCostsSmartGRid.pdf

Goldman, C.; Hopper, N.; Bharvirkar, R.; Neenan, B.; and Cappers, P. (2007) Estimating demand response market potential among large commercial and industrial customers: A scoping study. Retrieved June 13, 2011 from http://eetd.lbl.gov/ea/EMS/EMS_pubs.html

Global Energy Partners (2010). Assessment of Demand Response and Energy Efficiency Potential, Volume 2 Eastern Interconnection Analysis. Report #1314 prepared for Midwest ISO. November 2010.

Greer, J. A., Bates, T. L., Murphy, M. C., Pruett, K. R., Puckett, J. R., & Sherburne, J. M. (2008). Oncor Electric Delivery Company LLC's Request for Approval of AMS Deployment Plan and Request for AMS Surcharge. Austin, Texas. Retrieved from http://interchange.puc.state.tx.us/WebApp/Interchange/application/dbapps/filings/pgControl.asp?TXT_CNTRL_NO=35718&TXT_UTILITY_TYPE=A&TXT_CNTRL_NO=&TXT_ITEM_MATCH=1&TXT_ITEM_NO=&TXT_N_UTILITY=&TXT_N_FILE_PARTY=&TXT_DOC_TYPE=ALL&TXT_D_FROM=05%2F28%2F2008&TXT_D_TO=05%2F28%2F2008&TXT_NEW=true

Hadley, Stan, and Eric Hirst, *Possible Effects of Competition on Electricity Consumers in the Pacific Northwest*, ORNL/CON-455, Oak Ridge National Laboratory, January 1998. http://www.osti.gov/bridge/servlets/purl/573097-f30IwT/webviewable/

Hadley, Stanton W., *The Oak Ridge Competitive Electricity Dispatch (ORCED) Model*, ORNL/TM-2007/230, Oak Ridge National Laboratory, June 2008. http://apps.ornl.gov/~pts/prod/pubs/ldoc9472_orced_modelfinal.pdf

Hadsell, L.; Marthe, A.; and Shawky, H.A. (2004) Estimating the volatility of wholesale electricity spot prices in the US. *The Energy Journal,* 25(4), 23-40

Haney, A. B., Jamasb, T., & Pollitt, M. G. (2009). *Smart Metering and Electricity Demand: Technology, Economics, and International Experience*. Cambridge, United Kingdom.

Heffner, G. (2010) Demand Response Valuation Frameworks Paper. Lawrence Berkeley National Laboratory. LBNL-2489E. Available at http://escholarship.org/uc/item/401781d4

Hirst, Eric and Stan Hadley, *Maintaining Generation Adequacy in a Restructuring U.S. Electricity Industry*, ORNL/CON-472, Oak Ridge National Laboratory, October 1999. http://www.osti.gov/bridge/servlets/purl/15044-quHiNl/webviewable/

Isser, S. (2009) What is demand response. *Electric Light & Power*. Retrieved May 31, 2011 from (homepage) www.elp.com

Jenkins, Nancy; Haiad, Carlos; Price, Snuller; Horii, Brian; Mahone, Douglas; McHugh, Jon; Tyler, Matt; Saxena, Mudit; Reiss, Rachael. (2005) Case Update: Programmable Communicating Thermostats – PIER Buildings Program, SCE Codes & Standards Program, CEC Title 24 Workshop. Public Interest Energy Research (PIER).

Kiergan, Christopher D.; Freeman, Kent K. (2009) Verified Petition of Duke Energy Indiana, Inc. Requesting the Indiana Utility Regulatory Commision to Approve an Alternative Regulatory Plan Pursuant to IND. Code sub-section 8-1-2.5-1, ET SEQ., for the Implementation of an Electric Distribution System "SmartGrid" and Advanced Metering Infrastructure… Indiana Utility Regulatory Commission Cause No. 43501.

Lafferty, R.; Hunger, D.; Ballard, J.; Mahrenholz, G.; Mead, D.; Bandera, D. (2001) Demand Responsiveness in Electricity Markets. Federal Energy Regulatory Commission. Available online at: http://www.naseo.org/committees/energyproduction/documents/demand_responsiveness_in_electricity_markets.pdf

LBNL (2007b) Deemed savings estimates for Legacy Air Conditioning and Water Heating direct load control programs in PJM region. Retrieved June 13, 2011 from http://eetd.lbl.gov/ea/EMS/EMS_pubs.html

Li, F., Hadley, S., Leiby, P., Oladosu, G., Lee, R., Uria-Martinez, R., Baek, Y. S., et al. (2012). Interim Project Report: Eastern Interconnection Demand Response.

Maters, Bruce R., et al. (2010) In the matter of the application of the Detroit Edison Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority. Michigan Public Service Commission Case No. U-16472 (Paperless e-file).

McIndoo, W. (2008). In the Matter of Idaho Power Company's Application to Accelerate Depreciation of Existing Metering Equipment to be Replaced by Advanced Metering Infrastructure ("AMI") Installation; and to Implement Revised Depreciation Rates for the Company's Electric Pl. Salem, Oregon. Retrieved from http://edocs.puc.state.or.us/efdocs/UAA/ue202uaa11834.pdf

Office of Management and Budget (2003) Circular A-4. Available online at: http://www.whitehouse.gov/omb/circulars_a004_a-4

PBS (2011) Public vs. private power: From FDR to today. Retrieved June 17, 2011 from http://www.pbs.org/wgbh/pages/frontline/shows/blackout/regulation/timeline.html

PECO Energy Company. (2009). Petition of PECO Energy Company for Approval of its Smart Meter Technology and Installation Plan. Harrisburg, Pennsylvania. Retrieved from www.puc.state.pa.us/electric/Act129/Smart_Meter_Technology.aspx

PLMA (2002) Demand response: Design principles for creating customer and market value. Retrieved June 02, 2011 from http://www.peaklma.com/publications.aspx

PLMA (2004) Final results of the EEI/PLMA 2003 demand response benchmarking survey. Retrieved June 02, 2011 from http://www.peaklma.com/publications.aspx

Pollock, Z; Clavenna, S. (2012) Can the Smart Meter and AMI Market Continue its Meteoric Growth?. Podcast: The Smart Grid AMI Market, Q1 2012. Accessed July 2, 2012. Available online at http://www.greentechmedia.com/articles/read/podcast-the-smart-grid-ami-market-q1-20121/

Potts, George W. (2009) Potomac Electric Power Company, Delmarva Power & Light Company, before the Public Service Commission of Maryland, Direct Testimony of George W. Potts. Public Service Commission of Maryland Case No. 9207.

Roche, Jim (2011) Advanced Metering Infrastructure: The Rural Co-op Perspective. In Electricity Light and Power magazine. Available at http://www.elp.com/elp/en-us/index/display/elp-article-tool-template.articles.utility-automation- engineering-td.volume-13.issue-7.features.advanced-metering-infrastructure-the-rural-co-op- perspective.html

Rumolo, D. J. (2006). Compliance Filings as Required by Decision No. 68112, Docket No's. E-01345A-03-0775 and E-01345A-04-0657. Reading. Phoenix, Arizona. Retrieved from http://images.edocket.azcc.gov/docketpdf/0000046608.pdf

Shigekawa, J. T., Reed, B. A., & Combs, J. S. (2007). Southern California Edison Company's (U 338-E) Application for Approval of Advanced Metering Infrastructure Deployment Activities and Cost Recovery Mechanism. San Francisco, California. Retrieved from http://asset.sce.com/microsite/Documents/ESC/A0707XXXSCEAMIPhaseIIIApplication.pdf

Sloneker, K. L. (2008). Direct Testimony of Karen L. Sloneker on Behalf of Columbus Southern Power Company and Ohio Power Company. Columbus, Ohio. Retrieved from https://aepohio.com/global/utilities/lib/docs/info/news/rates/OH/Sloneker_testimony_1232011_Final.pdf

Smith, A. M., Hadley, S. W., & Brown, M. A. (2011). A Model for Estimating Costs of Demand Response Programs: Providing Supplementary Analysis to the Eastern Interconnection Planning Collaborative. Atlanta, Georgia.

Snook, L. R. (2009). March 2009 AMI Plan Biannual ACC Report, Decision No. 68112, Docket No. E-01345A-03-0775 and E-01345A-04-0657. Regulation. Phoenix, Arizona. Retrieved from http://images.edocket.azcc.gov/docketpdf/0000094364.pdf

Standish, T.R., et al. (2008). Application of CenterPoint Energy Houston Electric, LLC, for Approval of Deployment Plan and Request for Surcharge for an Advanced Metering System. Public Utility Commission of Texas Docket No. 35639.

Starke, M.: Onar, O.; Devault, B. (2011). Key Residential Building Equipment Technologies for Control and Grid Support-PART I (Residential). ORNL/TM-2011/143.

Thompson, V. L., & Morton, K. M. (2005). Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design. San Francisco, California: California Public Utilities Commission. Retrieved from http://www.smartgridinformation.info/pdf/2092_doc_1.pdf

US Department of Energy. (2006). Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them. Retrieved from www.smartgrid.gov

U.S. Department of Energy, & Office of Electricity Delivery and Energy Reliability. (2010). Smart Future Greater Philadelphia. Retrieved April 16, 2012, from www.smartgrid.gov/project/peco_smart_future_greater_philadelphia

Vardi, J. and B. Avi-Ithak. 1981. Electric Energy Generation Economics, Reliability, and Rates. MIT Press, Cambridge, MA.

West Penn Power Company. (2009). Pennsylvania Act 129: Smart Meter Technology Procurement and Installation Plan. System. Harrisburg, Pennsylvania. Retrieved from http://www.puc.state.pa.us/pcdocs/1051015.pdf

Wharton, J.B.; Palmer, J. (2011). "PG&E'S No-Residential Enrollment Forecast". Retrieved November 1, 2011 from http://www.brattle.com/Publications/ReportsPresentations.asp?PublicationID=1313

Whitehurst, Stacy, et al. (2010) Texas-New Mexico Power Company's Request for Approval of an Advance Metering System (AMS) Deployment and AMS Surcharge. Public Utility Commission of Texas Control Number 38306.

Wisconsin Power and Light Company. (2007). Application of Wisconsin Power and Light Company for a Certificate of Authority to Purchase, Install and Place into Operation an Advanced Metering Infrastructure System in the Entire WPL Natural Gas Service Territory. Madison, Wisconsin.

Retrieved from http://psc.wi.gov/apps35/ERF_view/viewdoc.aspx?docid=83859

APPENDIX A. DEMAND RESPONSE LITERATURE REVIEW SUMMARIES

Report name: Assessment of Achievable Potential form Energy Efficiency and Demand Response Programs in the U.S. (2010-2030)
Institution: EPRI (with collaboration of Global Energy Partners and The Brattle Group)
Date of release: January 2009

Key definitions
Baseline demand
AEO 2008 Reference Case forecast for total electricity consumption (adding back the effect of accounted-for energy efficiency programs)
NERC 2007 Peak Demand and Energy Projection Bandwidths extrapolated to 2030
Included DR programs
Residential sector: direct load control for air conditioning, direct load control for water heating and dynamic pricing programs including time-of-use (TOU), critical-peak pricing (CPP), real-time pricing (RTP) and peak time rebates)
Commercial sector: direct load control management for cooling, lighting and other uses, interruptible demand (e.g., interruptible, demand bidding, emergency, ancillary services) and dynamic pricing programs (TOU, CPP, RTP).
Industrial sector: direct control load management for process, interruptible demand (e.g., interruptible, demand bidding, emergency, ancillary services) and dynamic pricing programs (TOU, CPP, RTP).
Excluded DR programs
Spatial scope
United States
Spatial disaggregation
Census Division
Temporal disaggregation
Annual
Temporal scope
2010-2030
Technological detail
For the residential and commercial sectors, the study implemented a bottom-up approach for determining electric energy efficiency savings potential
For the industrial sector, the study applied a top-down approach in which the sector forecast is allocated to end uses and regions. The study used a modeling tool (LoadMAPTM, created by Global Energy Partners) for forecasting energy use, peak demand and energy efficiency and demand response savings, which incorporates a comprehensive technology database that includes the latest findings from EPRI energy efficiency research.
Dynamic pricing representation
Load curves
Elasticities
Main result
Achievable potential savings by 2030 is 7% to 9% of peak demand. The expected savings from DR measures are roughly equal across the three sectors. Direct load control, dynamic pricing and interruptible demand deliver similar levels of savings.

Report name: Demand Response Impact and Value Estimation Model
Institution: Brattle Group
Date of release:

Key definitions
Baseline demand
AEO Annual peak demand forecast without new DR (Note: AEO uses NERC's forecast as its default peak demand forecast)
Included DR programs
Dynamic pricing without enabling technology
Dynamic pricing with enabling technology
Direct load control
Interruptible tariffs
Capacity bidding, demand bidding and other aggregator offerings to medium and large commercial and industrial customers
Excluded DR programs
Time of use rates (although there is a table that can be used to implement a TOU rate where the peak period is defined as the five hours preceding the hour of the system peak on all weekdays), back-up generation, permanent load shifting and plug-in hybrid vehicles
Spatial scope
National
Spatial disaggregation
State-by-state or 13 NERC subregions
Temporal disaggregation
Annual
Temporal scope
2009-2019
Technological detail
Bottom-up approach.
It takes into consideration the characteristics of specific regional, state or utility power system (e.g., the existing supply mix, projections of fuel prices, the cost of new capacity, planned capacity additions by technology type)
It incorporates detailed information on current DR program enrollment by customer class (residential, small commercial and industrial (C&I), medium C&I and large C&I and the resulting peak load reductions.
Dynamic pricing representation
Load curves- Hourly load shapes are constructed aggregating those in 2005's FERC Form 714 database. This information is used to establish the relative shape of hourly loads. The absolute magnitude of these estimates does not matter as they are scaled to the peak and energy demand forecasts.
Elasticities- Taken from FERC's National Assessment of Demand Response study
Main result
It calculates total potential peak reduction by state under each different program considered and under four different scenarios which reflect different levels of AMI deployment, enabling technology eligibility, dynamic pricing participation rates and non-pricing participation rates.

Report name: Electricity Market Module of the National Energy Modeling System (NEMS), Model Documentation Report
Institution: EIA
Date of release: May 2010

Key definitions
Smart grid technologies include a wide array of measurement, communications and control equipment

employed throughout the transmission and distribution system that will enable real-time monitoring of the production, flow and use of power from generator to consumer.

Baseline demand

AEO total electricity consumption by Census division and end use

Included DR programs

It models smart grid to the extent that it was initiated by ARRA

Excluded DR programs

AEO always seeks to represent existing policies but not potential new ones

Spatial scope

United States

Spatial disaggregation

13 NERC and sub-NERC regions

Temporal disaggregation

Annual results although some variables are constructed with finer granularity (e.g., hourly loads)

Temporal scope

2010-2035

Technological detail

Bottom-up estimates of hourly load curves based on individual end uses and user classes, such as is done for some utilities, was viewed as not-yet workable at the national level. "At present, the end-use load shape data readily available for this effort are not of sufficient quality to allow the construction of system load shapes from the ground up"

Dynamic pricing representation

Load curves- the Electricity Load and Demand submodule develops load shape information for individual end-uses (e.g., heating, lighting, AC). There are also system load shapes that vary by region, season and time of day.

Elasticities-

Main result

Smart grid initiatives included in AEO2010 have three effects: line loss reductions (from 6.9% in 2008 to 5.3% in 2025), peak demand reduction (3% of what would otherwise be in 2035), enhanced price responsiveness (no information on how this effect is implemented/assessed)

Report name: National Assessment of Demand Response
Institution: FERC (with The Brattle Group, Freeman, Sullivan & Co. and Global Energy Partners)
Date of release: June 2009
Source link: http://www.ferc.gov/industries/electric/indus-act/demand-response/dr-potential/assessment.asp (accessed on February 9, 2011)
http://www.eei.org/ourissues/electricitydistribution/Documents/appendixH_final.pdf (appendix on estimation of price impacts using PRISM model, accessed on February 9, 2011)

1. Key definitions

Demand response- Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments design to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.

Smart grid- Broad concept that includes advanced, grid-friendly appliances that communicate with each other and whose operation can be managed remotely or locally on households through a digital home energy management system.

2. Baseline demand

NERC's summer peak demand forecast (version that includes energy efficiency and excludes DR)

3. Included DR programs

☒**Dynamic pricing** (two types of dynamic pricing are included: with/without enabling technologies. The enabling technology for residential and small and medium commercial and industrial customers is a programmable communicating thermostat and, for large commercial and industrial customers, is an automated response system)

☐**Time of use rates**
☐**Critical peak pricing**
☐**Real-time pricing**

☒**Direct load control**
☒**Interruptible tariffs**
☒**Capacity bidding, demand bidding and other aggregator offerings**
☐**Smart grid**

Other excluded programs: back-up generation, permanent load shifting, plug-in hybrid vehicles, distributed energy resources, targeted energy efficiency programs and technology-enabled DR programs with the capability of providing ancillary services in wholesale market.

4. Technological detail

Bottom up. It constructs load curves starting from a cross-section of available utility-level data. It uses all available data on participation rates by type of program and type of customer (residential, small commercial and industrial (C&I), medium C&I and large C&I).

5. DR treatment

There are three fundamental building blocks for estimating DR potential:

1. An estimate of average energy use during peak periods when DR programs are likely to be used (<u>between 2 and 6 pm on the top 15 system load days in each state</u>) but before demand response impacts take effect

Lack of data on energy use during peak periods is a big challenge. Most utilities might have aggregate hourly load data but not for a representative sample of customers. One of the important contributions of this report is that FERC/Brattle Group/Global Energy Partners used cross section of available hourly load data (from utilities in 21 states) and regression analysis to <u>develop normalized load shapes for five customer segments</u>: residential customers with and without central air conditioning, small non-residential customers (less than 20 kW), medium non-residential customers (20-200 kW) and large non-residential customers (peak demand exceeding 200 kW). The explanatory variables used for the regression analysis were (weather, central AC saturation and seasonal, monthly, day-of-week and hourly usage patterns).

2. An estimate of the change in energy use during peak periods resulting from customer participation in DR programs and response to DR price signals and incentives

DR potential for non-price based DR options is based on average values determined through analysis of data from existing programs

DR potential for price-based DR options was determined using the normalized load shapes and estimates of price elasticities (see table D-13 of Appendix D of the report). Peak period prices during high demand days are assumed to be 8 times higher than those in a static rate (5-to-1 for large C&I customers since most are already under TOU rates). This price ratio is intended to depict the ratio between an average price and a dynamic price that reflects a large portion of the avoided cost of capacity being incorporated into the small number of hours in which peak-period dynamic price signals are into effect. A two-equation CES demand system is used to estimate how electricity demand would change in response to time-varying prices. One equation determines the rate at which consumers substitute off-peak energy use for peak-period energy use and the second equation estimates the overall demand for energy.

Price elasticities and impacts estimates from 15 dynamic pricing pilots were synthesized to produce impact estimates for each state using the *Pricing Impact Simulation Model* (PRISM), originally created by

Charles River Associates for the California Statewide Pricing Pilot study. One important feature of PRISM is its capability to model nonlinearities in the estimation of usage impacts when price changes extend from minimal to maximal. Differences in impacts across states are driven by differences in central AC saturation rates, climate and the effect of enabling technology.

3. An estimate of the number of customers that participate in DR programs (eligible customers*participation rate)

6. Spatial scope
United States
7. Spatial disaggregation
State
8. Temporal scope
2010-2019
9. Temporal detail
Annual (but load curves are estimated hourly and the impact of dynamic pricing on peak demand focuses on the period from 2:00 pm to 6:00 pm during the top 15 system load days)
10. Main results
The range of total potential reductions in peak demand by 2019 relative to the baseline described above goes from 4% in the *business as usual* scenario to 20% in the *full participation* scenario (universally deployed AMI, dynamic pricing as default and other programs available to those opting out of dynamic pricing with full participation in all programs where and when it is cost effective to do so).
Largest untapped DR potential by sector is in residential sector.
Largest untapped DR potential by program is in dynamic pricing programs
There are multiple barriers to realizing full DR potential:
Regulatory (general): retail-wholesale disconnect, perception of gaming, lack of real-time info sharing (ISOs and utilities), lack of reliability/predictability in DR (relative to supply-side resources), policy restrictions on demand response, ineffective program design, financial disincentives for utilities (DR programs will reduce their revenues), disagreement on cost-effectiveness analysis, lack of retail competition, market structures oriented toward accommodating supply-side resources.
Economic: inaccurate price signals, lack of sufficient financial incentives to induce participation (it is argued that one way to improve incentives would be for utilities to take out from rates the implied hedging cost they now charge for dealing with price volatility in the context of flat retail rates)
Technological: lack of advanced metering infrastructure (only one US utility, PPL, has in place all the infrastructure needed to put all of its customers on default dynamic pricing), lack of cost-effective enabling technologies, concerns about technological obsolescence and cost recovery, lack of interoperability and open standards
Other: lack of customer awareness and education, risk aversion, fear of customer backlash, perceived lack of ability to respond, perceived temporary nature of DR impacts, concern over environmental impacts (if a DR program shifts load from peak to off-peak hours in which coal plants are on the margin, it could result in an increase in emissions).

11. Links to other studies
Baseline demand is an input from **NERC**
Peak demand reduction results for the different scenarios are an input from Brattle's **DRIVE** model
Peak demand reduction in response to dynamic pricing is an input from **PRISM** model

Report name: 2010 Long-Term Reliability Assessment
Institution: NERC (based on data and information submitted by each of the 8 Regional Entities in May

2010[27])
Date of release: October 2010
Source link: http://www.nerc.com/files/2010_LTRA_v2-.pdf

1. Key definitions
Demand response- Changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.
Response fatigue- A characteristic of demand resources who enroll on a DR program because of the financial incentives. Once the electric supply to their equipment has actually been interrupted a number of times, the inconvenience outweighs the cost savings and they may potentially withdraw from the program.
Demand Response Availability Data System (DADS)- NERC initiative for developing data collection requirements regarding DR and a uniform system to measure delivered DR and to specify statistics that quantify DR performance. DADS Phase I started in 2010 and collects historical DR performance data on a voluntary basis. Phase II will impose mandatory submittal.
2. Baseline demand
NERC's peak summer demand forecast (without energy efficiency and without demand response). Supply and demand projections are based on industry forecasts submitted in May 2010. NERC validates them to ensure correctness and consistency.
3. Included DR programs

- ☒**Dynamic pricing**
  - ☒**Time of use rates**
  - ☒**Critical peak pricing**
  - ☒**Real-time pricing**
- ☒**Direct load control**
- ☒**Interruptible tariffs**
- ☐**Capacity bidding, demand bidding and other aggregator offerings**
- ☐**Smart grid**

Other included programs: load as capacity resource, ancillary DR which provides spinning and non-spinning reserves as well as regulation, emergency-voluntary DR and system peak response transmission tariff.
Note: NERC includes only existing and planned DR programs in its peak demand forecasts.
4. Technological detail
No technological detail is provided here. NERC validates and aggregates DR projections from each of the regional entities.
5. DR treatment
Each Regional Entity must discuss in its self-assessment how they represent DR and what are the planning approaches currently used to ensure DR resources perform as expected. Those details are not included in this report.
6. Spatial scope
United States
7. Spatial disaggregation
NERC regions
8. Temporal scope
Annual

Corporation, Southwest Power Pool (SPP), Texas Reliability Entity (TRE), Western Electricity Coordinating Council (WECC).

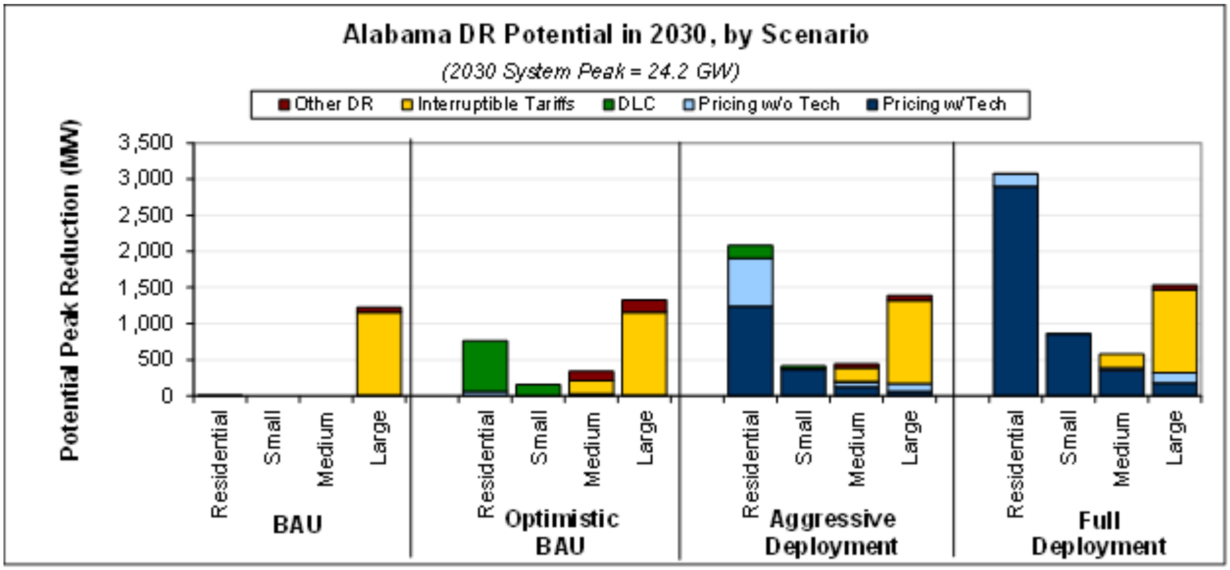
9. Temporal detail
2009-2019
10. Main results
Expected contributions from DR are 30,000MW in 2010 and 40,000MW in 2030. Most of the increase takes place during the first three years. The plateau effect from 2014 to 2019 represents uncertainty in committing DR beyond what is currently planned and contracted. Not only DR deployment is uncertain but also its long-term responsibility (concept of response fatigue).
Among the benefits of DR is its ability to provide ancillary services and to help integrating renewables.
11. Links to other studies
NERC's peak demand forecast is a reference/baseline for AEO, FERC's DR assessment and EPRI's DR assessment.

APPENDIX B. STATE-BY-STATE SCENARIO ANALYSIS RESULTS

Below are results for each of the states in the Eastern Interconnection, similar to the analysis in Chapter 5. The first graph shows the amount of DR potential in MW for each of the four scenarios by type and customer class. The table following provides the values of the bars in the graph. The next graph shows the potential peak demand growth if the full DR potential is available for peak reduction. (Note that in Chapter 7 we show that if DR is limited in the number of hours that it is available, the impact on peak demand is greatly lessened under high DR penetration amounts.)

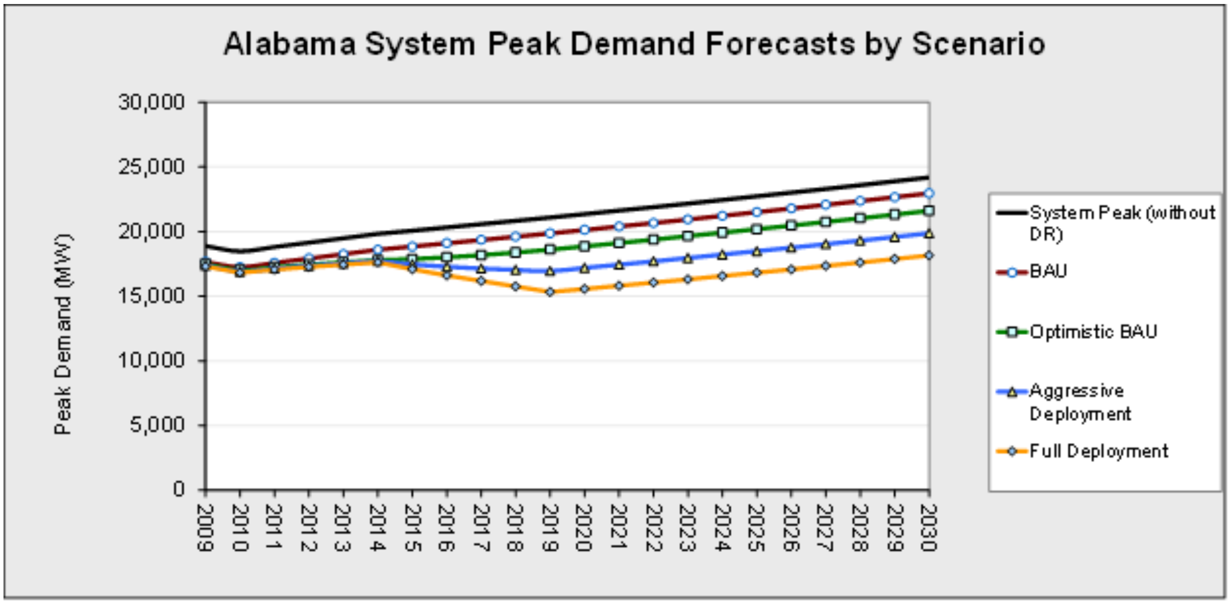
The last table in each section shows the results of the Monte Carlo simulations and the effect of increasing peak prices on those DR categories that are price-responsive. As the peak prices rise to 5X, 10X, and 15X the average price, the amount of DR available increases.

Alabama State Profile



Total Potential Peak Reduction from Demand Response in Alabama, 2030

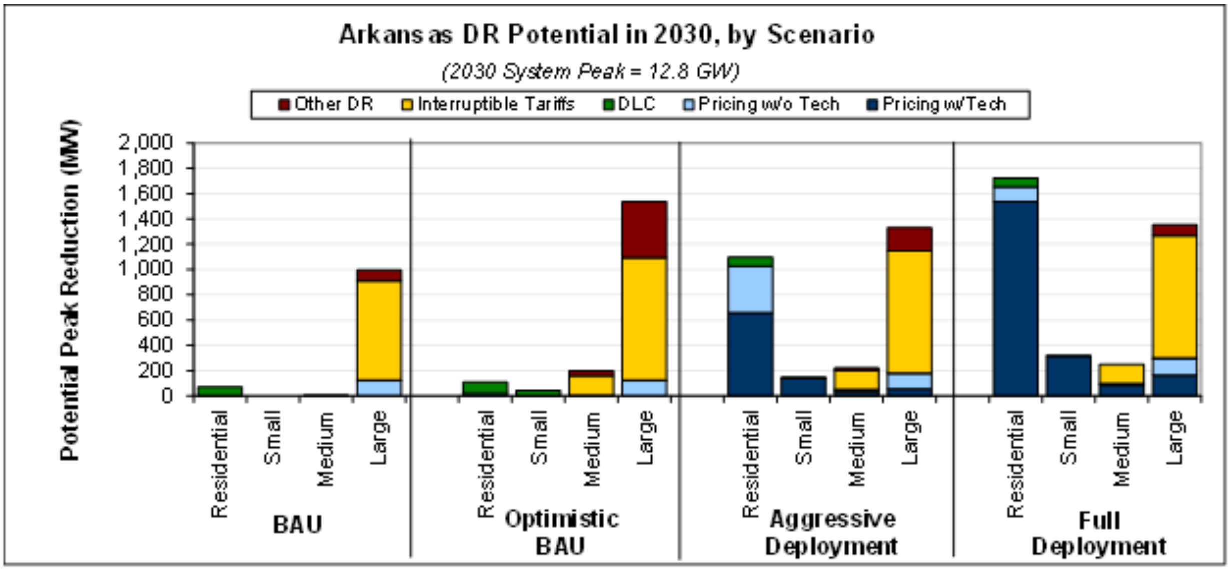
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	1	0.0%	0	0.0%	0	0.0%	10	0.0%	11	0.1%
Automated/Direct Load Control	7	0.0%	0	0.0%	0	0.0%	0	0.0%	7	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	1,148	5.4%	1,148	5.4%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	62	0.3%	62	0.3%
Total	8	0.0%	0	0.0%	0	0.0%	1,220	5.8%	1,228	5.8%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	62	0.3%	1	0.0%	8	0.0%	10	0.0%	80	0.4%
Automated/Direct Load Control	700	3.3%	154	0.7%	16	0.1%	0	0.0%	870	4.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	187	0.9%	1,148	5.4%	1,335	6.3%
Other DR Programs	0	0.0%	0	0.0%	128	0.6%	166	0.8%	294	1.4%
Total	762	3.6%	155	0.7%	339	1.6%	1,324	6.3%	2,580	12.2%
Aggressive Deployment										
Pricing with Technology	1,240	5.9%	365	1.7%	121	0.6%	61	0.3%	1,786	8.5%
Pricing without Technology	662	3.1%	6	0.0%	72	0.3%	111	0.5%	851	4.0%
Automated/Direct Load Control	181	0.9%	40	0.2%	7	0.0%	0	0.0%	228	1.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	187	0.9%	1,148	5.4%	1,335	6.3%
Other DR Programs	0	0.0%	0	0.0%	53	0.3%	69	0.3%	122	0.6%
Total	2,083	9.9%	411	1.9%	440	2.1%	1,388	6.6%	4,322	20.5%
Full Deployment										
Pricing with Technology	2,900	13.7%	854	4.0%	354	1.7%	178	0.8%	4,285	20.3%
Pricing without Technology	170	0.8%	3	0.0%	35	0.2%	143	0.7%	352	1.7%
Automated/Direct Load Control	7	0.0%	0	0.0%	0	0.0%	0	0.0%	7	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	187	0.9%	1,148	5.4%	1,335	6.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	62	0.3%	62	0.3%
Total	3,076	14.6%	857	4.1%	576	2.7%	1,531	7.3%	6,041	28.6%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in Alabama by Scenario, Pricing Program and Price Ratio (MW)

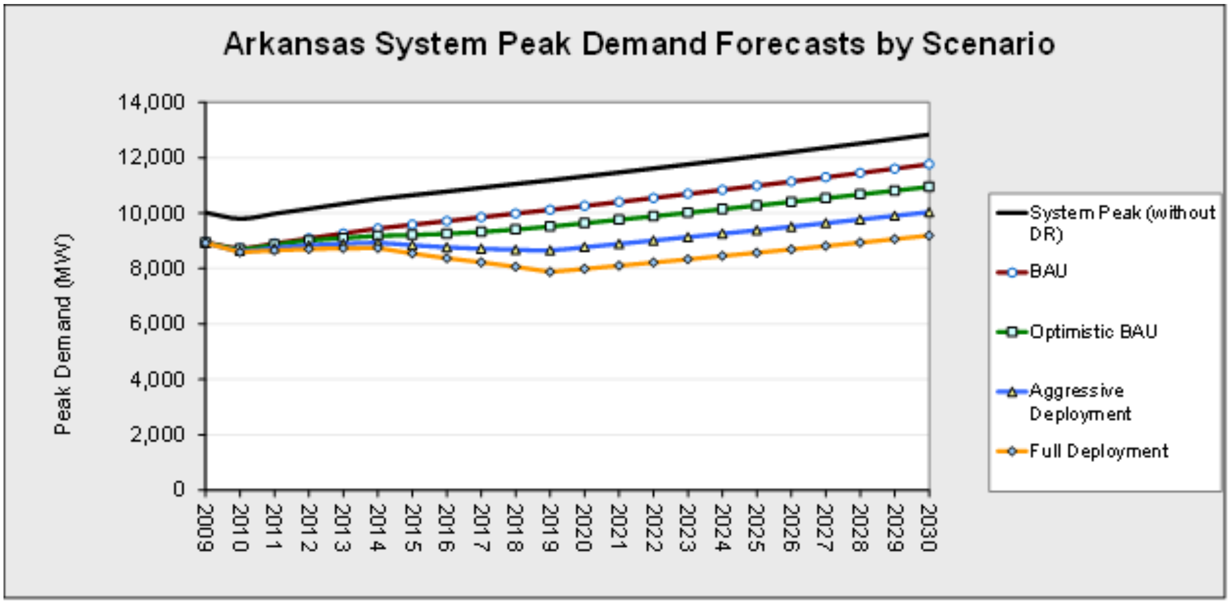
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	10	10	10	10	10	10	10	10	10	10	10	10
10	10	10	10	10	10	10	10	10	10	10	10	10
15	10	10	10	10	10	10	10	10	10	10	10	10
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	23	14	32	62	27	97	63	27	99	64	27	101
10	30	17	44	92	35	149	94	35	152	96	36	156
15	34	18	51	109	37	180	111	38	185	114	38	189
Aggressive Deployment												
Pricing with Technology												
5	315	99	531	1341	422	2261	1374	432	2316	1409	443	2374
10	442	76	808	1880	322	3438	1926	330	3522	1974	338	3610
15	569	184	955	2423	782	4064	2482	801	4164	2544	821	4267
Pricing without Technology												
5	155	50	260	658	208	1109	673	213	1134	689	217	1160
8	219	38	399	928	161	1695	949	164	1734	971	168	1773
15	282	92	473	1200	389	2010	1227	398	2056	1255	407	2103
Full Deployment												
Pricing with Technology												
5	761	247	1275	3238	1050	5427	3320	1077	5564	3405	1104	5705
10	1122	376	1869	4778	1600	7957	4899	1640	8158	5024	1682	8365
15	1315	410	2220	5599	1746	9452	5740	1790	9690	5886	1836	9936
Pricing without Technology												
5	68	23	112	289	95	484	299	98	500	309	101	517
10	101	34	167	432	147	717	446	152	741	461	157	766
15	119	38	200	509	162	857	526	167	885	544	173	915

Arkansas State Profile



Total Potential Peak Reduction from Demand Response in Arkansas, 2030

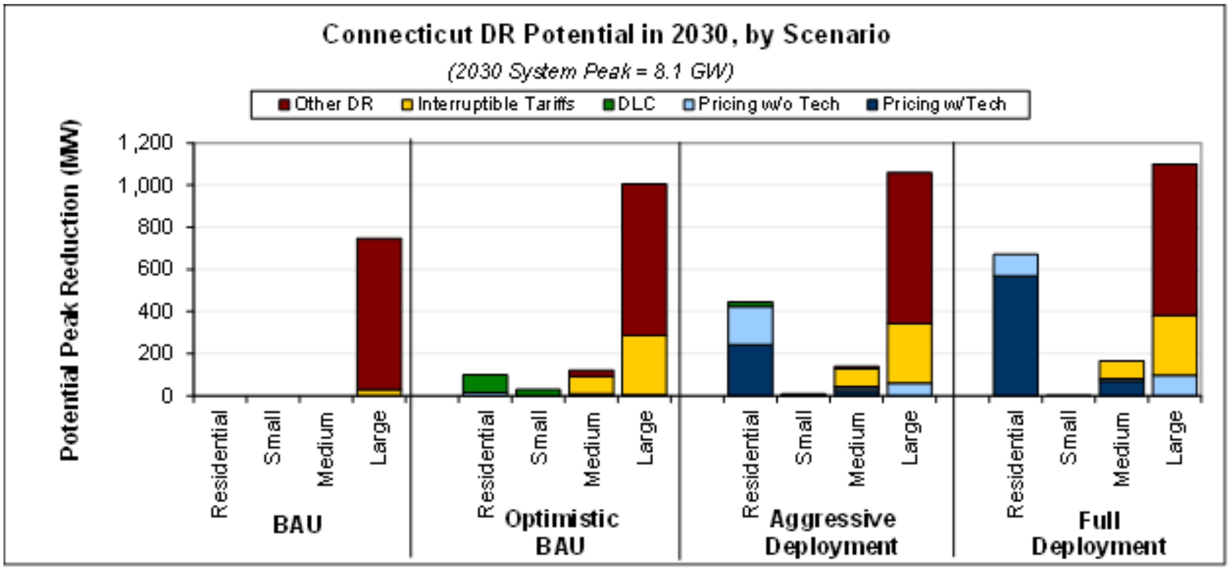
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	122	1.1%	122	1.1%
Automated/Direct Load Control	70	0.6%	0	0.0%	1	0.0%	1	0.0%	73	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	2	0.0%	786	7.0%	788	7.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	85	0.8%	85	0.8%
Total	70	0.6%	0	0.0%	3	0.0%	994	8.9%	1,067	9.5%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	20	0.2%	0	0.0%	1	0.0%	122	1.1%	143	1.3%
Automated/Direct Load Control	86	0.8%	42	0.4%	4	0.0%	1	0.0%	133	1.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	154	1.4%	970	8.7%	1,123	10.0%
Other DR Programs	0	0.0%	0	0.0%	40	0.4%	443	4.0%	483	4.3%
Total	106	1.0%	42	0.4%	199	1.8%	1,535	13.7%	1,882	16.8%
Aggressive Deployment										
Pricing with Technology	656	5.9%	135	1.2%	30	0.3%	56	0.5%	877	7.8%
Pricing without Technology	372	3.3%	2	0.0%	18	0.2%	122	1.1%	514	4.6%
Automated/Direct Load Control	70	0.6%	11	0.1%	2	0.0%	1	0.0%	84	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	154	1.4%	970	8.7%	1,123	10.0%
Other DR Programs	0	0.0%	0	0.0%	16	0.1%	181	1.6%	197	1.8%
Total	1,098	9.8%	148	1.3%	220	2.0%	1,329	11.9%	2,795	25.0%
Full Deployment										
Pricing with Technology	1,534	13.7%	317	2.8%	87	0.8%	164	1.5%	2,102	18.8%
Pricing without Technology	119	1.1%	1	0.0%	9	0.1%	133	1.2%	261	2.3%
Automated/Direct Load Control	70	0.6%	0	0.0%	1	0.0%	1	0.0%	73	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	154	1.4%	970	8.7%	1,123	10.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	85	0.8%	85	0.8%
Total	1,723	15.4%	318	2.8%	251	2.2%	1,353	12.1%	3,645	32.6%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in Arkansas by Scenario, Pricing Program and Price Ratio (MW)

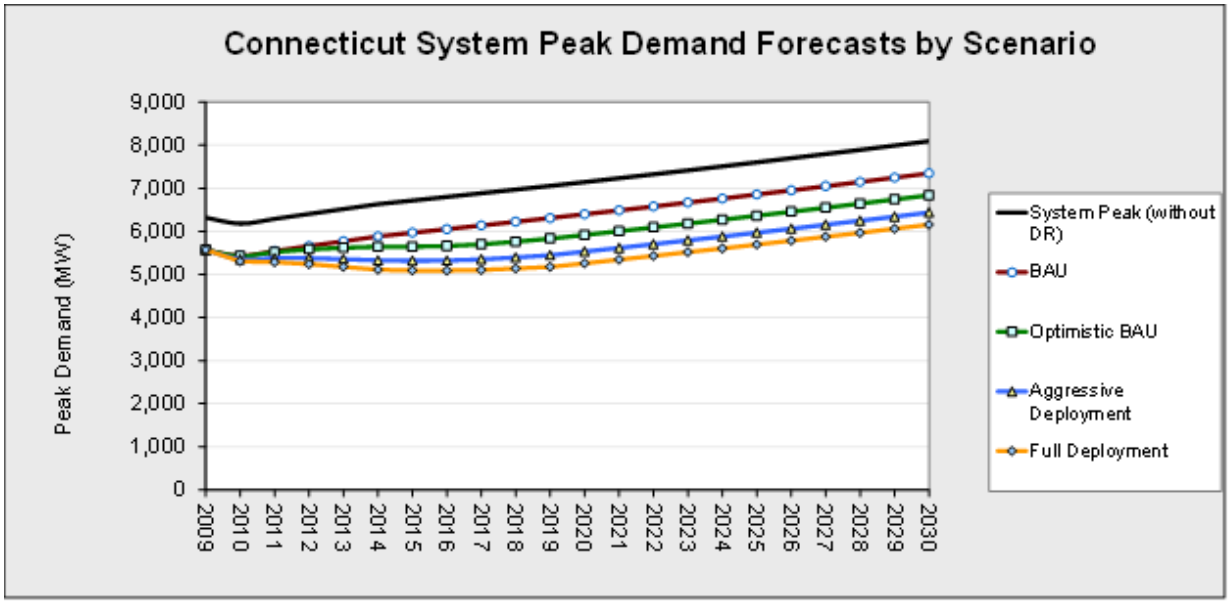
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	121	121	121	121	121	121	121	121	121	121	121	121
10	121	121	121	121	121	121	121	121	121	121	121	121
15	121	121	121	121	121	121	121	121	121	121	121	121
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	132	125	140	137	126	147	137	126	148	138	127	149
10	137	126	149	144	128	160	145	128	161	146	128	163
15	141	129	154	150	132	167	151	133	169	152	133	171
Aggressive Deployment												
Pricing with Technology												
5	250	80	419	630	203	1057	655	211	1099	681	219	1143
10	383	119	646	965	302	1629	1004	314	1694	1044	326	1761
15	435	116	755	1099	292	1905	1142	304	1981	1188	316	2060
Pricing without Technology												
5	232	157	307	401	207	596	413	207	618	425	207	642
8	292	175	409	580	224	936	601	227	976	624	230	1018
15	316	174	459	660	220	1099	685	224	1146	711	227	1196
Full Deployment												
Pricing with Technology												
5	602	182	1022	1518	458	2578	1579	477	2682	1643	496	2791
10	853	161	1545	2153	407	3898	2240	423	4056	2330	440	4220
15	1060	310	1809	2674	783	4565	2782	814	4749	2894	847	4941
Pricing without Technology												
5	158	133	183	228	126	329	235	124	347	244	122	366
10	174	132	216	311	104	518	324	103	546	339	103	575
15	188	139	236	380	140	619	398	144	652	417	148	685

Connecticut State Profile



Total Potential Peak Reduction from Demand Response in Connecticut, 2030

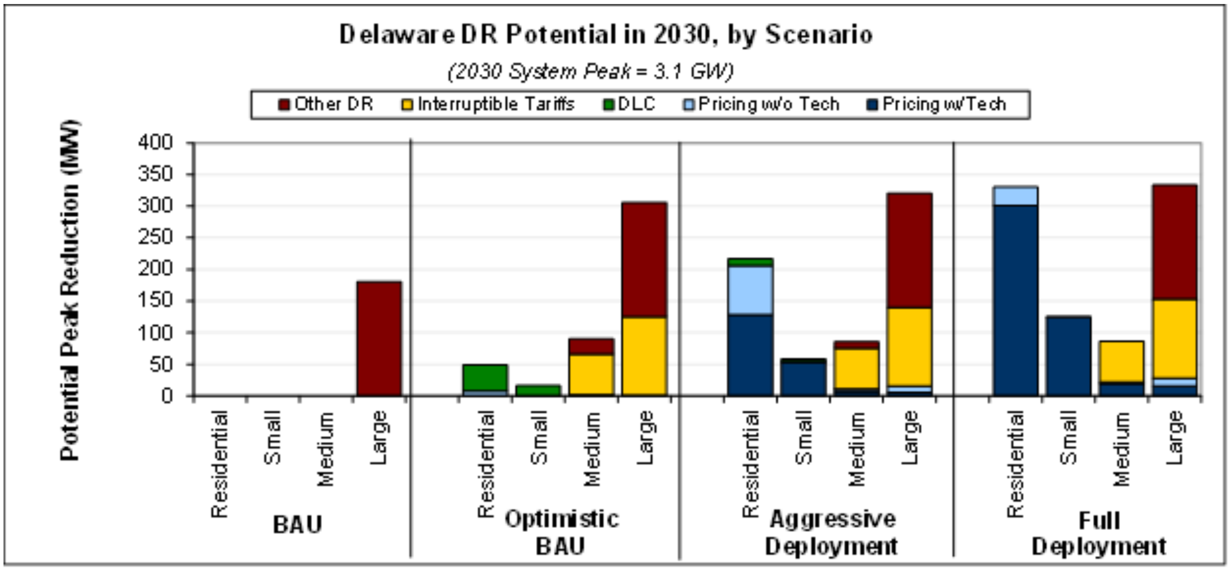
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	29	0.4%	29	0.4%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	718	10.2%	718	10.2%
Total	0	0.0%	0	0.0%	0	0.0%	747	10.6%	747	10.6%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	16	0.2%	0	0.0%	2	0.0%	4	0.1%	22	0.3%
Automated/Direct Load Control	84	1.2%	29	0.4%	6	0.1%	0	0.0%	120	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	85	1.2%	283	4.0%	368	5.2%
Other DR Programs	0	0.0%	0	0.0%	28	0.4%	718	10.2%	745	10.6%
Total	100	1.4%	29	0.4%	122	1.7%	1,004	14.2%	1,255	17.8%
Aggressive Deployment										
Pricing with Technology	243	3.4%	0	0.0%	24	0.3%	0	0.0%	267	3.8%
Pricing without Technology	181	2.6%	1	0.0%	17	0.2%	60	0.8%	258	3.7%
Automated/Direct Load Control	22	0.3%	8	0.1%	3	0.0%	0	0.0%	32	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	85	1.2%	283	4.0%	368	5.2%
Other DR Programs	0	0.0%	0	0.0%	12	0.2%	718	10.2%	729	10.3%
Total	446	6.3%	9	0.1%	140	2.0%	1,060	15.0%	1,654	23.4%
Full Deployment										
Pricing with Technology	569	8.1%	0	0.0%	70	1.0%	0	0.0%	639	9.1%
Pricing without Technology	101	1.4%	1	0.0%	11	0.2%	99	1.4%	213	3.0%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	85	1.2%	283	4.0%	368	5.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	718	10.2%	718	10.2%
Total	670	9.5%	1	0.0%	166	2.4%	1,100	15.6%	1,937	27.5%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in Connecticut by Scenario, Pricing Program and Price Ratio (MW)

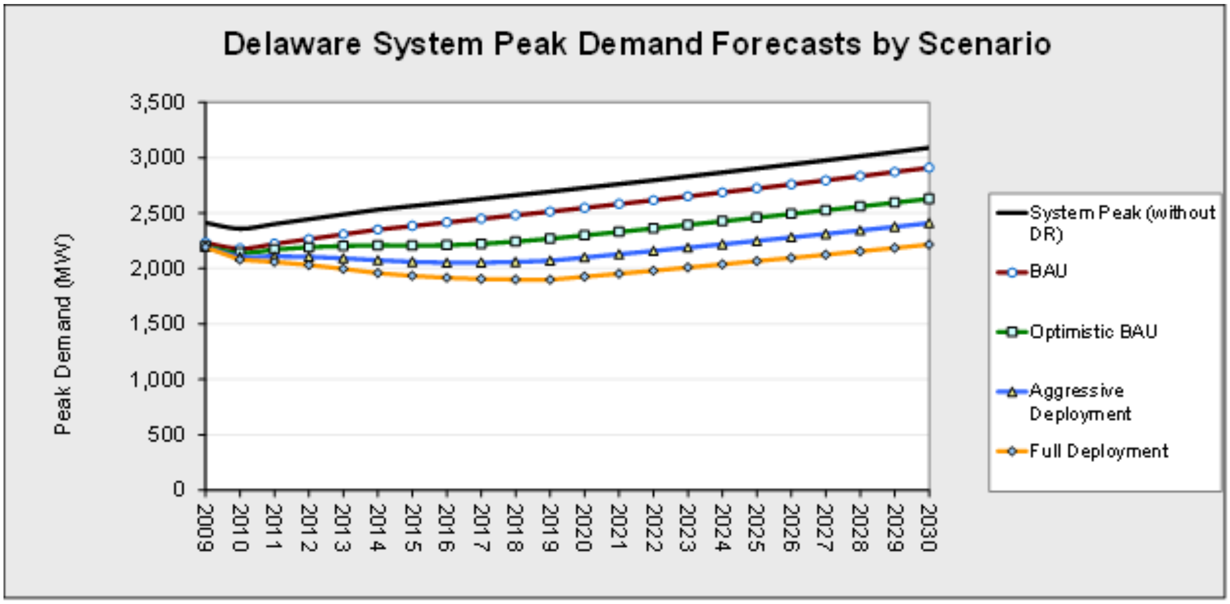
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	17	5	29	17	5	29	17	6	29	18	6	30
10	26	10	42	26	10	43	27	10	43	27	10	44
15	30	9	51	30	9	51	31	10	52	31	10	53
Aggressive Deployment												
Pricing with Technology												
5	158	49	268	201	62	340	204	63	346	208	64	351
10	233	89	377	296	113	479	301	115	487	306	117	495
15	283	86	480	359	110	609	365	111	619	372	113	630
Pricing without Technology												
5	163	51	276	206	64	348	210	65	355	215	67	362
8	242	93	391	305	117	493	311	120	503	318	122	513
15	295	91	499	372	115	629	380	117	642	387	120	655
Full Deployment												
Pricing with Technology												
5	362	99	624	459	126	792	467	128	806	475	130	819
10	559	166	952	709	211	1208	721	214	1228	734	218	1249
15	618	129	1107	784	164	1404	797	166	1428	811	169	1453
Pricing without Technology												
5	138	38	237	172	48	297	177	49	304	181	50	311
10	214	65	364	269	81	456	275	83	467	282	85	478
15	238	51	425	299	64	533	306	66	545	313	67	558

Delaware State Profile



Total Potential Peak Reduction from Demand Response in Delaware, 2030

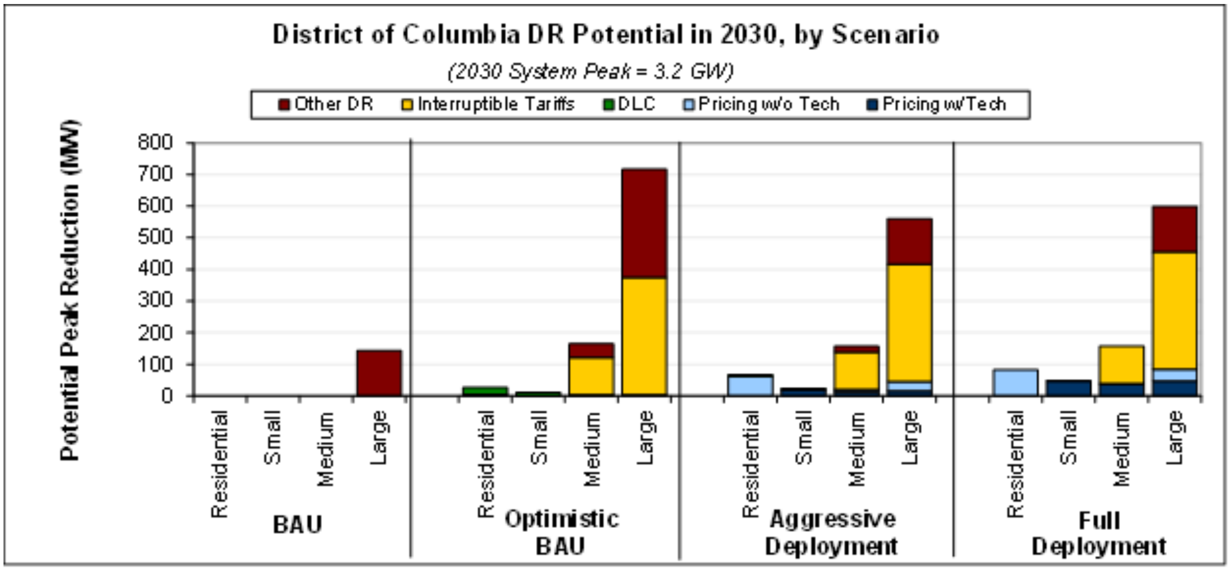
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	180	6.7%	180	6.7%
Total	0	0.0%	0	0.0%	0	0.0%	180	6.7%	180	6.7%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	8	0.3%	0	0.0%	1	0.0%	1	0.0%	9	0.3%
Automated/Direct Load Control	41	1.5%	16	0.6%	1	0.0%	0	0.0%	58	2.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	65	2.4%	125	4.6%	189	7.0%
Other DR Programs	0	0.0%	0	0.0%	24	0.9%	180	6.7%	204	7.6%
Total	49	1.8%	16	0.6%	90	3.3%	306	11.3%	460	17.1%
Aggressive Deployment										
Pricing with Technology	129	4.8%	53	2.0%	7	0.2%	5	0.2%	194	7.2%
Pricing without Technology	77	2.9%	1	0.0%	4	0.1%	10	0.4%	92	3.4%
Automated/Direct Load Control	11	0.4%	4	0.2%	0	0.0%	0	0.0%	15	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	65	2.4%	125	4.6%	189	7.0%
Other DR Programs	0	0.0%	0	0.0%	10	0.4%	180	6.7%	190	7.1%
Total	217	8.0%	58	2.2%	86	3.2%	320	11.9%	681	25.3%
Full Deployment										
Pricing with Technology	301	11.2%	125	4.6%	19	0.7%	16	0.6%	461	17.1%
Pricing without Technology	29	1.1%	1	0.0%	2	0.1%	13	0.5%	44	1.6%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	65	2.4%	125	4.6%	189	7.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	180	6.7%	180	6.7%
Total	330	12.2%	125	4.6%	86	3.2%	333	12.4%	875	32.5%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in Delaware by Scenario, Pricing Program and Price Ratio (MW)

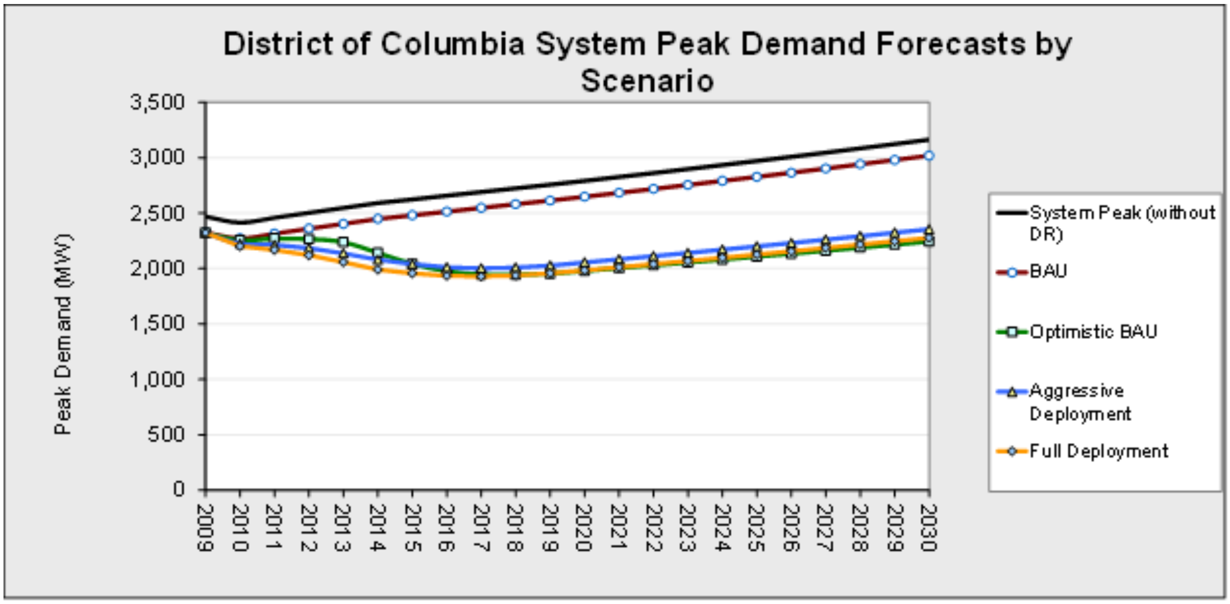
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	6	2	10	7	2	11	7	2	12	7	2	12
10	9	2	15	10	3	17	11	3	18	11	3	19
15	10	3	18	12	3	21	12	3	22	13	3	23
Aggressive Deployment												
Pricing with Technology												
5	95	25	165	134	35	232	141	37	245	148	38	258
10	146	38	253	205	54	356	216	56	375	227	60	395
15	174	49	298	244	69	419	257	73	441	271	77	464
Pricing without Technology												
5	47	12	82	65	17	113	68	18	119	72	19	125
8	73	19	127	100	26	174	105	28	183	111	29	192
15	87	25	150	120	34	206	126	36	216	132	38	227
Full Deployment												
Pricing with Technology												
5	231	73	390	324	102	546	341	107	576	360	113	606
10	340	108	572	477	151	802	502	160	845	529	168	890
15	424	128	720	594	180	1008	626	189	1062	659	200	1119
Pricing without Technology												
5	25	8	42	33	11	56	35	11	59	37	12	62
10	38	12	63	50	16	83	52	17	88	55	18	93
15	47	15	80	62	19	105	66	20	111	69	21	117

District of Columbia Profile



Total Potential Peak Reduction from Demand Response in District of Columbia, 2030

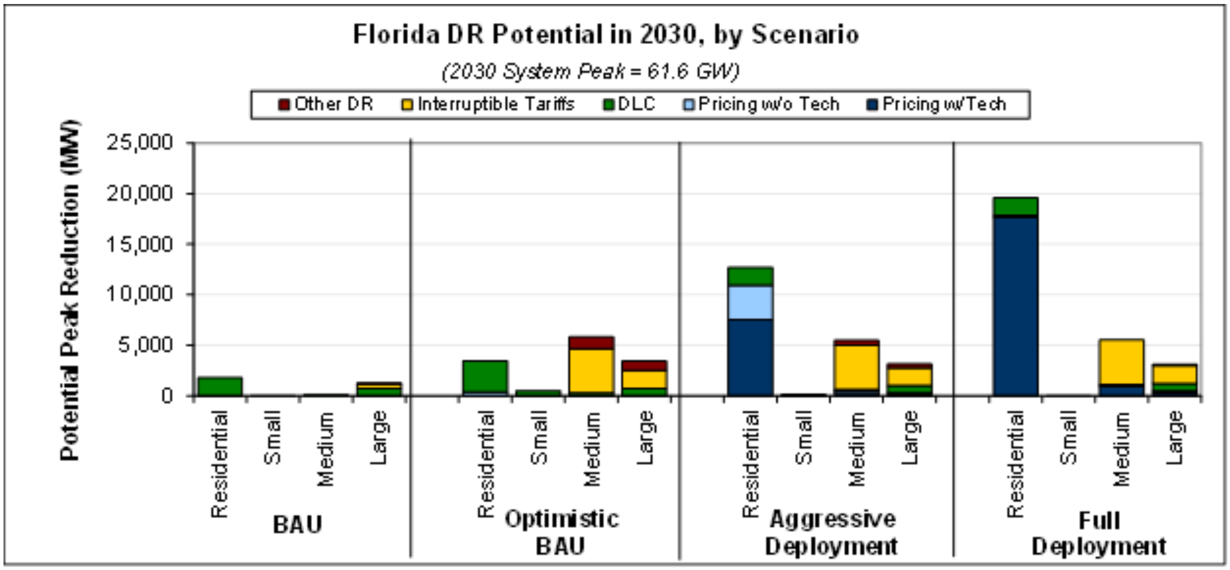
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	143	5.2%	143	5.2%
Total	0	0.0%	0	0.0%	0	0.0%	143	5.2%	143	5.2%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	4	0.1%	0	0.0%	1	0.0%	3	0.1%	8	0.3%
Automated/Direct Load Control	23	0.8%	10	0.4%	2	0.1%	0	0.0%	35	1.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	118	4.3%	371	13.5%	489	17.7%
Other DR Programs	0	0.0%	0	0.0%	43	1.6%	343	12.4%	386	14.0%
Total	27	1.0%	11	0.4%	164	6.0%	717	26.0%	918	33.3%
Aggressive Deployment										
Pricing with Technology	0	0.0%	20	0.7%	12	0.4%	16	0.6%	48	1.7%
Pricing without Technology	62	2.2%	0	0.0%	7	0.3%	29	1.1%	98	3.6%
Automated/Direct Load Control	6	0.2%	3	0.1%	1	0.0%	0	0.0%	9	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	118	4.3%	371	13.5%	489	17.7%
Other DR Programs	0	0.0%	0	0.0%	18	0.7%	144	5.2%	162	5.9%
Total	68	2.5%	23	0.8%	157	5.7%	560	20.3%	808	29.3%
Full Deployment										
Pricing with Technology	0	0.0%	47	1.7%	36	1.3%	47	1.7%	129	4.7%
Pricing without Technology	82	3.0%	0	0.0%	4	0.1%	38	1.4%	124	4.5%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	118	4.3%	371	13.5%	489	17.7%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	143	5.2%	143	5.2%
Total	82	3.0%	47	1.7%	157	5.7%	599	21.7%	886	32.1%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in District of Columbia by Scenario, Pricing Program and Price Ratio (MW)

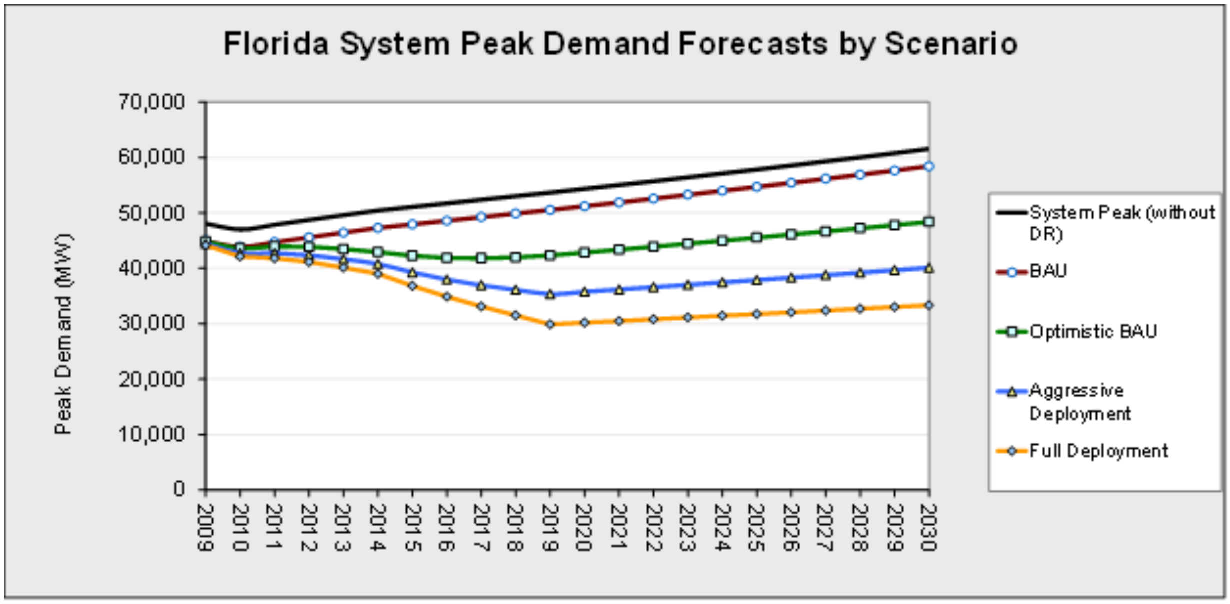
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	8	3	12	7	3	11	7	3	12	7	3	12
10	11	4	19	11	3	18	11	4	18	11	4	19
15	13	4	22	12	3	20	12	4	21	13	4	22
Aggressive Deployment												
Pricing with Technology												
5	39	11	67	37	10	63	39	11	67	42	12	72
10	55	12	98	52	12	93	56	12	99	59	13	105
15	68	20	117	64	19	110	69	20	117	73	21	125
Pricing without Technology												
5	84	23	146	80	22	138	82	23	141	84	23	145
8	121	27	214	114	25	203	117	26	208	120	27	213
15	149	43	256	142	41	242	145	42	248	148	43	254
Full Deployment												
Pricing with Technology												
5	99	21	176	92	19	165	98	21	176	105	22	187
10	155	42	267	145	39	250	154	42	266	164	44	284
15	188	59	317	176	55	297	187	59	316	200	62	337
Pricing without Technology												
5	99	21	177	94	20	169	96	20	172	98	20	176
10	156	42	270	148	40	257	151	41	262	155	41	268
15	190	59	321	181	56	306	185	57	312	189	59	319

Florida State Profile



Total Potential Peak Reduction from Demand Response in Florida, 2030

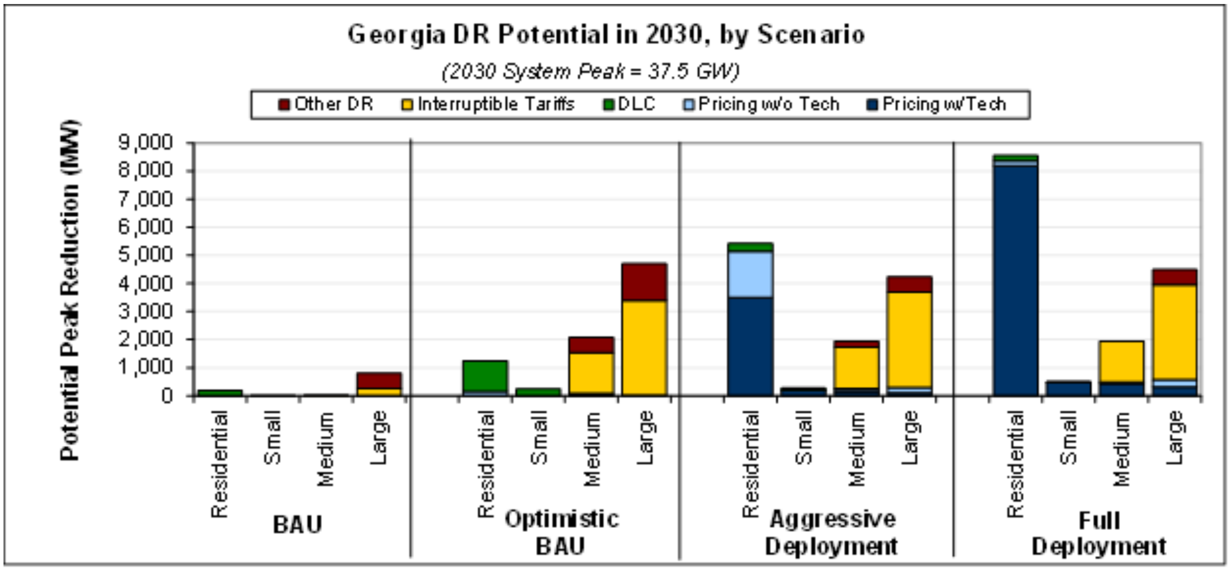
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	17	0.0%	0	0.0%	0	0.0%	11	0.0%	28	0.1%
Automated/Direct Load Control	1,764	3.3%	0	0.0%	100	0.2%	722	1.3%	2,586	4.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	414	0.8%	414	0.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	113	0.2%	113	0.2%
Total	1,781	3.3%	0	0.0%	100	0.2%	1,260	2.3%	3,141	5.9%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	379	0.7%	0	0.0%	23	0.0%	14	0.0%	416	0.8%
Automated/Direct Load Control	3,077	5.7%	492	0.9%	237	0.4%	722	1.3%	4,528	8.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4,400	8.2%	1,785	3.3%	6,185	11.5%
Other DR Programs	0	0.0%	0	0.0%	1,145	2.1%	904	1.7%	2,049	3.8%
Total	3,456	6.4%	492	0.9%	5,804	10.8%	3,425	6.4%	13,178	24.5%
Aggressive Deployment										
Pricing with Technology	7,533	14.0%	0	0.0%	318	0.6%	94	0.2%	7,945	14.8%
Pricing without Technology	3,393	6.3%	6	0.0%	190	0.4%	172	0.3%	3,761	7.0%
Automated/Direct Load Control	1,764	3.3%	128	0.2%	100	0.2%	722	1.3%	2,714	5.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4,400	8.2%	1,785	3.3%	6,185	11.5%
Other DR Programs	0	0.0%	0	0.0%	476	0.9%	375	0.7%	851	1.6%
Total	12,690	23.6%	134	0.2%	5,483	10.2%	3,149	5.9%	21,456	40.0%
Full Deployment										
Pricing with Technology	17,620	32.8%	0	0.0%	930	1.7%	276	0.5%	18,826	35.1%
Pricing without Technology	195	0.4%	8	0.0%	92	0.2%	223	0.4%	517	1.0%
Automated/Direct Load Control	1,764	3.3%	0	0.0%	100	0.2%	722	1.3%	2,586	4.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4,400	8.2%	1,785	3.3%	6,185	11.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	113	0.2%	113	0.2%
Total	19,579	36.5%	8	0.0%	5,521	10.3%	3,119	5.8%	28,227	52.6%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in Florida by Scenario, Pricing Program and Price Ratio (MW)

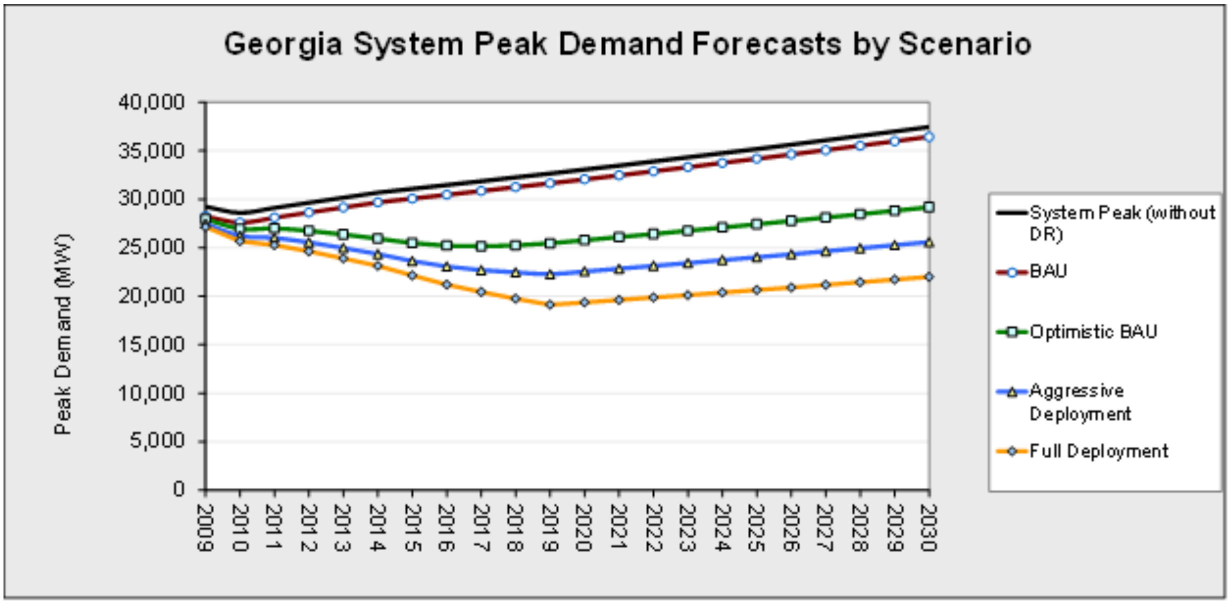
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	27	27	27	27	27	27	27	27	27	27	27	27
10	27	27	27	27	27	27	27	27	27	27	27	27
15	27	27	27	27	27	27	27	27	27	27	27	27
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	148	53	243	274	89	459	301	97	504	330	105	554
10	198	39	357	370	64	677	406	69	743	446	75	817
15	254	67	440	477	120	834	523	131	916	575	143	1006
Aggressive Deployment												
Pricing with Technology												
5	2160	558	3762	4949	1278	8621	5443	1405	9480	5985	1545	10425
10	3198	932	5464	7328	2135	12521	8059	2348	13769	8862	2582	15142
15	3951	1164	6737	9053	2668	15438	9955	2933	16976	10947	3226	18669
Pricing without Technology												
5	1047	271	1823	2375	615	4135	2606	674	4538	2861	740	4981
8	1553	454	2652	3522	1029	6015	3865	1129	6601	4242	1239	7245
15	1920	568	3273	4354	1287	7422	4779	1412	8145	5245	1550	8940
Full Deployment												
Pricing with Technology												
5	5357	1647	9068	12238	3761	20715	13451	4133	22768	14785	4543	25027
10	8002	2226	13778	18279	5084	31475	20092	5587	34596	22085	6142	38029
15	9404	2775	16033	21484	6339	36628	23614	6967	40260	25957	7659	44255
Pricing without Technology												
5	192	60	323	394	123	666	425	133	717	457	143	772
10	289	82	495	594	169	1019	640	182	1097	689	196	1182
15	341	103	579	702	212	1192	756	228	1283	814	246	1382

Georgia State Profile



Total Potential Peak Reduction from Demand Response in Georgia, 2030

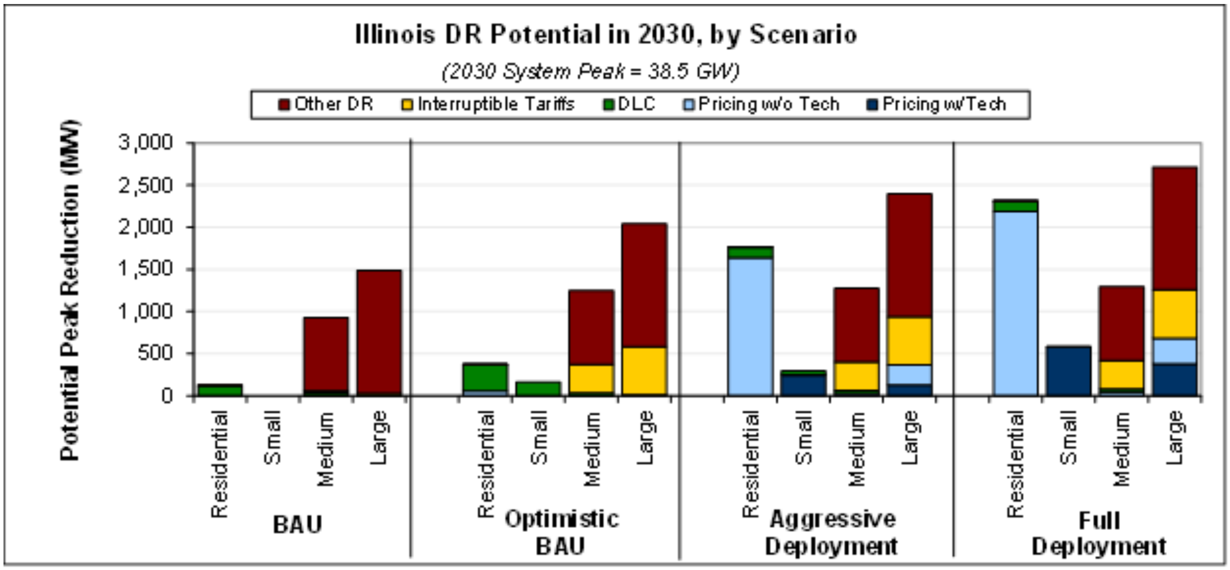
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	1	0.0%	0	0.0%	7	0.0%	4	0.0%	12	0.0%
Automated/Direct Load Control	189	0.6%	9	0.0%	0	0.0%	0	0.0%	197	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	1	0.0%	262	0.8%	263	0.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	538	1.6%	538	1.6%
Total	190	0.6%	9	0.0%	7	0.0%	804	2.5%	1,010	3.1%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	161	0.5%	0	0.0%	10	0.0%	19	0.1%	190	0.6%
Automated/Direct Load Control	1,089	3.3%	245	0.7%	67	0.2%	0	0.0%	1,401	4.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	1,456	4.5%	3,382	10.4%	4,839	14.8%
Other DR Programs	0	0.0%	0	0.0%	542	1.7%	1,301	4.0%	1,843	5.6%
Total	1,251	3.8%	245	0.8%	2,075	6.4%	4,703	14.4%	8,273	25.3%
Aggressive Deployment										
Pricing with Technology	3,504	10.7%	204	0.6%	150	0.5%	108	0.3%	3,966	12.1%
Pricing without Technology	1,637	5.0%	4	0.0%	90	0.3%	197	0.6%	1,927	5.9%
Automated/Direct Load Control	282	0.9%	63	0.2%	28	0.1%	0	0.0%	373	1.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	1,456	4.5%	3,382	10.4%	4,839	14.8%
Other DR Programs	0	0.0%	0	0.0%	224	0.7%	545	1.7%	769	2.4%
Total	5,422	16.6%	271	0.8%	1,948	6.0%	4,232	13.0%	11,874	36.4%
Full Deployment										
Pricing with Technology	8,196	25.1%	478	1.5%	439	1.3%	316	1.0%	9,428	28.9%
Pricing without Technology	169	0.5%	2	0.0%	43	0.1%	255	0.8%	469	1.4%
Automated/Direct Load Control	189	0.6%	9	0.0%	0	0.0%	0	0.0%	197	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	1,456	4.5%	3,382	10.4%	4,839	14.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	538	1.6%	538	1.6%
Total	8,553	26.2%	489	1.5%	1,938	5.9%	4,490	13.7%	15,471	47.4%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in Georgia by Scenario, Pricing Program and Price Ratio (MW)

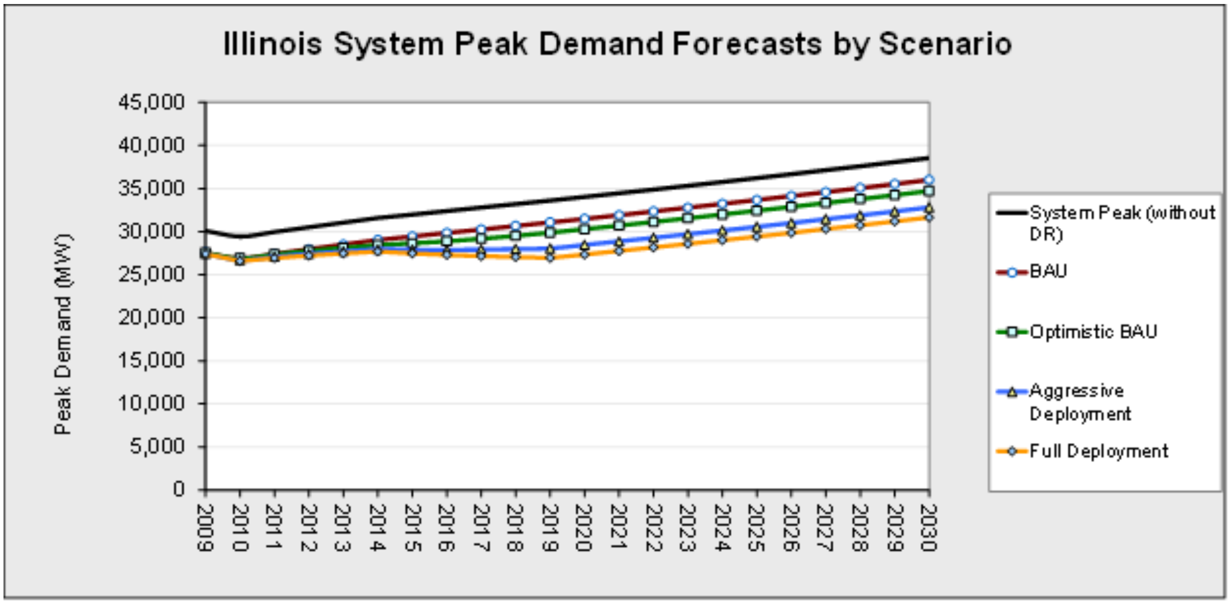
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	11	11	11	11	11	11	11	11	11	11	11	11
10	11	11	11	11	11	11	11	11	11	11	11	11
15	11	11	11	11	11	11	11	11	11	11	11	11
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	102	30	173	131	37	226	140	39	241	149	41	257
10	161	56	265	209	72	345	222	77	367	237	82	392
15	179	54	304	232	70	395	248	74	421	264	79	449
Aggressive Deployment												
Pricing with Technology												
5	1564	473	2656	2763	835	4690	2945	890	5000	3140	949	5330
10	2346	732	3961	4144	1292	6996	4417	1377	7458	4709	1468	7950
15	2770	788	4751	4891	1392	8391	5214	1484	8945	5559	1582	9535
Pricing without Technology												
5	791	240	1342	1372	416	2328	1462	443	2481	1559	472	2645
8	1189	372	2006	2062	645	3480	2198	688	3709	2343	733	3954
15	1405	402	2409	2438	697	4178	2598	743	4454	2770	792	4748
Full Deployment												
Pricing with Technology												
5	3636	1109	6163	6401	1952	10850	6823	2081	11566	7274	2218	12330
10	5329	1355	9302	9380	2384	16376	10000	2542	17458	10660	2710	18610
15	6617	1777	11457	11648	3127	20170	12417	3334	21501	13237	3554	22921
Pricing without Technology												
5	231	72	391	368	114	622	392	121	663	418	129	707
10	341	89	594	543	141	945	579	151	1007	617	161	1073
15	425	117	734	677	186	1168	721	198	1245	769	211	1326

Illinois State Profile



Total Potential Peak Reduction from Demand Response in Illinois, 2030

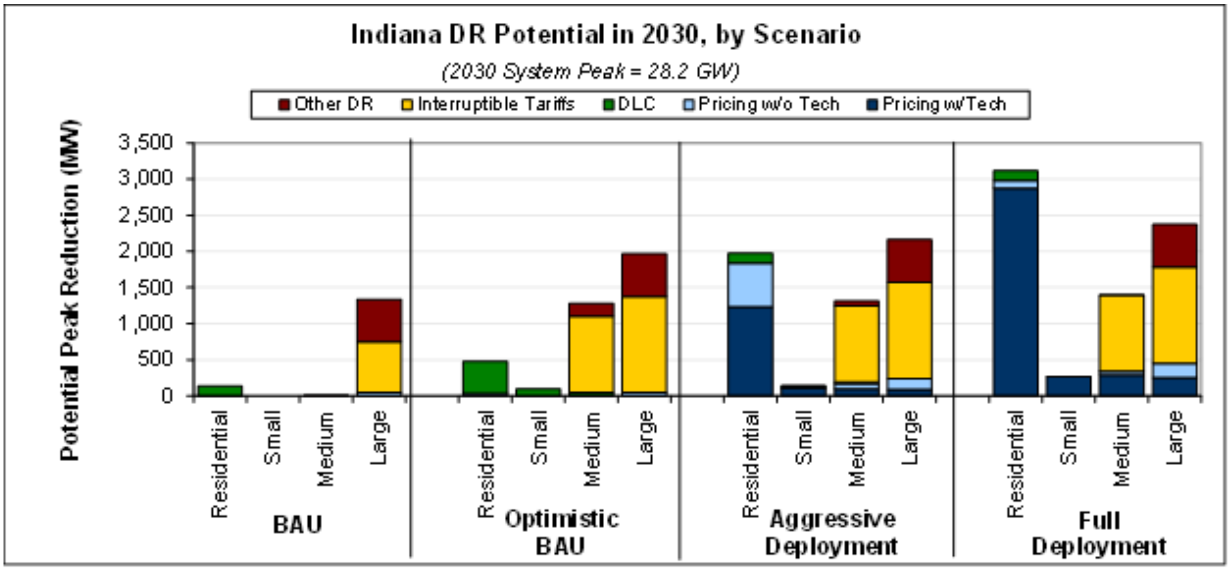
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	1	0.0%	2	0.0%	3	0.0%
Automated/Direct Load Control	122	0.4%	0	0.0%	36	0.1%	0	0.0%	158	0.5%
Interruptible/Curtailable Tariffs	1	0.0%	0	0.0%	19	0.1%	28	0.1%	47	0.1%
Other DR Programs	4	0.0%	0	0.0%	874	2.6%	1,457	4.3%	2,335	6.9%
Total	127	0.4%	0	0.0%	929	2.8%	1,486	4.4%	2,543	7.6%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	56	0.2%	0	0.0%	1	0.0%	13	0.0%	71	0.2%
Automated/Direct Load Control	316	0.9%	163	0.5%	36	0.1%	0	0.0%	515	1.5%
Interruptible/Curtailable Tariffs	1	0.0%	0	0.0%	338	1.0%	571	1.7%	910	2.7%
Other DR Programs	4	0.0%	0	0.0%	874	2.6%	1,457	4.3%	2,335	6.9%
Total	377	1.1%	164	0.5%	1,249	3.7%	2,041	6.1%	3,831	11.4%
Aggressive Deployment										
Pricing with Technology	0	0.0%	248	0.7%	0	0.0%	130	0.4%	378	1.1%
Pricing without Technology	1,642	4.9%	5	0.0%	28	0.1%	236	0.7%	1,911	5.7%
Automated/Direct Load Control	122	0.4%	42	0.1%	36	0.1%	0	0.0%	200	0.6%
Interruptible/Curtailable Tariffs	1	0.0%	0	0.0%	338	1.0%	571	1.7%	910	2.7%
Other DR Programs	4	0.0%	0	0.0%	874	2.6%	1,457	4.3%	2,335	6.9%
Total	1,769	5.3%	295	0.9%	1,276	3.8%	2,394	7.1%	5,734	17.1%
Full Deployment										
Pricing with Technology	0	0.0%	581	1.7%	0	0.0%	379	1.1%	960	2.9%
Pricing without Technology	2,189	6.5%	3	0.0%	47	0.1%	306	0.9%	2,545	7.6%
Automated/Direct Load Control	122	0.4%	0	0.0%	36	0.1%	0	0.0%	158	0.5%
Interruptible/Curtailable Tariffs	1	0.0%	0	0.0%	338	1.0%	571	1.7%	910	2.7%
Other DR Programs	4	0.0%	0	0.0%	874	2.6%	1,457	4.3%	2,335	6.9%
Total	2,316	6.9%	583	1.7%	1,295	3.9%	2,713	8.1%	6,908	20.6%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in Illinois by Scenario, Pricing Program and Price Ratio (MW)

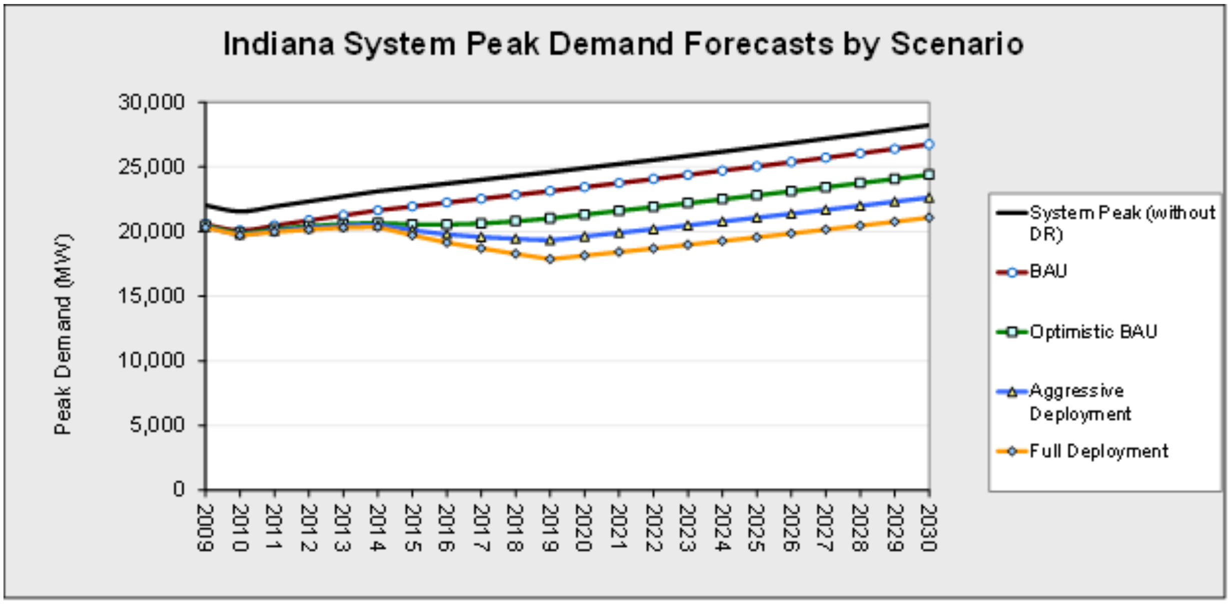
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	2	2	2	2	2	2	2	2	2	2	2	2
10	2	2	2	2	2	2	2	2	2	2	2	2
15	2	2	2	2	2	2	2	2	2	2	2	2
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	33	9	57	54	14	93	55	14	95	56	15	97
10	48	12	84	79	18	139	80	19	142	82	19	145
15	60	16	103	98	26	170	100	27	173	102	27	176
Aggressive Deployment												
Pricing with Technology												
5	124	38	211	298	90	505	309	93	525	321	97	546
10	190	56	325	455	133	777	473	138	807	491	144	839
15	228	75	381	546	179	912	567	186	948	590	194	986
Pricing without Technology												
5	595	179	1012	1464	439	2489	1490	447	2533	1517	455	2579
8	915	265	1565	2251	652	3849	2291	664	3918	2332	676	3988
15	1101	359	1844	2708	881	4535	2757	897	4616	2806	913	4699
Full Deployment												
Pricing with Technology												
5	322	107	537	763	254	1272	793	264	1322	824	275	1374
10	495	157	833	1173	372	1974	1219	387	2051	1267	402	2132
15	564	156	971	1335	369	2300	1387	384	2390	1442	399	2484
Pricing without Technology												
5	788	261	1314	1938	641	3234	1972	653	3291	2008	665	3350
10	1217	383	2051	2994	941	5047	3047	958	5136	3102	975	5228
15	1388	380	2397	3416	933	5898	3476	950	6003	3539	967	6110

Indiana State Profile



Total Potential Peak Reduction from Demand Response in Indiana, 2030

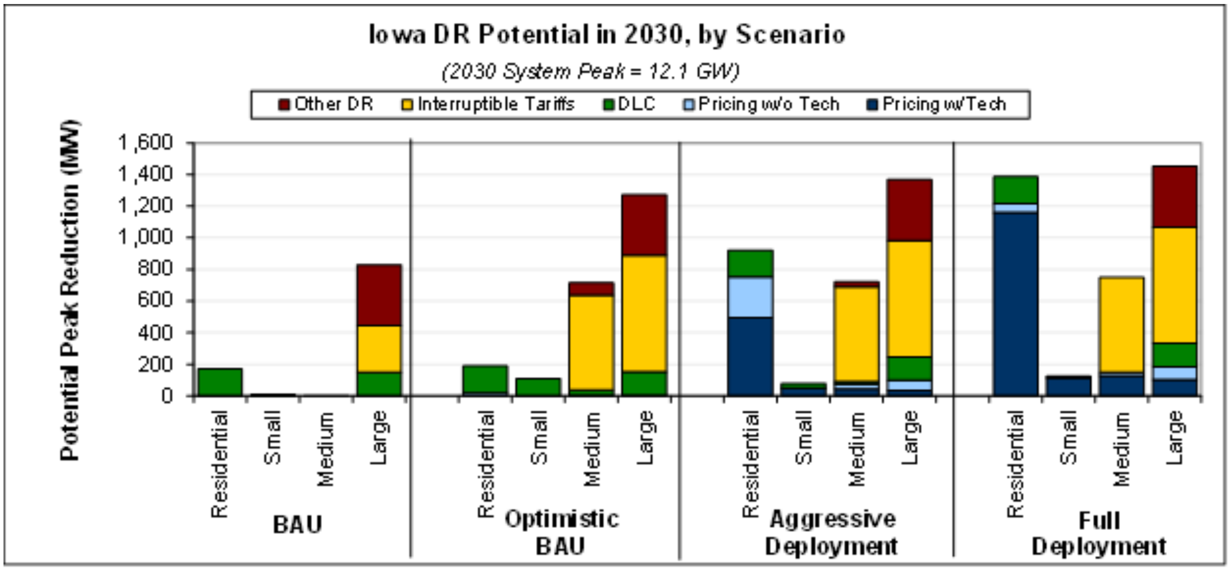
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	45	0.2%	46	0.2%
Automated/Direct Load Control	134	0.5%	0	0.0%	2	0.0%	0	0.0%	136	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	702	2.9%	702	2.9%
Other DR Programs	0	0.0%	0	0.0%	1	0.0%	589	2.4%	590	2.4%
Total	134	0.5%	0	0.0%	3	0.0%	1,336	5.4%	1,474	6.0%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	35	0.1%	0	0.0%	4	0.0%	45	0.2%	85	0.3%
Automated/Direct Load Control	442	1.8%	95	0.4%	41	0.2%	0	0.0%	578	2.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	1,056	4.3%	1,332	5.4%	2,388	9.7%
Other DR Programs	0	0.0%	0	0.0%	179	0.7%	589	2.4%	768	3.1%
Total	478	1.9%	95	0.4%	1,280	5.2%	1,967	8.0%	3,820	15.5%
Aggressive Deployment										
Pricing with Technology	1,229	5.0%	112	0.5%	98	0.4%	85	0.3%	1,525	6.2%
Pricing without Technology	610	2.5%	2	0.0%	71	0.3%	155	0.6%	838	3.4%
Automated/Direct Load Control	134	0.5%	24	0.1%	17	0.1%	0	0.0%	175	0.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	1,056	4.3%	1,332	5.4%	2,388	9.7%
Other DR Programs	0	0.0%	0	0.0%	73	0.3%	589	2.4%	662	2.7%
Total	1,973	8.0%	139	0.6%	1,315	5.3%	2,162	8.8%	5,588	22.7%
Full Deployment										
Pricing with Technology	2,874	11.7%	263	1.1%	288	1.2%	249	1.0%	3,674	14.9%
Pricing without Technology	107	0.4%	1	0.0%	48	0.2%	201	0.8%	357	1.5%
Automated/Direct Load Control	134	0.5%	0	0.0%	2	0.0%	0	0.0%	136	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	1,056	4.3%	1,332	5.4%	2,388	9.7%
Other DR Programs	0	0.0%	0	0.0%	1	0.0%	589	2.4%	590	2.4%
Total	3,115	12.7%	264	1.1%	1,395	5.7%	2,372	9.6%	7,146	29.0%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in Indiana by Scenario, Pricing Program and Price Ratio (MW)

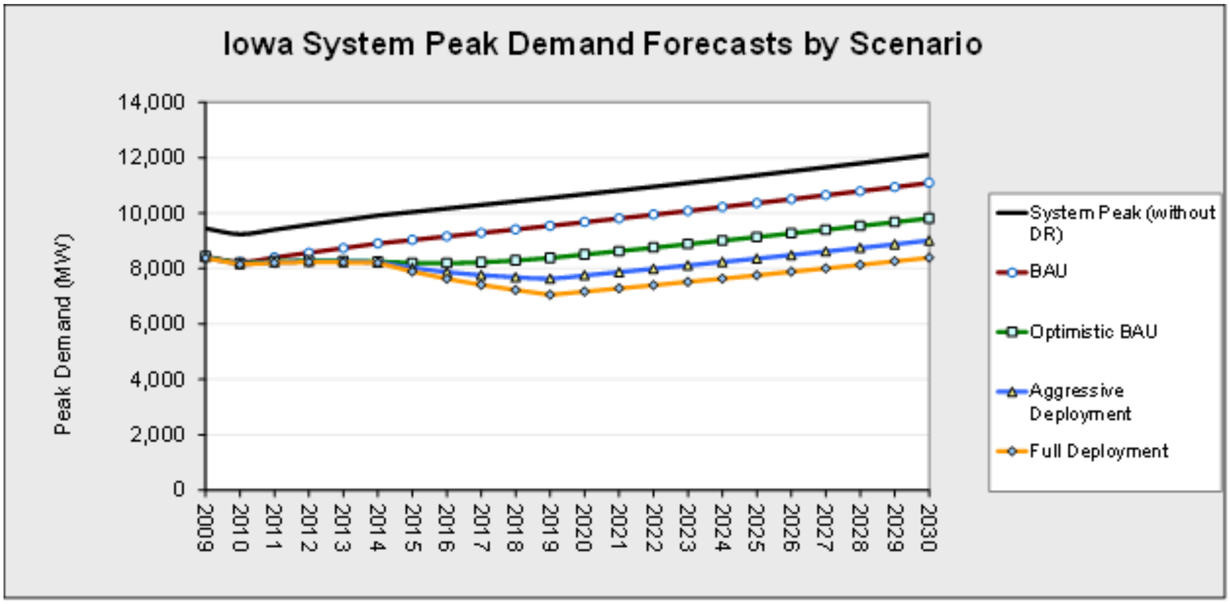
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	45	45	45	45	45	45	45	45	45	45	45	45
10	45	45	45	45	45	45	45	45	45	45	45	45
15	45	45	45	45	45	45	45	45	45	45	45	45
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	57	49	65	74	54	94	74	54	95	75	54	96
10	63	51	74	89	60	118	90	60	120	91	61	121
15	67	52	82	100	62	138	101	62	140	102	63	142
Aggressive Deployment												
Pricing with Technology												
5	329	116	542	1175	414	1936	1203	424	1982	1231	434	2028
10	473	139	807	1689	496	2882	1728	507	2949	1769	519	3019
15	580	225	935	2071	804	3338	2120	823	3416	2169	843	3496
Pricing without Technology												
5	197	89	305	668	237	1099	685	243	1127	702	248	1156
8	278	94	462	963	284	1641	987	292	1683	1013	299	1726
15	339	137	542	1183	462	1905	1213	474	1953	1244	486	2003
Full Deployment												
Pricing with Technology												
5	762	189	1334	2709	673	4745	2774	690	4858	2841	706	4975
10	1130	321	1939	4019	1143	6896	4115	1170	7061	4214	1198	7230
15	1412	452	2371	5021	1609	8432	5141	1647	8634	5264	1687	8841
Pricing without Technology												
5	94	41	147	297	75	519	307	78	537	318	80	555
10	135	48	223	444	129	759	459	133	785	475	138	812
15	168	61	276	556	182	931	575	188	963	595	194	996

Iowa State Profile



Total Potential Peak Reduction from Demand Response in Iowa, 2030

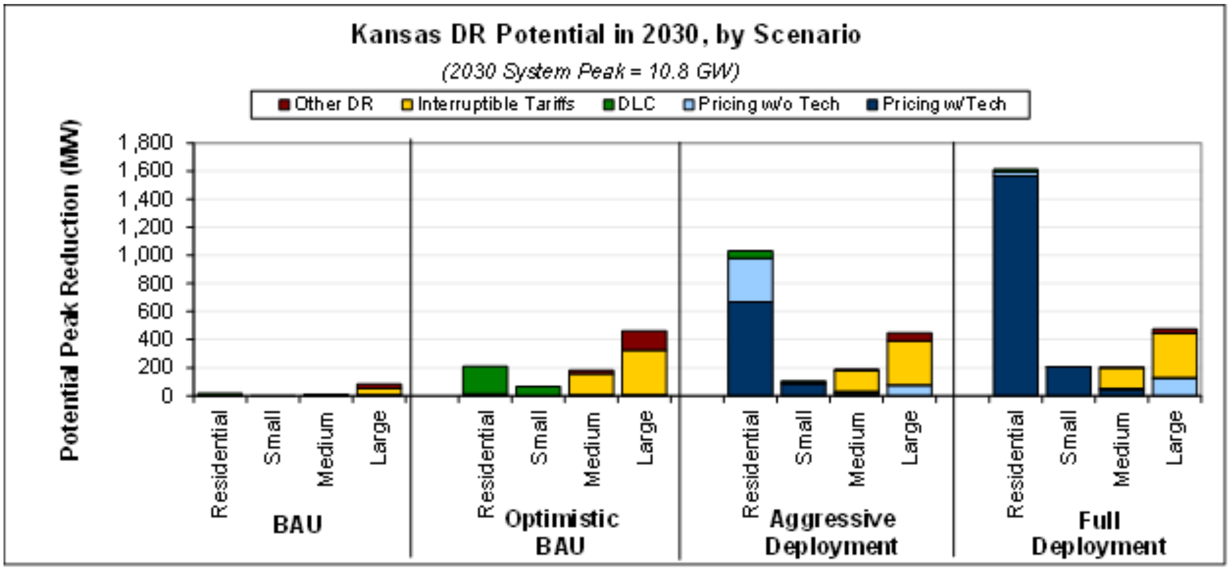
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	1	0.0%	1	0.0%	2	0.0%	4	0.0%
Automated/Direct Load Control	170	1.6%	7	0.1%	0	0.0%	147	1.4%	324	3.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	295	2.8%	295	2.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	385	3.7%	385	3.7%
Total	170	1.6%	8	0.1%	1	0.0%	829	7.9%	1,008	9.6%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	20	0.2%	1	0.0%	3	0.0%	4	0.0%	28	0.3%
Automated/Direct Load Control	170	1.6%	108	1.0%	34	0.3%	147	1.4%	458	4.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	600	5.7%	737	7.0%	1,337	12.7%
Other DR Programs	0	0.0%	0	0.0%	79	0.7%	385	3.7%	464	4.4%
Total	190	1.8%	109	1.0%	715	6.8%	1,273	12.1%	2,287	21.7%
Aggressive Deployment										
Pricing with Technology	495	4.7%	49	0.5%	44	0.4%	35	0.3%	623	5.9%
Pricing without Technology	256	2.4%	1	0.0%	31	0.3%	63	0.6%	353	3.3%
Automated/Direct Load Control	170	1.6%	28	0.3%	14	0.1%	147	1.4%	359	3.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	600	5.7%	737	7.0%	1,337	12.7%
Other DR Programs	0	0.0%	0	0.0%	32	0.3%	385	3.7%	418	4.0%
Total	922	8.7%	78	0.7%	721	6.8%	1,368	13.0%	3,089	29.3%
Full Deployment										
Pricing with Technology	1,159	11.0%	115	1.1%	128	1.2%	102	1.0%	1,504	14.3%
Pricing without Technology	57	0.5%	1	0.0%	21	0.2%	82	0.8%	162	1.5%
Automated/Direct Load Control	170	1.6%	7	0.1%	0	0.0%	147	1.4%	324	3.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	600	5.7%	737	7.0%	1,337	12.7%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	385	3.7%	385	3.7%
Total	1,386	13.1%	124	1.2%	749	7.1%	1,453	13.8%	3,712	35.2%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in Iowa by Scenario, Pricing Program and Price Ratio (MW)

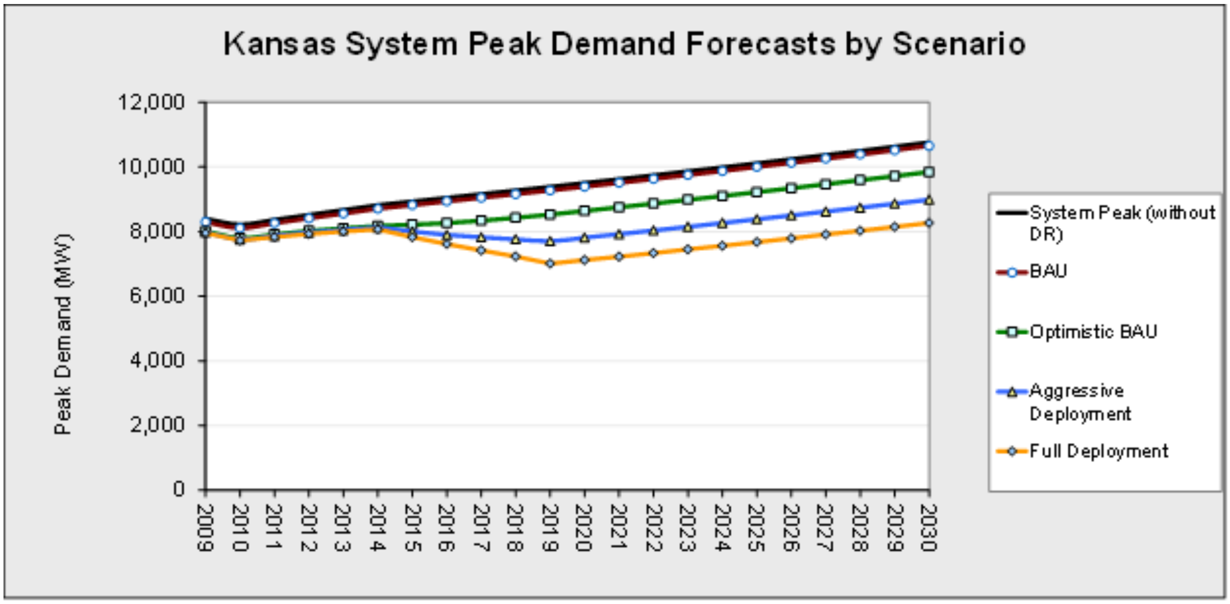
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	2	2	2	2	2	2	2	2	2	2	2	2
10	2	2	2	2	2	2	2	2	2	2	2	2
15	2	2	2	2	2	2	2	2	2	2	2	2
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	7	5	10	21	8	33	21	8	34	22	8	35
10	9	5	13	30	11	49	31	11	51	32	12	52
15	11	5	16	37	10	63	38	10	65	39	11	67
Aggressive Deployment												
Pricing with Technology												
5	102	26	178	452	116	788	466	120	813	481	124	838
10	157	44	270	693	194	1191	715	200	1229	737	206	1268
15	184	48	321	815	213	1417	841	219	1462	868	226	1509
Pricing without Technology												
5	62	17	106	265	69	460	273	72	475	282	74	491
8	94	28	161	407	116	699	420	119	721	434	123	744
15	111	30	192	480	127	833	495	131	860	511	135	887
Full Deployment												
Pricing with Technology												
5	252	75	428	1108	332	1885	1144	343	1945	1180	354	2007
10	386	121	651	1700	534	2866	1754	551	2957	1810	569	3051
15	429	114	743	1889	504	3273	1949	520	3377	2011	537	3485
Pricing without Technology												
5	33	11	55	135	42	228	139	43	236	144	45	244
10	50	17	83	208	67	348	215	70	360	222	72	372
15	55	16	95	232	64	399	240	66	413	248	69	427

Kansas State Profile



Total Potential Peak Reduction from Demand Response in Kansas, 2030

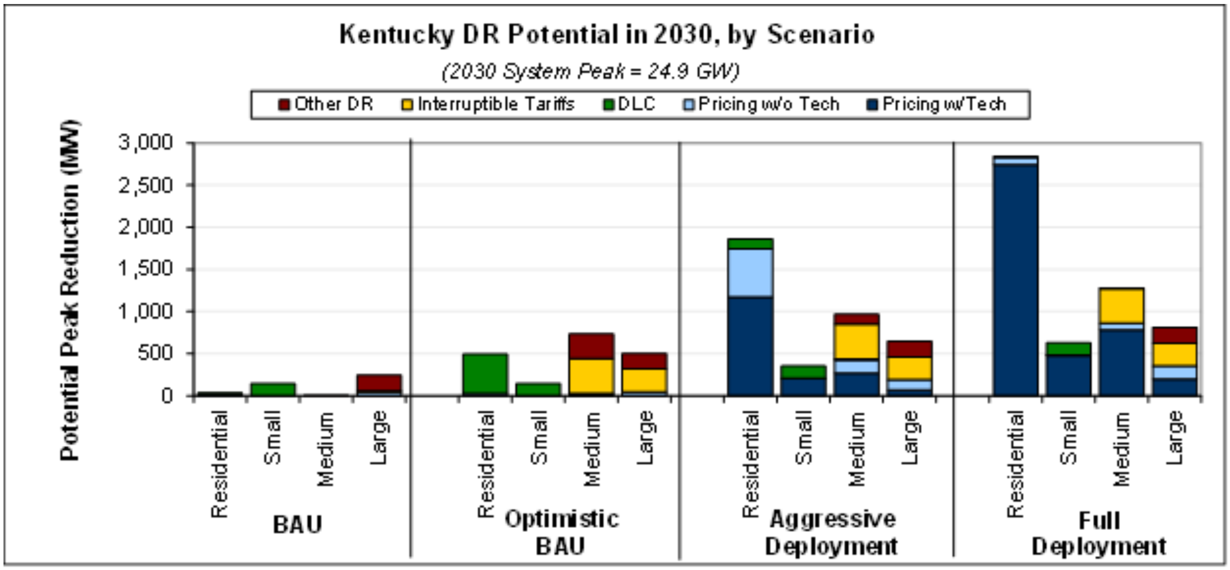
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	1	0.0%	0	0.0%	2	0.0%	6	0.1%	9	0.1%
Automated/Direct Load Control	16	0.2%	1	0.0%	6	0.1%	2	0.0%	25	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	44	0.5%	44	0.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	30	0.3%	30	0.3%
Total	17	0.2%	1	0.0%	8	0.1%	83	0.9%	109	1.2%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	14	0.1%	0	0.0%	2	0.0%	6	0.1%	22	0.2%
Automated/Direct Load Control	196	2.1%	65	0.7%	6	0.1%	2	0.0%	269	2.9%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	148	1.6%	315	3.4%	463	4.9%
Other DR Programs	0	0.0%	0	0.0%	25	0.3%	138	1.5%	163	1.7%
Total	209	2.2%	65	0.7%	181	1.9%	462	4.9%	917	9.8%
Aggressive Deployment										
Pricing with Technology	669	7.1%	88	0.9%	14	0.1%	0	0.0%	771	8.2%
Pricing without Technology	311	3.3%	2	0.0%	10	0.1%	76	0.8%	398	4.2%
Automated/Direct Load Control	50	0.5%	17	0.2%	6	0.1%	2	0.0%	74	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	148	1.6%	315	3.4%	463	4.9%
Other DR Programs	0	0.0%	0	0.0%	10	0.1%	56	0.6%	66	0.7%
Total	1,030	11.0%	106	1.1%	188	2.0%	449	4.8%	1,773	18.9%
Full Deployment										
Pricing with Technology	1,566	16.7%	206	2.2%	40	0.4%	0	0.0%	1,812	19.3%
Pricing without Technology	30	0.3%	1	0.0%	7	0.1%	126	1.3%	164	1.7%
Automated/Direct Load Control	16	0.2%	1	0.0%	6	0.1%	2	0.0%	25	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	148	1.6%	315	3.4%	463	4.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	30	0.3%	30	0.3%
Total	1,612	17.2%	207	2.2%	201	2.1%	474	5.0%	2,494	26.6%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in Kansas by Scenario, Pricing Program and Price Ratio (MW)

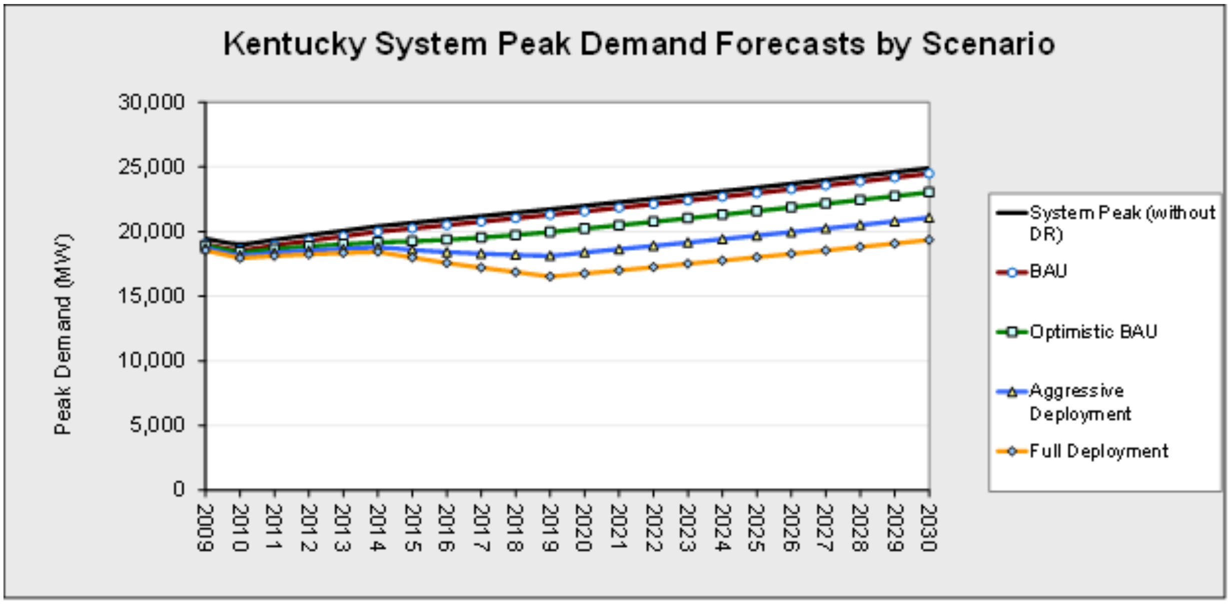
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	9	9	9	9	9	9	9	9	9	9	9	9
10	9	9	9	9	9	9	9	9	9	9	9	9
15	9	9	9	9	9	9	9	9	9	9	9	9
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	12	10	15	19	12	25	19	12	26	19	12	26
10	15	11	18	24	14	34	24	14	34	25	14	35
15	16	11	20	27	15	39	27	15	39	27	15	40
Aggressive Deployment												
Pricing with Technology												
5	148	50	246	583	197	969	594	201	988	606	205	1006
10	219	73	366	863	286	1440	880	292	1467	896	297	1495
15	258	67	449	1015	263	1766	1034	268	1800	1053	273	1834
Pricing without Technology												
5	82	29	134	318	108	527	324	110	539	331	112	550
8	121	41	201	471	157	785	481	160	802	492	164	819
15	142	37	247	554	145	964	566	148	985	578	151	1006
Full Deployment												
Pricing with Technology												
5	330	91	569	1298	360	2237	1323	366	2280	1348	373	2323
10	535	173	897	2104	682	3526	2144	694	3593	2184	708	3661
15	585	164	1007	2302	645	3959	2345	657	4034	2390	669	4110
Pricing without Technology												
5	38	12	63	142	40	244	147	42	252	152	43	261
10	60	21	100	231	76	386	239	79	399	247	81	412
15	66	20	112	253	73	434	262	75	449	271	78	464

Kentucky State Profile



Total Potential Peak Reduction from Demand Response in Kentucky, 2030

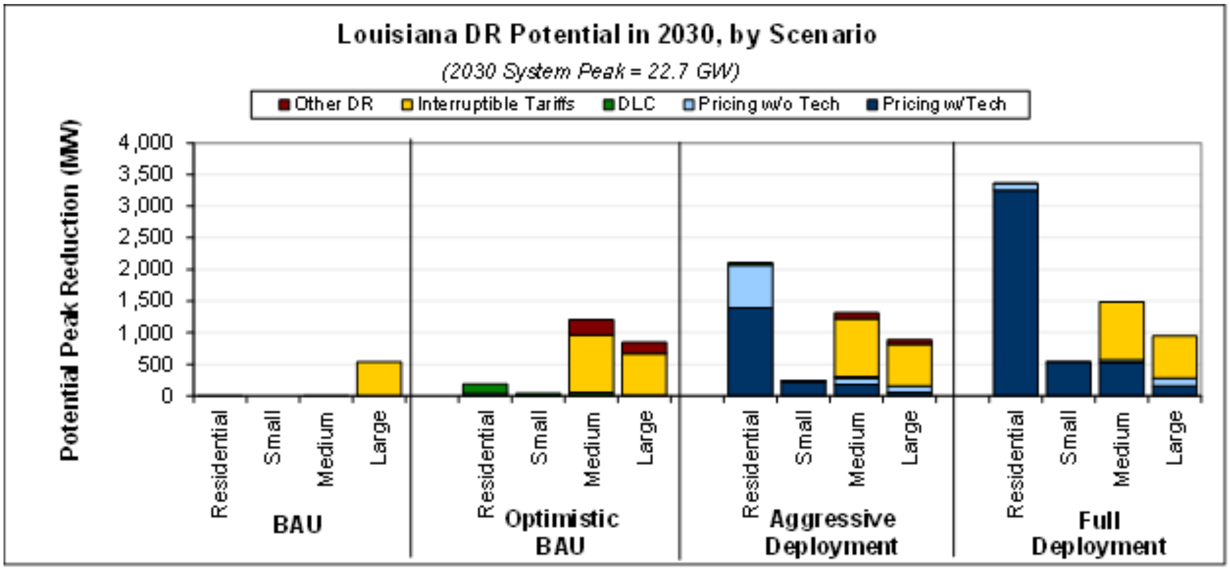
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	22	0.1%	0	0.0%	0	0.0%	45	0.2%	67	0.3%
Automated/Direct Load Control	11	0.1%	145	0.7%	0	0.0%	0	0.0%	156	0.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	15	0.1%	15	0.1%
Other DR Programs	0	0.0%	0	0.0%	5	0.0%	185	0.9%	190	0.9%
Total	33	0.2%	145	0.7%	5	0.0%	245	1.1%	428	2.0%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	27	0.1%	0	0.0%	9	0.0%	45	0.2%	81	0.4%
Automated/Direct Load Control	467	2.1%	145	0.7%	22	0.1%	0	0.0%	634	2.9%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	413	1.9%	273	1.3%	686	3.2%
Other DR Programs	0	0.0%	0	0.0%	288	1.3%	185	0.9%	473	2.2%
Total	494	2.3%	145	0.7%	732	3.4%	503	2.3%	1,874	8.6%
Aggressive Deployment										
Pricing with Technology	1,171	5.4%	205	0.9%	268	1.2%	67	0.3%	1,712	7.9%
Pricing without Technology	572	2.6%	4	0.0%	160	0.7%	122	0.6%	858	3.9%
Automated/Direct Load Control	119	0.5%	145	0.7%	9	0.0%	0	0.0%	273	1.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	413	1.9%	273	1.3%	686	3.2%
Other DR Programs	0	0.0%	0	0.0%	117	0.5%	185	0.9%	302	1.4%
Total	1,862	8.6%	354	1.6%	967	4.5%	647	3.0%	3,830	17.6%
Full Deployment										
Pricing with Technology	2,739	12.6%	481	2.2%	783	3.6%	196	0.9%	4,199	19.3%
Pricing without Technology	90	0.4%	2	0.0%	78	0.4%	158	0.7%	327	1.5%
Automated/Direct Load Control	11	0.1%	145	0.7%	0	0.0%	0	0.0%	156	0.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	413	1.9%	273	1.3%	686	3.2%
Other DR Programs	0	0.0%	0	0.0%	5	0.0%	185	0.9%	190	0.9%
Total	2,840	13.1%	628	2.9%	1,279	5.9%	812	3.7%	5,559	25.6%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in Kentucky by Scenario, Pricing Program and Price Ratio (MW)

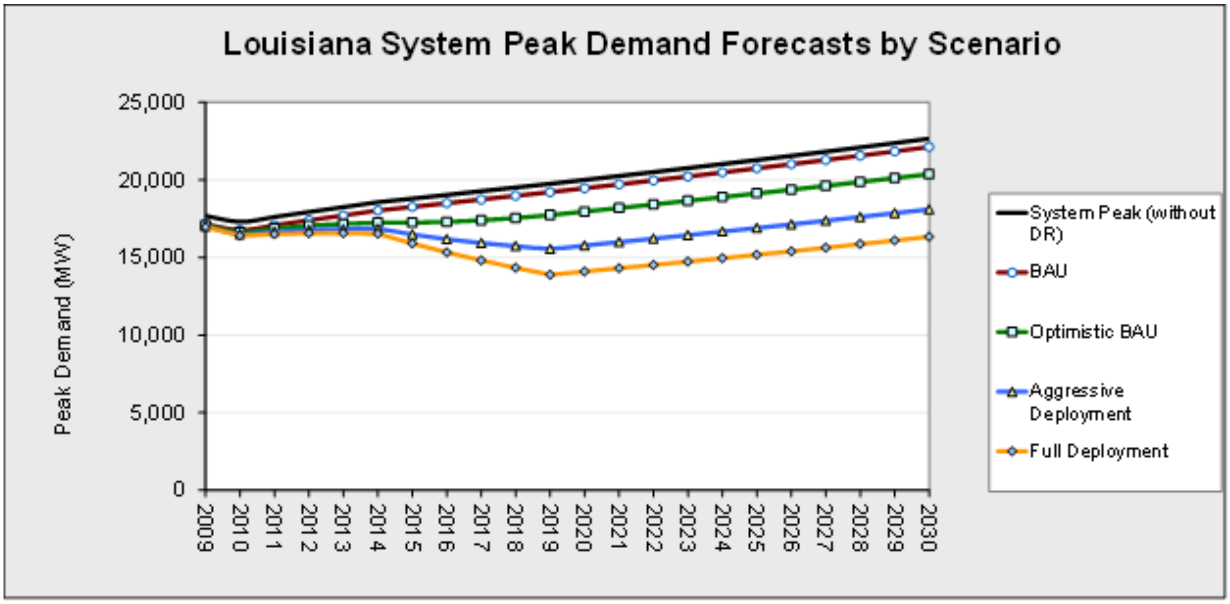
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	67	67	67	67	67	67	67	67	67	67	67	67
10	67	67	67	67	67	67	67	67	67	67	67	67
15	67	67	67	67	67	67	67	67	67	67	67	67
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	71	68	75	75	65	86	76	65	87	77	65	88
10	76	64	87	85	62	107	86	62	109	87	62	111
15	81	62	99	94	62	125	95	62	127	96	63	129
Aggressive Deployment												
Pricing with Technology												
5	458	143	773	1261	395	2127	1297	406	2188	1335	418	2252
10	700	241	1160	1927	662	3191	1982	681	3283	2039	701	3378
15	797	255	1339	2193	702	3684	2256	722	3790	2321	743	3900
Pricing without Technology												
5	244	101	388	650	209	1091	669	214	1124	689	220	1158
8	365	137	593	997	344	1649	1026	355	1698	1057	365	1749
15	416	144	688	1138	366	1910	1172	377	1967	1207	388	2026
Full Deployment												
Pricing with Technology												
5	1056	222	1890	2906	610	5201	2992	628	5356	3082	647	5516
10	1694	573	2816	4663	1577	7748	4801	1624	7978	4945	1673	8217
15	1913	407	3418	5263	1121	9405	5420	1155	9684	5581	1189	9973
Pricing without Technology												
5	100	53	147	251	57	446	261	57	465	272	60	485
10	149	65	234	406	139	672	422	145	700	440	151	729
15	170	52	287	460	101	819	479	105	853	499	109	888

Louisiana State Profile



Total Potential Peak Reduction from Demand Response in Louisiana, 2030

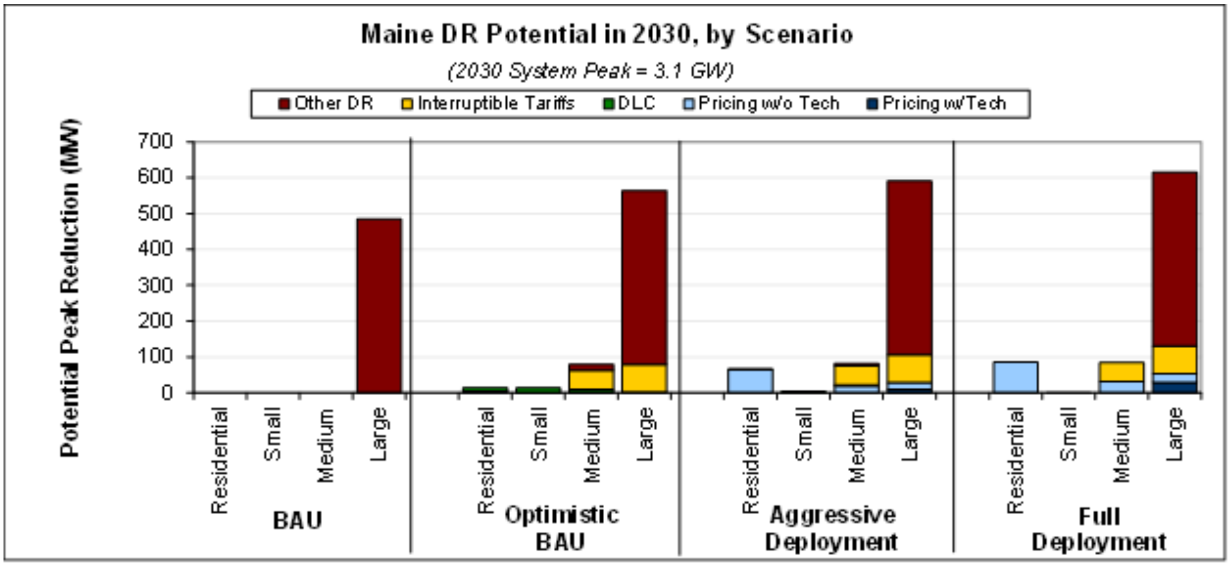
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	1	0.0%	0	0.0%	1	0.0%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	535	2.7%	535	2.7%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	0	0.0%	0	0.0%	1	0.0%	535	2.7%	537	2.7%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	39	0.2%	0	0.0%	7	0.0%	4	0.0%	51	0.3%
Automated/Direct Load Control	151	0.8%	38	0.2%	46	0.2%	0	0.0%	234	1.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	915	4.6%	663	3.4%	1,579	8.0%
Other DR Programs	0	0.0%	0	0.0%	237	1.2%	178	0.9%	415	2.1%
Total	190	1.0%	38	0.2%	1,205	6.1%	846	4.3%	2,279	11.5%
Aggressive Deployment										
Pricing with Technology	1,389	7.0%	229	1.2%	178	0.9%	53	0.3%	1,849	9.4%
Pricing without Technology	679	3.4%	4	0.0%	106	0.5%	97	0.5%	887	4.5%
Automated/Direct Load Control	38	0.2%	10	0.0%	19	0.1%	0	0.0%	67	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	915	4.6%	663	3.4%	1,579	8.0%
Other DR Programs	0	0.0%	0	0.0%	97	0.5%	73	0.4%	170	0.9%
Total	2,107	10.7%	242	1.2%	1,315	6.7%	886	4.5%	4,551	23.0%
Full Deployment										
Pricing with Technology	3,250	16.5%	535	2.7%	520	2.6%	156	0.8%	4,460	22.6%
Pricing without Technology	107	0.5%	2	0.0%	52	0.3%	126	0.6%	287	1.5%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	915	4.6%	663	3.4%	1,579	8.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	3,358	17.0%	537	2.7%	1,487	7.5%	945	4.8%	6,326	32.0%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in Louisiana by Scenario, Pricing Program and Price Ratio (MW)

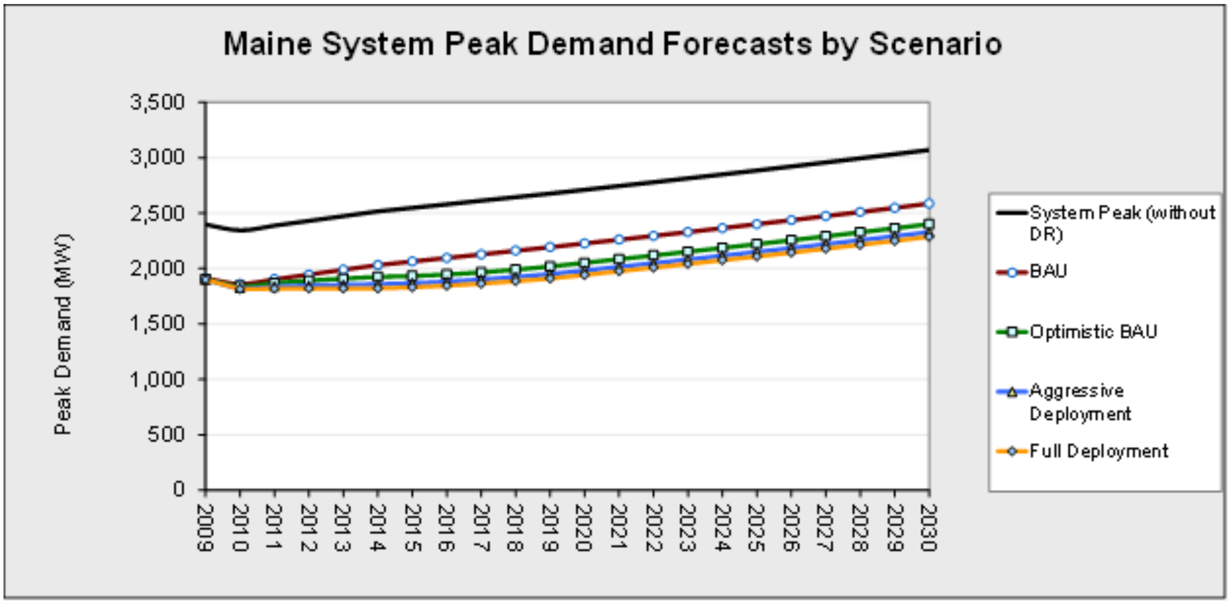
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	1	1	1	1	1	1	1	1	1	1	1	1
10	1	1	1	1	1	1	1	1	1	1	1	1
15	1	1	1	1	1	1	1	1	1	1	1	1
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	20	5	36	37	9	64	38	10	66	39	10	68
10	30	8	52	54	15	94	56	15	97	57	15	99
15	38	10	66	68	18	119	70	18	122	72	19	124
Aggressive Deployment												
Pricing with Technology												
5	457	142	773	1350	418	2282	1383	429	2338	1417	439	2395
10	692	185	1199	2041	545	3538	2091	558	3624	2143	572	3714
15	807	182	1431	2381	537	4225	2439	550	4328	2499	564	4434
Pricing without Technology												
5	224	70	379	662	206	1118	678	211	1145	695	216	1174
8	341	91	590	1005	270	1740	1030	276	1783	1055	283	1827
15	399	91	707	1175	267	2083	1204	274	2134	1234	281	2187
Full Deployment												
Pricing with Technology												
5	1146	387	1906	3382	1141	5624	3469	1170	5767	3558	1201	5916
10	1635	431	2838	4823	1272	8375	4946	1305	8587	5074	1339	8809
15	1902	479	3325	5613	1414	9813	5756	1450	10061	5904	1488	10321
Pricing without Technology												
5	78	27	130	235	80	390	245	84	407	256	88	425
10	113	30	196	338	91	585	353	95	611	369	99	638
15	132	34	230	396	102	690	413	107	720	432	111	752

Maine State Profile



Total Potential Peak Reduction from Demand Response in Maine, 2030

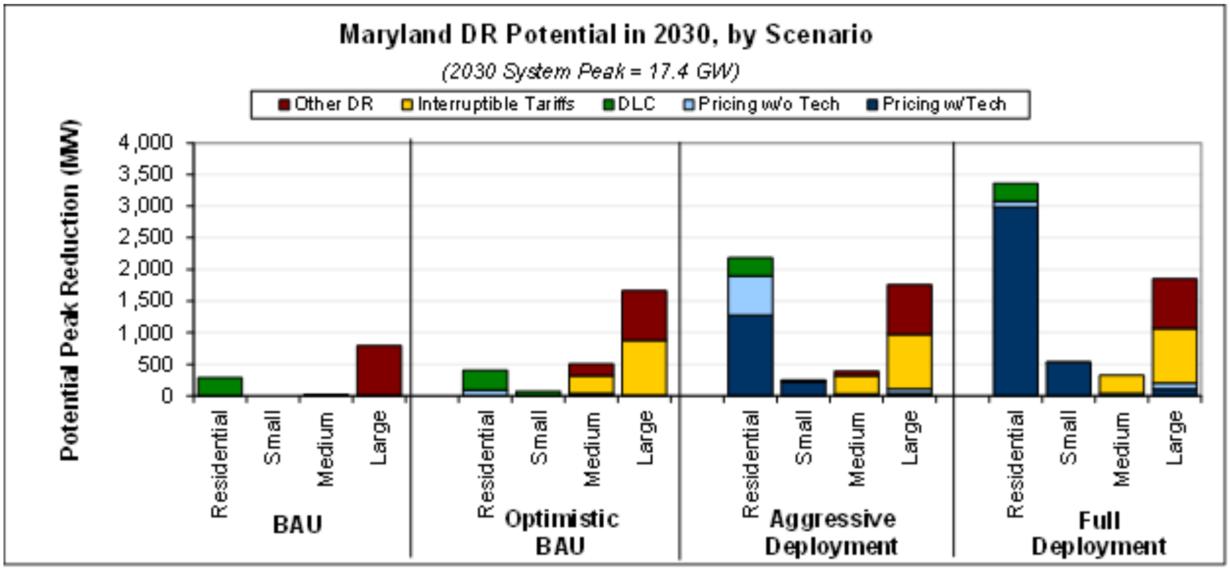
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	484	18.1%	484	18.1%
Total	0	0.0%	0	0.0%	0	0.0%	484	18.1%	484	18.1%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	3	0.1%	0	0.0%	1	0.0%	2	0.1%	6	0.2%
Automated/Direct Load Control	10	0.4%	13	0.5%	8	0.3%	0	0.0%	31	1.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	53	2.0%	78	2.9%	131	4.9%
Other DR Programs	0	0.0%	0	0.0%	17	0.6%	484	18.1%	502	18.7%
Total	14	0.5%	13	0.5%	79	3.0%	564	21.1%	670	25.0%
Aggressive Deployment										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	10	0.4%	10	0.4%
Pricing without Technology	64	2.4%	0	0.0%	19	0.7%	18	0.7%	101	3.8%
Automated/Direct Load Control	3	0.1%	3	0.1%	3	0.1%	0	0.0%	9	0.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	53	2.0%	78	2.9%	131	4.9%
Other DR Programs	0	0.0%	0	0.0%	7	0.3%	484	18.1%	492	18.4%
Total	66	2.5%	4	0.1%	82	3.1%	590	22.0%	743	27.7%
Full Deployment										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	29	1.1%	29	1.1%
Pricing without Technology	85	3.2%	0	0.0%	31	1.2%	23	0.9%	140	5.2%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	53	2.0%	78	2.9%	131	4.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	484	18.1%	484	18.1%
Total	85	3.2%	0	0.0%	84	3.1%	615	23.0%	784	29.3%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in Maine by Scenario, Pricing Program and Price Ratio (MW)

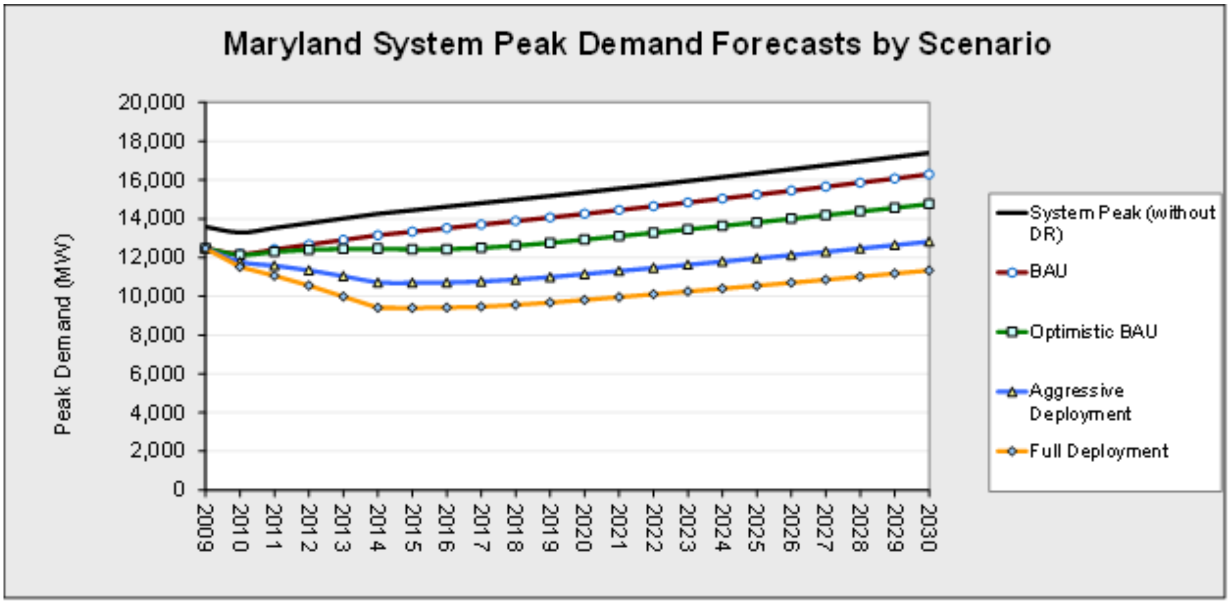
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	5	2	8	5	2	8	5	2	9	5	2	9
10	7	2	12	7	2	12	7	2	13	8	2	13
15	9	3	15	9	3	15	9	3	15	9	3	16
Aggressive Deployment												
Pricing with Technology												
5	8	3	13	10	3	16	10	3	16	10	3	17
10	12	4	21	14	4	25	15	4	25	15	5	26
15	15	5	25	18	6	29	18	6	30	19	6	31
Pricing without Technology												
5	65	22	109	78	26	129	80	27	132	82	28	136
8	100	29	170	119	35	203	122	36	208	125	37	213
15	122	39	204	144	47	242	148	48	248	152	49	254
Full Deployment												
Pricing with Technology												
5	24	7	42	29	8	49	30	9	51	31	9	52
10	35	9	61	41	11	72	42	11	74	44	12	76
15	42	13	70	49	15	83	51	16	86	52	16	88
Pricing without Technology												
5	94	27	160	111	33	189	114	33	194	117	34	199
10	135	35	234	160	42	278	164	43	285	168	44	292
15	162	49	274	192	59	325	197	60	333	202	62	342

Maryland State Profile



Total Potential Peak Reduction from Demand Response in Maryland, 2030

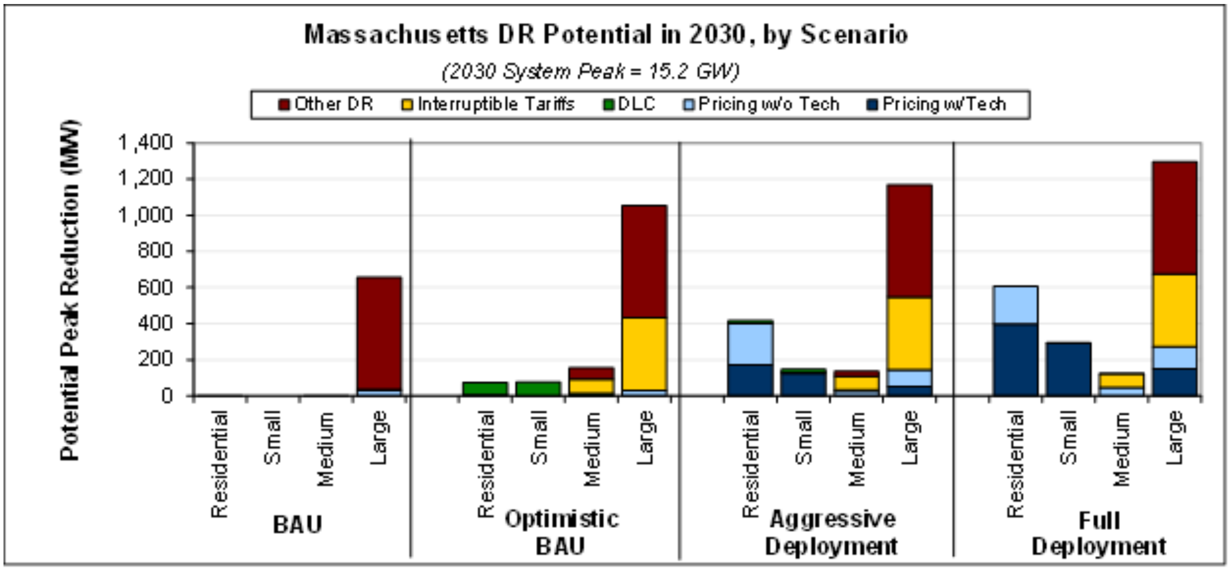
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	1	0.0%	0	0.0%	26	0.2%	0	0.0%	27	0.2%
Automated/Direct Load Control	286	1.9%	0	0.0%	0	0.0%	0	0.0%	286	1.9%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	11	0.1%	11	0.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	783	5.2%	783	5.2%
Total	287	1.9%	0	0.0%	26	0.2%	794	5.2%	1,108	7.3%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	89	0.6%	0	0.0%	26	0.2%	7	0.0%	123	0.8%
Automated/Direct Load Control	317	2.1%	71	0.5%	11	0.1%	0	0.0%	398	2.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	284	1.9%	869	5.7%	1,153	7.6%
Other DR Programs	0	0.0%	0	0.0%	185	1.2%	783	5.2%	968	6.4%
Total	406	2.7%	71	0.5%	505	3.3%	1,660	10.9%	2,642	17.4%
Aggressive Deployment										
Pricing with Technology	1,277	8.4%	227	1.5%	0	0.0%	37	0.2%	1,541	10.2%
Pricing without Technology	618	4.1%	4	0.0%	26	0.2%	68	0.4%	716	4.7%
Automated/Direct Load Control	286	1.9%	19	0.1%	4	0.0%	0	0.0%	309	2.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	284	1.9%	869	5.7%	1,153	7.6%
Other DR Programs	0	0.0%	0	0.0%	78	0.5%	783	5.2%	861	5.7%
Total	2,181	14.4%	249	1.6%	392	2.6%	1,758	11.6%	4,581	30.2%
Full Deployment										
Pricing with Technology	2,986	19.7%	530	3.5%	0	0.0%	110	0.7%	3,626	23.9%
Pricing without Technology	90	0.6%	2	0.0%	40	0.3%	88	0.6%	220	1.5%
Automated/Direct Load Control	286	1.9%	0	0.0%	0	0.0%	0	0.0%	286	1.9%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	284	1.9%	869	5.7%	1,153	7.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	783	5.2%	783	5.2%
Total	3,363	22.2%	533	3.5%	323	2.1%	1,851	12.2%	6,070	40.0%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in Maryland by Scenario, Pricing Program and Price Ratio (MW)

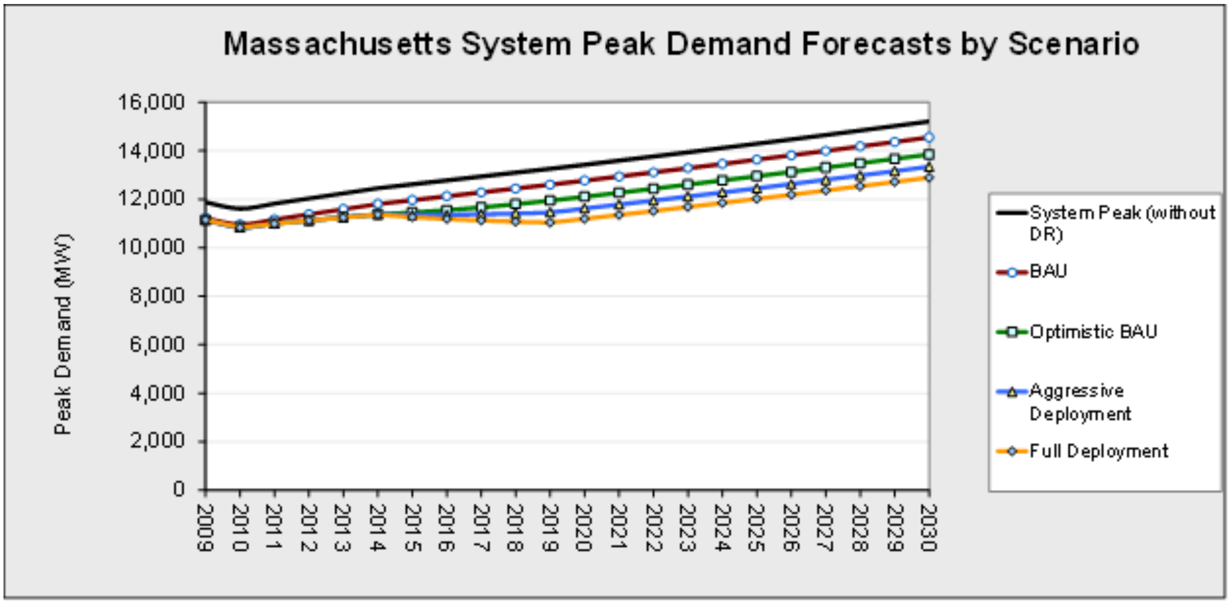
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	26	26	26	26	26	26	26	26	26	26	26	26
10	26	26	26	26	26	26	26	26	26	26	26	26
15	26	26	26	26	26	26	26	26	26	26	26	26
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	93	48	137	95	49	141	99	50	147	102	52	153
10	125	52	199	128	53	204	134	54	214	139	55	223
15	150	67	233	154	68	239	160	70	250	167	73	262
Aggressive Deployment												
Pricing with Technology												
5	1000	251	1750	1052	264	1840	1107	278	1937	1166	293	2040
10	1497	384	2609	1573	404	2743	1657	425	2888	1745	448	3042
15	1884	714	3054	1980	750	3211	2085	790	3381	2196	832	3560
Pricing without Technology												
5	493	143	844	508	147	868	533	153	913	560	160	960
8	731	202	1261	751	209	1294	790	218	1363	831	227	1435
15	919	355	1483	943	366	1521	993	384	1602	1045	403	1687
Full Deployment												
Pricing with Technology												
5	2410	629	4191	2530	660	4399	2664	696	4633	2806	733	4879
10	3439	806	6072	3610	846	6374	3802	891	6712	4004	938	7069
15	4220	992	7448	4430	1041	7818	4665	1096	8233	4913	1154	8671
Pricing without Technology												
5	181	59	304	172	58	286	182	60	304	192	61	322
10	258	68	448	244	66	423	259	69	449	274	72	476
15	318	82	554	301	79	523	319	83	554	337	87	588

Massachusetts State Profile



Total Potential Peak Reduction from Demand Response in Massachusetts, 2030

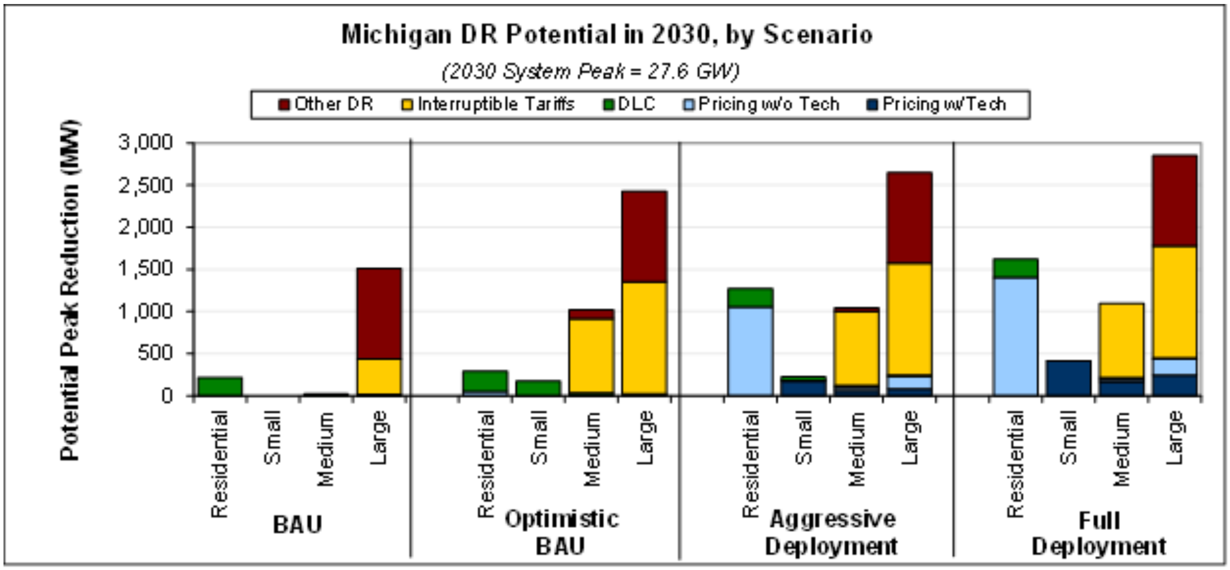
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	31	0.2%	31	0.2%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	5	0.0%	5	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	620	4.7%	620	4.7%
Total	0	0.0%	0	0.0%	0	0.0%	655	4.9%	656	4.9%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	6	0.0%	0	0.0%	1	0.0%	31	0.2%	37	0.3%
Automated/Direct Load Control	68	0.5%	76	0.6%	13	0.1%	0	0.0%	157	1.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	77	0.6%	403	3.0%	480	3.6%
Other DR Programs	0	0.0%	0	0.0%	64	0.5%	620	4.7%	684	5.2%
Total	73	0.6%	77	0.6%	155	1.2%	1,054	7.9%	1,359	10.2%
Aggressive Deployment										
Pricing with Technology	170	1.3%	125	0.9%	0	0.0%	51	0.4%	346	2.6%
Pricing without Technology	229	1.7%	2	0.0%	27	0.2%	94	0.7%	352	2.7%
Automated/Direct Load Control	17	0.1%	19	0.1%	5	0.0%	0	0.0%	42	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	77	0.6%	403	3.0%	480	3.6%
Other DR Programs	0	0.0%	0	0.0%	26	0.2%	620	4.7%	646	4.9%
Total	417	3.1%	146	1.1%	136	1.0%	1,168	8.8%	1,867	14.1%
Full Deployment										
Pricing with Technology	399	3.0%	291	2.2%	0	0.0%	150	1.1%	840	6.3%
Pricing without Technology	208	1.6%	2	0.0%	45	0.3%	121	0.9%	376	2.8%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	77	0.6%	403	3.0%	480	3.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	620	4.7%	620	4.7%
Total	606	4.6%	293	2.2%	123	0.9%	1,295	9.8%	2,316	17.5%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in Massachusetts by Scenario, Pricing Program and Price Ratio (MW)

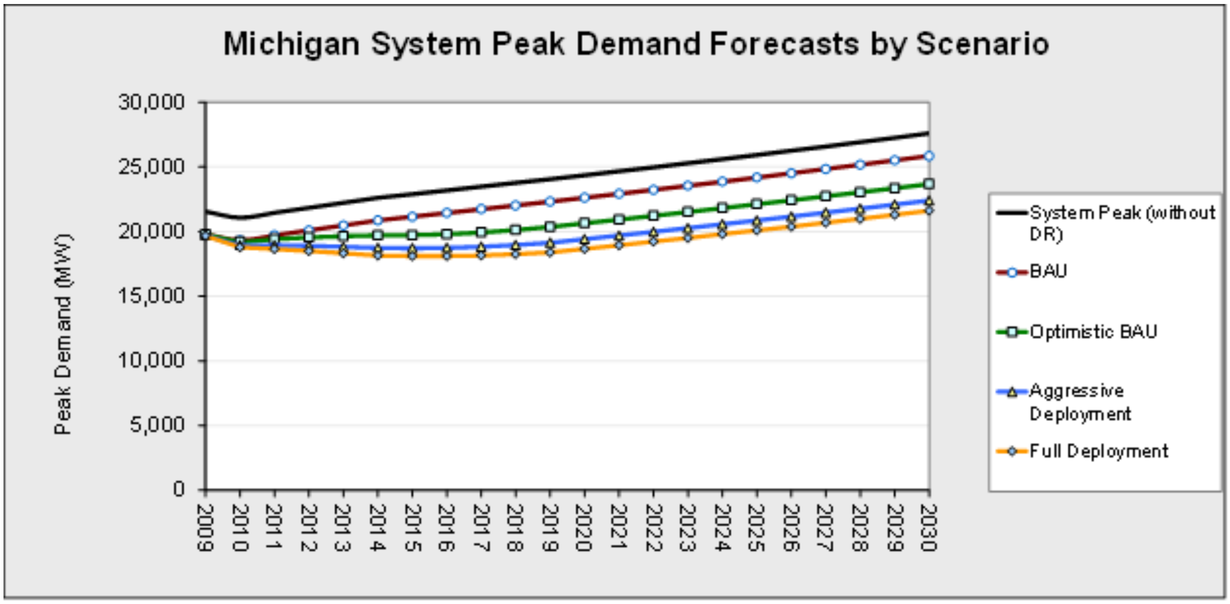
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	30	30	30	30	30	30	30	30	30	30	30	30
10	30	30	30	30	30	30	30	30	30	30	30	30
15	30	30	30	30	30	30	30	30	30	30	30	30
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	32	31	33	35	32	39	35	32	39	36	32	39
10	32	31	34	38	33	42	38	33	43	38	33	43
15	33	31	34	39	33	45	39	33	45	39	33	46
Aggressive Deployment												
Pricing with Technology												
5	54	14	94	259	65	453	265	67	463	271	68	474
10	79	22	136	380	108	653	389	111	668	398	113	684
15	95	25	165	457	121	792	467	124	811	478	127	830
Pricing without Technology												
5	69	40	98	272	71	473	278	72	484	284	73	494
8	91	43	138	404	116	691	412	118	706	421	121	721
15	106	43	170	487	131	844	498	134	862	509	137	881
Full Deployment												
Pricing with Technology												
5	135	35	234	647	169	1124	662	174	1151	678	178	1178
10	197	48	345	945	232	1658	967	238	1697	990	243	1737
15	230	55	405	1105	265	1946	1132	271	1992	1158	278	2039
Pricing without Technology												
5	71	39	103	299	79	519	306	81	531	313	83	544
10	97	37	156	443	111	775	453	113	793	464	116	811
15	112	37	187	522	128	916	534	131	937	546	134	959

Michigan State Profile



Total Potential Peak Reduction from Demand Response in Michigan, 2030

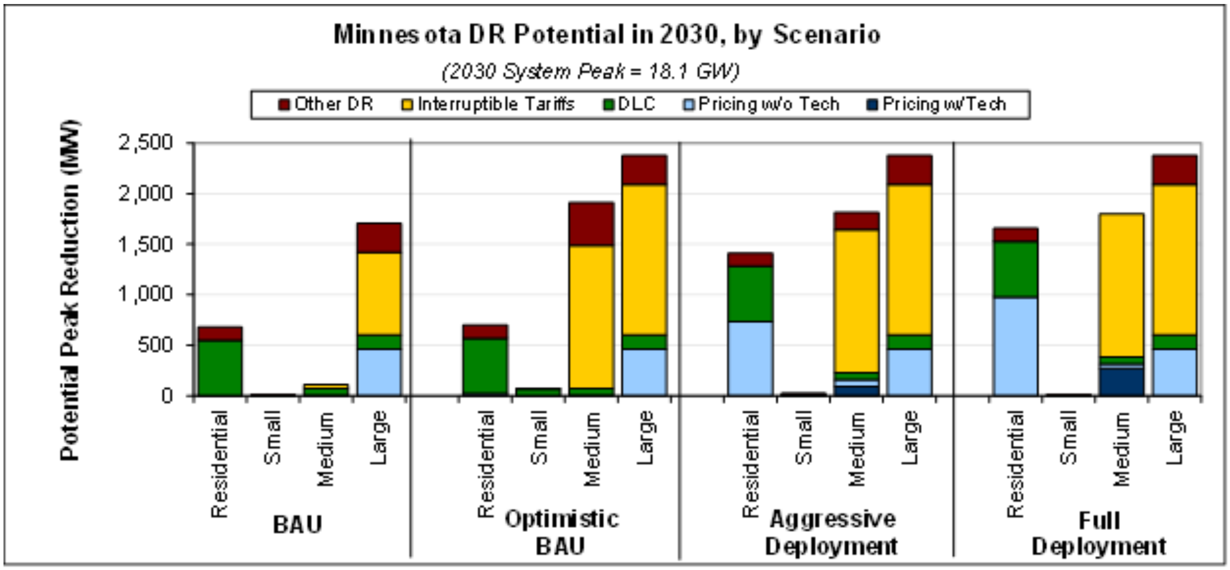
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	3	0.0%	3	0.0%
Automated/Direct Load Control	217	0.9%	0	0.0%	20	0.1%	12	0.0%	248	1.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	423	1.8%	423	1.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,072	4.5%	1,072	4.5%
Total	217	0.9%	0	0.0%	20	0.1%	1,509	6.3%	1,746	7.3%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	52	0.2%	0	0.0%	5	0.0%	12	0.0%	69	0.3%
Automated/Direct Load Control	239	1.0%	174	0.7%	30	0.1%	12	0.0%	455	1.9%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	883	3.7%	1,332	5.5%	2,215	9.2%
Other DR Programs	0	0.0%	0	0.0%	103	0.4%	1,072	4.5%	1,175	4.9%
Total	291	1.2%	175	0.7%	1,020	4.2%	2,428	10.1%	3,914	16.3%
Aggressive Deployment										
Pricing with Technology	0	0.0%	176	0.7%	58	0.2%	83	0.3%	316	1.3%
Pricing without Technology	1,054	4.4%	3	0.0%	41	0.2%	151	0.6%	1,249	5.2%
Automated/Direct Load Control	217	0.9%	45	0.2%	20	0.1%	12	0.0%	294	1.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	883	3.7%	1,332	5.5%	2,215	9.2%
Other DR Programs	0	0.0%	0	0.0%	43	0.2%	1,072	4.5%	1,115	4.6%
Total	1,271	5.3%	224	0.9%	1,044	4.3%	2,649	11.0%	5,189	21.6%
Full Deployment										
Pricing with Technology	0	0.0%	411	1.7%	168	0.7%	242	1.0%	821	3.4%
Pricing without Technology	1,405	5.8%	2	0.0%	28	0.1%	195	0.8%	1,631	6.8%
Automated/Direct Load Control	217	0.9%	0	0.0%	20	0.1%	12	0.0%	248	1.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	883	3.7%	1,332	5.5%	2,215	9.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,072	4.5%	1,072	4.5%
Total	1,622	6.7%	413	1.7%	1,099	4.6%	2,853	11.9%	5,987	24.9%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in Michigan by Scenario, Pricing Program and Price Ratio (MW)

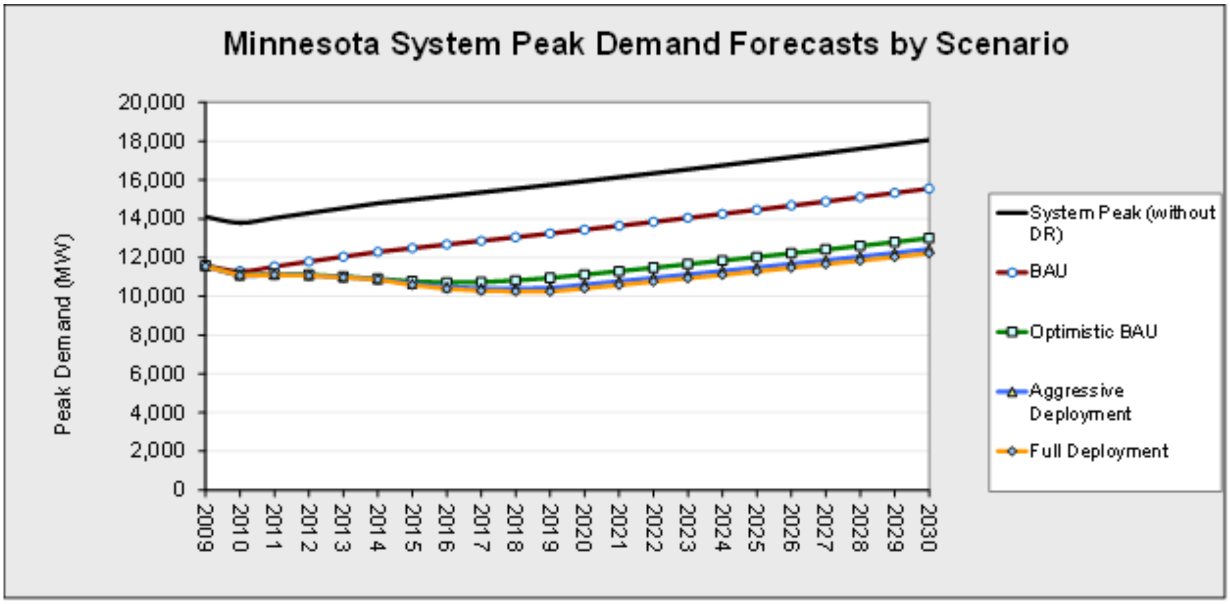
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	2	2	2	2	2	2	2	2	2	2	2	2
10	2	2	2	2	2	2	2	2	2	2	2	2
15	2	2	2	2	2	2	2	2	2	2	2	2
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	55	17	92	55	17	92	56	18	94	57	18	96
10	81	24	138	80	24	137	82	25	140	84	25	143
15	93	24	162	92	24	161	94	25	164	96	25	168
Aggressive Deployment												
Pricing with Technology												
5	200	70	329	248	88	409	258	91	425	268	95	442
10	294	79	510	366	98	634	380	102	659	395	106	684
15	350	102	599	436	127	745	453	132	774	471	137	805
Pricing without Technology												
5	767	269	1264	973	341	1604	992	348	1636	1011	355	1668
8	1138	303	1973	1444	385	2503	1472	392	2552	1501	400	2603
15	1360	392	2328	1726	497	2954	1760	507	3012	1794	517	3071
Full Deployment												
Pricing with Technology												
5	540	194	887	667	239	1096	694	249	1139	721	258	1183
10	776	268	1284	959	331	1587	997	344	1649	1036	358	1714
15	937	310	1565	1158	383	1933	1204	398	2009	1251	414	2088
Pricing without Technology												
5	1023	365	1682	1302	464	2140	1327	473	2181	1352	482	2223
10	1480	508	2453	1883	646	3120	1919	659	3180	1956	671	3241
15	1794	588	2999	2282	748	3815	2325	763	3888	2370	777	3963

Minnesota State Profile



Total Potential Peak Reduction from Demand Response in Minnesota, 2030

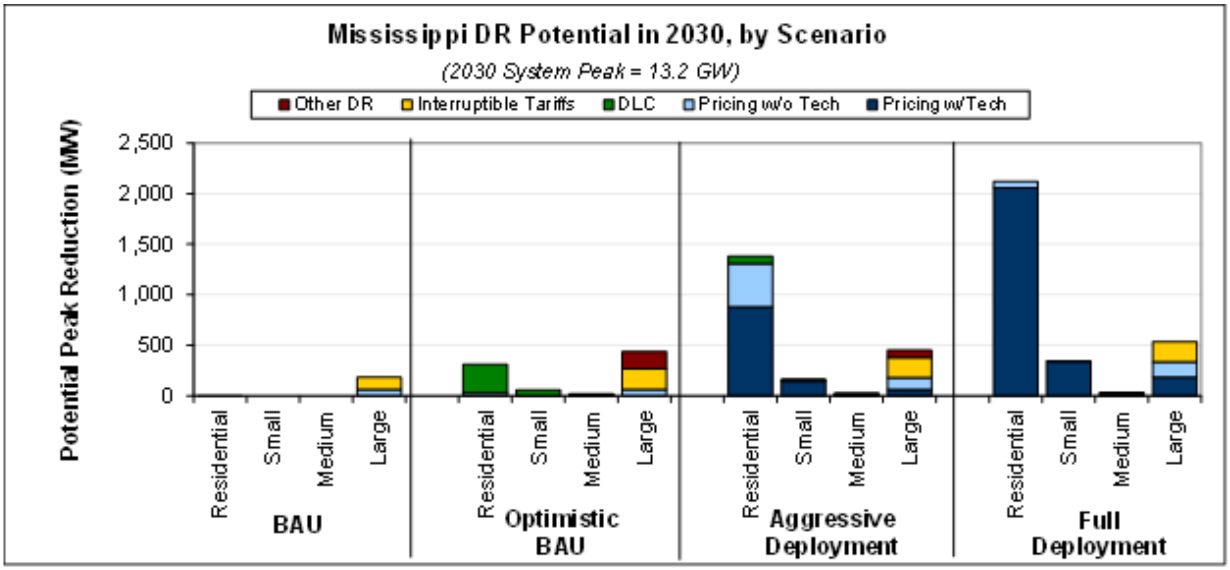
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	1	0.0%	1	0.0%	7	0.0%	463	2.9%	472	3.0%
Automated/Direct Load Control	548	3.5%	3	0.0%	68	0.4%	139	0.9%	758	4.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	35	0.2%	815	5.2%	850	5.4%
Other DR Programs	130	0.8%	5	0.0%	0	0.0%	288	1.8%	422	2.7%
Total	679	4.3%	10	0.1%	110	0.7%	1,705	10.8%	2,503	15.9%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	23	0.1%	1	0.0%	7	0.0%	463	2.9%	493	3.1%
Automated/Direct Load Control	548	3.5%	66	0.4%	68	0.4%	139	0.9%	821	5.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	1,413	9.0%	1,487	9.4%	2,900	18.4%
Other DR Programs	130	0.8%	5	0.0%	423	2.7%	288	1.8%	846	5.4%
Total	700	4.4%	72	0.5%	1,912	12.1%	2,376	15.1%	5,060	32.1%
Aggressive Deployment										
Pricing with Technology	0	0.0%	0	0.0%	92	0.6%	0	0.0%	92	0.6%
Pricing without Technology	734	4.7%	1	0.0%	66	0.4%	463	2.9%	1,264	8.0%
Automated/Direct Load Control	548	3.5%	17	0.1%	68	0.4%	139	0.9%	772	4.9%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	1,413	9.0%	1,487	9.4%	2,900	18.4%
Other DR Programs	130	0.8%	5	0.0%	173	1.1%	288	1.8%	596	3.8%
Total	1,412	9.0%	23	0.1%	1,813	11.5%	2,376	15.1%	5,624	35.7%
Full Deployment										
Pricing with Technology	0	0.0%	0	0.0%	270	1.7%	0	0.0%	270	1.7%
Pricing without Technology	979	6.2%	2	0.0%	45	0.3%	463	2.9%	1,488	9.5%
Automated/Direct Load Control	548	3.5%	3	0.0%	68	0.4%	139	0.9%	758	4.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	1,413	9.0%	1,487	9.4%	2,900	18.4%
Other DR Programs	130	0.8%	5	0.0%	0	0.0%	288	1.8%	422	2.7%
Total	1,656	10.5%	10	0.1%	1,796	11.4%	2,376	15.1%	5,839	37.1%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in Minnesota by Scenario, Pricing Program and Price Ratio (MW)

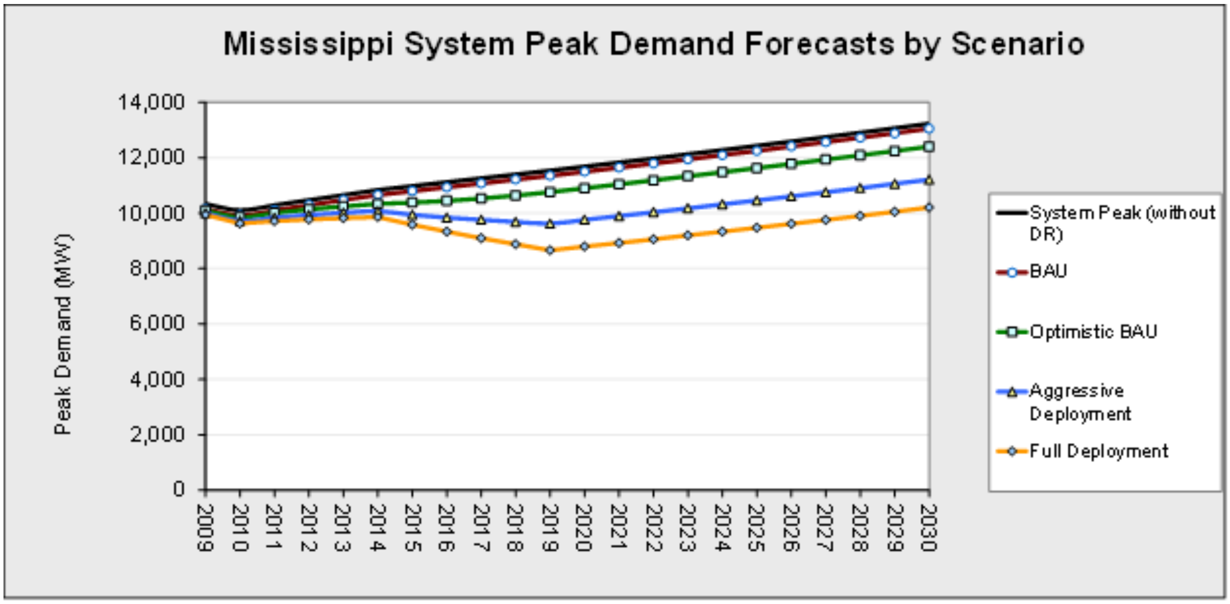
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	470	470	470	470	470	470	470	470	470	470	470	470
10	470	470	470	470	470	470	470	470	470	470	470	470
15	470	470	470	470	470	470	470	470	470	470	470	470
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	475	472	478	487	475	498	487	476	499	488	476	500
10	477	473	482	494	478	511	496	478	513	497	478	515
15	479	473	485	500	477	522	501	478	525	503	478	527
Aggressive Deployment												
Pricing with Technology												
5	19	5	32	67	19	115	69	20	119	72	21	123
10	27	9	45	98	34	162	102	35	168	105	36	174
15	33	10	56	118	35	201	122	36	208	127	37	216
Pricing without Technology												
5	600	504	696	1033	626	1440	1058	633	1483	1084	641	1528
8	665	533	797	1305	751	1859	1342	764	1920	1381	777	1984
15	707	535	879	1481	760	2203	1526	773	2279	1573	787	2359
Full Deployment												
Pricing with Technology												
5	54	13	94	193	46	339	200	48	352	207	49	364
10	75	22	127	268	79	457	278	82	474	288	85	491
15	93	24	162	333	85	582	346	88	603	358	91	625
Pricing without Technology												
5	635	507	763	1181	633	1728	1212	641	1784	1245	648	1842
10	703	535	871	1470	757	2183	1515	770	2259	1561	784	2339
15	763	540	985	1722	780	2665	1779	791	2767	1839	803	2874

Mississippi State Profile



Total Potential Peak Reduction from Demand Response in Mississippi, 2030

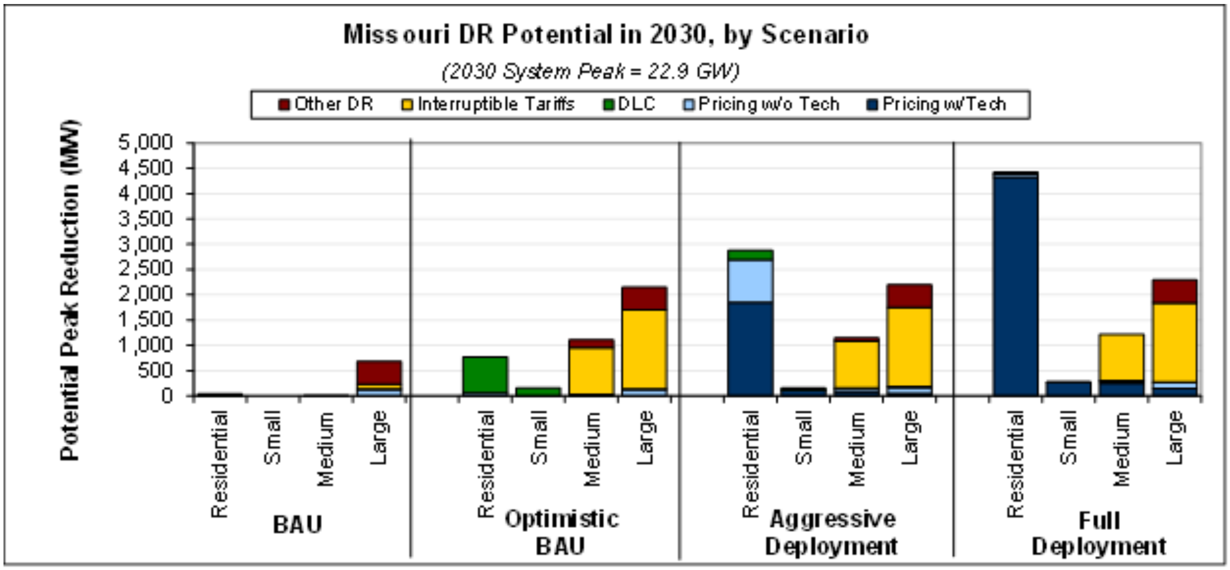
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	64	0.6%	64	0.6%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	119	1.0%	119	1.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	0	0.0%	0	0.0%	0	0.0%	183	1.6%	183	1.6%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	26	0.2%	0	0.0%	0	0.0%	64	0.6%	90	0.8%
Automated/Direct Load Control	286	2.5%	58	0.5%	1	0.0%	0	0.0%	346	3.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	11	0.1%	202	1.7%	212	1.8%
Other DR Programs	0	0.0%	0	0.0%	7	0.1%	173	1.5%	180	1.6%
Total	313	2.7%	58	0.5%	19	0.2%	438	3.8%	829	7.2%
Aggressive Deployment										
Pricing with Technology	878	7.6%	146	1.3%	7	0.1%	63	0.5%	1,094	9.5%
Pricing without Technology	429	3.7%	3	0.0%	4	0.0%	115	1.0%	550	4.8%
Automated/Direct Load Control	73	0.6%	15	0.1%	1	0.0%	0	0.0%	89	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	11	0.1%	202	1.7%	212	1.8%
Other DR Programs	0	0.0%	0	0.0%	3	0.0%	71	0.6%	74	0.6%
Total	1,379	12.0%	163	1.4%	25	0.2%	450	3.9%	2,018	17.5%
Full Deployment										
Pricing with Technology	2,053	17.8%	341	3.0%	20	0.2%	185	1.6%	2,599	22.5%
Pricing without Technology	67	0.6%	1	0.0%	2	0.0%	149	1.3%	219	1.9%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	11	0.1%	202	1.7%	212	1.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	2,120	18.4%	343	3.0%	32	0.3%	535	4.6%	3,031	26.3%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in Mississippi by Scenario, Pricing Program and Price Ratio (MW)

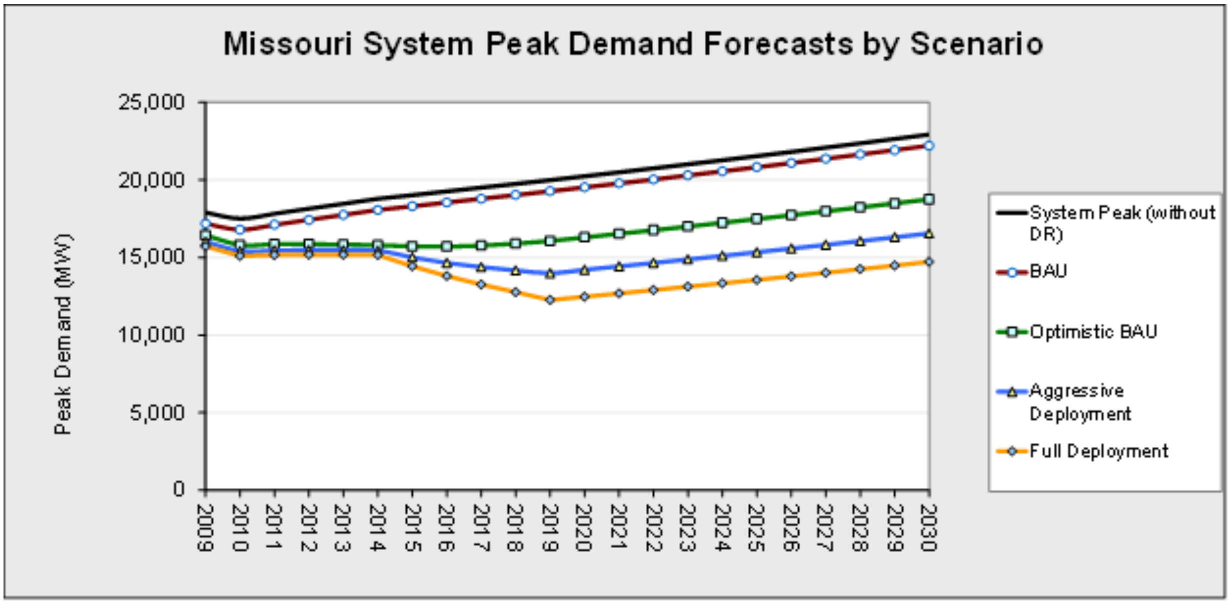
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	63	63	63	63	63	63	63	63	63	63	63	63
10	63	63	63	63	63	63	63	63	63	63	63	63
15	63	63	63	63	63	63	63	63	63	63	63	63
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	76	68	84	84	71	97	84	71	97	84	71	98
10	81	69	94	93	72	114	93	72	114	94	72	115
15	84	69	99	97	72	122	98	72	123	98	72	124
Aggressive Deployment												
Pricing with Technology												
5	304	100	508	831	274	1387	848	280	1416	866	286	1446
10	466	145	788	1274	396	2151	1300	405	2196	1328	413	2242
15	520	109	930	1419	297	2540	1448	304	2593	1479	310	2648
Pricing without Technology												
5	184	104	265	438	158	718	448	161	735	458	163	753
8	256	113	398	671	216	1125	686	220	1151	701	224	1179
15	283	94	472	748	163	1333	765	165	1364	782	167	1397
Full Deployment												
Pricing with Technology												
5	746	242	1250	2038	661	3415	2082	675	3489	2127	690	3564
10	1031	246	1817	2817	672	4963	2878	686	5070	2940	701	5179
15	1295	410	2180	3538	1121	5956	3614	1145	6083	3692	1170	6215
Pricing without Technology												
5	86	65	106	199	73	324	206	75	337	214	77	351
10	107	54	159	274	69	480	285	70	500	296	72	520
15	128	56	200	345	111	579	359	116	601	373	120	625

Missouri State Profile



Total Potential Peak Reduction from Demand Response in Missouri, 2030

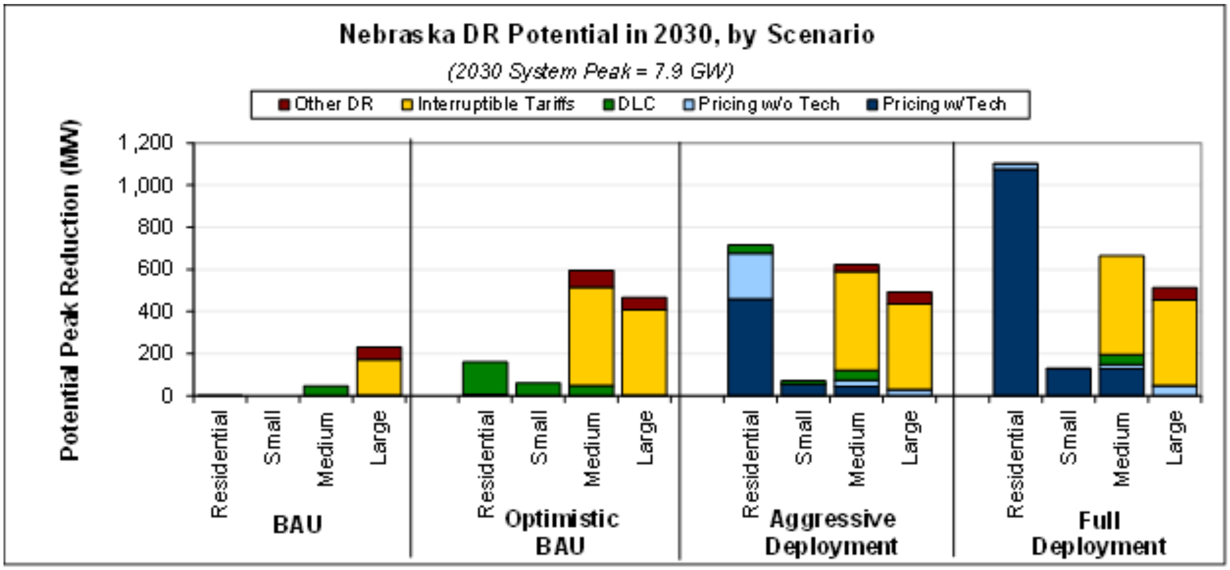
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	1	0.0%	0	0.0%	0	0.0%	120	0.6%	121	0.6%
Automated/Direct Load Control	36	0.2%	0	0.0%	2	0.0%	14	0.1%	53	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	96	0.5%	96	0.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	448	2.2%	448	2.2%
Total	37	0.2%	0	0.0%	2	0.0%	678	3.4%	718	3.6%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	57	0.3%	0	0.0%	4	0.0%	120	0.6%	182	0.9%
Automated/Direct Load Control	711	3.6%	156	0.8%	22	0.1%	14	0.1%	902	4.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	923	4.6%	1,564	7.8%	2,487	12.4%
Other DR Programs	0	0.0%	0	0.0%	156	0.8%	448	2.2%	604	3.0%
Total	768	3.8%	156	0.8%	1,105	5.5%	2,145	10.7%	4,174	20.9%
Aggressive Deployment										
Pricing with Technology	1,849	9.2%	114	0.6%	86	0.4%	49	0.2%	2,098	10.5%
Pricing without Technology	844	4.2%	2	0.0%	62	0.3%	120	0.6%	1,028	5.1%
Automated/Direct Load Control	182	0.9%	40	0.2%	9	0.0%	14	0.1%	245	1.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	923	4.6%	1,564	7.8%	2,487	12.4%
Other DR Programs	0	0.0%	0	0.0%	64	0.3%	448	2.2%	511	2.6%
Total	2,875	14.4%	156	0.8%	1,143	5.7%	2,194	11.0%	6,369	31.9%
Full Deployment										
Pricing with Technology	4,325	21.6%	267	1.3%	252	1.3%	143	0.7%	4,986	24.9%
Pricing without Technology	63	0.3%	1	0.0%	42	0.2%	120	0.6%	226	1.1%
Automated/Direct Load Control	36	0.2%	0	0.0%	2	0.0%	14	0.1%	53	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	923	4.6%	1,564	7.8%	2,487	12.4%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	448	2.2%	448	2.2%
Total	4,424	22.1%	269	1.3%	1,219	6.1%	2,288	11.4%	8,200	41.0%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in Missouri by Scenario, Pricing Program and Price Ratio (MW)

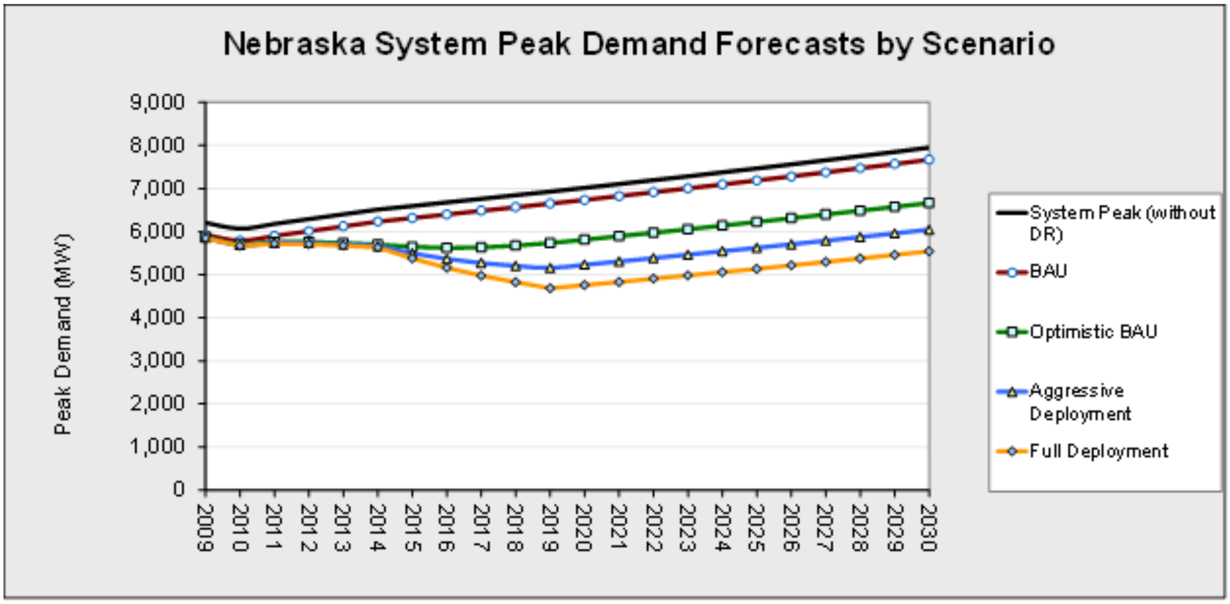
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	121	121	121	121	121	121	121	121	121	121	121	121
10	121	121	121	121	121	121	121	121	121	121	121	121
15	121	121	121	121	121	121	121	121	121	121	121	121
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	142	127	156	165	135	195	166	135	197	167	135	199
10	153	130	175	188	142	234	189	142	237	191	143	239
15	159	132	186	201	145	258	203	146	261	205	146	265
Aggressive Deployment												
Pricing with Technology												
5	499	132	865	1537	407	2668	1577	417	2737	1618	428	2808
10	756	212	1301	2333	655	4011	2393	672	4114	2455	689	4220
15	856	225	1487	2639	694	4584	2707	712	4703	2777	730	4824
Pricing without Technology												
5	335	177	493	781	293	1269	798	296	1300	816	299	1333
8	447	212	682	1147	380	1913	1176	385	1966	1205	391	2019
15	491	218	764	1293	389	2198	1326	395	2258	1360	402	2319
Full Deployment												
Pricing with Technology												
5	1201	372	2031	3697	1144	6250	3793	1174	6413	3892	1205	6580
10	1776	481	3071	5465	1480	9450	5607	1519	9695	5753	1558	9948
15	2094	600	3588	6444	1846	11042	6612	1894	11330	6784	1943	11624
Pricing without Technology												
5	146	128	165	207	126	288	211	124	298	216	123	309
10	160	131	189	286	118	455	295	119	472	304	120	489
15	167	134	201	334	123	544	345	126	563	356	128	583

Nebraska State Profile



Total Potential Peak Reduction from Demand Response in Nebraska, 2030

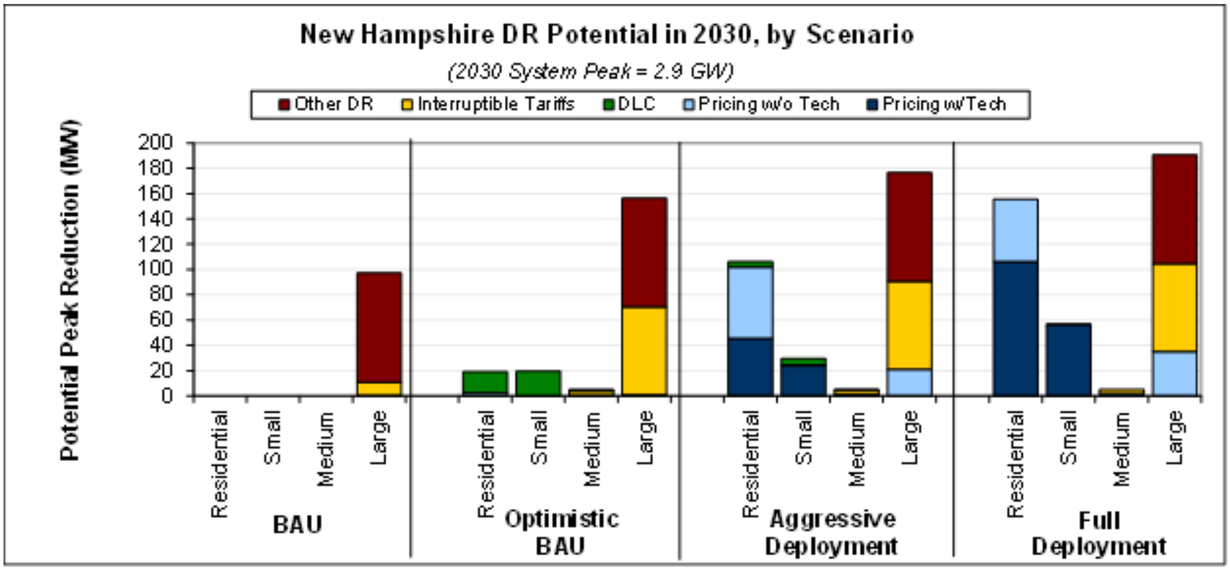
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	2	0.0%	2	0.0%
Automated/Direct Load Control	2	0.0%	0	0.0%	47	0.7%	1	0.0%	50	0.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	170	2.4%	170	2.4%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	58	0.8%	58	0.8%
Total	2	0.0%	0	0.0%	47	0.7%	231	3.3%	280	4.0%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	6	0.1%	0	0.0%	1	0.0%	2	0.0%	9	0.1%
Automated/Direct Load Control	155	2.2%	61	0.9%	47	0.7%	1	0.0%	264	3.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	468	6.7%	405	5.8%	873	12.6%
Other DR Programs	0	0.0%	0	0.0%	80	1.2%	58	0.8%	138	2.0%
Total	161	2.3%	61	0.9%	596	8.6%	466	6.7%	1,284	18.5%
Aggressive Deployment										
Pricing with Technology	460	6.6%	55	0.8%	44	0.6%	0	0.0%	559	8.1%
Pricing without Technology	216	3.1%	1	0.0%	31	0.5%	29	0.4%	278	4.0%
Automated/Direct Load Control	39	0.6%	15	0.2%	47	0.7%	1	0.0%	103	1.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	468	6.7%	405	5.8%	873	12.6%
Other DR Programs	0	0.0%	0	0.0%	32	0.5%	58	0.8%	90	1.3%
Total	715	10.3%	71	1.0%	622	9.0%	493	7.1%	1,902	27.4%
Full Deployment										
Pricing with Technology	1,076	15.5%	128	1.9%	128	1.8%	0	0.0%	1,332	19.2%
Pricing without Technology	24	0.3%	1	0.0%	21	0.3%	48	0.7%	94	1.4%
Automated/Direct Load Control	2	0.0%	0	0.0%	47	0.7%	1	0.0%	50	0.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	468	6.7%	405	5.8%	873	12.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	58	0.8%	58	0.8%
Total	1,102	15.9%	129	1.9%	664	9.6%	512	7.4%	2,407	34.7%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in Nebraska by Scenario, Pricing Program and Price Ratio (MW)

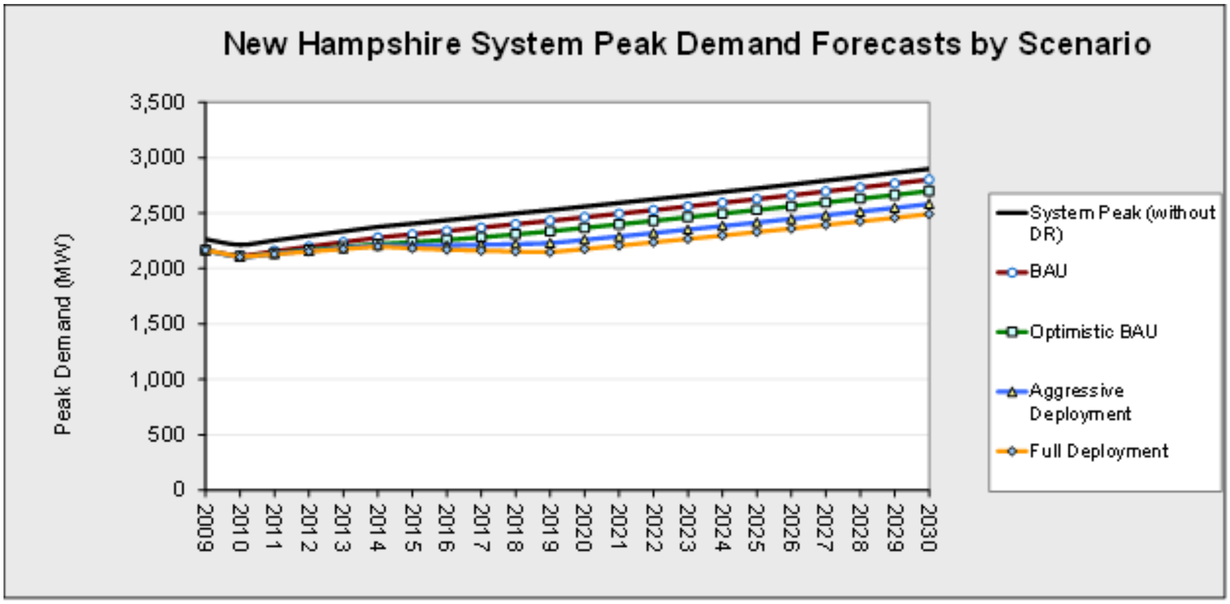
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	1	1	1	1	1	1	1	1	1	1	1	1
10	1	1	1	1	1	1	1	1	1	1	1	1
15	1	1	1	1	1	1	1	1	1	1	1	1
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	4	2	5	7	3	10	7	3	10	7	3	11
10	5	2	7	9	4	14	9	4	15	9	4	15
15	6	3	8	11	5	16	11	5	17	11	5	17
Aggressive Deployment												
Pricing with Technology												
5	99	27	172	404	108	701	417	111	723	430	115	746
10	147	33	261	598	136	1061	617	140	1094	637	145	1129
15	171	44	299	697	180	1214	719	185	1253	742	191	1292
Pricing without Technology												
5	52	14	90	207	55	359	214	57	370	220	59	382
8	77	18	136	307	70	544	317	73	562	327	75	580
15	90	23	156	359	93	624	370	96	644	382	99	665
Full Deployment												
Pricing with Technology												
5	244	65	422	987	263	1711	1018	271	1765	1050	279	1821
10	329	84	575	1335	338	2331	1377	349	2405	1420	360	2481
15	426	100	751	1725	405	3045	1780	418	3141	1836	431	3240
Pricing without Technology												
5	21	6	36	80	22	139	83	22	143	86	23	149
10	29	7	50	109	28	190	113	29	197	117	30	204
15	37	9	65	142	34	249	147	35	258	152	37	267

New Hampshire State Profile



Total Potential Peak Reduction from Demand Response in New Hampshire, 2030

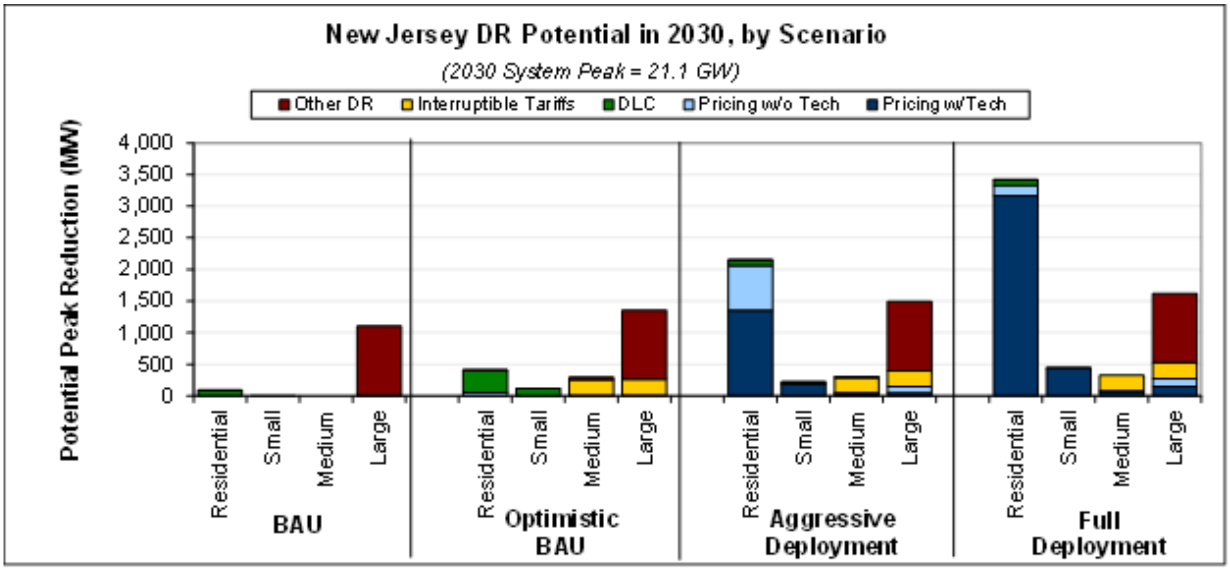
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	11	0.4%	11	0.4%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	86	3.4%	86	3.4%
Total	0	0.0%	0	0.0%	0	0.0%	97	3.8%	97	3.8%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	2	0.1%	0	0.0%	0	0.0%	1	0.0%	3	0.1%
Automated/Direct Load Control	17	0.7%	19	0.8%	0	0.0%	0	0.0%	36	1.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	3	0.1%	70	2.8%	73	2.9%
Other DR Programs	0	0.0%	0	0.0%	1	0.0%	86	3.4%	87	3.4%
Total	19	0.8%	19	0.8%	5	0.2%	156	6.2%	200	7.9%
Aggressive Deployment										
Pricing with Technology	45	1.8%	24	1.0%	0	0.0%	0	0.0%	69	2.7%
Pricing without Technology	57	2.2%	0	0.0%	1	0.0%	21	0.8%	79	3.1%
Automated/Direct Load Control	4	0.2%	5	0.2%	0	0.0%	0	0.0%	9	0.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	3	0.1%	70	2.8%	73	2.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	86	3.4%	86	3.4%
Total	106	4.2%	30	1.2%	5	0.2%	176	7.0%	317	12.5%
Full Deployment										
Pricing with Technology	106	4.2%	56	2.2%	0	0.0%	0	0.0%	162	6.4%
Pricing without Technology	50	2.0%	0	0.0%	2	0.1%	35	1.4%	87	3.4%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	3	0.1%	70	2.8%	73	2.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	86	3.4%	86	3.4%
Total	156	6.2%	57	2.2%	5	0.2%	190	7.5%	408	16.1%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in New Hampshire by Scenario, Pricing Program and Price Ratio (MW)

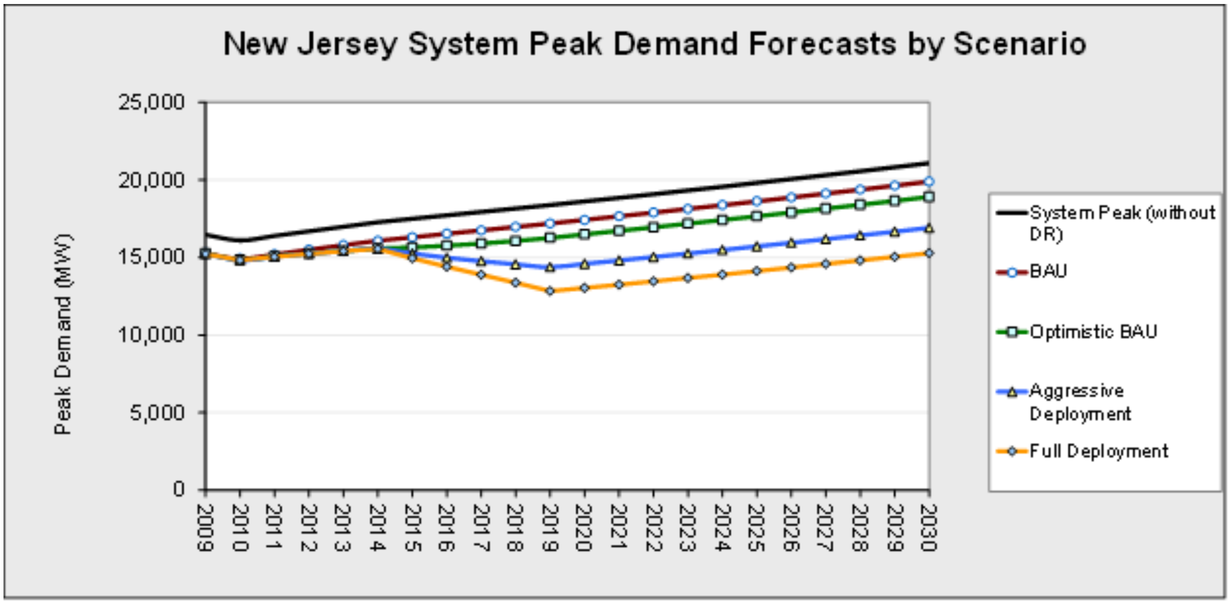
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	1	1	2	3	1	4	3	1	4	3	1	5
10	1	1	2	4	1	6	4	1	7	4	1	7
15	2	1	3	4	1	7	5	1	8	5	1	8
Aggressive Deployment												
Pricing with Technology												
5	14	4	24	50	15	85	52	16	88	54	16	92
10	20	5	35	73	20	127	76	20	132	80	21	138
15	24	7	41	88	26	149	91	27	155	95	29	162
Pricing without Technology												
5	17	5	29	61	19	104	64	19	109	67	20	113
8	25	7	44	91	25	157	95	26	164	99	27	171
15	31	9	52	110	33	186	114	35	194	119	36	202
Full Deployment												
Pricing with Technology												
5	32	9	56	116	31	201	121	33	210	126	34	219
10	49	17	81	178	63	293	186	65	306	194	68	319
15	55	14	96	199	51	347	208	53	362	217	55	378
Pricing without Technology												
5	20	5	34	70	19	121	73	20	125	76	21	130
10	30	11	50	108	39	178	113	40	185	117	42	192
15	34	9	60	122	32	212	127	33	220	132	35	229

New Jersey State Profile



Total Potential Peak Reduction from Demand Response in New Jersey, 2030

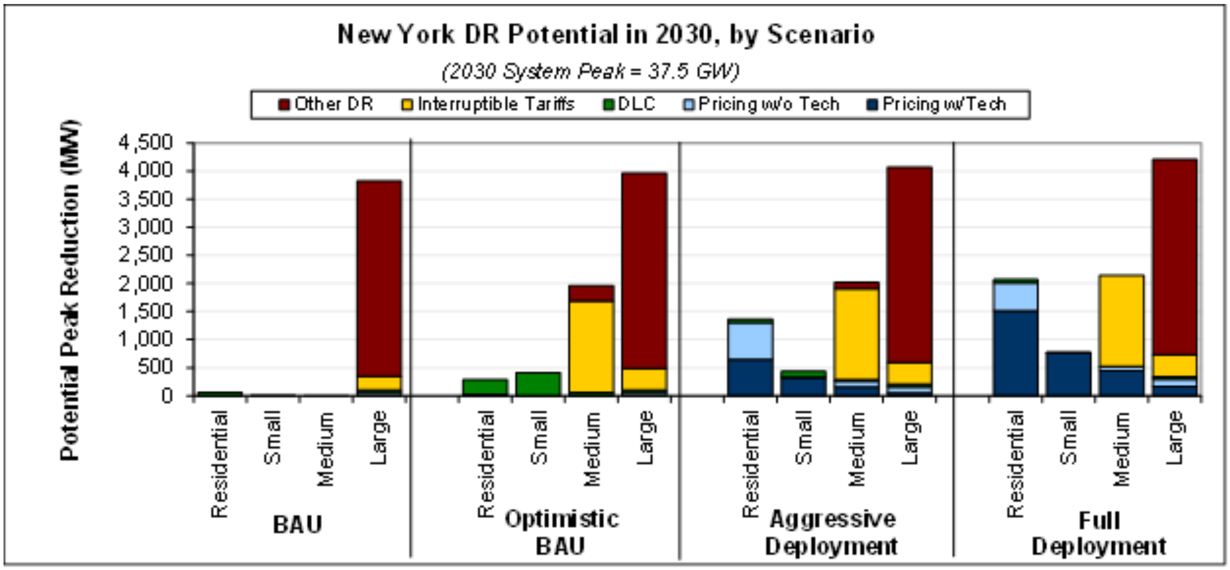
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	88	0.5%	0	0.0%	0	0.0%	0	0.0%	88	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	8	0.0%	8	0.0%
Other DR Programs	1	0.0%	0	0.0%	0	0.0%	1,093	5.9%	1,094	6.0%
Total	90	0.5%	0	0.0%	0	0.0%	1,100	6.0%	1,190	6.5%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	55	0.3%	0	0.0%	1	0.0%	6	0.0%	62	0.3%
Automated/Direct Load Control	353	1.9%	120	0.7%	6	0.0%	0	0.0%	478	2.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	245	1.3%	256	1.4%	501	2.7%
Other DR Programs	1	0.0%	0	0.0%	41	0.2%	1,093	5.9%	1,135	6.2%
Total	409	2.2%	120	0.7%	293	1.6%	1,354	7.4%	2,176	11.8%
Aggressive Deployment										
Pricing with Technology	1,352	7.4%	188	1.0%	23	0.1%	51	0.3%	1,614	8.8%
Pricing without Technology	707	3.8%	4	0.0%	16	0.1%	93	0.5%	820	4.5%
Automated/Direct Load Control	91	0.5%	31	0.2%	2	0.0%	0	0.0%	124	0.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	245	1.3%	256	1.4%	501	2.7%
Other DR Programs	1	0.0%	0	0.0%	17	0.1%	1,093	5.9%	1,111	6.0%
Total	2,151	11.7%	223	1.2%	304	1.7%	1,492	8.1%	4,170	22.7%
Full Deployment										
Pricing with Technology	3,162	17.2%	440	2.4%	68	0.4%	149	0.8%	3,819	20.8%
Pricing without Technology	166	0.9%	2	0.0%	11	0.1%	120	0.7%	300	1.6%
Automated/Direct Load Control	88	0.5%	0	0.0%	0	0.0%	0	0.0%	88	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	245	1.3%	256	1.4%	501	2.7%
Other DR Programs	1	0.0%	0	0.0%	0	0.0%	1,093	5.9%	1,094	6.0%
Total	3,418	18.6%	443	2.4%	324	1.8%	1,618	8.8%	5,802	31.6%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in New Jersey by Scenario, Pricing Program and Price Ratio (MW)

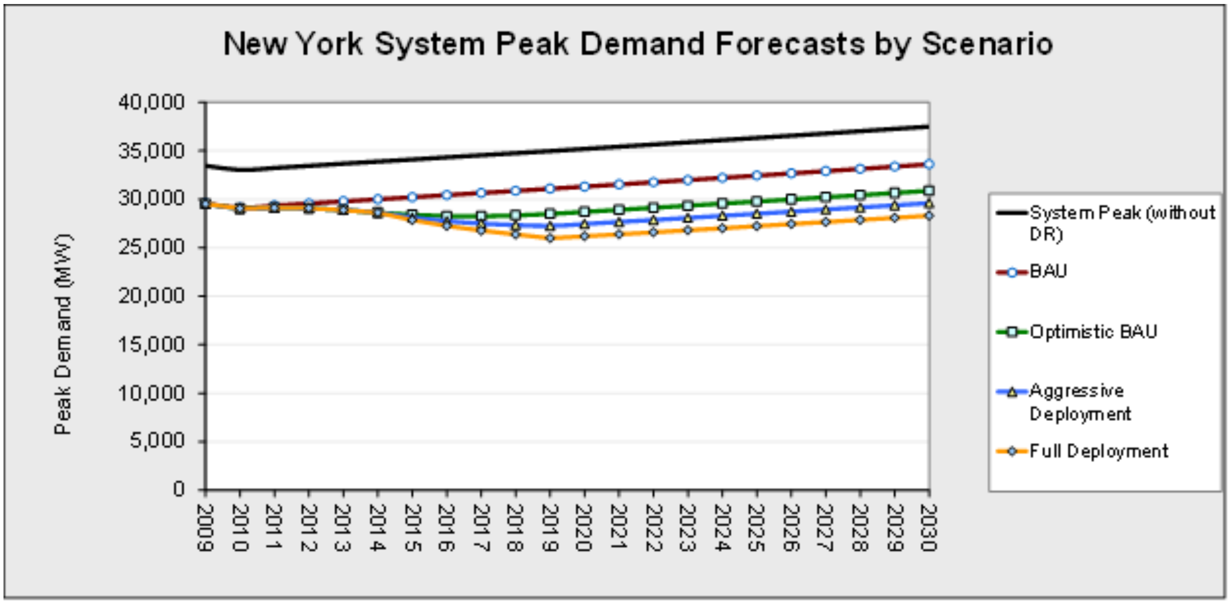
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	10	3	17	48	15	80	49	15	83	50	15	85
10	15	4	25	69	21	118	71	21	121	73	22	124
15	18	5	31	84	23	146	86	23	149	89	24	153
Aggressive Deployment												
Pricing with Technology												
5	244	73	414	1205	363	2048	1236	372	2100	1267	382	2153
10	359	97	621	1776	481	3071	1821	493	3149	1867	505	3229
15	433	136	731	2141	672	3610	2196	689	3702	2251	707	3796
Pricing without Technology												
5	130	39	220	627	189	1064	643	194	1091	659	199	1119
8	192	52	331	927	252	1601	950	259	1642	974	265	1684
15	232	73	390	1120	353	1887	1148	362	1935	1178	372	1984
Full Deployment												
Pricing with Technology												
5	549	121	977	2705	596	4814	2774	611	4936	2844	627	5062
10	849	249	1448	4183	1229	7137	4289	1260	7318	4398	1292	7504
15	1008	324	1691	4965	1597	8334	5091	1637	8545	5220	1679	8762
Pricing without Technology												
5	52	12	92	235	53	418	241	54	428	247	56	438
10	81	24	138	368	110	625	377	113	641	386	116	656
15	97	32	162	439	144	734	450	147	752	461	151	770

New York State Profile



Total Potential Peak Reduction from Demand Response in New York, 2030

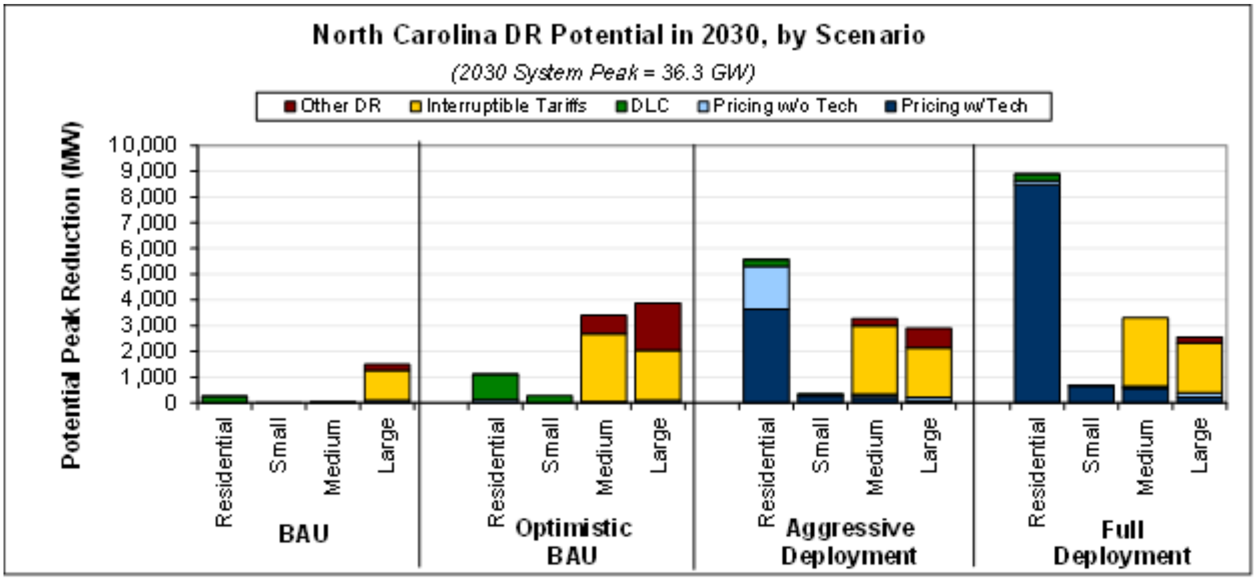
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	1	0.0%	0	0.0%	0	0.0%	53	0.2%	53	0.2%
Automated/Direct Load Control	57	0.2%	11	0.0%	1	0.0%	47	0.1%	117	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	249	0.7%	249	0.7%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	3,473	9.9%	3,473	9.9%
Total	58	0.2%	11	0.0%	1	0.0%	3,821	10.9%	3,891	11.1%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	29	0.1%	0	0.0%	7	0.0%	53	0.2%	89	0.3%
Automated/Direct Load Control	261	0.7%	412	1.2%	55	0.2%	47	0.1%	776	2.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	1,624	4.6%	391	1.1%	2,015	5.8%
Other DR Programs	0	0.0%	0	0.0%	274	0.8%	3,473	9.9%	3,747	10.7%
Total	290	0.8%	412	1.2%	1,960	5.6%	3,964	11.3%	6,626	18.9%
Aggressive Deployment										
Pricing with Technology	647	1.8%	325	0.9%	153	0.4%	56	0.2%	1,182	3.4%
Pricing without Technology	653	1.9%	6	0.0%	108	0.3%	102	0.3%	870	2.5%
Automated/Direct Load Control	67	0.2%	105	0.3%	23	0.1%	47	0.1%	242	0.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	1,624	4.6%	391	1.1%	2,015	5.8%
Other DR Programs	0	0.0%	0	0.0%	112	0.3%	3,473	9.9%	3,585	10.2%
Total	1,367	3.9%	437	1.2%	2,019	5.8%	4,069	11.6%	7,892	22.6%
Full Deployment										
Pricing with Technology	1,513	4.3%	761	2.2%	449	1.3%	164	0.5%	2,887	8.3%
Pricing without Technology	499	1.4%	4	0.0%	71	0.2%	132	0.4%	707	2.0%
Automated/Direct Load Control	57	0.2%	11	0.0%	1	0.0%	47	0.1%	117	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	1,624	4.6%	391	1.1%	2,015	5.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	3,473	9.9%	3,473	9.9%
Total	2,070	5.9%	776	2.2%	2,144	6.1%	4,207	12.0%	9,197	26.3%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in New York by Scenario, Pricing Program and Price Ratio (MW)

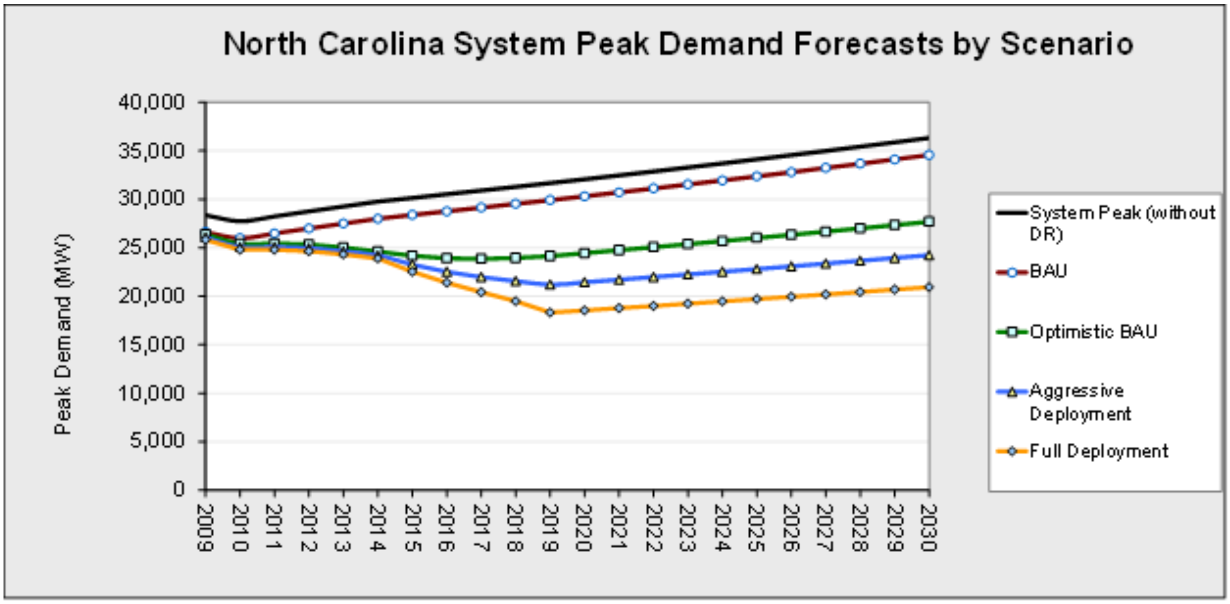
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	52	52	52	52	52	52	52	52	52	52	52	52
10	52	52	52	52	52	52	52	52	52	52	52	52
15	52	52	52	52	52	52	52	52	52	52	52	52
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	58	54	62	79	60	99	79	60	99	80	60	99
10	61	54	67	92	61	122	92	61	122	92	62	123
15	63	56	70	102	70	135	103	70	135	103	70	136
Aggressive Deployment												
Pricing with Technology												
5	182	47	317	881	227	1535	892	230	1554	904	233	1574
10	283	94	472	1373	457	2290	1391	462	2319	1409	468	2349
15	320	83	558	1553	401	2706	1573	406	2741	1593	411	2776
Pricing without Technology												
5	169	83	256	663	184	1143	670	185	1155	676	186	1166
8	237	114	359	1043	353	1733	1053	356	1750	1063	359	1768
15	263	106	421	1187	311	2064	1199	313	2084	1210	316	2104
Full Deployment												
Pricing with Technology												
5	476	188	764	2295	904	3686	2325	916	3735	2357	929	3784
10	655	154	1157	3160	740	5580	3202	750	5654	3245	760	5730
15	817	250	1384	3939	1203	6674	3991	1219	6762	4044	1236	6852
Pricing without Technology												
5	145	89	200	582	235	928	588	238	938	594	240	948
10	184	81	287	813	195	1431	822	197	1447	830	199	1462
15	221	96	346	1022	318	1727	1033	321	1745	1044	325	1764

North Carolina State Profile



Total Potential Peak Reduction from Demand Response in North Carolina, 2030

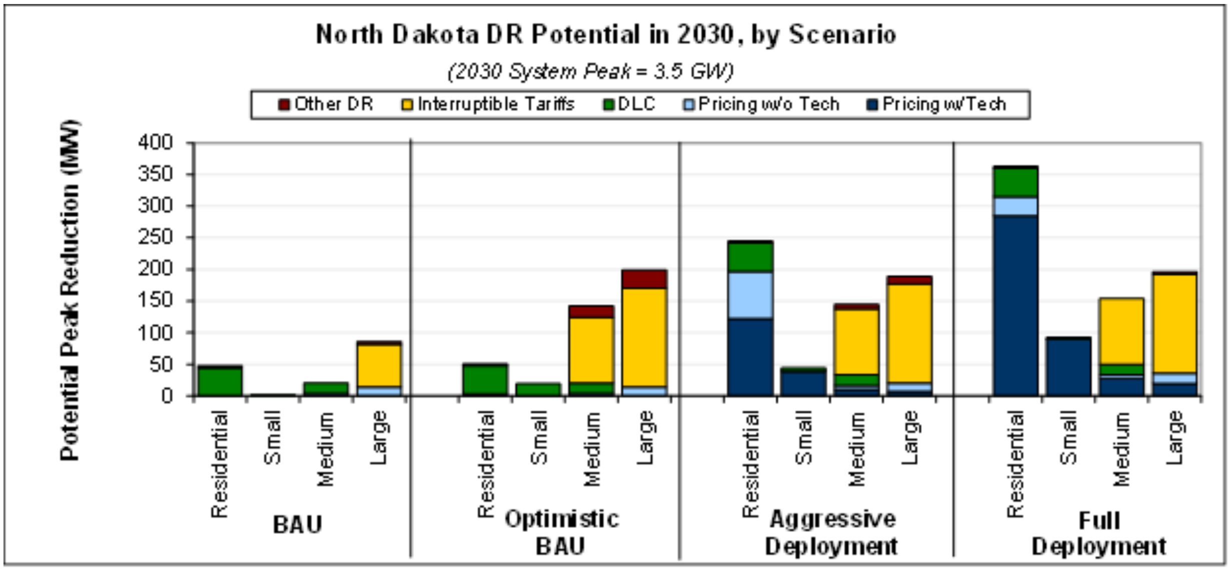
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	2	0.0%	0	0.0%	3	0.0%	102	0.3%	107	0.3%
Automated/Direct Load Control	246	0.8%	1	0.0%	18	0.1%	0	0.0%	265	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	1	0.0%	1,162	3.7%	1,163	3.7%
Other DR Programs	1	0.0%	0	0.0%	0	0.0%	222	0.7%	222	0.7%
Total	249	0.8%	1	0.0%	21	0.1%	1,486	4.7%	1,757	5.5%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	118	0.4%	0	0.0%	9	0.0%	102	0.3%	229	0.7%
Automated/Direct Load Control	987	3.1%	268	0.8%	25	0.1%	0	0.0%	1,280	4.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	2,658	8.4%	1,937	6.1%	4,594	14.5%
Other DR Programs	1	0.0%	0	0.0%	707	2.2%	1,833	5.8%	2,541	8.0%
Total	1,105	3.5%	269	0.8%	3,399	10.7%	3,871	12.2%	8,644	27.3%
Aggressive Deployment										
Pricing with Technology	3,625	11.4%	280	0.9%	194	0.6%	74	0.2%	4,174	13.2%
Pricing without Technology	1,677	5.3%	5	0.0%	116	0.4%	135	0.4%	1,933	6.1%
Automated/Direct Load Control	253	0.8%	69	0.2%	18	0.1%	0	0.0%	339	1.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	2,658	8.4%	1,937	6.1%	4,594	14.5%
Other DR Programs	1	0.0%	0	0.0%	290	0.9%	751	2.4%	1,041	3.3%
Total	5,556	17.5%	354	1.1%	3,274	10.3%	2,897	9.1%	12,081	38.1%
Full Deployment										
Pricing with Technology	8,480	26.8%	656	2.1%	566	1.8%	217	0.7%	9,920	31.3%
Pricing without Technology	152	0.5%	3	0.0%	56	0.2%	175	0.6%	386	1.2%
Automated/Direct Load Control	246	0.8%	1	0.0%	18	0.1%	0	0.0%	265	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	2,658	8.4%	1,937	6.1%	4,594	14.5%
Other DR Programs	1	0.0%	0	0.0%	0	0.0%	222	0.7%	222	0.7%
Total	8,880	28.0%	660	2.1%	3,298	10.4%	2,551	8.1%	15,388	48.6%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in North Carolina by Scenario, Pricing Program and Price Ratio (MW)

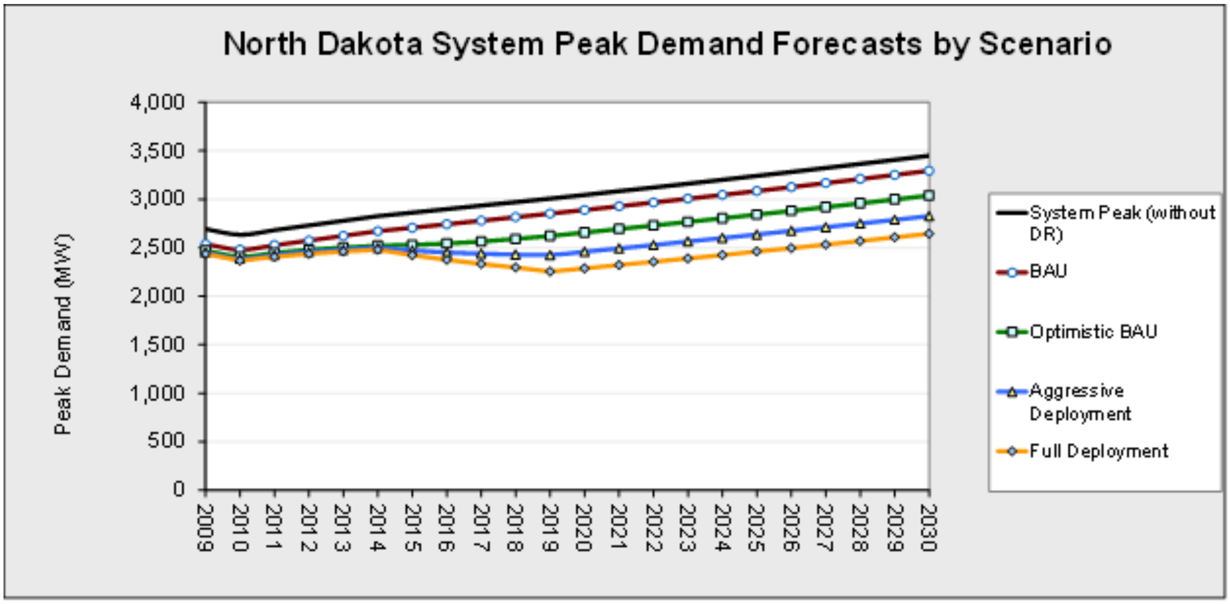
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	105	105	105	105	105	105	105	105	105	105	105	105
10	105	105	105	105	105	105	105	105	105	105	105	105
15	105	105	105	105	105	105	105	105	105	105	105	105
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	135	113	158	185	125	245	191	127	256	198	129	267
10	150	114	186	223	130	316	232	132	331	241	134	347
15	162	123	202	255	153	357	266	157	375	278	160	395
Aggressive Deployment												
Pricing with Technology												
5	818	238	1398	2872	835	4908	3074	894	5253	3290	957	5623
10	1185	381	1989	4162	1338	6985	4455	1432	7477	4768	1533	8004
15	1441	469	2412	5059	1648	8470	5415	1764	9066	5796	1888	9705
Pricing without Technology												
5	452	204	700	1360	434	2286	1453	457	2449	1554	483	2624
8	611	266	955	1966	653	3278	2103	696	3510	2251	742	3759
15	721	304	1138	2391	797	3985	2559	850	4267	2738	907	4569
Full Deployment												
Pricing with Technology												
5	1866	524	3208	6535	1834	11235	6994	1963	12025	7486	2101	12871
10	2821	800	4841	9880	2803	16956	10574	3000	18148	11318	3211	19425
15	3377	872	5882	11826	3053	20600	12658	3267	22048	13548	3497	23599
Pricing without Technology												
5	142	113	171	297	116	478	316	119	512	336	123	549
10	165	118	212	445	145	745	474	152	797	505	158	853
15	183	112	254	533	151	916	568	157	979	606	165	1047

North Dakota State Profile



Total Potential Peak Reduction from Demand Response in North Dakota, 2030

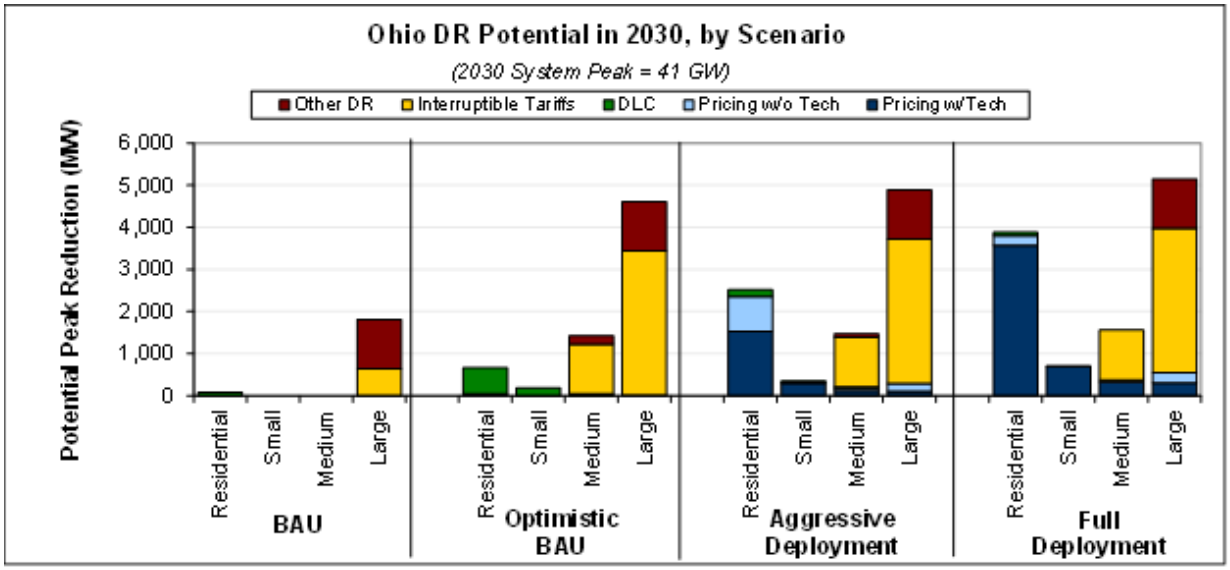
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	4	0.1%	14	0.5%	17	0.6%
Automated/Direct Load Control	45	1.5%	2	0.1%	17	0.6%	0	0.0%	63	2.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	68	2.3%	68	2.3%
Other DR Programs	3	0.1%	0	0.0%	0	0.0%	4	0.1%	7	0.2%
Total	47	1.6%	2	0.1%	20	0.7%	86	2.9%	156	5.2%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	3	0.1%	0	0.0%	4	0.1%	14	0.5%	21	0.7%
Automated/Direct Load Control	45	1.5%	19	0.6%	17	0.6%	0	0.0%	81	2.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	104	3.5%	156	5.2%	260	8.7%
Other DR Programs	3	0.1%	0	0.0%	18	0.6%	29	1.0%	49	1.6%
Total	51	1.7%	19	0.6%	142	4.7%	199	6.6%	411	13.7%
Aggressive Deployment										
Pricing with Technology	122	4.0%	38	1.3%	10	0.3%	7	0.2%	177	5.9%
Pricing without Technology	75	2.5%	1	0.0%	7	0.2%	14	0.5%	97	3.2%
Automated/Direct Load Control	45	1.5%	5	0.2%	17	0.6%	0	0.0%	66	2.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	104	3.5%	156	5.2%	260	8.7%
Other DR Programs	3	0.1%	0	0.0%	7	0.2%	12	0.4%	22	0.7%
Total	245	8.1%	44	1.5%	145	4.8%	189	6.3%	622	20.7%
Full Deployment										
Pricing with Technology	285	9.5%	90	3.0%	28	0.9%	20	0.7%	423	14.0%
Pricing without Technology	31	1.0%	0	0.0%	5	0.2%	16	0.5%	52	1.7%
Automated/Direct Load Control	45	1.5%	2	0.1%	17	0.6%	0	0.0%	63	2.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	104	3.5%	156	5.2%	260	8.7%
Other DR Programs	3	0.1%	0	0.0%	0	0.0%	4	0.1%	7	0.2%
Total	363	12.1%	92	3.1%	154	5.1%	196	6.5%	805	26.8%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in North Dakota by Scenario, Pricing Program and Price Ratio (MW)

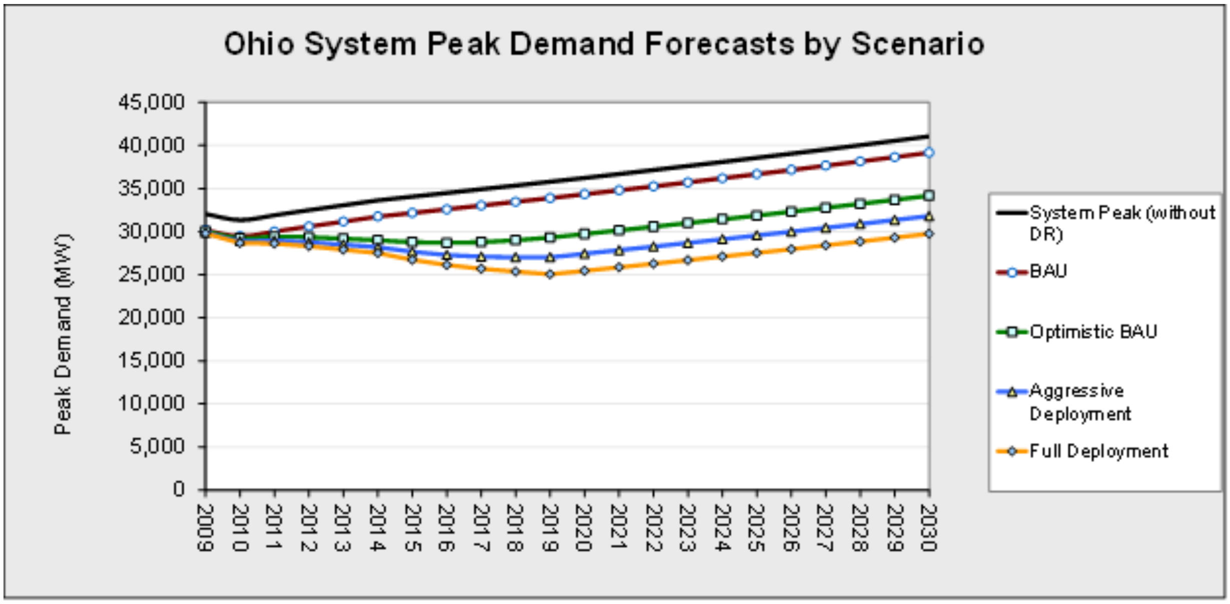
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	16	16	16	16	16	16	16	16	16	16	16	16
10	16	16	16	16	16	16	16	16	16	16	16	16
15	16	16	16	16	16	16	16	16	16	16	16	16
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	18	18	19	20	18	21	20	18	21	20	18	22
10	19	18	20	21	18	23	21	18	23	21	18	24
15	19	18	21	22	19	25	22	19	25	22	19	25
Aggressive Deployment												
Pricing with Technology												
5	36	11	61	128	40	216	132	41	223	136	42	230
10	56	19	93	196	66	327	203	68	337	209	70	348
15	66	20	112	232	71	393	240	74	406	248	76	419
Pricing without Technology												
5	33	22	43	74	32	116	76	33	119	78	33	123
8	41	25	57	110	42	179	114	42	185	117	43	191
15	46	26	66	131	45	218	135	46	225	139	47	232
Full Deployment												
Pricing with Technology												
5	83	17	148	290	60	520	299	62	537	309	64	554
10	138	49	227	485	173	797	501	178	823	517	184	850
15	162	62	261	568	219	917	586	226	946	605	234	977
Pricing without Technology												
5	23	19	28	41	18	64	42	18	66	43	17	69
10	27	21	34	65	27	103	67	28	107	69	28	111
15	29	22	36	76	32	121	79	33	125	82	34	129

Ohio State Profile



Total Potential Peak Reduction from Demand Response in Ohio, 2030

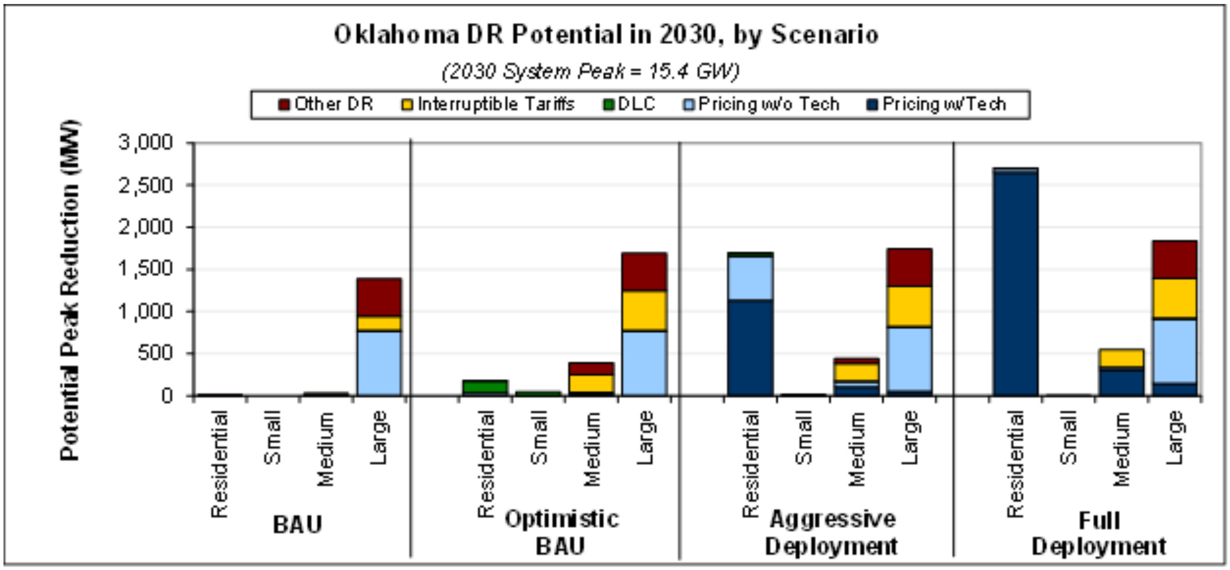
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	5	0.0%	5	0.0%
Automated/Direct Load Control	80	0.2%	0	0.0%	0	0.0%	0	0.0%	80	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	633	1.8%	633	1.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,174	3.3%	1,174	3.3%
Total	80	0.2%	0	0.0%	0	0.0%	1,812	5.1%	1,892	5.3%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	45	0.1%	0	0.0%	5	0.0%	8	0.0%	57	0.2%
Automated/Direct Load Control	623	1.7%	186	0.5%	37	0.1%	0	0.0%	846	2.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	1,184	3.3%	3,428	9.6%	4,612	12.9%
Other DR Programs	0	0.0%	0	0.0%	201	0.6%	1,174	3.3%	1,374	3.8%
Total	668	1.9%	186	0.5%	1,426	4.0%	4,609	12.9%	6,889	19.2%
Aggressive Deployment										
Pricing with Technology	1,526	4.3%	299	0.8%	110	0.3%	103	0.3%	2,039	5.7%
Pricing without Technology	831	2.3%	6	0.0%	79	0.2%	188	0.5%	1,104	3.1%
Automated/Direct Load Control	159	0.4%	47	0.1%	15	0.0%	0	0.0%	221	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	1,184	3.3%	3,428	9.6%	4,612	12.9%
Other DR Programs	0	0.0%	0	0.0%	82	0.2%	1,174	3.3%	1,256	3.5%
Total	2,516	7.0%	352	1.0%	1,471	4.1%	4,893	13.7%	9,231	25.8%
Full Deployment										
Pricing with Technology	3,570	10.0%	698	2.0%	323	0.9%	302	0.8%	4,894	13.7%
Pricing without Technology	231	0.6%	3	0.0%	54	0.2%	244	0.7%	532	1.5%
Automated/Direct Load Control	80	0.2%	0	0.0%	0	0.0%	0	0.0%	80	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	1,184	3.3%	3,428	9.6%	4,612	12.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,174	3.3%	1,174	3.3%
Total	3,881	10.8%	702	2.0%	1,561	4.4%	5,147	14.4%	11,291	31.5%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in Ohio by Scenario, Pricing Program and Price Ratio (MW)

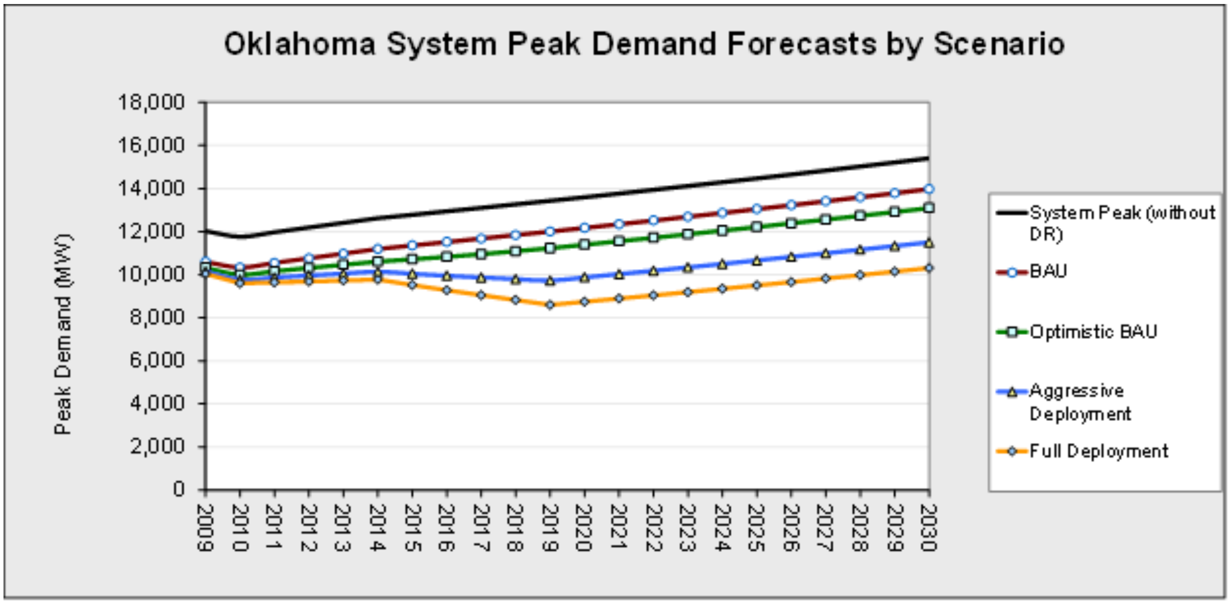
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	4	4	4	4	4	4	4	4	4	4	4	4
10	4	4	4	4	4	4	4	4	4	4	4	4
15	4	4	4	4	4	4	4	4	4	4	4	4
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	41	14	67	45	16	75	46	16	76	47	16	77
10	58	16	100	65	18	112	66	18	114	67	18	115
15	72	22	122	81	25	136	82	25	138	83	25	140
Aggressive Deployment												
Pricing with Technology												
5	732	242	1222	1562	516	2608	1583	523	2642	1604	530	2678
10	1046	276	1816	2233	589	3877	2262	596	3928	2293	604	3981
15	1320	406	2235	2819	867	4770	2856	879	4833	2894	891	4897
Pricing without Technology												
5	417	138	695	874	290	1457	886	294	1478	898	298	1499
8	599	159	1038	1255	333	2177	1273	338	2207	1291	343	2239
15	758	235	1281	1588	492	2685	1611	499	2722	1634	506	2761
Full Deployment												
Pricing with Technology												
5	1770	655	2885	3766	1393	6139	3819	1413	6225	3873	1433	6313
10	2643	772	4514	5625	1643	9607	5704	1666	9741	5784	1690	9878
15	3090	1000	5181	6577	2127	11026	6668	2157	11179	6762	2188	11337
Pricing without Technology												
5	219	82	357	447	167	727	459	171	746	470	176	765
10	331	98	563	674	200	1147	691	206	1177	709	211	1207
15	389	128	650	792	261	1324	813	267	1358	834	274	1393

Oklahoma State Profile



Total Potential Peak Reduction from Demand Response in Oklahoma, 2030

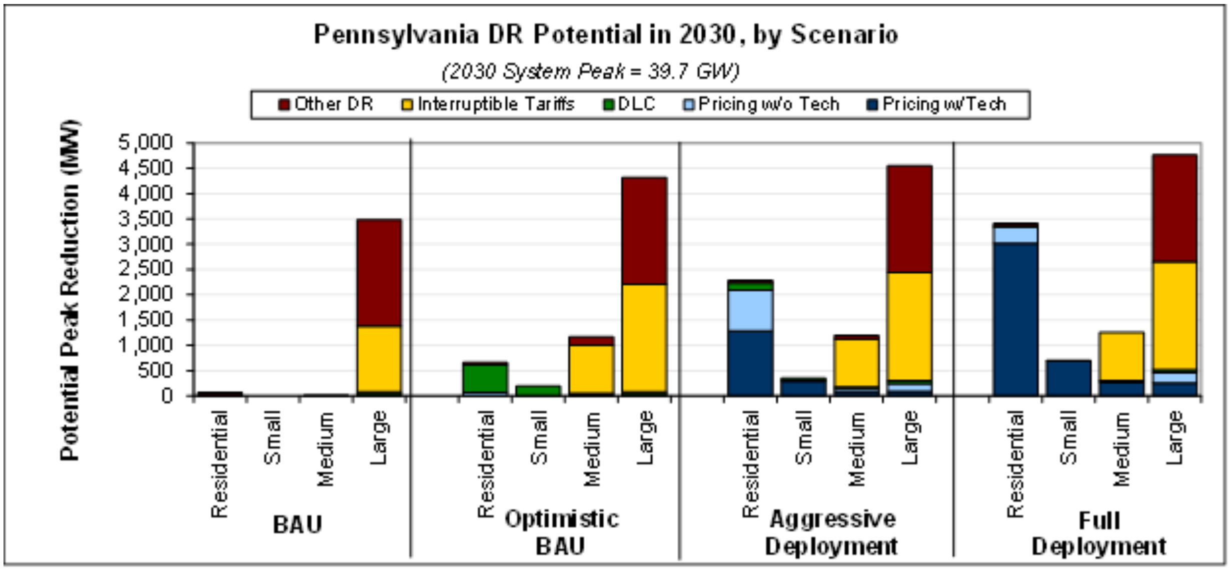
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	7	0.0%	0	0.0%	22	0.2%	762	5.7%	790	5.9%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	12	0.1%	12	0.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	7	0.0%	169	1.3%	176	1.3%
Other DR Programs	4	0.0%	0	0.0%	0	0.0%	444	3.3%	448	3.3%
Total	11	0.1%	0	0.0%	29	0.2%	1,386	10.3%	1,426	10.6%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	32	0.2%	0	0.0%	22	0.2%	762	5.7%	816	6.1%
Automated/Direct Load Control	146	1.1%	48	0.4%	16	0.1%	12	0.1%	222	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	211	1.6%	475	3.5%	686	5.1%
Other DR Programs	4	0.0%	0	0.0%	140	1.0%	444	3.3%	588	4.4%
Total	182	1.4%	48	0.4%	390	2.9%	1,691	12.6%	2,312	17.2%
Aggressive Deployment										
Pricing with Technology	1,131	8.4%	0	0.0%	105	0.8%	50	0.4%	1,286	9.6%
Pricing without Technology	525	3.9%	2	0.0%	63	0.5%	762	5.7%	1,352	10.1%
Automated/Direct Load Control	37	0.3%	12	0.1%	7	0.0%	12	0.1%	68	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	211	1.6%	475	3.5%	686	5.1%
Other DR Programs	4	0.0%	0	0.0%	57	0.4%	444	3.3%	505	3.8%
Total	1,698	12.6%	15	0.1%	443	3.3%	1,741	13.0%	3,897	29.0%
Full Deployment										
Pricing with Technology	2,646	19.7%	0	0.0%	308	2.3%	146	1.1%	3,100	23.1%
Pricing without Technology	50	0.4%	3	0.0%	31	0.2%	762	5.7%	845	6.3%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	12	0.1%	12	0.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	211	1.6%	475	3.5%	686	5.1%
Other DR Programs	4	0.0%	0	0.0%	0	0.0%	444	3.3%	448	3.3%
Total	2,700	20.1%	3	0.0%	550	4.1%	1,838	13.7%	5,091	37.9%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in Oklahoma by Scenario, Pricing Program and Price Ratio (MW)

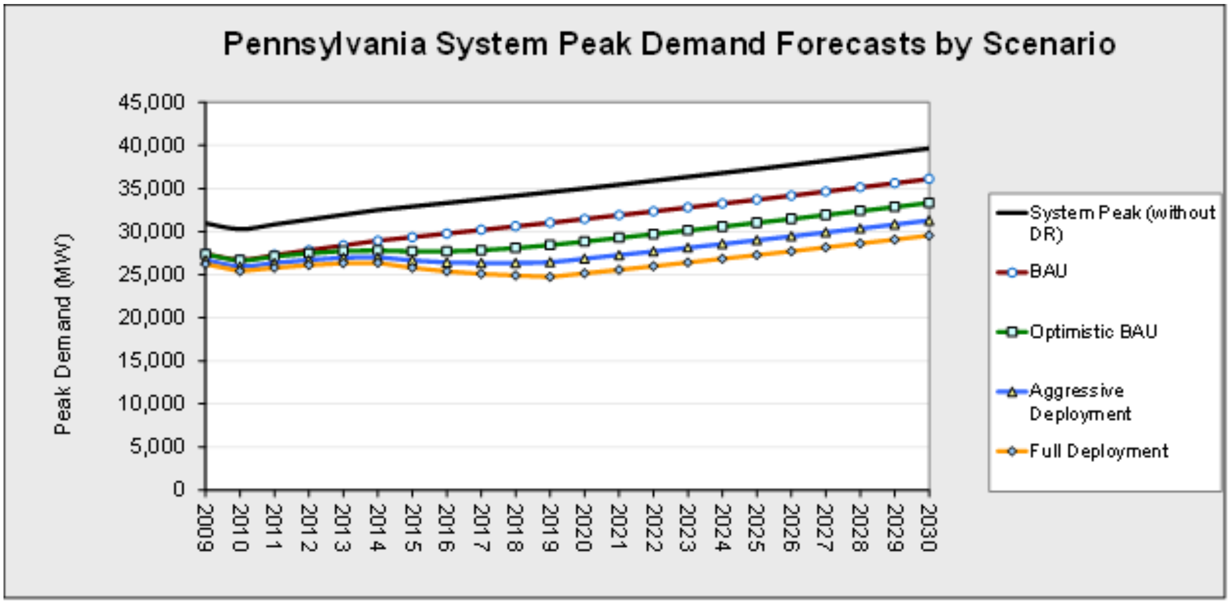
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	789	789	789	789	789	789	789	789	789	789	789	789
10	789	789	789	789	789	789	789	789	789	789	789	789
15	789	789	789	789	789	789	789	789	789	789	789	789
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	804	790	817	808	791	825	809	792	826	809	792	827
10	812	791	833	819	793	845	820	793	846	820	793	848
15	818	795	841	826	797	855	827	797	856	828	798	858
Aggressive Deployment												
Pricing with Technology												
5	428	146	710	963	328	1599	987	336	1638	1012	344	1679
10	647	176	1117	1456	397	2515	1492	407	2578	1530	417	2642
15	734	197	1270	1652	443	2861	1693	454	2932	1735	465	3005
Pricing without Technology												
5	960	841	1079	1199	914	1483	1209	918	1501	1220	921	1519
8	1058	850	1265	1424	944	1903	1439	948	1931	1456	952	1959
15	1097	859	1336	1513	964	2063	1531	968	2095	1550	973	2127
Full Deployment												
Pricing with Technology												
5	987	259	1716	2225	584	3866	2283	599	3966	2342	615	4070
10	1519	459	2579	3422	1035	5810	3511	1062	5961	3603	1089	6116
15	1813	526	3100	4085	1184	6986	4191	1215	7167	4300	1247	7354
Pricing without Technology												
5	801	789	812	823	791	856	825	790	859	826	790	863
10	810	792	828	853	796	910	856	796	916	859	797	922
15	816	792	839	871	798	943	875	799	950	879	800	957

Pennsylvania State Profile



Total Potential Peak Reduction from Demand Response in Pennsylvania, 2030

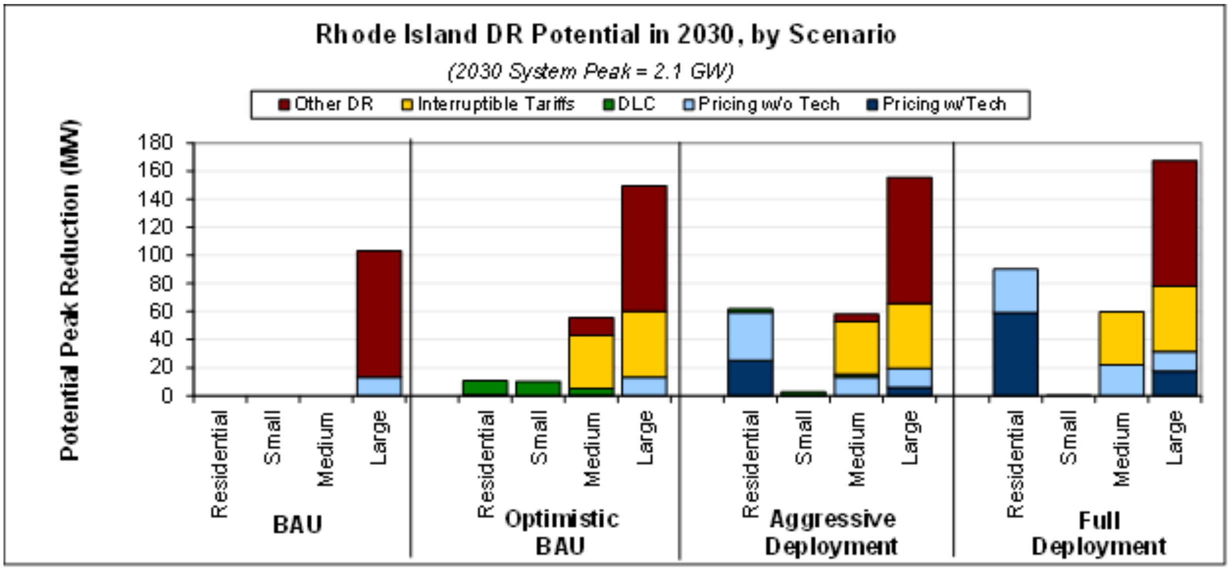
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	1	0.0%	0	0.0%	2	0.0%	15	0.0%	18	0.1%
Automated/Direct Load Control	20	0.1%	0	0.0%	0	0.0%	60	0.2%	80	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	1	0.0%	1,300	3.8%	1,301	3.8%
Other DR Programs	48	0.1%	0	0.0%	0	0.0%	2,108	6.1%	2,156	6.2%
Total	69	0.2%	0	0.0%	3	0.0%	3,483	10.1%	3,555	10.3%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	65	0.2%	0	0.0%	6	0.0%	15	0.0%	87	0.3%
Automated/Direct Load Control	545	1.6%	190	0.6%	45	0.1%	60	0.2%	841	2.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	954	2.8%	2,131	6.2%	3,085	8.9%
Other DR Programs	48	0.1%	0	0.0%	159	0.5%	2,108	6.1%	2,315	6.7%
Total	658	1.9%	191	0.6%	1,164	3.4%	4,314	12.5%	6,328	18.3%
Aggressive Deployment										
Pricing with Technology	1,286	3.7%	296	0.9%	90	0.3%	87	0.3%	1,759	5.1%
Pricing without Technology	807	2.3%	6	0.0%	63	0.2%	158	0.5%	1,033	3.0%
Automated/Direct Load Control	141	0.4%	49	0.1%	19	0.1%	60	0.2%	269	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	954	2.8%	2,131	6.2%	3,085	8.9%
Other DR Programs	48	0.1%	0	0.0%	66	0.2%	2,108	6.1%	2,222	6.4%
Total	2,281	6.6%	351	1.0%	1,192	3.4%	4,544	13.1%	8,368	24.2%
Full Deployment										
Pricing with Technology	3,008	8.7%	693	2.0%	264	0.8%	253	0.7%	4,217	12.2%
Pricing without Technology	336	1.0%	4	0.0%	42	0.1%	204	0.6%	586	1.7%
Automated/Direct Load Control	20	0.1%	0	0.0%	0	0.0%	60	0.2%	80	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	954	2.8%	2,131	6.2%	3,085	8.9%
Other DR Programs	48	0.1%	0	0.0%	0	0.0%	2,108	6.1%	2,156	6.2%
Total	3,412	9.9%	696	2.0%	1,259	3.6%	4,757	13.8%	10,124	29.3%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in Pennsylvania by Scenario, Pricing Program and Price Ratio (MW)

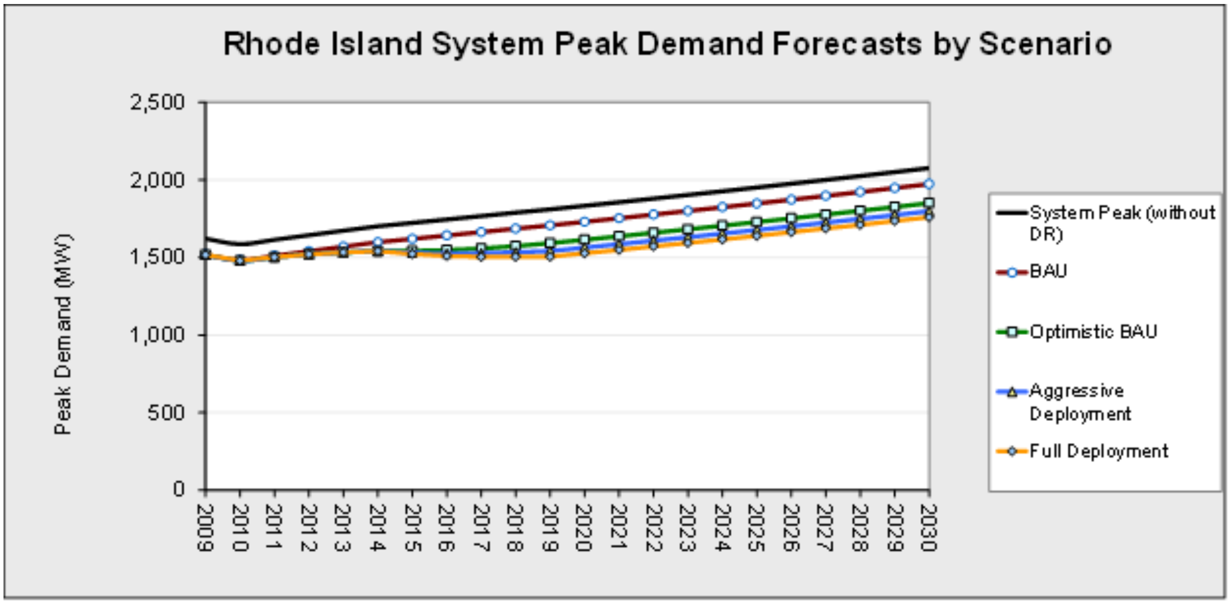
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	16	16	16	16	16	16	16	16	16	16	16	16
10	16	16	16	16	16	16	16	16	16	16	16	16
15	16	16	16	16	16	16	16	16	16	16	16	16
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	51	29	74	71	36	107	72	36	108	73	36	110
10	67	30	103	97	37	158	98	37	160	99	37	162
15	78	32	123	116	41	192	118	41	194	119	41	197
Aggressive Deployment												
Pricing with Technology												
5	650	211	1090	1350	438	2263	1368	443	2292	1385	449	2322
10	983	305	1661	2041	633	3450	2067	641	3494	2094	649	3539
15	1154	302	2007	2397	627	4167	2428	635	4221	2459	643	4276
Pricing without Technology												
5	399	130	667	816	266	1366	826	269	1383	837	272	1401
8	607	189	1024	1241	387	2096	1257	392	2122	1273	397	2149
15	715	189	1241	1463	386	2540	1482	391	2572	1500	396	2605
Full Deployment												
Pricing with Technology												
5	1563	499	2627	3235	1033	5437	3278	1046	5509	3321	1060	5582
10	2260	646	3874	4677	1336	8018	4739	1354	8124	4802	1372	8231
15	2828	937	4719	5854	1939	9768	5931	1965	9897	6009	1991	10027
Pricing without Technology												
5	241	78	405	484	156	811	491	159	824	499	161	837
10	353	103	603	708	206	1210	719	209	1229	730	213	1248
15	445	150	739	892	301	1483	906	306	1506	920	310	1529

Rhode Island State Profile



Total Potential Peak Reduction from Demand Response in Rhode Island, 2030

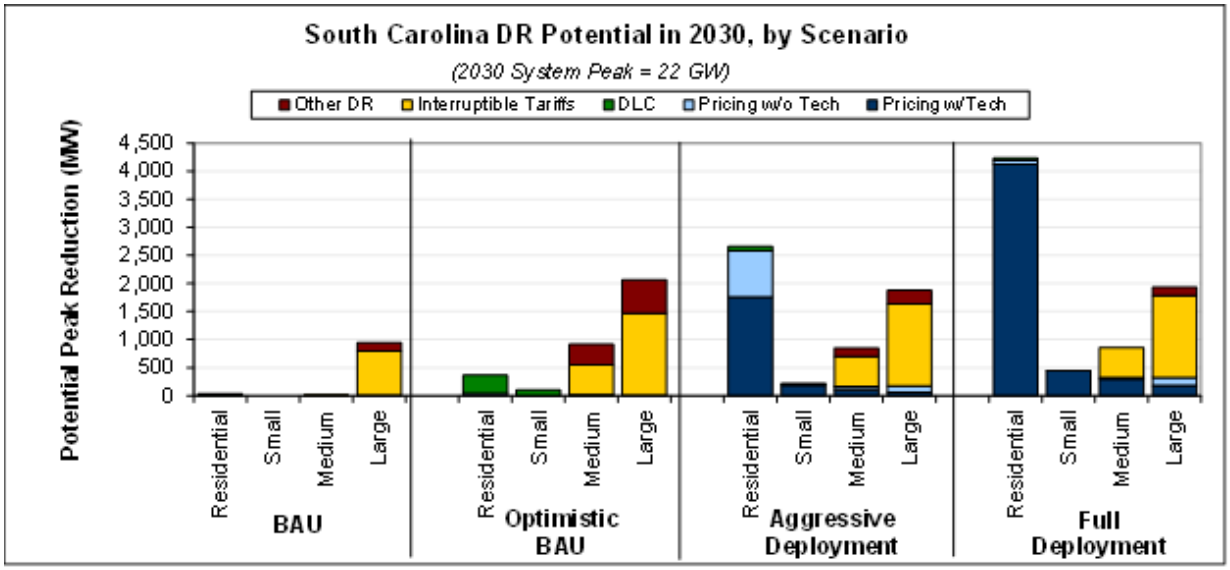
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	13	0.7%	13	0.7%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	90	4.9%	90	4.9%
Total	0	0.0%	0	0.0%	0	0.0%	103	5.7%	103	5.7%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	1	0.0%	0	0.0%	0	0.0%	13	0.7%	15	0.8%
Automated/Direct Load Control	10	0.5%	10	0.6%	5	0.3%	0	0.0%	25	1.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	38	2.1%	47	2.6%	84	4.6%
Other DR Programs	0	0.0%	0	0.0%	13	0.7%	90	4.9%	102	5.6%
Total	11	0.6%	10	0.6%	56	3.1%	150	8.3%	226	12.5%
Aggressive Deployment										
Pricing with Technology	25	1.4%	0	0.0%	0	0.0%	6	0.3%	31	1.7%
Pricing without Technology	34	1.9%	0	0.0%	13	0.7%	13	0.7%	61	3.4%
Automated/Direct Load Control	3	0.1%	3	0.1%	2	0.1%	0	0.0%	7	0.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	38	2.1%	47	2.6%	84	4.6%
Other DR Programs	0	0.0%	0	0.0%	5	0.3%	90	4.9%	95	5.2%
Total	62	3.4%	3	0.2%	58	3.2%	155	8.6%	278	15.4%
Full Deployment										
Pricing with Technology	59	3.3%	0	0.0%	0	0.0%	17	1.0%	76	4.2%
Pricing without Technology	31	1.7%	0	0.0%	22	1.2%	14	0.8%	67	3.7%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	38	2.1%	47	2.6%	84	4.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	90	4.9%	90	4.9%
Total	90	5.0%	0	0.0%	60	3.3%	167	9.2%	318	17.5%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in Rhode Island by Scenario, Pricing Program and Price Ratio (MW)

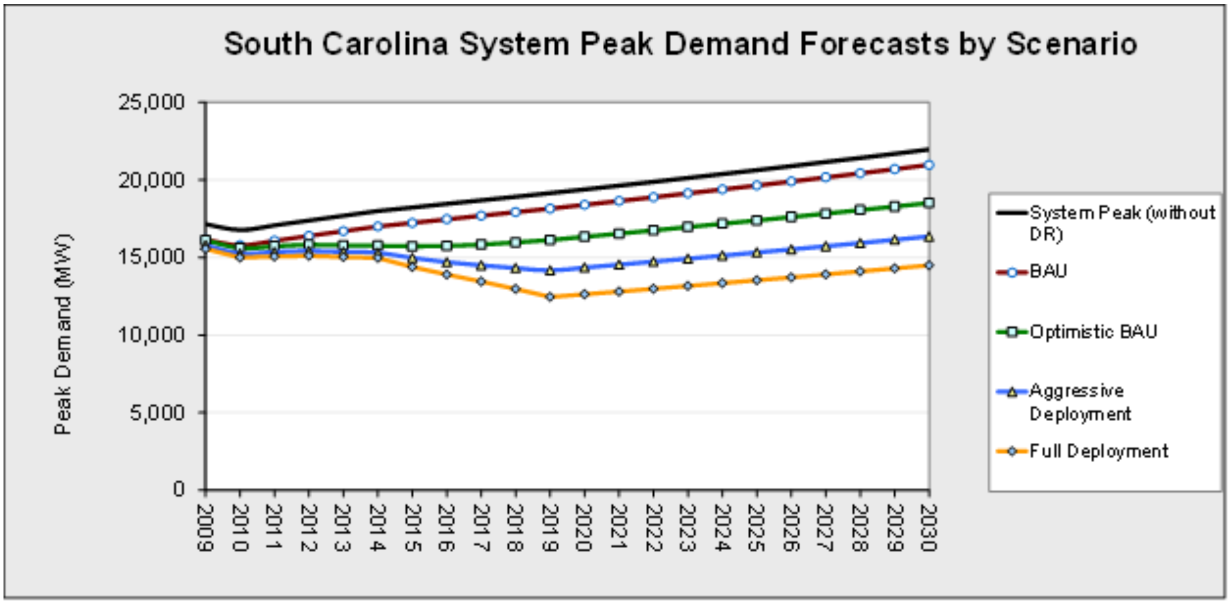
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	13	13	13	13	13	13	13	13	13	13	13	13
10	13	13	13	13	13	13	13	13	13	13	13	13
15	13	13	13	13	13	13	13	13	13	13	13	13
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	14	14	14	14	14	15	14	14	15	14	14	15
10	14	14	14	15	14	15	15	14	15	15	14	16
15	14	14	14	15	14	16	15	14	16	15	14	16
Aggressive Deployment												
Pricing with Technology												
5	5	1	9	24	5	44	25	5	44	25	5	45
10	7	2	12	35	9	60	36	9	62	36	10	63
15	9	4	15	47	18	75	48	19	77	49	19	78
Pricing without Technology												
5	20	15	26	49	20	77	49	20	79	50	20	81
8	24	16	31	67	24	110	68	24	112	70	24	115
15	27	19	35	88	37	138	90	38	142	92	39	145
Full Deployment												
Pricing with Technology												
5	12	3	21	59	14	104	60	15	106	62	15	108
10	18	5	30	87	27	147	89	28	151	91	28	154
15	20	5	36	101	26	176	104	27	180	106	28	184
Pricing without Technology												
5	21	15	27	53	20	86	54	20	88	56	20	91
10	25	17	33	77	28	126	79	28	130	81	29	133
15	27	17	37	90	27	153	92	28	157	95	28	161

South Carolina State Profile



Total Potential Peak Reduction from Demand Response in South Carolina, 2030

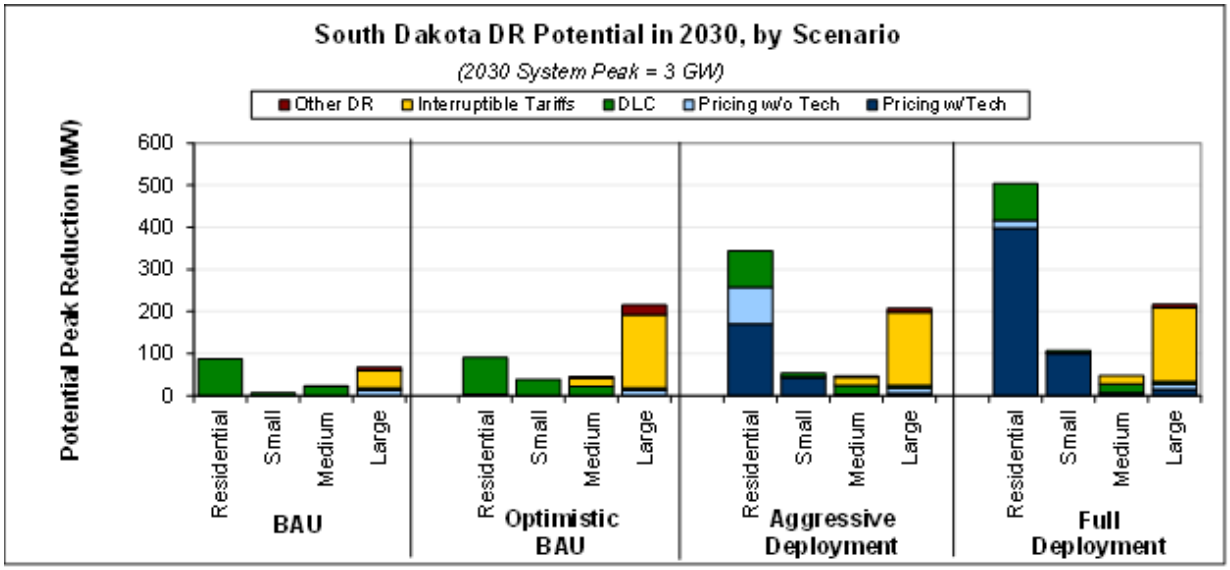
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	1	0.0%	7	0.0%	8	0.0%
Automated/Direct Load Control	37	0.2%	0	0.0%	0	0.0%	0	0.0%	37	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	15	0.1%	784	4.1%	799	4.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	151	0.8%	151	0.8%
Total	37	0.2%	0	0.0%	16	0.1%	942	4.9%	995	5.2%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	44	0.2%	0	0.0%	4	0.0%	7	0.0%	55	0.3%
Automated/Direct Load Control	319	1.7%	102	0.5%	10	0.1%	0	0.0%	430	2.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	537	2.8%	1,458	7.6%	1,995	10.4%
Other DR Programs	0	0.0%	0	0.0%	368	1.9%	601	3.1%	970	5.1%
Total	363	1.9%	102	0.5%	918	4.8%	2,067	10.8%	3,450	18.0%
Aggressive Deployment										
Pricing with Technology	1,763	9.2%	191	1.0%	100	0.5%	62	0.3%	2,116	11.0%
Pricing without Technology	813	4.2%	3	0.0%	60	0.3%	112	0.6%	988	5.2%
Automated/Direct Load Control	81	0.4%	26	0.1%	4	0.0%	0	0.0%	111	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	537	2.8%	1,458	7.6%	1,995	10.4%
Other DR Programs	0	0.0%	0	0.0%	150	0.8%	245	1.3%	395	2.1%
Total	2,657	13.9%	221	1.2%	851	4.4%	1,877	9.8%	5,605	29.3%
Full Deployment										
Pricing with Technology	4,123	21.5%	447	2.3%	293	1.5%	180	0.9%	5,044	26.3%
Pricing without Technology	71	0.4%	2	0.0%	29	0.2%	145	0.8%	247	1.3%
Automated/Direct Load Control	37	0.2%	0	0.0%	0	0.0%	0	0.0%	37	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	537	2.8%	1,458	7.6%	1,995	10.4%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	151	0.8%	151	0.8%
Total	4,231	22.1%	449	2.3%	859	4.5%	1,935	10.1%	7,474	39.0%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in South Carolina by Scenario, Pricing Program and Price Ratio (MW)

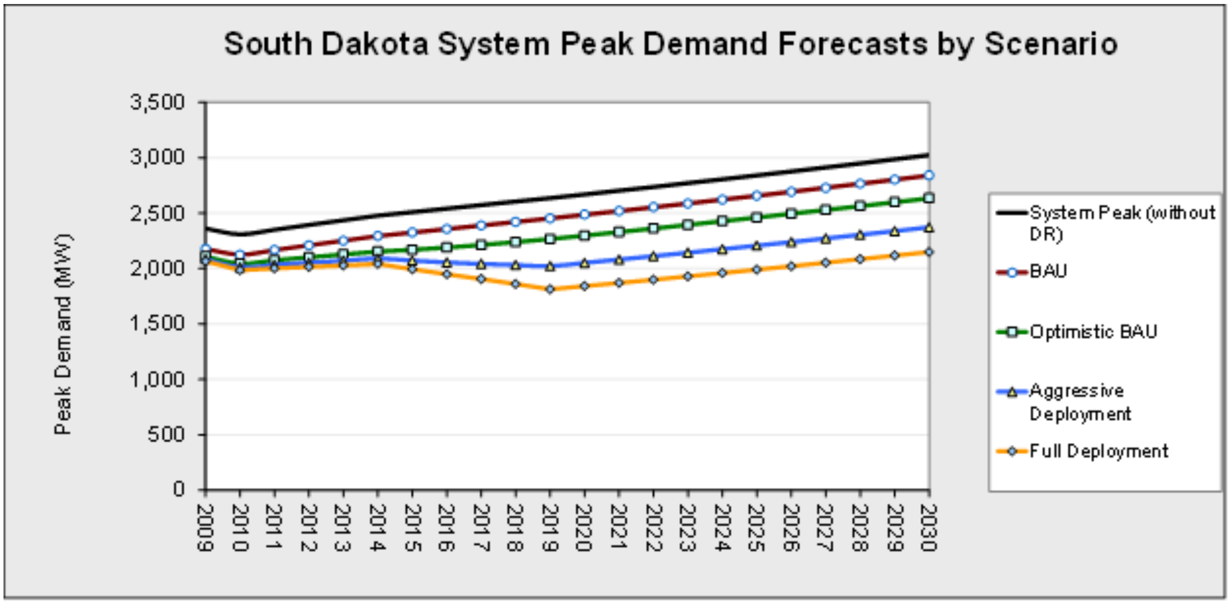
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	7	7	7	7	7	7	7	7	7	7	7	7
10	7	7	7	7	7	7	7	7	7	7	7	7
15	7	7	7	7	7	7	7	7	7	7	7	7
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	29	14	44	40	17	63	42	18	66	44	18	69
10	41	18	65	60	22	97	62	23	101	65	23	106
15	46	17	75	68	22	114	71	22	120	74	23	125
Aggressive Deployment												
Pricing with Technology												
5	528	164	892	1461	454	2468	1530	475	2584	1602	498	2706
10	800	242	1359	2213	668	3757	2317	700	3934	2426	733	4119
15	935	226	1643	2584	626	4543	2706	655	4756	2833	686	4980
Pricing without Technology												
5	255	79	430	699	218	1180	732	228	1236	767	239	1295
8	387	117	656	1061	321	1800	1111	337	1886	1165	353	1976
15	452	110	794	1241	302	2180	1300	316	2284	1362	331	2393
Full Deployment												
Pricing with Technology												
5	1339	420	2258	3696	1159	6234	3872	1214	6530	4055	1271	6839
10	1930	449	3410	5327	1240	9414	5580	1299	9860	5844	1361	10328
15	2297	597	3996	6340	1648	11032	6641	1726	11555	6956	1808	12103
Pricing without Technology												
5	77	25	130	207	66	348	219	70	369	232	74	391
10	112	27	198	300	72	528	318	76	560	337	80	593
15	134	36	232	358	95	621	380	101	658	402	107	698

South Dakota State Profile



Total Potential Peak Reduction from Demand Response in South Dakota, 2030

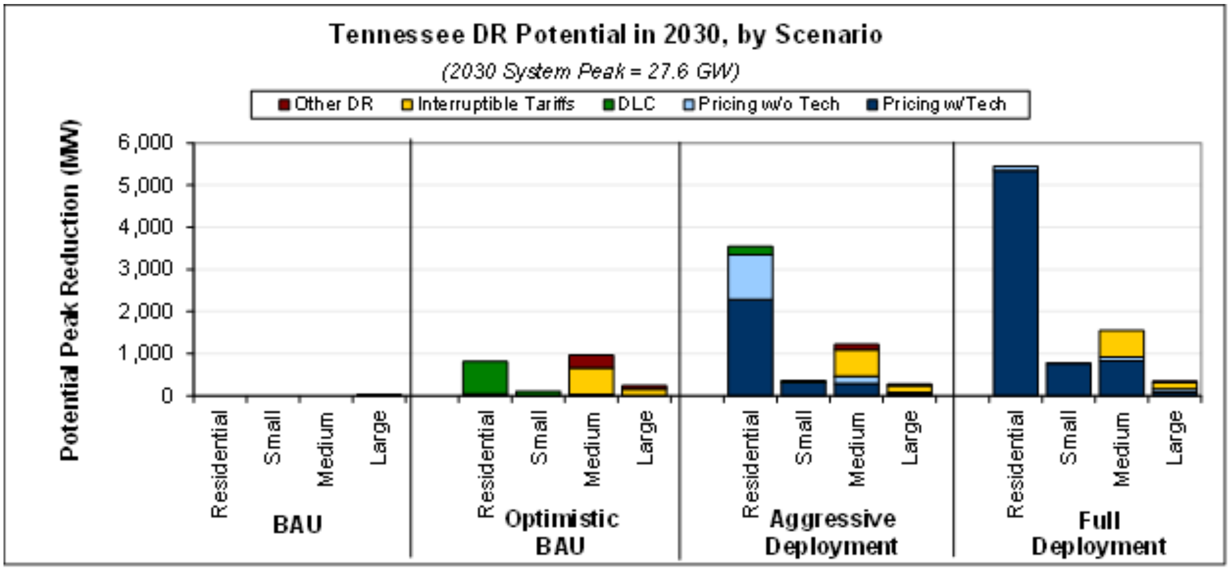
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	13	0.5%	13	0.5%
Automated/Direct Load Control	87	3.3%	6	0.2%	22	0.8%	6	0.2%	121	4.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	1	0.0%	41	1.5%	42	1.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	8	0.3%	8	0.3%
Total	87	3.3%	6	0.2%	23	0.9%	67	2.5%	184	7.0%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	3	0.1%	0	0.0%	0	0.0%	13	0.5%	17	0.6%
Automated/Direct Load Control	87	3.3%	39	1.5%	22	0.8%	6	0.2%	153	5.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	20	0.8%	174	6.6%	194	7.4%
Other DR Programs	0	0.0%	0	0.0%	3	0.1%	23	0.9%	26	1.0%
Total	91	3.4%	39	1.5%	45	1.7%	215	8.2%	390	14.8%
Aggressive Deployment										
Pricing with Technology	170	6.4%	43	1.6%	2	0.1%	5	0.2%	220	8.3%
Pricing without Technology	87	3.3%	1	0.0%	1	0.1%	13	0.5%	102	3.9%
Automated/Direct Load Control	87	3.3%	10	0.4%	22	0.8%	6	0.2%	124	4.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	20	0.8%	174	6.6%	194	7.4%
Other DR Programs	0	0.0%	0	0.0%	1	0.1%	9	0.3%	11	0.4%
Total	345	13.1%	54	2.0%	46	1.7%	207	7.9%	651	24.7%
Full Deployment										
Pricing with Technology	398	15.1%	101	3.8%	5	0.2%	15	0.6%	519	19.7%
Pricing without Technology	19	0.7%	1	0.0%	1	0.0%	13	0.5%	33	1.3%
Automated/Direct Load Control	87	3.3%	6	0.2%	22	0.8%	6	0.2%	121	4.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	20	0.8%	174	6.6%	194	7.4%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	8	0.3%	8	0.3%
Total	504	19.1%	107	4.1%	48	1.8%	216	8.2%	875	33.2%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in South Dakota by Scenario, Pricing Program and Price Ratio (MW)

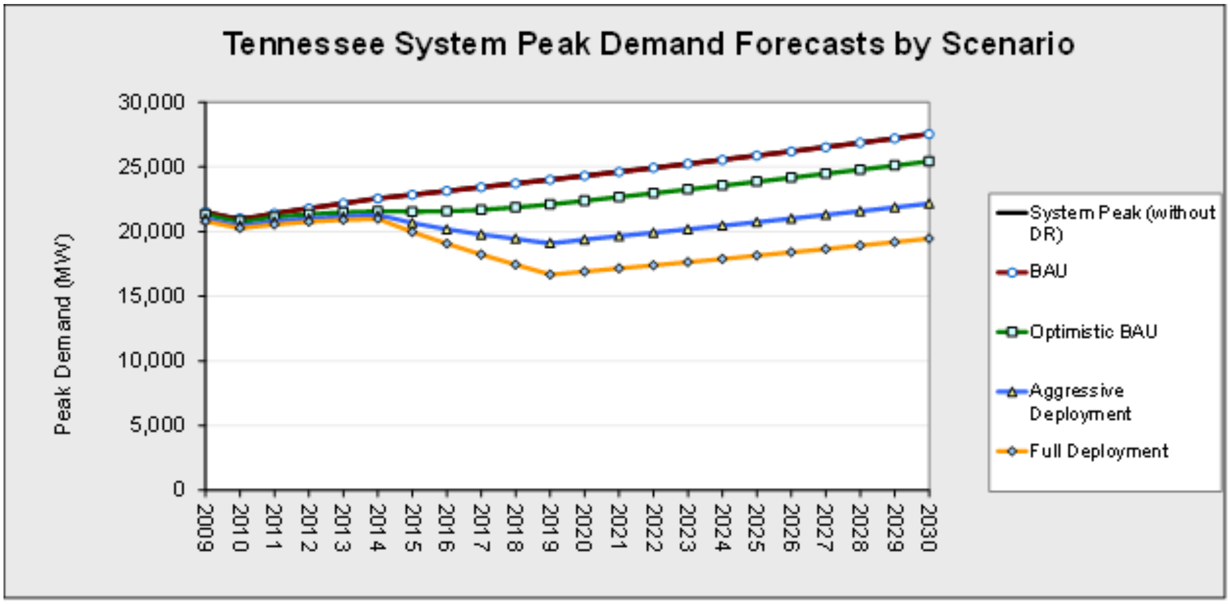
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	12	12	12	12	12	12	12	12	12	12	12	12
10	12	12	12	12	12	12	12	12	12	12	12	12
15	12	12	12	12	12	12	12	12	12	12	12	12
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	15	14	17	16	14	17	16	14	17	16	14	17
10	16	14	19	17	14	19	17	14	19	17	14	20
15	17	14	20	17	14	20	17	14	21	18	14	21
Aggressive Deployment												
Pricing with Technology												
5	63	19	108	162	48	277	167	49	286	173	51	295
10	94	26	161	240	66	414	248	68	427	256	70	441
15	106	31	181	272	79	466	281	81	480	290	84	496
Pricing without Technology												
5	38	20	56	78	32	125	80	32	129	83	33	133
8	51	23	78	113	37	188	116	38	194	119	38	200
15	56	25	87	127	42	213	131	42	220	135	43	227
Full Deployment												
Pricing with Technology												
5	147	43	252	378	109	647	390	113	667	402	116	688
10	215	60	369	551	154	948	569	159	978	587	164	1009
15	260	66	455	669	170	1168	690	175	1205	712	181	1243
Pricing without Technology												
5	19	15	22	28	15	41	29	15	43	30	15	44
10	21	15	27	39	16	63	41	16	65	42	16	68
15	23	16	31	48	16	79	49	16	82	51	16	85

Tennessee State Profile



Total Potential Peak Reduction from Demand Response in Tennessee, 2030

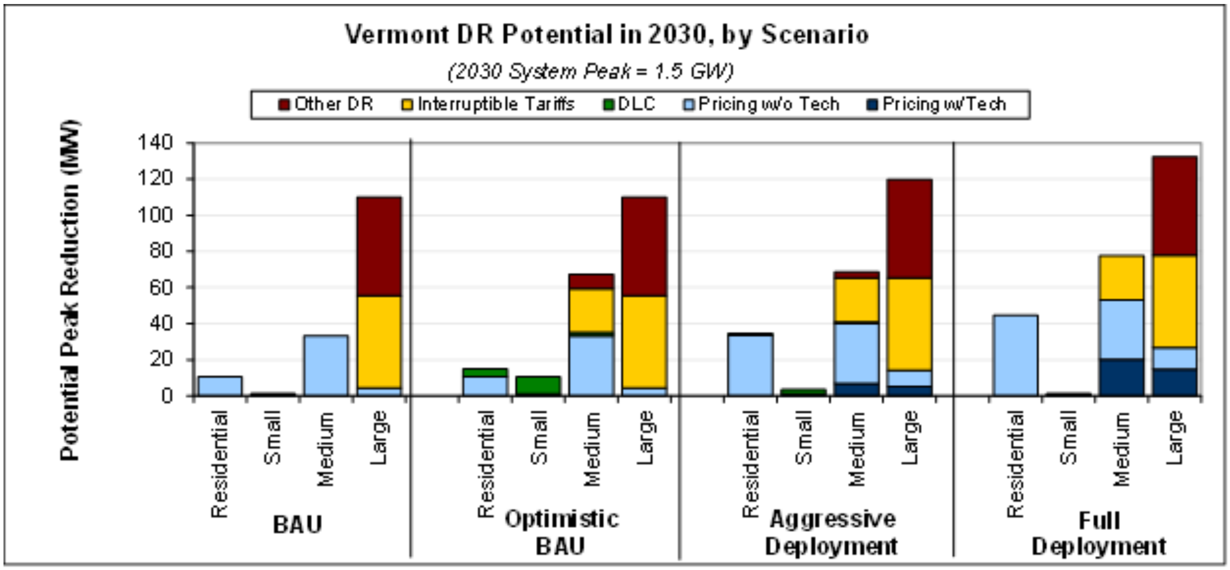
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	29	0.1%	29	0.1%
Total	0	0.0%	0	0.0%	0	0.0%	29	0.1%	29	0.1%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	45	0.2%	0	0.0%	8	0.0%	2	0.0%	55	0.2%
Automated/Direct Load Control	764	3.2%	110	0.5%	24	0.1%	0	0.0%	898	3.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	629	2.6%	159	0.7%	788	3.3%
Other DR Programs	0	0.0%	0	0.0%	307	1.3%	82	0.3%	389	1.6%
Total	809	3.4%	110	0.5%	969	4.0%	242	1.0%	2,130	8.9%
Aggressive Deployment										
Pricing with Technology	2,282	9.5%	327	1.4%	285	1.2%	30	0.1%	2,924	12.2%
Pricing without Technology	1,068	4.4%	6	0.0%	170	0.7%	54	0.2%	1,298	5.4%
Automated/Direct Load Control	194	0.8%	28	0.1%	10	0.0%	0	0.0%	231	1.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	629	2.6%	159	0.7%	788	3.3%
Other DR Programs	0	0.0%	0	0.0%	125	0.5%	33	0.1%	158	0.7%
Total	3,543	14.7%	361	1.5%	1,220	5.1%	276	1.1%	5,399	22.5%
Full Deployment										
Pricing with Technology	5,338	22.2%	765	3.2%	834	3.5%	87	0.4%	7,024	29.2%
Pricing without Technology	112	0.5%	3	0.0%	83	0.3%	70	0.3%	268	1.1%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	629	2.6%	159	0.7%	788	3.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	29	0.1%	29	0.1%
Total	5,450	22.7%	768	3.2%	1,546	6.4%	345	1.4%	8,109	33.7%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in Tennessee by Scenario, Pricing Program and Price Ratio (MW)

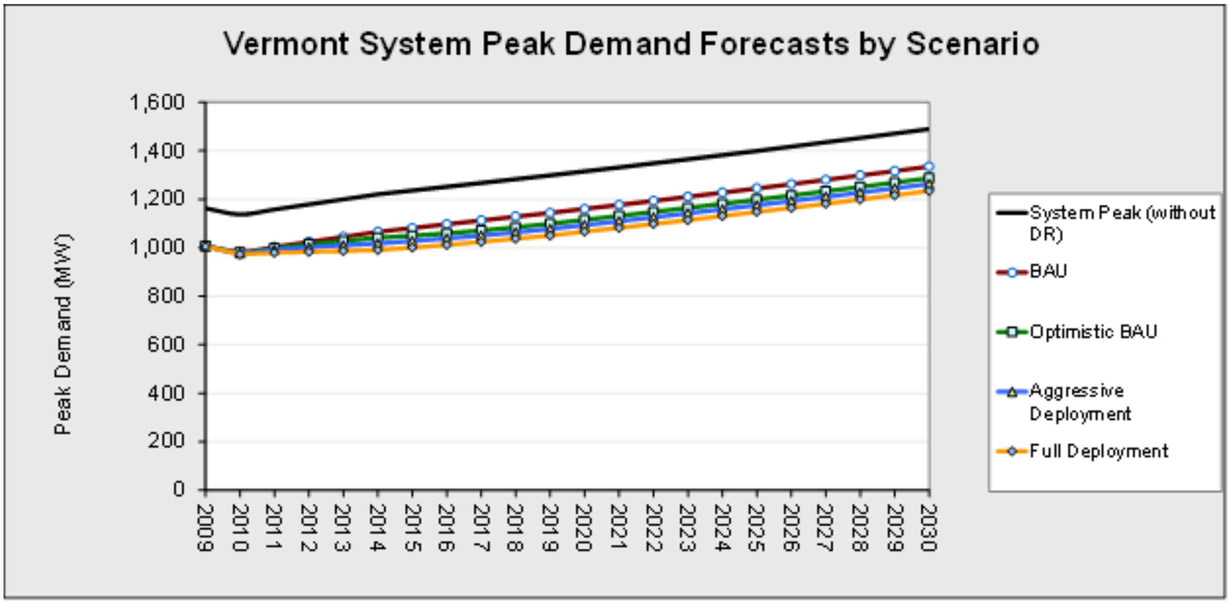
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	19	6	31	39	12	67	41	12	70	43	13	73
10	28	9	46	59	19	99	62	20	103	64	21	108
15	34	12	56	72	26	118	75	27	124	79	28	129
Aggressive Deployment												
Pricing with Technology												
5	591	217	964	2173	800	3547	2270	835	3705	2371	873	3870
10	865	294	1435	3182	1082	5281	3323	1130	5516	3471	1181	5762
15	962	249	1674	3539	918	6161	3697	959	6435	3862	1001	6722
Pricing without Technology												
5	264	97	431	972	358	1585	1015	374	1655	1060	391	1729
8	389	132	645	1429	487	2370	1492	509	2475	1558	531	2585
15	433	113	754	1593	415	2771	1664	433	2894	1738	453	3023
Full Deployment												
Pricing with Technology												
5	1319	435	2203	4853	1601	8106	5070	1672	8467	5296	1747	8845
10	2081	780	3382	7656	2869	12443	7997	2997	12998	8354	3130	13578
15	2287	636	3937	8412	2339	14485	8787	2443	15131	9179	2552	15806
Pricing without Technology												
5	54	18	89	197	66	329	206	69	344	216	72	360
10	86	33	139	315	120	510	330	125	534	345	131	559
15	95	27	163	349	99	598	365	104	626	382	109	655

Vermont State Profile



Total Potential Peak Reduction from Demand Response in Vermont, 2030

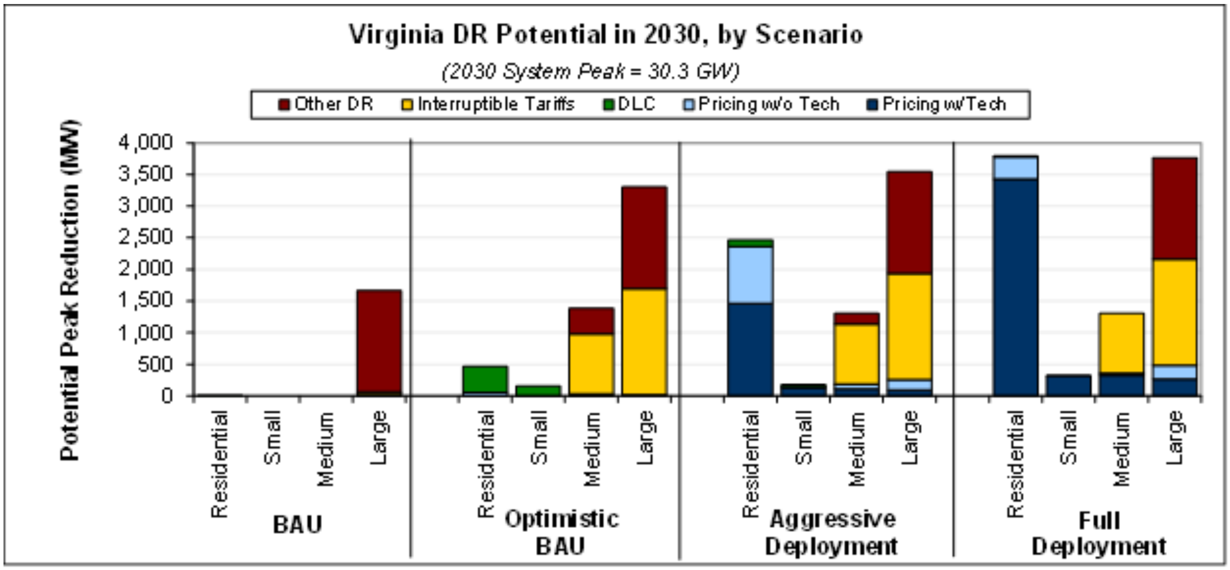
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	11	0.8%	1	0.1%	33	2.6%	4	0.3%	49	3.8%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	51	3.9%	51	3.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	55	4.2%	55	4.2%
Total	11	0.8%	1	0.1%	33	2.6%	110	8.5%	155	11.9%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	11	0.8%	1	0.1%	33	2.6%	4	0.3%	49	3.8%
Automated/Direct Load Control	4	0.3%	9	0.7%	2	0.1%	0	0.0%	16	1.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	24	1.9%	51	3.9%	76	5.8%
Other DR Programs	0	0.0%	0	0.0%	8	0.6%	55	4.2%	62	4.8%
Total	15	1.1%	10	0.8%	67	5.2%	110	8.5%	203	15.6%
Aggressive Deployment										
Pricing with Technology	0	0.0%	0	0.0%	7	0.5%	5	0.4%	12	0.9%
Pricing without Technology	33	2.6%	1	0.1%	33	2.6%	9	0.7%	77	5.9%
Automated/Direct Load Control	1	0.1%	2	0.2%	1	0.1%	0	0.0%	4	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	24	1.9%	51	3.9%	76	5.8%
Other DR Programs	0	0.0%	0	0.0%	3	0.3%	55	4.2%	58	4.5%
Total	35	2.7%	3	0.3%	69	5.3%	120	9.2%	227	17.4%
Full Deployment										
Pricing with Technology	0	0.0%	0	0.0%	20	1.5%	15	1.1%	35	2.7%
Pricing without Technology	45	3.4%	1	0.1%	33	2.6%	12	0.9%	91	7.0%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	24	1.9%	51	3.9%	76	5.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	55	4.2%	55	4.2%
Total	45	3.4%	1	0.1%	78	6.0%	132	10.2%	256	19.7%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in Vermont by Scenario, Pricing Program and Price Ratio (MW)

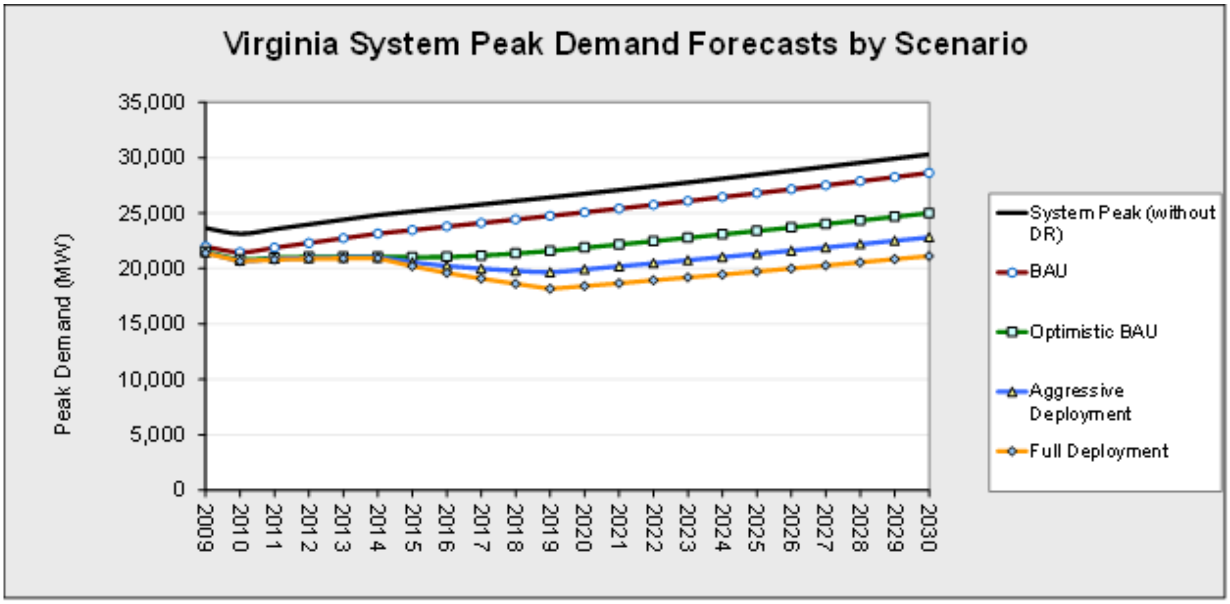
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	48	48	48	48	48	48	48	48	48	48	48	48
10	48	48	48	48	48	48	48	48	48	48	48	48
15	48	48	48	48	48	48	48	48	48	48	48	48
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	49	49	49	49	49	49	49	49	49	49	49	49
10	49	49	49	49	49	49	49	49	49	49	49	49
15	49	49	49	49	49	49	49	49	49	49	49	49
Aggressive Deployment												
Pricing with Technology												
5	9	3	16	10	3	17	10	3	17	10	3	18
10	13	4	23	14	4	24	15	4	25	15	4	26
15	16	4	28	17	4	30	18	4	31	18	4	32
Pricing without Technology												
5	65	45	84	67	46	89	68	46	91	69	46	93
8	78	47	109	82	48	117	84	48	119	85	49	122
15	87	47	128	93	48	137	94	48	140	96	49	143
Full Deployment												
Pricing with Technology												
5	26	5	46	27	5	49	28	6	51	29	6	52
10	39	11	66	41	11	71	43	12	73	44	12	76
15	48	14	81	51	15	87	53	15	90	54	16	92
Pricing without Technology												
5	72	44	101	76	44	108	77	44	111	78	44	113
10	92	50	133	97	52	143	99	52	147	101	53	150
15	106	55	156	113	57	168	115	58	172	118	59	176

Virginia State Profile



Total Potential Peak Reduction from Demand Response in Virginia, 2030

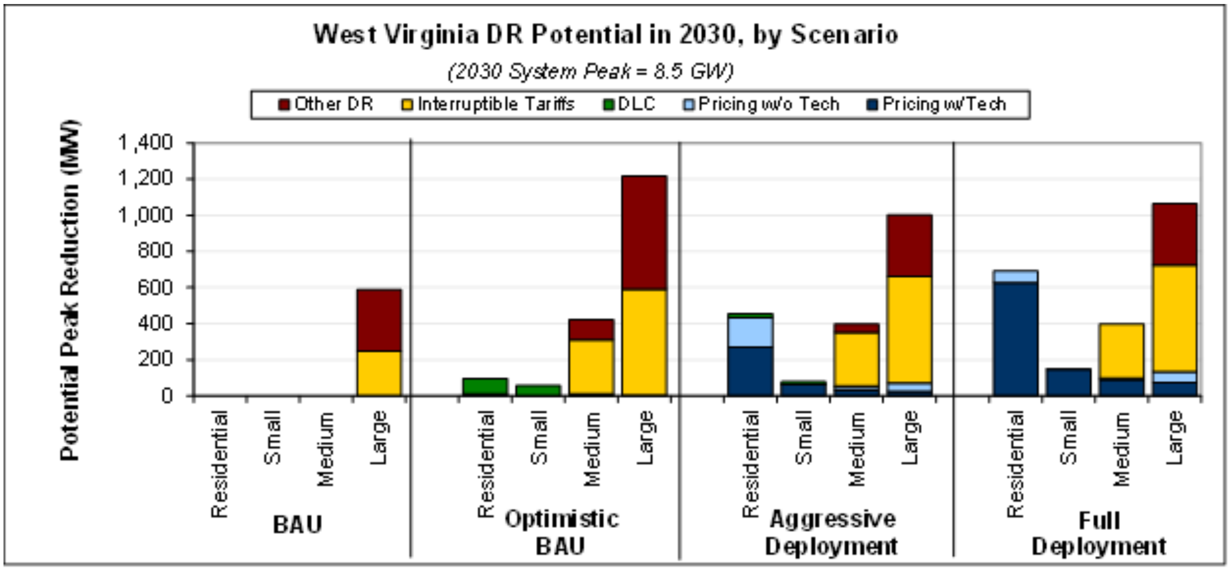
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	14	0.1%	14	0.1%
Automated/Direct Load Control	11	0.0%	0	0.0%	0	0.0%	0	0.0%	11	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	45	0.2%	45	0.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,605	6.1%	1,605	6.1%
Total	11	0.0%	0	0.0%	0	0.0%	1,664	6.3%	1,675	6.3%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	53	0.2%	0	0.0%	5	0.0%	14	0.1%	72	0.3%
Automated/Direct Load Control	410	1.6%	154	0.6%	27	0.1%	0	0.0%	590	2.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	949	3.6%	1,683	6.4%	2,632	10.0%
Other DR Programs	0	0.0%	0	0.0%	404	1.5%	1,605	6.1%	2,009	7.6%
Total	463	1.8%	154	0.6%	1,385	5.2%	3,302	12.5%	5,304	20.1%
Aggressive Deployment										
Pricing with Technology	1,465	5.5%	135	0.5%	111	0.4%	91	0.3%	1,802	6.8%
Pricing without Technology	896	3.4%	2	0.0%	66	0.3%	165	0.6%	1,130	4.3%
Automated/Direct Load Control	105	0.4%	39	0.1%	11	0.0%	0	0.0%	155	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	949	3.6%	1,683	6.4%	2,632	10.0%
Other DR Programs	0	0.0%	0	0.0%	165	0.6%	1,605	6.1%	1,771	6.7%
Total	2,466	9.3%	177	0.7%	1,302	4.9%	3,543	13.4%	7,489	28.3%
Full Deployment										
Pricing with Technology	3,428	13.0%	316	1.2%	323	1.2%	265	1.0%	4,332	16.4%
Pricing without Technology	353	1.3%	1	0.0%	32	0.1%	214	0.8%	600	2.3%
Automated/Direct Load Control	11	0.0%	0	0.0%	0	0.0%	0	0.0%	11	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	949	3.6%	1,683	6.4%	2,632	10.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,605	6.1%	1,605	6.1%
Total	3,792	14.3%	317	1.2%	1,305	4.9%	3,766	14.3%	9,180	34.7%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in Virginia by Scenario, Pricing Program and Price Ratio (MW)

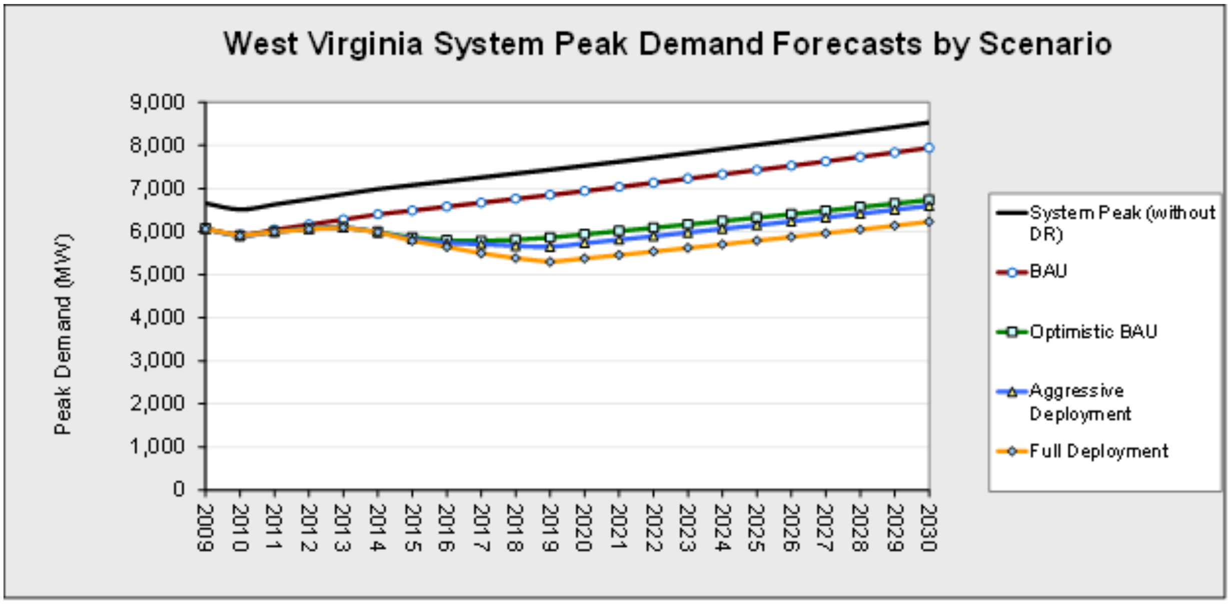
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	14	14	14	14	14	14	14	14	14	14	14	14
10	14	14	14	14	14	14	14	14	14	14	14	14
15	14	14	14	14	14	14	14	14	14	14	14	14
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	25	18	32	55	28	83	57	28	87	60	29	91
10	30	19	41	73	30	116	77	31	123	81	31	130
15	33	20	47	87	32	141	91	33	150	96	34	159
Aggressive Deployment												
Pricing with Technology												
5	277	71	484	1218	311	2125	1289	329	2249	1364	348	2380
10	420	118	721	1843	518	3168	1951	548	3353	2064	580	3548
15	512	190	834	2249	835	3662	2380	883	3876	2518	935	4101
Pricing without Technology												
5	180	48	312	783	201	1365	829	213	1445	877	225	1529
8	273	77	469	1192	337	2046	1261	357	2166	1335	378	2292
15	334	125	544	1458	545	2372	1544	577	2511	1634	611	2658
Full Deployment												
Pricing with Technology												
5	720	229	1211	3152	1001	5303	3336	1059	5613	3531	1121	5941
10	1016	302	1731	4448	1321	7576	4708	1398	8018	4983	1480	8487
15	1246	380	2111	5452	1663	9242	5771	1760	9782	6108	1863	10353
Pricing without Technology												
5	109	35	183	471	151	790	499	161	838	530	170	889
10	156	47	265	672	203	1141	713	215	1210	756	229	1283
15	192	60	325	829	258	1400	879	273	1484	932	290	1574

West Virginia State Profile



Total Potential Peak Reduction from Demand Response in West Virginia, 2030

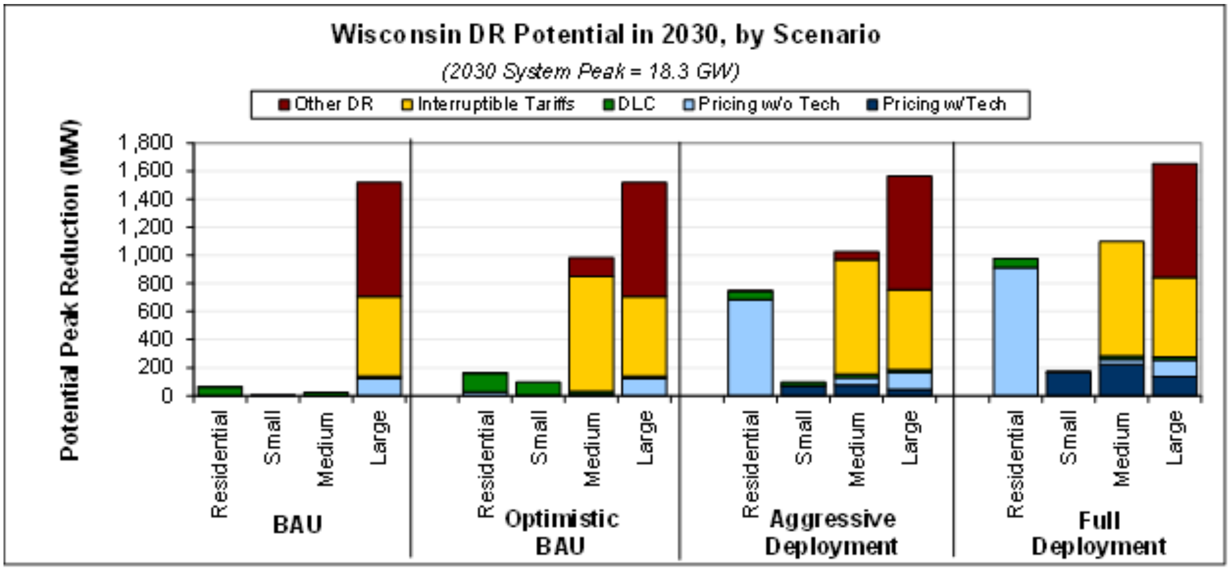
	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	246	3.3%	246	3.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	341	4.6%	341	4.6%
Total	0	0.0%	0	0.0%	0	0.0%	587	7.9%	587	7.9%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	9	0.1%	0	0.0%	1	0.0%	2	0.0%	13	0.2%
Automated/Direct Load Control	87	1.2%	56	0.8%	9	0.1%	0	0.0%	153	2.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	299	4.0%	589	7.9%	888	11.9%
Other DR Programs	0	0.0%	0	0.0%	113	1.5%	626	8.4%	739	9.9%
Total	97	1.3%	56	0.8%	423	5.7%	1,217	16.4%	1,793	24.1%
Aggressive Deployment										
Pricing with Technology	268	3.6%	63	0.8%	31	0.4%	25	0.3%	387	5.2%
Pricing without Technology	164	2.2%	1	0.0%	18	0.2%	46	0.6%	230	3.1%
Automated/Direct Load Control	22	0.3%	14	0.2%	4	0.1%	0	0.0%	40	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	299	4.0%	589	7.9%	888	11.9%
Other DR Programs	0	0.0%	0	0.0%	46	0.6%	341	4.6%	387	5.2%
Total	454	6.1%	78	1.1%	398	5.4%	1,001	13.5%	1,932	26.0%
Full Deployment										
Pricing with Technology	626	8.4%	146	2.0%	90	1.2%	74	1.0%	937	12.6%
Pricing without Technology	65	0.9%	1	0.0%	9	0.1%	60	0.8%	134	1.8%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	299	4.0%	589	7.9%	888	11.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	341	4.6%	341	4.6%
Total	692	9.3%	147	2.0%	398	5.4%	1,064	14.3%	2,301	30.9%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in West Virginia by Scenario, Pricing Program and Price Ratio (MW)

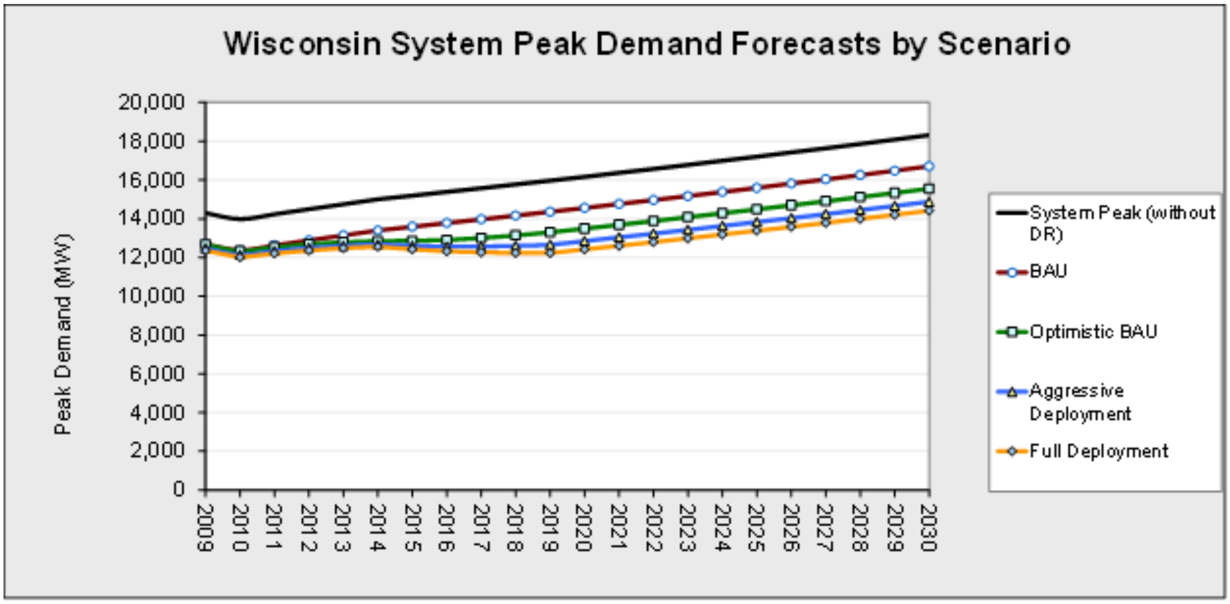
	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	2	1	4	10	3	18	11	3	18	11	3	18
10	3	1	6	15	4	26	15	4	27	16	4	27
15	4	1	7	18	6	31	19	6	31	19	6	32
Aggressive Deployment												
Pricing with Technology												
5	61	19	104	296	89	503	301	91	511	306	92	520
10	88	22	154	425	108	743	432	110	755	440	111	768
15	111	30	191	533	145	921	542	148	936	551	150	953
Pricing without Technology												
5	39	12	66	183	55	310	186	56	315	189	57	321
8	56	14	97	264	67	460	268	69	468	273	70	477
15	70	19	121	332	91	573	338	93	582	344	94	593
Full Deployment												
Pricing with Technology												
5	150	53	247	719	255	1184	732	259	1206	747	264	1229
10	223	74	372	1072	355	1789	1091	362	1821	1112	369	1856
15	264	66	462	1268	317	2219	1291	323	2260	1316	329	2303
Pricing without Technology												
5	24	9	39	111	40	182	114	41	188	119	42	195
10	36	12	60	167	56	277	172	58	287	178	60	297
15	43	11	75	198	51	346	205	52	358	212	54	370

Wisconsin State Profile



Total Potential Peak Reduction from Demand Response in Wisconsin, 2030

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	1	0.0%	2	0.0%	1	0.0%	121	0.8%	124	0.8%
Automated/Direct Load Control	62	0.4%	1	0.0%	23	0.1%	20	0.1%	106	0.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	568	3.6%	568	3.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	809	5.1%	809	5.1%
Total	63	0.4%	3	0.0%	23	0.1%	1,517	9.5%	1,607	10.1%
Optimistic BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	29	0.2%	2	0.0%	5	0.0%	121	0.8%	157	1.0%
Automated/Direct Load Control	132	0.8%	94	0.6%	27	0.2%	20	0.1%	274	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	816	5.1%	568	3.6%	1,384	8.7%
Other DR Programs	0	0.0%	0	0.0%	137	0.9%	809	5.1%	946	5.9%
Total	162	1.0%	96	0.6%	985	6.2%	1,517	9.5%	2,761	17.3%
Aggressive Deployment										
Pricing with Technology	0	0.0%	72	0.5%	76	0.5%	46	0.3%	194	1.2%
Pricing without Technology	684	4.3%	2	0.0%	55	0.3%	121	0.8%	862	5.4%
Automated/Direct Load Control	62	0.4%	24	0.2%	23	0.1%	20	0.1%	129	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	816	5.1%	568	3.6%	1,384	8.7%
Other DR Programs	0	0.0%	0	0.0%	56	0.4%	809	5.1%	865	5.4%
Total	746	4.7%	99	0.6%	1,026	6.4%	1,564	9.8%	3,434	21.5%
Full Deployment										
Pricing with Technology	0	0.0%	169	1.1%	223	1.4%	135	0.8%	526	3.3%
Pricing without Technology	913	5.7%	2	0.0%	37	0.2%	121	0.8%	1,073	6.7%
Automated/Direct Load Control	62	0.4%	1	0.0%	23	0.1%	20	0.1%	106	0.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	816	5.1%	568	3.6%	1,384	8.7%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	809	5.1%	809	5.1%
Total	975	6.1%	172	1.1%	1,099	6.9%	1,652	10.4%	3,898	24.4%



Summary of Monte Carlo Simulation of Potential Peak Load Reduction from Demand Response in Wisconsin by Scenario, Pricing Program and Price Ratio (MW)

	2015			2020			2025			2030		
	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper	Mean	Lower	Upper
BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	123	123	123	123	123	123	123	123	123	123	123	123
10	123	123	123	123	123	123	123	123	123	123	123	123
15	123	123	123	123	123	123	123	123	123	123	123	123
Optimistic BAU												
Pricing with Technology												
5	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
Pricing without Technology												
5	136	127	145	148	130	166	149	131	167	150	131	168
10	142	128	155	160	134	186	161	134	187	162	134	189
15	146	129	162	168	135	200	169	136	202	170	136	204
Aggressive Deployment												
Pricing with Technology												
5	65	19	111	153	44	262	159	45	272	165	47	283
10	92	27	158	217	63	372	226	66	386	235	68	401
15	111	31	191	262	74	450	272	77	468	283	80	486
Pricing without Technology												
5	342	185	498	673	277	1069	688	280	1097	704	283	1125
8	436	213	660	926	327	1524	950	331	1569	975	335	1615
15	502	228	776	1108	358	1859	1138	363	1914	1170	369	1970
Full Deployment												
Pricing with Technology												
5	174	44	304	407	102	713	423	106	741	440	110	770
10	261	82	440	612	193	1030	636	201	1071	661	209	1113
15	313	110	517	734	257	1210	763	267	1258	793	278	1307
Pricing without Technology												
5	397	190	603	823	281	1366	844	284	1404	865	286	1444
10	537	252	822	1214	419	2009	1247	427	2067	1281	436	2127
15	622	296	947	1456	535	2376	1496	547	2445	1538	561	2515

APPENDIX C. BENEFIT-COST TESTS TYPICALLY APPLIED TO DR PROGRAMS

Benefits Considered	**Costs Considered**	**Implications**
Participant Cost Test (PCT)		
Incentive Payments, Bill Savings Realized, Applicable Tax Credits or Incentives	Incremental Equipment Costs, Incremental Installation Costs	Positive PCT shows that program provides net savings for customer
Program Administrator Test (PACT)		
Energy-Related costs avoided by utility, Capacity-related costs avoided by utility (including generation, transmission, and distribution)	Program overhead costs, Utility/program administrator incentive costs, Utility/program administrator installation costs	Positive PACT shows that costs of saving energy are less than costs of delivering energy.
Ratepayer Impact Measure (RIM)		
Energy-Related costs avoided by utility, Capacity-related costs avoided by utility (including generation, transmission, and distribution)	Program overhead costs, Utility/program administrator incentive costs, Utility/program administrator installation costs, lost revenue due to reduced energy bills	Negative RIM implies that rates would need to increase in the short term for utility to maintain current earnings
Total Resource Cost Test (TRC)		
Energy-Related costs avoided by utility, Capacity-related costs avoided by utility (including generation, transmission, and distribution), Additional Resource Savings (e.g. gas and water), Monetized environmental and non-energy benefits (e.g. avoided fines), Applicable tax credits	Program overhead costs, Program installation costs, Incremental measure costs (whether paid by the customer or the utility)	Positive TRC shows that entire program has net benefits to the region as a whole
Societal Cost Test (SCT)		
Energy-Related costs avoided by utility, Capacity-related costs avoided by utility (including generation, transmission, and distribution), Additional Resource Savings (e.g. gas and water), Non-monetized environmental and non-energy benefits (e.g. health and climate improvements)	Program overhead costs, Program installation costs, Incremental measure costs (whether paid by the customer or the utility)	Positive SCT shows that the program has net benefits to those do not participate in it and who are not customers of the utility administering the program, i.e. the program is beneficial to third parties

APPENDIX D. COST AND DEVICE DEPLOYMENT ESTIMATES FOR CENSUS DIVISIONS IN ORNL-NADR

		AMI Meters Deployed (Thousands)	DLC Devices Deployed (Thousands)	PCT Devices Deployed (Thousands)	Total Costs (High, Million$)	Total Costs (Medium, Million$)	Total Costs (Low, Million$)
New England	BAU	3,732	299	0	2,435	1,117	685
	Optimistic BAU	3,732	297	0	2,434	1,116	684
	Aggressive Deployment	7,654	234	566	4,666	2,208	1,377
	Full Deployment	7,654	211	1,326	4,831	2,373	1,541
Middle Atlantic	BAU	12,856	2,087	0	7,558	3,488	2,186
	Optimistic BAU	12,856	2,076	0	7,554	3,484	2,182
	Aggressive Deployment	21,811	1,792	4,314	13,164	6,453	4,230
	Full Deployment	21,811	1,690	10,109	14,201	7,491	5,267
East North Central	BAU	12,651	3,269	0	8,130	3,768	2,405
	Optimistic BAU	12,651	3,258	0	8,127	3,764	2,401
	Aggressive Deployment	23,610	2,971	3,137	14,681	7,106	4,620
	Full Deployment	23,610	2,865	7,365	15,574	8,000	5,514
West North Central	BAU	4,912	1,783	0	2,697	1,266	813
	Optimistic BAU	4,912	1,778	0	2,695	1,264	812
	Aggressive Deployment	11,900	1,610	2,989	6,896	3,460	2,302
	Full Deployment	11,900	1,548	7,010	7,559	4,123	2,965
South Atlantic	BAU	21,986	6,091	0	12,665	6,118	3,954
	Optimistic BAU	21,986	6,071	0	12,659	6,111	3,948
	Aggressive Deployment	36,171	5,586	12,048	21,809	11,400	7,856
	Full Deployment	36,171	5,406	28,237	24,462	14,054	10,510
East South Central	BAU	4,404	2,145	0	2,692	1,364	948
	Optimistic BAU	4,404	2,142	0	2,691	1,363	947
	Aggressive Deployment	10,522	2,012	3,375	6,522	3,440	2,406
	Full Deployment	10,522	1,966	7,911	7,310	4,228	3,194
West South Central	BAU	2,560	461	0	1,583	721	448
	Optimistic BAU	2,560	460	0	1,583	721	448
	Aggressive Deployment	6,348	406	1,874	3,957	2,001	1,344
	Full Deployment	6,348	385	4,407	4,440	2,485	1,827

		AMI Meters Deployed (Thousands)	DLC Devices Deployed (Thousands)	PCT Devices Deployed (Thousands)	Total Costs (High, Million$)	Total Costs (Medium, Million$)	Total Costs (Low, Million$)
Eastern Inter-connection Total	**BAU**	**63,101**	**16,136**	**0**	**37,761**	**17,841**	**11,439**
	Optimistic BAU	**63,101**	**16,082**	**0**	**37,743**	**17,824**	**11,421**
	Aggressive Deployment	**118,016**	**14,610**	**28,303**	**71,694**	**36,069**	**24,135**
	Full Deployment	**118,016**	**14,071**	**66,365**	**78,378**	**42,752**	**30,818**