STATE OF INDIANA
INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF DUKE ENERGY INDIANA, INC., FOR APPROVAL OF (1) A PHASE 2 COMPLIANCE PLAN REGARDING EMISSIONS REDUCTION REQUIREMENTS; (2) THE USE OF CERTAIN QUALIFIED POLLUTION CONTROL PROPERTY AND CLEAN ENERGY PROJECTS; (3) CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY FOR CLEAN COAL TECHNOLOGY; (4) THE USE OF CONSTRUCTION WORK IN PROGRESS RATEMAKING TREATMENT; (5) CERTAIN FINANCIAL INCENTIVES IN CONNECTION WITH PETITIONER'S COMPLIANCE PLAN, INCLUDING THE TIMELY RECOVERY OF COSTS INCURRED DURING CONSTRUCTION AND OPERATION OF THE CLEAN COAL TECHNOLOGY PROJECTS VIA DUKE ENERGY INDIANA'S RIDER NOS. 62 AND 71, AND THE USE OF ACCELERATED DEPRECIATION; (6) THE AUTHORITY TO DEFER POST-IN-SERVICE CARRYING COSTS, DEPRECIATION COSTS, AND OPERATION AND MAINTENANCE COSTS ON AN INTERIM BASIS UNTIL THE APPLICABLE COSTS ARE REFLECTED IN PETITIONER'S RATES; (7) CONDUCTING ONGOING REVIEWS OF THE IMPLEMENTATION OF PETITIONER'S COMPLIANCE PLAN; (8) THE TIMELY RECOVERY OF EMISSION ALLOWANCE COSTS IN DUKE ENERGY'S RIDER NO. 63; AND (9) DEFERRAL AND RECOVER THE PHASE 3 PLAN DEVELOPMENT, ENGINEERING AND PRE-CONSTRUCTION COSTS	**)**	**CAUSE NO. 44217**

Direct Testimony of
Dr. Frank Ackerman
PUBLIC VERSION

On Behalf of
Citizens Action Coalition of Indiana, Sierra Club, Save the Valley, and Valley Watch

November 29, 2012

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1. INTRODUCTION AND QUALIFICATIONS

Q. What is your name, position and business address?

A. My name is Frank Ackerman. I am a Senior Economist at Synapse Energy Economics, Incorporated, 485 Massachusetts Avenue, Cambridge, Massachusetts 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics ("Synapse") is a research and consulting firm specializing in energy and environmental issues. Its primary focus is on electricity resource planning and regulation. Synapse works for a wide range of clients, including attorneys general, offices of consumer advocates, public utility commissions, environmental advocates, federal government agencies, and the National Association of Regulatory Utility Commissioners. Synapse has more than 20 professional staff with extensive experience in analysis of the electricity industry.

Q. Please describe your educational and professional background.

A. I received a BA in mathematics and economics from Swarthmore College, and a PhD in economics from Harvard University. I have had more than 25 years of experience in economic analysis of energy, climate change, environmental policy, and related issues. Before joining Synapse Energy Economics, I held senior research positions at Tellus Institute in Boston; at Tufts University's Global Development and Environment Institute; and at the Stockholm Environment Institute's U.S. Center, located at Tufts University in Massachusetts. At the Stockholm Environment Institute (SEI) center from 2007 to mid-2012, I directed SEI's Climate Economics Group. That research group was engaged in modeling and analysis of many aspects of climate-related costs, benefits, and policy options.

I have published more than 40 articles in professional journals, written or edited more than a dozen books, and directed numerous studies for state and federal government agencies, non-governmental organizations, and international bodies such as the United Nations. More detail on my experience and publications is provided in my resume, which is attached as Exhibit FA-1.

Q. Have you testified as an expert witness in the past?

A. I have testified on electric utility rate design and other issues in regulatory proceedings before utility commissions in a number of states, in my work at Tellus Institute between 1985 and 1994. More recently, I have testified on the economics of climate change impacts and policies before committees of the U.S. House of Representatives in Washington and the European Parliament in Brussels.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the Citizens Action Coalition of Indiana, Sierra Club, Save the Valley, and Valley Watch (the Joint Intervenors).

Q. Have you testified previously before the Indiana Utility Regulatory Commission (Commission)?

A. No, I have not.

Q. What is the purpose of your testimony?

A. The Joint Intervenors retained the Synapse team of Rachel Wilson and me to assist in their review of Duke Energy Indiana's (Duke Indiana or Company) application for Certificates of Public Convenience and Necessity (CPCN) for retrofits to the Cayuga, Gallagher, and Gibson power plants, which are intended to achieve compliance with existing or emerging regulations.

The purpose of my testimony is to provide an economic analysis of the reasonableness and cost-effectiveness of the Company's proposed CPCNs. My testimony discusses four areas in which the Company should expand or correct its analysis, describes a Synapse base case that the Commission should use as the starting point for analysis of the proposed CPCNs, and summarizes the conclusions and significance of Synapse Witness Wilson's modeling of the Synapse base case.

Wilson's testimony examines the new and emerging environmental regulations that motivate the CPCN, reviews the Company's modeling of resource options using PROSYM and other models, and presents her results using PROSYM to model those resource options under the Synapse base case and other scenarios. Drawing on her results as well as my own analysis, I will offer conclusions regarding the proposed CPCNs and recommendations for options that minimize the present value of the Company's revenue requirements.

Q. What data sources did you rely upon to prepare your review of the Company's request?

A. My review relies primarily upon the direct testimonies and exhibits of Company witnesses McMurry and Miller, and on responses to various data requests. The specific responses I cite in this testimony are attached as Exhibit FA-2. In addition, I rely on the testimony and Exhibits of Synapse witness Wilson.

2. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your primary conclusions.

A. I have identified four areas where the Company's analysis is inadequate, presented a Synapse base case that improves the treatment of two of these areas, and evaluated the proposed CPCNs for the Cayuga and Gallagher units under the Synapse base case and other scenarios.

Q. Please describe the four areas where the Company's analysis is inadequate.

A. First, the Company should have analyzed the potential for increased energy efficiency and demand response beyond the minimum amount required by the Commission. This analysis should include the option of continued expansion of energy efficiency and demand response programs beyond 2020, the date at which the Company projects an abrupt halt to almost all new initiatives in these areas.

Second, the Company should examine low load-growth scenarios in greater detail, and explore scenarios below its current low-load scenario, to reflect the substantial risks of continued macroeconomic instability. The suggestion that the current low load-growth scenario could represent either lower load growth or energy efficiency conflates two unrelated factors that deserve separate treatment: cost-effective energy efficiency and demand response should always be pursued, and in addition, the Company should consider risks such as macroeconomic instability that might lower load growth in its scenario analysis.

Third, the Company should analyze its proposed investments under scenarios with higher carbon dioxide (CO_2) prices, rather than comparing only a relatively low price to no price at all. Finally, it should consider fuel price scenarios with a wider range of relative prices of coal vs. gas; the ratio between these two prices is of great importance to the Company's analysis, which in large part compares continued operation of retrofitted coal plants vs. replacement with gas plants.

"Stress testing" of resource options against such scenarios will provide a better understanding of the risks facing the Company's ratepayers. If the proposed CPCNs are granted, ratepayers will be responsible for the costs of the proposed investments, whether or not future conditions turn out to match the Company's base case scenario. It is important, therefore, to consider what could go wrong, and how much is at risk, under plausible alternative future scenarios.

Q. How does the Synapse base case differ from the Company's base case?

A. The Synapse base case differs from the Company's base case in two respects. First, it assumes continuation of incremental gains in energy efficiency and demand response beyond 2020, at a rate somewhat slower than the peak rate the Company proposes to achieve up to 2020. Second, it adopts the Synapse mid-case CO_2 price forecast (shown in Exhibit FA-3), based on a review of dozens of utility and other forecasts. These are more reasonable assumptions about future conditions than the Company's assumptions.

Q. Please describe your conclusions regarding particular power plants.

A. The change in the present value of revenue requirements for Cayuga 1 and 2, and for Gallagher 2 and 4, is shown in Table 1 for the Company base case and for several alternatives, based on the modeling calculations reported in Ms. Wilson's testimony. The Synapse base case, as explained below, combines the extended energy efficiency and mid-range carbon price assumptions used in the other two new scenarios shown in Table 1.

Table 1: Costs or Benefits of Unit Retirements

[redacted]

Even under the Company's base case assumptions, retrofitting and continuing to operate Cayuga 1 and 2 involves a large investment that has a relatively modest return: an investment of roughly [redacted] million produces a levelized reduction in revenue requirements of about [redacted] million per year, if everything goes as expected.[1]

[1] The present value of revenue requirements over a 23-year period under the Company's base case is [redacted] lower than in the case where both Cayuga 1 and 2 are retired (McMurry confidential exhibit F-3). Thus the levelized annual present value benefit is [redacted].

That small reported benefit disappears under many other scenarios. Under the Synapse projection of extended potential for energy efficiency savings, continued operation of Cayuga 1 reduces revenue requirements by only [redacted], while the corresponding number for Cayuga 2 is [redacted]. If CO_2 prices match the Synapse mid-range forecast – which is lower than the forecasts used by many utilities – then continued operation of Cayuga 1 and 2 increases revenue requirements by [redacted] and [redacted], respectively. Under the Synapse base case, combining these two changes, the savings to ratepayers from retiring and replacing Cayuga 1 and 2 are even greater, [redacted] and [redacted]. In combination with other risk factors which Ms. Wilson has not modeled, such as low load growth or a less favorable fuel price ratio, losses from continuing to operate Cayuga could be even worse.

Regarding Gallagher 2 and 4, there are at least three significant errors in the Company modeling, as explained by Ms. Wilson in her testimony. First, in the Company calculations for scenarios in which either of the Gallagher units is retired, both Gallagher units are erroneously still assumed to operate. Correction of this error alone, leaving all Company base case assumptions unchanged, eliminates roughly three-fourths of the reported economic benefit of continuing to operate the two Gallagher units. The corrected benefit to ratepayers under Company base case assumptions is estimated at [redacted] for Gallagher 2 and [redacted] for Gallagher 4, as shown in Table 1. These numbers shrink to [redacted] and [redacted] in the Synapse base case.

Two other errors in the Gallagher calculations could not easily be corrected in our modeling runs. In the Company's retrofit scenarios for Gallagher, it is assumed that Gallagher 2 retires at the beginning of 2033, and Gallagher 4 at the beginning of 2032. The Company's calculation of the present value of revenue requirements, the standard used to evaluate resource options, extends through 2034. Therefore, the retrofit scenarios should include the costs of replacement capacity for the final two years for Gallagher 2, and for the final three years for Gallagher 4. The Company's ad hoc approach to calculation of revenue requirements for 2033-34, however, makes it difficult to incorporate these costs. Therefore, we added the levelized costs of replacement capacity to the retrofit scenarios for 2033-34 for Gallagher 2 and 2032-34 for Gallagher 4, as shown in Table 1.

Finally, the Company stated that they used the wrong coal prices in modeling the Gallagher units, causing an overestimate of the present value benefit of retrofitting each unit by [redacted]. Lacking access to the corrected coal prices, we applied a [redacted] reduction to the present value of retrofitting each unit, as shown in Table 1**.**

Correcting for both of these errors lowers the net benefit of retrofitting the plants to [redacted] for Gallagher 2 and [redacted] for Gallagher 4 under the Company's base case, or [redacted] and [redacted] – i.e., a [redacted] net *cost* – under the Synapse base case. That is, under the Synapse base case, which I believe is the appropriate set of assumptions for this analysis, retrofitting Gallagher 2 achieves a tiny benefit, and retrofitting Gallagher 4 causes an even smaller loss, approximately breaking even against retirement. The benefit of retrofitting Gallagher 4, a total of [redacted] over 23 years, amounts to a levelized annual reduction in revenue requirements of only [redacted] per year.

As Ms. Wilson explains, there are other omissions and uncertainties in the Gallagher modeling results, which could jeopardize the tiny estimated gains at Gallagher 2. A change in the costs of environmental compliance, or an adverse movement in fuel costs or market prices, or a decrease in load (as I discuss below), could tip the balance against retrofitting either of the Gallagher plants. Even a simple extension of the period of analysis to 2036, including two more years of levelized capital costs of Gallagher replacement capacity in the retrofit scenario, would show that ratepayers would be better off if both Gallagher 2 and 4 are retired.

Q. Please summarize your recommendations.

A. I have six principal recommendations.

1. The Company should revise or expand its analysis to include: increased gains from energy efficiency and demand response continuing to grow beyond 2020; lower load-growth scenarios, in

combination with energy efficiency and demand response; higher CO_2 prices, such as the Synapse mid case price projection; and wider variation in the relative prices of gas and coal.

2. The Synapse base case, described in my testimony and Ms. Wilson's, addresses two of the areas in which the Company analysis needs revision. Although it does not address all the areas needing revision, it is a better starting point for analysis than the existing Company base case. The Company should do sensitivity analyses reflecting different price levels, load growth rates, and other factors around the Synapse base case.

3. The Commission should deny the proposed CPCN for Cayuga 1 and 2. The large proposed investments at these units – the bulk of the amount requested companywide – is projected to provide only modest benefit to ratepayers under the Company's base case assumptions, while it creates large losses under the Synapse base case and under many plausible alternative assumptions.

4. The Commission should deny the proposed CPCN for Gallagher 2 and 4. After correction of errors in the Company modeling of these units, there is little remaining benefit to ratepayers from Gallagher 2, and literally none from Gallagher 4. The small benefits seen in the corrected Gallagher analysis are at risk from many possible changes that could render the plant unprofitable. The discovery of three serious errors in the Company's modeling for Gallagher suggests the need for a new, more transparent analysis of the costs and benefits of this facility to ratepayers.

5. The Company demonstrates that under its base case assumptions, Wabash units 2-6 are unprofitable, raising costs to ratepayers above the costs of alternatives. The Commission should confirm the Company's recommendation that these units should cease operation as coal-burning power plants, and should not approve

any additional expenditures at these units. (I have not examined the question of whether the Company should repower Wabash 6 with natural gas.)

6. Regarding Gibson 5, the Company expresses uncertainty about the appropriate short-run investment strategy and net benefits to ratepayers, but presents no analysis supporting the continued operation of this plant beyond 2017. The Commission should confirm that Gibson 5 should cease operation no later than 2017, and should not approve any expenditures at Gibson 5 beyond the Phase 2 investments needed for operation through 2017.

Due to the tight timeline for this proceeding, I have not been able to analyze the Company's calculations for Gibson 1-4, and do not have a recommendation for these units.

3. OVERVIEW OF THE COMPANY'S ANALYSIS

Q. Please summarize the Company's current mix of capacity and energy by resource.

A. Duke Energy Indiana relies largely on coal for energy, with multiple coal-burning units at the Cayuga, Gallagher, Gibson, and Wabash River plants. It also has several natural gas combustion turbines (CTs) used primarily for peaking capacity, one gas combined cycle (CC) plant, one hydro facility, and small amounts of other renewable capacity. Overall, the system is heavily dependent on coal. As shown in Figures 1 and 2 below (from pages 8 and 9 of Witness Esamann's testimony), coal accounted for 93% of the Company's energy generation in 2011, and is expected to represent 88% in 2016.

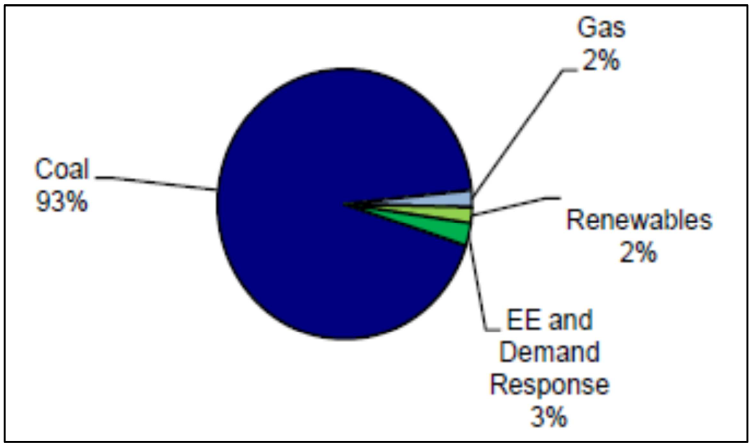

Figure 1: Duke Energy Indiana Energy Resource by Type in 2011
(directly from Esamann, page 8)

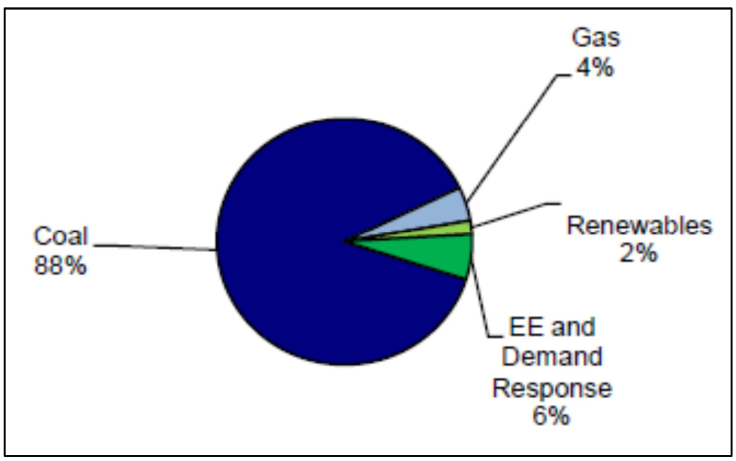

Figure 2: Duke Energy Indiana Energy Resource by Type in 2016
(directly from Esamann, page 9)

Q. Please describe the costs which the Company is seeking to recover under the proposed CPCN.

A. The Company is currently facing several existing and emerging environmental regulations that affect coal plants, as described in Ms. Wilson's testimony. The Cayuga, Gallagher, Gibson, and Wabash River plants would need retrofits to comply with these regulations; the proposed CPCN covers the retrofit costs for the Cayuga, Gallagher, and Gibson units. (The Company does not plan to continue operation of coal-burning units at Wabash River.) The Company is requesting recovery of its Phase 2 plan which includes an estimated $448 million in upfront costs[2]. The Company is also proposing to recover planning costs associated with its Preliminary Phase 3 plan which has an estimated capital cost of $945 million[3].

To assess the required retrofit expenditures at each unit, the Company uses its Engineering Screening Model. Based on estimates of compliance costs from outside contractors and on the Company's assessment of requirements from emerging federal regulations, the Engineering Screening Model is used to find the lowest cost suite of environmental controls at each unit.

Q. Please summarize the economic evaluation the Company conducted to evaluate its options for complying with environmental regulations.

A. The Company calculates the net present value (NPV) of its revenue requirements from 2012 through 2034, with and without each of its coal plants, under a base case and a limited set of additional scenarios. Specifically, the Company compares the cost of continued operation of each coal unit with environmental controls (including the costs of all projects in their Phase 2 and Preliminary Phase 3 plans) to the costs of retiring and replacing the generation with new natural gas CCs or CTs. Witness McMurry's testimony shows the results of these comparisons by unit (as well as for the combination of Cayuga 1 and 2) under a number of scenarios, in terms of their effects on the companywide present value of revenue requirements (PVRR).

Q. Is this an adequate representation of the available alternatives to the Company's coal plants?

A. No, it is not. The Company should have examined the possibilities of increasing their use of energy efficiency and demand response measures, expanding their portfolio of renewable energy, and increasing purchases of energy from other generators within MISO. In making this statement, I am not suggesting that any one of these alternatives alone could replace any of the Company's coal units. Rather, combinations of these alternatives may contribute to the least-cost alternatives to continued operation of some existing coal plants.

[2] Company's Exhibit C-8
[3] Company's Exhibit C-14

Q. What conclusions does the Company draw from its analysis?

A. For most of the plants, the Company finds that continued operation of the plant lowers revenue requirements under the base case and some of the other scenarios. Therefore, continued operation of each plant, including the required modifications, is said to benefit ratepayers, since it is projected to lower the total amount that the Company needs to recover in rates.

Q. Are there some plants for which the Company finds that continued operation would increase revenue requirements?

A. Yes. The Company finds that continued operation of Wabash units 2-6 is more expensive than retiring these units, and therefore plans to retire them. For Gibson 5, the Company finds that on the one hand, the modest Phase 2 investments required to keep the plant in operation through 2017 would slightly reduce revenue requirements; on the other hand, any of three variants of the much larger Phase 3 investments required for operation after 2017 would increase revenue requirements.

Q. Please describe the approach the Synapse team used to determine whether the proposed CPCNs are reasonable and cost-effective for complying with the environmental regulations the Company is facing.

A. We reviewed the Company's proposal in detail. We identified four areas in which the Company should correct or expand its analysis (see Sections 4 - 7 of my testimony), and developed a Synapse base case addressing two of these areas (see Section 8 of my testimony). We also evaluated the Company's modeling, corrected important modeling errors, and re-ran the calculations for the Synapse base case and other scenarios (see Ms. Wilson's testimony, and Section 8 of my testimony).

Q. Do you agree with the conclusions of the Company's analysis?

A. Only for the retirement of Wabash 2-6 as coal plants, and for the retirement of Gibson 5 no later than 2017. I am not addressing the question of whether the Company should repower Wabash 6 with gas, or the relative merits of retirement of Gibson 5 in 2015 vs. 2017.

I disagree with the Company conclusions about Cayuga 1 and 2, and Gallagher 2 and 4. The Company's ratepayers will be better off if these units are retired.

Q. Have you reached a conclusion about Gibson 1-4?

A. No. Due to the tight timeline available for completion of this analysis, it was not possible to analyze Gibson 1-4 in the same manner as the other plants. It would be useful to repeat our analysis for Gibson 1-4 as well.

Q. Will you present an alternative to the Company's analysis?

A. Yes. Drawing on the modeling done by Ms. Wilson, I will present an economic analysis of retirement of Cayuga 1 and 2, and Gallagher 2 and 4, finding that retirement and replacement of these units reduces revenue requirements under many scenarios. This is the topic of Section 8 of my testimony.

4. ENERGY EFFICIENCY AND DEMAND RESPONSE

Q. Why should Duke consider energy efficiency and demand response as alternatives to generation?

A. Energy efficiency and demand response are frequently low-cost resources compared to electricity generation. These measures lower demand, thus reducing the need to build more generating capacity in the future. It is often cheaper to reduce the need for energy and peak capacity than to supply more of them.

Q. Did the Company forecast future energy efficiency and demand response in its planning?

A. Yes, the Company incorporates some new energy efficiency and demand response into its load forecasts. There is an increase in new efficiency before 2020 due to the Company's compliance with the IURC's Generic Order of Cause No. 42693-S1.[4] However, it assumes that energy efficiency and demand response make almost no new contribution to reducing load and energy after 2020.

The following figures show the assumed contributions of energy efficiency to peak load and energy reduction:

[4] Data Response CAC 1.32

- **Figure 3** shows the assumed annual incremental (or new) energy efficiency—defined as a percentage of the previous year's retail energy sales. This peaks at approximately 1.5% for the low load case, and then plummets to 0.1% annually after 2020 in both the base and low load cases.
- **Figure 4** shows the assumed peak load reduction due to energy efficiency and demand response. It levels off after 2020, corresponding to the collapse of new demand response shown in **Figure 3**.
- **Figure 5** shows the base and low load forecasts with and without new energy efficiency and demand response (i.e. gross and net, respectively).

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Q. The Company states in Data Response CAC 2.7 that the Commission's Generic Order is "aggressive." Do you agree with this judgment?

A. No, I do not. There is ample evidence from other states' energy efficiency savings that it is possible to achieve more than is required under the Generic Order. Indiana is currently among the lowest states in the U.S. in terms of net incremental energy efficiency savings by state, according to American Council for an Energy-Efficient Economy (ACEEE), as shown in Figure 6 below (provided in Exhibit FA-5). Based on this figure, the experience of other states suggests that Indiana has plenty of potential for increasing energy efficiency. While I applaud the Commission for issuing the Generic Order, I do not think that Duke Indiana should restrict itself to the amount required by that order. Energy efficiency is a viable, cost-effective resource for planning purposes, as many states have recognized.

At least 15 states have set cumulative energy efficiency savings goals for 2020 in excess of 10%, which amounts to at least 1% savings per year. Nine states achieved energy savings of more than 1.2% in 2009 or 2010.[5] Ohio passed

[5] Exhibit FA-5: ACEEE, *2012 Energy Efficiency Scorecard*. See also Figure 6.

legislation in 2009 requiring 22% energy savings by 2025, starting at 0.3% annual savings in 2009, ramping up to 1% annual savings by 2014, and 2% in 2019.[6] A comprehensive analysis by ACEEE, ICF International, Synapse Energy Economics, and Summit Blue Consulting found such savings levels could be "easily" satisfied with "proven utility programs and innovative policies."[7].

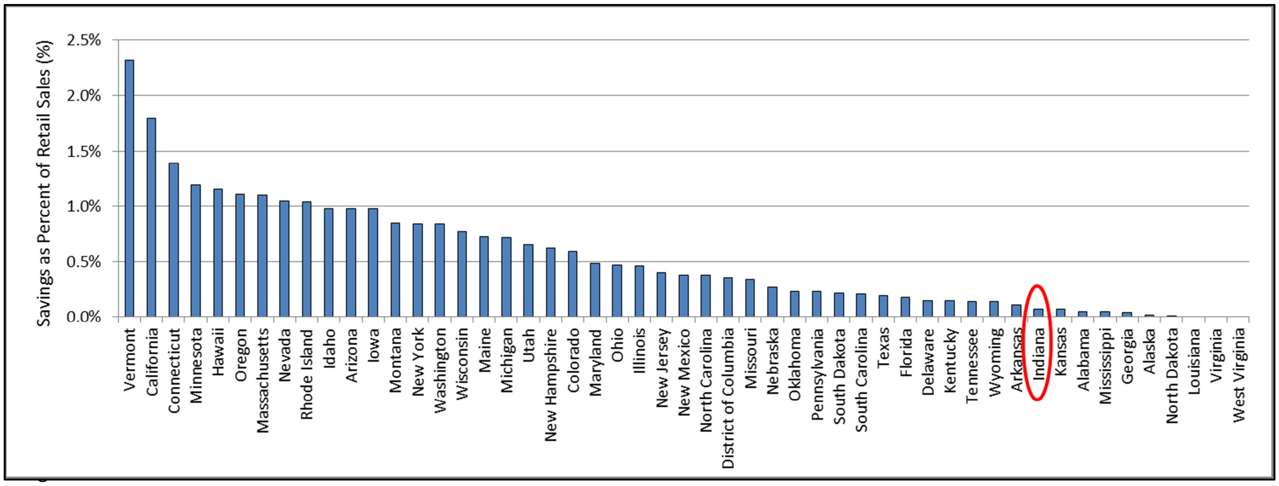

Figure 6: Net Incremental Electricity Savings by State – Percentage of 2010 Retail Sales
(Exhibit FA-5: ACEEE, *The 2012 State Energy Efficiency Scorecard*, October 2012, report Number E12C)

Q. Some of the states that rely most on energy efficiency are in other parts of the country, and have higher electricity prices than Indiana. Are there other Midwestern states with comparable electricity prices that do better than Indiana in promoting energy efficiency?

A. Yes. Note that in Figure 6, Indiana is ranked number 42 out of 51 in energy efficiency savings (the District of Columbia is included along with the 50 states). In the same ranking, Minnesota is number 4, Iowa is 12, Wisconsin is 16, Michigan is 18, Ohio is 23, and Illinois is 24. All six of these states reported much greater efficiency savings than Indiana in 2010, as a percentage of electricity sales, as shown in Figure 6. All but one of those states had electricity prices below the U.S. average in 2010; Iowa had electricity rates essentially identical to Indiana's.[8]

[6] Ohio Revised Code 4928.66.
[7] Exhibit FA-4: ACEEE et al., *Shaping Ohio's Energy Future: Energy Efficiency Works* (March 2009).
[8] Electricity rates from U.S. Energy Information, http://www.eia.gov/electricity/data.cfm#sales, spreadsheet avprice_annual, downloaded Nov. 26, 2012. Michigan had electricity rates 0.5% above the national average in 2010. The average retail rate was $.0766/kwh in Iowa, compared to $.0767 in Indiana.

Q. Has the Company performed an energy efficiency potential study in the past five years?

A. No. According to Data Response CAC 1.20, the Company "does not have a market potential study that was completed in the last five years."

Q. Are you aware of any estimates of the potential for energy efficiency or demand response in Indiana?

A. A 2009 staff report of the Federal Energy Regulatory Commission (FERC), prepared by the Brattle Group and other consultants (provided in Exhibit FA-6), developed national and state estimates of the potential for demand response.[9] It described four scenarios, ranging from business-as-usual (BAU), continuing the demand response policies already in place, up to full participation, with universal deployment of smart meters, time-of-use pricing, and technology to enable demand reductions. By 2019, the report estimated that the national peak demand reduction would range from 38 GW under BAU up to 188 GW under the full participation scenario; the latter scenario would eliminate all projected increase in peak demand through 2019.

For Indiana, the report estimated peak demand reductions in 2019 from 1,338 MW under BAU, up to 4,855 MW under full participation. More than half of Indiana's increased savings under more ambitious scenarios came from the residential sector, from measures such as increased use of direct load control on central air conditioning systems, widespread adoption of time-of-use pricing, and new end-use technologies that allow automated responses to time-of-use prices.

Q. Should the Company rely on projections such as the FERC report on demand response, which assume successful implementation of new technologies and policies that are not yet in large-scale use?

A. Yes, it should. The Company's current forecast appears to assume that the emergence of new energy efficiency opportunities will come to a halt once the Generic Order is satisfied in 2020. Energy-conserving technologies have continued to evolve over time, however, as shown, for example, by the ever-improving energy efficiency of new refrigerators. Many observers expect

[9] Exhibit FA-6: FERC Staff Report, *A National Assessment of Demand Response Potential*, June 2009.

technological progress in energy efficiency to continue into the future. In a panel discussion in 2010, Duke Energy CEO Jim Rogers said that today's efficiency measures may soon look "primitive" in retrospect:

> Historically, our mission as utilities was to provide universal access… I think our mission today is to make the cleanest, most efficient communities in the world… communication on the other side of the meter is really key… We may look back 10 or 15 years from now and say that what we do today is primitive in terms of energy efficiency…[10]

The Company should develop projections for continuing effort in energy efficiency and demand response, consistent with the broad vision of its parent company's CEO.

5. SCENARIO ANALYSIS AND LOW LOAD GROWTH

Q. How should Duke address risks and uncertainties in electricity resource planning?

A. Electricity generation involves very long-term investments, which will often produce energy, and impose costs on ratepayers, for decades. Over the projected lifetime of a new power plant or major retrofit, there is inescapable uncertainty about market conditions, prices, load growth, and the regulatory environment. Therefore it is necessary to evaluate any proposed major investment under a range of possible future scenarios.

Q. Please summarize the future scenarios the Company modeled in its evaluation of resource options.

A. The Company evaluated installation of environmental controls versus retirement of its coal units under a base case and nine other scenarios. The base case represents the Company's current best guess about future conditions, while the nine additional scenarios explore certain alternatives:

[10] "Industry Transformation: A Colloquy on Energy Efficiency, the Smart Grid, and a New Regulatory Paradigm," http://www.duke-energy.com/pdfs/OP-Colloquy-09-16-10.pdf.

- A high energy price scenario, assuming higher than base-case prices for coal, gas, and electricity, and a low energy price scenario, assuming coal, gas, and electricity prices are below the base-case levels;
- High and low load growth scenarios (used only in the Cayuga analyses and the Gibson 5/new FGD analysis);
- High and low cost of capital for environmental controls;
- High and low cost of capital for new combined cycle units (used only in the Cayuga and Gibson analyses); and
- No price on CO_2 emissions.

Q. Is this range of future scenarios sufficient for a reasonable evaluation of the risks and uncertainties facing the Company's proposed investments?

A. No, it is not. There are at least three other dimensions of uncertainty that the Company must consider in evaluating the proposed CPCN: even lower load growth; higher carbon prices; and a different ratio of gas-to-coal prices. I address these topics in this and the next two sections of my testimony.

Q. How does the Company address uncertainty about load growth?

A. In addition to its base load forecast, the Company has developed high-load-growth and low-load-growth scenarios. Use of these scenarios, however, was restricted to the Cayuga analyses and one of the several cases in the Gibson 5 analysis. According to witness Merino, the high- and low-load forecasts represent the 95 percent confidence interval around the base case load forecast in Duke Indiana's forecasting model, or in practice, about 7 percent above and below the base forecast.

Q. Does the Company model its low load forecast in a consistent manner?

A. No, it does not. It applies the low load forecast scenario only to the analysis of Cayuga retirements, and to one of the multiple Gibson retirement cases. In the Cayuga low-load analysis, the Company assumes that if either or both Cayuga units are retired, they are replaced with an identical amount of gas combined cycle capacity. The result is capacity far above what the Company needs to serve its customers under the low load forecast, with reserve margins greater than 20 percent.

Q. How should the Company model retirements in the low load growth scenario?

A. It should revise its capacity planning to achieve a reasonable reserve margin under the assumed load scenario. This means replacing significantly less than 100 percent of the retired capacity. One of the economic benefits of plant retirement is that it may be possible to postpone replacement of a fraction of the retired capacity; this is especially important in a low load growth scenario. The Company's modeling technique, however, hides this potential benefit, thus biasing its results against retirement.

Q. Is the Company's choice of high-, base-, and low-load scenarios a reasonable analysis of uncertainties in load growth?

A. The Company's base load forecast is based on one plausible macroeconomic scenario, assuming slow, steady growth in the national and regional economies. There are, however, major uncertainties that could lead to different outcomes. The recovery from the 2008-2009 financial crisis and recession is still incomplete and insecure. Failure in the negotiations to stabilize the weaker European countries and banks could precipitate a new downturn, as could failure to resolve the federal budget deadlock in Congress. Such factors are hard to quantify in a load forecasting model, but it is unfortunately easy to imagine that they could lead to future energy sales and peak demand falling more than 7 percent below the Company's base load forecast.

The Company's approach, using the upper and lower bounds of the 95 percent confidence interval in its forecasting model, may be an appropriate reflection of those uncertainties that can be included within its model. I believe, however, that it is impossible to quantify the major political and economic risks of economic downturns facing Indiana and the nation today. This implies that it is not meaningful to state, for example, that we have 95 percent confidence that future load will be within 7 percent of the base case forecast. Instead, judgments about the potential magnitudes and impacts of these risks must inevitably be made.

Q. What magnitude of macroeconomic risks should be considered in the Company's load forecasting process?

A. Lacking precise quantification of future uncertainties, we can turn to the experience of the recent past. In Figure 7, I have graphed Indiana state gross domestic product (GDP), a comprehensive measure of state output and income, comparing actual GDP in recent years to the 1997-2007 trend line. After 11 years of almost linear growth, Indiana GDP dropped sharply in the recent recession – which, of course, was caused by events outside Indiana, and outside the control of the state and its utilities.

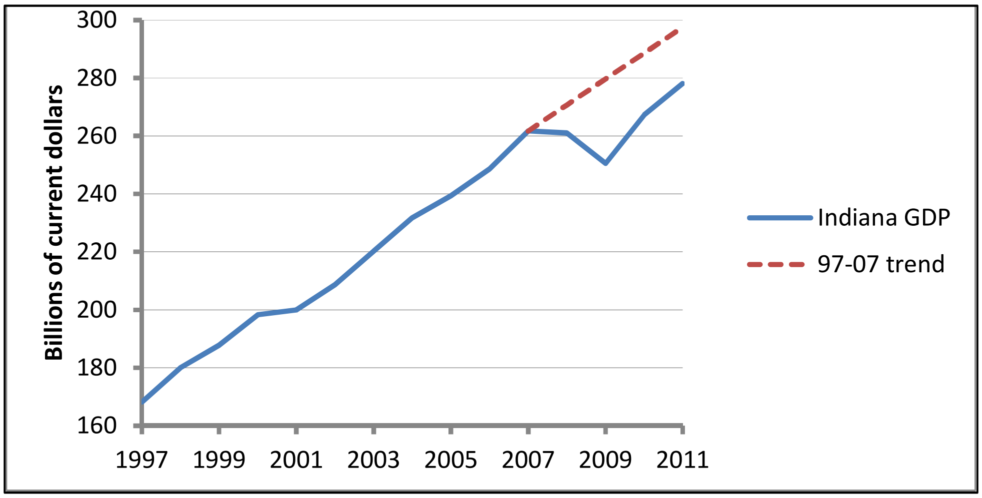

Figure 7: Indiana Gross Domestic Product, 1997-2011 (U.S. Bureau of Economic Analysis)

In 2009 Indiana GDP was 10 percent below the earlier trend; the three-year average for 2009-2011 was 8 percent below the trend, as shown in Figure 7. It is not surprising that electricity sales in the state followed a similar pattern, falling 12 percent below the earlier trend in 2009, and averaging 10 percent below the trend in 2009-2011, as shown in Figure 8.

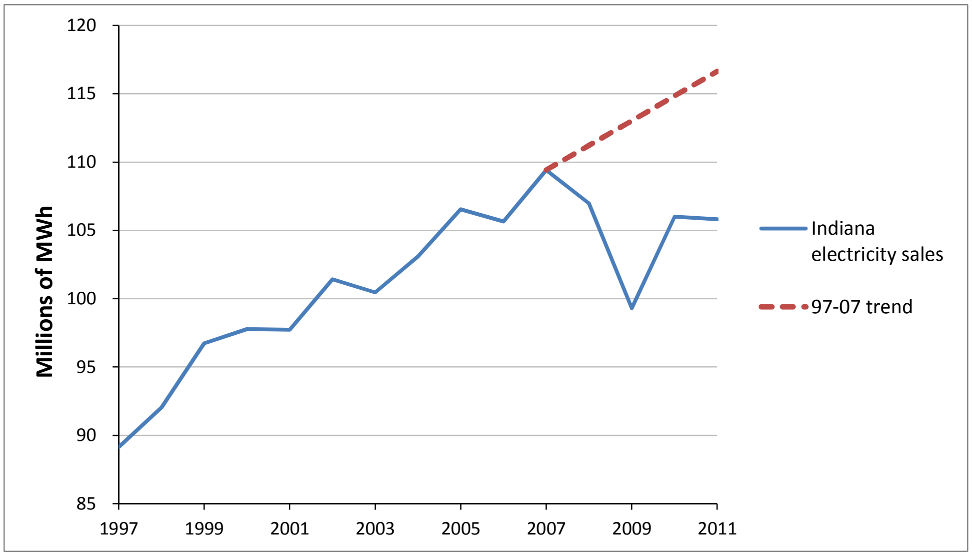

Figure 8: Indiana Electricity Sales, 1997-2011 (U.S. Energy Information Administration)

Thus recent experience demonstrates that macroeconomic risks can cause the state economy to fall by 8 to 10 percent below expected trends, and to remain that low for years – with, if anything, a slightly greater impact on electricity sales. This experience alone could justify a lower low-load-growth scenario than the Company has used, even prior to consideration of energy efficiency options.

Q. The 2008-09 economic slump was the worst downturn in many decades. How likely is it that a similar-sized downturn will occur in the next few years?

A. Again, there is no way to attach a precise numerical probability to a "double-dip" recession, but it has happened before. The 2008-09 economic slump has often been described as the worst since the 1930s. In the 1930s, the U.S. economy hit bottom in 1933, then began to recover. After just a few years of recovery, however, a secondary slump occurred in 1937-38. By 1938, U.S. GDP was 14 percent below the 1933-36 trend, as shown in Figure 9. Many economists attribute the 1937-38 recession to ill-chosen federal budget decisions that choked off the recovery – a risk that is unfortunately hard to rule out today.

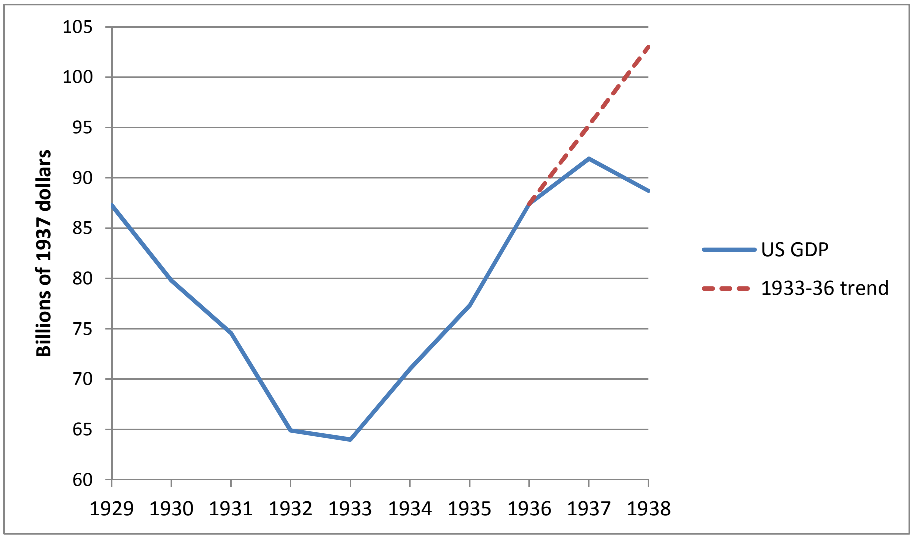

Figure 9: U.S. GDP, 1929-1938 (U.S. Bureau of Economic Analysis)[11]

Q. Have other analysts projected slower load growth than the Company's low load-growth scenario?

A. Yes. The North American Electric Reliability Corporation (NERC) has analyzed load forecast uncertainty for regions of the country, estimating uncertainty bands based on the historical patterns of load variability. In the 2011 report from the NERC Load Forecast Working Group, there are estimates for future energy and peak demand through 2019 for the Reliability First Corporation (RFC) region, which includes Indiana. The NERC report estimates 90th and 10th percentile values, in addition to its base case forecast. By 2019, the 90th and 10th percentile values are 15.5% above and below the basic NERC forecast for RFC net energy demand, and 21.9% above and below for RFC summer peak demand. Although it covers a shorter period of time and a narrower percentile range[12], this is a much wider estimate of uncertainty than is assumed in the Company's high and low load forecasts. The graph of the NERC peak demand forecast for RFC is reproduced here as Figure 10.

[11] Figure 9 is in constant (1937) dollars, while Figure 7 is in current (nominal) dollars. The distinction is of little importance for Figure 9, however, since there was virtually no inflation in the 1930s.
[12] The Company's forecasts are described as representing a 95% confidence interval around the base load forecast. Hence the Company is assuming that its high and low load forecasts represent the 97.5th and 2.5th percentiles of possible outcomes.

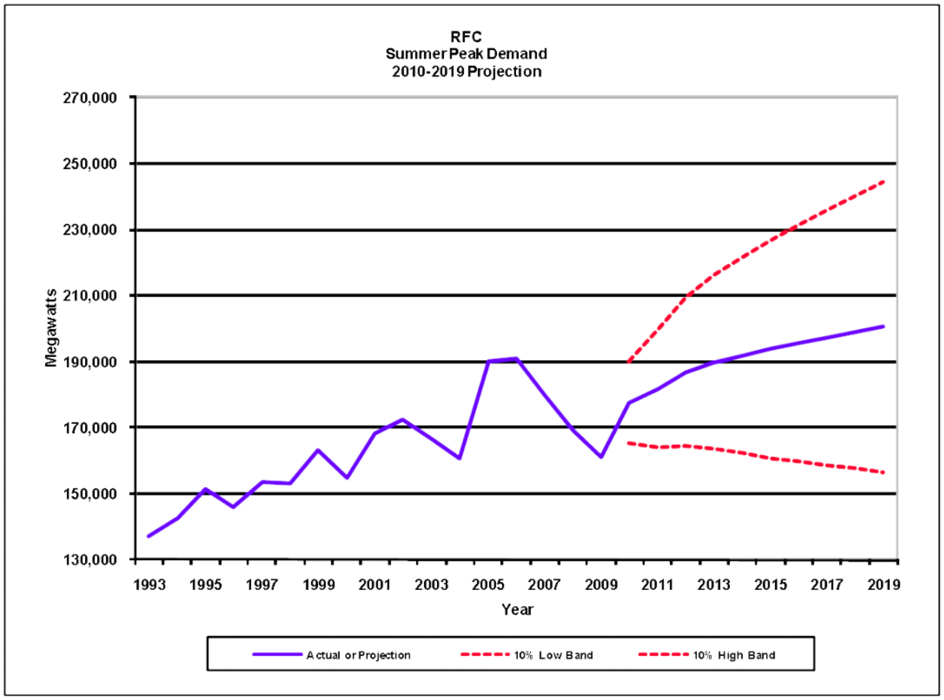

Figure 10. **RFC Summer Peak Demand Projection, 2010-2019.**
(NERC, Regional and National Peak Demand and Energy Forecast Bandwiths, 2010-2019)

Q. What is the relationship between lower load growth and increased energy efficiency?

A. Company witnesses Merino (direct testimony, p.19) and McMurry (direct testimony, p.8) both suggest that the low load scenario can be taken as a proxy for increased energy efficiency. As I noted in Section 4, there are good reasons to believe that the Company could expand its energy efficiency programs and continue to achieve additional gains from efficiency beyond 2020 – the date at which the Company's efficiency programs are projected to stop growing.

The Company's low load forecast could be taken as a proxy for additional energy efficiency, as witnesses Merino and McMurry suggest. It would represent an energy efficiency program sufficient to lower the projected base case load by about 7 percent. Or, of course, the low load forecast could represent risks of lowered load growth. But it cannot play both roles at once. Thus it fails to capture the risks of lower load growth *and* the opportunities for increased energy efficiency.

Q. Why should the Company consider the possibility of both lower load growth and increased energy efficiency?

A. These two factors have independent, unrelated causes. Risks of lower than base-case load growth are driven by macroeconomic developments far beyond the Company's control. Increased gains from energy efficiency, on the other hand, are an available option for use by the Company. If Duke can identify cost-effective energy efficiency options, which reduce load at less than the cost of generation or power purchases, then it should pursue such options – even if load growth slows below base-case projections.

By using only one scenario for lower than base-case load growth, the Company is in effect modeling an either-or choice between two unrelated phenomena. This framework assumes either that there are risks of below-base-case load growth, or that there are opportunities for cost-effective energy efficiency gains, but not both.

Q. How should the Company represent the combination of lower load growth and increased energy efficiency?

A. It should add a scenario reflecting both of these factors. Such a scenario would have energy sales and peak demand below the current low load scenario.

Q. Have you created such a scenario?

A. No, I have not been able to, due to the tight timelines for this analysis. In the absence of such a scenario, I recommend that the Commission give increased weight to the Company's low load scenario, recognizing that an adequate range of scenarios would include even lower ones. That is, the Company's low load scenario is not the extreme of the relevant range, but lies within the range of possible outcomes.

6. HIGHER CARBON PRICES

Q. Why is it important for the Company to consider carbon price scenarios?

A. Although the United States does not currently place a price on CO_2 emissions, many thoughtful observers anticipate that it will do so in the not-too-distant future. For example, Duke Energy CEO Jim Rogers said in an interview on CNN in September 2012,

> My view is that we built power plants for 40 years and we need clarity in terms of the road forward. I believe eventually there will be regulation of carbon in this country. I think it's critical in the long term to have the smallest emissions footprint possible when you generate electricity.[13]

Q. How did the Company develop the carbon price forecast used in its base case?

A. Witnesses Geers, McMurry, and Miller all make brief mention of the carbon price forecast, but do not provide any support for the specific levels or timing assumed in the Base Case. The Company response to CAC Data Request 1.87 says that the base-case carbon price projection "reflects Duke Energy's belief that if or when Congress does act, it will do so cautiously, and therefore, reflects our consideration of what might be plausible politically." It also says that the sources reviewed for purposes of developing this forecast were two federal government reports, both released in 2009.

Q. Why do you believe that the Company needs to consider higher carbon prices?

A. The Company has considered a cautious assumption about the introduction of future carbon prices, supported by very limited information, versus the alternative of no carbon price throughout the forecast period. The latter alternative appears unlikely to many observers, evidently including Duke Energy CEO Jim Rogers.

On the other hand, there are many available forecasts of carbon prices; other utilities and government agencies have developed forecasts, which the Company could have considered. Synapse prepares regular reviews of carbon price forecasts developed by utilities and others; our 2012 review is attached as Exhibit FA-3. A graph taken from that Exhibit is included here in Figure 11, comparing 26 different utility carbon price forecasts to the Synapse mid case (the heavy black line with triangle markers), with the Company's forecast (the heavy red line with

[13] As reported on Cleantechnica.com, http://cleantechnica.com/2012/09/05/jim-rogers-of-duke-energy-supports-obama-energy-policies/

diamond markers) superimposed on the original graph. As Figure 11 demonstrates, the Synapse mid case is within the range of utility forecasts, perhaps lower than average; in contrast, the Duke Indiana forecast is among the lowest of the utility forecasts.

[redacted]

[redacted]

Figure 11: Synapse 2012 Carbon Forecasts Compared to Utilities' Forecasts
(Exhibit FA-3, Synapse 2012 Carbon Forecasts, with Duke Indiana forecast added)

Q. How does the Company's carbon price forecast compare to the range of utility forecasts reviewed by Synapse?

A. Based on a review of about 40 forecasts from utilities and others, Synapse develops low, mid, and high case forecasts. As shown in our 2012 review, there are some utility forecasts below our low case, and others above our high case. Nonetheless, we believe that our three cases span a reasonable range of uncertainty about future carbon prices. Duke Indiana's carbon price forecast used in this case is almost identical to the Synapse low case, as shown in **Figure 12.**

[redacted]

[redacted]

Figure 12: Synapse 2012 Carbon Forecasts Compared to Duke Indiana Forecast
Synapse forecasts (from Exhibit FA-3) are reported in 2012 dollars, and have been converted to 2011 dollars for comparability with the Company's forecast.

Q. How does Synapse define its low, mid, and high case forecasts?

A. As explained in Exhibit FA-3, the Synapse low case "represents a scenario in which Congress begins regulation of greenhouse gas emissions slowly" or with significant safety valve and offset provisions, or relies heavily on complementary policies that reduce emissions through non-price measures. The mid case assumes "a federal cap-and-trade program is implemented with significant but reasonably achievable goals," likely with complementary policies providing flexibility in meeting the goals. The high case assumes one or more factors that raise prices, including "somewhat more aggressive emissions reduction targets; greater restrictions on the use of offsets," more international pressure, or higher baseline emissions.

Q. What carbon price scenarios do you recommend for use in evaluating the Company's proposed CPCN?

A. I recommend evaluation of the proposed investments under the Synapse low, mid, and high carbon price forecasts. The assumptions behind these scenarios represent a reasonable range of political uncertainties. The Company has, in effect, used the only the low case of a reasonable range. It should also consider the Synapse mid and high cases for carbon prices.

7. THE RATIO OF GAS TO COAL PRICES

Q. Why should the Company consider different ratios of gas-to-coal prices?

A. The Company includes high and low fuel price scenarios, but these scenarios assume that prices for different fuels move up and down together. Such scenarios fail to address one of the important uncertainties in this case. Comparison of gas vs. coal power plants is central to evaluation of the proposed CPCNs; in the scenarios assuming retirement of coal plants or units, the Company assumes that the alternative is construction of new gas combined cycle (CC) or combustion turbine (CT) plants. The economic viability of gas vs. coal plants depends, among other things, on the relationship between gas and coal prices.

Q. How does the ratio of gas-to-coal prices vary across the Company scenarios?

A. I have prepared a graph showing the ratio of gas-to-coal prices in the Company scenarios (and in one additional scenario, which I will explain later), in **Figure 13** below. The Base Case ratio is the heavy, solid black line in the figure. The ratio in the high fuel and market price scenario is the green dashed line just above the Base Case; the ratio in the low fuel and market price scenario is the solid red line at the top of the figure. That is, the ratio is higher – hence more favorable to coal – in both the Company low-price scenario and the Company high-price scenario than in the Base Case. Within each scenario, the ratio of gas prices to coal prices rises – making coal relatively more attractive as time goes on - throughout most of the projection period.

[redacted]

[redacted]

Figure 13: Ratio of Natural Gas to Coal Prices for the Company's Cases and Synapse's Low Gas/Base Coal Case (Data Response CAC 1.79A workbook)

Q. What additional fuel price uncertainties should Duke include in evaluation of the CPCN?

A. The Company should consider scenarios with ratios of gas prices to coal prices that are less favorable to coal than its Base Case, rather than restricting its attention to scenarios where this price ratio is more favorable to coal.

Q. Have you developed an alternative price scenario?

A. The proprietary status of the Company's price forecasts and the underlying calculations makes it difficult to develop comparable new scenarios. On the basis of the information available in this case, one could examine, for example, the combination of the Company's base coal price and low gas price forecasts. The ratio of gas to coal prices in that scenario is the blue line with triangle markers, at the bottom of Figure 13.

Q. The Company's price forecasts assume that gas and coal prices will move up and down together. Is this a reasonable assumption about future fuel prices?

A. No, it is not reasonable to assume highly correlated movements in gas and coal prices. Recent history does not support this assumption. I have compared Henry Hub gas prices and Illinois River Basin coal prices, using monthly data from March 2007 to December 2011. The results are shown in Figure 14 below. The correlation coefficient (r^2) between these two data series is 0.07, implying almost no link between movements in gas and coal prices – as the figure visually suggests.

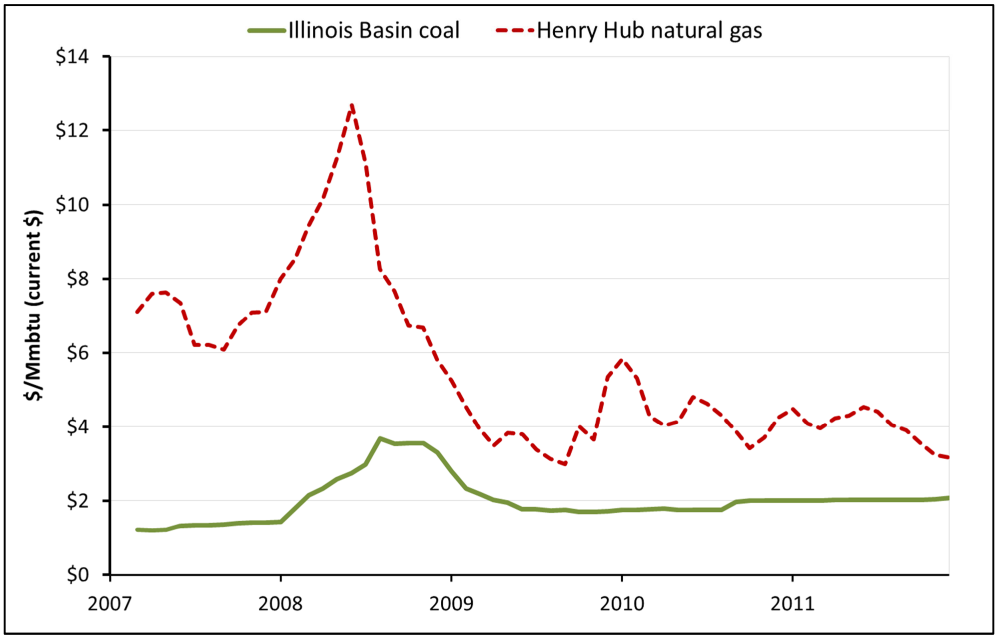

Figure 14: Illinois River Basin coal price and Henry Hub natural gas price, March 2007 – December 2011 (Energy Information Administration).

To test whether this result holds for other time periods, I have also compared U.S. Energy Information Administration data for Henry Hub gas prices and bituminous coal prices on an annual basis from 1997 (the first available year for the Henry Hub data) through 2011. The correlation coefficient (r^2) between these two series is 0.12, again indicating almost no relationship between the movements of the two prices.

Q. Gas prices have dropped sharply relative to coal in the recent past. Why should the Company consider scenarios which assume further weakness in gas prices?

A. Fuel prices are subject to numerous uncertainties over the multi-decade time span of analysis used in this case. Factors such as geological discoveries, innovations in mining and drilling techniques, the strength of export markets, and the evolving regulatory environment for the extraction and use of both fuels could drive either gas or coal prices in either direction. Since, as shown above, the two prices are not closely correlated, it is prudent to consider shifts in relative prices in both directions.

8. ANALYSIS OF CAYUGA AND GALLAGHER RETIREMENTS

Q. What is the basis for your analysis of retirement of the Cayuga and Gallagher units?

A. In this section of my testimony, I summarize and discuss key findings from the testimony of Synapse Witness Wilson, drawing on her review of the Company's modeling and her analyses using the PROSYM model. Modeling issues and results that I discuss here are explained in greater detail in her testimony.

Q. What new scenarios did Synapse use in analysis of the Company's resource options?

A. We developed scenarios reflecting two of the four areas I have discussed in which the Company's analysis seemed inadequate. We modeled extended energy efficiency, assuming that the Company could continue to make gains in this area after 2020. And we applied the Synapse mid-case CO_2 price forecast, as an alternative to the Company's lower forecast. The Synapse base-case combines these two changes, while leaving Company base case assumptions unchanged (except for correction of specific modeling errors identified by Ms. Wilson.)

Q. Does the Synapse base-case represent the extreme case that the Company should consider?

A. No, it does not. The Synapse base-case is an improvement over the Company base-case, more accurately representing the central estimate of future conditions. Regarding CO_2 prices, the Synapse low- and high-cases represent reasonable extremes; the Company's sole forecast in this area is almost identical to the Synapse low-case. Regarding energy efficiency, the Synapse scenario assumes incremental annual gains of one percent, while as I have noted, some states have already achieved more than this; in addition, greater use of demand response measures that reduce peak loads could be modeled.

In addition, the Company should consider the other two factors I discussed: it should analyze a less favorable ratio of coal-to-gas prices; and it should include low load growth scenarios, as low as or lower than the Company's low load scenario. Energy efficiency and low load growth are two separate phenomena with unrelated causes; the Company should model them separately, not treat them as alternative explanations for a single, moderate reduction in load. Our extremely limited access to the models used by the Company to develop prices, and the limited time available after we obtained access to the Company's PROSYM model, prevented the development of a more adequate ensemble of Synapse scenarios.

Q. Please describe the results of the Synapse modeling of Cayuga retirements.

A. As shown in Table 1 near the beginning of my testimony, retrofit of both Cayuga 1 and 2 appears beneficial under Company base case assumptions. That benefit is sharply reduced by the extended energy efficiency scenario, and is reversed by the Synapse mid-case CO_2 price. The combination of these two changes, in the Synapse base-case, makes the retrofit of either Cayuga unit very costly to the ratepayers: revenue requirements are [redacted] lower if Cayuga 1 is retired, and [redacted] lower if Cayuga 2 is retired.

In short, the case for continued operation of Cayuga 1 and 2 is crucially dependent on the Company's low CO_2 price forecast, and on the Company base-case assumptions about limited energy efficiency options after 2020. With CO_2 prices comparable to many other utility forecasts, such as the Synapse mid-case, it is much cheaper to retire both Cayuga units. I therefore recommend that the Commission should not approve the requested CPCN for Cayuga 1 and 2.

Q. Please describe the Synapse findings regarding the Company's modeling of Gallagher retirements.

A. The Company's modeling of Gallagher retrofits vs. retirement contains multiple errors. At least three of these errors have substantial effects on the estimated revenue requirement impacts of retiring Gallagher 2 and 4.

First, the Company PROSYM scenarios modeling retirement of either unit erroneously include continued operation of both Gallagher 2 and 4, and include the costs of operating both units, along with costs for replacement capacity.

Correction of this error alone, in the Synapse PROSYM analysis, leads to revised estimates of the net benefits of retrofits of [redacted] for Gallagher 2 and [redacted] for Gallagher 4 under Company base case assumptions, as shown in Table 1. These revised estimates are far below the figures reported by the Company.

Second, in the Gallagher retrofit scenarios, the Company projects retirement of Gallagher 2 at the beginning of 2033 and Gallagher 4 at the beginning of 2032, but fails to model the costs of replacement capacity through 2034 – even though the calculation of revenue requirements extends through 2034. It was difficult to include the appropriate costs in our modeling, due to the ad hoc treatment of 2033 and 2034 data in the revenue requirement calculations: the Company's PROSYM analysis runs through 2032, and data for 2033 and 2034 are based on data for 2032 with inflation adjustments. Therefore, we calculated the capital costs for replacement capacity, following the pattern in the Company's retirement scenarios, levelized those costs over 30 years, and included the present value of the appropriate number of years of levelized replacement costs (two years for Gallagher 2, three years for Gallagher 4) in a spreadsheet adjustment. The results, as shown in Table 1, reduce the benefits of retrofits by [redacted] for Gallagher 2 and [redacted] for Gallagher 4.

Third, the Company acknowledged in a discovery response that it used the wrong coal prices in its analysis of the Gallagher units, and estimated that correcting this error would reduce the revenue requirement benefits of retrofitting each unit by [redacted]. We therefore included this adjustment as well, as shown in Table 1.

Q. What conclusions do you draw from these calculations about the appropriate treatment of the Gallagher units?

A. After correcting these three major errors, there is no remaining benefit of retrofitting Gallagher 4 under the Synapse base-case, and a mere [redacted] benefit for Gallagher 2. The Company's total investments under Phases 2 and 3 combined would total about [redacted] for each of the Gallagher units, with the largest expenditures for ACI, SNCR, and increased ash disposal costs. This investment seems disproportionate to the small expected benefit at Gallagher 2, let alone the absence of any benefit at Gallagher 4.

At the same time, there are significant environmental risks to continued operation of these units. The new ozone NAAQS has not yet been decided; strict limits on ozone could require SCR rather than SNCR, an expense that would render either Gallagher unit unprofitable to operate. Removal of mercury, via ACI, will entail disposal of ash containing mercury throughout the remaining lifetime of the Gallagher units. There are, moreover, economic risks that could worsen the prospects for the Gallagher plants, as discussed earlier in my testimony.

Thus I conclude that the risks associated with continued operation of either Gallagher unit outweigh the small to nonexistent economic benefit found under a corrected analysis of these plants. I therefore recommend that the Commission should not approve the requested CPCN for Gallagher 2 and 4.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

I, Frank Ackerman, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Frank Ackerman   29 Nov. 2012

Frank Ackerman   Date

EXHIBIT FA-1

Frank Ackerman

Senior Economist
Synapse Energy Economics
485 Massachusetts Ave., Suite 2, Cambridge, MA 02139
(617) 453-7064 • fax: (617) 661-0599
www.synapse-energy.com
fackerman@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. Senior Economist, 2012 – present.
Consult on issues of energy economics, environmental impacts, climate change policy, and environmental externalities valuation.

Stockholm Environment Institute - U.S. Center, Somerville, MA. Senior Economist and Director of Climate Economics Group, 2007 – 2012.
Wrote extensively for academic, policy, and general audiences, and directed studies for a wide range of government agencies, international organizations, and nonprofit groups.

Tufts University, Global Development and Environment Institute, Medford, MA. Senior Researcher, 1995 – 2007.
Editor of GDAE's *Frontier Issues in Economic Thought* book series, a coauthor of GDAE's macroeconomics textbook, and director of the institute's Research and Policy program. Taught courses in the Tufts Department of Urban and Environmental Policy and Planning.

Tellus Institute, Boston, MA. Senior Economist, 1985 – 1995.
Responsible for research and consulting on aspects of economics of energy systems and of solid waste and recycling.

University of Massachusetts, Boston, MA. Visiting Assistant Professor of Economics, 1982 – 1984.

Dollars and Sense, Somerville, MA. Editor and Business Manager, 1974 – 1982.

EDUCATION

Harvard University, PhD, Economics, 1975
Swarthmore College, BA, Mathematics and Economics, 1967

AFFILIATIONS

Economics for Equity and the Environment (E3 Network), Portland, OR
Co-founder and steering committee member, 2007 – present

Center for Progressive Reform, Washington, DC
Member scholar, 2002 – present

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“Stern Advice for Copenhagen” (2009). Review of *Blueprint for a Safer Planet*, by Nicholas Stern, in *Nature Reports: Climate Change* (online journal), April 2009.

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Dated October 2012.

EXHIBIT FA-2

CAC
IURC Cause No. 44217
Data Request Set No. 1
Received: October 3, 2012

CAC 1.20

Request:

Please provide any DSM potential studies performed by or for Duke Energy Indiana and Duke Energy in the last five years, including attendant workbooks or calculations. Please describe if or how these studies are incorporated into the current case. If they are not, please explain why not.

Objection:

As to Duke Energy, Duke Energy Indiana objects to this request as such information is not relevant to this proceeding and not reasonably calculated to lead to admissible evidence. In addition, Duke Energy Indiana objects to the term “potential studies” as it is vague, ambiguous and overly broad.

Response:

Subject to and without waiving the foregoing general and specific objections,

Duke Energy Indiana does not have a market potential study that was completed in the last five years.

CAC
IURC Cause No. 44217
Data Request Set No. 1
Received: October 3, 2012

CAC 1.32

Witness Esamann

Request:

Please refer to Direct Testimony of Douglas Esamann, pages 8 and 9.

a. Please provide supporting workpapers for the figures entitled: “2012 Duke Energy Indiana Capacity by Resource Type”, “2011 Duke Energy Indiana Energy by Resource Type”, “Projected 2016 Duke Energy Indiana Capacity by Resource Type”, and “Projected 2016 Duke Energy Indiana Energy by Resource Type.”

b. Please provide supporting workpapers for the estimates Duke Energy Indiana’s emissions of SO_2, NO_X and mercury, including each emission type by unit.

c. Identify and explain the basis for projecting that DEI’s demand response and energy efficiency capacity increasing from 6% and 3%, respectively, in 2012 to 7% and 5%, respectively in 2016.

    i. Please state whether DEI has evaluated the cost or feasibility of increasing demand response and energy efficiency capacity beyond 7% and 5%, respectively, by 2016. If so, produce such evaluation. If not, explain why not.

d. Please identify and explain the basis for projecting that DEI’s demand response and energy efficiency capacity increasing from 6% and 3%, respectively, in 2012 to 7% and 5%, respectively in 2016.

e. Please state whether DEI has evaluated the cost or feasibility of increasing demand response and energy efficiency capacity savings beyond 7% and 5%, respectively, by 2016. If so, produce such evaluation. If not, explain why not.

f. Please identify and explain the basis for projecting that DEI’s demand response and energy efficiency would increase from four percent to six percent from 2012 to 2016.

g. Please state whether DEI has evaluated the cost or feasibility of increasing demand response and energy efficiency savings beyond 4% and 6%, respectively, by 2016. If so, produce each evaluation. If not, explain why not.

Objection:

Duke Energy Indiana objects to this question as to subpart (f). Subpart (f) assumes facts that are not in the evidence. Therefore, the request is not reasonably calculated to lead to the discovery of admissible evidence.

Response:

a. See Confidential Attachment CAC 1.32-A.

b. The historical SO_2 and NOx data used to develop the chart provided in Mr. Esamann's testimony on page 10 titled "Duke Energy Indiana Emissions Performance" and the data provided on pages 9-10 was retrieved from US EPA's CAMD website. A copy of that emissions information is provided in CD-Rom Attachment CAC 1.32-B. The 2010 estimated mercury emissions provided on page 9 came from the Company's 2010 TRI emissions report. The individual site data is provided in Attachment CAC 1-32-B. The 2013 and 2014 SO_2 and NOx data presented represent the number of emission allowances the company expected to receive under the CSAPR program.

c. Duke Energy Indiana's analysis assumes that it will be in compliance with the Generic Order in Cause No. 42693-S1 which requires achievement of pre-determined levels of Energy Efficiency by certain dates in the future. The increase in the share of the overall Duke Energy Indiana Capacity represented by Energy Efficiency is due to the addition of programs designed to produce savings in compliance with the Generic Order. For Demand Response, continued increases in the Power Manager and PowerShare programs contribute to increasing capacity values. In addition, it is projected that demand response load reductions from special contract customers is maintained over this projected period.

c (i). Duke Energy Indiana has not evaluated the costs or feasibility of increasing demand response or energy efficiency capacity savings beyond 7% and 5%, respectively, by 2016. The Generic Order levels of achievements were used as the basis for the approval of the portfolio of energy efficiency measures to be offered by Duke Energy Indiana and additional achievements over and above these levels have not been authorized for energy efficiency programs by the IURC. Note that certain demand response program achievements are captured in Duke Energy Indiana Rider 70 proceedings.

d. Same question as c. above.

e. Same question as c(i) above.

f. Mr. Esamann's testimony shows that the Energy portion of the EE and Demand Response achievements increases from 3% to 6% rather than the 4% to 6% asked in this question. See response to c.

g. See responses to f. and c(i).

CAC
IURC Cause No. 44217
Data Request Set No. 1
Received: October 3, 2012

CAC 1.87

Request:

Please refer to Direct Testimony of Robert McMurry, page 7, lines 20 to 23.

a. Please provide the analysis and supporting workpapers for the Company's CO_2 price projections.

b. Please provide a list of sources the Company has reviewed for projecting CO_2 prices.

c. Does the Company believe that their CO_2 price projections are consistent with projections from utilities or other sources it has reviewed? If so, identify which utilities or other sources you have reviewed. If not, explain why not.

d. Has the Company performed a scenario or sensitivity with higher CO2 price assumptions than in the base case? If not, please explain why not. If so, please provide the results from that analysis in electronic, machine-readable format.

e. If the Company believes that "it is likely that there will be a carbon constrained future" then please explain why the Company did not include a sensitivity for higher CO_2 prices in its economic analysis in the filing.

Objection:

Duke Energy Indiana objects to subpart (a) of this Request on the grounds that it is vague, ambiguous, overbroad and unduly burdensome, particularly as to the phrase "analysis and supporting workpapers." Duke Energy Indiana also objects to subpart (b) of this Request on the grounds that it is overbroad and burdensome to seek all sources that "the Company has reviewed for projecting CO_2 prices."

Response:

Subject to and without waiving its objections, Duke Energy Indiana states as follows:

a. At the time Duke Energy developed its current base case CO_2 price projection in late 2011, there were no legislative proposals in play. Prior to that time there had been numerous legislative proposals introduced in Congress, with one proposal, H.R. 2454, passing in the U.S. House of Representatives, but not passing in the U.S. Senate. Given this earlier failure of CO_2 legislation in Congress, the economic challenges facing the nation, and the changing political landscape following the 2010 mid-term elections, it was not possible to predict what action might be taken at the federal level to enact climate change legislation. Despite the uncertainty, however, Duke Energy believed at the time it developed its current base case CO_2 price projection and still believes there is a risk that Congress could eventually enact legislation of some form that puts a price on greenhouse gas emissions from the electric utility sector. The intent of Duke Energy's base case CO_2 price projection is to reflect the fact that there was and is a risk associated with our greenhouse gas emissions. The price level of our base case projection reflects Duke Energy's belief that if or when Congress does act, it will do so cautiously, and therefore, reflects our consideration of what might be plausible politically. See also Confidential Attachment CAC 1.87-A.

b. Limiting its response to just sources reviewed for purposes of projecting its current base case CO_2 price projections, Duke Energy Indiana states as follows: U.S. Environmental Protection Agency, *EPA Analysis of the American Clean Energy and Security Act of 2009 H.R. 2454 in the 111th Congress*, 6/23/09

Energy Information Administration Office of Integrated Analysis and Forecasting, *Energy Market and Economic Impacts of H.R. 2454, the American, Clean Energy and Security Act of 2009*, August 2009

c. While Duke Energy's current base case CO_2 price projection is not based on a specific policy, we did compare our price projection to price projections developed for earlier legislative proposals. That comparison reinforced our belief that our base case CO_2 price projection was reasonable given the uncertainty surrounding potential future federal climate change legislation. Please refer to the response (b) above for sources Duke Energy reviewed for projecting its current base case CO_2 price projection.

d. No. Please see Duke Energy Indiana's responses to subparts (a) and (c) above.

e. Including CO_2 price assumptions in <u>all</u> scenarios except the "No CO_2" scenario reflects the Company's belief that it is likely that there will be a carbon constrained future, as discussed in its responses to (a) and (c) above.

Witness: Robert Mc Murry

CAC
IURC Cause No. 44217
Data Request Set No. 2
Received: October 29, 2012

CAC 2.7

Request:

Please refer to data response CAC 1.88(e). Does the Company claim that "increasing EE beyond what is required" should not be considered as an additional resource in the Company's planning?

Objection:

Duke Energy Indiana objects to this Request on the grounds that it misrepresents the Company's prior response to CAC 1.88(e), which stated in relevant part that "Increasing EE beyond what is required in the Commission's Generic Order was not considered." Nowhere in Duke Energy Indiana's response to CAC 1.88(e) did the Company "claim that increasing EE beyond what is required should not be considered as an additional resource in the Company's planning."

Response:

Subject to and without waiving its objections, Duke Energy Indiana responds as follows:

The Company's assumptions in its modeling are reasonable. The analysis accounts for compliance with the Commission's Generic Order, which results in a reduction of retail sales of approximately 9% by 2020. This amount of reduction is highly dependent upon customer adoption of offered EE measures. Duke Energy believes that the requirements of the Generic Order are aggressive. After 2020, Duke Energy Indiana's modeling assumes the EE portfolio continues to grow at the same rate as load growth, which maintains the 9% reduction in retail sales throughout the planning period.

Witness: Robert A. Mc Murry

EXHIBIT FA-3

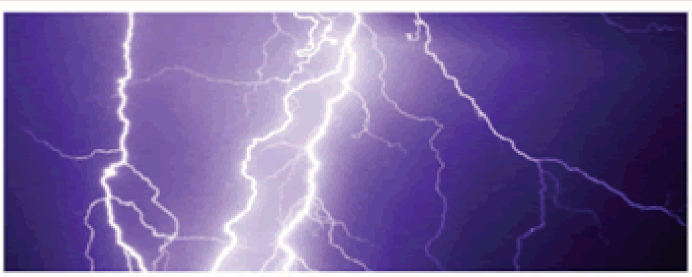
Synapse
Energy Economics, Inc.

2012 Carbon Dioxide Price Forecast

October 4, 2012

AUTHORS

Rachel Wilson, Patrick Luckow,
Bruce Biewald, Frank Ackerman,
and Ezra Hausman



485 Massachusetts Ave.
Suite 2
Cambridge, MA 02139

617.661.3248
www.synapse-energy.com

Table of Contents

1. Executive Summary

Electric utilities and others should use a reasonable estimate of the future price of carbon dioxide (CO_2) emissions when evaluating resource investment decisions with multi-decade lifetimes. Estimating this price can be difficult because, despite several attempts, the federal government has not come to consensus on a policy (or a set of policies) to reduce greenhouse gas (GHG) emissions in the U.S.

Although this lack of a defined policy certainly creates challenges, a "zero" price for the long-run cost of carbon emissions is not a reasonable estimate. The need for a comprehensive effort in the U.S. to reduce GHG emissions has become increasingly clear, and it is certain that any policy requiring, or leading to, these reductions will result in a cost associated with emitting CO_2 over some portion of the life of long-lived electricity resources. Prudent planning requires a reasonable effort to forecast CO_2 prices despite the considerable uncertainty with regard to specific regulatory details.

This 2012 forecast seeks to define a reasonable range of CO_2 price estimates for use in utility Integrated Resource Planning (IRP) and other electricity resource planning analyses. This forecast updates Synapse's 2011 CO_2 price forecast, which was published in February of 2011. Our 2012 forecast incorporates new data that has become available since 2011, and extends the study period end-date to 2040 in order to provide recommended CO_2 price estimates for utilities planning 30 years out into the future.

A. Key assumptions

Synapse's 2012 CO_2 price forecast reflects our expectation that cap-and-trade legislation will be passed by Congress in the next five years, and the resultant allowance trading program will take effect in or around 2020. These assumptions are based on the following reasoning:

- We believe that a federal cap-and-trade program for GHGs is a key component of the most likely policy outcome, as it enables the reduction of significant amounts of GHGs while allowing those reductions to come from sources that can mitigate their emissions at the least cost.
- We believe that federal legislation is likely by the end of the session in 2017 (with implementation by about 2020) prompted by one or more of the following factors:
    - o technological opportunity
    - o a patchwork of state policies to achieve state emission targets for 2020 spurring industry demands for federal action
    - o a Supreme Court decision to allow nuisance lawsuits to go ahead, resulting in a financial threat to energy companies
    - o increasingly compelling evidence of climate change

Given the interest and initiatives on climate change policies in states throughout the nation, a lack of federal action will result in a hodgepodge of state policies. This scenario is a challenge for any company that seeks to make investments in existing, modified, or new power plants. It would also lead to inefficient emissions decisions that are driven by inconsistent policies rather than economics. Historically, this pattern of states and regions initiating policies that are eventually superseded at a national level has been common for energy and environmental regulation in the U.S. It seems likely that this will be the dynamic that ultimately leads to federal action on greenhouse gases, as well.

In addition to the assumptions regarding a federal GHG program described above, we anticipate that regional and state policies will lead to costs associated with GHGs in the near-term (i.e., prior to 2020). Prudent planning requires that utilities take these costs into account when engaging in resource planning.

B. Study approach

To develop its 2012 CO_2 price forecast, Synapse reviewed more than 40 carbon price estimates and related analyses, including:

- McKinsey & Company's 2010 analyses of the marginal abatement costs and abatement potential of GHG mitigation technologies
- Analyses of the CO_2 allowance prices that would result from the major climate change bills introduced in Congress over the past several years, including analyses by the Energy Information Association (EIA) and the Environmental Protection Agency (EPA)
- The U.S. Interagency Working Group's estimates for the social cost of carbon
- Analyses of the factors that affect projections of allowance prices, including analyses by the EIA and Resources for the Future
- CO_2 price estimates used by utilities in a wide range of publicly available utility Integrated Resource Plans

Because we expect that a federal cap and allowance trading program will ultimately be adopted, analyses of the various Congressional proposals to date using this approach offer some of the most relevant estimates of costs associated with greenhouse gas emissions under a variety of regulatory scenarios. It is not possible to compare the results of all of these analyses directly, however, because the specific models and the key assumptions vary.

Synapse also considered the impact on CO_2 prices of regulatory measures outside of a cap-and-trade program—such as a federal Renewable Portfolio Standard—that could simultaneously help to achieve the emission-reduction goals of cap-and-trade. These "complementary policies" result in lower CO_2 allowance prices, since they would reduce the demand for CO_2 emissions allowances under cap-and-trade.

C. Synapse's 2012 CO_2 price forecast

Based on analyses of the sources described above, and relying on its own expert judgment, Synapse developed Low, Mid, and High case forecasts for CO_2 prices from 2020 to 2040. These cases represent different appetites for reducing carbon, as described below.

- The Low case forecast starts at $15/ton in 2020, and increases to approximately $35/ton in 2040.[1] This forecast represents a scenario in which Congress begins regulation of greenhouse gas emissions slowly—for example, by including a modest emissions cap, a safety valve price, or significant offset flexibility. This price forecast could also be realized through a series of complementary policies, such as an aggressive federal Renewable Portfolio Standard, substantial energy efficiency investment, and/or more stringent automobile CAFE mileage standards (in an economy-wide regulation scenario).
- The Mid case forecast starts at $20/ton in 2020, and increases to approximately $65/ton in 2040. This forecast represents a scenario in which a federal cap-and-trade program is implemented with significant but reasonably achievable goals, likely in combination with some level of complementary policies to give some flexibility in meeting the reduction goals. Also assumed in the Mid case is some degree of technological learning, i.e. assuming that prices for emissions reductions technologies will decline as greater efficiencies are realized in their design and manufacture and as new technologies become available.
- The High case forecast starts at $30/ton in 2020, and increases to approximately $90/ton in 2040. This forecast is consistent with the occurrence of one or more factors that have the effect of raising prices. These factors include somewhat more aggressive emissions reduction targets; greater restrictions on the use of offsets (nationally or internationally); restricted availability or high cost of technology alternatives such as nuclear, biomass and carbon capture and sequestration; or higher baseline emissions.

Table ES-1 presents Synapse's Low, Mid, and High case price projections for each year of the study period, as well as the levelized cost for each case.

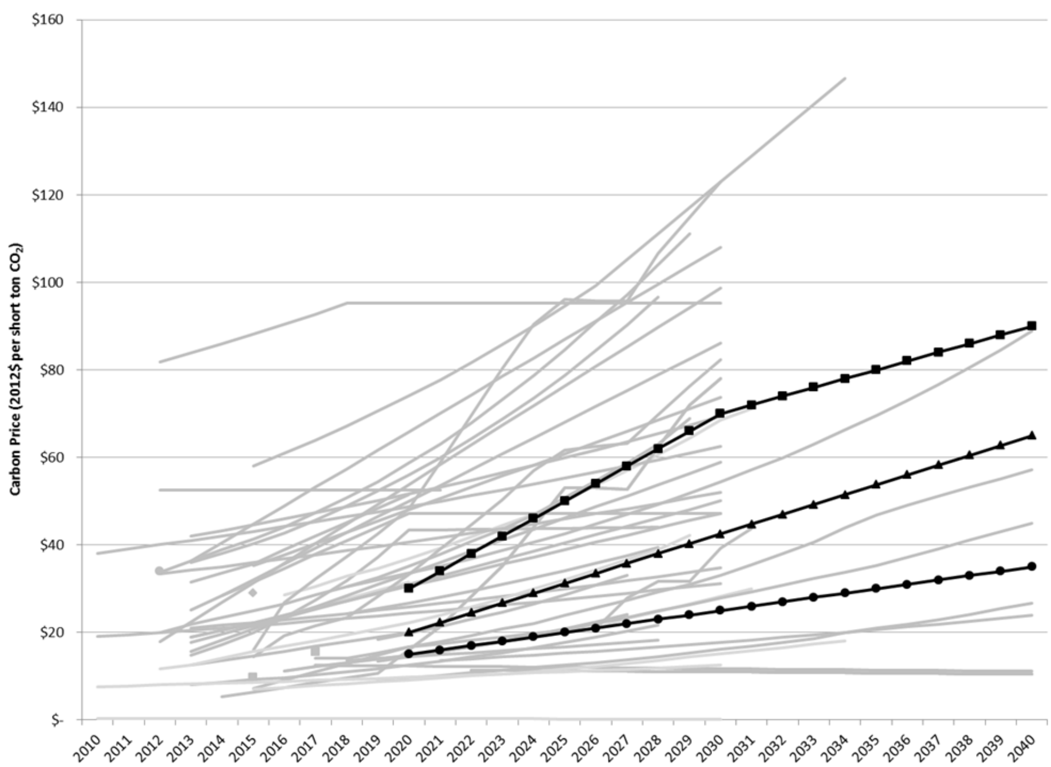
Figure ES-1 presents Synapse's Low, Mid, and High case forecasts as compared to a broad range of CO_2 allowance prices used by utilities in resource planning over the past three years. Synapse forecasts are represented by black lines, while utility forecasts are represented by grey.

[1] Throughout this report, CO_2 allowance prices are presented in $2012 per short ton CO_2, except in reference to a few original sources, where alternate units are clearly labeled. Results from other modeling analyses were converted to 2012 dollars using price deflators taken from the US Bureau of Economic Analysis. Because data were not available for 2012 in its entirety, values used for conversion were taken from Q2 of each year. Results originally provided in metric tonnes were converted to short tons by multiplying by a factor of 1.1.

Table ES-1: Synapse 2012 CO_2 allowance price projections (2012 dollars per ton CO_2)

Year	Low Case	Mid Case	High Case
2020	$15.00	$20.00	$30.00
2021	$16.00	$22.25	$34.00
2022	$17.00	$24.50	$38.00
2023	$18.00	$26.75	$42.00
2024	$19.00	$29.00	$46.00
2025	$20.00	$31.25	$50.00
2026	$21.00	$33.50	$54.00
2027	$22.00	$35.75	$58.00
2028	$23.00	$38.00	$62.00
2029	$24.00	$40.25	$66.00
2030	$25.00	$42.50	$70.00
2031	$26.00	$44.75	$72.00
2032	$27.00	$47.00	$74.00
2033	$28.00	$49.25	$76.00
2034	$29.00	$51.50	$78.00
2035	$30.00	$53.75	$80.00
2036	$31.00	$56.00	$82.00
2037	$32.00	$58.25	$84.00
2038	$33.00	$60.50	$86.00
2039	$34.00	$62.75	$88.00
2040	$35.00	$65.00	$90.00
Levelized	$23.24	$38.54	$59.38

Figure ES-1: Synapse forecasts compared to a range of utility forecasts



2. Structure of this Paper

This paper presents Synapse's assumptions, data sources, and estimates of reasonable future CO_2 prices for use in resource planning analyses. The report is structured as follows:

- Section 3 discusses the key assumptions behind Synapse's estimates
- Sections 4 through 8 present data from the sources reviewed by Synapse in developing its estimates of the future price of CO_2 emissions
- Section 9 presents Synapse's 2012 Low, Mid, and High CO_2 price forecasts, and compares these projections to a range of utility forecasts
- Appendix A provides a more detailed discussion of state and regional GHG initiatives. Collectively, these initiatives suggest that momentum is building toward federal GHG action

3. Discussion of Key Assumptions

A. Federal GHG legislation is increasingly likely

Congressional action in the form of cap-and-trade or clean energy standards is only one avenue in an increasingly dynamic and complex web of activities that could result in internalizing a portion of the costs associated with emissions of greenhouse gases from the electric sector. The states, the federal courts, and federal agencies are also grappling with the complex issues associated with climate change. Many of these efforts are proceeding simultaneously.

Nonetheless, we believe that a federal cap-and-trade program for GHGs is the most likely policy outcome, as it enables the reduction of significant amounts of GHGs while allowing those reductions to come from sources that can mitigate their emissions at the least cost. Several cap-and-trade proposals have been taken up by Congress in the past few years, though none yet have been passed by both houses. (More discussion of this topic is provided in Section 5 of this report.)

We further believe that federal action will occur in the near-term. This 2012 CO_2 price forecast assumes that cap-and-trade legislation will be passed by Congress in the next five years, and the resultant allowance trading program will take effect in 2020, prompted by one or more of the following factors:

- technological opportunity
- a patchwork of state policies to achieve state emission targets for 2020 spurring industry demands for federal action
- a Supreme Court decision to allow nuisance lawsuits to go ahead, resulting in a financial threat to energy companies
- increasingly compelling evidence of climate change

Given the interest and initiatives on climate change policies in states throughout the nation, a lack of federal action will result in a hodgepodge of state policies. This scenario is a challenge for any company that seeks to make investments in existing, modified, or new power plants. It would also lead to inefficient emissions decisions driven by inconsistent policies rather than economics. Historically, this pattern of states and regions initiating policies that are eventually superseded at a national level has been common for energy and environmental regulation in the U.S. It seems likely that this will be the dynamic that ultimately leads to federal action on greenhouse gases, as well.

B. State and regional initiatives building toward federal action

The states—individually and coordinating within regions—are leading the nation's policies to respond to the threat of climate change. In fact, several states, unwilling to wait for federal action, are already pursuing policies on their own or in regional groups. These policies are described below, and are discussed in more detail in Appendix A of this report.

Cap-and-trade programs

The Northeast/Mid-Atlantic region and the state of California have developed, or are in the last stages of developing, greenhouse gas caps and allowance trading. [2]

Under the Regional Greenhouse Gas Initiative (RGGI), ten Northeast and Mid-Atlantic states have agreed to a mandatory cap on CO_2 emissions from the power sector with the goal of achieving a ten percent reduction in these emissions from levels at the start of the program by 2018.

Meanwhile, California's Global Warming Solutions Act (AB 32) has created the world's second largest carbon market, after the European Union's Emissions Trading System (EU ETS). The first compliance period for California's cap-and-trade program will begin on January 1, 2013, and will cover electricity generators, carbon dioxide suppliers, large industrial sources, and petroleum and natural gas facilities emitting at least 25,000 metric tons of CO_2e[3] per year. The initial cap is set at 162.8 million metric tons of CO_2e and decreases by 2% annually through 2015.

State GHG reduction laws

Massachusetts: In 2008, the Massachusetts Global Warming Solutions Act was signed into law. In addition to the commitments to power sector emissions reductions associated with RGGI, this law committed Massachusetts to reduce statewide emissions to 10-25% below 1990 levels by 2020 and 80% below 1990 levels by 2050. Following the development of a comprehensive plan on steps to meet these goals, the 2020 target was set at 25% below 1990 levels.[4] Rather than put a price on carbon in the years before 2020, this plan will achieve a 25% reduction through a combination of federal, regional, and state-level regulations applying to buildings, energy supply, transportation, and non-energy emissions.

Minnesota: In 2008, the Next Generation Energy Act was signed to reduce Minnesota emissions by 15% by 2015, 30% by 2025, and 80% by 2050.[5] While the law called for the development of an action plan that would make recommendations on a cap-and-trade system to meet these goals, the near-term goals will be met by a combination of an aggressive renewable portfolio standard and energy efficiency.

Connecticut: Also in 2008, the state of Connecticut passed its own Global Warming Solutions Act, establishing state level targets 10% below 1990 levels by 2020 and 80% below 2001 levels by 2050. In December 2010, the state released a report on mitigation options focused on regulatory mechanisms in addition to strengthening RGGI and reductions of non-CO_2 greenhouse gases.[6]

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[2] The Midwest Greenhouse Gas Reduction Accord was developed in 2007. Though the agreement has not been formally suspended, the participating states are no longer pursuing it.
[3] CO2e refers to carbon dioxide equivalent, a measure that includes both carbon dioxide and other greenhouse gases converted to an equivalent amount of carbon dioxide based on their global warming potential.
[4] Massachusetts Clean Energy and Climate Plan for 2020, Available at: http://www.mass.gov/green/cleanenergyclimateplan
[5] Minnesota Statutes 2008 § 216B.241
[6] See http://www.ctclimatechange.com for further details on CT plans for emissions mitigation.

Renewable portfolio standards and other initiatives

A renewable portfolio standard (RPS) or renewable goal specifies that a minimum proportion of a utility's resource mix must be derived from renewable resources. The standards range from modest to ambitious, and qualifying energy sources vary by state.

Currently, 29 U.S. states have renewable portfolio standards. Eight others have renewable portfolio goals. In addition, many states are pursuing other policy actions relating to reductions of GHGs. These policies include, but are not limited to: greenhouse gas inventories, greenhouse gas registries, climate action plans, greenhouse gas emissions targets, and emissions performance standards.

In the absence of a clear and comprehensive federal policy, many states have developed a broad array of emissions and energy related policies. For example, Massachusetts has a RPS of 15% in 2020 (rising to 25% in 2030), belongs to RGGI (requiring specific emissions reductions from power plants in the state), and has set in place aggressive energy efficiency targets through the 2008 Green Communities Act.

4. Marginal Abatement Costs and Technologies

This chapter presents key data related to marginal abatement costs for CO_2, which were reviewed by Synapse in developing its estimates of the future price of CO_2 emissions.

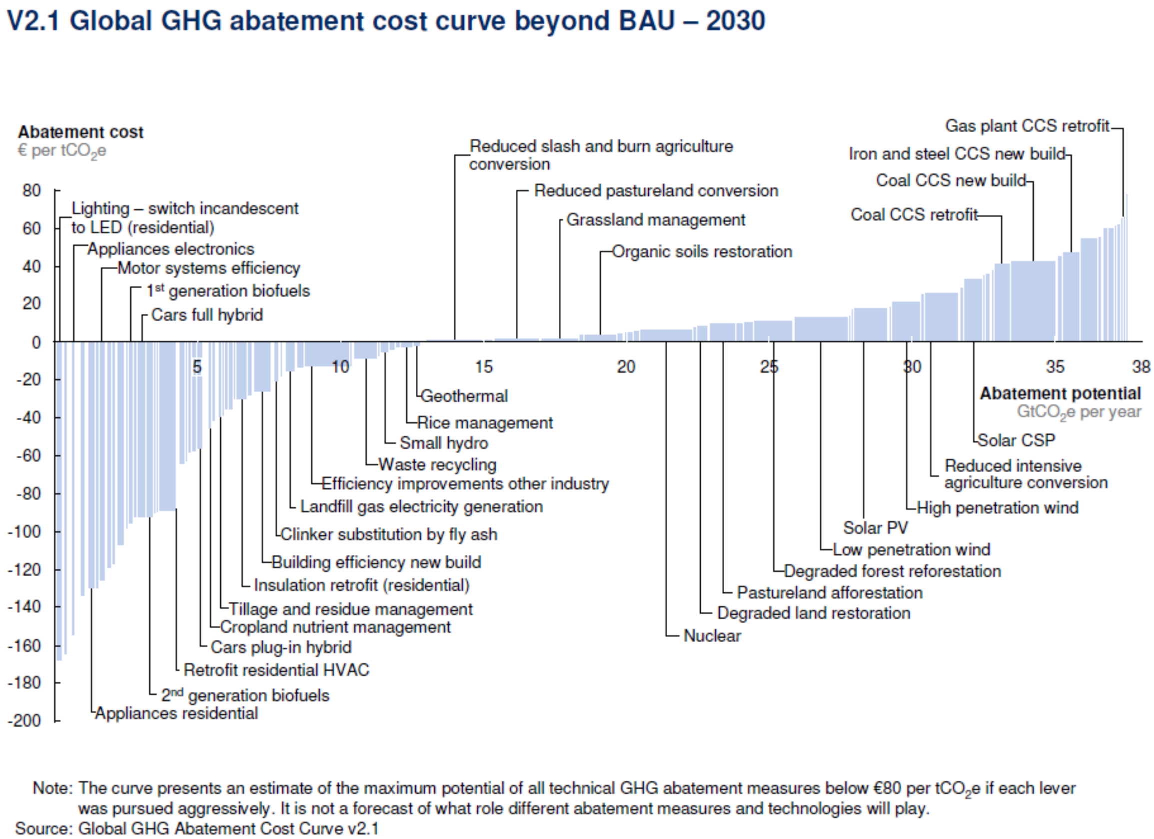
The long-run marginal abatement cost for CO_2 represents the cost of the control technologies necessary for the last (or most expensive) unit of emissions reduction required to comply with regulations. This cost depends on emission reduction goals: lower emissions reduction targets can be met by lower-cost technologies, while more stringent targets will require additional reduction technologies that are implemented at higher costs. The Copenhagen Agreement, drafted at the 15th session of the Conference of the Parties to the United Nations Framework Convention on Climate Change in 2009, recognizes the scientific view that in order to prevent the more drastic effects of climate change, the increase in global temperature should be limited to no more than 2° Celsius. Atmospheric concentrations of CO_2 would need to be stabilized at 450 ppm in order to limit the global temperature increase to no more than 2°C.[7]

In recent years, there have been several analyses of technologies that would contribute to emission reductions consistent with an increase in temperature of no more than 2°C. McKinsey & Company examined these technologies in a 2010 report entitled *Impact of the Financial Crisis on Carbon Economics: Version 2.1 of the Global Greenhouse Gas Abatement Cost Curve*. The CO_2 mitigation options identified by McKinsey and the costs of those options are shown in Figure 1. Global mitigation options are ordered from least expensive to most expensive, and the width of each bar represents the amount of mitigation likely at these costs. The chart represents a marginal abatement cost price curve, where cost of abatement is shown on the y-axis and cumulative metric tonnes of GHG reductions are shown on the x-axis. It is likely that the lowest cost reductions will be implemented first, but as reduction targets become more stringent and low-cost options are saturated, the cost of the marginal abatement technology is likely to increase.

The chart below, from the McKinsey report, provides a useful reference to the types of options and technologies that might be employed at specific CO_2 prices.

[7] IPCC, 2007: Summary for Policymakers. In: *Climate Change 2007: Mitigation. Contribution of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change* [B. Metz, O.R. Davidson, P.R. Bosch, R. Dave, L.A. Meyer (eds)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

Figure 1: McKinsey & Company marginal abatement technologies and associated costs for the year 2030[8]



As shown in Figure 1, technologies for carbon mitigation that are available to the electric sector include those related to energy efficiency, nuclear power, renewable energy, and carbon capture and storage (CCS) for fossil-fired generating resources. McKinsey estimates CCS technologies to cost 50-60 €/metric tonne (2005€). Converted into current dollars, this is equivalent to $65 to $85/ton ($71.5 to $93.5/metric tonne, 2012$). According to the International Energy Agency (IEA), "in order to reach the goal of stabilizing global emissions at 450 ppm by 2050, CCS will be necessary."[9] If this is true, it is reasonable to expect that a CO_2 allowance price will rise to $65/ton or higher under a GHG policy designed to limit the global temperature increase to no more than 2°C. However, if significant reductions could be accomplished with CCS at the high $65 to $85/ton CO_2 range, we would not expect CO_2 mitigation prices to significantly exceed the top of that range.

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[8] McKinsey & Company. *Impact of the Financial Crisis on Carbon Economics: Version 2.1 of the Global Greenhouse Gas Abatement Cost Curve.* 2010. Page 8.

[9] International Energy Agency. *Technology Roadmap: Carbon Capture and Storage*. 2009. Page 4.

5. Analyses of Major Climate Change Bills

This chapter presents key data related to analyses of major climate change bills proposed in Congress over the past few years, which were reviewed by Synapse in developing its estimates of the future price of CO_2 emissions. Because we expect that a federal cap and allowance trading program will ultimately be adopted, analyses of these proposals offer some of the most relevant estimates of costs associated with greenhouse gas emissions under a variety of regulatory scenarios. It is not possible to compare the results of all of these analyses directly, however, because the specific models and the key assumptions vary.

A. Cap-and-trade proposals

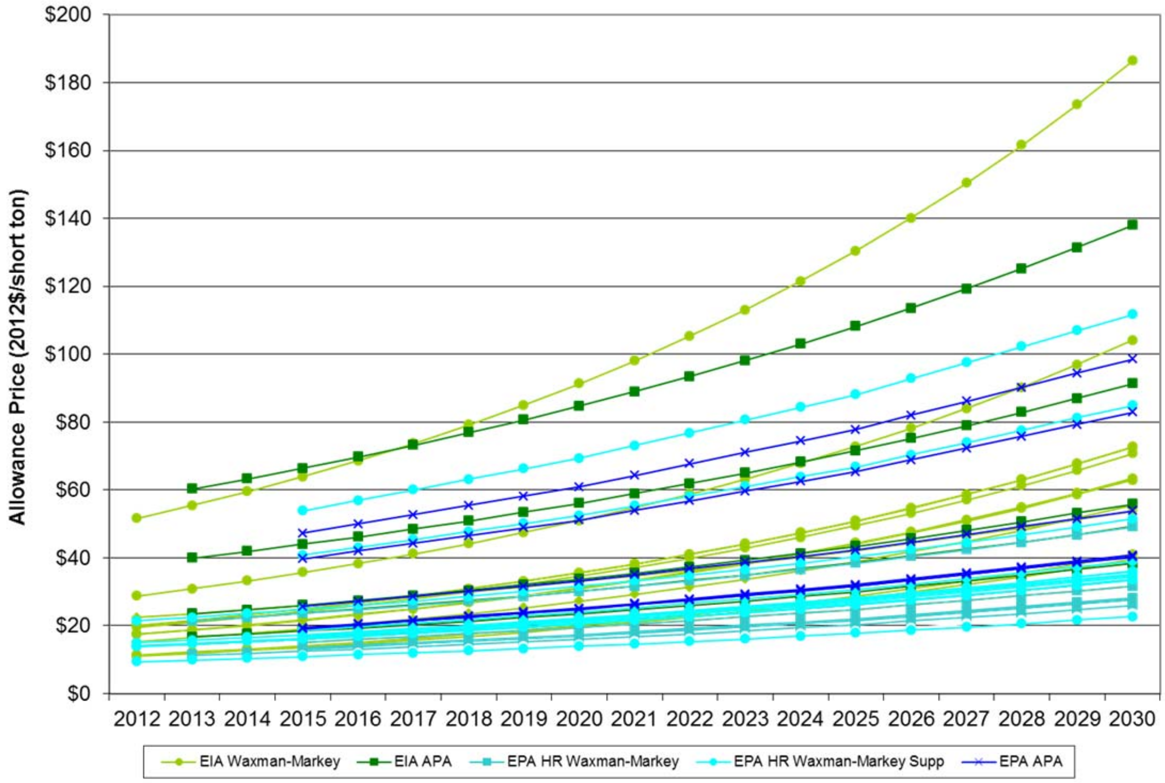
In the past decade, the expectation has been that action on climate change policy will occur at the Congressional level. Legislative proposals have largely taken the form of cap-and-trade programs, which would reduce greenhouse gas emissions through a federal cap, and would allow trading of allowances to promote reductions in GHG emissions where they are most economic. Legislative proposals and President Obama's stated target aim to reduce emissions by up to 80% from current levels by 2050.

Comprehensive climate legislation was passed in the House in the 111th Congress in the form of the American Clean Energy and Security Act of 2009 (ACES, also known as Waxman-Markey and HR 2454); however, the Senate ultimately did not take up climate legislation in that session. HR 2454 was a cap-and-trade program that would have required a 17% reduction in emissions from 2005 levels by 2020, and an 83% reduction by 2050. It was approved by the House of Representatives in June, 2009, but the Senate bill, known as the American Power Act of 2010 (APA, also known as Kerry-Lieberman), never came to a vote.

Figure 2 shows the results of EIA and EPA analyses of HR 2454 and APA. The chart shows the forecasted allowance prices in the central scenarios, as well as a range of sensitivities. Figure 3 shows these values as levelized prices for the time period 2015 to 2030.[10]

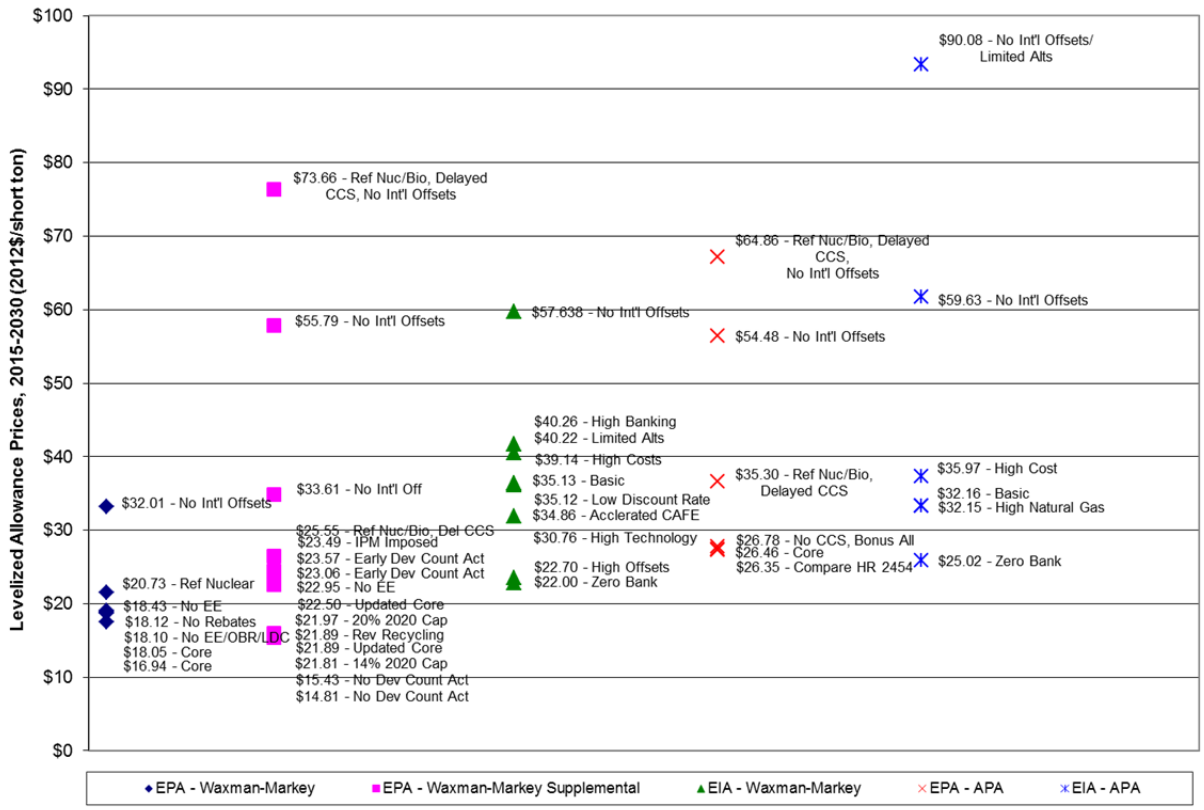
[10] Consistent with EIA and EPA modeling analyses, a 5% real discount rate was used in all levelization calculations.

Figure 2: Greenhouse gas allowance price projections for HR 2454 and APA 2010[11]



[11] Sources for Figure 2 include the following:
U.S. Energy Information Administration (EIA); *Energy Market and Economic Impacts of the American Power Act of 2010* (July 2010). Available at http://www.eia.gov/oiaf/servicerpt/kgl/index.html
EIA; *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009* (August 2009). Available at http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html
U.S. Environmental Protection Agency ("EPA"); *Analysis of the American Power Act of 2010 in the 111th Congress* (June 2010). Available at http://www.epa.gov/climatechange/Downloads/EPAactivities/EPA_APA_Analysis_6-14-10.pdf
EPA; *Supplemental EPA Analysis of the American Clean Energy and Security Act of 2009 (H.R. 2454)* (January 2010). Available at: Available at http://www.epa.gov/climatechange/economics/pdfs/HR2454_SupplementalAnalysis.pdf
EPA; *Analysis of the American Clean Energy and Security Act of 2009 (H.R. 2454)* (June 2009). Available at: http://www.epa.gov/climatechange/Downloads/EPAactivities/HR2454_Analysis.pdf

Figure 3: GHG allowance price projections for HR 2454 and APA 2010 - levelized 2015-2030



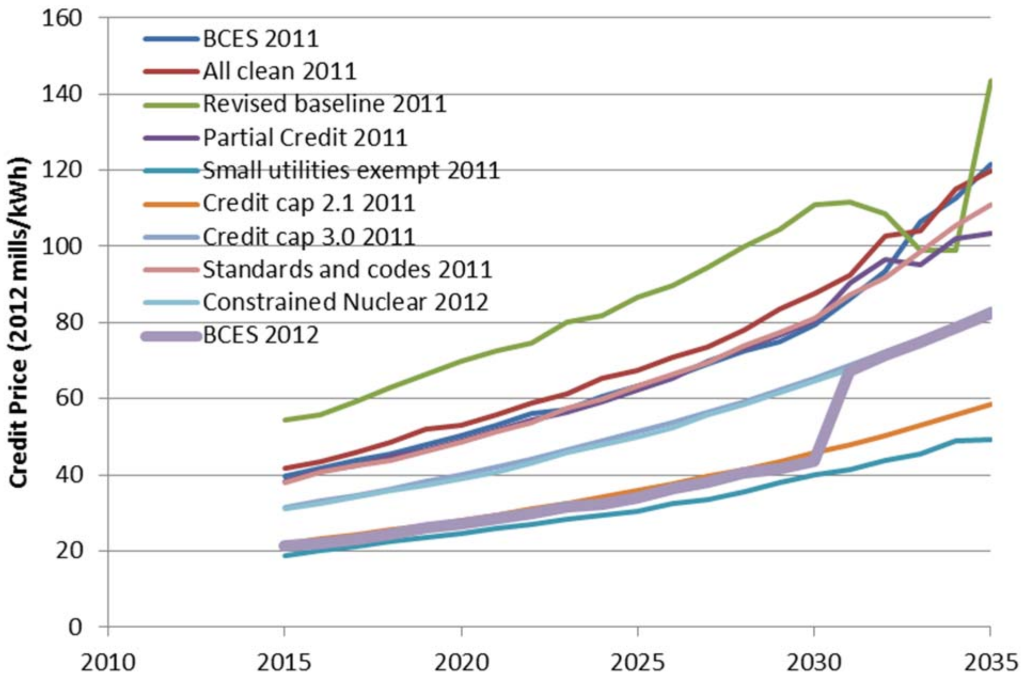
B. Clean Energy Standard

The 112th Congress chose not to revisit legislation establishing an economy-wide emissions cap, and instead focused on policies aimed at fostering technology innovation and developing renewable energy or clean energy standards. In March 2012, Senator Bingaman introduced the Clean Energy Standard Act of 2012 (S.2146), under which larger utilities would be required to meet a percentage of their sales with electric generation from sources that produce fewer greenhouse gas emissions than a conventional coal-fired power plant. All generation from wind, solar, geothermal, biomass, municipal solid waste, and landfill gas would earn a full CES credit, as would hydroelectric and nuclear facilities. Lower-carbon fossil facilities, such as natural gas and coal with carbon capture, would earn partial credits based on their CO_2 emissions. Generation owners would be required to hold credits equivalent to 24% of their sales beginning in 2015, and the CES requirement rises over time to 84% by 2035, creating demand for renewable energy and low-emissions technologies. The credits generated by these clean technologies would be tradable and have a value that would change depending on how costly the policy is to achieve. The Clean Energy Standard would apply to utilities with sales greater than 2 million MWh, and expand to include those with sales greater than 1 million MWh by 2025.

The EIA conducted analyses of a potential Clean Energy Standard in both 2011 and 2012.[12,13] All of these cases result in some level of increase in nuclear, gas, and renewable generation, typically at the expense of coal. The exact generation mix, as well as the resulting reduction in emissions, is highly dependent on both the technology costs and policy design. The resulting CES credit prices (Figure 4) vary widely, from 25 to 70 mills/kWh in 2020,[14] rising to 47 to 138 mills/kWh in 2035. The credit cap cases show a smaller rise in credit prices. When credit prices are capped at a specific value, clean energy deployment and emissions abatement is reduced.

An effective CO_2 allowance price can be calculated based on the fact that this policy gives existing gas combined cycle units 0.48 credits and existing coal units zero credits, and the emissions from an average gas unit are about 0.57 tCO_2/MWh and from an average coal unit 1.125 tCO_2/MWh.[15] For the BCES 2012 case, for example, this conversion would result in effective allowance prices of \$18.4/tCO_2 in 2015 and \$71.4/tCO_2 in 2035.

Figure 4: CES credit prices in EIA analyses of a U.S. Clean Energy Standard



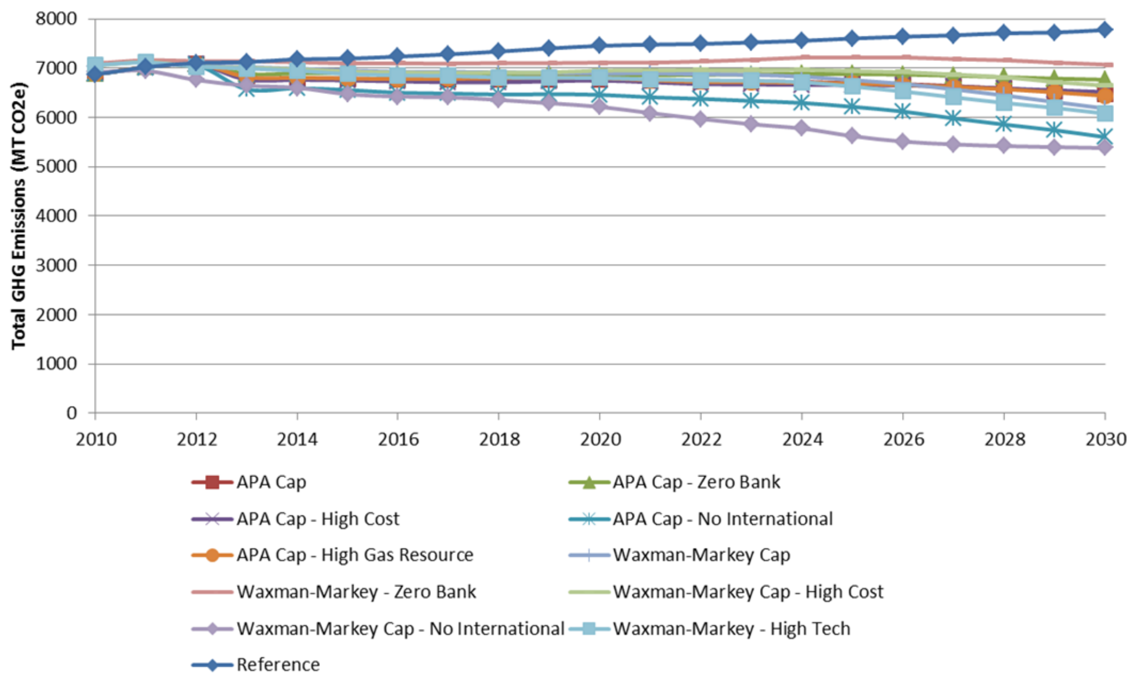
[12] US EIA. 2011. Analysis of Impacts of a Clean Energy Standard as requested by Chairman Bingaman. http://www.eia.gov/analysis/requests/ces_bingaman/.
[13] US EIA. 2012. Analysis of the Clean Energy Standard Act of 2012. http://www.eia.gov/analysis/requests/bces12/.
[14] A mill is one one-hundredth of a cent. Therefore, these CES prices in 2020 represent costs of 0.25 to 0.70 c/kWh, or \$2.5 to \$7/MWh.
[15] EPA Air Emissions Overview, Available at: http://www.epa.gov/cleanenergy/energy-and-you/affect/air-emissions.htm

6. Key Factors Affecting Allowance Price Projections

Dozens of analyses over the past several years have shown that there are a number of factors that affect projections of allowance prices under federal greenhouse gas regulation. Some of these factors derive from the details of policy design, while others pertain to the context in which a policy would be implemented.

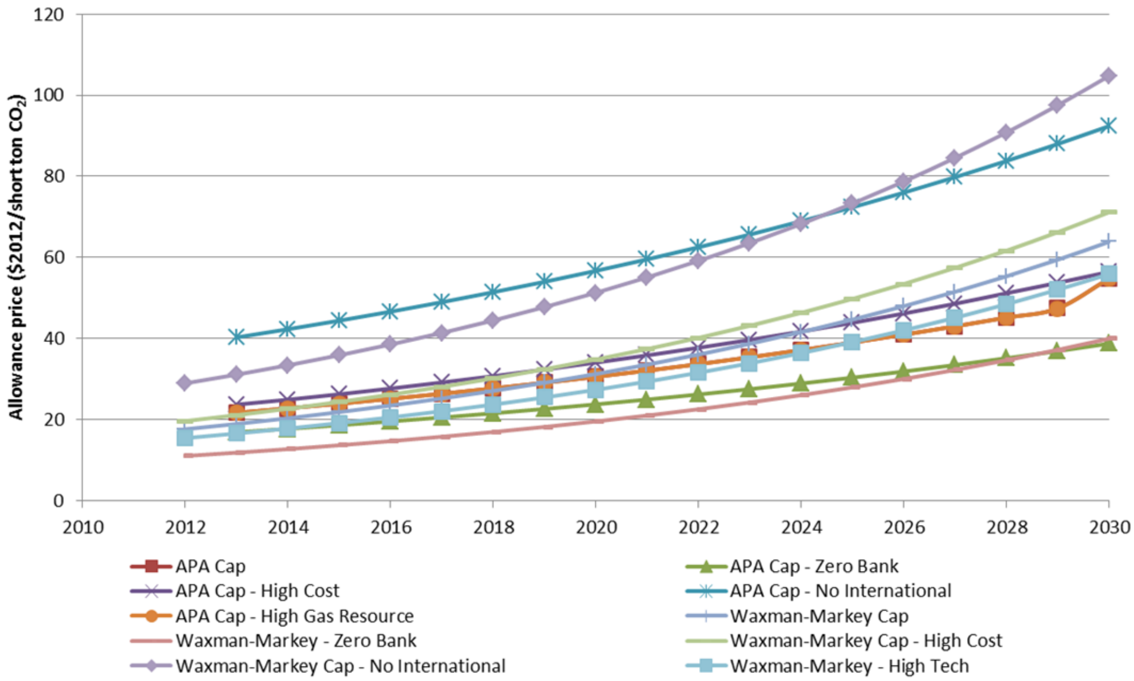
Factors in a forecast include: the base case emissions forecast; the reduction targets in each proposal; whether complementary policies such as aggressive investments in energy efficiency and renewable energy are implemented independent of the emissions allowance market; the policy implementation timeline; program flexibility regarding emissions offsets (perhaps including international offsets) and allowance banking; assumptions about technological progress; the presence or absence of a "safety valve" price; and treatment of emissions co-benefits. Figures 5 and 6 show the very significant ranges in emissions and allowance prices for the Waxman-Markey and APA federal cap-and-trade policies, as well as several associated sensitivities, including assumptions on banking, international offsets, technology cost and progress, and gas supply.

Figure 5: GHG Emissions in Waxman-Markey and APA policies and sensitivities[16]



16 Sources for Figure 5 include the following:
U.S. Energy Information Administration (EIA); *Energy Market and Economic Impacts of the American Power Act of 2010* (July 2010). Available at http://www.eia.gov/oiaf/servicerpt/kgl/index.html
EIA; *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009* (August 2009). Available at http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html

Figure 6: Allowance prices in ACES and APA policies and sensitivities[17]



A. Assessing the potential impact of a natural gas supply increase

The recent shale gas boom has put substantial downward pressure on natural gas prices. Several factors could influence future gas prices, including the estimated ultimate recovery per well and regulations addressing the environmental impacts of hydraulic fracturing.[18] The impact of higher or lower gas prices on carbon prices is uncertain. In the near term, lower natural gas prices are likely to make emissions mitigation in the electric sector less expensive, as gas power plants can displace coal plants at lower cost. Conversely, as marginal electricity prices are frequently set by natural gas plants, lower gas prices will contribute to lower electricity prices, potentially increasing electricity consumption and associated emissions. Lower electricity prices also make it more difficult for renewable technologies with even lower emissions than gas to compete in electricity markets.

In 2010, Resources for the Future (RFF) used a version of the EIA's National Energy Modeling System (NEMS) energy model to test effects of increased gas supply from shale gas on the economics of energy policy. Under a moderate climate policy, the high gas scenario decreased the 2030 allowance price by less than 1%, from $61.1 to $60.8 per ton of CO_2.[19] The EIA showed

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[17] Sources for Figure 6 include the following:
U.S. Energy Information Administration (EIA); *Energy Market and Economic Impacts of the American Power Act of 2010* (July 2010). Available at http://www.eia.gov/oiaf/servicerpt/kgl/index.html
EIA; *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009* (August 2009). Available at http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html

[18] EIA (2012) "Projected natural gas prices depend on shale gas resource economics" http://www.eia.gov/todayinenergy/detail.cfm?id=7710

[19] Brown et al (2010). "Abundant Shale Gas Resources: Some Implications for Energy Policy". Available at: http://www.rff.org/RFF/Documents/RFF-BCK-Brownetal-ShaleGas.pdf

similar results in its analysis of the American Power Act: increased gas supply decreased the 2030 allowance price by less than 0.1%, from $49.80 to $49.78 per ton of CO_2.[20] In the policies studied by EIA and RFF, the result of an increased gas supply amounted to an inconsequential reduction in CO_2 prices. At this point it appears that, while a large shale gas resource may change how each policy is met, it is not a significant factor in the CO_2 cost that utilities should use for planning. Ongoing studies are expected to provide further insight into this issue.[21]

[20] EIA (2010) "Energy Market and Economic Impacts of the American Power Act of 2010". Available at: http://www.eia.gov/oiaf/servicerpt/kgl/index.html

[21] The Energy Modeling Forum will evaluate carbon constraints under cases of reference and high case supply levels in the EMF 26 study, which began in late 2011 and is ongoing (see http://emf.stanford.edu/research/emf_26/)

7. The U.S. Interagency Social Cost of Carbon

In 2010, the U.S. government began to use “social cost of carbon” values in an attempt to account for the damages resulting from climate change.[22] Four values for the social cost of carbon were initially provided by the Interagency Working Group on the Social Cost of Carbon, a group composed of members of the Department of Agriculture, Department of Commerce, Department of Energy, Environmental Protection Agency, and Department of Transportation, among others. This group was tasked with the development of a consistent value for the global societal benefits of climate change abatement. These values, $5, $21, $35, and $65 per metric tonne of CO_2 in 2007 dollars ($4.9, $20.7, $34.5, and $64.0 per ton in 2012 dollars), reflected three discount rates and one estimate of the high cost tail-end of the distribution of impacts. As of May 2012, these estimates have been used in at least 20 federal government rulemakings, for policies including fuel economy standards, industrial equipment efficiency, lighting standards, and air quality rules.[23]

The U.S. “social cost” values are the result of analysis using the DICE, PAGE, and FUND integrated assessment models. The combination of complex climate and economic systems with these reduced-form integrated assessment models leads to substantial uncertainties. In a 2012 paper, Ackerman and Stanton[24] explored the impact of specific assumptions used by the Interagency Working Group, and found values for the social cost of carbon ranging from the Working Group’s level up to more than an order of magnitude greater. Despite limitations in the calculations for the social cost of carbon stemming from the choice of socio-economic scenarios, modeling of the physical climate system, and quantifying damages around the globe for hundreds of years into the future, this multi-agency effort represents an important initial attempt at incorporating consistent values for the benefits associated with CO_2 abatement in federal policy.

[22] Interagency Working Group on the Social Cost of Carbon, U. S. G. (2010). Appendix 15a. Social cost of carbon for regulatory impact analysis under Executive Order 12866. In Final Rule Technical Support Document (TSD): Energy Efficiency Program for Commercial and Industrial Equipment: Small Electric Motors. U.S. Department of Energy. URL http://go.usa.gov/3fH.

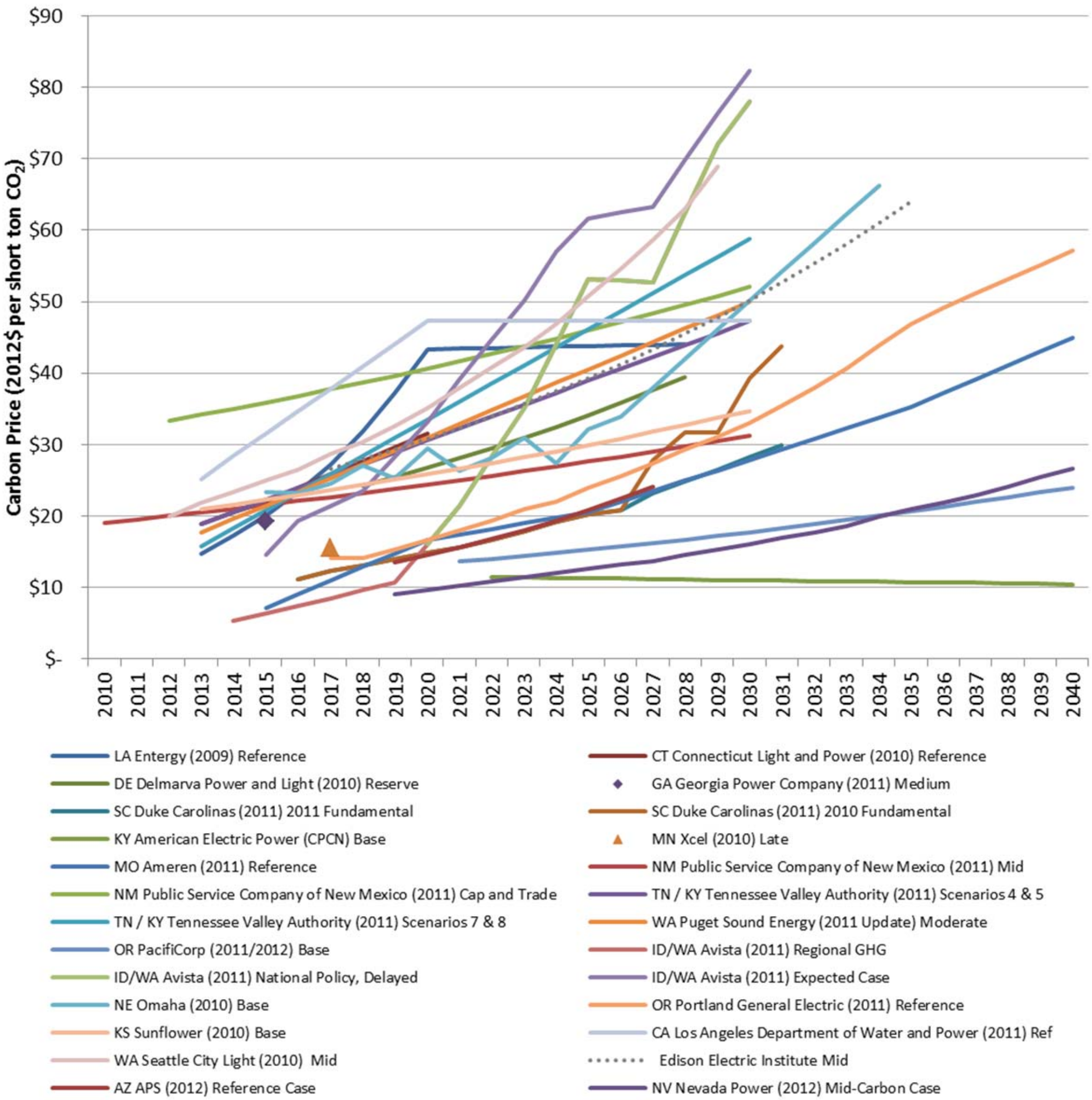
[23] Robert E. Kopp and Bryan K. Mignone (2012). The U.S. Government’s Social Cost of Carbon Estimates after Their First Two Years: Pathways for Improvement. Economics: The Open-Access, Open-Assessment E-Journal, Vol. 6, 2012-15. http://dx.doi.org/10.5018/economics-ejournal.ja.2012-15

[24] Frank Ackerman and Elizabeth A. Stanton (2012). Climate Risks and Carbon Prices: Revising the Social Cost of Carbon. Economics: The Open-Access, Open-Assessment E-Journal, Vol. 6, 2012-10. http://dx.doi.org/10.5018/economics-ejournal.ja.2012-10

8. CO_2 Price Forecasts in Utility IRPs

A number of electric companies have included projections of costs associated with greenhouse gas emissions in their resource planning procedures. Figure 7 presents the mid-case values of publicly available forecasts used by utilities in resource planning over the past three years.

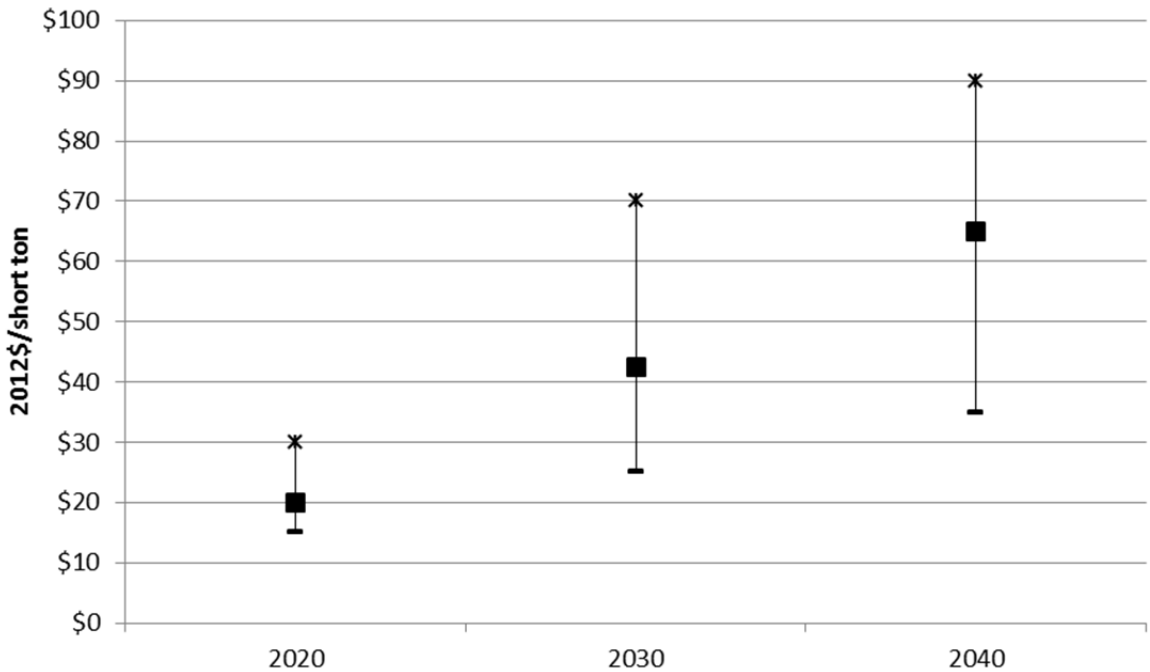
Figure 7: Utility Mid Case CO_2 Price Forecasts



9. Recommended 2012 CO_2 Price Forecast

Based on analyses of the sources described in Sections 4 through 8, and relying on our own expert judgment, Synapse developed Low, Mid, and High case forecasts for CO_2 prices from 2020 to 2040. Figure 8 shows the range covered by the Synapse forecasts in three years: 2020, 2030, and 2040. These forecasts share the common assumption that a federal cap-and-trade policy will be passed sometime within the next five years, and will go into effect in 2020. All annual allowance prices and levelized values are reported in 2012 dollars per ton of carbon dioxide.[25]

Figure 8: Synapse 2012 Forecast Values



Each of the forecasts shown in Figure 8 represents a different appetite for reducing carbon, as described below.

- The Low case forecast starts at $15/ton in 2020, and increases to approximately $35/ton in 2040, representing a $23/ton levelized price over the period 2020-2040. This forecast represents a scenario in which Congress begins regulation of greenhouse gas emissions slowly—for example, by including a modest emissions cap, a safety valve price, or significant offset flexibility. This price forecast could also be realized through a series of complementary policies, such as an aggressive federal Renewable Portfolio Standard, substantial energy efficiency investment, and/or more stringent automobile CAFE mileage standards (in an economy-wide regulation scenario). Such complementary policies would

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[25] All values in the Synapse Forecast are presented in 2012 dollars. Results from EIA and EPA modeling analyses were converted to 2012 dollars using price deflators taken from the US Bureau of Economic Analysis, and available at: http://www.bea.gov/national/nipaweb/SelectTable.asp Because data were not available for 2012 in its entirety, values used for conversion were taken from Q2 of each year. Consistent with EIA and EPA modeling analyses, a 5% real discount rate was used in all levelization calculations.

lead directly to a reduction in CO_2 emissions independent of federal cap-and-trade, and would thus lower the expected allowance prices associated with the achievement of any particular federally mandated goal.

- The Mid case forecast starts at $20/ton in 2020, and increases to approximately $65/ton in 2040, representing a $39/ton levelized price over the period 2020-2040. This forecast represents a scenario in which a federal cap-and-trade program is implemented with significant but reasonably achievable goals, likely in combination with some level of complementary policies to give some flexibility in meeting the reduction goals. These complementary policies would include renewables, energy efficiency, and transportation standards, as well as some level of allowance banking and offsets. Also assumed in the Mid case is some degree of technological learning, i.e. assuming that prices for emissions reductions technologies will decline as greater efficiencies are realized in their design and manufacture and as new technologies become available.
- The High case forecast starts at $30/ton in 2020, and increases to approximately $90/ton in 2040, representing a $59/ton levelized price over the period 2020-2040. This forecast is consistent with the occurrence of one or more factors that have the effect of raising prices. These factors include somewhat more aggressive emissions reduction targets; greater restrictions on the use of offsets; restricted availability or high cost of technology alternatives such as nuclear, biomass, and carbon capture and sequestration; more aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters); or higher baseline emissions.

Synapse's Low, Mid, and High case price projections for each year of the study period are presented in graphic and tabular form, below.

Figure 9: Synapse 2012 CO_2 Price Trajectories

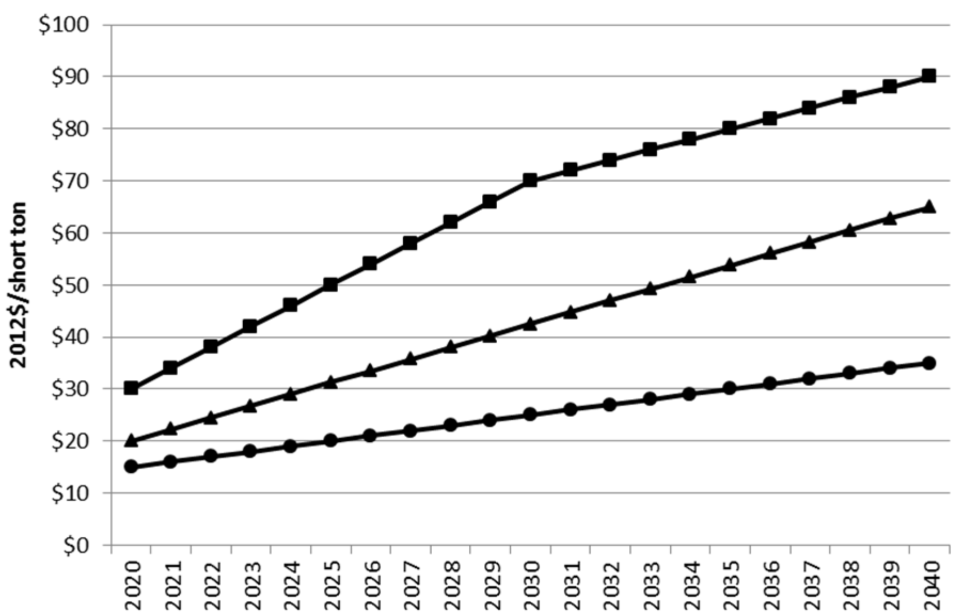


Table 1: Synapse 2012 CO_2 Allowance Price Projections (2012 dollars per ton CO_2)

Year	Low Case	Mid Case	High Case
2020	$15.00	$20.00	$30.00
2021	$16.00	$22.25	$34.00
2022	$17.00	$24.50	$38.00
2023	$18.00	$26.75	$42.00
2024	$19.00	$29.00	$46.00
2025	$20.00	$31.25	$50.00
2026	$21.00	$33.50	$54.00
2027	$22.00	$35.75	$58.00
2028	$23.00	$38.00	$62.00
2029	$24.00	$40.25	$66.00
2030	$25.00	$42.50	$70.00
2031	$26.00	$44.75	$72.00
2032	$27.00	$47.00	$74.00
2033	$28.00	$49.25	$76.00
2034	$29.00	$51.50	$78.00
2035	$30.00	$53.75	$80.00
2036	$31.00	$56.00	$82.00
2037	$32.00	$58.25	$84.00
2038	$33.00	$60.50	$86.00
2039	$34.00	$62.75	$88.00
2040	$35.00	$65.00	$90.00
Levelized	$23.24	$38.54	$59.38

The following charts compare the Synapse Mid, High, and Low case forecasts against various utility estimates. Data on utility estimates was collected from a wide range of available public Integrated Resource Plans (IRPs). We have excluded several IRPs with zero carbon prices or IRPs with no carbon price given, accounting for 9 of 65 collected.

Figure 10 shows 26 utility CO_2 price forecasts, with 2030 prices ranging from $10/t$CO_2$ to above $80/t$CO_2$. Due to the extended development period of many IRPs, some of these forecasts may not accurately reflect very recent years; a NM Public Service forecast, for example, begins in 2010, when there was no economy-wide CO_2 price. Nevertheless, IRPs do their best to represent accurate views of the future, in order to develop least-cost plans. The Synapse Mid forecast, beginning at $20/t$CO_2$ and rising to $65/t$CO_2$, lies well within the range of the mid-case forecasts shown here.

Figure 10: Synapse 2012 Mid forecast as compared to the Mid forecasts of various U.S. utilities (2010-2012)[26]

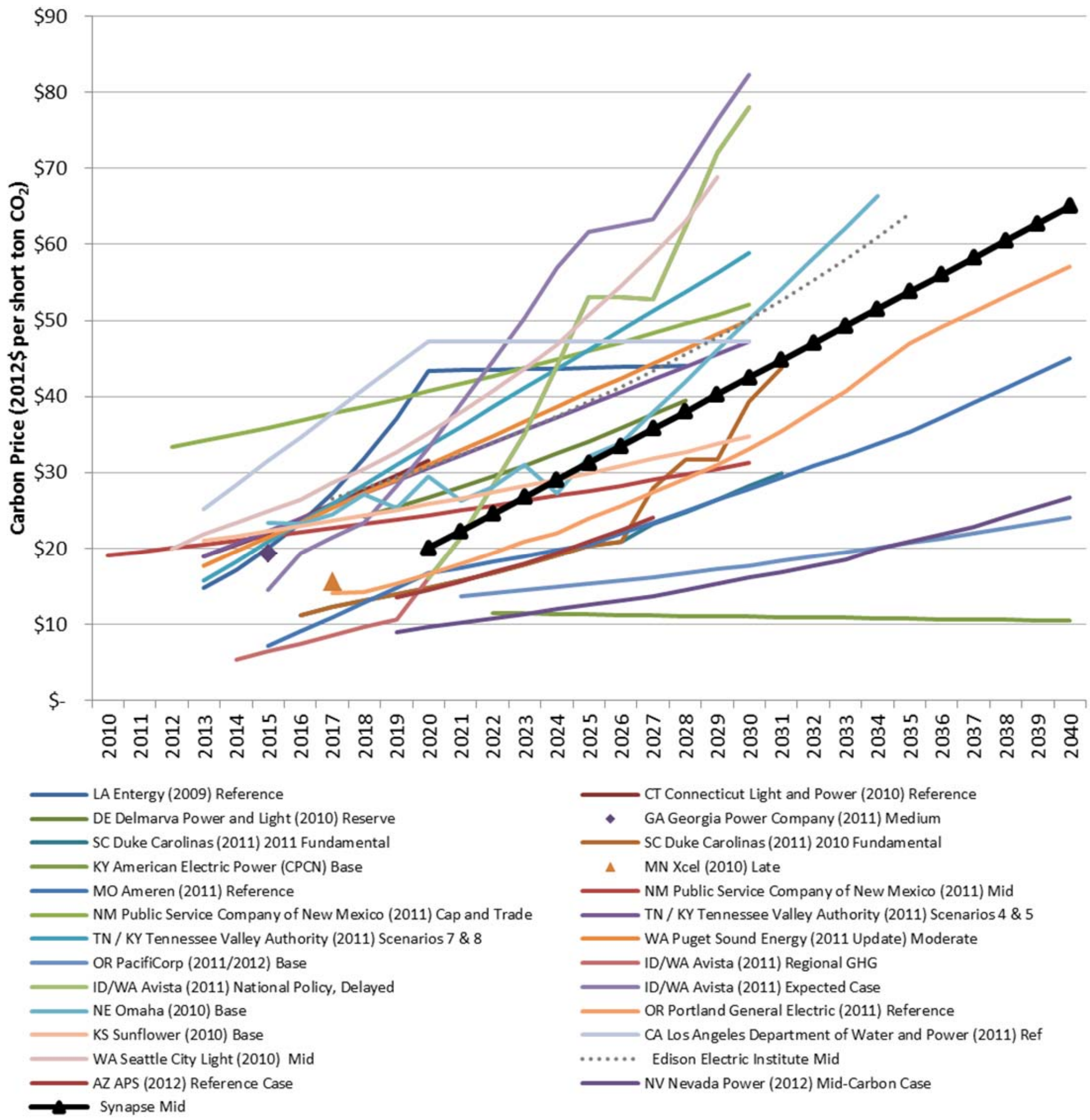


Figure 11 overlays the Synapse High case and the high case forecasts of many IRPs on top of the utility mid case forecasts shown in Figure 10 (now shaded in grey). Not all IRPs that provide mid-level forecasts also provide high forecasts. The high cases generally reflect a nearer-term policy start date, as well as a more rapid rate of increase in prices with time. The Synapse forecast starts later than most, and rises from \$30/tCO_2 in 2020 to \$90/tCO_2 in 2040.

[26] Legend given here is common to all subsequent utility price forecast charts. While scenario names may change, colors are constant for a given utility.

Figure 11: Synapse High forecast as compared to the High and Mid forecasts of various utilities (see legend in Figure 10)

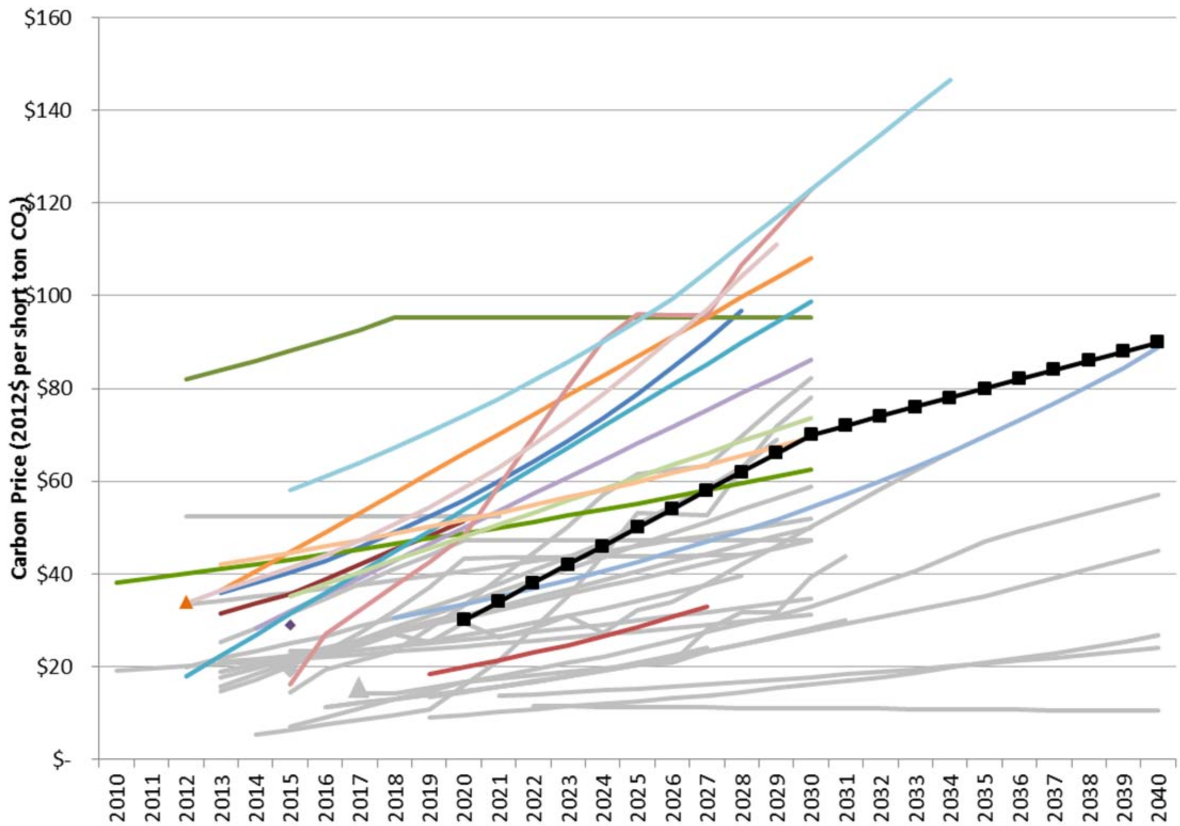


Figure 12 overlays the Synapse Low case and the low case forecasts of many IRPs on top of the utility mid case forecasts shown in Figure 10 (shaded in grey). The low case forecasts both start at substantially lower values (occasionally at zero values), and rise at slower rates. The Synapse forecast starts later than most and rises from $15/tCO_2$ in 2020 to $35/tCO_2$ in 2040.

Figure 12: Synapse Low forecast as compared to the Low and Mid forecasts of various utilities (see legend in Figure 10)

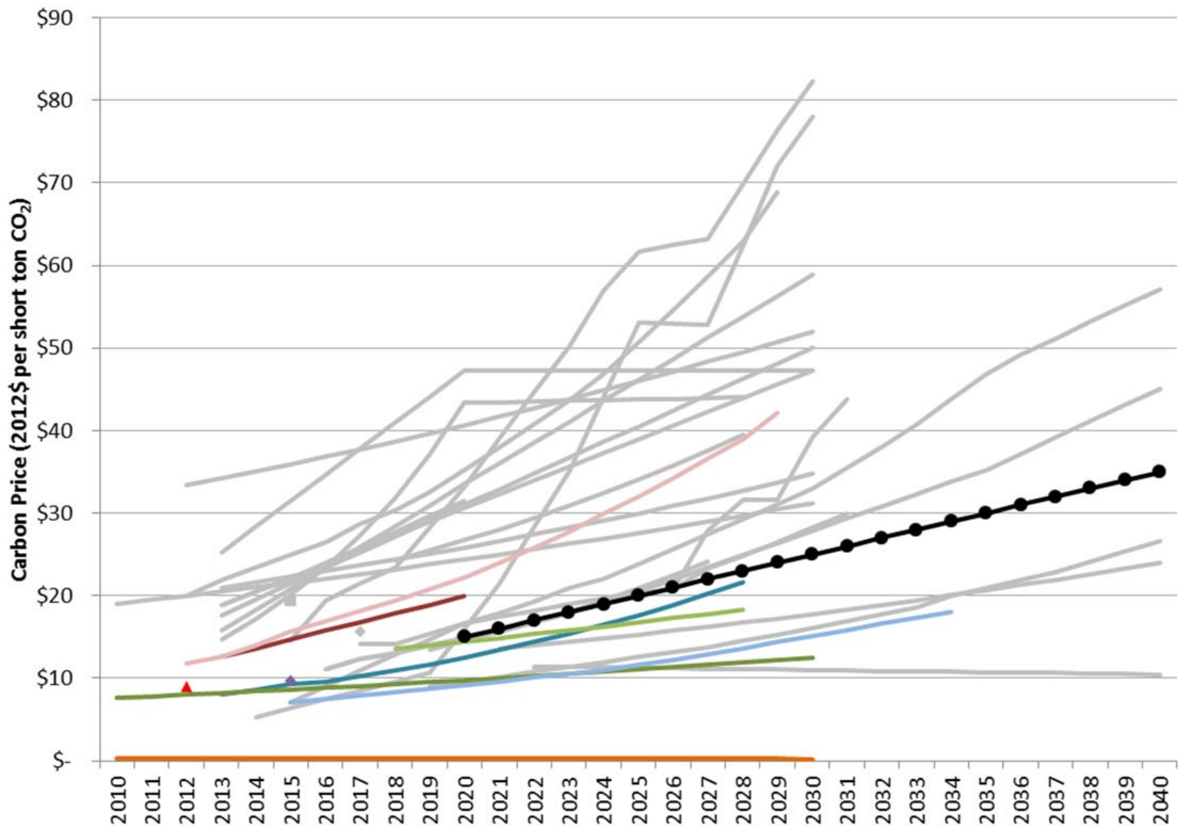


Figure 13 shows Synapse's Low, Mid, and High forecasts compared to the full range of utility forecasts shown above. The Synapse projections represent a plausible range of possible future costs. Using all three recommended price trajectories will facilitate sensitivity testing of long-term investment decisions in electric sector resource planning against likely federal climate policy scenarios.

Figure 13: Synapse forecasts compared to the range of utility forecasts

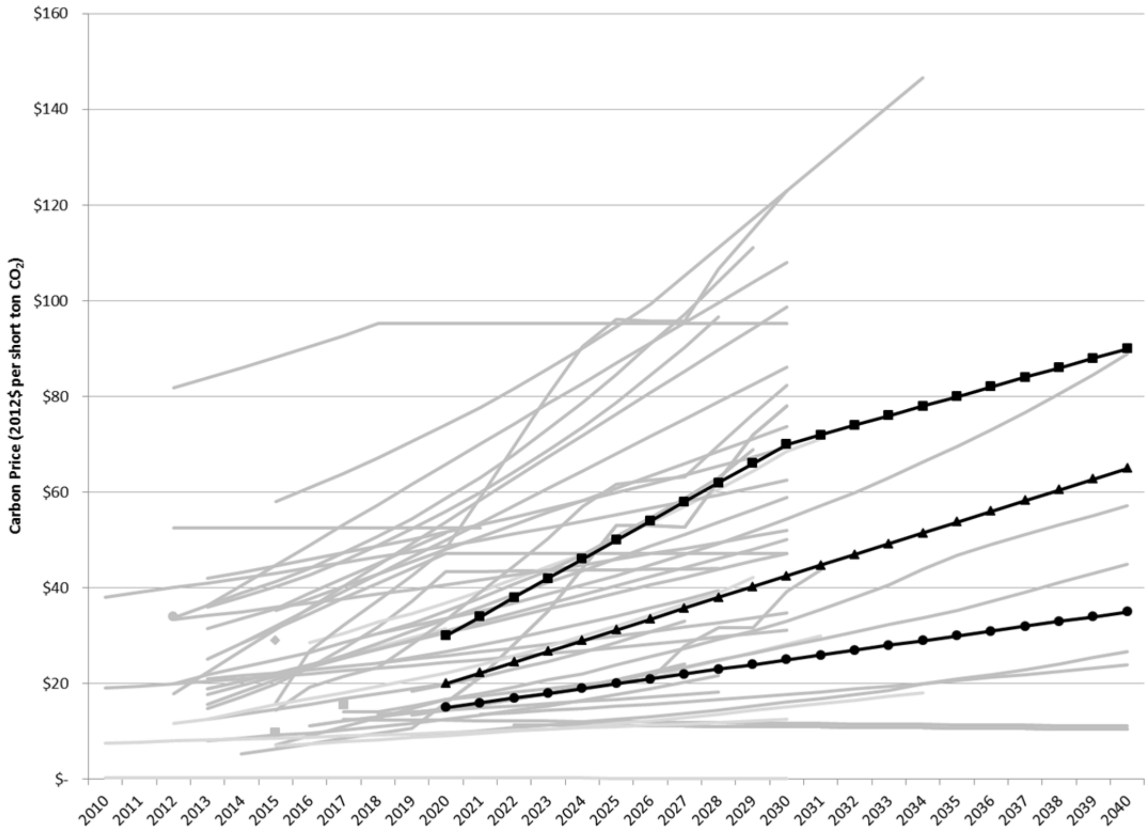
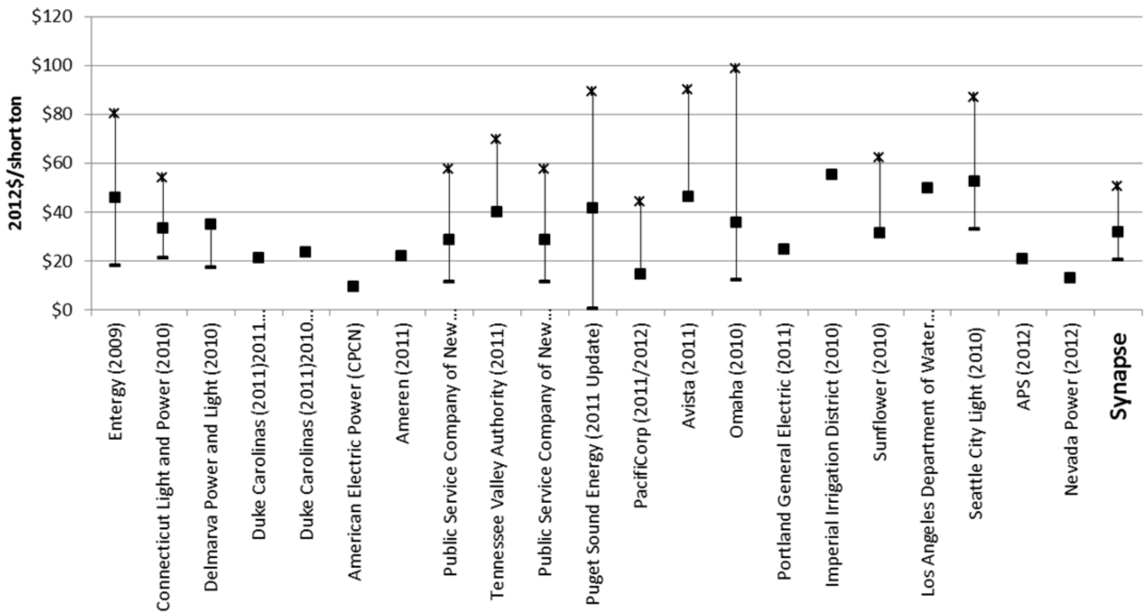


Figure 14 compares the levelized costs of Synapse's Low, Mid, and High cases to the levelized costs of utility estimates for 2020 through 2030, a period after the start and before the end of most forecasts. While levelizing between 2020 and 2030 results in different Synapse values than presented in Table 1 (where forecasts were levelized between 2020 and 2040), this approach allows for overlap and comparison with a broader range of utility estimates.

Figure 14: Levelized price of CO_2, 2020-2030, utilities and Synapse[27]



[27] All forecasts are levelized with a 5% discount rate based on CO_2 prices between 2020 and 2030. Forecasts with a price for only a single year excluded.

Appendix A: State and Regional GHG Initiatives

The states—individually and coordinating within regions—are leading the nation's policies to respond to the threat of climate change. In fact, several states, unwilling to postpone and wait for federal action, are pursuing policies specifically because of the lack of federal legislation.

This appendix provides a more thorough discussion of state and regional greenhouse gas (GHG) initiatives. Collectively, these initiatives suggest that momentum is building toward more comprehensive federal GHG action.

Cap-and-trade programs

The Northeast/Mid-Atlantic region and the state of California have developed, or are in the last stages of developing, greenhouse gas caps and allowance trading. [28]

Regional Greenhouse Gas Initiative: The Regional Greenhouse Gas Initiative (RGGI) is an effort of ten Northeast and Mid-Atlantic states to limit greenhouse gas emissions, and is the first market-based CO_2 emissions reduction program in the United States. Participating states have agreed to a mandatory cap on CO_2 emissions from the power sector with the goal of achieving a ten percent reduction in these emissions from levels at the start of the program by 2018.[29] This is the first mandatory carbon trading program in the nation. Recently, allowance prices have been hitting the CO_2 price floor, as actual emissions are far below the budget of 188 mtons/year.

California: In 2006, the California Legislature passed the Global Warming Solutions Act (AB 32), which requires the state to reduce emissions of GHGs to 1990 levels by 2020. The California Air Resources Board (CARB) outlined more than a dozen measures to reduce carbon emissions to target levels in its 2008 *Scoping Plan*. Those measures include a renewable portfolio standard, a low carbon fuel standard, and a cap-and-trade program. Approximately 22.5% of the emissions reductions called for by AB 32 are estimated to occur under the cap-and-trade program. California will have the world's second largest carbon market, after the European Union's Emissions Trading System (EU ETS).

The first compliance period for the program will begin on January 1, 2013, and will cover electricity generators, carbon dioxide suppliers, large industrial sources, and petroleum and natural gas facilities emitting at least 25,000 metric tons of CO_2e per year. The second compliance period will run from 2015-2017, and the third compliance period will cover 2018-2020. During these periods, the cap-and-trade program will expand to cover suppliers of natural gas, distillate fuel oil, and liquefied petroleum gas if the combustion of their products would result in 25,000 metric tons of CO_2e or more.[30] The initial cap is set at 162.8 million metric tons of CO_2e and decreases by 2% annually through 2015. When additional sources are added, the cap increases to accommodate them, but then increases the percentage reductions in emissions to 3% in 2016, rising to 2.5% in 2020. The state plans to allocate the bulk of allowances for free in 2013, but will gradually auction

[28] The Midwest Greenhouse Gas Reduction Accord was developed in 2007. Though the agreement has not been formally suspended, the participating states are no longer pursuing it.

[29] The ten states are: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont. Information on the RGGI program, including history, important documents, and auction results is available on the RGGI Inc website at www.rggi.org

[30] §95812 (d)(1), page 48

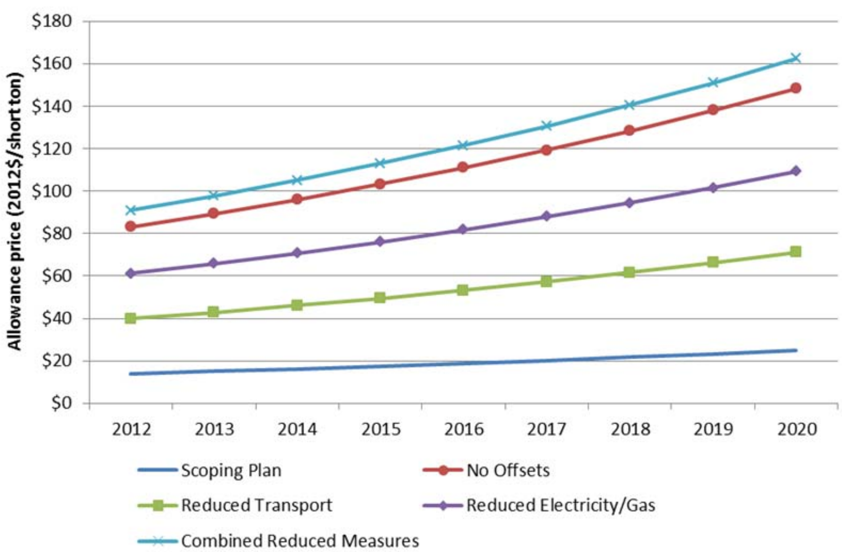
an increasing number of allowances between 2013 and 2020. Banking[31] and offsets[32] are both allowed under the California program.

The state of California has set a floor price for allowances beginning at $9.1/ton in 2013 ($10/metric tonne), and rising annually by 5% plus the rate of inflation.[33] In 2010 the Air Resources Board modeled the CO_2 allowance price trajectory that would enable reduction targets to be met under the following five cases:

1. Scoping Plan: Implements all of the measures contained in CARB's *Scoping Plan*
2. No Offsets: Does not allow offsets in the cap-and-trade program
3. Reduced Transport: Examines less effective implementation of the transportation-sector measures
4. Reduced Electricity/Gas: Examines less successful implementation of the electricity and natural gas measures
5. Combined Measures Reduced: Examines less successful implementation of transportation, electricity, and natural gas measures[34]

These five cases represent different scenarios of regulatory programs which, although different from the cap-and-trade program, can simultaneously help to achieve the goals of cap-and-trade. These regulatory measures are known as complementary policies. Figure A-1 shows the allowance price trajectories associated with those five cases.

Figure A-1: AB 32 Modeled Allowance Price Trajectories[35]



31 §95922 (a), page 151
32 §95973 (a)(2)(C), page 156
33 §95911 (b)(6), page 129
34 California Air Resources Board. *Updated Economic Analysis of California's Climate Change Scoping Plan: Staff Report to the Air Resources Board.* March 24, 2010. Page ES-6.
35 Id. Page 40.

As shown in Figure A-1, when the policies that are complementary to the cap-and-trade program are less effective, greater CO_2 reductions need to occur under the cap-and-trade program, and the allowance price is much higher. Similarly, the availability of offsets lowers the allowance price in the cap-and-trade program, as compliance with reduction targets can be met with offsets. This allows banking of allowances in the beginning of the program, which can keep allowance prices lower in later years.

California's first allowance auction is scheduled for November 14. A trial auction was completed on August 30, and more than 430 entities that will be regulated under the cap-and-trade program were invited to participate. CARB does not plan to release a settlement price, but on the date of the test auction, futures for December 2013 were trading at $14.77/ton, and forward contracts had sold for $14.77 and $14.82/ton.

State GHG reduction laws

Massachusetts: In 2008, the Massachusetts Global Warming Solutions Act was signed into law. In addition to the commitments to power sector emissions reductions associated with RGGI, this law committed Massachusetts to reduce statewide emissions to 10-25% below 1990 levels by 2020 and 80% below 1990 levels by 2050. Following the development of a comprehensive plan on steps to meet these goals, the 2020 target was set at 25% below 1990 levels.[36] Rather than put a price on carbon in the years before 2020, this plan will achieve a 25% reduction through a combination of federal, regional, and state level regulations applying to buildings, energy supply, transportation, and non-energy emissions.

Minnesota: In 2008, the Next Generation Energy Act was signed to reduce Minnesota emissions by 15% by 2015, 30% by 2025, and 80% by 2050.[37] While the law called for the development of an action plan that would make recommendations on a cap-and-trade system to meet these goals, the near-term goals will be met by a combination of an aggressive renewable portfolio standard and energy efficiency.

Connecticut: Also in 2008, the state of Connecticut passed its own Global Warming Solutions Act, establishing state level targets 10% below 1990 levels by 2020 and 80% below 2001 levels by 2050. In December 2010, the state released a report on mitigation options focused on regulatory mechanisms in addition to strengthening RGGI and reductions of non-CO_2 greenhouse gases.[38]

Renewable portfolio standards and other initiatives

A renewable portfolio standard (RPS) or renewable goal specifies that a minimum proportion of a utility's resource mix must be derived from renewable resources. These policies require electric utilities and other retail electric providers to supply a specified minimum amount—usually a percentage of total load served—with electricity from eligible resources. The standards range from modest to ambitious, and qualifying energy sources vary by state.

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[36] Massachusetts Clean Energy and Climate Plan for 2020, Available at: http://www.mass.gov/green/cleanenergyclimateplan

[37] Minnesota Statutes 2008 § 216B.241

[38] See http://www.ctclimatechange.com for further details on CT plans for emissions mitigation.

In general the goal of an RPS policy is to increase the development of renewable resources by creating a market demand. Increasing demand makes these technologies more economically competitive with other less expensive, but polluting, forms of electric generation. Many other policy objectives drive the adoption of an RPS or renewable goal, including climate change mitigation, job creation, energy security, and cleaner air.

The impact of an RPS on CO_2 emissions is dependent on factors such as:

- the types of resources that are eligible to meet the standard,
- the target level set by the RPS,
- the base quantity of electricity sales upon which the standard is set,
- how renewable energy credits (RECs) or attributes are tracked or counted,
- how RECs are assigned to different resources,
- banking, trading and borrowing of RECs,
- alternative compliance options, and
- coordination with other state and federal policies.

Currently, 29 US states have renewable portfolio standards. Eight others have renewable portfolio goals.

In addition, many states are pursuing other policy actions relating to reductions of GHGs. These policies include, but are not limited to: greenhouse gas inventories; greenhouse gas registries; climate action plans, greenhouse gas emissions targets, and emissions performance standards.

In the absence of a clear and comprehensive federal policy, many states have developed a broad array of emissions and energy related policies. For example, Massachusetts has a RPS of 15% in 2020 (rising to 25% in 2030), belongs to RGGI, requiring specific emissions reductions from power plants in the state, and has set in place aggressive energy efficiency targets through the 2008 Green Communities Act.

Hawaii, while not part of a regional climate initiative, has an even more aggressive RPS, seeking to achieve 40% renewable energy by 2030, coupled with an Energy Efficiency Portfolio Standard with the goal of reducing electricity use by 4,300 GWh by 2030. After 2013, 2% of electricity revenues in Hawaii will go towards a Public Benefit Fund, an independent entity tasked with promoting and incentivizing energy efficiency measures across the state.

EXHIBIT FA-4

SHAPING OHIO'S ENERGY FUTURE: ENERGY EFFICIENCY WORKS

March 2009

American Council for an Energy-Efficient Economy,
Summit Blue Consulting, ICF International,
and Synapse Energy Economics

ACEEE Report Number E092

529 Fourteenth Street, N.W., Suite 600, Washington, D.C. 20045
(202) 507-4000 phone, (202) 429-2248 fax, http://aceee.org

Prepared by:

American Council for an Energy-Efficient Economy
(Project Lead and Energy Efficiency Analysis)

Max Neubauer, mneubauer@aceee.org
Neal Elliott
Amanda Korane
Skip Laitner
Vanessa McKinney
Jacob Talbot
Dan Trombley
Anna Chittum
Maggie Eldridge
Steve Nadel

Summit Blue Consulting
(Demand Response Analysis)

Dan Violette
Marca Hagenstad
Stuart Schare

ICF International
(CHP Analysis)

Kenneth Darrow
Anne Hampson
Bruce Hedman

Synapse Energy Economics
(Utility Avoided Costs Estimates)

David White
Rick Hornby

Disclaimer: *While several organizations, including Summit Blue Consulting, ICF International, and Synapse Energy Economics, assisted ACEEE in the completion of this analysis and report, the ultimate viewpoints and recommendations expressed herein are those of ACEEE.*

Contents

EXECUTIVE SUMMARY

The passing of Senate Bill 221 (SB 221), which was signed by Governor Ted Strickland on May 1, 2008, was a landmark event that has positioned Ohio to become a national leader in energy efficiency. SB 221 created an aggressive Energy Efficiency Resource Standard (EERS) mandating that Ohio's investor-owned utilities save at least 22% of electricity consumption by 2025, which our report clearly demonstrates is not only achievable, but can also be accomplished cost-effectively while providing significant job and financial benefits to Ohio's economy. The timing of the legislation is opportune, as rising unemployment and a deepening state budget deficit have shown that Ohio and its consumers are in great need of economic revitalization. Deployed as Ohio's "first fuel," investments in energy efficiency will facilitate this revitalization in three ways: (1) by minimizing employment losses through the creation of new "green collar" jobs; (2) by providing critical financial relief to Ohio's consumers through lower energy bills and stable rates, and; (3) by easing the strain on the state budget through lower state operating costs, enabled by the expansion of energy efficiency into state and local government buildings.

Ohio's current fiscal and economic challenges do not preclude the state from garnering considerable benefits from energy efficiency. Energy efficiency and demand response are the lowest-cost resources available to moderate short-term impacts and are also the quickest to deploy, meaning that efficiency resources begin to generate financial savings for the state and its consumers quickly, which can then be reinvested to further stimulate Ohio's ailing economy. A comprehensive state energy plan is also important in order to effectively leverage the boon of federal funding from the *American Recovery and Reinvestment Act*, which includes $6.3 billion for state and local energy efficiency and clean energy grants. So long as investments in energy efficiency are made prudently and complemented by strong programs and policies, Ohio will be able to alleviate these short-term issues and improve its economic vitality well into the future.

Policy Recommendations

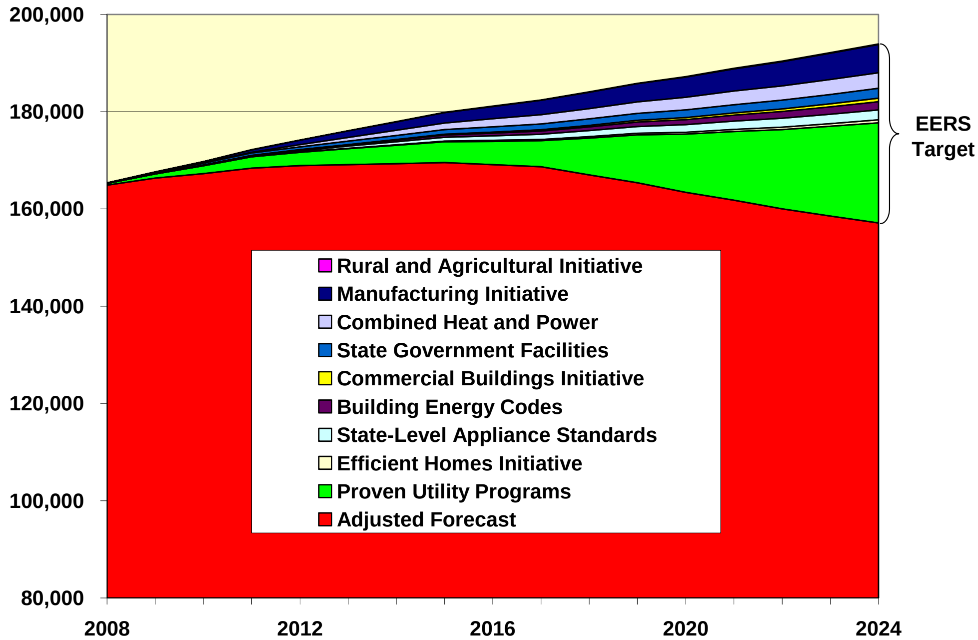
To meet the state's savings targets, ACEEE suggests a suite of ten "innovative" programs and policies (henceforth referred to as "innovative policies" or "policies") in addition to the proven utility program approaches ("programs") that are already beginning to be implemented by the state's utilities. We believe that five of these policies, which could be implemented by utilities or in cooperation with a statewide effort, should be allowed to contribute towards the EERS target. Together these policies and programs would more than satisfy the 22% savings goal; however, we did not attempt to quantify the potential for additional savings beyond the EERS target in this analysis. Our innovative policies are:

A. Energy Efficiency Resource Standard
    1. Advanced Residential Buildings Initiative
    2. Advanced Commercial Buildings Initiative
    3. Manufacturing Initiative
    4. Rural and Agricultural Initiative
    5. Combined Heat and Power

B. Complementary Policies
    6. Workforce Development
    7. State and Local Government Facilities
    8. State-Level Appliance and Equipment Efficiency Standards
    9. Building Energy Codes
    10. Expanded Demand Response Programs

Figure ES-2 shows the contribution of the individual policies and programs towards the EERS target. Our suite of innovative energy efficiency policies will contribute savings of 16,235 GWh, or 10% of Ohio's electricity needs, by 2025. This will leave only 12%, or 20,596 GWh, of the EERS target to be met by the proven programs. In this report we highlight best practice programs that have proven to be effective at reducing electricity consumption in other states across the U.S. With the combination of these innovative policies and proven utility programs, we believe that Ohio can easily satisfy the EERS target cost-effectively and with a net positive benefit to the economy.

Figure ES-1. Share of Projected Electricity Use Met by Innovative Energy Efficiency Policies & Proven Utility Programs



These policy suggestions draw from the best practice policies currently implemented throughout the country. The establishment of Ohio's EERS target represents the core of these policies, providing the foundation upon which the five supporting policies can begin to help achieve the savings goal.

In addition, we find that a suite of demand response (DR) recommendations, which focuses on shifting energy from peak periods to off-peak periods and cutting back electricity needs during periods with the highest needs, is a critical component of reducing peak demand in Ohio. Figure ES-3 presents the combined effects of energy efficiency and demand response on peak reductions.

Economic Potential of Energy Efficiency Resources

This report assesses the total cost-effective, or "economic," potential for energy efficiency investments in Ohio. By characterizing the incremental costs and energy savings for a number of efficient technologies or measures for residential, commercial, and industrial consumers, we determine the cost-effectiveness for each measure and estimate the total energy efficiency "resource" potential. We estimate an economic potential for efficiency resources in Ohio of over 64,000 GWh, or 33% of projected electricity consumption in 2025, as illustrated by Figure ES-3 below. Our results show that contributions from cost-effective resources are not evenly distributed across all sectors, which will necessitate the development and implementation of proven programs that take this weighting into account.

Figure ES-2. Estimated Reductions in Summer Peak Demand through Energy Efficiency and Demand Response (2025 peak reduction = 11,416 MW, or 29%)

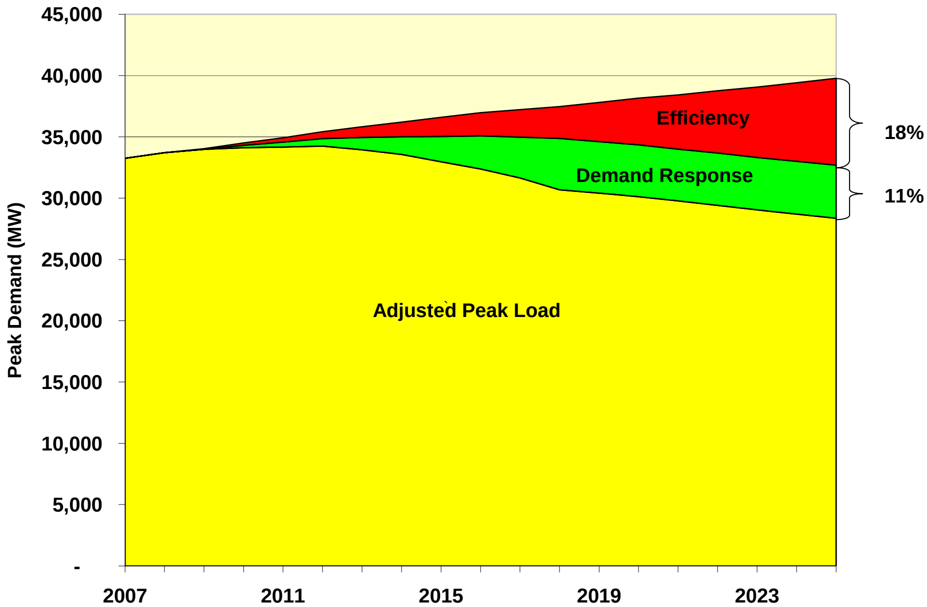
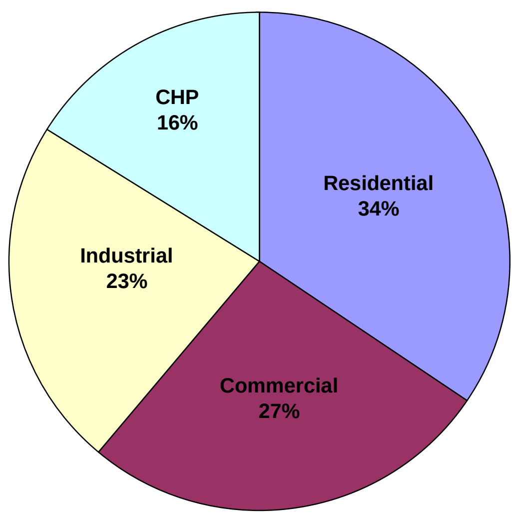


Figure ES-3. Summary of Energy Efficiency Economic Resource Potential (64,284 GWh, or 33% of Projected Electricity Consumption in 2025)



Impacts on Employment and the Economy

The energy savings from these efficiency policies and programs can cut the electricity bills for customers by a net $430 million in 2015. Net annual savings grow eight-fold to $3.3 billion in 2025. While these savings will require some public and customer investment, by 2025 net cumulative savings on electricity bills will reach almost $19 billion. These savings are the result of two effects. First, participants in energy efficiency programs will install energy efficiency measures, such as more efficient appliances or heating equipment, therefore lowering their electricity consumption and electric bills. In addition, because of the current volatility in energy prices, efficiency strategies have the added benefit of improving the balance of demand and supply in energy markets, thereby stabilizing regional electricity prices for the future.

Investments in efficiency policies and programs have the added benefit of creating new, high-quality "green-collar" jobs in Ohio and increasing both wages and Gross State Product (GSP). Our analysis shows that energy efficiency investments can create over 32,000 new jobs in Ohio by 2025 (see Table ES-1), including well-paying trade and professional jobs needed to design, install, and operate energy efficiency measures. These new jobs, including both direct and indirect employment effects, would be equivalent to over 250 new manufacturing facilities relocating to Ohio, but without the public costs for infrastructure or the environmental impacts of new plants.

Table ES-1. Economic Impact of Energy Efficiency Investments in Ohio

Macroeconomic Impacts	2015	2025
Jobs (Actual)	7,928	32,061
Wages (Million $2006)	300	1,615
GSP (Million $2006)	444	2,559

Conclusions

The State of Ohio is poised to make great strides in expanding efficiency throughout the state. As this report documents, there is tremendous potential for Ohio to become a national leader in efficiency and to take advantage of the numerous cost-effective energy efficiency and demand response opportunities that exist in the state. Nonetheless, Ohio does have some difficult decisions to make with regards to its energy future. Faced with severe budgetary constraints and a slumping economy, there may be an inclination to dispel energy efficiency in light of the present conditions. It is therefore extremely important that the momentum created by the establishment of the aggressive EERS target by legislation included in SB 221 not be lost. This legislation has sent a strong signal of Ohio's intent, which in large part contributed to its respectable ranking in ACEEE's 2008 state energy efficiency scorecard. However, Ohio will have to continue to balance its priorities in order for energy efficiency to affect its economy as beneficially as this report highlights.

The various energy efficiency and demand response policies we suggest have been successful in other states in delivering efficiency resources and reducing consumer electric expenditures. We estimate efficiency can meet 122% of the increase in the state's electricity needs over the next 17 years while meeting 188% of the increase in peak demand and reducing emissions by 12%. What is more, these policies and programs can accomplish this at a lower cost than building new supply infrastructure, while simultaneously creating over 32,000 new, high-quality "green collar" jobs by 2025.

Our suggestions are intended to be the starting point for dialog among stakeholders on how to realize the demand-side efficiency resource potential in the state, particularly given the economic challenges it faces. ACEEE's suggestions are based on our review of existing opportunities and stakeholder discussions, and reflect proposals that we think are politically viable. However, it is important to note that these suggestions will not necessarily meet all of the state's future energy needs. While energy efficiency is perhaps the only new energy resource available that can be deployed quickly in the short term and continue to contribute significantly into the long term, the state will still require additional resources to meet the remainder of new load and to replace older, dirtier generation plants as they are retired. Furthermore, additional policies and programs exist that could be implemented to realize even more of the available energy efficiency resources. Ultimately, energy efficiency can delay the immediate need for investments in infrastructure, allowing Ohio the time to rigorously consider its future resource choices.

ACKNOWLEDGMENTS

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ABOUT THE AMERICAN COUNCIL FOR AN ENERGY-EFFICIENT ECONOMY (ACEEE)

ACEEE is a nonprofit organization dedicated to advancing energy efficiency as a means of promoting economic prosperity, energy security, and environmental protection. For more information, see http://www.aceee.org. ACEEE fulfills its mission by:

- Conducting in-depth technical and policy assessments
- Advising policymakers and program managers
- Working collaboratively with businesses, public interest groups, and other organizations
- Organizing conferences and workshops
- Publishing books, conference proceedings, and reports
- Educating consumers and businesses

Projects are carried out by staff and selected energy efficiency experts from universities, national laboratories, and the private sector. Collaboration is key to ACEEE's success. We collaborate on projects and initiatives with dozens of organizations including federal and state agencies, utilities, research institutions, businesses, and public interest groups.

Support for our work comes from a broad range of foundations, governmental organizations, research institutes, utilities, and corporations.

[1] Acknowledgement of support from an entity is not indicative of their sponsorship or endorsement of this report.

GLOSSARY

ENERGY POLICY AND ORGANIZATIONS

(ASHRAE) American Society of Heating, Refrigerating and Air-Conditioning Engineers: Organization of over 50,000 professionals in the air-conditioning, heating, refrigerating and ventilating fields. Support the integration of increased energy efficiency in building design via technological enhancements of these systems (http://www.ashrae.org/).

Avoided Costs: The marginal costs incurred by utilities for additional electric supply resources. Used by utilities to evaluate the cost-effectiveness of energy efficiency programs.

(EERS) Energy Efficiency Resource Standard: A simple, market-based mechanism to encourage more efficient generation, transmission, and use of electricity and natural gas. An EERS consists of electric and/or gas energy savings targets for utilities. All EERS include end-user energy saving improvements that are aided and documented by utilities or other program operators. Often used in conjunction with a Renewable Portfolio Standard (RPS). (See ACEEE's fact sheet for state details: http://aceee.org/energy/state/policies/2pgEERS.pdf.)

(EISA 2007) Energy Independence and Security Act of 2007: Law covering issues from fuel economy standards for cars and trucks to renewable fuel and electricity to training programs for a “green collar” workforce to the first federal mandatory efficiency standards for appliances and lighting.

ENERGY STAR®: A joint program of the U.S. Environmental Protection Agency and the U.S. Department of Energy helping residential customers save money and protect the environment through energy-efficient products and practices (http://www.energystar.gov/). Includes appliance efficiency standards and new building codes.

(EPAct) Energy Policy Act: Law directing U.S. energy policy; first passed in 1992 and major revisions were passed in 2005 and 2007.

(ESCO) Energy Service Company: Provides designs and implementation of energy savings projects. The ESCO performs an in-depth analysis of the property, designs an energy-efficient solution, installs the required elements, and maintains the system to ensure energy savings.

(ESPC) **Energy Service Performance Contracting:** A financing technique that uses cost savings from reduced energy consumption to repay ESCO's (see above) for the cost of installing energy conservation measures and other services.

(FEMP) Federal Energy Management Program: U.S. Department of Energy program “works to reduce the cost and environmental impact of the Federal government by advancing energy efficiency and water conservation, promoting the use of distributed and renewable energy, and improving utility management decisions at Federal sites” (http://www1.eere.energy.gov/femp/about/index.html).

(FERC) Federal Energy Regulation Commission: Federal agency that “regulates and oversees energy industries in the economic, environmental, and safety interests of the American public” (www.ferc.org).

(IRP) Integrated Resource Plan: A comprehensive and systematic blueprint developed by a supplier, distributor, or end-user of energy who has evaluated demand-side and supply-side resource options and economic parameters and determined which options will best help them meet their energy goals at the lowest reasonable energy, environmental, and societal cost (http://www.energycentral.com/centers/knowledge/glossary/home.cfm).

(LIHEAP) **Low-Income Home Energy Assistance Program**: A federally funded program intended to assist low-income households that pay a high proportion of household income for home energy, primarily in meeting their immediate home energy needs.

(NERC) North American Electric Reliability Corporation: NERC’s mission is to improve the reliability and security of the bulk power system in North America. To achieve that, NERC develops and enforces reliability standards; monitors the bulk power system; assesses future adequacy; audits owners, operators, and users for preparedness; and educates and trains industry personnel. NERC is a self-regulatory organization that relies on the diverse and collective expertise of industry participants. As the Electric Reliability Organization, NERC is subject to audit by the U.S. Federal Energy Regulatory Commission and governmental authorities in Canada (www.nerc.com).

GENERAL REPORT TERMINOLOGY

Cumulative Savings: Sum of the total annual energy savings over a certain time frame.

Demand Side Management (DSM): Programs that focus on minimizing energy demand by influencing the quantity and use-patterns of energy consumption by end users, as opposed to supply side management, which focuses on investments in system infrastructure.

Energy Efficiency: The implementation of programs and policies that minimize the consumption of energy resources while stimulating economic growth.

Incremental Annual Savings: Energy savings occurring in a single year from the current year programs and policies only.

Percent Turnover: Percentage of technology replaced on burnout with more efficient technology. Does not include retrofits.

Potential: amount of energy savings possible

- **Achievable Potential**: Potential that could be achieved through normal market forces, new state building codes, equipment efficiency, and utility energy efficiency programs
- **Economic Potential**: Potential based on both the Technical Potential and economic considerations (e.g., system cost, avoided cost of energy)
- **Technical Potential:** Potential based on technological limitations only (no economic or other considerations)

Replace-on-Burnout: The act of waiting until a technology's end of life before replacing it with a more energy-efficient technology. Cost basis is the incremental cost of choosing a more efficient technology over a less efficient one. Incremental cost usually means incremental equipment cost with no labor cost; that is, there is no labor cost or it is the same in both cases and thus a zero-sum.

Retrofit Measure: The act of replacing a technology with a more energy-efficient technology before its end of life. Cost basis is the full cost of the new technology, including installation.

Total Annual Savings: Energy savings occurring in a single year from the current year programs and policies and counting prior year savings. Sum of all Incremental Annual Savings.

INDUSTRY and BUILDINGS TECHNOLOGY

(CHP) Combined Heat and Power: method of using waste heat from electrical generation to offset traditional process or space heating. Also called cogeneration (cogen).

Electricity Use Feedback: System that monitors home/building electricity use and provides real time feedback to occupants. This allows occupants to increase energy efficiency.

ENERGY STAR® New Homes: 15% electricity savings over a comparable size home.

HVAC: Heating, ventilation, and air conditioning system.

(NAICS) **North American Industry Classification System**: 6-digit code used to group industries by product.

UTILITY TERMS

Coincidental Peak: The sum of two or more peak loads that occur in the same time interval.

Coincidental Peak Factor: The ratio of annual peak demand savings (kW) from an energy-efficiency measure to the annual energy savings (kWh) from the measure; also called Coincidence Factor.

Demand Response: The reduction of customer energy usage at times of peak usage in order to help address system reliability, reflect market conditions and pricing, and support infrastructure optimization or deferral. Demand response programs may include dynamic pricing/tariffs, price-responsive demand bidding, contractually obligated and voluntary curtailment, and direct load control/cycling.

Deregulation: Allows a rate payer to choose other electricity providers over a local provider. Deregulation efforts vary from reducing to completely eliminating a local monopoly on electricity.

Distributed Energy Resource: Electrical power generation or storage located at or near the point of use, as well as demand-side measures

Distributed Generation: Electric power generation located at or near the point of use.

Distributed Power: Electrical power generation or storage located at or near the point of use.

Electricity Distribution: Regulating voltage to usable levels and distributing electricity to end-users from substations

Electricity Generation: Converting a primary fuel source (e.g., coal, natural gas, or wind) into electricity.

Electricity Transmission: Transport of electricity from the generation source to a distribution substation, usually via power lines.

Henry Hub: The market price for natural gas is by convention set at the Henry Hub (which is a physical location in southern Louisiana where a number of pipelines from the Gulf of Mexico originate). Futures and spot market contracts for delivery of gas are traded on the New York Mercantile Exchange (NYMEX) with regional wholesale prices set at key hubs where pipelines originate or come together. These prices are set relative to the Henry Hub price with adders for transportation and congestion.

(IOU) Investor-Owned Utility: Also known as a private utility, IOU's are utilities owned by investors or shareholders. IOU's can be listed on public stock exchanges.

(ISO) Independent System Operator: Entity that controls and administers nondiscriminatory access to electric transmission in a region or across several systems, independent from the owners of facilities.

Levelized Cost: The level of payment necessary each year to recover the total investment and interest payments at a specified interest rate over the life of the measure.

(MISO) Midwest Independent System Operator: The Midwest ISO is an independent, nonprofit organization that supports the constant availability of electricity in 15 U.S. states and the Canadian province of Manitoba.

Peak Demand: The highest level of electricity demand in the state measured in megawatts (MW) during the year.

Peak Shaving: Technologies or programs that reduce electricity demand only during peak periods (frequently combined with "valley filling" policies that shift consumption to periods of low demand. The combination is referred to as load shifting.)

PJM: PJM Interconnection is a Regional Transmission Organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

Power Pool: Two or more inter-connected electric systems planned and operated to supply power in the most reliable and economical manner for their combined load requirements and maintenance programs.

Renewable Generation: Electric power generation from a renewable energy source such as wind, solar, sustainably harvested biomass, or geothermal.

(RTO) Regional Transmission Organization: An independent regional transmission operator and service provider that meets certain criteria, including those related to independence and market size. Controls and manages the transmission and flow of electricity over large areas.

(REC) Rural Electric Cooperative: REC's are nonprofit, cooperative utilities that provide electricity to rural areas and are owned by all customers of that utility.

Transformer: Electrical device that changes the voltage in AC circuits from high-voltage transmission lines to low voltage distribution lines.

Wholesale Competition: A system in which a distributor of power would have the option to buy its power from a variety of power producers, and the power producers would be able to compete to sell their power to a variety of distribution companies.

Wholesale Electricity: Power that is bought and sold among utilities, non-utility generators, and other wholesale entities, such as municipalities.

Wholesale Power Market: The purchase and sale of electricity from generators to resellers (that sell to retail customers) along with the ancillary services needed to maintain reliability and power quality at the transmission level.

INTRODUCTION

The State of Ohio is one of the nation's largest users of electricity, led only by Texas, Florida, and California. Consumption in the state is projected to grow at an average annual rate of 1% between 2008-2025, and peak demand, a measure of consumption during the hottest periods of the year, is estimated to grow at 1% over that same period.[2] While these growth rates are relatively modest, the dual shocks of a slumping economy and volatile energy markets are placing an inordinate amount of financial pressure on Ohio's electricity consumers. As an added concern, rate stabilization plans (RSP) – introduced in 2006 to help moderate Ohio's transition to a deregulated electricity market – are scheduled to expire at the end of the year, which most anticipate will herald higher retail rates without intervention from utilities and their regulatory body, the Public Utilities Commission of Ohio (PUCO).

On May 1, 2008, Governor Ted Strickland signed Senate Bill (SB) 221, which included legislation mandating investments in energy efficiency and renewable energy intended to alleviate these issues, while also bolstering Ohio's workforce, cleaning its air, and leading the state down a path towards greater energy independence and sustainability. This laudably aggressive target, which through a state Energy Efficiency Resource Standard (EERS) requires investor-owned utilities to accumulate 22% reductions in electricity consumption by 2025, sets the foundation for Ohio to become a national leader in energy efficiency. Unfortunately, the collapse of financial markets and the subsequent economic recession have magnified the ramifications of the state's current budget deficit, leading many to question how Ohio and its consumers will be able to fund these investments and, ultimately, meet the 22% target.

Our report demonstrates that through a combination of innovative policies and proven utility programs, meeting the 22% target is, in fact, achievable and can be accomplished cost-effectively while concomitantly providing significant job and financial benefits to Ohio's economy. Energy efficiency and demand response can provide critical relief from short-term market impacts as they represent the least-cost resources available and are the quickest to deploy. During a time when Ohio's tax revenues are falling and its unemployment is rising, this central tenet is extremely important. And unlike supply-side energy resources, efficiency and demand response are the only resources that can begin to reduce electric bills by decreasing overall consumption, which will save the state and its consumers money that can then be reinvested in Ohio's ailing economy.

Ohio will also have assistance from federal funding to supplement its efficiency investments. On February 17, 2009, President Obama signed the economic stimulus bill, titled the *American Recovery and Reinvestment Act*, which includes $6.3 billion for state and local energy efficiency and clean energy grants. If these funds are invested prudently, it will be possible to reap benefits into the long term, especially if these resources are allocated to supporting policies like workforce education and training, energy-service performance contracting, and weatherization programs. With diligence, energy efficiency has the potential to help Ohio weather the current economic maelstrom, improving the vitality of its economy well into the years ahead.

The goal of this study is to inform policymakers and stakeholders of the opportunities for energy efficiency and demand response in Ohio, and also to suggest policies Ohio could implement to facilitate the development of these clean energy resources. We present the results in a fashion designed to help educate policymakers and the general public about the importance of energy efficiency and demand response, as well as to influence policy development in Ohio over the next several years by identifying policy and technical opportunities for achieving major energy efficiency benefits and savings.

This report is organized into the following sections:

[2] These estimates were made before the current economic downturn and may overproject near-term growth, but in the long term we anticipate increasing growth in consumption as the economy recovers.

- ***Background:*** Reviews the electricity market in Ohio, including recent actions and future opportunities regarding energy efficiency and demand response.

- ***Project Overview and Methodology:*** Provides a context for ACEEE's work with state-level energy efficiency and demand response potential studies and an overview of both the project approach and analysis methodology.

- ***Reference Case:*** Discusses the reference case electricity, peak demand, and price forecasts used in this analysis.

- ***Energy Efficiency Resource Assessment:*** Estimates the cost-effective potential, from the customer's perspective, for increased energy efficiency in the state's residential, commercial, and industrial sectors by 2025 through the adoption of specific energy-efficient technology measures. The resource assessment goes beyond what the state can achieve through penetration of specific programs and policies.

- ***Energy Efficiency Policy Analysis:*** Outlines the recommended policies for Ohio to adopt to tap into the energy efficiency resource potential. This section presents the electricity and peak demand impacts from energy efficiency, the associated costs, and an evaluation of program costs using two cost-effectiveness tests (TRC and the Participant Cost tests). Also included in this section is an estimation of carbon dioxide emissions impacts.

- ***Demand Response Analysis:*** Estimates the potential for increased demand response in Ohio and makes specific recommendations to the State.

- ***Macroeconomic Impacts:*** Estimates the impact of energy efficiency policies on Ohio's economy, employment, and energy prices.

In addition, we provide details and references to resources on most of these sections in the technical appendices that accompanies the body of this report.

BACKGROUND

In 2007, Ohio sold over 161,000 GWh, making it the nation's fourth-largest consumer of electricity. The industrial sector accounts for the greatest share of electricity consumption (36%), though the residential (33%) and commercial sectors (30%) retain only a slightly smaller share (EIA 2008a).[3] Ohio generates about 86% of its electricity from coal, almost twice the national average (see Figure 2). As a result, Ohio is the nation's largest emitter of sulfur dioxide and ranks second in both nitrogen and carbon dioxide emissions (EIA 2007b). In this section we discuss the current condition of the Ohio electricity market and the overall role of energy efficiency and related opportunities to meet the state's energy needs.

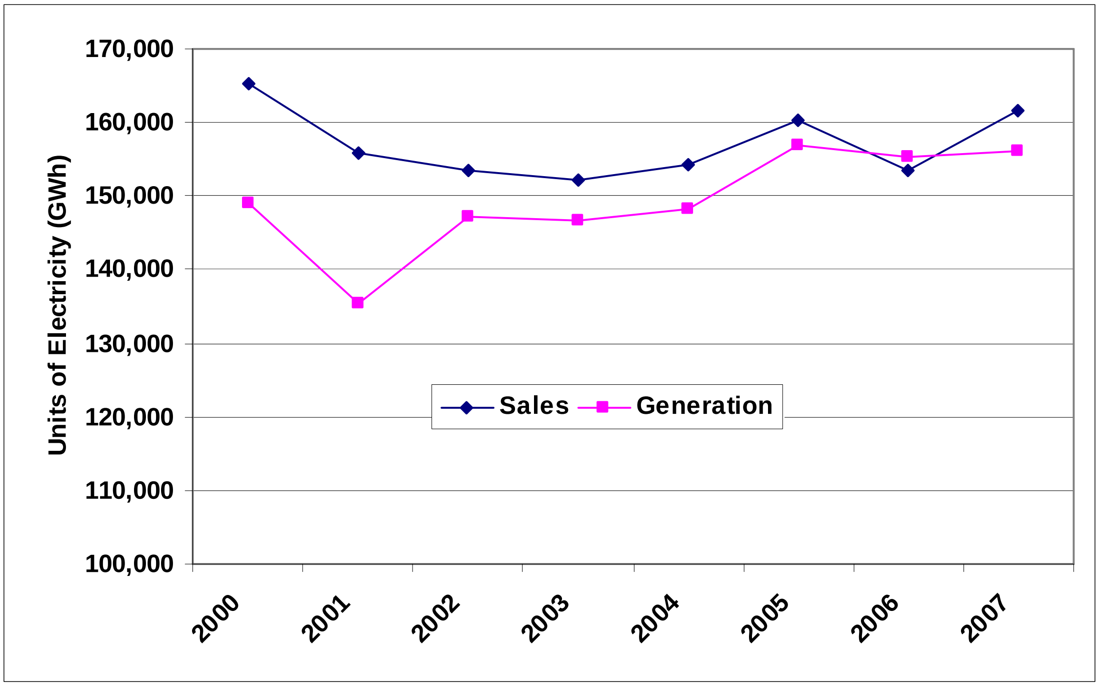
Ohio Electricity Market

In 2007, Ohio generated 156,069 GWh of electricity yet consumed 161,547 GWh, making the state a net importer of more than 3% of its electricity generation (see Figure 1). Two regional transmission organizations (RTO) service utilities in the state: the Midwest Independent Transmission System Operator (MISO) and the PJM Interconnection (PJM), allowing Ohio utilities to purchase or sell electricity on the wholesale market.[4] The vast majority of this in-state generated electricity comes

[3] We do not cover the transportation sector in this analysis since the sector's consumption of electricity is negligible relative to the other economic sectors (for a discussion of state-level opportunities for increased efficiency in the transportation sector, see Geller et al. 2007).
[4] FirstEnergy and Duke Energy are members of MISO. AEP and DP&L are members of PJM.

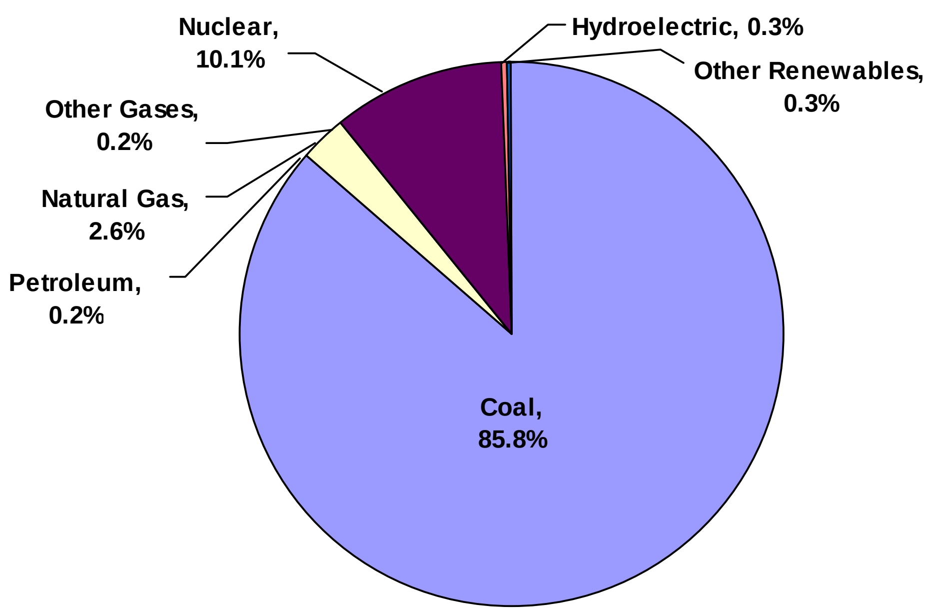
from coal (86%) and nuclear (10.1%) (see Figure 2). By comparison, the national average mix of electricity generation is 49% coal and 19% nuclear (EIA 2007b).

Figure 1. Electricity Sales and Generation in Ohio, 2000-2006



Source: EIA 2008a

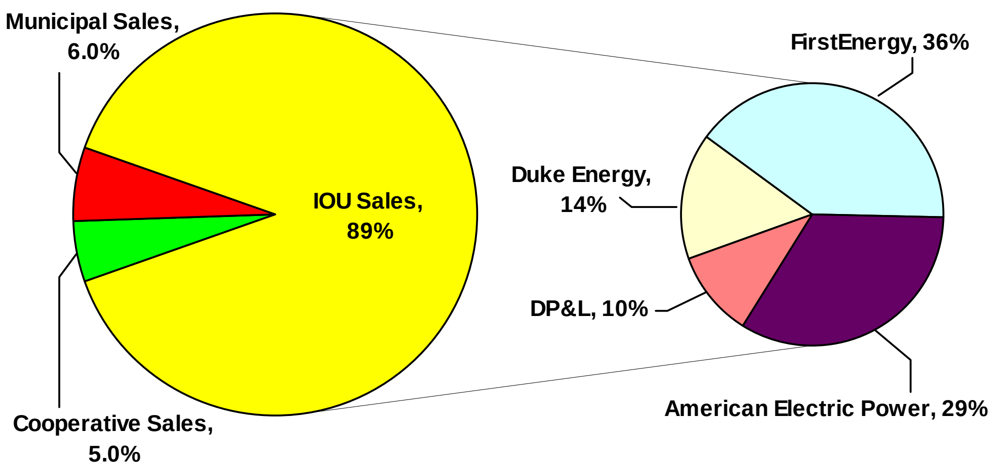
Figure 2. 2007 Ohio Electricity Generation by Fuel Type
Total Generation: 156,069 GWh



Source: EIA 2008a

Electricity is delivered in Ohio to consumers by three types of providers: investor-owned utilities (IOUs), rural electric cooperatives, and municipal electric suppliers. As can be seen in Figure 3, of the three types of providers, IOUs dominate sales in the state (89%), the two largest being FirstEnergy (36%) and AEP (29%). Duke Energy and Dayton Power & Light retain 14% and 10% of the market, respectively. Cooperatives and municipal utilities account for the remaining 11% of sales.

Figure 3. Electricity Deliveries (GWh) by Supplier in 2006



Source: EIA 2007a

The gradual introduction of deregulation starting in 2001 never had the impact on competition that was envisioned, which is evident by the fact that 86% of electricity services remain bundled, while only 8% is delivered to a third party for distribution.

Deregulation of Ohio's Electricity Market

As many states did when faced with rising electricity rates in the mid- to late-1990's, Ohio embraced deregulation in hopes of lowering retail rates for its customers. In 1999, Senate Bill (SB) 3 was passed with the intention of introducing competition into Ohio's electricity market, beginning in 2001. Included in the legislation was the imposition of a five-year market-development period where utility rates were frozen in order to facilitate competition in the market. Competition, however, failed to materialize, and as the end of the development period grew nearer, there was growing concern that the removal of rate caps would effectuate dramatic hikes in retail rates. The Public Utilities Commission of Ohio (PUCO) began to work with utilities to devise Rate Stabilization Plans (RSP) to guarantee stable, predictable rates. Most of these RSP's expire at the end of 2008, which, unattended, will leave Ohio consumers at the mercy of the market.[5]

To address this issue, legislation was included in SB 221 essentially weakening the state's commitment to deregulation in an effort to protect consumers from impending rate increases.[6] The bill requires all utilities to file a standard service offer, effective January 1st, 2009, which determines how utilities' retail rates will be set. A utility can choose between two methods to set its rates: an Electric Security Plan (ESP) or a Market Rate Option (MRO). Initially, however, all investor-owned utilities

[5] The PUCO approved Dayton Power & Light's current rate plan to extend through 2010.
[6] Please see Sections 4928.141 through 4928.143 of SB 221 for more information.

must *at least* file for an ESP, where retail rates are regulated by the PUCO. In conjunction with, or after, this initial filing, a utility may also choose to file for a Market Rate Option (MRO), where its retail rate would reflect prices in the PJM and MISO wholesale markets.[7]

By providing two ways for utilities to set their retail electricity rates, the PUCO is searching for the least-cost option: that being the plan most likely to present customers with the lowest rate. FirstEnergy was the only utility to file for an MRO, which they filed for simultaneously with their ESP, but the MRO was rejected by the PUCO on November 25, 2008 (PUCO 2008). No other Ohio utilities have shown interest in filing for an MRO. Unlike MROs, ESPs, with retail prices regulated by the PUCO, offer greater stability in prices and therefore ensure that the utilities will earn a favorable rate of return while also allowing them to recuperate any losses due to rising fuel costs.

It was believed that deregulation would produce lower retail rates by fostering competition, but since deregulation has failed to meet those expectations, the PUCO now offers these alternative methods of setting rates in the interest of Ohio customers. Nonetheless, because Ohio's electricity market remains deregulated – albeit in principle rather than in fact – when filing for an ESP, utilities are required to show that rates set by an ESP will be favorable to those set by an MRO. Additionally, for those utilities that have had an ESP approved by the PUCO that exceeds a three-year period, the PUCO requires that the ESP be reviewed every fourth year to ensure that the rates being delivered are still favorable when compared to an MRO.[8]

Utility-Level Projects

There are several major generation projects transpiring in Ohio that are aimed at meeting growing demand. The Haverhill North Coke Company completed construction of its Haverhill Generating Facility in August 2008 and began operation on December 1st, 2008. The 61 MW cogeneration facility, located in Haverhill, uses waste heat from coke ovens to generate electricity and has a maximum capacity of 75 MW. The Fremont Energy Center, owned by FirstEnergy and currently under construction in the Sandusky Township, is a 540 MW natural gas-fired combined-cycle electric generating facility with peaking capabilities of 704 MW that is scheduled to begin commercial operations in 2009. American Electric Power's (AEP) Dresden Energy Facility, also slated to begin commercial operations in 2009 and located in the Cass Township, is a 500 MW combined-cycle gas turbine, also with peaking capabilities of 704 MW (OPSB 2008a, 2008b).

Five other generation projects have been approved by the Ohio Power Siting Board (OPSB) and are in varying states of completion. Construction of the Lima Energy IGCC Station, a 580 MW base load synthetic gas plant owned by the Lima Energy Company, has been halted temporarily. Calpine Corporation's Lawrence Energy Center, an 850 MW combined-cycle gas facility, and AEP's Great Bend IGCC station have also been suspended. Construction of American Municipal Power's (AMP) 960 MW coal-fired generating station in Meigs County is scheduled to begin in the second quarter of 2009, though a request to modify a condition in its certificate is currently under investigation (OPSB 2008a, 2008b). The 135 MW FDS Coke Plant Co-Generation Facility in Toledo was approved by the OPSB October 28, 2008 and, according to their Web site, will take two years to complete (OPSB 2008a; FDS 2008).

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[7] Utilities that file for an MRO and directly own, in whole or in a part, generating facilities are required to phase in the new rates, gradually transitioning to 100% market-based rates. In the first year, 90% of the new rates would be determined by the ESP and 10% would reflect the market price, ratcheting up the MRO portion each year. Ohio utilities that own their own generating facilities include American Electric Power, Dayton Power & Light, and Duke.

[8] Section 4928.143 (C) (1) of SB 221 requires utilities to conduct their own electricity price forecasts for the purposes of reviewing the benefits of an ESP versus an MRO. This has caused some concern as there is an incentive for utilities to exaggerate their price forecasts in order to make the ESPs appear more economically beneficial.

Role of Energy Efficiency

Ohio has already begun to take significant steps towards promoting energy efficiency. This momentum is vital given the bleak economic conditions and the pending expiration of RSPs, as well as the fact that Ohio generates 86% of its electricity through coal-fired power plants with no plans of reducing that mixture in the foreseeable future (OPSB 2008a). Energy efficiency has the potential to provide short- and long-term economic and social benefits to Ohio consumers, such as lowering consumer bills, abating emissions, and stimulating the economy. Though electricity is forecast to grow at a modest annual average of 1%, deploying energy efficiency in the short term will greatly reduce the need for investing in infrastructure to maintain current services and to meet growing demand in the future.

Ohio's efforts to advance energy efficiency are captured in ACEEE's *2008 State Energy Efficiency Scorecard*, which ranks states on eight energy efficiency policy and performance criteria. Ohio tied for the 18th spot in our *2008 Scorecard*, aided by recent developments that helped Ohio jump eight spots relative to our *2006 Scorecard*, giving it the rank of the third most-improved.[9] Ohio is one of the leading states dedicated to expanding combined heat and power (CHP) and, in fact, tied for 1st in the category (Eldridge et al. 2008). Ohio also provides financial incentives for energy efficiency in the form of grants for industrial efficiency projects, equal to 25% of the project cost with a maximum of $50,000 (DSIRE 2008).

Of particular importance was the introduction of SB 221 on May 1st, 2008, which included legislation encouraging the advancement and growth of alternative energy resources, specifically renewable energy and energy efficiency. SB 221 mandates an Energy Efficiency Resource Standard (EERS), which requires utilities to accumulate savings of at least 22% of consumption by 2025. Currently eighteen states have adopted some form of an EERS and of those eighteen, Ohio's EERS ranks among the more stringent (Eldridge et al. 2008). Effective as of January 1st, 2009, the annual savings target begins at 0.3% and ramps up 0.1–0.2% every year until 2014, where the target increases by 1% annually until 2019 and by 2% annually through 2024.[10] Utilities are also required to implement peak demand reduction programs beginning in 2009. Peak demand savings are targeted at 1% in the first year, followed by a 0.75% annual increase until 2018.[11]

The movement to incorporate energy efficiency is also being fostered by Ohio's utilities. Several utilities offer financial incentives for the purchase and installation of energy-efficient appliances and energy-efficient home improvements. Cleveland Electric Illuminating Co., Ohio Edison, and Toledo Edison – all subsidiaries of FirstEnergy – offer rebates to contractors and homeowners under the auspices of the Home Performance with ENERGY STAR program. FirstEnergy's rebate programs cover rebates on HVAC equipment and appliances, as well as investments in the weatherization of the home envelope. Duke Energy also offers rebates to both homeowners and contractors through its Smart Saver program, but its rebates extend only to HVAC equipment (DSIRE 2008).[12]

In leading states, energy efficiency is meeting 1–2% of the state’s electricity consumption each year (Nadel 2007; Hamilton 2008) at a average cost of about 3¢ per kWh (Kushler, York, and Witte 2004),

[9] Ohio and Maryland tied for third, both having jumped eight spots relative to our *2006 Scorecard.*

[10] The baseline for calculating savings is the average of total kilowatt hours utilities sold during the preceding three years.

[11] While the EERS target set forth in SB 221 directs utilities to accumulate savings of at least 22% of consumption by 2025, the actual requirement specifies annual savings for each year based on a percentage of the average consumption in the prior three years. While the annual percent energy savings targets sum to 22.2% in 2025, the application of the formula specified in the legislation result in a savings of 36,831 GWh in 2025, which represents just under 19% savings relative to the reference forecasted electricity consumption used in this report.

[12] For more information on these utility rebate programs, please visit the Database of State Incentives for Renewables and Efficiency (DSIRE) at www.dsireusa.org.

compared with a utility avoided cost of about 5–10¢ per kWh in Ohio (see Figure 7).[13] States across the country, including California, Connecticut, Massachusetts, Minnesota, New York, and Vermont, are realizing the benefits of energy efficiency today, having enacted policies and programs that effectively tap into their energy efficiency resources. Results from these states show that energy efficiency represents an immediate low cost, low risk strategy to help meet the state's future electricity needs (York, Kushler, and Witte 2008).

Together, energy efficiency and demand response can delay the need for expensive new supply in the form of generation and transmission investments (Elliott et al. 2007; 2007b), thus keeping the future cost of electricity affordable for the state and freeing up energy dollars to be spent on other resources that expand the state's economy. In addition, a greater share of the dollars invested in energy efficiency go to local companies that create new jobs compared with conventional electricity resources, where much of the money flows out of state to equipment manufacturers and energy suppliers.

PROJECT APPROACH AND METHODOLOGY

Stakeholder Engagement

Awareness of the demographics and political climate in the State of Ohio was an integral part of the formulation of the policies that we are suggesting. Each State in the Union is different and we do not presume that any one policy will work ubiquitously. Identifying and engaging stakeholders in Ohio, therefore, was imperative to the relevance and success of our report. We endeavored to meet in person with as many different representative groups as possible in order to better understand Ohio's specific energy structure and needs. For those we were unable to meet with personally, we conducted telephone conferences to facilitate the process. We met with several environmental groups, the PUCO, the Ohio Consumers Council (OCC), the Ohio Department of Development (ODOD), the Ohio Manufacturers Association (OMA), the Ohio Hospital Association (OHA), as well as many of the utilities, such as AEP, Buckeye Power, and American Municipal Power Ohio (AMP Ohio).[14]

One theme that surfaced quite regularly was the necessity of a trained, qualified workforce with which to implement, operate, and evaluate energy efficiency programs. These include positions such as contractors, building operators, auditors, etc. Our stakeholders were particularly emphatic about the need for properly trained workers to conduct evaluation, measurement and verification (EM&V) of efficiency programs. However, considering the high demand for these types of workers at the national level, Ohio is struggling to find qualified firms or individuals to meet its indigenous needs. Efforts to expand the workforce will therefore have to be done within the state through the cooperation of entities such as the Ohio Board of Regents, the PUCO, and the ODOD. Fortunately there are already programs in Ohio that serve the state in this capacity. We will discuss the workforce issue in greater detail in the section discussing our innovative policies.

Analysis Methodology

The following is a description of the energy efficiency analysis methodology:

- ***Reference Case Forecasts:*** The first step in conducting an energy efficiency potential study for Ohio is to collect data and to characterize the state's current and expected patterns of electricity consumption over the time period of the study (2009-2025). In the next section of this report we describe the assumed reference forecasts for electricity and

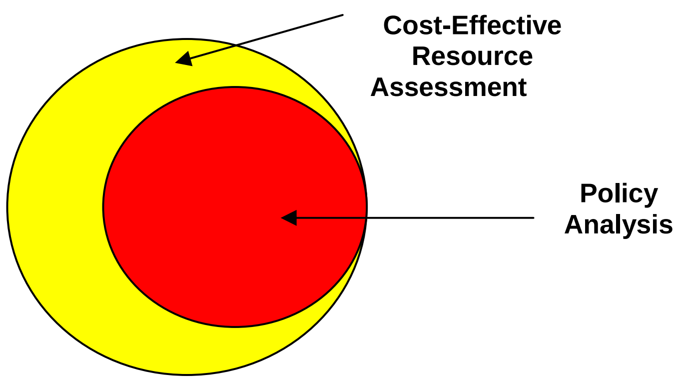
[13] The avoided cost analysis does not take into account a cost of carbon that would be imposed under a federal cap and trade program.
[14] This list is not intended to be exhaustive, but merely indicative of the steps we have taken to ensure that we incorporate the insight of as many different interest groups as possible.

peak demand. Reference case avoided costs for electric utilities, developed by Synapse Energy Economics, are described in this section along with projections of retail energy price forecasts.

- ***Energy Efficiency Resource Assessment:*** The energy efficiency resource assessment examines the overall potential in the state for increased cost-effective efficiency using technologies and practices of which we are currently aware (see Figure 4). Cost-effectiveness is evaluated from the customer's perspective (i.e., a measure is deemed cost-effective if its cost of saved energy is less than the average retail rate of energy). We review specific, efficient technology measures that are technically feasible for each sector; analyze costs, savings, and current market share/penetration; and estimate total potential from implementation of the resource mix. The technology assessment is reported by sector (i.e., residential, commercial, and industrial) and includes an analysis of potential for expanded CHP, which is prepared by ICF International.

- ***Energy Efficiency Policy Analysis:*** For this analysis, we develop a suite of energy efficiency policy recommendations based on successful models implemented in other states and in consultation with stakeholders in Ohio. This analysis assumes a reasonable program and policy penetration rate, and therefore is less than the overall resource potential (see Figure 4). We draw upon our resource assessment and evaluations of these policies in other states to estimate the energy savings and the investments required to realize the savings. The draft policy list for stakeholder review is presented after the reference forecast section in this document.

Figure 4. Levels of Energy Efficiency Potential Analysis



- ***Demand Response (DR) Analysis:*** The Demand Response Analysis, which is prepared by Summit Blue Consulting, assesses current demand response activities in Ohio, uses benchmark information to assess the potential for expanded activities in the state, and offers policy recommendations that could foster DR contributing appropriately to the resource mix in Ohio that could be used to meet electricity needs. Potential load reductions are estimated for a set of DR programs that represent the technologies and customer types that span a range of DR efforts, and are in addition to the demand reductions resulting from expanded energy efficiency investments.

- ***Macroeconomic Impacts:*** Based on the energy savings, program costs, and investment results from the policy analysis, we will then run ACEEE's macroeconomic model, DEEPER, to estimate the policy impacts on jobs, wages, and gross state product (GSP) in Ohio.

REFERENCE CASE

The first task in developing an energy efficiency and demand response potential assessment is to determine a reference case forecast of electricity consumption, peak demand, and electricity prices in the state for a "business as usual" scenario. As with all forecasts, they are subject to significant uncertainty, particularly in times such as these when the economic outlook is a major unknown. Still, it is important to understand that while the forecast will affect the final numbers, the forecast has a very minor impact on the effectiveness of the proposed policies.

In this section we report the reference case assumptions for the analysis time period, 2009-2025. Providing an historical and prospective look at electricity consumption and demand that is agreed upon by our stakeholders is crucial to the credibility of this study. Ideally this data is provided by a state's public utilities commission. While the PUCO estimated and published their own forecast in 2008, variations in historical sales arose between the data reported by the PUCO and the data reported by the Department of Energy's Energy Information Administration (EIA). Ultimately we chose to use data from the EIA to conduct our forecast. See Appendix A for further discussion and more detailed information on the reference case assumptions.

Electricity (GWh) and Peak Demand (MW)

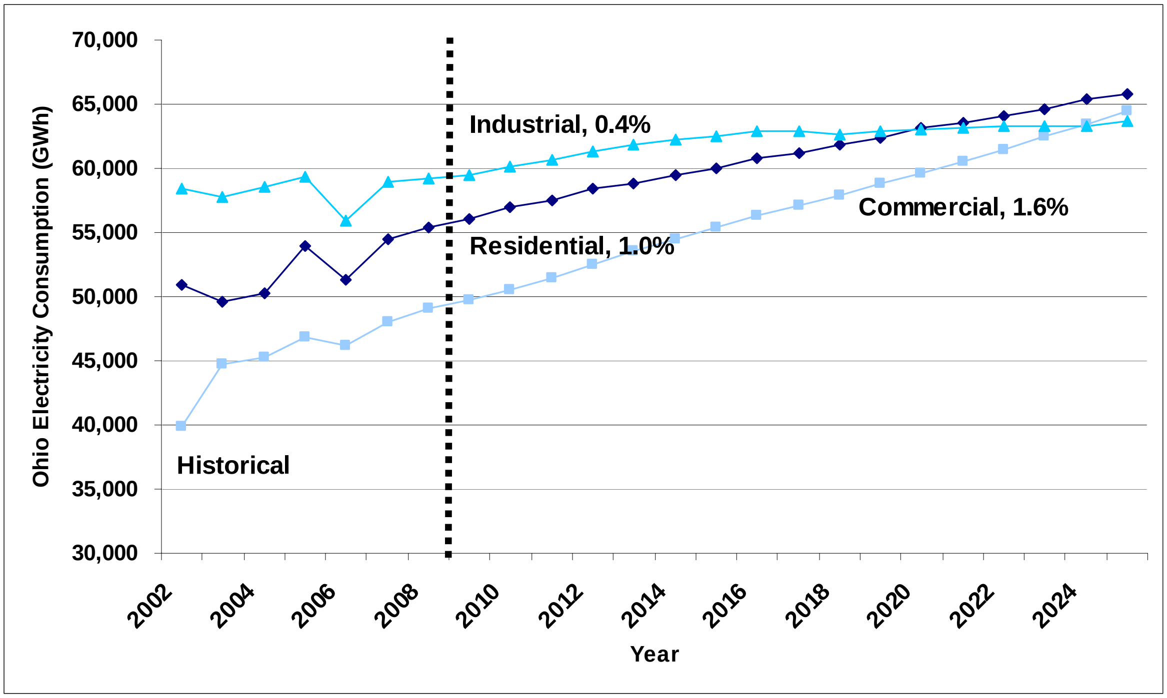
The development of the reference case for Ohio is the foundation of the quantitative analysis of the report. Our electricity consumption forecast is based on 2007 sales, the most recent year for which sales have been reported, which is then projected through 2025. For historical sales, covering 2002 through 2007, we used data from the EIA's *Electric Power Annual*, which publishes consumption data for all states individually. To estimate projected consumption, we then applied sector-specific growth rates, derived from the EIA's *Annual Energy Outlook* forecast for the East Central Area Reliability Coordination Agreement (ECARC), to actual 2007-year electric sales data. Using this methodology, we estimated total electricity consumption in the state to grow in the reference case at an average annual rate of 1.0% between 2008 and 2025, and 1.0%, 1.6%, and 0.4% in the residential, commercial, and industrial sectors, respectively (see Figure 5). Total electricity consumption in the three sectors in 2007 was 161,547 GWh and in the reference case grows to 177,954 GWh in 2015 and 193,945 GWh in 2025 (PUCO 2009).

To forecast peak demand we adjust our data from electricity sales forecast using a system load factor, which we assumed to be 60.0%. Using this methodology, we estimate peak demand growing at an average annual rate of 1.0% over the 2008-2025 period. In 2008, peak demand is expected to reach 33,705 MW increasing to 36,586 MW by 2015 and 39,770 MW in 2025 (see Figure 6).

Utility Avoided Costs

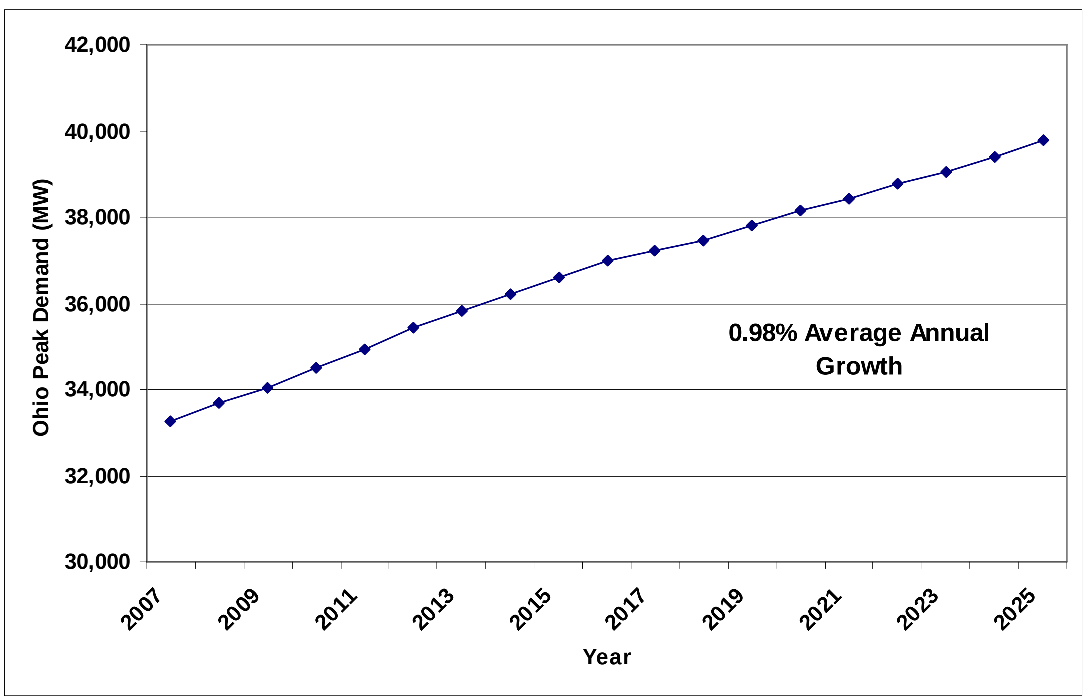
At ACEEE's request, Synapse Energy Economics developed simplified, high-level projections of utility production and avoided marginal costs. We then used these results in ACEEE's analysis to estimate the cost-effectiveness of energy efficiency measures and assess the macroeconomic impacts. The avoided cost estimates are based upon a number of simplifying and conservative assumptions. These simplifications include use of a single annual average avoided energy cost to evaluate the economics of energy efficiency measures rather than different avoided energy costs for energy efficiency measures with different load shapes. We also did not include a cost of compliance with anticipated greenhouse gas regulations. As a result, the production and avoided cost estimates should be viewed as unrealistically low. The vetting of our methodology with stakeholders revealed some concerns with the underlying assumptions. A detailed discussion of the assumptions, avoided cost estimates, and responses to these concerns can be found in Appendix A.

Figure 5. Electricity Forecast by Sector in the Reference Case, 2008-2025



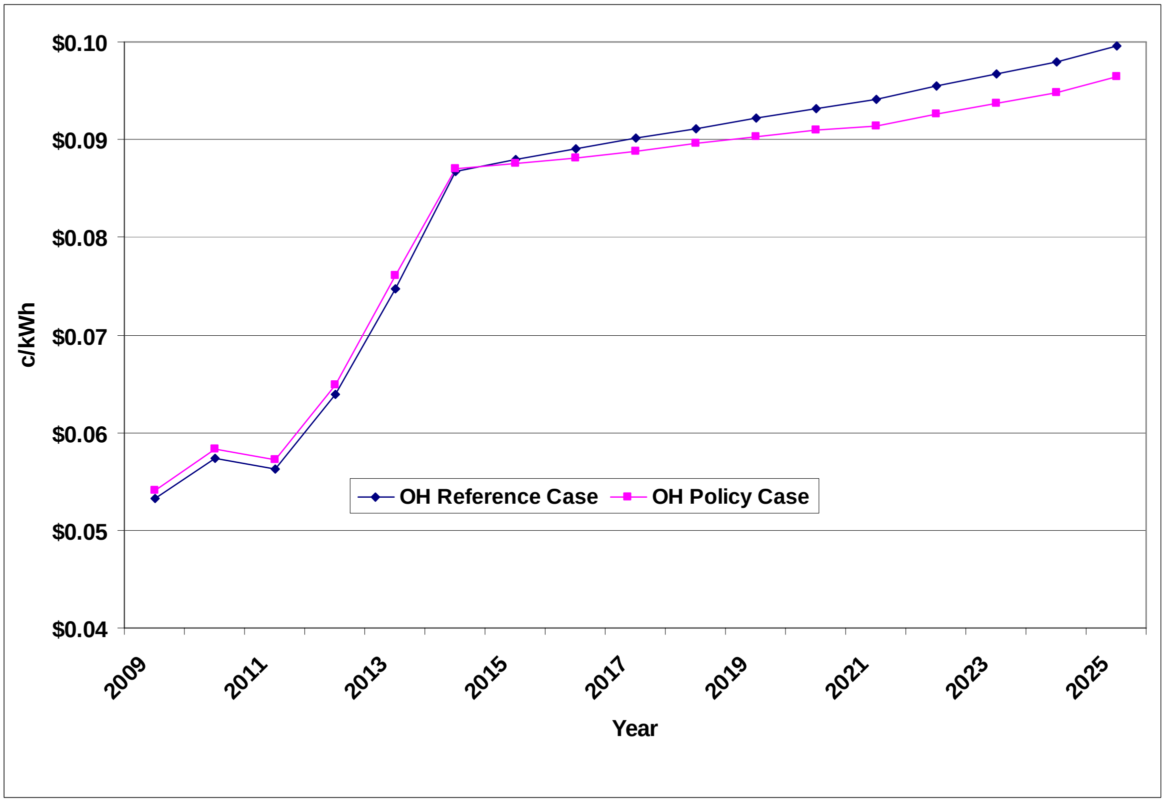
Source: EIA 2007b and 2007c

Figure 6. Ohio Peak Demand Forecast, 2008-2025



Because the level of energy efficiency and demand response measures assessed in this study significantly change the requirements of future resources, we developed two sets of production and avoided costs projections. The first case reflects the market conditions that would be anticipated in the reference case. The second case reflects the incorporation of our policy suggestions, which we discuss later. As would be anticipated, the policy case produced modestly lower avoided resource costs than the reference case, as can be seen in Figure 7. As a further conservatism in our analysis, we used this second, lower set of costs in valuing the savings that result from the analyzed policies and programs.

Figure 7. Estimates of Average Annual Avoided Resource Costs



These projections are a highly stylized representation of costs, so we suggest that a more detailed assessment of costs be undertaken as part of Ohio's energy planning process in order to reflect the locational and temporal variations across the state and throughout the year.

Retail Price Forecast

ACEEE also developed a possible scenario for retail electricity prices in the reference case. Readers should note the important caveat that ACEEE does not intend to project future electricity prices in Ohio for either the short or the long-term. Rather, our goal is to suggest a possible scenario, based on data from credible sources, and to use that scenario to estimate impacts from energy efficiency on electricity customers in Ohio.

Table 1 shows 2007 electricity prices in Ohio (EIA 2008a) and our estimates of retail rates by customer class over the study period. This price scenario is based on three key factors. First, we use the average generation cost of electricity in Ohio over the study period as calculated by Synapse Energy Economics (see above). Next, we use estimates of retail rate adders (the difference between generation costs and retail rates, which accounts for transmission and distribution costs) from the *Annual Energy Outlook* for the East Central Area Reliability Coordination Agreement (ECARC) (EIA 2007c). Finally, we estimate short-term decreases from falling generation costs due to lower prices in the cost of fuel inputs.

Table 1. Retail Electricity Price Forecast Scenario in Reference Case (cents per kWh in 2006$)

	2007*	2010	2015	2020	2025	Average
Residential	9.28	8.81	10.96	12.05	12.95	**11.01**
Commercial	8.42	8.22	9.99	11.07	12.11	**10.15**
Industrial	5.63	5.59	7.38	8.37	9.22	**7.44**
All Sector Average	7.69	7.34	9.31	10.27	11.03	**9.33**

Note: These figures are in real, 2006-year dollars and therefore do not take into account inflation.
* Actual rates (EIA 2008a), converted to 2006$

ENERGY EFFICIENCY COST-EFFECTIVE RESOURCE ASSESSMENT

In this section we present the results from our assessment of cost-effective efficiency resources in residential and commercial buildings, the industrial sector, and combined heat and power (CHP). We consider the cost-effectiveness of more-efficient technologies from the customer's perspective; i.e., a measure is deemed cost-effective if its cost of saved energy is less than the average retail rate of electricity for a given customer class. In Table 2 below we summarize the economic potential for energy efficiency by each sector in 2025. Our assessment includes only existing technologies and practices, but we anticipate that new and emerging technologies and market learning will significantly increase the cost-effective efficiency resource potential by 2025.

Table 2. Summary of Cost-Effective Energy Efficiency Potential in Ohio by Sector (2025)

Sector	Efficiency Potential (GWh)	As % of Electricity Consumption in 2025	As % of Sector Consumption in 2025
Residential	22,073	11%	34%
Commercial	17,140	9%	27%
Industrial	14,697	8%	23%
Combined Heat & Power	10,374	5%	8%*
Total	**64,284**	**33%**	

*Note: As percentage of commercial and industrial sectors combined

Residential Buildings

For our analysis of the potential for energy efficiency resources in Ohio's residential sector, we considered a scenario with widespread adoption of cost-effective energy efficiency measures during the 17-year period from 2009 to 2025. We evaluated 36 efficiency measures that might be adopted in existing and new residential homes based on their relative cost-effectiveness. An upgrade to a new measure is considered cost-effective if its levelized cost[15] of conserved energy (CCE) is less than \$0.1101/kWh saved, the average retail residential electricity price in Ohio over the study time period (see Table 2). All 36 measures have a levelized cost of less than \$0.1101/kWh.[16] The substantial majority (83%) of the total efficiency potential has a levelized cost of 7 cents per kWh saved or less and 53% of the measures have a cost of 4 cents per kWh or less. For the sum of all measures, we estimate a levelized cost of less than 3 cents per kWh saved (see Table 2.).[17] See Appendix C.1 for a detailed methodology and specific efficiency opportunities and cost-effectiveness for residential buildings (see Table 25).

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[15] Levelized cost is a level of investment necessary each year to recover the total investment over the life of the measure.
[16] We explored additional measures, but measures above this cost-threshold were dropped from the analysis.
[17] Assuming a 5% real discount rate.

Table 2. Residential Energy Efficiency Potential and Costs by End-Use

End-Use	Savings (GWh)	Savings (%)	% of Efficiency Potential	Weighted Levelized Cost of Saved Energy ($/kWh)
HVAC	8,259	13%	37%	$ 0.029
Water Heating	2,864	4%	13%	$ 0.041
Lighting	4,774	7%	22%	$ (0.003)
Refrigeration	536	1%	2%	$ 0.058
Appliances	139	0.2%	1%	$ 0.077
Furnace Fans	1,945	3%	9%	$ 0.047
Plug Loads	1,060	2%	5%	$ 0.024
Electricity Use Feedback	1,460	2%	7%	$ 0.057
Existing Homes	21,037	32%	95%	$ 0.028
New Homes	1,036	2%	5%	$ 0.045
All Electricity	**22,073**	**34%**	**100%**	**$ 0.029**

Our analysis shows an economic potential for efficiency resources in the residential sector of 22,073 GWh over the 17-year period of 2009–2025, a potential savings of 34% of the reference case electricity consumption in 2025 (Table 2). Existing homes can reduce electricity consumption by 32% through the adoption of a variety of efficiency measures (see Appendix C, Table 26). While newly constructed homes built today can readily achieve 15% energy savings (ENERGY STAR® new homes meet this level of efficiency), we also estimate that new homes can reach 30% to 50% energy savings cost-effectively. We estimate that new residential homes can yield electricity savings of about 1,036 GWh by 2025, or 5% of total potential savings in the residential sector.

In the residential sector, improved housing shell performance (e.g., insulation measures, duct sealing and repair, reduced air infiltration, and ENERGY STAR windows) and efficient heating, ventilation, and air conditioning (HVAC) equipment and systems comprise the greatest percentage of the savings achieved through electricity efficiency resources.[18] These measures account for a total of 37% of potential savings and 13% of total electricity consumption.

Substantial savings are also attributed to improvements in lighting systems and water heating (including both more efficient water heaters as well as water-consuming appliances), which constitute 22% and 13% of residential efficiency potential, respectively (see Figure 8). Both new and existing homes in Ohio can achieve considerable energy savings by replacing household incandescent light bulbs with more efficient compact fluorescent light bulbs (CFLs).[19] Additionally, measures to reduce hot water loads (such as high-efficiency clothes washers, low-flow showerheads, and water heater jackets and pipe insulation) can yield considerable savings for households with electric water heaters. More efficient water heaters, particularly advanced technologies such as heat-pump water heaters, can further reduce electricity used for water heating.

Adoption of efficient household appliances can also yield significant savings. Our analysis shows that the energy savings from replacing existing refrigerators, clothes washers, and dishwashers with units that exceed the minimum ENERGY STAR efficiency standards (Consortium for Energy Efficiency “Tier 2” in most cases), or through quality installations of these efficient models in new homes reaches 139 GWh by 2025, or 1% of total potential. Another 6% of the total savings potential can be attributed to reducing the power consumption of electronic devices that use considerable amounts of energy in standby mode. We include a measure for reducing television power consumption in active mode, which is based on ENERGY STAR Version 3.0 television specification. These measures are

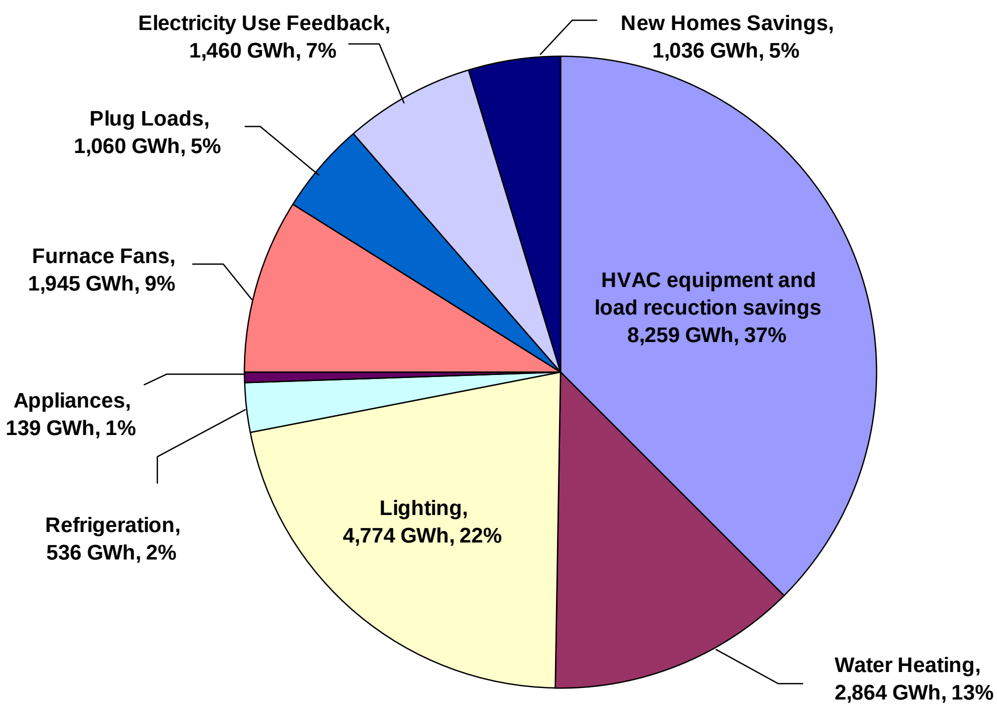
[18] Savings from air-conditioners assume a baseline of 13 SEER equipment, which is the recently updated federal standard.

[19] Efficiency provisions included in the EISA 2007 will help reduce lighting loads, which decrease potential savings attributable to CFL installation. However, this does not preclude other lighting and lighting design opportunities from having an impact. LED lighting, for example, while still an emerging technology and thus not included in this study, presents another avenue for significant energy savings in the near future.

among the most cost-effective in the residential sector. The balance of potential savings comes from installing a real-time energy use feedback mechanism. Although involving a behavioral component, in-home monitors, which allow residents to track how much electricity their house is using, have been documented to result in significant and persistent savings.

Figure 8. Residential Energy Efficiency Potential in 2025 by End-Use in Ohio

Total: 22,073 GWh, 34% of Projected Electricity Consumption in 2025



Commercial Buildings

The potential for commercial electricity savings through energy efficiency in Ohio is examined through a scenario of 37 cost-effective measures for electricity savings which would be adopted during the 17-year period from 2009 to 2025. An upgrade to a new measure is considered cost-effective if its levelized cost of conserved energy (CCE) is less than $0.1015/kWh saved, which is the average retail commercial electricity price in Ohio over the study time period (Reference Price Forecast). For the sum of all measures, the estimated levelized cost is $0.016/kWh saved (see Table 4). See Appendix C.2 for a detailed methodology and specific efficiency opportunities and cost-effectiveness for commercial buildings (See Appendix C.2, Table 29).

Table 4. Commercial Electricity Efficiency Potential and Costs by End-Use

End-Use	Savings (GWh)	Savings (%)	% of Efficiency Potential	Weighted Levelized Cost of Saved Energy ($/kWh)
HVAC	3,911	6.1%	23%	$ 0.033
Water Heating	212	0.3%	1%	$ 0.033
Refrigeration	689	1.1%	4%	$ 0.017
Lighting	8,286	12.8%	48%	$ 0.011
Office Equipment	3,356	5.2%	20%	$ 0.003
Appliances and Other	30	0.0%	0%	$ 0.029
Existing Buildings	16,484	25.6%	96%	$ 0.015
New Buildings	656	1.0%	4%	$ 0.029
Total	**17,140**	**27%**	**100%**	**$ 0.016**

Commercial buildings can reduce electricity consumption by 27% through the adoption of a variety of efficiency measures. The economic potential for efficiency resources in the commercial sector, will reduce electricity use by 17,140 GWh through the period 2008-2025.

In the commercial sector, electricity savings from efficiency resources are realized through improved HVAC equipment, controls and building shell measures (e.g., roof insulation and new windows); improved water heating (e.g. heat pump water heaters); more efficient refrigeration systems (e.g. ENERGY STAR vending machines); and efficient lighting, office equipment, and miscellaneous appliances. The largest chunk of the savings, at 48%, is improved lighting efficiency. This includes more efficient light bulbs such as fluorescent and HID, as well as improved lighting controls such as daylight dimming systems and occupancy sensor.

HVAC and office equipment also provide substantial savings, at 23% and 20% respectively. HVAC measures include improved shell measures (e.g. roof insulation and improved windows), better heating and cooling systems (e.g. high efficiency chillers and heat pumps), and better controls (e.g. dual enthalpy controls and energy management system installations). Improved office equipment includes more efficient computers, printers, copiers, etc., as well as turning off this equipment after hours.

Water heating measures include heat pump water heaters, and efficient clothes washers, which reduce hot water demand. Refrigeration measures include improved commercial refrigeration systems (e.g. walk-in coolers, ice makers, vending machines).

For commercial new construction, we estimate that up to 50% savings can be reached cost-effectively.

Industry

The industrial sector is the most diverse economic sector, encompassing agriculture, mining, construction and manufacturing. Because energy use and efficiency opportunities vary by individual industry, if not individual facility, it is important to develop a disaggregated forecast of industrial electricity consumption. Unfortunately, this energy use data is not available at the state level, so ACEEE has developed a method to use state-level economic data to estimate disaggregated electricity use. This study drew upon national industry data to develop a disaggregated forecast of economic activity for the sector. We then applied energy intensities derived from industry group electricity consumption data reported and the value of shipments data to characterize each sub-sector's share of the industrial sector electricity consumption and projected the energy use through 2025. Figure 10 shows the largest electricity consuming industries in Ohio in 2008 and 2025.

Figure 9. Commercial Electricity Efficiency Potential in 2025 by End-Use in Ohio
27% of Projected Electricity Use in 2025

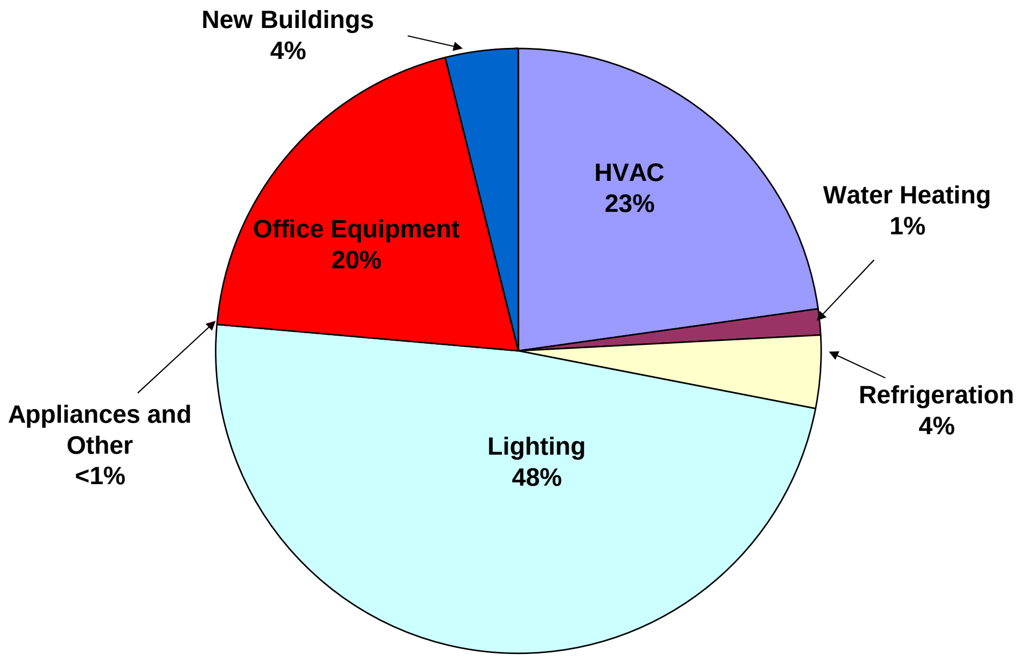
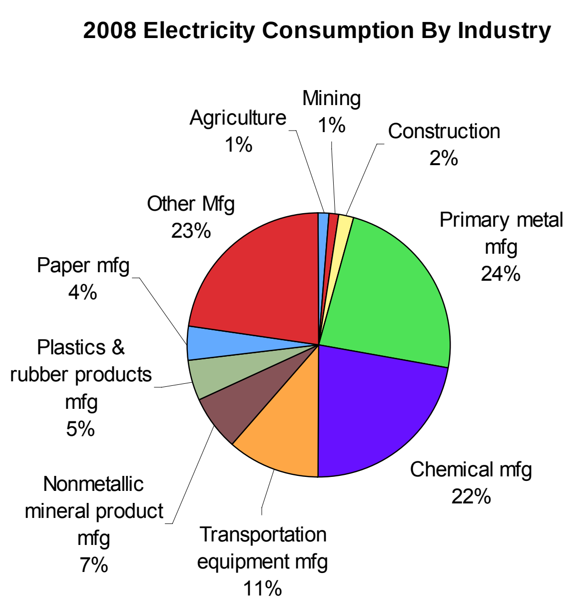
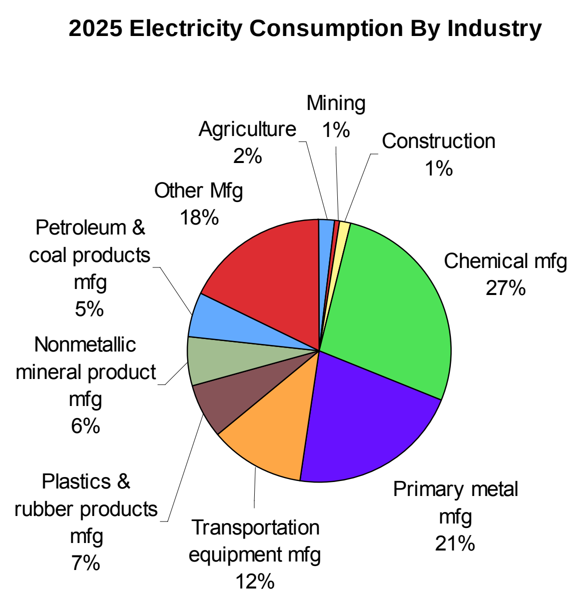


Figure 10. Estimated Electricity Consumption for the Largest Consuming Industries in Ohio in 2008 and 2025





Due to changes in economic activity and energy intensity as discussed in Appendix C, we see a significant intra-sectoral shift in electricity consumption. A small decrease in projected energy use by primary metal manufacturing coincides with a significant increase in energy use by the chemical manufacturing and plastics & rubber industries. The figure above shows their respective percentage changes in overall industrial electricity consumption. Also of note is the petroleum and coal products industry, which is projected to nearly double its energy use by 2025, and paper manufacturing, whose energy use will fall by almost half. Transportation manufacturing and machinery manufacturing will see their energy use increase by about 10% and 20%, respectively. These intra-sectoral shifts are important because they identify where new investments are being made and where energy efficiency opportunities are concentrated.

Electricity Savings

We examined 18 electricity saving measures, 10 of which were cost effective considering Ohio's 2008 average industrial electric rate of $0.0744/kWh. These measures were applied to an industry specific end-use electricity breakdown. Table 5 shows results for industrial energy efficiency potential by 2025.

Table 5. Industrial Electricity Efficiency Potential and Costs by Measure

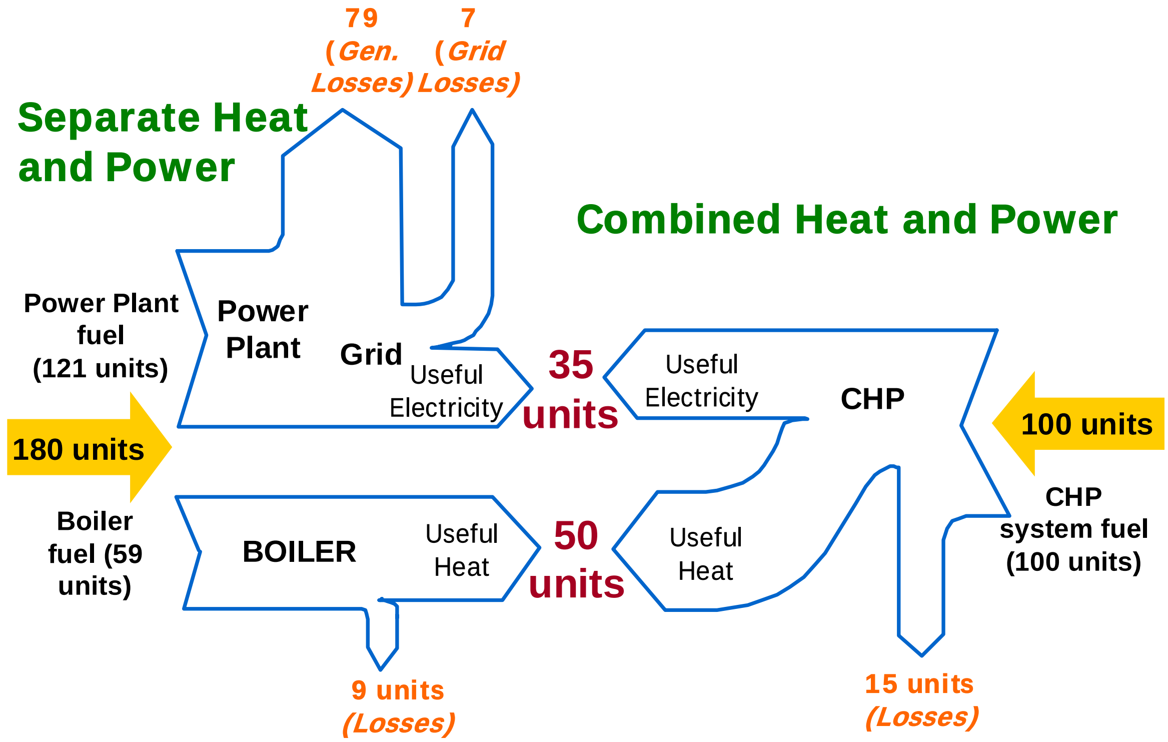
Measures	Savings Potential in 2025 (GWh)	Savings Potential in 2025 (%)	% of Efficiency Potential	Levelized Cost of Saved Energy ($/kWh)
Sensors & Controls	249	0.4%	2%	$0.014
EIS	91	0.1%	1%	$0.061
Duct/Pipe insulation	2,029	3.2%	20%	$0.052
Electric Supply	1,911	3.0%	19%	$0.010
Lighting	732	1.1%	7%	$0.020
Motors	2,352	3.7%	23%	$0.027
Compressed Air	1,015	1.6%	10%	$0.000
Pumps	1,432	2.2%	14%	$0.008
Fans	241	0.4%	2%	$0.024
Refrigeration	137	0.2%	1%	$0.003
Total	**10,191**	**16%**	**100%**	**$0.023**

This analysis found economic savings from these cross-cutting measures of 10,191 million kWh or 16% of industrial electricity use in 2025 at a levelized cost of about $0.02 per kWh saved. This analysis did not consider process-specific efficiency measures that would be applied at the individual site level because available time, funding, and data did not allow this level of analysis. However, based on experience from site assessments by the U.S. Department of Energy and other entities, we would anticipate an additional economic savings of 5–10%, primarily at large energy-intensive manufacturing facilities. The overall economic industrial efficiency resource opportunity is on the order of 21–26%. Therefore, the total economic potential for electricity savings in the industrial sector in 2025 would be about 14,967 GWh.

COMBINED HEAT AND POWER

Combined heat and power (CHP) improves efficiency by combining usable thermal energy (e.g., chilled water and steam) and power production (e.g., electricity). This co-generation process bypasses most of the thermal losses inherent in traditional thermal electricity generation, where half to two-thirds of fuel input is rejected as waste heat. By combining heat and power in a single process, CHP systems can produce fuel utilization efficiencies of 65% or greater (Elliott and Spurr 1998).

Figure 11. Schematic Comparing a Combined Heat and Power System to Separate Heat and Power Systems



For this report, Energy and Environmental Analysis (EEA), a division of ICF International, undertook an assessment of the cost-effective potential for CHP in Ohio by assessing the electricity end-uses at existing industrial, commercial, and institutional sites across the state and also considering sites that will likely be built in the future. These facilities would replace a thermal system (usually a boiler) with a CHP system that also produces power and that is primarily intended to replace purchased power that would otherwise be required at the site. EEA identified 665 MW from 45 CHP plants currently in operation. Detailed information from this analysis is provided in Appendix E.

An additional application of CHP considered by this analysis is in the production of power and cooling through the use of thermally activated technologies such as absorption refrigeration. This application has the benefit of producing electricity to satisfy onsite power requirements and displacing electrically generated cooling, which reduces demand for electricity from the grid, particularly during periods of peak demand (see Elliott and Spurr 1998).

Three levels of potential for CHP were assessed (see Appendix E for detailed results):

- *Technical Potential* represents the total capacity potential from existing and new facilities that are likely to have the appropriate physical electric and thermal load characteristics that would support a CHP system with high levels of thermal utilization during business operating hours.
- *Economic Potential* reflects the share of the technical potential capacity (and associated number of customers) that would consider the CHP investment economically acceptable according to a procedure that is described in more detail in Appendix E.
- *Cumulative Market Penetration* represents an estimate of CHP capacity that will actually enter the market between 2008 and 2025. This value discounts the economic potential to reflect non-economic screening factors and the rate that CHP is likely to actually enter the market. This potential is described in the energy efficiency policy scenarios, which are shown in the next section of the report.

The analysis identified an economic potential of around 2,600 MW of CHP capacity beyond what is already installed, assuming estimated electricity and natural gas price forecasts. In a scenario where customers installing CHP systems are given a $500 incentive per MW installed, the economic potential increases to around 4,000 MW. Policies and incentives provide an important catalyst to increasing the presence of CHP systems. In the next section, we estimate the impact that such an incentive can have on the market penetration of CHP in Ohio.

ENERGY EFFICIENCY POLICY ANALYSIS

In this section we present the suite of innovative policies and proven programs that we suggest Ohio implement in order to catalyze energy efficiency in the state.[20] We then estimate the resulting energy savings, costs, and consumer energy bill savings ($) that can be realized from their implementation. With the passing of SB 221 and the introduction of an EERS, the PUCO is now engaged in ruling how utilities will be allowed to meet the 22%+ target outlined in the EERS. Of the ten policies that we are promoting, there are five which ACEEE suggests be allowed to contribute towards the efficiency target, which have the potential to meet 10% of Ohio's electricity needs. This will leave only 12% of the EERS target to be met by the proven programs. Based on ACEEE's experience with utility programs we are confident that it is entirely feasible for them to meet and exceed 12% savings cost-effectively, however we did not attempt to quantify the degree of additional savings in this analysis.

At the end of this section we discuss the sorts of programs utilities can implement in order to satisfy the remaining 12% obligation as stipulated by the EERS. The discussion offers examples of best-practice energy efficiency programs that have proven to be successful in other states, which we take from ACEEE's report *Compendium of Champions: Chronicling Exemplary Energy Efficiency Programs from across the U.S.* (York, Kushler, and Witte 2008). In Appendix B we include a table estimating the incremental annual savings required by the EERS, which is based off of our electricity consumption forecast, and the savings that utilities will have to supplement in order to reach the percent annual EERS savings goals. The table illustrates the annual savings requirements, which are disaggregated by sector, both as a percentage as well as in GWh.

Discussion of Policies

This section provides greater detail of each of the suggested policies as well as the assumptions used in the analysis. While these policies were developed before the economic downturn, the potential for Federal stimulus funding created by the *American Recovery and Reinvestment Act* (Congress 2009) creates a unique opportunity to leverage this funding to build important human infrastructure necessary for sustained success of energy efficiency programs and policies in Ohio. The state and municipalities in the state should consider these innovative policies set forth in this section as the state prepares its plans for spending this windfall so that the Ohio will continue to benefit from this investment for years to come.[21]

Energy Efficiency Resource Standard

An Energy Efficiency Resource Standard (EERS) is a quantitative, long-term energy savings target for utilities and other entities, which is often coupled with a peak demand reduction target. Currently eighteen states, including Ohio, have adopted some form of an EERS or have established legislation directing a state agency to set an energy-savings target. This approach contrasts with many earlier state-legislated targets that were set in terms of funding levels or were relatively short term. EERS targets are typically set independently of specific program, technology, or market targets in order to

[20] The Workforce Development Initiative is not analyzed quantitatively as it is an enabling policy and does not have direct savings associated with it. Our Expanded Demand Response (DR) policy is assessed separately from the policy analysis by Summit Blue Consulting.

[21] At the time of the writing of this report, the details on conditions related to the transfer of these funds are still undecided. For current information on implementation of the federal stimulus visit: http://www.aceee.org/energy/national/fedeconomicstimulus.htm.

allow utilities maximum flexibility to find the least-cost path toward meeting the targets (Nadel et al. 2006; ACEEE 2008).

On May 1st, 2008, Governor Strickland signed SB 221, a bill created to encourage the advancement and growth of alternative energy resources, specifically renewable energy and energy efficiency. SB 221 established an EERS, which, starting in 2009, requires utilities to accumulate savings of at least 22% by 2025. The annual savings rate is set to begin at 0.3% in 2009, ramping up to 1% by 2014, followed by 1% annual savings through 2018 and 2% every year thereafter until 2025. The baseline for annual savings is the average of total kilowatt hours utilities sold during the preceding three years. The EERS is also complemented by a requirement for utilities to implement peak demand reduction programs that will save 1% in 2009, followed by 0.75% annual savings between 2010 and 2018.

The Public Utilities Commission of Ohio is currently holding rulings on what criteria should apply to the EERS as well as what policies should be allowed to contribute towards meeting the savings targets. ACEEE believes that the following criteria should apply to the EERS:

- Mandatory for Investor Owned Utilities (already included in SB 221 language)
- Voluntary commitment to lower target level by cooperatives and municipalities with some inducement
- Include incentives for exceeding savings targets, such as increased return on investment, etc.
- Require evaluation, monitoring and verification, preferably by a third-party organization

Additionally, we suggest that the following five policies – advanced residential and commercial buildings, manufacturing, rural and agricultural, and combined heat and power initiatives – be allowed to contribute towards meeting the 22%+ target. We estimate that these innovative policies will satisfy 10% of the EERS target and, along with the incentives outlined above and proven programs illustrated below, will enable utilities to surpass the 22% goal.

Advanced Residential Buildings Initiative

The development of an effective buildings program in the residential sector must focus on both new and existing homes for households of all income levels if efficiency is to be advanced on a large scale. Ohio currently has two state-sponsored residential programs in place: the Ohio *Electric Partnership Program* (EPP) and Ohio's *Home Weatherization Assistance Program* (HWAP).[22] These programs, however, focus exclusively on servicing the energy needs of low-income households. Though they have proven to be effective, we believe that there is potential to complement and broaden their scope, thus extending benefits to a larger portion of the population and, as a result, increasing the volume of electricity savings realized across the state.

Ohio's *Electric Partnership Program* (EPP) was recognized by ACEEE as one of the nation's exemplary low-income efficiency programs in our 2008 report entitled *Compendium of Champions: Chronicling Exemplary Energy Efficiency Programs from Across the U.S* (York, Kushler, and Witte 2008). EPP was designed to reduce the electric consumption of individuals in *Ohio's Percent Income Payment Plan* (PIPP) program, which assists households at or below 150% of the federal poverty level with their monthly payments (Blasnik 2006). These programs complement Ohio's *Home Weatherization Assistance Program* (HWAP), which was introduced in 1977 to provide audits and weatherization services to low-income households, as well as to improve the health, safety and overall comfort of the residents (Khawaja et al. 2006).

It is important to build upon these residential programs so that they are available to all income levels and include services beyond weatherization. Both the EPP and HWAP programs focus on weatherization assistance for low-income households in existing homes, though EPP offers equipment upgrades, such as lighting retrofits, replacement of inefficient refrigerators and freezers,

[22] More information on Ohio's residential efficiency programs is provided in the technical appendix.

and electric hot water reduction measures (Blasnik 2006) in addition to its weatherization services. An expanded weatherization initiative should redefine low-income households to include those with annual incomes up to 200% of the federal poverty level while also supporting the development of weatherization programs for existing homes for non-low-income residences.[23] Implementing energy efficiency in new construction must also be prioritized; ignoring efficiency improvements in new homes deprives Ohio of substantial energy savings and makes it more difficult to advance efficiency in the future, as these lost opportunities are more expensive and more difficult to retrofit.

The models for Ohio's residential efficiency programs should emulate ENERGY STAR's residential programs, which several states – such as New York, Vermont, and Wisconsin – have been doing for many years. For existing homes there is the Home Performance with ENERGY STAR program, which is designed as a comprehensive, whole-house approach to improving energy efficiency and comfort. The ENERGY STAR New Homes program, which is a similarly designed program that focuses on efficiency improvements during construction, can increase the efficiency of new homes 15% compared to homes built to the 2004 International Residence Code (IRC). Both programs focus not only on improving the efficiency of the home envelope, but also integrate efficient equipment, such as ENERGY STAR appliances and HVAC equipment. The incorporation of these myriad efficiency measures typically makes new homes 20-30% more efficient than standard homes.

Not all homes, new or existing, will be covered by these programs, so it is imperative that incentives are offered to households that are unable to participate. These incentives could be promoted either by utilities, or by the state through federal funding from the stimulus bill, and should establish a minimum savings of at least 20%, with greater incentives for products that generate higher savings. This sort of financial incentive, in conjunction with the advanced building initiative, also encourages contractors to purchase energy efficient appliances for new homes.

For our savings analysis of existing homes, we assume 0.5% annual savings and a participation rate (market share) of 0.5% in the first year, increasing 0.5% annually through 2016, followed by 1% annual increases through 2025. To analyze savings in new homes, we assume that new homes are able to achieve 50% savings beyond the current code, which we assume is the 2006 IECC. When the 2009 IECC becomes effective in 2011, new homes will be able to achieve 15% savings strictly from code improvements, leaving 35% still to be captured. We assume an initial participation rate of 2.5% in 2011, which doubles annually until 2014 when the 2012 IECC becomes effective. The 2012 IECC will likely deliver 30% savings beyond current code, leaving 20% savings still to be captured. Starting in 2014 we assume an annual participation rate of 20% of new homes for the remainder of the study period.[24] By the time the 2018 IECC becomes effective in 2020, which will deliver 50% savings, we assume that the program will have matured enough to allow an additional 20% savings beyond the 2018 IECC code. Under these assumptions, we estimate total savings for new and existing homes of 119 GWh in 2015 and 615 GWh in 2025, or a 0.3% reduction of total projected electricity consumption in 2025.

Advanced Commercial Buildings Initiative

Our stakeholders emphasized the necessity of a commercial buildings initiative that focuses on the ideas proposed in the Ohio Manufacturing Initiative: the need for assessments that identify energy efficiency opportunities; access to industry-specific expertise; and the need for an expansion of the trained buildings systems workforce with energy efficiency experience. Traditionally, advancing efficiency in commercial buildings was limited to efficient lighting and upgrades that focused on replacing individual pieces of equipment. While small commercial buildings will continue to reap

[23] The 2009 federal stimulus bill provides funding for low-income weatherization services as well as raises the qualification level to 200% above the poverty line.
[24] Our assumed participation rate for new homes is extremely conservative, especially for the short-term part of this analysis. For example, 57.2% of new homes in Iowa in 2006 qualified for the ENERGY STAR label, whereas 12.6% of new homes in Ohio met the ENERGY STAR standards (EPA 2007). By 2025, the ramping up of this initiative should allow Ohio to easily reach a much greater participation rate.

benefits from small-scale improvements, such as regular maintenance and individual equipment upgrades, larger commercial buildings require much broader improvements – through retrocommissioning, for example – in order to maximize energy savings.

Many retrofit programs are organized according to equipment or end-use with little emphasis on overall building performance, system optimization, or interactions among building systems. The establishment of an "Ohio Commercial Buildings Initiative" recognizes the need for programs that are tailored to address the contrasting efficiency issues between various-sized commercial buildings. A systems approach that goes beyond simple equipment upgrades to identify opportunities in system design, equipment interactions, and buildings operations and maintenance will generate greater energy savings, improve comfort, and bolster job growth through investment in training and certification for building operators, auditors, technicians, engineers, etc (Amann & Mendelsohn 2005). Again, incentives for retrofits and other commercial building upgrades could be offered by utilities, or by the state through funding allocated by the federal stimulus bill.

There are several excellent resources on how to model an effective advanced buildings program. The U.S. Department of Energy, for instance, has developed materials on how to achieve significant savings in new and existing buildings.[25] Another useful source of information is the New Buildings Institute, which has a web site on "Getting to Fifty" [percent savings].[26] ENERGY STAR also publishes a breadth of information on energy efficiency in commercial buildings and industrial plants.[27] Providing financial incentives to contractors or building owners will be crucial to guaranteeing that efficiency measures are implemented beyond what is already required by code. The Energy Policy Act of 2005 included a $1.80/square foot tax deduction for commercial building owners for each building constructed that uses 50% less than a new building designed to a national model reference code.

Combined heat and power, in conjunction with other efficiency measures, also has potential to generate significant savings in new and existing commercial buildings. H.R. 1424, titled the *Economic Stabilization Act of 2008*, includes a 10% tax credit against the cost of installing CHP systems (for the first 15MW) for systems up to 50 MW in size. Our discussions with stakeholders revealed that the health care sector – in particular hospitals and clinics, of which Ohio has well over 100 throughout the state that perpetually generate and consume considerable amounts of energy – is an excellent candidate for CHP (OHA 2008). This tax credit will provide significant impetus for the expansion of CHP systems in commercial buildings in general and help buildings in the health care sector reduce their operating costs during a time where remittances from Medicare have fallen significantly.

To estimate savings from existing buildings, we assume 1% annual savings throughout the analysis period and 1% participation rate (market share) in first year, with participation increasing by 1% annually. Savings from new construction assumes 50% savings beyond current code (IECC 2006), thereby decreasing with the adoption of new energy codes except in 2020, where we assume program implementation and participation has matured to allow for savings beyond the 50% savings from IECC 2018. In 2011 we assume an initial participation rate of 2.5%, doubling annually until 2014, when IECC 2012 becomes effective. We then assume a participation rate of 20% of new buildings for the remainder of the analysis period.[28] In 2020, when IECC 2018 becomes effective, delivering 50% savings, we assume 20% additional savings beyond IECC 2018 are achievable. Under these assumptions we estimate total savings for new and existing commercial buildings to be 133 GWh in 2015 and 715 GWh in 2025, or 0.4% of total projected electricity consumption in 2025.

[25] http://www.eere.energy.gov/buildings/highperformance/
[26] http://www.advancedbuildings.net/
[27] http://www.energystar.gov/index.cfm?c=business.bus_index
[28] Our assumed participation rate for new homes is extremely conservative, especially for the short-term part of this analysis. In other states, best practice programs for new construction in the commercial sector are achieving 50% participation rates. With time, the ramping up of this program should allow Ohio to easily meet a much greater participation rate.

Manufacturing Initiative

Based on discussions with a broad range of stakeholders involved with the manufacturing sector in Ohio, we propose a government/utility/industrial collaborative we are calling the "Ohio Efficient Manufacturing Initiative." The goal of the initiative would be to address the three key barriers to expanded industrial energy efficiency identified by the stakeholders: the need for assessments that identify energy efficiency opportunities; access to industry-specific expertise; and the need for an expansion of the trained manufacturing workforce with energy efficiency experience.

The initiative would establish Manufacturing Centers of Excellence in the model of the U.S. Department of Energy's Industrial Assessment Center (IAC)[29] program, where university engineering students are trained to conduct energy audits at industrial sites. Centers could be established at two or three main technical universities in Ohio, including The University of Dayton (UD) (the only current IAC in the state) and sites in Cleveland or Columbus. Expanding beyond the IAC model, these centers would partner with local community colleges and trade schools to bring their students into the larger network centered around the local Center of Excellence. These nearby satellite centers would extend training and associated materials to trade school and community college partners, and offer the opportunity to join the audits they conduct. Working with the Ohio Manufacturing Association and manufacturing trade associations, together with the local Manufacturing Extension Partnership (MEP) program could provide outreach to manufacturing companies that might not otherwise be aware of energy efficiency programs. Further collaboration with the Ohio Energy Office's industrial energy efficiency and sustainability programs would let the program rely on existing infrastructure and expertise on sustainability, energy, and job creation.

This initiative would provide multiple benefits to the state:

- Meet the needs of Ohio manufacturers for a trained technical workforce;
- provide valuable real-world work experience to students interested in working in manufacturing energy management;
- Meet the need of manufacturing facilities for reliable, knowledgeable, and affordable consultation with regard to their energy usage and opportunities for improved productivity; and
- Build capacity at educational facilities and in the MEP outreach efforts that connect Ohio's manufacturers to the wealth of knowledge and proficiency that resides in the state.

IAC program and implementation results recorded over the last 20 years show that this program could identify 10-20% electricity savings per facility and achieve a 50% implementation rate. Program costs for the IAC program are about $1 for every $10 saved by industry. We factor in another $0.25 per $10 saved to account for additional education costs. Under these assumptions we estimate savings of 1,721 GWh in 2015 and 5,771 GWh in 2025, or 3% of total projected electricity consumption in 2025.

We are also researching complementary policies that could leverage economic development programs to reduce Ohio's energy consumption. We also encourage the state to support an expanded federal manufacturing initiative similar to what has been suggested in recent congressional discussions.[30]

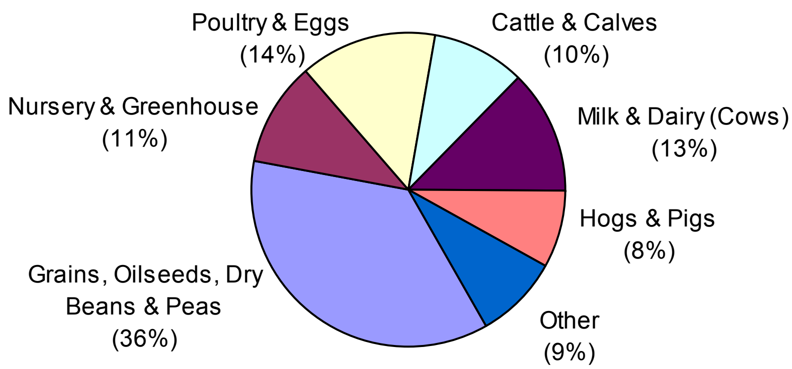
Rural and Agricultural Initiative

Agriculture makes up a little more than 1% of Ohio's industrial sector electricity use, averaging 708 GWh per year. The agricultural sector is one of the most energy-dependent sectors of our economy, relying on both direct sources of energy, such as fuels or electricity that power farm activities, or indirect energy sources such as fertilizers or other chemicals. When energy prices are unstable or increasing, farmers, ranchers and rural communities are significantly and adversely affected as

[29] For more information on the IAC program, visit: http://iac.rutgers.edu/.
[30] See http://aceee.org/industry/iac.htm.

agriculture becomes unprofitable. In 2004, electricity accounted for 21% of all energy uses on U.S. farms (Miranowski 2005). Ohio's agricultural sector produces a number of energy-intensive commodity crops, the bulk of which are grains such as soybeans, wheat and feed grains.

Figure 12. Estimated Electricity Consumption of Ohio Commodity Crops (2002)



In recent years, organizations specifically dedicated to improving efficiency on farms, ranches and rural small businesses have emerged. Existing programs are widening their focus to include agricultural energy efficiency issues and to provide more online and on-farm audits, as well as both technical and financial support. The Energy Title (IX) of the *2008 Farm Bill* provides more funding than previous legislative efforts to the Rural Energy for America Program (REAP, formerly Section 9006), which provides technical assistance and audits, as well as grants and loan guarantees for energy efficiency and renewable energy projects.[31] Although there is more money and awareness today, many states still lack the internal structure to aid their farmers, ranchers, and rural small businesses in leveraging these Farm Bill funds.[32]

The 2008 Farm Bill also authorized a new program which would provide financial assistance toward increasing the energy self-sufficiency of rural communities. The Rural Energy Self Sufficiency Initiative will fund energy assessments, help create blueprints for reducing energy use from conventional sources, and install community-based renewable energy systems.[33]

The initiatives described below are meant to build capacity within the state of Ohio in order to better provide energy efficiency-related knowledge, assessments, technical assistance and funding for rural small businesses and agricultural operations.

I. Develop an Educational Program to be administered through the Rural Electric Cooperatives, the Ohio Farm Bureau and the extension service

The Ohio Department of Agriculture, in conjunction with Ohio Department of Development, the Ohio Farm Bureau, the Ohio State Extension Service, Buckeye Power and the Ohio Rural Electric Cooperatives should establish an educational program which would disseminate information on energy efficiency best practices for farmers, ranchers and rural small businesses. This could take the

[31] Specifics on REAP project eligibility and additional information on the REAP program: http://farmenergy.org/incentives/9006faq.php#_Toc194481353.

[32] Of 1,158 applications for REAP funds in 2008, 766 were awarded grants or loan guarantees. Ohio had 12 of 22 projects awarded funds ($1,037,038). From the Environmental Law and Policy Center (ELPC)

[33] See Title VI, Energy Efficiency and Renewable Energy Programs for related program information: http://www.ers.usda.gov/FarmBill/2008/Titles/titleVIRural.htm#rural1.

form of a partnership with national organizations, such as the Rural Electricity Resource Council (RERC)[34] or the USDA-RD.[35]

There are several examples of state-specific educational programs. Southern California Edison utility runs an agriculture program that "promotes energy-efficient solutions for small and large farms, ranches, and dairies."[36] Their website provides information on a number of topics, including a *Dairy Farm Energy Efficiency Guidebook* and the Agricultural Technology Application Center (AGTAC). The latter, an "educational resource energy center," includes hands-on displays and exhibits which are open to public; demonstrations of energy-efficient technologies; educational seminars and free workshops; and provides information regarding scheduling consultations with energy experts. AGTAC "connects customers to energy-related technology solutions that are energy efficient, positive for the environment and cost competitive."[37]

In the Midwest, the Iowa Energy Center funded a project looking at the "Development of an Energy Conservation Education Program for Iowa's Livestock and Poultry Industry."[38] The work products of the study will include a curriculum, with day-long training sessions for farmers, fact-sheets and a reference manual covering energy efficiency techniques, and a training regimen for extension agricultural field specialists, to assist with the distribution of the educational materials.

Because of the regional specific nature of the agriculture sub-sector (Brown and Elliott 2003), it will be important for Ohio to tailor its programs to the unique needs of the state's agricultural industries.

II. Offer a rural audit program, building on the USDA-REAP program

Ohio utilities and extension services should make use of the reauthorized REAP program, which has $255 million dollars in mandatory funding for use over a 4-year period, to expand energy efficiency and renewable energy efforts throughout the state. ACEEE recommends that these entities provide on-site audits to farmers, ranchers and rural small businesses as a preliminary step in the REAP application process. Pinpointing areas where a farmer could save energy or implement an energy efficiency project is the first step toward identifying a successful REAP project.

Wisconsin's *Focus on Energy* program provides on-site audits with Focus energy advisors to farms and agricultural-related businesses (crop storage, grain processing, etc.). The program is marketed through multiple channels, is promoted by stakeholders including universities, extension agents, contractors, utilities and cooperatives. During the 2001-2007 period 1,500 dairy farmers participated in the program. *Focus on Energy* has promoted awareness of the Farm Bill REAP opportunities in conjunction with the Department of Agriculture and local USDA offices. Energy savings since the program began are 14.8MW, 74 kWh, and 1.4 million Therms annually (Brooks and Elliott 2007).

Alliant Energy operates a rebate and audit program for livestock and grain operations in Iowa, Minnesota and Wisconsin. The program has been in effect for more than 20 years, with over four hundred participating farms in 2006 and annual savings of 8-10 million kWh. The program also assists customers in applying for USDA funding, offering assistance for both grant application and project implementation. Specifically, the on-farm audit identifies energy waste, potential energy-efficient technologies to reduce energy usage, recommends efficient equipment specific to the

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[34] RERC's web site, www.rerc.org, provides materials on energy efficiency and is a national center for information on rural electricity topics.
[35] The Ohio Dept of Development does have a Web page for the energy office and information on saving energy for industry and businesses; however, there is no agriculture or rural community-specific section. The development of that on-line resource could be one component of a future education initiative. See http://development.ohio.gov/cdd/oee/c___i_services.htm for the page in question.
[36] http://www.sce.com/b-rs/agriculture/
[37] http://www.sce.com/b-sb/energy-centers/agtac/
[38] http://www.energy.iastate.edu/Efficiency/Agricultural/cs/harmon_conserv.htm

operation, and provides information on available agricultural rebate programs. Operators can also earn cash back for purchasing recommended equipment.[39]

III. Create a pool of matching funds for USDA grants

To further promote the implementation of energy-efficient technologies and projects, Ohio should establish a system benefits charge (SBC) on electric utility bills to provide funds for matching USDA-REAP grants. Current SBC-funded programs include an advanced energy program that funds combined heat and power projects and a manufacturing facilities program that promotes advanced lighting and HVAC projects, however there are currently no such programs specifically for the agricultural sector. [40] Availability of these funds could prove vital for successful REAP applications, as the USDA is considering availability of non-REAP funding as a criterion for the application ranking process.

The New York State Energy Research and Development Authority (NYSERDA) runs the *FlexTech* program, providing cost-sharing of energy audits or feasibility studies of improvements and load management techniques that would save money on farmers' energy bills. The NYSERDA program is open to all sectors, but could be adapted in Ohio to focus exclusively on agricultural operations as a tie-in with the USDA-REAP program funding. Across all sectors, *FlexTech* realizes $5 in energy savings and $17 in implementation/construction costs for every dollar spent on feasibility studies (Brooks and Elliott 2007).

One alternative to state-run programs of the type described above would be for the state to designate a non-governmental organization to implement energy efficiency programs. Examples include Vermont's *Efficiency Vermont* organization, and the *Northwest Energy Efficiency Alliance* (NEEA) which operates in the Pacific Northwest. Additionally, there are for-profit entities such as Vermont-based *EnSave* which focus specifically on improving energy efficiency in the agricultural sector. *EnSave* works in a number of states, from Maryland to Minnesota and California, implementing programs that range from dairy efficiency and diesel emission reduction to programs that operate farm energy audits and provide rebates for implementation of on-farm energy efficiency measures.

Expanded CHP and Clean Distributed Generation

Ohio has made good strides in establishing a regulatory environment that is hospitable to the deployment of CHP and clean distributed generation (generally referred to here as "CHP"), but there is still much work to be done.

Of chief concern are the recently adopted rules guiding the development of interconnection standards applicable to distributed generation, including CHP. Ohio's Administrative Code Chapter 4901:1-22-01 delineates that ideal interconnection standards should "make compliance [with interconnection standards] not unduly burdensome or expensive for any applicant […]" The code further requires that electric distribution utilities "establish uniform requirements for offering nondiscriminatory technology-neutral interconnection to customers who generate electricity" while considering the safety of utility workers and the environment.

The code relies heavily upon the IEEE's 1547 interconnection standard (http://grouper.ieee.org/groups/scc21/1547/1547_index.html), a widely accepted model for interconnection rules. Interconnection is separated into three tiers to allow for easier and more streamlined applications for small generators and includes a similarly streamlined application for medium-sized generators up to 2MW. A third tier provides a process for generators up to 20MW in

[39] More information on the Alliant Energy-IPL Farm Energy Audit program can be found on their web site: http://alliantenergy.com/docs/groups/public/documents/pub/p014750.hcsp.

[40] For more information visit the Ohio Department of Development web site, http://www.odod.state.oh.us/cdd/oee/ELFGrant.htm.

size. The Public Utilities Commission of Ohio provides a plain-language guide to interconnection via the new tiered system.[41]

Despite these nearly year-old requirements for new interconnection standards, research into the practices of Ohio utilities corroborated by anecdotal evidence suggests that utilities have not been quick to improve their interconnection practices in the manner required. In order to expand CHP in Ohio, the newly developed requirements for interconnection standards will need to be better implemented and enforced among the regulated utilities of the state.

Other significant regulatory treatments of CHP in Ohio include the inclusion of CHP as an eligible "alternative energy resource" within the context of the state's recently enacted *Alternative Energy Resource Standard,* part of Senate Bill 221. This is viewed as a favorable treatment of CHP. But there are other regulatory treatments of CHP that should be improved to further increase deployment. Developing output-based air emissions regulations, as promoted by the United States Environmental Protection Agency,[42] will incentivize more efficient use of fuel inputs, thus encouraging the deployment of the most efficient CHP systems. And the energy conversion property tax incentive that currently benefits the owners of some CHP systems is set to expire after the 2008 tax year. Since Ohio is currently phasing in a restructured tax code, an extension of this tax incentive may not be possible within the new tax paradigm; a continued emphasis, however, on reducing the costs of CHP systems is encouraged.

The economics of CHP have recently been assisted by the passage of the federal H.R. 1424, titled the *Economic Stabilization Act of 2008.*This act authorized the expansion of the Investment Tax Credit to include investments in CHP. It is a 10% tax credit against the cost of installing CHP systems (for the first 15MW) for systems up to 50 MW in size. While this tax credit is a boon for CHP deployment in the state, other Ohio-specific policies are not as favorable and may work to negate the positive influence on deployment that more favorable policies have. For example, current tariffs used by the largest utilities in Ohio to charge for standby electric service are counterproductive to the expanded implementation of CHP. PUCO may wish to review and address these tariffs and work to find solutions that make CHP projects more attractive to customers. The economics of CHP could also be improved through the power of the Ohio Air Quality Development Authority, which could leverage its ability to issue bonds to grant loans and other financial incentives to help companies address the high first costs of CHP systems. Since economic benefits of CHP systems accrue over time, using financing mechanisms to help spread out the costs could help business owners better integrate CHP systems into their long-term energy strategies.

Additional national incentives for CHP may be in the works. The *2007 Energy Independence and Security Act*'s Section 451 authorized additional funding and support for waste-heat recovery projects, which are an important subset of clean distributed generation. Though this authorization has not been funded, anecdotal evidence suggests it will garner attention in 2009.

Workforce Development

A key challenge stalling the achievement of the energy efficiency resource targets in SB 221 is the availability of a trained workforce. Energy efficiency tends to be more labor intensive than are supply resources, so developing a well-trained, indigenous workforce that can address efficiency issues across all market sectors is critical – a sentiment shared by the majority of stakeholders with whom we met. We thus see workforce development as a necessary element of many of the initiatives proposed above. But advancing efficiency in all sectors and throughout the entire state will require a workforce with training beyond the identification/assessment of efficiency opportunities: trained installers, technicians, engineers, architects, evaluation professionals, building operators, etc., all must be empowered with general and esoteric knowledge. Such investment in human capital will

[41] To view the guide, visit http://www.puco.ohio.gov/PUCO/Consumer/Information.cfm?id=6608
[42] For more information, visit the United States Environmental Protection Agency's CHP Partnership's informational page on output-based emissions: http://www.epa.gov/chp/state-policy/output.html

maximize the efficacy of efficiency programs while also providing additional benefit to the state's economy by creating new "green collar" jobs.

The advent of corporate and social environmental responsibility has already begun to influence the evolution of careers in building system design and operations, but identifying the needs of the market – in particular workforce needs – is and will continue to be an important facet of any initiative that aims to improve the energy efficiency of commercial and residential buildings, especially over the long term. Another key challenge will be coordinating the various programs. The establishment of an inter-agency stakeholder group to coordinate workforce development activities is therefore critical and should bring together entities such as Ohio's universities, the Ohio Board of Regents, the ODOD, and the PUCO. In New York, for example, the Building Performance Lab, housed at the City University of New York's (CUNY) Institute for Urban Systems, has established a stakeholder consortium that meets semiannually to "discuss the benefits and challenges of 'going green'" within the commercial sector. The consortium includes property owners and managers, labor representatives, utilities, city and state agencies, as well as other non-profits.[43] Since all of the initiatives we suggest within the context of the EERS policies include workforce training elements, the dynamics of the individual programs will be facilitated by a stakeholder group overseeing the process in general while providing the various parties a venue for exchanging and soliciting ideas. Communication within and between the programs is imperative to guarantee that individuals are obtaining the proper education to satisfy the needs of the individual market sectors as well as guaranteeing job placement once their training has been completed.

Ohio has already begun the process of bolstering workforce development. Universities are offering degrees and training not only through departmentally-sponsored programs, but also through joint programs with the State and Federal government. The Industrial Assessment Center at the University of Dayton (UDIAC) is one of 26 industrial assessment centers that are funded by the U.S. Department of Energy. With this funding, the UDIAC sends a small team of faculty, trained students, and professional staff to conduct free assessments for mid-sized industries, compiling reports with recommendations for reducing energy, waste and production costs.[44] UD has also joined forces with Wright State University, Central State University, and the Air Force Institute of Technology to offer the state's first masters program in clean and renewable energy, focusing on developing "a workforce for more than 45 existing Ohio companies with a stake in renewable energy and energy efficiency, as well as graduates who can start new businesses to create new Ohio jobs."[45] The program was approved by the Ohio Board of Regents in November 2008.

In July 2007, Ohio State University (OSU) created its Institute for Energy and the Environment (IEE), which brings together deans, faculty and researchers from OSU's five "hard" science colleges.[46] The IEE is not an academic unit, i.e., it does not confer degrees. But it aims to serve many other laudable purposes. As a single entity the IEE facilitates collaboration and communication amongst the five colleges, aiding in the dissemination of research at the state, national, and global level. It is also working to become a trusted resource for the state government, by acting as an intermediary between OSU experts and governmental leaders. One of its primary goals, however, is to assist OSU in advancing sustainability throughout its campus, both with regards to energy and environmental issues.

As part of one of the largest universities in the world, the IEE has the potential to become an invaluable resource. Though research at OSU focuses predominantly on supply-side efficiency issues – squeezing more Btu's out coal, solar radiation, etc. – it does have plans to expand its expertise in demand-side efficiency. The IEE is already involved in AEP's advanced metering infrastructure (AMI) program and has recently started a program called SMART@CAR, or Sustainable Mobility: Advanced

[43] For more information, please visit http://www.cunyurbansystems.org/pages/building-performance-lab.php
[44] For more information on this program, please visit: http://www.engr.udayton.edu/udiac/
[45] For more information on this program, please visit: http://www.udayton.edu/News/Article/?contentId=21494
[46] Biological Sciences; Engineering; Food, Agricultural and Environmental Sciences; Math and Physical Sciences; and Social and Behavioral Sciences.

Research Team at the Center for Automotive Research, which is a systems approach to developing the necessary infrastructure for electric vehicles. The IEE also plans to create an industrial assessment center and is cooperating with the University of Dayton in order to move forward with its project (Potter 2008).[47]

State and Local Government Facilities

State and local government facilities represent unique opportunities for Ohio to implement energy-efficient practices. Government buildings in Ohio represent almost 31% of electricity consumption in commercial buildings throughout the state (EIA 2006b)[48]. Employing energy efficiency in Ohio's government facilities serves as a model for others to follow, allowing Ohio to "lead by example." The Federal Government and a number of other states use Energy Savings Performance Contracts (ESPC) to implement energy efficiency projects at government facilities. Under the ESPC model, state agencies hire Energy Service Companies (ESCO) to implement projects designed to improve the energy efficiency and lower maintenance costs of the facility. The ESCO guarantees the performance of its services, and the energy savings are used to repay this project cost as shown in Figure 13 (KCC 2008; Birr 2008). This model has proven highly effective in many places both in terms of delivering energy savings and in terms of cost effectiveness (Hopper, Goldman, and McWilliams 2005).

Figure 13. Graphical Representation of How an ESPC Project Is Financed

Source: KCC (2008)

The key to the success of these projects is to bring together a project structure that can facilitate all aspects of the program, as is the case in Pennsylvania. Under that program, there are approximately three full-time equivalent staff supported by an experienced contractor:

1. Pre-qualifies ESCOs that can participate in the program;
2. Reviews and negotiates the terms of the ESPC agreements since the government facilities do not have the expertise to evaluate either the technical or contractual aspects of these projects; and
3. Reviews the completed projects to ensure that the projects are performing as agreed to in the contract.

Pennsylvania has been able to manage almost 50 projects each year, with total program and administrative costs of less than 2% of project costs (PA-GSA 2008; Birr 2008).

Ohio's EPSC program might be strengthened when compared to leading states such as Pennsylvania, Kansas, and Colorado, since it reaches only a portion of state facilities. A more robust structure and additional technical support might also be engaged. State agencies participate in

[47] For more information on the IEE, please visit http://iee.osu.edu/

[48] In lieu of a lack of state-specific data, we have used data for the East North Central region and assumed it is representative of Ohio.

efficiency programs, so significant additional energy efficiency opportunities still exist that could increase savings in state facilities. To address these opportunities, we recommend that Ohio expand its program, modeling the restructured program around the Pennsylvania experience drawing upon an expert consultant to complement the state agency staff (PA-GSA 2008). We also recommend that Ohio draw upon a national organization that has been formed with DOE support, the *Energy Services Coalition,*[49] which supports state and other entities in implementing ESPC programs (ESC 2008).

We also suggest that the program be extended to local government facilities. We understand that local governments can encounter bond rating problems with ESPC contracts because the rating entities may view these ESPC agreements as unsecured loans. To address this problem, the state should consider using its bonding authority, perhaps through the OAQDA, that would finance these EPSC projects, with the project funding paid back by the energy savings. The state should engage the rating entities on this issue.

In 1994, House Bill 7 was passed allowing state government agencies and universities to enter into performance contracts for energy projects. For state agencies, the authority to enter into performance contracts is vested in the Department of Administrative Services; for universities the authority is given to its Board of Trustees. The Ohio Revised Code Section 165 establishes guidelines for entering into performance contracts, requiring that:

- All contracts must be competitively solicited;
- Energy savings must exceed installation cost over a ten-year period;
- For projects involving cogeneration the maximum term is five years;
- Prevailing wage provisions apply;
- Such projects must pay for themselves out of operating funds and cannot require the use of capital budget funds; and
- Performance contracts for state agencies require the approval of the State Controlling Board.

Based on this model, we assume that state and municipal buildings in Ohio can achieve an average of 20% reduction in projected 2025 electricity sales and a 50% participation rate. We assume the average investment costs are consistent with the projected efficiency resource cost for the commercial sector identified in this report and that the program and administrative costs, which include evaluation, measurement, and verification, are 10% of the project cost. Under these assumptions, we estimate savings of 837 GWh in 2015 and 2,032 GWh in 2025, or 1% of total electricity sales in 2025.

State-Level Appliance and Equipment Efficiency Standards

Lighting and appliance standards, first authorized by Congress in the 1970s and legislated again in 1987, 1992, 2005, and 2007, have become a core energy policy for the United States, setting performance targets for dozens of common household and business products and systems. Individual states have played and continue to play an important role in advancing standards for the nation. In the 1980s, states' initiative in developing standards in the face of federal inaction led to the landmark National Appliance Energy Conservation Act of 1987 (NAECA). Since then, state enactment of product standards not covered by federal law has led to federal adoption of those same standards.

Only thirteen states have implemented standards on products that are not currently covered by federal standards introduced by the Energy Policy Act of 2005 (EPAct) and the Energy Independence and Security Act of 2007 (EISA). Estimates conducted by ACEEE show that appliance standards introduced by EPAct and EISA will save 53 and 178 TWh, respectively, by 2030, or 5% of the total projected electricity use for the U.S. While the usage and energy cost for a single device may seem small, the extra energy consumed by less efficient products collectively adds up to a significant amount of wasted energy. By implementing appliance standards on nine products not currently

[49] For more information on the Energy Services Coalition, see http://www.energyservicescoalition.org/about/index.html.

covered by federal legislation[50], Ohio could add a small, but not insignificant, amount of savings at negligible cost.

We first examine the potential savings and costs associated with the federal appliance standards promulgated by EPAct and EISA, which set standards for around 30 different products. We then estimate the additional savings that Ohio could realize should the state introduce standards on the recommended nine additional products (ASAP 2008). If Ohio were to implement its own state standards, it could realize 593 GWh of savings by 2015 and 2,003 GWh by 2025, or 1% of total electricity consumption in 2025. We estimate that federal appliance standards alone will contribute 3,071 GWh across all sectors in Ohio by 2015, increasing to 6,388 GWh by 2025. Federal and state standards together would yield savings of 3,664 GWh by 2015 and 8,390 GWh by 2025, or 4.3% of total electricity consumption in 2025. Our analysis of this scenario includes only state standards – savings from federal standards would be in addition but are not included.

Building Energy Codes

Building energy codes are a foundational policy to ensure that efficiency is integrated into all new buildings in Ohio. If efficiency is not incorporated at the time of construction, the new building stock represents a “lost opportunity” for energy savings because efficiency is difficult and expensive to install after construction is completed. Mandatory building energy codes are one way to target energy efficiency by requiring a minimum level of energy efficiency for all new residential and commercial buildings.

Ohio currently mandates compliance with ASHRAE 90.1-2004 for commercial buildings. For residential buildings, Ohio mandated compliance with the 2006 International Energy Conservation Code (IECC) code, but on March 31st, 2008, the 2006 IECC was dropped in favor of the 2003 IECC pending further investigation of the 2006 version. A specially appointed committee, the Public Hearing Draft Amendments Group 6, formed to review the 2006 IECC and recommended that, given the current economic downturn, the Ohio Board of Building Standards (OBBS) allow for an Ohio-specific prescriptive path that offers another, less stringent method of compliance in hopes of minimizing the financial burden on Ohio's home contractors and buyers. The OBBS convened November 7th, 2008, to hear public comments on the proposed re-adoption of the 2006 IECC and the additional prescriptive path (BCAP 2008). On December 12th, 2008, the OBBS passed Amendments Group 6, which effectively relaxed code standards on new residential construction.

A closer look at the changes recommended by the Public Hearing Draft Amendments Group 6 shows that they are counterproductive to advancing energy efficiency in Ohio. The proposed changes decrease the stringency of the state code and, consequently, could lead to a significant loss of energy efficiency statewide as well as greater energy costs for home owners. Home builders will be able to comply with the state code by following one of three paths: the 2006 IECC, the 2006 IRC, and the state-specific prescriptive path. These paths have distinctly different efficiency requirements – the 2006 IECC being the most stringent – and collectively have the potential to reduce energy efficiency in new homes significantly. Code officials will be trained to the Ohio-prescriptive path, further reducing the incentive to build homes that are energy efficient.

The implementation of the changes in Amendments Group 6 will also make it more difficult for utilities to meet the savings targets promulgated in SB 221. Allowing home builders to follow a state-specific prescriptive path, which allows equipment "trade-offs" for homes with a window-to-wall area of less than 23%, is an option that is prohibited by the 2009 IECC and one that makes Ohio unique. For example, contractors will essentially be able to trade-off a more efficient furnace instead of making improvements to the thermal envelope, such as windows or insulation. However, many utilities offer incentives for the purchase and installation of efficient furnaces as a means of decreasing energy consumption. Allowing contractors to exchange an efficient furnace for thicker insulation encourages

[50] These products include furnace fans, compact audio equipment, DVD players and recorders, portable electric spas (hot tubs), water dispensers, hot food holding cabinets, televisions, and portable light fixtures.

them to downgrade the home envelope for efficiency improvements that they are already installing. Substituting efficient HVAC equipment for an efficient home envelope will hurt energy efficiency over the life of the home because HVAC equipment typically has a lifetime half as long as envelope measures. And home owners will not necessarily replace their furnace with an equally efficient product, while a less-efficient thermal envelope will be difficult, and costly, to upgrade in the future. The availability of this trade-off could completely offset the level of energy savings that utilities can realize through furnace-incentive programs (MEEA 2008 and Misuriello 2008).

Additionally, the changes in Amendments Group 6 will redraw the climate zones created by the Department of Energy, relocating 30% of Ohio's population into a zone whose energy efficiency requirements are less stringent. Currently only nine counties reside in climate zone 5, which has less-stringent efficiency requirements. The changes in Amendments Group 6 will move an additional twenty-seven counties from climate zone 4 into climate zone 5.

Installing energy efficient products increases costs marginally, but improves the marketability of a new home by increasing comfort and minimizing energy bills through reduced consumption. While the economic concerns of Ohio's home builders should not be ignored, we believe it is imperative that Ohio's prescriptive path remain effective only temporarily. Furthermore, Ohio should be diligent about updating its energy codes by implementing new versions of the IECC as they become available. Our policy analysis reflects this ideal commitment: we assume that the 2006 IECC is the baseline efficiency standard and that Ohio will adopt the 2009 IECC, effective 2011, followed by the 2012 IECC, effective 2014, and the 2018 IECC, effective 2020. We assume enforcement of each codes starts at 70% compliance in the first year, 80% in the second year, and 90% in the third and subsequent years.[51] Given these assumptions, we estimate that savings from energy codes will reach 343 GWh by 2015 and 1707 GWh by 2025, or 0.9% of total electricity consumption in 2025.

Discussion of Proven Utility Programs

We have illustrated that the innovative policies suggested above have the potential to generate 10% of the required 22% electricity savings by 2025, giving utilities a substantial boost towards meeting the EERS target. Based on the results from our policy analysis, we estimate that these programs will only have to meet the remaining 12%, or 20,596 GWh, of the 22% EERS target. Our economic potential analysis for the residential and commercial sectors show that they account for 56% and 44% GWh, respectively, of the 39,213 GWh in total savings we estimate for those two sectors in 2025. We assume that this same ratio will apply to the relative contribution of the two sectors from future utility-run programs, which amounts to 11,594 and 9,003 GWh for the residential and commercial sectors, respectively.

There are many examples of program designs that have proven successful over the past three decades. In the text box below, we present several of these program types along with specific examples of successful implementations that are drawn from ACEEE's report *Compendium of Champions: Chronicling Exemplary Energy Efficiency Programs from across the U.S.* (York, Kushler, and Witte 2008).

Examples of Proven Energy Efficiency Programs

- ***Commercial/Industrial Lighting Programs***: Provide recommendations and incentives to businesses to increase lighting efficiency. Aiming to expedite the adoption of new technologies and decrease end-user's energy costs, the programs focus on marketing the most advanced lighting products and encourage greater efficiency in system design and

[51] It is important to note that adopting the most recent energy codes will require a concomitant effort to enforce their implementation. Statewide verification of compliance rates is critical in determining the efficacy of energy codes in reducing electricity demand.

layout. Xcel Energy's *Lighting Efficiency* program reached 4,346 participants, saving a total of 273 GWh during the years 2002-2006.

- ***Commercial/Industrial Motor and HVAC Replacement Programs*****:** Encourage the marketing and adoption of higher efficiency motors and HVAC equipment by offering rebates to distributors and end-users of qualifying equipment. Through monetary incentives and energy efficiency education, program advocates are shifting market tendencies away from a focus on initial equipment cost and toward an environment where lifecycle cost is increasingly considered by consumers. During 2006, Pacific Gas & Electric's *Motor and HVAC Distributor Program* saved a total of 16.55 GWh of electricity by offering $3.9 million in rebates.

- ***Commercial/Industrial New Construction Programs:*** Focus on training, educating, and providing financial incentives for architects, engineers, and building consultants to implement energy saving measures and technologies. By offering both prescribed and customizable incentive packages, these programs are able to influence a wide range of projects, which have in turn had the effect of raising the standards for energy efficiency in normal building practices. With its four distinct, yet combinable project "tracks," Energy Trust of Oregon, Inc.'s *Business Energy Solutions: New Buildings* program offers qualifying projects incentives of up to $465,000 each, which saved approximately 46.8 GWh of electricity and 1.2 million therms of natural gas through the end of 2007.

- ***Commercial/Industrial Retrofit Programs:*** With programs ranging from energy efficiency audits to financial assistance to even providing detailed engineering installation plans, Commercial/Industrial Retrofit Programs are designed to help implement cost-effective energy efficiency measures during new construction, expansion, renovation, and retrofit projects in commercial buildings. Programs focus on long-term energy management, peak load reduction, load management, technical analysis, and implementation assistance in order to give building owners and operators a better understanding of the energy related costs of, and potential savings for, their commercial buildings. Rocky Mountain Power and Pacific Power created approximately 100 GWh of gross electricity savings in Washington and Utah with their *Energy FinAnswer and FinAnswer Express* programs.

- ***Residential Lighting and Appliances:*** Headed by utility companies and energy nonprofits alike, Residential Lighting and Appliances Programs advocate the adoption of ENERGY STAR light bulbs, light fixtures, and home appliances through the use of rebates, marketing campaigns, advertising, community outreach, and retailer education. Lighting programs have focused on establishing and maintaining a customer base for compact fluorescent bulbs, in addition to fostering relationships between manufacturers and retailers in order to lower costs to the consumer. Appliance programs have sought to educate consumers on the long-term benefits of replacing aging, inefficient refrigerators, freezers, air conditioning units, and other large appliances with ENERGY STAR models, while providing an incentive to upgrade older models through rebates offered both for recycling old units and purchasing new ones. By selling 1.3 million CFLs during 2006 through its *ENERGY STAR Residential Lighting Program*, Arizona Public Service anticipates saving a total of 360 GWh of electricity during the lifetime of the light bulbs. Additionally, the *California Statewide Appliance Recycling Program* recycled 46,829 aging appliance units in 2007, a measure that saved 33.3 GWh of electricity in 2006.

- ***Residential Mechanical Systems Programs:*** Provide rebates and other financial incentives to contractors trained to properly install and service high-efficiency air conditioning, heat pumps, and geothermal heat-pump technologies. In addition to encouraging the purchase of energy-efficient appliances, these programs help to verify that existing equipment is appropriately installed and tuned in accordance with manufacturers' specifications, in order to optimize energy savings. Long Island Power Authority's *Cool Homes* Program has helped to introduce approximately 40,000 high-efficiency central cooling systems into the market, creating 29 GWh of annual electricity savings in 2006.

- ***Residential New Homes Programs:*** Provide incentives to builders who construct energy-efficient homes that achieve long-term, cost-effective energy savings. By addressing efficiency during the construction of homes and apartments, builders are able to maximize the financial and environmental benefits of efficient insulation, windows, air ducts, and appliances. Furthermore, ENERGY STAR certification provides developers with additional marketing strategies to attract buyers and renters. Some Residential New Homes programs also offer assistance to builders in developing efficiency objectives, and to potential buyers in locating efficient homes. With 100 participating residential builders and over 2,300 homes built to date, Rocky Mountain Power's *ENERGY STAR New Homes Program* saved 3.4 GWh of electricity during 2006.

- ***Residential Retrofit Programs:*** With an emphasis on large scale systematic retrofits, Residential Retrofit Programs are designed to reduce electric and natural gas consumption and peak-time demand of residential buildings. Financial incentives, low-interest financing, and training are offered to residents and customers interested in assessing and improving their energy efficiency. From weatherization and duct sealing to installation of new technologies, proponents of Residential Retrofit Programs direct their efforts both to buildings with the highest energy usage and constituents with the greatest financial need. Since its inception in 1993, Vermont Gas Systems, Inc.'s *HomeBase Retrofit Program* has installed over 1,600 kWh in energy saving measures, contributing to over 77,000 Mcf of natural gas savings.

- ***Low-Income Programs:*** Seek to educate and assist qualifying participants in acquiring appropriate home weatherization, energy-efficient lighting and appliances, and other efficiency improvements. By helping limited income households increase their energy efficiency and reduce energy consumption, these programs in turn minimize long-term energy costs to customers. Through its *Appliance Management Program and Low-Income Services*, National Grid has reached over 40,000 customers, creating 42 GWh of annual energy savings.

Energy Efficiency Policy Scenario Results

This section describes results from our policy analysis, including estimated electricity savings and peak demand impacts from efficiency in 2015 and 2025. More detailed results are shown in Appendix B. The demand response potential and impacts on peak demand are covered in the next section and in Appendix D.

Table 6. Summary of Electricity Savings by Policy or Program

	Annual Electricity Savings by Policy (GWh)	2015	2025	Total Savings in 2025 (%)*
	Innovative Programs & Policies			
1	Efficient Homes Initiative	119	615	0.4%
2	State-level Appliance Standards	593	2,003	1.3%
3	Building Energy Codes	343	1,707	1.1%
4	Commercial Buildings Initiative	133	715	0.5%
5	State Facilities	837	2,032	1.3%
6	CHP	1,072	3,238	2.1%
7	Manufacturing Initiative	1,721	5,771	3.7%
8	Rural and Ag. Initiative	57	155	0.1%
	Innovative Program & Policy Savings	**4,876**	**16,235**	**10.3%**
9	*Proven Utility Programs*			
	Residential	2,078	11,328	7.2%
	Commercial	1,701	9,268	5.9%
	Proven Utility Program Savings	**3,779**	**20,596**	13.1%
	Total Savings (Policy + Program)	**8,655**	**36,831**	**23.4%**
	Adjusted Electricity Forecast (GWh)	**169,299**	**157,114**	
	Savings (% Reduction in Reference Case)	**4.9%**	**19.0%**	

Notes

***** Percent relative to adjusted reference case forecast

1 Initiative broken down into programs for existing homes and new construction. Existing homes program assumes 0.5% savings throughout the analysis period and 1% participation rate in first year, with participation increasing by 1% annually. Savings from new construction assumes 50% savings beyond current code (IECC 2006), thereby decreasing with the adoption of new energy codes except in 2020, where we assume program implementation and participation has matured to allow for savings beyond the 50% savings from IECC 2018. In 2011 we assume an initial participation rate of 2.5%, doubling annually until 2014, when IECC 2012 becomes effective. We then assume a participation of 20% for the remainder of the analysis period. In 2020, when IECC 2018 becomes effective, delivering 50% savings, we assume 20% additional savings beyond IECC 2018 are achievable

2 Appliance and equipment efficiency standards were adopted at the federal level in the 2007 energy bill, which also directed DOE to set standards for additional products in the coming years. This Scenario assumes savings from these standards, which are not taken into account in the reference case load forecast. Savings and cost assumptions are from a forthcoming ACEEE and ASAP standards analysis.

3 We assume IECC 2009 is adopted, which goes into effect 2011, the IECC 2012 is adopted and goes into effect in 2014, and the IECC 2018, effective 2020. We estimate that these codes achieve a 15%, 30%, and 50% energy savings improvement beyond IECC 2006 requirements, respectively. Savings apply only to end-uses covered under building codes, which are HVAC, lighting, and water heating end-uses, or 50% of electricity consumption in new residential construction and nearly 60% of electricity consumption in commercial buildings. We assume enforcement of each code starts at 70% compliance in the first year, 80% in second year, and 90% in the third and subsequent years. Buildings analysis shows $0.47 per kWh investment cost for new ENERGY STAR homes, which achieve 15% savings, and $0.32 per kWh for new commercial buildings meeting 15% and 30% beyond code. We assume $1.5 million dollars per year to implement and enforce codes, based on recommendations in New York (NY DPS 2007). This is similar to estimates in VA that new program costs run 2-3% of building costs.

4 Initiative broken down into programs for existing buildings and new construction. Existing buildings program assumes 1% savings throughout the analysis period and 1% participation rate in first year, with participation increasing by 1% annually. We assume that 68.5% of total commercial electric floorspace is non-governmental buildings, to avoid double-counting savings attributable to state facilities program (CBECS 2003, table C17). Savings from new construction assumes 50% savings beyond current code (IECC 2006), thereby decreasing with the adoption of new energy codes except in 2020, where we assume program implementation and participation has matured to allow for savings beyond the 50% savings from IECC 2018. In 2011 we assume an initial participation rate of 2.5%, doubling annually until 2014, when IECC 2012 becomes effective. We then assume a participation of 20% for the remainder of the analysis period. In 2020, when IECC 2018 becomes effective, delivering 50% savings, we assume 20% additional savings beyond IECC 2018 are achievable.

5 We estimate 31.5% of total electric commercial floorspace is government buildings, from EIA (CBECS 2003, table C17). We then assume a savings rate of 20% and a participation rate of 50% over the period of the analysis.

6 We assume a $500 incentive per MW for CHP facilities.

7 This scenario assumes that the number of industrial assessments ramps up from 50 to 200 in first three years, that each assessment identifies 15% electricity savings, and that 50% of identified savings are implemented. Project costs assume the average investment cost per kWh from the industrial sector analysis ($0.28/kWh) and program cost is assumed to be 12.5% of projected cost savings to the end-user.

8 Based on similar programs and values from the State of Wisconsin Focus on Energy 2007 Semiannual Report, we assume the average cost of conserved energy at $0.025/kWh, that program & administrative costs are 24% of the cost of investment, and that customers cover half of the investment cost.

9 Savings for proven programs are the difference between EERS requirements and policy savings. Sector savings are then allocated based on the contribution to economic potential savings of the residential and commercial sectors.

Table 7. Summary of Summer Peak Demand Reductions by Sector (MW)

Sector	2015	2025	Total Savings in 2025 (%)
Residential	637	3,801	10%
Commercial	328	1,121	3%
Industrial	585	2,159	5%
Total Savings (MW)	**1,550**	**7,081**	**18%**
% Reduction (relative to forecast)	**4%**	**18%**	

Cost and Benefits from Policy Analysis

In this section we estimate the costs and benefits of our energy efficiency policy analysis to determine overall cost-effectiveness. There is no single answer to whether energy efficiency is cost-effective, but rather there are multiple perspectives analysts utilize to determine cost-effectiveness. Here, we examine our policy analysis using two cost-effectiveness tests: the Total Resource Cost (TRC) test and the Participant Cost test. We do not do an equivalent analysis for the demand response policy scenario, which is discussed in the next section, due to the difficulty in evaluating the dollar savings benefits to consumers from demand response measures.

The costs needed to run the efficiency policies suggested in our policy analysis and to achieve the estimated electricity savings include both the investments in efficient technologies or measures and the administrative or marketing costs to run programs and administer policies. The technology investments might include any combination of incentives paid to customers or direct consumer costs. See Table 8 for a breakdown of the estimated costs of the policies from our analysis. See Appendix B for estimates of Total Resource Costs.

Table 8. Annual Energy Efficiency Costs from Policy Analysis (Millions of 2006$)

	2015		2025	
Customer Investments	$	380	$	823
Incentives Paid to Customers	$	126	$	390
Admin/Marketing Costs	$	28	$	99
Total Costs	**$**	**533**	**$**	**1,312**

Note: These costs are undiscounted and shown in real 2006$

The chapter on macroeconomic impacts uses these cost assumptions to estimate impacts of the efficiency policies on the economy, including overall benefits to customers. Here, we report a net present value (NPV) analysis of costs and benefits to society and to participants. The next two tables (see Table 9 and 10) show results from the TRC test and the Participant Cost test, respectively, with a breakdown of total costs and benefits (present value in 2006$) by policy type and by sector over the study time period (2008–2025). Readers should note that although the study time period ends in 2025, savings from the efficiency measures persist over the lifetime of each specific measure. Accounting for these additional savings beyond the study time period would yield additional benefits and therefore a higher benefit/cost ratio.

The TRC test, as shown in Table 9, evaluates the net benefits of energy efficiency to the region as a whole. This test considers total costs, including investments in efficiency measures (whether incurred by customers or through incentives) and administrative or marketing costs. Benefits in the TRC test are the avoided costs of energy, or the marginal generation costs that utilities avoid by reducing electricity consumption through energy efficiency. The avoided energy resource costs were determined by the analysis by Synapse Energy Economics (see Appendix A). The TRC test, which shows an overall benefit-to-cost ratio of 1.7, suggests a net positive benefit to Ohio as a whole from implementing these efficiency programs and policies. Accounting for additional savings beyond the study time period would yield a benefit/cost ratio of 2.9.

See Figure 14 for a representation of the results using three different discount rates.

Table 9. Total Resource Cost (TRC) Test (2008-2025) (Millions of 2006$)

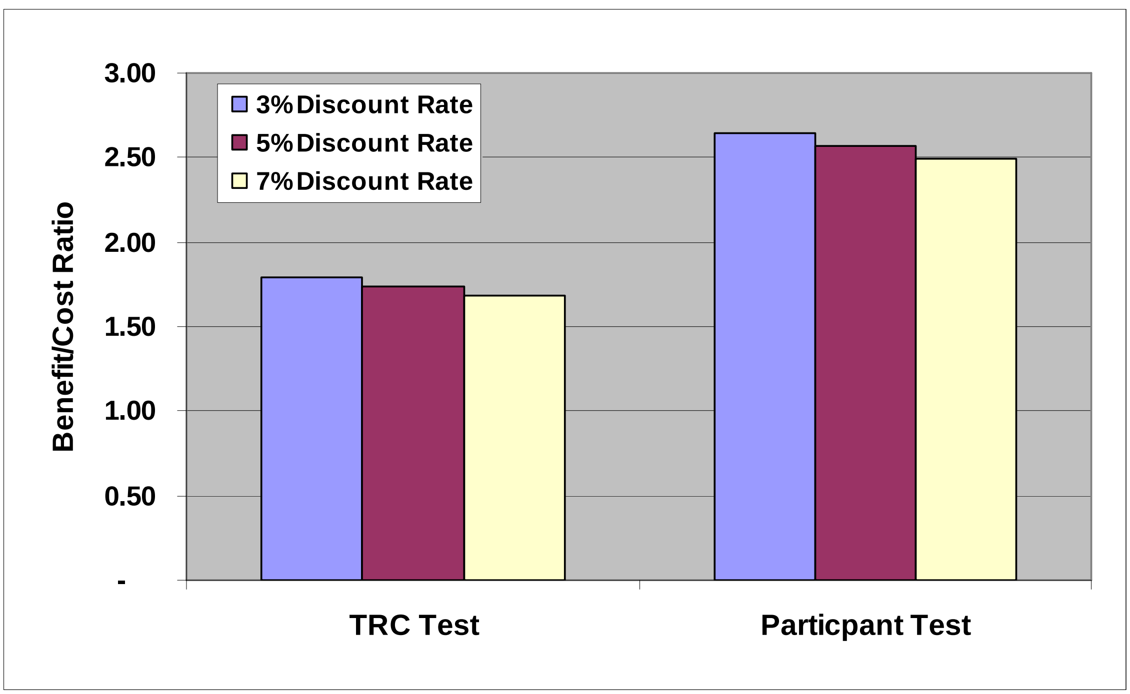
By Policy/Program	**NPV Costs**	**NPV Benefits**	**Net Benefit**	**B/C Ratio**
Innovative Programs & Policies				
Efficient Homes Initiative	$ 164	$ 194	$ 29	1.2
State-level Appliance Standards	$ 566	$ 795	$ 229	1.4
Building Energy Codes	$ 439	$ 541	$ 102	1.2
Commercial Buildings Initiative	$ 195	$ 220	$ 25	1.1
State Facilities	$ 253	$ 926	$ 673	3.7
CHP	$ 1,232	$ 1,340	$ 109	1.1
Manufacturing Initiative	$ 1,016	$ 2,200	$ 1,184	2.2
Rural and Ag. Initiative	$ 3	$ 66	$ 63	21.3
Proven Utility Programs				
Residential	$ 2,250	$ 3,436	$ 1,186	1.5
Commercial	$ 1,095	$ 2,811	$ 1,716	2.6
Total	**$ 7,214**	**$ 12,528**	**$ 5,314**	**1.7**
By Sector	**NPV Costs**	**NPV Benefits**	**Net Benefit**	**B/C Ratio**
Residential	$ 3,196	$ 4,733	$ 1,537	1.5
Commercial	$ 2,377	$ 4,862	$ 2,485	2.0
Industrial	$ 1,642	$ 2,934	$ 1,292	1.8
Total	**$ 7,214**	**$ 12,528**	**$ 5,314**	**1.7**

The Participant Cost test, as shown in Table 10, takes the perspective of a customer installing an energy efficiency measure in order to determine whether the participant benefits. The costs are the costs to customers for purchasing or installing energy efficiency and the benefits are the savings on customers' electricity bills due to reduced consumption plus any incentives paid to the customers. Again, this analysis only takes into account costs and benefits through 2025, even though customer savings on electric bills would continue well past 2025. Without accounting for the benefits that persist after measures installed in 2025, the Participant Cost test yields a positive benefit to participants, with a benefit/cost ratio of 1.9. Accounting for additional savings beyond the study time period would yield a benefit/cost ratio of 4.0.

Table 10. Participant Cost Test (2008-2025) (Millions of 2006$)

By Policy/Program	NPV Costs	NPV Benefits	Net Benefit	B/C Ratio
Innovative Programs & Policies				
Efficient Homes Initiative	$ 131	$ 309	$ 178	2.4
State-level Appliance Standards	$ 564	$ 1,056	$ 491	1.9
Building Energy Codes	$ 425	$ 711	$ 286	1.7
Commercial Buildings Initiative	$ 156	$ 332	$ 176	2.1
State Facilities	$ 230	$ 1,156	$ 926	5.0
CHP	$ 1,232	$ 1,881	$ 649	1.5
Manufacturing Initiative	$ 978	$ 2,060	$ 1,081	2.1
Rural and Ag. Initiative	$ 2	$ 63	$ 61	25.2
Proven Utility Programs				
Residential	$ 2,000	$ 5,643	$ 3,643	2.8
Commercial	$ 996	$ 4,014	$ 3,019	4.0
Total	**$ 6,715**	**$ 17,225**	**$ 10,510**	**2.6**
By Sector	**NPV Costs**	**NPV Benefits**	**Net Benefit**	**B/C Ratio**
Residential	$ 2,905	$ 7,432	$ 4,527	2.6
Commercial	$ 2,207	$ 6,833	$ 4,626	3.1
Industrial	$ 1,603	$ 2,960	$ 1,357	1.8
Total	**$ 6,715**	**$ 17,225**	**$ 10,510**	**2.6**

Figure 14. Results of TRC and Participant Cost Tests Using Three Discount Rates



ASSESSMENT OF DEMAND RESPONSE POTENTIAL

This section defines Demand Response (DR), assesses current DR activities in Ohio, uses benchmark information to assess DR potential in Ohio, and concludes with policy recommendations that could foster DR contributing appropriately to the resource mix in Ohio that can be used to meet electricity needs. Potential load reductions from DR are estimated for set of DR programs that represent the technologies and customer types that span a range of DR efforts.

Defining Demand Response

DR focuses on shifting energy from peak periods to off-peak periods and clipping peak demands on days with the highest demands. Within the set of demand-side options, DR focuses on clipping peak demands that may allow for the deferral of new capacity additions and enhance operating reserves to mitigate system emergencies. Energy efficiency focuses on reducing overall energy consumption with attendant permanent reductions in peak demand growth. Taken together, these two demand-side options can provide opportunities to more efficiently manage growth, provide customers with increased options to manage energy costs, and develop least cost resource plans.

DR resources are usually grouped into two types: 1) load-curtailment activities where utilities can “call” for load reductions; and 2) price-based incentives which use time-differentiated and/or dispatchable rates to shift load away from peak demand periods and reduce overall peak-period consumption. Interest in both types of DR activities has increased across the country as fuel input prices have increased, environmental compliance costs have become more uncertain, and the substantial investment in overall electric infrastructure needed to support new generation resources.

The summary of DR potential presented on Table 1 focuses on load-curtailment and backup generation and does not include savings resulting from price-based incentives. Residential load-curtailment typically involves direct load control (DLC) of air conditioners—although this can also cover appliances—as well as temperature offsets, which increase thermostat settings for a certain period of time. Commercial and industrial applications of DR focus on load control of space conditioning equipment, however this depends on customer size: self-activated load reductions are usually more prudent for larger customers. Backup generation for commercial and industrial applications involves generators with start-up equipment that allows them to come online with short notice from utilities, relieving the additional demand on the system during peak hours.

Rationale for Investigating Demand Response

DR alternatives can be implemented to help ensure that a utility continues to provide reliable electric service at the least cost to its customers. Specific drivers often cited for DR include the following:

- **Ensure reliability** – DR provides load reductions on the customer side of the meter that can help alleviate system emergencies and help create a robust resource portfolio of both demand-side and supply-side resources that meet reliability objectives.
- **Reduce supply costs** – DR may be less expensive per megawatt than other resource alternatives.
- **Manage operational and economic risk through portfolio diversification –** DR capability is a resource that can diversify peaking capabilities. This creates an alternative means of meeting peak demand and reduces the risk that utilities will suffer financially due to transmission constraints, fuel supply disruptions, or increases in fuel costs.
- **Provide customers with greater control over electric bills –** DR programs would allow customers to save on their electric bills by shifting their consumption away from higher cost hours and/or responding to DR events.
- **Address legislative/regulatory interest in DR –** Recent legislation, Ohio House Bill 2200, calls for peak load reduction, smart meter deployment, and the availability of time-based rates for all customers.

Background of Demand Response in Ohio

A sound strategy for development of DR resources requires an understanding of Ohio's demand and resource supply situation, including projected system demand, peak-day load shapes, and existing and planned generation resources and costs.

Ohio utilities serves a population of over 11.5 million, generation over 155 million megawatt hours of electricity, that is expected to have a system peak load of almost 30,000 MW in 2009 (ACEEE base case for Ohio).

Electricity demand in Ohio has fluctuated over the past 15 years (EIA 2009). Total consumption has grown only slightly. Total retail sales in 2007 in Ohio totaled 161.5 billion kWh. This is an aggregate figure for all sectors, including industrial, commercial and residential.

Ohio has been and likely will continue to be a modest importer of energy and likewise be dependent on out-of-state capacity. In 2007, in-state generation provided less than 97% of total Ohio retail sales, thus requiring import of approximately 3% (EIA 2008a).

Role of Demand Response in Ohio's Resource Portfolio

The DR capabilities deployed by Ohio utilities can become part of a long-term resource strategy that also includes resources such as traditional generation resources, power purchase agreements, options for fuel and capacity, and energy efficiency and load management programs. Objectives include meeting future loads at lower cost, diversifying the portfolio to reduce operational and regulatory risk, and allow Ohio customers to better manage their electricity costs.

The 2005 Energy Policy Act provisions for Demand Response and Smart Metering has lead to a number of states and utilities piloting and implementing a Smart Grid, or sometimes referred to as Advanced Metering Infrastructure (AMI). Smart Grid is a transformed electricity transmission and distribution network or "grid" that uses robust two-way communications, advanced sensors, and distributed computers to improve the efficiency, reliability and safety of power delivery and use. For energy delivery, the Smart Grid has the ability to sense when a part of its system is overloaded and reroute power to reduce that overload and prevent a potential outage situation. Principal benefits of Smart Grid technologies for DR include increased participation rates and lower costs.

The growth of renewable energy supply (and plans for increased growth) can also increase the importance of DR in the portfolio mix. For example, sudden renewable energy supply reductions (e.g., from an abrupt loss in wind) may be mitigated quickly with DR.

Assessment of Demand Response Potential in Ohio

Table 11 shows the resulting load shed reductions possible for Ohio, by sector, for years 2015, 2020, and 2025. Load impacts grow rapidly through 2018 as program implementation takes hold. After 2018, the program impacts increase at the same rate as the forecasted growth in peak demand.

The high scenario DR load potential reduction is within a range of reasonable outcomes in that it has an eleven year rollout period (beginning of 2010 through the end of 2020), providing a relatively long period of time to ramp up and integrate new technologies that support DR. A value nearer to the high scenario than the medium scenario would make a good MW target for a set of DR activities.

The high scenario results show a reduction in peak demand of 3,078 MW is possible by 2015 (8.4% of peak demand); 6,293 MW is possible by 2020 (16.4% of peak demand); and 6,471 MW is possible by 2025 (16.2% of peak demand).

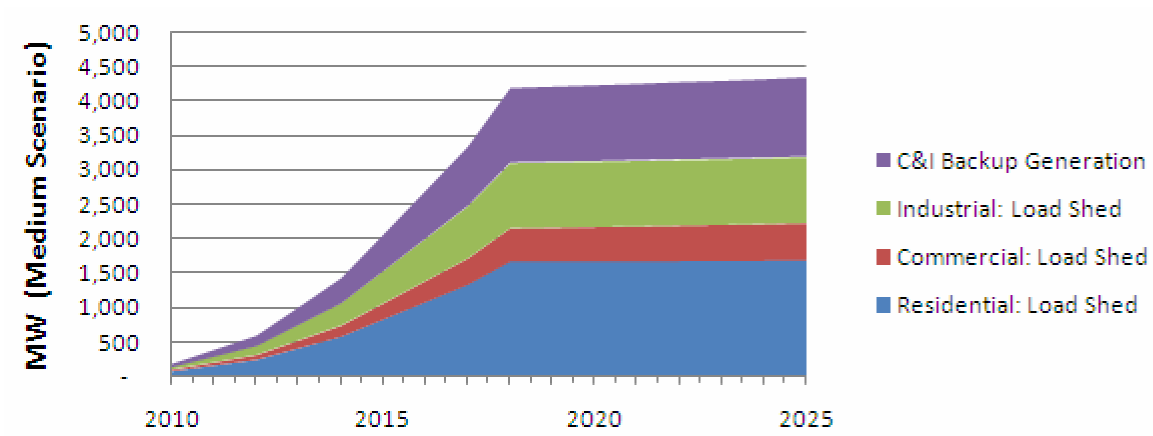
The more conservative medium scenario results show a reduction in peak demand of 2,052 MW is possible by 2015 (5.6% of peak demand); 4,193 MW is possible by 2020 (11.0% of peak demand); and 4,309MW is possible by 2025 (10.8% of peak demand).

Table 11. Summary of Potential DR in Ohio, By Sector, for Years 2015, 2020, and 2025a

	Low Scenario			Medium Scenario			High Scenario		
	2015	**2020**	**2025**	**2015**	**2020**	**2025**	**2015**	**2020**	**2025**
Load Sheds (MW):									
Residential	502	1,008	1,017	837	1,680	1,696	1,172	2,352	2,374
Commercial	86	184	199	228	491	531	428	921	996
Industrial	206	415	420	464	933	944	824	1,660	1,678
C&I Backup Generation (MW)	393	817	854	524	1,089	1,138	655	1,361	1,423
Total DR Potential (MW)	1,186	2,424	2,490	2,052	4,193	4,309	3,078	6,293	6,471
DR Potential as % of Total Peak Demand	3.2%	6.4%	6.3%	5.6%	11.0%	10.8%	8.4%	16.4%	16.2%
a. See Section 3 for underlying data and assumptions.									

Figure 15 shows the resulting load shed reductions possible for Ohio, by sector, from year 2010, when load reductions are expected to begin, through year 2025.

Figure 15. Potential DR Load Reduction in Ohio by Sector (MW)



These estimates reflect the level of effort put forth and utilities are recommended to set targets for the high scenarios. These estimates are based on assumptions regarding growth rates, participation rates, and program design. These factors are discussed in Chapter 3. In developing these DR potential estimates, the integration of DR with select energy efficiency activities was considered to help ensure that load impacts were not double counted. The estimated load reduction per program participant is conservatively estimated to account for increased energy efficiency in the future.

Recommendations

Key recommendations include:

- *Implement programs focused on achieving firm capacity reductions as this provides the highest value demand response.* This is accomplished through establishing appropriate customer expectations and by conducting program tests for each DR program in each year. These tests should be used to establish expected DR program impacts when called and to work with customers each year to ensure that they can achieve the load reductions expected at each site.

- *Appropriate financial incentives for the Ohio' utilities either for programs administered directly by the utilities or for outsourcing DR efforts to aggregators.* The basic premise is that a utility's least-cost plan should also be its most profitable plan. Developing these incentives poses some complexities in that MW's in that DR programs likely will be bid into PJM's DR programs and will receive financial payments from PJM. Whether this provides adequate incentives for the appropriate development of DR programs in Ohio should be examined.

- *Combine and cross-market EE and DR programs.* These can include new building codes and standards that include not only EE construction and equipment, but also the installation of addressable and dispatchable equipment. This can include addressable thermostats in new residences and the installation of addressable energy management systems in commercial and industrial buildings that can reduce loads in select end-uses across the building/facility. In addition, energy audits of residential or commercial facilities can also include an assessment of whether that facility is a good candidate for participation in a DR program through the identification of dispatchable loads. Furthermore, building commissioning and retro-commissioning EE programs that are becoming popular in many commercial and industrial sector programs have the energy management system as a core component of program delivery. At this time, the application of auto-DR can be assessed and marketed to the customer along with the EE savings from these site-commissioning programs.

- *Include customer education in DR efforts.* There is some perceived lack of customer awareness of programs and incentives. In addition, new programs will need marketing efforts as well as technical assistance to help customers identify where load reductions can be obtained and the technologies/actions needed to achieve these load reductions. Also, high-level education on the volatility of electricity markets helps customers understand why utilities and other entities are promoting DR and the customers' role in increasing demand response to help match up with supply-side resources to achieve lower cost resource solutions when markets become tight

- *Increase clarity and coordination between the Federal and State agencies and programs.* While states have primary jurisdiction over retail demand response, the FERC has jurisdiction over demand response in wholesale markets. Greater clarity and coordination between the Federal and State programs is needed. At the Federal level, both EPACT and EISA contain multiple provisions on demand response and smart grid technologies. EISA authorized a matching grant program to offset the costs of Smart Grid investments.

- *Understand that pricing may form the cornerstone of an efficient electric market.* Daily TOU pricing and day-ahead hourly pricing will increase overall market efficiency by causing shifts in energy use from on-peak to off-peak hours every day of the year. However, this does not diminish the need to have dispatchable DR programs that can address those few days that represent extreme events where the highest demands occur. These events are best addressed by dispatchable DR programs.

MACROECONOMIC IMPACTS: IMPACT OF POLICIES AND PROGRAMS ON OHIO'S ECONOMY, EMPLOYMENT, AND ENERGY PRICES

Up to this point in the analysis we have examined the potential costs and benefits of implementing policies that might stimulate greater levels of energy efficiency and onsite solar energy in Ohio. The evidence suggests that smart policies and programs can drive more productive investments in energy-efficient technologies, and they can do so in ways that reduce the state's total energy bill. But the question remains, what does this mean for the state economy? Do the higher gains in energy productivity – that is, do the increased levels of efficiency investment with their concomitant reduction in the need for conventional energy resources – create a net economic boost for Ohio? Or, does the diversion of revenues away from energy-related industries negatively impact the economy? In this chapter, we explore those issues and we present the analytical results of an economic model used to evaluate the impact of efficiency investments on jobs, income, and the overall size of the economy.

A recent meta-review of some past 48 energy policy studies done within the United States suggests that if investments in more efficient technologies are cost-effective, the impacts on the economy should be small but net positive (Laitner and McKinney 2008). As shown elsewhere in the report, it turns out that from a total resource cost perspective, the benefits (i.e., the energy bill savings) outweigh both the policy costs and investments by about two and one-half times. In other words, the energy efficiency policy recommendations highlighted in the policy scenario result in a substantial savings for households and businesses compared to the costs of implementing the policies. As we also discuss below, this consumer energy bill savings can drive a significant increase in the number of net new jobs within the Ohio.[52] In fact, continued investments in energy efficiency resources would maintain the energy resource benefits for many years into the future, well beyond the period of analysis examined in this report.[53] The state therefore has the opportunity to transition its energy markets to a more sustainable pattern of energy production and consumption in ways that benefit consumers.

A quick glance at the results in Table 12 below, detail the benefits that will accrue to the state of Ohio when policies encourage a more efficient use of energy resources. Further discussion in this section will provide an overview of the DEEPER model and more detailed background information for the state of Ohio.

Table 12. Economic Impact of Energy Efficiency Investment in Ohio

Macroeconomic Impacts	2010	2015	2020	2025
Jobs (Actual)	1,582	7,928	19,506	32,061
Wages (Million $2006)	$50	$300	$851	$1,615
GSP (Million $2006)	$58	$444	$1,310	$2,559

Methodology

The macroeconomic evaluation that we report in this chapter is undertaken in three separate steps. First, we calibrate ACEEE's economic assessment model called DEEPER (Dynamic Energy Efficiency Policy Evaluation Routine) to reflect the economic profile of the Ohio economy (Laitner and McKinney 2009). This is done for the period 2006 (the base year of the model) through 2025 (the last year of the analysis). In this respect, we incorporate the anticipated investment and spending patterns that are suggested by the standard forecast modeling assumptions. These range from typical spending by businesses and households in the analytical period to the anticipated construction of new electric power plants and other energy-related spending that might also be highlighted in the forecast. Second, we transform the set of key efficiency scenario results from the policy analysis into the direct inputs which are needed for the economic model. The resulting inputs include such parameters as:

[52] As we use the term here, the word "consumer" refers to any one who buys and uses energy. Thus, we include both households and businesses as among the consumers who benefit from greater investments in energy efficiency.

[53] As we note elsewhere, the policy analysis ends in the year 2025. Yet, many of the investments we describe have a technology of perhaps 15 years. This means that investments made in 2025 would continue to pay for themselves through perhaps the year 2044 and beyond; and none of those ongoing energy bill savings are reflected in the analysis described in this chapter.

- The level of annual policy and/or program spending that drives the key policy scenario investments;
- The capital and operating costs associated with more energy-efficient technologies;
- The energy bill savings that result from the various energy efficiency policies described in the main body of the report; and
- Finally, a set of calibration or diagnostic model runs to check both the logic and the internal consistency of the modeling results.

So that we can more fully characterize the analysis that was completed for this report, we next provide a simplified working example of how the modeling is done. We first describe the financial assumptions that underpin the analysis. We then highlight the analytical technique by showing the kinds of calculations that are used and then summarize the overall results in terms of net job impacts. Following this example, we then review the net impacts of the various policies as evaluated in our DEEPER model.

Illustrating the Methodology: Ohio Jobs From Efficiency Gains

To illustrate how a job impact analysis might be done, we will use the simplified example of installing one hundred million dollars of efficiency improvements within large office buildings throughout Ohio. Office buildings (traditionally large users of energy due to heating and air-conditioning loads, significant use of electronic office equipment, and the large numbers of persons employed and served) provide substantial opportunities for energy-saving investments. The results of this example are summarized in Table 13.

The assumption used in this example is that the investment has a positive benefit-cost ratio of 2.0. In other words, the assumption is that for every dollar of cost used to increase a building's overall energy efficiency, the upgrades might be expected to return a total of two dollars in reduced electricity and natural gas costs over the useful life of the technologies. This ratio is similar to those cited elsewhere in this report. At the same time, if we anticipate that the efficiency changes will have an expected life of roughly 15 years, then we can` establish a 15-year period of analysis. In this illustration, we further assume that the efficiency upgrades take place in the first year of the analysis, while the electricity bill savings occur in years one through 15.

Table 13. Illustrative Example: Job Impacts from Commercial Building Efficiency Improvement

Expenditure Category	Amount (Million $)	Employment Coefficient	Job Impact
Installing Efficiency Improvements in Year One	$100	13	1,300
Diverting Expenditures to Fund Efficiency Improvements	$-100	12	-1,200
Energy Bill Savings in Years One through 15	$200	12	2,400
Lower Utility Revenues in Years One through 15	$-200	5	-1,000
Net 15-Year Change	$0.0		1,500

Note: The employment multipliers are adapted from the appropriate sector multipliers from IMPLAN. The benefit-cost ratio is assumed to be 2.0. The jobs impact is the result of multiplying the row change in expenditure by the row multiplier. The sum of these products yields a working estimate of total net job-years over the 15-year time horizon. To find the average annual net jobs in this simplified analysis we would divide the total job-years by 15 years which, of course, gives us an estimated net gain of 100 jobs per year for each of the 15 years. For more details, see the text that follows.

The analysis assumes that we are interested in the net effect of employment and other economic changes. This means we must first examine all changes in household and business expenditures – both positive and negative – that result from a movement toward greater levels of energy efficiency. Although more detailed and complicated within the DEEPER model, for this heuristic exercise we then multiply each change in expenditures by the appropriate sector employment coefficient (adapted from IMPLAN). The sum of these products will then yield the net result for which we are looking.

In our example above, there are four separate changes in expenditures, each with their separate impact. As Table 13 indicates, the net impact of the scenario suggests a cumulative gain of 1,500 jobs in each of the 15-year period of analysis. This translates into an average net increase of 100 jobs each year for 15 years. In other words, the $100 million efficiency investment made in Ohio's office buildings is projected to sustain an average of 100 jobs each year over a 15-year period compared to a "business-as-usual" scenario.

The economic assessment of the alternative energy scenarios was carried out in a very similar manner as the example described above. That is, the changes in energy expenditures brought about by investments in energy efficiency and renewable technologies were matched with their appropriate employment multipliers. There are several modifications to this technique, however.

First, it was assumed that only 72% of both the efficiency investments and the savings are spent within Ohio. We based this initial value on the Minnesota IMPLAN Group, Inc. (IMPLAN 2007) dataset as it describes local purchase patterns that typically now occur in the state. We anticipate that this is a conservative assumption since most efficiency and renewable energy installations are likely (or could be) carried out by local contractors and dealers. If the set of policies encourages greater local participation so that the share was increased to 90%, for example, the net jobs might grow another 15% compared to our standard scenario exercise. At the same time, the scenario also assumes Ohio provides only 40% of the manufactured products consumed within the state. But again, a concerted effort to build manufacturing capacity for the set of clean energy technologies would increase the benefits from developing a broader in-state energy efficiency and renewable energy manufacturing capability.

Second, an adjustment in the employment impacts was made to account for assumed future changes in labor productivity. As outlined in the Bureau of Labor Statistics Outlook 2006–2016, productivity rates are expected to vary widely among sectors (BLS 2007). For instance, drawing from the BLS data we would expect that electric utilities might increase labor productivity by 1.8% annually while the business and personal service sectors of the economy might increase productivity by 2.2% per year. This means, for example, that we might expect a one million dollar expenditure for utility services in the year 2025 would support only 68% of the jobs that the same expenditure would have supported in 2008, while other services sectors of the economy would support only 62% of the jobs as in 2008.

Third, for purposes of estimating energy bill savings, it was assumed that all energy prices within Ohio would follow the same growth rate as those published by the Energy Information Administration in its *Annual Energy Outlook* (EIA 2008). Fourth, it was assumed that approximately 80% of the efficiency investments' upgrades are financed by bank loans that carry an average 8% interest rate over a five-year period. To limit the scope of the analysis, however, no parameters were established to account for any changes in interest rates as less capital-intensive technologies (i.e., efficiency investments) are substituted for conventional supply strategies, or in labor participation rates – all of which might affect overall spending patterns. Fortunately, however, it is unlikely that these sensitivities would greatly impact the overall outcome of this analysis.

While the higher cost premiums associated with the energy efficiency investments might be expected to drive up the level of borrowing (in the short term), and therefore interest rates, this upward pressure would be offset to some degree by the investment avoided in new power plant capacity, exploratory well drilling, and new pipelines. Similarly, while an increase in demand for labor would tend to increase the overall level of wages (and thus lessen economic activity), the job benefits are small compared to the current level of unemployment or underemployment in the state. Hence the effect would be negligible.

Fifth, as described in the previous chapters for the buildings, industrial, and transportation end-use sectors it was assumed that a program and marketing expenditure would be required to promote market penetration of the efficiency improvements. Since these vary significantly by policy bundle we don't summarize them here but payment for these policy and program expenditures were treated as if new taxes were levied on the state commensurate with the level of energy demands within the state. Hence, the positive program spending impacts are offset by reduced revenues elsewhere in the economy.

Sixth, it should be noted that the full effects of the efficiency investments are not accounted for since the savings beyond 2025 are not incorporated in the analysis. Nor does the analysis include other benefits and costs that can stem from the efficiency investments. Non-energy benefits can include increased worker productivity, comfort and safety, and water savings, while non-energy costs can include aesthetic issues associated with compact fluorescent lamps and increased maintenance costs due to a lack of familiarity with new energy-efficiency equipment (NAPEE 2007b, 3-8). Productivity benefits, for example, can be substantial, especially in the industrial sector. Industrial investments that increase energy efficiency often result in achieving other economic goals such as improved product quality, lower capital and operating costs, increased employee productivity, or capturing specialized product markets (see, for example, Worrell et al. 2003). To the extent these "co-benefits" exceed any non-energy costs, the economic impacts of an energy efficiency initiative in Ohio would be more favorable than those reported here. Finally, although we show how the calculations would look from an employment perspective, we don't show the same kind of data or assumptions for either income or for impacts on the Gross State Product (the sum of value-added contributions to the Ohio State economy). Nonetheless, the approach is very similar to that described for net job impacts.

Impacts of Recommended Energy Efficiency Policies

For each year in the analytical period, the given change in a sector spending pattern (relative to the reference scenario) was matched to the appropriate sectoral impact coefficients. Two points are worth special note: first, it was important to match the right change in spending to the right sector of the Ohio economy; and second, these coefficients change over time. For example, labor productivity changes mean that there may be fewer jobs supported by a one million dollar expenditure today compared to that same level of spending in 2025. Both the negative and positive impacts were summed to generate the estimated net results shown in the series of tables that follow. Presented here are two basic sets of macroeconomic impacts for the benchmark years of 2010, 2015, 2020, and 2025. These include the financial flows that result from the policies described in the previous chapters. They also include the net jobs, income, and GRP impacts that result from the changed investment and spending patterns.

Table 14 presents the changes in consumer expenditures that result from these policies. While the first row in the table presents the full cost of the energy efficiency policies, programs and investments, the utility customers will likely borrow a portion of the money to pay for these investments. Thus, "annual consumer outlays," estimated at about $193 million 2010, rise to nearly $2.1 billion in 2025. These outlays include actual "out-of-pocket" spending for programs and investments, along with money borrowed to underwrite the larger technology investments. The annual energy bill savings reported in Table 14 are a function of reduced energy purchases from the many Ohio utilities and other energy providers within the state.

As we further highlight in the table that follows, the annual energy bill savings begins with a modest first year benefit of $58 million. As more and more investments are directed toward the purchase of more energy-efficient technologies, the annual consumer energy bill savings rise to about $1 billion by 2025.

Table 14. Financial Impacts from Energy Efficiency Policy Scenario

(Millions of 2006 $)	2010	2015	2020	2025
Annual Consumer Outlays	$193	$723	$1,496	$2,146
Annual Energy Savings	$111	$1,154	$2,961	$5,461
Energy Bill Adjustment Savings	$58	$267	$626	$1,059
Annual Net Consumer Savings	-$23	$431	$1,465	$3,314
Cumulative Net Energy Savings	$9	$954	$5,951	$18,980

'Annual' refers to the total that is reported in the benchmark year while 'Cumulative' is the total from previous years beginning in 2010 through the benchmark year.
Annual consumer outlays include administrative costs to run programs, incentives provided to consumers, investments in energy efficiency devices and interest paid on loans needed to underwrite the needed efficiency investments.
Annual energy savings is the reduced energy bill expenditures that benefit both households and businesses within a given year. The net savings is the difference between savings and outlays. The numbers in parentheses are losses in that specific year.

Readers should note from Table 14 that in the early years and especially as the policies ramp up quickly to stimulate a greater level of efficiency improvements, the consumer outlays outweigh the energy bill savings. In 2010, the net annual savings are negative at $-23 million and a positive $431 million by 2015. These savings mount steadily through the year 2025 by when they reach an estimated $3.2 billion net annual savings for the state as a whole. The last row of the table highlights cumulative impacts. By 2025, the net cumulative savings over the period 2010 through 2025 show a strong net positive result, reaching nearly $18.9 billion.

At this point we then have the financial flows estimated as they are distributed across the end-use sectors described earlier in the report. The question then becomes what might be the impacts on the state economy as we've been able to evaluate them for a given year using the DEEPER model. The modeling then evaluates impact on jobs and wages sector-by-sector, and evaluates their contribution to Ohio's Gross State Product (GSP), which is a sum of the net gain in value-added contributions provided by the energy productivity gains throughout all sectors of the state economy. As with the previous table on financial impacts, Table 15 highlights the net impacts for the benchmark years 2010, 2015, 2020 and 2025.

Table 15. Economic Impact of Energy Efficiency Investment in Ohio

Macroeconomic Impacts	2010	2015	2020	2025
Jobs (Actual)	1,582	7,928	19,506	32,061
Wages (Million $2006)	$50	$300	$851	$1,615
GSP (Million $2006)	$58	$444	$1,310	$2,559

Given both the financial flows and the modeling framework, the analysis suggests a net contribution to the state's employment base as measured by full-time jobs equivalent. In the year 2010 we see a net increase of 1,582 jobs which increases to a significantly larger total of 32,061 jobs by 2025. The early years of the policy scenarios show small net cost to the economy. Yet we continue to see a net increase in jobs. How is this possible?

In Ohio, the electric power and the natural gas service sectors directly and indirectly employ about 3.0 and 1.5 jobs, respectively, for every $1 million of spending. But, sectors vital to energy efficiency improvements like construction, utilize 8.5 jobs per $1 million of spending. Once job gains and losses are netted out in each year, the analysis suggests that, by diverting expenditures away from non-labor intensive energy sectors, the cost-effective energy policies can positively impact the larger Ohio economy – even in the early years, but especially in the later years of the analysis as the energy savings continue to mount.

To highlight the results of this analysis in a little more detail, Figure 16 provides year-by-year impacts on net jobs within Ohio. Figure 17 highlights the anticipated net gain to the state's wage and salary compensation and Gross State Product, both measured in millions of 2006 dollars.

Figure 16. Net Job Impacts for Ohio (2008-2025)

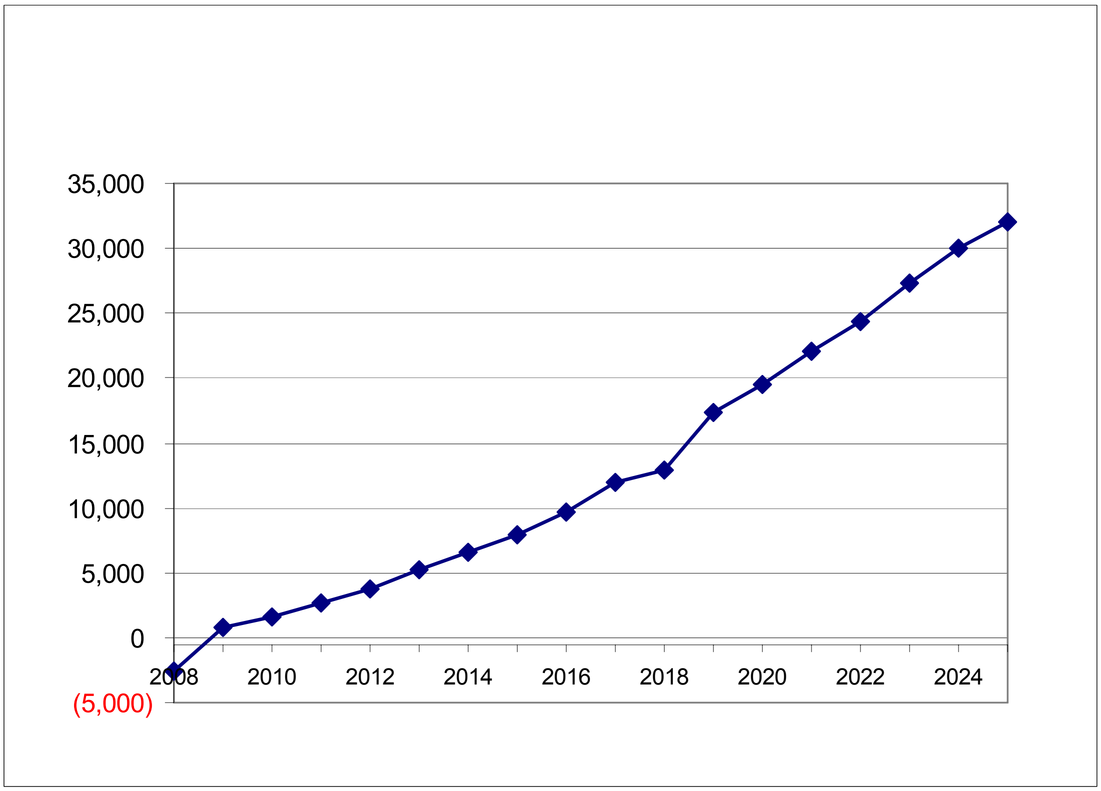


Figure 17. Wages and Gross State Product Impacts for Ohio

The end result of this policy analysis, then, suggests that an early program stimulus which drives a higher level of efficiency investments can actually increase economic impact, creating an average of 4,624 net new jobs from 2010-2015, and rising to an estimated average of 20,726 net new jobs over the last decade of the analysis. This is roughly equivalent to the employment that would be directly and indirectly supported by the construction and operation of 256 small manufacturing plants within Ohio. As indicated by Figure 17, these investments also increase both wages and Gross State Product throughout Ohio.

In short, the more efficient use of energy resources provides a cost-effective redirection of spending away from less labor-intensive sectors into those sectors that provide a greater number of jobs within Ohio. Similarly, cost-effective energy productivity gains also redirect spending away from sectors that provide a smaller rate of value-added into those sectors with slightly higher levels of value-added returns per dollar of revenue. The extent to which these benefits are realized will depend on the willingness of business and policy leaders to implement the recommendations that are at the heart of this report and found earlier in this assessment. It is also important to note that these results are not finalized. Several policy areas remain to be incorporated into the DEEPER model, including onsite solar. It is expected that finalized results will estimate a higher impact on job creation and GSP.

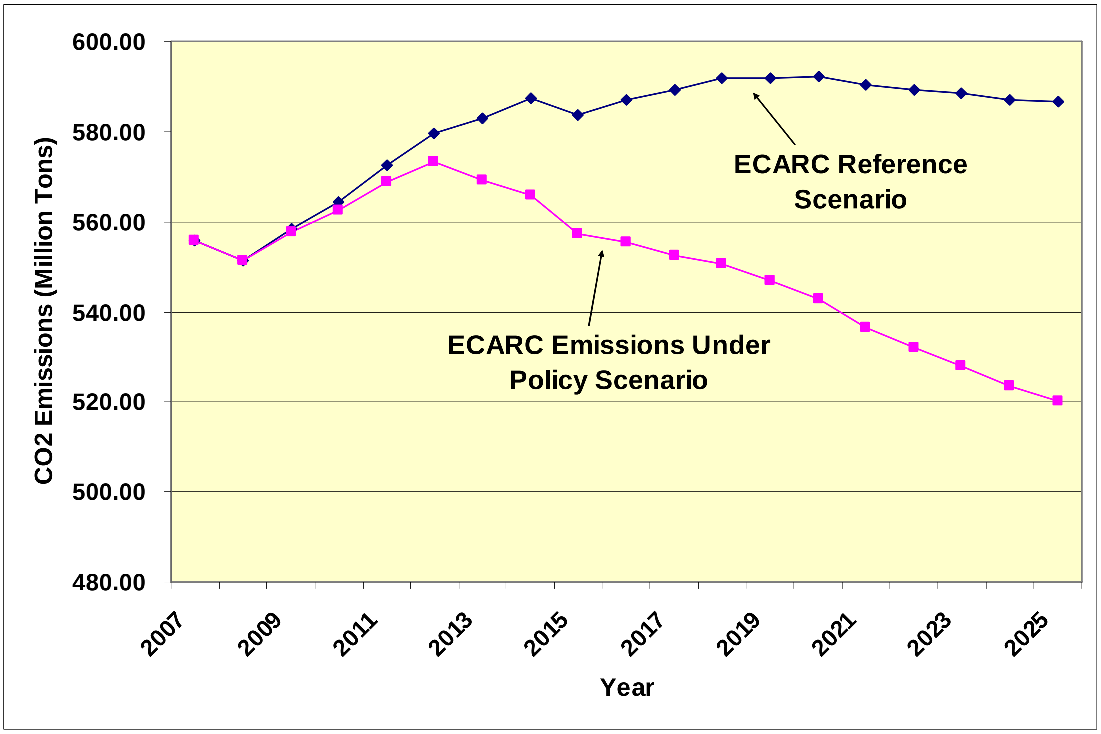
Emissions Impacts in Policy Scenario

Meeting the demand for electricity through efficiency resources reduces electricity generation; thus, any environmental impacts that would result can be avoided. Efficiency represents a cost-effective strategy to reduce global warming emissions. One caveat of the avoided emissions from efficiency that readers should note is that Ohio imports about 3% of its electricity from outside the state.

Therefore, not all of the electricity avoided through efficiency is attributable to power plants in Ohio, but rather from the PJM and MISO wholesale power markets in which Ohio participates.

The policies we suggest would reduce carbon dioxide (CO_2) emissions in the East Central Area Reliability Council (ECARC) by 5.9 million tons in 2015 and almost 20 million tons in 2025, or 1% and 3% of total emissions in the region, respectively (see Figure 18). Through 2025, energy efficiency can reduce CO_2 emissions cumulatively by around 152 million tons. In 2006, Ohio accounted for 142 million tons of CO_2 emission, more than 26% of regional emissions (EIA 2007a). Because electricity savings from efficiency policies in Ohio will have an impact across the ECARC, we therefore estimate these CO_2 reductions from energy efficiency programs and policies relative to the entire region.

Figure 18. ECARC CO_2 Emissions in Reference and Policy Scenario

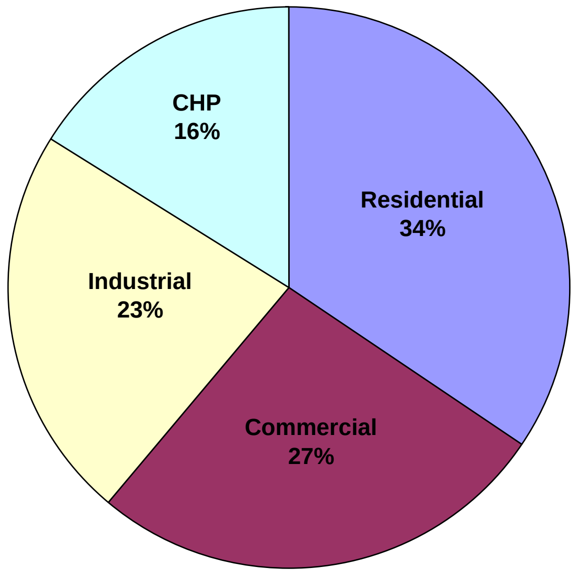


SUMMARY OF FINDINGS

Energy Efficiency Resource Potential

ACEEE's assessment of the economic potential for energy efficiency resources in Ohio estimates efficiency resources equivalent to 33% of the electricity needs of the state in 2025. Energy efficiency resources are identified across all sectors: residential, commercial, and industrial (see Figure 19), which highlights the important fact that everyone in Ohio can make contributions to improve energy efficiency across the state. Combined heat and power and demand response contribute further to the potential for both lower electricity consumption and reduced peak demand.

Figure 19. Summary of Energy Efficiency Resource Economic Potential (64,284 GWh or 33% of Projected Electricity Consumption in 2025)



Impacts of Energy Efficiency and Demand Response

In our policy discussion above, ACEEE suggested a suite of energy efficiency and demand response policies and programs that would enable Ohio to tap into its energy efficiency resource potential. The impacts of these policies and programs on electricity consumption in Ohio over the period of this analysis are shown in Figure 20. The combined effects of efficiency and demand response on overall summer peak demand are shown in Table 16 and Figure 21.

Consumer Savings

The energy savings from these efficiency policies and programs can cut the electricity bills for customers by a net $430 million in 2015. Net annual savings grow eight-fold to $3.3 billion in 2025. While these savings will require some public and customer investment, by 2025 net cumulative savings on electricity bills will reach almost $19 billion. These savings are the result of two effects. First, participants in energy efficiency programs will install energy efficiency measures, such as more efficient appliances or heating equipment, therefore lowering their electricity consumption and electric bills. In addition, because of the current volatility in energy prices, efficiency strategies have the added benefit of improving the balance of demand and supply in energy markets, thereby stabilizing regional electricity prices for the future.

Figure 20. Estimated Reductions in Electricity Use in Ohio through Energy Efficiency

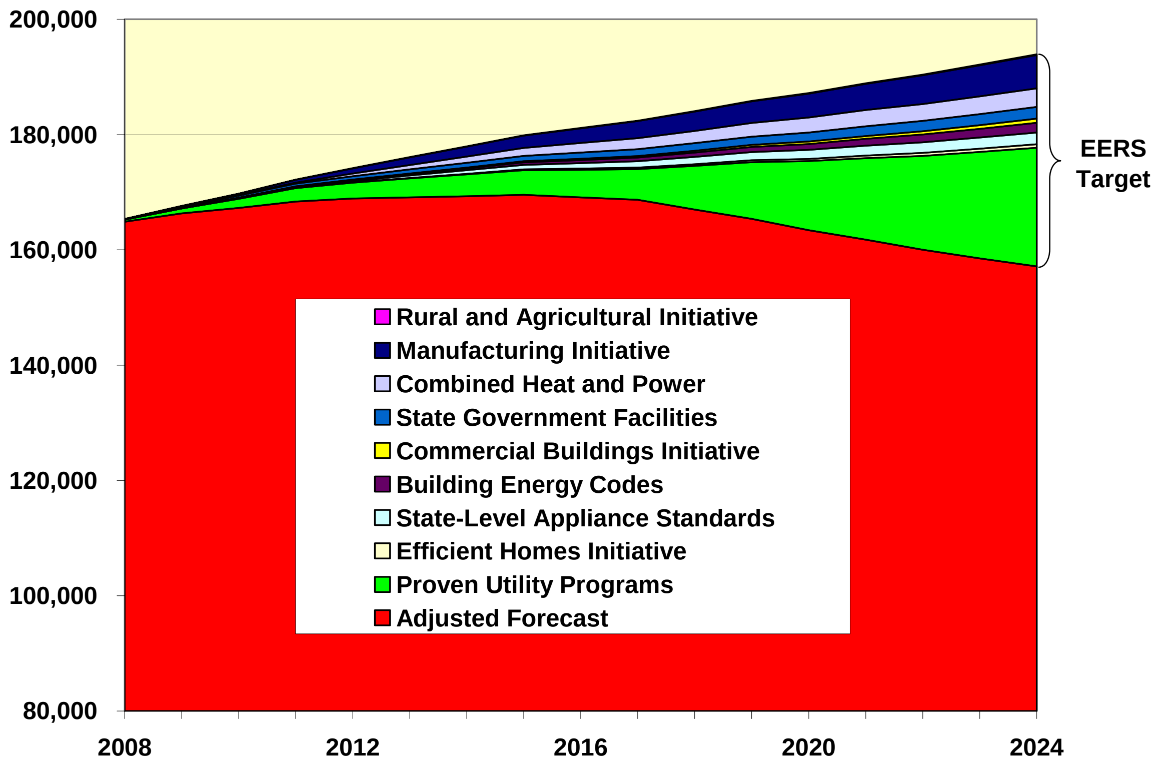


Table 16. Summary of Peak Demand Reduction Potential in Ohio

	2015	2025	% Reduction
Energy Efficiency Peak Reductions	1,550	7,081	18%
Demand Response Peak Reductions	2,064	4,335	11%
Total Peak Reductions	3,615	11,416	**29%**
% Reduction (total relative to forecast)	**10%**	**29%**	

Macroeconomic Impacts

Investments in efficiency policies and programs have the added benefit of creating new, high-quality "green-collar" jobs in Ohio and increasing both wages and Gross State Product (GSP). Our analysis shows that energy efficiency investments can create over 32,000 new jobs in Ohio by 2025 (see Table 17) including well-paying trade and professional jobs needed to design, install, and operate energy efficiency measures. These new jobs, including both direct and indirect employment effects, would be equivalent to over 300 new manufacturing facilities relocating to Ohio, but without the public costs for infrastructure or the environmental impacts of new plants.

Figure 21. Estimated Reductions in Summer Peak Demand through Energy Efficiency and Demand Response (2025 peak reduction = 11,416 or 29%)

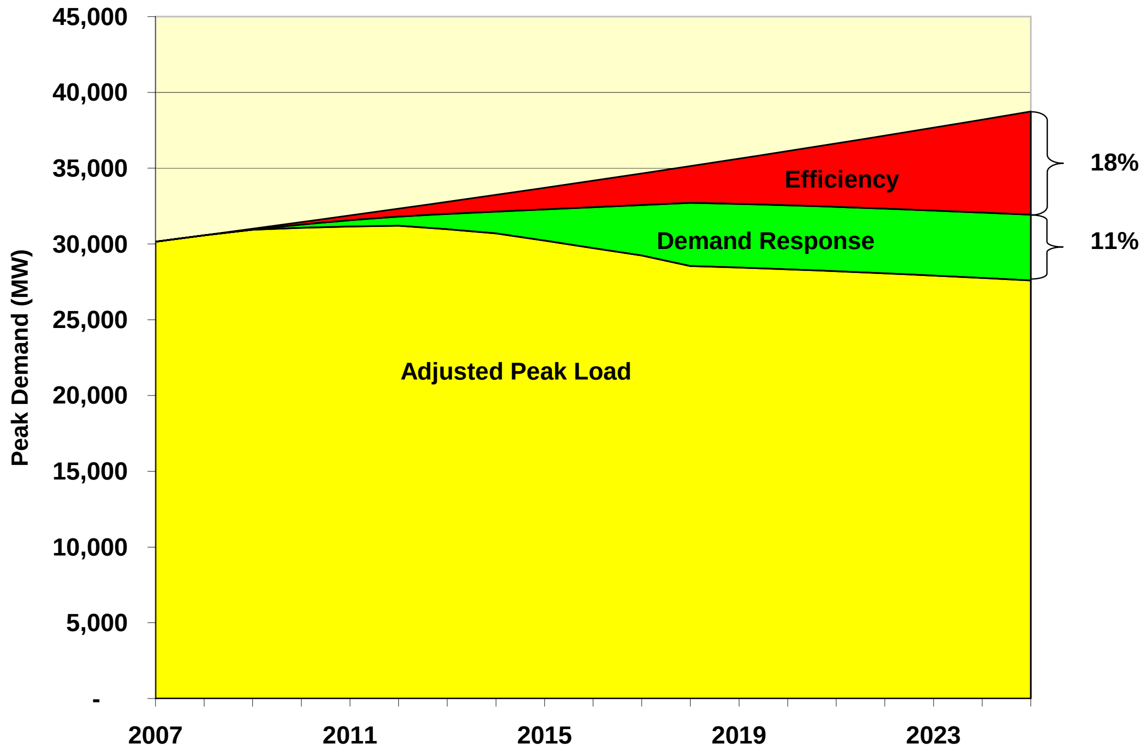


Table 17. Economic Impact of Energy Efficiency Investments in Ohio

Macroeconomic Impacts	2015	2025
Jobs (Actual)	7,928	32,604
Wages (Million $2006)	300	1,615
GSP (Million $2006)	444	2,559

Discussion and Recommendations

ACEEE offers this report to the state of Ohio to help inform its deliberations on energy and climate change policies. We have attempted to tailor our nationwide experiences to the specific needs and opportunities of the state, recognizing that what is implemented with respect to programs and policies should be a decision of the citizens through their elected officials.

The objectives of this report are threefold:

- to engage various stakeholders in Ohio who have a vested interest in energy issues on the political viability of energy efficiency
- to perform an analysis of the potential for increased energy efficiency in Ohio and to make and analyze specific policy suggestions tailored to Ohio; and
- to inform the dialogue of Ohio stakeholders as energy efficiency policies and programs are considered utilizing the study's findings and to provide ongoing follow-up (as resources allow) to interested parties.

Our intention is that this report be used as a roadmap for further development of energy efficiency policies and programs. In preparing this report, ACEEE has drawn upon almost three decades of experience working on energy efficiency policies and programs. Our policy suggestions and examples of utility-run programs are based upon our assessment of "best practices." We have attempted in many places to identify resources that are available for further development, and stand prepared to assist Ohio with additional information and referrals. Ohio's policymakers must focus on what policies and program options they are committed to pursuing.

Role of Key Policymakers

The review of our policy suggestions included possible entities that are well-positioned to lead their implementation. In our prior research, we have documented that many of these policies and programs can be successfully implemented by a number of different entities, though the choice remains with the policymakers.

- ***The Governor*** – Governor Strickland has already established himself as a key figure in the advancement of energy efficiency across the state of Ohio. In August 2007, Governor Strickland announced his Energy, Jobs, and Progress plan, which effectively set the gears in motion for the introduction and subsequent passing of SB 221 in April of 2008. The Governor has the potential to implement at least parts of a number of our suggestions, including the expansion of the state and local facilities initiative. In part, the Governor's most important role may be to use his position to raise awareness among the policy community and the public as to the role of energy efficiency in utility and climate policy. The Governor will also have to play a role in securing long-term funding for state-sponsored initiatives.
- ***Legislature*** – The Ohio legislature has already played a key role in setting Ohio on its current energy path and will continue to play a pivotal role because of its ability to both fund and direct energy policy for the state. The legislature should consider such steps as adoption of state appliance and equipment efficiency standards; updating state residential and commercial energy codes as they are introduced by the IECC and ASHRAE; and allocating funds from the American Recovery and Investment Act. The legislature will also have to secure long-term funding for these initiatives.
- ***Electric Utilities*** – Ohio's investor-owned utilities are legally obligated to meet the efficiency requirements set by SB 221. The suite of policies we have suggested the PUCO allow to contribute towards the EERS will meet a significant part of the target so that utilities will only have to rely on their own proven programs to meet 12% of the 22% consumption savings target.
- ***Ohio Air Quality Development Authority*** – The OAQDA, through its bond underwriting capability, has the authority to fund programs directly impacting activities that contribute to air pollution within the state. Because energy efficiency has the ancillary benefit of reducing emissions attributable to electricity generation, OAQDA funding can be utilized for a number of efficiency programs.
- ***State Agencies*** – Various agencies would have a significant role in implementing provisions such as the advanced buildings initiatives, as well as the manufacturing and agricultural/rural initiatives. These agencies would also be involved in the education and outreach effort that would be crucial in engaging the state's consumers with the information needed for them to make informed energy investment decisions. Funding from the American Recovery and Reinvestment Act will be available for these purposes, but there will be a need to secure long-term funding as well. Long-term funding could come from future climate change legislation mandated at the federal level or through utility rates.
- ***Local Governments*** – Local government entities are uniquely positioned to implement several important policies such as building energy codes and programs for local government facilities (as discussed in Elliott and Eldridge 2007). Funding from the American Recovery and Investment Act will be available for these purposes.

- ***State Educational System*** – With the identification of Ohio's workforce as a key requirement, the state educational system would be responsible for ensuring that a trained workforce is developed to fill the jobs that increased investment in energy efficiency would create.

Industrial Self-Direct

SB-221 includes a provision, which can be implemented at the option of the PUCO, to allow for large electric consumers to opt-out of paying utility energy efficiency program charges if they implement energy efficiency projects at their own facilities at their own expense. The motivation for this results from a perception by some large consumers that the programs offered to them by the utilities are not responsive to their needs (ELCON 2008). The history of this type of provision has been mixed, with some self-direct programs not requiring rigorous evaluation, measurement and verification of the customer implemented measures. In these instances, it's been very difficult to determine if the savings projected by industrial customers has been achieved.[54] To address this concern, the PUCO could require that the customer who chooses to self-direct retain at their own expense a commission-approved contactor to undertake an assessment of the savings to ensure that they are in compliance with their savings obligation.

As an alternative, the PUCO and the utilities can ensure that program offerings are responsive to the needs of the manufacturing sector. This approach is consistent with our recommendation for the establishment of the *Ohio Manufacturing Initiative* that we have proposed as part of the suite of innovative policies, based on our consultation with Ohio industrial trade associations. We see this approach as preferred for both the state – since industrial energy efficiency savings tend to be lower cost than other sectors – and the customers – since they receive the benefits of a program tailored specifically to meet their needs. It also helps ensure that the lessons learned and institutional knowledge gained by administering efficiency programs to the largest industrial customers benefits future industrial customers. This approach has worked well with the Oregon Energy Trust and BC Hydro in Canada.[55]

Program and Policy Implementation

Beyond the obligation of Ohio's private utilities to implement energy efficiency, there are many entities in the electricity market, both consumers and providers, which have voiced their support for energy efficiency and are willing to invest voluntarily. Leveraging these other market players could increase the prevalence of energy efficiency significantly. For example, the OMA, through its Energy Efficiency Collaborative, and the University of Dayton, through its IAC program, are beginning or have already begun to deliver services to the manufacturing community, so building on these existing efforts allows expanded services to be delivered more quickly. Our meeting with the Ohio Hospital Association revealed that integrating distributed generation, such as combined heat and power, into their operations could reduce their operating costs in light of their perpetual need for massive amounts of electric power. Buckeye Power, Inc., an electric cooperative owned by Ohio's 25 rural electric cooperatives, has also taken a keen interest in energy efficiency, though demographics and the sparse service areas of these cooperatives preclude them from achieving the level of savings expected from Ohio's IOU's.

Evaluation, Measurement, and Verification (EM&V)

The implementation of energy efficiency policies and programs must include a mechanism that emphasizes transparency and ensures success. Funding of and participation in efficiency programs will only be guaranteed, however, if policymakers and consumers are cognizant of the benefits these programs are delivering, which, of course, also requires that these benefits be verified. An inherent

[54] From discussions between Anna Chittum and multiple industrial energy efficiency program managers, January – March 2009.
[55] Ibid.

element of any attempt to advance energy efficiency is an indigenous entity dedicated to the evaluation, measurement, and verification of efficiency programs. As the utility regulatory body, the PUCO is ideally situated to command this role. However, adding EM&V to the PUCO's obligations would require time to organize and staff so that it would be able to fully engage in its new duties.

Allocation of Benefits from Energy Efficiency

Reducing total electricity consumption is an effect of energy efficiency that avails customers through lower electricity bills, but can be a bane for utilities as lower sales mean lower revenues. Naturally there is concern from IOU's and their shareholders that, over time, dwindling revenues could impede utilities' ability to provide energy services due to decreased earnings or financial margins. To counter this phenomenon, IOU's have expressed their interest in pursuing cost recovery in order to guarantee a return on their efficiency investments, which can be done through decoupling, performance-based incentives, or some other rate mechanism (EPA 2007b). ACEEE does not support one method over another, but it is vital that energy efficiency benefits be allocated fairly between ratepayers and shareholders alike. Nonetheless, it is also important that utilities earn profits equivalent to what they would under a supply-only scenario.

CONCLUSIONS

The State of Ohio is poised to make great strides in expanding efficiency throughout the state. As this report documents, there is tremendous potential for Ohio to become a national leader in efficiency and to take advantage of the numerous cost-effective energy efficiency and demand response opportunities that exist in the state. Nonetheless, Ohio does have some difficult decisions to make with regards to its energy future. Faced with severe budgetary constraints and a slumping economy, there may be an inclination to dispel energy efficiency in light of the present conditions. Regrettably, the ramifications of a bleak economic outlook have already begun to impact important energy policy decisions, such as the state's rollback of its building energy codes. It is therefore extremely important that the momentum created by the establishment of the aggressive EERS target by legislation included in SB 221 not be lost. This legislation has sent a strong signal of Ohio's intent, which in large part contributed to its respectable ranking in ACEEE's 2008 state energy efficiency scorecard. However, Ohio will have to continue to balance its priorities in order for energy efficiency to affect its economy as beneficially as this report highlights.

The various energy efficiency and demand response policies we suggest have been successful in other states at delivering efficiency resources and reducing consumer electric expenditures. We estimate efficiency can meet 122% of the increase in the state's electricity needs over the next 17 years, while meeting 188% of the increase in peak demand and reducing emissions by over 12%. What is more, these policies and programs can accomplish this at a lower cost than building new supply infrastructure, while simultaneously creating over 32,000 new, high-quality "green collar" jobs by 2025.

Our suggestions are intended to be the starting point for dialog among stakeholders on how to realize the demand-side efficiency resource potential in the state, particularly given the economic challenges it faces. ACEEE's suggestions are based on our review of existing opportunities and stakeholder discussions, and reflect proposals that we think are politically viable. However, it is important to note that these suggestions will not necessarily meet all of the state's future energy needs. While energy efficiency is perhaps the only new energy resource available that can be deployed quickly in the short term and continue to contribute significantly into the long term, the state will still require additional resources to meet any new load while replacing older, dirtier generation plants as they are retired. Furthermore, additional policies and programs exist that could be implemented to realize even more of the available energy efficiency resources. Ultimately, energy efficiency can delay the immediate need for investments in infrastructure, allowing Ohio the time to rigorously consider its future resource choices.

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APPENDIX A – REFERENCE CASE

A.1. Projection of Electricity Consumption and Peak Demand

The development of the reference case for Ohio is the foundation of the quantitative analysis of the report. The first task in developing an energy efficiency and demand response potential assessment is to determine a reference case forecast of energy consumption, peak demand, and electricity prices in the state in a “business as usual” scenario. As with all forecasts, they are subject to significant uncertainty, particularly in times such as we are in when the economic outlook is a major unknown. It is however important to understand that while the forecast may affect the final numbers resulting from the analysis, that the forecast has very minor impact of the effectiveness of the proposed policies, particularly in the long-run.

When developing a reference case, it is preferable to use forecasts that are specific to the state or region and that are agreed upon by key stakeholders. Initially we used a report released by the Public Utilities Commission of Ohio (PUCO) in 2008 forecasting electricity consumption and peak demand over the 2008-2027 period, which included historical data starting in 2002. However, the historical data from the PUCO forecast were not consistent with consumption data from the Energy Information Administration's *Electric Power Annual* (EIA 2007b) and *Annual Energy Outlook* (EIA 2007c) and neither reflected current economic conditions in their projections. We elected to use the forecast we estimated based on the EIA's data until we were able to clear up the reasons for the variations between the PUCO and the EIA forecasts.

In the meantime, several key stakeholders voiced their concern about basing our forecast off data from the EIA as opposed to using the PUCO forecast. Ultimately the PUCO responded about the variations, noting that the 2008 forecast had been made with data several years old and providing an updated forecast using the most recent data. However, the updated forecast has not yet been published and did not include a breakdown of electricity consumption by sector. We thus chose to continue to use the forecast we developed based on the EIA data because it was not significantly different in the long-term from the PUCO forecast. We also felt our forecast was more current and that we had a greater understanding of the strengths and deficiencies of our forecast than we did with the PUCO forecast.

A.1.1 Electricity Consumption Forecast

To develop our electricity consumption forecast we used a number of data sources. For historical sales, covering 2002 through 2007, we used data from the EIA's *Electric Power Annual* (EIA 2007b), which publishes consumption data for all states individually. To estimate projected consumption, we then applied sector-specific growth rates, derived from the EIA's *Annual Energy Outlook* (EIA 2007c) forecast for the East Central Area Reliability Coordination Agreement (ECARC), to actual 2007-year electric sales data. Using this methodology, we estimated total electricity consumption in the state to grow in the reference case at an average annual rate of 1.0% between 2008 and 2025, and 1.0%, 1.6%, and 0.4% in the residential, commercial, and industrial sectors, respectively (see Figure 5). Total electricity consumption in the three sectors in 2007 was 161,547 GWh and in the reference case grows to 177,954 GWh in 2015 and 193,945 GWh in 2025 (PUCO 2009).

A.1.2 Peak Demand Forecast

To forecast peak demand we adjust our data from the electricity sales forecast using a system load factor, which we assumed to be 60.0%. Using this methodology, we estimate peak demand growing at an average annual rate of 1% over the 2008-2025 period. In 2008, peak demand is expected to reach 33,705 MW increasing to 36,586 MW by 2015 and 39,770 MW in 2025.

Table 18. Retail Electricity Sales and Peak Demand Forecast

	2010	2015	2020	2025	Average Annual Growth Rate
Electricity (GWh)					
Residential	56,925	60,011	63,217	65,748	**1.01%**
Commercial	50,571	55,383	59,662	64,510	**1.63%**
Industrial	60,112	62,559	62,974	63,688	**0.43%**
Total	**167,607**	**177,954**	**185,853**	**193,945**	**0.98%**
Summer Peak Demand (MW)					
Total	**34,497**	**36,586**	**38,612**	**39,770**	**0.98%**

A.1.3. Ohio Population Forecast

Population estimates were needed for this analysis to determine per-capita sales data. We consulted Economy.com (2008) for data on population in the State of Ohio. According to this source, population in Ohio will grow at an average annual rate of about 0.21%.

Table 19. Ohio Population Forecast

	2010	2015	2020	2025	Average Annual Growth Rate
Population Estimate	11,509,050	11,574,410	11,696,320	11,883,570	0.20%

A.2. Projection of supply prices and avoided costs

Synapse Energy Economics developed projections of supply prices and avoided costs used in this analysis. These estimates were developed based on key input assumptions that were developed as part of the stakeholder engagement process. Synapse then developed a simplified Electricity Planning and Costing Model to develop the projections. As noted in the main report, two set of projections were developed for the reference and moderate policy cases.

A.2.1. Caveats

The projections of production costs and avoided costs presented in this memo are based upon a number of simplifying and conservative assumptions that the stakeholder group consider reasonable for the purpose of this high-level policy study. These simplifications include use of a single annual average avoided energy costs to evaluate the economics of energy efficiency measures rather than different avoided energy costs for energy efficiency measures with different load shapes. In addition, Synapse Energy Economics considers it unrealistic to rely upon projections that exclude the cost of compliance with anticipated CO_2 emission regulations.

A.2.2. Key Assumptions

This section describes the key inputs to the electricity model that Synapse Energy Economics has developed for this project (Synapse electricity cost model), the rationale for the proposed values and the sources of those values. The final inputs are based upon a set of draft inputs developed by

Synapse[56] that ACEEE reviewed with key stakeholders in Ohio. The key substantive difference between these final input assumptions and the draft input assumptions was the use of a lower peak load factor, from 66.2% to 60.0%.

The memo also provides a description of the Electricity Cost model that we use to estimate future production costs and avoided costs.

Changes from the December 8 version, Deliverable 1A, are indicated in ***italics***.

A.2.3. Input Assumptions

The key inputs to the electricity model are presented under the following thirteen categories:

- Basic Modeling assumptions
- Base year Sales and revenues
- Base year Load and resource Balance
- In-State Base Year Generation Resource Performance and Cost Data
- New Generation Resource Performance and Cost Data
- Fuel Types
- Annual Energy and Peak Load
- Capacity retirements
- Capacity additions
- Fuel prices
- Purchased Power Costs
- Carbon Emission Costs
- Wholesale Market Prices

Basic Modeling Assumptions:

- The base year is 2007. All monetary values are reported in constant 2006 year dollars unless noted otherwise.
- The study period begins in 2008 and ends in 2030, an analysis period of 23 years.
- The reporting period is 2009 through 2025, a total of 17 years.
- The financial parameters for costing resource additions are as follows:
  - Inflation Rate. 2.50%. Rationale - the twenty year average (1987-2006) derived from the chained GDP deflator is 2.47%.
  - Nominal Discount Rate. 10.0%. This represents the value for an independent power producer with a mix of equity and bond financing. Based on a 50/50 equity/debt mix with 12% for equity and 8% for debt. Used for levelization of capital expenditures. Actual rates for specific projects will vary depending on the nature of the project and the implementing entity.

[56] Deliverable 1A Draft Input Assumptions for Electricity Cost Model, December 8, 2008.

- o Real Discount Rate. ***7.32%***. Derived from the Nominal Discount Rate and the Inflation Rate.

- o Income Tax Rate. Federal rate of 35% and Ohio state corporate rate of 6.8%. Property tax rate at the nominal level of 0.5% per annum of the initial plant cost (local rates vary considerably). Used for capital cost levelization.

A.2.4. Base Year Sales and Revenues

The historic sales and revenues data are obtained from the EIA's "State Electric Profile" Table 8 (http://www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html). This has been supplemented with data for 2007 from the EIA "Electric Power Monthly" report of March 2008 which contains data through December of 2007 (Tables 5.4 and 5.5) (http://www.eia.doe.gov/cneaf/electricity/epm/epm_ex_bkis.html). The historic data indicates that Ohio is net exporter and generates about 12% more electricity than it needs. Likewise the capacity in Ohio is in excess of the in-state peak loads.

A.2.5. Base Year Load and Resource Balance

The historic sales and revenues data are obtained from the EIA's "State Electric Profile" Tables 5, 8 and 10 (http://www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html). This has been supplemented with data for 2007 from the EIA "Electric Power Monthly" report of March 2008 which contains data through December of 2007 (tables 1.6, 4.6, 4.20, 4.12 and 4.13) (http://www.eia.doe.gov/cneaf/electricity/epm/epm_ex_bkis.html).

Our forecasts of future net imports and exports of electricity are based on this reference year data and thus are consistent with the existing transmission system. We did not model or forecast projected changes in transmission transfer capability. Instead, our model assumes that future imports and exports will be at the same relative level as in the recent past and that transmission transfer capability will change in the future to match load growth and that level of relative imports and exports.

A.2.6. In-State Base Year Generation Resource Performance and Cost Data

From the above EIA data, we have the generation, CO_2 emissions and fuel costs for each generating group. From that we can derive the average heat rate for each group and the fuel component of the generation costs. To that we add typical industry values for O&M. Also from that EIA data we have the historic capacity factors associated with resource group. Those historic patterns are used to set the basis for future performance.

The capacity factors used are the historic average for all plants using a given fuel in the state. Some newer plants do much better, but because there is so much coal capacity in Ohio some older coal plants must cycle and follow load. The data includes average historic emission rate data for all pollutants. Emission allowance costs for pollutants, other than CO_2, are reflected in the O&M costs.

A.2.7. New Generation Resource Performance and Cost Data

For new generation resources we have used the technology parameters from the AEO 2008 Assumptions document. For capital costs we have used our professional judgment based on a number of sources to reflect current cost expectations for new construction. The costs represent the all-in costs, including construction financing costs, as of the year of operation. No CO_2 retrofit costs are assumed other than the allowance cost of CO_2 emissions. Fixed costs of new capacity are allocated over the generation from that new capacity based on the expected operating capacity factor of the new resource.

A.2.8. Fuel Types

We use the three basic fuel types as specified in the EIA documents (Coal, Petroleum and Natural Gas) with the addition of nuclear and biomass.

A.2.9. Annual Energy and Peak Load

For energy and peak loads we have used the ACEEE Reference Case Forecast as of 11/24/08 that increases historic load at the rates as represented in the AEO 2008 report for the East-Central region. A system load factor of ***60%*** based on 2007 load data is used to produce future peak loads based on forecasted energy use.

A.2.10. Capacity Retirements

There is very little information about future plant retirements and a variety of unknown circumstances may either work in favor of or against individual plants. We have attempted to reflect the generation retirements (Future Deactivation) posted on the PJM website as well as the aging of plants in future years. Ultimately we forecast modest gradual retirement of existing resources in the model. But it is quite likely that many existing plants will be retrofitted and their lives extended.

A.2.11. Capacity Additions

In order to meet future load growth, new generation resources must be added to the existing generation mix.

The electricity model is not a capacity expansion model that optimizes capacity additions by choosing among a set of resource alternatives to develop a least cost expansion plan. Instead, we will add new resources “manually” to meet reserve needs. Our analysis will consider three sets of additions:

- Planned Additions—Near-term proposed new additions or uprates to existing plants that are in development or advanced stages of permitting and have a high likelihood of reaching commercial operation;
- RPS Additions—Renewable generators that are added to meet existing or anticipated renewable portfolio standards (RPS) in each state; and,
- Generic Additions—New, generic conventional resources that are added to meet the residual capacity need after adding planned and RPS additions.

<u>Planned Additions</u>

Description: Our near-term entry forecast is guided by the projects in the PJM Interconnection Queue plus the expected addition of some additional future coal resources based upon market conditions in MISO and in Ohio in general based on the types of projects in the PJM queue. Looking at the 2010-2013 period for Ohio, the mix is about 85% coal, 13% wind and 2% for a mix of various other types. Based on this we have added 2,200 MW of new coal capacity by 2012. For PJM as a whole though, the queue is 66% natural gas and new natural gas generation is also likely in Ohio depending on load growth and other factors.

***Data Sources**:* PJM Interconnection Queue Requests.

<u>AEPS Additions</u>

In 2008, Ohio enacted S.B. 221 establishing an Alternative Energy Portfolio Standard (AEPS) (enacted 5/1/2008 and effective 1/1/2009) with alternative energy and renewable generation requirements. The renewable requirement takes effect in 2009 and increases to a target of 12.5% by 2024. The solar component of this requirement increases to 0.5% of retail sales in that target year.

Eligible renewable resources are defined to include the following technologies: solar photovoltaics (PV), solar thermal, wind, geothermal, biomass, biologically derived methane gas, landfill gas, certain non-treated waste biomass products, fuel cells that generate electricity and qualified hydroelectric facilities.[57]

The specific mix of these resources is not known, but we have assumed for the renewables (less the solar component) that 1/3 of the energy will come from wind and 2/3 from biomass.

The operating characteristics are based on AEO 2008 and Synapse estimates derived from experience elsewhere in the US.

<u>Generic Additions</u>

In order to reliably serve the forecasted load in the mid- to long-term portion of the forecast period, new generic additions will need to be added to the model. A range of generation technologies was initially considered for this purpose, including gas/oil-fired combined-cycle, gas/oil combustion turbines, conventional coal, and nuclear. We use the mix represented in the PJM Interconnection Queue as the guide.

Generic additions based on requirements after the AEPS additions specified above are based on meeting a system-wide reserve goal. For these generic additions we use a mix of 30% conventional coal, 35% NGCC and 35% gas peakers.

A.2.12. Fuel Prices

We start with fuel prices reported for the base year of 2007. In general the price forecasts are basically long-term reflecting underlying conditions as presented in the Annual Energy Outlook of 2008 (Table 64). We have however updated those AEO forecasts of natural gas and crude oil prices based on market conditions as of 11/13/2008.

We used several sources to reflect current prices through mid 2008, and expectations for the future.

- For natural gas our projection of wholesale prices in Ohio for the next twelve years is equal to the Henry Hub price per the NYMEX futures as of November 13, 2008 plus a basis differential based on the state and Henry Hub prices in the reference year. After that point we apply the relative price trends from the AEO 2008 modeling.

- Petroleum prices are set at a historically determined multiple of natural gas prices.

- For coal we use the reported base year cost scaled by the relative year to year changes from AEO 2008.

A.2.13. Power Purchase and Sale Prices

Ohio utilities operate in two wholesale electricity markets. AEP and Dayton Power & Light operate in PJM, while Duke Ohio and FirstEnergy operate in MISO. The prices for wholesale electric energy delivered in Ohio from each of those two markets are very similar. Using 2007 as the reference year, the annual average energy price at the PJM Ohio Hub was $46.18/MWh while the annual average prices to FirstEnergy from MISO was $45.57/MWh in the Real Time market and $46.13/MWh in the Day Ahead market. Thus the price for the PJM Ohio Hub is a reasonable estimate of wholesale energy prices to Ohio for either ISO.

[57] Information obtained from DSIRE (Database of State Incentives for Renewables & Efficiency). *Ohio Incentives for Renewables and Efficiency – Alternative Energy Resource Standard.* 12/5/08 at http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=OH14R&state=OH&CurrentPageID=1&RE=1&EE=1

This wholesale energy market price is applied to the interstate net purchase/sale of energy and thus is only a relatively small factor in the final model results. As noted earlier, our model assumes that future imports and exports will be at the same relative levels as in the recent past and that prices for those imports/exports will follow the same trajectory as average prices in Ohio.

The price forecast is discussed in Section 13 below.

A.2.14. Carbon Emission Costs

Carbon compliance costs are set at the Synapse 2008 mid-case level (see Schlissel 2008).

A.2.15. Wholesale Market Prices

Since much of Ohio operates within the deregulated PJM and MISO markets, any changes in load will be reflected as savings or costs based on those market prices. This consists of two major components - the Energy and the Capacity markets.

The starting point for the market energy price forecast are the PJM futures market Energy futures for the PJM Western Hub are traded in NYMEX and are available through 2012. However those prices are then adjusted to reflect Ohio markets. The first step is to calculate the differential between the Ohio and the PJM Western Hub. The calculations begin with the actual 2007 price for the PJM Ohio Hub, which was $46.12/MWh. This annual average price was $13.59 below the 2007 annual average price for the PJM Western hub. Also as noted in Section 11, the 2007 Ohio energy prices in both PJM and MISO were nearly the same, so this forecast is applicable for the entire state. Our forecasts of prices for the Ohio consist of futures prices for the PJM Western Hub plus the “basis differential” between the PJM Western Hub and the Ohio markets. This represents a whole state energy price consistent with historic data.

For the capacity cost we use the RTO prices from the PJM RPM auction which are also available through 2012. The energy and capacity prices are then combined to produce a total market-based avoided cost.

The market price is an approximation that reflects general behavior, but does not capture the details of any specific purchase and sale agreements. This price also only applies to the interstate net purchase/sale of energy and thus only a relatively small component of the final model results.

A.3. Electricity Planning and Costing Model

This model was developed by Synapse for ACEEE's clean energy state studies.

A.3.1. Background

ACEEE has initiated a series of state-specific “Clean Energy” potential studies through which it will work with key stakeholders in order to build a common understanding of, and consensus on, the role that clean energy resources, i.e., energy efficiency and demand response, can play in meeting the future electricity end-use requirements in each state, the economic benefits of treating those resources as the “first fuel” for meeting future requirements and the policies for maximizing reliance upon those resources. The time horizon for the studies is through 2025.

In each of those studies ACEEE will evaluate the cost effectiveness of reductions from energy efficiency and demand response, and will also demonstrate the benefits of those reductions to all consumers in the state by estimating retail prices in the long-term under a clean energy Policy Case.

ACEEE retained Synapse to provide three deliverables to support these studies

- projections of long-term wholesale electricity supply prices under a reference, or business-as-usual case;
- credible, consistent, “high-level” estimates of avoided electric energy ($/kWh) and capacity costs ($/kW-year); and
- projections of long-term electricity supply prices under a clean energy policy case.

In light of time and budget constraints, and the policy nature of these studies, ACEEE requested that Synapse develop and apply an electricity planning and costing model that would produce accurate “high-level” estimates of each of these deliverables in a well-documented, transparent manner.

In order to satisfy the ACEEE request, Synapse had to develop an electricity planning and costing model that would be:

- applicable to planning and costing from a state perspective, although most electric utility operations cross state boundaries;
- applicable from state to state, although some states are part of deregulated multi-state markets while others operate under traditional utility regulation;
- applicable using public data;
- inexpensive to setup and run; and
- relatively transparent.

Synapse has developed an EXCEL based planning and costing model with these characteristics.

A.3.2. Methodology

The model begins with an analysis of actual physical and cost data for a base year, develops a plan for meeting projected physical requirements in each future year of the study period and then calculates the incremental wholesale electricity costs associated with that plan. (Incremental to electricity supply costs being recovered in current retail rates).

A.3.3. Base Year Data

The actual data for the base year, and prior years, provides our starting point. That dataset contains historical data in the following categories:

1. Recent year summary statistics.
2. Listing of the ten largest plants in the state.
3. Top five providers of retail electricity
4. Electric capability by primary energy source.
5. Generation by primary energy source.
6. Fuel prices and quality.
7. Emissions.
8. Retail sales and revenues by customer class.
9. Retail sales by various provider types.
10. Supply and distribution of electricity.

This data enables us to characterize the electric supply system and its costs for a given state. For example the capacity, generation and capacity factor, average heat rate and fuel costs for different classes of resources. We can also calculate the retail margin from this data, i.e., the margin between average retail rates and variable production costs. The retail margin reflects the transmission and distribution costs being recovered in retail rates plus the fixed generation costs being recovered in those rates. This data is a very broad brush since the resources are grouped by fuel type and their operation is not characterized in great detail.

A.3.4. Future Years

We begin with the forecast of annual demand and energy in each future year provided by the ACEEE stakeholder group.

Next we develop a physical plan to meet the load in each of those future years. This is done in the model via the following steps:

1. Derive annual capacity and generation requirements from forecast of retail annual demand and energy, and reserve margins,
2. Determine the relative quantities of annual capacity and generation to be provided by in-state and out-state resources based on the current mix of in-state and out-of state resources,
3. Estimate resource retirements. It is quite difficult to predict the timing of actual plant retirements, but it is reasonable to assume that some older facilities will be retired during the study period. We assume gradual retirement of existing resources over time based on typical operating lifetimes. This is explicitly specified in the input data section and can easily be modified if more specific data becomes available.
4. Estimate the capacity, timing and timing of new generation additions, in-state and out of state. Our model is not a capacity expansion model and therefore does not make capacity additions “automatically.” Instead, after we include “planned” capacity additions, we add enough “generic” capacity additions to maintain the reserve margin. Our generic additions are a mix of peaking, intermediate and baseload units that maintains the historical mix of those categories in the state. This approach is transparent as the additions are explicitly specified in the input data section.
5. Calculate the quantity of annual generation from each category of capacity, existing and new, in-state and out of state. The estimated quantity of generation from each category of capacity is derived from the operating capacity factors. These are generally based upon economic dispatch, i.e., dispatch from each category in order of increasing variable production costs

A.3.5. Calculate Production Costs

The model calculates the average production costs, i.e., energy plus capacity, for the particular case in the Production Model worksheet.

States with Regulated Wholesale Markets

For states with regulated wholesale markets the Production Model worksheet calculations are made as follows:

6. Calculate total cost of generation from existing in-state resources, purchases from out-of-state resources, and new in-state resources.
    a. The unit production costs of existing in-state generation includes variable operating costs plus fixed costs.[58] The aggregate cost of generation from these resources decline over time as existing coal, oil and gas plants are retired, while the existing nuclear plants with low operating costs continue operation;
    b. The unit production costs of new in-state generation consists of the levelized capital cost of new capacity additions plus their variable operating costs. The capacity cost of new capacity additions are levelized using the capital recovery factors developed in the Capital Recovery Calculation (CRC) worksheet.

[58] For existing resources fixed costs are estimated on an aggregate basis based on the base year difference between fuel and other variable costs and the retail revenues less a retail markup component.

   c. The cost of power imported or exported is indexed to the generation-weighted average cost of generation from the in-state resources, i.e., existing and new. That is, the base-year import/export price changes in parallel with the in-state cost, e.g. an x% change of in-state production costs is reflected in an x% change of import/export prices. The rationale is that relative changes of in-state costs will be reflected outside the state as well.

States with Deregulated Wholesale Markets

For states with deregulated wholesale markets the Production Model worksheet calculations are made as follows:

7. The first step is to calculate the reference year market prices for the state being studied. The next step is to calculate the relationship between those state prices and market location for which future prices are available. The third step is to then apply that relationship to the futures prices to produce a forecast for market prices in the study state.

A.3.6. Calculate Avoided Costs

States with Regulated Wholesale Markets

For states with regulated wholesale markets the Production Model worksheet calculates the total avoided costs, avoided capacity costs and avoided energy costs via the following steps:

8. Total Avoided Costs. The worksheet calculates "all-in" avoided costs that include both energy and capacity costs.
   a. Years 1 to 5. For the first five years the avoided costs are a mix of avoided dispatch of existing resources and avoided total cost of new resources that would otherwise come-on-line during that period. The percentage of new resources included in that mix is phased-in, starting at 0% in year 1 and rising to 100% in year 5.
   b. Year 6 onward. After year 5 the avoided costs in each year equal the average total costs of new resources in that year. This calculation assumes that the capital costs of new resources are avoidable either through avoiding their actual construction or through recovery from revenues from off-system sales.
9. Avoided capacity cost. To estimate the avoided cost of capacity only we use the proxy plant approach which is used by several ISOs. This avoided capacity cost is based upon cost of "capacity only" from a new gas combustion turbine "peaker" unit. Basing avoided capacity cost on the capital cost of a new peaker is a commonly accepted method.
10. Avoided Energy Cost. The avoided energy cost is the total avoided cost from step 8 minus the avoided capacity cost from step 9

States with Deregulated Wholesale Markets

For states with deregulated wholesale markets the Production Model worksheet calculates the total avoided costs, avoided capacity costs and avoided energy costs differently for different time-periods.

11. Near-term years for which futures prices are available, e.g. first 4 to 5 years.
   a. Avoided energy cost – This is calculated from the energy futures market prices with appropriate historic-based adjustments for the state service area.
   b. Avoided capacity cost – This is based on the available appropriate capacity market results.
   c. Total avoided cost – This is obtained by combining the avoided energy cost with the avoided capacity cost using the base year system load factor to arrive at the combined total avoided cost on a per MWh basis.

12. Long-term years for which futures prices are not available. After the period for which futures are available, the total avoided costs, avoided capacity cost, and avoided energy cost are developed in the same manner as for regulated states, in steps 8, 9 and 10.

A.4. Reference Case Electricity Supply Prices and Avoided Costs

This section presents Synapse's projections of *Reference Case* electricity supply prices and avoided costs for Ohio. The projections are outputs from the electricity costing model that Synapse has developed for this project. The inputs to the model and the structure of the model are described above.

A.4.1 Reference Case Electricity Supply Prices

There reference case load forecast, load forecast, and supply prices are presented in Table 20. The supply forecast exceeds the load forecast by the level of estimated losses in transmission and distribution. The supply prices include the projected incremental generation costs each year, the retail margin each year and the resulting total average retail rate.

A.4.2. Avoided Electricity Costs

The avoided costs are presented in Table 21. The avoided capacity costs are presented in $/kW-year while the avoided electric energy costs are given in ¢/kWh.

Table 20. Reference Case Load, Supply and Price Forecasts

All costs in constant 2006 dollars.																		
CASE:	Ohio Reference Case - 1/16/09																	
Category	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load Forecast																		
Retail Energy	GWh	165,334	167,560	169,652	172,047	174,016	175,872	177,709	179,587	180,817	182,011	183,632	185,362	186,657	188,317	189,744	191,427	193,173
Retail Demand	MW	31,456	31,880	32,278	32,733	33,108	33,461	33,811	34,168	34,402	34,629	34,938	35,267	35,513	35,829	36,100	36,421	36,753
Supply Forecast																		
Capacity Requirement	MW	39,144	39,672	40,167	40,734	41,200	41,639	42,074	42,519	42,810	43,093	43,477	43,886	44,193	44,586	44,924	45,322	45,736
Capacity Sources																		
In-State Capacity	MW	33,842	33,586	33,900	34,278	34,753	36,543	36,377	36,918	37,275	37,531	37,827	38,230	38,612	38,877	39,290	39,565	39,969
Out-of-State Capacity	MW	5,302	6,086	6,267	6,456	6,447	5,096	5,698	5,601	5,535	5,562	5,650	5,656	5,581	5,709	5,634	5,757	5,767
Total Capacity Provided	MW	39,144	39,672	40,167	40,734	41,200	41,639	42,074	42,519	42,810	43,093	43,477	43,886	44,193	44,586	44,924	45,322	45,736
Energy Requirement	GWh	178,907	181,316	183,580	186,171	188,302	190,310	192,298	194,331	195,662	196,953	198,707	200,579	201,981	203,778	205,321	207,143	209,032
Energy Sources																		
In-State Generation	GWh	155,357	154,247	155,392	156,771	158,501	167,503	168,005	171,747	174,650	177,099	179,759	182,925	185,987	188,521	191,727	194,306	197,470
Out-of-State Generation	GWh	23,550	27,070	28,188	29,400	29,800	22,807	24,293	22,584	21,011	19,855	18,948	17,654	15,995	15,256	13,594	12,836	11,562
Total Energy Provided	GWh	178,907	181,316	183,580	186,171	188,302	190,310	192,298	194,331	195,662	196,953	198,707	200,579	201,981	203,778	205,321	207,143	209,032
Supply Price Forecast																		
Average Production Cost	¢/kWh	5.01	5.09	5.18	5.24	6.53	6.86	7.06	7.29	7.51	7.72	7.92	8.12	8.30	8.50	8.70	8.89	9.09
Retail Adder	¢/kWh	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42
Average Retail Rate	¢/kWh	7.43	7.51	7.60	7.66	8.95	9.28	9.48	9.71	9.93	10.14	10.34	10.54	10.72	10.92	11.12	11.31	11.51

Table 21. Reference Case Avoided Costs

All costs in constant 2006 dollars.																		
CASE:	Ohio Reference Case - 1/16/09																	
Category	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Avoided Costs by costing period																		
Avoided Resource Cost	¢/kWh	5.40	5.83	5.73	6.50	7.62	8.71	8.78	8.84	8.92	9.00	9.08	9.17	9.23	9.37	9.49	9.63	9.80
Avoided Capacity Cost	$/kW-yr	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23
	¢/kWh	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43
Avoided Energy Only Cost	¢/kWh	3.97	4.40	4.30	5.07	6.18	7.28	7.35	7.41	7.49	7.57	7.65	7.74	7.80	7.94	8.06	8.20	8.37

Notes: Avoided Resource Costs represent avoided production costs (fuel, O&M, CO_2) for all resources, plus levelized capital costs for new resources.
Avoided Capacity Cost in $/kw-yr is converted into an energy cost equivalent (c/kWh) using the system load factor.
Avoided Energy Cost represents Total Avoided Resource Cost less Avoided Capacity Cost expressed as energy cost equivalent.

A.5 Policy Case Electricity Supply Prices and Avoided Costs

This section presents Synapse's projections of *Policy Case* electricity supply prices and avoided costs for Ohio. The projections are outputs from the electricity costing model that Synapse has developed for this project as discussed above. ACEEE provided the Policy Case Load Forecast.

A.5.1. Policy Case Electricity Supply Prices

The Policy Case load forecast, supply forecast, and supply prices are presented in Table 22. The supply forecast exceeds the load forecast by the level of estimated losses in transmission and distribution. The supply prices include the projected incremental generation costs each year, the retail margin each year and the resulting total average retail rate.

A.5.2. Avoided Electricity Costs

The avoided costs are present in Table 21. The avoided capacity costs are presented in $/kW-year while avoided electric energy costs are given in ¢/kWh.

Table 22. Policy Case Load, Supply and Price Forecasts

All costs in constant 2006 dollars.																		
CASE:	**Ohio Policy Case - 3/10/09**																	
Category	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load Forecast																		
Retail Energy	GWh	164,884	166,312	167,280	168,382	168,889	169,108	169,299	169,528	169,117	168,675	166,959	165,374	163,380	161,788	160,009	158,514	157,114
Retail Demand	MW	31,371	31,642	31,826	32,036	32,133	32,174	32,211	32,254	32,176	32,092	31,765	31,464	31,084	30,782	30,443	30,159	29,892
Supply Forecast																		
Capacity Requirement	MW	39,038	39,376	39,605	39,866	39,986	40,038	40,083	40,137	40,040	39,935	39,529	39,154	38,682	38,305	37,884	37,530	37,198
Capacity Sources																		
In-State Capacity	MW	33,842	33,519	33,695	33,865	34,087	35,261	34,881	35,014	35,055	34,949	34,890	34,433	34,194	33,734	33,497	33,111	32,878
Out-of-State Capacity	MW	5,196	5,857	5,910	6,001	5,899	4,777	5,202	5,123	4,985	4,986	4,639	4,721	4,488	4,570	4,386	4,419	4,320
Total Capacity Provided	MW	39,038	39,376	39,605	39,866	39,986	40,038	40,083	40,137	40,040	39,935	39,529	39,154	38,682	38,305	37,884	37,530	37,198
Energy Requirement	GWh	178,421	179,966	181,013	182,206	182,754	182,992	183,197	183,445	183,001	182,523	180,666	178,950	176,793	175,070	173,145	171,528	170,012
Energy Sources																		
In-State Generation	GWh	155,356	154,009	154,658	155,292	156,106	162,272	161,747	163,558	164,934	165,638	166,507	165,554	165,561	164,564	164,581	163,915	163,954
Out-of-State Generation	GWh	23,065	25,956	26,355	26,914	26,649	20,720	21,450	19,887	18,067	16,885	14,159	13,397	11,232	10,506	8,564	7,612	6,058
Total Energy Provided	GWh	178,421	179,966	181,013	182,206	182,754	182,992	183,197	183,445	183,001	182,523	180,666	178,950	176,793	175,070	173,145	171,528	170,012
Supply Price Forecast																		
Average Production Cost	¢/kWh	5.02	5.09	5.17	5.22	6.51	6.80	7.00	7.22	7.44	7.63	7.83	8.01	8.19	8.37	8.55	8.73	8.92
Retail Adder	¢/kWh	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42	2.42
Average Retail Rate	¢/kWh	7.44	7.51	7.59	7.64	8.93	9.22	9.42	9.64	9.86	10.05	10.25	10.43	10.61	10.79	10.97	11.15	11.34

All costs in constant 2006 dollars.

CASE:	**Ohio Policy Case - 3/10/09**																	
Category	Units	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Avoided Costs by costing period																		
Avoided Resource Cost	¢/kWh	5.40	5.83	5.73	6.49	7.61	8.70	8.76	8.81	8.88	8.96	9.03	9.10	9.14	9.26	9.37	9.48	9.64
Avoided Capacity Cost	$/kW-yr	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23	75.23
	¢/kWh	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43
Avoided Energy Only Cost	¢/kWh	3.97	4.40	4.30	5.06	6.18	7.27	7.33	7.38	7.45	7.53	7.60	7.67	7.71	7.83	7.94	8.05	8.21

Notes: Avoided Resource Costs represent avoided production costs (fuel, O&M, CO2) for all resources, plus levelized capital costs for new resources.
Avoided Capacity Cost in $/kw-yr is converted into an energy cost equivalent (c/kWh) using the system load factor.
Avoided Energy Cost represents Total Avoided Resource Cost less Avoided Capacity Cost expressed as energy cost equivalent.

A.6. Responses to Questions Regarding the Avoided Cost Methodology

The process of vetting the methodology for our avoided cost analysis revealed the overall comment that "…it appears that some of the assumptions used in the analysis result in a relatively high avoided cost number." That overall comment is based upon comments regarding several specific assumptions. Following are our responses, *in italics*, to those each specific comments.

1) Basic Modeling Assumptions. Financial Parameters

a) The discount rate at (8%) seems low. Is it reflective of the new credit realities?

We use a nominal discount rate of 10% and a real discount rate of 7.32%. (There is an error on page 2 of the memo where a real rate of 5.85% is given.). We believe that these are reasonable assumptions for long-term planning.

b) Is an Allowance for Funds Used During Construction (AFUDC) for modifying the plant cost included in this analysis? As used in the calculation of installed plant capital cost, AFUDC represents the time value of money during construction and is based on an internal rate equal to the weighted cost of capital.

The installed plant cost, including construction financing, is converted into a levelized cost that appears in the market in the year the plant comes on line. We do not reflect any pre-operation construction expenses in earlier year costs or electricity prices.

3) Base Year Load and Resource Balance. Was the transmission transfer capability taken into account for the amount of imported resources?

Net imported/exported electricity is based on reference year data and thus consistent with the existing transmission system. We did not model or forecast projected changes in transmission transfer capability. Instead, our model assumes that future imports and exports will be at the same relative level as in the recent past and that transmission transfer capability will change in the future to match load growth and that level of relative imports and exports.

4) In-State Base Year Generation Resource Performance and Cost

a) Isn't the actual capacity factor shown for Coal low?

The capacity factor used is the historic average for all coal plants in the state. Some newer plants do much better, but because there is so much coal capacity in Ohio some older plants must cycle and follow load.

b) Does the dataset include any emission rate and allowance cost data for SO_2?

The data includes average historic emission rate data for all pollutants. Emission allowance costs for pollutants, other than CO_2*, are reflected in the O&M costs.*

5) New Generation Resource Performance and Cost

a) Is the Total Plant Cost ($/kW) overnight or installed? Does the capital cost reflect and transmission upgrades or retrofits for CO_2 control equipment?

Total plant cost is "installed," including construction interest. No CO_2 *retrofit costs are assumed other than the allowance cost of* CO_2 *emissions.*

b) Isn't the Capital Levelization Factor rather low considering the high discount rate (10%)?

The Capital Levelization Factor is reasonable since it is expressed in real dollars.

c) Are the total fixed costs of each new capacity option adjusted by its equivalent availability in order to account for differing availabilities (including seasonal derates) among the options.

Fixed costs of new capacity are allocated over its generation based on the operating capacity factor of the new resource, not its availability factor.

8) Capacity Retirements in-State. Do the projected retirements reflect any of the generation retirements (Future Deactivation) posted on the PJM website?

We have attempted to reflect those listings as well as to take into consideration the aging of plants in future years. But that all is very uncertain and has only minor effects on avoided costs per se.

9) Capacity Additions In-State

a) Are the active generation queues considered as well as the PJM Interconnection Queue that is used as a guide for the new generation capacity mix.

Yes we have tried to do so, along with the addition of some additional future coal resources to reflect conditions in MISO and in Ohio in general.

b) For the renewables, will they be based on the Ohio Renewable Portfolio Standard (enacted 5/1/2008 and effective 1/1/2009) for a target of 12.5% by year 2024?

We have done so based on our understanding of that standard.

10) Fuel Prices. Aren't the fuel prices used lower than the consensus of industry and consultants' recent forecasts?

In general the price forecasts are basically long-term reflecting underlying conditions as presented in the Annual Energy Outlook of 2008 (Table 64). We have however updated those AEO forecasts of natural gas and crude oil prices based on market conditions as of 11/13/2008.

APPENDIX B – ENERGY EFFICIENCY POLICY ANALYSIS

B.1. Electricity Savings, Peak Demand Reductions, and Costs from Policy Analysis

Table 23. Electricity Savings from Policy Analysis

	Annual Electricity Savings by Policy (GWh)	2010	2015	2020	2025	Total Savings in 2025 (%)*
	Innovative Programs & Policies					
1	Efficient Homes Initiative	4	119	327	615	0.4%
2	State-level Appliance Standards	23	593	1,423	2,003	1.3%
3	Building Energy Codes		343	880	1,707	1.1%
4	Commercial Buildings Initiative	10	133	361	715	0.5%
5	State Facilities	239	837	1,434	2,032	1.3%
6	CHP	87	1,072	2,366	3,238	2.1%
7	Manufacturing Initiative	51	1,721	3,746	5,771	3.7%
8	Rural and Ag. Initiative	9	57	106	155	0.1%
	Innovative Program & Policy Savings	**424**	**4,876**	**10,644**	**16,235**	**10.3%**
9	*Proven Utility Programs*					
	Residential	480	2,078	5,410	11,328	7.2%
	Commercial	392	1,701	4,426	9,268	5.9%
	Proven Utility Program Savings	**872**	**3,779**	**9,836**	**20,596**	13.1%
	Total Savings (Policy + Program)	**1,295**	**8,655**	**20,480**	**36,831**	**23.4%**
	Adjusted Electricity Forecast (GWh)	**166,312**	**169,299**	**165,374**	**157,114**	
	Savings (% Reduction in Reference Case)	**0.8%**	**4.9%**	**11.0%**	**19.0%**	

Notes

***** Percent relative to adjusted reference case forecast

1 Initiative broken down into programs for existing homes and new construction. Existing homes program assumes 0.5% savings throughout the analysis period and 1% participation rate in first year, with participation increasing by 1% annually. Savings from new construction assumes 50% savings beyond current code (IECC 2006), thereby decreasing with the adoption of new energy codes except in 2020, where we assume program implementation and participation has matured to allow for savings beyond the 50% savings from IECC 2018. In 2011 we assume an initial participation rate of 2.5%, doubling annually until 2014, when IECC 2012 becomes effective. We then assume a participation rate of 20% for the remainder of the analysis period. In 2020, when IECC 2018 becomes effective, delivering 50% savings, we assume 20% additional savings beyond IECC 2018 are achievable

2 Appliance and equipment efficiency standards were adopted at the federal level in the 2007 energy bill, which also directed DOE to set standards for additional products in the coming years. This Scenario assumes savings from these standards, which are not taken into account in the reference case load forecast. Savings and cost assumptions are from a forthcoming ACEEE and ASAP standards analysis.

3 We assume IECC 2009 is adopted, which goes into effect 2011, the IECC 2012 is adopted and goes into effect in 2014, and the IECC 2018, effective 2020. We estimate that these codes achieve a 15%, 30%, and 50% energy savings improvement beyond IECC 2006 requirements, respectively. Savings apply only to end-uses covered under building codes, which are HVAC, lighting, and water heating end-uses, or 50% of electricity consumption in new residential construction and nearly 60% of electricity consumption in commercial buildings. We assume enforcement of each code starts at 70% compliance in the first year, 80% in second year, and 90% in the third and subsequent years. Buildings analysis shows $0.47 per kWh investment cost for new ENERGY STAR homes, which achieve 15% savings, and $0.32 per kWh for new commercial buildings meeting 15% and 30% beyond code. We assume $1.5 million dollars per year to implement and enforce codes, based on recommendations in New York (NY DPS 2007). This is similar to estimates in VA that new program costs run 2-3% of building costs.

4 Initiative broken down into programs for existing buildings and new construction. Existing buildings program assumes 1% savings throughout the analysis period and 1% participation rate in first year, with participation increasing by 1% annually. We assume that 68.5% of total commercial electric floorspace is non-governmental buildings, to avoid double-counting savings attributable to state facilities program (CBECS 2003, table C17). Savings from new construction assumes 50% savings beyond current code (IECC 2006), thereby decreasing with the adoption of new energy codes except in 2020, where we assume program implementation and participation has matured to allow for savings beyond the 50% savings from IECC 2018. In 2011 we assume an initial participation rate of 2.5%, doubling annually until 2014, when IECC 2012 becomes effective. We then assume a participation rate of 20% for the remainder of the analysis period. In 2020, when IECC 2018 becomes effective, delivering 50% savings, we assume 20% additional savings beyond IECC 2018 are achievable.

5 We estimate 31.5% of total electric commercial floorspace is government buildings, from EIA (CBECS 2003, table C17). We then assume a savings rate of 20% and a participation rate of 50% over the period of the analysis.

6 We assume a $500 incentive per MW for CHP facilities.

7 This scenario assumes that the number of industrial assessments ramps up from 50 to 200 in first three years, that each assessment identifies 15% electricity savings, and that 50% of identified savings are implemented. Project costs assume the average investment cost per kWh from the industrial sector analysis ($0.28/kWh) and program cost is assumed to be 12.5% of projected cost savings to the end-user.

8 Based on similar programs and values from the State of Wisconsin Focus on Energy 2007 Semiannual Report, we assume the average cost of conserved energy at $0.025/kWh, that program & administrative costs are 24% of the cost of investment, and that customers cover half of the investment cost.

9 Savings for proven programs are the difference between EERS requirements and policy savings. Sector savings are then allocated based on the contribution to economic potential savings of the residential and commercial sectors.

Table 24. Summer Peak Demand Reductions from Policy Analysis (MW)

Sector	2010	2015	2020	2025	Total Savings in 2025 (%)
Residential	104	637	1,771	3,801	10%
Commercial	56	328	687	1,121	3%
Industrial	26	585	1,349	2,159	5%
Total Savings (MW)	**186**	**1,550**	**3,807**	**7,081**	**18%**
% Reduction (relative to forecast)	**0.5%**	**4%**	**10%**	**18%**	

Table 25. Total Resource Costs* from the Policy Analysis (Million 2006$)

By Policy/Program	2010	2015	2020	2025
Innovative Programs & Policies				
Efficient Homes Initiative	$ 1	$ 17	$ 22	$ 27
State-level Appliance Standards	$ 26	$ 64	$ 64	$ 64
Building Energy Codes	$ -	$ 42	$ 57	$ 76
Commercial Buildings Initiative	$ 3	$ 15	$ 26	$ 40
State Facilities	$ 22	$ 22	$ 22	$ 22
CHP	$ 14	$ 124	$ 169	$ 218
Manufacturing Initiative	$ 16	$ 115	$ 115	$ 115
Rural and Ag. Initiative	$ 0.3	$ 0.3	$ 0.3	$ 0.3
Proven Utility Programs				
Residential	$ 92	$ 91	$ 397	$ 507
Commercial	$ 44	$ 43	$ 188	$ 242
Total	**$ 219**	**$ 533**	**$ 1,062**	**$ 1,312**

*Note: Total Resource Costs include total investments in energy efficiency, whether made by customers or through incentives, plus program and administrative costs.

Figure 22. Incremental Annual Savings Requirements from EERS (% and GWh)

	2009	2010	2011	2012	2013	2014	2015
Efficient Homes Initiative	1	3	8	15	27	32	34
State-level Appliance Standards	-	23	46	46	116	186	178
Building Energy Codes	-	-	60	54	54	82	93
Commercial Buildings Initiative	3	7	16	20	25	29	33
State Facilities	120	120	120	120	120	120	120
CHP	-	87	29	29	309	309	309
Manufacturing Initiative	-	51	152	304	405	405	405
Rural and Ag. Initiative	-	9	9	10	10	10	10
Policy Savings	**124**	**299**	**439**	**596**	**1,064**	**1,172**	**1,181**
Savings as Percent of Forecasted Sales	**0.08%**	**0.18%**	**0.27%**	**0.36%**	**0.63%**	**0.68%**	**0.68%**
Proven Utility Programs							
Residential	195	285	394	403	243	280	279
Commercial	159	233	322	330	199	229	228
Utility Program Savings	**354**	**518**	**715**	**733**	**442**	**510**	**507**
Total Savings (Policy+Progam)	**479**	**817**	**1,155**	**1,329**	**1,506**	**1,682**	**1,688**
EERS Annual Savings Requirements (%)	0.30%	0.50%	0.70%	0.80%	0.90%	1%	1%
EERS Incr. Annual Svgs. Requirements (GWh)	**479**	**817**	**1,155**	**1,329**	**1,506**	**1,682**	**1,688**
Difference (%)	0.2%	0.3%	0.4%	0.4%	0.3%	0.3%	0.3%
Difference (GWh)	**354**	**518**	**715**	**733**	**442**	**510**	**507**

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Efficient Homes Initiative	35	38	42	45	48	51	54	57	61	64
State-level Appliance Standards	170	170	169	169	152	152	152	116	80	80
Building Energy Codes	104	108	103	95	127	151	169	164	166	176
Commercial Buildings Initiative	37	42	46	48	54	60	65	70	76	83
State Facilities	120	120	120	120	120	120	120	120	120	120
CHP	309	309	225	225	225	225	225	141	141	141
Manufacturing Initiative	405	405	405	405	405	405	405	405	405	405
Rural and Ag. Initiative	10	10	10	10	10	10	10	10	10	10
Policy Savings	**1,190**	**1,202**	**1,119**	**1,117**	**1,141**	**1,173**	**1,200**	**1,082**	**1,058**	**1,077**

0.68%	**0.68%**	**0.62%**	**0.62%**	**0.62%**	**0.64%**	**0.65%**	**0.58%**	**0.56%**	**0.57%**
276	270	316	1,246	1,223	1,192	1,157	1,203	1,197	1,169
226	221	258	1,019	1,001	975	947	985	979	956
501	**492**	**574**	**2,265**	**2,224**	**2,167**	**2,105**	**2,188**	**2,177**	**2,125**
1,691	**1,693**	**1,693**	**3,382**	**3,365**	**3,340**	**3,305**	**3,270**	**3,235**	**3,202**
1%	1%	1%	2%	2%	2%	2%	2%	2%	2%
1,691	**1,693**	**1,693**	**3,382**	**3,365**	**3,340**	**3,305**	**3,270**	**3,235**	**3,202**
0.3%	0.3%	0.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%
501	**492**	**574**	**2,265**	**2,224**	**2,167**	**2,105**	**2,188**	**2,177**	**2,125**

B.2. Carbon Dioxide Emissions Reductions

To estimate annual regional emissions reductions, we first took data on projected electricity generation and carbon dioxide emissions over the 2008-2025 period for the East Central Area Reliability Coordination Agreement (ECARC) region as reported by the *Annual Energy Outlook* (EIA 2007c). We then calculated an *output emission rate*, defined as the ratio of emissions (lbs) to electricity generation (MWh). Using data from the Emissions and Generation Resource Integrated Database (eGRID) on subregional emissions rates and converting to standard tons (EPA 2007a), we calculated a *net marginal emissions factor* (ton/MWh), which is our *output emissions rate* multiplied by the ratio of marginal to average emissions rate. We then took out *emissions factor* and multiplied Ohio's estimated electricity savings (GWh) from the Policy Analysis in order to determine the regional *carbon dioxide emissions savings* for the 17-year period.

APPENDIX C – ENERGY EFFICIENCY RESOURCE ASSESSMENT

C.1. Residential Buildings

C.1.1. Overview of Approach

We analyzed thirty-six electricity efficiency measures for existing residential buildings, which are grouped by end-use (HVAC, water heating, refrigeration, appliances, lighting, furnace fans, and plug loads) and three measures for new residential buildings (see Table 25). For each measure, we estimated average measure lifetime, electricity savings (kWh) and costs per home upon replacement of the product or retrofitting of the measure. For a replacement-on-burnout measure,[59] the cost is the incremental cost of the efficient technology compared to the baseline technology. For retrofit measures, where existing equipment is not being replaced, such as improved insulation and infiltration reduction, the cost is the full installation cost of the measure. For measures modeled as replacement-on-burnout, the baseline is set according to the current market for that product, so the baseline efficiency is the minimum efficiency standard of that product. For measures modeled as retrofit, the baseline efficiency is that of estimated energy use in existing Ohio homes.

A measure is determined to be cost-effective if its levelized cost of saved energy, or cost of conserved energy (CCE), is less than $0.1101/kWh, the current average residential cost of electricity in Ohio (EIA 2008a). Estimated levelized costs for each efficiency measure, which assume a discount rate of 5%, are shown in Table 25. Equation one shows the calculation for cost of conserved energy.

Equation 1. *CCE = PMT ((Discount Rate), (Measure Lifetime), (Measure Cost)) / (Annual Savings per Measure (kWh))*

[59] In a replacement-on-burnout scenario, a consumer purchases the more efficient product at the time of replacement of that product.

Table 25. Residential Energy Efficiency Measure Characterizations

Measures	End-Use Category	Annual savings per household (kWh)	Cost of Saved Energy ($/kWh)	Pass Cost-Effective Test?	% Turnover	Adjustment Factor	Interaction Factor	% End Use Savings	Total Savings in 2025
Existing Building					**2025**		**2025**	**2025**	
Seal Ductwork	HVAC (load)	753	$ 0.0799	yes	85%	30%	100%	8%	1,013
Insulate Ductwork, R-8	HVAC (load)	602	$ 0.0318	yes	68%	43%	92%	7%	855
Infiltration reduction	HVAC (load)	753	$ 0.0128	yes	100%	44%	85%	12%	1,485
Insulation, ceiling, R-11 to R-38	HVAC (load)	703	$ 0.0077	yes	85%	28%	71%	5%	623
Insulation, ceiling, R-19 to R-38	HVAC (load)	314	$ 0.0172	yes	85%	41%	71%	3%	409
Blow-in wall insulation	HVAC (load)	1,129	$ 0.0140	yes	57%	15%	60%	2%	299
Estar Window, from single pane	HVAC (load)	3,794	$ 0.0077	yes	57%	15%	56%	7%	951
Estar Window, from double pane	HVAC (load)	596	$ 0.0491	yes	57%	55%	56%	4%	551
Cool Roof shingles	HVAC (load)	271	$ 0.0415	yes	85%	78%	36%	3%	339
HVAC Load Reducing Measures								**51%**	
Central HP (heating cycle); HSPF 9	HVAC (equip.)	2,823	$ 0.0303	yes	94%	5%	49%	2%	316
GSHP w/ desuperheater (14 EER)	HVAC (equip.)	2,530	$ 0.0812	yes	94%	1%	49%	0%	42
Central AC (cooling cycle) SEER 15	HVAC (equip.)	624	$ 0.0127	yes	94%	63%	49%	8%	975
ENERGY STAR Dehumidifier	HVAC (equip.)	213	$ 0.0159	yes	100%	6%	49%	0%	33
ENERGY STAR Room A/C (CEE Tier 2, 11.8 EER)	HVAC (equip.)	85	$ 0.0378	yes	100%	26%	49%	0%	57
Ceiling Fan (including light kit)	HVAC (equip.)	243	$ 0.0709	yes	100%	49%	49%	2%	310
HVAC Equipment Measures								**13%**	
TOTAL HVAC								**64%**	**8,259**
High-efficiency showerheads	Water Heating	234	$ 0.0127	yes	100%	60%	100%	17%	740
Faucet aerators	Water Heating	47	$ 0.0194	yes	100%	65%	100%	4%	160
Water heater pipe insulation	Water Heating	65	$ 0.0460	yes	100%	88%	100%	7%	302
H-axis clothes washer (2.0 MEF) (water heating)	Water Heating	232	$ 0.0640	yes	100%	65%	100%	19%	796
Dishwasher (Electric WH; 0.72 EF) (water heating)	Water Heating	37	$ 0.0647	yes	100%	85%	100%	4%	166
Efficient electric water heater (0.93 EF)	Water Heating	113	$ 0.0625	yes	100%	7%	53%	1%	23
Heat pump water heater (COP = 2.0)	Water Heating	2,103	$ 0.0427	yes	100%	12%	53%	16%	676
Water Heating Savings								**68%**	**2,864**
Refrigerator (20%)	Refrigeration	114	$ 0.0465	yes	89%	75%	100%	7%	404

Measures	End-Use Category	Annual savings per household (kWh)	Cost of Saved Energy ($/kWh)	Pass Cost-Effective Test?	% Turnover	Adjustment Factor	Interaction Factor	% End Use Savings	Total Savings in 2025
Refrigerator (25%)	Refrigeration	29	$ 0.0929	yes	89%	98%	100%	2%	132
Refrigeration Savings								**9%**	**536**
CFL, Advanced Incandescent Replacements	Lighting	1,005	$ (0.0032)	yes	100%	90%	100%	58%	4,774
Lighting Savings								**58%**	**4,774**
H-axis clothes washer (2.0 MEF)	Appliances	26	$ 0.0774	yes	100%	65%	100%	3%	89
Dishwasher (Electric WH; 0.68 EF)	Appliances	11	$ 0.0761	yes	100%	85%	100%	1%	49
Appliances Savings								**4%**	**139**
Efficient Furnace Fan (Heating Season)	Furnace Fans	367	$ 0.0473	yes	100%	67%	100%	41%	1,299
Efficient Furnace Fan (Cooling Season)	Furnace Fans	182	$ 0.0471	yes	100%	67%	100%	20%	646
Furnace Fan Savings								**61%**	**1,945**
ENERGY STAR Version 3.0 Television Spec.	Plug Loads	52	$ 0.0947	yes	100%	74%	100%	1%	50
Set-Top Box Power Reduction	Plug Loads	120	$ 0.0293	yes	100%	58%	100%	3%	90
1-watt standby power	Plug Loads	264	$ 0.0196	yes	100%	66%	100%	7%	920
Total Plug Load Savings								**11%**	**1,060**
In-home energy feedback monitor	All	525	$ 0.0573	yes	100%	79%	66%	3%	1,460
New Construction Building Measures									
New home 15% better than code (ENERGY STAR home)	New Construction	1,172	$ 0.0447	yes	100%	17%	100%	2%	66
New home 30% better than code (Proposed Building Code)	New Construction	2,345	$ 0.0411	yes	100%	35%	100%	8%	301
New home 50% better than code (Tax-credit-eligible)	New Construction	3,908	$ 0.0462	yes	100%	47%	100%	18%	669
New Homes Subtotal									**1,036**

C.1.2. Existing Buildings

To estimate the efficiency resource potential in existing homes in Ohio by 2025, we first adjusted individual measure savings by an *Adjustment Factor*. This factor accounts for the technical feasibility of efficiency measures (the percent of Ohio homes that satisfy the base case conditions and other technical prerequisites such as number of household members, heating fuel type, etc.) and the current market share of products that already meet the efficiency criteria. These assumptions are made explicit in Table 25.

We then adjusted savings from the improved building envelope (insulation, windows, infiltration reduction, and duct sealing) to account for the reduced heating and cooling loads imparted by each of the envelope measures. Then we adjusted HVAC equipment savings to account for savings already realized from the reduced loads. Similarly, we adjusted water heating equipment savings to account for reduced water heating loads from the use of more efficient clothes washers, low-flow shower heads, water heater pipe insulation, and faucet aerators. The multiplier for these adjustments is called the *Interaction Factor.*

We then adjusted replacement measures with lifetimes more than 17 years to only account for the percent turning over in 17 years, which represents the time period of the analysis. Note that the multiplier, *Percent Turnover,* is only applicable to products being replaced upon burnout and not retrofit measures such as insulation and duct sealing and testing. These retrofit measures therefore have 100% of measures "turning over."

Equation 2 shows our calculation for efficiency resource potential, incorporating the three factors discussed above:

Equation 2. *Efficiency Resource Potential = ∑ (Annual Savings per Measure (kWh))* x *(Percent Turnover) x (Adjustment Factor)* x *(Interaction Factor)*

To calculate the efficiency resource potential savings by end-use in 2025, we present the savings as a percent of end-use electricity consumption (assuming current electricity consumption by end-use from AEO 2007). For the non-HVAC savings, we then multiply the "% savings" by projected residential electricity consumption for that end-use in 2025 to estimate the total savings potential in that year (see Equation 2). We assume that savings in the residential new construction sector cover projected new HVAC consumption, and therefore multiply the HVAC "% savings" by 2008 electricity consumption of this end use. See Equation 3 for a summary of how we derive the savings estimate for existing residential buildings.

Equation 3. *Efficiency Resource Potential by end-use in 2025 (GWh) = (% End-Use Savings)* x *(Electricity Consumption by sector in 2025* (GWh))*
* 2008 for HVAC

New Construction

We estimate savings from new construction in a similar manner as existing home measures. We looked at three levels of efficiency in new homes: 15%, 30%, and 50% better than current energy code. In estimating new home energy savings, we use a similar approach as building codes, which address HVAC consumption only. We estimated *% Applicable* by allocating each home into one of the three bins, with 15% predominating the early years and 50% the later years. See Equation four for a summary of how we calculate savings in new construction.

Equation 4. *Efficiency Resource Potential in 2025 (GWh) = (% HVAC savings per home) x (Percent Applicable) x (Projected new HVAC consumption between 2008 and 2025 (GWh))*

C.1.3. Efficiency Measures

In-home energy feedback monitor

Measure Description: A device installed inside the home that communicates with the electric meter and displays real-time electricity use information to occupants.

Basecase: Average metered home with no feedback mechanism other than monthly utility bills

Data Explanation: Total households applicable (80%) from RECS 2005 (EIA 2008). Baseline electricity consumption is for an average household excluding multifamily buildings above four units from RECS (EIA 2008). Cost includes cost of product ($150) plus one hour of installation from Parker 2006. Percent savings (10%) from Stein 2004 and Hydro One 2006. Useful life (11 years) assumed to be similar to programmable thermostat, from ACEEE 2006. Penetration in residential sector technically achievable in all metered residential units.

Duct Sealing

Measure Description: Professional duct-sealing service suitable for retrofits and new construction, involving testing and either hand-applied or aerosol-based mastic (Jump 2006).

Basecase: Single-family home with a forced-air furnace and air conditioner.

Data Explanation: Baseline energy use from RECS (EIA 2008) depending on primary fuel use, plus a 25% adder representing high-use homes. Savings (10%) in each season (cooling and heating) is derived from 80% reduction in duct leakage (Jump 1996), which comprises half of the 20% of total HVAC energy use that can be associated with duct-related energy losses (the other half being by conduction [Hammurlund 1992; Proctor 1993]). A cost of $750 is mature-market cost of Aeroseal, from Bourne et al 1999. Applies to top 50% of residential homes with forced-air systems. Measure life is 20 years (SWEEP 2002)

Duct Insulation

Measure Description: R8 insulation applied to exposed ductwork in unconditioned spaces.

Basecase: Single-family home with a forced-air furnace and air conditioner with uninsulated ductwork passing through un-conditioned space (attic, un-finished basement, garage)

Data Explanation: Baseline energy use from RECS 2005 (EIA 2008) depending on primary fuel use, plus a 25% adder representing high-use homes. Savings from SWEEP, based on 10% heating/cooling energy use in forced-air system associated with conductive duct losses. Cost are $0.15–$0.20 per square foot of floor area. Floor area (1800 sq. ft) based off average floor area of colonial and ranch single family detached from ACEEE 1994. Applies to top 50% of residential homes with forced-air systems. Useful life is 25 years (SWEEP 2002).

Blower-Door Aided Infiltration Reduction

Measure Description: Application of foam and/or caulk around leakage areas applied and tested by a professional using a blower-door.

Basecase: Household with higher-than average heating and cooling energy use.

Data Explanation: Baseline energy use from RECS (EIA 2008) depending on primary fuel use, plus a 25% adder representing high-use homes. Savings of 10% from MT Screening Reports. Cost of $0.46/s.f. from XENERGY 2001. Useful life of 10 years from SWEEP 2002. Savings applied to percentage of homes that report drafts (44%), from RECS (EIA 2008).

Attic Insulation

Measure Description: Add insulation in attic floor to R-38.

Basecase: R-11assumed for houses reported to be "well insulated."

Data Explanation: Savings average of colonial and ranch savings for R11-R30 attic insulation from NYSERDA 1994, increased by multiplier (1.09) to incorporate savings from upgrading to R38. Total households applicable (28%) average from RECS 2008 for house that are "well insulated" and houses that are "not well insulated" (EIA 2008). Baseline energy use from RECS 2005 (EIA 2008) depending on primary fuel use, plus a 25% adder representing high-use homes. Cost of $0.70/s.f. from DEER database (CEC 2005a). Assumes 1000 s.f. of insulation needed. Useful measure life of 20 years from NYSERDA (2003).

Attic Insulation

Measure Description: Add insulation in attic floor to R-38.

Basecase: R-19 assumed for houses reported to be "well insulated."

Data Explanation: Savings average of colonial and ranch savings for R19-R30 attic insulation from NYSERDA 1994, increased by multiplier (1.34) to incorporate savings from upgrading to R38. Total households applicable (41%) from RECS 2008 for house that are "well insulated" (EIA 2008). Baseline energy use from RECS 2005 (EIA 2008) depending on primary fuel use, plus a 25% adder representing high-use homes. Cost of $0.70/s.f. from DEER database (CEC 2005a). Assumes 1000 s.f. of insulation needed. Useful measure life of 20 years from NYSERDA 2003.

Blow-in Cellulose Wall Insulation

Measure Description: Add blow-in cellulose insulation to un-insulated wall cavities

Basecase: Average-sized single-family home with wood-frame construction built before 1970.

Data Explanation: Total households applicable (15%) from RECS 2008 for houses that are "not well insulated" (EIA 2008). Baseline energy use from RECS 2005 (EIA 2008), depending on primary fuel use, plus a 25% adder representing high-use homes. Savings of 15% and 1700 s.f. of uninsulated wall space are based on average of colonial and ranch single-family detached house types from 1994 ACEEE study on Gas EE opportunities in Long Island. Cost of $1.32/s.f. (unit and installation cost) from DEER database (CEC 2005a). Useful measure life of 30 years from NYSERDA 2003.

Cool Roof Shingles

Measure Description: Roof shingles that meet ENERGY STAR residential requirements for reflectivity and thermal emittance due to light color or other material properties.

Basecase: Standard high-pitched residential roof with dark asphalt shingles

Data Explanation: Baseline electricity reflects cooling load only, from RECS 2005 (EIA 2008). Savings of 20% of cooling load and cost ($.10/s.f.) are from ACEEE Emerging Technologies analysis (Sachs et al 2004). Roof area (1400 sq. ft) based off assumption of 1000 sq. ft for attic area, multiplied by 1.4 (roof area generally 1.4 times greater than the area of the attic). Percent of homes applicable (86%) are the percent of households with asphalt shingles, from Dejarlais 2006 presentation (CEE Cool Roofs workshop). Market share (10%) and measure life (20 years) are from Sanchez et al. 2007.

ENERGY STAR Windows

Measure Description: Window replacements that meet regional ENERGY STAR requirements for U value and solar heat gain coefficient (SHGC).

Basecase: Replacement of 20 *single-pane* windows measuring approximately 15 s.f. each.

Data Explanation: Baseline energy use from RECS 2005 (EIA 2008). Savings (36%) from ratio of U-values associated with upgrading from single pane (U-value = 1.10) to ENERGY STAR (U-value = .40), from Lekcie et al. 1981. Number of units (20) from ACEEE 2006. Incremental cost assumes 300 sq. ft. of windows at $1.50 per sq. ft. (NEEP 2006). Measure life (30) from SWEEP 2002. Percent of applicable households (50%) based on ENERGY STAR market share data.

ENERGY STAR Windows

Measure Description: Window replacements that meet regional ENERGY STAR requirements for U value and solar heat gain coefficient (SHGC).

Basecase: Replacement of 20 *double-pane* windows measuring approximately 15 s.f. each.

Data Explanation: Baseline energy use from RECS 2005 (EIA 2008). Savings (9%) from ratio of U-values associated with upgrading from double pane (U-value = .49) to ENERGY STAR (U-value = .40), from Lekcie et al. 1981. Number of units (20) from ACEEE 2006. Incremental cost assumes 300 sq. ft. of windows at $1.50 per sq. ft. (NEEP 2006).

Measure life (30) from SWEEP 2002. Percent of applicable households (50%) based on ENERGY STAR market share data.

High-efficiency Central Air Conditioner (cooling only)
Measure Description: SEER 15

Basecase: Current federal standard: SEER 13

Data Explanation: Baseline consumption from RECS 2005 (EIA 2008). Percent savings (27%) and incremental cost from ENERGY STAR calculator for Central Air Conditioners using Columbus, OH, as a proxy. Assumed not to be used in conjunction with programmable thermostat. Market share (9%) from Sanchez et al. 2007, assumed to be half of market share for ENERGY STAR qualified unit with SEER = 15. Percent applicable (64%) equivalent to households with central AC, with and w/o heat pump (EIA 2003). Measure life (18 years) from DOE TSD (DOE 2001).

High-efficiency Heat Pump (heating only)
Measure Description: HSPF 9

Basecase: Current federal standard: HSPF 7.7

Data Explanation: Baseline consumption from RECS 2005 (EIA 2008). Percent savings (22%) and incremental cost ($1000) from ENERGY STAR calculator for Air-Source Heat Pumps using Richmond, VA, as a proxy and apportioned based on heating hours for Richmond, VA. Assumed not to be used in conjunction with programmable thermostat. Market share (11%) from Sanchez et al. 2007, assumed to be half of market share for ENERGY STAR qualified unit with HSPF = 8.2. Measure life (18 years) from DOE TSD (DOE 2001).

Efficient Furnace Fan (heating season)
Measure Description: High efficiency, ECM fan

Basecase: PSC fan

Data Explanation: Baseline electricity consumption from Lutz (2004), accounting for parasitics and adjusted by ratio of national to state HDD. Percent applicable (75%) equivalent to sum of households with forced air systems (EIA 2008). Electricity savings (425 kWh, 41%) from Pigg (2003) and adjusted by ratio of national to state HDD. Incremental costs ($200) from Sachs & Smith 2004, apportioned by ratio of national to state CDD ($161), although report notes that incremental costs will drop to $25-$45 upon market maturity. Incremental costs apportioned for heating season from ratio of heating season savings to total annual savings.

Efficient Furnace Fan (cooling season)
Measure Description: High efficiency, ECM fan

Basecase: PSC fan

Data Explanation: Baseline electricity consumption from Lutz (2004), accounting for parasitics and adjusted by ratio of national to state CDD. Percent applicable (58%) equivalent to sum of households with forced air systems (EIA 2003). Electricity savings (103 kWh, 21%) from Pigg (2008) and adjusted by ratio of national to state CDD ($39). Incremental costs ($200) from Sachs & Smith 2004, apportioned by ratio of seasonal savings, although report notes that incremental costs will drop to $25-$45 upon market maturity. Incremental costs apportioned for cooling season from ratio of cooling season savings to total annual savings.

Ground-Source Heat Pump
Measure Description: Closed ground-source heat pump with EER 14.

Basecase: Conventional air-source heat pump of SEER 13, HSPF 7.7

Data Explanation: Baseline energy use (for homes with electricity as primary fuel multiplied by 2 for high-use homes) and market penetration (of heat pumps) from RECS 2001(EIA 2003). New measure savings (21%) and cost ($2400) from ACEEE Emerging Technologies analysis (Sachs 2007). Analysis assumes technical feasibility in 10% of houses with forced-air electric heat (0.3%). Measure life (18 years) from Sachs 2007.

Ground-Source Heat Pump with Desuperheater (space heating)
Measure Description: HSPF 14

Basecase: Current federal standard: HSPF 7.7

Data Explanation: Total households applicable 1% (10% of house with electric heat and ducts) from RECS 2005 (EIA 2008). New measure savings (21%) and cost ($1,000 per ton) from ACEEE Emerging Technologies analysis (Sachs 2007). Analysis assumes technical feasibility in 10% of houses with electric forced-air heat (0.3%). Measure life (18 years) from Sachs 2007.

Ground-Source Heat Pump with Desuperheater (water heating only)
Measure Description: HSPF 9

Basecase: Current federal standard: HSPF 7.7

Data Explanation: Baseline energy use and market penetration (of heat pumps) from RECS 2005 (EIA 2008). New measure savings (25%) and cost ($1,000 per ton) from ACEEE Emerging Technologies analysis (Sachs 2007). Analysis assumes technical feasibility in 10% of houses with electric forced-air heat (0.3%). Measure life (18 years) from Sachs 2007.

Efficient Electric Storage Water Heater
Measure Description: 50-gallon electric storage water heater, 0.93 EF

Basecase: Current federal standard for typical, 50-gallon electric storage water heater, 0.90 EF

Data Explanation: Baseline consumption from GAMA water heater directory. Savings (3%) derived from EF increase. Incremental cost ($70) from Amann et al. 2007. Measure life (14 years) from NYSERDA 2003. Percent applicable (29%) equivalent to houses with electric water heaters (EIA 2003). Market share (36%) estimated based on percent of products on the market meeting EF 0.93 in the GAMA product database (GAMA 2007).

Heat Pump Water Heater
Measure Description: Either add-on or integrated heat-pump that uses the evaporation-compression cycle to extract heat from surrounding air to heat water in a conventional storage tank. COP 2.0 or above.

Basecase: Current federal standard for typical, 50-gallon electric storage water heater, 0.90 EF

Data Explanation: Baseline consumption from GAMA water heater directory. Percent applicable (10%) equivalent to households with electric water heaters multiplied by percentage of households that have three or more occupants (EIA 2008). Percent Savings (60%) and measure life (14.5 years) are from Sachs, et al 2004. Incremental cost ($910) based off electric heat pump with COP=2.2, from Amann et al. 2007 (Consumer Guide).

High-efficiency showerheads
Measure Description: 2.0 gallons per minute (gpm) showerhead

Basecase: Assumes electric water heater meeting current federal standard (see Electric Storage Water heater above). Showerhead meets federal requirements of 2.5 gpm

Data Explanation: Baseline consumption from RECS 2005 (EIA 2008) depending on primary water heating fuel. Savings (10%) from Brown et al. 1987. Cost estimate ($23) for a low-cost, basic model from the DEER database (CEC 2005a). Useful measure life of 9 years from Efficiency Vermont 2005. Percent of households applicable (29%) is percentage of households with electric water heating (EIA 2003).

Faucet Aerators
Measure Description: 1.5 gallons per minute (gpm) faucet aerator

Basecase: Assumes electric water heater meeting current federal standard (see Electric Storage Water heater above). Baseline aerator meets federal requirements of 2.5 gpm

Data Explanation: Baseline consumption from RECS 2005 (EIA 2008) depending on primary water heating fuel. Savings (2%) from Frontier Associates (2006). Cost estimate ($7) for a low-cost, basic model from the DEER database (CEC 2005a). Percent of homes applicable (29%) is percentage of households with electric water heating (EIA 2003).

Water Heater Pipe Insulation
Measure Description: Insulating 10 feet of exposed pipe in unconditioned space, ¾" thick.

Basecase: Assumes electric water heater meeting current federal standard (see Electric Storage Water heater above).

Data Explanation: Baseline consumption from RECS 2005 (EIA 2008) depending on primary water heating fuel. Savings estimate from CL&P 2007. Costs ($28) from DEER Database based off $0.37 per linear foot equipment cost and $2.44 per linear foot installation cost (CEC 2005a). Useful life of insulation 13 years from Efficiency Vermont 2005. Percent of homes applicable (29%) is percentage of households with electric water heating (EIA 2003).

Efficient Dehumidifier
Measure Description: Replacement dehumidifier that is ENERGY STAR certified based on the 2008 ENERGY STAR specification.

Basecase: Dehumidifier that meets current (2005) federal energy standards.

Data Explanation: Baseline and incremental costs ($150) and electricity consumption from ENERGY STAR calculator. Percent applicable (14%) equivalent to percent of households with a dehumidifier (EIA 2008). Percent savings (19%), measure life (12 years), and market share (60%) from Sanchez et al. 2007.

Efficient Room Air Conditioner
Measure Description: ENERGY STAR Room A/C (10000 Btu unit at 10.8 EER).

Basecase: Room A/C that meets 2000 federal energy standards (10000 Btu at 9.8 EER)

Data Explanation: Baseline consumption, savings, and incremental cost from ENERGY STAR savings calculator. Percent homes applicable (28%) based on number of units per home from RECS 2005 (EIA 2008). Measure life (13 years) from Sanchez et al. 2007. Market share (49%) from ENERGY STAR 2006 appliance sales data.

Refrigerator Tier I
Measure Description: Replacement refrigerator that meets 2008 ENERGY STAR requirements (20% better than federal standard)

Basecase: Refrigerator that meets current 2001 federal energy standards.

Data Explanation: Baseline consumption, incremental cost ($64) and measure life (19 years) from ACEEE analysis for PG&E/CA Title 24 (PG&E 2007). Market share (31%) from Sanchez et al. 2007.

Refrigerator Tier II
Measure Description: Replacement refrigerator that exceeds federal energy standard by 25% (CEE Tier 2)

Basecase: Refrigerator that meets current 2001 federal energy standards.

Data Explanation: Baseline consumption, incremental cost ($33) and measure life (19 years) from ACEEE analysis for PG&E/CA Title 24 (PG&E 2007).

Horizontal-Axis Clothes Washer (appliances)
Measure Description: Front-loading (H-axis) clothes washer meeting ENERGY STAR requirements (2.0 MEF)

Basecase: Federal standard for clothes washers: 1.26 MEF

Data Explanation: Savings (20%) from ENERGY STAR savings calculator, isolating appliance energy savings only. Incremental cost ($20) apportioned based on percentage of electricity consumption not dedicated to water heating. Percent of homes applicable (20%) based on appliance saturation data from RECS 2005 (EIA 2008). 2006 market share (33%) from EPA 2007c. Measure life (14 years) is from Sanchez et al. 2007.

Horizontal-Axis Clothes Washer (water heating)
Measure Description: Front-loading (H-axis) clothes washer meeting ENERGY STAR requirements (2.0 MEF)

Basecase: Federal standard for clothes washers: 1.26 MEF

Data Explanation: Savings (20%) from ENERGY STAR savings calculator, isolating water heating energy savings only. Incremental cost ($180) apportioned based on percentage of electricity consumption dedicated to water heating.

Percent of homes applicable (20%) based on appliance saturation data from RECS 2005 (EIA 2008). 2006 market share (33%) from EPA 2007c. Measure life (14 years) is from Sanchez et al. 2007.

Efficient Dishwasher (appliances)
Measure Description: Dishwasher meeting 2011 ENERGY STAR requirement of 0.72 EF

Basecase: Dishwasher meeting 2010 federal energy standard of 0.62 EF

Data Explanation: Incremental cost ($30) and electricity savings from DOE 2007 Technical Support Document, isolating appliance energy savings only. Percent applicable (55%) equivalent to households with a dishwasher. Incremental cost apportioned based off ratio of electricity savings between the appliance and electricity used for water heating. Measure life (13 years) is from Sanchez et al. 2007. Market share (15%) from April 2007 LBL analysis on the AHAM-efficiency advocate agreement.

Efficient Dishwasher (water heating)
Measure Description: Dishwasher meeting 2011 ENERGY STAR requirement of 0.72 EF

Basecase: Dishwasher meeting 2010 federal energy standard of 0.62 EF

Data Explanation: Incremental cost ($30) and energy savings from DOE 2007 Technical Support Document, isolating water heating energy savings only. Percent applicable (16%) equivalent to households with dishwasher and electric water heater. Incremental cost apportioned based off ratio of electricity savings between the appliance and electricity used for water heating. Measure life (13 years) is from Sanchez et al. 2007. Market share (15%) from April 2007 LBL analysis on the AHAM-efficiency advocate agreement.

Ceiling Fan
Measure Description: ENERGY STAR certified ceiling fan

Basecase: Standard ceiling fan as defined by ENERGY STAR

Data Explanation: Baseline consumption, new measure consumption, and incremental cost ($185) from ENERGY STAR calculator. 2.15 units per household assumed from RECS 2005. Percent applicable (74%) equivalent to number of households with a ceiling fan. Baseline and new measure consumption, as well as units per household, specific to East North Central region. Measure life (10 years) and market share (24%) are from Sanchez et al. 2007.

Compact Fluorescent Lighting
Measure Description: Savings from the 17-watt equivalent to baseline lamp (75%) applied to 80% of baseline incandescent lamp hours.

Basecase: Baseline house requires 25,659 incandescent lamp-hours per year; average incandescent wattage is 63 watts based on 2001 federal government lighting inventory survey (DOE 2002).

Data Explanation: Measure of 80% replacement by lamp-hours is ACEEE assumption based on a conservative estimate of feasible applications. Applies to all households. Market share (10%) from ACEEE estimate based on EPA's estimate of ENERGY STAR lamp sales in 2007 and ACEEE's estimate of total lamp sales.

Active Mode Efficiency for Televisions
Measure Description: ENERGY STAR Television Specification, Version 3.0

Basecase: Average of all TVs from ENERGY STAR data set (CEE 2008).

Data Explanation: Baseline consumption, new measure consumption, measure life (6 yrs), and savings from CEE 2008.

Low Power Set-Top Boxes
Measure Description: Require digital set-top boxes to have a maximum sleep state power level of 10 watts and to automatically enter sleep mode after 4 hours without user input.

Basecase: Typical house with 1.9 set top boxes.

Data Explanation: All data except cost is from Rainer (2008). No reliable incremental cost data is available. In the case of set-top boxes, efficiency measures are largely software-related, likely resulting in very low cost per kWh saved per household. Our cost estimate is set to result in a levelized cost similar to that for TVs.

One-Watt Standby for All Household Electronics
Measure Description: All new electronics devices required to have maximum "off" mode power level of 1 watt.

Basecase: Typical house with 17-20 devices.

Data Explanation: Baseline consumption, savings, incremental costs and measure life available from ACEEE 2004 emerging technologies analysis (Sachs et al. 2004). Penetration of new measure assumed by averaging market shares of all ENERGY STAR home electronics equipment.

ENERGY STAR New Home
Measure Description: New home that uses 15% less energy than code

Basecase: Code-compliant home (proposed 2008 IECC residential code revision)

Data Explanation: Baseline equals delivered HVAC and water heating energy use per household (across all households) from AEO (2007). Incremental costs ($805) and market share (5%) from personal communication with Shadid (2007). Percent applicable for new homes assume that 30% and 50% new buildings are phased-in one to two years prior to enactment of codes (30% in 2012 and 50% in 2020).

Advanced Building Code New Home
Measure Description: New home that uses 30% less energy than code

Basecase: Code-compliant home (proposed 2008 IECC residential code revision)

Data Explanation: Baseline equals delivered HVAC and water heating energy use per household (across all households) from AEO (2007). Incremental costs ($1480) and market share (0%) from personal communication with Shadid (2007). Percent applicable for new homes assume that 30% and 50% new buildings are phased-in one to two years prior to enactment of codes (30% in 2012 and 50% in 2020).

Tax-Credit-Eligible New Home
Measure Description: New home that uses 50% less energy than code.

Basecase: Code-compliant home (proposed 2008 IECC residential code revision)

Data Explanation: Baseline equals delivered HVAC and water heating energy use per household (across all households) from AEO (2007). Incremental costs ($2775) and market share (0%) from personal communication with Shadid (2007). Percent applicable for new homes assume that 30% and 50% new buildings are phased-in one to two years prior to enactment of codes (30% in 2012 and 50% in 2020).

C.2. Commercial Buildings

C.2.1. Baseline End-Use Electricity Consumption

To estimate the resource potential for efficiency in commercial buildings in Ohio, we first develop a disaggregate characterization of baseline electricity consumption in the state for current electricity use and a reference load forecast (see Table 27). Highly disaggregated commercial electricity consumption data is unfortunately not available at the state level. To estimate these data, we start with current electricity consumption for the Ohio commercial sector (EIA 2008) and a forecast out to 2025 based on PJM forecasts, and we disaggregate by end-use using average regional data from CBECS 2003 (EIA 2006b) and AEO 2007 (EIA 2007c).

Table 27. Baseline Commercial Electricity Consumption by End-Use (GWh)

End-Use	2009	%	2015	%	2025	%
Heating	1,746	4%	1,972	4%	2,070	3%
Cooling	5,286	11%	5,972	11%	6,738	10%
Ventilation	2,502	5%	2,826	5%	3,135	5%
HVAC subtotal	9,534	19%	10,770	19%	11,943	19%
Water Heating	1,350	3%	1,525	3%	1,565	2%
Refrigeration	2,927	6%	3,306	6%	3,639	6%
Lighting	17,628	36%	19,913	36%	22,178	34%
Office Equipment	7,055	14%	7,970	14%	10,253	16%
Other	10,533	21%	11,899	21%	14,932	23%
Total	**49,027**	**100%**	**55,383**	**100%**	**64,510**	**100%**

Next, we estimate commercial square footage in the state using electricity intensity data (kWh per square foot) by census region from CBECS (EIA 2006b). We use the East North Central region to estimate an overall electricity intensity for the state of Ohio of 13.8 kWh per square foot. Total electricity consumption in the state divided by the electricity intensity provides an estimate of commercial floorspace. Using this methodology, we estimate 3,553 million square feet of commercial floorspace in the state.

C.2.2. Measure Cost-Effectiveness

We then analyze 34 efficiency measures for existing commercial buildings and 3 new construction whole-building measures to examine the cost-effective energy efficiency resource potential. For each efficiency measure, we estimate electricity savings (*Annual Savings per Measure)* and incremental cost (*Measure Cost)* in a "replacement on burnout scenario," which assumes that the product is replaced or the measure is installed at the end of the measure's useful life. Savings and costs are incremental to an assumed *Baseline Measure*. We estimate savings (kWh) and costs ($) on a per-unit and/or a per-square foot commercial floorspace basis. For each measure we also assume a *Measure Lifetime*, or the estimated useful life of the product.

A measure is determined to be cost-effective if its levelized cost of saved energy, or cost of conserved energy (CCE), is less than $0.1015/kWh, the estimated current average commercial cost of electricity in Ohio. The estimated CCE for each efficiency measure, which assume a discount rate of 5%, are shown in the measure descriptions below. Equation 1 shows the calculation for cost of conserved energy.

Our assumed *Baseline Measure*, *Annual Savings per Measure, Measure Cost, Measure Lifetime, and CCE* are reported for each of the efficiency measures in the list of measure descriptions below. We group the 33 efficiency measures for existing commercial buildings by end-use and list the 3 new building measures last.

Equation 1. *CCE = PMT ((Discount Rate)*, *(Measure Lifetime)*, *(Measure Cost)) / (Annual Savings per Measure (kWh))*

C.2.3. Total Statewide Resource Potential

For each measure, we then derive *Annual Savings per Measure* on a per square foot basis *(kWh per square foot)* for the applicable end-use. For measures that we only have savings on a per-unit or per-building basis, we first derive the percent savings and multiply by the *Baseline Electricity Intensity* for that end-use. The assumed baseline intensities for each end use are shown in Table 28. As an example, for a specific lighting measure we multiply its percent savings by the baseline electricity intensity (kWh per square foot) for the lighting end-use.

Table 28. Commercial End-Use Baseline Electricity Intensities (kWh per s.f.)

End-Use	2009
Heating	0.5
Cooling	1.5
Ventilation	0.7
HVAC Subtotal	2.7
Water Heating	0.4
Cooking	0.1
Lighting	5.0
Refrigeration	0.8
Office Equipment	2.0
Other	2.8
Total	**13.8**

To estimate the total efficiency resource potential in existing commercial buildings in Ohio by 2025, we must first adjust the individual measure savings by an *Adjustment Factor* (See Equation 2). This factor accounts for two adjustments: the technical feasibility of efficiency measures, called the *Percent Applicable* (the percent of Ohio floorspace that satisfy the base case conditions and other technical prerequisites such as heating fuel type and cooling equipment, etc); and the *Current Market Share*, or the percent of products that already meet the efficiency criteria. These assumptions are outlined in each of the efficiency measure descriptions below.

Equation 2. *Adjustment Factor = Percent Applicable x (1-Current Market Share).*

We then adjust total savings for interactions among individual measures. For example, we must adjust HVAC equipment savings downward to account for savings already realized through improved building envelope measures (insulation and windows), which reduce heating and cooling loads. Similarly, we adjust water heating equipment savings to account for reduced water heating loads from the use of more efficient clothes washers. The multiplier for these adjustments is called the *Interaction Factor.*

Finally, we adjust replacement measures with lifetimes more than 7 and 17 years to only account for the percent turning over in 7 and 17 years, which represents the benchmark years of 2015 and 2025, respectively. Note that the multiplier, *Percent Turnover,* is only applicable to products being replaced upon burnout and not retrofit measures such as insulation. These retrofit measures therefore have 100% of measures “turning over.”

We then calculate the resource potential for each measure in the state using Equation 3, which takes into account all of the adjustments described above. The sum of the resource potential from all measures is the overall energy efficiency resource potential in the state’s commercial buildings sector.

Equation 3. *Efficiency Resource Potential in 2015 and 2025 (GWh) = (Annual Savings per Measure (kWh per square foot)) x (Commercial floor space in Ohio in millions of square feet) x (Percent Applicable)* x *(Interaction Factor) x (Percent Turnover)*

C.2.4. Efficiency Measures

Table 29 shows the thirty-eight efficiency measures examined for this analysis, grouped by end-use costs, savings (kWh) per product or square foot, *Percent Applicable, Interaction Factor, Percent Turnover,* and total savings potential (GWh) in 2025. Detailed descriptions of each measure are given below, grouped by end-use.

<u>HVAC</u>

1. Duct testing and sealing

Measure Description: Testing and sealing air distribution ducts saves energy. This measure assumes supply and return ducts will be fully sealed.

Basecase: The basecase assumes air loss of 29% of fan flow, and leakage of 15% of the system flow.

Data Explanation: Percent savings of 6% apply to whole-building electricity consumption (SWEEP 2002). An incremental cost of $3,375, which assumes $300 per ton, a 10 year lifetime, and 25% applicability are ACEEE estimates. The levelized cost is calculated to be 1.8 cents/kWh.

2. Cool roof

Measure Description: This measure involves installing a sun-reflective coating on the roof of a building with a flat top. This reduces air conditioning energy loads by reducing the solar energy absorbed by the roof.

Basecase: The baseline electricity intensity for HVAC end uses in Ohio (2.7 kWh/ft^2/year) is used as the basecase.

Data Explanation: We assume 4% HVAC load savings (ACEEE 1997) off the baseline electricity intensity for HVAC end-uses in Ohio (CBECS 2003), an incremental cost of $0.25 per ft^2 (SWEEP 2002), and a 20-year average lifetime (SWEEP 2002). Percent applicable (80%) is an ACEEE estimate. Savings and cost per unit are based on a 15,000 ft^2 building from ACEEE Mid-Atlantic study (1997). The levelized cost is calculated to be 5.5 cents/kWh.

3. Roof insulation

Measure Description: Fiberglass or cellulose insulation material in roof cavities will reduce heat transfer, though the type of building construction limits insulation possibilities. R-values describe the performance factor for insulation levels.

Basecase: The basecase electricity intensity for this measure was disaggregated from the post-savings electricity intensity and the percentage of savings.

Data Explanation: We assume 3% savings and a post-savings electricity intensity of 0.28 kWh/ft^2/year, based on an average of four building types (ACEEE 1997). An average lifetime of 25 years (CL&P 2007) and an incremental cost of 12 cents/ft^2 were also assumed. The levelized cost is 30 cents/kWh.

4. Double Pane Low-Emissivity Windows

Measure Description: Double-pane windows have insulating air- or gas-filled spaces between each pane, which resist heat flow. Low-emissivity (low-e) glass has a special surface coating to reduce heat transfer back through the window, and a window's R-value represents the amount of heat transfer back through a window. Low-e windows are particularly useful in climates with heavy cooling loads, because they can reflect anywhere from 40% to 70% of the heat that is normally transmitted through clear glass. The Solar Heat Gain Coefficient (SHGC) represents the fraction of solar energy transferred through a window. For example, a low-e window with a 0.4 SHGC keeps out 60% of the sun's heat.

Basecase: The basecase electricity intensity for this measure was disaggregated from the post-savings electricity intensity and the percent savings.

Data Explanation: Percent savings of 3% apply to whole-building electricity consumption (ACEEE 1997). Incremental costs assume $2 per window (SWEEP 2002). A measure life of 25 years is from SWEEP 2002. Percent applicable is an ACEEE estimate. The levelized cost is calculated to be 2 cents/kWh.

5. Ventilation fans with Variable-Frequency Drive

Measure Description: Variable Frequency Drive (VFD) controls the speed of a motor by adjusting the frequency of incoming power. By controlling the speed of a motor, the output of the system can be matched to the requirements of the process, thereby improving efficiency.

Basecase: The basecase unit is a 50 hp fan with 60% load factor, 93% efficiency (ODP, EPAct levels) and 3653 operating hours/year (21-50 hp category from ACEEE standards savings analysis).

Data Explanation: We assume 25% savings applies to ventilation only (ACEEE 1997), which is a conservative estimate. We estimate a $6,650 incremental cost, which assumes $125/hp for VFD and $8/hp for a better fan, and a 10-year measure life (SWEEP 2002). ACEEE estimates that this measure can apply to 40% of systems. The levelized cost is calculated to be 3.9 cents/kWh.

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6. High-Efficiency Unitary AC/HP
65,000 Btu — 135 Btu
135,000 Btu — 240,000 Btu

Measure Description: Unitary packaged air conditioners and heat pumps represent the heating, ventilating, and air conditioning (HVAC) equipment class with the greatest energy use in the commercial sector in the United States, and are used in approximately 48% of the cooled floor space in the commercial sector (DOE 2004). High efficiency units have a greater energy efficiency ratio (EER).

Basecase: The assumed basecase unit meets the 2010 federal efficiency standard. Baseline electricity intensity for this end-use,2.7 kWh per ft^2, is the estimated HVAC consumption in commercial buildings in Ohio. This is data from the East North Central region from EIA's commercial buildings survey (EIA 2006b).

Data Explanation: This measure includes two size ranges; the first is 65,000 Btu to 135,000 Btu, and the second is 135,000 Btu to 240,000 Btu. The measure assumes a 12 EER unit relative to the 2010 federal standard, which ranges from about 10.4 EER to 11.2 EER, depending on the unit type and size. The energy savings average 1,070 kWh (7.2%) for the smaller unit and 3,371 kWh (10.8%) for the larger unit. We assume a measure lifetime of 15 years (LBNL 2003). Incremental costs (average $629 for 65 kBtu to135 kBtu and $1,415 for 135 kBtu to 240 kBtu) are derived from DOE's Technical Support Document (DOE 2004). Percent applicable (33% for 65 kBtu to135 kBtu), and the percent of floorspace with cooling from unitary equipment are also from DOE's Technical Support Document (DOE 2004). The levelized cost is calculated to be 4–5.7 cents/kWh, depending on unit type and size.

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7. High-Efficiency Packaged Terminal AC/HP

Measure Description: PTACs and PTHPs are self-contained heating and air-conditioning units encased inside a sleeve specifically designed to go through the exterior building wall. The basic design of a PTAC is comprised of a compressor, an evaporator, a condenser, a fan, and an enclosure. They are primarily used to provide space conditioning for commercial facilities such as hotels, hospitals, apartments, dormitories, schools, and offices. High-efficiency units have a higher energy efficiency ratio (EER) for cooling units and coefficient of performance (COP) for heat pumps.

Basecase: Consistent with all HVAC-related measures, the baseline electricity intensity is 2.7 kWh per ft^2, which is the estimated HVAC consumption in commercial buildings in Ohio. This is based on the East North Central region from EIA's commercial buildings survey (EIA 2006b).

Data Explanation: We assume that high efficiency units save an average of 7.8%, or 226 kWh per unit, relative to a basecase, which is based on an ACEEE submission to ASHRAE using web data. The measure life is 15 years (ASHRAE 90.1-1999). Percent applicable is 5%, which is the percent of cooling floorspace from packaged terminal units (ADL 2001). The levelized cost is calculated to be 3.8 cents/kWh.

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8. Efficient Room Air Conditioner

Measure Description: An ENERGY STAR room AC must be at least a 10% improvement over the 2000 federal standard (an average 8000 Btu unit must have a 10.8 EER).

Basecase: The assumed basecase unit is a room A/C that meets 2000 federal energy standards (an average 8000 Btu unit has a 9.8 EER) and uses an average of 677 kWh per unit. Baseline electricity intensity for this end-use, 1.5 kWh per ft^2, is the estimated cooling consumption in commercial buildings in Ohio. This is based on the East North Central region from EIA's commercial buildings survey (EIA 2006).

Data Explanation: We assume an ENERGY STAR room AC uses 590 kWh per year, saves 9% of basecase energy, and has an incremental cost of $30 (ENERGY STAR calculator). We assume a measure life of 9 years (ENERGY STAR calculator), a current market share of 52% (EPA 2007c), and percent applicable assumes 4% of cooling floorspace uses room AC units (ADL 2001). The levelized cost is calculated to be 4.3 cents/kWh.

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9. High-Efficiency Chiller

Measure Description: "Chillers" are the hearts of very large air-conditioning systems for buildings and campuses with central chilled water systems. A centrifugal chiller utilizes the vapor compression cycle to chill water and reject the heat collected from the chilled water plus the heat from the compressor to a second water loop controlled by a cooling tower.

Basecase: The basecase unit assumes 0.634 kW/ton T24 from DEER for an average 150 ton system and 1,593 national average full-load operating hours from the ASHRAE 90.1-1999 analysis. Baseline electricity intensity for this end-use, 2.7 kWh per ft^2, is the estimated HVAC consumption in commercial buildings in Ohio. This is based on the East North Central region from EIA's commercial buildings survey (EIA 2006b).

Data Explanation: We assume the new measure has 20% savings, which is derived from estimates provided in SWEEP 2002 and ACEEE 1997. The lifetime estimate of 23 years is from the ASHRAE Handbook (HVAC Applications). Incremental costs are $9,900 and assume a 150 ton average unit (CEC 2005a). Percent applicable (33%) assumes percentage of cooling floorspace using chillers (ADL 2001). The levelized cost is calculated to be 2.4 cents/kWh.

10. Dual-Enthalpy Economizer

Measure Description: Economizers modulate the amount of outside air introduced into the ventilation system based on the relative temperature and humidity of the outside and return air. If the enthalpy, or the latent and sensible heat, of the outside air is less than that of the return air when space cooling is required, then the outside air is allowed to reduce or eliminate the cooling requirement of the AC equipment.

Basecase: Baseline electricity intensity, 1.5 kWh per ft^2, is the estimated cooling consumption in commercial buildings in Ohio. This is based on the East North Central region from EIA's commercial buildings survey (EIA 2006b).

Data Explanation: Savings per unit assume 276 kWh (20% savings) per ton for an average 11-ton unit (CL&P 2007). Average measure life is 10 years (CL&P 2007). Incremental costs per unit are from NYSERDA 2003. Percent applicable is the portion of cooling square footage represented by packaged AC and HP units, and assumes that 90% of these unitary systems could benefit from economizers (ACEEE estimate). It also assumes a 5% current market share (ACEEE estimate). The levelized cost is calculated to be 3.8 cents/kWh.

11. Demand-Controlled Ventilation

Measure Description: Often, HVAC systems are designed to supply ventilated air based on assumed occupancy levels, resulting in over-ventilation. Demand-controlled ventilation monitors CO_2 levels in different zones and delivers the required ventilation only when and where it is needed.

Basecase: The basecase is standard ventilation electricity consumption for a 50,000 ft^2 office building, or about 40,000 kWh/year (Sachs et al. 2004). Baseline electricity intensity for this end-use, 0.7 kWh per ft^2, is the estimated ventilation consumption in commercial buildings in Ohio. This is based on the East North Central region from EIA's commercial buildings survey (EIA 2006b).

Data Explanation: We assume 20% savings for this measure (ET 2004). Energy use per unit is 32,000 kWh/year, assuming a 50,000 ft^2 building (Sachs et al. 2004). The lifetime estimate is 15 years, and incremental costs are $3,450 (Sachs et al. 2004). The measure is applicable to 90% of larger (60%) cooling units (Sachs et al. 2004). The levelized cost is calculated to be 4.2 cents/kWh.

12. HVAC Tune-up

Measure Description: Most HVAC technicians lack interest, training, equipment and methods to perform quality refrigerant charge and airflow (RCA) tune-ups. Because many new and existing air conditioners have improper RCA, which reduces efficiency, there is significant potential for energy savings by diagnosing and correcting RCA.

Basecase: The assumed basecase unit is a 4.5 ton commercial unitary AC/HP per California program experience (CPUC 2006), estimated to use 8,396 annual kWh per the unitary AC/HP measure. The base electricity intensity for the HVAC end-use is 3.4 kWh/ ft^2, the average for small buildings less than 25,000 ft^2, for which this measure is applicable.

Data Explanation: We assume 11% savings from this measure according to California's DEER database (CEC 2005a) and the California Refrigerant and Air Charge (RCA) program report (CPUC 2006). We assume that 60% of units have improper RCA (CPUC 2006), and therefore this measure is applicable to 60% of unitary HVAC units in buildings less than or equal to 25,000 ft^2 (CBECS 2003; E N Central region). We estimate an average measure life of 3 years, as units need to be periodically re-tuned. We assume a cost of $158 for this measure, based on a $35/ton labor cost (CEC 2005a) and an assumed 4.5-ton unit. The levelized cost is calculated to be 6.3 cents/kWh.

13. Energy Management System (EMS)

Measure Description: An Energy Management System (EMS) is a computerized system that collects, analyzes and displays information on HVAC, lighting, refrigeration, and other commercial building subsystems to aid commercial building and facility energy managers, financial managers, and electric utilities in reducing energy use in buildings.

Basecase: Baseline electricity intensity is the average HVAC end-use consumption in Ohio, estimated from CBECS (EIA 2006b) to be the average of consumption in the East North Central region.

Data Explanation: We assume 10% cooling savings and 7.5% heating and ventilation savings from an installed EMS (NYSERDA 2003). We estimate a 15-year measure life for the system. We assume total incremental costs of $19,333 for a 60,000 ft^2 building, which is derived from NYSERDA 2003, and assume a third of this ($6,380) for this measure by assuming the cost is spread equally among electric HVAC, gas HVAC and lighting. Percent applicable is an ACEEE estimate. The levelized cost is calculated to be 5.8 cents/kWh.

13. Retrocommissioning

Measure Description: Commercial building performance tends to degrade over time, and many new buildings do not perform as designed, requiring periodic upgrades to restore system functions to optimal performance. Retrocommissioning (RCx) is a systematic process to optimize building performance through O&M tune-up activities and diagnostic testing to identify problems in mechanical systems, controls, and lighting. The best candidates for RCx are buildings over 50,000 or 100,000 ft2.

Basecase: The baseline is electricity intensity for HVAC and lighting end-uses in buildings greater than 50,000 ft2 (8 kWh/ ft2), which is based on data from CBECS (EIA 2006b). We take the average of the East North Central region to estimate electricity intensity in Ohio buildings.

Data Explanation: We assume 10% savings for HVAC and lighting end-uses (Sachs et al. 2004) in all commercial floorspace for buildings greater than 100,000 ft2, and 50% of floorspace in buildings 50,000 ft2 or greater based on data from CBECS (EIA 2006b). Xcel Energy's RCx program results estimate an average RCx useful life of 7 years (Xcel Energy 2006). We assume a $0.25 cost per ft2 (Sachs et al. 2004). The levelized cost is calculated to be 5.4 cents/kWh.

Water Heating Measures

14. Heat Pump Water Heater

Measure Description: A heat pump water heater uses electricity to move heat from one place to another, rather than a less efficient electric resistance water heater which uses electricity to generate the heat directly. The heat source is the outside air or air in the basement where the unit is located.

Basecase: The basecase is standard electric water heating, with electricity consumption of 22,831 kWh/year (derived from energy savings and percent savings). Baseline electricity intensity for this end-use, 0.38 kWh per ft^2, is the estimated water heating consumption in commercial buildings in Ohio. This is based on the East North Central region from EIA's commercial buildings survey.

Data Explanation: We assumed a 62% savings, based on a simple coefficient of performance ratio. The assumed 14,155 kWh savings, $4,067 incremental cost, and 12 year lifetime estimates are from NYSERDA 2003. Percent applicable is based on engineering estimates for NYSERDA 2003, which assumes the measure is applicable to 70% of food service floorspace and 30% of lodging, education, and health care floorspace. Percent applicable is then multiplied by 2, since these building types are more energy and hot-water intensive than the average commercial building. The levelized cost is calculated to be 3.2 cents/kWh.

15. Efficient Commercial Clothes Washer (water heating portion)

Measure Description: A high-efficiency commercial clothes washer saves both energy and water, and as a result reduces water heating loads. For a high-efficiency clothes washer, we assume a unit with an MEF of 2.0, which represents about 80% of products on ENERGY STAR's product lists.

Basecase: The basecase unit is a clothes washer that meets DOE's federal efficiency standard of 1.26 MEF. An average unit consumes 1,136 kWh annually for water heating, which is derived from DOE 2007. Baseline electricity intensity for this end-use is 0.38 kWh/ft^2/year (water heating portion only).

Data Explanation: Savings on electric water heating from this measure assume a 2.0 MEF clothes washer uses an average 431 kWh annually, for a 62% savings, which is derived from DOE's TSD (DOE 2007). We assume the measure is applicable to the 17% of units that have electric water heating, and assume a 20% market share of efficient products. The overall stock estimate is based on national stock data (DOE 2007) and prorated to Ohio based on commercial building floorspace. We assume an incremental cost for an efficient unit is $316 and an 11-year measure life (DOE 2007). The levelized cost is calculated to be 3.2 cents/kWh.

Refrigeration Measures

16. Efficient Walk-In Refrigerators & Freezers

Measure Description: Walk-in refrigerators and freezers (walk-ins) are medium and low-temperature refrigerated spaces that can be walked into, and that are used to maintain the temperature of pre-cooled materials (not to rapidly cool down materials from warmer temperatures). A high-efficiency walk-in is defined as meeting the 2004 CEC standard for walk-ins. This includes prescriptive requirements such as higher levels of insulation, motor types, and the use of automatic door-closers (Nadel et al. 2006).

Basecase: The baseline energy use for an average walk-in is 18,859 kWh/year (Nadel et al. 2006). Baseline electricity intensity for this end-use, 0.82 kWh per ft^2, is the estimated refrigeration energy consumption in commercial buildings in Ohio. This is based on the East North Central region from EIA's commercial buildings survey.

Data Explanation: For a high-efficiency walk-in unit, we assume 44% savings over a baseline unit, or 8220 kWh/year, $957 incremental cost, and a 12 year measure lifetime (Nadel et al. 2006), which are based on a PG&E CASE study (2005). We estimate percent applicable as the 18% of refrigeration energy use attributed to walk-ins (ADL 2006) and estimate a 50% current market share of high-efficiency products (ACEEE estimate). The levelized cost is calculated to be 1.3 cents/kWh.

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17. Efficient Reach-In Coolers & Freezers

Measure Description: This measure includes high-efficiency packaged commercial reach-in refrigerators and freezers with solid doors, and refrigerators with transparent doors such as beverage merchandisers. High-efficiency units are those that meet the CEE Tier 2 performance standard, as estimated in PG&E 2005.

Basecase: We assume a baseline unit, which is one that meets that upcoming (2009 or 2010) federal standard, uses 4,027 kWh per year. This is weighted by sales of unit type per PG&E 2004. Baseline electricity intensity for this end-use, 0.82 kWh per ft^2, is the estimated refrigeration energy consumption in commercial buildings in Ohio. This is based on the East North Central region from EIA's commercial buildings survey.

Data Explanation: The savings estimate for a high-efficiency unit, 31% savings or 1,268 kWh per year, is a weighted average of different types of reach-ins that meet CEE's Tier 2 performance standard (PG&E 2005). We estimate an average lifetime of 9 years and an incremental cost of $341, both per PG&E 2005. We estimate percent applicable as the percent of refrigeration energy use attributed to reach-ins and beverage merchandisers, or 17% (ADL 2006), and assume a 10% current market share of high-efficiency products per PG&E 2005. The levelized cost is calculated to be 2.0 cents/kWh.

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18. Efficient Ice-Maker

Measure Description: Commercial ice makers, which are used in hospitals, hotels, and food service and preservation, have energy savings potential largely in their refrigeration systems. We assume an efficient icemaker meets CEC's Tier 2 level of energy savings, which incorporate improved compressors, heat exchangers, and controls, as well as better insulation and gaskets.

Basecase: The baseline energy use, 3,338 kWh per year, is a weighted average of different types of ice-makers that meet the 2010 standard. Baseline electricity intensity for this end-use, 0.82 kWh per ft^2, is the estimated refrigeration energy consumption in commercial buildings in Ohio. This is based on the East North Central region from EIA's commercial buildings survey.

Data Explanation: The 16% savings estimate for a high-efficiency unit, or 542 kWh per year, is a weighted average of different types of ice-makers that meet CEC's tier 2 energy savings (PG&E 2005). We estimate an average lifetime of 10 years and an incremental cost of $100, both per PG&E 2005. We estimate percent applicable as the percent of refrigeration energy use attributed to ice-makers, or 10% (ADL 2006), and assume a 10% current market share of high-efficiency products per PG&E 2005 and ACEEE judgment. The levelized cost is calculated to be 2.4 cents/kWh.

19. Efficient Built-up Refrigeration System

Measure Description: Built-up or supermarket refrigeration systems are primarily made up of refrigerated display cases for holding food for self-service shopping, as well as machine room cooling technologies. More efficient built-up systems include improved machine room technologies (evaporative condensers, mechanical sub-cooling, and heat reclaim), high-efficiency evaporative fan motors, hot gas defrost, liquid-suction heat exchangers, antisweat control, and defrost control.

Basecase: The measure baseline is 1,600,000 kWh for a 45,000 ft^2 supermarket with a built-up refrigeration system. Baseline electricity intensity for this end-use, 0.82 kWh per ft^2, is the estimated refrigeration energy consumption in commercial buildings in Ohio. This is based on the East North Central region from EIA's commercial buildings survey.

Data Explanation: Per-unit savings of 336,000 kWh (21%) are from ADL 1996 and assume an average new 45,000 ft^2 supermarket with a 5-year payback. We estimate percent applicable as the percent of refrigeration energy use attributed to built-up refrigeration, or 33% (ADL 1996). Incremental cost ($37,000) and lifetime (10 years) are from ADL 1996. The levelized cost is calculated to be 1.4 cents/kWh.

20. Efficient Vending Machine

Measure Description: ENERGY STAR vending machines must consume 50% less energy than standard machines. Under the Tier II ENERGY STAR level, this translates to a maximum energy consumption of 6.53 kWh/day for a 650-can machine.

Basecase: A Tier I ENERGY STAR level vending machine is assumed to be the basecase. On average, it uses 2,816 kWh per year (ENERGY STAR calculator for a 600 can machine). Baseline electricity intensity for this end-use, 0.82 kWh per ft^2, is the estimated refrigeration energy consumption in commercial buildings in Ohio. This is based on the East North Central region from EIA's commercial buildings survey.

Data Explanation: Per unit savings of 18% (509 kWh/year) are estimated from ASAP 2007 based on ENERGY STAR calculator estimates. Likewise, an incremental cost of $30, and a lifetime estimate of 10 years are from ASAP 2007. We estimate percent applicable as the percent of refrigeration energy use attributed to built-up refrigeration, or 13% (NYSERDA 2003). Stock estimates are from the 2005 TSD (DOE 2005). The levelized cost is calculated to be 0.8 cents/kWh.

21. Vending Miser

Measure Description: A Vending Miser is an energy control device for refrigerated vending machines. Using an occupancy sensor, the control turns off the machine's lights and duty cycles the compressor based on ambient air temperature.

Basecase: The basecase unit is an efficient vending machine that meets the ENERGY STAR tier II level and uses 2,309 kWh per year (ENERGY STAR calculator for a 600 can machine). Baseline electricity intensity is for the refrigeration end-use (0.82 kWh/ ft^2).

Data Explanation: We assume 35% savings for this measure based on manufacturer data (usatech.com 2008), an incremental cost of $167 (NYSERDA 2003), and a measure life of 10 years (NYSERDA 2003). The levelized cost is calculated to be 2.7 cents/kWh.

<u>Appliances</u>

22. Efficient Hot Food Holding Cabinets

Measure Description: Commercial hot food holding cabinets are used in the commercial kitchen industry primarily for keeping food at safe serving temperature, without drying it out or further cooking it. These cabinets can also be used to keep plates warm and to transport food for catering events. High efficiency models differ mainly in that they are better insulated.

Basecase: The basecase unit is an uninsulated cabinet that consumes 5,190 kWh per year. This was calculated from CASE (2004) using a simple average of three sizes of cabinets, and then weighting the average using CASE figures for insulated cabinets.

Data Explanation: The energy savings from an insulated holding cabinet are 1,815 kWh per year (35% savings), with an incremental cost of $453, and an estimated 15 year lifetime (ASAP 2007, based on PG&E CASE study (2004)). Percent applicable refers to the 25% of holding cabinets that are currently uninsulated (ASAP 2007, based on PG&E CASE study (2004)). The levelized cost is calculated to be 2.4 cents/kWh.

23. Efficient Commercial Clothes Washer (excluding hot water energy)

Measure Description: A high-efficiency commercial clothes washer saves both energy and water. For a high-efficiency clothes washer, we assume a unit with an MEF of 2.0, which represent about 80% of products on ENERGY STAR's product lists.

Basecase: The basecase unit is a clothes washer that meets DOE's federal efficiency standard of 1.26 MEF. An average unit consumes 1,530 kWh annually for non-water heating uses, which is derived from DOE 2007.

Data Explanation: Electric savings from this measure assume a 2.0 MEF clothes washer uses an average 1,191 kWh annually, for a 22% savings, which is derived from DOE's TSD (DOE 2007). We assume the measure is applicable to the 39% of units that have electric dryer heating (removal of moisture from clothes), and assume a 20% market share of efficient products. The overall stock estimate is based on national stock data (DOE 2007) and prorated to Ohio based on commercial building floorspace. We assume an incremental cost for an efficient unit is $316 and an 11-year measure life (DOE 2007). The levelized cost is calculated to be 3.7 cents/kWh.

Lighting Measures

24. Fluorescent Lighting Improvements

Measure Description: The new measure assumes extra-efficient ballasts and high-lumen lamps are installed with no change in light level (low ballast factor).

Basecase: Basecase watts per square foot reflects current installed fixtures. This includes 84,000 annual tube fluorescent kWh used per average 14,000 ft^2 commercial building (Navigant 2002). On average, fluorescent lights are operated 9.7 hours/day. We assume 2-lamp standard T8 fixtures and electronic ballasts as the baseline, plus a small number of existing 3-lamp T12 fixtures with magnetic ballasts that are not likely to be replaced in the absence of programs over the time horizon.

Data Explanation: We assume a percent savings of 27%.The incremental costs are $2 extra per ballast, and $1 extra for each of 2 lamps. The percent applicable (56%) is the fluorescent percent of total commercial lighting kWh (Navigant 2002). The levelized cost is calculated to be 0.7 cents/kWh.

25. HID Lighting Improvements

Measure Description: Metal halide lamps produce light by passing an electric arc through a mixture of gases. Efficiency improvements in metal halide lamps include pulse start lamp technology, electronic ballasts, and improved fixtures.

Basecase: Same basecase as #27 (Fluorescent lighting improvements).

Data Explanation: The new measure savings and costs are from a PG&E CASE study on Metal Halide Lamps & Fixtures (PG&E 2004). Energy savings were 447 kWh per year (26%), and incremental costs were $60. Percent applicable (12%) is the percentage of commercial electricity use for lighting that comes from HIDs (Navigant 2002). The levelized cost is calculated to be 6.3 cents/kWh.

26. Replace Incandescent Lamps

Measure Description: The new measure assumes that 4 average 75 W incandescent lamps are replaced with 23 W CFLs. It is assumed that the lights operate 9.5 hours per day.

Basecase: Same basecase as #27 (Fluorescent lighting improvements).

Data Explanation: Energy savings are 180 kWh per year, or 69%. Incremental costs include $10 in the cost of 4 CFLs, but save $32 in labor for replacing the bulbs, so the result is a cost savings. Percent applicable assumes that 32% of commercial electricity use for lighting is from incandescents (Navigant 2002), and ACEEE estimates that 70% of sockets are applicable for the new measure. The levelized cost is calculated to be -1.3 cents/kWh.

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27. Occupancy Sensor for Lighting

Measure Description: Installation of occupancy sensors can greatly reduce lighting energy demands in commercial spaces, by automatically turning off lights in unoccupied spaces.

Basecase: Same basecase as #27 (Fluorescent lighting improvements).

Data Explanation: Energy savings of 361 kWh per year (NYSERDA 2003) assumes 30% energy reduction in individual offices and rooms and 7.5% reduction in open spaces (ACEEE estimate). Incremental cost ($48) and lifetime (10 years) estimates are from NYSERDA 2003. Percent applicable (38%) is from ACEEE 2004. The levelized cost is calculated to be 1.7 cents/kWh.

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28. Daylight Dimming System

Measure Description: A daylight dimming system automatically dims electric lights to take advantage (or “harvest”) natural daylight.

Basecase: Same basecase as #27 (Fluorescent lighting improvements).

Data Explanation: Energy savings are estimated to be 143 kWh per year, or 35% (NYSERDA 2003). Savings apply for lamps on the perimeters of buildings (25% applicable – PIER 2003). Incremental cost ($68) and lifetime (20 years) estimates are from NYSERDA (2003). The levelized cost is calculated to be 3.8 cents/kWh.

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29. Outdoor Lighting – Controls

Measure Description: This measure includes a variety of lighting control technologies for exterior lights.

Basecase: No basecase data was available for this measure.

Data Explanation: We assume a savings of 174 kWh, or 20%, from lighting controls. Incremental costs of $43 are from DEER 2001 and assume each control on average controls three fixtures. Percent applicable of 30% is an ACEEE estimate. The levelized cost is calculated to be 2.5 cents/kWh.

Miscellaneous

30. Office Equipment

Measure Description: This measure assumes a high-efficiency fax, printer, computer display, internal power supply, and a low mass copier.

Basecase: Baseline electricity use is 2886 kWh per year (NYSERDA 2003). Baseline electricity intensity for this end-use, 2.0 kWh per ft^2, is the estimated office equipment energy consumption in commercial buildings in Ohio. This is based on the East North Central region from EIA’s commercial buildings survey.

Data Explanation: Energy savings were 1410 kWh per year (49%), lifetime was 5 years, and incremental costs were $20. Percent applicable is estimated to be (50%) (NYSERDA 2003). The levelized cost is calculated to be 0.3 cents/kWh.

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31. Turn off appliances

Measure Description: This measure involves turning off, or putting into a low-power state: vending machines, computers, monitors, printers and copiers.

Basecase: Baseline electricity use is 1.1 kWh/ft2, based on data from CBECS, LBNL, and ENERGY STAR.

Data Explanation: Energy savings were 9114 kWh per year (40%), lifetime was 5 years, and incremental costs were $0. Percent applicable is 100%, as data for the savings already took into account the number of buildings that already shut down equipment after hours/. The levelized cost is $0/kWh

New Buildings

32. Efficient New Building (15% Savings)

Measure Description: Incorporating energy efficiency into building design is best achieved at the time of construction. New buildings can achieve major energy savings in heating and cooling, as well as energy-saving appliances.

Basecase: Basecase of 7.2 kWh per ft^2 is an estimate of HVAC, water heating, and lighting end-use electricity intensity for new buildings in Ohio, derived from data for buildings built from 2000-2003 (EIA 2006).

Data Explanation: Incremental cost of $0.35 per ft^2 and measure life of 17 years are from NGRID 2007. Percent applicable of 18% for this new buildings measure assume that 30% and 50% new buildings savings are phased in one to two years prior to enactment of codes in the policy scenarios (30% in 2012 and 50% in 2020). The levelized cost is calculated to be 2.9 cents/kWh.

33. Efficient New Building (30% Savings)

Measure Description: Incorporating energy efficiency into building design is best achieved at the time of construction. New buildings can achieve major energy savings in heating and cooling, as well as energy-saving appliances.

Basecase: Basecase of 7.2 kWh per ft^2 is an estimate of HVAC, water heating, and lighting end-use electricity intensity for new VA buildings, derived from data for buildings built from 2000-2003 (EIA 2006).

Data Explanation: In New York, estimates show that commercial buildings can reach 30% beyond code at an investment of $0.54/kWh. To be conservative, we estimate $0.70/kWh by doubling the costs of a 15%-beyond-code building. Measure life of 17 years is from NGRID 2007. Percent applicable of 35% for 30% savings new buildings assume that 30% and 50% new buildings savings are phased in one to two years prior to enactment of codes in the policy scenarios (30% in 2012 and 50% in 2020). The levelized cost is calculated to be 2.9 cents/kWh.

34. Tax-Credit Eligible Building (50% Savings)

Measure Description: A federal tax incentive is available for new buildings that are constructed to save at least 50% of the heating, cooling, ventilation, water heating, and interior lighting cost of a building that meets ASHRAE standard 90.1-2001.

Basecase: Basecase of 7.2 kWh per ft^2 is an estimate of HVAC, water heating, and lighting end-use electricity intensity for new buildings in Ohio, derived from data for buildings built from 2000-2003 (EIA 2006).

Data Explanation: Incremental costs of $1.20 per ft^2 are from ACEEE 2004. Measure life of 17 years is from NGRID 2007. The levelized cost is calculated to be 3.0 cents/kWh

Table 29. Commercial Energy Efficiency Measure Characterizations

Measures	Measure Life (Years)	Annual kWh svgs per unit	2007 Ohio Stock	kWh svgs per s.f.	Increment-al cost per unit	Increment -al cost per s.f.	Cost of Conserved Energy (2006$/kWh saved)	Adjust-ment Factor	% Turn-over	Inter-action Factor	Savings in 2025 (GWh)
Existing Buildings											
HVAC											
HVAC tuneup (smaller buildings)	10	24,828	NA	0.53	$ 3,375	NA	$ 0.018	25%	100%	100%	472
Energy management system install	20	5,513	NA	0.10	$ 3,750	$ 0.25	$ 0.055	80%	85%	100%	240
Cool roof	25	NA	NA	0.28	NA	$ 0.12	$ 0.030	35%	100%	100%	345
Roof insulation	25	NA	NA	0.26	NA	$ 0.07	$ 0.020	75%	68%	100%	480
Low-e windows	10	21,977	NA	0.18	$ 6,650	NA	$ 0.039	40%	100%	86%	216
Load-Reducing Measures Subtotal											**1,753**
High-effic. unitary AC & HP	15	1,070	NA	0.19	$ 629	NA	$ 0.057	33%	100%	84%	191
High-effic. unitary AC & HP (65-135 kBtu)	15	3,371	NA	0.29	$ 1,415	NA	$ 0.040	15%	100%	84%	130
High-effic. unitary AC & HP (135-240 kBtu)	15	226	NA	0.21	$ 88	NA	$ 0.038	5%	100%	84%	31
Packaged Terminal HP and AC	13	87	NA	0.19	$ 35	NA	$ 0.043	4%	100%	84%	22
Efficient room air conditioner	23	30,347	NA	0.54	$ 9,900	NA	$ 0.024	33%	74%	84%	393
HVAC Equipment Measures Subtotal											**767**
High-efficiency chiller system	10	3,036	NA	0.30	$ 889	NA	$ 0.038	46%	100%	77%	380
Dual Enthalpy Control	15	8,000	NA	0.14	$ 3,450	NA	$ 0.042	54%	100%	77%	209
Retrocommissioning	3	924	NA	0.37	$ 158	NA	$ 0.063	20%	100%	77%	200
Duct testing and sealing	10	14,308	NA	0.24	$ 6,380	NA	$ 0.058	33%	100%	77%	217
Measures	7	NA	NA	0.30	NA	$ 0.25	$ 0.054	46%	100%	77%	385
HVAC Control Measures Subtotal											**1,391**
HVAC Subtotal											**3,911**
Water Heating											
Energy star commercial clothes washer	11	705	108824	0.00	$ 316	NA	$ 0.037	14%	100%	100%	10
Demand-Controlled Ventilation	12	14,155	NA	0.24	$ 4,067	NA	$ 0.032	24%	100%	99%	202
											212
Refrigeration											
Heat pump water heater	12	8,220		0.36	$ 957	NA	$ 0.013	9%	100%	100%	116
Walk-in coolers & freezers	9	1,268		0.26	$ 177	NA	$ 0.020	15%	100%	100%	143
Reach-in coolers & freezers	10	542		0.13	$ 100	NA	$ 0.024	9%	100%	100%	44
Ice-makers	10	336,00		0.17	$ 37,000	NA	$ 0.014	33%	100%	100%	202
Supermarket (built-up) refrigeration	10	507		0.15	$ 30	NA	$ 0.008	13%	100%	100%	71
Vending machines (to tier 2 ENERGY STAR level)	10	808		0.24	$ 167	NA	$ 0.027	13%	100%	100%	113

Shaping Ohio's Energy Future: Energy Efficiency Works, ACEEE

Measures	Measure Life (Years)	Annual kWh svgs per unit	2007 Ohio Stock	kWh svgs per s.f.	Increment-al cost per unit	Increment -al cost per s.f.	Cost of Conserved Energy (2006$/kWh saved)	Adjust-ment Factor	% Turn-over	Inter-action Factor	Savings in 2025 (GWh)
Refrigeration Subtotal											**689**
Lighting											
Energy star commercial clothes washer	13	64	0	1.36	$ 4	NA	$ 0.007	56%	100%	100%	2,698
Fluorescent lighting improvements	2	447	0	1.29	$ 60	NA	$ 0.063	12%	100%	100%	552
HID lighting improvements	13	180	0	3.44	$ (22)	NA	$ (0.013)	22%	100%	100%	2,738
Replace incandescent lamps	10	361	0	0.93	$ 48	NA	$ 0.017	38%	100%	71%	904
Occupancy sensor for lighting	20	143	0	1.74	$ 68	NA	$ 0.038	25%	85%	67%	876
Measures	7	NA	NA	0.50	NA	$ 0.25	$ 0.054	46%	100%	63%	519
Outdoor lighting -- improved efficiency	14	174	0	NA	$ 43	NA	$ 0.025	30%	100%	100%	-
											8,286
Office Equipment											
Outdoor lighting -- controls	5	1,410	0	0.97	$ 0	$ 20.00	$ 0.003	50%	100%	100%	1,723
Turn off office equipment after-hours	5	9,557	0	0.56	$ -	$ -	$ -	100%	100%	82%	1,633
											3,356
Appliances/Other											
Vending miser	15	1,815	41763.	NA	$ 453	NA	$ 0.024	25%	100%	100%	19
Hot Food Holding Cabinets	11	339	108824	NA	$ 316	NA	$ 0.037	31%	100%	100%	11
											30
Total Existing											**16,484**
New Buildings											
Turn off office equipment after-hours	17	NA	0	1.09	NA	$ 0.35	$ 0.029	18%	100%	100%	107
Efficient new building (15% savings)	17	NA	0	2.17	NA	$ 0.70	$ 0.029	35%	100%	100%	428
Efficient new building (30% savings)	17	NA	0	3.60	NA	$ 1.20	$ 0.030	6%	100%	100%	121
											656
											17,140

C.3. Industrial Sector

Overview of Approach

The analysis of electricity savings potential was accomplished in several steps. First, the industrial market in Ohio was characterized at a disaggregated level and electricity consumption for key end-uses was estimated. Then cost effective energy-saving measures were selected based on the projected average retail industrial electricity price. The economic potential savings for these measures was estimated by applying the efficiency measures to electricity end-use consumption. The following sections described the process for estimating the savings potential in Ohio.

Market Characterization and Estimation of Base Year Electricity Consumption

The industrial sector is made up of a diverse group of economic entities spanning agriculture, mining, construction and manufacturing. Significant diversity exists within most of these industry sub-sectors, with the greatest diversity within manufacturing. The various product categories within manufacturing are classified using the North American Industrial Classification System (NAICS) (Census 2002).[60]

Comprehensive, highly-disaggregated electricity data for the industrial sector is not available at the state level. To estimate the electricity consumption, this study drew upon a number of resources, all using the NAICS system and a consistent sample methodology. Fortunately, a conjunction of the various economic censuses for each state allows us to use a common base-year of 2002.

We then used national industry energy intensities derived from industry group electricity consumption data reported in the *2005 Annual Energy Outlook* (AEO) (EIA 2005) and value of shipments data reported in the *2002 Annual Survey of Manufacturing* (ASM) (Census 2005) to apportion industrial energy consumption. These intensities were then applied to the value of shipments data for the manufacturing energy groups (three-digit NAICS) in Ohio. These energy consumption estimates were then used to estimate the share of the industrial sector electricity consumption for each sub-sector.

Preparation of Baseline Industrial Electricity Forecast

As is the case for state-level energy consumption data, no state-by-state disaggregated electricity consumption forecasts are publicly available. Several alternate data sources were used to calculate estimated energy consumption growth rates for each state and sub-sector. We made the assumption that energy consumption will be a function of gross state value of shipments (VOS). Electricity consumption, however, will not grow at the same rate as value of shipments. This is because in general, energy intensity (energy consumed per value of output) decreases with time.

Because state-level disaggregated economic growth projections are not publicly available, data was used from Moody's Economy.com. The average growth rate for specific industrial-subsectors was estimated based on Economy.com's estimates of gross state product. We used this estimated industrial energy consumption distribution to apportion the EIA estimate (2005) of industrial energy consumption.

The industry sector is comprised of four sub-sectors: Manufacturing, Mining, Agriculture, and Construction. The manufacturing sector is broken down into 21 subsectors, defined by three digit NAICS codes. In order to most closely match available data from the *ASM* and *AEO*, three subsectors were further broken down to four digit NAICS codes: chemical manufacturing, nonmetallic mineral product manufacturing, and primary metal manufacturing. Table 30 below shows the estimated electrical consumption for all these subsectors in Ohio in 2008.

[60] The industry sector is comprised of four sub-sectors: Manufacturing, Mining, Agriculture, and Construction. Each sub-sector is further broken down into individual industry groups reflecting the many different definitions for the term 'industrial.'

Table 30. 2008 Base-Case Electricity Consumption by Industry in Ohio

Industry	NAICS Code	Electricity (GWh)	(%)
Agriculture	**11**	844	1%
Mining	**21**	592	1%
Construction	**23**	1,236	2%
Food mfg	311	1,987	3%
Beverage & tobacco product mfg	312	607	1%
Textile mills	313	70	0%
Textile product mills	314	91	0%
Apparel mfg	315	55	0%
Leather & allied product mfg	316	27	0%
Wood product mfg	321	487	1%
Paper mfg	322	2,506	4%
Printing & related support activities	323	882	1%
Petroleum & coal products mfg	324	1,670	3%
Chemical mfg	325	13,184	22%
Pharmaceutical & medicine mfg	*3254*	*797*	*1%*
All other chemical products	*-3253,3255-*	*12,387*	*21%*
Plastics & rubber products mfg	326	2,988	5%
Nonmetallic mineral product mfg	327	3,936	7%
Glass & glass product mfg	*3272*	*877*	*1%*
Cement & concrete product mfg	*3273*	*2,545*	*4%*
Other minerals	*3271,3274-*	*514*	*1%*
Primary metal mfg	331	13,765	23%
Iron & steel mills & ferroalloy mfg	*3311*	*4,180*	*7%*
Steel product mfg from purchased steel	*3312*	*1,775*	*3%*
Alumina and Aluminum	*3313*	*3,975*	*7%*
Nonferrous Metals, except Aluminum	*3314*	*2,133*	*4%*
Foundries	*3315*	*1,702*	*3%*
Fabricated metal product mfg	332	2,154	4%
Machinery mfg	333	1,736	3%
Computer & electronic product mfg	334	911	2%
Electrical equipment, appliance, & component mfg	335	1,144	2%
Transportation equipment mfg	336	6,723	11%
Furniture & related product mfg	337	685	1%
Miscellaneous mfg	339	967	2%
Total Industrial Sector		59,246	100%

Market Characterization Results

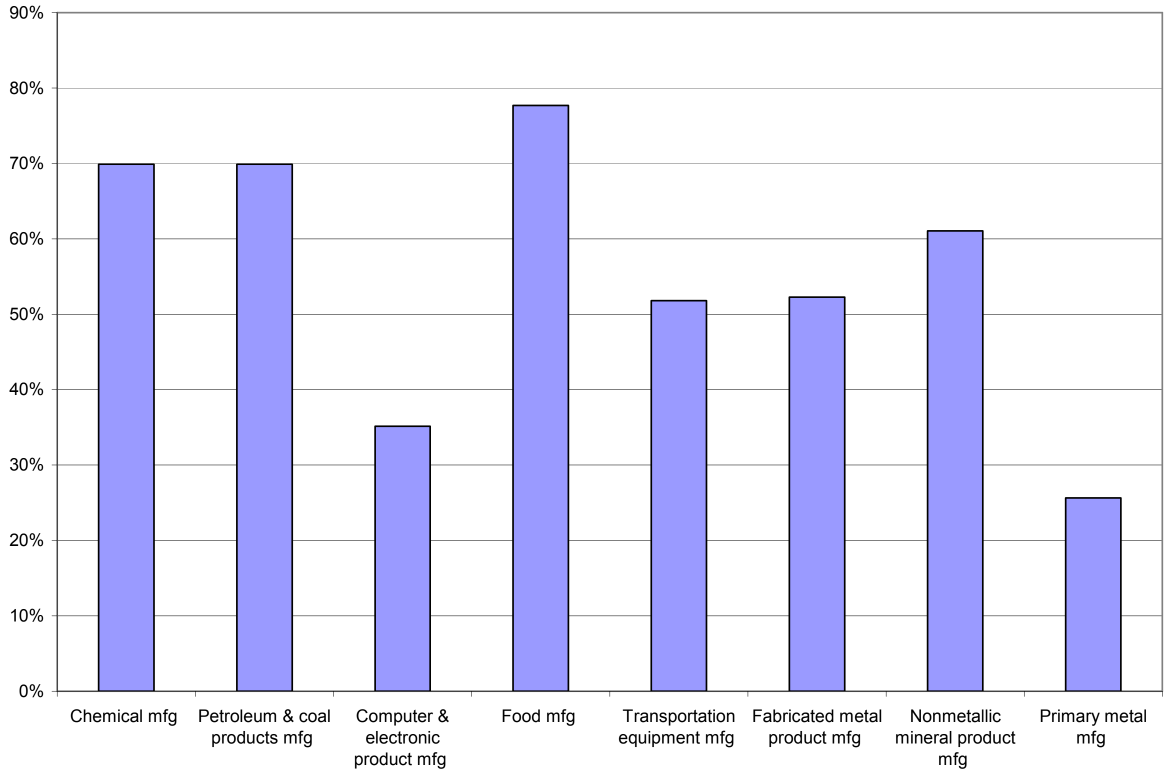
In 2008, the State of Ohio industrial sector consumed 59,246 GWh of electricity. Within the manufacturing sector, the chemical, primary metal, and transportation equipment manufacturing industries are the largest consumers of energy, accounting for over 55% of industrial electricity consumption.

Industrial Electricity End Uses

In order to determine the electricity savings for any technology, the fraction of the electricity to which the technology is applicable must be determined. Much of the energy consumed by industry is directly involved in processes required to produce various products. Electricity accounts for about a third of the primary energy used by industries (EIA 2005). Electricity is used for many purposes, the most important being to run motors, provide lighting, provide heating, and to drive electrochemical processes.

While detailed end-use data is only available for each manufacturing sub-sector and group through the MECS survey (EIA 2005), motor systems are estimated to consume 60% of the industrial electricity (Xenergy 1998). The fraction of total electricity attributed to motors is presented in Figure 23.

Figure 23. Percent of Total Electricity Consumption by Motor Systems

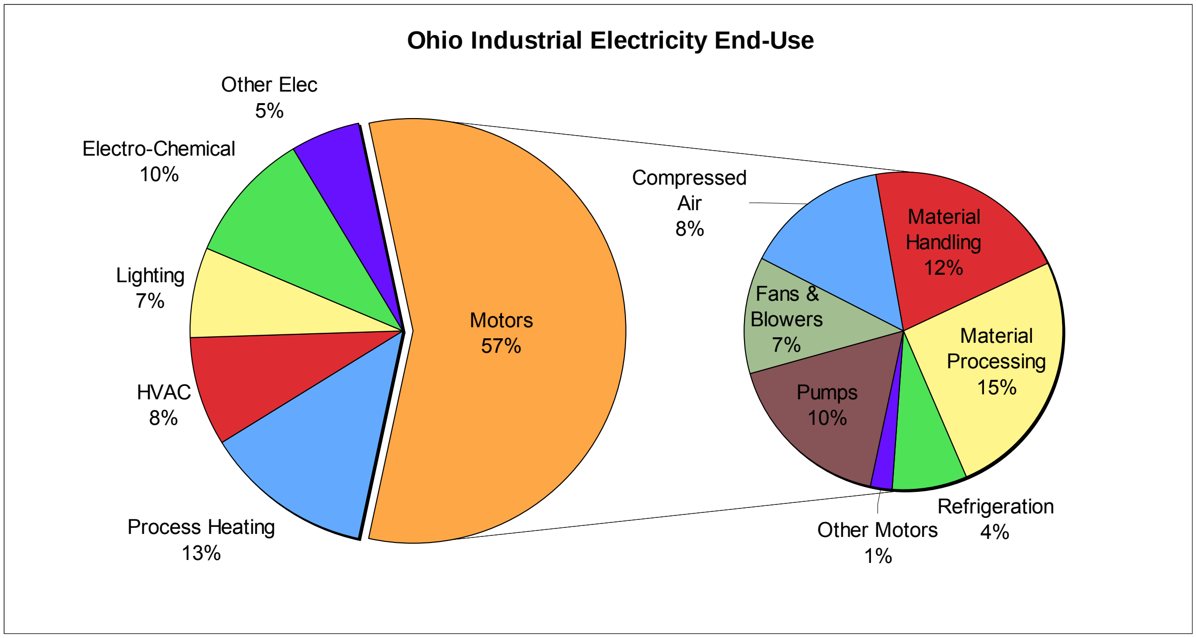


Source: XENERGY (1998)

Motors are used for many diverse applications from fluids (pumps, fans, and air and refrigeration compressors) to materials handling and processing (conveyors, machine tools and other processing equipment). The distribution of these motor uses varies significantly by industry, with material processing being the largest consumer in the sector.

Figure 24 shows the total weighted average of end-use electricity consumption in Ohio with a breakdown of motors use in the state.

Figure 24. Weighted Average of Total Industrial Electricity End-Uses in Ohio with Breakdown of Industrial Motor System End-Uses



While lighting and space conditioning represent a relatively small share of the overall industrial sector electricity consumption, they are important in some of the key industries found in the region such as transportation equipment manufacturing and other mechanical manufacturing and assembling industries, and the electricity savings potential can be significant.

Overview of Efficiency Measures Analyzed

The first step in our technology assessment was to collect limited information on a broad "universe" of potential technologies. Our key sources of information included the U.S. Department of Energy, Office of Industrial Technologies; the Center for the Analysis and Dissemination of Demonstrated Energy Technologies (CADDET); Lawrence Berkeley National Laboratory (LBNL) and American Council for an Energy-Efficient Economy reports; and information from NYSERDA. We did not collect any primary data on technology performance.

Oftentimes, no one source provided all of the information we sought for our assessment (energy use, energy savings compared to average current technology, investment cost, operating cost savings, lifetime, etc.). We therefore made our best effort to combine readily available information along with expert judgment where necessary.

We sought to identify technologies that could have a large potential impact in terms of saving energy. These may be technologies that are specific to one process or one industry sector, or so-called "cross-cutting" technologies that are applicable to a variety of sectors. In estimating energy savings, we first identified the specific energy savings of each technology by comparing the energy used by the efficient technology to the energy required by current processes. Our second step was to "scale up" this savings estimate to see how much energy savings—for industry overall—this technology would achieve. For the most part, we derived specific energy savings information from the various technology assessment studies noted above.

In scaling up the technology-specific energy savings, we relied on our general knowledge of the various industrial processes to which this technology could be applied. We also took into account structural limitations to the penetration of the technology. Additionally, we recognized that market penetration, in the absence of significant policy support, can take time given the slowness of stock turnover in many industrial facilities.

Measures

We identified 14 measures that were cost effective at the average projected industrial electricity rates in Ohio of $0.0744/kWh (see Table 31). The cost and performance of these measures has been developed over the past decade by ACEEE from research into the individual measures and review of past project performance. The costs of many of these measures has increased in recent years as a result of significant increases in key commodity costs such as copper, steel and aluminum, as well as overall manufacturing costs due to energy prices and market pressures. The estimates presented in Table 31) represent ACEEE's most current estimates. We present the full normalized installed measure cost (i.e., the full cost required to install a measure per unit of saved energy) as well as the levelized cost (i.e., the annual cost of the measure amortized over the life of the measure).

Table 31. Cost and Performance of Industrial Measures

		Cost of Saved Energy		
Measure	**Measure Life**	**Installed Cost/kWh**	**Levelized cost/kWh**	**Annual Savings for End-Use**
Sensors & Controls	15	$0.145	$0.014	3%
Energy Information Sys.	15	$0.635	$0.061	1%
Duct/Pipe insulation	20	$0.653	$0.052	20%
Electric supply	15	$0.104	$0.010	3%
Lighting	15	$0.212	$0.020	23%
Advanced efficient motors	25	$0.491	$0.035	6%
Motor management	5	$0.079	$0.018	1%
Lubricants	1	$0.000	$0.000	3%
Motor system optimization	15	$0.097	$0.009	1%
Compressed air manage	1	$0.000	$0.000	17%
Compressed air -advanced	15	$0.001	$0.000	4%
Pumps	15	$0.083	$0.008	20%
Fans	15	$0.249	$0.024	6%
Refrigeration	15	$0.034	$0.003	10%

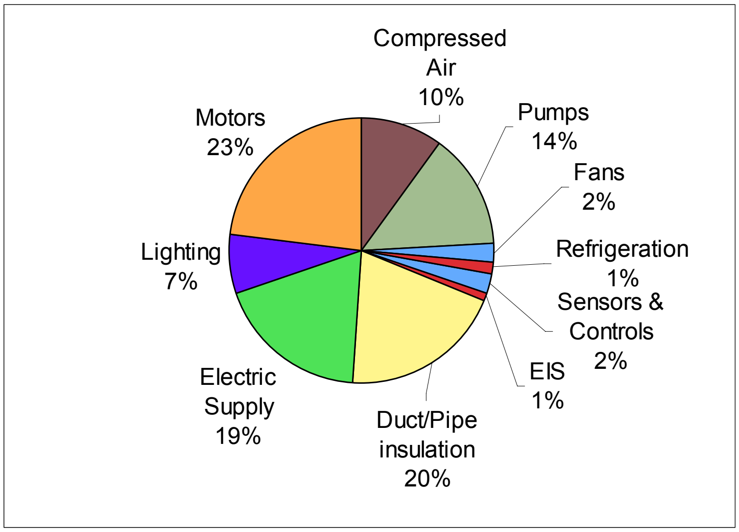
In addition, we estimated the average normalized cost of industrial energy efficiency investments to be $0.275/kWh saved. This estimate was arrived at by estimating the sum of the annual incremental savings for each measure in each industry based on end-use energy distribution and dividing the corresponding total investment required.

Potential for Energy Savings

In Ohio, a diverse set of efficiency measures will provide electricity savings for industry. The application of these measures contributes to total economic electric savings potential of 16%. These savings are distributed as presented in

Figure 25.

Figure 25. Fraction of Savings Electricity Potential by Measure



In addition, this analysis did not consider process-specific efficiency measures that would be applied at the individual site level because available data does not allow this level of analysis. However, based on experience from site assessments by U.S. Department of Energy and others entities, we would anticipate an additional economic savings of 5-10%, primarily at large energy intensive manufacturing facilities. Therefore, the overall economic industrial efficiency resource opportunity for electricity is on the order of 21-26%.

APPENDIX D – DEMAND RESPONSE ANALYSIS

D.1. Introduction

This report defines Demand Response (DR), assesses current DR activities in Ohio, identifies policies in the state that impact DR, uses benchmark information to assess DR potential in Ohio, and identifies barriers in the state that might keep DR contributing appropriately to the resource mix that can be used to meet electricity needs. The analysis concludes with identification of policy recommendations regarding DR.

D.1.1. Objectives of this Assessment

This assessment develops estimates of DR potential for Ohio. Potential load reductions from DR are estimated for the residential, commercial, and industrial sectors (see Section 3). The assessment also includes discussions of reductions possible from other DR programs, such as DR rate designs (see Section 3.6).

D.1.2. Role of Demand Response in Ohio's Resource Portfolio

The DR capabilities developed by Ohio utilities will become part of a long-term resource strategy that includes resources such as traditional generation resources, renewable energy, power purchase agreements, options for fuel and capacity, energy efficiency and load management programs. Objectives include meeting future loads at lower cost, diversifying the portfolio to reduce operational and regulatory risk, and allow Ohio customers to better manage their electricity costs. The growth of renewable energy supply (and plans for increased growth) can increase the importance of DR in the portfolio mix. For example, sudden renewable energy supply reductions (e.g., from an abrupt loss in wind) may be mitigated quickly with DR.

D.1.3. Summary of DR Potential Estimates in Ohio

Table 32 shows the resulting load shed reductions possible for Ohio, by sector, for years 2015, 2020, and 2025. Load impacts grow rapidly through 2018 as program implementation takes hold. After 2018, the program impacts increase at the same rate as the forecasted growth in peak demand.

The high scenario DR load potential reduction is within a range of reasonable outcomes in that it has an eleven year rollout period (beginning of 2010 through the end of 2020), providing a relatively long period of time to ramp up and integrate new technologies that support DR. A value nearer to the high scenario than the medium scenario would make a good MW target for a set of DR activities.

The high scenario results show a reduction in peak demand of 3,078 MW is possible by 2015 (8.4% of peak demand); 6,293 MW is possible by 2020 (16.4% of peak demand); and 6,471 MW is possible by 2025 (16.2% of peak demand).

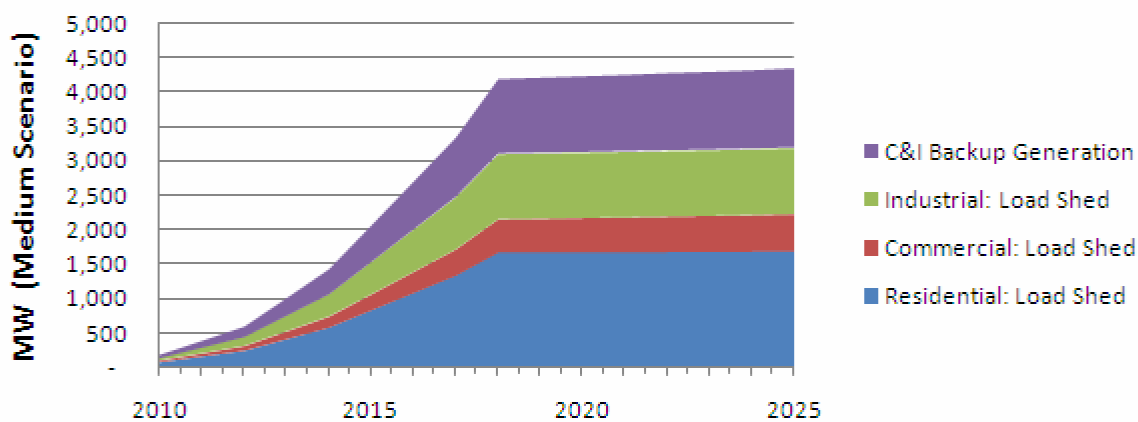
The more conservative medium scenario results show a reduction in peak demand of 2,052 MW is possible by 2015 (5.6% of peak demand); 4,193 MW is possible by 2020 (11.0% of peak demand); and 4,309MW is possible by 2025 (10.8% of peak demand).

Table 32. Summary of Potential DR in Ohio, By Sector, for Years 2015, 2020, and 2025

	Low Scenario			Medium Scenario			High Scenario		
	2015	2020	2025	2015	2020	2025	2015	2020	2025
Load Sheds (MW):									
Residential	502	1,008	1,017	837	1,680	1,696	1,172	2,352	2,374
Commercial	86	184	199	228	491	531	428	921	996
Industrial	206	415	420	464	933	944	824	1,660	1,678
C&I Backup Generation (MW)	393	817	854	524	1,089	1,138	655	1,361	1,423
Total DR Potential (MW)	1,186	2,424	2,490	2,052	4,193	4,309	3,078	6,296	6,471
DR Potential as % of Total Peak Demand	3.2%	6.4%	6.3%	5.6%	11.0%	10.8%	8.4%	16.4%	16.2%
a. See Section 3 for underlying data and assumptions.									

Figure 26 shows the resulting load shed reductions possible for Ohio, by sector, from year 2010, when load reductions are expected to begin, through year 2025.

Figure 26. Potential DR Load Reductions in Ohio by Sector (MW)



D.2. Defining Demand Response

DR focuses on shifting energy from peak periods to off-peak periods and clipping peak demands on days with the highest demands. Within the set of demand-side options, DR focuses on clipping peak demands that may allow for the deferral of new capacity additions, and it can enhance operating reserves available to mitigate system emergencies. Energy efficiency focuses on reducing overall energy consumption with attendant permanent reductions in peak demand growth. Taken together, these two demand-side options can provide opportunities to more efficiently manage growth, provide customers with increased options to manage energy costs, and develop least cost resource plans.

DR is an increasingly important tool for resource planning as power plant siting has grown more difficult and the costs of peak power have increased. Through development of DR capability, utilities can complement existing energy efficiency programs with a set of offerings that provide, at a minimum, 1) enhanced reliability, 2) cost savings, 3) reduced operating risk through resource diversification, and 4) increased opportunities for customers to manage their electric bills.

DR resources are usually grouped into two types: 1) load-curtailment activities where utilities can "call" for load reductions; and 2) price-based incentives which use time-differentiated and/or dispatchable rates to shift load away from peak demand periods and reduce overall peak-period consumption. Interest in both types of DR activities has increased across the country as fuel input prices have increased, environmental compliance costs have become more uncertain, and investment in overall electric infrastructure is needed to support new generation resources.

The mechanisms that utilities may use to achieve load reductions can range from voluntary curtailments to mandatory interruptions. These mechanisms include, but are not limited to:

- Direct load control by the utility using radio frequency or other communications platforms to trigger load devices connected to air conditioners, electric water heaters, and pool pumps;
- Manual load curtailments at commercial and industrial (C&I) facilities, including shutting off production lines and dimming overhead lighting;
- Automated DR ("Auto-DR") technologies utilizing controls or energy management systems to reduce major C&I loads in a pre-determined manner (e.g., raising temperature set points and reducing lighting loads); and
- Behavior modifications such as raising thermostat set points, deferring electric clothes drying in homes, and reducing lighting loads in commercial facilities.

D.3. Rationale for Demand Response

DR alternatives can be implemented to help ensure that a utility continues to provide reliable electric service at the least cost to its customers. Specific drivers often cited for DR include the following:

- **Ensure reliability** – DR provides load reductions on the customer side of the meter that can help alleviate system emergencies and help create a robust resource portfolio of both demand-side and supply-side resources that meet reliability objectives.
- **Reduce supply costs** – DR may be a less expensive option per megawatt than other resource alternatives. DR resources compete directly with supply-side resources in many regions of the country. Portfolios that help lower the increase in customers' expenditures on electricity over time represent an increasingly important attribute from the perspective of many energy customers.
- **Manage operational and economic risk through portfolio diversification** – DR capability is a resource that can diversify peaking capabilities. This creates an alternative means of meeting peak demand and reduces the risk that utilities will suffer financially due to transmission constraints, fuel supply disruptions, or increases in fuel costs.
- **Provide customers with greater control over electric bills –** DR programs would allow customers to save on their electric bills by shifting their consumption away from higher cost hours and/or responding to DR events. The ability to manage increases in energy costs has increased in importance for both residential and commercial customers. Standard residential and commercial tariffs provide customers with relatively few opportunities to manage their bills.
- **Address legislative/regulatory interest in DR –** Ohio's adopted renewable portfolio standards (RPS) include demand side options among the means by which the standards can be met. Senate Bill 221 includes strong standards for renewable energy and energy efficiency that will result in 12.5% of Ohio's electricity coming from renewable sources of power and a 22% cumulative reduction in energy usage by 2025. Also, EPACT 1252 has been adopted in Ohio, requiring electric distribution companies to offer dynamic pricing to all customer classes and to make available smart meters to all customers.

DR is gaining greater acceptance among both utilities and regulators in the United States. A 2006 FERC survey found that 234 "entities" were offering direct load control programs and the FERC's assessment noted that "there has been a recent upsurge in interest and activity in DR nationally and, in particular, regional markets” (FERC 2006).[61] The recent proliferation of DR offerings has been promoted in part by utilities hoping to reduce system peaks while offering customers more control over electric bills and in part by regulators. Although federal legislation has not been the driver behind the trend, it is one of many indications, at all levels of government and industry, of the growing support for DR.[62]

Many states experience significant reductions in peak demand from Demand-Side Management (DSM) programs (which include DR programs). Regulatory filings show that California experienced 495 MW in peak demand reductions in 2005 (1% of total peak demand); New York experienced 288 MW reductions in 2005 (1% of total peak demand); and Texas experienced 181 MW in reductions in 2005 (1% of total peak demand) from DSM programs. These results are annual values that do not consider the cumulative (i.e., year-to-year) impacts that accrue over the lifetimes of the conservation measures. Therefore, cumulative percentage reductions in peak demand are much higher than the annual figures stated.

D.4. Assessment Methods

As has been shown in numerous other jurisdictions across North America, well-designed DSM programs incorporating DR strategies represent an effective and affordable option for reducing peak demand and meeting growing demand for electricity. This effort estimated conservative peak demand reduction for Ohio using local energy use characteristics, demographics, and forecast peak demand, assuming relatively basic DR strategies comprising responsive reductions in demand. The following research approach was used to conduct the analysis:

- Review of existing information regarding Ohio’s customer base including:
  - Customer counts and average annual energy consumption by market segment;
  - Forecasts of future energy consumption and customer counts by market segment;
  - Previous DSM planning and potential studies.
- Review of additional publicly-available secondary sources including:
  - U.S. DOE’s Commercial Building Energy Consumption Survey (CBECS) and Residential Energy Consumption Survey (RECS) data;
  - Previous studies relevant to the current effort completed by Summit Blue in other regions as well as entities in other jurisdictions.
- Development of baseline profiles for residential and commercial customers. These profiles include current and forecast numbers of customers by market segment and electricity use profiles by segment.
- Incorporation of ACEEE baseline data and reference case into analysis.
- Obtaining state-level data when possible and estimation of information for the State of Ohio, when state-level data was not available.

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[61] The FERC report uses the term “entities” to refer to all types of electric utilities, as well as organizations such as power marketers and curtailment service providers.

[62] The federal Energy Policy Act of 2005 (EPAct) directs the Secretary of Energy to “identify and address barriers to the adoption of demand response programs,” and the Act declares a U.S. policy in support of “State energy policies to provide reliable and affordable demand response services.” EPAct directed FERC to conduct its survey of DR programs and also directed the U.S. Department of Energy to report on the benefits of DR and how to achieve them (DOE, 2006). Separately, a *National Action Plan for Energy Efficiency,* which advocates DR and other efficiency efforts, was developed by more than 50 U.S. companies, government bodies, and other organizations, including co-chairs Diane Munns, President of NARUC and Jim Rogers, President and CEO of Duke Energy (U.S. Environmental Protection Agency, 2006). Other utility industry members of the Leadership Group included Southern Company, AEP, PG&E, TVA, PJM Interconnection, ISO New England, and the California Energy Commission.

- Development of a spreadsheet approach for estimating peak demand reduction potential associated with the DR programs/technologies deemed to be most applicable to Ohio. Estimates are developed for three scenarios—low, medium and high case scenarios.
- Conference calls with ACEEE staff and industry professionals to discuss assessment processes and legislative, regulatory, and other factors specific to the State of Ohio.
- Incorporation of all sources of information and references into report, noting on each figure the source of the information.
- Revision of draft report based on comments from ACEEE, industry specialists and utility commenters.

The DR potential estimated used historical data and experience to obtain curtailment levels. This potential is assumed to be the achievable potential that would be cost effective, given the range of incentives that are typically required and the range of the utilities' avoided costs. A cost-effectiveness analysis was not performed for this study. Sufficient incentives could be provided to customers to encourage load reductions while maintaining a cost-effective program given avoided costs of approximately $76 per kW (based on the analysis reference case).

D.4.1. State of Ohio - Background

A sound strategy for development of DR resources requires an understanding of Ohio's demand and resource supply situation, including projected system demand, peak-day load shapes, and existing and planned generation resources and costs.

Ohio utilities serves a population of over 11.5 million, generation over 155 million megawatt hours of electricity, that is expected to have a system peak load of almost 30,000 MW in 2009 (ACEEE base case for Ohio).

Electricity demand in Ohio has fluctuated over the past 15 years (EIA 2009). Total consumption has grown only slightly. Total retail sales in 2007 in Ohio totaled 161.5 billion kWh. This is an aggregate figure for all sectors, including industrial, commercial and residential.

Ohio has been and likely will continue to be a modest importer of energy and likewise be dependent on out-of-state capacity. In 2007, in-state generation provided 89% of total Ohio retail sales, thus requiring import of approximately 11% (EIA 2009).

Most of Ohio is located within the PJM regional transmission organization (RTO), the largest power region in the US with installed capacity of over 164,000 MW. PJM covers 11 states including Pennsylvania, New Jersey, Maryland, Delaware, Virginia, and parts of Ohio, Indiana, Illinois, Michigan and North Carolina. See Section 2.2 for a discussion of PJM's DR programs.

The five largest electricity retailers in Ohio are the following entities, with percent contribution in parentheses:

- Ohio Power Co (17%)
- Ohio Edison Co (13%)
- Duke Energy Ohio Inc (13%)
- Columbus Southern Power Co (13%)
- Cleveland Electric Illum Co (11%) (EIA 2009).

D.4.2. Assessment of Utility DR Activities

The PJM Interconnection provides opportunities for DR to realize value for demand reductions in the Energy, Capacity, Synchronized Reserve, and Regulation markets. The FERC authorized PJM to provide these opportunities as permanent features of these markets in early 2006 (PJM 2008a).

The PJM Economic Load Response Program enables customers to voluntarily respond to PJM Locational Marginal Price ("LMP") prices by reducing consumption and receiving a payment for the reduction. The growth of participation by end-use customers since 2002 is significant, with over 225,000 MWh of participation in 2006 (PJM 2008a).

Under the Reliability Pricing Model (RPM), customers can offer DR as a forward capacity resource. DR providers can submit offers to provide a demand reduction as a capacity resource in the forward RPM auctions. In the first annual RPM auction which was held in April 2007 for the 2007/2008 planning period, 127.6 MW of demand response offers were cleared (PJM 2008a).[63]

PJM held a symposium on DR in May, 2007 that was attended by a broad mix of stakeholders and subject matter experts. One of the most prominent themes to emerge from the symposium was the need for coordination between retail and wholesale markets in order to increase DR participation in PJM's markets. The participants at the PJM Symposium on DR identified priority opportunities, which formed the basis of a “Demand Response Roadmap” to guide action (PJM 2008b).

Duke Energy offers the following programs:

- Smart $aver Incentive Program for rebates on products ranging from clothes washers to window films to chillers. Incentives are prescriptive, based on the efficiency and capacity of equipment.
- PowerShare pricing program, in which participants are remunerated for reducing load below a customer-specific baseline during summer weekdays when market prices are high. There are two options: a voluntary and mandatory one. Payments are higher for the mandatory program, but there is a penalty for not meeting the committed load shed during notified events.
- Real Time Pricing Program, in which participants are alternatively credited or charged, based on the hourly price, for usage below or above a pre-determined customer baseline load profile.

Ohio Edison (a subsidiary of First Energy) offers an interruptible option and a voluntary real-time pricing rate:

- OE's Interruptible Rider is for customers on the General Service Large rate (with an interruptible load of at least 1000 kW), who can curtail within 10 minutes of notification. A demand credit is given each month per kVA of interruptible load based on the customer's load that is coincident with the utility's peak demands.
- A "block-and-swing" Experimental Market Based Tariff is available where customers designate a market exposure percentage representing the amount of usage to be applied to real-time pricing. The market exposure percentage must be at least 5% but not more than 30%.

Toledo Edison and the Illuminating Company (Cleveland Electric), both subsidiaries of First Energy, also offer an Experimental Market Based Tariff to customers whose peak load is greater than 100 kW. The customer designates a market exposure percentage representing the amount of usage to be applied to real-time pricing. The remaining usage is priced under a fixed price tariff.

D.4.3. Assessment of Current State Policies Affecting DR

Many states have put in place renewable portfolio standards (RPS) to ensure that a minimum amount of renewable energy is included in the portfolio of the electricity resources serving a state. Many RPS include demand side options among the means by which the standards can be met. In April 2008, a unanimous vote in the Ohio State Senate passed Sub Senate Bill 221 that was previously passed by

[63] It is not known at this time what portion of PJM DR reductions have been fulfilled by Ohio customers.

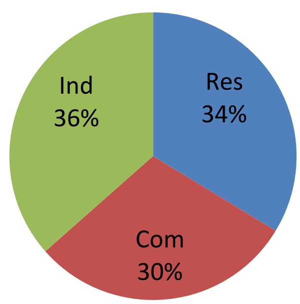
the Ohio House. Included in the legislation are strong standards for renewable energy and energy efficiency that will result in 12.5% of Ohio's electricity coming from renewable sources of power and a 22% cumulative reduction in energy usage by 2025.

Section 1252 of the Energy Policy Act of 2005 (EPACT) includes demand side management provisions (in the form of a new PURPA Standard on Demand Response and Advanced Metering) and directed States and other bodies with authority over utilities to determine whether utilities under their jurisdiction to implement such. Ohio opened a proceeding in December 2005. Via a March 2007 Finding and Order, the Ohio Commission adopted EPACT 1252 and directed electric distribution companies to offer dynamic pricing to all customer classes and to make available smart meters to all customers. This proceeding is still open, however, and further activity is planned. In May 2007, the Commission opened a new proceeding to facilitate a series of technical workshops on EPACT 1252. So far, there have been two workshops: one in July 2007 and one in September 2007.

D.4.4. Energy and Peak Demands

Use of energy in Ohio is distributed to end use categories as follows: 34% residential, 30% commercial, and 36% industrial sectors (see Figure 27). Energy consumption in Ohio's industrial sector ranks among the highest in the Nation (EIA 2009).

Figure 27. Energy Sales in Ohio by Sector (2007)

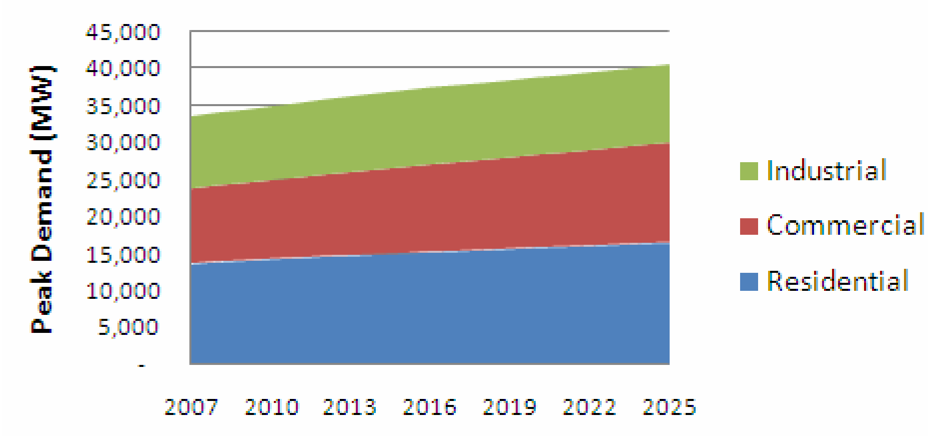


Source: EIA (2008a)

In 2007, the total summer peak load was 33,259 MW and is projected to grow an average of 1% per year through 2025.

Figure 28 displays peak demand by sector. In 2007, residential peak demand was 13,443 MW (41%); commercial was 9,900 MW (30%); and industrial was 9,717 MW (29%).

Figure 28. Peak Demand by Sector in Ohio (MW)



Source: ACEEE Reference Case for Ohio

Smart Grids and Advanced Metering Infrastructure (AMI)

The 2005 EPAct provisions for DR and Smart Metering has lead to a number of states and utilities piloting and implementing a Smart Grid, or sometimes referred to as Advanced Metering Infrastructure (AMI).

Smart Grid is a transformed electricity transmission and distribution network or "grid" that uses robust two-way communications, advanced sensors, and distributed computers to improve the efficiency, reliability and safety of power delivery and use. For energy delivery, the Smart Grid has the ability to sense when a part of its system is overloaded and reroute power to reduce that overload and prevent a potential outage situation. The end user is equipped with real-time communication between the consumer and utility allowing optimization of a consumer’s energy usage based on environmental and/or price preferences (for example, critical peak pricing and time of use rates).

AMI provides:

- Two-way communication between the utility and the customer through the customer’s smart meter.
- More efficient management of customer outages (location, re-routing).
- More accurate meter reading (minute, 15 minute intervals).
- More timely collection efforts (real time).
- Improved efficiency in handling service orders.
- More detailed, timely information about energy use to help customers make informed energy decisions (real time).
- Ability to reduce peak demand.
- More innovative rate options and tools for customers to manage their bills.

Smart Energy Pricing provides:

- Incentives to customers to shift energy away from critical peak periods
- The ability to for customers to save on their electricity bills.
- Lower wholesale prices for capacity and transmission—in the longer term.
- Improved electric system reliability, as demand is moderated.
- Potential to defer new transmission and generation.

The Smart Grid is comprised of multiple communication systems and equipment, which interoperability is crucial. Not all communication protocols are applicable to every utility’s geography; therefore, pilots are essential in testing the equipment and communication software for various geographies. Furthermore, the identification of those geographic regions with the best return on investment during a pilot will aid the staged implementation plan. Standards are continuing to be researched through organizations including: 1) IntelliGrid—Created by the Electric Power Research Institute (EPRI); 2) Modern Grid Initiative (MGI) is a collaborative effort between the U.S. Department of Energy (DOE), the National Energy Technology Laboratory (NETL), utilities, consumers, researchers, and other grid stakeholders; 3) Grid 2030—Grid 2030 is a joint vision statement for the U.S. electrical system developed by the electric utility industry, equipment manufacturers, information technology providers, federal and state government agencies, interest groups, universities, and national laboratories; 4) GridWise—a DOE Office of Electricity Delivery and Energy Reliability (OE) program; 5) GridWise Architecture Council (GWAC) was formed by the U.S. Department of Energy; and 6) GridWorks—A DOE OE program.

Principal benefits of Smart Grid technologies for DR include increased participation rates and lower costs. In 2009, Dominion plans to deploy 200,000 smart meters as part of a large demonstration program of smart grid technology in urban and rural areas of Dominion's service territory. Dominion expects to improve customer service and business operations through advanced system control, real-time outage notification, and power quality monitoring. As part of this program, Dominion is deploying a number of smart thermostats for a residential critical peak pricing pilot during the summer of 2008. Dominion will measure customer responsiveness to changing energy prices and the impact on energy demand during peak usage periods (Utility Products 2008).

These developments in technology allowing real time signaling and automated response will improve DR capabilities. However, existing technology exists for successful DR implementation and it is important to point out that there are no technology obstacles to effective DR.

D.5. Assessment of DR Potential in Ohio

This section examines and quantifies DR potential in Ohio. Section 5.1 outlines the general DR program categories, while Sections 5.2 and 5.3 outline the DR potential in the residential and commercial /industrial sectors, respectively. Section 5.4 discusses the load reduction potential from backup generation and Section 5.5 explains the issues surrounding rate pricing, even though benefits from this form of DR are not quantified in this analysis. Section 5.6 concludes with a summary of DR potential in Ohio.

D.5.1. Demand Response Program Categories

For the purposes of assessing DR alternatives, the following programs could be employed in Ohio to achieve the DR potential we outlined in this report:

Resource Category	Characteristics
Direct Load Control (DLC)	Direct load control (DLC) programs have typically been mass-market programs directed at residential and small commercial (<100 kW peak demand) air conditioning and other appliances. However, an emerging trend is to target commercial buildings with what has become known as Automated Demand Response or Auto-DR. Increased use and functionality of energy management systems at commercial sites and an increased interest by commercial customers in participating in these programs is driving growth in automated commercial curtailment in response to a utility signal. The common factor in these programs is that they are actuated directly by the utility and require the installation of control and communications infrastructure to facilitate the control process.
Callable Customer Load Response	With this type of program, utilities offer customers incentives to reduce their electric demand for specified periods of time when notified by the utility. These programs include curtailable and interruptible rate programs and demand bidding/buyback programs. Curtailable and interruptible rate programs can be used as “emergency demand response” if the advanced notice requirements are short enough. All customer load response programs require communications protocols to notify customers and appropriate metering to assess customer response.
Scheduled Load Control	This is a class of programs where customers schedule load reductions at pre-determined times and in pre-determined amounts. A variant on this theme is thermal energy storage which employs fixed asset technology to reduce air conditioning loads consistently during peak afternoon load periods.
Time-differentiated Rates	Pricing programs can employ rates that vary over time to encourage customers to reduce their demand for electricity in response to economic signals—in some cases these load reductions can be automated when a price trigger is exceeded. An example is a critical peak price which is “called” by the utility or system operator. In response to this critical price, residential customers can have AC cycling or temperature setbacks automatically deployed. Similar automated responses can be deployed by commercial customers. These rate programs are not analyzed for this assessment, but are further discussed in Section 3.5.

D.5.2. DR for Residential Customers

Air conditioner and other appliance direct load control (DLC) is the most common form of non-price-based DR program in terms of the number of utilities using it and the number of customers enrolled. According to FERC’s 2006 assessment of DR and advanced metering, there are 234 utilities (including municipalities, cooperatives, and related entities) with DLC programs across the United States. Approximately 4.8 million customers are participating in DLC programs across the country (FERC 2006).

The prominent and growing role of air conditioning in creating system peaks makes it a high-profile candidate for DR efforts. The advances in DR technology that make AC load management economically viable make AC load control a high-priority program—one that has been proven reliable and effective at many utilities. Pool pumps are also a relatively easy and non-disruptive load that can be controlled for DR purposes.

Residential Control Strategies

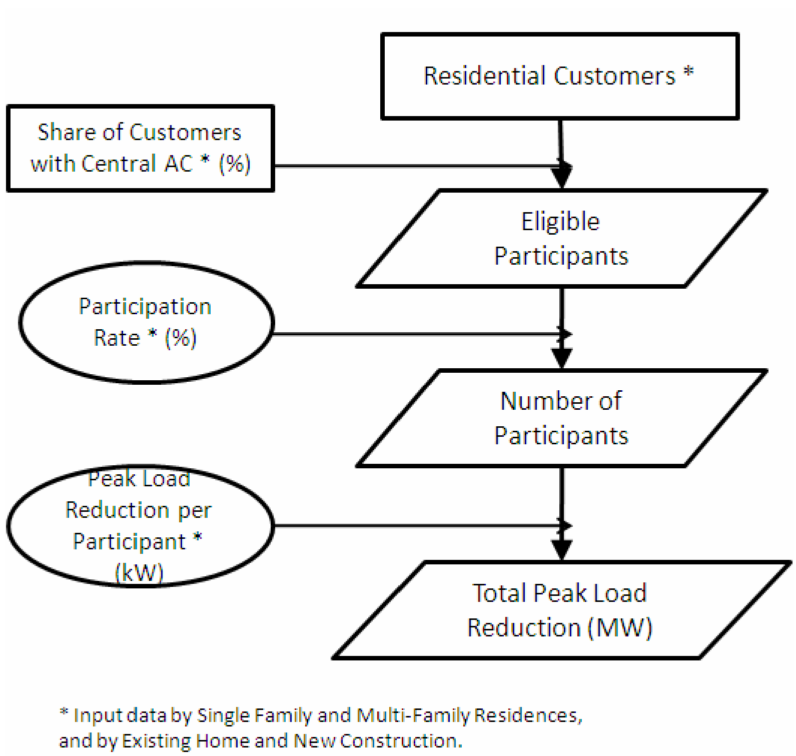
There are two basic types of control strategies: AC cycling and temperature offset. AC cycling limits ACs being on to a certain number of minutes than they otherwise would have been on. Some techniques limit ACs to being on for 50% of the minutes they would otherwise have been on. A temperature offset increases the thermostat setting for a certain period of time, for a certain number of degrees higher than it would have otherwise been set. This essentially causes the AC compressor to cycle as the temperature set-back reduces the AC demand. Sequential thermostat setbacks, i.e., one degree in a hour one, two degrees in hour two, three degrees in hour three, and four degrees in hour four can mimic an AC cycling strategy.

Cycling strategies have evolved where an optimal impact on peak kW demand may be obtained by varying the cycling time across the hours of an event. For example, there may be one hour of pre-cooling followed by 33% cycling in the first hour, 50% cycling in the second hour, 66% cycling in the third hour and dropping back to 33% in the fourth hour. Strategies like this have been deployed in pilot programs at Progress Energy Carolinas (PEC) and in PSE&G's MyPower pilot program. This type of strategy requires that forecasters accurately predict the hour(s) in which the peak system demand will occur.

Assessment of DR Potential in Residential Homes in Ohio

For Ohio, estimates for possible load reductions for residential housing units were obtained by applying the methodology displayed in Figure 29.

Figure 29. Residential Peak Load Reduction



The figure shows how load reductions and participations rates are applied to housing data. Items listed in rectangular shapes are factual inputs; items in circular shapes are assumptions; and items in parallelogram shapes are results.

D.5.3. Load Reductions

Recent surveys show that DLC programs are being implemented by a number of utilities. Load impacts are dependent on many variables. The control strategy used, the outdoor temperature, the time of day, the customer segment, ease of and ability to override control, reliability of communication signals, age and working condition of installed equipment, and local AC use patterns all have significant effects on the load impact. Even within a single program, there is variability in impacts across event days that cannot yet be fully explained. Measuring impacts typically requires expensive monitoring equipment and as a result is often done on small sample sizes.

Even with this variability, a review of reported impacts does show some general consistencies. As expected, impacts increase as the duty cycle goes up. Table 33 shows the average reported kW impact based on 20 load control impact studies for programs based on the duty cycle used. These results support the oft-quoted rule-of-thumb that the load impact for 50% duty cycling is 1 kW per customer, which is the impact used in this analysis. However, many homes will experience an impact greater than I kW, especially newer homes.

Table 33. Average Load Impacts by Cycling Strategy for AC DLC Programs

Cycling Strategy	Average Load Impact KW/Customer
33%	0.74
45%	0.81
50%	1.04
66%	1.36

Source: Summit Blue 2007b.

Customer type also makes a difference. In a few cases where single-family and multi-family impacts were measured separately, multi-family impacts were 60% of single-family, and thus a 0.6kW load reduction is applied in this analysis for multi-family units (Summit Blue 2007b).

Eligible Residential Customers

All residential customers with central air-conditioning that live in areas that can receive control signals are considered eligible for the direct load control program. This includes single family and multi-family housing units. Residential accounts without central AC are assumed to have no participation. The ACEEE Reference Case reports that 64% of all housing units have CAC in Ohio – both single family and multi-family.

Multi-family housing units often have building tenants which are not the account holders, therefore accounts are often aggregated into buildings. Some accounts have a master meter for the entire building, including tenants. Some accounts are for the “common” building loads (i.e., those loads that are part of a building account such as elevators, A/C (if applicable), lobby lighting, etc.), but individual tenants in these buildings have their own accounts. There, multi-family units often have fewer units with central AC than single family. However, in this analysis, due to data constraints, 64% was applied to both single and multi-family customers, and leads to a more conservative estimate of impacts.

Residential Participation Rates

Participation rates experienced in AC DLC programs vary across utilities typically from 7% of eligible customers to 40%, depending upon the effort made in maintaining and marketing the program (Summit Blue 2007a). The utilities with the low levels of participation had essentially stopped marketing the program in recent years. Utilities with programs with sustained attention to customer retention or recruitment show higher participation rates than utilities with one-time or intermittent promotion. In Maryland, BG&E’s Demand Response Service program anticipates a residential participation rate of 50%, or approximately 450,000 controlled units (BGE 2007). The pilot phase of this program was conducted from June 1 through September 30, 2007, and 58% received a “smart” load control switch, and 42% had a “smart” thermostat installed (BGE 2007). One study examined 15 AC DLC programs nationwide and found an average of 24% participation for eligible customers (Summit Blue 2008a).[64] For this analysis, 3 typical yet conservative scenarios were used: a low scenario of 15% for eligible customers; a medium scenario of 25%; and a high scenario of 35%.

Results

Table 34 displays the input data and results. In summary, the results for residential programs reveal that a medium scenario reduction of 837MW is possible by 2015 (with 502MW possible by the low scenario, and 1,172MW by the high scenario). By 2020, 1,680MW is achievable through the medium scenario (with 1,008MW possible by the low scenario, and 2,352MW by the high).

Table 34. Potential Load Reduction from AC-DLC In Ohio Residential Homes, in years 2015 and 2020

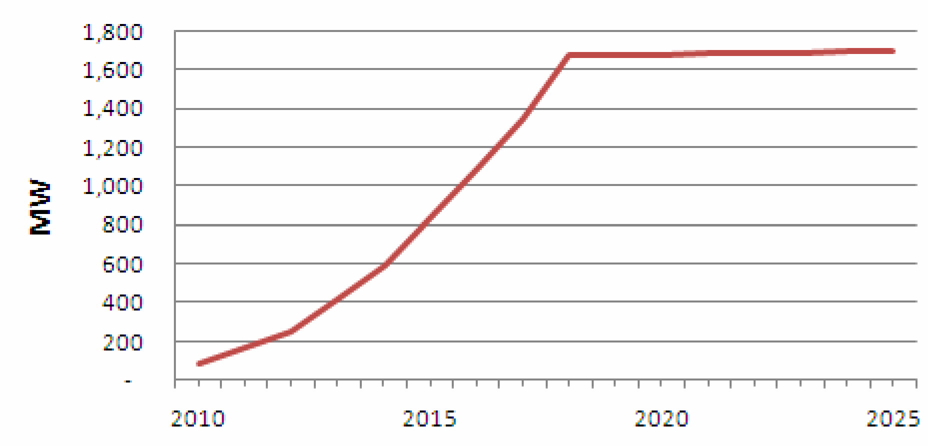
INPUTS	**2015**	**2020**
Residential Peak Demand (MW)	14,826	15,618
Residential Customers (in thousands) [a]: Total	11,472	11,513
Single Family	8,777	8,793
Multi-Family	2,695	2,720
Eligible Residential Customers: Single and Multi-Family[b]	64%	
Load Reduction per AC-DLC per Single-Family Unit (kW)	1.0	
Load Reduction per AC-DLC per Multi-Family Unit (kW)	0.6	
DR Participation Rates of eligible customers:		
Low Scenario	25%	
Medium Scenario	25%	
High Scenario [c]	35%	
RESULTS	**2015**	**2020**
Residential Potential DR Load Reduction (MW):		
Low Scenario	502	1,008
Medium Scenario	837	1,680
High Scenario	1,172	2,352

Notes:
a. Residential customers reflect number of housing units, as reported from Economy.com.
b. Analysis assumes residences with central AC are eligible. Residential accounts without central AC are assumed to have no participation. Central AC percents obtained from ACEEE Reference Case.
c. Higher participation than applied in the High Scenario is possible through design of program features, such as “opt-out” participation where participants are included in a program unless they chose to “opt-out.”

Figure 30 shows the resulting residential load shed reductions possible for Ohio, from year 2010, when load reductions are expected to begin, through year 2025.

Figure 30. Potential Residential Load Shed in Ohio (Medium Scenario)

[64] Programs where participants are included in a program unless they chose to “opt-out” experience much higher participation rates. One utility is proposing a “hybrid” program for new construction, where existing customers must opt-in and new construction customers must opt-out. This program assumes that 70% of new construction customers will enroll in the initial years, and 80% in later years (Summit Blue, 2008b).



D.5.4. Room Air Conditioners

Other DR residential programs could involve tapping into the potential for callable load reductions from room air conditioners. At least one prominent DR provider is exploring the possibility of having manufacturers of room AC units embedding a home-area-network communication device into new units. This would enable cycling of room air conditioners without the need to install radio frequency load switches commonly used for residential direct load control applications. Callable load reductions from room air conditioners would provide a significant boost to load control capability and these reductions would be dispatchable in less than ten minutes. Some utilities are projecting to add a large number of new room air conditioners in the next five to ten years. The additional participation of a fraction of these room AC units could provide a substantial increase to the AC DLC program.

D.5.5 Other Appliances

Based on the experiences of other utilities, expanding the equipment controlled to other equipment beyond AC units can produce additional kW reductions. This could include electric hot water heaters and pool pumps. However, the saturation of electric hot water heaters is lower than for air conditioning, and control of hot water heaters generally produces only about one-third the load impact of air conditioners, especially in the summer when Ohio utilities would most likely be calling DR events.

D.6. Commercial and Industrial DR Potential in Ohio

Appropriate commercial sector DR programs will vary according to customer size and the type of facility. Direct load control of space conditioner equipment is a primary DR strategy intended for small commercial customers (e.g., under 100 kW peak load), although TOU rates combined with promising new thermal energy storage technologies could prove an effective combination. Mid-to-large commercial customers and smaller industrial customers could best be targeted for a curtailable load program requiring several hours of advanced notification or, where practical, for an Auto-DR program that can deliver load reductions with no more than ten minutes of advance notice. Thermal energy storage and other scheduled load control programs may also be applicable for some larger buildings or water pumping customers. In this assessment of DR potential, the focus is on the use of direct load control and curtailable load response programs. Studies have shown that pricing programs, specifically dispatchable pricing programs such as critical peak pricing (CPP) programs can provide similar impacts. These pricing programs are discussed in Section 5.2. However, for the purposes of this assessment, a focus on these load response programs is believed to be able to fully represent the DR potential, even though pricing programs could be used instead of these curtailable load programs with equal, or in some cases, greater efficiency.

The following DR program descriptions apply to both commercial and industrial customers:

- Small business direct load control (air conditioning)—Small commercial customers (under 100 kW peak load) account for a majority of customer accounts but typically only about one-quarter of total commercial load. Due to the nature of small businesses, particularly their small staffs for which energy management is a relatively low priority, it is not practical to rely on active customer response to load control events. Thus, small businesses may best be viewed in the same way as residential customers for purposes of DR.

- Curtailable load program—This program would be applicable to commercial and industrial customers willing to commit to self-activated load reductions of a minimum of perhaps 50 kW in response to a notice and request from a utility. The minimum curtailment threshold is designed to improve program cost-effectiveness by ensuring that recruitment and technical assistance costs are used for customers who can deliver significant load reductions. Advanced notice requirements would likely be two hours— long enough to allow customers an opportunity to prepare but short enough to maintain the DR resource as a viable resource that can be dispatched by operations staff. Enabling technologies would vary greatly, but utilities would educate customers about alternatives and could work with equipment vendors to facilitate equipment acquisition and installation. Incentives would be paid as capacity payment (in $/kW-month) or a discount on the customers' demand charges. Utilities could also offer a voluntary version of the program to attract greater participation. Customers would not commit to load reductions, but incentives would be lower and would be paid only on the reductions achieved during curtailment events.

- Automated demand response (Auto-DR)—This program would be marketed to facilities such as high-rise office buildings and large retail businesses that have energy management and control systems (EMCS) that monitor and control HVAC systems, lighting, and other building functions. The benefits of Auto-DR over curtailable load programs include customer loads curtailments with as little as ten minutes notice and greater assurance that customers will reduce loads by at least their contracted amount. Incentives would be paid as either capacity payments or demand charge discounts, but would be greater than for curtailable load program participants due to the additional technology investment that may be required and the allowance of curtailments on relatively short notice. Utilities would offer extensive technical assistance in setting up Auto-DR capability and would potentially provide financial assistance as well for customers making long-term commitments.

- Scheduled load control programs (including thermal energy storage)—Scheduled load control can help reduce utility peak demand, especially through shifting of space cooling loads enabled by thermal energy storage technologies. Large-customer TES systems could be promoted along with customer commitments to reduce operation of chillers or rooftop air conditioners during specified peak hours. Customers' return on investment can be increased by encouraging migration to a TOU rate, which would offer a rate discount for many of the hours that TES systems are recharging cooling capacity. Water pumping systems are typically good candidates for scheduled load control programs and utilities can investigate opportunities in the municipal water supply and irrigation sectors. Other, less traditional, opportunities may also be available, such as the leisure/resort industry's limiting recharging of electric golf carts to off-peak hours.

- Emergency under-frequency relay (program add-on)—Under-frequency relays (UFRs) automatically shut off electrical circuits in response to the circuits exceeding pre-set voltage thresholds specified by the utility. Use of UFRs is a valuable addition to a DR portfolio because the load response is both automatic and virtually instantaneous. UFRs can best be integrated into another DR program where participants are already engaging in load curtailment activities. It is expected that some customers who might consider participating in a DR program will not be willing to allow loads to be controlled via UFR since they would not receive any advanced notice. Incentives would also need to be greater to attract participants and provide acceptable compensation. However, the benefits of UFRs warrant their consideration as part of a utility's proposed DR portfolio.

D.6.1. Commercial DR Potential in Ohio

To estimate potential load reductions for commercial units, a straight-forward approach of applying load shed participation rates and curtailment rates directly to commercial peak demand.

First, assumptions were made on the percentage of commercial customers who are willing to participate in DR programs. One study applied commercial participation rates ranging from 11% to 48% for commercial customers (Summit Blue 2008a). Table 35 displays participation rates for various types of commercial customers, disaggregated into two different peak demand categories (<300kW and >300kW).

Table 35. Examples of Commercial Load Shed Participation Rates

	Peak Category	
Customer Segment	<300kW	>300kW
Office Buildings	11% - 15%	45% - 48%
Hospitals	13%	48%
Hotels	14%	45%
Educational Facilities	13%	43%
Retail	11%	42%
Supermarkets	12%	33%
Restaurants	11%	39%
Other Government Facilities	15%	44%
Entertainment	13%	41%

Source: Summit Blue 2008a.

Because facility-specific data was not available for Ohio, three conservative scenarios for participation rates were applied. A medium-scenario load participation rate of 20% was applied as it appears to be an average participation rate found by utilities with DR programs in place. A low scenario of 10% and a high scenario of 30% are applied.

Then, assumptions were made for curtailment rates, based on existing estimates of the fraction of load that has been shed by commercial customers enrolled in event-based DR programs callable by the utility.

Table 36. Examples of Commercial Curtailment Rates

displays curtailment rates for various types of commercial customers, which range from 13% to 43%. For the purposes of this analysis, 3 conservative scenarios were applied: a low curtailment rate of 15%, a medium curtailment rate of 20%, and a high rate of 25%.

Table 36. Examples of Commercial Curtailment Rates

Customer Segment	Average Curtailment Rate
Office Buildings	21%
Hospitals	18%
Hotels	15%
Educational Facilities	22%
Retail	18%
Supermarkets	13%
Restaurants	17%
Other Government Facilities	38%
Entertainment	43%

Source: Summit Blue 2008a

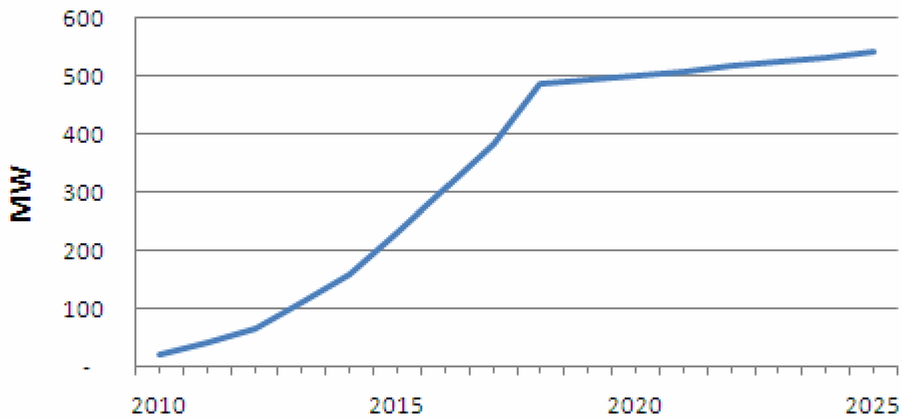
Table 37 displays the input data and results. In summary, the commercial sector results reveal that a medium scenario reduction of 232MW is possible by 2015 (with 86 MW possible by the low scenario, and 428 MW by the high). By 2020, 491 MW is achievable through the medium scenario (with 184 MW possible by the low scenario, and 921 MW by the high).

Table 37. Potential Commercial Load Shed in Ohio, in Years 2015 and 2020

INPUTS	**2015**	**2020**
Commercial Peak Demand (MW)	11,402	12,283
Load Shed Participation Rates:		
Low	10%	
Medium	20%	
High	30%	
Curtailment Rates:		
Low	15%	
Medium	20%	
High	25%	
RESULTS	**2015**	**2020**
Commercial DR load reductions (MW):		
Low	86	184
Medium	228	491
High	428	921

Figure 31 shows the resulting commercial load shed reductions possible for Ohio, from year 2010, when load reductions are expected to begin, through year 2025.

Figure 31. Potential Commercial Load Shed in Ohio (Medium Scenario)



DR programs that move towards the auto-DR concept can typically provide some load sheds that only require ten-minute notification or less. While some customer surveys have shown that most customers would prefer longer notification periods, many of these customers have not put in place the technologies to automate DR both load shed within a facility and the startup of emergency generation (ConEd 2008). The value of DR and the design of DR programs should take into account system operations. Ten-minute notice DR can be valuable in helping defer some investment in T&D. While not all customers may choose to provide ten-minute notice response, there should be an increasing number of customers that will provide this type of response in the future and programs should be designed to acquire this resource. This type of DR is often a more valuable form of DR with higher savings for the utility, and utilities are often ready to pay up to twice as much to customers for this short-notice responsiveness.

Industrial DR Potential in Ohio

A similar analysis was conducted for the industrial sector: load shed participation rates and curtailment rates were applied to industrial peak demand. A previous study found industrial participation rates to vary from 25% for facilities <300kW, to 50% for >300kW (Summit Blue 2008a). For this study, the following rates were applied to participation: Low (20%); Medium (30%); and High (40%).

Previous studies have found industrial curtailment rates to vary from 17% (Quantec 2007), to 30% (Consortium 2004), to 75% (Nordham 2007), resulting in a mean of 41%. The following conservative rates were applied to curtailment for this study: Low (20%); Medium (30%); and High (40%). With these participation rates and potential load curtailments, the high load reduction potential for the overall industrial sector loads is 16% (i.e., 40% participation and 40% of that load participating).

Table 38. Potential Industrial Load Shed in Ohio, for years 2015 and 2020

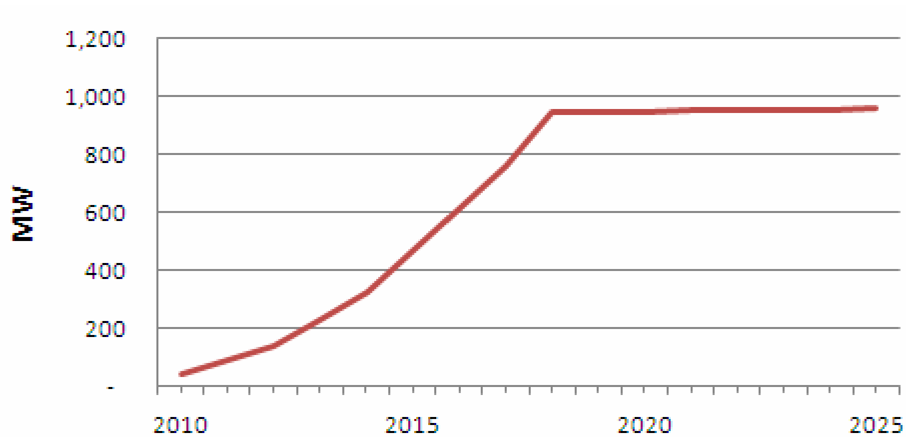
displays the input data and results. In summary, the industrial sector results reveal that a medium scenario reduction of 464 MW is possible by 2015 (with 206 MW possible by the low scenario, and 824 MW by the high). By 2020, 933 MW is achievable through the medium scenario (with 415 MW possible by the low scenario, and 1,660 MW by the high).

Table 38. Potential Industrial Load Shed in Ohio, for years 2015 and 2020

INPUTS	2015	2020
Industrial Peak Demand (MW)	10,304	10,372
Load Participation Rates:		
Low	20%	
Medium	30%	
High	40%	
Curtailment Rates:		
Low	20%	
Medium	30%	
High	40%	
RESULTS	**2015**	**2020**
Industrial DR load reductions (MW):		
Low	206	415
Medium	464	933
High	824	1,660

Figure 32 shows the resulting industrial load shed reductions possible for Ohio, from year 2010, when load reductions are expected to begin, through year 2025.

Figure 32. Potential Industrial Load Shed in Ohio (Medium Scenario)



The largest load reductions, and often the most cost-effective, may be found in Ohio's largest commercial and industrial customers. Data concerning these largest facilities were not available in Ohio so estimates are not quantified separately from the industrial analysis given in the previous section.

D.6.2. Commercial and Industrial Backup Generation Potential in OH

Emergency backup generation is a prominent component of a callable load program strategy. Some of the emergency generators not currently participating in DR programs may not be permitted for use as a DR resource and regulations may further limit the availability of emergency generation for DR. In some cases, backup generators may not be equipped with the start-up equipment to allow the generator to participate in short-term notification programs. Utilities could consider a program to assist customers with equipment specification and set-up to promote DR program participation by backup generators.

In some instances, there may be environmental restrictions on emergency generation. Emissions of emergency generation may be regulated, and the future of such regulations may add some uncertainty. However, some areas have been able to have such restrictions lifted during system emergencies.

Two approaches can increase the amount of emergency generation in DR programs: 1) facilitating customer-owned generation, and 2) utility ownership of the generation, which is used to provide additional reliability for customers willing to locate the equipment at their facilities.

Customer-Owned Emergency Generation

To increase customer-owned emergency generation, utilities may assist customers with ownership of grid-synchronized emergency generation. Utilities may offer to pay for all equipment necessary for parallel interconnection with the utility grid, as well as all maintenance and fuel expenses. Once operational, the standby generators can be monitored and dispatched from a utility's control center, and they can also provide backup power during an outage. An additional benefit to the customer relative to typical backup generation is the seamless transition to and from the generator without the usual momentary power interruption.

Utility-Owned Emergency Generation

A second approach to increasing the availability of emergency generation for DR is by locating generation at customer sites that can be owned by a utility. Through this type of program, the customer receives emergency generation capability during system outages in exchange for paying a monthly fee consisting of both levelized capital costs and operation and maintenance costs. Participants would likely receive capacity payments ($/kW-month) and/or energy payments ($/kWh) in exchange for granting a utility to dispatch the units for a limited number of events and total hours per year.

Backup Generation in Ohio

Total Ohio back-up generation capacity for 2015 is estimated at approximately 2,618 MW.[65] Additional analysis revealed that the commercial and industrial back-up capacity, each, is almost half of the total capacity, 1,309 MW.[66] Assuming a medium scenario that 40% of the total backup in Ohio is available for load shed, then 524 MW of backup generation is available by 2015 and 1,089 MW is available by 2020 (see

[65] Back-up generation capacity in Ohio was estimated from form EIA-861 filings submitted by utilities nationwide (EIA, 2006). However, only utilities providing approximately one-quarter of total kWh report these numbers. It was assumed that the prevalence and usage of distributed generation in the remaining 75% of utilities is similar.

[66] The analysis first determined the back-up generator population nation-wide, and then scaled the data down to the New England region (CBECS resolution), accounting for proportional differences in building stock nation-wide and region-wide. The region-wide results were then scaled down to Ohio specifically using the ratio of Ohio population to regional population.

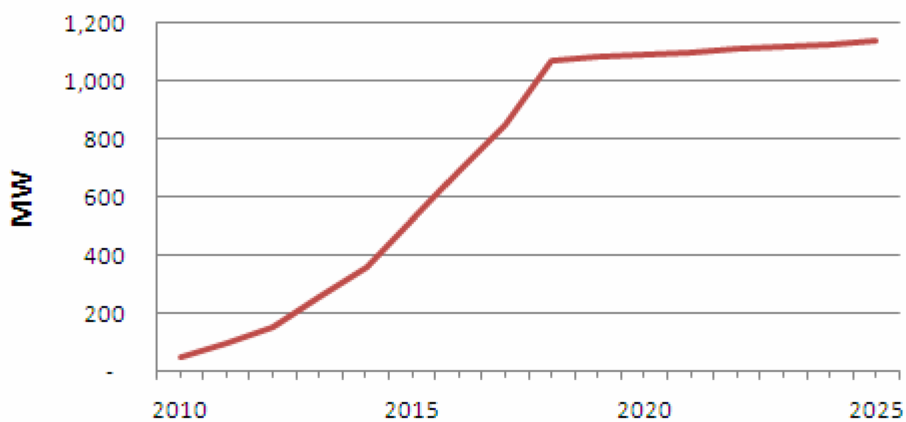
Table 39. Potential Reductions from C&I Backup Generation in Ohio, in Years 2015 and 2020a

). The low scenario estimates a 393 MW reduction by 2015 and an 817 MW reduction by 2020. The high scenario estimates a 655 MW reduction by 2015 and a 1,361 MW reduction by 2020.

Table 39. Potential Reductions from C&I Backup Generation in Ohio, in Years 2015 and 2020[a]		
INPUTS	**2015**	**2020**
Total Backup Generation Capacity in OH (MW)	2,618	2,722
Backup Generation Potential (%):		
Low	30%	
Medium	40%	
High	50%	
RESULTS	**2015**	**2020**
Potential Reduction from C&I Backup Generation (MW):		
Low	393	817
Medium	524	1,089
High	655	1,361

Figure 33 shows the resulting commercial and industrial backup generation reductions possible for Ohio, from year 2010, when load reductions are expected to begin, through year 2025.

Figure 33. Potential Reductions from C&I Backup Generation



D.6.3. Pricing and Rates

In this assessment of DR potential, the focus is on the use of direct load control and curtailable load response programs callable by the utility. Studies have shown that pricing programs, specifically dispatchable pricing programs such as critical peak pricing (CPP) programs can provide similar impacts; however, for the purposes of this assessment, a focus on the these load response programs is believed to be able to fully represent the DR potential, even though pricing programs could be used instead of these curtailable load programs with equal, or in some cases, greater efficiency.

New rates may be introduced as part of a DR program, and may include real-time prices, or other time-differentiated rates, for commercial and industrial customers, and a modification of any existing residential time-of-use (TOU) rates. Any new rate structures would be designed to reduce system demand during peak periods and provide an opportunity for customers to reduce electric bills through load shifting.

Critical peak pricing (CPP) is a viable option for inclusion in a DR portfolio. In FERC's 2006 survey of utilities offering DR programs (citation below), roughly 25 entities reported offering at least one CPP tariff. However, many of the tariffs were pilot programs only, and almost all of the 11,000 participants were residential customers. The apparent lack of commercial CPP programs is supported by a 2006 survey of pricing and DR programs commissioned by the U.S. EPA (below), which found only four large-customer CPP programs, all of them in California. The pilot programs in California linked the CPP rate with "automated demand response" technologies that provide most of the impact. The CPP rate itself, and the price incentive that it creates, is not the driver behind the load reductions.

As stated, rate pricing options were not analyzed in this analysis. Event-based pricing programs achieve impacts very similar to the callable load programs presented above. Pilot studies and tariff evaluations of TOU-CPP programs[67] show the load reductions for called events are similar in magnitude to air conditioning DLC programs. This is not surprising in that most TOU-CPP participants use a programmable-automated thermostat to respond to CPP events in a manner similar to a DLC strategy. One difference is that the customer response is less under the control of the program or system operator that could change cycling strategies or thermostat set points across different events or different hours within an event. Similarly, demand-bid programs are simply calls for target load sheds, i.e., those bid into the program.

In general, the direct load shed programs seem to provide greater MW of participation and more reliable reductions. However, the use of either TOU-CPP or a demand-bid program represents a point of view or policy position that price should be a centerpiece of the DR effort and help customers see prices in the electricity markets. From a point of view of simplicity and attaining firm capacity reductions, the direct load shed programs may offer some advantages. Ultimately, the choice between these direct load shed programs and pricing programs may come down to customer preferences and decisions by policy makers on the emphasis of DR efforts.

A time-differentiated rate is another option to consider that may not be "callable." Such rates include day-ahead real-time pricing (RTP), two-part RTP tariffs, and standard TOU rates. Although they are not "callable" in that the rate is generally in effect every day, there may be synergies between time-differentiated rates and callable load programs. In general, an RTP option will result in customers learning how to reduce energy consumption on essentially a daily basis when prices tend to be high (e.g., summer season afternoons and early evenings). Customers do not tend to track exact hourly prices, but they know when prices are likely to be higher (e.g., summer season afternoons with higher prices on hot days).[68] The benefits to the customer come from reducing consumption across many summer days when prices are high, rather than a focus on reduction during system event days. In general, the reductions on system peak days are roughly the same as on any summer day when prices are reasonably high. As a result, an RTP option can provide substantial benefits by increasing overall market and system efficiency through shifting loads from high priced periods to periods with lower prices. However, these tariffs may not provide the needed load relief on system-constrained event days.[69, 70]

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[67] See Public Service Electric and Gas Company, "Evaluation of the MyPower Pricing Pilot Program," prepared by Summit Blue Consulting, 2007; and the California Energy Commission, "Impact evaluation of the California Statewide Pricing Pilot—Final Report," March 16, 2005. http://www.energy.ca.gov/demandresponse/documents/index.htmll#group3

[68] See evaluations of the hourly pricing experiment offered by ComEd and the Chicago Energy Cooperative performed by Summit Blue Consulting (2003 through 2006).

[69] One way to make an RTP tariff more like an event-based DR program is to overlay a critical peak pricing (CPP) component on the RTP tariff where unusually high prices would be posted to customers with some notification period. Otherwise, it is unlikely that the high levels of reduction needed for system-event days would be attained.

[70] The complementary of event-based load shed programs with RTP tariffs is assessed in: Violette, D., R. Freeman, and C. Neil. "*DR Valuation and Market Analysis—Volume II: Assessing the DR Benefits and Costs*," Prepared for the International Energy Agency, TASK XIII, Demand-Side Programme, Demand Response Resources, January 6, 2006. Updated results are presented in: Violette, D. and R. Freeman; "*Integrating Demand Side Resource Evaluations in Resource Planning*;" Proceedings of the International Energy Program Evaluation Conference (IEPEC), Chicago, August 2007 (also at www.IEPEC.com).

Summary of DR Potential Estimates in Ohio

Table 40 shows the resulting load shed reductions possible for Ohio, by sector, for years 2015, 2020, and 2025. Load impacts grow rapidly through 2018 as program implementation takes hold. After 2018, the program impacts increase at the same rate as the forecasted growth in peak demand.

The high scenario DR load potential reduction is within a range of reasonable outcomes in that it has an eleven year rollout period (beginning of 2010 through the end of 2020), providing a relatively long period of time to ramp up and integrate new technologies that support DR. A value nearer to the high scenario than the medium scenario would make a good MW target for a set of DR activities.

The high scenario results show a reduction in peak demand of 3,078 MW is possible by 2015 (8.4% of peak demand); 6,293 MW is possible by 2020 (16.4% of peak demand); and 6,471 MW is possible by 2025 (16.2% of peak demand).

The more conservative medium scenario results show a reduction in peak demand of 2,052MW is possible by 2015 (5.6% of peak demand); 4,193MW is possible by 2020 (11.0% of peak demand); and 4,309 MW is possible by 2025 (10.8% of peak demand).

These estimated reductions in peak demand are within a range to be expected for a population of Ohio's size. Estimates of DR in other states show that the estimates calculated here for Ohio are reasonable: 15% reductions in peak demand in Florida are possible by 2023 (Elliot et al. 2007a), and 13% are possible in Texas, also by year 2023 (Elliot et al. 2007b). DR potential for a utility in New York was estimated to be 9.3% of peak demand in 2017 (Summit Blue 2008a). This finding is similar to that of a recent analysis estimating that peak load reductions from DR in the Northeast will be 8.2% of system peak load in 2020 and more than 11% by 2030 (EPRI and EEI 2008). Estimation methods differ among the studies, but nonetheless show that the 10.8% reductions in Ohio are realistic for the medium scenario by 2020.

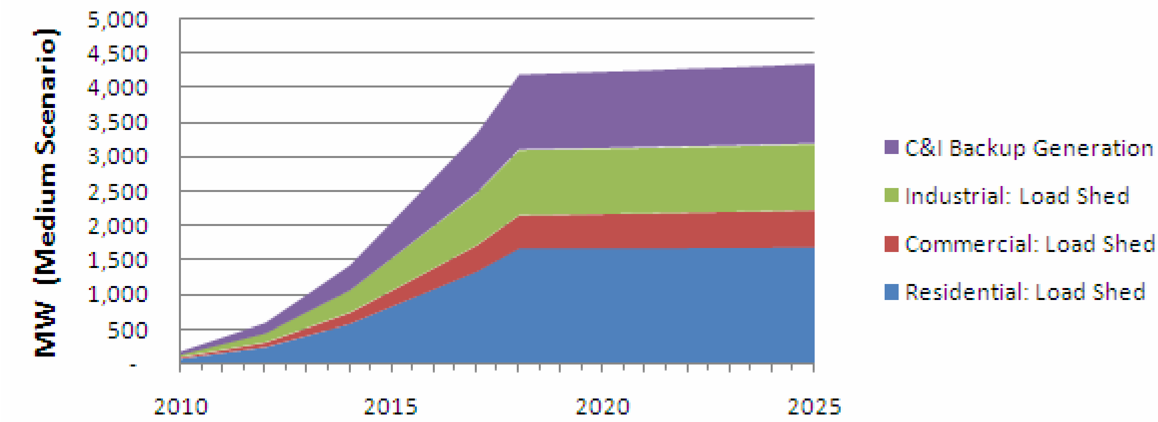
Table 40. Summary of Potential DR in Ohio, By Sector, for Years 2015, 2020, and 2025[a]

	Low Scenario			Medium Scenario			High Scenario		
	2015	**2020**	**2025**	**2015**	**2020**	**2025**	**2015**	**2020**	**2025**
Load Sheds (MW):									
Residential	502	1,008	1,017	837	1,680	1,696	1,172	2,352	2,374
Commercial	86	184	199	228	491	531	428	921	996
Industrial	206	415	420	464	933	944	824	1,660	1,678
C&I Backup Generation (MW)	393	817	854	524	1,089	1,138	655	1,361	1,423
Total DR Potential (MW)	1,186	2,424	2,490	2,052	4,193	4,309	3,078	6,293	6,471
DR Potential as % of Total Peak Demand	3.2%	6.4%	6.3%	5.6%	11.0%	10.8%	8.4%	16.4%	16.2%

a. See Section 3 for underlying data and assumptions.

Figure 34 shows the resulting load shed reductions possible for Ohio, by sector, from year 2010, when load reductions are expected to begin, through year 2025.

Figure 34. Potential DR Load Reductions in Ohio by Sector (MW)



These estimates reflect the level of effort put forth and utilities are recommended to set targets for the high scenarios. These estimates include assumptions based on utility experience regarding growth rates, participation rates, and program design, among others, and will adjust accordingly if differing assumptions are made. The assumptions made are believed to be conservative, and reflect minimum achievable DR potential. For example, participation rates for all of the sectors are based on experience in other states, and are based primarily on customer awareness, the ability to have automated response, and the adequacy of reward. If the statewide education program now required in Ohio promotes DR programs and adequate incentives are offered, then participation rates higher than the medium scenario are entirely realistic.

Recommendations

This assessment indicates that the system peak demand can be reduced by approximately 11.0% or 4,193 MW in 2020 in the medium case. In the high case, the reduction can be as high as 16.4% or 6,293 MW. The high case is considered to be within a reasonable range if aggressive action begins by the end of 2009, providing for a twelve-year rollout of the DR efforts (at the beginning of 2010 through the end of 2020).

Key recommendations include:

- Implement programs focused on achieving firm capacity reductions as this provides the highest value demand response. This is accomplished through establishing appropriate customer expectations and by conducting program tests for each DR program in each year. These tests should be used to establish expected DR program impacts when called and to work with customers each year to ensure that they can achieve the load reductions expected at each site.

- Appropriate financial incentives for the Ohio' utilities either for programs administered directly by the utilities or for outsourcing DR efforts to aggregators. The basic premise is that a utility's least-cost plan should also be its most profitable plan. Developing these incentives poses some complexities in that MW's in that DR programs likely will be bid into PJM's DR programs and will receive financial payments from PJM. Whether this provides adequate incentives for the appropriate development of DR programs in Ohio should be examined.

- Combine and cross-market EE and DR programs. These can include new building codes and standards that include not only EE construction and equipment, but also the installation of addressable and dispatchable equipment. This can include addressable thermostats in new residences and the installation of addressable energy management systems in commercial and industrial buildings that can reduce loads in select end-uses across the building/facility. In addition, energy audits of residential or commercial facilities can also include an assessment of whether that facility is a good candidate for participation in a DR program through the identification of dispatchable loads. Furthermore, building commissioning and retro-commissioning EE programs that are becoming popular in many commercial and industrial sector programs have the energy management system as a core component of program delivery. At this time, the application of auto-DR can be assessed and marketed to the customer along with the EE savings from these site-commissioning programs.

- Include customer education in DR efforts. There is some perceived lack of customer awareness of programs and incentives. In addition, new programs will need marketing efforts as well as technical assistance to help customers identify where load reductions can be obtained and the technologies/actions needed to achieve these load reductions. Also, high-level education on the volatility of electricity markets helps customers understand why utilities and other entities are promoting DR and the customers' role in increasing demand response to help match up with supply-side resources to achieve lower cost resource solutions when markets become tight

- Increase clarity and coordination between the Federal and State agencies and programs. While states have primary jurisdiction over retail demand response, the FERC has jurisdiction over demand response in wholesale markets. Greater clarity and coordination between the Federal and State programs is needed. At the Federal level, both EPACT and EISA contain multiple provisions on demand response and smart grid technologies. EISA authorized a matching grant program to offset the costs of Smart Grid investments.

- Understand that pricing may form the cornerstone of an efficient electric market. Daily TOU pricing and day-ahead hourly pricing will increase overall market efficiency by causing shifts in energy use from on-peak to off-peak hours every day of the year. However, this does not diminish the need to have dispatchable DR programs that can address those few days that represent extreme events where the highest demands occur. These events are best addressed by dispatchable DR programs.

APPENDIX E – COMBINED HEAT AND POWER

E.1. Technical Potential for CHP

This section provides an estimate of the technical market potential for combined heat and power (CHP) in the industrial, commercial/institutional, and multi-family residential market sectors. Two different types of CHP markets were included in the evaluation of technical potential. Both of these markets were evaluated for high load factor (80% and above) and low load factor (51%) applications resulting in four distinct market segments that are analyzed.

E.1.1. Traditional CHP

Traditional CHP electrical output is produced to meet all or a portion of the base load for a facility and the thermal energy is used to provide steam or hot water. Depending on the type of facility, the appropriate sizing could be either electric or thermal limited. Industrial facilities often have "excess" thermal load compared to their on-site electric load. Commercial facilities almost always have excess electric load compared to their thermal load. Two sub-categories were considered:

High load factor applications: This market provides for continuous or nearly continuous operation. It includes all industrial applications and round-the-clock commercial/institutional operations such colleges, hospitals, hotels, and prisons.

Low load factor applications: Some commercial and institutional markets provide an opportunity for coincident electric/thermal loads for a period of 3,500 to 5,000 hours per year. This sector includes applications such as office buildings, schools, and laundries.

E.1.2. Combined Cooling Heating and Power (CCHP)

All or a portion of the thermal output of a CHP system can be converted to air conditioning or refrigeration with the addition of a thermally activated cooling system. This type of system can potentially open up the benefits of CHP to facilities that do not have the year-round thermal load to support a traditional CHP system. A typical system would provide the annual hot water load, a portion of the space heating load in the winter months and a portion of the cooling load in during the summer months. Two sub-categories were considered:

Low load factor applications. These represent markets that otherwise could not support CHP due to a lack of thermal load.

Incremental high load factor applications: These markets represent round-the-clock commercial/institutional facilities that could support traditional CHP, but with cooling, incremental capacity could be added while maintaining a high level of utilization of the thermal energy from the CHP system. All of the market segments in this category are also included in the high load factor traditional market segment, so only the incremental capacity for these markets is added to the overall totals.

The estimation of technical market potential consists of the following elements:

- Identification of applications where CHP provides a reasonable fit to the electric and thermal needs of the user. Target applications were identified based on reviewing the electric and thermal energy consumption data for various building types and industrial facilities.
- Quantification of the number and size distribution of target applications. Several data sources were used to identify the number of applications by sector that meet the thermal and electric load requirements for CHP.
- Estimation of CHP potential in terms of megawatt (MW) capacity. Total CHP potential is

then derived for each target application based on the number of target facilities in each size category and sizing criteria appropriate for each sector.

- Subtraction of existing CHP from the identified sites to determine the remaining technical market potential.

The technical market potential does not consider screening for economic rate of return, or other factors such as ability to retrofit, owner interest in applying CHP, capital availability, natural gas availability, and variation of energy consumption within customer application/size class. The technical potential as outlined is useful in understanding the potential size and size distribution of the target CHP markets in the state. Identifying technical market potential is a preliminary step in the assessment of market penetration.

The basic approach to developing the technical potential is described below:

- *Identify existing CHP in the state.* The analysis of CHP potential starts with the identification of existing CHP. In Ohio, there are 45 operating CHP plants totaling 665 MW of capacity. Of this existing CHP capacity, 55% of the sites and 85% of the capacity are in the industrial sector. This existing CHP capacity is deducted from any identified technical potential. A summary of the existing CHP capacity by industry is shown in Table 41.

- *Identify applications where CHP provides a reasonable fit to the electric and thermal needs of the user*. Target applications were identified based on reviewing the electric and thermal energy (heating and cooling) consumption data for various building types and industrial facilities. Data sources include the DOE EIA *Commercial Buildings Energy Consumption Survey (CBECS),* the DOE *Manufacturing Energy Consumption Survey (MECS)* and various market summaries developed by DOE, Gas Technology Institute (GRI), and the American Gas Association. Existing CHP installations in the commercial/institutional and industrial sectors were also reviewed to understand the required profile for CHP applications and to identify target applications.

- *Quantify the number and size distribution of target applications*. Once applications that could technically support CHP were identified, the iMarket, Inc*. MarketPlace Database* and the *Major Industrial Plant Database* (MIPD) from IHI were utilized to identify potential CHP sites by SIC code or application, and location (county). The *MarketPlace Database* is based on the Dun and Bradstreet financial listings and includes information on economic activity (8 digit SIC), location (metropolitan area, county, electric utility service area, state) and size (employees) for commercial, institutional and industrial facilities. In addition, for select SICs limited energy consumption information (electric and gas consumption, electric and gas expenditures) is provided based on data from Wharton Econometric Forecasting (WEFA). MIPD has detailed energy and process data for 16,000 of the largest energy consuming industrial plants in the United States. The *MarketPlace Database* and MIPD were used to identify the number of facilities in target CHP applications and to group them into size categories based on average electric demand in kilowatt-hours.

- *Estimate CHP potential in terms of MW capacity.* Total CHP potential was then derived for each target application based on the number of target facilities in each size category. It was assumed that the CHP system would be sized to meet the average site electric demand for the target applications unless thermal loads (heating and cooling) limited electric capacity. Tables 42 through 44 present the specific target market sectors, the number of potential sites and the potential MW contribution from CHP. There are two distinct applications and two levels of annual load making for four market segments in all. In traditional CHP, the thermal energy is recovered and used for heating, process steam, or hot water. In cooling CHP, the system provides both heating and cooling needs for the facility. High load factor applications operate at 80% load factor and above; low load factor applications operate at an assumed average of 4500 hours per year (51%) load factor. The high load factor cooling applications are also applications for traditional CHP, though the cooling applications have 25-30% more capacity than traditional. Therefore, the totals for the entire state, all four market segments, discounts these applications to avoid double counting.

- *Estimate the growth of new facilities in the target market sectors.* The technical potential included economic projections for growth through 2025 by target market sectors in Ohio. The growth factors used in the analysis for growth between the present and 2025 by individual sector are shown in Table 45. These growth projections provided by ACEEE were used in this analysis as an estimate of the growth in new facilities. In cases where an economic sector is declining, it was assumed that no new facilities would be added to the technical potential for CHP. Based on these growth rates the total technical market potential is summarized in Table 46.

Table 41. Ohio Existing CHP Facilities

SIC	Industry Description	Sites	Cap. kW
24	Lumber and Wood Products	2	10,900
2511	Wood Household Furniture	1	1,000
26	Paper	6	151,730
28	Chemicals	6	47,425
2911	Petroleum Refining	1	6,000
30	Rubber and Plastics	2	41,900
33	Primary Metals	4	102,050
35	Industrial Machinery	1	700
37	Transportation Equipment	1	75
39	Miscellaneous Manufacturing	1	200,000
49	Utilities	4	8,625
7011	Hotels and Motels	1	100
7991	Physical Fitness Facility	1	150
80	Health Services	2	1,765
82	Educational Services	6	73,573
8412	Museums and Art Galleries	1	240
8811	Private Households	1	115
91	Executive, Legislative, General Government	3	16,615
9711	Military Base	1	2,075
	Total	45	665,038

Table 42. Ohio Technical Market Potential for CHP in Existing Facilities – Industrial Sector

SICs	Application	50-500 kW Sites	50-500 kW MW	500-1 MW Sites	500-1 MW (MW)	1-5 MW Sites	1-5 MW (MW)	5-20 MW Sites	5-20 MW (MW)	>20 MW Sites	>20 MW (MW)	Total Sites	Total MW
	Industrial (Traditional, High Load Factor												
20	Food	242	36.3	90	67.5	62	155.0	21	262.5	3	225.0	418	746.3
22	Textiles	43	4.8	12	6.8	2	3.8	0	0.0	0	0.0	57	15.3
24	Lumber and Wood	234	7.0	31	4.7	10	5.0	2	5.0	1	15.0	278	36.7
25	Furniture	21	0.9	2	0.5	0	0.0	0	0.0	0	0.0	23	1.4
26	Paper	173	26.0	107	80.3	89	222.5	2	25.0	0	0.0	371	353.7
27	Printing/Publishing	121	18.2	5	3.8	0	0.0	0	0.0	0	0.0	126	21.9
28	Chemicals	254	38.1	108	81.0	135	337.5	37	462.5	22	1,650.0	556	2,569.1
29	Petroleum Refining	128	19.2	11	8.3	6	15.0	0	0.0	0	0.0	145	42.5
30	Rubber/Misc. Plastics	361	16.2	339	76.3	203	152.3	31	116.3	0	0.0	934	361.0
32	Stone/Clay/Glass	14	2.1	6	4.5	1	2.5	1	12.5	3	225.0	25	246.6
33	Primary Metals	80	3.0	56	10.5	45	28.1	5	15.6	1	18.8	187	76.0
34	Fabricated Metals	409	18.4	88	19.8	41	30.8	0	0.0	0	0.0	538	69.0
35	Machinery/Computer Equip	23	0.9	1	0.2	4	2.5	0	0.0	0	0.0	28	3.6
37	Transportation Equip.	98	7.4	69	25.9	106	132.5	29	181.3	13	487.5	315	834.5
38	Instruments	21	1.6	3	1.1	0	0.0	0	0.0	0	0.0	24	2.7
39	Misc. Manufacturing	26	1.0	5	0.9	1	0.6	0	0.0	0	0.0	32	2.5
	Total Industrial	2248	201.0	933	391.8	705	1,088.0	128	1,080.6	43	2,621.3	4057	5,382.7

Table 43. Ohio Technical Market Potential for CHP in Existing Facilities – Commercial, Traditional CHP

SICs	Application	50-500 kW Sites	50-500 kW MW	500-1 MW Sites	500-1 MW (MW)	1-5 MW Sites	1-5 MW (MW)	5-20 MW Sites	5-20 MW (MW)	>20 MW Sites	>20 MW (MW)	Total Sites	Total MW
	Commercial, Multifamily(Traditional, High Load Factor)												
6513	Apartments	381	28.6	138	51.8	21	26.3					540	106.6
4222, 5142	Warehouses	15	2.3	22	16.5	5	12.5					42	31.3
4941, 4952	Water Treatment/Sanitary	103	15.5	71	53.3	33	82.5	1	12.5			208	163.7
7011, 7041	Hotels	893	100.5	169	95.1	34	63.8					1096	259.3
8051, 8052, 8059	Nursing Homes	664	99.6	388	291.0	32	80.0					1084	470.6
8062, 8063, 8069	Hospitals	106	15.9	59	44.3	128	320.0	3	37.5			296	417.7
8221, 8222	Colleges/Universities	106	15.9	80	60.0	54	135.0	16	200.0	2	50.0	258	460.9
9223, 9211 (Courts), 9224 (firehouses)	Prisons	10	1.5	31	23.3	38	95.0	8	100.0			87	219.8
	Total C/I High LF	2278	279.6	958	635.1	345	815.0	28	350.0	2	50.0	3611	2,129.7
	Commercial (Traditional, Low Load Factor)												
7211, 7213, 7218	Laundries	71	10.7	2	1.5							73	12.2
7542	Carwashes	113	17.0									113	17.0
7991, 00, 01	Health Clubs	144	21.6	19	14.3							163	35.9
7992, 7997-9904, 7997-9906	Golf/Country Clubs	328	49.2	25	18.8							353	68.0
8211, 8243, 8249, 8299	Schools	1227	46.0	233	43.7	23	14.4	4	12.5			1487	116.6
8412	Museums	60	9.0	10	7.5							70	16.5
	Total C/I Low LF	1943	153.4	289	85.7	23	14.4	4	12.5			2259	266.0
	Total C/I Traditional	4221	433.1	1247	720.8	368	829.4	32	362.5	2	50.0	5870	2,395.7

Table 44. Ohio Technical Market Potential for CHP in Existing Facilities – Commercial, Cooling

SICs	Application	50-500 kW Sites	50-500 kW MW	500-1 MW Sites	500-1 MW (MW)	1-5 MW Sites	1-5 MW (MW)	5-20 MW Sites	5-20 MW (MW)	>20 MW Sites	>20 MW (MW)	Total Sites	Total MW
Commercial Cooling, High Load Factor													
7011, 7041	Hotels- Cooling	894	134.1	169	126.75	34	85.0					1097	345.9
8051, 8052, 8059	Nursing Homes- Cooling	664	119.5	388	349.2	32	96.0					1084	564.7
8062, 8063, 8069	Hospitals- Cooling	106	19.1	60	54	129	387.0	3	45.0			298	505.1
	Total Cooling High LF	1664	272.7	617	529.95	195	568.0	3	45.0			2479	1,415.7
Commercial Cooling, Low Load Factor													
5411, 5421, 5451, 5461, 5499	Food Sales	1619	121.4	232	87.0	20	25.0					1871	233.4
5812, 00, 01, 03, 05, 07, 08	Restaurants	2402	180.2	15	5.6							2417	185.8
43	Post Offices	189	28.4									189	28.4
4581	Airports	17	2.6	1	0.8							18	3.3
52,53,56,57	Big Box Retail	1252	187.8	304	228.0	105	262.5					1661	678.3
7832	Movie Theaters	71	10.7									71	10.7
6512	Office Buildings - Cooling	2773	208.0	1213	454.875	347	433.8					4333	1,096.6
	Total Cooling Low LF	8323	738.9	1765	776.25	472	721.3					10560	2,236.4
	Total Cooling	9987	1,011.6	2382	1306.2	667	1,289.3	3	45.0			13039	3,652.1
	Total C/I All Types	12544	1,253.8	3012	1,656.0	840	1,721.0	32	376.0	2	50.0	16430	3,491.3

Note: High Load factor cooling adds only 30% to the total C/I MW potential because the sites are already included in High LF Traditional. The 30% represents the incremental capacity offered by adding cooling.

Table 45. Ohio Sector Growth Projections Through 2025

SIC Code	Market Sector	2008-2025 Real Growth
20	Food	14.6%
22	Textiles	2.6%
24	Lumber and Wood	15.4%
25	Furniture	15.4%
26	Paper	15.4%
27	Printing/Publishing	2.6%
28	Chemicals	71.7%
29	Petroleum Refining	71.7%
30	Rubber/Misc. Plastics	71.7%
32	Stone/Clay/Glass	39.8%
33	Primary Metals	28.4%
34	Fabricated Metals	28.4%
35	Machinery/Computer Equip	67.5%
37	Transportation Equip.	43.9%
38	Instruments	28.8%
39	Misc. Manufacturing	15.4%
43	Post Offices	15.6%
4581	Airports	15.6%
6512	Office Buildings - Cooling	0.0%
6513	Apartments	0.0%
7542	Carwashes	0.0%
7832	Movie Theaters	17.6%
8412	Museums	17.6%
4222, 5142	Warehouses	77.6%
4941, 4952	Water Treatment/Sanitary	20.6%
52,53,56,57	Big Box Retail	25.1%
5411, 5421, 5451, 5461, 5499	Food Sales	25.1%
5812, 00, 01, 03, 05, 07, 08	Restaurants	17.6%
7011, 7041	Hotels	17.6%
7011, 7041	Hotels- Cooling	17.6%
7211, 7213, 7218	Laundries	0.0%
7991, 00, 01	Health Clubs	17.6%
7992, 7997-9904, 7997-9906	Golf/Country Clubs	17.6%
8051, 8052, 8059	Nursing Homes	2.0%
8051, 8052, 8059	Nursing Homes- Cooling	2.0%
8062, 8063, 8069	Hospitals	2.0%
8062, 8063, 8069	Hospitals- Cooling	2.0%
8211, 8243, 8249, 8299	Schools	2.0%
8221, 8222	Colleges/Universities	2.0%
9223, 9211 (Courts), 9224 (firehouses)	Prisons	0.1%

Table 46. CHP Market Segments, Ohio Existing Facilities and Expected Growth 2008-2025

Market	50-500 kW MW	500-1 MW (MW)	1-5 MW (MW)	5-20 MW (MW)	>20 MW (MW)	Total MW
Traditional High Load Factor Market						
Existing Facilities	481	1,027	1,903	1,287	2,975	7,672
New Facilities	251	542	985	673	1,865	4,316
Total	732	1,569	2,888	1,960	4,840	11,988
Traditional Low Load Factor Market						
Existing Facilities	153	86	14	13	0	266
New Facilities	86	50	7	6	0	149
Total	239	136	21	19	0	415
Cooling CHP High Load Factor Market (partially additive)						
Existing Facilities	273	530	568	45	0	1,416
New Facilities	158	285	295	15	0	752
Total	430	815	863	60	0	2,168
Cooling CHP Low Load Factor Market						
Existing Facilities	739	776	721	0	0	2,236
New Facilities	529	518	478	0	0	1,524
Total	1,268	1,294	1,199	0	0	3,760
Total Market including Incremental Cooling Load						
Existing Facilities	1,455	2,048	2,809	1,313	2,975	10,600
New Facilities	913	1,195	1,558	683	1,865	6,215
Total	2,368	3,243	4,367	1,997	4,840	16,814

Note: High load factor cooling market is comprised of a portion of the traditional high load factor market that has both heating and cooling loads. The total high load factor cooling market is shown, but only 30% of it is incremental to the portion already counted in the traditional high load factor market. Growth rates were extrapolated for the 2020-2025 market penetration forecast.

E.2. Energy Price Projections

The expected future relationship between purchased natural gas and electricity prices, called the *spark spread* in this context, is one major determinant of the ability of a facility with electric and thermal energy requirements to cost-effectively utilize CHP. For this screening analysis, a fairly simple methodology was used:

E.2.1. Electric Price Estimation

- Retail electric price forecasts EIA's Annual Energy Forecast for 2007 were used as the starting point for the analysis. ACEEE provided state by state estimates. The annual price forecasts provided were converted to 5 year averages for use in the market penetration model. These prices are shown in **Table E-7**.
- The electricity price assumptions for the high load factor CHP applications were as follows

- 50-500 kW – Commercial average price
- 500 kW to 5 MW – Industrial average price
- 5 MW and above – 90% of industrial average price

- Price adjustments for customer load factor were defined as follows:
  - High load factor – 100% of the estimated value
  - Low load factor – 120% of the estimated value
  - Peak cooling load – 150% of the estimated value
- For a customer generating a portion of his own power with CHP, standby charges are estimated at 15% of the defined average electric rate. Therefore, when considering CHP, only 85% of a customer's rate can be avoided.

E.2.2. Natural Gas Price Estimation

- The natural gas price assumptions are based on the industrial retail price shown in the table.
  - All customer boiler fuel is assumed at the industrial rate except for the CHP market below 500 kW where the boiler gas price is assumed to be $0.50/MMBtu higher
  - All CHP fuel is assumed to be at a $0.60/MMBt discount to the retail industrial price.

Table 47. Input Price Forecast (EIA-AEO 2007) and Ohio Industrial Electric Price Estimation

Ohio Energy Prices	Avg. 2007-2009	Avg.2010-2014	Avg.2015-2019	Avg.2020-2024
Ohio Retail Electricity Prices (2006$/kWh)				
Residential	$0.091	$0.101	$0.116	$0.126
Commercial	$0.083	$0.094	$0.106	$0.117
Industrial	$0.056	$0.067	$0.080	$0.089
Ohio Retail Natural Gas Prices (2006$/MMbtu)				
Residential	$13.729	$12.531	$12.782	$13.262
Commercial	$12.135	$10.709	$10.829	$11.193
Industrial	$10.813	$9.046	$9.209	$9.662

E.3. CHP Technology Cost and Performance

The CHP system itself is the engine that drives the economic savings. The cost and performance characteristics of CHP systems determine the economics of meeting the site's electric and thermal loads. A representative sample of commercially and emerging CHP systems was selected to profile performance and cost characteristics in combined heat and power (CHP) applications. The selected systems range in capacity from approximately 100 – 20,000 kW. The technologies include gas-fired reciprocating engines, gas turbines, microturbines and fuel cells. The appropriate technologies were allowed to compete for market share in the penetration model. In the smaller market sizes, reciprocating engines competed with microturbines and fuel cells. In intermediate sizes (1 to 20 MW), reciprocating engines competed with gas turbines.

Cost and performance estimates for the CHP systems were based on work being undertaken for the EPA.[71] The foundation for these updates is based on work previously conducted for NYSERDA,[72] on

[71] EPA CHP Partnership Program, Technology Characterizations, December 2007 (under review).

peer-reviewed technology characterizations that Energy and Environmental Analysis (EEA) developed for the National Renewable Energy Laboratory (NREL 2003) and on follow-on work conducted by DE Solutions for Oak Ridge National Laboratory (ORNL 2004). Additional emissions characteristics and cost and performance estimates for emissions control technologies were based on ongoing work EEA is conducting for EPRI (EPRI 2005). Data is presented for a range of sizes that include basic electrical performance characteristics, CHP performance characteristics (power to heat ratio), equipment cost estimates, maintenance cost estimates, emission profiles with and without after-treatment control, and emissions control cost estimates. The technology characteristics are presented for three years: 2005, 2010, 2020. The 2007-2010 estimates are based on current commercially available and emerging technologies. The cost and performance estimates for 2010-2015 and 2015-2020 reflect current technology development paths and currently planned government and industry funding. These projections were based on estimates included in the three references mentioned above. NOx, CO and VOC emissions estimates in lb/MWh are presented for each technology both with and without aftertreatment control (AT). For this analysis, aftertreatment was only included for the 800 kW and 3000 kW engines. The installed costs in Tables 48 through 51 are based on typical national averages.

[72] *Combined Heat and Power Potential for New York State*, Energy Nexus Group (later became part of EEA), for NYSERDA, May 2002.

Table 48. Reciprocating Engine Cost and Performance Characteristics

CHP System	Characteristic/Year Available	2007-2010	2010-2015	2016-2020
100 kW	Installed Costs, $/kW	$2,210	$1,925	$1,568
	Heat Rate, Btu/kWh	12,000	10,830	10,500
	Electric Efficiency, %	28.4%	31.5%	32.5%
	Thermal Output, Btu/kWh	6100	5093	4874
	O&M Costs, $/kWh	0.022	0.013	0.012
	NOx Emissions, lbs/MWh (w/ AT)	0.10	0.15	0.15
	CO Emissions w/AT, lb/MWh	0.32	0.60	0.30
	VOC Emissions w/AT, lb/MWh	0.10	0.09	0.05
	PMT 10 Emissions, lb/MWh	0.11	0.11	0.11
	SO_2 Emissions, lb/MWh	0.0068	0.0064	0.0062
	After-treatment Cost, $/kW	incl.	incl.	incl.
800 kW	Installed Costs, $/kW	$1,640	$1,443	$1,246
	Heat Rate, Btu/kWh	9,760	9,750	9,225
	Electric Efficiency, %	35.0%	35.0%	37.0%
	Thermal Output, Btu/kWh	2313	3791	3250
	O&M Costs, $/kWh	0.013	0.01	0.009
	NOx Emissions, lbs/MWh (w/ AT)	0.5	1.24	0.93
	CO Emissions w/AT, lb/MWh	1.87	0.45	0.31
	VOC Emissions w/AT, lb/MWh	0.47	0.05	0.05
	PMT 10 Emissions, lb/MWh	0.10	0.01	0.01
	SO_2 Emissions, lb/MWh	0.0068	0.0057	0.0054
	After-treatment Cost, $/kW	300	190	140
3000 kW	Installed Costs, $/kW	$1,130	$1,100	$1,041
	Heat Rate, Btu/kWh	9,492	8,750	8,325
	Electric Efficiency, %	35.9%	39.0%	41.0%
	Thermal Output, Btu/kWh	3510	3189	2982
	O&M Costs, $/kWh	0.011	0.0083	0.008
	NOx Emissions, lbs/MWh (w/ AT)	1.52	1.24	0.775
	CO Emissions w/AT, lb/MWh	0.78	0.31	0.31
	VOC Emissions w/AT, lb/MWh	0.34	0.10	0.10
	PMT 10 Emissions, lb/MWh	0.01	0.01	0.01
	SO_2 Emissions, lb/MWh	0.0057	0.0051	0.0049
	After-treatment Cost, $/kW	200	130	100
5000 kW	Installed Costs, $/kW	$1,130	$1,099	$1,038
	Heat Rate, Btu/kWh	8,758	8,325	7,935
	Electric Efficiency, %	39.0%	41.0%	43.0%
	Thermal Output, Btu/kWh	3046	2797	2605
	O&M Costs, $/kWh	0.009	0.008	0.008
	NOx Emissions, lbs/MWh (w/ AT)	1.55	1.24	0.775
	CO Emissions w/AT, lb/MWh	0.75	0.31	0.31
	VOC Emissions w/AT, lb/MWh	0.22	0.10	0.10
	PMT 10 Emissions, lb/MWh	0.01	0.01	0.01
	SO_2 Emissions, lb/MWh	0.0054	0.0049	0.0047
	After-treatment Cost, $/kW	150	115	80

Table 49. Microturbine Cost and Performance Characteristics

CHP System	Characteristic/Year Available	2007-2010	2010-2015	2016-2020
60 kW	Installed Costs, $/kW	$2,739	$2,037	$1,743
	Heat Rate, Btu/kWh	13,891	12,500	11,375
	Electric Efficiency, %	24.6%	27.3%	30.0%
	Thermal Output, Btu/kWh	6308	3791	3102
	O&M Costs, $/kWh	0.022	0.016	0.012
	NOx Emissions, lbs/MWh (w/ AT)	0.15	0.14	0.13
	CO Emissions w/AT, lb/MWh	0.24	0.22	0.20
	VOC Emissions w/AT, lb/MWh	0.03	0.03	0.02
	PMT 10 Emissions, lb/MWh	0.22	0.20	0.19
	SO_2 Emissions, lb/MWh	0.0079	0.0074	0.0067
	After-treatment Cost, $/kW			
250 KW	Installed Costs, $/kW	$2,684	$2,147	$1,610
	Heat Rate, Btu/kWh	13,080	11,750	10,825
	Electric Efficiency, %	2.6%	29.0%	31.5%
	Thermal Output, Btu/kWh	4800	3412	2625
	O&M Costs, $/kWh	0.015	0.013	0.012
	NOx Emissions, lbs/MWh (w/ AT)	0.43	0.24	0.13
	CO Emissions w/AT, lb/MWh	0.26	0.26	0.24
	VOC Emissions w/AT, lb/MWh	0.03	0.03	0.02
	PMT 10 Emissions, lb/MWh	0.18	0.18	0.16
	SO_2 Emissions, lb/MWh	0.0070	0.0069	0.0064
	After-treatment Cost, $/kW	500	200	90

Table 50. Fuel Cell Cost and Performance Characteristics

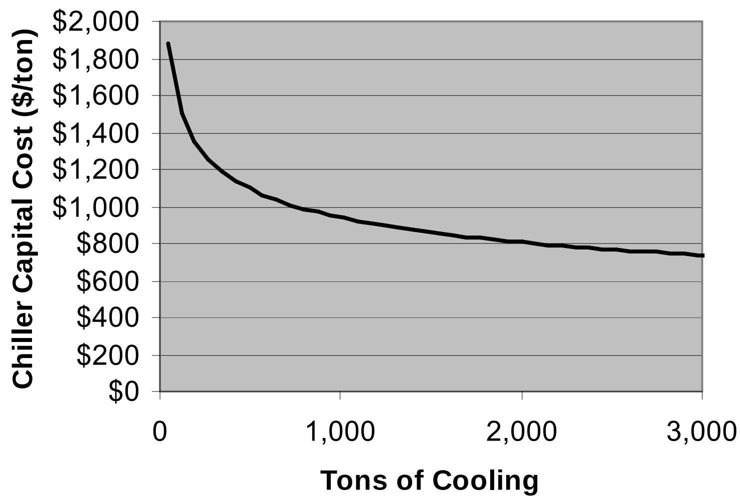
CHP System	Characteristic/Year Available	2007-2010	2010-2015	2016-2020
200 kW PAFC in 2005 150 kW PEMFC in outyears	Installed Costs, $/kW	$6,310	$4,782	$3,587
	Heat Rate, Btu/kWh	9,480	9,480	8,980
	Electric Efficiency, %	36.0%	36.0%	38.0%
	Thermal Output, Btu/kWh	4250	3482	3281
	O&M Costs, $/kWh	0.038	0.017	0.015
	NOx Emissions, lbs/MWh (w/ AT)	0.06	0.05	0.04
	CO Emissions w/AT, lb/MWh	0.07	0.07	0.07
	VOC Emissions w/AT, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.00	0.00	0.00
	SO_2 Emissions, lb/MWh	0.0057	0.0056	0.0053
	After-treatment Cost, $/kW	n.a.	n.a.	n.a.
300 kW MCFC	Installed Costs, $/kW	$5,580	$4,699	$3,671
	Heat Rate, Btu/kWh	8,022	7,125	6,920
	Electric Efficiency, %	42.5%	47.9%	49.3%
	Thermal Output, Btu/kWh	1600	1723	1602
	O&M Costs, $/kWh	0.035	0.02	0.015
	NOx Emissions, lbs/MWh (w/ AT)	0.1	0.05	0.04
	CO Emissions w/AT, lb/MWh	0.07	0.05	0.04
	VOC Emissions w/AT, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.00	0.00	0.00
	SO_2 Emissions, lb/MWh	0.0057	0.0042	0.0041
	After-treatment Cost, $/kW	n.a.	n.a.	n.a.
1200 kW MCFC	Installed Costs, $/kW	$5,250	$4,523	$3,554
	Heat Rate, Btu/kWh	8,022	7,110	6,820
	Electric Efficiency, %	42.5%	48.0%	50.0%
	Thermal Output, Btu/kWh	1583	1706	1503
	O&M Costs, $/kWh	0.032	0.019	0.015
	NOx Emissions, lbs/MWh (w/ AT)	0.05	0.05	0.04
	CO Emissions w/AT, lb/MWh	0.04	0.04	0.03
	VOC Emissions w/AT, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.00	0.00	0.00
	SO_2 Emissions, lb/MWh	0.0044	0.0042	0.0040
	After-treatment Cost, $/kW	n.a.	n.a.	n.a.

Table 51. Gas Turbine Cost and Performance Characteristics

CHP System	Characteristic/Year Available	2007-2010	2010-2015	2016-2020
3000 KW GT	Installed Costs, $/kW	$1,690	$1,560	$1,300
	Heat Rate, Btu/kWh	13,100	12,650	11,200
	Electric Efficiency, %	26.0%	27.0%	30.5%
	Thermal Output, Btu/kWh	5018	4489	4062
	O&M Costs, $/kWh	0.0074	0.0065	0.006
	NOx Emissions, lbs/MWh (w/ AT)	0.68	0.38	0.2
	CO Emissions w/AT, lb/MWh	0.55	0.53	0.47
	VOC Emissions w/AT, lb/MWh	0.03	0.03	0.02
	PMT 10 Emissions, lb/MWh	0.21	0.20	0.18
	SO_2 Emissions, lb/MWh	0.0070	0.0069	0.0069
	After-treatment Cost, $/kW	210	175	150
10 MW GT	Installed Costs, $/kW	$1,298	$1,342	$1,200
	Heat Rate, Btu/kWh	11,765	10,800	9,950
	Electric Efficiency, %	29.0%	31.6%	34.3%
	Thermal Output, Btu/kWh	4674	4062	3630
	O&M Costs, $/kWh	0.007	0.006	0.005
	NOx Emissions, lbs/MWh (w/ AT)	0.67	0.37	0.2
	CO Emissions w/AT, lb/MWh	0.50	0.46	0.42
	VOC Emissions w/AT, lb/MWh	0.02	0.02	0.02
	PMT 10 Emissions, lb/MWh	0.20	0.18	0.17
	SO_2 Emissions, lb/MWh	0.0069	0.0064	0.0059
	After-treatment Cost, $/kW	140	125	100
40 MW GT	Installed Costs, $/kW	$972	$944	$916
	Heat Rate, Btu/kWh	9,220	8,865	8,595
	Electric Efficiency, %	37.0%	38.5%	39.7%
	Thermal Output, Btu/kWh	3189	3019	2892
	O&M Costs, $/kWh	0.004	0.004	0.004
	NOx Emissions, lbs/MWh (w/ AT)	0.55	0.2	0.1
	CO Emissions w/AT, lb/MWh	0.04	0.04	0.04
	VOC Emissions w/AT, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.16	0.15	0.15
	SO_2 Emissions, lb/MWh	0.0054	0.0052	0.0051
	After-treatment Cost, $/kW	90	75	40

In the cooling markets, an additional cost was added to reflect the costs of adding chiller capacity to the CHP system. These costs depend on the sizing of the absorption chiller which in turn depends on the amount of usable waste heat that the CHP system produces. Figure 35 shows this cost approximation.

Figure 35. Absorption Chiller Capital Costs



E.4. Market Penetration Analysis

EEA has developed a CHP market penetration model that estimates cumulative CHP market penetration in 5-yrar increments. For this analysis, the forecast periods are 2012, 2017, and 2022. These results are interpolated to the output years 2010, 2015, 2020, and 2025. The target market is comprised of the facilities that make up the technical market potential as defined in previously in this section. Thee economic competition module in the market penetration model compares CHP technologies to purchased fuel and power in 5 different sizes and 4 different CHP application types. The calculated payback determines the potential pool of customers that would consider accepting the CHP investment as economic. Additional, non economic screening factors are applied that limit the pool of customers that can accept CHP in any given market/size. Based on this calculated economic potential, a market diffusion model is used to determine the cumulative market penetration for each 5-year time period. The cumulative market penetration, economic potential and technical potential are defined as follows:

- *Technical potential* represents the total capacity potential from existing and new facilities that are likely to have the appropriate physical electric and thermal load characteristics that would support a CHP system with high levels of thermal utilization during business operating hours.
- *Economic potential*, as shown in the table, reflects the share of the technical potential capacity (and associated number of customers) that would consider the CHP investment economically acceptable according to a procedure that is described in more detail below.
- *Cumulative market penetration* represents an estimate of CHP capacity that will actually enter the market between 2008 and 2025. This value discounts the economic potential to reflect non-economic screening factors and the rate that CHP is likely to actually enter the market.

In addition to segmenting the market by size, as shown in the table, the analysis is conducted in four separate CHP market applications (high load and low load factor traditional CHP and high and low load factor CHP with cooling.) These markets are considered individually because both the annual load factor and the installation and operation of thermally activated cooling has an impact on the system economics.

Economic potential is determined by an evaluation of the competitiveness of CHP versus purchased fuel and electricity. The projected future fuel and electricity prices and the cost and performance of CHP technologies determine the economic competitiveness of CHP in each market. CHP technology and performance assumptions appropriate to each size category and region were selected to represent the competition in that size range (Table 52). Additional assumptions were made for the competitive analysis. Technologies below 1 MW in electrical capacity are assumed to have an economic life of 10 years. Larger systems are assumed to have an economic life of 15 years. Capital related amortization costs were based on a 10% discount rate. Based on their operating characteristics (each category and each size bin within the category have specific assumptions about the annual hours of CHP operation (80-90% for the high load factor cases with appropriate adjustments for low load factor facilities), the share of recoverable thermal energy that gets utilized (80%-90%), and the share of useful thermal energy that is used for cooling compared to traditional heating. The economic figure-of-merit chosen to reflect this competition in the market penetration model is simple payback.[73] While not the most sophisticated measure of a project's performance, it is nevertheless widely understood by all classes of customers.

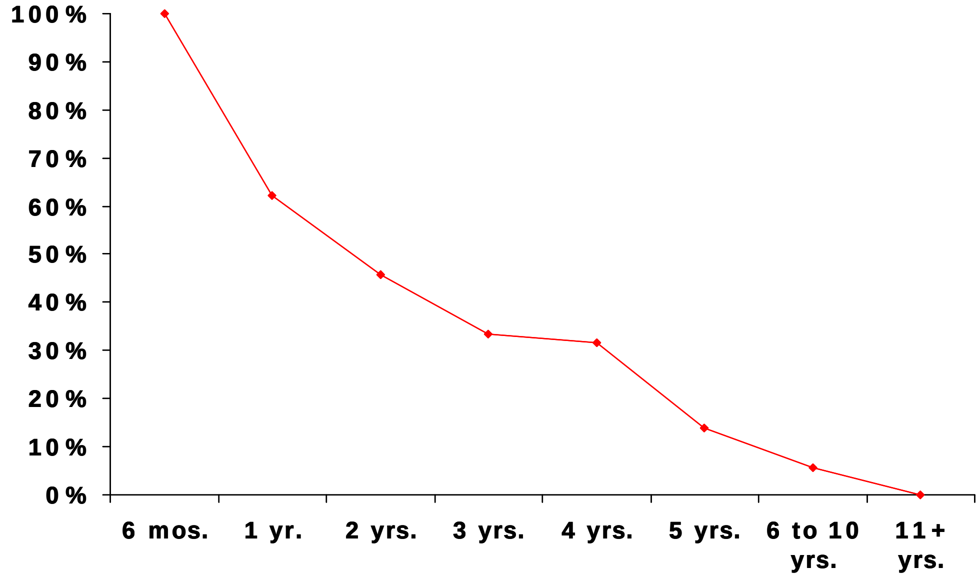
Table 52. Technology Competition Assumed within Each Size Category

Market Size Bins	*Competing Technologies*
50 - 500 kW	100 kW Recip Engine
	70 kW Microturbine
	150 kW PEM Fuel Cell
500 - 1,000 kW	300 kW Recip Engine (multiple units)
	70 kW Microturbine (multiple units)
	250 kW MC/SO Fuel Cell (multiple units)
1 - 5 MW	3 MW Recip Engine
	3 MW Gas Turbine
	2 MW MC Fuel Cell
5 - 20 MW	5 MW Recip Engine
	5 MW Gas Turbine
20 - 100 MW	40 MW Gas Turbine

Rather than use a single payback value, such as 3-years or 5-years as the determinant of economic potential, we have based the market acceptance rate on a survey of commercial and industrial facility operators concerning the payback required for them to consider installing CHP. Figure 36 shows the percentage of survey respondents that would accept CHP investments at different payback levels (CEC 2005b). As can be seen from the figure, more than 30% of customers would reject a project that promised to return their initial investment in just one year. A little more than half would reject a project with a payback of 2 years. This type of payback translates into a project with an ROI of between 49-100%. Potential explanations for rejecting a project with such high returns is that the average customer does not believe that the results are real and is protecting himself from this perceived risk by requiring very high projected returns before a project would be accepted, or that the facility is very capital limited and is rationing its capital raising capability for higher priority projects (market expansion, product improvement, etc.).

[73] Simple payback is the number of years that it takes for the annual operating savings to repay the initial capital investment.

Figure 36. Customer Payback Acceptance Curve



Source: *Primen's 2003 Distributed Energy Market Survey*

For each market segment, the economic potential represents the technical potential multiplied by the share of customers that would accept the payback calculated in the economic competition module.

The estimation of market penetration includes both a non-economic screening factor and a factor that estimates the rate of market penetration (diffusion). The non-economic screening factor was applied to reflect the share of each market size category (i.e., applications of 50 to 500 kW, applications of 500 to 1,000 kW, etc) within the economic potential that would be willing and able to consider CHP at all. These factors range from 32% in the smallest size bin (50-500 kW) to 64% in the largest size bin (more than 20 MW). These factors are intended to take the place of a much more detailed screening that would eliminate customers that do not actually have appropriate electric and thermal loads in spite of being within the target markets, do not use gas or have access to gas, do not have the space to install a system, do not have the capital or credit worthiness to consider investment, or are otherwise unaware, indifferent, or hostile to the idea of adding CHP. The specific value for each size bin was established based on an evaluation of EIA facility survey data and gas use statistics from the iMarket database.

The rate of market penetration is based on a *Bass diffusion curve* with allowance for growth in the maximum market. This function determines cumulative market penetration for each 5-year period. Smaller size systems are assumed to take a longer time to reach maximum market penetration than larger systems. Cumulative market penetration using a Bass diffusion curve takes a typical S-shaped curve. In the generalized form used in this analysis, growth in the number of ultimate adopters is allowed. The curves shape is determined by an initial market penetration estimate, growth rate of the technical market potential, and two factors described as *internal market influence* and *external market influence*.

The cumulative market penetration factors reflect the economic potential multiplied by the non-economic screening factor (maximum market potential) and by the Bass model market cumulative market penetration estimate.

Once the market penetration is determined, the competing technology shares within a size/utility bin are based on a *logit function* calculated on the comparison of the system paybacks. The greatest market share goes to the lowest cost technology, but more expensive technologies receive some market share depending on how close they are to the technology with the lowest payback. (This technology allocation feature is part of the EEA CHP model that is not specifically used for this analysis.)

Two cases were run to show the effects of providing an economic stimulus for CHP market penetration consisting of a capital cost reduction of $500/kW for all CHP systems 5 MW and below. The results of the base case, without incentives, are shown in Table 53. Table 54 shows the results of the $500/kW incentive case.

Table 53. Market Penetration Results for Base Case

CHP Measurement	2010	2015	2020	2025
Cumulative Market Penetration (MW)				
Industrial	0	294	678	937
Commercial/Institutional	0	57	170	263
Total	0	351	848	1,200
Avoided Cooling	0	4	11	15
Scenario Grand Total	0	355	859	1,215
Annual Electric Energy (Million kWh)				
Industrial	0	2023	5014	7,055
Commercial/Institutional	269	543	1085	1,728
Total	269	2565	6099	8,783
Avoided Cooling	0	9	30	49
Scenario Grand Total	269	2,574	6,128	8,832
Incremental Onsite Fuel (billion Btu/year)				
Industrial	0	11,782	27,025	37,161
Commercial/Institutional	0	2,153	6,316	9,742
Total	0	13,935	33,341	46,903
Cumulative Investment (million 2006$)	$0	$380	$942	$1,351
Cumulative Incentive Payments (Million 2006$)	$0	$1	$7	$14

Note: Incentive Payments in the Base Case represent fuel cell tax credits

Table 54. Market Penetration Results for $500/kW Incentive Case

CHP Measurement	2010	2015	2020	2025
Cumulative Market Penetration (MW)				
Industrial	4	379	876	1,209
Commercial/Institutional	3	140	370	546
Total	7	520	1246	1,755
Avoided Cooling	1	16	36	44
Scenario Grand Total	9	536	1,282	1,799
Annual Electric Energy (Million kWh)				
Industrial	41	2548	6140	8,564
Commercial/Institutional	309	1055	2254	3,360
Total	351	3603	8394	11,924
Avoided Cooling	6	44	100	145
Scenario Grand Total	356	3,647	8,494	12,069
Incremental Onsite Fuel (billion Btu/year)				
Industrial	117	14,690	33,771	46,446
Commercial/Institutional	86	4,985	13,161	19,375
Total	203	19,674	46,933	65,820
Cumulative Investment (million 2006$)	$5	$446	$1,045	$1,452
Cumulative Incentive Payments (Million 2006$)	$7	$183	$477	$705

APPENDIX F – THE DEEPER MODEL AND MACRO MODEL

The Dynamic Energy Efficiency Policy Evaluation Routine—or the DEEPER Model—is a 15-sector quasi-dynamic input-output impact model of the U.S. economy.[74] Although an updated model with a new name, the model has a 15-year history of use and development. See, for example, Laitner, Bernow, and DeCicco (1998) and Laitner (2007) for a review of past modeling efforts. The model is generally used to evaluate the macroeconomic impacts of a variety of energy efficiency (including renewable energy) and climate policies at both the state and national level. The national model now evaluates policies for the period 2008 through 2050. Although, the DEEPER Model for the Ohio specific analysis will cover the period between 2008 through 2025. As it is now designed, the model solves for the set of energy prices that achieves a desired and exogenously determined level of greenhouse gas emissions (below some previously defined reference case). Although the model does include non-CO_2 emissions and other emissions reduction opportunities, it currently focuses on energy-related CO_2 emissions and on the prices, policies, and programs necessary to achieve the desired emissions reductions. DEEPER is an Excel-based analytical tool that consists generally of six sets of key modules or groups of worksheets. These six sets of modules now include:

Global data: The information in this module consists of the economic time series data and key model coefficients and parameters necessary to generate the final model results. The time series data includes the projected reference case energy quantities such as trillion Btus and kilowatt-hours, as well as the key energy prices associated with their use. It also includes the projected gross domestic product, wages and salary earnings, and levels of employment as well as information on key technology cost and performance characteristics. The sources of economic information include data from the Energy Information Administration, the Bureau of Economic Analysis, the Bureau of Labor Statistics, and Economy.com. The cost and performance characterization of key technologies is derived from available studies completed by ACEEE and others, as well as data from the Energy Information Administration's (EIA) National Energy Modeling System (NEMS). One of the more critical assumptions in this study is that alternative patterns of electricity consumption will change and/or defer the mix of investments in conventional power plants. Although we can independently generate these impacts within DEEPER, we can also substitute assumptions from the ICF Integrated Planning Model (IPM) and similar models as they may have different characterizations of avoided costs or alternative patterns of power plant investment and spending.

Macroeconomic model: This set of modules contains the "production recipe" for the region's economy for a given "base year"—in this case, 2006, which is the latest year for which a complete set of economic accounts are available for the regional economy. The I-O data, currently purchased from the Minnesota IMPLAN Group (IMPLAN 2007), is essentially a set of input-output accounts that specify how different sectors of the economy buy (purchase inputs) from and sell (deliver outputs) to each other. In this case, the model is now designed to evaluate impacts for 15 different sectors, including: Agriculture, Oil and Gas Extraction, Coal Mining, Other Mining, Electric Utilities, Natural Gas Distribution, Construction, Manufacturing, Wholesale Trade, Transportation and Other Public Utilities (including water and sewage), Retail Trade, Services, Finance, Government, and Households.

Investment, Expenditures and Energy Savings: Based on the scenarios mapped into the model, this worksheet translates the energy policies into a dynamic array of physical energy impacts, investment flows, and energy expenditures over the desired period of analysis. It estimates the needed investment path for an alternative mix of energy efficiency and other technologies (including efficiency gains on both the end-use and the supply side). It also provides an estimate of the avoided investments needed by the electric generation sector. These quantities and expenditures feed

[74] There is nothing particularly special about this number of sectors. The problem is to provide sufficient detail to show key negative and positive impacts while maintaining a manageable sized model. If we choose to reflect a different mix of sectors and stay within the 15 x 15 matrix, that can be done easily. If we wish to expand the number of sectors, that would take some minor programming changes or adjustments to reflect the larger matrix.

directly into the final demand module of the model which then provides the accounting that is needed to generate the set of annual changes in final demand (see the related module description below).

Price dynamics: There are two critical drivers that impact energy prices within DEEPER. The first is a set of carbon charges that are added to retail prices of energy depending on the level of desired level of emission reductions and also depending on the available set of alternatives to achieve those reductions. The second is the price of energy as it might be affected by changed consumption patterns. In this case DEEPER employs an independent algorithm to generate energy price impacts as they reflect changed demand. Hence, the reduced demand for natural gas in the end-use sectors, for example, might offset increased demand by utility generators. If the net change is a decrease in total natural gas consumption, the wellhead prices might be lowered. Depending on the magnitude of the carbon charge, the change in retail prices might either be higher or lower than the set of reference case prices. This, in turn, will impact the demand for energy as it is reflected in the appropriate modules. In effect, then, DEEPER scenarios rely on both a change in prices and quantities to reflect changes in overall investments and expenditures.

Final demand: Once the changes in spending and investments have been established and adjusted to reflect changes in prices within the other modules of DEEPER, the net spending changes in each year of the model are converted into sector-specific changes in final demand. This, in turn, drives the input-output model according to the following predictive model:

$$X = (I-A)^{-1} * Y$$

where:

X = total industry output by sector

I = an identity matrix consisting of a series of 0’s and 1’s in a row and column format for each sector (with the 1’s organized along the diagonal of the matrix)

A = the production or accounting matrix also consisting of a set of production coefficients for each row and column within the matrix

Y = final demand, which is a column of net changes in final demand by sector

This set of relationships can also be interpreted as

$$\Delta X = (I-A)^{-1} * \Delta Y$$

which reads: a change in total sector output equals $(I-A)^{-1}$ times a change in final demand for each sector. Employment quantities are adjusted annually according to exogenous assumptions about labor productivity in each of the sectors (based on Bureau of Labor Statistics forecasts).

Results: For each year of the analytical time horizon (again out to 2025 for the Ohio specific analysis), the model copies each set of results into this module in a way that can also be exported to a separate report.

Further results from Ohio’s DEEPER analysis is provided to show macroeconomic trends between 5-year time periods. Although similar 2015 & 2025 results were presented in the body of this report, differences between 5-year time periods offer more reference points for the reader to understand Ohio’s macroeconomic trends under the efficiency scenario. This section highlights the net changes Ohio’s economy will experience as the result of our efficiency scenario.

Table 55. Changes in Ohio Electricity Production and Financial Impacts from Energy Efficiency Policy Scenario: 2010, 2015, 2020 & 2025

(Millions of 2006 $)	2010	2015	2020	2025
Efficiency Gains (GWh)	1,383	9,728	22,845	40,069
Change from Reference Case	2.3%	15.5%	36.3%	62.9%
Policy Cost	$89	$154	$413	$489
Investment	$214	$629	$1,152	$1,382
Annual Consumer Outlays	$193	$723	$1,496	$2,146
Annual Electricity Savings	$111	$1,154	$2,961	$5,461
Electricity Supply Cost Adjustment	$58	$267	$626	$1,059
Net Consumer Savings	-$23	$431	$1,465	$3,314
Net Cumulative Energy Savings	$9	$954	$5,951	$18,980

The macroeconomic module of the DEEPER model traces how each set of changes works or ripples its way through the Ohio economy in each year of the assessment period, see Table 55. This module estimates the number of jobs and amount of wages each sector provides the Ohio economy. Changes in sectoral spending are provided in Table 56 below.

Table 56. Changes in Sector Spending (Millions of 2006 Dollars)

Sector	2010	2015	2020	2025
Agriculture	$0.5	$7.8	$29.1	$47.1
Oil and Gas Extraction	$0.3	$5.0	$21.5	$32.3
Coal Mining	$0.0	$0.1	$0.6	$0.9
Other Mining	$0.2	$3.2	$13.9	$20.8
Construction	$121.0	$195.9	$479.1	$719.0
Manufacturing	$8.4	$115.1	$362.1	$648.0
Petroleum Refining	$2.8	$40.8	$163.1	$255.0
Electric Utility Services	-$44.5	-$167.0	-$388.6	-$656.8
Natural Gas Utility Services	-$52.6	-$397.2	-$1,040.5	-$1,690.5
Transportation Other Public Utilities	-$3.0	$3.0	$14.0	$35.0
Wholesale Trade	$9.9	$150.8	$415.2	$809.2
Services	$40.1	$464.3	$1,278.1	$2,462.2
Financial Services	-$11.7	$48.1	$125.1	$244.4
Governmental Services	$5.0	$13.2	$36.5	$58.5

There are other support spreadsheets as well as routines in visual basic programming that support the automated generation of model results and reporting. For more detail on the model assumptions and economic relationships, please refer to the forthcoming model documentation (Laitner 2009). For a review of how an I-O framework might be integrated into other kinds of modeling activities, see Hanson and Laitner (2007). While not an equilibrium model, we borrow from some key concepts of mapping technology representation into DEEPER using the general scheme outlined in Laitner and Hanson (2007).

EXHIBIT FA-5

The 2012 State Energy Efficiency Scorecard

Ben Foster, Anna Chittum, Sara Hayes, Max Neubauer, Seth Nowak, Shruti Vaidyanathan, Kate Farley, Kaye Schultz, and Terry Sullivan

Contributing Authors: Colin Sheppard, Arne Jacobson, and Charles Chamberlin (Schatz Energy Research Center, Humboldt State University); and Yerina Mugica (Natural Resources Defense Council)

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529 14th Street NW, Suite 600, Washington, DC 20045
Phone: (202) 507-4000 • Twitter: @ACEEEDC
Facebook.com/myACEEE • www.aceee.org

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Executive Summary

Conversations about energy use in the United States often revolve around the need to expand the supply of energy to support the growth of our national economy. There is, however, a resource that is cheaper and quicker to deploy, and cleaner, than building new supply—energy efficiency. Energy efficiency improvements help businesses, governments, and consumers meet their needs by using *less* energy, saving them money, driving investment across all sectors of the economy, creating much-needed jobs, and reducing environmental impacts.

Governors, legislators, regulators, and citizens are increasingly recognizing that energy efficiency is a critical state resource. In fact, a great deal of the innovation in policies and programs that promote energy efficiency originates in states across the country. The *2012 State Energy Efficiency Scorecard* captures this activity through a comprehensive analysis of state efforts to advance energy efficiency.

In this sixth edition of ACEEE's *State Energy Efficiency Scorecard*, we rank states on their policy and program efforts, document best practices, and provide recommendations for ways in which states can improve their energy efficiency performance. The State Scorecard serves as a benchmark for state efforts on energy efficiency policies and programs each year, encouraging them to continue strengthening efficiency commitments as a pragmatic and effective strategy for securing environmental benefits and promoting economic growth.

KEY FINDINGS

- **Massachusetts** retained the top spot in the *State Energy Efficiency Scorecard* rankings for the second year in a row, having overtaken California last year, based on its continued commitment to energy efficiency under its Green Communities Act of 2008. Among other things, the Act spurred greater investments in energy efficiency programs by requiring utilities to save a large and growing percentage of energy every year through efficiency measures.

- Joining Massachusetts in the top five are **California**, **New York**, **Oregon,** and **Vermont**, which together comprise a group of truly leading states that have made broad, long-term commitments to developing energy efficiency as a state resource.

- Rounding out the top ten states are **Connecticut**, **Washington**, **Rhode Island, Maryland,** and **Minnesota**. Connecticut appears poised to break back into a top five spot, which it has held in the past.

- This year's most improved states are **Oklahoma**, **Montana,** and **South Carolina**. All three states significantly increased their budgets for electric efficiency programs in 2011 over previous years, and saved more energy from such programs in 2010 than in 2009. Oklahoma put in place natural gas efficiency programs for the first time in 2011, and Montana dramatically increased its budgets for these programs. These funding increases will likely yield further savings in coming years.

- Other states making significant progress include **Arizona**, **Michigan**, **North Carolina,** and **Pennsylvania**, whose implementation of Energy Efficiency Resource Standards led to large increases in efficiency program spending from 2010 to 2011.

- Annual savings from customer-funded energy efficiency programs topped 18 million MWh in 2010, a 40% increase over a year earlier. This is roughly equivalent to the amount of electricity the state of Wyoming uses each year.

- Utility budgets for electric and natural gas efficiency programs rose to almost $7 billion in 2011, a 27% increase over a year earlier. Of this, $5.9 billion went to electric efficiency programs, with the remaining $1.1 billion for natural gas programs. These represent 29% and 18% increases, respectively, over 2010 budgets.

- Twenty-four states have adopted and adequately funded an Energy Efficiency Resource Standard, which sets long-term energy savings targets and drives investments in utility-sector energy efficiency programs. The states with the most aggressive savings targets include **Arizona**, **Hawaii**, **Maryland**, **Massachusetts**, **Minnesota**, **New York**, **Rhode Island,** and **Vermont**.

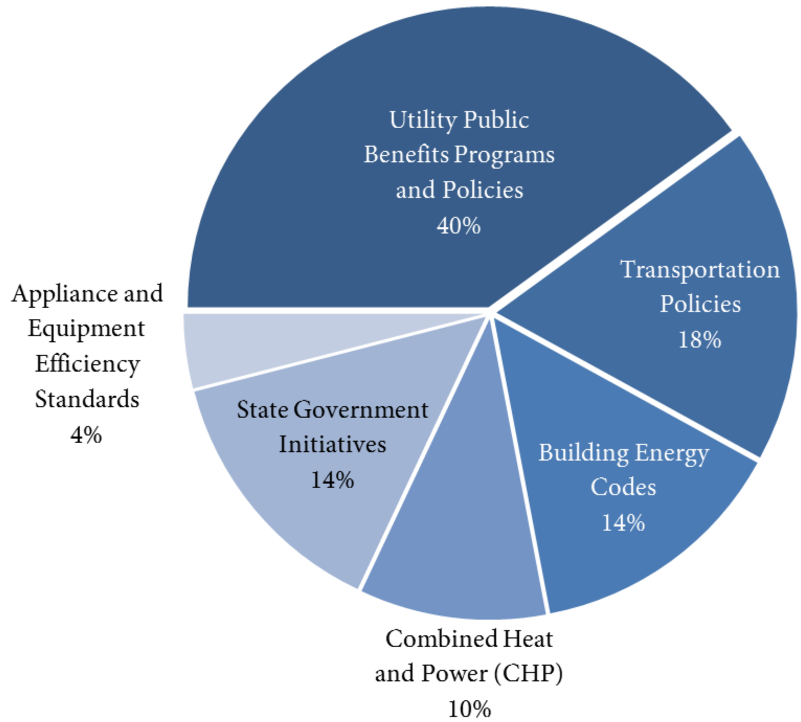
Ten states have adopted energy efficiency codes for new building construction that exceed the IECC 2009 or ASHRAE 90.1-2007 codes for residential and commercial building construction. Two additional states, **Maryland** and **Illinois**, have advanced even further by adopting the most recent and most stringent code for residential construction, the 2012 IECC.

METHODOLOGY

The *2012 State Energy Efficiency Scorecard* provides a broad assessment of policy and programs that improve energy efficiency in our homes, businesses, industry, and transportation. This report examines six of the primary policy areas in which states typically pursue energy efficiency: utility and "public benefits" programs and policies; transportation policies; building energy codes; combined heat and power policies; state government-led initiatives around energy efficiency; and appliance and equipment standards. Figure ES-1 provides a percentage breakdown of the points assigned to each policy area.

The baseline year against which we assessed policy and program changes varies by policy category. Most scores are based on policies in place as of September 2012. In Chapter 2 on utility and public benefits programs, however, we scored states based on data from 2011 and 2010, the latest years in which data were available for our metrics.

Figure ES-1: Percent of Total Points by Policy Area



This year we updated the scoring methodology in four policy areas to better reflect potential energy savings, limitations in the data, economic realities, and changing policy landscapes. Regarding utility and public benefits programs and policies (Chapter 2), as in the past, we asked state public utility commissions for net electric savings, but in some cases states only report gross electric savings. To aid in comparison, we have adjusted reported gross savings by a standard factor (a "net-to-gross ratio"). In Chapter 3 on transportation, we consider for the first time whether or not states have adopted legislation that encourages transit investment by state or local governments. This new category takes one-half point from previous scoring of complete streets legislation and high-efficiency vehicle tax credits, based on their relative potential for energy savings. The scoring of building energy codes in Chapter 4 is more stringent this year, with states receiving full points for building code stringency only if they have updated, or have made significant progress toward updating, their statewide energy codes to the IECC 2012 and ASHRAE 90.1-2010 codes. In Chapter 5 on combined heat and power, we made changes to the types of policies considered and their relative weighting in the overall category score, and more clearly defined the criteria that states must meet to receive points.

This year we contacted every state utility commission to review spending and savings data for the customer-funded energy efficiency programs presented in Chapter 2. In an effort to more fully represent states' customer-funded energy efficiency programs, this year we also requested program savings and budget data from 43 of the largest municipal utilities and cooperatives. These were added, where appropriate, to the savings and budget data reported in Chapter 2. In addition, state energy officials were given the opportunity to review the material on ACEEE's State Energy Efficiency Policy Database (ACEEE 2012) and to provide updates to the information scored in Chapter 6.

RESULTS

Figure ES-2 shows states' rankings in the *2012 State Energy Efficiency Scorecard*, dividing them into five tiers for ease of comparison. The scores upon which these rankings are based are detailed in Table ES-1 on the next page. States could score a maximum of 50 possible points allocated across the six policy areas considered. Although we provide individual state scores and rankings, the difference between states is both easiest to understand and most instructive in tiers of ten. This is because the group of states that compose each of the five tiers have tended to be fairly consistent over time, although states can and do move into new tiers from year to year. Therefore, differences between individual states are generally less important than differences between the tiers of states. An identical ranking for two or more states indicates a tie (e.g., Arizona and Michigan both rank 12th).

Figure ES-2: 2012 State Scorecard Rankings Map

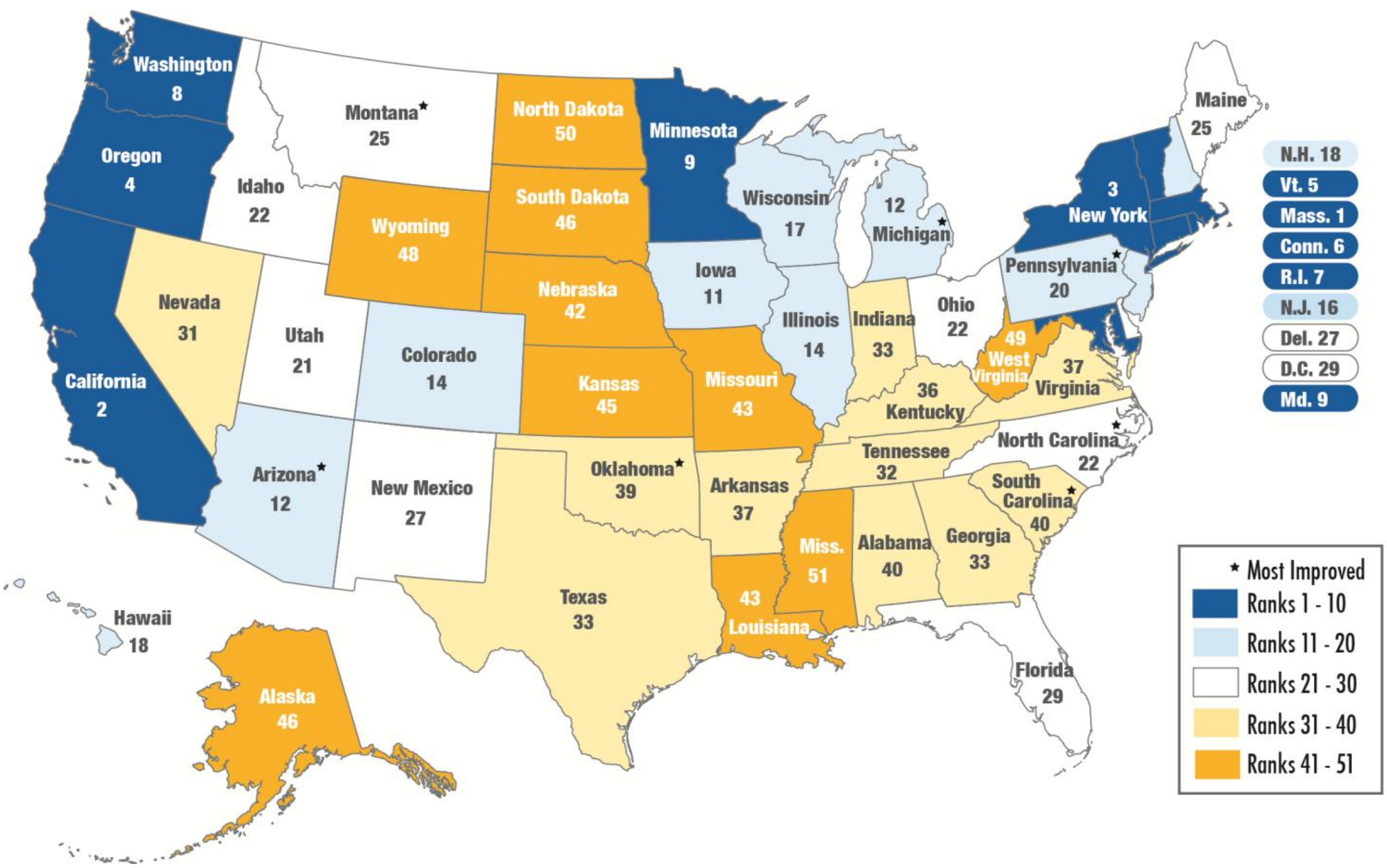


Table ES-1: Summary of State Scores

Rank	State	Utility & Public Benefits Programs & Policies (20 pts.)	Transport-ation Policies (9 pts.)	Building Energy Codes (7 pts.)	Combined Heat & Power (5 pts.)	State Government Initiatives (7 pts.)	Appliance Efficiency Standards (2 pts.)	**TOTAL SCORE (50 pts.)**	Change in rank from 2011
1	Massachusetts	19.5	6.5	6	4.5	7	0	**43.5**	0
2	California	17.5	7.5	6	2	5.5	2	**40.5**	0
3	New York	17.5	7.5	5	2.5	6.5	0	**39**	0
4	Oregon	16	6	6	2.5	6.5	0.5	**37.5**	0
5	Vermont	19	4.5	5	2.5	4.5	0	**35.5**	0
6	Connecticut	15	5.5	4.5	3	5.5	1	**34.5**	2
7	Rhode Island	18.5	5.5	4	2.5	2	0.5	**33**	-2
8	Washington	14.5	6	6	2.5	2.5	0.5	**32**	-3
9	Maryland	12	6	5.5	1	5	0.5	**30**	1
9	Minnesota	19	2.5	3	1	4.5	0	**30**	-1
11	Iowa	15.5	1	4.5	2	3.5	0	**26.5**	0
12	Arizona	13.5	2	3	2	4.5	0.5	**25.5**	5
12	Michigan	13.5	2	3.5	2	4.5	0	**25.5**	5
14	Colorado	11	2	4	2	6	0	**25**	-2
14	Illinois	8	3.5	6	2.5	5	0	**25**	3
16	New Jersey	9	5.5	3.5	3	3.5	0	**24.5**	-1
17	Wisconsin	10.5	1	4	2	5	0	**22.5**	-1
18	Hawaii	12.5	3	4	0.5	2	0	**22**	-6
18	New Hampshire	10	1	4.5	1.5	4.5	0.5	**22**	3
20	Pennsylvania	5	4.5	4	2	6	0	**21.5**	5
21	Utah	11.5	0.5	4.5	0.5	3	0	**20**	-4
22	Idaho	10.5	0	5	0	4	0	**19.5**	4
22	North Carolina	6	1	5	1.5	6	0	**19.5**	5
22	Ohio	8.5	0	3.5	3.5	4	0	**19.5**	2
25	Maine	8.5	4	2.5	2	2	0	**19**	-13
25	Montana	9	1	5	0.5	3.5	0	**19**	10
27	Delaware	3.5	5	4	2	4	0	**18.5**	4
27	New Mexico	9	2	3.5	1	3	0	**18.5**	0
29	District of Columbia	6	3.5	5	0.5	2	0.5	**17.5**	-7
29	Florida	3.5	4.5	5.5	0.5	3.5	0	**17.5**	-2
31	Nevada	9.5	0	4.5	1	1.5	0	**16.5**	-9
32	Tennessee	1.5	3	3	1.5	6	0	**15**	-2
33	Georgia	1.5	2.5	5.5	0.5	3.5	0.5	**14**	3
33	Indiana	7	0	3.5	2	1.5	0	**14**	-1
33	Texas	3	0	3.5	2	5	0.5	**14**	0
36	Kentucky	4	0	4	0.5	5	0	**13.5**	1
37	Arkansas	7	0	3	1	2	0	**13**	1
37	Virginia	1.5	1.5	4.5	1	4.5	0	**13**	-3
39	Oklahoma	5	0.5	2.5	0	3	0	**11**	8
40	Alabama	2.5	0	3.5	0.5	4	0	**10.5**	3
40	South Carolina	2	1	4	0.5	3	0	**10.5**	6
42	Nebraska	2	0	4	0	3.5	0	**9.5**	-2
43	Louisiana	2.5	0.5	3.5	0.5	2	0	**9**	-3
43	Missouri	3.5	0	2.5	0.5	2.5	0	**9**	1
45	Kansas	1.5	1	1.5	1	3.5	0	**8.5**	3
46	Alaska	0	1	0.5	0.5	6	0	**8**	-8
46	South Dakota	4.5	0	1	1	1.5	0	**8**	-4
48	Wyoming	2.5	0	2	0.5	1.5	0	**6.5**	2
49	West Virginia	0	0.5	3	0.5	2	0	**6**	-5
50	North Dakota	0.5	1	1	1	0.5	0	**4**	1
51	Mississippi	0	0	0	0	2.5	0	**2.5**	-2

Massachusetts scored a total of 43.5 points, retaining the top spot in the *State Energy Efficiency Scorecard* rankings for the second year in a row, based in large part on its continued commitment to energy efficiency under its Green Communities Act of 2008. It continues to lead California, which remained in second place.

Joining Massachusetts and California in the top five are New York, Oregon, and Vermont. These five states have long supported energy efficiency as a state energy resource, scoring in the top five of the State Scorecard at least five out of six years (see Table ES-2). The states rounding out the top ten—Connecticut, Rhode Island, Washington, Maryland, and Minnesota—all scored more than 29.5 points, significantly higher than the trailing states.

Table ES-2: Leading States in the State Scorecard, by Years at the Top

State	Year in Top 5	Years in Top 10
California	6	6
Oregon	6	6
Massachusetts	5	6
New York	5	6
Vermont	5	6
Connecticut	3	6
Minnesota	0	6
Washington	0	6
Rhode Island	0	5
Maine	0	2
Maryland	0	2
New Jersey	0	2
Wisconsin	0	1

The difference between states' total scores in the second, third, and fourth tiers of the State Scorecard is small: only five points separate the states in the second tier, 2.5 points in the third tier, and six points in the fourth tier. For the states in these three tiers, small improvements in energy efficiency may have a significant effect on their rankings. Therefore, idling states will easily fall behind as other states in this large group ramp up efficiency efforts.

Changes in states' overall scores are a function both of changes in their efforts to improve energy efficiency (as is expected in the scoring) and adjustments to our scoring methodology. Therefore, differences between this and last year's rankings cannot be explained only by changes in states' energy efficiency programs or policies. As noted above, we updated the scoring methodology in four policy areas to better reflect potential energy savings, limitations in the data, economic realities, and changing policy landscapes. See the relevant chapter in the main body of the report for the specifics of these updates to the methodology.

STATES ON THE MOVE

Twenty-two states rose in the rankings this year, with several states moving up more significantly than others. "Most improved" status was granted to states based on their change in rank compared to the *2011 State Energy Efficiency Scorecard* (reflecting their efforts relative to those of other states) and percentage change in score over last year (reflecting their efforts relative to themselves).

This year's most improved states are Oklahoma, Montana, and South Carolina. All three states had significantly higher budgets for electric efficiency programs in 2011 than in previous years, and saved more energy from such programs in 2010 than in 2009. Oklahoma put in place natural gas efficiency programs for the first time in 2011, and Montana dramatically increased its budgets for these programs. Each of these states also earned more points this year for their state-led efficiency initiatives, while South Carolina and Montana also earned credit for transportation efficiency measures. Oklahoma and South Carolina earned credit for, respectively, adopting and pursuing greater compliance with more efficient statewide building energy codes.

The continued implementation of energy efficiency resource standards by Arizona, Michigan, North Carolina, and Pennsylvania led to large increases in efficiency program spending from 2010 to 2011 by these states. While not most improved, Kansas, Wyoming, and North Dakota all improved their scores significantly on a percentage basis.

STRATEGIES FOR IMPROVING ENERGY EFFICIENCY

No state received a full 50 points in the *2012 State Energy Efficiency Scorecard*, reflecting the fact that there remain a wide range of opportunities in all states—including the leading states—to further improve energy efficiency. We offer the following recommendations to highlight key ways states may improve their energy efficiency:

- **Put in place, and adequately fund, an Energy Efficiency Resource Standard or similar energy savings target.** Many of the leading states have an Energy Efficiency Resource Standard in place, which can have a catalytic effect on increasing energy efficiency and its associated economic and environmental benefits. The long-term goals associated with an EERS send a clear signal to market actors about the importance of energy efficiency in utility program planning, creating a level of certainty to encourage large-scale, productive investment in energy efficiency technology and services. Long-term energy savings targets require leadership, sustainable funding sources, and institutional support to deliver on their goals. See Chapter 2 for further details.

- **Adopt updated building energy codes and enable the involvement of utility program administrators in building energy code compliance.** Buildings consume more than 40% of total energy in the United States, making them an essential target for energy savings. Utilities can also support code compliance financially by purchasing equipment that code officials can use to measure compliance, as well as generally through new construction programs. See Chapter 4 for further details.

- **Adopt stringent tailpipe emissions standards for cars and trucks, and set quantitative targets for reducing vehicle miles traveled.** States that have adopted California's stringent tailpipe emissions standards (a proxy for energy use) will realize energy savings and pollution reductions greater than those resulting from new federal fuel economy standards. Codified targets for reducing vehicle miles traveled are an important step towards states' achieving substantial reductions in energy use and certain pollutants. See Chapter 3 for further details.

- **Treat combined heat and power as an energy efficiency resource equivalent to other forms of energy efficiency in an Energy Efficiency Resource Standard.** See Chapter 5 for further details.

- **Put in place sustainable funding for state government-led energy efficiency incentive programs; enact policies that require benchmarking of state building energy use and that drive the market for energy service contracting; and invest in energy efficiency-related research, development and demonstration centers.** State government-led initiatives complement the existing landscape of utility programs, leveraging resources from the state's public and private sectors to generate energy and cost savings that benefit taxpayers and consumers. See Chapter 6 for further details.

CONCLUSIONS AND LOOKING AHEAD

Energy efficiency policies and programs have continued to advance at the state level over the past year. A group of leading states remains committed to pursuing more efficient use of energy in transportation, buildings, and industry; fostering economic development in the energy efficiency services and technology industry; and saving money for consumers to spur growth in all sectors of the economy.

A growing number of states have progressed, some rapidly, over the past few years in the pursuit of their energy efficiency goals. There has been a lot of movement within and outside of the top tier of states, with Connecticut poised to break into the top five again, and with several states potentially able to move into the top tier. This dynamism at the policy and program levels is reflected in growing utility program budgets and savings, as well as in the wide range of other efforts states are taking to improve their energy efficiency.

We see signs that many states will continue to raise the bar on their commitments to energy efficiency in 2013 and beyond. For example:

- A July 2012 draft of Massachusetts' second Three-Year Energy Efficiency Plan (State of Massachusetts 2012), required by the Green Communities Act, proposes annual savings goals of 2.5% of electricity retail sales from 2013-2015, and 1.1% of natural gas retail sales starting in 2013 (and increasing in subsequent years), supported by funding for energy efficiency programs of $2 billion over the three years.

- Oregon's Governor Kitzhaber recently released a draft of his *10-Year Energy Action Plan* (State of Oregon 2012), which calls for energy efficiency and conservation to meet 100% of future growth in the electricity load. He called for improving the energy performance of every occupied state-owned building over the next ten years as a first step towards meeting this goal.

- Connecticut's Governor Malloy has made a commitment to pursue the top spot in the State Scorecard in future years, calling for an increase in spending for utility energy efficiency programs, a strengthening of the bonding authority of the state's clean energy investment authority, and reductions in state building energy use starting in 2013 (State of Connecticut 2012).

- In October 2011, the New York Public Service Commission extended the state's Energy Efficiency Portfolio Standard for an additional 4 years, through 2015, and increased funding for energy efficiency programs operated by the New York State Energy Research and Development Authority and the state's investor-owned utilities by more than $2 billion. The Commission also approved a new Technology & Market Development program providing an additional $410 million in public benefit funding over the next 5 years.

- The State of Vermont released its Final Comprehensive Energy Plan 2011, its first since the late 1990s, which promotes increased use of efficiency as one of its first priorities. The plan recommends: the use of innovative energy efficiency program designs to capture all cost-effective efficiency; changes to building efficiency program design; goals for increasing the stringency of and compliance with building energy codes in new construction (including in public buildings); and a review of state land use provisions and infrastructure needs for electric vehicles. The Climate Cabinet, established through Executive Order No. 05-11, is responsible for implementation of the plan (State of Vermont 2011).

  Oklahoma, one of the most improved states this year, is poised to make further improvements in energy efficiency with the recent enactment of Bill 1096, which calls for a 20% reduction in the energy use of state buildings and educational institutions. Governor Fallin, in her 2012 State of the State address, specifically called for Oklahoma to pursue further strategies for improving the state's energy efficiency (State of Oklahoma 2012).

In addition, numerous states that only recently began implementing utility-sector energy efficiency programs such as Michigan, Ohio, Indiana, Arkansas, and Arizona will likely continue to ramp up efficiency program activity over the next few years to meet those rising goals.[1] As noted in Chapter 2, combined utility investments in electric and natural gas efficiency programs are estimated to more than double from 2010 levels to $10.8 billion by 2025, if current savings targets are met, and more than triple to $16.8 billion if many states give energy efficiency a prominent role as a resource (Goldman et al. 2012).

[1] See (Nowak et al. 2011) for a full discussion of how states are preparing to meet higher energy savings targets.

These projections of an increasing role for energy efficiency will not, however, occur in a vacuum. Both state support for energy efficiency and external factors beyond states' control will likely influence the impact of energy efficiency programs and policies in 2013 and beyond. Continued uncertainty around the economic recovery could dampen consumer demand for energy efficiency upgrades in the residential and commercial sectors, which would impact savings from efficiency programs. More concerning is the impact on budgets for efficiency. Some policymakers have responded to continued strain on state budgets by redirecting funds from utility customers or other sources originally meant for efficiency programs to shore up state finances in other areas,[2] or have not allocated energy efficiency budgets at a level necessary to meet mandated savings goals.[3]

Energy efficiency can save consumers money, drive investment across sectors of the economy, and create jobs. While several states are consistently leading the way on energy efficiency and many more are dramatically increasing their efforts, significant opportunities remain to both sustain current efforts and continue to scale up. Energy efficiency is a resource abundant in every state and reaping its full economic, energy security, and environmental benefits will require continued leadership from a wide range of stakeholders, including legislators, regulators, and the utility industry.

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[2] New Jersey Governor Christie redirected $42.5 million from the state's Clean Energy Fund in fiscal year 2011 to cover state energy bills, and will do the same in FY 2013 (which started July 1, 2012), with a reallocation of $210 million (NJ Spotlight 2012; State of New Jersey 2012). At the beginning of this year, New Jersey also withdrew from the Regional Greenhouse Gas Initiative, which had been providing the state with substantial funding for energy efficiency projects (State of New Jersey 2011).

[3] Maine legislators have not sufficiently allocated FY 2013 funds to efficiency programs in the state. This point is discussed more fully in Chapter 2.

Introduction

Conversations about energy use in the United States often revolve around the need to expand the supply of energy to support the growth of our national economy. There is, however, a resource that is cheaper and quicker to deploy, and cleaner, than building new supply—energy efficiency. Energy efficiency improvements help businesses, governments, and consumers meet their needs by using *less* energy, saving them money, driving investment across all sectors of the economy, creating much-needed jobs, and reducing environmental impacts.

Governors, legislators, regulators and citizens are increasingly recognizing that energy efficiency is a critical state resource. In fact, a great deal of the innovation in policies and programs that promote energy efficiency originates in states and localities across the country. The *2012 State Energy Efficiency Scorecard* captures this activity through a comprehensive analysis of state efforts to support energy efficiency.

The *State Energy Efficiency Scorecard* ranks states on their policy and program efforts, and allows us to document best practices, recognize leadership, and provide examples for other states to follow. It serves as a benchmark for state efforts on energy efficiency policies and programs each year, encouraging states to continue strengthening efficiency commitments as a pragmatic and effective strategy for promoting economic growth and environmental benefits.

The State Scorecard builds on previous ACEEE research that focused on each state's spending on energy efficiency programs by utilities and the resulting energy savings. In 2007, ACEEE brought together this state-focused research and release *The State Energy Efficiency Scorecard for 2006* (Eldridge et al. 2007), which provided a comprehensive approach to scoring and ranking states on energy efficiency policies. Due to the broad interest in the 2007 report and the continued demand for a state-by-state comparison on energy efficiency, we have continued to update the report on an annual basis and present the *2012 State Energy Efficiency Scorecard* as its sixth edition.

This year's report has nine chapters. In Chapter 1, we discuss our methodology for scoring states (including changes made this year), present the overall results of our analysis, and provide several strategies states can use to improve their energy efficiency. Chapter 1 also highlights the leading states, most improved states, and other trends in state-level energy efficiency that were revealed by the rankings.

Following this, we present the detailed results for each policy area that we review. Chapter 2 covers utility and "public benefits" programs and policies. Chapter 3 discusses transportation policies, and adds a new metric for state transit legislation this year. Chapter 4 deals with building energy codes, and has updated its scoring of stringency. Chapter 5 scores states on their friendliness towards combined heat and power projects, based on a significantly updated methodology. Chapter 6 deals with state government initiatives, including financial incentives, "lead-by-example" policies, and research, development and demonstration. Chapter 7 covers appliance and equipment efficiency standards.

The *2012 State Energy Efficiency Scorecard* also includes a chapter (Chapter 8) prepared by Humboldt State University on state energy consumption trends and efficiency performance metrics in the residential sector. As in previous years, this chapter is not incorporated into the scoring, but has been included to provide an important complement to the policy metrics covered in the rest of the report. Finally, Chapter 9 discusses areas for future research and offers our closing thoughts on the report's findings.

Chapter 1: Methodology & Results

Author: Ben Foster

SCORING

Every state has different policy and regulatory environments, and we have made an effort to reflect this diversity by choosing metrics that are flexible enough to capture the range of policy and program options that states employ. The policies and programs scored in this report aim to:

- Directly reduce end-use energy consumption
- Set long-term commitments to energy efficiency
- Establish mandatory performance codes and standards
- Accelerate the adoption of the most energy-efficient technologies
- Reduce market, regulatory, and information barriers to energy efficiency
- Provide funding for energy efficiency programs

Table 1 lists six of the primary policy areas in which states have historically pursued energy efficiency. These include utility and "public benefits" programs and policies, transportation policies, building energy codes, policies regarding combined heat and power systems, state government initiatives around energy efficiency, and appliance and equipment standards.

Table 1 also lists the associated scoring metrics, which are weighted according to their potential energy savings (i.e., state policies that are likely to result in the highest energy savings have the highest maximum score). The weighting of policy areas is with the same as in last year's scoring, and is based on several considerations: state and regional studies done by ACEEE that have identified the relative energy savings impacts from state-level policies (SWEEP 2007; Neubauer et al. 2009b and 2011; Molina, Elliot et al. 2010 and Molina et al. 2011); and the judgment of ACEEE staff and outside experts about the impact that state policy (versus federal or local policies) can have on improving energy efficiency in the sectors of the economy covered here.

Specifically, the studies cited above on energy efficiency savings potential identified savings opportunities in the utility and public benefits programs that could contribute about 40% of the total energy savings potential. Building energy codes could contribute, on average, about 15% of the total savings potential, and improved combined heat and power policies about 10%. Therefore, we allocate 40% of the total 50 possible points, or 20 points, to utility and public benefits program and policy metrics. Similarly, we allocate about 15% of the points, or seven points, to building energy codes, and 10%, or five points, to improved combined heat and power policies. The other policy area points were estimated using the same methodology. The assignment of points across all areas was then reviewed by expert advisors and adjusted where appropriate.

Within each policy category, we then developed a scoring methodology based on a diverse set of criteria, detailed in each policy chapter. Finally, we assigned a score for each state based on these criteria and informed by surveys sent to state energy officials, public utility commission staff and experts in the field. To the best of our knowledge, policy information for the *State Energy Efficiency Scorecard* is accurate as of the end of August 2012.

We do not envision that the allocation of points both across and within sectors will forever remain the same. As new efficiency potential studies and new policy designs emerge, we will consider changing the allocation of points, adding or subtracting new metrics, or even eliminating entire categories of scoring, all with the goal of better representing state efforts to capture energy efficiency potential.

Table 1. Scoring by Policy Category

Policy Category & Subcategory	Maximum Score	% of Total Points
Utility and Public Benefits Programs and Policies	20	40%
Electric Efficiency Program Budgets	*5*	10%
Natural Gas Efficiency Program Budgets	*3*	6%
Annual Savings from Electric Efficiency Programs	*5*	10%
Energy Efficiency Resource Standards(EERS)	*4*	8%
Performance Incentives and Fixed Cost Recovery	*3*	6%
Transportation Policies	9	18%
Greenhouse Gas (GHG) Tailpipe Emissions Standards	*2*	4%
Integration of Transportation and Land Use Planning	*2*	4%
Vehicle Miles Traveled (VMT) Targets	*2*	4%
Transit Funding	*1*	2%
Transit Legislation	*1*	2%
Complete Streets Policies	*0.5*	1%
High-Efficiency Vehicle Consumer Incentives	*0.5*	1%
Building Energy Codes	7	14%
Level of Stringency	*5*	10%
Enforcement/Compliance	*2*	4%
Combined Heat and Power	5	10%
Interconnection Standard	*1*	2%
Treatment under Energy Efficiency Resource Standards (EERS)/Renewable Portfolio Standards (RPS)	*1*	2%
Financial Incentives	*1*	2%
Net Metering Rules	*0.5*	1%
Emissions Treatment	*0.5*	1%
Financing Assistance	*0.5*	1%
Additional Policy Support	*0.5*	1%
State Government Initiatives	7	14%
Financial and Information Incentives	*3*	6%
"Lead by Example" Efforts in State Facilities and Fleets	*2*	4%
Research, Development, and Demonstration (RD&D)	*2*	4%
Appliance and Equipment Efficiency Standards	2	4%
Maximum Total Score	**50**	**100%**

Changes in Scoring from 2011

This year we updated the scoring methodology in four policy areas to better reflect potential energy savings, economic realities and changing policy landscapes. In Chapter 2 on utility and public benefits programs and policies, as in the past, we asked state public utility commissions for net electric savings, but in some cases states only report gross electric savings. Therefore, to aid in comparison, we adjusted reported gross savings by a standard factor (a "net-to-gross ratio").

In Chapter 3 on transportation, we considered for the first time whether or not states have adopted legislation that encourages transit investment by state or local governments. This new sub-category takes one-half point from the points possible in last year's *State Energy Efficiency Scorecard* for "complete streets" legislation and high-efficiency vehicle tax credits, based on consideration of their relative energy savings potentials.

The scoring of building codes in Chapter 4 is more stringent this year than in the *2011 State Energy Efficiency Scorecard*. States received full points for building code stringency only if they have updated their statewide energy codes to the most recent residential and commercial codes (IECC 2012 and ASHRAE 90.1-2010 or equivalent, respectively). States that show significant progress towards the adoption of these codes (e.g., Massachusetts) also received full credit.

In Chapter 5 on combined heat and power (CHP), we made significant changes to the methodology to better reflect the multiple factors that influence the development of CHP facilities, and their relative importance. We made changes to the types of policies considered, their relative weighting in the overall chapter score, and better defined the criteria that must be met to receive points. As was the case in the *2011 State Energy Efficiency Scorecard*, this year we scored states on interconnection policies, CHP eligibility under a Renewable Portfolio Standard (RPS) or Energy Efficiency Resources Standard (EERS), financial incentives for CHP development, net metering standards, and emissions treatment. We added scoring of additional supportive policies and financing assistance for CHP, and eliminated scoring of standby rates. Local electricity prices, natural gas prices, and state-installed CHP capacity are presented for the first time, but do not factor into states' scores. For an in-depth discussion of changes to combined heat and power scoring in the *2012 State Energy Efficiency Scorecard*, refer to Chittum (2012).

All these changes appear to have affected states' scores in the *State Energy Efficiency Scorecard*, although the effect on relative ranking is less clear. Refer to the appropriate chapter for a complete discussion of these methodological changes, and see below for further discussion on the resulting impact on scoring.

State Data Collection and Review

We continue to improve our outreach to state-level stakeholders to verify the accuracy and comprehensiveness of the policy information on which we score the states. This year we asked every state utility commission to review spending and savings data for customer-funded programs presented in Chapter 2, and 36 states responded. In addition, state energy officials were given the opportunity to review the material on ACEEE's State Energy Efficiency Policy Database (ACEEE 2012) and to provide updates to the information scored in Chapter 6 on state-led energy efficiency initiatives; we received responses from 22 state energy offices. Officials were also given the opportunity to review and provide comments on a draft of the *2012 State Energy Efficiency Scorecard* prior to publication.

For the first time, we gathered additional data in several areas that had not been reported in previous versions of the State Scorecard. First, in an effort to more fully represent states' utility customer-funded energy efficiency programs, this year we requested program savings and budget data from 43 of the largest municipal utilities and cooperatives in the 31 relevant states, receiving 14 responses. The responses we received were added, where appropriate, to the savings and budget data reported in Chapter 2. We plan to strengthen this area of outreach in future updates to the State Scorecard.

Second, we gathered data on the energy savings from natural gas efficiency programs and solicited data on whether states report gross or net electricity savings. We did not receive a response sufficient to warrant including natural gas savings data in the scoring at this time, but data on net versus gross electricity savings is included in Table 12.

DATA LIMITATIONS

The State Scorecard reflects state-level energy efficiency policy environments as well as states' performance in implementing the efficiency programs. We have generally not included the energy efficiency initiatives implemented by actors at the federal and local level or in the private sector (with the exception of investor owned utilities and combined heat and power facilities). Regions, counties, and municipalities have become very active in energy efficiency program development, a trend that we do not track in the State Scorecard but a positive development that should reinforce the energy efficiency efforts taking place at the state level. A few metrics in the State Scorecard do capture non-state efforts, such as local enforcement of building codes, local land-use policies and state financial incentives aimed at local energy efficiency efforts. As much as possible, however, we aim to focus specifically on state-level energy efficiency activities.

Private sector investments in efficient technologies outside of customer-funded or government-sponsored energy efficiency programs are also not covered in the State Scorecard. While utility and public programs are critical to leveraging private capital, the development of an independent metric measuring private sector investment falls outside the scope of this report.

"Best Practice" Policy and Performance Metrics

The scoring framework described above is our best attempt to represent the myriad efficiency metrics as a quantitative "score." There are clear limitations to converting spending data, energy savings data, and policy adoption metrics across six policy areas into one score. Energy savings performance metrics are confined mostly to efficiency with regard to electricity. Although we did attempt to gather gas program savings data, we have not included them in this year's scoring. Due to data lags, these performance metrics reflect activity in 2010 and 2011 rather than 2012.

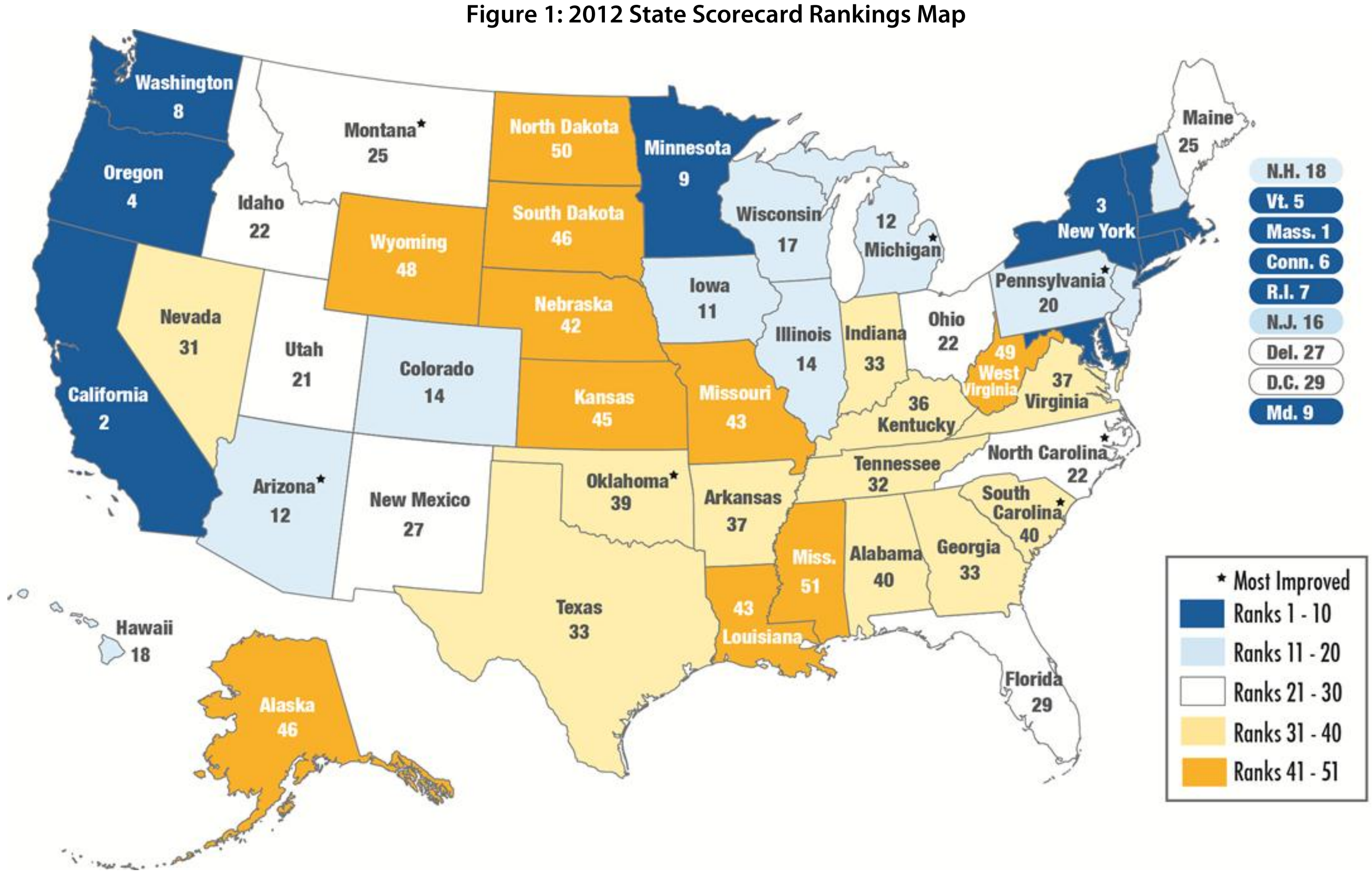
We have not scored energy efficiency policy areas on reported savings or spending data attributable to a particular policy action, and instead we have developed "best practice" metrics according to which to score the states. For example, *potential* energy savings from improved building energy codes and appliance efficiency standards have been documented, although *actual* savings from these policies are rarely evaluated. Therefore, we have relied on "best practice" metrics for building energy codes; in the case of building energy codes, we rank states according to the level of stringency of their residential and commercial codes.

With the knowledge that policies are effective only if they are implemented properly, in many areas we have adjusted our scoring metrics to reflect actual policy implementation. We give states points for building code compliance, for example, to underscore the importance of enforcement. Full discussions of the policy and performance metrics used can be found in each chapter.

2012 State Energy Efficiency Scorecard Results

The results of the State Scorecard are presented in Figure 1, and more fully in Table 2. Below we present some key highlights of changes in state rankings, discuss which states are making notable new commitments to energy efficiency, and provide a series of recommendations for states wanting to increase their energy efficiency.

Figure 1: 2012 State Scorecard Rankings Map



How to Interpret Results

Although we provide individual state scores and rankings, the difference between states is both easiest to understand and most instructive in tiers of ten. This is because the group of states that compose each of the five tiers have tended to be fairly consistent over time, although states can and do move into new tiers from year to year. Therefore, differences between individual states are generally less important than differences between the tiers of states. The difference between states' total scores in the second, third and fourth tiers of the *State Energy Efficiency Scorecard* is small: only five points separate the states in the second tier, 2.5 points in the third tier, and six points in the fourth tier. For the states in these three tiers, small improvements in energy efficiency may have a significant effect on their rankings. Therefore, idling states will easily fall behind as other states in this large group ramp up efficiency efforts.

The top tier, however, exhibits more variation in scoring (with a 13.5-point range) than the other tiers, representing approximately one-third the total variation in scoring among all the states. The top tier might arguably be divided in half, with the top five states—Massachusetts, California, New York, Oregon, and Vermont—being considered "truly leading" states. These five scored significantly higher than most other states, and retained the same rank order from 2011, despite several methodological changes this year. The states in the top tier have also made broad, long-term commitments to energy efficiency, indicated by their having remained at the top of the State Scorecard over the past six years. This point is discussed further below.

Table 2. Summary of State Scores

Rank	State	Utility & Public Benefits Programs & Policies (20 pts.)	Transportation Policies (9 pts.)	Building Energy Codes (7 pts.)	Combined Heat & Power (5 pts.)	State Government Initiatives (7 pts.)	Appliance Efficiency Standards (2 pts.)	**TOTAL SCORE (50 pts.)**	Change in rank from 2011
1	Massachusetts	19.5	6.5	6	4.5	7	0	**43.5**	0
2	California	17.5	7.5	6	2	5.5	2	**40.5**	0
3	New York	17.5	7.5	5	2.5	6.5	0	**39**	0
4	Oregon	16	6	6	2.5	6.5	0.5	**37.5**	0
5	Vermont	19	4.5	5	2.5	4.5	0	**35.5**	0
6	Connecticut	15	5.5	4.5	3	5.5	1	**34.5**	2
7	Rhode Island	18.5	5.5	4	2.5	2	0.5	**33**	-2
8	Washington	14.5	6	6	2.5	2.5	0.5	**32**	-3
9	Maryland	12	6	5.5	1	5	0.5	**30**	1
9	Minnesota	19	2.5	3	1	4.5	0	**30**	-1
11	Iowa	15.5	1	4.5	2	3.5	0	**26.5**	0
12	Arizona	13.5	2	3	2	4.5	0.5	**25.5**	5
12	Michigan	13.5	2	3.5	2	4.5	0	**25.5**	5
14	Colorado	11	2	4	2	6	0	**25**	-2
14	Illinois	8	3.5	6	2.5	5	0	**25**	3
16	New Jersey	9	5.5	3.5	3	3.5	0	**24.5**	-1
17	Wisconsin	10.5	1	4	2	5	0	**22.5**	-1
18	Hawaii	12.5	3	4	0.5	2	0	**22**	-6
18	New Hampshire	10	1	4.5	1.5	4.5	0.5	**22**	3
20	Pennsylvania	5	4.5	4	2	6	0	**21.5**	5
21	Utah	11.5	0.5	4.5	0.5	3	0	**20**	-4
22	Idaho	10.5	0	5	0	4	0	**19.5**	4
22	North Carolina	6	1	5	1.5	6	0	**19.5**	5
22	Ohio	8.5	0	3.5	3.5	4	0	**19.5**	2
25	Maine	8.5	4	2.5	2	2	0	**19**	-13
25	Montana	9	1	5	0.5	3.5	0	**19**	10
27	Delaware	3.5	5	4	2	4	0	**18.5**	4
27	New Mexico	9	2	3.5	1	3	0	**18.5**	0
29	District of Columbia	6	3.5	5	0.5	2	0.5	**17.5**	-7
29	Florida	3.5	4.5	5.5	0.5	3.5	0	**17.5**	-2
31	Nevada	9.5	0	4.5	1	1.5	0	**16.5**	-9
32	Tennessee	1.5	3	3	1.5	6	0	**15**	-2
33	Georgia	1.5	2.5	5.5	0.5	3.5	0.5	**14**	3
33	Indiana	7	0	3.5	2	1.5	0	**14**	-1
33	Texas	3	0	3.5	2	5	0.5	**14**	0
36	Kentucky	4	0	4	0.5	5	0	**13.5**	1
37	Arkansas	7	0	3	1	2	0	**13**	1
37	Virginia	1.5	1.5	4.5	1	4.5	0	**13**	-3
39	Oklahoma	5	0.5	2.5	0	3	0	**11**	8
40	Alabama	2.5	0	3.5	0.5	4	0	**10.5**	3
40	South Carolina	2	1	4	0.5	3	0	**10.5**	6
42	Nebraska	2	0	4	0	3.5	0	**9.5**	-2
43	Louisiana	2.5	0.5	3.5	0.5	2	0	**9**	-3
43	Missouri	3.5	0	2.5	0.5	2.5	0	**9**	1
45	Kansas	1.5	1	1.5	1	3.5	0	**8.5**	3
46	Alaska	0	1	0.5	0.5	6	0	**8**	-8
46	South Dakota	4.5	0	1	1	1.5	0	**8**	-4
48	Wyoming	2.5	0	2	0.5	1.5	0	**6.5**	2
49	West Virginia	0	0.5	3	0.5	2	0	**6**	-5
50	North Dakota	0.5	1	1	1	0.5	0	**4**	1
51	Mississippi	0	0	0	0	2.5	0	**2.5**	-2

2012 Leading States

Massachusetts retained the top spot in the *State Energy Efficiency Scorecard* rankings for the second year in a row, having overtaken California last year, based on its continued commitment to energy efficiency under its Green Communities Act of 2008. The Act laid the foundation for greater investments in energy efficiency programs by requiring gas and electric utilities to save a large and growing percentage of energy every year through energy efficiency. Although goals for the second planning period, from 2013-2015, have not yet been set, a July 2012 draft proposes an increase in energy efficiency investments to more than $2 billion, and an increase in savings goals to 2.5% of electric and 1.1% of natural gas retail sales (State of Massachusetts 2012).

Massachusetts also leads in other areas of the State Scorecard, including its commitment to reducing energy use in state buildings and fleets, its efforts to ensure compliance with stringent state building codes, and its policies to create a supportive environment for the development of combined heat and power facilities in the state.

As was mentioned above, the states taking the top five places—Massachusetts, California, New York, Oregon, and Vermont—can be characterized as "truly leading" states, based on long-term commitments to improving end-use energy efficiency. This is reflected in their standing in the State Scorecard over the past six years, as listed here.

Table 3. Leading States in the State Scorecard, by Years at the Top

State	Year in Top 5	Years in Top 10
California	6	6
Oregon	6	6
Massachusetts	5	6
New York	5	6
Vermont	5	6
Connecticut	3	6
Minnesota	0	6
Washington	0	6
Rhode Island	0	5
Maine	0	2
Maryland	0	2
New Jersey	0	2
Wisconsin	0	1

Table 3 shows the number of years that states have been in the top five and top 10 spots in the State Scorecard rankings since 2007. In total, six states have occupied the top five spots, and 13 have appeared somewhere in the top ten. Both California and Oregon have been in the top five spots all six years, followed by Massachusetts, New York and Vermont for five years, and Connecticut for three. Rounding out the top 10, are Minnesota and Washington, each having been in the top 10 for six years; Rhode Island for five years; Maine, Maryland and New Jersey twice; and Wisconsin once. All 13 of these states have made broad, long-term commitments to energy efficiency in the past, and most continue to do so. In recent years, however, that commitment has waned in both New Jersey and Maine; among other things, they have not allocated budgets for energy efficiency at the same levels as in the past.

Changes in Outcome Compared to the *2011 State Energy Efficiency Scorecard*

Changes in states' overall scores this year compared to previous State Scorecards are a function of both changes in states' efforts to improve energy efficiency and changes to our scoring methodology. As a result, comparisons to last year's rankings cannot be understood as due solely to changes in states' energy efficiency programs or policies.

Table 4 presents the outcome of the *2012 State Energy Efficiency Scorecard* compared to last year, by policy area and direction of change. Overall, 20 states gained points and 30 states lost points in the *2012 State Energy Efficiency Scorecard* compared to last year, with one state having no change in score,[4] signaling that the landscape for energy efficiency is clearly in constant flux and many opportunities remain.

States have made significant efforts over the past year in utility policies and programs and state government initiatives. For example, in 2011 national spending by utilities on electric energy efficiency programs totaled $5.9 billion, a 29% increase over the previous year, and natural gas program spending grew by 18% to $1.1 billion over the same period. Savings from electric efficiency program in 2010 totaled approximately 18.4 million MWh, a 40% increase over a year earlier.

Table 4. Number of States Gaining or Losing Points Compared to 2011, by Policy

Policy Category	States Gaining Points		No Change		States Losing Points	
Utility & Public Benefits	28	55%	14	27%	9	18%
Transportation	15	29%	24	47%	12	24%
Building Energy Codes	9	18%	8	16%	34	67%
Combined Heat and Power	4	8%	5	10%	42	82%
State Gov't Initiatives	21	41%	15	29%	15	29%
Appliance Standards	1	2%	47	92%	3	6%
Total Score	20	39%	1	2%	30	59%

A broad range of opportunities exist for states to improve energy efficiency, but the results of this year's analysis suggest that the greatest opportunities are in policies aimed at combined heat and power and building codes.

This year's updated methodology for combined heat and power (CHP), combined with changes in states' policy support for CHP, affected almost all states in the same direction, though not to the same degree. Forty-two states lost points in this policy category compared to the *2011 State Energy*

[4] The State Scorecard looks at all 50 states and the District of Columbia, which, while not a "state", is grouped under that heading for convenience.

Efficiency Scorecard, but some states that lost points here actually rose in the overall rankings compared to last year. We believe that changes to the CHP scoring methodology were necessary to correct our assessment of states' relative friendliness towards the technology. The states that benefited from or remained unaffected by the new CHP methodology were primarily in the Southeast and mountain West regions—Alabama, Arkansas, Georgia, Louisiana, Oklahoma, Kansas, North Dakota and Wyoming. This appears to be an artifact of our scoring methodology, rather than a recent policy trend among the states in these regions.

Our updated scoring of building code stringency also affected the majority of states in the same direction, and again not to the same degree—34 states lost points compared to last year, eight were unaffected, and nine gained points. This reflects the fact that the majority of states have not continued to update their residential and commercial energy codes, with the notable exception of Maryland and Illinois, the only two states as of this writing to have adopted the 2012 version of the International Energy Conservation Code. Of the nine states gaining points in the building codes category this year, Arkansas and Oklahoma strengthened their statewide codes, while North Dakota and South Dakota gained points in this area for the first time for voluntary code adoption in major jurisdictions.

Despite slight changes in the scoring methodology for transportation, 24 states' scores remained unchanged from last year. Of the remaining states, 15 gained points and 12 lost points, suggesting that the transportation methodology changes did not affect states as broadly as changes in the CHP and building codes scoring.

"Most Improved" States

Twenty-two states rose in the rankings this year, but several states moved up more significantly than others. "Most improved" status was given to states based on their change in rank compared to the *2011 State Energy Efficiency Scorecard* (reflecting their efforts relative to other states) and the percentage change in this year's score over last year's (reflecting efforts relative to themselves).

This year's most improved states are Oklahoma, Montana and South Carolina. All three states had significantly higher budgets for electric efficiency programs in 2011 than in previous years, and saved more energy from electric energy efficiency programs in 2010 than in 2009. Oklahoma put in place natural gas efficiency programs for the first time in 2011, and Montana dramatically increased its budgets for these programs. These funding increases will likely yield further savings in coming years.

In addition to strides in the utility sector, these three states have made improvements in other energy efficiency areas. As of July 2012, Oklahoma resumed its Energy Efficient Residential Construction Tax Credit, which was suspended for two years in June 2010. The state also formed the Oklahoma Uniform Building Code Commission and adopted mandatory statewide building energy codes that went into effect in mid-2011. In addition, in May of this year Bill 1096 was signed into law, requiring all state agencies and institutions of higher education to achieve at least 20% energy savings over 2012 by 2020. State buildings will be benchmarked prior to the implementation of the program, and costs associated with the program will be fully funded by program savings.

Over the course of 2011, South Carolina expanded its building energy code compliance activities, including completing a gap analysis analyzing the current code implementation efforts in the state and making recommendations for achieving 90% compliance with the model energy code. The state also completed a compliance plan in November 2011, providing a five-year roadmap for energy code implementation in the state, and conducted extensive compliance training during 2011. On the transportation side, South Carolina extended its state tax credit for plug-in electric hybrid vehicles (PHEV) until 2017 and received credit for a complete streets resolution that has been in place for several years.

Montana received a correction to its score for efforts related to energy efficiency that have been in place for several years, including the 2009 passage of both the Omnibus Land Use Modernization Act and S.B. 49, which created energy efficiency standards for state-owned and –leased buildings.

Other states have also made recent efforts related to energy efficiency. Arizona, Michigan, North Carolina and Pennsylvania continue to reap the benefits of their EERS policies, which led to substantially higher electric efficiency program spending and savings compared to what we reported in the *2011 State Energy Efficiency Scorecard*.

North Carolina also saw a very large increase in savings from electric efficiency programs over the previous year. In addition, it received points for transit legislation that has been in place for several years which established funding for the implementation of public transit plans that aim to reduce energy consumption, relieve traffic congestion, improve air quality, and promote pedestrian and bike connections to transit stations.

States Losing Ground

Twenty-one states fell in the rankings, due to several factors—changes to scoring in the combined heat and power, transportation and building codes categories, and relatively faster progress by other states. Here we can see the complex relationship between changes in total score and changes in rank. Of the 30 states that lost points overall compared to last year, 21 fell in the rankings. The rankings of five others did not change, and the four remaining states that lost points actually moved up in the rankings. Because of the number of metrics covered in the State Scorecard and states' differing efforts, relative movement among the states should be expected. As mentioned earlier, the difference between states' total scores in the second, third and fourth tiers of the State Scorecard is small, so idling states will easily fall behind as others ramp up efforts to become more energy-efficient.

Maine fell the furthest, by thirteen places, compared to the *2011 State Energy Efficiency Scorecard*. This change is explained by three factors: Maine's decision not to fully fund its Energy Efficiency Resource Standard, its slow adoption of more stringent building codes, and its losing ground to other states in creating an environment conducive to combined heat and power development. Maine's apparent weakening of support for energy efficiency is of particular concern because of its laudable history of increasing efficiency budgets (as reflected in our scoring of 2011 budgets and 2010 savings in Chapter 2).

Nevada fell nine places from its rank in the *2011 State Energy Efficiency Scorecard*. It was affected by changes in our scoring of combined heat and power, and also lost points which it had previously been awarded for its adoption of incandescent lamp standards more stringent than federal standards, because it is unclear that the standards will be enforced. Nevada also lost points for a dip in electric program savings and, like many states, for its slow adoption of more stringent building codes.

Alaska fell eight spots from last year. Like most states, it fell in the rankings partially because of our revised methodology for combined heat and power. In addition, its score this year reflects a correction to our assessment of the number of new state-financed homes required to meet the statewide residential building energy code. Discussions with the Alaska Housing Finance Corporation led us to believe that we overestimated the percentage of new homes covered by the mandatory code in the *2011 State Energy Efficiency Scorecard*, and, in fact, that most new state-financed homes are *not* covered.

The District of Columbia fell seven places in the rankings. In addition to being affected by the change in CHP scoring, another dominant factor was a fall-off in energy efficiency program spending and savings over the previous year. This decrease is likely only temporary, however, as the D.C. Sustainable Energy Utility takes over efficiency program administration from Pepco, whose program budgets were eliminated as of September 30, 2010 (DC PSC 2011).[5]

STRATEGIES FOR IMPROVING ENERGY EFFICIENCY

No state received a full 50 points in the *2012 State Energy Efficiency Scorecard*, reflecting the fact that there are a wide range of opportunities in all states—including Massachusetts and other leaders—to improve energy efficiency. For states wanting to improve their standing the State Scorecard and, more importantly, wanting to capture greater energy savings and the concomitant public benefits, we offer the following recommendations from among the metrics that we track:

Put in place, and adequately fund, an Energy Efficiency Resource Standard (EERS) or similar energy savings target. These policies establish specific energy savings targets that utilities or independent statewide program administrators must meet through customer energy efficiency programs, and serve as an enabling framework for increases in investment, savings and program activity that, as seen in many of the leading states, can have a catalytic effect on increasing energy efficiency and its associated economic and environmental benefits. The long-term goals associated with an EERS send a clear signal to market actors about the importance of energy efficiency in utility program planning, creating a level of certainty to encourage large-scale, productive investment in energy efficiency technology and services. Long-term energy savings targets require leadership, sustainable funding sources and institutional support to deliver on their goals. See Chapter 2 for further details.

Examples: Massachusetts, Arizona, Hawaii, Vermont

Adopt updated building energy codes and enable the involvement of utility program administrators in building energy code compliance. Buildings consume more than 40% of total energy in the United States, making them an essential target for energy savings. Mandatory building energy codes are one way to ensure a minimum level of energy efficiency for new residential and commercial buildings. Another key policy driver for capturing energy savings from codes is to enable

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[5] DC SEU spending will double in 2012 to $15 million, from $7.5 million in 2011 (DDOE 2012).

involvement of utility and program administrators in compliance activities. Utilities can also support code compliance financially, by purchasing equipment that code officials can use to measure compliance, as well as generally through new construction programs. Utilities are motivated to support code compliance (and adoption) by the need to keep peak demand in check. See Chapter 4 for further details.

Examples: California, Idaho, Massachusetts, New York, Oregon

Adopt stringent tailpipe emissions standards for cars and trucks, and set quantitative targets for reducing vehicle miles traveled. Like buildings, transportation consumes a substantial fraction of total energy in the United States. States that have adopted California's stringent tailpipe emissions standards (a proxy for energy use) will realize energy savings and pollution reductions greater than those resulting from new federal fuel economy standards. Codified targets for reducing vehicle miles traveled (VMT) are an important step towards states' achieving substantial reductions in energy use and certain pollutants. See Chapter 3 for further details.

Examples: California, New York, Massachusetts, Oregon

Treat combined heat and power as an energy efficiency resource equivalent to other forms of energy efficiency in an Energy Efficiency Resource Standard. Many states list combined heat and power as an eligible technology within their Energy Efficiency Resource Standard or Renewable Portfolio Standard, but relegate it to a bottom tier, letting other renewable technologies and efficiency resources take priority within the standard. ACEEE recommends that combined heat and power be given equal footing, which does require that the state develop some methodology for how to count combined heat and power savings. Massachusetts has accomplished this in their Green Communities Act.

Examples: Ohio *SB 215* (2012), Texas *HB 3268* (2011), Massachusetts's *Green Communities Act* (2008)

Expand and make visible state-led efforts, such as putting in place sustainable funding for energy efficiency incentive programs; enacting policies that require benchmarking of state building energy use and that drive the market for energy service contracting; and investing in energy efficiency-related research, development and demonstration centers. State-led initiatives complement the existing landscape of utility programs, leveraging resources from the state's public and private sectors to generate energy and cost savings that benefit taxpayers and consumers. States have many opportunities to "lead by example," including reducing energy use in public buildings and fleets, enabling the market for energy service companies (ESCOs) that finance and deliver energy-saving projects, and funding centers that focus on energy-efficient technology breakthroughs. See Chapter 6 for further details.

Examples: New York, Hawaii, Alaska

Chapter 2: Utility and Public Benefits Programs and Policies

Authors: Ben Foster, Seth Nowak, Sara Hayes and Kaye Schultz

INTRODUCTION

The utility sector is critical to the implementation of energy efficiency, as electric and natural gas utilities and independent statewide program administrators deliver a substantial share of U.S. electric and natural gas efficiency programs.[6] Utility customers fund these programs, either through cost recovery mechanisms or statewide "public benefits funds." Utilities and independent statewide program administrators in some states have been delivering energy efficiency programs for decades, driven by regulation from state utility commissions, and have been offering various efficiency services for residential, commercial, industrial, and low-income customers. Today, almost every state implements utility-sector energy efficiency programs, which have come to include a variety of financial incentives such as rebates and loans, technical services such as audits and retrofits, and educational campaigns about the benefits of energy efficiency improvements.

We reviewed and ranked the states based on their performance in implementing utility-sector efficiency programs and enabling policies that are evidence of states' commitment to energy efficiency. The five subsets of scoring in this chapter include:

- Program budgets: Electricity program budgets as a percentage of statewide utility revenues, and natural gas program budgets per residential natural gas customer
- Energy savings: Incremental[7] electric program savings as a percentage of retail sales
- Enabling policy: Energy Efficiency Resource Standards (EERS)
- Financial incentives for utilities: Performance incentives and fixed cost recovery

Electric and Natural Gas Efficiency Program Budgets

The structure and delivery of customer-funded electric energy efficiency programs[8] have changed dramatically over the past two decades, mostly in conjunction with restructuring efforts. In the 1980s and 1990s, such programs were almost exclusively the domain of utilities; they administered and implemented programs under regulatory oversight.

Efforts in the mid-1990s to restructure and deregulate the electric utility markets led numerous states to put in place "public benefits charges" as a new source of funding for efficiency programs. These "public benefits" programs established new structures and, in some cases,[9] tasked organizations other

[6] The other major programs are run by state governments, which are discussed in chapter 6.

[7] Incremental annual savings represent new savings from programs in each program cycle, while cumulative savings represent all savings accrued over the life of a particular program.

[8] By "customer-funded energy efficiency" programs—also known as "ratepayer-funded energy efficiency" programs—we mean energy efficiency programs funded through charges wrapped into customer rates or as some type of charge on customer utility bills. This includes both utility-administered programs and public benefits programs administered by other entities. We do not include data on separately funded low-income programs, load management programs, or energy efficiency research and development.

[9] States that have established non-utility administration of efficiency programs include Vermont, New York, Oregon, Wisconsin, Delaware, New Jersey, and the District of Columbia.

than public utilities with the responsibility of administering and delivering energy efficiency and related energy programs (including low-income energy programs and renewable energy programs).

Not all public benefits programs are administered or delivered by non-utility organizations, however. In quite a few cases funds from a public benefits program go to the utilities to administer and implement the programs. Thus, while there have been changes in funding and administrative structures for customer programs over the past 20-30 years, utilities are still the primary administrator of such programs on a national basis.

Despite the enactment of public benefits programs in many states, restructuring resulted in a precipitous decrease in funding for customer-funded electric energy efficiency programs, from almost $1.8 billion in 1993 to about $900 million in 1998 (nominal dollars). The principal reasons for this decline included utility uncertainty about newly restructured markets and the expected loss of "cost recovery mechanisms" for their energy efficiency programs.[10] Generally, utilities did not see customer-funded energy efficiency programs as being compatible with competitive retail markets.

After restructuring efforts declined in some states over the past decade utility commissions have placed renewed focus and importance on energy efficiency programs. From its low point in 1998, spending for electricity programs increased five-fold by 2010, from approximately $900 million to $4.6 billion. And in 2011, total budgets for electricity efficiency programs reached approximately $5.9 billion. Adding this to natural gas program budgets of $1.1 billion, we estimate total efficiency program budgets of $7 billion in 2011 (see Figure 2).

Given the increasing commitments to energy efficiency on the part of state regulatory commissions, this growth will likely continue over the next decade. In one analysis of customer-funded energy efficiency program budgets, funding for electric and natural gas programs is estimated to more than double from 2010 levels to $10.8 billion by 2025, if current savings targets are met, and more than triple to $16.8 billion if states give energy efficiency a prominent role as an energy resource (Goldman et al. 2012). This analysis also suggests a significant broadening of the U.S. energy efficiency market, with a large portion of the projected increases in spending coming from states in the Midwest and South that have historically had relatively low levels of funding for energy efficiency.

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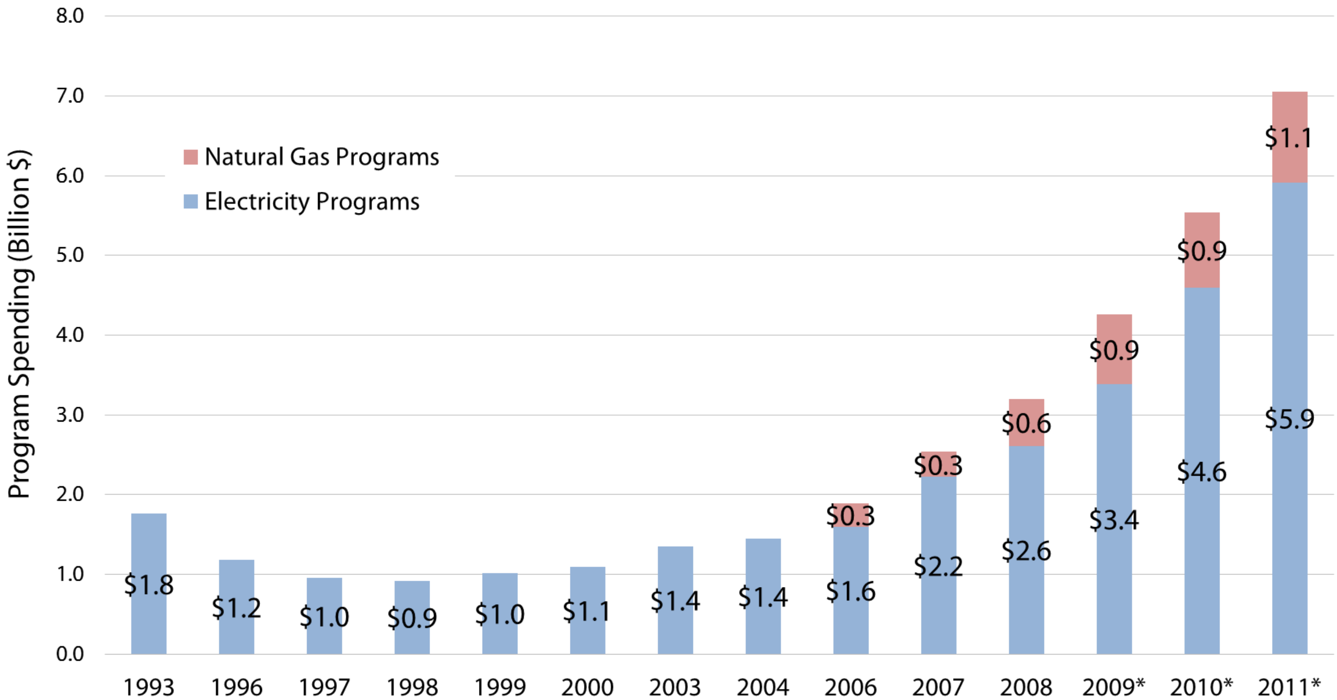
[10] Under traditional regulatory structures, utilities do not have an economic incentive to help their customers become more energy efficient because their revenues and profits fall in line with falling energy sales from energy efficiency programs. To address this disincentive, state regulators allow utilities to recover, at a minimum, the costs of running energy efficiency programs through charges on customer bills.

Figure 2. Annual Electric and Natural Gas Energy Efficiency Program Spending or Budgets



* From 1993-2008, values respresent actual program spending (including customer-funded programs); from 2009 on, they represent program budgets. Natural gas spending is not available for the years 1993-2004. Sources: Nadel et al. (2000); York and Kushler (2002, 2005); Eldridge et al. (2008, 2009); Molina, Neubauer et al. (2010); Sciortino et al. (2011).

Savings from Electric Efficiency Programs

We measure the overall performance of electric energy efficiency programs by the amount of electricity saved. Electricity savings are generated when a utility or statewide independent administrator offers a program that helps customers save energy in their home or business through improved energy efficiency. Utilities and non-utility program administrators pursue numerous strategies to achieve energy efficiency savings. Program portfolios may initially concentrate on the "lowest-hanging fruit"—measures that are quickly and readily attainable—such as energy-efficient lighting and appliances. As utilities gain experience and customers become aware of the benefits of energy efficiency, the number of approaches available to efficiency program portfolios increases. Subject to internal or third-party evaluation, monitoring, and verification, the utility earns credit for the energy savings achieved through customer programs.

In states ramping up funding levels in response to aggressive Energy Efficiency Resource Standards, programs will necessarily shift focus from "widget-based" approaches (e.g., installing a new, more efficient water heater) to more comprehensive "deep savings" approaches, which seek to generate more energy efficiency savings per program participant by, rather than installing a single piece of equipment, conduct whole-building or system retrofits. Some deep savings approaches also draw on savings from complementary efficiency efforts, such as the enforcement of building energy codes.[11] Deep savings approaches may also add to the emphasis on whole-building retrofits and comprehensive changes in systems and operations by including behavioral elements that empower customers with contextual information on energy use.

Energy Efficiency Resource Standards

Enabling policies such as "Energy Efficiency Resource Standards" (EERS) and financial incentives for utilities (see next section) are critical to leveraging energy efficiency funding and encouraging savings over the near and long terms. Twenty-four states now have fully-funded policies in place that establish specific energy savings targets that utilities or independent statewide program administrators must meet through customer energy efficiency programs. These policies—called "Energy Efficiency Resource Standards"—set multi-year targets for electric or natural gas efficiency, such as 2% incremental savings per year or 20% cumulative savings by 2020.[12]

Energy Efficiency Resource Standards aim explicitly for quantifiable energy savings, reinforcing the idea that energy efficiency is a utility system resource on par with supply-side resources. These standards also help utility system planners more clearly anticipate and project the impact of energy efficiency programs on utility system loads and resource needs. Energy savings targets are generally set at levels that push efficiency programs to achieve higher savings than they otherwise would have. EERS policies maintain strict requirements for cost-effectiveness so that efficiency programs are guaranteed to provide overall benefits to customers. And Energy Efficiency Resource Standards help to ensure a long-term commitment to energy efficiency as a resource, building essential customer engagement as well as the workforce and market infrastructure necessary to sustain the high levels of savings.[13]

EERS policies encompass three distinct approaches to achieving a single outcome—binding, long-term targets for energy efficiency savings from utility programs (Sciortino et al. 2011). The three approaches are a statewide an explicit Energy Efficiency Resource Standard, long-term energy savings targets set by utility commissions and tailored to individual utilities or statewide independent administrators, and the incorporation of energy efficiency as an eligible resource in a Renewable Portfolio Standard (RPS). While the latter two options may not technically be a "standard" in the traditional sense, ACEEE has defined all three approaches as an EERS to avoid confusion and to highlight the key similarity of all these policies—establishing binding, long-term energy savings targets. Table 5 describes key distinctions among these three policies and identifies the states that utilize them.

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[11] See ACEEE's recent research report, *Energy Efficiency Resource Standards: Strategies for Higher Savings* (Nowak et al. 2011) for a full discussion on this topic.

[12] "Multi-year" is defined as three or more years. EERS policies may set specific targets as a percentage of sales, as specific gigawatt-hour (GWh) energy savings targets without reference to sales in previous years, or as a percentage of load growth.

[13] ACEEE's 2011 report, *Energy Efficiency Resource Standards: A Progress Report on State Experience,* analyzes current trends in EERS implementation and finds that most states are meeting or are on track to meet energy savings targets (Sciortino et al. 2011).

Table 5. Key Distinctions of Energy Efficiency Resource Standards

Policy Type	Description	Applicable States
Statewide Energy Efficiency Resource Standard	Typically set by state legislatures and codified by utility commissions, the statewide EERS requires utilities to achieve a prescribed level of savings. In some states, legislatures require utilities to invest in all cost-effective efficiency, with specific targets set by stakeholder councils and public utilities commissions.	Arizona, Arkansas, California, Illinois, Indiana, Maryland, Massachusetts, Michigan, Minnesota, New Mexico, New York, Ohio, Pennsylvania, Rhode Island, Texas
Tailored Target	Initiated in a variety of ways, long-term energy efficiency targets in these states are tailored to each specific utility or third-party program administrator. In each case, law or regulation calls for the establishment of multi-year (3-year+), specific energy savings targets.	Colorado, Iowa, Oregon, Vermont, Washington, Wisconsin
Combined Energy Efficiency Resource Standard and Renewable Portfolio Standard	Energy efficiency may be classified as an eligible resource in state Renewable Portfolio Standards. In these cases, energy efficiency is measured on a cumulative, rather than annual, incremental basis.	Hawaii, Nevada, North Carolina

Financial Incentives Affecting Utility Investment in Efficiency: Earning a Return and Addressing Lost Revenues

Under traditional regulatory structures, utilities do not have an economic incentive to help their customers become more energy-efficient. In fact, they typically have a disincentive because falling energy sales from energy efficiency programs reduce utilities' revenues and profits, an effect referred to as "lost revenues" or "lost sales." Since utilities' earnings are usually based on the total amount of capital invested in certain asset categories (such as transmission lines and power plants) and the amount of electricity sold, the financial incentives are very much tilted in favor of increased electricity sales and expanding supply-side systems.

Understanding this dynamic has led industry experts to devise ways of addressing possible loss of earnings and profit that can result from customer energy efficiency programs while removing utilities' financial disincentive to promote energy efficiency. There are three key policy approaches to properly align utility incentives and remove barriers to energy efficiency (York & Kushler 2011). The first is to ensure recovery of the direct costs associated with energy efficiency programs. This is a minimum threshold requirement for utilities and related organizations to fund and offer energy efficiency programs and virtually every state allows this in some form. Given the wide acceptance of program cost recovery, we do not address it in the State Scorecard.

The other two mechanisms are fixed cost recovery (decoupling and other lost revenue adjustment mechanisms) and performance incentives. Decoupling—the disassociation of a utility's revenues from its sales—makes the utility indifferent to decreases or increases in sales, removing what is known as the “throughput incentive”. Although decoupling does not necessarily make the utility more likely to promote efficiency programs, it removes the disincentive for it to do so. Additional mechanisms for addressing lost revenues include modifications to customers’ rates that permit utilities to collect the revenues “lost” either through a lost revenue adjustment mechanism (LRAM) or other ratemaking approach. ACEEE views decoupling as the preferred approach to addressing the “throughput incentive”, and lost revenue adjustment mechanism as a second-best approach. Performance incentives are financial incentives that reward utilities (and in some cases, non-utility organizations) for reaching or exceeding specified program goals. These can include a shareholder incentive that is awarded based on achievement of energy savings targets, and incentives based on spending goals. Of the two, ACEEE recommends the latter, shareholder incentives. A number of states have enacted mechanisms to such as these that align utility incentives with energy efficiency, as seen in Table 16.

Results

A state could earn up to 20 points in this category, or 40% of the total possible 50 points in the State Scorecard. Among efficiency programs, studies suggest that electric programs typically achieve at least three times more primary energy savings than natural gas programs (Eldridge et al. 2009; SWEEP 2007). Therefore, we allocate 10 points in this category to performance metrics for electric programs (annual budgets and savings data) and three points to performance metrics for natural gas programs (annual budgets).[14] Table 6 lists states’ overall scoring in this category.

We gathered statewide data on:

- Budgets for electric and natural gas energy efficiency programs in 2011
- Utility revenues from sales to end users in 2011
- Number of residential natural gas customers in 2010
- Incremental savings from electric energy efficiency programs in 2010
- Actual spending from electric energy efficiency programs in 2010
- Utility sales to end users in 2010

[14] Energy savings data for natural gas programs are not tracked through a national clearinghouse and are not readily reported by states; therefore, these data do not appear in the scoring. This year we did attempt to collect such data, but the response did not warrant inclusion in our scoring. Similarly, programs that save home heating fuel or propane do not systematically report energy savings.

Table 6. Summary of State Scoring on Utility and Public benefits Programs and Policies

State	2011 Electricity Program Budgets (5 pts.)	2011 Gas Program Budgets (3 pts.)	2010 Electricity Program Savings (5 pts.)	Energy Efficiency Resource Standard (4 pts.)	Performance Incentives & Fixed Cost Recovery (3 pts.)	Total Score (20 pts.)
Massachusetts	5	3	4.5	4	3	19.5
Minnesota	5	2.5	4.5	4	3	19
Vermont	5	3	5	4	2	19
Rhode Island	5	2.5	4	4	3	18.5
California	5	2	5	2.5	3	17.5
New York	5	2	3.5	4	3	17.5
Oregon	5	3	4.5	2	1.5	16
Iowa	5	3	4	3.5	0	15.5
Connecticut	5	3	5	0	2	15
Washington	5	2	3.5	3	1	14.5
Arizona	3	0.5	4	4	2	13.5
Michigan	3	2	3	2.5	3	13.5
Maryland	4	0.5	2	4	1.5	12
Utah	5	3	2.5	0	1	11.5
Colorado	2.5	1	2	3	2.5	11
Idaho	5	0.5	4	0	1	10.5
Wisconsin	2.5	0.5	3	1.5	3	10.5
New Hampshire	3	3	2.5	0	1.5	10
Nevada	3	0.5	4	1	1	9.5
Montana	3.5	1	3.5	0	1	9
New Jersey	4	3	1.5	0	0.5	9
New Mexico	2.5	1	1.5	1.5	2.5	9
Maine	3	2.5	3	0	0	8.5
Ohio	1.5	1	1.5	2.5	2	8.5
Illinois	1.5	1	1.5	3.5	0.5	8
Arkansas	1	1	0	2.5	2.5	7
Indiana	1	1	0	3	2	7
District of Columbia	1	1.5	1	0	2.5	6
North Carolina	1	0.5	1.5	1	2	6
Oklahoma	1.5	1	0.5	0	2	5
Pennsylvania	2.5	1	0.5	1	0	5
South Dakota	0.5	1	0.5	0	2.5	4.5
Kentucky	0.5	0.5	0.5	0	2.5	4
Delaware	0.5	1	0.5	0	1.5	3.5
Florida	1.5	1.5	0.5	0	0	3.5
Missouri	1	0.5	1	0	1	3.5
Texas	0.5	0	0.5	1	1	3
Alabama	0	0	0	0	2.5	2.5
Louisiana	0	0	0	0	2.5	2.5
Wyoming	0.5	0.5	0.5	0	1	2.5
Nebraska	1	0	1	0	0	2
South Carolina	0	0	0.5	0	1.5	2
Georgia	0	0	0	0	1.5	1.5
Kansas	0.5	0.5	0	0	0.5	1.5

State	2011 Electricity Program Budgets (5 pts.)	2011 Gas Program Budgets (3 pts.)	2010 Electricity Program Savings (5 pts.)	Energy Efficiency Resource Standard (4 pts.)	Performance Incentives & Fixed Cost Recovery (3 pts.)	Total Score (20 pts.)
Tennessee	0.5	0	0.5	0	0.5	1.5
Virginia	0	0.5	0	0	1	1.5
North Dakota	0	0	0	0	0.5	0.5
Alaska	0	0	0	0	0	0
Mississippi	0	0	0	0	0	0
West Virginia	0	0	0	0	0	0

Our data sources include the Consortium for Energy Efficiency (CEE 2012),[15] the U.S. Energy Information Administration (EIA 2011, 2012a, 2012e), regional efficiency groups, and information requests sent to state utility commissions. Energy efficiency program data is subject to a certain degree of revision and updating depending on the timing of reporting and completeness of the reporting entities. For these reasons, we sent the utility data we gathered to state utility commissions and independent statewide administrators for review. We also asked commissions and program administrators for data on gas program savings, and whether program savings are reported as gross or net.[16] Tables 8, 10, and 12 provide this data on electric and natural gas efficiency budgets and on electricity savings.

We also requested, for the first time, efficiency program savings data from rural cooperative and municipal utilities not encompassed by the EIA dataset. Using the Database of State Incentives for Renewables and Efficiency (DSIRE 2012), we identified the largest electric cooperative and municipal utilities in each state that offer energy efficiency programs, and contacted 43 rural cooperative and municipal utilities in 31 states. Fourteen utilities responded and 12 provided data. Of those that provided data, six provided relevant savings data. These were incorporated into our totals and thus factor in states rankings in this category (see citations in Table 12).

Our methodology for this category, while comprehensive, does lead to some unintended impacts on state rankings. For example, our methodology here disadvantages several states because of the types of energy used or fuels offered to consumers. Hawaii, for example, has the lowest natural gas consumption among all the states, the bulk of which is accounted for by the commercial sector (EIA 2012b); therefore, energy efficiency efforts in that state are aimed at reducing electricity consumption only. Thus, Hawaii does not earn up to four points (up to three for natural gas energy efficiency budgets, up to one for gas decoupling and performance incentives) that other states may earn. Hawaii's position in the State Scorecard likely underestimates its actual energy efficiency performance relative to other states. Elsewhere, particularly in the Northeast, energy efficiency efforts often aim to

[15] CEE surveys administrators of public benefits programs annually to capture trends in aggregated budgets and expenditures. CEE has granted ACEEE permission to reference survey results as of a point in time for the purpose of capturing updates to the non-load management portion of the results. The full report is viewable at http://www.cee1.org/ee-pe/2011AIR.php3.

[16] "Gross" savings refer to savings that are expected from energy efficiency programs, according to planning assumptions. In contrast, "net" savings are those actually attributable to the program, and are typically calculated by removing "freeriders," or program participants who would have participated in the program even without any incentive, or with a reduced incentive. However, states differ in how they define, measure and account for freeridership and other components of the net savings calculation (Haeri & Khawaja 2012).

reduce fuel oil consumption. In some cases, we captured these efforts in budgets for electricity programs, but we have not specifically accounted for fuel oil savings from non-electricity programs.

Finally, the choice to report incremental annual savings—new savings from programs in each program cycle—from efficiency programs, as opposed to cumulative energy savings—all savings accrued over the life of a particular program–could be seen as disadvantaging states with long-standing energy efficiency efforts. We choose to report incremental savings in the State Scorecard for two reasons. First, to base our scoring on cumulative energy savings would invite several new levels of complexity which are beyond the scope of the State Scorecard, including identifying the start year for the cumulative series, accurately accounting for the life of energy efficiency measures, and measuring the persistence of savings (York et al. 2012). Second, the report aims to provide a snapshot of states' continuing energy efficiency programs, so incremental savings give a clearer picture of recent efforts.

Scoring on Electric Program Budgets

In this category, we score states on reported annual electric energy efficiency program budgets for 2011. The data presented in this section are for customer-funded energy efficiency programs, that is, energy efficiency programs funded through charges included in customer utility rates or directly on customer bills. This includes budgets for utility-administered programs—which may include investor-owned utilities, municipal utilities, cooperative utilities, other public power companies or authorities—and for customer-funded "public benefits" programs administered by independent statewide program administrators. We did not collect data on the federal Weatherization Assistance Program, which gives money to states on a formula basis. We did include revenues from the Regional Greenhouse Gas Initiative that contribute to customer-funded energy efficiency program portfolios of member states. (When Regional Greenhouse Gas Initiative funds are channeled to energy efficiency initiatives implemented by state governments, we have included them in Chapter 6.)

In the *2010 State Energy Efficiency Scorecard*, we began reporting energy efficiency program *budgets* rather than actual spending figures. This was done to make our reporting more timely and to better represent the rapid increases in energy efficiency funding being made in states.[17] As in previous years, we gathered energy efficiency program budget data from several sources: the Consortium for Energy Efficiency's *2011 Annual Industry Report*, *Efficiency Program Industry by State and Region Appendices* (CEE 2012),[18] state utility commission filings, regional efficiency groups, and other state sources.

As mentioned earlier, program data are subject to a certain degree of revision and updating by states depending on the timing of reporting and differences in reporting requirements of utilities and other program administrators. As in past years, we sent budget data gathered from the sources above to state utility commissions for review. Tables 8 and 10 report electric and natural gas efficiency program budgets, respectively.

It is important to clarify that budget data capture intention rather than the execution of actual energy efficiency spending, and that the difference between spending and budgets varies from state to state.

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[17] Prior to 2010, we depended on actual spending data from the U.S. EIA, which has a two-year time lag.

[18] CEE surveys administrators of public benefits programs annually to capture trends in aggregated budgets and expenditures. CEE has granted ACEEE permission to reference survey results as of a point in time for the purpose of capturing updates to the non-load management portion of the results. The full report is viewable at http://www.cee1.org/ee-pe/2011AIR.php3.

From year to year, however, the ratio of spending to budgets has remained fairly constant. For 2009, the first year for which we tracked both spending and budgets, we found that actual spending nationwide on electric efficiency programs was 89% of the reported budget figures, with a total spending gap of $301 million. In 2010, the spending gap rose to $505 million but actual spending remained at 89% of reported electric program budgets nationwide.

The difference between 2010 electric program spending and budgets also varies by U.S. Census region. Actual program spending by states in the South represented 125% of program budgets, while actual spending in Western states totaled 81% of budgets. In the Northeast, spending totaled 84% of budgets, and in the Midwest 91%. Although a handful of states spent far less (or far more) than they had budgeted, the close relationship nationwide between budgets and actual spending over the past few years signals that using budgets as our scoring metric not only captures current state efficiency efforts but also fairly accurately tracks actual program implementation.

States were scored on a scale of 0 to 5 based on of the percentage of electric utility revenues represented by energy efficiency budgets.[19] Budgets representing at least 2.5% of revenues earned the maximum of 5 points. For every 0.25% less than 2.5%, a state's score decreased by 0.5 points. Table 7 lists the scoring bins for each level of spending and Table 8 shows state-by-state results and scores for this category.

Table 7. Scoring of Electric Efficiency Program Budgets

Budgets as % of Revenues	Score
2.5% or greater	5
2.25% – 2.49%	4.5
2.00% – 2.24%	4
1.75% – 1.99%	3.5
1.50% – 1.74%	3
1.25% – 1.49%	2.5
1.00% – 1.24%	2
0.75% – 0.99%	1.5
0.50% – 0.74%	1
0.25% – 0.49%	0.5
Less than 0.25%	0

[19] Statewide revenues are from EIA (2012a). We measure budgets as a percentage of revenues to normalize the level of energy efficiency spending. Blending utility revenues from all customer classes gives a more accurate measure of utilities' overall spending on energy efficiency than expressing budgets per capita, which might skew the data for utilities that have a few very large customers. An alternative metric, statewide electric energy efficiency budgets per-capita, is presented in Appendix A.

Table 8. 2011 Electric Efficiency Program Budgets by State

State	2011 Budget ($million)	% of Statewide Utility Revenues	Score
Massachusetts[1]	453.0	5.77%	5
Vermont[2]	40.7	5.64%	5
Rhode Island[3]	54.2	5.34%	5
New York	1,073.2	4.69%	5
Oregon[4]	171.8	4.51%	5
Washington[5]	274.9	4.36%	5
California	1,162.5	3.35%	5
Minnesota[6]	191.2	3.24%	5
Utah[7]	49.2	3.19%	5
Connecticut[8]	138.3	2.83%	5
Idaho[5]	39.9	2.67%	5
Iowa[9]	88.8	2.55%	5
Maryland[10]	156.4	2.05%	4
New Jersey[11]	225.0	2.05%	4
Montana[5]	21.1	1.86%	3.5
Arizona	126.1	1.74%	3
New	25.6	1.60%	3
Maine[13]	22.8	1.59%	3
Nevada[14]	47.2	1.55%	3
Michigan[15]	127.6	1.50%	3
Pennsylvania	225.0	1.44%	2.5
New Mexico[16]	26.2	1.31%	2.5
Wisconsin[17]	92.3	1.31%	2.5
Colorado	64.1	1.28%	2.5
Hawaii[18]	35.6	1.13%	2
Florida[19]	188.5	0.77%	1.5
Ohio	134.4	0.96%	1.5
Illinois	115.7	0.91%	1.5
Oklahoma	39.6	0.85%	1.5
Nebraska[20]	16.5	0.71%	1
Arkansas[21]	25.2	0.70%	1
Indiana[22]	58.2	0.69%	1
Missouri	47.2	0.67%	1
District of Columbia[23]	7.7	0.52%	1
North Carolina	57.4	0.50%	1
Wyoming[5]	5.4	0.47%	0.5
South Dakota[24]	4.3	0.46%	0.5
Kentucky	28.2	0.44%	0.5
Texas[25]	144.1	0.43%	0.5
Tennessee[26]	36.7	0.40%	0.5
Delaware[27]	3.3	0.25%	0.5
Kansas[28]	9.1	0.25%	0.5
South Carolina	16.3	0.23%	0
Georgia	21.7	0.16%	0
Alabama[26]	10.7	0.13%	0
Louisiana	9.0	0.13%	0
Mississippi	4.9	0.11%	0
Alaska	0.0	0.00%	0
North Dakota	0.0	0.00%	0
Virginia[26]	0.1	0.00%	0
West Virginia	0.0	0.00%	0
U.S. Total	**5,916.8**	**1.60%**	
Median	**40.7**	**0.96%**	

Sources & notes: Budget data are from CEE (2012), except where noted. Statewide revenue data are from EIA (2011).
[1] MA DOER (2012); [2] VEIC (2012); [3] RI PUC (2011); [4] OR PUC (2012), BPA (2012); [5] Actual spending from EIA (2011) and BPA (2012); [6] MN DOC (2012); [7] UT PSC (2012); [8] CT DEEP (2012a); [9] IUB (2012); [10] MD PSC (2012); [11] AEG (2012); [12] NH PUC (2012); [13] Efficiency Maine (2012); [14] SPPC (2011), NV Power (2011), BPA (2012); [15] MI PSC (2012, 2011); [16] NM PRC (2012); [17] WI PSC (2012); [18] Jim Flanagan Associates (2012); [19] SACE (2012), based on FL PSC (2011a, b, c, d); [20] NE Energy Office (2012); [21] AR PSC (2012); [22] IN URC (2012); [23] DC SEU (2011), DDOE (2012); [24] SD PUC (2012); [25] Frontier Associates (2012), additional budget data provided by PEC (2012); [26] Actual spending based on TVA (2012); [27] DNREC (2012); [28] KCC (2012).

Scoring on Natural Gas Program Budgets

We also scored states on natural gas efficiency program budgets by awarding up to three points based on 2011 program budget data gathered from utility commission filings, the Consortium for Energy Efficiency (CEE 2012), and a survey of state utility commissions and independent statewide administrators. In order to directly compare state spending data, we normalize spending by the number of residential natural gas customers in each state, as reported by EIA (2012c).[20] Table 9 shows scoring bins for natural gas program spending and Table 10 shows state scores.

Table 9. Scoring of Natural Gas Utility and Public Benefits Budgets

Budget Range ($ per customer)	Score
$35 or greater	3
$28–34.99	2.5
$21–27.99	2
$14–20.99	1.5
$7–13.99	1
$1—6.99	0.5
Less than $1	0

[20] We use spending per residential customers for natural gas because reliable natural gas revenue data are sparse, and per capita unfairly penalizes states with natural gas service to only a portion of the state's population (such as Vermont). State data on the number of residential customers is from EIA (2012c).

Table 10. 2011 Natural Gas Efficiency Program Budgets by State

State	2011 Budgets ($million)	$ Per Residential Customer	Score
Massachusetts[1]	118.0	84.92	3
New Hampshire[2]	7.8	82.11	3
Vermont[3]	2.1	54.93	3
Iowa[4]	44.0	50.06	3
Connecticut[5]	20.0	40.77	3
New Jersey[6]	106.0	40.03	3
Utah[7]	32.2	39.24	3
Oregon[8]	24.5	35.86	3
Maine[9]	0.7	34.06	2.5
Rhode Island[10]	6.6	29.51	2.5
Minnesota[11]	40.9	28.61	2.5
Washington	29.7	27.76	2
New York	119.4	27.55	2
California	268.0	25.43	2
Michigan[12]	80.5	25.22	2
Florida	13.6	20.13	1.5
District of Columbia[13]	2.2	15.23	1.5
Arkansas[14]	7.6	13.73	1
Illinois	51.6	13.44	1
Ohio	42.6	13.14	1
Oklahoma[15]	11.8	12.85	1
Colorado	19.0	11.61	1
Montana[16]	2.9	9.91	1
Pennsylvania	21.6	8.18	1
Indiana	13.3	7.99	1
New Mexico[17]	3.4	7.36	1
Delaware	1.1	7.31	1
South Dakota[18]	1.2	7.11	1
Idaho	2.2	6.42	0.5
Wyoming	0.9	6.06	0.5
Missouri[19]	7.2	5.80	0.5
Virginia	6.2	5.51	0.5
Nevada	4.1	5.35	0.5
Wisconsin	8.7	5.22	0.5
Maryland[20]	4.6	4.29	0.5
Arizona	4.8	4.22	0.5
Kentucky	2.1	2.79	0.5
North Carolina	1.3	1.14	0.5
Kansas[21]	0.9	1.02	0.5
Texas	2.7	0.64	0
Alabama	0.0	0.00	0
Alaska	0.0	0.00	0
Georgia	0.0	0.00	0
Hawaii	0.0	0.00	0
Louisiana	0.0	0.00	0
Mississippi	0.0	0.00	0
Nebraska	0.0	0.00	0
North Dakota	0.0	0.00	0
South Carolina	0.0	0.00	0
Tennessee	0.0	0.00	0
West Virginia	0.0	0.00	0
U.S. Total	**1,138.2**	**17.40**	
Median	**4.6**	**7.36**	

Sources & notes: Budget data is from CEE (2012) unless otherwise noted. [1]MA DOER (2012); [2] NH PUC (2012); [3] Vermont Gas (2012); [4] IUB (2012); [5] CT DEEP (2012a, 2011); [6] AEG (2012); [7] UT PSC (2012); [8] OR PUC (2012); [9] Efficiency Maine (2012); [10] RI PUC (2011); [11] MN DOC (2012); [12] MI PSC (2011, 2012); [13] DDOE (2012); [14] AR PSC (2012); [15] CenterPoint (2012), ONG (2012); [16] MT PSC (2012); [14] NM PRC (2012); [17] DNREC (2012); [18] SD PUC (2012); [19] MO PSC (2012); [20] MD PSC (2012); [21] KCC (2012).

Scoring on Annual Savings in 2010 from Electric Efficiency Programs

We scored states on net annual incremental electricity savings[21] that resulted from energy efficiency programs offered in 2010.[22] Data for electricity sales and savings are based on EIA's *Annual Electric Power Industry Report* (2012a), which we supplemented with data from a survey of state utility commissions and independent statewide utility program administrators. This year, for the first time, we also reached out to the largest municipal and rural cooperative utilities in each state that are running programs but whose program data are not captured in the EIA dataset.

States use different methodologies for determining energy savings from efficiency programs, differences that can produce inequities making comparisons are made.[23] A state's evaluation, measurement and verification (EM&V) process plays a key role in determining how savings are measured. This is particularly true of a state's treatment of "freeriders" (savings attributed to a program that would have occurred anyway in the absence of the program) and "free-drivers" (savings *not* attributed to a program that would *not* have occurred without it). Energy savings are reported as either "net" or "gross," with "net" savings accounting for free-riders and free-drivers, and gross savings not accounting for these and thus potentially overstating program performance. Our research specifically focuses on "net" savings figures.

In a national survey of evaluation practices for state energy efficiency programs, Kushler et al. (2012) found that of the 45 jurisdictions with formally approved customer-funded energy efficiency programs, 21 jurisdictions said they report net savings, 12 indicated gross savings, and 9 indicated both (for different purposes).[24]

These findings point to several important caveats to the electric program savings data. First, a number of states do not estimate or report net savings. In these cases, we have applied a standard factor of 0.9 to convert gross savings to net savings (a "net-to-gross ratio").[25] Doing so allows easier comparison with other states that report net electricity savings. Savings (or some portion of which) reported as gross[26] are marked by an asterisk (*) in Table 12.

A second caveat is that gross savings are calculated differently by some states: Many states that report only gross savings apply "deemed savings" methodologies that do take into account free-ridership, so these states' gross savings figures may be closer to net figures than those of states that do not calculate

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[21] Net incremental electricity savings are new savings achieved from measures implemented in the reporting year.

[22] While 2011 savings data are available in some states, it is not feasible to compare 2011 data for all 50 states due to significant differences in the timing of reporting across and within the states. Readers should also note that programs that have been running for several years at a high level of funding are achieving the highest levels of *cumulative* electricity savings (total energy savings achieved to date from efficiency measures). *Incremental* savings data, which measure new savings achieved in the current program year, are the best way to directly compare state efforts due to the difficulty in tracking the duration of programs and their savings.

[23] See Sciortino (2011).

[24] This includes 44 states and the District of Columbia.

[25] A net-to-gross ratio of 0.9 falls within the range of factors used by several states in calculating net efficiency program savings, including Massachusetts (MAGEEPA 2010), Maryland (Itron 2011), New York (NY DPS 2010), Vermont (Efficiency Vermont 2012), and Michigan (ACEEE survey).

[26] Savings were determined to be gross based on Kushler et al. (2012) and on responses to our survey of public utility commissions.

gross savings in this way. Absent a more consistent EM&V methodology across states, we must rely upon the states' own reporting of energy savings that result from efficiency programs.

Energy efficiency savings is a critical metric for the robust analysis of state energy efficiency performance. We have reported statewide energy efficiency savings from EIA (2012a) as a percentage of retail electricity sales in 2010 and scored the states on a scale of 0 to 5. States that achieved savings equivalent to at least 1.2% of electricity sales earned five points, with scores dropping 0.5 point for every 0.12%-decrease.

Table 11 lists the scoring bins for each level of savings and Table 12 shows state-by-state results and scores. Across the nation, reported savings from utility and public benefits electricity program in 2010 totaled 18 million MWh, equivalent to 0.49% of sales. By way of comparison, savings from 2009 totaled just over 13 million MWh (0.37% of sales). Savings in 2010 therefore represent an increase of 40% over the previous year, and an increase of savings as a percentage of sales of more than one-tenth of a percentage point.

Table 11. Scoring Methodology for Utility and Public Benefits Electricity Savings

Savings as % of Sales	Score
1.2% or greater	5
1.08% – 1.19%	4.5
0.96% – 1.07%	4
0.84% – 0.95%	3.5
0.72% – 0.83%	3
0.60% – 0.71%	2.5
0.48% – 0.59%	2
0.36% – 0.47%	1.5
0.24% – 0.35%	1
0.12% – 0.23%	0.5
Less than 0.12%	0

Table 12. 2010 Net Incremental Electricity Savings by State

State	2010 Net Incremental Savings (MWh)	% of Retail Sales	Score
Vermont[1]	117,233	2.32%	5
California[2]	4,617,000*	1.79%	5
Connecticut[3]	422,097	1.39%	5
Minnesota[4]	809,598*	1.19%	4.5
Hawaii[5]	114,974	1.15%	4.5
Oregon[6]	510,889*	1.11%	4.5
Massachusetts[7]	628,709	1.10%	4.5
Nevada[7]	355,106*	1.05%	4
Rhode Island[8]	81,275	1.04%	4
Idaho[9]	232,702*	0.98%	4
Arizona[10]	710,564*	0.98%	4
Iowa[11]	443,799*	0.98%	4
Montana[9]	113,558*	0.85%	3.5
New York[12]	1,215,844	0.84%	3.5
Washington[9]	763,099*	0.84%	3.5
Wisconsin[13]	527,404	0.77%	3
Maine[14]	83,710*	0.73%	3
Michigan[15]	714,110*	0.72%	3
Utah	182,045*	0.65%	2.5
New Hampshire[16]	67,389*	0.62%	2.5
Colorado[17]	310,218	0.59%	2
Maryland[18]	330,678	0.48%	2
Ohio	722,929*	0.47%	1.5
Illinois[19]	659,532	0.46%	1.5
New Jersey[20]	313,116*	0.40%	1.5
New Mexico[21]	85,752	0.38%	1.5
North Carolina[22]	521,219	0.38%	1.5
District of Columbia	41,685	0.35%	1
Missouri[23]	289,362	0.34%	1
Nebraska	80,029	0.27%	1
Oklahoma	133,973	0.23%	0.5
Pennsylvania[24]	344,256*	0.23%	0.5
South Dakota[25]	25,486	0.22%	0.5
South Carolina	173,385	0.21%	0.5
Texas[26]	688,103*	0.19%	0.5
Florida[27]	402,100	0.18%	0.5
Delaware[28]	16,995*	0.15%	0.5
Kentucky	139,368*	0.15%	0.5
Tennessee	142,860	0.14%	0.5
Wyoming[9]	23,727*	0.14%	0.5
Arkansas[29]	55,184*	0.11%	0
Indiana	79,366	0.07%	0
Kansas[30]	29,323*	0.07%	0
Alabama	43,543	0.05%	0
Mississippi	25,907	0.05%	0
Georgia	51,904	0.04%	0
Alaska	1,086	0.02%	0
North Dakota	1,593	0.01%	0
Louisiana	0	0.00%	0
Virginia	677	0.00%	0
West Virginia	908	0.00%	0
U.S. Total	**18,436,366**	**0.49%**	
Median	**142,860**	**0.38%**	

* At least a portion of savings reported as gross. The gross portion has been adjusted by a net-to-gross factor of 0.9 to make it more comparable to net savings figures reported by other states.

Sources and Notes: All savings data are as reported in EIA (2012a), unless noted. [1] VT DPS (2012); [2] CEC (2011); [3] CT DEEP (2012a); [4] MN DOC (2012); [5] Jim Flanagan Associates (2012); [6] OR PUC (2012), includes gross savings from BPA (2012) public utilities and Central Electric (2012) that have been adjusted; [7] MA DOER (2012), MMWEC (2012), Reading (2012); [8] RI PUC (2011); [9] Includes gross savings from BPA (2012) public utilities that have been adjusted; [10] AZCC (2012); [11] IUB (2012); [12] Includes savings from NYSERDA (2012); [13] WI PSC (2012); [14] Efficiency Maine (2010a); [15] MI PSC (2012); [16] NH PUC (2012); [17] Includes savings provided by SWEEP (2012); [18] MD PSC (2012); [19] Navigant (2010, 2011) and Ameren (2010); [20] AEG (2012); [21] NM PRC (2012); [22] Includes savings from Union Power (2012); [23] Includes savings from Springfield (2012); [24] PA PUC (2012); [25] SD PUC (2012); [26] Frontier Associates (2012), includes gross savings from PEC (2012) that have been adjusted; [27] FL PSC (2012); [28] DNREC (2012); [29] AR PSC (2012); [30] KCC (2012).

Scoring on Energy Efficiency Resource Standards

In this section of the chapter, we credit states with mandatory savings targets called Energy Efficiency Resource Standards (EERS). We rely on legislation and utility commission dockets for our research in this section.

A state could earn up to four (4) points for an EERS policy based on a number of factors. As shown in Table 13, the major considerations include savings target levels, whether the EERS covers both electricity and natural gas, and whether the policy is binding. Some EERS policies also contain "exit ramps" that allow utilities to request permission to lower stipulated savings goals, or "cost caps" that limit spending, both of which reduce the effectiveness of the EERS policy.

Table 13. Scoring Methodology for Energy Savings Targets

Percent Savings Target or Current Level of Savings Met	Score
1.5% or greater	4
1% – 1.49%	3
0.5% – 0.99%	2
0.1% – 0.49%	1
Less than 0.1%	0

Other Considerations	Score
Cost cap is in place	-1
Exit ramp is in place	-0.5
EERS includes natural gas	+0.5

To aid in comparing states, we estimate an average annual savings target over the period specified in the policy. For example, Arizona plans to achieve 22% cumulative savings by 2020, so the annual average target is 2.2%.

States with pending targets must be on a clear path towards establishing a binding mechanism to earn points in this category. Examples of a clear path include draft decisions by commissions awaiting approval within six months, or agreements among major stakeholders on targets. States with a pending EERS policy that have not yet established a clear path toward implementation include Alaska, Connecticut,[27] Tennessee,[28] Oklahoma, New Hampshire, Utah,[29] Delaware, and Virginia. See Table 14 below for scoring results, and Appendix B for full policy details.

[27] Connecticut's 2012-13 Integrated Resources Plan (IRP) estimates that the state can cost-effectively achieve 2% annual electricity savings from energy efficiency through 2022, supported by a doubling of annual budgets to approximately $200 million (CT DEEP 2012b). If implemented, the plan would likely earn points in future versions of the State Scorecard.

[28] In its 2011 Integrated Resource Plan (TVA 2011), the Tennessee Valley Authority recommends increased use of energy efficiency and demand response resources, the use of which is estimated to achieve energy savings of approximately 11-14,000 GWh by 2020. Because TVA generates the vast majority of Tennessee's power, the state could receive points in this section in the future if the IRP recommendations are implemented.

[29] Utah has both a legislative goal (House Joint Resolution 9) and a Renewable Portfolio Goal (S.B. 202) that includes energy efficiency savings targets. Neither of these goals has been codified into regulatory language by the Public Service Commission, so they remain advisory, not binding.

Table 14. State Scores for Energy Efficiency Resource Standards

State	Annual Electric Savings Target (2012+)[30]	Stringency	Score (4 pts.)
Arizona	2.31%	Binding	4
Hawaii	2%	Binding	4
Maryland[31]	2.44%	Binding	4
Massachusetts	1.91%	Binding	4
Minnesota	1.50%	Binding	4
New York	2.14%	Binding	4
Rhode Island	2.10%	Binding	4
Vermont	2.20%	Binding	4
Illinois	1.67%	Cost cap	3.5
Iowa	1.24%	Binding	3.5
Colorado	1.40%	Binding	3
Indiana	1.46%	Binding	3
Washington	1.34%	Binding	3
Arkansas	0.63%	Binding	2.5
California	0.86%	Binding	2.5
Michigan	1.00%	Cost cap	2.5
Ohio	1.19%	Exit ramp	2.5
Oregon	0.98%	Exit ramp	2
New Mexico	0.88%	Exit ramp	1.5
Wisconsin	0.65%	Cost cap	1.5
Nevada	0.3%	Binding	1
North Carolina	0.46%	Binding	1
Pennsylvania	0.87%	Cost cap	1
Texas	0.14%	Binding	1

Sources: See Appendix B

[30] This target applies to utilities covered under the EERS policy. For some states, this would be significantly lower if based on statewide sales rather than only on the sales of covered utilities.
[31] The goal of reducing per-capita electricity use by 15% translates to around 17% cumulative savings over 2007 retail sales.

Since the publication of the *2011 State Energy Efficiency Scorecard*, there have been changes in the use of EERS policies in two states. Wisconsin has recommitted to its energy savings goals, and thus receives credit in the *2012 State Energy Efficiency Scorecard* for its EERS efforts. By contrast, in Maine regulators have rendered their energy savings targets ineffective; although there is an EERS in place, FY2013 state budget allocations fall approximately $30 million short of what Efficiency Maine, the independent statewide program administrator, projects that it needs to meet savings targets established by state statute (State of Maine 2009, 2011; Efficiency Maine 2010b). Therefore, Maine fails to get three points in this section of the State Scorecard.

Long-term energy savings targets require leadership, sustainable funding sources and institutional support to deliver on their goals. In addition to Wisconsin and Maine, several other states currently have or have had in the past EERS-like structures in place, but have lacked one or more of these enabling elements, so have undercut the achievement of their savings goals. States in this situation have included Florida,[32] New Jersey, Delaware and Utah, none of which has earned points in this year's State Scorecard. On the whole, however, most states with EERS policies or other energy savings targets in place are currently meeting their goals and on are track to meet future goals.

Scoring on Financial Incentives Affecting Utility Investment in Efficiency: Earning a Return and Addressing Lost Revenues

Like an EERS, regulatory mechanisms that provide incentives and remove disincentives for utilities to pursue energy efficiency (i.e., performance incentives and decoupling/lost revenue adjustment mechanisms) are critical to leveraging energy efficiency funding and encouraging savings over the near and long terms. A state could earn up to three (3) points for having adopted financial incentive mechanisms for utilities' efficiency program for electric and natural gas and for having implemented decoupling to address lost revenues for its electric and natural gas utilities. States with a policy in place for at least one major utility were given credit. Information about individual state decoupling policies and financial incentive mechanisms is available on ACEEE's State Energy Efficiency Policy Database (ACEEE 2012) and in Appendix C. Details describing the scoring methodology are provided in Table 15.

[32] In Florida, cumulative energy savings targets of ~3.3% by 2019 remain in place for seven utilities (5 IOUs), but the Florida Public Service Commission approved program plans in 2011 for Progress Energy and Florida Power & Light, which represent three-quarters of electric load in the state, that will fall short of the targets. The five other utilities subject to targets are slated to meet their tailored utility targets.

Table 15. Scoring Methodology for Utility Financial Incentives

Scoring Criteria for Addressing Fixed Cost Recovery	Score
Decoupling has been established for at least one major utility, for both electric and natural gas.	1.5
Decoupling has been established for at least one major utility, either electric or natural gas. LRAM or ratemaking approach for recovery of lost revenues established for at least one major utility, for both electric and natural gas.	1
The legislature or commission has authorized or recommended decoupling within the last three years, but it has not yet been implemented. A lost revenue adjustment mechanism (LRAM) or ratemaking approach for recovery of lost revenues has been established for a major utility, for either electric or natural gas.	0.5
Scoring Criteria for "Performance Incentives"	**Score**
Performance incentives have been established for a major utility (or statewide independent administrator), for both electric and natural gas.	1.5
Performance incentives have been established for a major utility (or statewide independent administrator), for either electric or natural gas.	1
The legislature or commission has authorized or recommended a performance incentive within the last three years, but the use of a given mechanism has not yet been implemented.	0.5

This year's scores have decreased for a number of states. Between 2006 and 2008 there was great interest in states to implement performance incentives, and many states made great strides. But, recent efforts in a number of states have stagnated. Last year 37 states had a performance incentive in place or pending for electric utilities, while this year only 27 states are credited with a performance incentive in place or pending. The pattern for gas utilities is similar, dropping from 26 states last year to 18 this year. It is important to note that this trend is not because states have eliminated performance incentives; rather, many states that considered them in a docket or via legislation have failed to take action to implement them in a reasonable time frame, and therefore they have ceased to be "pending.".

The number of states with decoupling pending or in place for electric utilities has remained almost the same, while the number of states with natural gas decoupled (or pending) has dropped from 24 to 20. This change is not because states have dropped their plans for decoupling; rather (again), states where decoupling has been pending have not taken any further action.

Table 16. Utility Efforts to Address Lost Revenues and Financial Incentives

	Decoupling (or related mechanism)		Performance Incentives		
State	Electric	Natural Gas	Electric	Natural Gas	Score (3 pts.)
California	Yes	Yes	Yes	Yes	3
Massachusetts	Yes	Yes	Yes	Yes	3
Michigan	Yes	Yes	Yes	Yes	3
Minnesota	Yes	Yes	Yes	Yes	3
New York	Yes	Yes	Yes	Yes	3
Rhode Island	Yes	Yes	Yes	Yes	3
Wisconsin	Yes	Yes[3]	Yes	Yes	3
Alabama	Yes[2]	Yes[2]	Yes	Yes	2.5
Arkansas	Yes[2]	Yes[2]	Yes	Yes	2.5
Colorado	Yes[2]	Yes[2]	Yes	Yes	2.5
District of Columbia	Yes	No	Yes	Yes	2.5
Kentucky	Yes[2]	Yes[2]	Yes	Yes	2.5
Louisiana	Yes[2]	Yes[2]	Yes	Yes	2.5
New Mexico	Yes[2]	Yes[2]	Yes	Yes	2.5
South Dakota	Yes[2]	Yes[2]	Yes	Yes	2.5
Arizona	Yes[2]	Yes[3]	Yes	No	2
Connecticut	Yes[3]	Yes[2]	Yes	No	2
Hawaii	Yes	No	Yes	No	2
Indiana	Yes[2]	Yes[2]	Yes	No	2
North Carolina	Yes[2]	Yes	Yes	No	2
Ohio	Yes[3]	Yes[2]	Yes	No	2
Oklahoma	Yes[2]	No	Yes	Yes	2
Vermont	Yes[1]	Yes[1,2]	Yes	No	2
Delaware	Yes	Yes	No	No	1.5
Georgia	Yes[2]	No	Yes	No	1.5
Maryland	Yes	Yes	No	No	1.5
New Hampshire	No	No	Yes	Yes	1.5
Oregon	Yes	Yes	No	No	1.5
South Carolina	Yes[2]	No	Yes	No	1.5
Idaho	Yes	No	No	No	1
Missouri	No	Yes[2]	Yes[1]	Yes[1]	1
Montana	Yes[2]	Yes[2]	No	No	1
Nevada	Yes[2]	Yes[3]	No	No	1
Texas	No	No	Yes	No	1
Utah	No	Yes	No	No	1
Virginia	No	Yes	No	No	1
Wyoming	Yes[2]	Yes	No	No	1
Illinois	No	Yes[1]	No	No	0.5

State	Decoupling (or related mechanism) Electric	Decoupling (or related mechanism) Natural Gas	Performance Incentives Electric	Performance Incentives Natural Gas	Score (3 pts.)
Kansas	Yes[2]	No	No	No	0.5
New Jersey	Yes[1,2]	Yes[2]	No	No	0.5
North Dakota	No	Yes[2]	No	No	0.5
Tennessee	No	Yes[2]	No	No	0.5
Washington	Yes[2]	Yes[1]	No	No	0.5
Alaska	No	No	No	No	0
Florida	No	No	No	No	0
Iowa	No	No	No	No	0
Maine	No	No	No	No	0
Mississippi	No	No	No	No	0
Nebraska	No	No	No	No	0
Pennsylvania	No	No	No	No	0
West Virginia	No	No	No	No	0

Notes: [1] Decoupling for electric or gas utilities, or both, or performance incentives are authorized according to legislation or commission order but are not yet implemented. [2] No decoupling, but some other mechanism for lost revenue adjustment. [3] Both decoupling and some other mechanism for lost revenue adjustment.

Figure 3. Leading States: Utility and Public Benefits Programs

Massachusetts: Massachusetts has a long record of success in implementing energy efficiency programs, which are implemented by electric and natural gas distributors. The state took a major leap forward in 2008, when it passed the Green Communities Act, which established energy efficiency as the "first-priority" energy resource and created an Energy Efficiency Advisory Council to collaborate with utilities to develop statewide efficiency plans in three-year cycles. The first three-year plan aims to achieve annual electric savings equal to 2.4% of sales and annual natural gas savings equal to 1.5% of sales in 2012, making it one of the most aggressive EERS targets in the nation. The Green Communities Act is expected to lead to a total investment of $2.2 billion in energy efficiency and demand resources between 2010 and 2012. As of this writing, the Advisory Council is in the midst of drafting its second three-year plan for statewide energy efficiency programs, with final plans due in October. The July 2 draft proposes annual electricity savings targets of 2.5% from 2013-2015, and natural gas targets of 1.1% in 2013, increasing in subsequent years.

Minnesota: Minnesota's investor-owned and publicly owned utilities offer broad portfolios of energy efficiency programs that have benefitted from consistent and strong regulatory support, allowing them to evolve and improve for many years. The state allows utilities to earn an incentive for successful energy efficiency program performance and, in 2007, the state enacted the Next Generation Act, which set aggressive energy-saving goals for utilities equal to 1.5% of sales each year. The impact of the EERS is evident in the steadily increasing savings figures in the state.

Rhode Island: Building on its strong program history, Rhode Island leapt forward with the Comprehensive Energy Conservation and Affordability Act of 2006, which established energy efficiency as the state's first-priority resource and laid the groundwork for major investments in energy efficiency programs. Similar to efficiency program planning in Massachusetts, the state's major utility collaborates with an expert council to develop three-year plans with ambitious savings and budget goals. In its latest plan, approved for 2012-2014, the state seeks to reach 2.5% annual electric savings and 1.2% annual natural gas savings in 2014.

Vermont: Vermont pioneered the third-party administration model of energy efficiency program implementation, which has been replicated in many states, including Maine, New Jersey, Delaware, Oregon, and the District of Columbia. Efficiency Vermont, the state's "energy efficiency utility," runs energy efficiency programs for a wide range of customers and leads the nation in producing consistent energy savings. Vermont's excellent performance is due in large part to a strategic commitment by the Vermont Public Service Board to fund programs at aggressive levels to reach new customers and achieve deep savings. The Public Service Board has also put in place an optimal mix of policies, including an EERS and performance incentives to encourage successful programs.

California: California utilities have implemented energy efficiency programs for decades, achieving substantial savings thanks to significant regulatory and budget support from the California Public Utilities Commission. The state implemented decoupling in 1982 for its three electric investor-owned utilities, which has played a major role in the state's success with energy efficiency. Over the past several years, California has invested almost $1 billion per year in energy efficiency to achieve impressive levels of cost-effective energy savings. California public- and investor-owned utilities are national leaders in energy efficiency program implementation, consistently achieving savings around 1% of sales annually.

Chapter 3: Transportation Policies

Author: Shruti Vaidyanathan

INTRODUCTION

The energy efficiency score for the transportation category is based on a review of state actions that go beyond federal policies to achieve a more energy-efficient transportation sector. These may be actions to improve the efficiency of vehicles purchased or operated in the state, policies to increase the use of more efficient modes of transportation, or the integration of land use and transportation planning so as to reduce the need to drive.

Tailpipe Emission Standards

Vehicles' greenhouse gas (GHG) emissions are largely proportional to their fuel use. In 2002, California passed the Pavley Bill (AB1493), the first U.S. law to address GHG emissions from vehicles. The law required the California Air Resource Board (CARB) to regulate greenhouse gas as part of the California Motor Vehicle Program. In 2004, California Air Resource Board adopted a rule requiring automakers to begin in the 2009 model year to phase in lower-emitting cars and trucks that will collectively emit 22% lower levels of greenhouse gases than 2002 vehicles in model year 2012 and 30% fewer in model year 2016. Sixteen states have adopted California's greenhouse gas regulations; in addition to California, including Connecticut, Delaware, the District of Columbia, Florida, Maine, Maryland, Massachusetts, New Jersey, New Mexico, New York, Oregon, Pennsylvania, Rhode Island, Vermont and Washington (Clean Cars Campaign 2012).

The greenhouse gas reductions will be achieved largely through improved vehicle efficiency, making these standards, to a large degree, energy efficiency policies. Several technologies stand out as providing significant, cost-effective reductions in emissions, including turbocharged engines with direct injection, optimization of valve operation, improved multi-speed transmissions, use of high-strength, lightweight materials, and improved air-conditioning systems.

In April 2010, the Environmental Protection Agency and the U.S. Department of Transportation issued harmonized national standards for fuel economy and greenhouse gas emissions for model years 2012 to 2016. These standards match California's greenhouse gas tailpipe standards in stringency and call for a fleet-wide average fuel economy of 34.1 miles per gallon by 2016. States may choose to adopt either the federal vehicle standards or California's. In 2012, the two agencies proposed new standards for model years 2017 to 2025.

California continues to make its own progress with regards to vehicle tailpipe and fuel economy standards. As a longtime leader in the vehicle standard setting process, the state has been instrumental in prodding the federal government to establish standards that are both stringent and as realistic as possible. California's success in this role is due in part to auto manufacturers preference for minimizing the number of distinct regulatory regimes for vehicles. This year, the U.S. Department of Transportation and Environmental Protection Agency finalized new greenhouse gas and fuel economy standards for model years 2017 to 2025, calling for a fleet-wide average of 49.6 miles per gallon by 2025. At the same time, the

California Air Resources Board is working to establish new, aggressive greenhouse gas emissions standards for model years 2017-2025 as part of its Low Emission Vehicles program. For this category, states that have adopted California's standards are awarded two points for showing a commitment to future efficiency progress in the transportation sector regardless of federal action.

Integration of Policies for Land Use and Transportation Planning

Sound land use planning is vital to stem the growth in vehicle miles traveled (VMT) in the United States. Successful strategies for changing land use patterns to reduce the need to drive vary widely among states due to current infrastructure, geography and political structure; however, core principles of smart growth need to be embodied in state comprehensive plans. Energy-efficient transportation is inherently tied to the integration of transportation and land use policies, and an approach to planning that successfully addresses land use and transportation considerations simultaneously is critical to statewide reductions in vehicle miles traveled. This approach includes measures that encourage the creation of:

- Transit-oriented development, including mixed land uses (mix of jobs, stores, and housing) and good street connectivity that makes neighborhoods pedestrian-friendly
- Areas of compact development
- Convenient modes of transportation that provide alternatives to automobiles
- Activity centers where destinations are close together

States with codified growth management legislation that identify specific growth boundaries scored one (1) point, as did those with smart growth statutes, which includes the creation of zoning overlay districts such as the Massachusetts Chapter 40R program, as well as various other incentives to encourage sustainable growth. For further detail, refer to ACEEE's *State Energy Efficiency Policy Database* (http://aceee.org/sector/state-policy).

Vehicle Miles Traveled (VMT) Reduction Targets

Raising fuel economy and emissions standards will not adequately address energy use in the transportation sector in the long term if growth in total vehicle miles traveled goes unchecked. While vehicle miles traveled on U.S. highways have not increased in recent years, an economic recovery is likely to bring a return to an upward trend. Projections by the Energy Information Administration indicate a 28% increase in light-duty vehicle miles traveled between now and 2030, substantially outpacing any anticipated population growth in the United States (EIA 2012d). Other analyses indicate, however, that the plateau in growth rates for vehicle miles traveled may persist. Increases in travel cost, stabilizing public transit shares after years of decline, and stabilizing mode shares for bike and walk travel after years of decline could directly contribute to a reduced rate of growth in vehicle miles traveled in the future (Polzin 2006).

In any case, maintaining low rates of growth in vehicle miles traveled must be a priority for federal, state and local governments. Achieving such a goal requires the coordination of transportation and land use planning, and state and local governments play more important roles in this coordination than the federal government does.

Codified VMT reduction targets are an important component in achieving substantial reductions in vehicle miles traveled. States that have specific targets earned two (2) points.

State Transit Funding

While states receive some federal funds for public transit, they provide a significant proportion of transit funding from their own budgets. A state's investment in public transit is a key indicator of its interest in promoting energy-efficient modes of transportation, although realizing the potential for energy savings through transit typically requires land use planning changes as well. States that spent a combined $50 or more per capita on public transit in 2010 earned one (1) point, and states that spent between $20 and $50 per capita in 2010 received one-half (0.5) point.

State Transit Legislation

As states find themselves faced with increasingly uncertain federal funding streams and federal transportation policies that remain highway-focused, they are taking the lead when it comes to finding dedicated funding sources for long-term public transit expenditures.

To generate a sustainable stream of capital and operating funds, a number of states have adopted legislation that identifies specific sources of funding for public transit and other alternatives to highway modes of transportation. North Carolina, for instance, established an intermodal transportation fund that allocates money to local governments for the express purpose of maintaining and developing public transportation systems. Likewise, the state of New York passed Assembly Bill 8180, which directs certain vehicle registration and renewal fees towards public transportation.

Not only do such bills enable the growth of multimodal transit facilities, they can lead to environmental benefits from reduced vehicle emissions and can encourage economic development around transportation nodes in expanded transit networks. States with transit legislation in place earned one (1) point.

"Complete Streets" Policies

Equally vital to the discussion of land use planning and reduction of vehicle miles traveled is the concept of "complete streets." Complete streets policies focus on the interconnectivity of streets and target safe, easy access to roads by all pedestrians, bicyclists, motorists and public transportation users. Complete streets foster increased use of alternative modes of transportation to driving and, therefore, can have a significant impact on a state's fuel consumption. According to the National Complete Streets Coalition, modest increases in biking and walking can potentially save 2.4 billion gallons of fuel annually (NCSC 2012b). Complete streets legislation directs states' transportation agencies to evaluate and incorporate complete streets principles. Transportation planners are tasked with ensuring that all roadway infrastructure projects allow for equitable access and use of those roadways. For this category, states that have codified complete streets legislation earned one-half (0.5) point. Although for this year's State Scorecard we have removed one-half point from the scoring of complete streets in previous years and applied it to transit legislation, we continue to recognize the importance of states taking the lead in this area, especially given the recent failed attempt to include a complete streets provision in the 2012 federal transportation bill.

Incentives for High-Efficiency Vehicles

The high cost of advanced-technology, fuel-efficient vehicles is a key barrier to their entry into the marketplace. To encourage consumers to purchase these vehicles, states offer a number of financial incentives, including tax credits, rebates, and sales tax exemptions. Several states offer tax incentives to individual purchasers of alternative-fuel vehicles, which typically include vehicles that run on compressed natural gas, ethanol, propane, or electricity, and in some cases hybrid vehicles (electric or hydraulic). While alternative-fuel vehicles can provide substantial environmental benefits by reducing pollution, they do not generally improve vehicle fuel efficiency, and policies to promote their purchase therefore are not specifically included in our State Scorecard. However, electric vehicles and hybrids typically do have high fuel efficiency, so incentives for purchase of these vehicles in particular are eligible for one (1) point.[33] With the arrival of the Chevrolet Volt plug-in hybrid sedan and the Nissan Leaf all-electric vehicle, tax credits for electric vehicles are playing an important role in spurring the adoption of high-tech, energy-efficient vehicles. States with purchase incentives framed in terms of fuel economy are also awarded one (1) point.

A state "feebate" policy that provides a rebate or charges a fee for the purchase of a vehicle, depending on its fuel efficiency, would also receive credit in our scoring of transportation policies. However, although several states have considered feebates, none has yet put such a policy in place. We do not give credit for incentives for the use of high occupancy vehicle lanes and preferred parking programs for high-efficiency vehicles, as they may promote automobile use and consequently bring no net energy benefit.

RESULTS

Significant steps have been taken recently at the federal level to reduce fuel consumption in the United States. The U.S. Environmental Protection Agency and Department of Transportation have just finalized new greenhouse gas and fuel economy standards for vehicle model years 2017 to 2025, requiring cars and light trucks to meet an average standard of 49.6 miles per gallon by 2025. Nevertheless, states continue to lead the charge with regard to the efficiency of vehicles and our transportation system. California, for instance, is working to update its low emission vehicles program to include more stringent tailpipe and greenhouse gas standards for model years through 2025. As a result, states that have chosen to adopt California's greenhouse gas tailpipe emissions standards earned two (2) points in this year's State Scorecard.

Despite the potential energy saving benefits of the California Clean Car program, recent efforts have been made in certain states to repeal the adoption of these more stringent standards. In January of 2012, the state of Arizona repealed the clean car program that it adopted in 2008 considering that the program was too costly to implement. The Arizona Department of Environmental Quality stated that the new federal standards were as strict as California's and thus provided no additional savings.

Elsewhere, we are seeing a resurgence in state incentive programs targeted at purchases of high-efficiency vehicles. While many states chose to phase out such tax credits and rebate programs after federal tax

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[33] Several early hybrids provided little fuel economy benefit, because the technology was used to increase vehicle power rather than to improve fuel economy. These hybrids did not sell well and have mostly been discontinued, but this issue remains a concern for hybrid incentive programs.

credits for hybrid vehicles expired in 2010, others, such as New Jersey and Pennsylvania, have recently introduced new policies to encourage the purchase of high-efficiency vehicles overall. On top of the $7,500 federal tax credit available to plug-in hybrid and all electric vehicles, New Jersey exempts buyers of vehicles identified as zero emission vehicles from sales and use taxes. Pennsylvania provides a tax credit of up to $3,500 for buyers of plug-in hybrid and electric vehicles. States with such consumer incentives were awarded one-half (0.5) point.[34]

In the category of actions to promote non-auto modes of transportation, this year for the first time we award one (1) point to states that have adopted legislation that encourages transit investment by state or local government. Currently, ten states have transit legislation in place. For details, see Appendix E. We also award one-half (0.5) point to states with "complete streets" legislation that ensures proper attention to the needs of pedestrians and cyclists in all road projects.[35] State investments in transit also receive points: relatively large investments (of $50 per capita or more) receive one (1) point, while investments ranging from $20 to $50 per capita receive one-half (0.5) point.

Policies to promote compact development and ensure accessibility of major destinations are essential to reducing energy use in transportation in the long term. Given the significant energy savings potential of these policies, states that have adopted coordinated land-use and transportation policies could score up to two (2) points. Those adopting targets for vehicle miles traveled statewide were also eligible for two (2) points. Thus far, only four states scored the full two points available for VMT targets: California, Massachusetts, New York, and Washington. Oregon is still in the process of adopting specific VMT reduction goals and, therefore, earned one point.

[34] This is a change from the *2011 State Energy Efficiency Scorecard*, when tax high-efficiency vehicle tax credits were awarded a full point. This change brings the scoring for hybrid tax credits in this chapter in line with Chapter 6, where tax credit programs applicable to other sectors of the economy are awarded one-half point.
[35] This is a change from last year, when complete streets policies were awarded a full point.

Table 17. State Scoring on Transportation Policies

State	GHG Tailpipe Emissions Standards (2 pts.)[1]	Integration of Transportation and Land Use Planning (2 pts.)[2]	VMT Targets (2 pts.)[3]	Transit Funding (1 pt.)[4]	Transit Legislation (1 pt.)[5]	Complete Streets Legislation (0.5 pt.)[6]	High-Efficiency Consumer Incentives (0.5 pt.)[7]	Total Score (9 pts.)
California	2	1	2	0.5	1	0.5	0.5	7.5
New York	2	1	2	1	1	0.5	0	7.5
Massachusetts	2	1	2	1	0	0.5	0	6.5
Maryland	2	2	0	1	0	0.5	0.5	6
Oregon	2	2	1	0.5	0	0.5	0	6
Washington	2	1	2	0	0	0.5	0.5	6
Connecticut	2	2	0	1	0	0.5	0	5.5
New Jersey	2	2	0	1	0	0	0.5	5.5
Rhode Island	2	2	0	1	0	0.5	0	5.5
Delaware	2	2	0	1	0	0	0	5
Florida	2	1	0	0	1	0.5	0	4.5
Pennsylvania	2	1	0	1	0	0	0.5	4.5
Vermont	2	2	0	0	0	0.5	0	4.5
Maine	2	2	0	0	0	0	0	4
District of Columbia	2	0	0	1	0	0	0.5	3.5
Illinois	0	1	0	0.5	1	0.5	0.5	3.5
Hawaii	0	2	0	0	0	0.5	0.5	3
Tennessee	0	1	0	0	1	0.5	0.5	3
Georgia	0	1	0	0	1	0	0.5	2.5
Minnesota	0	0	0	1	1	0.5	0	2.5
Arizona	0	2	0	0	0	0	0	2
Colorado	0	0	0	0	1	0.5	0.5	2
Michigan	0	1	0	0.5	0	0.5	0	2
New Mexico	2	0	0	0	0	0	0	2
Virginia	0	1	0	0.5	0	0	0	1.5
Alaska	0	0	0	1	0	0	0	1
Iowa	0	1	0	0	0	0	0	1
Kansas	0	0	0	0	1	0	0	1
Montana	0	1	0	0	0	0	0	1
New Hampshire	0	1	0	0	0	0	0	1
North Carolina	0	0	0	0	1	0	0	1
North Dakota	0	1	0	0	0	0	0	1
South Carolina	0	0	0	0	0	0.5	0.5	1

State	GHG Tailpipe Emissions Standards (2 pts.)[1]	Integration of Transportation and Land Use Planning (2 pts.)[2]	VMT Targets (2 pts.)[3]	Transit Funding (1 pt.)[4]	Transit Legislation (1 pt.)[5]	Complete Streets Legislation (0.5 pt.)[6]	High-Efficiency Consumer Incentives (0.5 pt.)[7]	Total Score (9 pts.)
Wisconsin	0	0	0	0.5	0	0.5	0	1
Louisiana	0	0	0	0	0	0	0.5	0.5
Oklahoma	0	0	0	0	0	0	0.5	0.5
Utah	0	0	0	0	0	0	0.5	0.5
West Virginia	0	0	0	0	0	0	0.5	0.5
Alabama	0	0	0	0	0	0	0	0
Arkansas	0	0	0	0	0	0	0	0
Idaho	0	0	0	0	0	0	0	0
Indiana	0	0	0	0	0	0	0	0
Kentucky	0	0	0	0	0	0	0	0
Mississippi	0	0	0	0	0	0	0	0
Missouri	0	0	0	0	0	0	0	0
Nebraska	0	0	0	0	0	0	0	0
Nevada	0	0	0	0	0	0	0	0
Ohio	0	0	0	0	0	0	0	0
South Dakota	0	0	0	0	0	0	0	0
Texas	0	0	0	0	0	0	0	0
Wyoming	0	0	0	0	0	0	0	0

Sources and Notes: [1] Clean Cars Campaign (2012); [2] State legislation; [3] State legislation and Center for Climate and Energy Solutions (2012); [4] AASHTO (2012), see Appendix D for a complete ranking of state transit funding; [5] State legislation; [6] NCSC (2012a); [7] DOE (2012b).

Table 18 outlines the consumer incentives available by state.

Table 18. State Purchase Incentives for High-Efficiency Vehicles

State	Tax Incentive
California	AB 118 funds a voucher program, targeted at medium- and heavy-duty trucks, whose goal is to reduce the upfront incremental cost of purchasing a hybrid vehicle. Vouchers range from $20,000 to $40,000, depending on vehicle specifications, and will be paid directly to fleets that purchase hybrid trucks for use within the state. California also offers tax rebates of up to $5,000 for light-duty zero emission electric vehicles and plug-in hybrid electric vehicles on a first come, first serve basis from March 15th, 2010 onwards.
Colorado	In 2009, Colorado extended financial incentives available for purchasers of high-efficiency vehicles out to 2015. Consumers can claim up to $6,000 for the purchase of a plug-in or hybrid vehicle. Individuals that convert a personal vehicle to plug-in hybrid technology can claim up to $7,500.
District of Columbia	The Department of Motor Vehicles Reform Amendment Act of 2004 exempts owners of hybrid electric and electric vehicles from vehicle excise tax and reduces the vehicle registration charge.
Georgia	Purchasers of electric vehicles may qualify for a tax credit equivalent to 10% of the cost of a new vehicle, up to $2,500.
Illinois	Residents of Illinois may claim a rebate for 80% of the incremental cost of purchasing an electric vehicle (up to $4,000) as part of the Illinois Alternative Fuels Rebate Program.
Louisiana	Louisiana offers an income tax credit equivalent to 50% of the incremental cost of purchasing an electric vehicle under the state's alternative fuel vehicle tax credit program. Alternatively, taxpayers may claim the lesser of 10% of the total cost of the vehicle, or $3,000.
Maryland	Purchasers of qualifying all electric and plug-in hybrid electric light-duty vehicles may claim up to $2,000 against the vehicle excise tax in the state of Maryland. Vehicles must meet certain speed, weight and motor requirements to qualify.
New Jersey	All zero emission vehicles in the state of New Jersey are exempt from state sales and use taxes.

State	Tax Incentive
Oklahoma	A one-time tax credit for 50% of the incremental cost of purchasing an electric vehicle is available to residents in Oklahoma. If the incremental cost of the vehicle cannot be determined, the state will provide a tax credit equivalent to 10% of the total purchase price of an electric vehicle (up to $1,500). The program expires January 1, 2015.
Oregon	Oregon residents and business owners can claim in tax credits for the purchase of a high-efficiency vehicles and electric vehicles. The tax credit for residents is up to $1,500, and for business owners is 35% of the incremental cost of the system or equipment and is taken over five years.
Pennsylvania	The Alternative Fuels Incentive Grant Program provides rebates of up to $3,500 for qualifying electric and plug-in hybrid vehicles.
South Carolina	South Carolina offers up to $2,000 in tax credits for the purchase of a plug-in hybrid electric vehicle. The credit is equal to $667, plus $111 if the vehicle has at least 5 kWh of battery capacity, and an additional $111 for each additional kWh above 5 kWh.
Tennessee	The first 1,000 electric vehicles purchased in the state of Tennessee qualify for a $2,500 rebate from the Tennessee Department of Revenue.
Utah	Until December 31st, 2013, electric vehicles qualify for up to $605 worth of tax credits.
Washington	Electric vehicles are exempt from state motor vehicle sales and use taxes under the Alternative Fuel Vehicle Tax Exemption program.
West Virginia	Since July 1, 2011, residents of West Virginia have been eligible for a tax credit equivalent to 35% of the purchase price of an electric vehicle. Up to $7,500 is available for vehicles that have a gross vehicle weight rating of up to 26,000 lbs., and as much as $25,000 is available for vehicles having gross vehicle weight rating greater than 26,000 lb.

Source: DOE (2012b)

Figure 4. Leading States: Transportation Policies

California: As part of its plans to implement AB 32, which requires a 25% reduction from 1990 levels in greenhouse gas emissions by 2020, California has identified several strategies for smart growth and reduction of vehicle miles traveled. In 2008, the state passed SB 375, which requires the California Air Resources Board to develop regional transportation-specific greenhouse gas reduction goals, in collaboration with metropolitan planning organizations. These goals must subsequently be reflected by regional transportation plans that create compact, sustainable development across the state and thus reduce the growth of vehicle miles traveled. The California Air Resources Board released draft targets in June 2010 that recommended a 5–10% reduction in vehicle greenhouse gas emissions by 2020 for the four largest metropolitan planning organizations in the state (CARB 2010).

California also passed AB 118 in 2009, a clean transportation program that includes funding for a hybrid vehicle rebate program targeted at medium- and heavy-duty vehicles. The goal of the Hybrid Truck and Bus Voucher Incentive Project is to reduce the high upfront costs associated with the purchase of high-efficiency vehicles. The third year of the program began in July 2012. Rebates range from $20,000 to $40,000 per vehicle depending on vehicle specification. California also offers tax rebates of up to $5,000 for light-duty zero emission electric vehicles and plug-in hybrid electric vehicles.

New York: New York has steadily moved up the ranks in recent years with its strong efforts toward transportation efficiency. Ranked second this year, the state has made a number of changes in recent years targeted at reducing fuel consumption in the transportation sector. Last year, New York adopted a new "complete streets" policy, aimed at providing accessibility for multiple modes of transport.

Additionally, the state passed Assembly Bill 8180 in 2010 directing a portion of vehicle registration and license renewal fees to public transportation. The bill also created the Metropolitan Transit Authority Financial Assistance Fund to support subway, bus and rail service and capital improvements. New York is also one of the few states in the nation to have a concrete vehicle miles traveled reduction target. A 2008 goal calls for a 10% reduction in 10 years.

Maryland: Maryland has long been a leader in forward-looking transportation policies. In 1992, the state passed the Economic Growth, Resource Protection and Planning Act as a means to coordinate planning priorities amongst state, regional and municipal government. The act requires that conservation practices and transportation be considered as part of comprehensive plans.

Maryland's Smart Growth program, initiated in 1997, aims to promote development near transit hubs and other centers of activity. Policies to encourage this development include focusing state spending on existing centers and areas designated for growth, limiting road expansion in favor of public transit and promoting urban redevelopment. In 2001, Maryland state general assembly dedicated $500 million to the upgrade of mass transit service and infrastructure.

Additional transportation policies include the adoption of a tax credit to encourage the deployment of plug-in hybrid and electric vehicles, as well as codification of a complete streets policy to ensure equal access to transportation facilities by all vehicular modes.

Chapter 4: Building Energy Codes

Author: Max Neubauer

INTRODUCTION

Buildings consume 74% of electricity use and 41% of total energy use in the United States. They account for 40% of carbon dioxide emissions (DOE 2011a). Buildings are clearly an essential target for energy savings; however, because they have long lifetimes and are often not easily retrofitted, it is crucial that efficiency measures in buildings be considered prior to completing construction. Mandatory building energy codes are one way to improve buildings' energy efficiency, requiring a minimum level of energy efficiency for new residential and commercial buildings.

In 1978, California enacted the first statewide building energy code in its Title 24 Building Standard. Several states (including Florida, New York, Minnesota, Oregon, and Washington) followed with state-developed codes in the 1980s. During the 1980s and 1990s, the International Code Council (ICC) and its predecessor developed its Model Energy Code (MEC), which was later renamed the International Energy Conservation Code (IECC). Today, most states use a version of the MEC or IECC for their residential building codes, which require a minimum level of energy efficiency in new residential construction. Most commercial building codes are based on ASHRAE 90.1, jointly developed by the American Society of Heating, Refrigerating and Air Conditioning (ASHRAE) and the Illuminating Engineering Society (IES). The IECC commercial building provisions also include prescriptive and performance requirements based primarily on ASHRAE requirements.

The most recent versions of the IECC and ASHRAE are the 2012 IECC and the ASHRAE 90.1-2010 standards. Only Maryland has officially adopted the 2012 IECC (for both residential and commercial buildings), although several states are in the process of adopting or updating their standards to the most recent versions.

Historically, the provisions for commercial buildings in the IECC have consistently differed from those in ASHRAE 90.1, so that the ASHRAE 90.1 standard has generally been considered more stringent. According to a study by the U.S. Department of Energy comparing the 2012 IECC and ASHRAE 90.1-2010, both exceed the energy savings of ASHRAE 90.1-2007 and the 2009 IECC, so that their adoption would meet or exceed the standards referenced in the American Recovery and Reinvestment Act (see ARRA section below). Therefore, states can adopt either commercial provisions and still meet the requirements stipulated in the Recovery Act (DOE 2011b).

The Department of Energy's Building Code Determinations

With the publication of each new edition of the IECC and ASHRAE standards, the Department of Energy (DOE) issues determinations on the codes to ascertain their relative impact when compared to older versions and, if justified, establish the latest iteration as the base code with which all states must comply. While no enforcement mechanism is in place to address non-compliance, states are nonetheless required within two years of the final determination either to certify their compliance, to request an extension for compliance, or to explain their decision not to comply.

On May 17, 2012, the Department of Energy issued its final determination on the 2012 IECC, reporting that the 2012 IECC achieves greater energy efficiency than its predecessor editions (DOE 2012c). DOE estimates that the 2012 IECC achieves about 20% greater site energy savings than the 2009 IECC (DOE 2011c). States must file certification statements with DOE by July 19, 2013.

On October 19, 2011, the DOE issued its final determination on ASHRAE Standard 90.1-2010, reporting that ASHRAE 90.1-2010 achieves greater energy efficiency than its predecessor editions, generating 18.2% more energy savings at site than ASHRAE 90.1-2007. States must file certification statements with DOE by July 20, 2013.

Building Codes and the American Recovery and Reinvestment Act

The impact of the American Recovery and Reinvestment Act of 2009 (ARRA) on the adoption of building codes has shown that federal policy can catalyze tremendous progress at the state level. The appropriation of stimulus funding through DOE's State Energy Program has spurred the majority of states to adopt the 2009 IECC and ANSI/ASHRAE/IESNA Standard 90.1-2007 (hereafter referred to as the "ARRA codes").[36]

In this year's State Scorecard, 36 states and the District of Columbia have either adopted or are on a clear path towards the adoption of the ARRA codes for either residential or commercial buildings, or both. Undoubtedly, ARRA has served as a major catalyst in the adoption of building codes across the country, although its influence was more apparent in 2009 and 2010; the rate of adoption of the ARRA codes has ebbed considerably in 2011. Although a dozen states have not complied with the ARRA requirements, several have adopted more stringent codes relative to what had been in place previously. Yet another handful has not shown any movement whatsoever.

Still, several states have acknowledged the value of regularly adopting the latest iterations of the IECC and ASHRAE 90.1 code standards and have already moved beyond the ARRA codes, having either adopted the 2012 iterations or having begun the process towards their adoption. Some states have also adopted mandatory codes where there were previously none in place. While these efforts to adopt stringent building energy codes are certainly laudable, the key to ensuring that states will reap the benefits of their proactivity lies in the enforcement of compliance. DOE is collaborating with the five regional energy efficiency organizations (REEOs)[37] to support states in their adoption and compliance efforts.

ARRA and Building Code Compliance

The American Recovery and Reinvestment Act called for states to achieve 90% compliance with the ARRA minimum standard building energy code (2009 IECC for residential; ASHRAE 90.1-2007 for commercial) by 2017. While some states have made laudable progress in funding and training code officials to ensure enforcement, attaining the 90% compliance goal will require a much more concerted effort on the part of states, utilities, and other stakeholders that incorporates other efforts beyond training.

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[36] In the building energy code community the latest official versions of these codes are referred to as the ARRA codes because of the technical requirement in ARRA to adopt these codes as a prerequisite to disbursal of stimulus funds.

[37] The five regional energy efficiency organizations are the Northeast Energy Efficiency Partnerships (NEEP), Midwest Energy Efficiency Alliance (MEEA), Northwest Energy Efficiency Alliance (NEEA), Southwest Energy Efficiency Project (SWEEP), and the Southeast Energy Efficiency Alliance (SEEA).

For instance, the Pacific Northwest National Laboratory, which leads the DOE's Building Energy Codes Program, released a request for proposals in August 2010 for states and territories for activities that will facilitate the adoption of and compliance with the most recent building energy codes. In addition, a separate source of funding was provided to nine of those states to conduct pilot studies on methods for measuring compliance,[38] determining patterns of compliance, creating comprehensive protocols for measuring compliance, and producing best practices for state building departments to follow when designing training programs.

The Building Codes Awareness Project is another national resource for states as they formulate a plan to meet the 90% compliance goal. The Building Codes Awareness Project began a Compliance Planning Assistance (CPA)[39] program that works with states to achieve full compliance with the model energy codes. The CPA program is divided into two phases:

- Helping states conduct a Gap Analysis Report, which documents a state's existing energy code infrastructure to assess the current gaps, identify best practices, and offer initial recommendations for improvement.
- Working with states to develop a Strategic Compliance Plan, a targeted, state-specific plan with practical near- and long-term action items to move a state towards full energy code compliance.

Along with the CPA program, the Building Codes Awareness Project has also been working with the National Association of State Energy Officials and the Northwest Energy Efficiency Alliance on promoting Energy Codes Compliance Collaboratives,[40] which are groups of stakeholders that explore their common interests around energy code adoption and compliance. The idea of establishing state collaboratives was borne out of the Compliance Planning Assistance program, where research found that establishing a collaborative was pivotal in several states not only in the success of adoption of building codes, but also in supporting education and training, developing key messaging, and advocacy.[41]

Utility Involvement in Building Codes

Finally, another means of achieving code compliance and maximizing savings is to engage the support of utilities. In several states that have passed Energy Efficiency Resource Standards,[42] programs have been established that allow utilities to claim savings for code enhancement activities, both adoption and compliance.[43] Utilities are in a unique position to assist with state compliance goals, as they offer energy efficiency programs that target energy efficiency in buildings and also collect important data on buildings' energy consumption through their customers' utility bills. Many utilities across the country offer programs that specifically target the improvement of energy efficiency in new construction, programs

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[38] For more information on the compliance pilot studies, please see: http://www1.eere.energy.gov/wip/solutioncenter/pdfs/Policies%20and%20Procedures%20for%20Enhancing%20Code%20Compliance.pdf

[39] Visit http://energycodesocean.org/compliance-planning-assistance-program for more information.

[40] NASEO sponsored a webinar on April 17, 2012, titled Energy Codes Collaborative. To view a slide summary of the webinar, along with an audio recording, visit http://www.naseo.org/codes/events/2012-04-17/

[41] For more information on existing state collaboratives, see Wagner and Lin, 2012, *Leveraging State-Utility Partnerships to Advance Building Energy Codes*.

[42] See Chapter 2 on Utility and Public Benefits Programs and Policies.

[43] See Footnote 41 – Wagner and Lin (2012) also provides case studies on utility involvement with building energy codes.

that, in addition to ensuring compliance, help to push building energy efficiency beyond code requirements.

There are a number of ways that utilities can become involved in augmenting compliance with state and local building codes. Utilities can fund and/or administer training and certification programs, assist local jurisdictions with the implementation of tools that streamline enforcement, provide funding for the purchase of diagnostic equipment, and assist with compliance evaluation. Allowing utilities to take credit for savings generated through their participation is not enough, since any program costs incurred directly reduce utility earnings; therefore, prudent regulatory mechanisms such as those discussed in Chapter 2 must be in place to compensate utilities for their efforts in order to encourage them to participate.

RESULTS

States earned scores on two measures of building energy codes: level of stringency of residential and commercial codes (up to five (5) points) and level of efforts to enforce compliance (up to two (2) points), for a combined score of up to seven (7) points.

Scoring on Stringency

In keeping with our scoring practice in past years, states received full points for code stringency only if they met or exceeded the most recent versions of the IECC and ASHRAE standards, which are the 2012 IECC and the ASHRAE 90.1-2010, respectively. Our review of state building energy codes is based predominantly on publicly available information such as that provided by the Online Code Environment and Advocacy Network (BCAP 2012), which maintains maps and state overviews of building energy codes, as well as the DOE's Building Energy Codes Program. The Database of State Incentives for Renewables and Efficiency (DSIRE 2012) also collects and disseminates the status of state energy codes. We assigned each state a score of 0 to 5 for the stringency of residential and commercial building energy codes, with 5 being assigned to the most stringent codes (see Table 19). We then averaged the two for an overall stringency score. For detailed information on building code stringency in each state, visit ACEEE's State Energy Efficiency Policy Database (ACEEE 2012), or see Appendix F.

Several states are still in the process of updating their building energy codes, so we awarded full credit (commensurate with the degree of code stringency as noted in Table 19) to those states that have exhibited progress and show a clear path leading toward the adoption and implementation of codes within the next year (denoted with an asterisk in Table 20). In other words, we have not limited qualification to codes that have already gone into effect. Other states have begun the process of updating their codes but have not yet officially adopted them nor have they demonstrated a clear path toward their adoption with a definitive effective date for implementation. Nonetheless, we consider it important to recognize that the processes in these states have begun and are moving along. We have denoted these cases with a "+,"and the states were awarded credit only for the code versions that are currently effective. Once their efforts have culminated in a clear path toward adoption and implementation of the new codes, the full credit will be reflected in future editions of the State Scorecard.

Many "home rule" states, such as Arizona, Missouri, and Oklahoma, do not have mandatory statewide codes and, instead, adopt and enforce building energy codes at the local level. We awarded credit to those states if major local jurisdictions—large urban areas—have adopted the ARRA and 2012 codes.

Scoring on Compliance

Scoring states on building energy code compliance is difficult due to the lack of data—very few states actually collect comprehensive data on residential and commercial compliance with state energy codes, typically because of lack of funds. In order to collect information on code compliance and enforcement activities, we distributed a survey to energy offices and other knowledgeable officials in each state requesting information regarding their efforts to measure and enforce code compliance, including: (1) published studies that have estimated statewide compliance; (2) enforcement methods; and (3) methods for code official and builder training.

States were ranked on a scale of 0 to 2, in increments of 0.5, based on the following metrics. States were given two (2) points for making substantial efforts to achieve compliance, such as training code officials and funding studies of compliance; 1.5 points for making multiple, but not extensive, efforts; one (1) point for some compliance efforts, such as training; 0.5 point for limited efforts; and 0 points for no or unverifiable efforts. Appendix G provides further details on each state's compliance efforts.

Table 19. Scoring Methodology for State Residential and Commercial Building Energy Code Stringency

Score	Residential Building Code	Commercial Building Code
5	Meets or exceeds 2012 IECC or equivalent	Meets or exceeds 2012 IECC or ASHRAE 90.1-2010 or equivalent
4	Exceeds 2009 IECC or equivalent	Exceeds 2009 IECC or ASHRAE 90.1-2007 or equivalent
3	Meets 2009 IECC or equivalent	Meets 2009 IECC or equivalent or ASHRAE 90.1-2007
2	Meets or exceeds 1998-2006 MEC/IECC (meets EPCA[44]) or equivalent, or significant adoption in major jurisdictions	Meets or exceeds 1998-2006 MEC/IECC or ASHRAE 90.1-1999/2001 – ASHRAE 90.1-2004 or equivalent, or significant adoptions in major jurisdictions
1	No mandatory state energy code, but some adoption in major jurisdictions	No mandatory state energy code, but some adoption in major jurisdictions
0	No mandatory state energy code or precedes 1998 MEC/IECC (does not meet EPAct of 1992	No mandatory state energy code or precedes ASHRAE 90.1-1999 or equivalent (does not meet EPAct of 1992)

Note: Full credit was awarded to states that have adopted the 2012 versions of the IECC and ASHRAE 90.1 as well as those states that are on a clear path toward their adoption within the twelve months following September 1, 2012.

As shown in Table 20, the majority of states have not kept pace with updates to residential and commercial energy codes. The two exceptions include Maryland and Illinois, which are the only states as of this writing to have adopted the 2012 version of the IECC. Notably, Arkansas and Oklahoma gained points this year based on their strengthening of statewide codes. Also of note, North Dakota and South Dakota earned points for the first time based on voluntary code adoption in major jurisdictions. Appendices F and G provide further details of building code stringency and compliance by state.

In the *2012 Scorecard*, no state was awarded the maximum score of seven (7) points, though several achieved scores of six (6) points due to a combination of stringent energy codes and laudable compliance efforts. States that have not adopted a mandatory statewide energy code, or have poor or unverifiable rates of compliance, earn a score of 0. There are several "home rule" states that, despite no mandatory statewide energy code, are showing high rates of adoption at the jurisdictional level and were awarded points accordingly. Currently there are ten states that do not have mandatory statewide energy codes for either residential or commercial buildings: Alaska, Arizona, Colorado, Kansas, Mississippi, Missouri, North and South Dakota, Oklahoma, and Wyoming. Only one state has no verifiable rates of compliance, down from seven in our *2011 State Energy Efficiency Scorecard*.

[44] Under the federal Energy Policy and Conservation Act, states are required to review and adopt the MEC/IECC and the most recent version of ASHRAE Standard 90.1 for which DOE has made a positive determination for energy savings (currently 90.1-2010) or submit to the Secretary of Energy its reason for not doing so.

Table 20. State Residential and Commercial Building Energy Codes: Scoring on Stringency and Compliance Efforts

State	Stringency Residential Codes (5 pts.)	Commercial Codes (5 pts.)	Residential & Commercial Average (5 pts.)	Compliance Efforts (2 pts.)	Overall Score (7 pts.)
California	4	4	4	2	6
Illinois*	5	5	5	1	6
Massachusetts+	4	4	4	2	6
Oregon	4	4	4	2	6
Washington	4	4	4	2	6
Florida	4	4	4	1.5	5.5
Georgia	4	4	4	1.5	5.5
Maryland	5	5	5	0.5	5.5
District of Columbia+	4	4	4	1	5
Idaho	3	3	3	2	5
Montana	4	3	3.5	1.5	5
New York	3	3	3	2	5
North Carolina	4	4	4	1	5
Vermont	4	4	4	1	5
Connecticut	3	3	3	1.5	4.5
Iowa	3	3	3	1.5	4.5
Nevada	3	3	3	1.5	4.5
New Hampshire	3	3	3	1.5	4.5
Utah	2	3	2.5	2	4.5
Virginia	3	3	3	1.5	4.5
Colorado	2	2	2	2	4
Delaware	3	3	3	1	4
Hawaii	3	3	3	1	4
Kentucky	3	3	3	1	4
Nebraska	3	3	3	1	4
Pennsylvania	3	3	3	1	4
Rhode Island	3	3	3	1	4
South Carolina*	3	3	3	1	4
Wisconsin	2	3	2.5	1.5	4
Alabama*	3	3	3	0.5	3.5
Indiana	3	3	3	0.5	3.5
Louisiana	2	3	2.5	1	3.5
Michigan	3	3	3	0.5	3.5
New Jersey	3	3	3	0.5	3.5
New Mexico	3	3	3	0.5	3.5

State	Stringency: Residential Codes (5 pts.)	Stringency: Commercial Codes (5 pts.)	Stringency: Residential & Commercial Average (5 pts.)	Compliance Efforts (2 pts.)	Overall Score (7 pts.)
Ohio*	3	3	3	0.5	3.5
Texas	3	3	3	0.5	3.5
Arizona	2	2	2	1	3
Arkansas	2	3	2.5	0.5	3
Minnesota	2	2	2	1	3
Tennessee	2	2	2	1	3
West Virginia	2	2	2	1	3
Maine	2	2	2	0.5	2.5
Missouri	2	2	2	0.5	2.5
Oklahoma	2	2	2	0.5	2.5
Wyoming	1	1	1	1	2
Kansas	1	1	1	0.5	1.5
North Dakota	1	1	1	0	1
South Dakota	1	1	1	0	1
Alaska	1	0	0.5	0	0.5
Mississippi	0	0	0	0	0

Sources & Notes: Stringency scores derived from BCAP (2012) as of July 2012. Compliance and enforcement scores based on information gathered through surveys of state building energy code contacts.

* These states have signed or passed legislation mandating compliance with a new iteration of codes, effective at a later date, or their rulemaking processes are far enough along that mandatory compliance is imminent. These states are awarded full credit commensurate with the degree of code stringency as noted in Table 19.

+ These states have signed or passed legislation mandating compliance with a new iteration of codes, but have not demonstrated a clear path forward toward their adoption, so that the effective date remains uncertain. These states are not awarded full credit commensurate with the degree of code stringency of that next iteration.

Figure 5. Leading States: Building Energy Codes

Alabama: Effective October 1, 2012, the Alabama Energy and Residential Code (AERC) will become mandatory statewide, for the first time in the state's history. The residential provisions of the AERC reference Chapter 11 of the 2009 IRC with Alabama amendments. The commercial provisions of the AERC reference the 2009 IECC with Alabama amendments while referencing ASHRAE Standard 90.1-2007 as an alternative compliance path. Local jurisdictions may adopt more stringent codes.

Maryland: The 2012 Maryland Building Performance Standards are mandatory statewide and reference the 2012 ICC Codes, including the 2012 IECC, for all new and renovated residential and commercial buildings. Maryland is the first state to adopt the 2012 iterations of the IECC. § 12-503 of the Maryland Code requires the Department of Housing and Community Development to adopt the most recent version of the IECC 12 months after it is issued, and allows adoption of energy efficiency requirements that are more stringent than the codes.

Chapter 5: Combined Heat and Power

Authors: Anna Chittum, Kate Farley, and Terry Sullivan

INTRODUCTION

Combined heat and power (CHP) systems generate electricity and thermal energy in a single, integrated system. Combined heat and power is more energy efficient than separate generation of electricity and thermal energy because heat that is normally wasted in conventional power generation is recovered as useful energy. Energy recovered in this way is used to satisfy an existing thermal demand, such as the heating and cooling of a building or industrial process. CHP systems can save customers money and reduce overall net emissions.

A state could earn up to five (5) points based upon its adoption of regulations and policies that encourage the deployment of CHP systems. There are multiple ways in which states can actively encourage or discourage the deployment of CHP. Financial, technical, policy, and regulatory factors all impact the extent to which CHP is deployed. The seven factors considered when scoring CHP for the *2012 State Energy Efficiency Scorecard* are:

- Standard interconnection rules
- Combined heat and power /waste heat recovery in a state Renewable Portfolio Standard, Energy Efficiency Resource Standard, or other standard
- Applicable financial incentive programs
- Favorable net metering regulations
- Output-based emissions regulations
- Loan and loan guarantee programs
- Additional supportive policies

We have also included, but did not score, an assessment of two additional factors in the *2012 State Energy Efficiency Scorecard*:

- The number of CHP installations in each state, and the total CHP capacity installed in each state
- State retail industrial electricity and natural gas prices

Interconnection Standard

CHP deployment is encouraged when multiple levels (or tiers) of interconnection exist because smaller systems can be offered a faster—and often cheaper—path toward interconnection. Scaling these transaction costs to project size makes economic sense, because customers with larger projects—and thus larger potential economic gains—often have more incentive to spend time and money to interconnect their more complex systems than do customers with smaller projects facing smaller economic returns.

Additionally, interconnection standards that have higher size limits are preferable, as are standards based upon widely accepted technical industry standards, such as the IEEE 1547 standard.[45]

Treatment of Combined Heat and Power Under an EERS/RPS

Renewable Portfolio Standards and Energy Efficiency Resource Standards define a particular amount of a state's electricity resources that must be derived from renewable energy or energy efficiency. Most states with RPS or EERS policies set goals for future years, generally a percentage of total electricity sold that must be derived from renewable or efficiency resources, with the percentage increasing over time. Not only are utilities required to meet the policy goals, but these standards are often paired with financial incentives or support programs that encourage specific technologies. Thus, when CHP is explicitly listed as eligible for RPS or EERS credit, this creates a large incentive to deploy CHP systems.

Incentives for CHP

Incentives can include per-kW or per-kWh production incentives or project-based grants. They can also include tax incentives, which are generally more permanent than grant programs. Tax incentives for CHP take many forms, but are often credits taken against business or real estate taxes. Rebates, grants, and deductions are all ways in which CHP can be encouraged at the state level, and the leading states have mixtures of multiple types of incentives.

Net Metering

Net metering is most commonly applied to renewable energy systems, but it is also applicable to small combined heat and power systems—those under 2 MW. Sound net metering regulations allow the owners of small distributed generation systems to get credit for excess electricity that they produce on site. Under net metering rules, owners of distributed generation systems are compensated for some or all excess generation either at the utility's avoided cost or (less often) at higher retail rates. Less optimal situations constitute barriers to the deployment of CHP and other distributed generation systems, such as the levying of fees on net-metered systems or rules that set overly strict limits on individual system size and aggregate capacity. Limits on individual and aggregate system capacities can prevent system owners from installing the most efficient or cost-effective systems, and sometimes even prevent them from meeting onsite load requirements. Any size limits should be based only on objective engineering standards and facility load requirements. Other best practices for net metering include eligibility for all distributed generation technologies, including CHP; eligibility for all customer classes; system size limits that go up to 2 MW; indefinite net excess generation carryover at the utility's retail rate; and prohibition of special fees for net metering.

Emissions Treatment

Output-based emissions regulations are air quality regulations that take the useful energy output of CHP systems into consideration when quantifying a system's criteria pollutant emissions. Many states employ emissions regulations for generators by calculating levels of pollutants based upon the system's fuel input.

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[45] This standard establishes criteria and requirements for interconnection of distributed energy resources with electric power systems (EPS). It provides requirements relevant to the performance, operation, testing, safety considerations, and maintenance of the interconnection. For more information, visit http://www.ieee.org/portal/site.

For CHP systems, electricity and useful thermal outputs are generated from a single fuel input. Therefore, calculating emissions based solely on input ignores the additional power created by the system, using little or no additional fuel. Output-based emissions, in contrast, acknowledge that the additional useful energy output was generated in a manner generally cleaner than the separate generation of electricity and thermal energy. Additional information for policies in this category is also available from the Environmental Protection Agency via its CHP Partnership website (EPA 2012).

Financing Assistance

Appropriate financing opportunities can be a major barrier to development of CHP systems. Low-interest-loan programs, loan guarantees, and bonding authorities are all strategies states can use to make CHP systems financially attractive.

Other Supportive Policies

Other supportive policies include technical assistance programs, education campaigns, and other unique policies or incentives that support CHP. Detailed descriptions of these policies in applicable states are noted in the "Clean Distributed Generation" section of the ACEEE State Policy Website (ACEEE 2012).

Unscored Factors

Two additional sets of factors are noted in Table 22 but do not factor into a state's score. For the first time, we have included the **number of individual CHP systems** installed in each state in the past two years, as well as the **total capacity installed** in each state in each of the past two years. CHP systems often take a long time to plan and install; therefore, data for a single year do not optimally reflect a state's CHP activity. Although this information is not, in its own right, a full indicator of a state's CHP friendliness (as economic factors well beyond the control of a state may strongly impact the degree to which CHP projects are installed), it is useful for comparisons among states. The *State Energy Efficiency Scorecard* in future years may score states on their installed CHP rather than measures of technical or economic potential, although such scoring was not possible for 2012.

We have also included the **retail electricity and natural gas rates** paid by facilities in a given state, which can have significant impacts on the overall economics of a CHP system. However, states did not earn points in this category but are instead indicated as having above average, average, or below average rates. This reflects one aspect of economic attractiveness to CHP developers: higher electricity prices may make the economic case for CHP easier in some states, while lower and stable natural gas prices may help hasten investment in CHP in others. The fact that these prices do not enter into each state's actual ranking recognizes that a state cannot directly control the retail price of electricity or gas. However, the price of electricity and gas drives a state's CHP market to varying degrees, and policymakers can implement policies that help overcome economic barriers presented in part by lower electricity prices or higher gas prices. The retail prices shown in Table 22 for both electricity and natural gas are that for the industrial sector, reflecting the fact that herein lies the largest opportunity for combined heat and power.

RESULTS

States are scored for CHP on a total scale of 0 to 5 points, with 5 being the maximum number of points a state can earn for all of their efforts to encourage CHP through the above regulatory and financial mechanisms. Table 21 lists each state total and its point distribution in each of the above categories.

The change in methodology this year (described below) dramatically altered the rankings of states for CHP policies. Scoring guidelines were stricter than in years past, requiring that policies, particularly net metering, feature a number of specific characteristics in order for a state to earn credit for it at all. As a result, no state earned the full five points. The top state, Massachusetts, earned 4.5 points and the second-place state, Ohio, earned 3.5 points, indicating that there is significant room for growth in all states' CHP policies.

Several states—Texas, California, and Ohio—are leading examples of CHP-friendly policy deployment. They have implemented notable new policies pertaining to combined heat and power, further enhancing the states' attractiveness to CHP developers. Figure 6 describes the three new policies currently in place.

Some states have recently adopted new and improved policies or regulations, while some are still in the process of developing or improving them. Generally, credit was not given for a policy unless it was in place—enacted by a legislative body or promulgated as an order from an agency or regulatory body. Some states that formerly had policies in place have since removed or in other ways nullified them; in these situations, we did not give credit for the policy in question. Policies in place as of June 2012 were considered for this review, though programs that are no longer accepting applications, such as recently closed ARRA-funded financing programs, were not considered.

This year, we have updated our methodology for ranking combined heat and power. The impetus for these changes was a general sense among CHP developers and advocates that states' CHP rankings in previous versions of the State Scorecard did not always tell the full story of a state's friendliness towards the deployment of CHP. Based on research by Chittum and Kaufman (2011), we concluded that many of the "on-the-ground" realities of deploying CHP projects were indeed not being fully captured in the State Scorecard, and we have modified our scoring methodology accordingly.

This year, in addition to clarifying the scoring system itself, we also changed the distribution of points between policies. In particular, less weight has been given to interconnection standards, net metering, standby rates, and emissions treatment of CHP, and more weight has been given to CHP treatment in a Renewable Portfolio Standard or Energy Efficiency Resource Standard (RPS/EERS). This year we also score states on available financing assistance (e.g., low-interest loan programs) and the presence of additional policy support such as technical assistance programs and education campaigns. We believe that this year's scores more closely align with on-the-ground realities experienced by CHP developers and other parties involved. For an in-depth discussion of changes to this year's CHP scoring, see Chittum (2012).

Scoring

States could receive up to one (1) point for the presence of an **interconnection standard** that explicitly establishes parameters and procedures for the interconnection of CHP systems. We relied upon secondary sources—such as the Database of State Incentives for Renewable Energy (DSIRE 2012) and the Environmental Protection Agency's *CHP Partnership* database (EPA 2012)—as well as primary sources such as public utility commission dockets and interviews with commission staff and utility representatives. A maximum size limit of at least 10 MW is required for a top score in this category.

We awarded up to one (1) point for **eligibility of CHP for credit in a Renewable Portfolio Standard (RPS), Energy Efficiency Resource Standard (EERS),** or other enforced energy standard. States scored higher for policies that set targets that were binding.

States could receive up to one (1) point for incentives for combined heat and power. **Financial incentives** offered through state entities that apply to all CHP systems are viewed most favorably in this category, but some credit was also given to incentives for exclusively biomass or renewable CHP projects. Additional information on incentives for CHP is available from ACEEE's State Policy Website (ACEEE 2012), the Environmental Protection Agency through its CHP Partnership (EPA 2012), and the Database of State Incentives for Renewables and Efficiency (DSIRE 2012).

We awarded up to one-half (0.5) point for **net metering regulations** that apply to CHP. We awarded one-half (0.5) point for the presence of **output-based emissions regulations**. States could receive one-half (0.5) point for providing **financing assistance** available for CHP systems. We awarded one-half (0.5) point for **other supportive policies**.

Table 21. State Scoring for CHP

State	Inter-connection (1 pt.)	RPS/EERS Treatment (1 pt.)	Incentives (1 pt.)	Net Metering (0.5 pt.)	Emissions Treatment (0.5 pt.)	Financing (0.5 pt.)	Additional Policies (0.5 pt.)	Total Score (5 pts.)
Massachusetts	1	1	1	0.5	0.5	0	0.5	4.5
Ohio	1	1	0.5	0	0.5	0.5	0	3.5
Connecticut	1	0.5	0.5	0	0.5	0.5	0	3
New Jersey	0.5	0	1	0	0.5	0.5	0.5	3
Illinois	1	0.5	0.5	0	0.5	0	0	2.5
New York	0	0.5	1	0	0.5	0	0.5	2.5
Oregon	1	0	0.5	0	0.5	0.5	0	2.5
Rhode Island	0	1	1	0	0.5	0	0	2.5
Vermont	1	1	0.5	0	0	0	0	2.5
Washington	1	0.5	0.5	0	0.5	0	0	2.5
Arizona	0	1	0.5	0.5	0	0	0	2
California	0.5	0	1	0	0.5	0	0	2
Colorado	0.5	1	0	0	0	0.5	0	2
Delaware	0.5	0	1	0	0.5	0	0	2
Indiana	1	0.5	0	0	0.5	0	0	2
Maine	1	0.5	0	0	0.5	0	0	2
Michigan	1	0.5	0.5	0	0	0	0	2
Pennsylvania	0	0.5	0.5	0.5	0	0.5	0	2
Texas	0.5	0.5	0	0	0.5	0	0.5	2
Wisconsin	1	0	0.5	0	0.5	0	0	2
Iowa	0.5	0.5	0.5	0	0	0.5	0	2
New Hampshire	0	0	1	0	0.5	0	0	1.5
North Carolina	0.5	0.5	0.5	0	0	0	0	1.5
Tennessee	0.5	0	0.5	0	0	0.5	0	1.5
Arkansas	0.5	0	0	0	0.5	0	0	1
Kansas	0	0	1	0	0	0	0	1
Maryland	0.5	0	0.5	0	0	0	0	1
Minnesota	0.5	0.5	0	0	0	0	0	1
Nevada	0	0.5	0.5	0	0	0	0	1
New Mexico	0.5	0	0.5	0	0	0	0	1
North Dakota	0	0.5	0.5	0	0	0	0	1
South Dakota	0.5	0	0.5	0	0	0	0	1
Virginia	0	0	0.5	0	0	0.5	0	1
Alabama	0	0	0	0	0	0.5	0	0.5
Alaska	0	0	0.5	0	0	0	0	0.5
District of Columbia	0.5	0	0	0	0	0	0	0.5

State	Inter-connection (1 pt.)	RPS/EERS Treatment (1 pt.)	Incentives (1 pt.)	Net Metering (0.5 pt.)	Emissions Treatment (0.5 pt.)	Financing (0.5 pt.)	Additional Policies (0.5 pt.)	Total Score (5 pts.)
Florida	0	0	0.5	0	0	0	0	0.5
Georgia	0	0	0.5	0	0	0	0	0.5
Hawaii	0	0.5	0	0	0	0	0	0.5
Kentucky	0	0	0.5	0	0	0	0	0.5
Louisiana	0	0	0	0	0	0	0.5	0.5
Missouri	0	0	0	0	0.5	0	0	0.5
Montana	0	0	0.5	0	0	0	0	0.5
South Carolina	0	0	0.5	0	0	0	0	0.5
Utah	0	0	0.5	0	0	0	0	0.5
West Virginia	0	0.5	0	0	0	0	0	0.5
Wyoming	0	0	0.5	0	0	0	0	0.5
Idaho	0	0	0	0	0	0	0	0
Mississippi	0	0	0	0	0	0	0	0
Nebraska	0	0	0	0	0	0	0	0
Oklahoma	0	0	0	0	0	0	0	0

Sources: ICF (2012), EIA (2012e), EIA (2012f)

Table 22. Installed CHP Capacity and Fuel Prices by State, 2010-2011

State	Total Score	# CHP Installations 2011	Total Capacity Installed 2011 (kW)	# CHP Installations 2010	Total Capacity Installed 2010 (kW)	Industrial Electricity Prices	Industrial Natural Gas Prices
Massachusetts	4.5	0	0	17	3,162	>avg.	>avg.
Ohio	3.5	1	46,000	3	11,150	avg.	>avg.
Connecticut	3	3	16,000	8	30,515	>avg.	>avg.
New Jersey	3	0	0	2	3,000	>avg.	>avg.
Illinois	2.5	1	2,250	0	0	avg.	avg.
New York	2.5	11	2,310	25	94,038	>avg.	>avg.
Oregon	2.5	2	18,805	0	0	<avg.	avg.
Rhode Island	2.5	0	0	1	75	>avg.	>avg.
Vermont	2.5	0	0	3	840	>avg.	avg.
Washington	2.5	1	400	1	750	<avg.	>avg.
Arizona	2	0	0	0	0	avg.	avg.
California	2	6	5,010	15	35,572	>avg.	avg.
Colorado	2	0	0	1	2,500	avg.	avg.
Delaware	2	0	0	0	0	>avg.	>avg.
Indiana	2	0	0	0	0	avg.	<avg.
Maine	2	1	425	0	0	>avg.	>avg.
Michigan	2	0	0	0	0	>avg.	>avg.
Pennsylvania	2	3	6,800	6	1,705	>avg.	>avg.
Texas	2	1	4,200	3	56,900	avg.	<avg.
Wisconsin	2	3	3,158	3	2,300	>avg.	avg.
Iowa	2	0	0	1	2,800	<avg.	<avg.
New Hampshire	1.5	0	0	2	130	>avg.	>avg.
North Carolina	1.5	1	800	1	5	<avg.	avg.
Tennessee	1.5	0	0	1	1,500	avg.	<avg.
Arkansas	1	0	0	0	0	<avg.	avg.
Kansas	1	0	0	0	0	avg.	<avg.
Maryland	1	0	0	3	15,395	>avg.	>avg.
Minnesota	1	0	0	4	8,500	avg.	<avg.

State	Total Score	# CHP Installations 2011	Total Capacity Installed 2011 (kW)	# CHP Installations 2010	Total Capacity Installed 2010 (kW)	Industrial Electricity Prices	Industrial Natural Gas Prices
Nevada	1	0	0	1	5,500	<avg.	>avg.
New Mexico	1	0	0	0	0	<avg.	avg.
North Dakota	1	0	0	0	0	avg.	<avg.
South Dakota	1	0	0	0	0	avg.	avg.
Virginia	1	1	450	0	0	avg.	avg.
Alabama	0.5	0	0	0	0	<avg.	<avg.
Alaska	0.5	2	750	2	1,892	>avg.	<avg.
District of Columbia	0.5	0	0	2	475	>avg.	n/a
Florida	0.5	0	0	1	125	>avg.	>avg.
Georgia	0.5	0	0	0	0	avg.	avg.
Hawaii	0.5	0	0	0	0	>avg.	>avg.
Kentucky	0.5	0	0	0	0	<avg.	<avg.
Louisiana	0.5	2	29,500	1	300	<avg.	<avg.
Missouri	0.5	0	0	0	0	<avg.	>avg.
Montana	0.5	0	0	0	0	<avg.	avg.
South Carolina	0.5	2	35,000	0	0	<avg.	<avg.
Utah	0.5	0	0	1	6,000	<avg.	<avg.
West Virginia	0.5	0	0	1	325	avg.	<avg.
Wyoming	0.5	0	0	0	0	<avg.	<avg.
Idaho	0	0	0	2	3,980	<avg.	avg.
Mississippi	0	0	0	1	150	avg.	<avg.
Nebraska	0	0	0	0	0	avg.	<avg.
Oklahoma	0	0	0	0	0	<avg.	avg.
U.S.		41	171,858	112	289,584		

Source: ICF 2012, EIA 2012e, 2012f

Figure 6. Leading State Policies: Combined Heat & Power

***Texas*: In 2011 Texas House Bill 3268 became law, directing the state's environmental quality commission to develop a streamlined permitting mechanism for some CHP systems. The permit is to use output-based emission calculations and will be adopted by the commission in late 2012. While previous permitting processes for CHP were often long (over one year) and financially burdensome, this new permitting is expected to take 4-6 weeks and offer additional clarity within the permitting process.

***Ohio*: Ohio maintained its rank at the top this year by improving its existing Energy Efficiency Resource Standard and offering additional technical assistance and support to industrial facilities concerned about impending federal emissions regulations. In 2012, the state legislature passed Senate Bill 315, which stipulated that major forms of CHP can qualify for the state's EERS. In 2012, the state also began partnering with the U.S. Department of Energy to offer guidance, technical assistance, and sharing of best practices among industrial facilities with older boilers that will be affected by new and updated U.S. Environmental Protection Agency rules. Such customers are being encouraged to consider CHP in their facilities as a long-term cost-saving response to the regulatory changes.

***California*: In late 2011, a significant change to California's long-standing Self-Generation Incentive Program (SGIP) allowed non-renewable-fueled CHP systems to participate in the program. Additionally, the SGIP now offers an incentive for waste heat recovery projects equal to the incentive offered to wind-powered projects.

Chapter 6: State Government-Led Initiatives

Authors: Ben Foster and Kaye Schultz

INTRODUCTION

State legislatures and governors can advance policies and programs that impact many of the sectors discussed in previous chapters, including utility-sector energy efficiency, transportation efficiency, building codes, and combined heat and power. This chapter, however, is dedicated to the energy efficiency initiatives that are designed, funded, and implemented by a broad array of state-level administrators such as state energy offices, universities, and economic development and general services agencies (Sciortino and Eldridge 2010). We focus on three initiatives commonly undertaken by state governments: financial incentive programs for consumers, businesses, and industry; "lead by example" policies and programs put in place by states to improve the energy efficiency of their facilities and fleets; and research, development, and demonstration activities for energy efficiency technologies and practices.

In light of the wave of energy efficiency funding to states from the American Recovery and Reinvestment Act (see section below) and the groundwork it laid for continuing energy efficiency programs, it is critical to recognize state government-led initiatives, which play a unique role in fostering an energy-efficient economy. State government-led initiatives complement the existing landscape of utility programs, leveraging resources from the state's public and private sectors to generate energy and cost savings that benefit taxpayers and consumers (Sciortino & Eldridge 2010).

Financial and Information Incentives

Financial incentives are an important instrument to spur the adoption of technologies and practices in homes and businesses. They can take many forms: rebates, loans, grants, or bonds for energy efficiency improvements; income tax credits and income tax deductions for individuals or businesses; and sales tax exemptions or reductions for eligible products. Financial incentives can lower the upfront cost and shorten the payback period of energy efficiency upgrades, two critical barriers to consumers' and businesses' making cost-effective efficiency investments. Incentives also raise consumer awareness of eligible products, encouraging manufacturers and retailers to market these products more actively and to continue to innovate. As economies of scale improve, prices of energy-efficient products fall, and the products eventually compete well in the market without the incentives. Information-related incentives such as building energy disclosure laws improve consumers' purchasing power by raising awareness of the energy use of homes and commercial buildings being offered for sale, which can have a significant impact on the economic value of a home or building. A requirement to disclose a building's energy use also provides owners with an incentive to improve the energy efficiency of their buildings.

"Lead by Example"

State governments can advance energy-efficient technologies and practices in the marketplace by adopting policies and programs to save energy in public sector buildings and fleets, a practice commonly referred to as "lead by example" (LBE). In the current environment of fiscal austerity, lead by example policies and programs are a proven strategy to improve the operational efficiency and economic performance of states' assets. Furthermore, lead by example initiatives reduce negative environmental and health impacts of high energy use, and promote energy efficiency to the broader public.

States commonly adopt policies and comprehensive programs that aim to reduce energy use in state buildings. State governments operate numerous facilities, including office buildings, public schools, colleges, and universities, the energy costs of which can account for as much as 10% of a typical government's annual operating budget (EPA 2009). Only a handful of states have yet to implement a significant energy efficiency policy for public facilities. The most widely adopted measure at the state level is a mandatory energy savings target for new and existing state government facilities. The building requirements encourage states to invest in efficient new building construction and retrofit projects, lowering energy bills and promoting economic development in the energy services and construction sectors.

Two critical elements of successful energy efficiency initiatives in the public sector are proper building energy management and institutional support for "energy savings performance contracting" (ESPC), such as housing state support for ESPCs within a specific state agency that serves as the lead contact for implementing them. Both of these initiatives can help projects overcome information and cost barriers to implementation. Benchmarking energy use in public-sector buildings through tailored or widely available tools such as the Environmental Protection Agency's ENERGY STAR Portfolio Manager ensures a comprehensive set of energy-use data[46] that drives cost-effective energy efficiency investments. If the necessary encouragement, leadership, and resources are in place, states can finance energy improvements through energy savings performance contracts, which allow the state to enter into a performance-based agreement with an energy service company (ESCO). The contract allows the state to pay the ESCO for its services with money saved by installing energy efficiency measures.[47]

In addition to lead-by-example initiatives in state government buildings, states have also put in place policies encouraging/requiring efficient vehicle fleets to reduce fleet fuel costs and hedge against rising fuel prices. Collectively, state governments own approximately 500,000 vehicles, with fleet sizes ranging from 1,000 to more than 50,000 per state. Operation and maintenance costs for these fleets run to more than $2.5 billion nationwide, ranging from $7 million to $250 million (NCFSA 2007). In response to this significant cost, states have often adopted a definitive efficiency standard for state vehicle fleets—a tool that ensures a reduction in fuel consumption and greenhouse gas emissions. Other policies include binding goals to reduce petroleum use by a certain amount over a given time frame, meaningful greenhouse gas reduction targets for fleets, and procurement requirements for hybrid-electric or plug-in electric vehicles. In order to receive credit in the *2012 State Energy Efficiency Scorecard*, fleet policies had to specify fuel economy improvements that exceed existing Corporate Average Fuel Economy (CAFE) standards.

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[46] Some states have in place their own databases of public building energy use that integrate with EPA's Portfolio Manager. For example, Maryland's EnergyCAP database (http://www.dgs.maryland.gov/energy/EnergyDatabasePublic.html) compiles the energy use (based on utility bills) of all public buildings in the state and provides a means of comparing buildings owned by different state agencies. The database is available to the public and to all state agencies.

[47] For a full discussion of ESPCs, the ESCO market, and actual implementation trends see (Satchwell et al. 2010) and the Energy Services Coalition website (http://www.energyservicescoalition.org/).

Research, Development and Demonstration (RD&D)

Research, development, and demonstration programs drive advances in energy-efficient technologies, and states play a unique role in laying the foundation for such progress. By leveraging resources in the public and private sectors, state governments can foster collaborative efforts that achieve the goals of rapidly creating, developing, and commercializing new, energy-efficient technologies. These programs can also encourage cooperation among organizations from different sectors and backgrounds to further spur innovation in energy-efficient technologies.

In response to the increasing need for state initiatives in energy-related RD&D, several state institutions for energy research, development, and demonstration established the Association of State Energy Research and Technology Transfer Institutions (ASERTTI) in 1990. Members of ASERTTI collaborate on applied RD&D and share technical and operational information with a strong focus on end-use efficiency and conservation. State RD&D efforts, in addition to providing a variety of services to create, develop, and deploy new technologies for energy efficiency, can address a number of market failures that exist in the energy services marketplace that impede the diffusion of new technologies (Pye & Nadel 1997).

Aside from those institutions affiliated with ASERTTI, numerous other state-level entities conduct research, development, and demonstration programs. A diverse set of institutions (including universities, state governments, research centers, and utilities) fund and implement RD&D programs for the purpose of energy efficiency. Such programs include research on energy consumption patterns in local industries, development of energy-saving technologies at state or university research centers, and demonstration projects created through public-private partnerships.

Individual state research institutions provide expertise and knowledge to their states from which policymakers can draw in order to advance successful efficiency programs. They also provide the impetus for commercial investment and manufacturing of the new technologies that these institutions conceive. In addition, these research institutions enable valuable knowledge spillovers to other states through the sharing of information—facilitated through membership with ASERTTI—allowing states to benefit from one another's research. States without RD&D institutions can use this shared information as a roadmap in order to begin or advance their own efficiency programs. Even leading states have the potential to improve or add to their research, development, and demonstration efforts by drawing from the programs and best practices of other states.

The American Recovery and Reinvestment Act and State Governments

The American Recovery and Reinvestment Act passed in February 2009 included the largest single investment in energy efficiency in U.S. history. The law directed approximately $17 billion to improve the country's energy efficiency and, as seen in Table 23 below, a substantial share went to states from the Department of Energy's Office of Energy Efficiency and Renewable Energy (DOE 2012a).[48] Additional programs that may indirectly provide money for state and local government programs include the Advanced Research Projects Agency-Energy (ARPA-E), which funds numerous energy efficiency research

[48] An additional $15 billion was allocated to programs and projects in which funding could be used for energy efficiency improvements among numerous other modernization or renovation measures.

projects at state universities. Particularly in states minimally served by utility efficiency programs, these programs have provided an important first step to introduce consumers and decision-makers to the benefits of energy efficiency programs.

Table 23. ARRA Energy Efficiency Funding to State and Local Governments

Program	FY 2008 Budget	Stimulus Funding
Weatherization Assistance Program	$227 million	$5 billion
State Energy Program	$33 million[49]	$3.1 billion
Energy Efficiency and Conservation Block Grant Program	N/A	$3.2 billion
Appliance Rebate Program	N/A	$300 million
Total	$260 million	$11.6 billion

Source: DOE (2012a)

While ARRA's main intent was to stimulate rapid job growth, its effects on state-level energy efficiency programs will last for years, if not decades. From the outset, state governments were encouraged to use ARRA funds to establish energy efficiency financing mechanisms that could leverage private sector capital and maximize the usefulness of the funds. Thirty-five states have established 51 revolving loan funds (RLFs) with approximately $650 million in ARRA money, which could finance approximately $150-200 million per year of energy projects over the next 20 years (Goldman et al. 2011).[50] ARRA also cemented better connections among state energy offices, the Department of Energy and lending institutions, in particular Community Development Financial Institutions (Freehling 2011). Along with its lasting effects on state-level energy efficiency, ARRA established connections between state and local governments to advance building and transportation energy efficiency at the community level (Sciortino 2011). In order to receive and spend Energy Efficiency and Conservation Block Grants, local governments have developed knowledge and staff capacity to implement energy efficiency projects, providing a solid foundation for future programs.

RESULTS

States could earn a maximum of seven (7) points for state initiatives: three (3) points for financial and information incentives; two (2) points for "lead by example" policies and programs in government buildings and fleets; and two (2) points for research, development, and demonstration programs. Table 24 presents the overall results of scoring on state initiatives.

State programs funded solely through ARRA or another federal source did not earn points in the State Scorecard. Because ARRA funds came from the federal stimulus, the existence of ARRA-funded programs does not necessarily reflect the efforts of the state. We do recognize that some states are utilizing

[49] Required states to contribute funds worth 20% of the DOE grant toward energy projects supported by the grant.
[50] For analysis of the initial implementation phase of energy-related ARRA funding at the state level, see Goldman et al. (2011).

these federal funds in an exemplary fashion by creating innovative and effective energy efficiency programs. Completing an assessment of a state's handling of stimulus funds, however, would rely on fluctuating spending data and rests outside the scope of this report. Examples of exemplary ARRA-funded programs are presented in Sciortino & Eldridge (2010), on DOE's Weatherization & Intergovernmental Program website (http://www1.eere.energy.gov/wip/recovery_act.html), and in publications of the National Association of State Energy Officials (NASEO 2011).

Table 24. Summary of Scoring on State Government Initiatives

State	Financial Incentives (3 pts.)	Lead By Example (2 pts.)	RD&D (2 pts.)	Total Score (7 pts.)
Massachusetts	3	2	2	7
New York	3	1.5	2	6.5
Oregon	3	1.5	2	6.5
Alaska	3	1	2	6
Colorado	2	2	2	6
North Carolina	2	2	2	6
Pennsylvania	3	1	2	6
Tennessee	3	2	1	6
California	1.5	2	2	5.5
Connecticut	2.5	2	1	5.5
Illinois	2.5	1.5	1	5
Kentucky	2.5	1.5	1	5
Maryland	2.5	1.5	1	5
Texas	1.5	1.5	2	5
Wisconsin	1.5	1.5	2	5
Arizona	1	1.5	2	4.5
Michigan	1.5	1	2	4.5
Minnesota	2.5	2	0	4.5
New Hampshire	2.5	2	0	4.5
Vermont	1	1.5	2	4.5
Virginia	2.5	1	1	4.5
Alabama	1	2	1	4
Delaware	2	2	0	4
Idaho	2	1	1	4
Ohio	1.5	1.5	1	4
Florida	0	1.5	2	3.5
Georgia	0.5	1	2	3.5
Iowa	1.5	1	1	3.5
Kansas	1.5	2	0	3.5
Montana	2	1.5	0	3.5
Nebraska	1	0.5	2	3.5

State	Financial Incentives (3 pts.)	Lead By Example (2 pts.)	RD&D (2 pts.)	Total Score (7 pts.)
New Jersey	0	1.5	2	3.5
New Mexico	1.5	1.5	0	3
Oklahoma	2	1	0	3
South Carolina	1.5	1.5	0	3
Utah	1	2	0	3
Mississippi	1	1.5	0	2.5
Missouri	1	1.5	0	2.5
Washington	0.5	2	0	2.5
Arkansas	0.5	1.5	0	2
District of Columbia	1	1	0	2
Hawaii	0	2	0	2
Louisiana	1	1	0	2
Maine	0.5	1.5	0	2
Rhode Island	0	2	0	2
West Virginia	0	1	1	2
Indiana	0.5	1	0	1.5
Nevada	1	0.5	0	1.5
South Dakota	0.5	1	0	1.5
Wyoming	1	0.5	0	1.5
North Dakota	0.5	0	0	0.5

Financial and Information Incentives

We relied primarily on the Database of State Incentives for Renewables and Efficiency (DSIRE 2012) for information on current state financial incentive programs. We supplemented this with a survey of state energy officials and with a review of state government websites and other online resources provided by the National Governor's Association, the Building Codes Assistance Project and the Institute for Market Transformation (NGA 2012, BCAP 2012, IMT 2012).

Points were not given for utility customer-funded financial incentive programs, which are covered in Chapter 2. Programs solely funded by ARRA (see box) were also not counted. Acceptable sources of funding include state appropriations or bonds, oil overcharge revenues, auction proceeds from the Regional Greenhouse Gas Initiative, and other non-customer sources. Tax incentives were also included in the scoring. While there is some overlap of state and customer funding, for example where state RD&D is funded through a systems benefits charge, this category is designed to capture energy efficiency initiatives not already covered in Chapter 2.

States earned up to three (3) points for major financial incentive programs that encourage the purchase of energy-efficient products, and these programs are judged upon their relative strength, customer reach, and impact.[51] Incentive programs generally get one-half (0.5) point each, but several states have major incentive programs that were deemed worth one (1) point each; these included Delaware, Idaho, Kansas, Michigan, Nebraska, Nevada, New Hampshire, Texas, and Wisconsin.

States were also given 0.5 points for energy-use disclosure laws that are in place; these require commercial and residential building owners to disclose their building's energy consumption to prospective buyers, lessees, or lenders. Scoring for disclosure requirements was based on the strength of the policy, and whether both commercial and residential buildings are covered.

Table 25 lists the basis for our scoring of state financial incentives.

[51] "Energy-efficient products" include any product or process that reduces energy consumption. While renewable energy technologies such as solar hot water heating may reduce energy consumption, they are not included because they are typically part of broader renewable energy incentive packages that would not result in energy efficiency gains.

Table 25. State Scoring on Major Financial and Information Incentives Programs

State	Major State Financial Incentives for Energy Efficiency	Score (3 pts.)
Alaska	Major rebate program (Home Energy Rebate Program); multiple loan programs; grant program; residential energy disclosure policy	3
Massachusetts	Alternative Energy and Energy Conservation Patent Exemption (personal & corporate); grant, rebate and bond programs; residential energy disclosure policy	3
New York	Green Jobs/Green New York loan program; multiple rebate programs; Energy Conservation Improvements Property Tax Exemption; residential energy disclosure policy	3
Oregon	Residential and business energy tax credits; several grant, loan and report programs	3
Pennsylvania	State-led Alternative Energy Investment Fund; six grant and five loan programs	3
Tennessee	Energy Efficient Schools Initiative (loans and grants); one grant and two loan programs; sales tax credit for emerging energy industry	3
Connecticut	One rebate, one loan and one grant program; commercial energy disclosure policy; sales tax exemption for energy-efficient products	2.5
Illinois	Large Customer Energy Analysis rebate program; two grant, one loan and one bond program	2.5
Kentucky	KY Home Performance rebate program; Green Bank of Kentucky loan program; personal and corporate energy efficiency tax credits; on-farm energy efficiency grant program; subsidized hybrid school bus purchase program.	2.5
Maryland	Clean Energies Community Grant Program; three loan and one rebate programs	2.5
Minnesota	Five loan programs	2.5
New Hampshire	2 major loan programs (Business Energy Conservation Revolving Loan Fund and Municipal Energy Reduction Fund); rebate program	2.5
Virginia	Energy Leasing Program for state-owned facilities; Clean Energy Manufacturing Grant Program; two loan programs; personal and property tax incentives	2.5
Colorado	Green Colorado Credit Reserve and two other loan programs; one rebate program	2

State	Major State Financial Incentives for Energy Efficiency	Score (3 pts.)
Delaware	Major bond-financed public buildings program; one grant and one loan program	2
Idaho	Income tax deduction for insulation projects; one grant program and one major low-interest energy loan program	2
Montana	Energy conservation installation tax credit; tax deduction for energy-conserving investment; bond and loan programs	2
North Carolina	One grant, two loan, and two rebate programs	2
Oklahoma	Energy Efficient Residential Construction Tax Credit; three loan programs	2
California	One grant program; sales tax exemption for alternative energy manufacturing equipment (includes combined heat and power); commercial energy disclosure policy	1.5
Iowa	Major loan program (Iowa Energy Bank); grant program	1.5
Kansas	Major loan program (Efficiency Kansas); residential energy disclosure policy	1.5
Michigan	Major loan program (Michigan Saves Home Energy Loan); tax credit for home energy efficiency improvements	1.5
New Mexico	Sustainable Building Tax Credit (personal & corporate); bond program	1.5
Ohio	Energy Loan Fund and one other loan program; property tax incentive	1.5
South Carolina	Tax credit for purchase of new energy-efficient manufactured homes; sales tax cap on energy-efficient manufactured homes; one loan program	1.5
Texas	Major loan program (Texas LoanSTAR); energy use disclosure policy	1.5
Wisconsin	Major loan program (Clean Energy Manufacturing Loan Program); one grant program	1.5
Alabama	State-funded local government loan program; WISE Home Energy rebate program	1
Arizona	Property tax exemption for energy-efficient building components	1
District of Columbia	Commercial energy disclosure policy; one rebate program	1
Louisiana	Home Energy Loan Program; one rebate program	1
Mississippi	One loan program; one public sector lease program for energy-efficient equipment	1

State	Major State Financial Incentives for Energy Efficiency	Score (3 pts.)
Missouri	Loan program for public buildings; tax deduction for home energy efficiency improvements	1
Nebraska	Major loan program (Dollar and Energy Savings Loans)	1
Nevada	Wide-reaching property tax abatement for green buildings	1
Utah	Two loan funds for state-owned buildings and schools	1
Vermont	Two loan programs	1
Wyoming	One grant and one loan program	1
Arkansas	Loan fund for small businesses	0.5
Georgia	Corporate Clean Energy Tax Credit	0.5
Indiana	Community Conservation Challenge grant program	0.5
Maine	Residential energy disclosure policy	0.5
North Dakota	One grant program for public facilities	0.5
South Dakota	Residential energy disclosure policy	0.5
Washington	Commercial energy disclosure policy	0.5
Florida	None	0
Hawaii	None	0
New Jersey	None	0
Rhode Island	None	0
West Virginia	None	0

Figure 7. State Financial and Information Incentives: Leading and Trending States

Alaska**:** Alaska uses a substantial amount of state appropriations to fund energy efficiency incentive programs. The Home Energy Rebate Program utilizes $160 million in state funding appropriated in 2008, a major investment relative to the population of Alaska. The program allows rebates of up to $10,000 based on improved efficiency and eligible receipts. Energy ratings are required before and after the home improvements to provide expert advice and to track savings.

Tennessee**:** Tennessee has partnered with Pathway Lending to provide low-interest energy efficiency loans to commercial customers. The state also offers energy efficiency grants to state government agencies, businesses and utility districts for projects that promote energy efficiency, clean energy technologies and improvements in air quality. Tax credits are also available for the manufacture of energy-efficient technologies.

Oklahoma: As of July 2012, the state has resumed its Energy Efficient Residential Construction Tax Credit, which was suspended for two years in June 2010. The tax credit applies to the installation of energy-efficient upgrades in homes less than 2000 sq. ft., and ranges from $2000-$4000 depending on the home's performance in an energy audit. The state also has several loan programs that encourage energy efficiency in schools and local government buildings.

"Lead by Example"

Our review of state lead by example initiatives is based on information from the Database of State Incentives for Renewables and Efficiency (DSIRE 2012), a survey of states energy officials, and independent research. States could earn a maximum of two (2) points in the LBE category: 0.5 points for energy savings targets in new and existing state buildings; 0.5 point for a benchmarking requirement for public facilities; 0.5 point for energy performance savings contracting activities; and 0.5 point for fleet efficiency mandates.

Energy savings targets must commit state government facilities to a specific energy reduction goal over a distinct time period. A benchmarking policy refers to a requirement that all buildings undergo an energy audit or have their energy performance tracked using a recognized tool such as the EPA ENERGY STAR Portfolio Manager. Public-sector energy benchmarking programs may also qualify for the half-point.

Scoring on activities related to energy savings performance contracting (ESPC) is based on three metrics: encouragement, leadership, and resources. The ESPC encouragement metric requires that the state explicitly promotes the usage of ESPCs to improve the energy efficiency of public buildings. We recognized the following methods of encouragement: statutory requirements for using energy savings performance contracting, statutory recommendation of ESPCs as a method of achieving efficiency improvements, explicit preference for ESPCs through statutes, executive orders that explicitly promote or require ESPCs, and/or financial incentives for agencies seeking to use energy savings performance contracts. States earning recognition for ESPC leadership were those that have either set up a distinct program that directly coordinates ESPC efforts (and, on occasion, other energy efficiency projects, as well) or housed the state support for ESPCs within a specific state agency that serves as the lead contact for implementing ESPCs. Lastly, the ESPC resources category is defined by states that offer documents that help streamline and standardize the ESPC process. Such documents include: a list of prequalified energy service companies, model contracts and other documents, and/or a manual that lays out the procedures required to utilize an energy service performance contact. A state was awarded 0.5 point if it satisfied at least *two of the three* categories described.

For state fleet initiatives, states get credit only if the plan or policy makes a specific, mandatory requirement for increasing state fleet efficiency. State requirements for the procurement of alternative-fuel vehicles that give only a voluntary option to count efficient vehicles are not included because they will likely not result in better fuel economy.

Table 26. State Scoring on Lead by Example Initiatives

State	Benchmarking Requirements for Public Buildings	New and Existing State Building Requirements	Efficient Fleets	ESPC Policy and Programs	Total Score (2 pts.)
Alabama	•	•	•	•	2
California	•	•	•	•	2
Colorado	•	•	•	•	2
Connecticut	•	•	•	•	2
Delaware	•	•	•	•	2
Hawaii	•	•	•	•	2
Kansas	•	•	•	•	2
Massachusetts	•	•	•	•	2
Minnesota	•	•	•	•	2
New	•	•	•	•	2
North Carolina	•	•	•	•	2
Rhode Island	•	•	•	•	2
Tennessee	•	•	•	•	2
Utah	•	•	•	•	2
Washington	•	•	•	•	2
Arizona	•	•		•	1.5
Arkansas	•	•		•	1.5
Florida		•	•	•	1.5
Illinois		•	•	•	1.5
Kentucky	•	•		•	1.5
Maine		•	•	•	1.5
Maryland	•	•		•	1.5
Mississippi	•		•	•	1.5
Missouri		•	•	•	1.5
Montana		•	•	•	1.5
New Jersey	•	•		•	1.5
New Mexico		•	•	•	1.5
New York	•	•		•	1.5
Ohio	•	•		•	1.5

State	Benchmarking Requirements for Public Buildings	New and Existing State Building Requirements	Efficient Fleets	ESPC Policy and Programs	Total Score (2 pts.)
Oregon	•	•		•	1.5
Texas	•	•		•	1.5
Vermont	•	•	•		1.5
Wisconsin		•	•	•	1.5
Alaska	•	•			1
District of	•	•			1
Georgia	•	•			1
Idaho		•		•	1
Indiana		•		•	1
Iowa	•	•			1
Louisiana		•		•	1
Michigan	•	•			1
Oklahoma	•	•			1
Pennsylvania		•		•	1
South Dakota	•	•			1
Virginia		•		•	1
West Virginia	•	•			1
Nebraska	•				0.5
Nevada		•			0.5
Wyoming				•	0.5
North Dakota					0

Figure 8. Lead by Example Initiatives: Leading and Trending States

***Hawaii*:** Hawaii's Lead by Example program offers a comprehensive set of services to state agencies. Aggressive policies underpin the program and include a benchmarking requirement that all state agencies evaluate the energy efficiency in existing buildings of qualifying size and energy characteristics. Each agency must identify opportunities for increased energy efficiency by setting benchmarks for these buildings using ENERGY STAR Portfolio Manager or similar tool, and buildings must be retro-commissioned every five years. In addition, new state buildings must meet LEED Silver standards. As a result of Hawaii's Lead By Example program, in 2011 total state agency electricity consumption was 4.6% below that in the baseline year of 2005 (State of Hawai'i 2012).

***Minnesota*:** Over the past decade, the state of Minnesota has shown its commitment to sustainable buildings by providing leadership, setting high performance standards, and putting forward an integrated framework of programs that provide a comprehensive system for designing, managing, and improving building energy performance. Beginning with aggressive standards for state buildings based on the long-term goal of having a zero-carbon building fleet by 2030, the state offers a complementary benchmarking program for tracking energy use, and the Public Building Enhanced Energy Efficiency Program that aids in implementing retrofits. Minnesota also requires on-road vehicles owned by state departments to reduce gasoline consumption by 50% by 2015. Also, new on-road vehicles must have a fuel efficiency rating that exceeds 30 mpg for city usage and 35 mpg for highway usage.

Kansas: Kansas has a long-standing performance contracting program, the Facility Conservation Improvement Program (FCIP), which is administered by the Kansas Corporation Commission. FCIP provides a list of preapproved energy service company partners and walks users through a series of well-laid-out steps toward forming an energy savings performance contact. Kansas is ranked #2 in the nation (after Hawaii) by the Energy Services Coalition for performance contracting spending per capita. In addition, Kansas requires all state-owned buildings to undergo an energy audit at least every 5 years to identify excessive energy usage; for leased buildings, an energy audit is required before State agencies may approve new leases or renew existing leases.

Research, Development and Demonstration

Our RD&D review was based on a state institution's participation in the Association of State Energy Research Technology and Transfer Institutions (ASERTTI) and the size of the effort relative to state population. Information about state energy efficiency RD&D institutions was based on the *National Guide to State Energy Research Centers* (PES Group 2011), a survey of state energy officials and other secondary research. In general, one (1) point was awarded for each major RD&D program dedicated to energy efficiency that is funded by the state government, including programs administered by state government agencies, public-private partnerships, and university programs.[52] In a few cases, a program's funding per capita was large enough to earn two (2) points, the maximum available in this category.

[52] Institutions that are primarily focused on renewable energy technology or alternative fuel RD&D do not receive credit in the Scorecard. In addition, programs that serve primarily an educational or policy development purpose also do not receive points.

Because RD&D funding often fluctuates and it is difficult to determine how much of it specifically supports energy efficiency, devising a quantitative metric based on RD&D program funding or staffing levels is currently outside the scope of this report.

Table 27. State Scoring on RD&D Programs

State	Major RD&D Programs	Score (2 pts.)
Alaska	The Cold Climate Housing Research Center and the Emerging Energy Technology Fund	2
Arizona	The Sustainable Energy Solutions Group of Northern Arizona State and Arizona State University's LightWorks Center	2
California	The California Energy Commission's Public Interest Energy Research program, University of California-Davis' Center for Water-Energy Efficiency and the Energy Efficiency Center, and University of California-Los Angeles' Center for Energy Science and Technology Advanced Research and Smart Grid Energy Research Center	2
Colorado	Colorado State University's Engines and Energy Conversion Lab and Institute for the Built Environment, University of Colorado-Boulder's Renewable and Sustainable Energy Institute, Colorado School of Mines' Research in Delivery, Usage, and Control of Energy, and the Center for Renewable Energy Economic Development	2
Florida	University of Central Florida's Florida Solar Energy Center, Florida State University's Energy and Sustainability Center, and University of Florida's Florida Institute for Sustainable Energy	2
Georgia	The Southface Energy Institute and Georgia Institute of Technology's Brook Byers Institute for Sustainable Systems	2
Massachusetts	The Massachusetts Energy Efficiency Partnership, High Performance Green Building Grants, and University of Massachusetts-Amherst's Center for Energy Efficiency and Renewable Energy	2
Michigan	The Michigan NextEnergy Center and Oakland University in Rochester's Clean Energy Research Center	2
Nebraska	The Nebraska Center for Energy Sciences Research and the Energy Savings Potential program	2
New Jersey	The Edison Innovation Clean Energy Fund and the Rutgers Energy Institute	2
New York	The New York State Energy Research and Development Authority, State University of New York's Center for Sustainable & Renewable Energy, Syracuse University's Building Energy and Environmental Systems Laboratory, and City University of New York's Institute for Urban Systems	2

State	Major RD&D Programs	Score (2 pts.)
North Carolina	The North Carolina Green Business Fund, the North Carolina Solar Center, North Carolina A&T State University's Center for Energy Research and Technology, and Appalachian State University's Energy Center	2
Oregon	The Oregon Built Environment and Sustainable Technologies Center, University of Oregon's Energy Studies in Building Laboratory and Baker Lighting Lab, Portland State University's Renewable Energy Research Lab, the Energy Trust of Oregon, and the Oregon Transportation Research and Education Consortium	2
Pennsylvania	Leigh University's Energy Research Center and Penn State's Indoor Environment Center	2
Texas	Texas A&M's Energy Systems Laboratory and University of Texas-Austin's Center for Energy and Environmental Resources	2
Vermont	The Center for Energy Transformation and Innovation	2
Wisconsin	The Energy Center of Wisconsin and Wisconsin Focus on Energy	2
Alabama	University of Alabama's Center for Advanced Vehicle Technologies	1
Connecticut	University of Connecticut's Center for Clean Energy Engineering	1
Idaho	The Center for Advanced Energy Studies	1
Illinois	University of Illinois at Chicago's Energy Resources Center	1
Iowa	The Iowa Energy Center	1
Kansas	Studio 804, Inc.	1
Kentucky	University of Louisville's Conn Center for Renewable Energy Research	1
Maryland	University of Maryland's Energy Research Center	1
Ohio	Ohio State University's Center for Energy, Sustainability, and the Environment	1
Tennessee	University of Tennessee partnerships with Oak Ridge National Laboratory and the Electric Power Research Institute	1
Virginia	The Modeling and Simulation Center for Collaborative Technology	1
West Virginia	West Virginia University's Advanced Energy Initiative	1

Notes: See Appendix H for expanded descriptions of state energy efficiency RD&D program activities.

Figure 9. Leading States: State Research, Development, and Demonstration Initiatives

Colorado: The state of Colorado is demonstrating leadership in many energy efficiency areas. State universities including Colorado State University, the University of Colorado, and the Colorado School of Mines have displayed a commitment to energy efficiency by dedicating research centers and facilities to the development of energy efficiency and clean energy technologies. The Center for Renewable Energy Economic Development also plays a major role in the state's energy efficiency activities by promoting and supporting new cleantech companies throughout the state.

New York: The New York State Energy Research and Development Authority (NYSERDA) is an outstanding model of an effective and influential research and development institution. Its RD&D activities include a wide range of energy efficiency and renewable energy programs organized into seven program areas: energy resources; transportation and power systems; energy and environmental markets; industry; buildings; transmission and distribution; and environmental research. NYSERDA's 2009/10 RD&D budget was approximately $165 million.

Oregon: The state of Oregon boasts an impressive array of organizations committed to energy efficiency. The Oregon Built Environment and Sustainable Technologies Center promotes cutting-edge technology related to energy efficiency and green buildings, the Energy Trust of Oregon provides funding for the testing of emerging technologies specifically related to utilities, and the Oregon Transportation Research and Education Consortium supports innovation specifically geared towards energy efficiency in the areas of land use and transportation.

Vermont: The state of Vermont is taking a giant step towards increased energy efficiency with the announcement of a new Center for Energy Transformation and Innovation at the University of Vermont. This collaborative project involves the University of Vermont, the State of Vermont, Sandia National Laboratories, and other Vermont institutions, such as Vermont Tech, Vermont State Colleges, Norwich University, and Vermont Law School. In addition to energy efficiency, the Center will focus on bringing sustainable energy and smart-grid technology to Vermont. The Center will receive $15 million in start-up funds from state, federal, and private sources.

Chapter 7: Appliance and Equipment Efficiency Standards

Author: Max Neubauer

INTRODUCTION

Every day in our homes, offices, and public buildings, we use appliances and equipment that are less energy-efficient than other available models, causing us to consume more energy than we would need to. While the usage and energy cost for a single device may seem small, the extra energy consumed by less efficient products collectively adds up to a great amount of wasted energy. For example, one battery charger may draw a small amount of electricity and waste an even smaller amount through inefficiency. However, there are more than 1.7 billion battery chargers in the U.S., so the total amount of energy wasted is significant. Persistent market barriers, however, inhibit sales of more efficient models. Appliance efficiency standards overcome these barriers by requiring manufacturers to meet minimum efficiency levels for all products, thus removing the most inefficient products from the marketplace.

States have historically led the way when it comes to establishing standards for appliances and other equipment. California was the first state to introduce appliance standards in 1976. Many states, including New York and Massachusetts, followed soon after. The federal government did not institute any national standards until 1988 when the National Appliance Energy Conservation Act of 1987 was passed, which created national standards based on those that had been adopted by California and several other states. Congress enacted additional national standards in 1988, 1992, 2005, and 2007. Congress enacted additional national standards in 1988, 1992, 2005, and 2007. In general, these laws set initial standards for products and require the U.S. Department of Energy to review and strengthen standards on a specific schedule. All told, about 45 products are now subject to national efficiency standards.

In February 2009, President Obama signed a Presidential Memorandum that, by 2013, will require the introduction or update of standards for 26 products. To date, DOE has set or updated more than 12 standards and currently has 15 rulemakings in progress. It is known that when DOE rulemaking activity picks up, the impetus for states to set standards decreases. Conversely, when the national standard-setting process lags, activity in the states increases, serving again as a catalyst for establishing national standards. Unsurprisingly, the current uptick in DOE activity coincides with only two states—California and Connecticut—having passed standards legislation in the last year.

Federal preemption generally prevents states from setting standards stronger than existing federal requirements for a given product. Under the general federal preemption rules applied by the Energy Policy Act of 2005 (EPAct) and the Energy Independence and Security Act of 2007 (EISA), states that have set standards prior to federal enactment may enforce their state standards up until the federal standards become effective; states that have not yet set standards are preempted immediately. States that wish to implement their own standard after federal preemption must apply for a waiver; however, states remain free to set standards for any products that are not subject to national standards.

Results

A state could earn up to two (2) points for adoption of appliance efficiency standards. We score states based on the potential savings in billion British Thermal Units (BBtu) generated through 2030 by appliance efficiency standards not currently preempted by federal standards. The savings estimates, which are based on an analysis by the Appliance Standards Awareness Project (ASAP) and ACEEE (Neubauer et al. 2009a), were normalized based on the number of residential customers in the state. Therefore, each state was scored on the amount of energy savings generated per customer, in half-point increments. Table 28 summarizes the scoring methodology, and Table 29 provides details of state energy savings from appliance and equipment standards and states' scores.

Table 28. Scoring Methodology for Savings from Appliance Standards

Energy Savings per Customer through 2030 (BBtu/customer)	Score
≤ 100	2
50 ≤ x < 100	1.5
10 ≤ x < 50	1
0 < x < 10	0.5
0	0

Table 29. State Scoring for Appliance Efficiency Standards

States	Energy Savings per Customer through 2030 (BBtu/customer)	Date Most Recent Standards Adopted	Score (2 pts.)
California**	144	2011	2
Connecticut	29	2011	1
Arizona	7.7	2009	0.5
Oregon	3.1	2007	0.5
Washington	1.2	2009	0.5
District of Columbia	0.6	2009	0.5
Maryland	0.5	2007	0.5
Rhode Island	0.5	2006	0.5
New Hampshire	0.4	2008	0.5
Georgia**	N/A	2010	0.5
Texas**	N/A	2010	0.5
Vermont	0	2006	0
New Jersey	0	2005	0
Nevada*	76	2007	0
Massachusetts	0	2007	0
New York	0	2010	0

Sources: Neubauer et al. (2009a); ASAP (2012)

* Nevada earned one-half point for advancing standards for general service incandescent lamps that are more stringent than the federal standards. California would earn an additional half point as well, but it has already been awarded the maximum number of points possible.

** Georgia and Texas adopted standards on plumbing products in 2010, as did California in 2007, which include toilets, urinals, faucet aerators, showerheads, and commercial pre-rinse spray valves. Since no analysis has yet been completed that estimates the savings, we awarded Georgia and Texas one-half point since the savings would at least be greater than zero. California was already awarded the maximum number of points.

California, scoring the maximum two points, continues to take the lead on appliance efficiency standards, most recently adopting the first-ever standards for televisions as well as standards for battery chargers. Not only has California adopted the greatest number of appliance and equipment standards, many other states' standards are based on California's, such as the television standards passed in Connecticut in 2011. Many of the current state standards have been adopted at the federal level or have been included in pending federal legislation; thus, without future state action to develop and implement standards for additional products, the percentage of state standards preempted by federal standards will increase.

Of the four states that received no credit for their standards in Table 29, Massachusetts, New Jersey, and Vermont have had their state standards preempted by federal standards. New York has passed legislation to create several state standards for which federal standards do not exist;[53] however, the standards levels have yet to be officially developed. In our two previous State Scorecards we awarded New York credit for these standards assuming the levels would be set over the course of the following years and the standards would therefore begin to generate savings. Since the levels of New York's standards have not been set and, as a result, no savings have been generated, in the *2012 State Energy Efficiency Scorecard* we have adjusted the score accordingly. In our *2011 State Energy Efficiency Scorecard*, Nevada earned credit for adopting standards for general service incandescent lamps that are more stringent than the existing federal standards. However, those standards are not yet being enforced and it is uncertain when they will begin to be enforced, so we have deducted these points indefinitely.

It is worth noting that the standards adopted for plumbing products by California, Georgia, and Texas, which include standards for toilets, urinals, faucet aerators, showerheads, and commercial pre-rinse spray valves, will generate a significant volume of water savings. The energy savings come from the reduced need for hot water as well as the reduced energy required to pump and treat both water and wastewater. These standards are particularly important in these three states, which have been experiencing frequent and persistent droughts in their regions at an increasing rate over the last decade or so.

Figure 10. Leading States: Appliance and Equipment Efficiency Standards

***Connecticut*:** In January 2011, the Connecticut General Assembly passed Bill 1243, which added standards for compact audio players, televisions, and DVD players and recorders. The standards are based on standards from Title 20 of the California Code of Regulations, making Connecticut only the second state to pass statewide standards on televisions. The standards are set to become effective in January 2014.

California: California was the first state in the country to adopt appliance and equipment efficiency standards. The authority to adopt appliance and equipment efficiency standards was bestowed upon the California Energy Commission as stipulated under the Warren-Alquist Act, enacted in 1974. Over the years, California has adopted standards on more than 50 products, many of which have subsequently become federal standards. California's 2006 Appliance Efficiency Regulations became effective on December 30, 2005, replacing all previous versions of the regulations. The Appliance Efficiency Regulations create standards for 21 categories of appliances, including standards for both federally-regulated and non-federally-regulated appliances. Currently, California has standards in place for ten products that are not covered by federal standards.

[53] Televisions, pool pumps, hot tubs, portable light fixtures, water dispensers, commercial hot-food holding cabinets, audio/video equipment, and digital TV adapters

Chapter 8: State Energy Efficiency in the Residential Sector: Measuring Performance

Authors: Colin Sheppard, Arne Jacobson and Charles Chamberlin (Schatz Energy Research Center, Humboldt State University), Yerina Mugica (Natural Resources Defense Council).

Note: ***Findings from this chapter are not scored and do not affect rankings in the*** **State Energy Efficiency Scorecard**. *The chapter is included here to explore one way of measuring energy consumption* trends *as a means of understanding energy efficiency in the residential sector. The performance-based approach of this chapter complements the largely policy-based approach in other chapters of the State Scorecard.*

Summary

In this chapter, we present the latest installment in an ongoing series that began with the *2009 State Energy Efficiency Scorecard*. For each of the 50 states (the District of Columbia is excluded), we estimate an aggregate, state-level metric of energy consumption intensity (i.e., per capita energy consumption) for the residential sector. The metric identifies changes in state energy consumption intensity after adjusting for changes due to year-to-year variations in weather.

This research indicates that it is possible to track trends in state energy consumption intensity, even with the imperfect data sets that are currently available. With improvements in the data collection process, the approach could be further strengthened into a powerful tool for evaluating states' progress in reducing energy consumption.

Acknowledgements

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Introduction

In this chapter, we present the latest installment in an ongoing series that began with the *2009 State Energy Efficiency Scorecard*. For each of the 50 states (the District of Columbia is excluded), we estimate an aggregate, state-level metric of energy consumption intensity (i.e., per capita energy consumption) for the residential sector.

Our approach for tracking energy consumption intensity (ECI) is based upon per capita energy consumption data for the residential sector in each state over a period of 10 years. For every given year we have adjusted the energy consumption intensity for changes in residential heating and cooling energy use due to annual variations in states' weather. We call this corrected value the adjusted energy consumption intensity (aECI), which is the data point for each state that we utilize in the scores and rankings in this chapter. We use the results of a regression analysis to adjust ECI in a given year for changes in residential heating and cooling energy use due to annual variations in state weather. In order to evaluate a state's performance in reducing aECI, we estimate the slope of a linear trend through the ten years including the test year and the nine preceding years. States with a downward (negative) slope are considered to have achieved progress, while those with a flat or increasing slope are not. The following section, "Methodological Approach", describes this methodology in further detail.

The performance-based metric for evaluating states' progress that is described in this chapter differs from the State Scorecard in some important ways. First, there are differences in the sectors that are currently covered by the respective approaches. For instance, the State Scorecard includes an evaluation of residential, commercial, and transportation sector policies, while the performance based metric presented here focuses exclusively on the residential sector. In addition, whereas the State Scorecard tends to give credit to states immediately for enacting efficiency-oriented policies, a performance-based approach gives credit only after states show reductions in energy consumption intensity over time. As a result, there is an inherent time lag between the two approaches. Importantly, with a performance-based approach states will not receive credit for enacting efficiency-oriented policies unless those policies result in measurable reductions in weather adjusted energy consumption intensity. Finally, as described in more detail in the "Key Conclusions" section below, the data currently reported for energy consumption by state are not perfect and differ from the data on which the State Scorecard's rankings are based. Therefore, not surprisingly, states' rankings under the performance metric presented here sometimes do not match those in the State Scorecard. The two approaches complement one another quite well, however, as one is primarily a measure of state energy efficiency policy while the other is a measure of progress in achieving reductions in energy consumption intensity.

The approach that we employed for tracking energy consumption intensity begins with data for aggregate energy consumption for the residential sector in each state over a period of ten years.[54] These data were adjusted according to state population, yielding figures for annual per capita residential energy consumption intensity (mmBtu/capita/year). The data were also corrected for an unrealistic assumption made by the U.S. Energy Information Administration that primary energy associated with electricity consumption should be estimated using a nationally averaged fossil-fueled heat rate. Our adjustment lets us estimate a state-specific heat rate based on the composition of electricity production in that state and which assumes no conversion losses from renewable electricity[55], hydropower, and nuclear power.[56]

While there are many causes for variation in energy consumption intensity, weather is most clearly beyond the influence of policymakers. (Other factors typically used in this kind of analysis include economic indicators and the price of energy. See the section below titled "PSEP vs. Other Econometric Approaches" for further discussion of our decision not to adjust for these factors.) Adjusting for weather is an important step in the evaluation of consumption trends that result from policy changes. Therefore,

[54] The energy data are from the Energy Information Agency of the U.S. Department of Energy's State Energy Data System (SEDS). Population data are from census and annual intercensal estimates from the U.S. Department of Commerce, Bureau of the Census.

[55] We treat the following as renewable sources of electricity: wind, solar, wood, geothermal, and municipal waste.

[56] Because the grid mix in each state changes from year to year, the heat rate estimate also changes. However, we seek to separate the impact on consumption of energy efficiency measures from the impact of changes in grid mix or conversion efficiency. To address this issue, we use a constant state-specific heat rate for any given evaluation period. For example, if our metric is concerned with ECI trends in California for the period 2000-2009, then we use the average heat rate over that period to make the adjustment to primary energy associated with electricity consumption.

we determined the response of ECI to heating and cooling degree days, both of which are strong indicators of the impact of climate on building energy consumption.[57] The estimated weather coefficients were used to adjust energy consumption intensity in a given year to a normal weather year based on the state's 30-year average number of heating and cooling degree days.[58]

The result is an adjusted residential sector ECI (hereafter called "aECI") time series for each state that includes corrections for changes in residential heating and cooling energy use due to annual variations in state weather. In order to evaluate a state's performance in reducing its adjusted energy consumption intensity, we estimated the slope of a linear trend line through the ten years including the test year and the nine preceding years. The PSEP score for the year equals this slope. States with a downward (negative) slope, which indicates a decrease in adjusted energy consumption intensity, are considered to have achieved progress, while those with a flat or increasing slope are experiencing increased energy consumption per capita.[59]

Differences from Previous State *Energy Efficiency* Scorecards

This is the fourth consecutive year that the Performance based State Efficiency Program (PSEP) scores have been presented in the State Scorecard. If one were to compare the results presented in Table 30 to the corresponding results from previous years, some subtle differences would be apparent in the historical PSEP scores for most states. These differences are the result of two changes in the Energy Information Administration's State Energy Data System (SEDS) data set that serve as the foundation of the metric. First, the data from EIA include adjustments made to the methodology for estimating losses in the electric power sector of states.[60] In addition, the 2010 SEDS data set uses population data from the 2010 U.S. Census. Therefore, estimates of state population for the years 2001-2009 were corrected by the Census Bureau to reflect the latest results. For many states, these changes had a noticeable impact on their adjusted energy consumption intensity and therefore the PSEP metric. Utah was affected the most by this adjustment. There were four historical years where Utah's PSEP metric was previously negative but are now positive.

Table 30 below presents a ranking of states based on the slope of aECI for the four most recent periods for which data are available (1998-2007, 1999-2008, 2000-2009, and 2001-2010). When the ten-year slope of aECI is recalculated on an annual basis, there is considerable overlap from period to period in the data used to create the metric. The four periods shown in Table 30 illustrate the variability and evolution of states' performance year over year.

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[57] We perform a fixed effect multiple linear regression to determine the response of ECI to heating and cooling degree days (HDD and CDD). The regression includes dummy coefficients to model the fixed differences in ECI from state to state as well as differences from year to year across all states.
[58] State level, population weighted heating degree days (HDD) and cooling degree days (CDD) values are not currently published for Alaska and Hawaii by the National Climatic Data Center. Our methodology for estimating these values from 1975-2010 is described in Appendix D of our broader report: http://www.schatzlab.org/projects/psep.
[59] It is also possible to add the condition that the slope estimate for a given test period be negative with some level of confidence. This can decrease the occurrence of false positives, that is, it would exclude states that actually made no improvement in adjusted energy consumption intensity from our definition of progress. In our broader report, we apply such a hypothesis test at the 20% significance level.
[60] See http://www.eia.gov/state/seds/seds-data-changes.cfm#2010.

Table 30. Ten-Year Slopes of aECI from 1998-2007, 1999-2008, 2000-2009, and 2001-2010

	2007		2008		2009		2010	
Rank	State	Slope	State	Slope	State	Slope	State	Slope
1	WA	-0.37	WA	-0.52	MA	-0.67	ME	-0.90
2	MA	-0.22	MA	-0.44	AK	-0.61	AK	-0.89
3	CA	-0.20	TX	-0.36	TX	-0.58	MI	-0.80
4	TX	-0.18	AK	-0.25	WA	-0.56	CT	-0.70
5	OR	-0.10	OR	-0.24	MI	-0.52	DE	-0.66
6	KS	-0.07	RI	-0.17	CT	-0.48	WA	-0.65
7	RI	0.00	CA	-0.15	DE	-0.46	TX	-0.61
8	NE	0.01	MI	-0.12	RI	-0.43	MA	-0.53
9	IL	0.03	NE	-0.11	ME	-0.39	RI	-0.46
10	NH	0.06	MD	-0.10	NY	-0.37	PA	-0.46
11	NY	0.09	NY	-0.09	PA	-0.35	NE	-0.44
12	NV	0.10	DE	-0.09	MD	-0.35	OR	-0.42
13	MD	0.10	KS	-0.08	OR	-0.30	MD	-0.41
14	HI	0.11	CT	-0.07	NE	-0.28	NY	-0.41
15	UT	0.12	NV	-0.06	IL	-0.21	MN	-0.40
16	NJ	0.17	IL	-0.03	MN	-0.20	IL	-0.39
17	LA	0.19	PA	0.01	AL	-0.20	NH	-0.33
18	IA	0.19	NJ	0.01	NV	-0.20	NJ	-0.33
19	MI	0.21	UT	0.02	NJ	-0.16	WI	-0.28
20	SD	0.23	NH	0.06	GA	-0.15	SC	-0.25
21	MS	0.24	AL	0.08	NH	-0.15	NC	-0.25
22	NC	0.24	MS	0.08	MS	-0.15	OH	-0.24
23	OK	0.25	MN	0.09	NC	-0.14	NV	-0.24
24	SC	0.26	NC	0.09	SC	-0.10	AL	-0.22
25	DE	0.28	SC	0.11	WI	-0.08	IN	-0.20
26	AL	0.29	IA	0.12	FL	-0.08	FL	-0.16
27	PA	0.31	HI	0.13	CA	-0.06	GA	-0.15
28	AR	0.35	ME	0.15	KS	-0.04	TN	-0.12
29	OH	0.35	LA	0.16	OH	-0.03	MS	-0.11
30	TN	0.37	FL	0.18	UT	0.00	CA	-0.04
31	FL	0.38	OH	0.18	TN	0.01	CO	-0.03
32	IN	0.39	AR	0.20	IN	0.03	UT	0.01
33	MN	0.39	WI	0.21	OK	0.06	VA	0.03
34	AK	0.41	GA	0.23	CO	0.07	KS	0.04
35	WI	0.43	SD	0.23	AR	0.10	OK	0.04
36	CT	0.43	TN	0.25	IA	0.14	IA	0.07
37	GA	0.44	OK	0.25	LA	0.14	AR	0.09
38	ME	0.47	IN	0.26	VA	0.18	KY	0.14
39	KY	0.58	CO	0.37	HI	0.21	MO	0.15
40	VA	0.61	KY	0.42	KY	0.23	SD	0.17
41	AZ	0.61	VA	0.44	SD	0.28	ND	0.19
42	CO	0.64	AZ	0.56	MO	0.37	HI	0.23
43	MO	0.65	MO	0.59	VT	0.41	VT	0.28
44	NM	0.65	NM	0.59	AZ	0.44	AZ	0.31
45	ID	0.66	ID	0.60	ND	0.51	LA	0.36
46	VT	0.70	VT	0.62	ID	0.56	NM	0.52
47	ND	1.07	ND	0.78	NM	0.58	ID	0.61
48	WY	1.17	WY	1.18	WV	1.08	WV	0.87
49	WV	1.43	WV	1.33	WY	1.09	WY	0.90
50	MT	1.55	MT	1.56	MT	1.53	MT	1.25

Figure 11 is a graphical display of the results from 2001-2010, ranking states according to their own baseline (i.e., based upon reductions in their aECI). This approach gives every state the opportunity to rise in the rankings.

Figure 11. Ten-Year Slope of Adjusted ECI from 2001-2010 for U.S. States

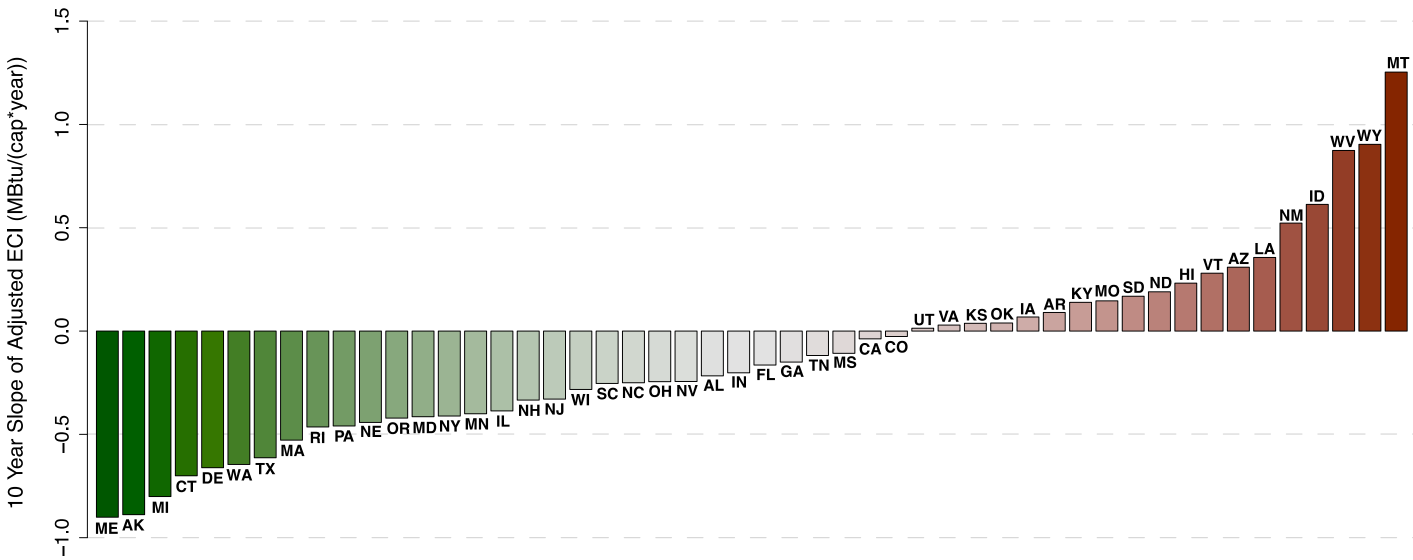
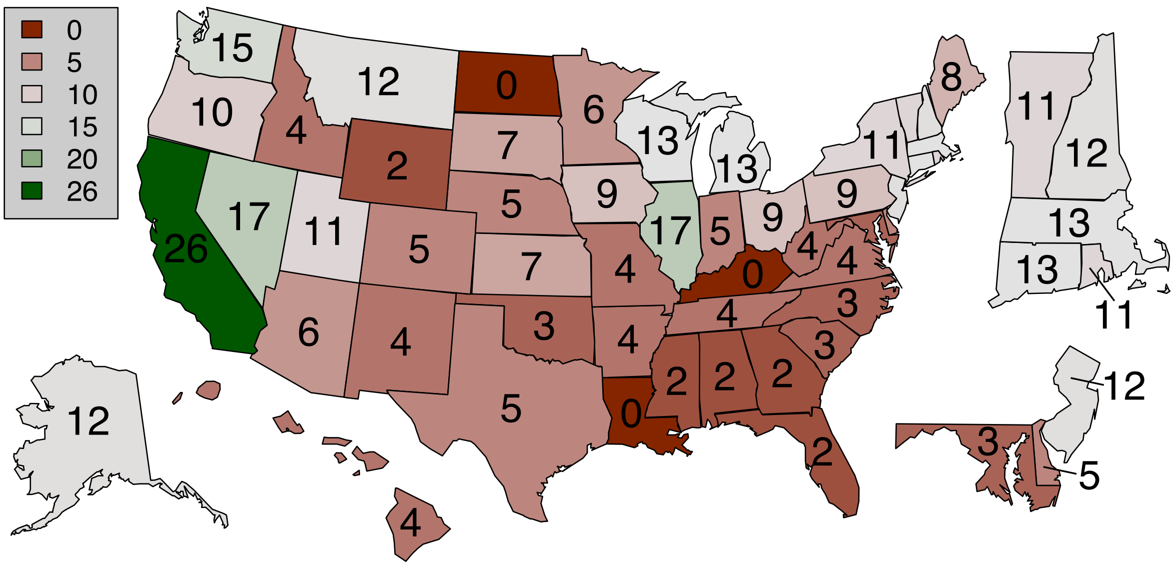


Figure 12 summarizes the historical performance of the states when this metric was applied to the 26 ten-year periods from 1976-1985 to 2001-2010; it presents the number of years in which the ten-year slope of aECI was negative for each state. The states with the largest number of negative slopes are the ones that have consistently decreased their adjusted energy consumption intensity over time.

Figure 12. Summary of the Number of 10-Year Periods from 1985-2010 in which the Slope of aECI Was Negative

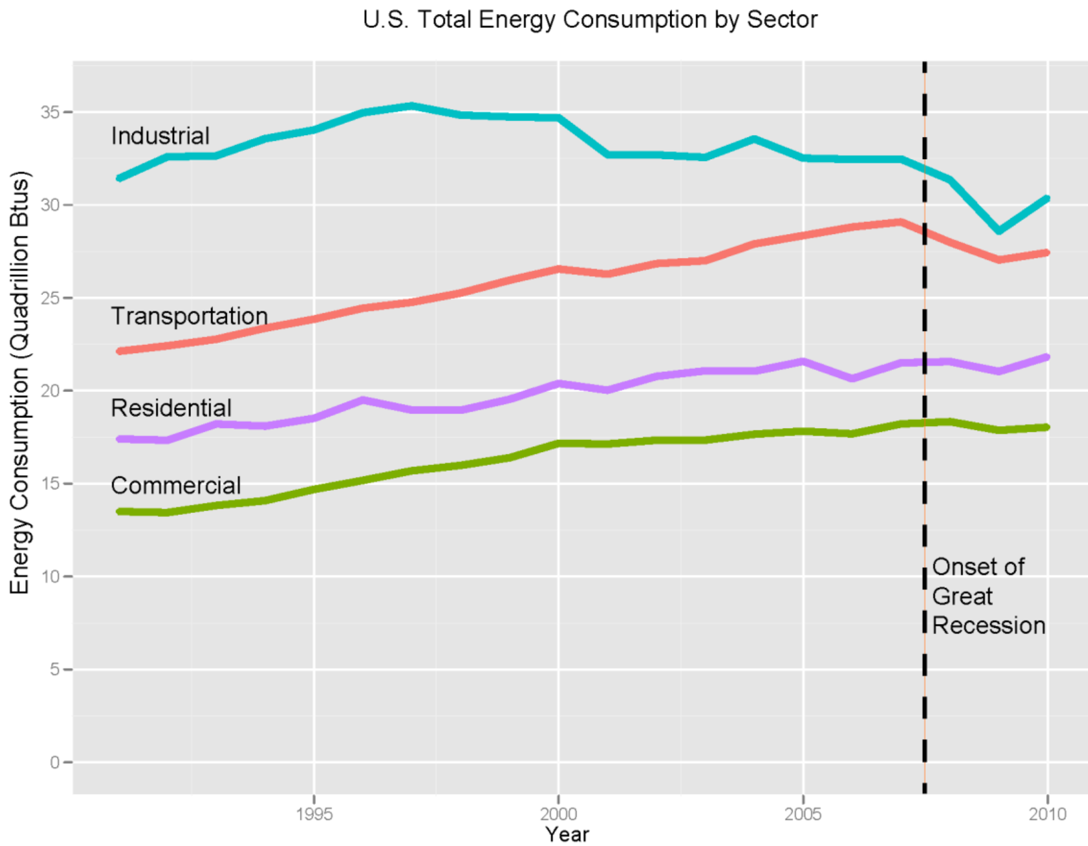


NOTABLE RESULTS

Some of the results presented above are especially notable, including the nationwide trend toward better (more negative) PSEP scores, as well as the particular performance of a few individual states.

From 2007 through 2010, the general trend in the PSEP metric has been toward lower scores, reflecting better overall performance and lower energy use per capita. As can be seen in Table 30, the number of states with negative PSEP scores increased between the ten-year period ending in 2007 and that ending in 2010 from six to 31. One might conclude that these reductions in consumption can be attributed to the nation's economic recession. Indeed, during 2008-2010, residential aECI generally decreased from its 2007 value for most states. However, this change was not precipitous or outside the bounds of normal variability. Although the total U.S. energy consumption did substantially decrease after the onset of the recession, the shifts were largely in the industrial and transportation sectors, whereas the residential sector only showed a very modest response to the economic slowdown (Figure 13). It is also important to note here that the aECI metric does not correct for economic activity, as discussed in the following section "PSEP vs. Other Econometric Approaches."

Figure 13. National Energy Consumption by Sector Before and After the Great Recession



Source: EIA State Energy Data System, www.eia.gov/state/seds/

Related to this, in 2011, we conducted an experiment to see whether including an economic indicator as a correction factor in the ECI adjustment would change the results. When we used real household disposable income in addition to heating and cooling degree days to adjust residential energy consumption intensity, we saw an almost identical overall downward trend across all states between 2006 and 2009. While the economy does play a role in energy consumption intensity, we do not believe it to be a primary driver of the trend. Other factors are likely of equal or greater importance, such as state and national efficiency policies, the price of energy, and demographic changes in the residential sector.

From 2007 to 2010, Connecticut, Maine, Delaware, Alaska, and Michigan stand out as demonstrating dramatic improvements in both their individual PSEP scores and their ranking among the 50 states. Similar to the trend toward better performance nationwide, these states' results are most likely attributable to, in addition to the more minor influence of the economic recession, state-level policies (e.g., Connecticut and Maine have ranked high in the State Scorecard in the past) as well as price spikes for major fuels. (A marked rise in petroleum prices has coincided with a steep reduction in the consumption of fuel oil for home heating in the New England states and Alaska, and high natural gas prices have coincided with decreases in natural gas consumption in Alaska and Michigan.)

Finally, it should be noted that some states have fallen in their PSEP rankings despite maintaining or even improving their PSEP score in recent years. Texas, for example, has had a decrease (improvement) in score over the last four years, but it has fallen in rank over that same period. Similarly, California has fallen in rank from second place in 2006 to thirtieth in 2010. The drop in California's rank is partially due to a leveling off of its improvement in adjusted energy consumption intensity, which may indicate that many of the low-cost efficiency opportunities have already been realized in California's residential sector.[61] However, most of the drop in rank for Texas and California can be explained by the substantial improvements in aECI exhibited by other states.

PSEP vs. Other Econometric Approaches

Other econometric approaches commonly cited in academic and policy literature (see Bernstein et al. 2003; Horowitz 2011; Loughran & Kulick 2004) focus on quantifying the impact of specific policies (or groups of policies) on energy consumption. They are usually based upon a regression analysis, which includes all relevant explanatory variables that are completely (or mostly) policy-independent (e.g., energy prices as well as economic and demographic indicators). The technical approach involves comparing the actual consumption trends to a *counterfactual*, or a prediction of what the trend would have been in the absence of policies or other factors not accounted for in the regression model. While this approach can be used successfully to discern the impact of specific policies, the general applicability of the scheme is somewhat limited.

The problem lies in the fact that a counterfactual model must be estimated from a time period before the introduction of the policy, while the evaluation of performance must occur in the time period after implementation. With careful application, this can be done for specific policy regimes within individual states or even across states with very similar policies and timelines, but it would be very difficult—if not impossible—to apply this methodology in a consistent manner to all 50 states *every* year due to the cacophony of policies that come and go over time, many of which have overlapping influence on energy consumption. So while the counterfactual approach has a greater potential of isolating the impact of specific policies than does the PSEP metric, that approach is a solution to a different set of objectives.

The PSEP metric was developed with the primary objective of initiating a national dialogue about tracking energy efficiency performance at the state level whereas the technical approach was designed to be all-inclusive. Changes in energy consumption occur for a multitude of reasons, but only those that are entirely beyond the influence of state policymakers (e.g., weather) are controlled for in the analysis. Other factors (in particular, energy prices as well as economic and demographic indicators) are not a part of the correction process. The following sections discuss the rationales for these choices in more detail.

Energy Prices

It is well known that consumers often respond to price signals by using less energy when prices are high and more when prices are low. It is unsurprising, therefore, that Bernstein et al. (2003) and others have

[61] The authors of this chapter conducted a detailed analysis of California's residential sector energy consumption and history of efficiency policies. See the California Ground Truth Analysis report at: http://www.schatzlab.org/projects/psep.

observed a significant correlation between residential energy consumption and the price of electricity and natural gas.

While this may suggest that the energy consumption intensity (ECI) values should be adjusted for year-to-year variations in electricity, natural gas, and other associated prices, PSEP does not make this adjustment. The reason is that the adjustment might negate states' efforts to reduce residential energy consumption through policies that influence prices, such as tiered billing (charging higher rates for higher levels of consumption). Although changes in prices due to other 'non-policy' related factors (e.g., speculation in the market, interruptions in supply, actual resource constraints) would also cause variation in energy consumption, it is difficult to separate these price effects from policy induced price changes. With all of this in mind, the question of whether adjustments should be made for variations due either to regulatory-induced or market-induced changes in prices is an important one. We decided against making such adjustments, since policy driven price variation provides a natural and powerful tool to produce reductions in residential energy consumption intensity.

Economic Factors

Bernstein et al. (2003) observed strong sensitivity in residential energy consumption intensity to various demographic and economic factors such as average household size, real disposable income per capita, and employment per capita.

State employment and disposable income are not factors that states can easily manipulate to reduce energy consumption. As such, they are reasonable candidates for factors with which to adjust year-to-year energy consumption. However, we question whether increases in consumption that are due to increases in disposable income should be excluded from a state's performance indicator. Why reward some states for a temporary economic boom if they are simultaneously increasing their per-capita energy consumption? Moreover, a decrease in energy consumption that accompanies an economic downturn may be unintentional, but it still represents a decrease, however temporary. States that do not have an effective set of energy efficiency programs or policies in place would not be well positioned to sustain reductions, so any "unearned" recognition would be short lived. Further, adding adjustments for disposable income provided only modest improvements in explaining the year-to-year variation in states' energy consumption intensity. For these reasons, we ultimately chose not to adjust for disposable income or any other economic factor.

KEY CONSIDERATIONS AND CONCLUSIONS

Our analyses indicate that it is possible to track trends in residential energy consumption intensity by state. However, the method, by design, does not isolate changes in ECI that are solely due to policy choices from changes due to other factors. But while we were not able to explain all of the year-to-year variability in the ECI with this approach, including additional policy independent variables (e.g., disposable income, percent employment, and gross domestic product by state) did not dramatically improve the results. Therefore, although no metric can isolate policy-driven changes in consumption with 100% reliability, this methodology is a reasonable approach to gauge policy impacts over the long term. Notably, a preliminary analysis of commercial sector data indicates that it may be possible to extend the use of the performance-based ECI metric to that sector as well, although access to improved data would be required to achieve this.

Almost all of the data used in the analyses in this report are from the EIA State Energy Data System (SEDS). These data are self-reported by utilities and electric power generating plants, and the sectoral classifications (residential, commercial, etc.) are based on the supplier classification of accounts and may vary by supplier, by state, and by year. In order to more accurately track state-level trends in energy efficiency, we recommend the following improvements in data collection and reporting:

1. Standardize the SEDS classification system: The sectoral classification system for the SEDS varies from state to state and even supplier to supplier. The resulting inconsistencies are most problematic for the commercial sector data, but may also affect the residential sector. Standardization of the classification system would enable more reliable tracking of energy consumption intensity in the commercial sector.

2. Collect quarterly data on energy consumption and heating and cooling degree days (HDD/CDD): If quarterly, not just annual, energy consumption data were available, the statistical power of the proposed analysis would be increased substantially. Data reporting by utilities could still happen annually, but they would report quarterly figures.

3. Weight heating and cooling degree days current year populations: Currently, HDD and CDD values are weighted by the decennial census population data. This weighting should be changed to population estimates made annually.

4. Publish data on population-weighted heating and cooling degree days for the states of Alaska and Hawaii: Currently, the National Climatic Data Center does not make estimates of annual HDD and CDD available for these states. While stand-in estimates can be made based on available data, the NCDC should include these states in their product to ensure that a consistent methodology is used.

5. Publish consumption-based grid mix data: Estimating the mix of generation types on the electricity grid would ideally be based on electricity consumption in each state rather than on energy production. Recent updates to the SEDS data have made this estimation possible.

6. Improve timeliness of data reporting: For the state energy consumption tracking system to be effective and have its desired influence, the interval between the end of the reporting period and the release of the tracking results should be as brief as is practical (6-12 months).

To successfully implement these changes, the EIA and other agencies will require modest funding increases in order to cover costs associated with additional data collection and processing.

Conclusions

Energy efficiency policies and programs have continued to advance at the state level over the past year. A group of leading states remains committed to pursuing more efficient use of energy in transportation, buildings, and industry, fostering economic development in the energy efficiency services and technology industries and saving money for consumers to spur growth in all sectors of the economy.

A growing number of states have progressed—some rapidly—over the past few years in the pursuit of their energy efficiency goals. There has been a lot of movement within and outside of the top tier of states, with Connecticut poised to break into the top five again and several states potentially able to move into the top tier as well. This dynamism at the policy and program levels is reflected in growing utility program budgets and savings, as well as in the range of other actions states are taking to improve their energy efficiency.

A wide gap remains, however, between states near the top and those at the bottom of the State Scorecard rankings. Because of market barriers and the regulated nature of the energy sector, a regulatory environment that levels the playing field for energy efficiency—the fastest, cheapest, cleanest energy resource—is critical to capturing its full range of benefits for states and for consumers.

LOOKING AHEAD

We see signs that many states will continue to raise the bar on their energy efficiency program and policy commitments in 2013 and beyond. For example:

- A July 2012 draft of Massachusetts' second Three-Year Energy Efficiency Plan (State of Massachusetts 2012), required by the Green Communities Act, proposes annual savings goals of 2.5% of electricity retail sales from 2013-2015, and 1.1% of natural gas retail sales starting in 2013 (and increasing in subsequent years), supported by funding for energy efficiency programs of $2 billion over the three years.

- Oregon's Governor Kitzhaber recently released a draft of his *10-Year Energy Action Plan* (State of Oregon 2012), which calls for energy efficiency and conservation to meet 100% of future growth in the electricity load. He called for improving the energy performance of every occupied state-owned building over the next ten years as a first step towards meeting this goal.

- Connecticut's Governor Malloy has made a commitment to pursue the top spot in the State Scorecard in future years, calling for an increase in spending for utility energy efficiency programs, a strengthening of the bonding authority of the state's clean energy investment authority, and reductions in state building energy use starting in 2013 (State of Connecticut 2012).

- In October 2011, the New York Public Service Commission extended the state's Energy Efficiency Portfolio Standard for an additional 4 years, through 2015, and increased funding for energy efficiency programs operated by NYSERDA and the state's investor-owned utilities by more than $2 billion. The Commission also approved a new Technology & Market Development program providing an additional $410 million in public benefit funding over the next 5 years.

- The State of Vermont released its Final Comprehensive Energy Plan 2011, its first since the late 1990s, which promotes increased use of efficiency as one of its first priorities. The plan recommends: the use of innovative energy efficiency program designs to capture all cost-effective efficiency; changes to building efficiency program design; goals for increasing the stringency of and compliance with building energy codes in new construction (including public buildings); and a review of state land use provisions and infrastructure needs for electric vehicles. The Climate Cabinet, established through Executive Order No. 05-11, is responsible for implementation of the plan (State of Vermont 2011).

- Oklahoma, one of the most improved states this year, is poised to make further improvements in energy efficiency with the recent enactment of Bill 1096, which calls for a 20% reduction in the energy use of state buildings and educational institutions. Governor Fallin, in her 2012 State of the State address, specifically called for Oklahoma to pursue further strategies for improving the state's energy efficiency (State of Oklahoma 2012).

In addition, numerous states that only recently began implementing utility-sector energy efficiency programs such as Michigan, Ohio, Indiana, Arkansas, and Arizona will likely continue to ramp up efficiency program activity over the next few years to meet those rising goals.[62] As noted in Chapter 2 on utility programs, combined utility spending on electric and natural gas efficiency programs is estimated to more than double from 2010 levels to $10.8 billion by 2025, if current savings targets are met, and to more than triple to $16.8 billion if many states give energy efficiency a prominent role as a resource (Goldman et al. 2012).

These projections of an increasing role for energy efficiency will not, however, occur in a vacuum. The impact and expansion of energy efficiency programs and policies in 2013 and beyond will be influenced by both state support for energy efficiency and external factors beyond states' control. Continued uncertainty around the economic recovery could dampen consumer demand for energy efficiency upgrades in the residential and commercial sectors, which would impact savings from efficiency programs. More concerning is the impact on budgets for efficiency. Some policymakers have responded to continued strain on state budgets by redirecting funds from utility customers or other sources originally meant for efficiency programs to shore up state finances in other areas,[63] or have not allocated energy efficiency budgets at a level high enough to meet mandated savings goals.[64]

Energy efficiency can save consumers money, drive investment across many sectors of the economy, and create jobs. While several states are consistently leading the way on energy efficiency and many more are dramatically increasing their efforts, significant opportunities remain to both sustain current efforts and

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[62] See (Nowak et al. 2011) for a full discussion of how states are preparing to meet higher energy savings targets.

[63] New Jersey Governor Christie redirected $42.5 million from the state's Clean Energy Fund in fiscal year 2011 to cover state energy bills and will do the same in FY 2013 (which started July 1, 2012), with a reallocation of $210 million (NJ Spotlight 2012; State of New Jersey 2012). At the beginning of this year, New Jersey also withdrew from the Regional Greenhouse Gas Initiative, which had been providing the state with substantial funding for energy efficiency projects (State of New Jersey 2011).

[64] Maine legislators have not sufficiently allocated FY 2013 funds to efficiency programs in the state. This point is discussed more fully in Chapter 2.

continue to scale up. Energy efficiency is a resource abundant in every state, and reaping its full economic, energy security, and environmental benefits will require continued leadership from a wide range of stakeholders, including legislators, regulators, and the utility industry.

FURTHER RESEARCH

Addressing Data Needs

The scoring framework described at the beginning of this report is currently our best attempt to represent the myriad efficiency metrics as a quantitative "score." Any effort to convert state spending data, energy savings data, and adoption of best practice policies across six policy areas into one state energy efficiency "score" has obvious limitations. We suggest here a few areas of future research that will assist our continuing refinement of our scoring methodology and more accurately represent the changing landscape of energy efficiency in the states.

One of the most prominent limitations is access to recent, reliable data on the results of energy efficiency efforts. Many states do not gather data on the performance of energy efficiency policy efforts, obligating us to score them using a "best practices" approach for some policy areas. To give just one example, to score states on building energy code compliance is difficult because the majority of states do not collect the required data to estimate their level of compliance. While states should be applauded for adopting stringent building energy codes, the success of these codes at reducing energy consumption is unclear without a means to verify actual implementation.

In the utility sector, we urge states to systematically track statewide savings and spending levels for energy efficiency programs. The current resources available for state-by-state comparisons of energy efficiency program spending and savings in the utility sector do not capture the full set of programs available to customers. In particular, programs administered by third parties, public power generators, and cooperative and municipal utilities appear to be under-represented in the major datasets used in this report. We have made some efforts to remedy this in the *2012 State Energy Efficiency Scorecard*, with some success, but future iterations of the report would benefit greatly from higher levels of reporting from utilities and administrators to the U.S. Energy Information Administration (EIA), the Consortium for Energy Efficiency (CEE), state utility commissions, and national groups such as the National Rural Electric Cooperative Association and the American Public Power Association.[65]

Furthermore, we would also like to capture spending and savings data for energy efficiency programs targeting home heating fuel and propane. Depending in the availability of data sources, we may examine metrics for fuel oil and propane efficiency, as well as incremental energy savings from natural gas efficiency programs.

Additional or Revised Metrics for Potential Inclusion

In future versions of the *State Energy Efficiency Scorecard*, we hope to develop a more comprehensive and quantitative assessment of state efficiency programs that fall outside the realm of utility-sector and public benefits programs. Since the passage of the American Recovery and Reinvestment Act of 2009, scoring

[65] See MJB&A (2011) for an assessment of the data gaps that inhibit the comprehensive benchmarking of utility energy efficiency spending and savings.

states on energy efficiency programs run by state governments has become a complex task. Our hope is that as ARRA funds run their course, states will be more adept at tracking and presenting program spending and savings data. We also hope to recognize state government and regulatory efforts to enable home- and business-owners to finance energy efficiency improvements through on-bill financing and other innovative incentive programs. One possible metric to aid in comparison between state financial incentives is the level and sustainability of budgets for these programs. In some cases, this information is available, but gathering it for all programs will continue to present challenges. State efforts related to research, development, and demonstration may also be amenable to comparison on the basis of budgets and staffing levels, although data availability is again an issue.

The deployment of smart meters in states across the United States has opened the way for overcoming some of the informational and motivational barriers that can lead to underinvestment in energy efficiency by consumers, especially in the residential sector. A new industry is emerging that aims to encourage energy savings among consumers by providing more frequent feedback on energy use, more tailored energy savings tips, and a better customer engagement through social marketing and social media. Several non-energy policies can enable the growth of this area of energy efficiency, including data access policies such as the industry-led Green Button standard, state data privacy policies, and disclosure policies for building energy use. We will consider including an analysis of some of these enabling policies—including strengthening discussion of energy use disclosure policies already covered in Chapter 6—in future versions of the *State Energy Efficiency Scorecard*.

New and forthcoming rules from the EPA to regulate emissions from multiple sources will alter the way emissions from some combined heat and power systems are calculated and regulated. State regulatory approaches and programs currently in place that affect the way CHP system emissions are regulated may be altered significantly by future EPA activity and the judicial decisions made about EPA regulations. Such changes will be reflected in the 2013 *State Energy Efficiency Scorecard* if applicable. More states and utilities also appear to be considering offering financial incentives and technical assistance dedicated to CHP, which are currently only available in a handful of states. Next year's report may reflect an uptick in these types of assistance for combined heat and power projects.

Another major area not currently addressed in the *State Energy Efficiency Scorecard* is energy efficiency efforts in rural areas, particularly in the agricultural sector. While we already capture some of these efforts in programs run by state energy offices and rural electric cooperatives, there are likely other state and extension programs that are being missed. Informed by current research into that sector by ACEEE, it may be feasible to include a new metric or even a new chapter on rural energy efficiency efforts in future editions of the report.

Finally, as U.S. territories have ramped up energy efficiency efforts over the last several years with the receipt of ARRA funds, we hope that the data become robust enough for reporting on select territory efforts in future editions of the *State Energy Efficiency Scorecard*.

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Appendix A: Electric Efficiency Program Budgets per Capita

State	2011 Budgets ($million)	$ Per Capita
Massachusetts	453.0	68.77
Vermont	40.7	64.97
New York	1,073.2	55.13
Rhode Island	54.2	51.53
Oregon	171.8	44.37
Washington	274.9	40.24
Connecticut	138.3	38.61
Minnesota	191.2	35.77
California	1,162.5	30.84
Iowa	88.8	28.99
Maryland	156.4	26.83
Hawaii	35.6	25.86
New Jersey	225.0	25.51
Idaho	39.9	25.15
Montana	21.1	21.14
Arizona	126.1	19.45
New Hampshire	25.6	19.45
Pennsylvania	225.0	17.65
Utah	49.2	17.46
Nevada	47.2	17.33
Maine	22.8	17.18
Wisconsin	92.3	16.16
Michigan	127.6	12.92
New Mexico	26.2	12.60
Colorado	64.1	12.53
District of Columbia	7.7	12.40

State	2011 Budgets ($million)	$ Per Capita
Ohio	134.4	11.64
Oklahoma	39.6	10.44
Florida	188.5	9.89
Wyoming	5.4	9.50
Illinois	115.7	8.99
Nebraska	16.5	8.95
Indiana	58.2	8.93
Arkansas	25.2	8.58
Missouri	47.2	7.86
Kentucky	28.2	6.46
North Carolina	57.4	5.94
Tennessee	36.7	5.74
Texas	144.1	5.61
South Dakota	4.3	5.23
Delaware	3.3	3.64
South Carolina	16.3	3.48
Kansas	9.1	3.15
Alabama	10.7	2.23
Georgia	21.7	2.21
Louisiana	9.0	1.96
Mississippi	4.9	1.63
Virginia	0.1	0.02
Alaska	0.0	0.00
North Dakota	0.0	0.00
West Virginia	0.0	0.00
U.S. Total	**5,916.8**	**18.99**
Median	**40.7**	**12.40**

Sources: See Table 8 in main body of text. Calculation of per capita spending is based on population data from Census (2011).

Appendix B: Details of States' Energy Efficiency Resource Standards

State (Year Enacted) Policy Type Sector(s) covered Applicability (% of statewide sales)	Description	Approx. Annual Electric Savings Target (2012+)[66]	Stringency	Reference	Score
Arizona (2009) EERS Electric IOUs, Co-ops (~59%)	2% annual savings beginning in 2013, 22% cumulative savings by 2020, of which 2% may come from peak demand reductions.	2.3%	Binding	Docket Nos. RE-00000C-09-0427, Decision No. 71436	4
Hawaii (2004 & 2009) RPS-EERS Electric Statewide Goal (100%)	Electric: 40% reduction from 2007 baseline by 2030.	2%	Binding	HRS §269-91, 92, 96; HI PUC Order, Docket 2010-0037	4
Maryland[67] (2008) EERS Electric Statewide Goal (100%)	Goal of 15% reduction in electricity use per capita by 2015 with targeted reductions of 5% by 2011 calculated against a 2007 baseline (10% by utilities, 5% achieved independently). 15% reduction in per capita peak demand by 2015, compared to 2007.	2.4%	Binding	Md. Public Utility Companies Code § 7-211	4
Massachusetts (2009) EERS Electric and Natural Gas IOUs, Coops, Munis, CLC (~80%)	Electric: 1.4% in 2010, 2.0% in 2011; 2.4% in 2012; 2.5% annually from 2013-2015 (proposed). Natural Gas: 0.63% in 2010, 0.83% in 2011; 1.15% in 2012; 1.1% in 2013 and increasing in subsequent years (proposed).	1.9%	Binding	Massachusetts Joint Statewide Three-Year Electric and Gas Energy Efficiency Plan, July 2, 2012	4
Minnesota (2007) EERS Electric and Natural Gas Statewide Goal (100%)	Electric: 1.5% annual savings in 2010 and thereafter. Natural Gas: 0.75% annual savings from 2010-2012; 1.5% annual savings in 2013 and thereafter.	1.5%	Binding	Minn. Stat. § 216B.241	4

[66] For utilities covered under the EERS policy. For some states, this would be significantly reduced if reported based on state-wide sales.
[67] The 15% per-capita electricity use reduction goal translates to around 17% cumulative savings over 2007 retail sales.

State (Year Enacted) Policy Type Sector(s) covered Applicability (% of statewide sales)	Description	Approx. Annual Electric Savings Target (2012+)[66]	Stringency	Reference	Score
New York (2008) EERS Electric and Natural Gas Statewide Goal (100%)	Electric: 15% cumulative savings by 2015. Natural Gas: ~14.7% cumulative savings by 2020.	2.1%	Binding	Electric: NY PSC Order, Case 07-M-0548 Natural Gas: NY PSC Order, Case 07-M-0748	4
Rhode Island (2006) EERS Electric and Natural Gas IOUs, Munis (~95%)	Electric: ~1.3% in 2010; 1.5% in 2011; Council proposed 1.7% in 2012, 2.1% in 2013, and 2.5% in 2014. EERS includes demand response targets. Natural Gas: ~0.4% of sales in 2011; Council proposed 0.75% in 2012, 1.0% in 2013, and 1.2% in 2014.	2.1%	Binding	R.I.G.L § 39-1-27.7	4
Vermont (2000) Tailored target Electric Efficiency Vermont (100%)	~6.6% cumulative savings from 2012 to 2014. EERS includes demand response targets.	2.2%	Binding	30 V.S.A. § 209; VT PSB Docket EEU-2010-06	4
Illinois (2007) EERS Electric and Natural Gas Utilities with over 100,000 customers, Illinois Department of Commercial and Economic Opportunity (~90%)	Electric: 0.2% annual savings in 2008, ramping up to 1% in 2012, 2% in 2015 and thereafter. Reduction of annual peak demand of 0.1% through 2018. Natural Gas: 8.5% cumulative savings by 2020 (0.2% annual savings in 2011, ramping up to 1.5% in 2019).	1.7%	Cost Cap	S.B. 1918; Public Act 96-0033; § 220 ILCS 5/8-103	3.5
Iowa (2009) Tailored targets Electric and Natural Gas Statewide Goal (100%)	Electric: Varies by utility from 1-1.5% annually by 2013. Natural Gas: Varies by utility from 0.74-1.2% annually by 2013.	1.2%	Binding	Senate Bill 2386; Iowa Code § 476	3.5

State (Year Enacted) Policy Type Sector(s) covered Applicability (% of statewide sales)	Description	Approx. Annual Electric Savings Target (2012+)[66]	Stringency	Reference	Score
Colorado (2007) Tailored targets Electric and Natural Gas IOUs (~57%)	Electric: PSCo and Black Hills Energy (BHE) both aim for 0.9% of sales in 2011, which increase to 1.35% (1.0% for BHE) of sales in 2015 and then 1.66% (1.2%) of sales in 2019. Natural Gas: Savings targets commensurate with spending targets (at least 0.5% of prior year's revenue).	1.4%	Binding	Colorado Revised Statutes 40-3.2-101, et seq. ; COPUC Docket No. 08A-518E; Docket 10A-554EG	3
Indiana (2009) EERS Electric Jurisdictional utilities (includes IOUs, Co-ops and Munis) (85%)	0.3% annual savings in 2010, increasing to 1.1% in 2014, and leveling at 2% in 2019.	1.46%	Binding	Cause No. 42693, Phase II Order	3
Washington (2006) Electric IOUs, Co-ops, Munis (~84%)	Biennial and Ten-Year Goals vary by utility. Law requires savings targets to be based on the Northwest Power Plan, which estimates potential savings of about 1.5% savings annually through 2030 for Washington utilities.	1.3%	Binding	Ballot Initiative I-937 WAC 480-109 WAC 194-37	3
Arkansas (2010) EERS Electric and Natural Gas IOUs (~61%)	Electric: Annual reduction of 0.25% of total kilowatt hour (kWh) sales in 2011, ramping up to 0.75% in 2013. Natural gas: A slightly lower percentage than for electric.	0.6%	Binding	Order No. 17, Docket No. 08-144-U; Order No. 15, Docket No. 08-137-U	2.5
California (2004 & 2009) EERS Electric and Natural Gas IOUs (~75%)	Electric: 0.86% average annual savings through 2020. Demand reduction of 4,541 MW through 2020. Natural Gas: 619 gross MMTh between 2012 and 2020.	0.9%	Binding	CPUC Decision 04-09-060; CPUC Decision 08-07-047; CPUC Decision 09-09-047	2.5
Michigan (2008) EERS Electric and Natural Gas Statewide Goal (100%)	Electric: 0.3% annual savings in 2009, ramping up to 1% in 2012 and thereafter. Natural Gas: 0.10% annual savings in 2009, ramping up to 0.75% in 2012 and thereafter.	1%	Cost Cap	M.G.L. ch. 25, § 21; Act 295 of 2008	2.5

State (Year Enacted) Policy Type Sector(s) covered Applicability (% of statewide sales)	Description	Approx. Annual Electric Savings Target (2012+)[66]	Stringency	Reference	Score
Ohio (2008) EERS Electric IOUs (~88%)	22% by 2025 (0.3% annual savings in 2009, ramping up to 1% in 2014 and 2% in 2019). EERS includes targets for reduction of peak demand. Exit ramp for utilities unable to meet targets.	1.2%	Exit ramp	ORC 4928.66 et seq. S.B. 221	2.5
Oregon (2010) Tailored targets Electric and Natural Gas Energy Trust of Oregon (100%)	Electric: Targets are equivalent to 0.8% of 2009 electric sales in 2010, ramping up to 1% in 2013 and 2014. Natural Gas: 0.2% of sales in 2010, ramping up to 0.4% in 2014.	0.98%	Exit ramp	Energy Trust of Oregon 2009 Strategic Plan	2
New Mexico (2008) EERS Electric IOUs (67%)	5% reduction from 2005 total retail electricity sales by 2014 and a 10% reduction by 2020. Exit ramp for utilities unable to meet targets.	0.9%	Exit ramp	N.M. Stat. § 62-17-1 et seq.	1.5
Wisconsin (2011) Tailored targets Electric and Natural Gas Focus on Energy (100%)	~0.65% annual savings from 2011-2014.	0.7%	Cost cap	Order, Docket 5-GF-191	1.5
Nevada (2005 & 2009) RPS-EERS Electric IOUs (~88%)	20% of retail electricity sales to be met by renewables and energy efficiency by 2015, and 25% by 2025. Energy efficiency may meet a quarter of the standard in any given year, or 5% cumulative savings by 2015 and 6.25% by 2025.	0.3%	Binding	NRS 704.7801 et seq.	1
North Carolina (2007) RPS-EERS Electric Statewide Goal (100%)	Renewable Energy and Energy Efficiency Portfolio Standard (REPS). Investor-owned: 12.5% by 2021 and thereafter. Energy efficiency is capped at 25% of the 2012-2018 targets and at 40% of the 2021 target.	0.5%	Binding	N.C. Gen. Stat. § 62-133.8; 04 NCAC 11 R08-64, et seq.	1

State (Year Enacted) Policy Type Sector(s) covered Applicability (% of statewide sales)	Description	Approx. Annual Electric Savings Target (2012+)[66]	Stringency	Reference	Score
Pennsylvania (2008) EERS Electric Utilities with 100k+ customers (~93%)	3% cumulative savings from 2009 to 2013; ~2.3% cumulative savings from 2014-2016.	0.9%	Cost cap	66 Pa C.S. § 2806.1; PUC Order Docket No. M-2008-2069887; PUC Implementation Order Docket M-2012-2289411	1
Texas (1999 & 2007) EERS Electric IOUs (~73%)	20% Incremental Load Growth in 2011 (equivalent to ~0.10% annual savings); 25% in 2012, 30% in 2013 onward.	0.1%	Binding	Senate Bill 7; House Bill 3693; Substantive Rule § 25.181	1

Appendix C: Status of State Efforts to Address Utility Lost Revenues and Incentives for Energy Efficiency[68]

State	Decoupling or Related Mechanism	Performance Incentive
Alabama	Lost revenue recovery is in place for electric and natural gas. Alabama Power and Alabama Gas Company can recover lost revenues by projecting losses and adjusting rates annually through Rate RSE which includes caps and automatic rate reductions when profits or expenses exceed authorized ranges.	In place for natural gas and electric. Alabama Power and Alabama Gas Company may recover a reasonable rate of return on efficiency spending via a rate rider.
Alaska	None	None
Arizona	Decoupling is in place for natural gas, lost revenue recovery in place for electric and natural gas. Southwest Gas was approved for decoupling in late 2011. Arizona Public Service and UNS Gas have lost revenue recovery mechanisms.	In place for electric. Arizona Public Service has a tiered shareholder performance incentive. Tucson Electric Power and UNS Electric also have incentives.
Arkansas	Lost revenue recovery is in place for electric and natural gas. All major, investor-owned utilities.	In place for electric and natural gas. In December 2010 the PSC approved incentives as a means to reward energy efficiency by investor owned utilities.
California	Decoupling is in place for electric and natural gas. All investor-owned utilities.	In place for electric and natural gas. Investor-owned utilities participate in a risk/reward incentive mechanism.
Colorado	Partial decoupling is in place for natural gas and a disincentive offset is in place for electric. In 2007 a partial decoupling three-year pilot mechanism was approved. The Public Service Company of Colorado has a disincentive offset.	In place for electric and natural gas – Incentive approved in 2008 for Public Service Company of Colorado and Black Hills.
Connecticut	Decoupling is in place for electric and lost revenue recovery for natural gas. United Illuminating was approved for decoupling in 2009	In place for electric only.
Delaware	Decoupling is in place for electric and natural gas. Delmarva Power & Light has applied for a form of decoupling for natural gas and electric, the Public Service Commission approved the mechanism in 2011.	None
District of Columbia	Decoupling is in place for electric. Potomac Electric Power Company collects a Stabilization Adjustment. Washington Gas Light has requested decoupling, but was denied.	In place for electric and natural gas – A third party administrator can earn a performance-based incentive.
Florida	None. Decoupling is authorized for natural gas and lost revenue recovery is authorized for electric, but no mechanisms have been approved.	None. Legislation has authorized an additional return on equity for energy savings in excess of goal in 2008, but no utilities have requested it.

[68] More detailed information is available on ACEEE's State Policy Database, www.aceee.org/sector/state-policy

State	Decoupling or Related Mechanism	Performance Incentive
Georgia	Lost revenue recovery for electric – Georgia Power may recover lost revenues from implementing efficiency programs via an "additional sum".	In place for electric. Georgia Power may use a percentage of net benefits from electricity savings from the implementation of efficiency programs via an "additional sum".
Hawaii	Decoupling is in place for electric. Decoupling was approved in 2010 for Hawaiian Electric Company.	Performance incentive for third party administrator – Hawaii transferred administration of efficiency programs to a third-party administrator in 2009.
Idaho	Decoupling is in place for electric. A fixed-cost adjustment was approved for Idaho Power Company in 2007 and was made permanent in March 2012.	None. A pilot program for Idaho Power Company was cancelled in 2009.
Illinois	Decoupling for natural gas is pending. North Shore Gas and Peoples Gas and Coke were approved for revenue-per-customer decoupling pilots through 2011.	None
Indiana	Decoupling is in place for natural gas and electric, and there is lost revenue recovery for electric. Indiana Gas Company, Inc. (Vectren North) and Southern Indiana Gas & Electric Company have decoupling. Vectren has a reliability cost mechanism and revenue adjustment mechanisms. Duke Energy Indiana has lost revenue recovery.	In place for electric and natural gas. Indianapolis Power & Light and Southern Indiana Gas & Electric Company have a tiered shareholder performance incentive and Indiana Michigan Power Company has a shared benefits approach.
Iowa	None. Utilities may request recovery of lost revenues on a case by case basis, though none currently have a mechanism in place.	None
Kansas	Lost revenue recovery in place for electric. Utilities may request decoupling on a case by case basis. Westar Energy collects lost revenues through a tariff.	None. Utilities can request shared savings performance incentives on a case by case basis, however no plans have been approved for any utilities.
Kentucky	Lost revenue recovery is in place for electric and natural gas.	In place for electric and natural gas. Duke Energy, Louisville Gas & Electric and Kentucky Power (AEP) have shared savings mechanisms in place.
Louisiana	In place for electric and natural gas utility. In New Orleans there is a rate rider that provides for recovery of lost contribution to fixed costs for the electric and natural gas utility Entergy.	In place for electric and natural gas. In New Orleans there is a rate rider that provides an incentive to the electric and natural gas utility Entergy.
Maine	None. Decoupling is authorized under statute, but efficiency programs are implemented by a government agency.	None. Incentives are authorized under statute, but efficiency programs are implemented by a government agency.
Maryland	Decoupling is in place for electric and natural gas. The three investor-owned utilities in Maryland have decoupling in place.	None. Legislation authorizes incentives, but none have been approved.
Massachusetts	Decoupling has been implemented for all major natural gas and electric utilities.	Incentives are in place for electric and natural gas. Performance incentives can be earned based on achievement of performance targets.

State	Decoupling or Related Mechanism	Performance Incentive
Michigan	Decoupling is in place for electric and natural gas. Decoupling has been implemented for Consumers Energy, Detroit Edison, Michigan Gas Utilities and Michigan Consolidated Gas Company.	Incentives are in place for electric and natural gas – Detroit Edison Company has an incentive in place.
Minnesota	Decoupling is in place for natural gas and electric – CenterPoint Energy has decoupling. Electric utilities were to submit proposals by the end of 2011.	Incentives are in place for electric and natural gas – Incentives have been in place since 1999.
Mississippi	None	None
Missouri	Straight-fixed variable pricing is in place for natural gas, and is authorized for electric, but is not in place. Missouri Gas Energy has a straight-fixed variable pricing structure. Laclede and Ameren Missouri have similar rate designs.	None. Commission rules permits incentives, but none have been authorized.
Montana	Lost revenue recovery is in place for electric and natural gas. NorthWestern Energy has a lost revenue recovery mechanism in place.	None. Statue allows an authorized rate of return, but none has been approved.
Nebraska	None. Decoupling mechanisms requested by SourceGas were denied by the Public Service Commission.	None
Nevada	Lost revenue recovery is in place for electric; decoupling is in place for natural gas – A lost revenue recovery mechanism was approved for NV Energy in 2010.	None. Eliminated in 2010. Utilities may request an incentive on a program-by-program basis.
New Hampshire	None. The Public Utility Commission has authorized utilities to apply for decoupling or lost revenue recovery on a case by case basis.	In place for electric and natural gas. All utilities participate in the state incentive program.
New Jersey	Lost revenue recovery is in place for natural gas, pending for electric. New Jersey Natural Gas Co. and South Jersey Gas Co. have revenue adjustment mechanisms. Atlantic City Electric and Rockland Electric Company have proposed a bill stabilization agreement that calls for monthly true-ups though a decision on the issue of lost revenues has been deferred.	None
New Mexico	Lost revenue is in place for electric and natural gas. A rate rider had been approved to remove regulatory disincentives. A recent Order by the Public Regulation Commission affirmed the mechanism. Legislation requires that regulatory disincentives to cost-effective efficiency be removed.	In place for electric and natural gas. A rate rider provides an incentive for efficiency.
New York	Decoupling is in place for electric and natural gas. Utilities are ordered to file proposals for true-up-based decoupling mechanisms in ongoing and new rate cases.	In place for electric and natural gas. An incentive program is mandatory for electric utilities. A similar program exists for natural gas utilities, but they may opt out.

State	Decoupling or Related Mechanism	Performance Incentive
North Carolina	Decoupling is in place for natural gas, lost revenue recovery is in place for electric – Duke Energy Carolinas has mechanisms in place that permit recovery of lost revenues. Piedmont Natural Gas and Public Service Company of North Carolina have decoupling.	In place for electric, but not natural gas. Progress Energy Carolinas and Duke Energy Carolinas have incentives in place.
North Dakota	Lost revenue recovery in place for natural gas, but not for electric. Xcel Energy has a straight fixed variable approach in place.	None
Ohio	Lost revenue recovery is in place for electric and natural gas, decoupling pilot is in place for electric. A decoupling pilot program was approved for AEP for 2012-2014. Utilities are permitted to request decoupling, but thus far all have requested straight fixed variable pricing.	In place for electric. Several electric utilities have incentives in place, including the Duke Save-A-Watt program.
Oklahoma	Lost revenue recovery in place for electric, but not natural gas. Both Public Service Oklahoma and Oklahoma Gas and Electric Company recover lost revenues.	In place for electric and natural gas. Public Service Oklahoma, Oklahoma Natural Gas and Oklahoma Gas and Electric Company have shared benefit incentive plans.
Oregon	Decoupling is in place for electric and natural gas. Portland General Electric has a "Sales Normalization Adjustment". Cascade Natural Gas and Northwest Natural Gas have had mechanisms in place since 2006 and 2003, respectively.	None
Pennsylvania	None	None. Electric utilities may be fined if they fail to meet their efficiency targets.
Rhode Island	Decoupling has been approved for electric and natural gas. A decoupling proposal from National Grid has been approved.	In place for electric and natural gas. Shareholder incentive for electric and natural gas since 2005 and 2007, respectively.
South Carolina	Lost revenue recovery is in place for electric, but not natural gas – Duke, Progress and South Carolina Electric & Gas all have lost revenue recovery mechanisms in place.	In place for electric, but not natural gas. Progress and South Carolina Electric & Gas have shared savings incentives. Duke has an avoided cost recovery plan.
South Dakota	Lost revenue adjustment for electric and natural gas – Northwestern Energy has a lost revenue adjustment mechanism for both electric and natural gas.	In place for electric and natural gas – Mechanisms have been approved for several utilities including OtterTail Power, MidAmerican, Montana-Dakota Utilities and Northwestern Energy.
Tennessee	Lost revenue recovery for natural gas, none for electric. Chattanooga Gas Co. collects a monthly charge for fixed costs in order to align utility interests to better promote efficiency, and it can adjust the remaining portion of rates annually.	None
Texas	None	In place for electric, but not natural gas. All investor-owned utilities have a shared benefit incentive.

State	Decoupling or Related Mechanism	Performance Incentive
Utah	Decoupling is in place for natural gas. Questar Gas has tariffs that authorize revenue based on the number of customers served. Legislation encourages the Commission to remove financial disincentives to efficiency.	None. Legislation expresses support for incentives, but none have been approved.
Vermont	In place for electric. Central Vermont Public Service has a decoupling mechanism that expires in 2011.	In place for electric. Vermont contracts an independent third party to operate efficiency programs. The contract includes a performance-based incentive.
Virginia	Decoupling is in place for natural gas. Several natural gas utilities have decoupling. Dominion has applied for recovery of lost revenues, but was not approved.	None. Legislation has authorized incentives for electric utilities, although none have been approved.
Washington	Lost revenue recovery is in place for natural gas – Avista has a lost revenue recovery mechanism in place.	None. Electric utilities may be fined if they fail to meet their efficiency targets.
West Virginia	None	None
Wisconsin	Decoupling is in place for electric and natural gas; lost revenue recovery is also in place for natural gas. Decoupling was approved for Wisconsin Public Service Corporation in 2008. A Gas Cost Recovery Mechanism was approved for Wisconsin Electric Power Company in 2011.	In place for electric and natural gas. Wisconsin Power & Light earns a rate of return on investments for commercial and industrial customers.
Wyoming	Decoupling is in place for natural gas, and lost revenue recovery is in place for electric. Questar Gas Company has a pilot decoupling program that began in 2009. Montana-Dakota Utilities Company has a lost revenue adjustment mechanism.	None

Appendix D: State Transit Funding

State	FY 2010 Funding ($million)	2010 Population Figures	Per Capita Transit Expenditure ($/person)
New York	4,352.3	19,378,102	224.60
Massachusetts	1,376.4	6,547,629	210.21
Maryland	889.3	5,773,552	154.03
Alaska	98.1	710,231	138.17
New Jersey	1,157.7	8,791,894	131.68
Pennsylvania	1,225.1	12,702,379	96.45
District of Columbia	322.0	3,500,000	92.01
Delaware	81.5	897,934	90.79
Connecticut	307.3	3,574,097	85.99
Minnesota	270.6	5,303,925	51.03
Rhode Island	53.5	1,052,567	50.86
California	1,731.3	37,253,956	46.47
Illinois	589.0	12,830,632	45.91
Oregon	108.1	3,831,074	28.20
Virginia	189.5	8,001,024	23.68
Wisconsin	132.1	5,686,986	23.22
Michigan	198.4	9,883,640	20.08
Vermont	6.3	625,741	10.11
Florida	184.5	18,801,310	9.81
New Mexico	18.4	2,059,179	8.94
Washington	57.2	6,724,540	8.51
Indiana	54.7	6,483,802	8.43
North Carolina	74.9	9,535,483	7.86
Tennessee	35.9	6,346,105	5.66
North Dakota	3.2	672,591	4.68
Wyoming	2.5	563,626	4.43
Iowa	10.9	3,046,355	3.57
Colorado	12.7	5,029,196	2.52
Kansas	6.0	2,853,118	2.10
Nebraska	3.0	1,826,341	1.64

State	FY 2010 Funding ($million)	2010 Population Figures	Per Capita Transit Expenditure ($/person)
Oklahoma	6.1	3,751,351	1.62
West Virginia	2.8	1,852,994	1.53
Arkansas	4.0	2,915,918	1.38
South Carolina	6.0	4,625,364	1.30
Texas	28.7	25,145,561	1.14
Louisiana	5.0	4,533,372	1.09
Missouri	6.2	5,988,927	1.04
South Dakota	0.8	814,180	0.95
Ohio	10.8	11,536,504	0.94
Mississippi	1.6	2,967,297	0.54
Montana	0.4	989,415	0.45
Maine	0.5	1,328,361	0.40
New Hampshire	0.5	1,316,470	0.38
Kentucky	1.4	4,339,367	0.33
Georgia	2.2	9,687,653	0.22
Idaho	0.3	1,567,582	0.20
Alabama	0.0	4,779,736	0.00
Arizona	0.0	6,392,017	0.00
Hawaii	0.0	1,360,301	0.00
Nevada	0.0	2,700,551	0.00
Utah	0.0	2,763,885	0.00

Appendix E: State Transit Legislation

State	Description of Transit Legislation	Source
California	California's Transportation Development Act provides two sources of funding for public transit: the Location Transportation Fund and the State Transit Assistance Fund. Monies are allocated to each county based on population, taxable sales, and transit performance and are used for the development and maintenance of transit infrastructure.	http://www.dot.ca.gov/hq/MassTrans/State-TDA.html
Colorado	Colorado adopted the FASTER legislation in 2009, which created a State Transit and Rail fund that accumulates $5 million annually. The legislation also allocated $10 million per year from the Highway Users Tax Fund to the maintenance and creation of transit facilities.	http://www.leg.state.co.us/clics/clics2009a/csl.nsf/billcontainers/636E40D6A83E4DE987257537001F8AD6/$FILE/108_enr.pdf
Florida	House Bill 1271 allows municipalities in Florida with a regional transportation system to levy a tax, subject to voter approval, that can be used as a funding stream for transit development and maintenance.	http://www.myfloridahouse.gov/sections/Bills/billsdetail.aspx?BillId=44036
Georgia	The Transportation Investment Act, enacted in 2010, allows municipalities to pass a sales tax for the express purpose of financing transit development and expansion.	http://www.dot.state.ga.us/localgovernment/FundingPrograms/transreferendum/Documents/Legislation/HB277-BreakdownbySection.pdf
Illinois	House Bill 289 allocates $2.5 billion for the creation and maintenance of mass transit facilities from the issuance of state bonds.	http://legiscan.com/gaits/text/70761
Kansas	The Transportation Works for Kansas legislation was adopted in 2010 and provides financing for a multimodal development program in communities with sensitive transportation needs.	http://votesmart.org/bill/11412/30514/transportation-works-for-kansas-program%20%28T-Works%20for%20Kansas%20Program%29
Minnesota	House File 2700, adopted in 2010, is an omnibus bonding and capital improvement bill which provides $43.5 million for transit maintenance and construction. The bill also prioritized bonding authorization so that appropriations for transit construction for fiscal years 2011 and 2012 would amount to $200 million.	http://wdoc.house.leg.state.mn.us/leg/LS86/CEH2700.1.pdf

State	Description of Transit Legislation	Source
New York	In 2010 New York adopted Assembly Bill 8180, which increases certain registration and renewal fees to fund public transit. It also created the Metropolitan Transit Authority financial assistance fund to support subway, bus, and rail.	http://www.ncsl.org/issues-research/transport/major-state-transportation-legislation-2010.aspx#N
North Carolina	In 2009 North Carolina passed House Bill 148, which calls for the establishment of a congestion relief and intermodal transportation fund.	http://www.ncleg.net/sessions/2009/bills/house/pdf/h148v2.pdf
Tennessee	Tennessee Senate Bill 1471, passed in 2009, calls for the creation of a Regional Transportation Authority in major municipalities. It allows these authorities to set up dedicated funding streams for mass transit either by law or through voter referendum.	http://state.tn.us/sos/acts/106/pub/pc0362.pdf

Appendix F: Summary of State Building Code Stringency

State	Summary of State Building Code Stringency	Score
Alabama	Effective October 1, 2012, the Alabama Energy and Residential Code (AERC) will become mandatory statewide, for the first time in the state's history. The residential provisions of the AERC reference Chapter 11 of the 2009 IRC with Alabama amendments. The commercial provisions of the AERC reference the 2009 IECC with Alabama amendments while referencing ASHRAE Standard 90.1-2007 as an alternative compliance path. Local jurisdictions may adopt more stringent codes.	3
Alaska	Alaska's residential code is the state-developed Building Energy Efficiency Standard (BEES), which is based on the 2009 IECC and ASHRAE Standard 62.2-2010 Ventilation and Acceptable Indoor Air Quality in Low-Rise Residential Buildings, with Alaska-specific amendments. BEES is mandatory for state-financed residential construction projects, a requirement that covers roughly 25% of housing starts in the state (those that qualify for state financial assistance). Alaska has no statewide commercial building code, but all public facilities must comply with the thermal and lighting energy standards adopted by the Alaska Department of Transportation and Public Facilities mandated by AS44.42020(a)(14).	0.5
Arizona	There is no statewide mandatory residential or commercial energy code in Arizona. For commercial structures, all state-funded buildings constructed after February 11, 2005 must achieve LEED Silver certification and meet the energy standards of ASHRAE 90.1-2004 as mandated by Executive Order 2005-05. Arizona is a "home rule" state, meaning that codes are adopted and enforced on a local rather than state level. According to analysis by the Southwest Energy Efficiency Project, jurisdictional adoption of codes has led to 73% of the population being covered by either the 2006 IECC (58%) or the 2009 IECC (15%), for both residential and commercial buildings.	2
Arkansas	The Arkansas Energy Code for New Building Construction is mandatory statewide for both residential and commercial buildings. The residential energy code is based on the 2003 IECC and includes state-specific amendments. As of January 1, 2013, Arkansas' commercial energy code will reference ASHRAE Standard 90.1-2007 with Chapter 5 of the 2009 IECC as an alternative compliance path. Newly constructed or remodeled public buildings must comply with ASHRAE 90.1-2007.	2.5
California	California's energy code is considered to be the most aggressive and best enforced energy code in the United States, and has been a powerful vehicle for advancing energy efficiency standards for building equipment. Many specifications are performance-based, offering flexibility for designers. The code also stands out because it includes field verification requirements for certain measures and reports high compliance rates overall. The most recent code, effective January 1, 2010, is mandatory statewide and exceeds 2009 IECC standards for residential buildings and meets or exceeds ASHRAE/IESNA 90.1-2007 for commercial buildings.	4

State	Summary of State Building Code Stringency	Score
Colorado	Colorado is a home rule state with a voluntary building code for both residential and commercial construction with the 2003 IECC as a mandatory minimum for jurisdictions that have adopted a code previously. Jurisdictions that have not adopted or enforced codes are exempt from the 2003 IECC requirement, although the 2009 IECC is mandatory for all factory-built and multi-family structures – commercial and residential – in areas that do not adopt or enforce buildings codes. A list of jurisdictions that have adopted codes can be found on the websites of the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy and the Building Codes Assistance Project.	2
Connecticut	Connecticut has statewide codes for both residential and commercial buildings based on the 2009 IECC. On January 28, 2009, HB 6284 was introduced in the Connecticut General Assembly with the purpose of creating a new state building energy code and green buildings for certain construction projects, and was passed in June 2009. The bill requires the incorporation of the 2012 IECC within 18 months of its publication. Effective July 1, 2010, the bill requires a LEED-Silver rating for certain residential buildings that are projected to cost $5 million or more as well as for renovation of certain residential buildings that are projected to cost $2 million or more.	3
Delaware	Through the passage of SB 59, which became effective July 1, 2010, Delaware's residential and commercial codes were updated to follow the 2009 IECC and ASHRAE 90.1-2007, respectively. Both residential and commercial codes are reviewed triennially for potential updates to the most recent versions of the IECC and ASHRAE Standard 90.1.	3
District of Columbia	Washington D.C.'s energy codes are mandatory across the District. For residential buildings, builders must comply with the 2008 D.C. Construction Codes, which are based on the "30% Solution" and are more stringent than the 2009 IECC. For commercial buildings, builders must again comply with the 2008 D.C. Construction Codes, which are based on ASHRAE 90.1-2007. On December 16, 2011, the District of Columbia's Construction Codes Coordinating Board (CCCB) voted in favor of adopting the 2012 IECC. Implementation is expected in late 2013 pending administrative review and legislative processes to officially enact the code update.	4
Florida	The first printing of the 2010 Florida Building Codes, including the now-separate 2010 Florida Building Code, Energy Conservation, became effective March 15, 2012. Adopted by the Florida Building Commission (FBC) in 2011, the state-developed code references the 2009 IECC and ASHRAE Standard 90.1-2007 as base documents, with significant Florida-specific amendments throughout. The FBC estimates that the 2010 state code is 5% more stringent that the 2007 code edition, or roughly 20% more stringent than the 2006 IECC.	4
Georgia	On January 1, 2011, the 2011 Georgia State Minimum Standard Energy Code became effective statewide as approved by the Georgia Department of Community Affairs on November 3, 2010. The state code is based on the 2009 IECC with state-specific strengthening amendments and is mandatory statewide. The commercial codes also reference ASHRAE 90.1-2007. The state also adopted the 2011 Georgia State Minimum Residential Green Building Standard, based on the 2008 National Green Building Standard (NGBS) with 2011 Georgia Amendments, as an optional code. It is available for local government adoption and enforcement.	4

State	Summary of State Building Code Stringency	Score
Hawaii	On October 13, 2009, the Hawaii Building Code Council approved the 2006 IECC with state-specific amendments as the mandatory statewide energy code for both the residential and commercial sectors. After over a year of work by the 2009 IECC subcommittee of the Hawaii Department of Business, Economic Development, and Tourism, the Hawaii Building Code Council has developed a proposal to update the Hawaii State Energy Conservation Code to the 2009 IECC with substantial state-specific strengthening amendments intended to serve as a model for warm weather areas worldwide. The effective date in each county was to be sometime during 2012, depending on when the state's four counties introduce bills to adopt the code locally.	3
Idaho	Effective January 1, 2011, the 2009 IECC is mandatory statewide for residential and commercial construction, the latter with reference to ASHRAE 90.1-2007.	3
Illinois	On August 17, 2012, Senate Bill 3724 was signed by Governor Pat Quinn, which amended the effective date of the adoption of the 2012 IECC to January 1, 2013. The Illinois Energy Conservation Code is mandatory statewide and applies to both residential and commercial buildings, the latter with reference to ASHRAE Standard 90.1-2010.	5
Indiana	On August 17, 2012, Senate Bill 3724 was signed by Governor Pat Quinn, which amended the effective date of the adoption of the 2012 IECC to January 1, 2013. The Illinois Energy Conservation Code is mandatory statewide and applies to both residential and commercial buildings, the latter with reference to ASHRAE Standard 90.1-2010.	3
Iowa	The Iowa State Energy code is mandatory statewide for residential and commercial buildings. Residential buildings must comply with the 2009 IECC, while the commercial buildings must also comply with the 2009 IECC, with reference to ASHRAE 90.1 – 2007.	3
Kansas	Kansas has no statewide residential building code, though realtors and homebuilders are required to fill out an energy efficiency disclosure form and provide it to potential buyers. In April 2007, the 2006 IECC became the applicable standard for new commercial and industrial structures. Jurisdictions in the state are not required to adopt the code.	1
Kentucky	As of October 1, 2012, the 2007 Kentucky Residential Code (KRC) mandates residential buildings must comply with the 2009 IECC or IRC with state amendments. The 2007 Kentucky Building Code (KBC) states that commercial construction must comply with the 2009 IECC or the 2009 IBC with state amendments.	3
Louisiana	Residential buildings must meet the 2006 IRC with reference to the 2006 IECC. Effective July 20, 2011, ASHRAE Standard 90.1-2007 applies to all private commercial buildings built or remodeled as well as state-owned buildings. Multi-family residential construction must comply with the 2009 IECC.	2.5
Maine	The Maine Uniform Building and Energy Code (MUBEC) was established legislatively in April 2008 through P.L. 699. On June 1, 2010, the 2009 IECC and ASHRAE 90.1-2007 became mandatory for residential, commercial, and public buildings statewide, although enforcement varies by population. Towns with a population of less than 2,000 are not required to enforce the code. Towns with a population of 2,000 that had a building code as of August 1, 2008 were required to begin enforcing the new codes on December 1, 2010. Towns with a population of 2,000 but that did not have a building code as of August 1, 2008, will be required to begin enforcing the new codes on December 1, 2012. According to the Northeast Energy Efficiency Partnership, this exempts 50-60% of the state's population for complying with building codes.	2

State	Summary of State Building Code Stringency	Score
Maryland	The 2012 Maryland Building Performance Standards are mandatory statewide and reference the 2012 ICC Codes, including the 2012 IECC, for all new and renovated residential and commercial buildings. § 12-503 of the Maryland Code requires the Department of Housing and Community Development to adopt the most recent version of the IECC within 12 months of its being issued; it may adopt energy conservation requirements that are more stringent than the codes, but not less. Maryland is a "home rule" state, so each of its 57 local jurisdictions may modify these codes to suit local conditions.	5
Massachusetts	As of January 1, 2010, the Massachusetts Board of Building Regulations and Standards (BBRS) requires the use of the 2009 IECC with state-specific amendments for both residential and commercial buildings, and also requires that the code be mandatory statewide. Massachusetts is required by the Green Communities Act of 2009 to adopt each new IECC edition within one year of its publication. In July 2009, Massachusetts became the first state to adopt an above-code appendix to its state code—the 120 AA 'Stretch' Energy Code. The 'Stretch' Code is an enhanced version of the 2009 IECC with greater emphasis on performance testing and prescriptive requirements. It was designed to be approximately 20 percent more efficient than the base energy code— the 2009 IECC for new construction, with less stringent requirements for residential renovations. The "Stretch" Code is voluntary.	4
Michigan	The 2009 Michigan Uniform Energy Code became effective March 9, 2011 and is mandatory statewide for residential and commercial buildings. Residential buildings must comply with the 2009 IECC, with state-specific amendments. Commercial buildings are required to comply with ASHRAE 90.1-2007.	3
Minnesota	Both Minnesota's residential and commercial building codes, the 2007 Minnesota State Building Code, are mandatory statewide. The residential code (Chapter 1322) is based on Chapter 11 of the 2006 IRC with amendments. The commercial code (Chapter 1323) is based on ASHRAE 90.1-2004 with amendments. The 2007 Minnesota State Building Code became effective June 1, 2009.	2
Mississippi	Mississippi's residential and commercial energy codes are voluntary, except for state-owned buildings, public buildings, and high-rise buildings. Mississippi's residential code is based on ASHRAE 90 – 1975 and the prior 92 MEC. The commercial code is also based on ASHRAE 90-1975.	0
Missouri	Missouri has no mandatory statewide codes but has significant adoption of codes in major jurisdictions. State-owned residential buildings must comply with the latest edition of the MEC or the ASHRAE 90.2-1993 (single-family and multifamily buildings). As of July 1, 2009, state-owned commercial buildings must comply with the 2006 IECC.	2
Montana	Montana's residential and commercial building codes—codified in the Administrative Rule s of Montana Title 24, Chapter 301.160—are mandatory statewide. Montana's residential code requires compliance with the 2009 IECC, with strengthening amendments. The commercial building code requires compliance with the 2009 IECC with reference to ASHRAE 90.1-2007.	3.5
Nebraska	Nebraska's residential and commercial energy codes, referred to as the Nebraska Energy Code, are mandatory statewide. Residential buildings are required to comply with the 2009 IECC. Commercial buildings must also comply with the 2009 IECC with reference to ASHRAE 90.1 – 2007. Two of the state's largest code jurisdictions (comprising more than half of the annual new construction in the state) have expressed an interest in working with the state to adopt "stretch" codes beyond the 2009 IECC.	3

State	Summary of State Building Code Stringency	Score
Nevada	The 2012 Nevada Energy Code became effective July 1, 2012 and is mandatory statewide. The residential codes are based on the 2009 IECC with Nevada amendments. The commercial codes are based on the 2009 IECC with Nevada amendments, with ASHRAE Standard 90.1-2007 as an acceptable compliance path through Chapter 5 of the 2009 IECC. Local jurisdictions are not allowed to adopt less stringent energy codes.	3
New Hampshire	Effective April 1, 2010, the New Hampshire State Building Code for residential and commercial buildings is based on the 2009 IECC, with state-specific amendments. The commercial code is also based on the 2009 IECC with references to ASHRAE 90.1-2007. Both codes are mandatory statewide.	3
New Jersey	The 2009 New Jersey Uniform Construction Code for residential and commercial buildings is mandatory statewide. The residential codes are based on the 2009 IECC with state-specific amendments. The commercial codes are based on ASHRAE 90.1-2007 with state-specific amendments.	3
New Mexico	The 2009 New Mexico Energy Conservation Code (NMECC) is based on the 2009 IECC with state-specific amendments for both residential and commercial building codes. ASHRAE Standard 90.1-2007 is an acceptable compliance path through Chapter 5 of the 2009 IECC.	3
New York	The 2010 Energy Conservation Construction Code of New York (ECCCNYS) became effective December 28, 2010, and is mandatory statewide for both residential and commercial buildings. The residential code is based on the 2009 IECC with state-specific amendments. The commercial code is also based on the 2009 IECC with state-specific amendments. The commercial codes can also follow ASHRAE 90.1-2007.	3
North Carolina	The 2012 North Carolina Energy Conservation Code (NCECC) is mandatory statewide for both residential and commercial buildings. The residential and commercial codes are based on the 2009 IECC, both with substantial strengthening amendments, while the commercial code also references ASHRAE 90.1-2007.	4
North Dakota	North Dakota is a “home rule” state and has no statewide mandatory energy codes. As of August 1, 2009, the 1993 MEC was removed as the voluntary state residential energy code and ASHRAE 90.1-1989 was removed as the voluntary state commercial energy code. The voluntary energy code has been placed under the purview of the North Dakota State Building Code and now the state Building Code Advisory Committee has the authority to make recommendations that could include energy standards in future editions of the State Building Code. Chapters 11 and 13 of the 2009 IRC and IBC are contingent upon adoption by local jurisdictions.	1
Ohio	Both Ohio's residential and commercial energy codes are mandatory statewide. Effective January 1, 2013, the residential code will reference the 2009 IECC. Residential home builders are also allowed to meet the requirements of sections 1101-1103 of Chapter 11 of the Residential Code of Ohio (based on Chapter 11 of the 2009 IRC) or by meeting the state code's new Prescriptive Energy Requirements (section 1104). In March 2011, the commercial code was amended to reference the 2009 IECC and ASHRAE 90.1-2007, and became effective November 1, 2011.	3

State	Summary of State Building Code Stringency	Score
Oklahoma	Oklahoma has in place mandatory statewide building energy codes for residential and commercial buildings. Until recently, the state had been a "home rule" state, but in June 2009, the Oklahoma Legislature passed a bill (SB 1182) creating the Oklahoma Uniform Building Code Commission that reviewed and recommended building codes (including energy codes) for residential and commercial construction for adoption. Beginning in October 2010, the Commission held several meetings discussing code change proposals. On March 31, 2011, the Commission formally recommended a residential code based on the 2009 IRC with Oklahoma amendments. The Legislature approved the rule, leading to the official adoption of the code on May 27. The statute became effective July 15, 2011.	2
Oregon	The 2011 Oregon Residential Specialty Code (ORSC) and the 2010 Oregon Energy Efficiency Specialty Code (OEESC) are mandatory statewide. The Oregon Building Codes Division issued a rulemaking in May 2011, effective July 2011, updating the residential code to the 2011 ORSC (from the 2008 ORSC), which is intended to achieve 10-15% greater savings than the 2008 ORSC, making it at least as stringent as the 2009 IECC. The OEESC is based on the 2009 IECC with state-specific amendments that make it more stringent than the 2009 IECC.	4
Pennsylvania	Both Pennsylvania's residential and commercial energy codes are mandatory statewide. Residential buildings must comply with the 2009 IECC or 2009 IRC, Chapter 11. Residential buildings can also comply with Pennsylvania's Alternative Residential Energy Provisions (2009). Commercial buildings must also comply with the 2009 IECC, with reference to ASHRAE 90.1 – 2007. Legislation requires the Pennsylvania Department of Labor and Industry (DLI) to promulgate regulations adopting "a new triennial BOCA National Building Code, or its successor building code," and/or "a new triennial ICC International One and Two Family Dwelling Code" by December 31 of the year in which they are issued. However, on January 31, 2011, HB 377 was introduced that would amend the Uniform Construction Code Act of 199 to require a 2/3 approval for any code update proposals by the DLI, along with other weakening amendments to the codes. The bill was signed by Governor Tom Corbett on April 25, 2011 as Act 1.	3
Rhode Island	The 2010 Rhode Island One and Two Family Dwelling Code for residential buildings became effective July 1, 2010 and is based on the 2009 IRC with state-specific amendments. The 2010 Rhode Island State Energy Conservation Code for commercial buildings also became effective July 1, 2010, and is based on the 2009 IECC and ASHRAE 90.1-2007 with state-specific amendments. Both codes are mandatory statewide.	3
South Carolina	On January 1, 2013, the 2013 South Carolina Energy Standard will become effective. The residential provisions will reference the 2009 IECC. The commercial provisions will reference the 2009 IECC as well, including that code's reference to ASHRAE Standard 90.1-2007 as an alternative compliance path. Until the effective date, the South Carolina Energy Standard will continue to reference the 2006 IECC for all new construction. Local jurisdictions may adopt more stringent energy codes.	3
South Dakota	South Dakota has no mandatory statewide energy codes for residential or commercial construction. Codes are adopted by jurisdiction voluntarily. As of July 2011, state law established the 2009 IECC as a voluntary residential standard. Local jurisdictions also have authority to adopt various residential building and energy codes, including IRC and IECC. For commercial construction, ASHRAE 90.1 or IECC compliance is required by reference in the 2012 IBC, which is the mandatory statewide commercial building standard in state law unless local jurisdictions have either opted out of it or specifically adopted another code.	1

State	Summary of State Building Code Stringency	Score
Tennessee	Tennessee is a "home rule" state, which gives local jurisdictions the power to adopt codes. On June 2, 2011, the Tennessee State Fire Marshal's Office announced that it would begin the implementation and enforcement of adopted energy codes beginning July 1, 2011. These include ASHRAE Standard 90.1-2007 for all state buildings and the 2006 IECC for all other residential and commercial construction.	2
Texas	Texas' building codes are mandatory for both residential and commercial construction. Effective January 1, 2012, the Texas Building Energy Performance Standards were updated requiring single family homes to comply with the 2009 IRC. For all other residential, commercial, and industrial buildings, the 2009 IECC became effective April 1, 2011. State-owned buildings must meet ASHRAE 90.1-2007. For all buildings, jurisdictions can choose to adopt more stringent standards.	3
Utah	Utah's Uniform Building Code (UUBC) for residential and commercial building energy codes is mandatory statewide. Residential construction must comply with the 2006 IECC. Commercial construction must comply with the 2009 IECC, with reference to ASHRAE 90.1-2007.	2.5
Vermont	Vermont's 2011 Residential and Commercial Building Energy Standards (RBES and CBES) are mandatory statewide. Effective October 1, 2011, the RBES references the 2009 IECC with several strengthening amendments from the 2012 IECC. Effective January 3, 2012, the CBES references the 2009 IECC and ASHRAE Standard 90.1-2007 with several strengthening amendments from the 2012 IECC.	4
Virginia	Virginia's Uniform Statewide Building Code (USBC) is mandatory statewide for residential and commercial buildings. As of March 1, 2011, the USBC was updated to reference the 2009 IECC and 2009 IRC. Residential buildings must comply with the 2009 IRC, while commercial buildings must comply with the 2009 IECC, with reference to ASHRAE 90.1-2007.	3
Washington	The 2009 Washington State Energy Code is a state-developed code that is mandatory statewide. The 2009 versions of the residential and commercial codes were developed to be substantially more stringent than the 2009 IECC and ASHRAE 90.1-2007. For residential construction covered by ASHRAE 90.1-2007 (high rise buildings with four or more stories), the state code is also more stringent.	4
West Virginia	West Virginia's residential and commercial building codes are mandatory statewide; however, adoption by jurisdictions is voluntary. Residential buildings are required to comply with the 2003 IECC and the 2003 IRC with amendments. Commercial buildings are required to comply with the 2003 IECC with amendments. On April 11, 2009, the West Virginia Legislature passed bills directing the State Fire Commission to promulgate rules adding the 2009 IECC and ASHRAE 90.1-2007. The updated codes have not yet become effective.	2
Wisconsin	Both Wisconsin's residential and commercial building energy codes are mandatory statewide. The state-developed residential code, referred to as COMM 22 of the Uniform Dwelling Code (UDC), is mandatory for one- and two-family dwellings and incorporates the 2006 IECC with state-specific amendments. The state-developed commercial code, referred to as COMM 63 of the Wisconsin Commercial Building Code, is based on the 2009 IECC.	2.5

State	Summary of State Building Code Stringency	Score
Wyoming	Wyoming's residential and commercial building codes are voluntary. Known as the ICBO Uniform Building Code, they are based on the 1989 MEC and may be adopted and enforced by local jurisdictions. Some jurisdictions have adopted more stringent codes than the voluntary standard: the 8 most populated cities and counties in Wyoming have an energy code that meets or exceeds the IECC 2006 or equivalent. Teton County and Jackson are moving to the IECC 2012 within the next month or two; Cheyenne adopted the IECC 2009; Casper, Rock Springs, and Gillette adopted a modified IECC 2006.	1

Appendix G: Summary of Building Code Compliance Efforts

State	Summary of State Building Code Compliance Efforts	Score
Alabama	Energy codes for private sector residential and commercial construction are enforced by local code officials in several jurisdictions. Many smaller jurisdictions currently have no code enforcement. Through a grant with Southface Energy Institute, the state energy office provided commercial and residential energy codes training for contractors, homebuilders, designers, code officials and policymakers. In addition, short–term grants with the Building Codes Assistance Project and Southface Energy Institute allowed for additional training of code officials on the newly adopted Alabama code, as well as development of checklists to assist with inspection and enforcement. Online training modules were developed for individuals who were unable to attend onsite training. Eleven code officials were also given additional training through the International Code Council's (ICC) Energy Code Ambassador Program (ECAP) to provide them the tools needed to assisted code officials throughout the state with technical assistance and training as requested. Homeowners, homebuyers, and home inspectors also have access to guides and checklist to help them determine whether a home meets the new energy standards adopted for the state. The available resources can be accessed through the ADECA Energy Division website as well as the Online Code Environment & Advocacy Network (OCEAN). ADECA and the Alabama Energy and Residential Codes Board will continue working with stakeholders in the construction industry in Alabama to seek ways to implement or increase enforcement in areas that currently have little or no enforcement. One solution being considered is to develop and execute interagency agreements between smaller jurisdictions with no enforcement and nearby jurisdictions that provide enforcement.	0.5
Alaska	While Alaska has no statewide energy code, all buildings that receive aid from the state of Alaska or the Alaska Housing Finance Corporation (AHFC) (including private mortgages) must meet the 2009 IECC codes with Alaska specific amendments. These buildings are fitted with energy rating systems to verify compliance. Currently roughly 50,000 of the 300,000 residences in Alaska are outfitted with these ratings systems. AHFC trains energy raters and home inspectors to monitor enforcement of these requirements.	0
Arizona	While Arizona has no statewide energy code, local communities have started adopting the 2012 IECC and many are planning to bypass the 2009 version of the code. The largest municipality in the state, Phoenix, has started the development/adoption process for the 2012 IECC (as of the publication date). Utility providers are working with code trainers, state energy office, and ICC chapters on training to the 2012 and 2009 IECC. During 2009 the state trained approximately 25 building industry professionals to become energy code trainers and funded many code officials to receive the ICC energy code certifications. As of September 2011 the state has 84 ICC IECC certified individuals.	1

State	Summary of State Building Code Compliance Efforts	Score
Arkansas	The latest study completed to measure compliance was published in 2006 by the Arkansas Economic Development Commission. Results indicated that compliance with the code is increasing but that more attention was needed in the colder, northwest part of the state. Enforcement is a major issue that varies with each jurisdiction. Enforcement is more common in larger cities with greater resources, but the focus of building inspections tends to be on structural integrity, fire, water, and safety. Builders and code officials periodically receive training on code compliance, typically through the Code Officials of Arkansas and the AR Economic Development Commission.	0.5
California	No studies have been conducted or funding identified to establish a baseline of compliance in California. Enforcement is at the local level and there are building departments in each of the 536 city and counties. Online training is available at www.energyvideos.com. Utilities, the California Energy Commission staff and local organizations and trade groups provide training to these building departments as well as to contractors and homeowners.	2
Colorado	The Governor's Energy Office (GEO) completed the Building & Energy Code Survey Report, which presents the results of a July 2009 survey on building code enforcement and adoption, as well as a needs assessment for the types of code assistance desired in the 333 code jurisdictions. Results from the survey indicate that 80% of respondents (n=174) claim to be enforcing residential codes and 79% for commercial codes, though this is not a measure of compliance. Additional support was requested by 84% of respondents from the state energy office on energy codes. The GEO has provided over 125 trainings on the 2009 IECC during 2010 and 2011. A statewide program funded by ARRA, called the Energy Codes Support Partnership, was developed to educate all jurisdictions on the 2009 IECC and provide assistance in its adoption. The program trained code officials, government employees, and building trades on the 2009 IECC across the entire state and was updated to included information and resources for jurisdiction adopting the 2012 IECC. The state has also partnered with BCAP to form a compliance collaborative that includes a number government agencies and non-governmental organizations.	2

State	Summary of State Building Code Compliance Efforts	Score
Connecticut	In 2012, Connecticut is establishing a baseline for code compliance, as well as a process for identifying training needs and tracking compliance each year, to ensure that 90% of all projects built in 2017 are in compliance with the new energy code. The Office of Education and Data Management (OEDM), in conjunction with the Office of the State Building Inspector, is responsible for the training and licensing of building code officials. OEDM, with the assistance of ISE, conducted two surveys in the spring of 2010, one of local code officials and one of licensed building inspectors, to determine the areas of frequent code violations in both the residential and commercial sectors. These surveys helped to identify the training needs for the code officials and inspectors. Connecticut completed initial training programs for code compliance for both IECC 2009 and ASHRAE 2007. Throughout 2010 and 2011, OEMD provided all 169 local building officials and 450 licensed inspectors with three days (15 hours) of training on the target code offered through regional workshops with certified instructors from the International Code Council. Participants were also provided with code books and application workbooks reinforcing the residential, IECC 2009 and ASHREA 90.1 2007 target codes. Starting in late spring 2012, local code officials, working with ISE is conducting at least 44 residential and 44 commercial plan reviews utilizing the DOE state code compliance guidelines. During the summer and early fall, these same code officials will complete the site inspection of these 88 building utilizing site evaluations forms supplied by DOE. Data collected in DOE's Score and Store software will be used to calculate the compliance percentage establish the Connecticut Code Compliance Baseline. Starting in the fall of 2012, the state of Connecticut will launch a formal assessment using third party certified energy auditors and Home Energy Rating System (HERS) raters to evaluate a statistically valid sample of buildings assessed in the baseline study to verify the compliance level determined by OEDM.	1.5
Delaware	The Delaware Division of Energy and Climate (DE&C), has legislative authority to review and adopt updated energy codes every three years. Given this leadership role, in partnership with BCAP the DE&C formed an Energy Codes Coalition in November 2011 as a platform for discussing code compliance and adoption and to inform the agency's work in these areas. This stakeholder group includes home builders, building code officials, and contractors, as well as representatives from the American Institute of Architects, the Delaware Sustainable Energy Utility (SEU), and ASHRAE Delaware and regional chapter. The Building Codes Assistance Project (BCAP) and the Northeast Energy Efficiency Partnerships (NEEP) provide additional technical support to DE&C. The coalition will use the Delaware Strategic Compliance Plan as a roadmap to achieve 100% code compliance by 2017 and will also coordinate stakeholder input into future code adoption processes. There is a baseline study of residential building codes under way that will provide an assessment of residential code compliance in the state.	1
District of Columbia	The codes are enforced by the codes division of the Department of Consumer and Regulatory Affairs (DCRA), which regularly trains its official on code updates.	1

State	Summary of State Building Code Compliance Efforts	Score
Florida	No studies have been conducted that attempt to measure compliance rates in the state, although the state plans to perform a study measuring the relative building performance between the implementation of the 2007 Florida Building Code and the 2009 Supplement. Enforcement is done at the local level by building departments with code clarifications issued by the Building Officials Association of Florida (BOAF), while Declaratory Statements are issued by the Florida Building Commission. Building departments receive training at the annual BOAF conference. Code officials and those in the construction industry are also required to take continuing education courses. The Florida Solar Energy Center has a contract to develop a Train-the-Trainer program and online web training to radically expand the number of persons qualified on Florida's energy code.	1.5
Georgia	The most recent survey on compliance was conducted by the Department of Community Affairs in 2004, which showed that about 50% of counties were enforcing the Georgia State Energy Code, though the study did not actually measure compliance. Currently there is no organized training program, though a comprehensive statewide training program is expected to begin in late 2010. Local jurisdictions may request training from the Department of Community Affairs' Construction Codes program.	1.5
Hawaii	The last study completed that measured compliance was done in 1999 and determined a compliance rate of 89%. Each of the four counties in Hawaii has a Building Division within the Public Works departments. State government buildings and military housing may voluntarily comply with the county codes. Code training was provided to approximately 130 government employees and 130 private sector design professionals in all four counties in March, 2012 in light of the code updates.	1
Idaho	The last study measuring compliance in Idaho was conducted in 2008 and was based on the 2001 Idaho energy code, which at the time followed the 1997 Uniform Building Code. At the time, compliance was measured at 88%. Training is scheduled each year through the Idaho Building Official Association (IDBAO). The IDABO also holds a two-day course on IECC training every January while the Idaho Energy and Green Building Conference every October also has a two-day training course. In 2010 there will be six educational seminars for builders, designers, and code officials that will provide continuing education credits for members of the American Institute of Architects and IDBAO. Idaho partnered with BCAP to from the Idaho Energy Code Collaborative, comprised of state, county, and city representatives, as well as energy code advocates and other interested stakeholders.	2
Illinois	Illinois recently completed a compliance study using a grant from the Department of Energy and contracting through the Midwestern Energy Efficiency Alliance; results were due in August 2011. Enforcement of codes is mandatory under state law and is carried out by local authorities. Training is provided by the Illinois Department of Commerce and Economic Opportunity through funding from the International Code Council.	1
Indiana	There are no recent studies that have attempted to measure compliance rates with the Indiana Energy Conservation Code. Codes are enforced at the state and local level for all buildings except single and dual-family dwellings, which are enforced only at the local level. Code officials receive training through the Division of Fire and Building Safety of the Indiana Department of Homeland Security. The Indiana Builders Association also provides training, and the Indiana Office of Energy and Defense Development has offered training sessions to several groups as well.	0.5

State	Summary of State Building Code Compliance Efforts	Score
Iowa	Enforcement takes place at the state and local levels. The Iowa State Building Code Bureau is currently conducting a compliance study with the assistance of the U.S. Department of Energy. A recent grant from the American Recovery and Reinvestment Act from the Iowa Office of Energy Independence to the Iowa Department of Public Safety allows for the hiring of an engineer to start a more active approach to energy code enforcement in Iowa. Through an outside vendor contracted by the Building Code Bureau, energy code inspections are conducted throughout the state. These inspections include plan reviews, onsite compliance checks during construction, and final inspections, which include reviews and compliance of various efficiency measures. There is no mandatory training program in Iowa, but the Iowa Association of Building Officials (IABO) provides several seminars each year on a variety of code enforcement topics. Investor-owned utilities also provide some energy code training throughout the year. The State Building Code Bureau and IABO hosted three two-day seminars throughout the state in the summer of 2010, which provided specific energy code training to all code officials on the 2009 IECC. Iowa Department of Public Safety has also begun to offer local training sessions. The Iowa Department of Public Safety also gets an allocation from the U.S. Department of Energy's State Energy Program formula annual award through the Iowa Economic Development Authority to strengthen and enforce its building codes program and provide long-term sustainability to the program.	1.5
Kansas	Local jurisdictions are responsible for enforcing all local codes including building energy codes. Beginning in 2012, the state's Energy Division will develop methodologies to assess and measure compliance rates in those jurisdictions that have already adopted the 2009 IECC. These methodologies will also address compliance rates in residential and commercial retrofits. The Energy Efficiency Building Codes Working Group was set up in 2009 to ensure compliance with federal guidelines surrounding stimulus funds and plans to address the need for code training, the level of which varies across jurisdictions. Currently, the state does not play a direct role in training codes officials and builders about codes. In 2010 the Kansas Energy Office surveyed 55 Kansas cities and counties in an attempt to better understand the enforcement of the codes throughout the state. Results were mixed and did not reveal a specific percentage of compliance. The Kansas Corporation Commission's Energy Division will update its summary of Kansas jurisdictions (the 55 cities and counties that taken together account for over 90% of the state's residential construction activity) and publish the findings in the Status of Residential and Commercial Building Codes in 55 Jurisdictions by the end of 2012. This summary enables the state to continue to assess the current status of energy codes adoption.	0.5
Kentucky	There are no recent studies that have attempted to measure code compliance in Kentucky. Enforcement is done at the state and local level by building inspection departments. The Department of Housing, Building, and Construction co-sponsored 20 days of training in 2008, while the efforts of several independent groups likely increased that to 30 days.	1

State	Summary of State Building Code Compliance Efforts	Score
Louisiana	There are no recent studies that have attempted to measure code compliance in Louisiana. Enforcement of the residential code is done by the Certified Building Official in each of the 64 parishes. Commercial codes are enforced by the Office of the State Fire Marshal. Code officials receive training through the International Code Council seminars and online courses. The Technology Assessment Division (TAD) travels statewide offering instruction on code software targeted towards designers, builders, code officials, architects, engineers and building owners, courses that qualify for continuing education credit. In 2009, 412 individuals attended TAD training programs. Building inspectors are trained through the Department of Natural Resources.	1
Maine	A study on compliance was conducted by the Maine Public Utilities Commission in 2008, though a copy of the study cannot be found on their website. Only towns with more than 2,000 residents are required to enforce the 2009 IECC. A training and certification program was launched simultaneously with the building energy code changes. All code officers are required to be certified and training is provided free of charge. Builders, architects and others are not required to be certified, but are encouraged to attend the training on a fee basis.	0.5
Maryland	In February 2012 the Maryland Energy Administration funded a study of local building codes and inspection offices as part of the state's plan to reach 90% energy code compliance. The study found that several code officials believe that 100% of the permitted construction in their jurisdiction is compliant with the 2009 IECC and almost one-third feel that 90% complies. Maryland is now embarking on an ambitious plan to drive energy code compliance statewide. A large component of this plan is aimed at training code officials, builders and design professionals. Codes are enforced by each local jurisdiction through its Department of Codes Enforcement and Permits and Inspections. Approximately 900 building inspectors from every jurisdiction, along with 400 architects and 300 building contractors are trained every year through the Department of Housing and Community Development.	0.5
Massachusetts	A study in 2011-2012 of commercial building energy code compliance is nearing completion. This complements a two-part study on residential building energy code compliance that sampled 40 homes built to the 2006 IECC, 40 homes built to ENERGY STAR (over a third of new construction), and another 40 built to the newer 2009 IECC. Results will be published the latter half of 2012. The Board of Building Regulations and Standards (BBRS), Department of Energy Resources (DOER) and other partners are planning a pilot evaluation of residential energy performance and code compliance that will inform how states determine code compliance rates. Enforcement is performed by local building code officials. In the 107 towns and cities that have elected to adopt the state's "stretch" energy code, enforcement of the building energy code is greatly assisted by the integrated role of HERS raters in the statewide New Homes with ENERGY STAR program. The BBRS has technical staff that provides advice and training to local code officials and works with regional organizations of local code officials to discuss enforcement issues. The state requires that all code officials fulfill a set of certification requirements in all aspects of construction and code enforcement, which includes continuing education through certified courses. The Green Communities Act requires the BBRS and the DOER to develop specific energy efficiency training and certification for all local code officials. Consequently, the DOER sponsored over 40 trainings in 2011 on three related themes: "Smart Building" training for residential contractors and code officials, trainings on best practices for deep energy retrofits, lessons learned from the statewide pilot, and on HVAC best practices.	2

State	Summary of State Building Code Compliance Efforts	Score
Michigan	There are no recent studies that have attempted to measure code compliance in Michigan. Enforcement is under the auspices of the state government as established by the Stille-DeRossett-Hale Single State Construction Code Act, but governmental subdivisions may exempt themselves from state enforcement by setting up an enforcement agency themselves. Code officials are required to receive continuing education under the Building Officials and Inspectors Registration Act. A number of code official organizations provide regular training throughout the state. The Bureau of Construction Codes also provides code training.	0.5
Minnesota	There are no recent studies that have attempted to measure code compliance in Minnesota. Enforcement takes place at the local level. Training is provided in the spring and fall by the Department of Labor and Industry.	1
Mississippi	Because Mississippi has no statewide building energy codes, all residential and commercial codes are enforced at the local jurisdictional level. However, the Mississippi Development Authority's Energy Division has recently held workshops on building energy codes.	0
Missouri	We currently have no information on compliance rates in Missouri.	0.5
Montana	The Building Codes Bureau in the Department of Labor and Industry (L&I) is responsible for compliance checks within the commercial sector. The last study measuring compliance in Montana was conducted in 2008 by the Northwest Energy Efficiency Alliance and was based on the code enforced in 2001, which was ASHRAE 90.1-1989. At the time, compliance was measured at 47%. A residential code compliance study is currently underway; results were to be available by November 2011. A residential code compliance study is currently underway with results due in the Fall of 2011. The Montana Department of Labor and Industry (L&I) coordinates code adoption and enforcement, although the residential energy code is enforced by the 46 local jurisdictions and most major cities enforce the energy code within their city limits. Builders are required to meet code requirements and show compliance through a builder self-certification process. Residential projects built outside of building code jurisdictional areas are not inspected, but the state provides information to builders on how to comply with code standards. L&I enforces compliance for commercial buildings and residences of more than five units that are located outside of jurisdictional areas. L&I provides some training, but the Department of Environmental Quality (DEQ) provides more training support in the form of workshops and onsite training sessions to code officials and builders. DEQ also participates with the state Building Codes Bureau in an annual code training conference on all ICC codes.	1.5

State	Summary of State Building Code Compliance Efforts	Score
Nebraska	Nebraska completed a baseline compliance study of 100 homes across the state comparing actual construction to requirements of the building energy code, modeled on the study performed by Pacific Northwest National Laboratory. Local jurisdictions that adopt and enforce an energy or thermal efficiency code are required by statute to adopt a code that meets or exceeds the minimum requirements of the Nebraska Energy Code. Otherwise, enforcement of the code falls to the Nebraska Energy Office. Since 2004, the Nebraska Energy Office has provided energy code compliance and education opportunities across the state. More than 1,100 members of the state's construction industry have been trained on the code requirements. In 2011, eleven trainings were provided by ICC, ASHRAE and other members of the building science community. Three ResCHECK and three ComCHECK workshops were held in 2012 for over 120 attendees. The agency has provided free copies of the 2009 IECC code books, 2009 IECC/ASHRAE combo code books, 2009 Inspector Guides and other enforcement tools to all code jurisdictions. The Nebraska Energy Office is hosting a regional energy codes conference in Omaha October 16-18, 2012. The conference will present practical how-to content, best practices and thought-provoking ideas, all with a focus on how states and local code jurisdictions can achieve compliance with the 2009 and 2012 International Energy Conservation Codes.	1
Nevada	A Gap Analysis study was completed in 2011 which looks into the current state of code implementation and offers suggestions to increase compliance. New Hampshire provided support to local jurisdictions under ARRA funding to pilot the BECP developed compliance tools to learn how local jurisdictions will/can use the tools and what time and expense it will cost the local jurisdictions. The NV State Office of Energy also partnered with BCAP to develop an energy codes collaborative for the state, which first met in April 2012, and has also named seven Code Ambassadors.	1
New Hampshire	A Gap Analysis study was completed in 2011, which looks into the current state of code implementation and offers suggestions to increase compliance. The state is also in the process of conducting a statewide compliance study. Building codes are enforced at the local level by the municipality with the Public Utilities Commission (PUC) reviewing applications for many cities and towns. In 55 of New Hampshire's municipalities, the fire department handles building code enforcement, focusing mainly on life-safety issues. The PUC, in coordination with the state's regulated electric utilities, GDS Associates, and the state Office of Energy and Planning, conduct energy code trainings in the fall and spring that are designed to teach builders, designers, engineers, and building officials how to build to code and beyond. New Hampshire has also increased outreach and training to "nontraditional" audiences, such as realtors, appraisers, lenders, and insurers. The Office of Energy and Planning (OEP) has developed a program on Building Code Compliance using stimulus funds to develop and implement training programs for code officials to achieve 90% verifiable compliance by 2017, titled the New Hampshire Building Energy Code Compliance Roadmap. The OEP has also partnered with BCAP to develop the NH Building Energy Code Compliance Collaborative, which will advance compliance in the state guided by recommendations from the compliance roadmap.	1.5
New Jersey	There are no recent studies that have attempted to measure code compliance in New Jersey. Enforcement is done at the local level through permits and inspections. Code officials are required to take continuing education courses, and license renewal through the Department of Community Affairs is required every three years.	0.5

State	Summary of State Building Code Compliance Efforts	Score
New Mexico	There are no current studies that have attempted to measure code compliance in New Mexico. Codes are enforced by the New Mexico Regulations and Licensing Department and by local governments. Code officials receive training through the Construction Industries Division on a regular basis. Stimulus funds were used to ramp-up these training programs.	0.5
New York	The New York State Research and Development Authority (NYSERDA) completed a compliance assessment in 2011 that tested U.S. Department of Energy protocols to determine whether New York State's new and renovated residential and commercial buildings exceed the 90% compliance threshold that states will be required to meet by 2017 as part of the ARRA legislation. While the report found that the compliance rate for buildings built under the ECCCNYS-2007 is below 90%, it is anticipated that compliance in future years will increase as result of training currently being provided as described below. Building energy codes are enforced at the local level by municipalities through the process of building permitting and inspection. Code officials are required to complete annual code update training, which includes a training component specific to the energy code. Additional training is being offered through NYSERDA, in conjunction with the New York State Department of State, to code officials and other participants in the building construction community.	2
North Carolina	There are no recent studies that have attempted to measure code compliance in North Carolina. Enforcement is the obligation of local jurisdictions through the permit/inspection process for new construction and additions. The North Carolina Department of Insurance is responsible for the general supervision statewide. Appalachian State University and Mathis Consulting have coordinated to put together over 30 workshops over the past three years, targeting training for specific jurisdictions. ARRA recovery grants were given to the Building Fire and Code Academy (BFCA) to conduct approximately 40 trainings on the updated NC energy code with code officials across the state. These trainings took place from 2011 to the beginning of 2012. The Department of Insurance also provides training as a part of its annual workshops for building inspectors and mechanical inspectors.	1
North Dakota	We currently have no information on compliance rates in North Dakota.	0
Ohio	The Ohio Energy Office conducted a study measuring enforcement in 2005, although there are no recent studies that have attempted to measure code compliance. The Ohio Board of Buildings Standards (BBS) adopts statewide energy codes and certifies the building departments and the personnel working for the departments throughout the state who enforce the codes. Code officials are required to take 30 hours of continuing education every three years to maintain their certification. There are other optional energy code courses that have been approved by the BBS so that the code officials can receive continuing education credits to be used to fulfill their 30-hour requirement, which includes an online energy code course.	0.5
Oklahoma	There are no recent studies that have attempted to measure compliance rates in Oklahoma. Because Oklahoma is a "home rule" state, the onus for enforcement falls on the municipality that has adopted an energy code. Code officials are trained by the Oklahoma Construction Industry Board (CIB). The Inspectors Examiners Committee has the authority to assist the CIB in establishing licensing, performance, continuing educations and other requirements for inspectors. Because Oklahoma has not yet adopted statewide energy codes, training is coordinated by municipalities.	0.5

State	Summary of State Building Code Compliance Efforts	Score
Oregon	In 2011, the Building Codes Division (BCD) conducted a preliminary "90% compliance study" through the Northwest Energy Efficiency Alliance to review compliance and quality of energy codes in the state. Results have not yet been put into a final report format. A study on compliance in Oregon was conducted in 2008 by the Northwest Energy Efficiency Alliance (NEEA) and was based on the code enforced in 2001. At the time, compliance was measured at 93%. The Oregon Building Codes Division Enforcement Program works with local jurisdictions to emphasize proper compliance. All jurisdictions are required to perform plan review, inspections and enforcement – without the ability to amend the state promulgated codes. BCD provides guidance and statewide interpretations to ensure consistent enforcement of the code throughout the state. All building officials are required to be certified by the state and must complete 16 hours of continuing education every three years. A variety of training formats and venues are made available directly through BCD and others through partners such as the Oregon Building Officials Association (OBOA) and Oregon Homebuilders Association (OHBA). In addition, NEEA has developed and is presenting a modified version of the BCD energy code training.	2
Pennsylvania	There are no recent studies that have attempted to measure compliance rates in Pennsylvania. Enforcement is done by certified individuals who are either state employees, municipal employees or who work for certified third-party agencies that have been retained by municipalities. Code officials receive training in anticipation of passing the exams required to obtain initial certification and must engage in continuing education.	1
Rhode Island	Rhode Island is in the process of doing a baseline compliance study for the state with the investor-owned utility National Grid. Enforcement is done by the code officials in local jurisdictions, while the State Building Commissioner enforces the code for all state buildings. The Rhode Island Department of Administration has recently set up a schedule for mandatory training for building officials.	1
South Carolina	South Carolina recently completed a gap analysis, analyzing the current code implementation efforts in the state and making recommendations for achieving 90% compliance with the model energy code. The state also participates in BCAP's Compliance Planning Assistance Program and completed a compliance plan in November 2011, providing a five-year roadmap for energy code implementation in the state. Extensive compliance training was conducted in SC during 2011. Under a grant from Pacific Northwest National Laboratory, approximately 500 code officials and others received training on the 2006 (with elements of 2009 and 2012) Code. Additionally, joint training for building code officials and homebuilders will be held at 8 locations around the state beginning in September 2012.	1
South Dakota	I In pursuance of ARRA requirements, the state completed a report that lists recommendations for maximum compliance. In addition, in partnership with BCAP's Compliance Planning Assistance program, a gap analysis was completed in January 2011 to analyze code adoption and recommend actions to achieve higher compliance. However, no studies measure compliance rates in the state. Enforcement is done at the local level. The Office of the State Engineer does contractually require building energy code compliance for state owned building projects. State government is not involved in training of local code officials or builders.	0

State	Summary of State Building Code Compliance Efforts	Score
Tennessee	No studies have been completed to measure compliance rates in the state. The Tennessee Department of Commerce and Insurance has the authority to enforce residential energy codes and has conducted training for staff and local governments. Energy Codes Training and Enforcement programs are underway at the Tennessee Codes Enforcement Academy and the Department of Commerce and Insurance is in the process of establishing a website for online code training, which will include energy code compliance. The Department has provided over 1,400 hours of IECC training for 235 code officials and has also initiated a web-based "Codes College" to provide computer-based codes training, particularly energy codes training, to officials and homebuilders. The University of Tennessee Municipal Technical Advisory Service (MTAS) also provides additional free energy codes training on campuses across the state as well as online webinar training on energy codes to local governments and enforcement officials at no cost to participants.	1
Texas	In 2011, Texas BCAP released a study on compliance in the state that found uneven performance and presented a range of ideas to improve compliance. Texas is a home rule state, so enforcement is done by local jurisdictions. Local jurisdictions also decide the code compliance training requirements for their code officials. The State Energy Conservation Office (SECO) is in charge of code compliance for state-owned buildings. Builders are not required to take training since the Texas Residential Commission was dismantled. City building officials have to keep their certifications by continuing education credits, but it is not mandated by the state. SECO has also partnered with BCAP to establish a building energy code collaborative, which includes a number of governmental agencies and non-governmental organizations.	0.5
Utah	Utah participated in a compliance pilot study in 2011 using Pacific Northwest National Lab methodology that showed, with limited numbers), compliance above 85% for residential buildings. Local jurisdictions are obligated to enforce the adopted state codes. The Utah State Energy Program has been conducting energy code education since 2007. The free trainings have been made available across the state in more than 40 half- or full-day sessions. The free trainings were scheduled to continue in 2010 with an additional 8 full-day sessions, 7 hour-long webinars, and up to 4 special presentations for industry association meetings. The Office of Energy Development continues to provide training through Utah utility DSM funding. Additionally, grant funds from DOE/PNNL have allowed for increased training and personnel in 2011. As a result, the state has increased the number of ICC Certified individuals from 15 to 83, has trained 14 Energy Code Ambassadors, and has three energy code trainers trained through the Southwest Energy Efficiency Project's coordinated energy code trainer curriculum by Pacific Northwest Laboratory. The governor's 2011 energy plan includes increased energy code education as a way to raise public awareness and to treat energy efficiency as a resource. Lastly, the Utah Building Energy Efficiency Strategies Partnership (UBEES), an ARRA funded program, established a monthly "Code Compliance Capitol Morningsides Trainings". These two hour trainings are available as a webcast or in person and have received numerous ENERGY STAR awards.	2

State	Summary of State Building Code Compliance Efforts	Score
Vermont	There are no current studies that have attempted to measure compliance rates in Vermont, but the Vermont Department of Public Service (DPS) is including measurements of compliance with the Residential Building Energy Standards (RBES) and Commercial Building Energy Standards (CBES) in their current Market Assessments to be completed in 2012. Both residential and commercial certifications are required to be filed with the DPS. Residential certifications must also be filed with the municipal government. The DPS also provides training to builders in conjunction with the Department of Public Safety. Efficiency Vermont, the state sustainable energy utility, also holds trainings. There are no code officials in the state.	1
Virginia	A statewide building compliance study was scheduled to be completed by June 2012. Enforcement is done by local building departments. The Department of Housing and Community Development conducts three days of code training every three years for the new codes and any changes. Local seminars occur more frequently. Each technical assistant goes through three days of training for each certification held, and all must take 16 hours of continuing education every two years.	1.5
Washington	The last study measuring compliance in Washington was conducted in 2008 by the Northwest Energy Efficiency Alliance and was based on the code enforced in 2001, which was based on ASHRAE 90.1-1999. At the time, compliance was measured at 94%. Enforcement is done through local jurisdictions. Training is up to local jurisdictions, where local trade associations and code chapters provide training for their members. Typically energy code trainings are contracted to Washington State University and the Northwest Energy Efficiency Council for instructors, and the Washington Association of Building Officials (WABO) offers some training sessions each year.	2
West Virginia	There are no current studies that have attempted to measure compliance rates in West Virginia. Enforcement is done by local planning offices throughout the state. The West Virginia Division of Energy has historically provided the only energy code training in the state. However, WVDOE has recently contracted with West Virginia Northern Community College to provide training on the state's current energy codes, the 2003 IECC, as well as on the planned update to the 2009 IECC to home builders across West Virginia. These training sessions began in May 2012.	1
Wisconsin	There are currently no studies that have attempted to measure compliance rates in Wisconsin due mostly to statewide requirements for inspection of all new buildings. However, the state did receive funding from the Department of Energy to implement a pilot study of compliance in commercial buildings. The study found that new commercial buildings were typically over 90% in compliance with the current commercial building code (at that time the 2006 IECC with Wisconsin amendments as addressed under SPS 363). All licensed UDC and Wisconsin Commercial Building Inspectors are required to obtain continuing education credits in order to renew their license. Each late winter/early spring, the four inspector associations put on training, but it is not mandatory. The Department of Safety and Professional Services offers various training courses throughout the year, which are also not mandatory. Some courses are available online, others are addressed by organizations such as Wisconsin Focus on Energy, Energy Center of Wisconsin, Wisconsin Builders Association and others.	1.5

State	Summary of State Building Code Compliance Efforts	Score
Wyoming	There are no current studies that have attempted to measure compliance rates in Wyoming. Local jurisdictions that are established as local enforcement may, but are not required to, enforce energy codes at the local level. The State Energy Office (SEO) has funded numerous trainings for code officials, industry, and elected officials since 2010, as well as an energy code train-the-trainer in Cheyenne with six Wyoming code officials in attendance. As a result of a partnership between the SEO and the Wyoming Conference of Building Officials, a 2009 Energy Codes Fundamentals course was held around the state. The SEO contracted with ICC to conduct those trainings. As a follow-up the SEO requested that ICC customize two one-day courses focused toward the designer and contractor communities that were held in June of 2011. The Wyoming Conference of Building Officials has formed an energy code subcommittee and is working across the state on energy code education. Additionally, two Wyomingites attended the sequel train-the-train for plan review and inspection. Three code officials are designated as ICC/BCAP Energy Code Ambassadors who are trained to train others on the energy code throughout 2012 and 2013. The state has agreed to partner with Rocky Mountain Power who has been asked to provide additional funding for adoption and compliance assistance.	1

Appendix H: Expanded Table of State RD&D Programs

State	Major RD&D Programs	Score
Alaska	The **Cold Climate Housing Research Center (CCHRC),** which represents 1,200 building industry organizations in Alaska and has a staff of 26, conducts applied research, development, and demonstration on sustainable, energy-efficient and healthy buildings. The Center's Research and Testing Facility first opened in 2006 after receiving $5.2 million in public and private funding. The Alaska Energy Authority (AEA) oversees the **Emerging Energy Technology Fund (EETF)**, which concentrates heavily on energy efficiency technologies. The Fund, which received $2.4 million in state appropriations in 2011 in addition to private contributions, provides grants to entities that perform research to develop or improve energy-efficient technologies.	2
Alabama	The **University of Alabama's Center for Advanced Vehicle Technologies (CAVT)** assists in the research and development of numerous transportation systems and vehicles, and has a faculty and staff of 30. Their efficiency research is primarily focused on improving powertrains as well as energy storage and fuel cells.	1
Arizona	The **Sustainable Energy Solutions (SES) Group of Northern Arizona State** provides research, development, and demonstration of new as well as improved energy technologies and systems, including those focused on efficiency. The Group is funded by the Arizona Technology Research and Initiative Fund as well as an average of $400,000 per year in external funding. **Arizona State University's LightWorks Center** is focused in part on energy efficiency, including research into solid state lighting as a way to reduce energy costs as well as the interaction of human behavior and energy-efficient technologies.	2
California	The **California Energy Commission's Public Interest Energy Research (PIER)** program supports research and development in several key areas including energy efficiency for buildings, industry, agriculture, and water systems. PIER is funded from a surcharge on electricity and natural gas use in the state that totals about $80 million per year. **UC Davis** houses the **Center for Water-Energy Efficiency (CWEE)** and the **Energy Efficiency Center (EEC)**. CWEE focuses on the research and development of efficient technologies that will lead to the conservation of water and energy resources. CWEE has a permanent staff of three and receives funding from the EEC, the California Lighting Technology Center, and the Western Cooling Efficiency Center. The EEC's mission is to accelerate the development and commercialization of energy efficiency technologies. It has a faculty and staff of 25 and received initial funding from the California Clean Energy Fund. The **Center for Energy Science and Technology Advanced Research (CESTAR) at UCLA**, with a faculty and staff of 42, includes energy efficiency as one of its four major research areas. The **Smart Grid Energy Research Center (SMERC)** also performs research into the development of the next generation of the electric utility grid, with one of their criteria being improving its efficiency. SMERC has a faculty and staff of 13 and is funded by a $10 million grant from US DOE.	2

State	Major RD&D Programs	Score
Colorado	The **Engines and Energy Conversion Lab (EECL) at Colorado State University** contributes to energy efficiency in their research on smart grid technology and engine efficiency, primarily in advanced ignition systems and after-treatment systems. EECL has a staff of 22 and is funded through numerous corporate sponsors. The **Institute for the Built Environment (IBE) at Colorado State University** engages faculty and industry partners in healthy and sustainable building issues including energy-efficient construction, integration of clean energy technologies and sustainable built environments. The **Renewable and Sustainable Energy Institute (RASEI) at the University of Colorado, Boulder** is a joint institute with the National Renewable Energy Laboratory (NREL) to research and develop ways to produce energy at a lower cost, with higher efficiency, and with reduced emissions. RASEI has 16 staff and 30 fellows. The **Research in Delivery, Usage, and Control of Energy (ReDUCE)** research group at the **Colorado School of Mines** includes energy efficiency projects such as the Cyber-Enabled Efficiency Energy Management of Structure, sponsored by the National Science Foundation, which concerns the sensing and control of energy flow in buildings, as enabled by cyber infrastructure. The **Center for Renewable Energy Economic Development (CREED)** is a catalyst for economic development in Colorado through clean energy and energy efficiency innovation and entrepreneurship. CREED is a product of the National Renewable Energy Lab and partners with state government agencies such as the Governor's Energy Office and the Office of Economic Development and International Trade and industry groups such as the Colorado Cleantech Industry Association.	2
Connecticut	The **University of Connecticut's Center for Clean Energy Engineering (C2E2)** focuses on advanced energy conversion technologies, fuels and fuel processing, energy storage, power management and smart grid and conservation of natural resources with a focus on water. The Center was founded in 2009 and received over $20 million in funding by March 2011. It has a staff of 21 that includes 17 researchers.	1
Florida	The **University of Central Florida's Florida Solar Energy Center's (FSEC)** building science program includes energy efficiency research relating to buildings, schools, and green standards. The Center has a staff of 150 and receives $3 million in operating funds annually from the University and $8-$12 million in external grants. The **Energy and Sustainability Center (ESC) at Florida State University** focuses on energy efficiency projects including the Center's Off-Grid Zero Emission Building project, which created an energy-efficient mold for alternative energy technologies in both residential and commercial buildings, and research focused on both PEM fuel cells and water electrolysis. The center has a staff of seven and receives funding from the University. The **University of Florida's Florida Institute for Sustainable Energy (FISE)** performs efficiency research that focuses on fuel cells, building construction, and lighting. The Institute has a faculty of over 150 spread among 22 energy research centers and its funding over the past several years has totaled $70 million.	2

State	Major RD&D Programs	Score
Georgia	Funded in part by the Georgia Environmental Finance Authority, the **Southface Energy Institute**, with a staff of almost 50, conducts research and training on energy-efficient housing and communities. The Georgia Environmental Finance Authority collaborates with the Institute on its weatherization training and technical assistance. At the **Georgia Institute of Technology, the Brook Byers Institute for Sustainable Systems (BBISS)** focuses on engineering water and power infrastructures, and the Institute's current efficiency-based research is focused around its Sustainable Infrastructure for Energy and Water Systems (SINEWS) Project funded by the National Science Foundation. This project has secondary teams from Arizona State University and the University of Georgia and has a total staff of 11.	2
Idaho	The **Center for Advanced Energy Studies (CAES)** is a partnership between Idaho National Laboratory and the State of Idaho through its three public research universities: Boise State University, Idaho State University, and the University of Idaho. The Center performs research on energy efficiency as well as a variety of other issues, and receives funding from the State of Idaho, U.S. DOE, and a variety of private and public customers. Most recently it received $5 million in three research grants from U.S. DOE to focus on solar energy, geothermal energy, and energy efficiency.	1
Illinois	The **University of Illinois at Chicago's Energy Resources Center (ERC)** focuses on energy conservation and production technologies and assists both private and public institutions at the local and state levels by identifying opportunities for improved efficiency and reduced utility bills. The Engineering Solutions Group has a dedicated staff of four of the Center's 16 personnel. The Center receives funding from the University, a variety of public and private clients, and sponsorships from Amoco Foundation, Commonwealth Edison, the Electric Power Research Institute, People's Energy Corp., and Nicor Inc.	1
Iowa	The **Iowa Energy Center** strives to advance efficiency and renewable energy within the state through research and development while providing a model for the state to decrease its dependence on imported fuels. The Iowa Energy Center has a staff of 12 and receives its funding from an annual assessment on the gross intrastate revenues of all natural gas and electric utilities in Iowa.	1
Kansas	**Studio 804, Inc.** is a nonprofit 501(c)(3) corporation that works in partnership with the University of Kansas' School of Architecture, Design, and Planning, and is committed to the continued research and development of sustainable, affordable, and inventive building solutions. For the last 16 years, Studio 804 has pioneered new technologies and advanced construction techniques including four LEED Platinum projects, including the *Sustainable Prototype* in Greensburg, Kansas.	1
Kentucky	The **Conn Center for Renewable Energy Research (CCRER) at the University of Louisville** leads research that increases homegrown energy sources to meet the national need while reducing energy consumption and dependence on foreign oil. The Center has nine full-time staff and partners with over 60 faculty members at universities across the state, and has steadily been increasing its annual research expenditures from $900,000 in 2007 to $2.1 million in 2011 with the goal of reaching $5 million by 2016.	1

State	Major RD&D Programs	Score
Maryland	The **University of Maryland Energy Research Center (UMERC)** is dedicated to the development of energy-efficient and environmentally sustainable technologies and practices and leads one of the U.S. DOE Energy Frontier Research Centers focused on energy storage. UMERC also educates the public on matters of energy efficiency and sustainability, and focuses specifically on heating, ventilation and air condition (HVAC), combined heat and power, lighting and building efficiency, and waste heat recovery. UMERC and its affiliated faculty receive funding from the University of Maryland, U.S. DOE, and a variety of other sources based on research topic.	1
Massachusetts	**Massachusetts Energy Efficiency Partnership (MAEEP)** supports demonstration of energy efficiency technology and tools to the industrial, commercial, and institutional sectors. The MAEEP program leverages resources from U.S. DOE, the University of Massachusetts and Massachusetts Electric Utilities, NSTAR, MECO and WMECO, in partnership. Massachusetts is also offering **High Performance Green Building Grants** administered by the Massachusetts Department of Energy Resources to demonstrate innovative ways to improve energy performance in various types of buildings. The grants will use $16.25 million of American Recovery and Reinvestment Act (ARRA) funds to leverage an additional $42.5 million from grant recipients. The state's program administrators also have a number of deep energy retrofits and behavioral pilot programs. The **Center for Energy Efficiency and Renewable Energy (CEERE) at the University of Massachusetts, Amherst** focuses on renewable energy resources, energy efficiency in buildings, industrial energy efficiency, and environmental technologies with unique abilities to service energy and environmental problems. The Center has 43 faculty and staff and is funded in part through U.S. DOE grants.	2
Michigan	The **Michigan NextEnergy Center** is a 501(c)(3) nonprofit organization focused on energy efficiency and battery storage that leases laboratory facilities, business incubator space, and other facilities to members of the state's alternative energy industry. As part of a "renaissance Zone," businesses within the NextEnergy Center may be eligible for tax benefits in addition to the numerous tax credits the state offers alternative energy businesses. The **Clean Energy Research Center (CERC) at Oakland University in Rochester, Michigan** conducts research to help deliver energy efficiency solutions, create new clean energy jobs, and develop natural resource, environmental, and economic technologies. The Center was created in March 2011, funded by an initial grant from the Michigan Department of Energy, Labor and Economic Growth, and the Energy Systems Group.	2

State	Major RD&D Programs	Score
Nebraska	The **Nebraska Center for Energy Sciences Research (NCESR)** is a collaboration between the University of Nebraska-Lincoln and the Nebraska Public Power District, established in 2006 to conduct research on renewable energy sources, energy efficiency and energy conservation, and to expand economic opportunities in Nebraska. The Center receives $70k annually from the University as well as additional funding from the Nebraska Public Power District, including $450,000 for energy research grants. The **Energy Savings Potential (ESP)** program is a collaboration between the University of Nebraska at Omaha and Omaha Public Power District. Since 2006, the District has allocated $500,000 per year for research on consumer behavior and ways to reduce energy consumption.	2
New Jersey	The New Jersey Commission on Science and Technology administers the **Edison Innovation Clean Energy Fund** through a Memorandum of Understanding with the New Jersey Board of Public Utilities. The Clean Energy Fund provides grants of $100,000 to $500,000 to New Jersey companies for demonstration projects and developmental and ancillary activities necessary to commercialize renewable energy and energy efficiency technologies. In 2011 the Fund had $4 million to disburse. The **Rutgers Energy Institute (REI)** was formed in 2006 to integrate basic research with real-world applications to advance energy technologies in a variety of areas. Its efficiency research focuses on energy-saving techniques and equipment, healthier indoor air-quality systems, building material reuse, and solid waste reduction. REI has 51 faculty and staff and is currently receiving $2 million in external research grants in addition to University funding.	2

State	Major RD&D Programs	Score
New York	The **New York State Energy Research and Development Authority (NYSERDA)** supports a broad range of technology research, development and commercialization activities. NYSERDA makes strategic investments in scientific research and market analysis and develops and tests new products and technologies that have the potential to improve energy efficiency and expand energy options in New York's buildings, industrial, transportation, power, and environmental sectors. NYSERDA's 2011-2012 budget for RD&D activities was approximately $64 million. The **Center for Sustainable & Renewable Energy (CSRE) at the State University of New York** is a clearinghouse for all 64 SUNY campuses' research and development in the areas of energy efficiency and sustainability, including the New York "Green Campus" Energy Efficiency Initiative. The **Building Energy and Environmental Systems Laboratory (BEESL) at Syracuse University** is a research lab associated with the Syracuse Center of Excellence in Environmental and Energy Systems, the New York Strategically Targeted Academic Research Center for Environmental Quality Systems, and the New York Indoor Environmental Quality Center. The Laboratory advances technologies related to a number of environmental issues, including energy efficiency in buildings. It was established in November 1999 with funds from U.S. EPA, New York State Assembly, investor-owned utility National Grid, Syracuse University, and a $2 million gift from Frances and Fritz Traugott, and has a staff of nearly 40. The **Institute for Urban Systems at City University of New York (CIUS)** identifies innovative solutions to the problems of aging capital stock, advances environmental sustainability, and works to increase urban economic competitiveness in the management of transportation, energy, water, buildings, and other infrastructure systems.	2

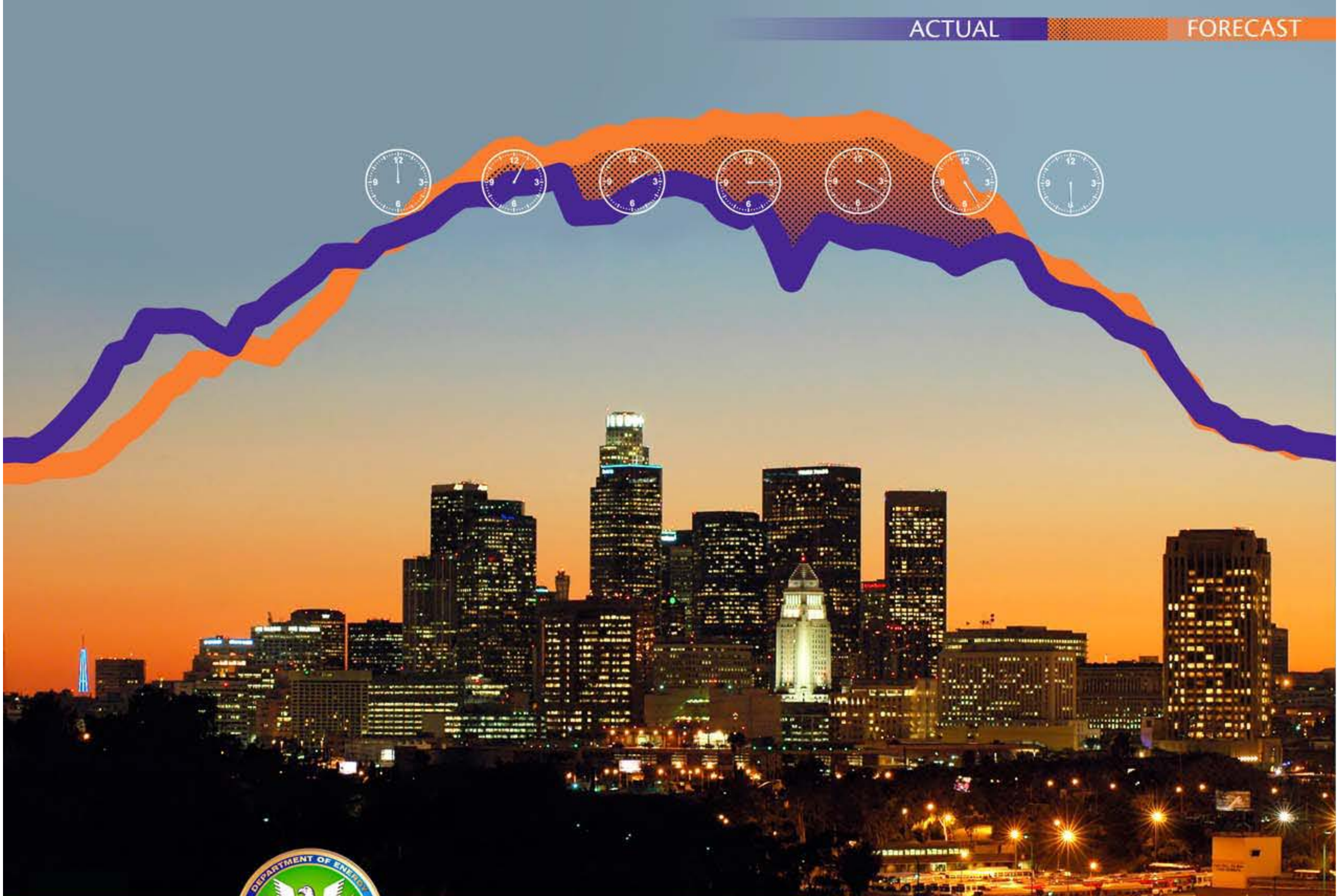
State	Major RD&D Programs	Score
North Carolina	The **North Carolina Green Business Fund** provides grants of up to $100,000 to small and mid-size businesses, nonprofit organizations, state agencies, and local governments with in the state to encourage the development and commercialization of promising renewable energy and energy-efficient building technologies. The total awarded amount in 2011 was $3.6 million. The **North Carolina Solar Center** has a focus on energy efficiency to assist commercial and industrial clients in saving energy. This team operates multiple programs focusing on combined heat and power technology in the Southeast, and the Center also operates the Database of State Incentives for Renewables & Efficiency. The Center received $500,000 in research grants from the American Recovery and Reinvestment Act in 2011, in addition to other funding sources. The **Center for Energy Research and Technology (CERT) at North Carolina A&T State University** conducts research on reducing energy and water consumption and promoting sustainable energy design practices. The Center promotes and develops strategies for the reduction of carbon dioxide emissions, energy independence, and net-zero energy and sustainable design practices. The Center was founded in 1984, has a staff of five, and received $300,000 in research grants in 2011 from the city of Greensboro and the North Carolina Department of Commerce. The **Appalachian State University Energy Center** is an applied research and public service program through which the university makes its resources, faculty, and professional staff available to address economic, business, government and social issues and problems related to renewable energy policy, technology and development.	2
Ohio	The **Center for Energy, Sustainability, and the Environment (CESE) at Ohio State University (OSU)** conducts research in efficient energy infrastructure systems (e.g., power grid, and transportation networks), as well as "systems of energy systems" (e.g., smart micro grids, and markets). As of 2009, the Center was receiving $1.8 million in funding from the University.	1

State	Major RD&D Programs	Score
Oregon	The **Oregon Built Environment and Sustainable Technologies Center (BEST)** is an independent, nonprofit organization established by the Oregon legislature to help Oregon businesses compete globally by transforming and commercializing university research into new technologies, services, products, and companies. BEST shares research facilities for the study of energy-efficient and green buildings as well as providing energy efficiency research grants. The **University of Oregon Energy Studies in Building Laboratory** conducts research on buildings and transportation to develop strategies for maximum energy efficiency in new materials, components, assemblies, and whole buildings. It has a staff of six and has received funding from numerous private and public sources totaling $16 million over the past 20 years. The **Baker Lighting Lab at the University of Oregon** provides support and opportunities for the exploration of lighting design, including studying daylighting and the control of these systems. **Portland State University's Renewable Energy Research Lab** conducts research on sustainable urban development, which covers smart grid development and net-zero energy use. The Lab is a joint project of the University and Portland General Electric, established in 2010 with $50,000 in funding from the utility. The **Energy Trust of Oregon** is an independent nonprofit organization dedicated to helping utility customers benefit from saving energy and generating renewable energy. In the area of energy efficiency, the Trust runs programs to field test emerging technologies. The **Oregon Transportation Research and Education Consortium (OTREC)** is a national University Transportation Center and a partnership between Portland State University, the University of Oregon, Oregon State University and the Oregon Institute of Technology. The group supports innovation through advanced technology, integration of land use and transportation, and healthy communities, and has also teamed up with Portland-based Green Lite Motors to bring a 100 mile-per-gallon vehicle closer to market.	2
Pennsylvania	The **Energy Research Center (ERC) at Lehigh University** emphasizes research dealing with energy conversion, power generation and environmental control. The Center's research is supported by contracts and grants from government and industry and has approximately 36 full-time staff. The Center also operates the Energy Liaison Program, which provides consultation and problem-solving assistance to participating companies for up to $20,000 a year. The **Indoor Environment Center (IEC) at the Penn State Institutes of Energy and the Environment (PSIEE)** conducts research, knowledge transfer, and outreach activities to support the development of indoor environments that are safer and more thermally, visually and acoustically comfortable, and that minimize the use of energy and other resources. IEC has a full-time staff of 22.	2
Tennessee	**The University of Tennessee** has a strong partnership with **Oak Ridge National Laboratory**, which collaborates with other state stakeholders and industry members, including the **Electric Power Research Institute**. The **University of Tennessee Research Foundation (UTRF)** also promotes the commercialization and deployment of advanced technologies, some of which are related to energy efficiency.	1

State	Major RD&D Programs	Score
Texas	The **Texas A&M's Energy Systems Laboratory (ESL)** focuses on energy-related research, energy efficiency, and emissions reduction. ESL directs its efforts toward innovative energy technologies and systems and commercializing affordable results for industry, and also plays an important role in the implementation of state energy standards. The Lab has an annual external research and testing income of $10 million and a staff of 46. The **University of Texas at Austin's Center for Energy and Environmental Resources (CEER)** focuses on the efficient and economical use of energy and on ensuring a cleaner environment by developing, in cooperation with industry, processes and technologies that minimize waste and conserve natural resources. CEER has a staff of 107 and is funded from numerous state, federal, and private sources.	2
Vermont	The **Center for Energy Transformation and Innovation at the University of Vermont** is a recently announced, not yet established research center that will be a partnership between the state, Sandia National Laboratories of New Mexico, the University of Vermont, and other academic institutions. The Center will focus on sustainable energy, energy efficiency, and smart-grid technology, and is initially designed to be a three-year project. The Center is receiving starting funds of $15 million, $9 million from Sandia, $3 million from the state, and $3 million from U.S. DOE.	2
Virginia	The new **Modeling and Simulation Center for Collaborative Technology** in Halifax County will be undertaking research and development work in energy-efficient advanced manufacturing. The Center received $1.2 million in start-up funds and expects to attract numerous research contracts from private engineering firms as well as federal agencies. The Center will start with a staff of eight.	1
West Virginia	The **Advanced Energy Initiative (AEI) at West Virginia University** focuses on high-efficiency engines and vehicle technologies and the sustainable use of water in energy production, as well as other research areas. AEI currently has 15 staff in their Sustainable Energy program, which houses the Initiative's energy efficiency research. The program received 32.2% of the $30.9 million, or $9.94 million, in research grants that AEI obtained in 2011.	1
Wisconsin	The **Energy Center of Wisconsin** conducts technology and field research, energy efficiency program evaluation and market research, offers education programs, and develops and implements programs. The Center features an award-winning program on building energy use in new commercial construction. The Center has a staff of 44 and has an annual budget of approximately $2 million from state, customer, private, and other sources. **Wisconsin Focus on Energy** operates an Emerging Technology program that promotes emerging, industrial, energy efficiency technologies. The program deploys and commercializes technologies that have the potential for large, cost-effective energy savings and that have multiple installations in Wisconsin, and it can provide technology evaluations, development plans, and funding for businesses that have developed new technologies. The annual budget for Wisconsin Focus on Energy was $100 million in 2012.	2

EXHIBIT FA-6

A National Assessment of Demand Response Potential



Staff Report

Federal Energy Regulatory Commission

June 2009

Prepared by

The Brattle Group | Freeman, Sullivan & Co. | Global Energy Partners, LLC

A NATIONAL ASSESSMENT OF DEMAND RESPONSE POTENTIAL

Federal Energy Regulatory Commission
STAFF REPORT

Prepared by

The Brattle Group
Freeman, Sullivan & Co
Global Energy Partners, LLC

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The analysis presented in this report was produced by a team of consultants from The Brattle Group (TBG), Freeman, Sullivan & Co. (FSC) and Global Energy Partners (GEP). Each firm led different parts of the project, typically with significant input from the other firms. TBG managed the project and was the lead contractor to the Federal Energy Regulatory Commission (FERC). TBG also had the lead in producing this report. FSC was the lead contractor on model development, and also developed the state and customer-segment level load shapes that were used as starting points for developing demand response impacts. FSC and TBG worked together to develop price impacts that reflect the extensive research that has been done in this area. GEP had the lead on data development with input from both TBG and FSC. Gary Fauth, an independent consultant specializing in advanced metering business case analysis, had the lead role in producing the advanced metering deployment scenario that underlies one of the potential estimates. Senior staff from all three firms worked jointly to develop scenario definitions and to provide defensible input assumptions for key drivers of demand response potential.

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The Brattle Group
Ahmad Faruqui
Ryan Hledik

Freeman, Sullivan & Co.
Stephen S. George
Josh Bode
Paul Mangasarian

Global Energy Partners, LLC
Ingrid Rohmund
Greg Wikler
Debyani Ghosh
Sharon Yoshida

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EXECUTIVE SUMMARY

Energy Independence and Security Act of 2007

Section 529 (a) of the Energy Independence and Security Act of 2007[1] (EISA 2007) requires the Federal Energy Regulatory Commission (Commission or FERC) to conduct a National Assessment of Demand Response Potential[2] (Assessment) and report to Congress on the following:

- Estimation of nationwide demand response potential in 5 and 10 year horizons on a State-by-State basis, including a methodology for updates on an annual basis;
- Estimation of how much of the potential can be achieved within those time horizons, accompanied by specific policy recommendations, including options for funding and/or incentives for the development of demand response;
- Identification of barriers to demand response programs offering flexible, non-discriminatory, and fairly compensatory terms for the services and benefits made available; and
- Recommendations for overcoming any barriers.

EISA 2007 also requires that the Commission take advantage of preexisting research and ongoing work and insure that there is no duplication of effort. The submission of this report fulfills the requirements of Section 529 (a) of EISA 2007.

This Assessment marks the first nationwide study of demand response potential using a state-by-state approach. The effort to produce the Assessment is also unique in that the Commission is making available to the public the inputs, assumptions, calculations, and output in one transparent spreadsheet model so that states and others can update or modify the data and assumptions to estimate demand response potential based on their own policy priorities. This Assessment also takes advantage of preexisting research and ongoing work to insure that there is no duplication of effort.

Estimate of Demand Response Potential

In order to estimate the nationwide demand response potential in 5 and 10 year horizons, the Assessment develops four scenarios of such potential to reflect different levels of demand response programs. These scenarios are: Business-as-Usual, Expanded Business-as-Usual, Achievable Participation and Full Participation. The results under the four scenarios illustrate how the demand response potential varies according to certain variables, such as the number of customers participating in existing and future demand response programs, the availability of dynamic pricing[3] and advanced metering infrastructure

[1] Energy Independence and Security Act of 2007, Pub. L. No. 110-140, § 529, 121 Stat. 1492, 1664 (2007) (to be codified at National Energy Conservation Policy Act § 571, 42 U.S.C. §§ 8241, 8279) (EISA 2007). The full text of section 529 is attached as Appendix F.

[2] In the Commission staff's demand response reports, the Commission staff has consistently used the same definition of "demand response" as the U.S. Department of Energy (DOE) used in its February 2006 report to Congress:

> 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 designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.

U.S. Department of Energy, Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005, February 2006 (February 2006 DOE EPAct Report).

[3] In this Assessment, dynamic pricing refers to prices that are not known with certainty ahead of time. Examples are "real time pricing," in which prices in effect in each hour are not known ahead of time, and "critical peak pricing" in which prices on certain days are known ahead of time, but the days on which those prices will occur are not known until the day before or day of consumption. Static time-varying prices, such as traditional time-of-use rates, in which prices vary by rate period, day of the week and season but are known with certainty, are not part of this analysis.

(AMI)[4], the use of enabling technologies, and varying responses of different customer classes. Figure ES-1 illustrates the differences in peak load starting with no demand response programs and then comparing the four scenarios. The peak demand without any demand response is estimated to grow at an annual average growth rate of 1.7 percent, reaching 810 gigawatts (GW) in 2009 and approximately 950 GW by 2019.[5]

This peak demand can be reduced by varying levels of demand response under the four scenarios. Under the highest level of demand response, it is estimated that there would be a leveling of demand between 2009 and 2019, the last year of the analysis horizon. Thus, the 2019 peak load could be reduced by as much as 150 GW, compared to the Business-as-Usual scenario. To provide some perspective, a typical peaking power plant is about 75 megawatts[6], so this reduction would be equivalent to the output of about 2,000 such power plants.

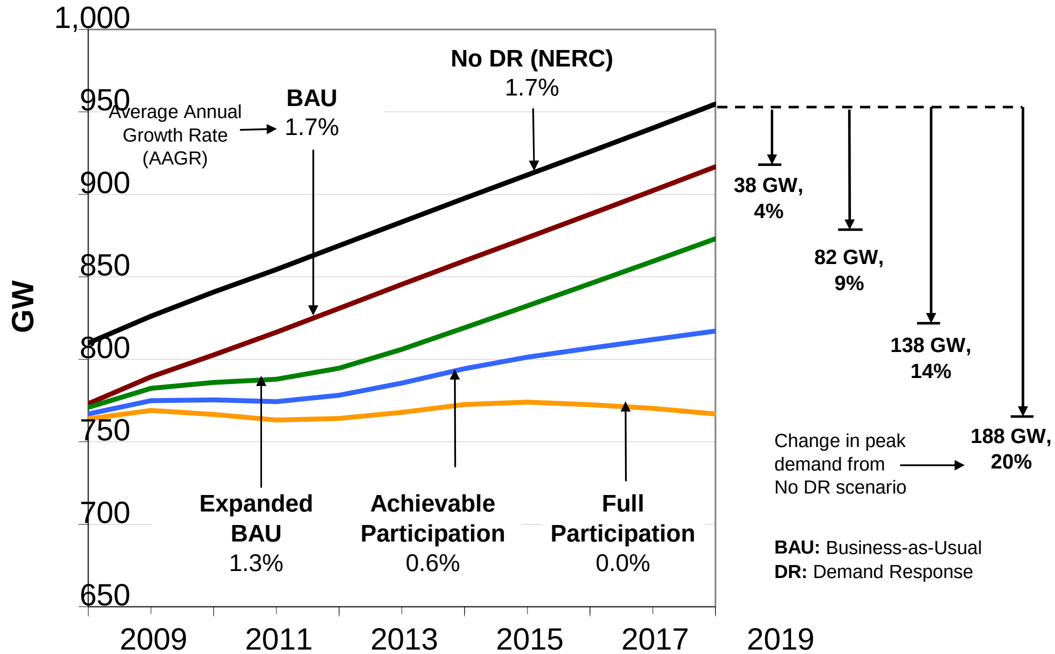


Figure ES-1: U.S. Peak Demand Forecast by Scenario

The amount of demand response potential that can be achieved increases as one moves from the Business-as-Usual scenario to the Full Participation scenario.

It is important to note that the results of the four scenarios 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, market acceptance of the programs, and the overall cost-effectiveness of the

4 A system including measurement devices and a communication network, public and/or private, that records customer consumption, and possibly other parameters, hourly or more frequently and that provides for daily or more frequent transmittal of measurements to a central collection point. AMI has the capacity to provide price information to customers that allows them to respond to dynamic or changing prices.

5 The "No DR (NERC)" baseline is derived from North American Electric Reliability Corporation data for total summer demand, which excludes the effects of demand response but includes the effects of energy efficiency. 2008 Long Term Reliability Assessment, p. 66 note 117; data at http://www.nerc.com/fileUploads/File/ESD/ds.xls

6 Energy Information Administration, Existing Electric Generating Units in the United States, 2007, available at http://www.eia.doe.gov/cneaf/electricity/page/capacity/capacity.html

programs. This report does not advocate what programs/measures should be adopted/implemented by regulators; it only sets forth estimates should certain things occur.

As such, the estimates of potential in this report should not be interpreted as targets, goals, or requirements for individual states or utilities. However, by quantifying potential opportunities that exist in each state, 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 uncertainties, most of them arising from limitations in the data that are used to estimate the model parameters. Demand response studies performed with accurate utility data have had error ranges of up to ten percent of the estimated response per participating customer. In this analysis, the use of largely publicly-available, secondary data sources makes it likely that the error range for any particular estimate in each of the scenarios studied is larger, perhaps as high as twenty percent.[7]

Business-as-Usual Scenario

The Business-as-Usual scenario, which we use as the base case, considers the amount of demand response that would take place if existing and currently planned demand response programs continued unchanged over the next ten years. Such programs include interruptible rates and curtailable loads for Medium and Large commercial and industrial customers, as well as direct load control of large electrical appliances and equipment, such as central air conditioning, of Residential and Small commercial and industrial consumers.

The reduction in peak demand under this scenario is 38 GW by 2019, representing a four percent reduction in peak demand for 2019 compared to a scenario with no demand response programs.

Expanded Business-as-Usual Scenario

The Expanded Business-as-Usual scenario is the Business-as-Usual scenario with the following additions: 1) the current mix of demand response programs is expanded to all states, with higher levels of participation ("best practices" participation levels);[8] 2) partial deployment of advanced metering infrastructure; and 3) the availability of dynamic pricing to customers, with a small number of customers (5 percent) choosing dynamic pricing.

The reduction in peak demand under this scenario is 82 GW by 2019, representing a 9 percent reduction in peak demand for 2019 compared to a scenario with no demand response programs.

Achievable Participation Scenario

The Achievable Participation 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. This scenario assumes full-scale deployment of advanced metering

[7] For example, an estimated demand response potential of 19 percent could reflect actual demand response potential ranging from 15 to 23 percent. See Chapter II for a description of one source of error resulting from data limitations, and Appendix E for an analysis of uncertainties arising from the study assumptions.

[8] For purposes of this Assessment, "best practices" refers only to high rates of participation in demand response programs, not to a specific demand response goal nor the endorsement of a particular program design or implementation. The best practice participation rate is equal to the 75th percentile of ranked participation rates of existing programs of the same type and customer class. For example, the best practice participation rate for Large Commercial & Industrial customers on interruptible tariffs is 17% (as shown in Table 5). See Chapter V for a full description.

infrastructure by 2019. It also assumes that 60 to 75 percent of customers stay on dynamic pricing rates, and that many of the remaining choose other demand response programs. In addition, it assumes that, in states where enabling technologies (such as programmable communicating thermostats) are cost-effective and offered to customers who are on dynamic pricing rates, 60 percent of the customers will use these technologies.

The reduction in peak demand under this scenario is 138 GW by 2019, representing a 14 percent reduction in peak demand for 2019 compared to a scenario with no demand response programs.

Full Participation Scenario

The Full Participation scenario is an estimate of how much cost-effective demand response would take place if advanced metering infrastructure were universally deployed and if dynamic pricing were made the default tariff and offered with proven enabling technologies. It assumes that all customers remain on the dynamic pricing tariff and use enabling technology where it is cost-effective.

The reduction in peak demand under this scenario is 188 GW by 2019, representing a 20 percent reduction in peak demand for 2019 compared to a scenario with no demand response programs.

Other Results of the Assessment

As shown in Figure ES-1, the size of the demand response potential increases from scenario to scenario, given the underlying assumptions.[9] Comparing the relative impacts of the four scenarios on a national basis, moving from the Business-as-Usual scenario to the Expanded Business-as-Usual scenario, the peak demand reduction in 2019 is more than twice as large. This difference is attributable to the incremental potential for aggressively pursuing traditional programs in states that have little or no existing participation. However, more demand response can be achieved beyond these traditional programs. By also pursuing dynamic pricing the potential impact could further be increased by 54 percent, the difference between the Achievable Participation scenario and the Expanded Business-as-Usual scenario. Removing the assumed limitations on market acceptance of demand response programs and technologies would result in an additional 33 percent increase in demand response potential (the difference between the Achievable Potential and Full Potential scenarios). A conclusion of this Assessment is that at the national level the largest gains in demand response impacts can be made

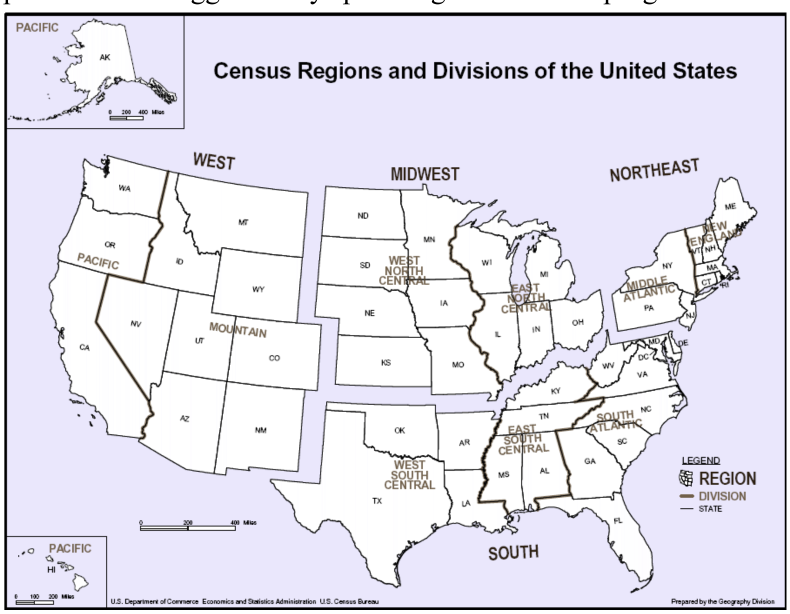


Figure ES- 2: Census Regions

9 There are other technologies that have the potential to reduce demand. These include emerging smart grid technologies, distributed energy resources, targeted energy efficiency programs, and technology-enabled demand response programs with the capability of providing ancillary services in wholesale markets (and increasing electric system flexibility to help accommodate variable resources such as wind generation.) However, these were not included in this Assessment because there is not yet sufficient experience with these resources to meaningfully estimate their potential.

through dynamic pricing programs when they are offered as the default tariff, particularly when they are offered with enabling technologies.

A mapping of states divided into the nine Census Divisions is provided in Figure ES-2. Regional differences in the four demand response potentials are portrayed by Census Division in Figure ES-3. To adjust for the variation in size among the divisions, the impacts are shown as a percentage of each Division's peak demand.

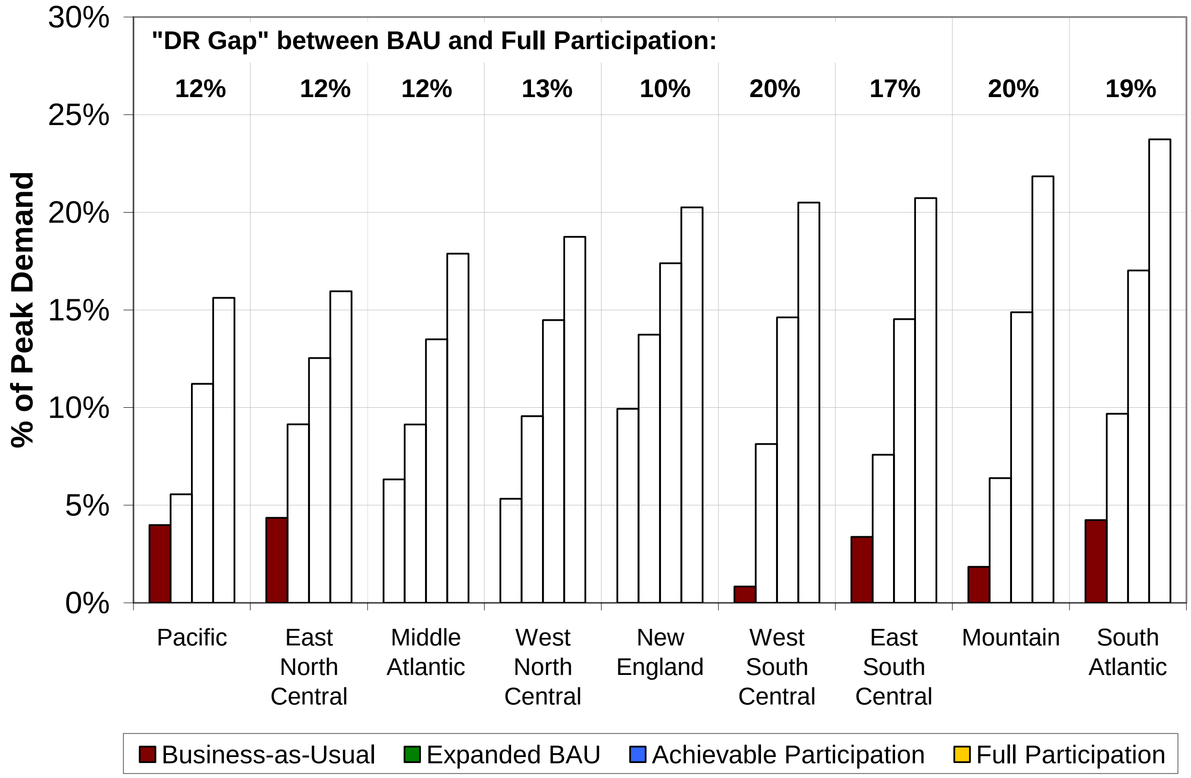


Figure ES-3: Demand Response Potential by Census Division (2019)

Regional differences in the estimated potential by scenario can be explained by factors such as the prevalence of central air conditioning, the mix of customer type, the cost-effectiveness of enabling technologies, and whether regions have both Independent System Operator/Regional Transmission Organization (ISO/RTO) and utility/load serving entity programs. For example, in the Business-as-Usual scenario, the largest impacts originate in regions with ISO/RTO programs that co-exist with utility/load serving entity programs. New England and the Middle Atlantic have the highest estimates, with New England having the ability to reduce nearly 10 percent of peak demand.

The prevalence of central air conditioning plays a key role in determining the magnitude of Achievable and Full Participation scenarios. Hotter regions with higher proportions of central air conditioning, such as the South Atlantic, Mountain, East South Central, and West South Central Divisions, could achieve greater demand response impacts per participating customer from direct load control and dynamic pricing programs. As a result, these regions tend to have larger overall potential under the Achievable and Full Participation scenarios, where dynamic pricing plays a more significant role, than in the Expanded Business-as-Usual scenario.

The cost-effectiveness of enabling technologies[10] also affects regional differences in demand response potential. Due to the low proportion of central air conditioning in the Pacific, New England, and Middle Atlantic Divisions, the benefits of the incremental peak reductions from enabling technologies, as determined in this study, do not outweigh the cost of the devices, so the effect of enabling technologies is excluded from the analysis. As a result, in some of these states and in some customer classes the demand reductions from dynamic pricing reflect only manual (rather than automated) customer response and so are lower than in states where customers would be equipped with enabling technologies. This also applies to the cost-effectiveness of direct load control programs.

The difference between the Business-as-Usual and Full Participation scenarios represents the difference between what the region is achieving today and what it could achieve if all cost-effective demand response options were deployed. Regions with the highest potential under the Full Participation scenario do not necessarily have the largest difference between Business-As-Usual and Full Participation. Generally, regions in the western and northeastern U.S. tend to be the closest to achieving the full potential for demand response, with the Pacific, Middle Atlantic, and New England regions all having gaps of 12 percent or less. Other regions, particularly in the southeastern U.S., have differences of as much as 20 percent of peak demand.

Comparing the results for these four scenarios provides a basis for policy recommendations. For example, the difference between the Business-As-Usual scenario and the Full Participation scenario reveals the "gap" between what is being achieved today through demand response and what could economically be realized in the future if appropriate polices were implemented. Similarly, the difference between the Expanded Business-as-Usual and the Achievable Participation scenarios reveals the additional amount of demand response that could be achieved with policies that rely on both dynamic pricing and other types of programs. The Assessment also provides valuable insight regarding regional and state differences in the potential for demand response reduction, allowing comparisons across the various program types – dynamic pricing with and without enabling technologies, direct load control, interruptible tariffs, and other types of demand response programs such as capacity bidding and demand bidding – to identify programs with the most participation today and those with the most room for growth.

Complete results for each of the fifty states and the District of Columbia are shown in Appendix A.

Barriers to Demand Response Programs and Recommendations for Overcoming the Barriers

A number of barriers need to be overcome in order to achieve the estimated potential of demand response in the United States by 2019. While the Assessment lists 25 barriers to demand response, the most significant are summarized here.

Regulatory Barriers. Some regulatory barriers stem from existing policies and practices that fail to facilitate the use of demand response as a resource. Regulatory barriers exist in both wholesale and retail markets.

- Lack of a direct connection between wholesale and retail prices.
- Measurement and verification challenges.
- Lack of real time information sharing.
- Ineffective demand response program design.

[10] The Assessment evaluates the cost-effectiveness of devices such as programmable communicating thermostats and excludes them where not cost-effective. See Chapter V for a complete description of the methodology.

- Disagreement on cost-effectiveness analysis of demand response.

Technological Barriers.

- Lack of advanced metering infrastructure.
- High cost of some enabling technologies.
- Lack of interoperability and open standards.

Other Barriers.

- Lack of customer awareness and education.
- Concern over environmental impacts.

As discussed above, three scenarios estimating potential reductions from the Business-as-Usual scenario have been developed. These scenarios estimate at 5 and 10 year horizons how much potential can be achieved by assuming certain actions on the part of customers, utilities and regulators. Each utility, together with state policy makers, must decide whether and how best to move forward with adoption of demand response, given their particular resources and needs; however, steps can be taken to help inform individual utility decisions and state policies, as well as national decisions.[11]

The increase in demand response under the Expanded Business-as-Usual scenario rests on the assumption that current "best practice"[12] demand response programs, such as direct load control and interruptible tariff programs, are expanded to all states and that there is some participation in dynamic pricing at the retail level. To encourage this expansion to all states and some adoption of dynamic pricing, FERC staff recommends that:

- Coordinated national and local education efforts should be undertaken to foster customer awareness and understanding of demand response, AMI and dynamic pricing.
- Information on program design, implementation and evaluation of these "best practices" programs should be widely shared with other utilities and state and local regulators.
- Demand response programs at the wholesale and retail level should be coordinated so that wholesale and retail market prices are consistent, possibly through the NARUC-FERC Collaborative Dialogue on Demand Response process.
- Both energy efficiency and demand response principles should be included and coordinated in education programs and action plans, to broaden consumers' and decision makers' understanding, improve results and use program resources effectively.
- Expanded demand response programs should be implemented nationwide, where cost-effective.
- Technical business practice standards for evaluating, measuring and verifying energy savings and peak demand reduction in the wholesale and retail electric markets should be developed.

[11] On a separate track FERC issued the Wholesale Competition Final Rule, which recognized the importance of demand response in ensuring just and reasonable wholesale prices and reliable grid operations. As part of the Final Rule, FERC required all RTOs and ISOs to study whether further reforms were necessary to eliminate barriers to comparable treatment of demand response in organized markets, among other things. Most RTOs and ISOs submitted filings that identified the particular barriers and possible reforms for their specific markets. Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, 73 Fed. Reg. 64, 100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 61,071 (2008).

[12] See definition of "best practices" at note 7.

- Open standards for communications and data exchange between meters, demand response technologies and appliances should be encouraged and supported, particularly the efforts of the National Institute of Standards and Technology to develop interoperability standards for smart grid devices and systems.
- Cost-effectiveness tools should be developed or revised to account for many of the new environmental challenges facing states and the nation, and to reflect the existence of wholesale energy and capacity markets in many regions.
- Regulators and legislators should clearly articulate the expected role of demand response to allow utilities and others to 1) plan for and include demand response in operational and long-term planning, and 2) recover associated costs.

The Achievable Participation and Full Participation scenarios estimate that the largest demand response would take place if advanced metering infrastructure were universally deployed and consumers respond to dynamic pricing. The Achievable Participation scenario is realized if all customers have dynamic pricing tariffs as their default tariff and 60 to 75 percent of customers adopt this default tariff, while the Full Participation scenario is based on all consumers responding to dynamic prices. For this to occur, in addition to the recommendations above,

- Dynamic pricing tariffs should be implemented nationwide.
- Information on AMI technology and its costs and operational, market and consumer benefits should be widely shared with utilities and state and local regulators.
- Grants, tax credits and other funding for research into the cost and interoperability issues surrounding advanced metering infrastructure and enabling technologies should be considered, as appropriate.
- Expanded and comprehensive efforts to educate consumers about the advantages of AMI and dynamic pricing should be undertaken.

The Full Participation scenario is dependent upon removal of limitations to market acceptance through implementation of these recommendations, and all customers must be able to respond under dynamic pricing.

FERC is required by Section 529 of EISA 2007, within one year of completing this Assessment, to complete a National Action Plan on Demand Response. The Action Plan will be guided in part by the results of this Assessment.

CHAPTER I. PURPOSE OF THE REPORT

Introduction

This report fulfills the requirements of the Energy Independence and Security Act of 2007 (EISA 2007) to conduct a national assessment of demand response ("the Assessment") using a state-by-state approach. As required by the EISA 2007, the analysis examines the potential for demand response over a ten year forecast horizon, with 2010 being the first year of the forecast and 2019 being the final year. In addition, the report identifies the barriers to achieving demand response potential, as required in EISA 2007. The work has been informed by preexisting research on the topic. The analysis concludes with policy recommendations by Federal Energy Regulatory Commission (FERC) staff for ways to overcome the barriers to demand response. FERC has commissioned The Brattle Group, along with Freeman, Sullivan & Co. and Global Energy Partners LLC to conduct this analysis.

As used in this report, the term demand response is defined as follows: [13]

> 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 designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.

The Assessment quantifies demand response potential for four scenarios, each designed to answer a different question:[14]

- <u>Business-as-Usual Scenario ("BAU"):</u> What will demand response and peak demand be in five and ten years?
- <u>Expanded BAU Scenario ("EBAU"):</u> What will demand response and peak demand be in five and ten years if the current mix of demand response programs is expanded to all states and achieves "best practices" levels of participation, and there are modest amounts of pricing programs and advanced metering infrastructure (AMI)[15] deployment?
- <u>Achievable Participation Scenario ("AP"):</u> What is the potential for demand response and peak demand in five and ten years if AMI is universally deployed, dynamic pricing is the default tariff, and other programs are available to those who decide to opt out of dynamic pricing?
- <u>Full Participation Scenario ("FP"):</u> What is the total potential amount of cost-effective demand response that could be achieved in five and ten years?

Comparing and contrasting the results for these four scenarios can answer a number of important questions. For example, the difference between the BAU scenario and the FP scenario reveals the "gap" between what is being achieved today through demand response and what could economically be realized in the future if the barriers are removed. Similarly, the difference between the EBAU and AP scenarios reveals the additional amount of demand response that could be achieved if policies shifted to an approach that relies on both economic and reliability based programs.

[13] U.S. Department of Energy, Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005, February, 2006.

[14] For more detail on the assumptions behind these scenarios, see Chapter V.

[15] A system including measurement devices and a communication network, public and/or private, that records customer consumption, and possibly other parameters, hourly or more frequently and that provides for daily or more frequent transmittal of measurements to a central collection point. AMI has the capability to provide customers with price information, allowing them to respond to dynamic or changing prices.

The study also provides insight regarding regional differences in demand response potential. The state-level nature of the analysis allows for comparisons across different regions of the U.S. to identify areas where there is opportunity for substantial growth and adoption of demand response. Comparisons can also be made across various program types - dynamic pricing with and without enabling technologies, direct load control, interruptible tariffs, and other types of demand response programs such as capacity bidding and demand bidding – to identify those programs with the most participation today and those with the most room for growth.

It is important to note that the results of the four scenarios 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, market acceptance of the programs, and the overall cost-effectiveness of the programs. This report does not advocate what programs/measures should be adopted/implemented by regulators; it only sets forth estimates should certain things occur.

As such, the estimates of potential in this report should not be interpreted as targets, goals, or requirements for individual states or utilities. However, by quantifying potential opportunities that exist in each state, 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 uncertainties, most of them arising from limitations in the data that are used to estimate the model parameters. Demand response studies performed with accurate utility data have had error ranges of up to ten percent of the estimated response per participating customer. In this analysis, the use of largely publicly-available, secondary data sources makes it likely that the error range for any particular estimate in each of the scenarios studied is larger, perhaps as high as twenty percent.[16]

The bottom-up, state-specific nature of the Assessment has led to a number of key developments which will contribute to future research on the topic. Of primary importance is the development of a flexible, user-friendly model for assessing demand response potential. The model is an Excel spreadsheet tool that contains user friendly drop-down menus which allow users to easily change between demand response potential scenarios, import default data for each state, and change input values on either a temporary basis for use in “what if” exercises or on a permanent basis if better data are available.

Highlights of additional unique contributions are as follows:

- The Assessment is the first nationwide, bottom-up study of demand response potential using a state-by-state approach. Previous national studies have taken a top-down approach and as a result have not captured the varying regional effects of some of the key drivers of demand response potential, such as market penetration of central air conditioning. Other studies have utilized a bottom-up approach, but have been limited to specific geographical regions and do not allow for a consistent comparison across all parts of the U.S.
- The Assessment led to the development of an internally consistent, state-by-state database containing all inputs needed to do a bottom-up estimate of demand response potential.
- Normalized load shapes were developed for five sectors (Residential with central air conditioning, Residential without central air conditioning, Small commercial and industrial, Medium commercial and industrial, and Large commercial and industrial). Historical usage data from twenty-one states and a newly-developed load shape estimation model created load shapes for the other twenty-nine states.

[16] For example, an estimated demand response potential of 19 percent could reflect actual demand response potential ranging from 15 to 23 percent. See Chapter II for a description of one source of error resulting from data limitations, and Appendix E for an analysis of uncertainties arising from the study assumptions.

- Price elasticities and impacts estimates from 15 dynamic pricing pilots were synthesized to produce impacts estimates for each state. The impacts take into account differences in central air conditioning (CAC) saturation for residential customers, climate, and the effect of enabling technology.
- The Assessment led to the development of a comprehensive and thorough summary of barriers to the achievement of demand response at the retail and wholesale level.

Structure of the Report

Chapter II of the Assessment identifies the key assumptions for each of the four demand response scenarios, along with a brief justification for the definitions of the scenarios.

Chapter III provides a summary of the results, identifying important trends and insights at the national, regional, and state levels.

Chapter IV is a qualitative discussion of future trends and opportunities for reducing peak demand, particularly in light of recent developments in smart grid technology. Ideas for future research are also recommended.

Chapter V provides more detail on how the results were developed. It includes a description of the modeling methodology as well as a summary of the data development process. More detailed backup is provided in Appendix D.

Chapter VI identifies existing barriers to demand response. These are barriers that are currently contributing to the "gap" between the amount of demand response in place today and the potential estimates that are described in this report.

Chapter VII concludes the report by presenting policy recommendations for addressing the demand response barriers and moving closer to achieving the identified potential.

Contained in the appendices of this report are documents which support the findings and recommendations of this Assessment.

Appendix A provides detailed information on the demand response potential projections for each state.

Appendix B offers lessons learned in the development of the data used in this Assessment.

Appendix C provides detail on the analysis of barriers to achieving demand response potential.

Appendix D contains documentation of the database development process used to create the model inputs for the report.

Appendix E is an uncertainty analysis, which represents the magnitude and impact of the uncertainty related to the results of this Assessment.

Appendix F is the full text of the Energy Independence and Security Act of 2007, Section 529 which applies to this Assessment.

Finally, Appendix G contains a glossary of terms.

CHAPTER II. KEY ASSUMPTIONS

This chapter identifies the key assumptions that are important for interpreting and understanding the results of the Assessment. This includes the type of demand response programs that were included in the Assessment, definition of the customer classes considered, and the key distinctions between the four demand response scenarios. The purpose of this chapter is to provide context for the discussion of the key results in Chapter III. For details on specific assumptions and their justification, as well as on modeling methodology and data development, see Chapter V.

Customer Classes

Retail customers are divided into four segments based on common metering and tariff thresholds. Much of the data used in this Assessment was segmented in this way.

- Residential: includes all residential customers.
- Small commercial and industrial: commercial and industrial customers with summer peak demand[17] less than 20 kilowatts (kW).
- Medium commercial and industrial: commercial and industrial customers with summer peak demand between 20 and 200 kW.
- Large commercial and industrial: commercial and industrial customers with summer peak demand greater than 200 kW.[18]

Demand Response Program Types

The analysis includes five types of demand response programs: dynamic pricing without enabling technology, dynamic pricing with enabling technology, direct load control, interruptible tariffs, and "other" demand response programs such as capacity/demand bidding and wholesale programs administered by Independent System Operators (ISOs) and Regional Transmission Operators (RTOs). These demand response program categories are defined below.

Dynamic pricing without enabling technology: Dynamic pricing refers to the family of rates that offer customers time-varying electricity prices on a day-ahead or real-time basis. Prices are higher during peak periods to reflect the higher-than-average cost of providing electricity during those times, and lower during off peak periods, when it is cheaper to provide the electricity. The rates are dynamic in the sense that prices change in response to events such as high-priced hours, unexpectedly hot days, or reliability conditions.[19] Customers respond to the higher peak prices by manually curtailing various end-uses. For example, residential customers might turn up the set-point on their central air conditioner or reschedule their kitchen and laundry activities to avoid running their appliances during high priced hours. The higher

[17] Summer peak demand is the customer's highest instantaneous level of consumption during the summer season.

[18] There is some justification for further dividing this class to separately analyze very large C&I customers (i.e. with peak demand greater than 1 MW), as these customers would behave differently and potentially be eligible for different demand response programs. However, this group of customers is heterogeneous in size, end-uses, and consumption patterns. To separately analyze them is very challenging from a data perspective and is an area where further research could lead to additional valuable insights.

[19] This definition excludes time-of-use (TOU) rates. TOU rates, in which prices typically vary by rate period, day of week and season, have higher prices during all peak rate periods and lower prices during all off-peak rate periods. They have not been included in the portfolio of demand response options because they are static rates and do not provide a dynamic price signal to customers that can be used to respond to unexpectedly high-priced days or reliability events. Other forms of dynamic pricing include critical peak pricing, in which the prices on certain days are known ahead of time, but the days on which those prices occur are not known until the day before or day of, and real time pricing, in which prices in effect in each hour are not known ahead of time.

priced peak hours are accompanied by lower priced off-peak hours, providing customers with the opportunity to reduce their electricity bills through these actions.

Examples of dynamic rates include critical peak pricing, peak time rebates, and real-time pricing. Peak time rebate is different than critical peak pricing and real-time pricing rates in that rather than charging a higher price during critical events, customers are provided a rebate for reductions in consumption. The analysis assumes that advanced metering infrastructure (AMI) must be in place to offer any of these rates. AMI includes "smart meters" that have the capability to measure customer usage over short intervals of time (often 15 minutes), as opposed to many conventional meters that are read manually on a monthly basis.

Dynamic pricing with enabling technology: This program is similar to the previously described dynamic pricing program, but customers are also equipped with devices that automatically reduce consumption during high priced hours. For Residential and Small and Medium commercial and industrial customers, the automated technology (known as a programmable communicating thermostat) adjusts air conditioning energy use where such devices are determined to be cost-effective. Large commercial and industrial customers are assumed to be equipped with automated demand response[20] systems, which coordinate reductions at multiple end-uses within the facility.

Direct load control (DLC): Customer end uses are directly controlled by the utility and are shut down or moved to a lower consumption level during events such as an operating reserve shortage. For residential customers, an air-conditioning DLC program is modeled.[21] Direct control of other residential end uses, such as water heating, was not included.[22] Non-residential DLC programs include air-conditional load control as well, but could also include other forms of DLC in some states, such as irrigation control.

Interruptible tariffs: Customers agree to reduce consumption to a pre-specified level, or by a pre-specified amount, during system reliability problems in return for an incentive payment of some form. The programs are generally only available for Medium and Large commercial and industrial customers.

Other DR programs: The Other DR category includes programs primarily available to Medium and Large commercial and industrial customers such as capacity bidding, demand bidding, and other aggregator offerings, whether operated by an ISO, RTO, or a utility in an area without an ISO or RTO. This category also includes demand response being bid into capacity markets. Some of these programs are primarily price-triggered while others are triggered based on reliability conditions.

We have excluded certain options from the scope of our study that are sometimes included in the definition of demand response. These include static time-of-use (TOU) rates, back up generation, permanent load shifting and plug-in hybrid vehicles (PHEVs). The reasons are briefly described below.

Often, demand response studies will include the impacts of all rates that are "time varying." Time varying rates typically are structured such that customers are offered higher prices during peak periods when demand for electricity is at its highest. This higher peak price is accompanied by a discounted, lower price during the remaining hours. By providing customers with rates that more accurately reflect the true cost of providing electricity over the course of the day, customers have an incentive to shift load from the peak period to the off-peak period, thus reducing the overall cost of providing electricity.[23]

Within the family of time-varying rates, there is a distinction between rates that are "static" and those that are "dynamic." For dynamic rates, as described previously, the peak period price can be triggered to

[20] Automated demand response is a communications infrastructure that provides the owner of the system with electronic signals that communicate with the facility's energy management control system to coordinate load reductions at multiple end-uses.
[21] Such DLC programs could be based on a programmable communicating thermostat or a conventional "switch" that cycles the air conditioner. For the purposes of this analysis, a switch is the basis for the DLC program.
[22] These other forms of DLC were excluded because they represent a fairly small share of aggregate DLC program impacts and the state-level appliance saturation data necessary to conduct such an analysis was not readily available.
[23] Alternatively, a rebate could be offered for consumption curtailment during peak periods.

target specific system events, such as high-priced hours, unexpectedly hot days, or reliability conditions. Customers are typically notified of the higher peak period price on a day-ahead or day-of basis. Static rates, on the other hand, do not have this feature and instead use fixed peak and off-peak prices that do not change regardless of system conditions. TOU rates fall under this category of static time-varying rates. While TOU rates provide incentive to permanently shift load from peak periods to off-peak periods, they do not have the flexibility to allow for an increase in response on short notice.

In addition, in many parts of the country TOU rates have been in place for decades and as a result their impacts are already factored into the reference load forecast. Further, FERC's Demand Response Survey database[24] impact estimates are not available for many TOU rates. It is for these reasons that TOU rates were excluded from the analysis.

Programs that specifically target back-up generation were excluded as well. However, if back-up generation as a technology underlies demand response for a more general program, that program was included. Additionally, permanent load shifting was excluded because it cannot be dispatched dynamically to meet system requirements. It is analogous to energy efficiency, which is also excluded from the scope of this report. Finally, we have excluded PHEVs because there is insufficient data to analyze their impacts and because, given the current absence of significant market penetration of PHEVs, their impact over the 10 year analysis horizon will likely be small.

Demand Response Scenarios

Four scenarios have been considered in this analysis. The first, Business-as-Usual, is simply a measure of existing demand response resources and planned growth in these resources. The other three scenarios are measurements of demand response potential under varying assumptions. All three of the demand response potential scenarios are limited only to cost-effective demand response programs, meaning that the net present value of the benefits of a given program exceeds the costs.[25]

Business-as-Usual (BAU) is an estimate of demand response if current and planned demand response stays constant. This scenario is intended to reflect the continuation of current programs and tariffs. In most instances, growth in program impacts is not modeled, although where information is available that explicitly states likely growth projections, that information has been included. The value in this scenario is that it serves as the starting point against which to benchmark the three other demand response potential scenarios.

Expanded BAU (EBAU) is an estimate of demand response if the current mix of demand response programs is expanded to all states and achieves "best practices" levels of participation, along with a modest amount of demand response from pricing programs and AMI deployment.[26] The key assumption driving participation in the non-pricing programs is that all programs achieve participation rates that are representative of "best practices." This scenario provides insight regarding what could be achieved through more aggressive pursuit of programs that exist today. However, it does not account for those programs that are not heavily pursued today but have significant potential, such as residential dynamic pricing.

Achievable Participation (AP) is an estimate of demand response if AMI is universally deployed, dynamic pricing is the default tariff, and other programs are available to those who decide not to enroll in

[24] Available at http://www.ferc.gov/industries/electric/indus-act/demand-response/2008/survey.asp

[25] For the purposes of this Assessment, the Total Resource Cost (TRC) test is used. More information on the cost-effectiveness screening is provided in Chapter V.

[26] For purposes of this Assessment, "best practices" refers only to high rates of participation in demand response programs, not to a specific demand response goal nor the endorsement of a particular program design or implementation. The best practice participation rate is equal to the 75th percentile of ranked participation rates of existing programs of the same type and customer class. For example, the best practice participation rate for Large Commercial & Industrial customers on interruptible tariffs is 17% (as shown in Table 5). See Chapter V for a full description.

dynamic pricing. Customer participation rates were developed to reflect the reality that not all customers will participate in demand response programs. In this scenario, participation in dynamic pricing programs is not limited as it is in the EBAU scenario, and all demand response programs can be equally pursued. This scenario considers the potential inherent in all available demand response programs while restricting the total potential estimate to maximum participation levels that could likely be achieved in reality.

Full Participation (FP) is an estimate of the total amount of cost-effective demand response. This scenario assumes that there are no regulatory or market barriers and that all customers will participate. The value of this scenario is that it quantifies the upper-bound on demand response under the assumptions and conditions modeled in this Assessment.[27]

Comparing the Key Scenario Assumptions

The four scenarios are differentiated by a set of distinguishing assumptions. The differentiation is driven mostly by assumptions about pricing programs. Table 1 summarizes these key differences.

Table 1: Key Differences in Scenario Assumptions

Assumption	Business-as-Usual	Expanded BAU	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% to 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

In the Full Participation and Achievable Participation scenarios, AMI is assumed to reach 100 percent deployment in all states by 2019. In the EBAU scenario, only partial deployment of AMI is achieved, depending on the current status of utility deployment plans in each state. This is consistent with the definition of the EBAU scenario as focusing heavily on non-pricing demand response programs, which do not require AMI for operation. By 2019, in the EBAU scenario, AMI market penetration ranges from 20 percent to 100 percent with a national average of about 40 percent. The BAU scenario assumes the existence only of those AMI systems that are in place today or for which plans for deployment have been announced.

Dynamic pricing is assumed to be widely available in the AP and FP scenarios. In the FP scenario, it is the only rate that is offered to customers. In the AP scenario, dynamic pricing is offered on a default basis, meaning that all customers are enrolled in a dynamic rate but they can “opt out” to a different rate type. Forty percent of Medium and Large commercial and industrial customers are assumed to opt out of the dynamic rate, as are 25 percent of Residential and Small commercial and industrial customers.[28] The EBAU scenario assumes a minimal amount of participation in dynamic pricing, with the rate being

[27] Technologies not modeled in the Assessement also have the potential to reduce demand. These include emerging smart grid technologies, distributed energy resources, targeted energy efficiency programs, and technology-enabled demand response programs with the capability of providing ancillary services in wholesale markets (and increasing electric system flexibility to help accommodate variable resources such as wind generation.) However, these were not included in this Assessment because there is not yet sufficient experience with these resources to meaningfully estimate their potential.

[28] For details on the basis for these assumptions, see Chapter V.

offered on a voluntary (opt-in) basis and only five percent of the customers in each customer class choosing to enroll.[29]

Another significant driver of the difference between the three demand response potential scenarios is the share of customers equipped with enabling technologies. Customers with enabling technology are a subset of those enrolled in dynamic pricing. In addition to being enrolled in dynamic pricing, for a customer to be equipped with enabling technology in a given scenario it must meet three criteria. It must first have load that is suitable for the technology,[30] then it must be offered the technology, and finally it must accept the technology.

In the FP scenario, all eligible customers with load suitable for the technology are assumed to be offered the technology where it is cost-effective. Further, all of the customers who are offered the technology are assumed to accept it. In the AP scenario, acceptance rates for both the utility and the customer reflect the reality that the equipment will not be utilized in all instances where it makes economic sense to do so. In this scenario, 95 percent of eligible customers are offered the technology and 60 percent of eligible customers who are offered the technology accept it. Enabling technologies are not part of the EBAU or BAU scenarios. These market acceptance rates are largely assumption-driven for the purposes of defining the scenarios. Given the illustrative nature of these assumptions, they are ideal candidates for an uncertainty analysis.

Participation rates in the non-dynamic pricing programs (DLC, interruptible tariffs, and Other DR) are determined using estimates of "best practices" developed using survey data from FERC's 2008 Assessment of Demand Response and Smart Metering. These participation rates are held constant on a percentage basis across ***all three scenarios*** and are applied to the segment of the population that is not participating in dynamic pricing. Thus, the major difference between the scenarios is that the participation rates are applied to a different population of eligible customers. More details on the development of the final participation rates are provided in Chapter V.

In most studies of demand response, data from multiple data sources must be brought together and reconciled to create a coherent and internally consistent picture. That is especially true of this study, where multiple scenarios of demand response potential have been created for the fifty states and the District of Columbia. In the construction of the BAU scenario, the Assessment has relied on a top-down approach that yields aggregate impacts of demand response potential. The main data source has been the FERC demand response survey. The construction of the other three scenarios has relied on a bottom-up approach that expresses demand response potential as the product of existing peak-demand, percent drop in load per participating customer and number of participating customers. In most cases, the assumptions underlying these other scenarios are consistent with the data underlying the BAU scenario.

However, in a few cases where the BAU numbers are a high proportion of the peak demand forecast, intrinsic discrepancies between the bottom-up and top-down approaches have prevented a complete reconciliation of the data from different sources. Empirically, the effect of these discrepancies is likely to be very small in magnitude and confined to small states with large amounts of existing demand response. In these states, the demand response potential may be slightly overstated, by not more than a percentage point or so. For the majority of states in the Assessment, the impact would be negligible and is dwarfed by other uncertainties in factors such as the peak load forecast, the per-customer impact of specific demand response programs and projections of the number of participating customers. In the future, this discrepancy could be reduced with more-detailed survey data to support the BAU scenario. FERC staff is evaluating changes to its survey methodology with this objective in mind. Also, the North American Electric Reliability Corporation (NERC) has designed and is refining a systematic approach to collecting demand response data that will contribute to the accuracy and usefulness of future analyses.[31]

[29] For programs in states where enrollment is already greater than five percent, the existing participation rate overrides this value.
[30] For example, for residential customers, only those with central air conditioning would be eligible for a programmable communicating thermostat since it specifically applies to air conditioning load. This assumption does not vary across scenarios but does vary across customer classes and states.
[31] See NERC, Demand Response Data Availability System (DADS) Preliminary Report, Phase I&II, June 3, 2009.

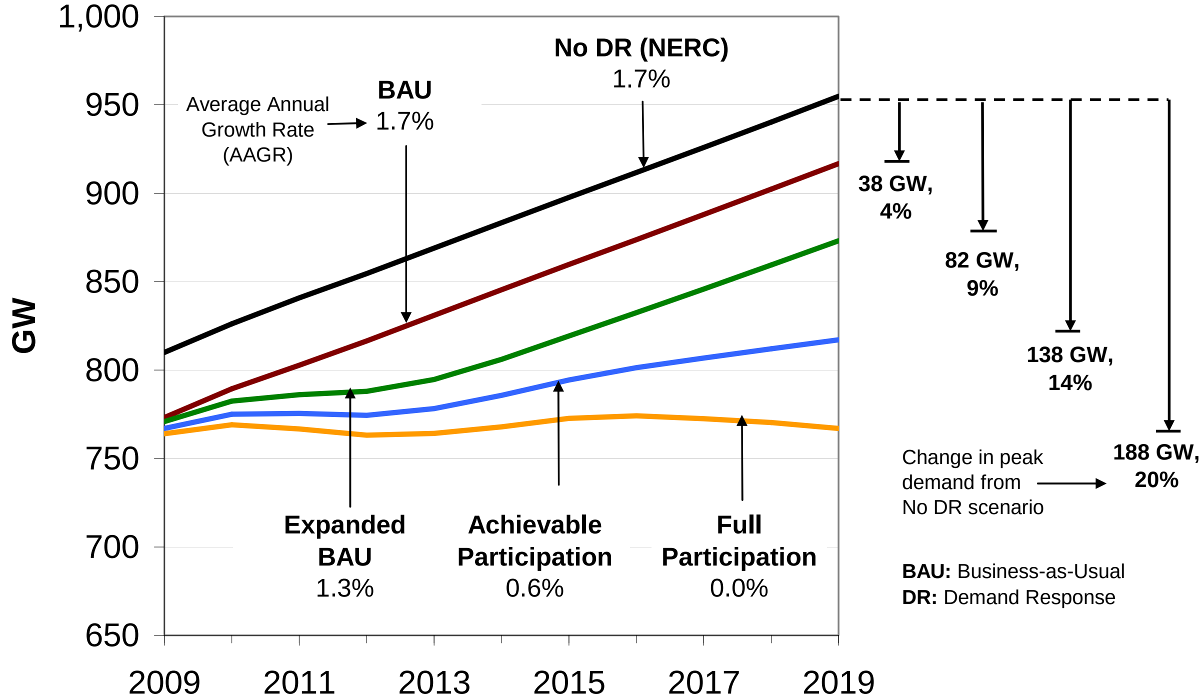
CHAPTER III. KEY RESULTS

This chapter summarizes the key results of the Assessment, identifies important trends in the findings, and compares demand response potential across scenarios, classes, program types, and regions. These findings are summarized for the U.S. as a whole, at the Census Division level, and at the state level.

National Results

A comparison of the demand response estimates under the four scenarios illustrates the potential impact of demand response on peak demand over the analysis horizon. This is illustrated in Figure 1. For the purposes of this Assessment, 2009 is considered to be the base year, and 2010 through 2019 is considered to be the analysis horizon.

Figure 1: U.S. Summer Peak Demand Forecast by Scenario



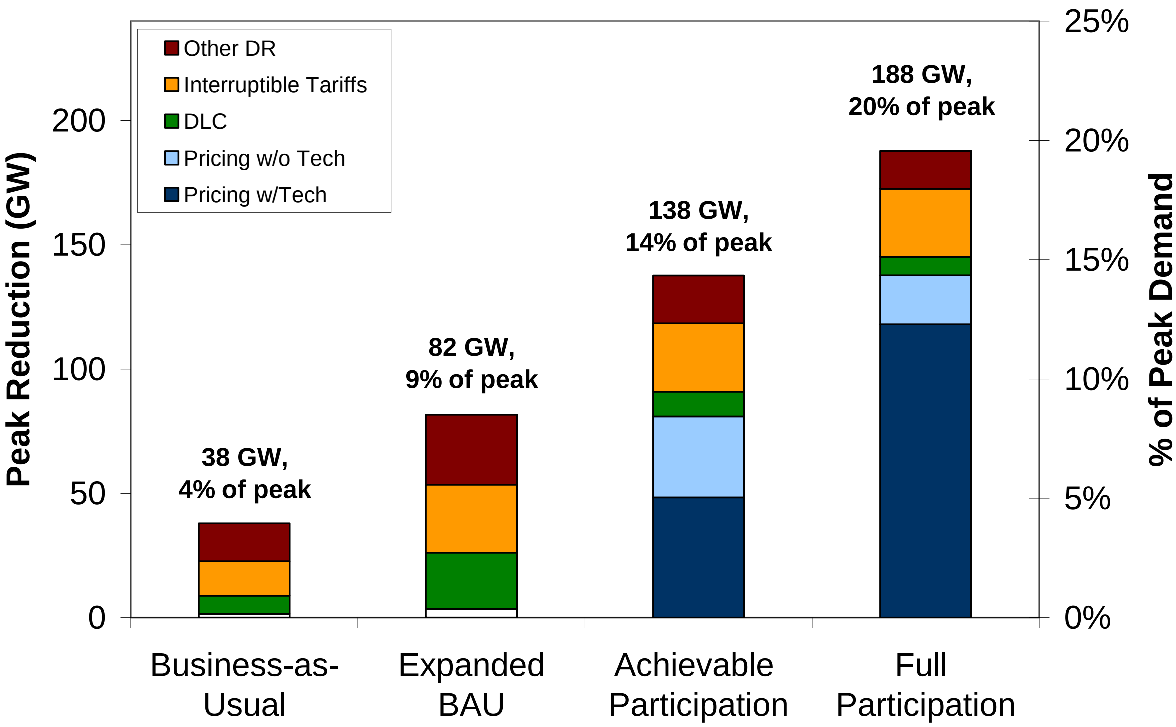
The black line represents a U.S. peak demand forecast that does not include any demand response, as provided by the North American Electric Reliability Corporation (NERC).[32] Peak demand begins at about 810 GW in 2009 and grows at an average annual growth rate (AAGR) of 1.7 percent, reaching slightly more than 950 GW by 2019. Peak demand in the BAU scenario grows at a very similar rate, but is lower overall. The reduction in peak demand under BAU, relative to the NERC forecast without demand response, is 37 GW in 2009 and 38 GW by 2019, representing a four percent reduction in peak demand. The EBAU demand response scenario produces a peak demand estimate that grows at an AAGR of 1.3 percent per year as a result of further reduction in peak demand of 82 GW, or nine percent, by 2019. The AP scenario produces even larger reductions in peak demand, reducing the AAGR to 0.6

[32] The "No DR (NERC)" baseline is derived from NERC data for total summer demand, which excludes the effects of demand response but includes the effects of energy efficiency. 2008 Long Term Reliability Assessment, p. 66 note 117; data at http://www.nerc.com/fileUploads/File/ESD/ds.xls. http://www.nerc.com/page.php?cid=4|38|41

percent by reducing the peak by 138 GW, or 14 percent, by 2019. The FP scenario produces the largest reductions. Under this scenario, peak demand growth is approximately zero, and by 2019 would be 188 GW (20 percent) less than if there were no demand response programs in place.[33]

The peak demand reduction estimates under the three demand response potential scenarios show a dip between 2010 and 2013, after which the reductions increase at varying rates. This pattern is a result of the assumed market penetration schedule of new demand response programs. For the traditional programs (i.e. direct load control, interruptible and curtailable, and RTO-sponsored), states are assumed to ramp-up to final participation rates over the five year period between 2009 and 2014 in an "S-shaped curve." In other words, between 2009 and 2010, these programs experience relatively little incremental growth and the growth in peak demand is greater than the growth in demand response reductions. Then, between 2010 and 2013, the incremental increase in demand response is much higher, resulting in negative peak load growth during those years. After that, the incremental increase is smaller and the new programs mature and reach full participation (as a percentage of total customers) by 2015. Further, the effect of dynamic pricing over time is dependent on AMI market penetration, which increases throughout the forecast horizon. The more aggressive AMI deployment assumption in the AP and FP scenarios explains why demand response increases more significantly in the later years of those scenarios.

Figure 2: U.S Demand Response Potential by Program Type (2019)



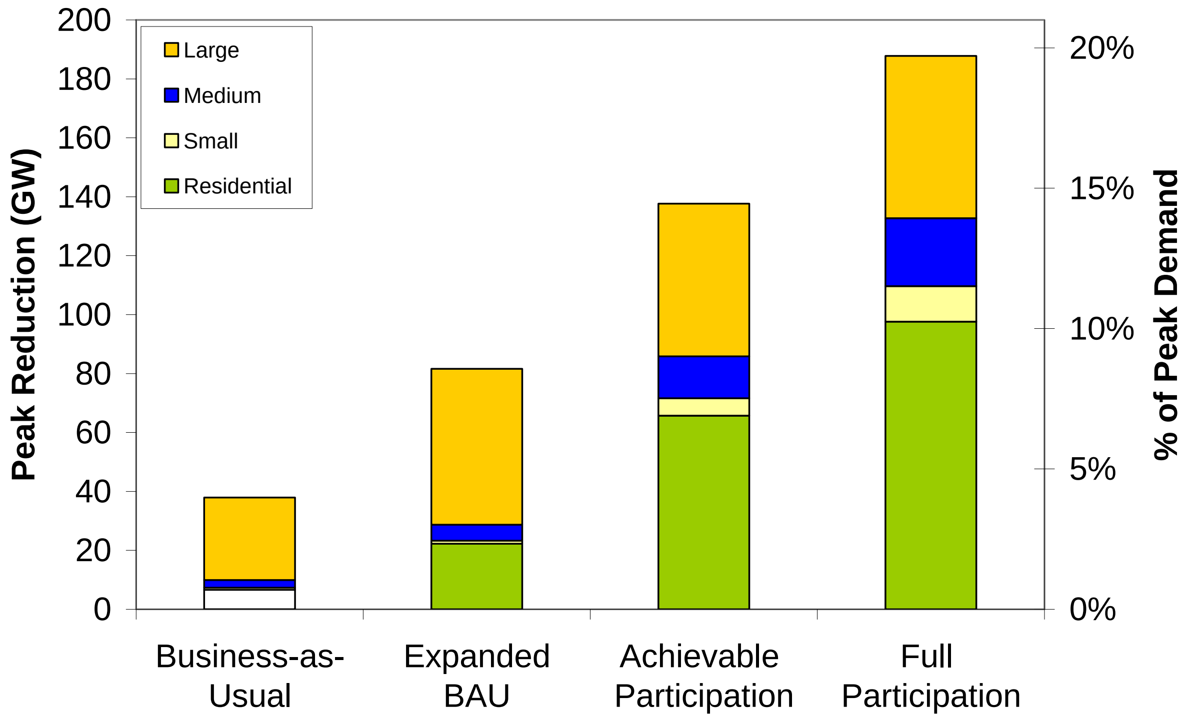
It is interesting to compare the relative impacts of the four scenarios. Moving from the BAU scenario to the EBAU scenario, the peak demand reduction in 2019 is more than twice as large. This difference is attributable to the incremental potential for aggressively pursuing non-pricing programs in states that have little or no existing participation. However, more demand response can be achieved beyond these non-pricing programs. By also pursuing dynamic pricing the potential impact could further be increased by 68 percent, the difference between the AP scenario and the EBAU scenario. Removing the assumed limitations on market acceptance of demand response programs and technologies would result in an

[33] This study assumes demand response occurs for four hours a day during the 15 highest load days of the year. Thus it reduces peak demand, but not necessarily demand in other (non-peak) times, and it may not reduce overall load growth in proportion to the reduction in peak demand.

additional 36 percent increase in demand response potential (the difference between the AP and FP Scenarios). A conclusion of this Assessment is that at the national level, the largest gains in demand response impacts can be made through pricing programs, particularly when offered with enabling technologies. This is more pronounced in the FP scenario, where roughly 70 percent of the impacts come from pricing programs. These findings are presented in Figure 2.

Just as demand response programs contribute to total demand response potential in varying degrees, so do the customer segments. Today, the majority of demand response comes from Large commercial and industrial customers, primarily through interruptible tariffs and capacity and demand bidding programs. However, it is the residential class that represents most untapped potential for demand response. As seen below, the impacts from this class drive the major differences in the demand response potential scenarios. Based on the assumptions underlying this study, residential customers provide the greatest per-customer impacts from pricing programs. While residential customers provide only roughly 17 percent of today's demand response potential, in the AP scenario they provide over 45 percent of the potential impacts. This is illustrated in Figure 3.

Figure 3: U.S. Demand Response Potential by Class (2019)



Regional Results

To identify regional differences in demand response potential, the results can be broken out at the level of the nine Census Divisions. A mapping of states to these regions is provided in Figure 4.

Regional differences in demand response potential are driven by many factors, including the customer mix, the 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. A summary of the regional demand response potential estimates by scenario is provided in Figure 5.

Figure 4: The Nine Census Divisions

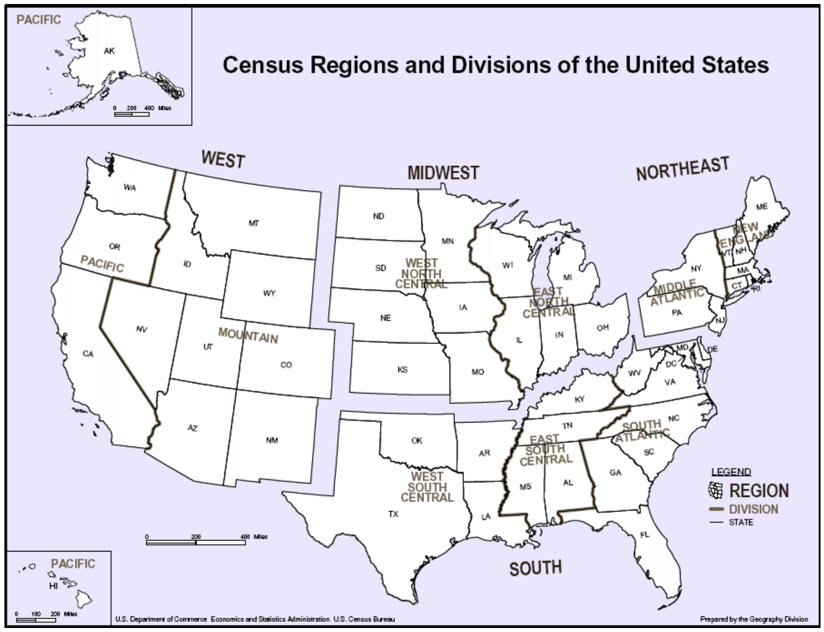
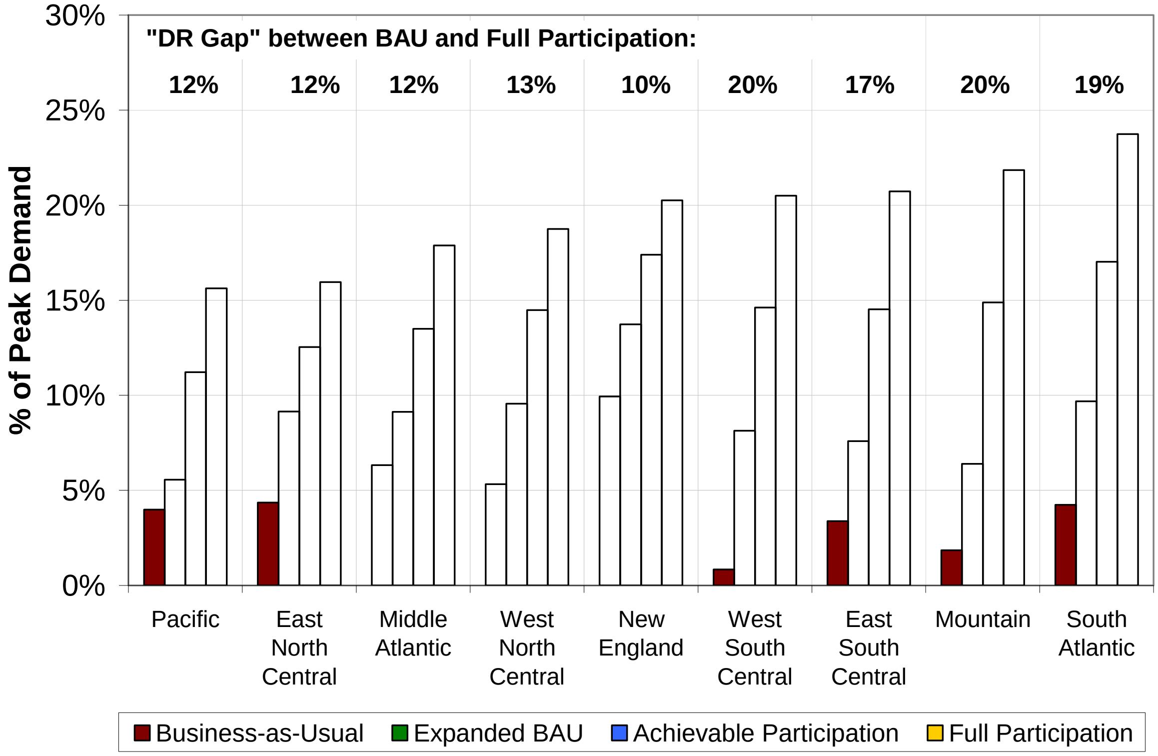


Figure 5: Demand Response Potential by Census Division (2019)



The largest existing (BAU) impacts are in regions with both wholesale demand response programs and utility/load serving entity programs. Thus, New England and the Middle Atlantic have the highest estimates for the BAU scenario, with New England reporting to have the ability to reduce nearly 10 percent of peak demand through demand response programs. Regions without significant wholesale organized markets demand response activity and relatively small existing programs, such as the West South Central and Mountain Divisions, have lower BAU estimates.

Central air conditioning saturation plays a key role in determining the magnitude of AP and FP demand response potential. Hotter regions with high central air conditioning saturations, such as the South Atlantic, Mountain, 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 AP and FP scenarios where dynamic pricing plays a more significant role than in the EBAU scenario.

Demand response potential in the EBAU scenario is driven partly by the customer mix in a given region. Specifically, regions with a higher share of load in the Large commercial and industrial sector will tend to have larger potential under this scenario. By definition, the EBAU scenario focuses on programs, such as interruptible tariffs and Other DR, that are geared toward these customers. Large commercial and industrial customers participating in these programs tend to produce large peak reductions, so regions with more load in the commercial and industrial class have higher potential. This potential will partly be determined by the average per-customer impacts that have been reported for these programs in each state. Those states reporting very high impacts will demonstrate the most potential.

The cost-effectiveness of enabling technologies also plays a role in driving regional differences in demand response potential. Due to lower per-customer air conditioning loads in the Pacific, New England, and Middle Atlantic Divisions, the benefits of the incremental peak reductions from enabling technologies do not outweigh the cost of the devices, and several states in these regions do not pass the cost-effectiveness screen.[34] As a result, in these states the impacts from dynamic pricing are only a function of manual customer response and are lower than in states where customers would be equipped with the technologies. This also applies to the cost-effectiveness of DLC programs, although these programs are found to be cost-effective for customer classes in most states.

It is interesting to quantify the "demand response gap" between the BAU scenario and the FP scenario. This gap represents the difference between what the region is achieving today and what it could achieve if all cost-effective demand response options were deployed. It is not necessarily the regions with the highest FP potential that have the largest demand response gap. Generally, regions in the western and northeastern U.S. tend to be the closest to achieving the full potential for demand response, with the Pacific, Middle Atlantic, and New England regions all having demand response gaps less than or equal to 12 percent. Other regions are significantly farther from achieving the full potential for demand response, falling short of FP potential by as much as 20 percent of peak demand.

State-level Results

At the most granular level, demand response potential was estimated for each of the fifty states and the District of Columbia. Across the states, there is significant variation in both existing demand response impacts and in the potential for new demand response. This variation can be seen in a comparison of the distribution of impacts across the states for the four scenarios, as provided in Figure 6.

[34] For more information on the cost-effectiveness analysis, see Chapter V and Appendix D.

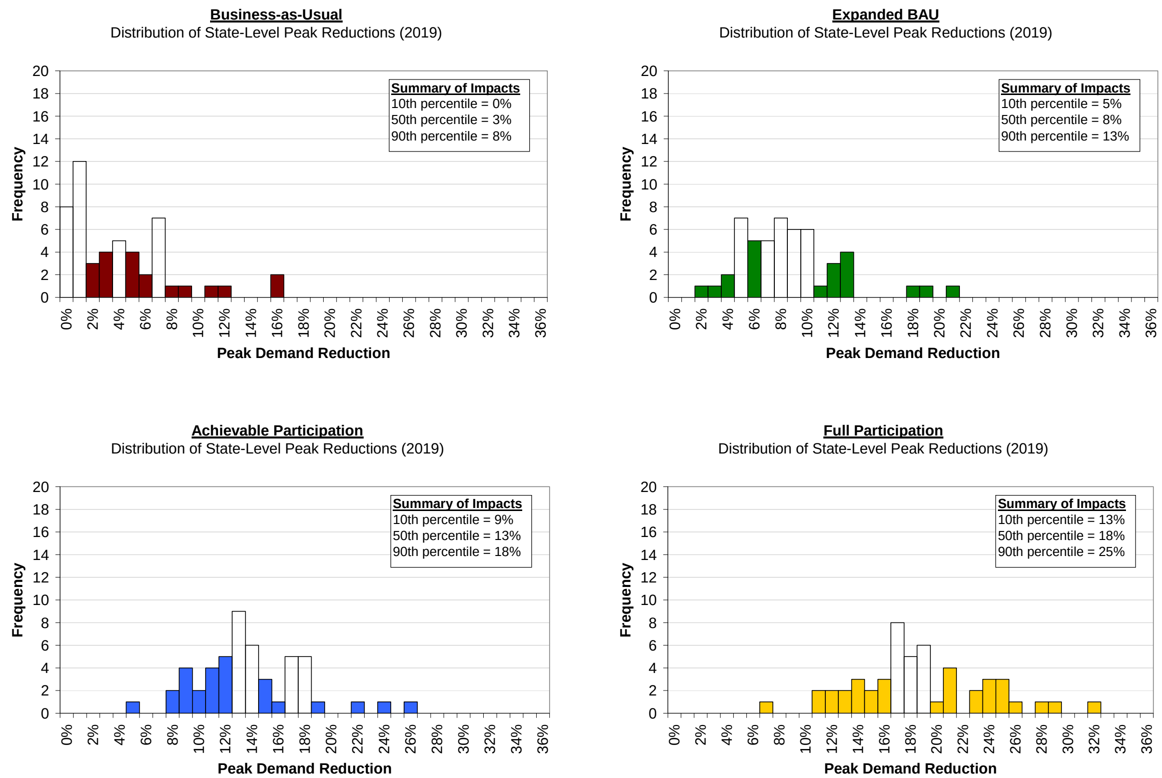


Figure 6: Comparison of Demand Response Impact Distribution across States

There is the least variation in impacts in the BAU scenario. In this scenario, demand response reductions are generally clustered between zero and five percent, with half of the state reductions being three percent or less. There are a few states that have reported the ability to achieve peak reductions greater than or equal to 10 percent today. These states are generally in the New England and Middle Atlantic regions and are reporting significant demand response enrollment by large commercial and industrial customers in wholesale demand response programs. The presence of strong wholesale programs plays a very significant role in the amount of existing demand response potential.

State-level impacts in the EBAU demand response scenario increase significantly relative to the BAU scenario. In Figure 6, this is shown by the rightward shift of the green bars along the horizontal axis relative to the red bars. In this scenario, the median demand response reduction is nine percent, while the range of the potential impacts is between two and 18 percent.

The AP impacts further shift to the right, with a median impact of 14 percent and a range of impacts from five percent up to 23 percent. The FP potential presents the widest distribution of potential impacts, ranging from seven percent to 31 percent and a median of 17 percent. This widening of the distribution across the scenarios is attributable to the increasingly important role of state-specific end-use characteristics such as central air conditioning saturation. To fully interpret the state-level impacts, it is necessary to consider some case studies in more detail. These are presented in the following section.

State Case Studies

To illustrate the details of the demand response potential estimations at the state level, it is helpful to walk through case studies of a few states that are distinctly different from each other yet generally representative of a larger group of states. Three such states have been selected: Georgia, Connecticut, and Washington. Georgia has existing demand response and some AMI in place and is not a member of an ISO/RTO while Connecticut has a significant amount of existing demand response, particularly in

ISO/RTO programs. Washington, on the other hand, has essentially no existing demand response. It is a region that historically has had a large amount of hydropower capacity and as a result has been energy constrained but not capacity constrained.[35] Washington also has low central air conditioning saturation, limiting the potential for future growth in demand response in this analysis.

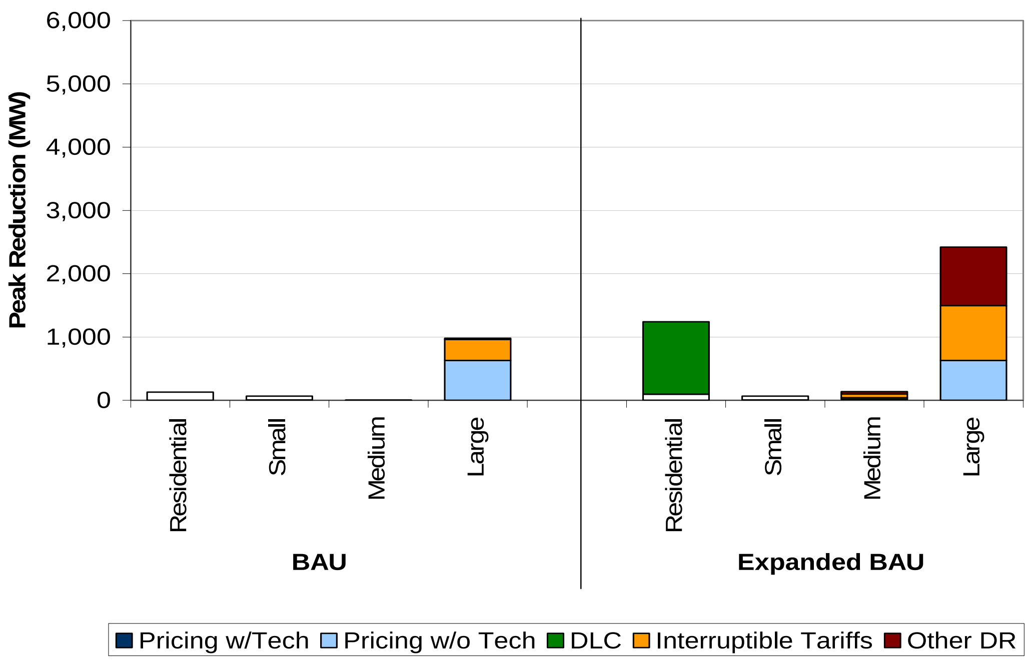
Case Study #1: Georgia

Today, Georgia's level of demand response is similar to the national average. The majority of peak impacts come from one of the nation's largest real-time pricing programs for Large commercial and industrial customers, as well as an interruptible tariff. Some additional impacts come from Residential and Small commercial and industrial DLC programs. In total Georgia is achieving a peak demand reduction of roughly 1.2 GW, or about 3.4 percent of the projected 2019 peak demand for Georgia of 34.7 GW.

In the EBAU scenario (Figure 7), participation in existing programs increases and new, primarily non-pricing programs are added. Significant growth takes place in the residential DLC program due to Georgia's high central air conditioning saturation rate of 82 percent. Medium and Large commercial and industrial customers are assumed to participate in a new capacity/demand bidding type of program (Other DR)[36] and a small amount of peak reduction could come from Small commercial and industrial DLC as well. Participation in these programs is assumed to achieve "best practices" levels that are the 75th percentile of participation rates in existing programs.

Pricing impacts remain significant in the existing Large commercial and industrial program, but under the EBAU scenario assumptions of a mild, voluntary rate offering, they do not play a significant role for the other customer classes. Relative to the BAU scenario, total impacts grow from 1.2 GW to 4.2 GW, or from 3.4 percent of peak demand to 12 percent.

Figure 7: Georgia BAU and EBAU Peak Demand Reduction in 2019



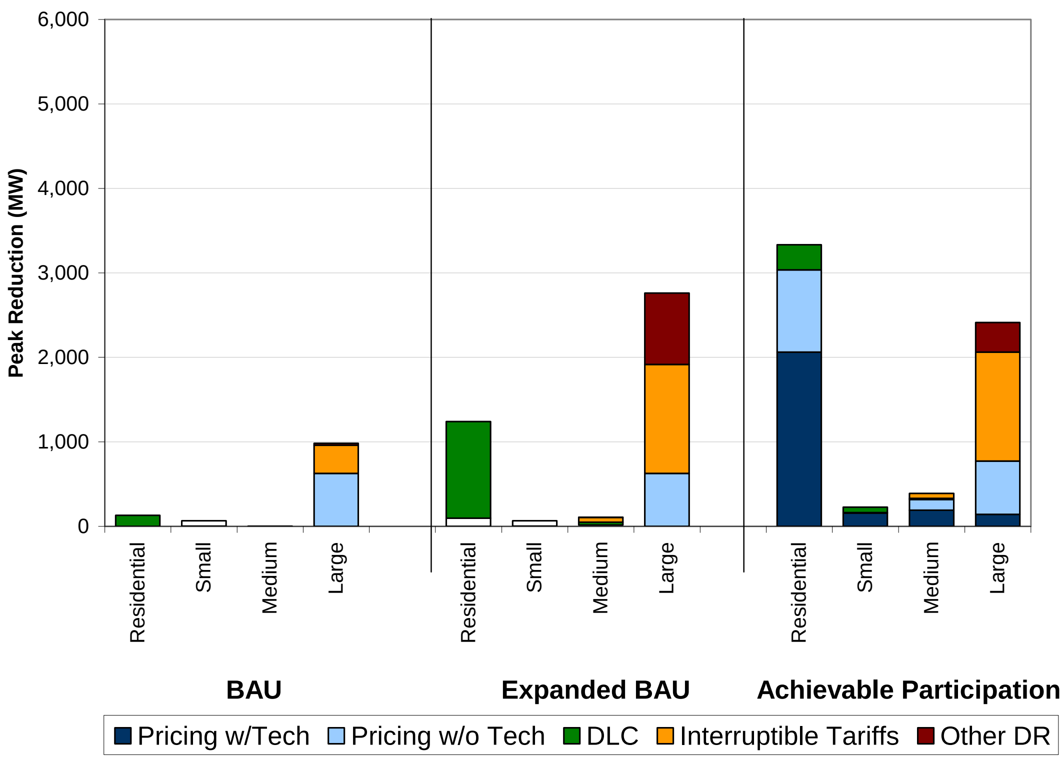
[35] In other words, hydropower resources can be ramped up to meet peak demands for a few hours but there are seasonal limits on energy production.

[36] Outside of RTO markets, capacity payments could be set at avoided capacity cost levels or could be negotiated on a case-by case basis with demand response providers.

Georgia's high residential central air conditioning saturation means that average per-customer impacts from dynamic pricing will be significant. As a result, in the AP scenario (Figure 8) impacts for the residential class increase under the assumption that dynamic pricing is offered as the default (opt-out) rate for all customers and 75 percent of the customers remain on the rate. A fraction of these customers (60 percent of those with central air conditioning) accept enabling technology – customers who, under the EBAU scenario and in the absence of the availability of enabling technology might have chosen to enroll in the DLC program. Additionally, of the customers who do not enroll in dynamic pricing, some are assumed to instead enroll in the DLC program. Based on a high-level assessment of the cost effectiveness of these programs, both were found to be economic for all customer classes in the state under the EBAU scenario.[37]

Interestingly, total impacts for the Large commercial and industrial class decrease in the AP scenario. The reason for this is that some customers who would have enrolled in Other DR programs under the EBAU scenario are instead assumed to have enrolled in dynamic pricing. The average per-customer peak reductions in Other DR programs (40 percent reduction) are higher than those of dynamic pricing (seven percent without enabling technology, 14 percent with enabling technology) and, as a result, the Large commercial and industrial potential drops in the AP scenario.[38] While this defining assumption of the AP scenario results in small impacts for the Large commercial and industrial class relative to the EBAU scenario, demand response potential for the entire state is higher. In total, the AP scenario potential system peak impacts increase to 6.4 GW, or 18 percent of peak demand.

Figure 8: Georgia BAU, EBAU, and AP Peak Demand Reduction in 2019



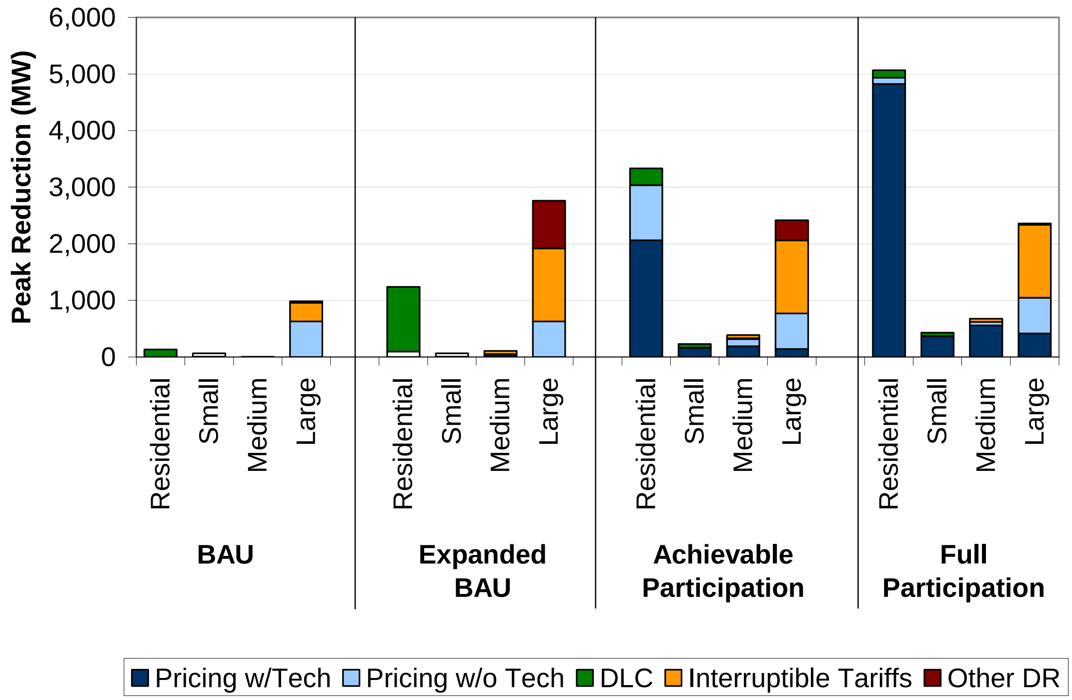
By definition, impacts are largest for the FP scenario (Figure 9). All customers are enrolled in dynamic pricing, with enabling technology being accepted by all customers. Customers currently enrolled in DLC are assumed to remain in that program. Total Large commercial and industrial impacts drop relative to

[37] Details on the cost effectiveness assessment are provided in Chapter V and Appendix D.

[38] It should be noted that the per-customer impacts from Other DR programs are based on the average of reported per-customer impacts in the 2008 FERC Demand Response survey. It is possible that impacts of this magnitude would not be achieved on a regular basis in practice and this is a topic that should be examined further.

the AP scenario, as the remaining participants in the Other DR programs are assumed to participate in dynamic pricing with enabling technology. However, on a system basis the total impacts increase to 8.5 GW, or 25 percent of peak demand in 2019. This is the total amount of cost-effective demand response potential in the state under the assumptions of this scenario. For more information on Georgia, see Appendix A.

Figure 9: Georgia Potential Peak Demand Reduction in All Scenarios, 2019

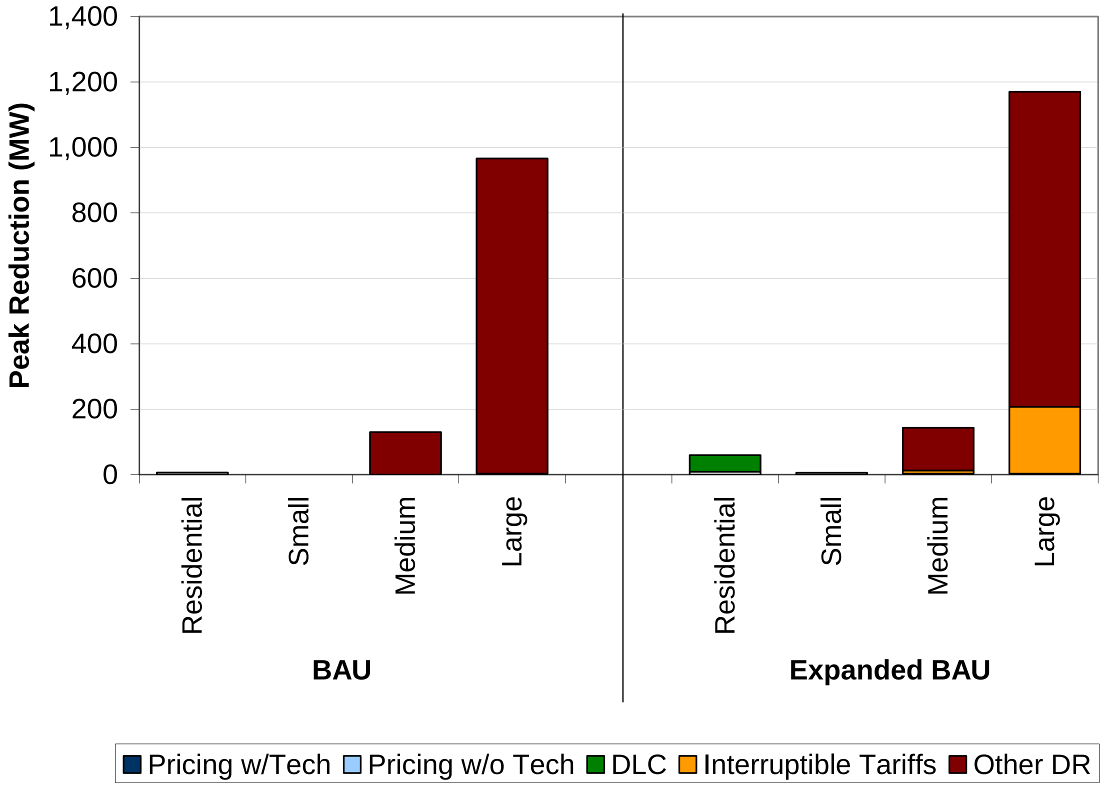


Case Study #2: Connecticut

Relative to Georgia, Connecticut is currently achieving significantly greater peak reductions from demand response on a percentage basis. In fact, Connecticut has one of the largest BAU demand response estimates of this Assessment. Where Georgia was achieving a 3.4 percent reduction, Connecticut is anticipating nearly a 13 percent reduction by 2019 in the BAU case. Much of this is due to large impacts being reported through participation in the ISO New England Forward Capacity Market. For the purposes of this Assessment, those impacts have been reported in the Other DR program category for Large commercial and industrial customers. Utility demand bidding programs in Connecticut are included in this category as well. The Other DR category represents nearly the entirety of the BAU peak reduction potential of 1,369 MW, or 16 percent of peak demand.

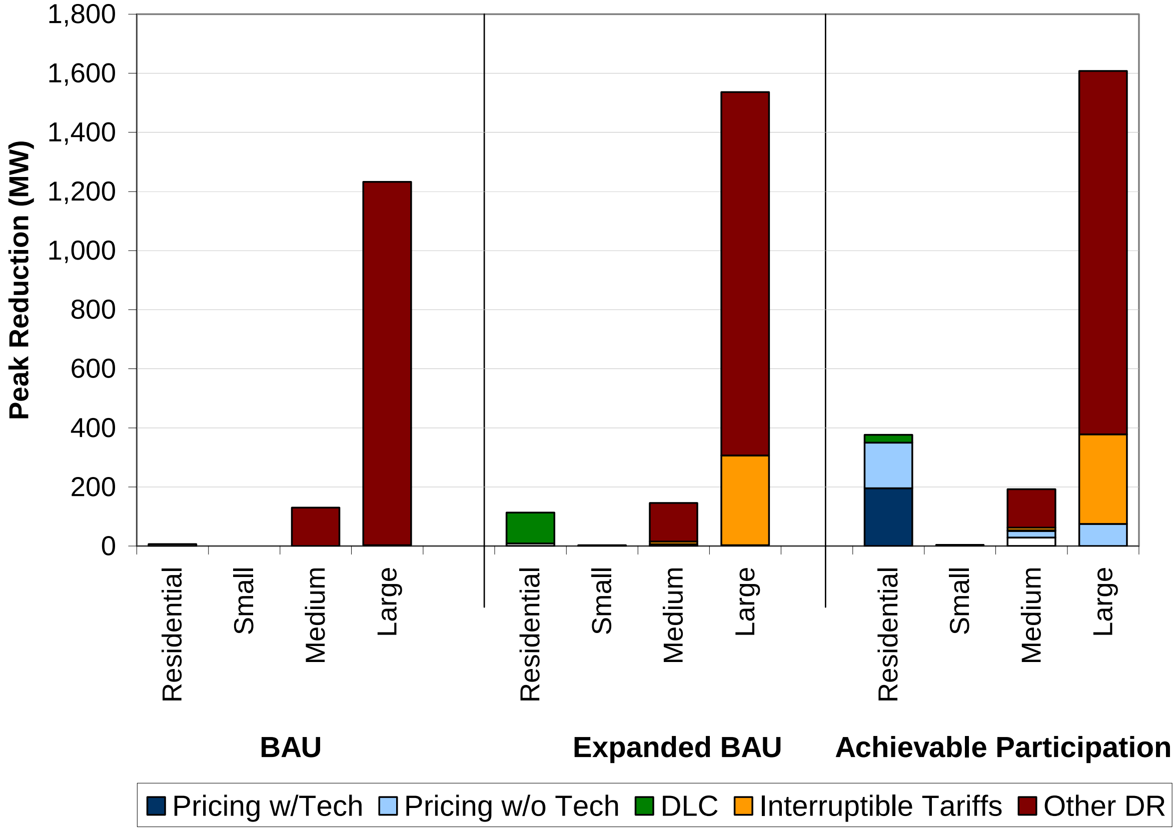
The EBAU scenario (Figure 10) assumes that programs will be put in place for other customer classes as well. DLC programs would increase demand response potential, although the low central air conditioning load in the residential class means that the impacts are not as significant as were seen in Georgia. Some additional Large commercial and industrial customers are assumed to participate in an interruptible tariff, but participation in Other DR does not increase as it is already beyond the 75th percentile of existing programs. (This study caps participation at the 75th percentile, unless participation in a program already exceeds that). Therefore, the total impact increases relative to the BAU scenario, but not to the degree that was seen in Georgia. Peak reduction potential increases from 1,369 MW to 1,798 MW or from 16 percent of peak demand to 21 percent.

Figure 10: Connecticut BAU and EBAU Peak Demand Reductions in 2019



Inclusion of default dynamic pricing in the AP scenario (Figure 11) increases overall demand response potential, but the incremental increase again is significantly smaller compared to Georgia. In the residential sector, this is driven by the low central air conditioning saturation rate. For Large commercial and industrial customers, existing participation in Other DR programs persists in the AP scenario impacts. The customers currently enrolled in Other DR programs are assumed to remain on those programs rather than enrolling in dynamic pricing. As a result, impacts from dynamic pricing are small but total impacts for the class remain large. The small potential impacts from dynamic pricing are further amplified by the fact that enabling technologies were not found to be cost-effective for Small and Large commercial and industrial customers in Connecticut, and therefore were assumed not to be available to customers in these classes. The end result is an increase in total demand response potential to 2181 MW, or 26 percent of peak demand in 2019.

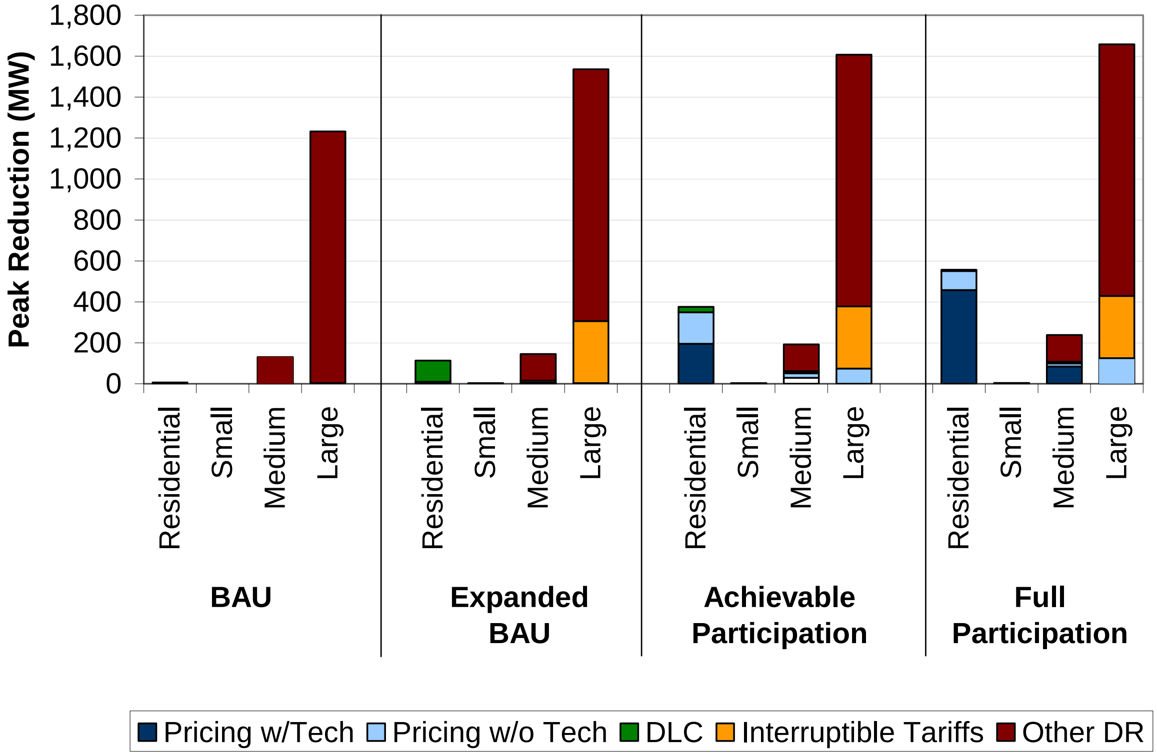
Figure 11: Connecticut BAU, EBAU, and AP Peak Reductions in 2019



Mandatory dynamic pricing further increases demand response potential in the FP scenario (Figure 12). This is coupled with a higher assumed acceptance rate for enabling technologies across the customer classes, and total demand response potential increases to 2,458 MW, or 29 percent of peak demand. The fairly small incremental increase relative to the AP scenario is partly attributable to enabling technologies not being cost effective for Small and Large commercial and industrial customers.

Relative to Georgia, the total potential for demand response is higher in Connecticut across the scenarios. While most categories of demand response programs actually have a lower potential in Connecticut, the presence of an ISO program that is reporting very large impacts makes for a higher overall potential estimate. It is also interesting to note that the incremental increase in demand response potential relative to the BAU scenario is smaller in Connecticut due to the large amount of existing demand response in the state. One interpretation of this finding is that Connecticut is currently achieving more of its potential. In other words, the "gap" between today's impacts and the total amount that could be achieved is smaller. A side-by-side comparison of all four scenarios is presented in Figure 12.

Figure 12: Connecticut Potential Peak Demand Reduction in All Scenarios, 2019



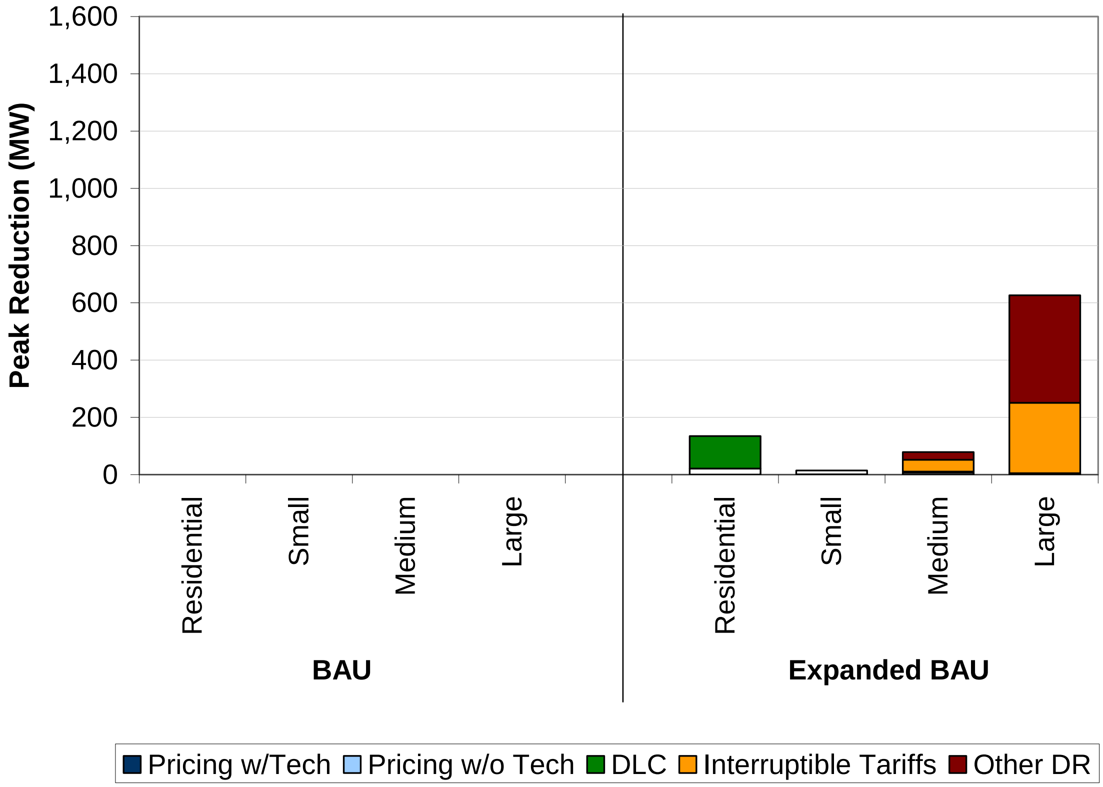
Case Study #3: Washington

In contrast to both Georgia and Connecticut, no impacts from existing demand response programs were identified in the 2008 FERC survey for the state of Washington. This is generally a reflection of the state of demand response in the Pacific Northwest. Historically, low energy prices and a surplus of hydro capacity have made demand response seemingly less attractive in this region. However, as peak demand continues to grow and constraints on the operation of hydro facilities become more restrictive[39], utilities in the region are beginning to take a more serious look at demand response as a resource option.[40]

For Washington, the EBAU scenario (Figure 13) represents the addition of an entirely new portfolio of non-pricing demand response programs which are assumed to reach "best practices" levels for the U.S. Dynamic pricing is included on a voluntary opt-in basis. Impacts are spread somewhat evenly across DLC and interruptible tariffs, with the largest impacts coming from Other DR programs. Total demand response potential for the scenario is 864 MW, or four percent of peak demand.

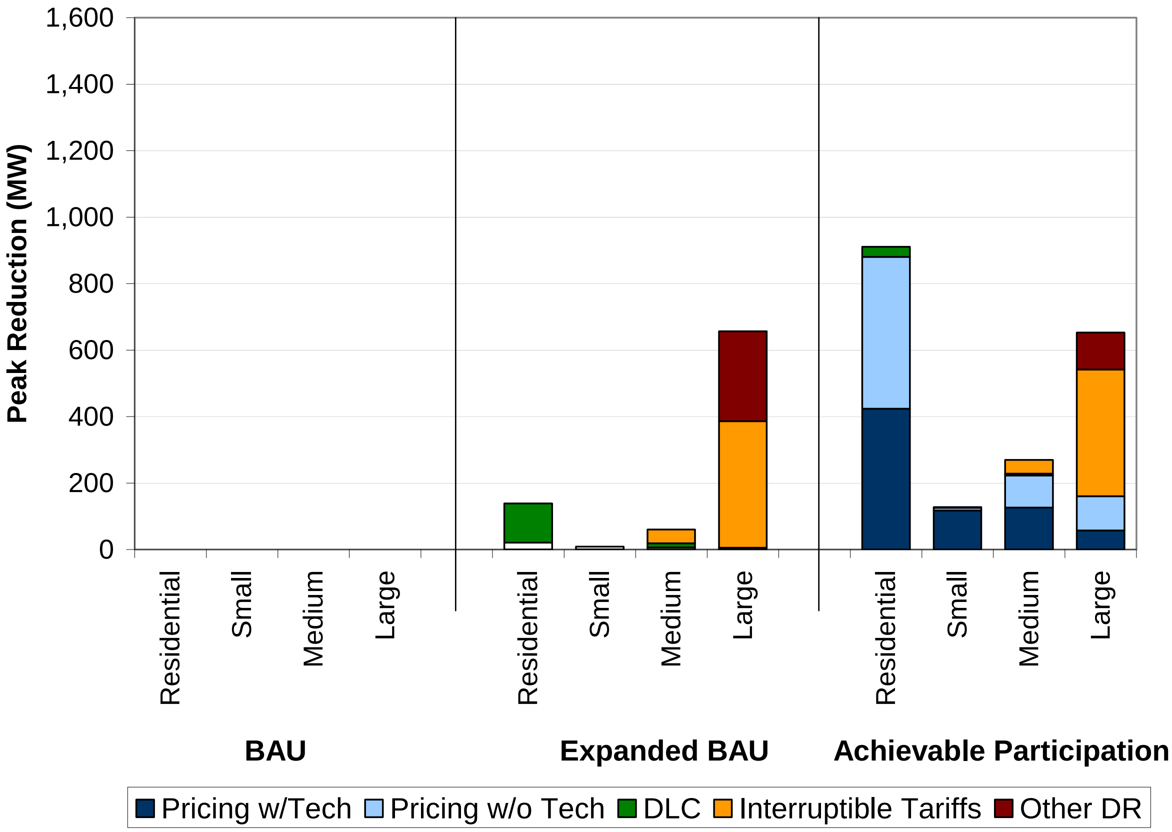
[39] Environmental constraints related to wildlife preservation have become more stringent.
[40] For example, Bonneville Power Administration, the wholesale provider of electricity for the region, has recently begun to explore opportunities to partner with its retail electric utility customers to integrate demand response into its portfolio of resource options. Source: http://www.bpa.gov/Energy/N/utilities_Sharing_EE/Utility_Brown_Bag/pdf/120408DR_BrownBag.pdf

Figure 13: Washington BAU and EBAU Peak Demand Reduction in 2019



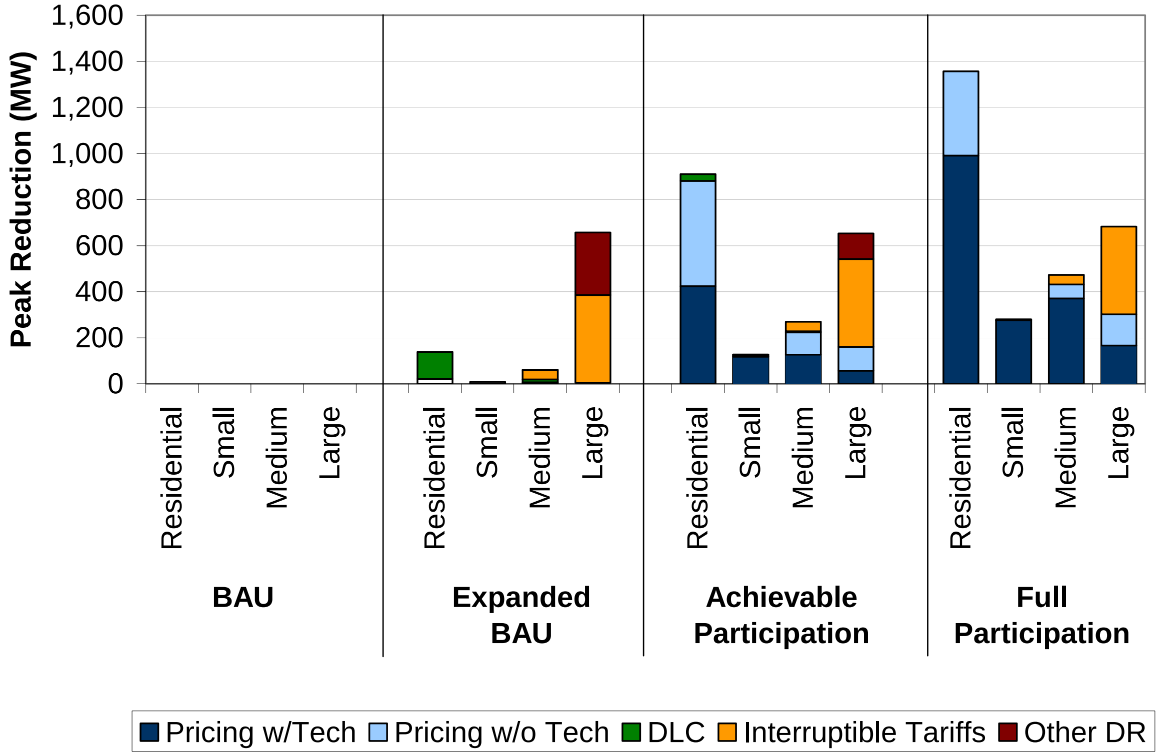
In the AP scenario (Figure 14), the inclusion of default dynamic pricing results in significantly higher demand response potential, particularly in the residential class. Acceptance of enabling technology replaces some of the participation in DLC in the EBAU scenario. As in the Georgia analysis, the Large commercial and industrial impacts are lower in the AP scenario than in the EBAU scenario. The explanation is the same in that the per-customer impacts of the new Other DR programs are larger than those of the dynamic pricing programs, and the total class potential drops in the AP scenario as a result. The total system demand response potential, however, increases to 2 GW, or nine percent of peak demand.

Figure 14: Washington BAU, EBAU, and AP Peak Reduction in 2019



Demand response potential under the FP scenario is dominated by dynamic pricing with enabling technology. Impacts from interruptible tariffs are still reported for some Medium and Large commercial and industrial customers, as customers simultaneously enrolled in these programs might be expected to provide larger reductions from the interruptible tariff. The FP potential for Washington is 2.8 GW, or 12 percent of peak demand. This is lower than that of Georgia or Connecticut, due to the lack of existing demand response and the state's low saturation of central air conditioning. Results are provided in Figure 15.

Figure 15: Washington Potential Peak Demand Reduction in All Scenarios, 2019



Summary of State Impacts

The previous three case studies demonstrate that each state has unique characteristics that will make its demand response potential different from that of other states. A comparison across these case studies has identified some of the key drivers of demand response potential. This includes:

- Central air conditioning saturation: High central air conditioning market penetration leads to larger demand response potential, because customers with central air conditioning are more responsive to dynamic pricing. Additionally, higher central air conditioning saturation means that a larger share of the population is eligible to participate in DLC programs. This is evident when contrasting residential demand response potential in Georgia and Connecticut.
- Cost-effectiveness: If a program does not pass the economic screen for a given customer class, then it will not be offered to those customers and demand response potential will be lower as a result. This was illustrated in Connecticut, where enabling technologies were not cost effective for Large commercial and industrial customers, and their dynamic pricing potential was low as a result.
- Customer mix: States with a higher concentration of load in the Residential and large commercial and industrial classes will often have higher demand response potential, as these classes tend to provide the largest per-customer peak reductions. A higher than average share of peak demand in these customer classes drives the relatively high demand response potential seen in Georgia.
- Regional price elasticity: Customers in the western U.S. have been found to be more price responsive than customers east of the Rocky Mountains. This drives regional differences in

dynamic pricing potential. In Washington, customers on dynamic pricing would potentially be more responsive to dynamic pricing (on a percentage basis) than customers in more humid states in the east due to the lower loss of comfort that they would experience when reducing air conditioning load on hot summer days.[41]

- Existing program impacts: States that are reporting above-average per-customer impacts from non-pricing programs will tend to have higher total demand response potential in those programs. In other words, it is assumed that as participation in the existing programs increases, customers will continue to provide large impacts. Further, a high participation rate in existing programs will contribute to higher overall demand response potential. In particular, the ability of demand response to participate in wholesale markets increases demand response potential, as seen in the Connecticut case study.
- AMI deployment: To the extent that dynamic pricing contributes to demand response potential in the EBAU scenario, its impact is limited by the final market penetration rate of AMI under the partial deployment scenario. The rate at which AMI is deployed over time affects the amount of dynamic pricing under all scenarios.

Demand response potentials were estimated for all 50 states and the District of Columbia. Figures 16 through 19 illustrate the potential of the ten states with the highest potential in 2019 and the ten states with the lowest 2019 potential (based on the AP scenario). On a gigawatt basis, California, Florida and Texas predominate because they have the highest peak demands. Ranked by demand response potential as a fraction of peak demand, Connecticut, Maryland and Maine are highest; each has substantial amounts of existing demand response, Maine has an above-average share of peak demand in the Large commercial and industrial customer class, and Maryland has a relatively large amount of residential central air conditioning.[42] There is a significant amount of variation across the states, both in terms of demand response potential and the amount of demand response that exists today. Complete state results appear in Appendix A.

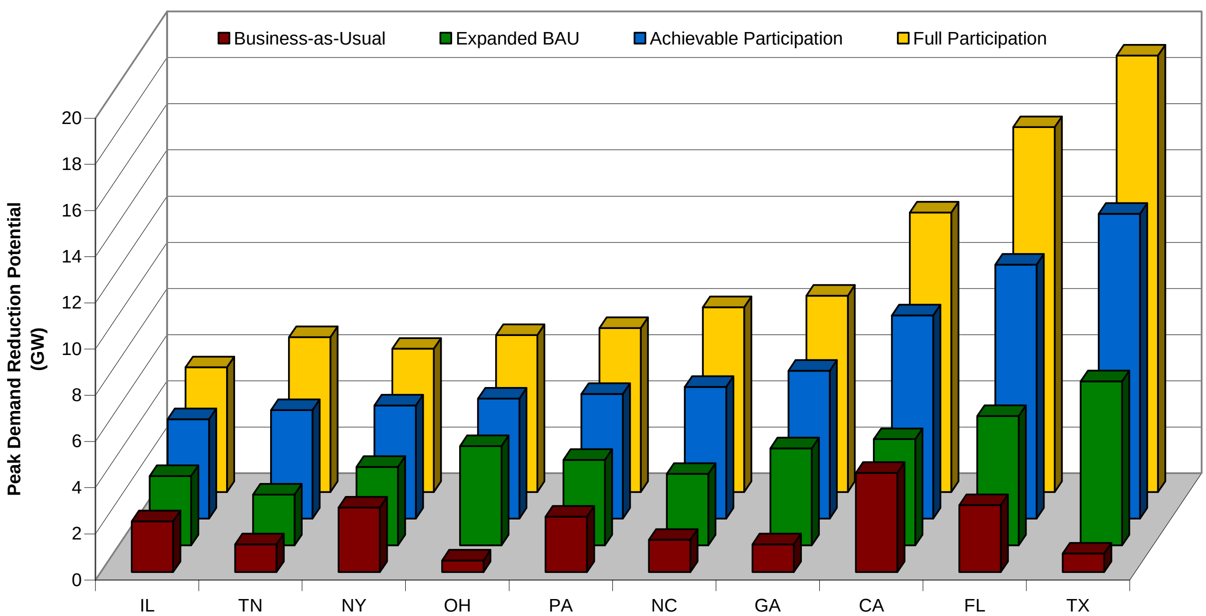


Figure 16: Top Ten States by Achievable Potential in 2019 (GW)

41 This is based on a survey of recent dynamic pricing pilots. More detail is provided in Appendix D.
42 Maryland is also assigned a high price elasticity based on results of Baltimore Gas & Electric Company's dynamic pricing pilot. More detail is provided in Appendix D.

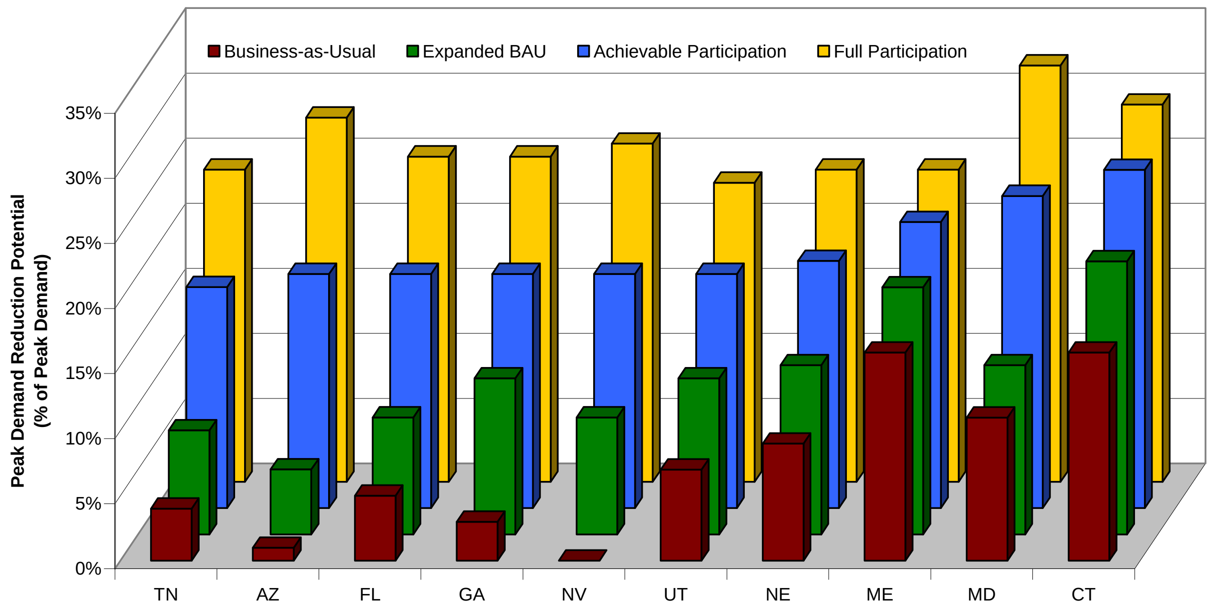


Figure 17: Top Ten States by Achievable Potential in 2019 (% of Peak Demand)

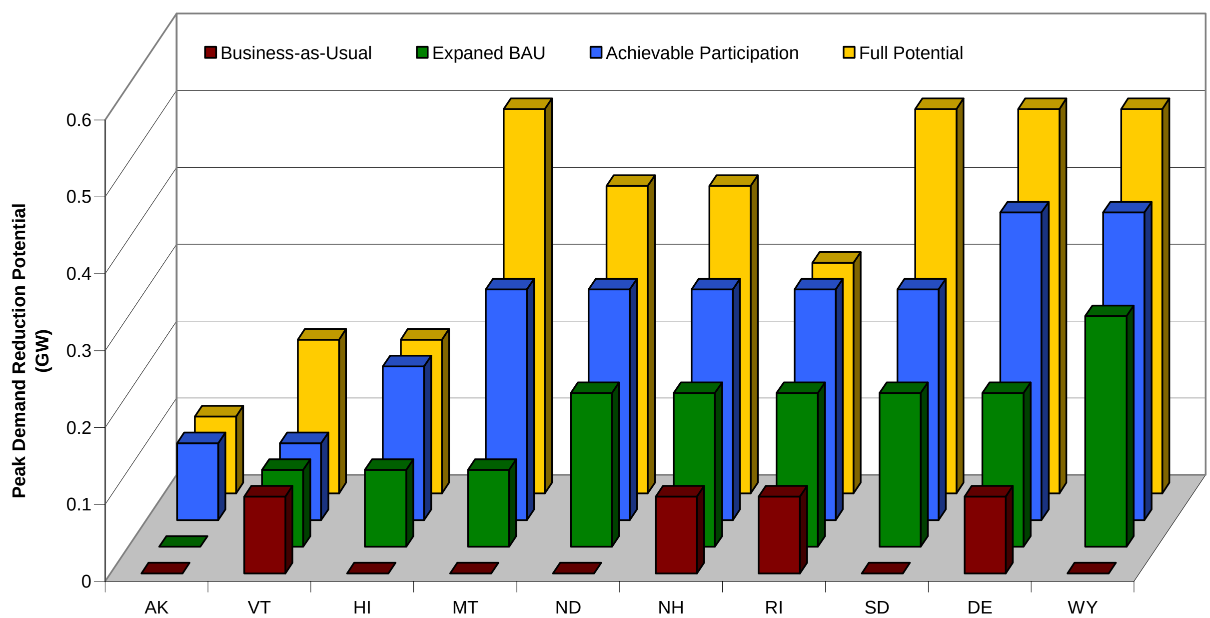


Figure 18: Bottom Ten States by Achievable Potential in 2019 (GW)

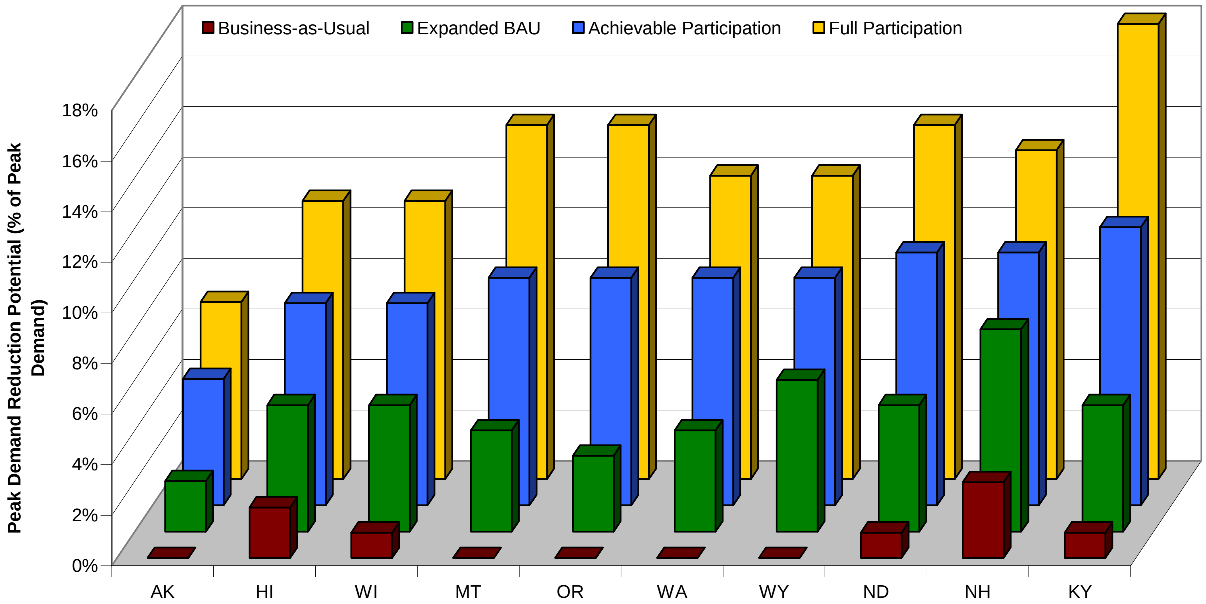


Figure 19: Bottom Ten States by Achievable Potential in 2019 (% of Peak Demand)

Benchmarking the Estimate for the Business-as-Usual Scenario

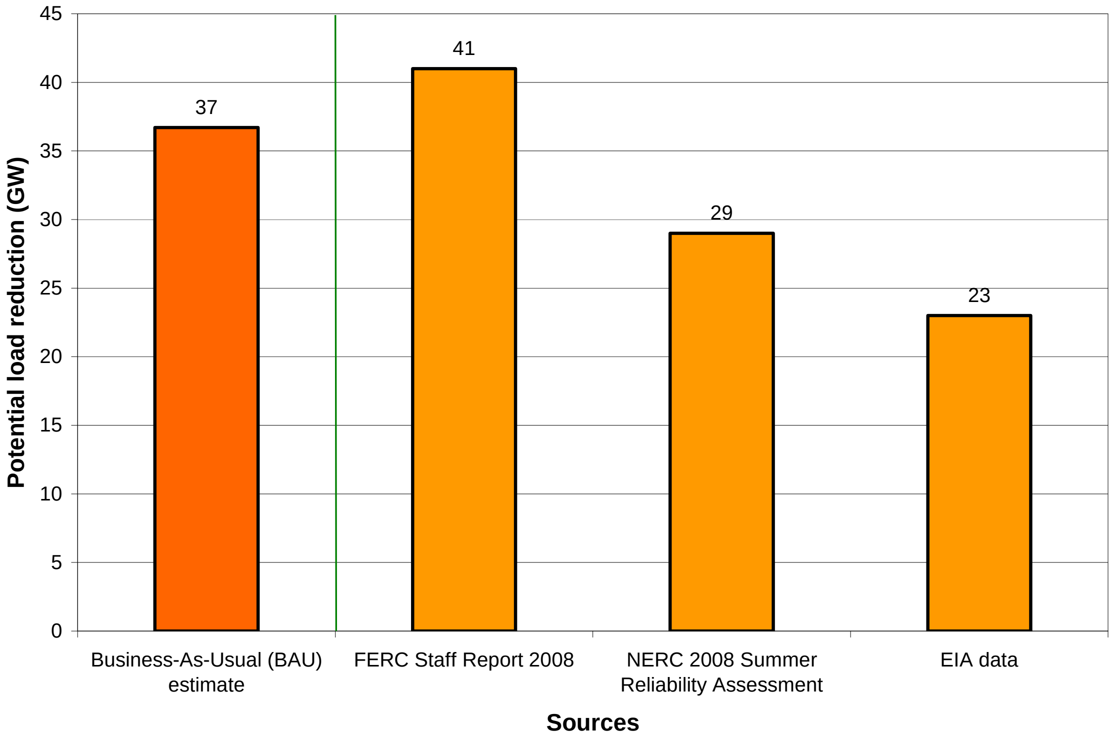
The estimate for the BAU scenario serves as the starting point for much of this analysis, so it must be carefully validated through comparisons to other available data sources. Specifically, the 2008 BAU estimate of 36.7 GW has been benchmarked against three recent estimates of existing demand response:

- *2008 FERC Assessment of Smart Metering and Demand Response* ("2008 FERC Staff Report");
- *NERC 2008 Summer Reliability Assessment*; and
- Data from the Energy Information Administration's (EIA's) Form-861 database.[43]

Figure 20 shows a comparison of the load reduction potential estimation for the BAU scenario with data from the three other sources.

[43] Table 9.2 'Demand Side Management Program Annual Effects by Program Category, 1996 through 2007', which reports a potential peak load reduction of 23.1 GW from load management programs offered by large utilities in 2007. This is based on the EIA Form-861 reporting by utilities. http://www.eia.doe.gov/cneaf/electricity/epa/epaxlfile9_3.pdf

Figure 20: Comparison of BAU Estimate to Other Data Sources (2008)



The BAU scenario estimate in the present analysis is based on the 2008 FERC Demand Response Survey Database which supports the staff report. The BAU potential estimate is lower than the 41 GW of potential indicated in the Staff Report and excludes two categories of programs that were included in the FERC analysis: 'Time-Of-Use (TOU)' rates and 'Back-Up Generation'; and also excludes additional state-specific adjustments (see Table 2). The reasons for excluding these three items from our BAU estimation are as follows:

1. Time-Of-Use (TOU) rates: For the purposes of this analysis, it is recognized that TOU rates can lead to significant reductions in peak demand. However, this generally happens through permanent load shifting rather than through demand response with short response time. See the discussion in Chapter II for more details on this exclusion.

2. Back-up generation: Programs that explicitly target back-up generation are not included in the BAU estimation, as back-up generation is not considered to be a demand response option by itself. But, back-up generation is included in cases where it is an underlying option in a general demand response program.

3. State-specific adjustments: An additional adjustment was made for an outlier program that is likely to have dramatically overstated impacts.[44]

[44] In the 2008 FERC survey database, a Minnesota utility, Great River Energy, reported a load reduction potential of around 50% of the total potential for the state. However, the EIA Form-861 database indicates that the summer peak load contribution from this utility was 13% of the total summer peak load for the state. We therefore adjusted the load reduction potential reported by this utility in the FERC survey database to represent approximately 13% of the total load reduction potential for the entire state. This led to a reduction of 1.9 GW of potential for the State of Minnesota (Item 3 in Table 2). This observation was confirmed through a review of Electric Power Research Institute, "Energy Efficiency Potential Assessment for Great River Energy." EPRI Technical Report 100891, July 2003.

Table 2: Explanation of Difference between FERC Staff Report and BAU Estimate

	Potential load reduction (GW)
2008 FERC Staff Report	41
1. TOU impacts	- 1.7
2. Backup generation	- 0.7
3. State-specific utility adjustment	- 1.9
BAU Estimate	= 36.7

The BAU scenario estimate is higher (by around 8 GW) than the amount of existing demand response provided in the 2008 NERC Summer Reliability Assessment report.[45] This discrepancy is most likely due to the fact that NERC's assessment is primarily focused on ISO/RTO estimates for demand response resource participation, while the BAU estimation based on FERC survey data was developed through a bottom-up estimation approach through aggregated utility reporting on demand response programs.

Lastly, the BAU scenario estimate is also substantially higher than the EIA estimate (by roughly 14 GW). This difference can be explained by the fact that the EIA estimate only includes data reported by large utilities, which leads to the estimation of a lower level of load reduction potential.

[45] In its subsequent 2009 Summer Reliability Assessment Report (May 2009) NERC reports the demand response potential for summer 2009 peak load reduction to be about 33 GW. This study estimates the BAU load reduction potential in 2009 to be 36.8 GW, higher by almost 3.8 GW than NERC's 2009 report.

CHAPTER IV. TRENDS AND FUTURE OPPORTUNITIES

This report estimates the potential for demand response in the United States at the national, regional, and state levels using four different definitions of potential. The four concepts of potential have been estimated for five program types across four customer classes. It relies on readily available information and data. As such, ideas and concepts that could not be quantified were excluded. This chapter briefly addresses some of these non-quantifiable aspects of demand response and suggests the role they may play in the future.

A wave of new technologies is emerging that falls under the broad rubric of the smart grid. At this point, these technologies are too new for their likely market penetration or impact per participating customer to be determined. These include advanced, grid-friendly appliances which communicate with each other and whose operation can be managed remotely or locally by households through a digital home energy management system. Early versions of these technologies have been shown to be very promising but also very expensive in the California statewide pricing pilot and the Olympic Peninsula pilot. It is important to keep an eye on the continued development, testing and consumer acceptance of these technologies.

Increasingly sophisticated in-home displays are being introduced that have the potential to reduce overall energy consumption. Future versions will be able to estimate how much of the bill was spent on the major end-uses, giving customers essential information to prioritizing their energy use during expensive times. These devices have the potential for lowering customer peak demands, thereby contributing indirectly to demand response. Some of these devices can work with time-of-use rates and future variants will probably be able to work with dynamic pricing rates.

In a similar vein, new pricing designs continue to be developed that can enhance the appeal of dynamic pricing to large numbers of customers by tailoring the risk-reward trade-off inherent in such rates to the preferences of individual customers. For example, various types of real-time pricing products are under consideration featuring either a two-part structure in which customer-specific baseline usage is priced at the existing rate and only usage that deviates from the baseline is priced through real-time rates. Other products are being introduced where customers buy a price-cap to insulate all their usage from excessive levels of price volatility. Other examples include variable peak pricing rates under which prices on critical days are not pre-specified but based on real-time costs in wholesale markets and dynamic pricing rates where, for a fee, customers can over-ride the price signal on certain days that are important to their business.

Today, codes and standards instituted by federal and in many cases state agencies affect energy used by appliances and by buildings. They are not designed to affect peak demand. However, that could change if agencies began to set standards for demand response. For example, the California Energy Commission is considering "load management" standards that may require all new Residential and Small commercial and industrial buildings to come equipped with programmable communicating thermostats.

Another trend that is beginning to be observed in states with large energy efficiency and demand response programs is the desire to integrate these two program offerings. The idea is that ultimately both involve the same customer and often the same end-uses. To promote faster adoption of both programs, the value proposition has to be conveyed clearly to customers and the actions required of them have to be streamlined. The combined effect of integrated programs on demand response could be significant. Future assessments should address this.

Distributed energy resources, such as photovoltaic arrays mounted on roof tops, hold the potential for having a significant effect on peak demand. Currently, their high capital cost poses a barrier to rapid market penetration. However, federal and state policies are addressing the cost barrier. As economies of scale increase, the cost should go down. When combined with appropriate rate designs, such as time-of-use rates, the impact of these dispersed resources on peak loads could be significant. Other examples include battery storage and thermal energy storage. Both items hold the potential to significantly reduce peak demand on a permanent basis by shifting it to off-peak periods. As in the case of photovoltaic arrays, cost is a significant barrier to their rapid market penetration today. Another example is behind-the-meter generation which includes a diverse set of technologies including small conventional generation units that are used as back-up generation during emergencies and cogeneration systems that combine heat and power, largely in industrial process applications.

Finally, another development to watch is the introduction of plug-in hybrid vehicles (PHEVs). If PHEVs can be charged during off-peak hours, they can improve capacity utilization in the power system and lower costs for all customers. However, if they are charged during peak hours, the load factor will worsen. The penetration of PHEVs will depend on several unknowns, including the price of gasoline, the price of electricity, customer driving habits and the incremental cost of PHEVs over conventional gasoline-power vehicles based on the internal combustion engine.

Time-of-use (TOU) rates are not considered a form of demand response in this report because they cannot be used to produce reductions in peak demand during critical periods. However, they do represent a way of reducing peak demand over the long-run and reducing the need for peaking generation units. While TOU rates have been in existance for a long time, their penetration of the market, especially for Residential and Small commercial and industrial customers, has been limited. There are two major limitations. The first one is that the peak period encompasses far too many hours to allow customers an opportunity to curtail usage during that period or to move it to off-peak periods. The second one is that the price differential between the peak and off-peak periods is not big enough to create significant savings opportunities. Both are being addressed in the TOU rate designs that are now being introduced by several utilities. Of particular interest is the idea of a super peak period which may be as narrow as three hours and which may be applied only during the two or three months of the summer where the system is likely to peak.

Another set of influences that will shape the future of demand response are utility and ISO/RTO administered energy efficiency programs. Many of these programs target end-uses such as central air conditioning which are a major driver of system peaks. As these appliances become more efficient, peak loads may diminish, albeit not by the same percentage amount as overall energy consumption. Similar comments can be made about inclining block rates which charge higher rates for usage in the upper tiers. Since that usage is highly correlated with the operation of peak-inducing appliances, reductions in upper tier usage brought about by inclining block rates can also lower peak demands.

Technology-enabled demand response programs can be activated on short notice and have the capability of providing ancillary services in restructured wholesale markets. There is insufficient evidence on whether demand response is being actively used in this fashion in ancillary service markets. Experience to date is largely limited to energy and capacity markets. However, this will change in the future as ancillary service markets are opened to demand resources.

Areas for Further Research

This study has relied upon the best available data to make projections of demand response potential. For example, several pilots with dynamic pricing rates have yielded results that have been used to inform the study's assumptions about likely customer response to such pricing programs. This required making some assumptions about the impact of humidity on customer response, as predicted from PRISM[46] that

[46] The California Statewide Pricing Pilot produced estimates of price elasticity for residential customers that captured variations in customer price responsiveness across four different climate zones in the state. These estimates were codified in the Pricing Impact Simulation Model (PRISM) which allows price elasticities to vary as a function of a zone's saturation of central air

was estimated using data from California's dynamic pricing pilot. It would be worthwhile to test the validity of this assumption by combining the data from the various pilots.

There is a long history with utility direct load control programs for Residential and Small commercial and industrial customers and curtailable/interruptible tariffs for Large commercial and industrial customers. Results from these programs have been used to inform this study's assumptions. However, in several areas, further research is warranted to improve the quality of the assumptions. Many of these deal with Large commercial and industrial customers. For example, there is need for much better information on the likely effect of automated demand response on peak loads and the response of these large customers to dynamic pricing rates.

As noted earlier, not much is known about the impact of dual-purpose programs that combine energy efficiency with demand response. More research is needed on this topic.

Most of these gaps in knowledge can be addressed by designing and implementing pilot programs. These pilots should focus on topics on which not much is known today and not repeat investigations that have already been carried out. It would be useful to conduct a pilot screening exercise to identify high priority areas. One approach to doing this is to focus future pilots on areas which simultaneously satisfy two criteria: (a) high potential savings and (b) high uncertainty (for example, where newer technologies are involved). Areas with low potential may not be worth piloting. Areas with high potential savings but low uncertainty do not require piloting and should instead be considered for full-scale implementation. The lowest priority should be given to areas with low potential savings and low uncertainty.

Another area in which further research is needed involves the prediction of customer participation rates. For certain programs with long histories, such as direct load control and curtailable/interruptible rates, considerable information on customer participation rates is available. Information from the distribution of participation rates has been widely used in this study. In other areas, such as customer participation in dynamic pricing programs, relatively little is known. New work is needed in this area. The traditional type of impact evaluation pilots will not help address the issue. Market research involving customer surveys, conjoint analysis and discrete choice modeling can provide initial answers. But all of these rely on stated preferences rather than observed (or revealed) preferences. Other creative research methodologies will need to be developed that combine information on stated preferences with information on revealed preferences (where it is readily available or where it can be inferred by analogy).

conditioning equipment and weather conditions. For more information, see Charles River Associates, *Impact Evaluation of the California Statewide Pricing Pilot, Final Report.* March 16, 2005

CHAPTER V. OVERVIEW OF MODELING AND DATA

This chapter provides an overview of the model and data that underlie the demand response potential estimates presented in prior sections and in the detailed, state-level summaries contained in Appendix A. The chapter is divided into the following subsections:

- High-level summary of modeling methodology
- High-level summary of data development
- Cost-effectiveness methodology

Model Overview

Development of the demand response potential model and default data underlying the estimates presented in this report was guided by the following objectives:

- Produce defensible estimates of demand response potential based on the definitions and assumptions underlying this analysis;
- Develop internally consistent estimates of demand response potential at the state, regional and national level;
- Provide defensible default data for all required model input variables at the state level, from publicly available sources;
- Ensure that there is no double counting of demand response load impacts;
- Provide a user friendly, extremely flexible model that can be used to update the estimates as better data become available, as policies change, and to aid in policy analysis and development.

Demand response potential estimation is inherently a "bottom-up" process. Load impacts associated with demand response programs are fundamentally driven by changes in consumer behavior, and demand response potential and load impacts vary significantly across customer segments. For example, the extensive literature on electricity demand developed over the last 30 years, and more recent evidence from time-based pricing pilots, indicates that residential customers are more responsive to time-varying price signals than are commercial and industrial customers (e.g., residential customers have higher price elasticities than do non-residential customers).[47] On the other hand, the average commercial and industrial customer has larger loads than does the average residential customer, so smaller percentage impacts still often translate into larger absolute impacts on a per customer basis. Residential customer impacts vary significantly across customers with and without central air conditioning and, for customers with central air conditioning, potential impacts vary across climate regions. These are a few examples of why it is important that the development of demand response potential estimates start at the customer level and work up to the segment and region level of interest.

There are three fundamental building blocks needed to estimate demand response potential:

[47] See, for example, Charles River Associates. *Impact Evaluation of the California Statewide Pricing Pilot, Final Report,* March 16, 2005 and Stephen S. George, Ahmad Faruqui and John Winfield. *California's Statewide Pricing Pilot: Commercial & Industrial Analysis Update*. Final Report, June 28, 2006.

- An estimate of average energy use during peak periods before demand response impacts take effect;
- An estimate of the change in energy use during peak periods resulting from customer participation in demand response programs and response to demand response price signals or incentives; and
- An estimate of the number of customers that participate in demand response programs.

These three building blocks are displayed in the blue shaded boxes in Figure 21 which also illustrates some of the primary input values that are needed to predict demand response effects.

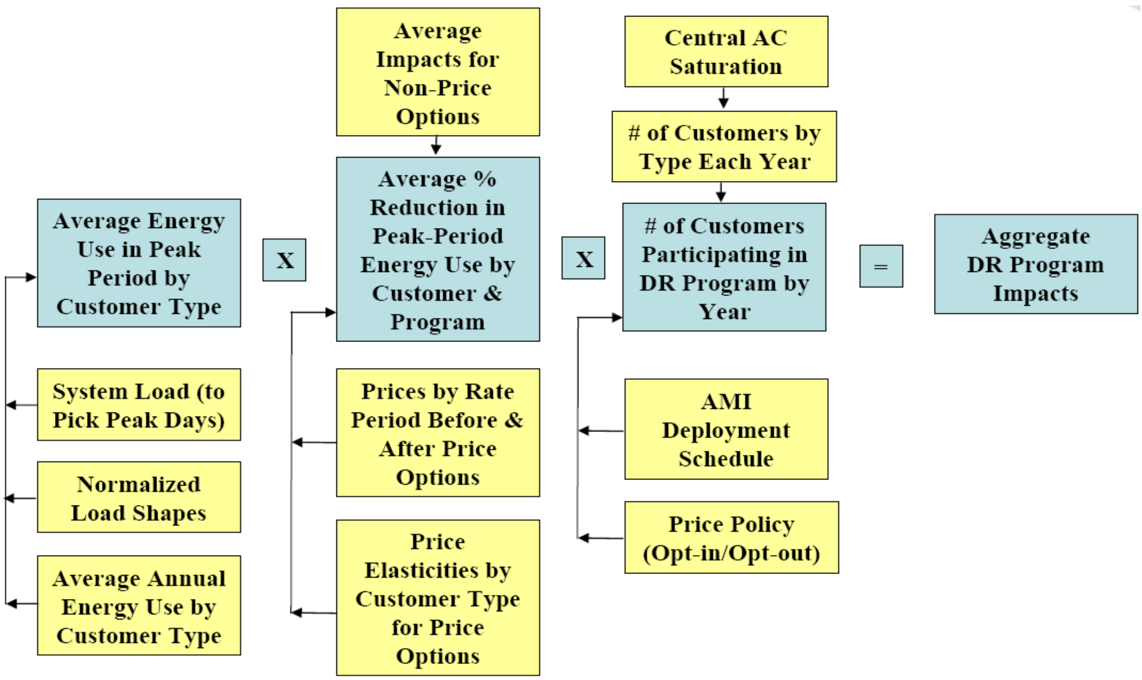


Figure 21: Key Building Blocks and Inputs for Demand Response Potential Model

A significant challenge in developing demand response potential estimates is the general lack of data on energy use during peak periods, when demand response is needed most and the benefits are greatest. Most utilities do not have hourly load data for a representative sample of customers and the lack of such information can be a stumbling block for developing demand response load impacts for utilities and states. Original work was done through this project to develop representative, hourly load data to use as input to the model for five customer segments: residential consumers with and without central air conditioning, small non-residential consumers (demands less than 20 kW), medium non-residential consumers (demands between 20 and 200 kW) and large non-residential consumers (peak demands exceeding 200 kW). These load estimates were developed using regression analysis based on hourly load data from utilities in 21 states, representing a broad cross section of customer segments and climate conditions. Normalized load shapes were developed using statistical analysis and combined with annual energy use, weather data and system load data (to identify top system load days) from each state to produce the starting values for energy use during peak periods depicted in the first blue box in Figure 21. These estimates are primarily used as input to load impact estimates for price-based demand response. This original work could be a valuable resource for states and utilities that want to refine the demand response potential estimates presented here or that might find hourly load data useful for demand response program planning or other purposes.

The demand response potential model uses two different approaches for determining load impacts for various demand response options. Load impact estimates for non-price based demand response options, such as direct load control and interruptible rates, are based on average values determined through analysis of data from existing programs. Load impact estimates for price-based demand response are determined using the normalized load shapes summarized above and estimates of the percentage change in energy use during peak periods based on price elasticities and the assumed change in prices during peak periods for demand response tariffs relative to non-time varying rates.

Price elasticities depict the percentage change in energy use given a percentage change in price. In recent years, there have been numerous studies done by utilities around the country that estimate price elasticities associated with time-based pricing.[48] Estimates from various studies were used here to determine price impacts that vary across states and customer segments based on key drivers of demand response, such as air conditioning saturation, climate and the presence or absence of enabling technology such as programmable communicating thermostats that can help to automate some forms of price response in regions where the technology is cost effective.

The percent reductions for price based demand response options used in each scenario are based on an assumption that prices during the peak period on high demand days are eight times higher on a dynamic time-varying rate than they are based on the average price associated with the non-time varying, otherwise applicable tariff.[49] This price ratio is intended to depict the ratio between an average price and a dynamic price that incorporates a large portion of the avoided cost of capacity[50] into the small number of hours in which peak-period dynamic price signals are in effect. In reality, price ratios could vary significantly across states if every state fully reflected the avoided cost of capacity in the dynamic rate, since the avoided capacity cost does not vary greatly across states but current average prices do. As such, the price ratio might be much higher in Idaho, for example, where current prices are relatively low, than it would be in California, where current prices are much higher.[51] However, tariff design is not just based on cost analysis—there is always a concern about extreme changes in prices whether or not they are cost-reflective. As such, using the same 8 to 1 price ratio across states may more accurately reflect how prices might evolve as they move closer to reflecting both avoided capacity costs and other requirements to be reflected in a rate design.

The third key element of demand response potential estimation is the number of customers that participate in each demand response program. The number of participants is a function of the number of eligible customers and the assumed participation rate. The number of eligible customers is based on the number of customers by segment and, in some cases, to the number of customers with specific end use equipment, such as central air conditioning.[52] For residential customers, the breakdown between those with and without central air conditioning is determined from data on air conditioning saturation in each state. The eligible population for price based demand response options is also driven by the presence or absence of

[48] A useful summary of numerous pilots is contained in Ahmad Faruqui and Sanem Sergici, "Household response to dynamic pricing of electricity: A survey of the experimental evidence," January 10, 2009. http://www.hks.harvard.edu/hepg/Papers/2009/The%20Power%20of%20Experimentation%20_01-11-09_.pdf. Price elasticities determined from a large, multi-year experiment conducted in California formed the starting point for the values used in the demand response potential model. These values are documented in Stephen S. George and Ahmad Faruqui, *Impact Evaluation of the California Statewide Pricing Pilot, Final Report.* March 16, 2005 and in Stephen S. George, Ahmad Faruqui and John Winfield. *California's Statewide Pricing Pilot: Commercial & Industrial Analysis Update*. Final Report, June 28, 2006. These starting values were modified, as discussed in Appendix D, based on information from other pilots and variation in key drivers of demand response such as air conditioning saturation and climate.

[49] The price ratio used for the large C&I customer segment is 5 to 1. This lower ratio is based on the fact that most large C&I customers are already on static time-of-use rates and, thus, have a higher peak-period price as part of their standard tariff than do other customers. As such, the ratio between the standard (TOU) peak price and a price that more fully reflects the avoided capacity cost is less for this customer group than it is for the other customer segments.

[50] "Avoided cost of capacity" refers to the amount of investment in new power plants that could be avoided or deferred through a reduction in peak demand.

[51] A recent rate filing by PG&E that reflects the full avoided cost of capacity in critical peak price hours has a peak period price of roughly $1.50/kWh for residential customers. This represents roughly a 10 to 1 price ratio compared to current average prices in CA but a state like Idaho, it would be closer to 20 to 1.

[52] Central air conditioning is a necessary condition to participate in air conditioning load control programs and also for the technology-enabled price responsive demand response options.

advanced metering infrastructure (AMI), which varies across years and scenarios. The number of customers assumed to participate in a demand response program is based on the assumed pricing policy (e.g., whether dynamic pricing is mandatory, is based on default, opt-out enrollment policies, or is based on opt-in enrollment). Enrollment assumptions for other demand response programs are based in part on enrollment in "best practices" programs that currently exist.

Much more detailed documentation of the model and input values is contained in Appendix E. The demand response potential model used to generate the estimates contained in this report is available from FERC. It was developed with the idea that state and utility policy makers may wish to use the model with different input data and assumptions to develop alternative, state-specific demand response potential estimates.

The demand response potential model is an Excel spreadsheet tool that contains user friendly drop-down menus that allow users to easily change between demand response potential scenarios, import default data for each state, and change input values on either a temporary basis for use in "what if" exercises or on a permanent basis if better data are available. Figure 22 shows half of the front-end, user input page of the spread sheet where scenarios can be selected and input values changed. Figure 23 shows the second half of the same input sheet. These "screen shots" are examples for a specific state and are shown here simply to give the reader a quick perspective on how input values can be changed and new scenarios created. Detailed documentation of the model and all variable names and input values are contained in Appendices D and E.

As seen in Figure 22, the first part of the input sheet contains pull-down menus that can be used to select the geographic region of interest (each of 50 states plus D.C., 9 census regions and the nation as a whole) and the demand response potential scenario (Business-as-Usual, Expanded BAU, Achievable Participation or Full Participation potential). The user can also select from among a wide range of price ratios (and differing ratios for each customer segment) that drive price-based demand response load impacts. Once these selections are made, the "Load Default Inputs" button is used to load the default data from the state-level database that pertains to the options selected. If the user changes input values in the other portions of the database through the input screen, the "Save As Default" button can be used to make those changes permanent.

The lower portion of Figure 22 shows the input values used by demand response program type and customer segment. Many of these values are either loaded in from the default database or are user defined. The line labeled "Customers with load suitable for enabling technology" is tied to the saturation of central air conditioning in each state and customer segment, as this value determines the percent of total customers where programmable communicating thermostats or direct load control options apply. The next line, "Offered Technology" is a function of whether such technology is determined to be cost effective in that state. This is typically 100 percent or 0, the latter being used in states where the particular technology is not cost effective. As indicated previously, all of the variables shown in Figure 22 are documented in the appendices. Figure 23 shows the remaining portion of the input sheet from the model. The top part contains input values for the number of customers by type and growth rates for the number of customers, peak demand and energy use. It also shows the AMI deployment schedule for each customer segment. The bottom part of this portion of the input sheet has values for the remaining key variables that drive load impacts. They include average use during the peak period by customer segment, and percent reductions in average use for customers who participate in various demand response options. The percent reductions for price-based demand response are based on the price elasticities underlying the default database and the assumed price ratios that drive each scenario. However, these values can be overridden by the user if, for example, there is more current or relevant data from a pricing pilot at a specific utility or state indicating that the estimated values based on the default price elasticities might be inappropriate for the scenario of interest to a specific user.

The demand response potential model produces a wide variety of numeric and graphical output reports and files. The graphs and tables shown in each of the state reports contained in Appendix A are examples of a few of the model outputs. In general, tables and/or graphs are produced that show the breakdown of demand response impacts (in both absolute and percentage terms) by program type, customer segment, and year under each of the four demand response potential scenarios. The model also creates a database containing all output values with built in pivot tables that can be used to easily manipulate the data and to produce customized output tables and figures. There are also output files and graphs that show the results for all four demand response potential scenarios in the same sheet.

Figure 22: User Friendly Input Sheet from Demand Response Potential Model

	A–C	D	E	F	G	H	I
1	FERC National DR Potential Assessment						
2	SCENARIO INPUTS - GA Achievable						
3							
4							
5	State	GA	Load Default Inputs		Instructions		
6	Type of Potential	Achievable					
7	New Peak to Old Peak Price Ratio Residential	8.00					
8	New Peak to Old Peak Price Ratio Small C&I	8.00	Save As Default Inputs and Results		Update Results Database (Cycles through 50 States)		
9	New Peak to Old Peak Price Ratio - Medium C&I	8.00					
10	New Peak to Old Peak Price Ratio - Large C&I	5.00					
11	Data from year	2008					
12							
13				Commercial & Industrial			
14	DR TYPE SPECIFIC INPUTS		Residential	Small	Medium	Large	
15	Dynamic Price Induced DR						
16	Max Percent Enrolled or Notified		75.0%	75.0%	60.0%	60.0%	
17	Rates become effective at (% AMI penetration)		0.0%	0.0%	0.0%	0.0%	
18	Enabling technology						
19	*Customers with load suitable for enabling technology (%)*		82.2%	78.0%	85.0%	40.0%	
20	*Offered technology (% of eligible)*		95.0%	95.0%	95.0%	95.0%	
21	*Accept technology (%) - used for achievable*		60.0%	60.0%	60.0%	60.0%	
22	Automated or Direct Control DR						
23	Current Market Penetration (% of eligible customers)		2.8%	0.3%	0.0%	0.0%	
24	Max Market Penetration (% of eligible customers)		25.0%	1.2%	7.2%	0.0%	
25	*Years required to achieve max penetration*		5.0	5.0	5.0	5.0	
26	Interruptible Tariffs						
27	Current Penetration (% of customers in segment)		0.0%	0.0%	0.0%	6.5%	
28	Current Penetration (% of MW in segment)		0.0%	0.0%	0.0%	4.9%	
29	Max Penetration (% of customers in segment)		0.0%	0.0%	0.3%	6.9%	
30	Max Penetration (% of MW in segment)		0.0%	0.0%	1.7%	16.8%	
31	Years required to achieve max penetration		5.0	5.0	5.0	5.0	
32	Other DR Programs						
33	Current Penetration (% of customers in segment)		0.0%	0.0%	0.0%	0.2%	
34	Current Penetration (% of MW in segment)		0.0%	0.0%	0.0%	1.1%	
35	Max Penetration (% of customers in segment)		0.0%	0.0%	0.1%	18.9%	
36	Max Penetration (% of MW in segment)		0.0%	0.0%	0.0%	23.4%	
37	Years to achieve max penetration		5.0	5.0	5.0	5.0	

Figure 23: User Friendly Input Sheet from Demand Response Potential Model (continued)

	J	K	L	M	N	O
4						
5				Commercial & Industrial		
6	GENERAL INPUTS		Residential	Small	Medium	Large
7	Population and Load Growth Factors					
8	Starting Customer Population		4,039,005	483,576	66,628	11,363
9	Population Growth Rate (Annual)		1.29%	1.57%	1.57%	1.57%
10	Annual Consumption Growth (Annual)		1.24%	1.13%	1.13%	1.13%
11	Critical Peak Growth (Annual)		0.60%	0.33%	0.33%	0.33%
12	AMI Deployment					
13	2009		10.7%	10.7%	10.7%	10.7%
14	2010		21.5%	21.5%	21.5%	21.5%
15	2011		32.2%	32.2%	32.2%	32.2%
16	2012		43.0%	43.0%	43.0%	43.0%
17	2013		53.7%	53.7%	53.7%	53.7%
18	2014		57.5%	57.5%	57.5%	57.5%
19	2015		61.2%	61.2%	61.2%	61.2%
20	2016		70.0%	70.0%	70.0%	70.0%
21	2017		80.0%	80.0%	80.0%	80.0%
22	2018		90.0%	90.0%	90.0%	90.0%
23	2019		100.0%	100.0%	100.0%	100.0%
24						
25						
26						
27				Commercial & Industrial		
28	AVERAGE PARTICIPANT CRITICAL DAY LOAD AND LOAD RED		Residential	Small	Medium	Large
29	Critical peak avg. hourly load (kW)		3.36	5.44	59.68	601.70
30	Critical peak avg. hourly load - CAC owners (kW)		3.73	DNA	DNA	DNA
31	Critical peak avg. hourly load - no CAC (kW)		1.63	DNA	DNA	DNA
32	Pricing - customers without central a/c (% reduction)		8.5%	0.7%	8.7%	7.5%
33	Pricing - customers with central a/c but no enabling tech (% redu		19.3%	0.7%	8.7%	7.5%
34	Pricing - customers with central a/c and enabling tech (% reducti		33.8%	14.9%	13.9%	13.9%
35	Automated or Direct Load Control DR (kW reduction per custon		1.24	2.48	7.44	37.18
36	Interruptible Tariffs - (% reduction)		0.0%	0.0%	69.9%	94.5%
37	Other DR - committed load reduction programs (% reduction)		0.0%	0.0%	39.4%	50.0%

Database Development

Each of the data elements that contribute to the model inputs were developed through careful review of a number of publicly available data sources. Table 3 lists the data elements developed and the sources used for developing these elements. Appendix D to the report describes in detail how the different data elements were developed and the interrelationships between the different elements and the sources. Appendix B details the challenges of developing state level data for this Assessment.

Table 3: Summary of Key Data Elements and Sources

Data Category	Data Elements	Data Sources
Market Characteristics Data	Number of customer accounts by rate class	• EIA State-Level data • FERC Form No. 1 database
	Electricity sales by rate class	• EIA State-Level data • FERC Form No. 1 database
	System peak load forecast by state	• 2008 NERC Long Term Reliability Assessment report • EIA State-Level data
	Average Peak Load per customer by rate class	• Utility/ISO system load data • Hourly load shapes by state • CAC saturation • Average energy use by customer segment • State weather data
	Growth rate in per customer peak load	• U.S. Census Bureau • Supplemental Tables to Annual Energy Outlook 2008
	Central air conditioning market saturation data	• Utility and state level appliance saturation survey reports • Direct utility contacts • EIA data on Regional Energy Consumption Survey (RECS) • American Housing Survey, U.S. Census Bureau • EIA data on Commercial Building Energy Survey (CBECS)
	AMI deployment schedule by state	• KEMA report • FERC survey • Utilipoint • Enernex
Demand Response Program Related Data	Business-As-Usual demand response potential estimation	• 2008 FERC demand response Survey data
	Current participation in demand response programs	• 2008 FERC Demand Response Survey data • Demand response program evaluation reports • Direct contacts with utilities
	Demand response program impacts	• 2008 FERC Demand Response Survey data • Demand response program evaluation reports • Direct contacts with utilities

Development of Load Shapes

One of the key inputs to demand response potential estimation is average electricity use per customer per hour during time periods when demand response programs are likely to be used but before any demand response occurs. We refer to the time period representing when demand response has a high probability of being used as the “peak period” on a “typical event day” and represent that period by the hours between 2 and 6 pm on the top 15 system load days in each state.[53] Note that average energy use across the top 15 system load days will produce demand response load impact estimates that are significantly lower than if they were based on the single hour of system peak or based on fewer than the top 15 system load days. Utility system load data were used to identify top system load days in each state.

As previously discussed, hourly load data were not available for all utilities and states or for all customer segments within states. Indeed, no data at all were found that distinguished between residential customers with and without central air conditioning. Fortunately, hourly load data were available on a large enough cross section of utilities and states (21 states in total) that it was possible to use regression analysis to estimate normalized load shapes for each relevant customer segment and to use these models to develop load shapes for all other states and customer segments. Data from these utilities were used to estimate regression models that relate normalized hourly load to a variety of variables that influence load in each hour, including weather, central air conditioning saturation and seasonal, monthly, day-of-week and hourly usage patterns. This statistical analysis was used to separate weather sensitive and non-weather sensitive load for residential customers. The normalized load shapes were then combined with estimates of average annual energy use and central air conditioning saturation by customer segment for each state and state-specific weather data to produce hourly load estimates for each customer segment and state. The average, hourly energy use between 2 and 6 pm on the top 15 system load days was used as the basis for estimating load impacts for price-based demand response options for each customer segment.

AMI Deployment

Advanced metering is a necessary technology to support price-responsive demand response for mass-market customers. As such, estimates of the penetration of AMI must be developed for each demand response potential scenario. However, having advanced meters is a necessary but sufficient condition to support price-responsive demand response—a utility also needs a meter data management system and billing system that will support price-responsive demand response options. Quite often, utilities install meters that qualify as advanced meters in that they gather hourly or sub-hourly data daily, but use them as an automated meter reading system to produce monthly meter reads—they do not install the meter data management system and billing systems needed to support wide scale price-responsive demand response. The AMI deployment scenarios described below recognize that more than just metering is needed to support price-responsive demand response. The deployment time lines for each scenario are based on the understanding that only systems that have MDMS and billing systems are considered AMI for purposes of supporting demand response potential.

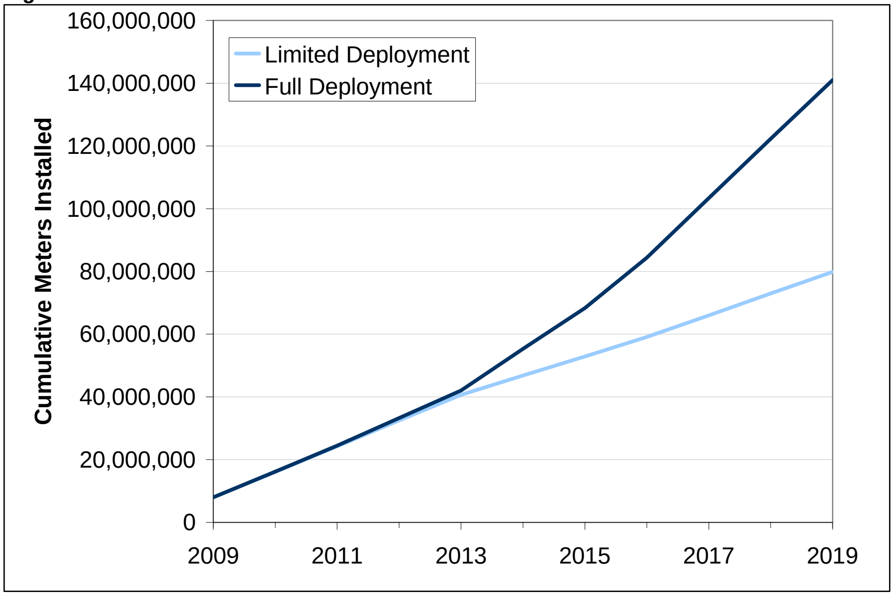
Two AMI deployment scenarios were developed for each state.

- The "Full Deployment" scenario is used to support the Achievable Participation and Full Participation demand response scenarios and assumes that all utilities will have AMI meters in place for all customers, along with the MDMS and billing systems required to support price-based demand response, by the end of the analysis horizon, 2019. Deployment timing is based on a set of assumptions described in Appendix D, and varies significantly across states based on current plans, the mix of utilities in each state, and other factors.
- The "Partial Deployment" scenario is used to support the Expanded BAU potential scenario and includes AMI deployment plans for each state based largely on a continuation of current trends. It includes 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 are believed to have a higher probability of installing such systems over the next ten years.

The following figure shows the cumulative number of AMI meters underlying the partial and full deployment scenarios.

[53] In recent AMI business cases and dynamic pricing pilots, the number of load days used varies roughly between the top 10 and top 20 days. The top 15 days were used in this study as an approximate midpoint.

Figure 24: Cumulative AMI Installations under Two Scenarios



These two alternative scenarios should not be considered forecasts of actual AMI meter and system deployment. The full deployment scenario is predicated on the assumption that all customers will have smart meters by the end of the ten-year forecast horizon. This assumption is combined with a variety of information and assumptions that drive the likely sequence of installations across utilities in a state and across states that are described below. The partial deployment scenario is probably closer to what might actually occur, but it is not a true forecast, since a true forecast would require conducting business cases on hundreds or perhaps thousands of utilities and an assessment of the likely barriers to deployment in each state. Such work was beyond the scope of this analysis.

Estimating the Impact of Dynamic Prices

The AP and FP potential estimates rely heavily on price-based demand response options, specifically on dynamic tariffs that deliver high price signals on relatively few high-demand days when demand response benefits are greatest. Estimates of the load impact associated with pricing options are based on variables known as price elasticities. Economists define the "own" price elasticity as the percentage change in the quantity purchased of a good or service divided by the percentage change in the price of that good or service. There is a similar concept, known as the elasticity of substitution, which summarizes the relationship of two goods or services that are substitutes for each other. The elasticity of substitution is equal to the percentage change in the ratio of the quantities purchased of two goods to the ratio of the prices of the two goods. Put another way, the elasticity of substitution summarizes the rate at which consumers substitute one good for another based on the relative prices of the two goods.

In the case of electricity demand, if prices are higher at one time of day relative to another, consumers may be willing to shift their load from the high priced to the low priced period. An example would be a consumer shifting the timing of their laundry from the peak to the off peak period. Alternatively, or in addition, a consumer might just forgo some energy use during the high price period. An example would be switching off lights during high priced periods—consumers don't use more lighting during low priced periods because they used less during high priced periods.

One approach to estimating how electricity demand would change in response to time varying prices involves estimating a two-equation demand system, where 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. In combination, the two equations can predict the change in energy use in each time period as consumers move from non-time varying to time-varying prices. This is the approach that underlies the estimates of time-based price response in the demand response potential model.

A variety of pricing experiments and other studies have been conducted that allow for estimation of demand models and price elasticities such as those described above. These studies show that price responsiveness for residential customers varies across regions based in part on differences in the use of air conditioning. Climate differences can also impact price responsiveness, as can the presence or absence of enabling technology such as programmable communicating thermostats and other load control devices. Price responsiveness also differs between residential and non-residential customers with residential customers generally being more price responsive than non-residential customers. These factors have been taken into account in developing estimates of price response that reflect variation in the characteristics of customers across states. More detail on these regional factors is provided in Appendix D.

The price elasticities summarized above for residential customers produce quite different percent reductions across states as a function of the variation in climate and air conditioning saturations. There are also differences in the estimated percent reduction in peak period energy use based on differences in the assumed ratio of prices during the peak period. The following table shows the percent reduction in peak period energy use for residential customers for two price ratios for each of three states that vary with respect to central air conditioning saturation and climate. Note that the relationship between price and energy use is not linear. That is, while the price ratio doubles going from 4 to 1 to 8 to 1, the percent reduction in peak demand increases by less than 100 percent. For example, the doubling of the price ratio in Massachusetts leads to a 58 percent decrease in peak period energy use.

Table 4: Percent Reduction in Peak Period Energy Use for Residential Customers in Selected States

State	CAC Saturation	Percent Peak Period Reduction for 4 to 1 Price Ratio	Percent Peak Period Reduction for 8 to 1 Price Ratio
Massachusetts	12.70%	6.20%	9.83%
Maryland	78.00%	12.56%	19.66%
Arizona	86.80%	14.28%	22.33%

Key Assumptions

The products of the previously described data collection and modeling approach are participation rates and impacts by program type, class, and state. These form the basis for the demand response potential estimates. Summary values of participation rate assumptions for non-pricing programs in the three potential scenarios are provided in Table 5.[54] Note that program participation is expressed as a percentage of the eligible population, which changes by scenario as the role of pricing programs changes. Participation rates in Table 5 represent the 75th percentile of participation in existing programs at the state-level.[55] The 75th percentile was chosen as the "best practices" estimate because it represents the participation rate that a state would need to achieve to be a "top quartile performer" which is a metric commonly used to identify best practices in potential studies. States with participation rates higher than the 75th percentile are assumed to remain at existing levels, rather than derated to the 75th percentile.

Table 5: Final Participation Rates for Non-Pricing Programs

	Residential	Small C&I	Medium C&I	Large C&I
Direct Load Control	25%	1%	7%	N/A
Interruptible Tariffs	N/A	N/A	2%	17%
Other DR	N/A	N/A	0%	19%

Assumptions driving the final participation rate in pricing programs for the three demand response potential scenarios are provided in Table 6. Ranges reflect differences across states.

[54] BAU participation rates span a broad range encompassing these best practices estimates and are provided in Appendix D.
[55] The assumed participation rate for residential DLC is higher than the 75th percentile. This assumption is based on general industry experience with these programs and a proven history of utilities consistently being able to achieve participation rates of 25 percent of the eligible population.

Table 6: Drivers of Final Participation Rates for Pricing Programs

	Expanded BAU	Achievable Participation	Full Participation
Residential			
Final AMI Market Penetration	19% to 100%	100%	100%
Peak Price Ratio (New Peak-to-Existing Peak)	8	8	8
Final Enrollment in Dynamic Pricing	5%	75%	100%
Percent of Customers Eligible for Enabling Tech	3% to 91%	3% to 91%	3% to 91%
Percent of Eligible Customers Offered Enabling Tech	0%	95%	100%
Percent of Eligible Customers Accepting Enabling Tech	0%	60%	100%
Small C&I			
Final AMI Market Penetration	19% to 100%	100%	100%
Peak Price Ratio (New Peak-to-Existing Peak)	8	8	8
Final Enrollment in Dynamic Pricing	5%	75%	100%
Percent of Customers Eligible for Enabling Tech	70% to 78%	70% to 78%	70% to 78%
Percent of Eligible Customers Offered Enabling Tech	0%	95%	100%
Percent of Eligible Customers Accepting Enabling Tech	0%	60%	100%
Medium C&I			
Final AMI Market Penetration	19% to 100%	100%	100%
Peak Price Ratio (New Peak-to-Existing Peak)	8	8	8
Final Enrollment in Dynamic Pricing	5%	60%	100%
Percent of Customers Eligible for Enabling Tech	79%	79%	79%
Percent of Eligible Customers Offered Enabling Tech	0%	95%	100%
Percent of Eligible Customers Accepting Enabling Tech	0%	60%	100%
Large C&I			
Final AMI Market Penetration	19% to 100%	100%	100%
Peak Price Ratio (New Peak-to-Existing Peak)	5	5	5
Final Enrollment in Dynamic Pricing	5%	60%	100%
Percent of Customers Eligible for Enabling Tech	40%	40%	40%
Percent of Eligible Customers Offered Enabling Tech	0%	95%	100%
Percent of Eligible Customers Accepting Enabling Tech	0%	60%	100%

As stated in the definition of the potential scenarios, AMI market penetration is assumed to reach 100 percent by 2019 in both the AP scenario and the FP scenario. Final AMI market penetration is lower in the EBAU scenario, in which only those utility AMI deployments that were deemed "likely" through a review of industry data are included.

The assumed price ratio of 8-to-1 for Residential, Small commercial and industrial, and Medium commercial and industrial customers is driven by the range of rates tested in recent dynamic pricing pilots, some of which have been greater than 10-to-1.[56] For Large commercial and industrial, the price

[56] The PSE&G residential pilot program price ratio was 14-1o-1. BGE recently tested price ratios of roughly 9-to-1 and 12-to-1.

ratio is lower to account for the fact that many of these customers are already enrolled on TOU rates, the impacts of which would be reflected in the load forecast.

The assumptions for participation in price-based demand response options are based on market research and the limited experience that has been gathered to date. For the EBAU scenario, a participation rate of five percent is used for all sectors. There is very little experience and research to date upon which to base these assumptions. The most recent experience for a dynamic rate for residential customers has to do with Pacific Gas & Electric Company's SmartRate tariff, which is a critical peak pricing tariff that was offered in 2008 to residential customers in the part of the PG&E service territory where AMI meters had been installed.[57] The program was offered through direct mail and roughly eight percent of customers enrolled after a single mailer. Thus, five percent could be quite conservative for a program that would be marketed over an extended period of time. Given the limited experience for other customer segments, this assumption was used for all customer segments for the EBAU scenario.

The assumptions for the opt-out enrollment strategy underlying the AP scenario are based on market research and recent experience in California. In conjunction with California’s Statewide Pricing Pilot, research was conducted on the opt-out rates that might occur for residential customers that were defaulted onto a CPP rate.[58] The opt-out rates for customers depended on assumptions about the level of customer awareness of alternatives and ranged from a low of 10 percent at a low level of awareness to a high of 33 percent based on complete customer awareness of all options. The opt-out rate of 25 percent assumed here (75 percent retention) is consistent with an awareness level of 70 percent from that study. This value is also reasonably close to what was actually observed following completion of California’s Southwest Power Pool, when some customers were allowed to stay on the rate after the end of the pricing pilot. Roughly 65 percent of participants remained on the critical peak pricing tariff one year after the end of the Southwest Power Pool even though the participation incentive provided as part of the experiment was discontinued and customers had to start paying a monthly meter charge of between $3 and $5 depending on the utility serving them.[59]

The retention/opt-out rate for small commercial and industrial customers was assumed to be the same as for residential customers. For medium and large commercial and industrial customers, a retention rate of 60 percent was assumed. This assumption is based in part on recent analysis of the opt-out rate experienced by San Diego Gas & Electric Co., which placed all of its commercial and industrial customers that had interval meters on default CPP/TOU rates in 2008.[60] This study found that 75 percent of all customers placed on the rate stayed on the rate after the initial opt-out period had passed. However, this may not represent the long term retention rate since customers were offered first-year bill protection as part of the transition strategy for the rate. How many customers might leave at the end of that period, which occurs in late 2009, is currently unknown. Thus, a lower retention rate seemed prudent. Another relevant data point for this assumption is the experience of large commercial and industrial customers in New York who were placed on an RTP rate several years ago. Roughly 66 percent of customers stayed on this rate. Based on these two data points, an assumption of 60 percent retention seemed reasonable.

Customers are assumed not to be offered enabling technologies in the EBAU scenario, as the focus of this scenario is on non-pricing demand response programs. In the AP scenario, 95 percent of all eligible customers are offered enabling technology (in states where it is cost-effective to do so), reflecting the assumption that some states or utilities would choose not to pursue enabling technology. Sixty percent of customers accept the technology in this scenario, which is another illustrative assumption designed for the purposes of defining the scenario and reflecting that only a subset of customers will make the decision to

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[57] Stephen S. George and Josh Bode. (Freeman, Sullivan & Co.). *2008 Ex Post Load Impact Evaluation for Pacific Gas and Electric Company’s SmartRate™ Tariff.* Prepared for Pacific Gas and Electric Co. December 31, 2008.

[58] Momentum Market Intelligence. Customer Preferences Market Research: A Market Assessment of Time Differentiated Rates Among Residential Customers in California. December 2003.

[59] Dean Schultz and David Lineweber, *Real Mass Market Customers React to Real Time-Differentiated Rates: What Choices Do They Make and Why?* 16th National Energy Services Conference. San Diego, CA. February 2006.

[60] Steven D. Braithwait, Daniel G. Hansen, Jess Reaser and Michael P. Welsh (Christensen Associates Energy Consulting, LLC) and Stephen S. George and Josh Bode (Freeman, Sullivan & Co.) *2008 Load Impact Evaluation of California Statewide Critical Peak Pricing (CPP) for Non-Residential Customers Ex Post and Ex Ante Report* (May 1, 2009)

install enabling technologies even if they are cost-effective. In the FP scenario, all customers are offered enabling technology where it is cost effective and it is assumed that all of the customers accept the technology. Given the limited basis for setting participation rates, readers may wish to carry out some type of uncertainty analysis on these assumptions.

Per-customer impacts from non-pricing programs are provided in Table 7. These specify the amount by which an average customer participating in a given demand response program would reduce its peak demand. In Table 7, the per-customer impact is represented as a percent of the average customer's peak demand.[61] These values are based on the range of reported impacts from existing programs. For states without an existing interruptible tariff or Other DR program, or with lower-than average impacts in these programs, the average per-customer impact was used. For states without an existing interruptible tariff or Other DR program, the average per-customer impact was used. For states without existing DLC impacts a 50 percent air-conditioning cycling strategy was assumed.

Table 7: Per-Customer Impacts for Non-Pricing Programs

	Residential	Small C&I	Medium C&I	Large C&I
Direct Load Control	19% to 52%	7% to 17%	2% to 5%	N/A
Interruptible Tariffs	N/A	N/A	27% to 100%	13% to 100%
Other DR	N/A	N/A	39% to 100%	10% to 100%

Per-customer impacts from pricing programs are presented in Table 8. The range of residential impacts is a function of both the central air conditioning saturation in the state as well as the regional price elasticity.[62] Pricing impacts were simulated using the results of recent dynamic pricing experiments and studies as described earlier in this chapter and in Appendix D.

Table 8: Assumed Per-Customer Impacts from Pricing Programs

	Without Technology	With Technology
Residential	7% to 18%	21% to 34%
Small C&I	1%	15%
Medium C&I	9%	14%
Large C&I	7%	14%

Cost-Effectiveness Analysis

For the purposes of economic screening, the five demand response programs being considered in the analysis can be divided into two broad categories – those that do not require an enabling technology for participation (e.g. dynamic pricing such as critical peak pricing, peak time rebate, real-time pricing) and those that do (e.g. dynamic pricing equipped with devices that automate or reduce consumption). The demand response options that do not require an enabling technology for participation were deemed to be cost-effective for all states. For the demand response options that do require an enabling technology for participation, an economic screen was conducted to assess their cost-effectiveness in each state. The two types of options for which an economic screen was conducted are: 1) Dynamic Pricing with Enabling Technology, and 2) Direct Load Control.

The economic screen uses a simple version of the Total Resource Cost (TRC) Test that compares the lifetime benefits of the demand response option (i.e., avoided capacity costs) relative to the associated costs to enable each option (i.e., costs related to technology adoption, program implementation and

[61] However, in modeling the demand response potential, nominal impact values are used for DLC programs.
[62] CAC saturation is the percent of customers with central air conditioning.

delivery, etc.). Inputs for the economic screen include impact estimates per participant by state, capacity costs, equipment costs per participant, implementation costs, and economic parameters such as discount and cost escalation rates. The benefits are obtained by multiplying the unit demand reduction for each technology by avoided capacity costs over the ten year time horizon and discounting the dollar savings to a present value equivalent basis. For this type of preliminary analysis, the effects of incentives and participation rates are ignored. If the benefit-cost ratio is greater or equal than 1.00, the demand response option is considered cost-effective and is included in the state's full participation potential results.

The economic screening results show that Dynamic Pricing with Enabling Technology is a cost-effective option for the majority of states. However, there are a number of states for which it fails the economic screen. The results vary by customer type. Dynamic Pricing with Enabling Technology for residential customers is cost-effective for 42 states (84% of states). The option for small C&I customers is cost-effective for 40 states (80% of states) as well as for the District of Columbia. For the medium C&I customers, the option is cost-effective for 43 states (86% of states) and the District of Columbia, while for the large C&I category it is cost-effective for 45 states (90% of states) and the District of Columbia. The results indicate that Dynamic Pricing with Enabling Technology is cost-effective primarily for those states with high critical peak loads associated with large cooling or other end-use requirements. In particular, this option is highly cost-effective in Arizona and Nevada.

A few observations are worth noting for the results of the Dynamic Pricing with Enabling Technology screen:

- Because a state does not pass the cost-effectiveness screen, it does not suggest these programs should not be pursued in that state. The estimates are based on price response using class-average load shapes. Many of the states that did not pass in fact have varying weather characteristics that would lead to different impacts. Some regions might have higher impacts and thus these programs may indeed be cost-effective.
- As the customer class size increases and approaches the large C&I class (starting with the small C&I), more states become cost-effective.
- These trends suggest that as dynamic pricing tariffs are introduced across the country, utilities that are considering adopting one of their own might consider starting with the larger customer classes and gradually introduce the tariffs to the smaller classes once more information is available.
- Careful attention should be given to the economic analysis for these types of programs, particularly when looking at the residential class, which in some regions of the country may not provide the needed level of savings to justify the cost of enablement technologies such as programmable communicating thermostats and automated demand response.

Direct Load Control is a cost-effective demand response option for most states because of the higher per participant savings associated with this option. The analysis showed that Direct Load Control is cost-effective for residential customers in 48 states (96%) and the District of Columbia. The only states for which it is not cost-effective for residential customers are Alaska and Hawaii. Among both small and medium C&I customers, Direct Load Control is cost-effective for all states and the District of Columbia.
A few observations are worth noting for the results of the Direct Load Control with Enabling Technology screen:

- Most states passed the economic screen. However, for those states that failed the screen, methods of direct load control other than air conditioning might be viable.
- Methods to control water heating and pumping loads may be more viable in these regions.

For more details on the cost effectiveness analysis as well as state-level benefit-cost ratios, see Appendix D.

CHAPTER VI. BARRIERS TO DEMAND RESPONSE

A number of barriers are preventing demand response from reaching the full potential identified through this study. Some of these barriers are regulatory in nature, stemming from existing policies and practices that are not designed to facilitate the use of demand response as a resource. These barriers exist in both wholesale and retail markets. Other barriers are economic in nature. Certain technological limitations are also standing in the way. In total, 24 unique barriers to demand response have been identified through this study. Consistent with the requirements of EISA 2007, this chapter briefly summarizes these barriers to demand response. Further detail on the barriers is provided in Appendix C.

The Barriers to Demand Response

The barriers to demand response fall into four major categories: regulatory barriers, economic barriers, technical barriers, and other barriers.

- Regulatory: Regulatory barriers are caused by a particular regulatory regime, market design, market rule, or the demand response program itself. They can be divided into three sub-categories: general, wholesale-level, and retail-level.
- Economic: Economic barriers refer to situations where the financial incentive for utilities or aggregators to offer demand response programs, and for customers to pursue these programs, is limited.
- Technological: Potential technological barriers to implementation of demand response include the need for new types of metering equipment, metering standards, or communications technology.
- Other: Some additional barriers do not fall into the categories described above. These are generally related to customer perceptions of demand response programs and a willingness to enroll.

An extensive survey of the existing literature led to the identification of the 24 barriers to demand response identified in Table 9. Detailed descriptions of the barriers are provided in Appendix C.

Table 9: The Barriers to Demand Response

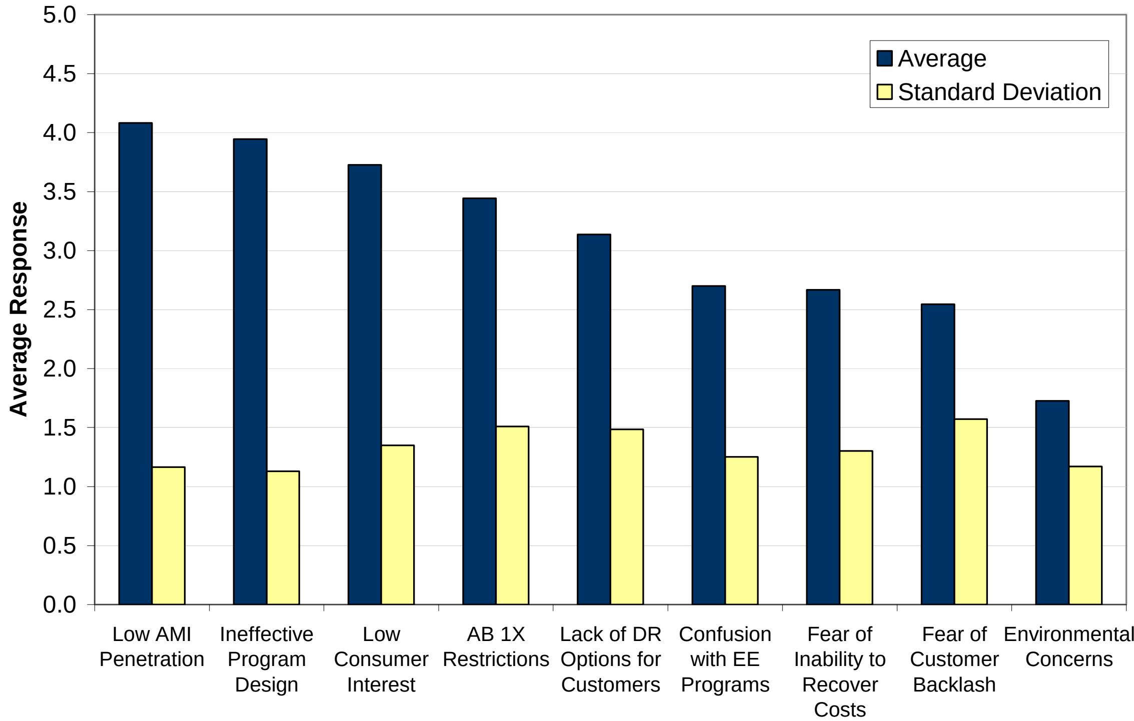
Type		Barrier
Regulatory (General)	1.	Retail-wholesale disconnect (lack of dynamic pricing)
	2.	M&V challenges
	3.	Shared State and Federal Jurisdiction
	4.	Perception of gaming
	5.	Lack of real-time info sharing (ISOs and utilities)
	6.	Lack of reliability/predictability in demand response
Regulatory (Retail)	7.	Policy restrictions on demand response
	8.	Ineffective demand response program design
	9.	Financial disincentives for utilities
	10.	Disagreement on cost-effectiveness analysis
	11.	Lack of retail competition
Regulatory (Wholesale)	12.	Market structures oriented toward accommodating supply side resources
Economic	13.	Inaccurate price signals
	14.	Lack of sufficient financial incentives to induce participation
Technological	15.	Lack of AMI
	16.	Lack of cost-effective enabling technologies
	17.	Concerns about technological obsolescence and cost recovery
	18.	Lack of interoperability and open standards
Other	19.	Lack of customer awareness and education
	20.	Risk aversion
	21.	Fear of customer backlash
	22.	Perceived lack of ability to respond
	23.	Concern over environmental impacts
	24.	Perceived temporary nature of demand response impacts

Assessing the Barriers

A review of the existing literature has identified a study in which many of the barriers to demand response were ranked in terms of their level of overall significance to impeding further market penetration of demand response programs. The study was conducted by The Brattle Group through a recent project with the California Energy Commission.[63] Stakeholders were interviewed, asked to identify barriers to demand response, and asked to rate the significance of the barriers on a scale from one to five, with one being "highly insignificant" and five being "highly significant." The results of the respondents' ratings are summarized in Figure 25 below.

[63] Ahmad Faruqui and Ryan Hledik, "The State of Demand Response in California," prepared for the California Energy Commission, April 2007.

Figure 25: Significance of Barriers to Demand Response in California as Identified by Stakeholders



Low AMI penetration topped the Brattle list of today's barriers to demand response. The second and third most significant barriers, both with average scores above 3.5, were ineffective program design and low consumer interest. It is interesting to note that these two barriers are probably highly correlated, as a more effective program design would be likely to encourage customer interest in demand response programs. Environmental concerns associated with demand response were deemed to be the least significant barrier.

CHAPTER VII. POLICY RECOMMENDATIONS

This chapter provides policy recommendations that, if implemented, could serve to remove the most significant barriers to achieving the demand response potential estimated in this report. At the outset, it is important to note that many of the opportunities to increase demand response potential lie at the retail level. The States and local governments will need to play a central role in promoting demand response programs needed to reach the full potential. The expansion of demand response programs will involve technologies that affect the electricity system across State and Federal jurisdictions. Some decisions may be made at the Federal level, while others will need to be made by State and local regulators or legislatures.

Statutory Requirement

EISA 2007 requires that, in addition to estimating nationwide demand response potential, FERC must include "specific policy recommendations that if implemented can achieve the estimated potential."[64] EISA 2007 states, "[s]uch recommendations shall include options for funding and/or incentives for the development of demand response resources."[65] EISA 2007 also directs FERC to note any barriers to demand response programs offering flexible, non-discriminatory, and fairly compensatory terms for the services and benefits made available, and shall provide recommendations for overcoming these barriers.[66] Through the recommendations provided below, this chapter is responsive to all three Congressional directives.

The preceding chapters of this report analyze three scenarios under which demand response potential could increase beyond the base case level of currently planned growth in demand response programs reflected by the Business-as-Usual scenario. These are the Expanded Business-as-Usual scenario, the Achievable Participation scenario, and the Full Participation scenario. Nationally, each is estimated to produce a significant increase in demand response potential relative to the Business-as-Usual scenario. However, as detailed in Chapter III, the estimated effect of each scenario in any particular state differs depending on a range of factors in that state, such as the level of central air conditioning saturation, the price of electricity, the generation capacity level, and the existing level of demand response, including whether the state has access to spot electricity and capacity markets with demand response programs.

Thus, how much and how best to increase demand response may differ from state to state. Further, given that each scenario is based on different approaches to increasing demand response, the critical barriers confronting each of these scenarios may differ. A more complete discussion of these barriers is found in Chapter VI and Appendix C.

General Recommendations to Overcome Barriers to Achieving Demand Response Potential

Several of the barriers identified in Chapter VI significantly impede the ability to implement the estimates of demand response potential identified in this report. These barriers are highlighted below, along with recommendations for overcoming those barriers.

[64] EISA 2007, sec. 529(a).
[65] *Ibid.*
[66] *Ibid.*

Sharing of Information on Effective Program Design

As noted in Chapter VI, improved program design represents one of the most significant means for improving the market penetration of demand response programs. To ensure the maximum impact for demand response programs, regulatory authorities and industry stakeholders should have access to tools and information to assist them in establishing programs that respond to their particular situation. Such assistance could include, for example, case studies on regulatory provisions, model state laws and retail tariffs, conferences and regional workshops, and technical papers on program implementation. In particular, many large customers complain that the wide variation in demand response programs offered by RTOs and by individual utilities increases their costs to monitor demand response programs, reducing the incentive to participate. Sharing demand response program alternatives across states or regions would encourage participation by large multi-state customers.

Increasing Customer Awareness of and Education on Demand Response

Achieving higher participation in demand response programs would require greater efforts by governments (federal, state and local), electric utilities and demand response providers to educate customers about the benefits, availability and operation of programs. Many consumers are unfamiliar with the benefits of demand response and may be averse to the perceived burdens of participation or risks in demand response programs.[67] Research shows, however, that customers who experience time varying rates have high levels of satisfaction and that, when offered the option of staying on such rates, most will do so and even recommend such rate programs to their friends.[68] Therefore, any plan to expand and increase participation in any type of demand response program should be accompanied by a plan to promote customer awareness and conduct targeted consumer education. This plan would raise awareness of the concept of demand response and educate consumers about the benefits of demand response, including an increased ability to control consumption, lower electric bills and possible environmental improvements. Strategies to build consumer acceptance could include marketing campaigns, customer outreach, coordination with the Environmental Protection Agency's Energy Star program on energy efficiency, development of cost effectiveness tools and implementation of a web-based clearinghouse of demand response information. Budgets for prudently deployed education and marketing efforts would need to be fully funded, and would likely be higher under the Achievable Participation and Full Participation scenarios given the estimated expansion of dynamic pricing to include most ratepayers in the former scenario and all ratepayers in the latter scenario.

Coordination of Wholesale and Retail Demand Response Strategy

In order for any demand response strategy to be effective, programs at the wholesale and retail level should be coordinated so that wholesale and retail market designs are complementary. For example, changes to RTO or ISO market rules could create opportunities for retail demand response. Industry and regulators should develop a comprehensive strategy for demand response that, mindful of respective jurisdictions, includes RTO market design changes necessary to accommodate retail demand response programs and retail tariff and pricing changes that are consistent with wholesale market designs.

Interoperability and Open Standards

Advanced metering infrastructure (AMI) will be encouraged by improving and expanding interoperability, open standards for communications protocols and meter data reporting standards. Development of these standards would allow the flow of information that is currently impeded by the existence of multiple, competing state and local requirements. Interoperability also would enable the development of new technologies, such as smart appliances, to support broader application of demand

[67] See discussion in Appendix C, p. 218.
[68] *Ibid*, p. 219.

response programs and dynamic pricing. Congress recognized the need for such standards in EISA 2007, granting the FERC authority to approve standards developed through the NIST consensus process. Regulators and industry participants should continue to support the development of adequate standards through the ongoing NIST process.

Coordination of Demand Response and Energy Efficiency Policies

Policies on demand response and energy efficiency should be coordinated, as appropriate. Demand response actions and energy efficiency investments are linked. Customer involvement in demand response activities typically leads to increased attention to electricity consumption and heightened interest in energy efficiency. In order to ensure that demand response and energy efficiency policies do not work at cross purposes, these policy initiatives should be coordinated. State energy master plans like those developed by Maryland, Michigan, and New Jersey represent a good example of explicit incorporation and linkage of demand response and energy efficiency goals and policies. Major initiatives such as the National Action Plan for Energy Efficiency and the National Action Plan on Demand Response should be closely coordinated.

Role of Demand Response in Operational and Long-Term Planning, and Recovery of Associated Costs

Demand response resources can play an important role in operational and long-term planning. Incorporating demand response resources into planning horizons and load forecasts allows transmission providers and load-serving entities to depict more accurately the energy needs of their areas, thereby potentially deferring or offsetting costly investments in new peaking generation and transmission. Demand response resources can also provide an important role in real-time operations, including providing emergency response and ancillary services. The Commission has recognized the value of demand response resources in long-term and operational planning in several key recent orders. Order No. 890 required transmission providers to establish a coordinated, open planning process that allows for the incorporation of demand response resources in all phases of the planning process on a basis comparable to other resources.[69] Order Nos. 693 and 719 recognized the ability of demand response resources to provide certain ancillary services when technically feasible.[70] Further integration of demand response will depend on a clear articulation by regulators and legislators of the expected role of demand response into operational and long-term planning. Key issues that should be resolved include how to account for and plan for customer electricity consumption changes in response to dynamic pricing, the ability of demand response resources to provide sustainable, long-term resources consistent with reliability requirements, appropriate compensation of demand response resources, and proper treatement of costs related to incorporation of demand response resources.

Recommendations to Achieve Specific Demand Response Potential Scenarios

Below are recommendations tailored to each scenario, consistent with the requirement to estimate how much of the potential can be achieved within five and ten years, accompanied by specific policy recommendations to achieve the potential.

Expanded Business-as-Usual Scenario

[69] Preventing Undue Discrimination and Preference in Transmission Service, Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 479, order on reh'g, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), order on reh'g, Order No. 890-B, 123 FERC ¶ 61,299 (2008), order on reh'g, Order No. 890-C, 126 FERC ¶ 61,228 (2009).

[70] Mandatory Reliability Standards for the Bulk-Power System, Order No. 693, FERC Stats. & Regs. ¶ 31,242, order on reh'g, Order No. 693-A, 120 FERC ¶ 61,053 (2007) and Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, 73 Fed. Reg. 61,400 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281 (2008), reh'g pending.

The increase in demand response estimated under the Expanded Business-as-Usual scenario is based on an assumption that current best-practice demand response programs are expanded to all states. To implement such an expansion of demand response activities, it would be necessary to increase significantly the number and extent of direct load control programs and interruptible tariffs, particularly in regions and states that currently lack programs. A means of broadly sharing information on the development, implementation and evaluation of direct load control programs and interruptible tariffs would be helpful to states and localities considering similar programs. Development and updating of model cost-effectiveness tools, particularly to include environmental challenges facing the states and the nation, and to reflect the existence of spot wholesale and capacity markets in many regions, would also be useful.

The Expanded Business-as-Usual scenario also assumes at least some amount of participation in dynamic pricing at the retail level. In particular, all currently planned and announced AMI deployments would need to be approved and installed to achieve the estimated demand response potential. This would require broad-based support from utilities, governors, legislatures and state and local regulators. In addition, funding issues would need to be addressed in order to consider the rate impact and benefits associated with AMI for all customers.

There are two additional recommendations for actions that could significantly expand the demand response programs necessary to achieve the potential represented by the Extended Business-as-Usual scenario. First, in order to encourage more aggressive participation in expanded direct load control programs and use of interruptible tariffs, payments to demand response resources should be designed to compensate them for the value they provide. Some direct load control programs and interruptible tariffs may not provide a sufficient financial incentive to participate. From an operational planning perspective, reliable and cost-effective demand response is valuable whether it is used or not, because it serves as an available resource that can be called upon during low probability events, such as system emergencies. Regulators and industry should examine compensation methods to assure that demand response is appropriately compensated.

Second, development of standardized practices for quantifying demand reductions would greatly improve the ability of system operators to rely on demand response programs of all kinds and would minimize gaming opportunities. For example, payments under direct load control programs and interruptible tariffs are dependent on estimates of demand reductions. The lack of standards for measuring and verifying reductions in demand has made it difficult to plan reliably for these resources, and has fueled concern about potential gaming by participants. Central to the issue of measurement is a determination of the customer baseline, or the estimate of what metered load would have been without the reduction in demand. The North American Energy Standards Board (NAESB) is in the process of developing business practice standards for measuring and verifying energy savings and peak demand reduction in the wholesale and retail electric markets. Upon completion, federal and state regulators should work with RTOs and utilities to incorporate these standards into their processes for settlement, operations and long-term planning. In addition, efforts by states such as California to develop protocols for estimating demand reduction should be encouraged and possibly adopted by other states.

Achievable Participation and Full Participation Scenarios

The increase in demand response participation estimated under the Achievable Participation and Full Participation scenarios is primarily driven by widespread implementation of dynamic pricing. Universal deployment of AMI is assumed in every state, along with implementation of cost-effective enabling technologies for those customers participating in a dynamic pricing program. Examples of enabling technologies include in-home displays, programmable communicating thermostats, or home area networks. In order to achieve the demand response potential estimated in these scenarios, it would be necessary for utilities to adopt and implement AMI. AMI has benefits to utilities beyond the facilitation of dynamic pricing; for example it can substantially reduce the cost to read meters. Moreover, all funding-related issues associated with AMI deployment would need to be addressed. In addition to directly funding AMI and implementing technologies, tax credits or accelerated depreciation could be offered for investments.

The Achievable Participation scenario assumes universal adoption of default tariffs that impose dynamic pricing on customers unless they expressly choose not to participate in the program. The Full Participation scenario assumes mandatory participation in dynamic pricing programs by all customers. To achieve the estimated demand response potential under either scenario, it would be necessary for retail regulators to modify existing electric utility rates and rate structures to implement dynamic pricing on a default or mandatory basis. Such rates would need to be designed to ensure that dynamic prices provide for adequate recovery of investments, while also offering time-varying electricity prices to customers. Funding for, or incentives to participate in, default dynamic pricing programs could be addressed by national energy policy leaders, the electric industry, consumer organizations, governors, state legislatures, and local and retail regulators. This is especially important as all these entities consider demand response programs in the context of climate change and renewable portfolio requirements.

A significant additional barrier exists for implementation of dynamic pricing under the Achievable Participation or Full Participation scenarios. This report notes that dynamic pricing with enabling technologies is not cost-effective for all customers in all states. For example, in cooler states without a large presence of central air conditioning, implementation of dynamic pricing with enabling technology for residential customers may not be cost-effective. While the cost of some technologies, such as programmable communicating thermostats, has declined (they are less than one-third of the price three years ago), government funding may be appropriate to expedite the development and deployment of other innovations, such as AMI and related technologies.

To support these scenarios, the customer education and technical assistance recommended above should be expanded and enhanced. Many customers, particularly residential customers, will need extensive help understanding the advantages of AMI and dynamic pricing. Sufficient resources should be expended under both the Achievable and Full Participation Scenarios to ensure that customers are comfortable with the new technology and are capable of adjusting their usage patterns and investment decisions. Similarly, better and more current information on AMI technology, costs, operational, market, and consumer benefits should be shared with regulators to support their decision-making on the full deployment of AMI and dynamic pricing.

National Action Plan on Demand Response

In addition to developing a national estimate of demand response that is documented in this report, EISA 2007 requires FERC to develop a National Action Plan within one year of submission of this report. EISA 2007 provides that the National Action Plan will, in the context of supporting demand response, develop: (1) a national, customer-based communications program; (2) a technical assistance strategy to states; and (3) a set of tools, information and support materials for use by stakeholders. The Action Plan will be guided in part by the results of this Assessment.

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APPENDIX A. STATE PROFILES

The following state profiles provide detailed information on the demand response potential projections for each state in the Assessment. The case studies presented in Chapter V of this report should be used as a guide for interpreting the results.

Some of the state profiles make reference to the "share of peak demand" that each sector contributes. This refers to the fraction of the entire state peak demand that is represented by that sector. In other words, if a state has peak demand of 10 GW and the residential class peak demand is 4 GW, the share of peak demand belonging to the residential class is 40 percent.

To provide context for interpreting the results, Table A-1 provides basic descriptive statistics for each of the states and the District of Columbia.

Also, in Table A-2 and Table A-3 are summaries of the potential peak reductions from demand response for 2014 (year five of the analysis horizon) and 2019 (year ten of the analysis horizon) for all states, as a fraction of the estimated summer peak demand without demand response. (In a few instances, estimated growth in peak demand between 2014 and 2019 exceeds estimated growth of demand response potential over the same period, causing the 2014 fraction to exceed the 2019 fraction)

Table A-1: Summary of Key Data by State

State	Total population	Number of accounts by rate class				System Peak Demand (MW)	Average peak load per customer (kW)				Annual average growth rate in peak (%)		CAC saturation for Residential sector (%)	AMI deployment in 2019 under EBAU scenario (%)
		Residential	Small C&I	Medium C&I	Large C&I		Residential	Small C&I	Medium C&I	Large C&I	Res	C&I		
Alabama	4,661,900	2,077,677	362,448	12,354	3,801	19,000	3.4	15.1	192	748	1.6	0.6	62	68
Alaska	686,293	266,671	45,183	3,270	62	1,417	0.9	4.5	80	1,029	0.4	0.2	3	21
Arizona	6,500,180	2,567,749	280,527	15,965	1,381	18,456	3.8	16.9	165	822	0.2	0.1	87	83
Arkansas	2,855,390	1,301,517	199,604	6,629	3,442	9,875	2.8	9.1	93	801	1.2	0.3	55	40
California	36,756,666	12,971,924	1,567,550	301,662	17,772	57,137	1.2	3.2	38	555	0.8	0.4	41	90
Colorado	4,939,456	2,068,055	282,139	88,021	1,531	10,837	1.5	1.9	40	901	0.9	0.1	47	43
Connecticut	3,501,252	1,449,983	141,998	11,261	8,044	7,524	1.6	3.9	63	206	0.9	0.4	27	52
Delaware	873,092	390,239	47,323	1,475	374	2,503	1.9	15.2	125	951	0.4	0.1	53	79
District of Columbia	591,833	206,047	24,506	1,842	1,229	2,403	1.6	9.5	158	745	1.5	0.1	56	100
Florida	18,328,340	8,615,249	921,368	224,874	9,195	49,453	3.1	2.9	40	696	0.2	0.6	91	74
Georgia	9,685,744	4,039,005	483,576	66,628	11,363	28,215	3.4	5.4	60	602	0.6	0.3	82	67
Hawaii	1,288,198	409,581	55,808	7,482	632	1,790	1.0	4.2	45	842	0.9	0.2	18	72
Idaho	1,523,816	647,581	65,923	55,692	928	4,962	2.9	3.9	31	636	0.4	0.1	67	69
Illinois	12,901,563	5,054,895	541,263	26,791	21,435	30,465	1.7	7.3	28	450	1.3	0.4	75	51
Indiana	6,376,792	2,734,788	286,888	65,468	8,038	22,890	2.4	6.3	52	798	1	0.3	74	40
Iowa	3,002,555	1,320,241	183,320	30,471	3,507	9,169	1.9	4.1	47	709	1.6	1.1	70	55
Kansas	2,802,134	1,213,189	221,809	10,962	7,594	8,630	2.8	6.4	44	318	1.3	0.5	84	29
Kentucky	4,269,245	1,918,247	272,458	27,771	3,050	18,889	3.0	10.5	176	959	1.3	0.4	76	33
Louisiana	4,410,796	1,870,160	196,805	89,052	3,192	16,332	3.5	14.6	39	771	1.6	0.4	75	40
Maine	1,316,456	693,400	75,666	13,927	1,065	2,812	0.8	2.0	30	571	0.7	0.4	14	54
Maryland	5,633,597	2,187,996	230,938	17,496	4,054	13,583	2.6	13.1	32	606	0.4	0.1	78	82
Massachusetts	6,497,967	2,631,568	367,459	22,605	4,510	12,695	1.0	6.0	24	642	0.8	0.4	13	26
Michigan	10,003,422	4,336,390	485,729	44,172	10,836	23,292	1.5	6.2	48	609	1.2	0.4	57	69
Minnesota	5,220,393	2,283,083	189,477	75,091	10,044	14,123	1.7	3.2	42	327	1.3	1.1	51	46
Mississippi	2,938,618	1,222,047	228,202	1,565	2,228	9,835	3.5	8.8	78	1,215	1.6	0.6	75	42
Missouri	5,911,605	2,670,172	347,394	25,739	4,651	17,362	3.1	5.0	110	748	1.3	0.7	88	45
Montana	967,440	456,112	103,892	890	238	2,991	1.6	12.3	157	1,101	1.3	0.2	42	22
Nebraska	1,783,432	787,312	178,123	10,854	2,889	5,771	2.6	4.5	128	291	1.6	1.1	83	19
Nevada	2,600,167	1,079,306	145,469	4,497	1,963	7,538	3.1	12.1	112	931	0.2	0.1	87	25
New Hampshire	1,315,809	600,399	102,868	831	1,875	2,539	1.1	4.7	32	306	0.2	0.4	13	45
New Jersey	8,682,661	3,414,289	461,304	10,998	10,375	17,273	2.2	7.1	77	395	0.8	0.7	55	56
New Mexico	1,984,356	829,100	122,560	16,755	1,296	4,671	1.3	4.8	61	707	1.2	0.1	42	37
New York	19,490,297	6,855,544	958,009	66,351	5,265	33,809	1.3	5.7	81	820	0.8	0.3	17	42
North Carolina	9,222,414	4,128,231	619,832	29,169	3,277	26,548	3.2	5.6	168	1,373	0.5	0.3	84	47
North Dakota	641,481	310,222	54,365	2,211	699	2,379	2.2	9.7	129	614	1.6	1.1	51	34
Ohio	11,485,910	4,908,791	569,999	59,607	13,010	33,238	2.0	8.5	65	604	1.3	0.3	63	39
Oklahoma	3,642,361	1,629,818	243,831	30,398	3,097	11,919	3.3	3.8	70	778	1.2	0.1	84	41
Oregon	3,790,060	1,610,829	220,262	36,132	1,521	10,476	1.9	4.5	75	680	0.7	0.4	38	59
Pennsylvania	12,448,279	5,217,010	618,439	75,656	10,577	31,488	1.7	8.2	43	644	1.2	0.7	50	64
Rhode Island	1,050,788	432,307	48,623	8,614	864	1,785	1.0	2.7	32	393	0.8	0.4	12	25
South Carolina	4,479,800	2,028,361	326,244	15,666	2,327	16,947	3.6	7.6	172	1,696	1	0.3	84	37
South Dakota	804,194	355,714	66,375	658	875	2,128	2.2	9.3	87	402	1.6	1.1	71	27
Tennessee	6,214,888	2,660,110	428,663	30,312	3,735	22,475	3.9	11.5	186	376	1	0.6	81	29
Texas	24,326,974	9,397,317	1,269,490	411,961	5,756	72,723	3.3	3.7	47	2,086	0.3	0.3	80	71
Utah	2,736,424	911,744	103,864	16,754	791	5,742	1.6	4.9	86	1,322	0.4	0.1	42	23
Vermont	621,270	310,842	46,230	3,075	313	1,085	0.9	2.2	49	773	0.6	0.4	7	59
Virginia	7,769,089	3,170,126	369,208	32,352	7,886	22,412	2.5	4.6	88	708	0.7	0.3	50	46
Washington	6,549,224	2,762,275	345,256	26,145	3,568	18,538	1.8	6.5	110	771	0.6	0.4	29	46
West Virginia	1,814,468	855,919	135,823	11,181	1,199	6,916	2.3	6.3	78	1,431	1.6	0.1	50	45
Wisconsin	5,627,967	2,581,840	290,192	44,419	4,518	14,845	1.4	4.1	61	782	1.5	0.9	62	65
Wyoming	532,668	245,648	61,758	3,587	585	3,236	1.7	14.9	66	1,551	1.6	0.2	42	21

Table A-2: Potential Peak Demand Reduction by State (2014)

	Business-as Usual	Expanded BAU	Achievable Participation	Full Participation
Alabama	6%	10%	13%	17%
Alaska	0%	2%	2%	2%
Arizona	1%	5%	14%	22%
Arkansas	3%	13%	13%	14%
California	7%	7%	12%	16%
Colorado	4%	5%	6%	7%
Connecticut	17%	22%	23%	24%
Delaware	4%	7%	11%	15%
District of Columbia	8%	18%	18%	21%
Florida	5%	9%	13%	17%
Georgia	4%	12%	16%	19%
Hawaii	2%	5%	7%	9%
Idaho	1%	6%	11%	15%
Illinois	7%	9%	9%	9%
Indiana	5%	7%	8%	10%
Iowa	6%	9%	10%	12%
Kansas	3%	7%	8%	9%
Kentucky	2%	5%	6%	7%
Louisiana	0%	5%	6%	7%
Maine	17%	19%	20%	21%
Maryland	11%	14%	22%	28%
Massachusetts	7%	10%	11%	11%
Michigan	8%	13%	14%	15%
Minnesota	12%	13%	15%	16%
Mississippi	1%	7%	8%	9%
Missouri	1%	9%	11%	13%
Montana	0%	4%	4%	5%
Nebraska	10%	14%	14%	15%
Nevada	0%	9%	10%	12%
New Hampshire	4%	8%	8%	8%
New Jersey	4%	8%	9%	10%
New Mexico	1%	6%	6%	7%
New York	8%	9%	10%	11%
North Carolina	5%	10%	10%	11%
North Dakota	1%	5%	6%	6%
Ohio	1%	11%	12%	12%
Oklahoma	0%	9%	10%	10%
Oregon	0%	3%	6%	9%
Pennsylvania	7%	11%	14%	16%
Rhode Island	7%	10%	11%	11%
South Carolina	4%	9%	10%	11%
South Dakota	1%	6%	6%	6%
Tennessee	5%	8%	9%	9%
Texas	1%	8%	12%	16%
Utah	8%	12%	13%	14%
Vermont	8%	9%	10%	11%
Virginia	1%	6%	7%	8%
Washington	0%	4%	5%	7%
West Virginia	3%	10%	10%	11%
Wisconsin	1%	5%	6%	7%
Wyoming	0%	6%	7%	7%

Table A-3: Potential Peak Demand Reduction by State (2019)

	Business-as Usual	Expanded BAU	Achievable Participation	Full Participation
Alabama	5%	10%	15%	21%
Alaska	0%	2%	5%	7%
Arizona	1%	5%	18%	28%
Arkansas	2%	13%	17%	21%
California	6%	7%	13%	17%
Colorado	3%	5%	12%	17%
Connecticut	16%	21%	26%	29%
Delaware	4%	7%	13%	19%
District of Columbia	7%	18%	17%	20%
Florida	5%	9%	18%	25%
Georgia	3%	12%	18%	25%
Hawaii	2%	5%	8%	11%
Idaho	1%	6%	14%	21%
Illinois	6%	8%	12%	15%
Indiana	5%	7%	13%	18%
Iowa	5%	8%	13%	17%
Kansas	2%	7%	13%	17%
Kentucky	1%	5%	11%	18%
Louisiana	0%	5%	12%	18%
Maine	16%	19%	22%	24%
Maryland	11%	13%	24%	32%
Massachusetts	7%	10%	14%	17%
Michigan	8%	12%	14%	16%
Minnesota	12%	13%	16%	19%
Mississippi	1%	7%	13%	19%
Missouri	1%	9%	14%	19%
Montana	0%	4%	9%	14%
Nebraska	9%	13%	19%	24%
Nevada	0%	9%	18%	26%
New Hampshire	3%	8%	10%	13%
New Jersey	4%	8%	12%	18%
New Mexico	1%	6%	11%	15%
New York	7%	9%	13%	17%
North Carolina	4%	10%	17%	25%
North Dakota	1%	5%	10%	14%
Ohio	1%	11%	14%	17%
Oklahoma	0%	9%	14%	19%
Oregon	0%	3%	9%	14%
Pennsylvania	7%	10%	15%	19%
Rhode Island	7%	10%	13%	16%
South Carolina	4%	9%	17%	23%
South Dakota	1%	6%	12%	17%
Tennessee	4%	8%	17%	24%
Texas	1%	8%	15%	21%
Utah	7%	12%	18%	23%
Vermont	7%	8%	11%	13%
Virginia	1%	6%	11%	16%
Washington	0%	4%	9%	12%
West Virginia	3%	10%	13%	18%
Wisconsin	1%	5%	8%	11%
Wyoming	0%	6%	9%	12%

Alabama State Profile

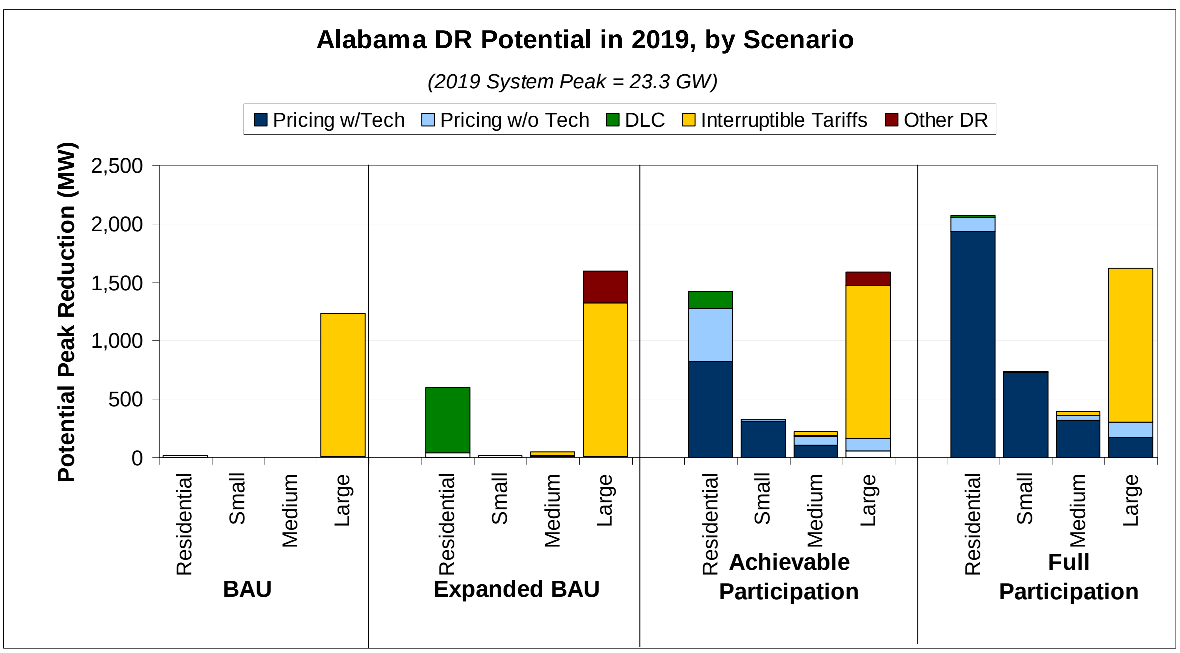
Key drivers of Alabama's demand response potential estimate include: higher-than-average residential CAC saturation of 62 percent, a customer mix that has an above average share of peak demand in the Small C&I class (31%), a moderate amount of existing Interruptible Tariffs for the Large C&I class, and the potential to deploy AMI at a faster-than-average rate. Enabling technologies and DLC are cost effective for all customer classes in the state. Most of the growth potential in demand response comes from the Residential class.

BAU: Alabama's existing demand response comes primarily from a large Interruptible Tariff program for Large C&I customers.

Expanded BAU: Growth in demand response impacts is driven primarily through two sources. There is the addition of Other DR programs for the Large C&I class, which currently do not exist in the state. In addition, there is a lot of growth potential for DLC in the Residential class due higher-than-average residential CAC saturation.

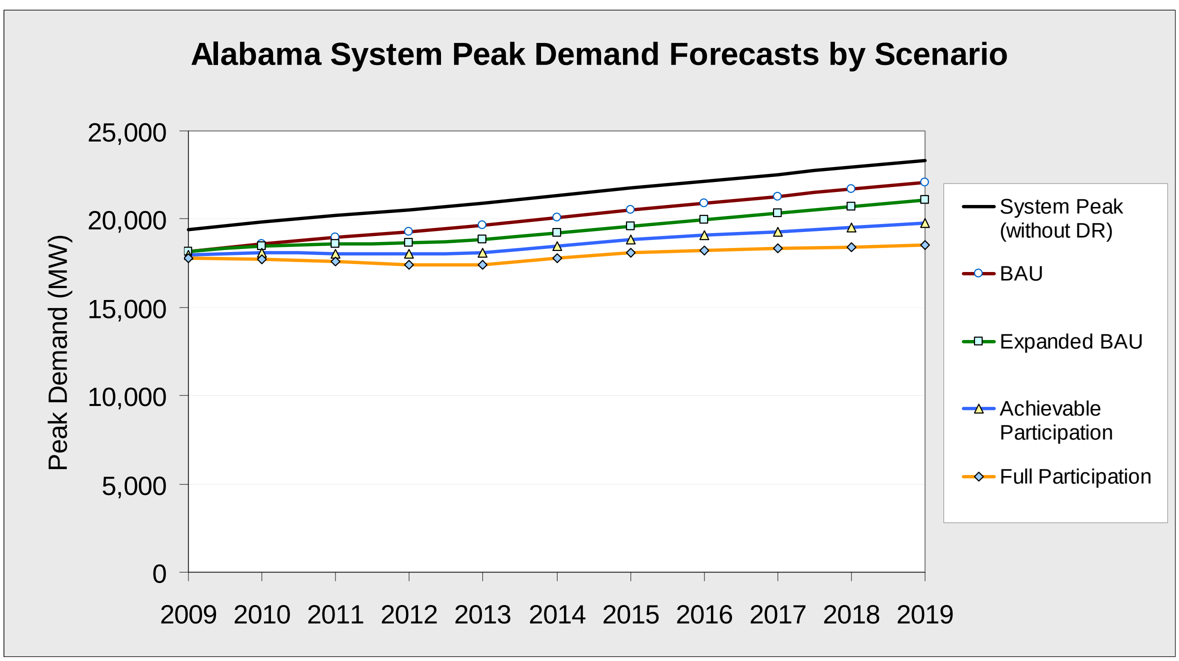
Achievable Participation: High CAC saturation in the Residential class drives a significant increase in demand response potential through dynamic pricing with and without enabling technologies. Large C&I demand response potential is not significantly higher than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR.

Full Participation: Similar to the Achievable Participation scenario, high CAC saturation in the Residential class drives the increase in impacts. The growth in impacts from the base BAU scenario are dominated by pricing with enabling technologies, which are cost-effective for all customer classes.



Total Potential Peak Reduction from Demand Response in Alabama, 2019

	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%	10	0.0%	10	0.0%
Automated/Direct Load Control	16	0.1%	0	0.0%	0	0.0%	0	0.0%	16	0.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	1,224	5.2%	1,224	5.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	16	0.1%	0	0.0%	0	0.0%	1,234	5.3%	1,250	5.4%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	42	0.2%	1	0.0%	8	0.0%	10	0.0%	61	0.3%
Automated/Direct Load Control	559	2.4%	13	0.1%	9	0.0%	0	0.0%	581	2.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	33	0.1%	1,311	5.6%	1,345	5.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	271	1.2%	271	1.2%
Total	601	2.6%	15	0.1%	50	0.2%	1,592	6.8%	2,258	9.7%
Achievable Participation										
Pricing with Technology	825	3.5%	312	1.3%	110	0.5%	58	0.2%	1,305	5.6%
Pricing without Technology	453	1.9%	17	0.1%	73	0.3%	105	0.5%	648	2.8%
Automated/Direct Load Control	145	0.6%	3	0.0%	4	0.0%	0	0.0%	152	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	33	0.1%	1,311	5.6%	1,345	5.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	112	0.5%	112	0.5%
Total	1,422	6.1%	333	1.4%	221	0.9%	1,586	6.8%	3,562	15.3%
Full Participation										
Pricing with Technology	1,929	8.3%	730	3.1%	322	1.4%	169	0.7%	3,150	13.5%
Pricing without Technology	130	0.6%	9	0.0%	36	0.2%	136	0.6%	310	1.3%
Automated/Direct Load Control	16	0.1%	0	0.0%	0	0.0%	0	0.0%	16	0.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	33	0.1%	1,311	5.6%	1,345	5.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	2,074	8.9%	739	3.2%	391	1.7%	1,616	6.9%	4,821	20.6%



Alaska State Profile

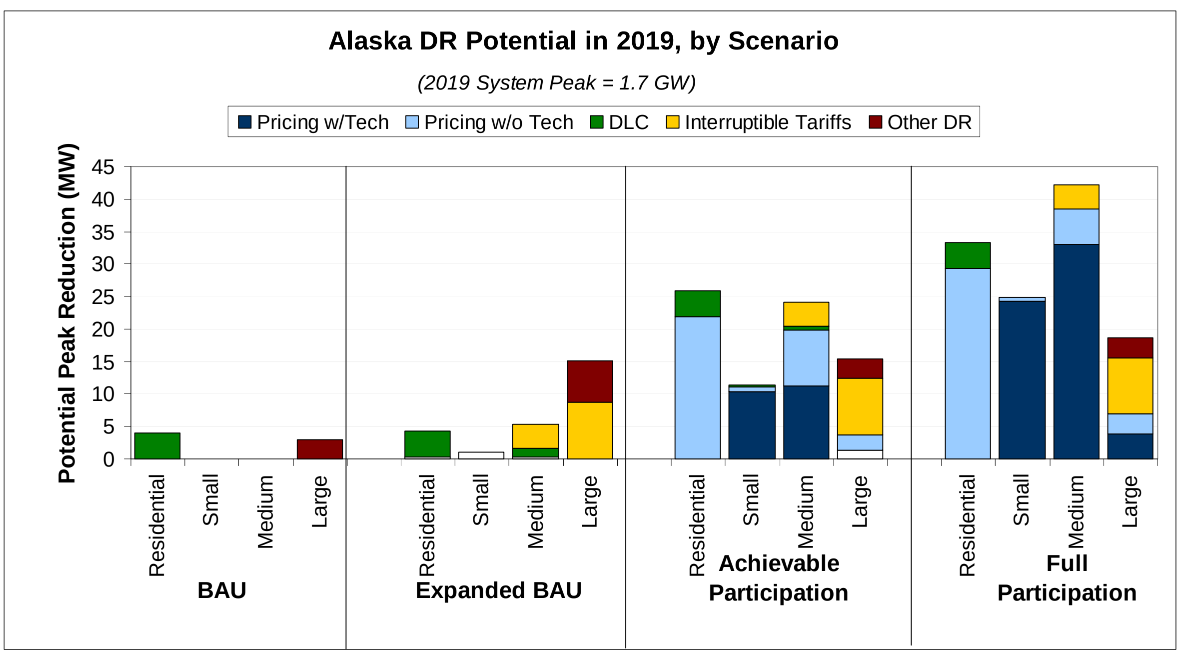
Key drivers of Alaska's demand response potential estimate include: very low residential CAC saturation, a customer mix that has an above average share of peak demand in the Small and Medium C&I classes (26% and 34%, respectively), a small amount of existing demand response, and the expectation that it will deploy AMI at a lower-than-average rate. Enabling technologies are cost effective for all C&I classes in the state, but not for the residential class.

BAU: Alaska's existing demand response comes from two sources. In the Residential class, there is a small amount of non-air conditioning DLC, and in the Medium C&I class, there is a small amount of Other DR.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of Interruptible Tariffs programs for the Large C&I class, which currently do not exist in the state. Within the Large C&I class, demand response is split between Interruptible Tariffs and Other DR. The only other substantial growth in demand response comes from Interruptible Tariffs in the Medium C&I class.

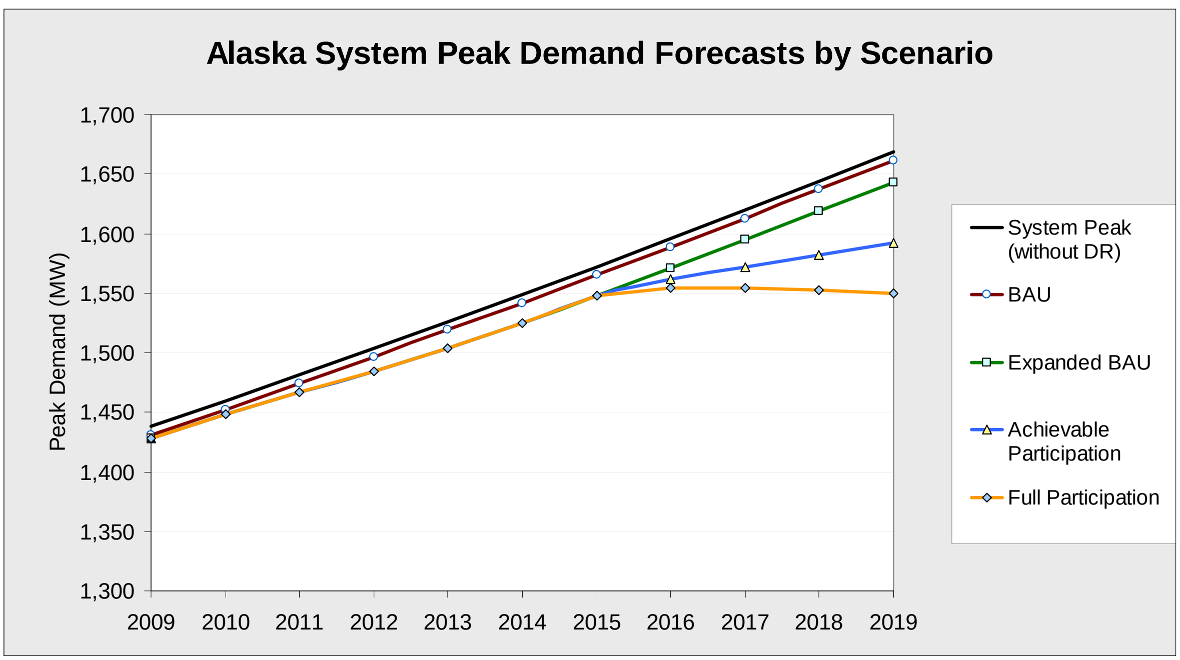
Achievable Participation: A significant increase in demand response potential comes from dynamic pricing with and without enabling technology. However, for the Large C&I class specifically, demand response potential does not change significantly from Expanded BAU scenario due to smaller per-customer impacts from pricing relative to Other DR. Since enabling technology did not prove to be cost-effective in the Residential sector, all of the pricing impacts are without enabling technology.

Full Participation: Similar to the Achievable Participation scenario, a significant increase in demand response potential comes from dynamic pricing. The majority of the statewide impacts come from pricing with enabling technologies, which are cost-effective for all customer classes except Residential.



Total Potential Peak Reduction from Demand Response in Alaska, 2019

	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	4	0.2%	0	0.0%	0	0.0%	0	0.0%	4	0.2%
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%	3	0.2%	3	0.2%
Total	4	0.2%	0	0.0%	0	0.0%	3	0.2%	7	0.4%
Expanded 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%	1	0.0%
Automated/Direct Load Control	4	0.2%	1	0.1%	1	0.1%	0	0.0%	6	0.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.2%	9	0.5%	12	0.7%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	6	0.4%	6	0.4%
Total	4	0.3%	1	0.1%	5	0.3%	15	0.9%	26	1.5%
Achievable Participation										
Pricing with Technology	0	0.0%	10	0.6%	11	0.7%	1	0.1%	23	1.4%
Pricing without Technology	22	1.3%	1	0.0%	9	0.5%	2	0.1%	34	2.0%
Automated/Direct Load Control	4	0.2%	0	0.0%	1	0.0%	0	0.0%	5	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.2%	9	0.5%	12	0.7%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	3	0.2%	3	0.2%
Total	26	1.6%	11	0.7%	24	1.4%	15	0.9%	77	4.6%
Full Participation										
Pricing with Technology	0	0.0%	24	1.5%	33	2.0%	4	0.2%	61	3.7%
Pricing without Technology	29	1.8%	0	0.0%	5	0.3%	3	0.2%	38	2.3%
Automated/Direct Load Control	4	0.2%	0	0.0%	0	0.0%	0	0.0%	4	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.2%	9	0.5%	12	0.7%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	3	0.2%	3	0.2%
Total	33	2.0%	25	1.5%	42	2.5%	19	1.1%	119	7.1%



Arizona State Profile

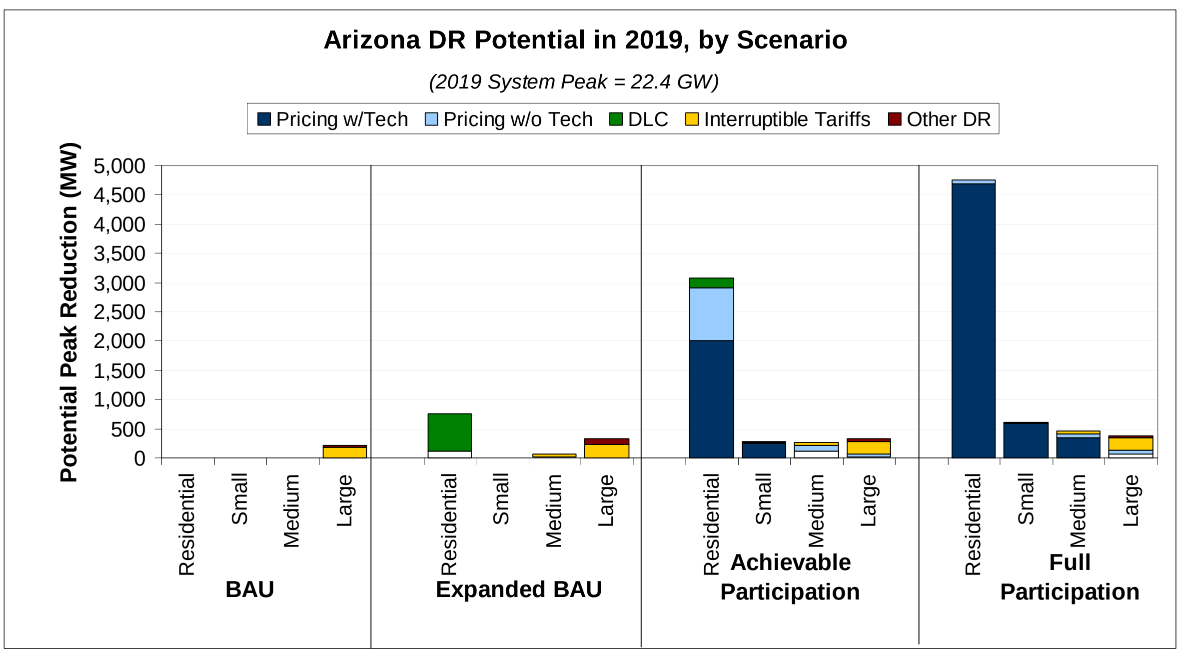
Key drivers of Arizona's demand response potential estimate include: higher-than-average residential CAC saturation of 87 percent, a customer mix that has an above average share of peak demand in the Residential and Small C&I classes (54% and 26%, respectively), a small amount of existing demand response, and the potential to deploy AMI at a faster-than-average rate. Enabling technologies and DLC are cost effective for all customer classes in the state. This cost-effectiveness, high residential CAC saturation and a large proportion of customers in the Residential and Small C&I sectors means that control of CAC load will be the key driver of demand response growth in Arizona.

BAU: Arizona's existing demand response comes primarily from a small Interruptible Tariffs program for large C&I customers. Note that Arizona has the largest residential TOU program in the U.S., but for reasons described previously in the report, TOU rates are excluded as a demand response option in this analysis.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of DLC programs for the Residential class, which currently do not exist in the state. This growth is due to Arizona's high share of Residential load and high CAC saturation rate.

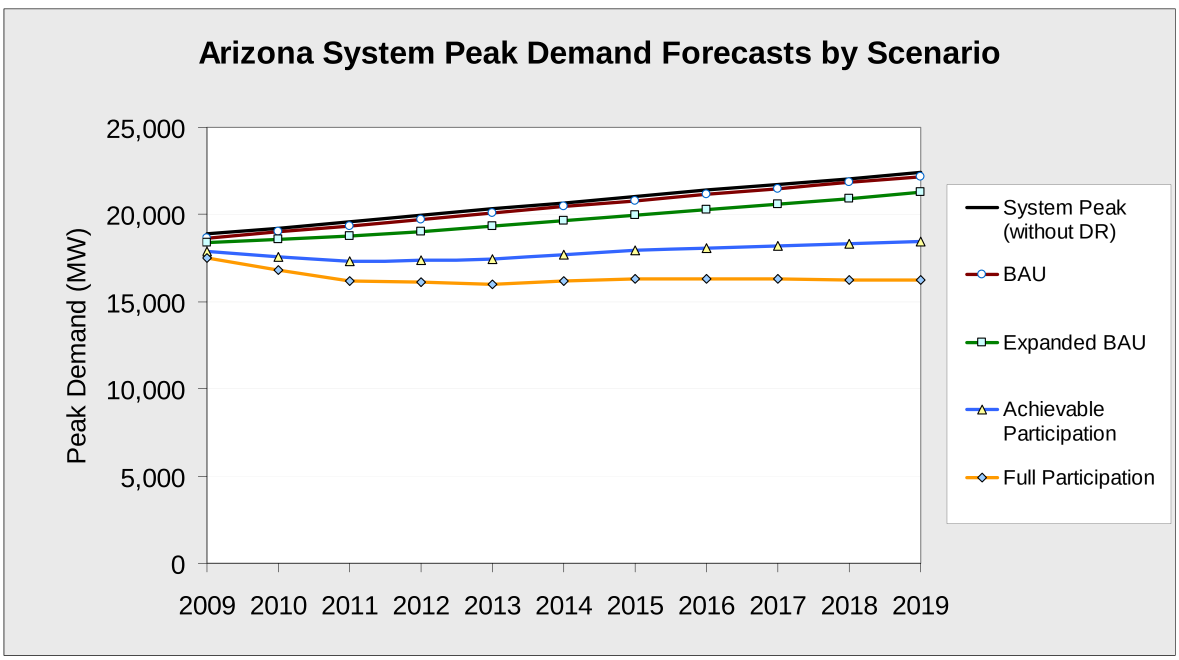
Achievable Participation: High CAC saturation in the Residential sector drives a significant increase in demand response potential through dynamic pricing with and without enabling technologies.

Full Participation: Similar to the Achievable Participation scenario, high CAC saturation combined with a large share of load in the Residential sector drives the increase in impacts. The impacts are dominated by pricing with enabling technologies, which are cost-effective for all customer classes.



Total Potential Peak Reduction from Demand Response in Arizona, 2019

	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	4	0.0%	0	0.0%	0	0.0%	0	0.0%	4	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	6	0.0%	184	0.8%	189	0.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	30	0.1%	30	0.1%
Total	4	0.0%	0	0.0%	6	0.0%	214	1.0%	223	1.0%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	114	0.5%	2	0.0%	11	0.1%	4	0.0%	130	0.6%
Automated/Direct Load Control	636	2.8%	6	0.0%	6	0.0%	0	0.0%	648	2.9%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	55	0.2%	220	1.0%	275	1.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	112	0.5%	112	0.5%
Total	750	3.3%	7	0.0%	74	0.3%	336	1.5%	1,166	5.2%
Achievable Participation										
Pricing with Technology	2,003	8.9%	254	1.1%	119	0.5%	24	0.1%	2,400	10.7%
Pricing without Technology	913	4.1%	17	0.1%	91	0.4%	44	0.2%	1,065	4.8%
Automated/Direct Load Control	166	0.7%	1	0.0%	3	0.0%	0	0.0%	170	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	55	0.2%	220	1.0%	275	1.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	47	0.2%	47	0.2%
Total	3,082	13.7%	273	1.2%	269	1.2%	334	1.5%	3,957	17.7%
Full Participation										
Pricing with Technology	4,685	20.9%	595	2.7%	349	1.6%	70	0.3%	5,698	25.4%
Pricing without Technology	67	0.3%	11	0.1%	58	0.3%	57	0.3%	193	0.9%
Automated/Direct Load Control	4	0.0%	0	0.0%	0	0.0%	0	0.0%	4	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	55	0.2%	220	1.0%	275	1.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	30	0.1%	30	0.1%
Total	4,755	21.2%	606	2.7%	462	2.1%	377	1.7%	6,200	27.7%



Arkansas State Profile

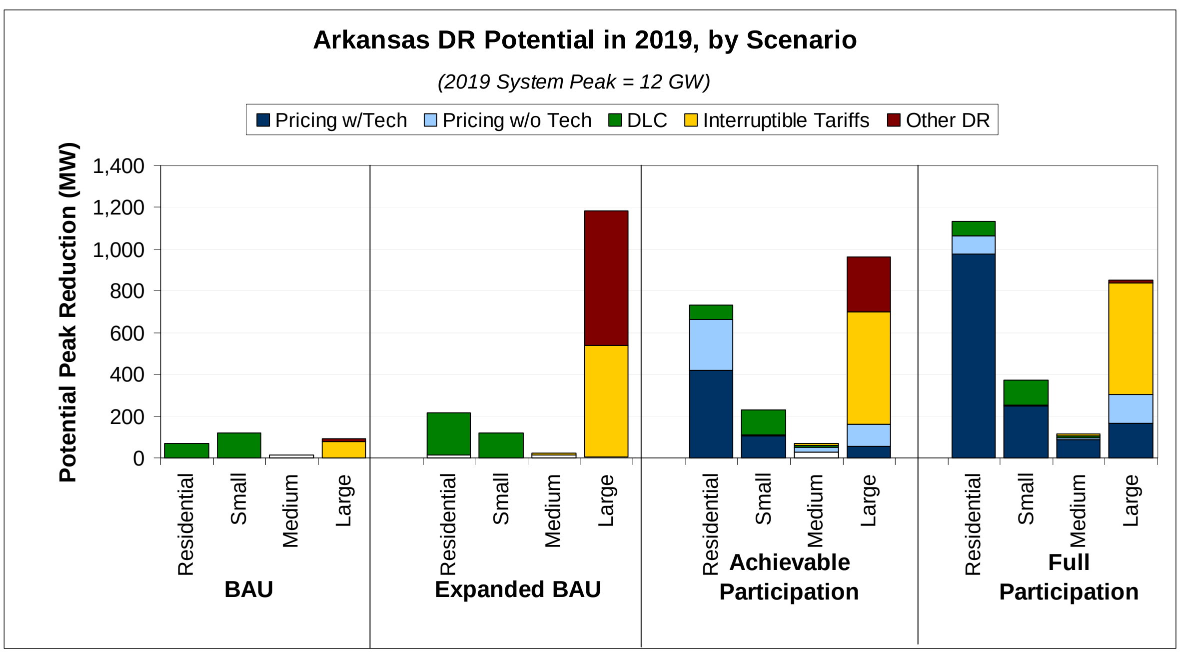
Key drivers of Arkansas's demand response potential estimate include: average residential CAC saturation of 55 percent, a customer mix that has an above average share of peak demand in the small and Large C&I classes (21% and 31%, respectively), a small amount of existing demand response, and the expectation that it will deploy AMI at a slightly lower-than-average rate. Enabling technologies and DLC are cost effective for all customer classes in the state.

BAU: Arkansas's existing demand response comes from all customer classes, but none of these programs are that large. DLC in all but the Large C&I class contributes the majority of the total.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of Other DR programs and Interruptible Tariffs for the Large C&I class. This high growth is due to Arkansas's high share of Large C&I load.

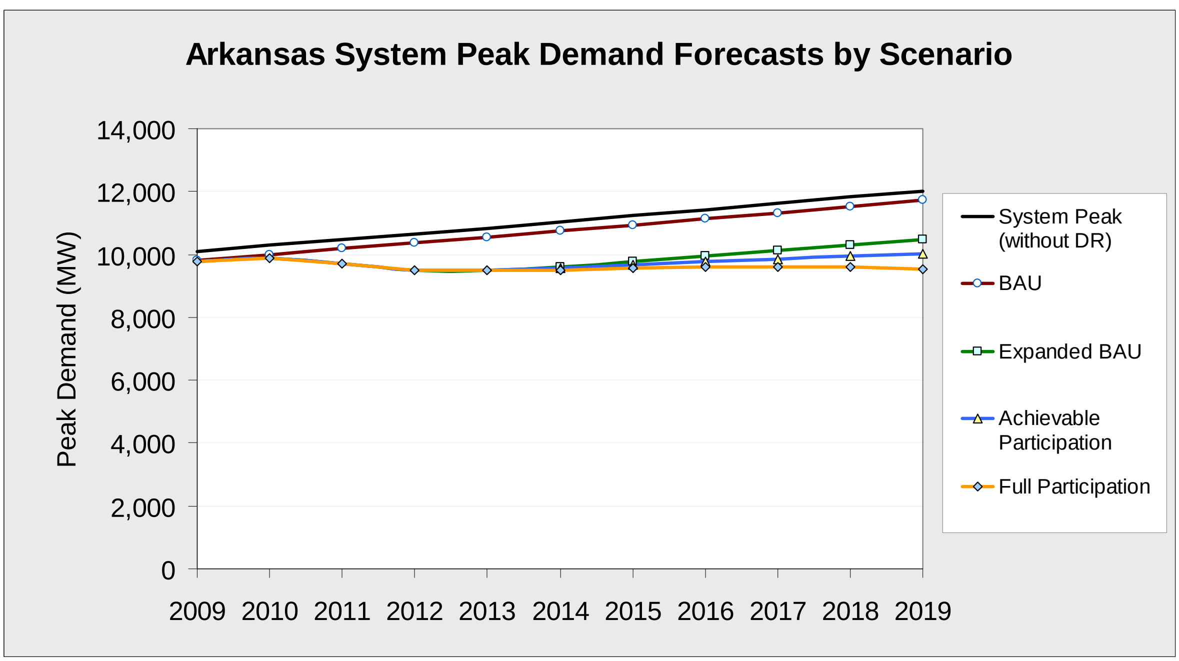
Achievable Participation: CAC saturation in the Residential sector drives a significant increase in demand response potential through dynamic pricing with and without enabling technologies. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR.

Full Participation: Similar to the Achievable Participation scenario, CAC saturation drives the increase in impacts. The impacts are dominated by pricing with enabling technologies, which are cost-effective for all customer classes. Interruptible Tariffs in the Large C&I sector remain a significant portion of overall impacts and a key source of growth from BAU.



Total Potential Peak Reduction from Demand Response in Arkansas, 2019

	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	69	0.6%	120	1.0%	13	0.1%	0	0.0%	202	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	79	0.7%	79	0.7%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	13	0.1%	13	0.1%
Total	69	0.6%	120	1.0%	13	0.1%	92	0.8%	295	2.4%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	13	0.1%	0	0.0%	1	0.0%	5	0.0%	19	0.2%
Automated/Direct Load Control	202	1.7%	120	1.0%	13	0.1%	0	0.0%	336	2.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	9	0.1%	536	4.5%	545	4.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	643	5.3%	643	5.3%
Total	215	1.8%	120	1.0%	23	0.2%	1,184	9.8%	1,543	12.8%
Achievable Participation										
Pricing with Technology	418	3.5%	106	0.9%	29	0.2%	57	0.5%	611	5.1%
Pricing without Technology	246	2.0%	6	0.0%	19	0.2%	104	0.9%	375	3.1%
Automated/Direct Load Control	69	0.6%	120	1.0%	13	0.1%	0	0.0%	202	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	9	0.1%	536	4.5%	545	4.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	262	2.2%	262	2.2%
Total	733	6.1%	232	1.9%	70	0.6%	960	8.0%	1,996	16.6%
Full Participation										
Pricing with Technology	978	8.1%	248	2.1%	85	0.7%	167	1.4%	1,479	12.3%
Pricing without Technology	87	0.7%	3	0.0%	9	0.1%	135	1.1%	235	2.0%
Automated/Direct Load Control	69	0.6%	120	1.0%	13	0.1%	0	0.0%	202	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	9	0.1%	536	4.5%	545	4.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	13	0.1%	13	0.1%
Total	1,134	9.4%	371	3.1%	117	1.0%	852	7.1%	2,474	20.6%



California State Profile

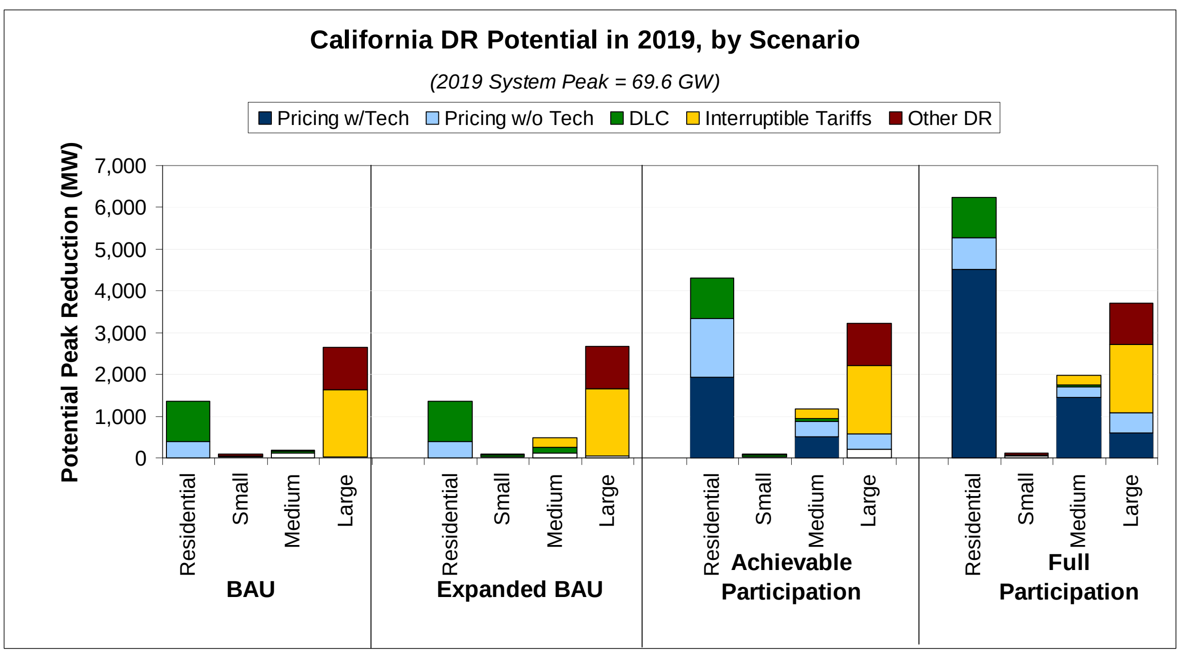
Key drivers of California's demand response potential estimate include: lower-than-average residential CAC saturation of 41 percent, a customer mix that has an above average share of peak demand in the Medium and Large C&I classes (50% combined), a large amount of existing demand response, and the potential to deploy AMI at a faster-than-average rate. DLC is cost effective for all customer classes in the state. Enabling technologies are not cost effective for the Small C&I class.

BAU: California's existing demand response comes from three major sources – Interruptible Tariffs and Other DR in the Large C&I class and DLC in the Residential class. In addition, there is moderate demand response in place in the Small and Medium C&I classes, as well as some dynamic pricing.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of Other DR programs for the Large C&I class. This is due to California's high share of Large C&I load, which would also allow for significant growth in the existing Interruptible Tariff. Demand response potential in the Large C&I class is nearly the same as in the BAU scenario.

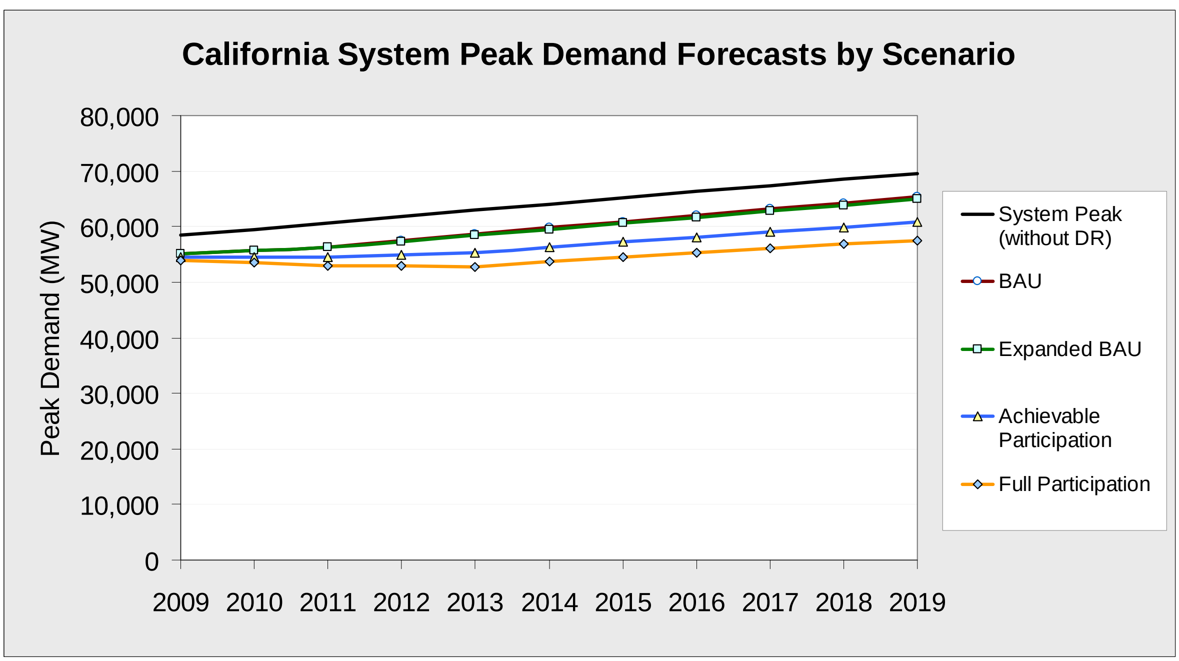
Achievable Participation: Dynamic pricing with technology in the Residential class drives a significant increase in demand response potential. Large C&I demand response potential is slightly higher than in the Expanded BAU scenario.

Full Participation: Similar to the Achievable Participation scenario, dynamic pricing with technology in the Residential sector drives a significant increase in demand response potential. Demand response potential in the Large C&I class is nearly the same as in the Achievable Participation scenario.



Total Potential Peak Reduction from Demand Response in California, 2019

	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	391	0.6%	21	0.0%	108	0.2%	13	0.0%	532	0.8%
Automated/Direct Load Control	970	1.4%	36	0.1%	45	0.1%	0	0.0%	1,050	1.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	25	0.0%	1,626	2.3%	1,651	2.4%
Other DR Programs	0	0.0%	31	0.0%	0	0.0%	1,012	1.5%	1,043	1.5%
Total	1,361	2.0%	88	0.1%	177	0.3%	2,651	3.8%	4,276	6.1%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	391	0.6%	21	0.0%	108	0.2%	36	0.1%	556	0.8%
Automated/Direct Load Control	970	1.4%	42	0.1%	152	0.2%	0	0.0%	1,163	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	233	0.3%	1,626	2.3%	1,859	2.7%
Other DR Programs	0	0.0%	31	0.0%	1	0.0%	1,012	1.5%	1,044	1.5%
Total	1,361	2.0%	94	0.1%	494	0.7%	2,674	3.8%	4,622	6.6%
Achievable Participation										
Pricing with Technology	1,931	2.8%	0	0.0%	500	0.7%	205	0.3%	2,636	3.8%
Pricing without Technology	1,400	2.0%	29	0.0%	382	0.5%	372	0.5%	2,184	3.1%
Automated/Direct Load Control	970	1.4%	36	0.1%	67	0.1%	0	0.0%	1,072	1.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	233	0.3%	1,626	2.3%	1,859	2.7%
Other DR Programs	0	0.0%	31	0.0%	1	0.0%	1,012	1.5%	1,043	1.5%
Total	4,302	6.2%	96	0.1%	1,182	1.7%	3,215	4.6%	8,795	12.6%
Full Participation										
Pricing with Technology	4,518	6.5%	0	0.0%	1,462	2.1%	598	0.9%	6,578	9.4%
Pricing without Technology	757	1.1%	38	0.1%	243	0.3%	482	0.7%	1,521	2.2%
Automated/Direct Load Control	970	1.4%	36	0.1%	45	0.1%	0	0.0%	1,050	1.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	233	0.3%	1,626	2.3%	1,859	2.7%
Other DR Programs	0	0.0%	31	0.0%	0	0.0%	1,012	1.5%	1,043	1.5%
Total	6,245	9.0%	105	0.2%	1,983	2.8%	3,719	5.3%	12,052	17.3%



Colorado State Profile

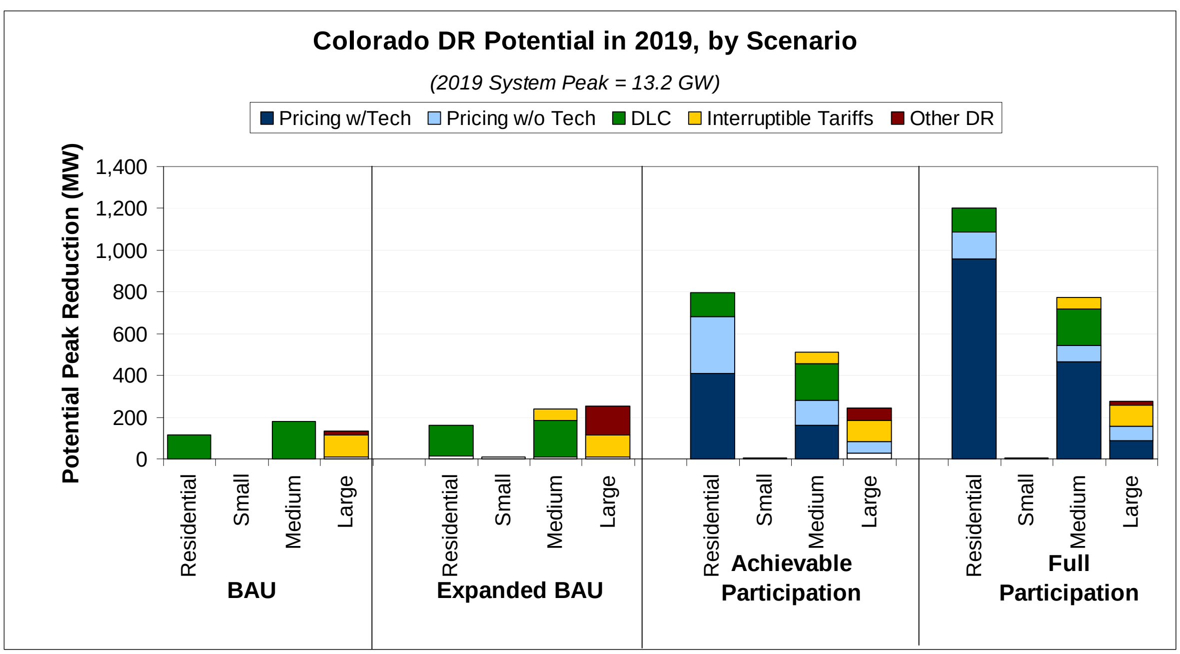
Key drivers of Colorado's demand response potential estimate include: lower-than-average residential CAC saturation of 47 percent, a customer mix that has an above average share of peak demand in Medium and Large C&I (57% combined), a moderate amount of existing demand response, and the expectation that it will deploy AMI at a slightly lower-than-average rate. DLC is cost effective for all customer classes in the state. Enabling technologies are not cost effective for the Small C&I class.

BAU: Colorado's existing demand response comes primarily from DLC for Residential and Medium C&I customers. An Interruptible Tariff program for Large C&I customers also contributes significantly to the total.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of Other DR programs for the Large C&I class. In addition, the Medium C&I class provides some Interruptible Tariffs demand response.

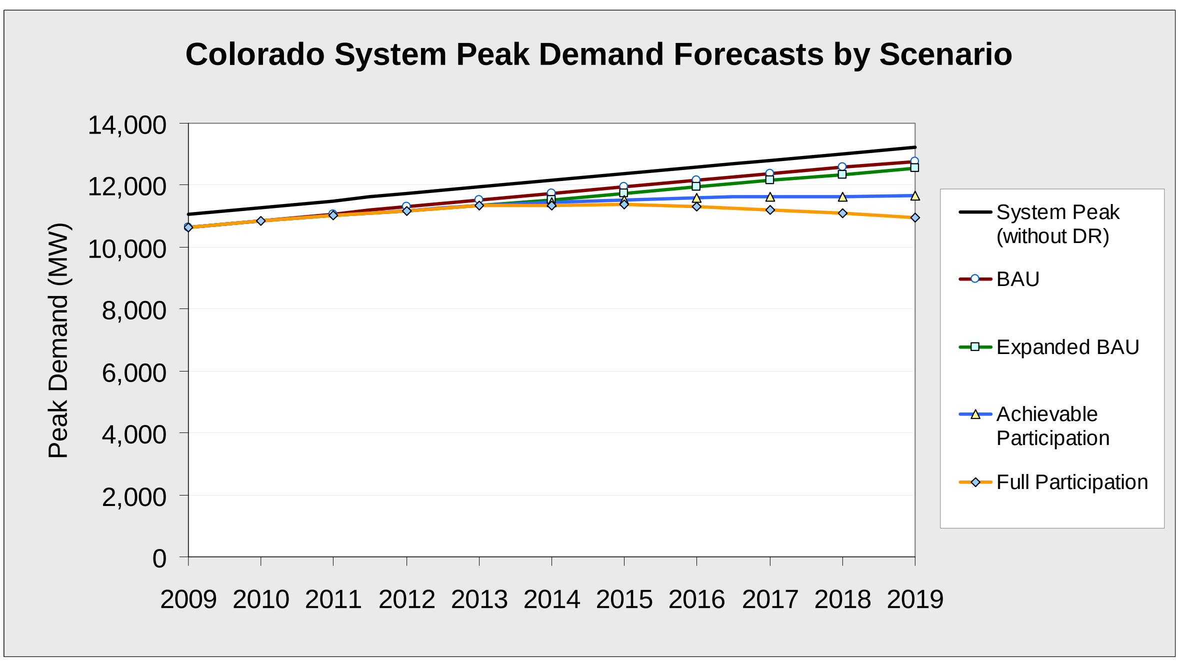
Achievable Participation: The Residential class and a large proportion of customers in the Medium C&I sector drive a significant increase in demand response potential through dynamic pricing with and without enabling technologies. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR.

Full Participation: Similar to the Achievable Participation scenario, customers in the Residential and Medium C&I sectors drive the increase in impacts. The impacts are dominated by pricing with enabling technology for Residential and Medium C&I customers.



Total Potential Peak Reduction from Demand Response in Colorado, 2019

	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%	0	0.0%	11	0.1%	12	0.1%
Automated/Direct Load Control	114	0.9%	1	0.0%	177	1.3%	0	0.0%	292	2.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	104	0.8%	104	0.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	20	0.2%	20	0.2%
Total	114	0.9%	2	0.0%	177	1.3%	135	1.0%	428	3.2%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	15	0.1%	1	0.0%	8	0.1%	11	0.1%	34	0.3%
Automated/Direct Load Control	145	1.1%	7	0.1%	177	1.3%	0	0.0%	329	2.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	52	0.4%	104	0.8%	156	1.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	140	1.1%	140	1.1%
Total	159	1.2%	7	0.1%	237	1.8%	255	1.9%	659	5.0%
Achievable Participation										
Pricing with Technology	409	3.1%	0	0.0%	159	1.2%	29	0.2%	598	4.5%
Pricing without Technology	273	2.1%	3	0.0%	122	0.9%	53	0.4%	451	3.4%
Automated/Direct Load Control	114	0.9%	2	0.0%	177	1.3%	0	0.0%	293	2.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	52	0.4%	104	0.8%	156	1.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	57	0.4%	57	0.4%
Total	796	6.0%	5	0.0%	510	3.9%	244	1.8%	1,555	11.8%
Full Participation										
Pricing with Technology	958	7.3%	0	0.0%	465	3.5%	86	0.6%	1,509	11.4%
Pricing without Technology	128	1.0%	4	0.0%	77	0.6%	69	0.5%	279	2.1%
Automated/Direct Load Control	114	0.9%	1	0.0%	177	1.3%	0	0.0%	292	2.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	52	0.4%	104	0.8%	156	1.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	20	0.2%	20	0.2%
Total	1,200	9.1%	5	0.0%	772	5.8%	278	2.1%	2,256	17.1%



Connecticut State Profile

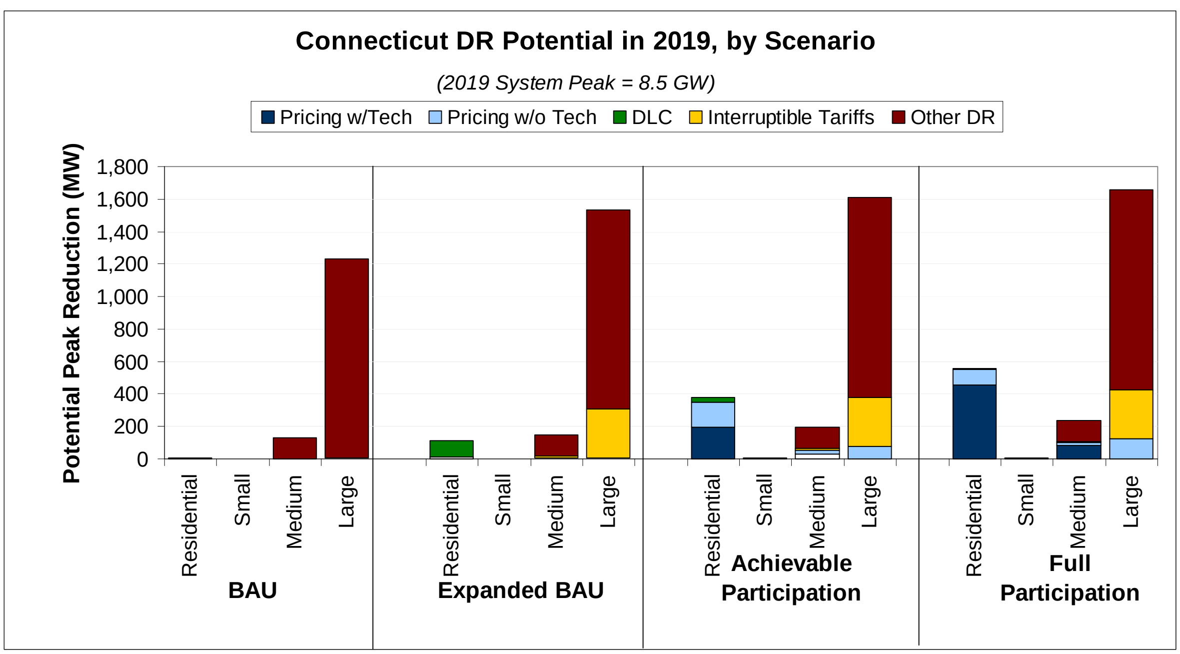
Key drivers of Connecticut's demand response potential estimate include: lower-than-average residential CAC saturation of 27 percent, a customer mix that has an above average share of peak demand in the Residential and Large C&I classes (45% and 31%, respectively), a large amount of existing demand response in the Medium and Large C&I sectors (especially Other DR), and the expectation that it will deploy AMI at a slightly lower-than-average rate. DLC is cost effective for all customer classes in the state. Enabling technologies are not cost effective for the Small and Large C&I classes.

BAU: Connecticut's existing demand response comes primarily from Other DR for Medium and Large C&I customers, the bulk of which is in the ISO New England forward capacity market.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of Interruptible Tariffs for the Large C&I class, which currently do not exist in the state. This high growth is due to Connecticut's large share of Large C&I load.

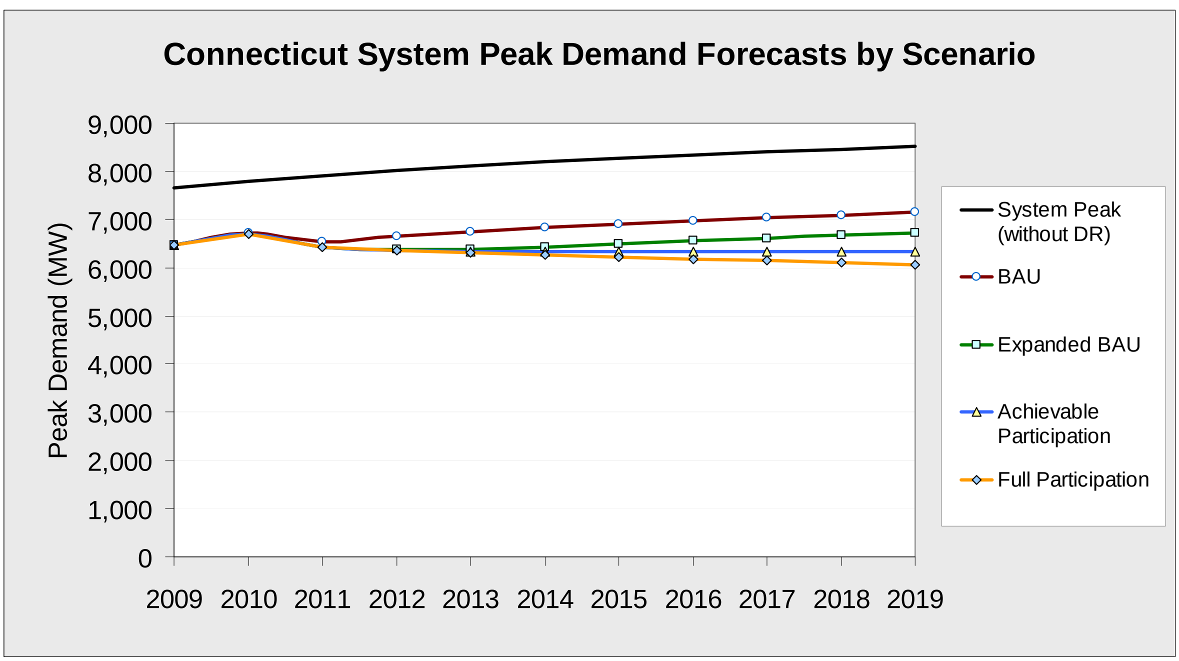
Achievable Participation: The Residential class drives a significant increase in demand response potential through dynamic pricing with and without enabling technologies. Large C&I demand response potential is slightly higher than in the Expanded BAU scenario.

Full Participation: Similar to the Achievable Participation scenario, a large share of load in the Residential class drives the increase in impacts. Since CAC saturation is lower than average, the growth the Residential sector is not as much as is seen in hotter states for this scenario. The Large C&I class does not experience any growth in pricing with enabling technology because it is not cost effective for that class. Overall, the incremental increase in potential is small relative to the BAU.



Total Potential Peak Reduction from Demand Response in Connecticut, 2019

	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	7	0.1%	0	0.0%	0	0.0%	0	0.0%	7	0.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	3	0.0%	3	0.0%
Other DR Programs	0	0.0%	0	0.0%	130	1.5%	1,229	14.4%	1,360	16.0%
Total	7	0.1%	0	0.0%	130	1.5%	1,233	14.5%	1,369	16.1%
Expanded 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%	2	0.0%	3	0.0%	14	0.2%
Automated/Direct Load Control	104	1.2%	3	0.0%	4	0.1%	0	0.0%	111	1.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	9	0.1%	303	3.6%	313	3.7%
Other DR Programs	0	0.0%	0	0.0%	130	1.5%	1,229	14.4%	1,360	16.0%
Total	113	1.3%	3	0.0%	146	1.7%	1,536	18.0%	1,798	21.1%
Achievable Participation										
Pricing with Technology	195	2.3%	0	0.0%	29	0.3%	0	0.0%	224	2.6%
Pricing without Technology	154	1.8%	3	0.0%	22	0.3%	75	0.9%	255	3.0%
Automated/Direct Load Control	27	0.3%	1	0.0%	2	0.0%	0	0.0%	29	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	9	0.1%	303	3.6%	313	3.7%
Other DR Programs	0	0.0%	0	0.0%	130	1.5%	1,229	14.4%	1,360	16.0%
Total	376	4.4%	4	0.0%	193	2.3%	1,608	18.9%	2,181	25.6%
Full Participation										
Pricing with Technology	457	5.4%	0	0.0%	84	1.0%	0	0.0%	541	6.4%
Pricing without Technology	93	1.1%	4	0.0%	15	0.2%	125	1.5%	237	2.8%
Automated/Direct Load Control	7	0.1%	0	0.0%	0	0.0%	0	0.0%	7	0.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	9	0.1%	303	3.6%	313	3.7%
Other DR Programs	0	0.0%	0	0.0%	130	1.5%	1,229	14.4%	1,360	16.0%
Total	557	6.5%	4	0.0%	239	2.8%	1,658	19.5%	2,458	28.9%



Delaware State Profile

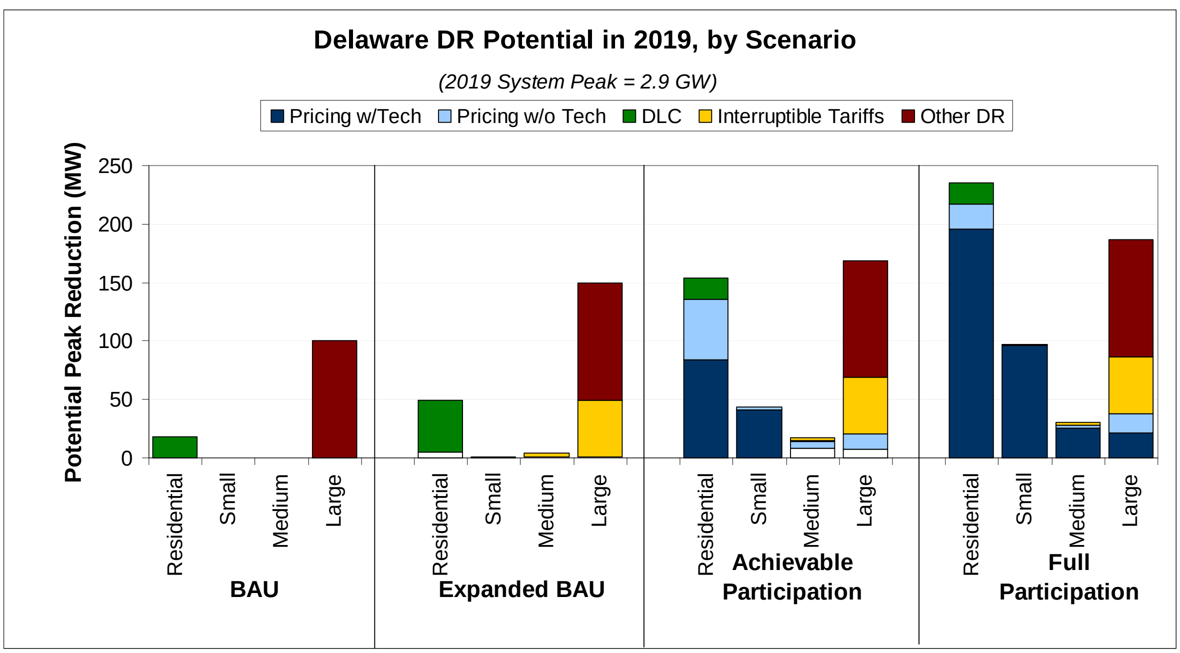
Key drivers of Delaware's demand response potential estimate include: average residential CAC saturation of around 55 percent, a customer mix that has an above average share of peak demand in the Small C&I class (36%), a moderate amount of existing demand response in the Large C&I class though Other DR, and the potential to deploy AMI at a faster-than-average rate. DLC and enabling technologies are cost effective for all customer classes in the state.

BAU: Delaware's existing demand response comes primarily from a large Other DR program for Large C&I customers. In addition, there is a moderate amount of DLC in the Residential class. Small and Medium C&I have any demand response.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of DLC programs for the Residential class and Interruptible Tariffs for the Large C&I class, which currently do not exist in the state. Although Delaware has a large share of Small C&I load, there is not much growth in that customer class in this scenario.

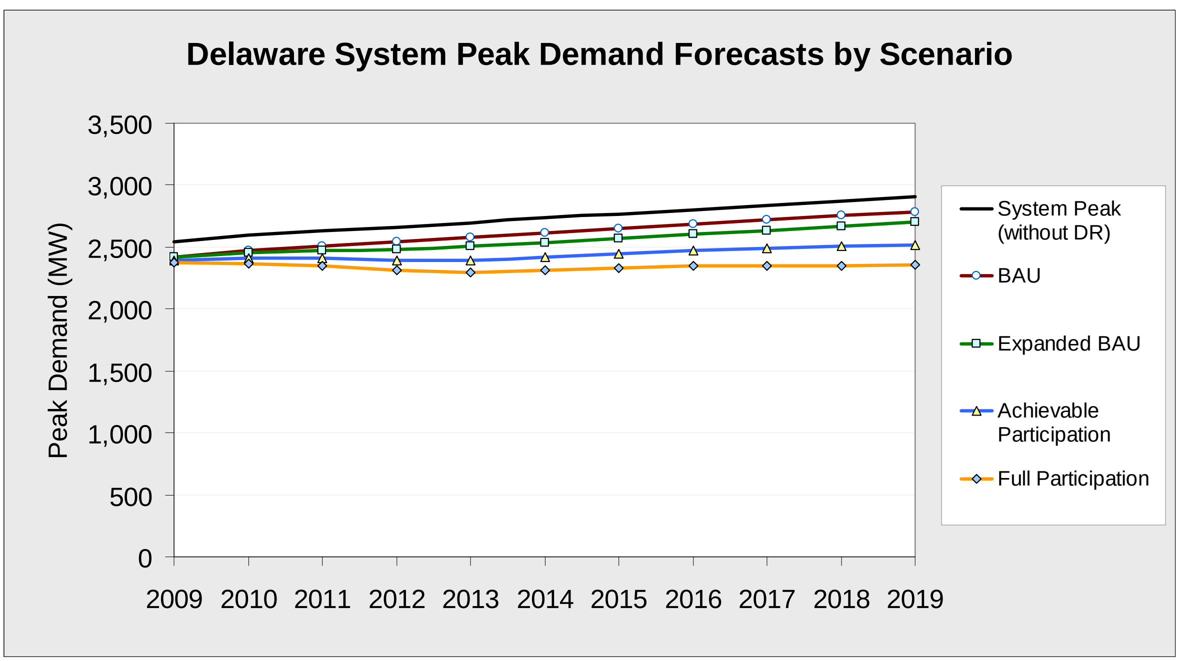
Achievable Participation: CAC saturation in the Residential class drives a significant increase in demand response potential through dynamic pricing with enabling technology. The Small C&I class shows some growth through dynamic pricing with enabling technology.

Full Participation: Similar to the Achievable Participation scenario, residential CAC saturation combined with a large share of load in the Small C&I class drives the increase in impacts. Medium and Large C&I also show an increase due to pricing with enabling technology.



Total Potential Peak Reduction from Demand Response in Delaware, 2019

	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	18	0.6%	0	0.0%	0	0.0%	0	0.0%	18	0.6%
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%	100	3.4%	100	3.4%
Total	18	0.6%	0	0.0%	0	0.0%	100	3.4%	118	4.1%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	5	0.2%	0	0.0%	1	0.0%	1	0.0%	7	0.3%
Automated/Direct Load Control	44	1.5%	1	0.0%	0	0.0%	0	0.0%	46	1.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	3	0.1%	48	1.7%	51	1.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	100	3.4%	100	3.4%
Total	50	1.7%	1	0.0%	4	0.1%	150	5.2%	204	7.0%
Achievable Participation										
Pricing with Technology	84	2.9%	41	1.4%	9	0.3%	7	0.2%	141	4.8%
Pricing without Technology	52	1.8%	2	0.1%	6	0.2%	13	0.5%	74	2.5%
Automated/Direct Load Control	18	0.6%	0	0.0%	0	0.0%	0	0.0%	18	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	3	0.1%	48	1.7%	51	1.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	100	3.4%	100	3.4%
Total	154	5.3%	44	1.5%	17	0.6%	169	5.8%	384	13.2%
Full Participation										
Pricing with Technology	196	6.7%	96	3.3%	25	0.9%	21	0.7%	338	11.6%
Pricing without Technology	22	0.8%	1	0.0%	3	0.1%	17	0.6%	43	1.5%
Automated/Direct Load Control	18	0.6%	0	0.0%	0	0.0%	0	0.0%	18	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	3	0.1%	48	1.7%	51	1.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	100	3.4%	100	3.4%
Total	235	8.1%	97	3.4%	30	1.0%	187	6.4%	550	18.9%



District of Columbia Profile

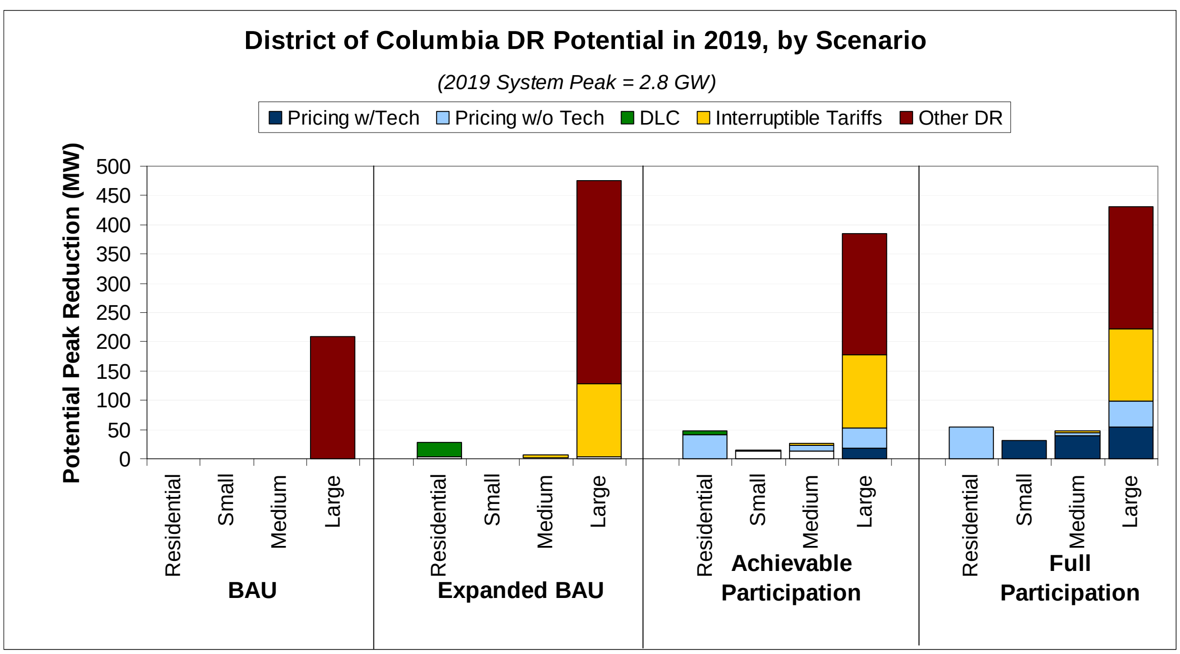
Key drivers of the District of Columbia's demand response potential estimate include: average residential CAC saturation of around 55 percent, a customer mix that has an above average share of peak demand in the Large C&I class (52%), a moderate amount of existing demand response in the Large C&I sector due to Other DR programs, and the potential to deploy AMI at a faster-than-average rate. DLC is cost effective for all customer classes in the state. Enabling technologies are not cost effective for the Residential class.

BAU: The District of Columbia's existing demand response comes entirely from Other DR for Large C&I customers.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of Interruptible Tariffs for the Large C&I class, which currently do not exist in the state. Other DR expands substantially as well. This high growth is due to the District of Columbia's large share of Large C&I load.

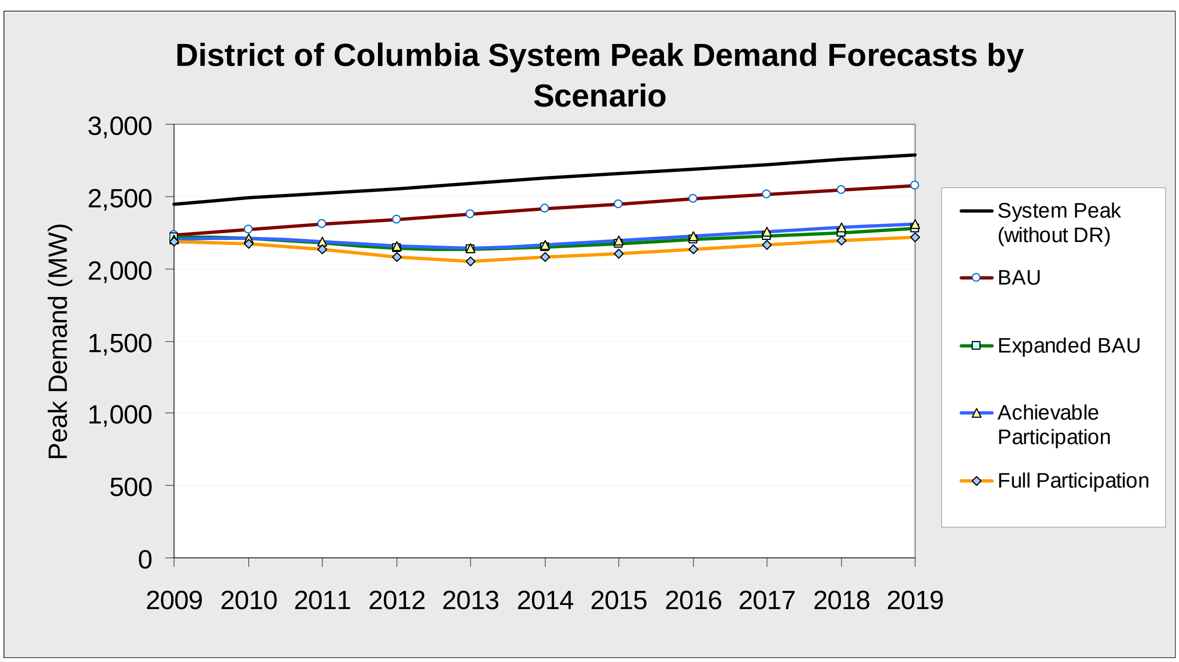
Achievable Participation: Large C&I demand response potential is lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR. This leads to lower demand response potential even though the other classes increase in demand response potential.

Full Participation: Similar to the Expanded BAU scenario, a large share of load in the Large C&I sector drives the increase in impacts. Since enabling technologies are not cost-effective for the Residential sector, the growth the Residential sector is not as much as is seen in other states for this scenario. C&I demand response potential is slightly higher than in the Achievable Participation scenario because of growth in pricing with and without enabling technology, which is cost-effective for all C&I sectors.



Total Potential Peak Reduction from Demand Response in District of Columbia, 2019

	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%	209	7.5%	209	7.5%
Total	0	0.0%	0	0.0%	0	0.0%	209	7.5%	209	7.5%
Expanded 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	0.1%	4	0.1%	8	0.3%
Automated/Direct Load Control	26	0.9%	0	0.0%	1	0.0%	0	0.0%	27	1.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.1%	124	4.5%	128	4.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	347	12.5%	347	12.5%
Total	29	1.0%	1	0.0%	6	0.2%	475	17.1%	511	18.3%
Achievable Participation										
Pricing with Technology	0	0.0%	13	0.5%	14	0.5%	19	0.7%	46	1.6%
Pricing without Technology	41	1.5%	1	0.0%	9	0.3%	34	1.2%	84	3.0%
Automated/Direct Load Control	7	0.2%	0	0.0%	0	0.0%	0	0.0%	7	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.1%	124	4.5%	128	4.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	209	7.5%	209	7.5%
Total	47	1.7%	14	0.5%	27	1.0%	386	13.8%	474	17.0%
Full Participation										
Pricing with Technology	0	0.0%	31	1.1%	40	1.4%	54	2.0%	125	4.5%
Pricing without Technology	54	1.9%	0	0.0%	4	0.2%	44	1.6%	103	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%	4	0.1%	124	4.5%	128	4.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	209	7.5%	209	7.5%
Total	54	1.9%	32	1.1%	48	1.7%	431	15.5%	565	20.3%



Florida State Profile

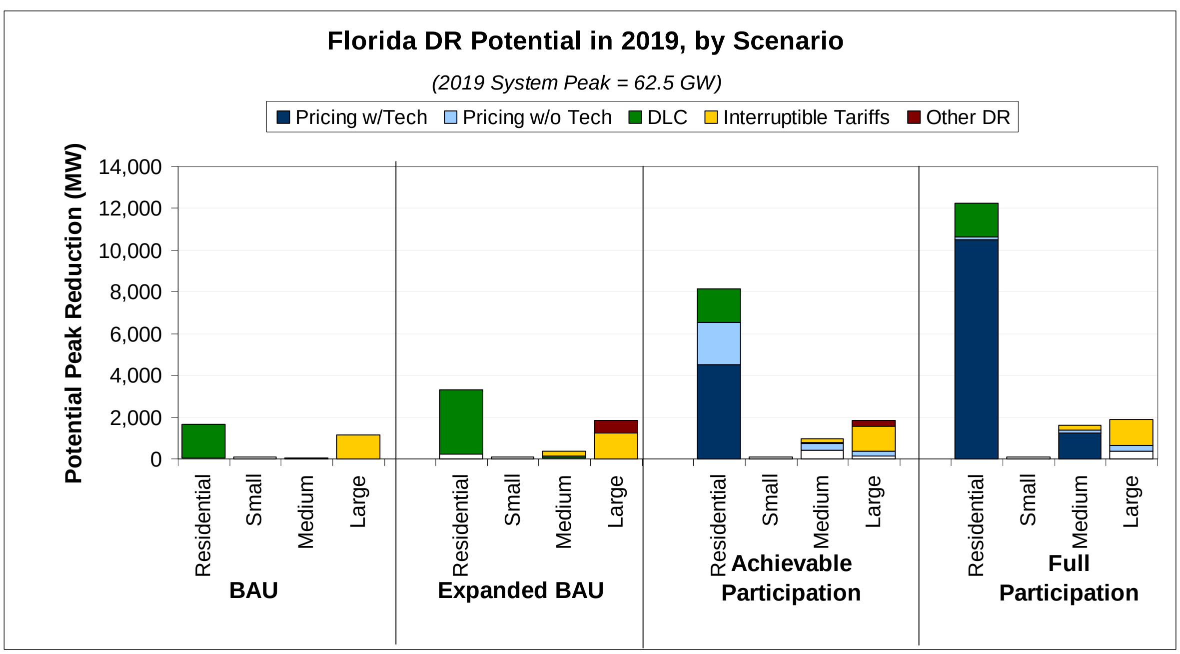
Key drivers of Florida's demand response potential estimate include: very high residential CAC saturation of 91 percent, a customer mix that has an above average share of peak demand in the Residential class (59%), a large existing residential DLC program, and the potential to deploy AMI at a faster-than-average rate. DLC is cost effective for all customer classes in the state. Enabling technologies are not cost effective for the Small C&I class. Florida's demand response potential is highly dependent on recruiting participants from the Residential class, as is shown in the Achievable and Full Participation scenarios.

BAU: Florida's existing demand response comes primarily from DLC in the Residential class and an Interruptible Tariffs program for Large C&I customers.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of DLC for the Residential class. This is due to Florida's high share of Residential load. There is also growth in the Large C&I class due to Other DR.

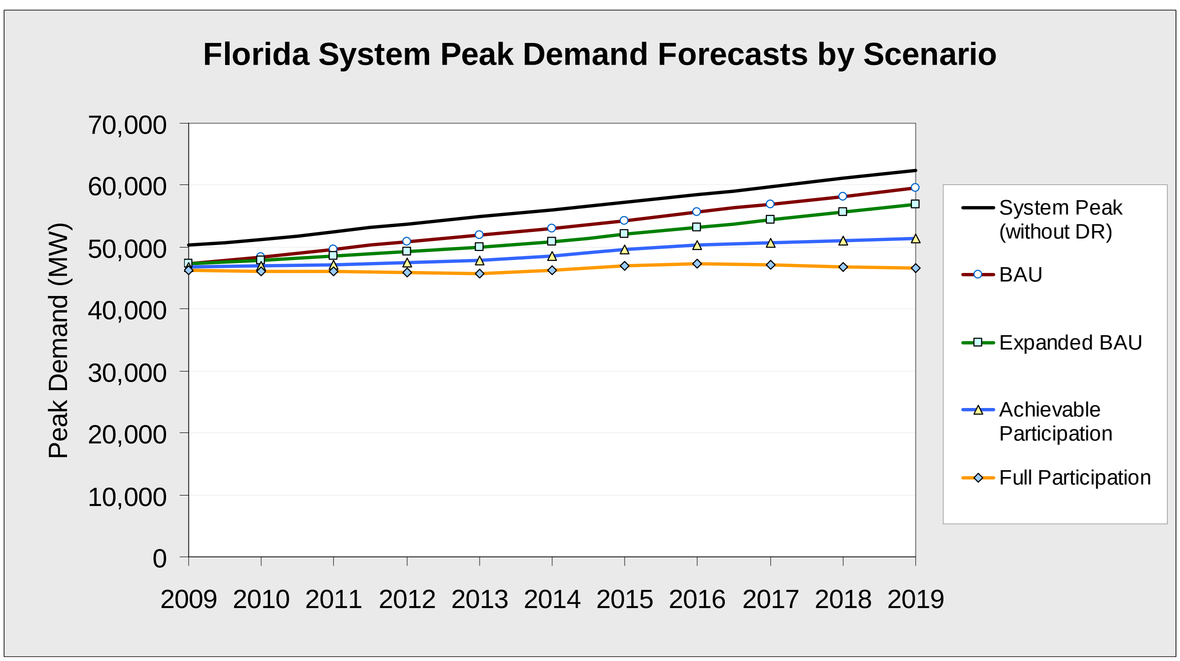
Achievable Participation: High CAC saturation in the Residential class drives a significant increase in demand response potential through dynamic pricing with and without enabling technologies. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR.

Full Participation: Similar to the Achievable Participation scenario, high CAC saturation combined with a large share of load in the Residential class drives the increase in impacts. The impacts are dominated by pricing with enabling technologies, which are cost-effective for all customer classes except Small C&I.



Total Potential Peak Reduction from Demand Response in Florida, 2019

	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	42	0.1%	0	0.0%	0	0.0%	0	0.0%	42	0.1%
Automated/Direct Load Control	1,622	2.6%	73	0.1%	0	0.0%	0	0.0%	1,695	2.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	24	0.0%	1,163	1.9%	1,187	1.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	1,665	2.7%	73	0.1%	24	0.0%	1,163	1.9%	2,924	4.7%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	227	0.4%	1	0.0%	34	0.1%	18	0.0%	280	0.4%
Automated/Direct Load Control	3,091	4.9%	73	0.1%	125	0.2%	0	0.0%	3,289	5.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	187	0.3%	1,242	2.0%	1,428	2.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	574	0.9%	574	0.9%
Total	3,318	5.3%	74	0.1%	346	0.6%	1,833	2.9%	5,571	8.9%
Achievable Participation										
Pricing with Technology	4,494	7.2%	0	0.0%	432	0.7%	123	0.2%	5,049	8.1%
Pricing without Technology	2,037	3.3%	16	0.0%	288	0.5%	223	0.4%	2,564	4.1%
Automated/Direct Load Control	1,622	2.6%	73	0.1%	52	0.1%	0	0.0%	1,747	2.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	187	0.3%	1,242	2.0%	1,428	2.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	238	0.4%	239	0.4%
Total	8,154	13.1%	89	0.1%	958	1.5%	1,825	2.9%	11,026	17.7%
Full Participation										
Pricing with Technology	10,513	16.8%	0	0.0%	1,264	2.0%	358	0.6%	12,135	19.4%
Pricing without Technology	133	0.2%	21	0.0%	139	0.2%	289	0.5%	582	0.9%
Automated/Direct Load Control	1,622	2.6%	73	0.1%	0	0.0%	0	0.0%	1,695	2.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	187	0.3%	1,242	2.0%	1,428	2.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	12,269	19.6%	94	0.2%	1,590	2.5%	1,889	3.0%	15,841	25.4%



Georgia State Profile

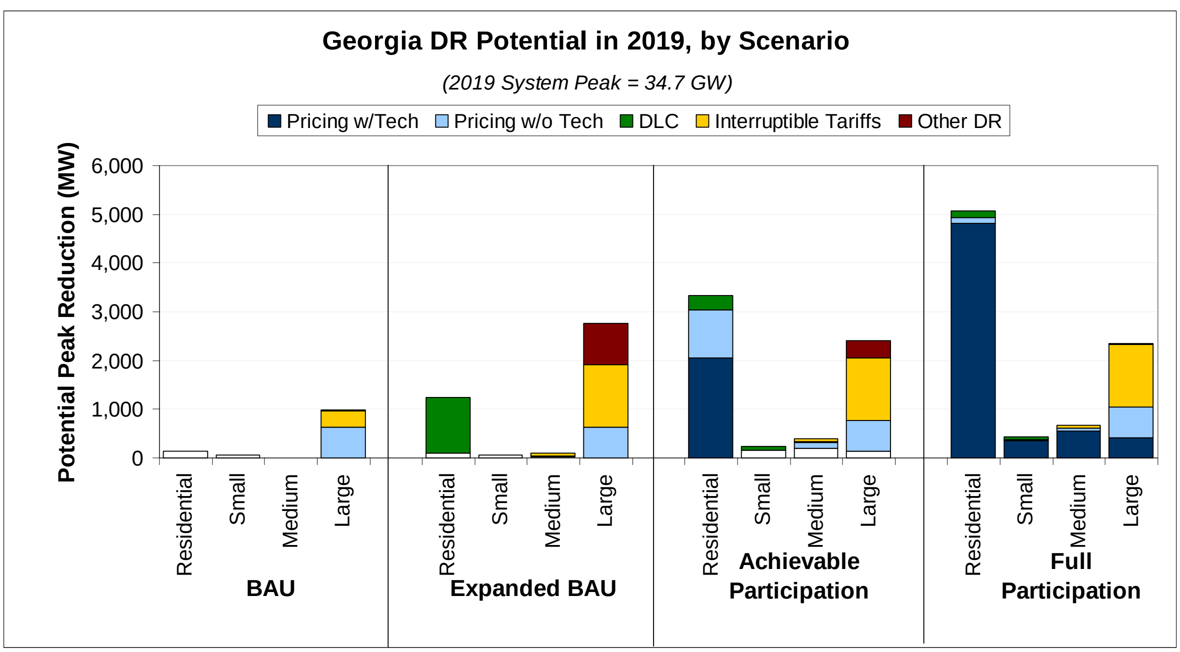
Key drivers of Georgia's demand response potential estimate include: higher-than-average residential CAC saturation of 82 percent, a customer mix that has an above average share of peak demand in the residential and Large C&I classes (50% and 25%, respectively), a moderate amount of existing demand response, and the potential to deploy AMI at a faster-than-average rate. Enabling technologies and DLC are cost effective for all customer classes in the state.

BAU: Georgia's existing demand response comes primarily from one of the largest RTP tariffs in the country for large C&I customers. An interruptible tariff program also contributes significantly to the total.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of Other DR programs for the Large C&I class, which currently do not exist in the state. This is due to Georgia's high share of Large C&I load, which would also allow for significant growth in the existing interruptible tariff. DLC also exhibits additional incremental potential in the Residential class as it is cost effective to implement.

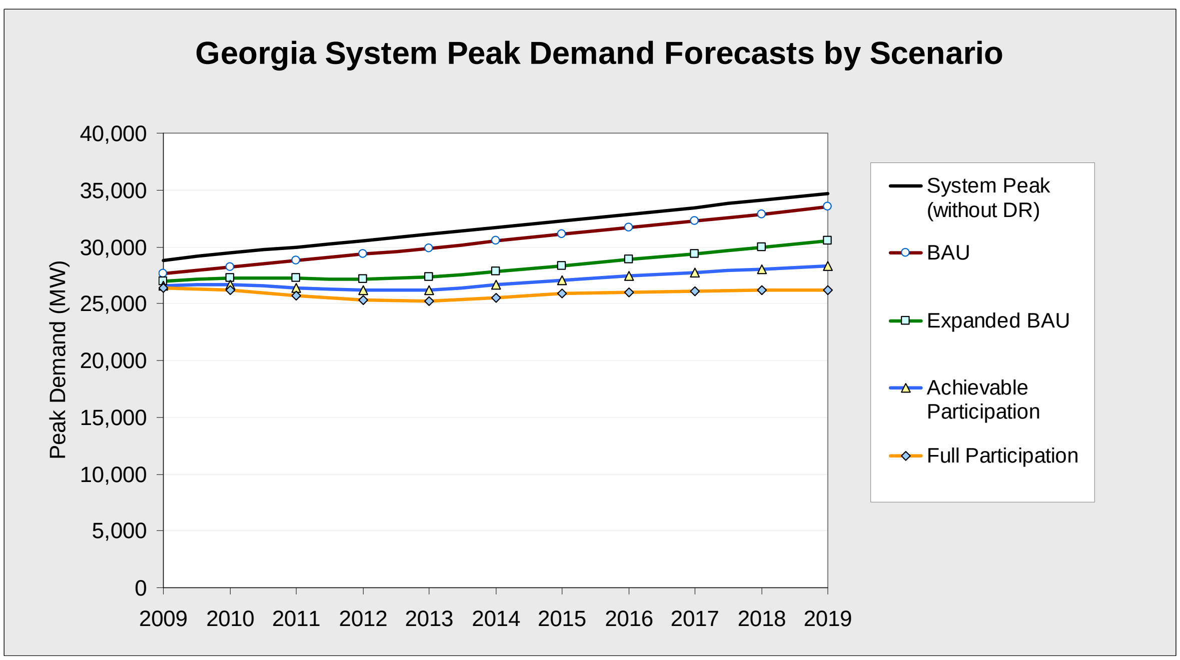
Achievable Participation: High CAC saturation in the residential sector drives a significant increase in demand response potential through dynamic pricing with enabling technologies. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR.

Full Participation: Similar to the Achievable Participation scenario, high CAC saturation combined with a large share of load in the residential sector drives the increase in impacts. The impacts are dominated by pricing with enabling technologies, which are cost-effective for all customer classes.



Total Potential Peak Reduction from Demand Response in Georgia, 2019

	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%	2	0.0%	0	0.0%	628	1.8%	630	1.8%
Automated/Direct Load Control	130	0.4%	63	0.2%	2	0.0%	0	0.0%	196	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	332	1.0%	332	1.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	22	0.1%	22	0.1%
Total	130	0.4%	65	0.2%	2	0.0%	982	2.8%	1,179	3.4%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	95	0.3%	2	0.0%	14	0.0%	628	1.8%	739	2.1%
Automated/Direct Load Control	1,146	3.3%	63	0.2%	35	0.1%	0	0.0%	1,244	3.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	58	0.2%	1,290	3.7%	1,348	3.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	844	2.4%	844	2.4%
Total	1,241	3.6%	65	0.2%	106	0.3%	2,761	8.0%	4,174	12.0%
Achievable Participation										
Pricing with Technology	2,062	5.9%	155	0.4%	190	0.5%	143	0.4%	2,550	7.4%
Pricing without Technology	974	2.8%	9	0.0%	127	0.4%	628	1.8%	1,737	5.0%
Automated/Direct Load Control	296	0.9%	63	0.2%	14	0.0%	0	0.0%	374	1.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	58	0.2%	1,290	3.7%	1,348	3.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	353	1.0%	353	1.0%
Total	3,332	9.6%	227	0.7%	389	1.1%	2,414	7.0%	6,363	18.4%
Full Participation										
Pricing with Technology	4,823	13.9%	363	1.0%	557	1.6%	419	1.2%	6,161	17.8%
Pricing without Technology	114	0.3%	5	0.0%	61	0.2%	628	1.8%	807	2.3%
Automated/Direct Load Control	130	0.4%	63	0.2%	2	0.0%	0	0.0%	196	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	58	0.2%	1,290	3.7%	1,348	3.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	22	0.1%	22	0.1%
Total	5,066	14.6%	431	1.2%	678	2.0%	2,358	6.8%	8,534	24.6%



Hawaii State Profile

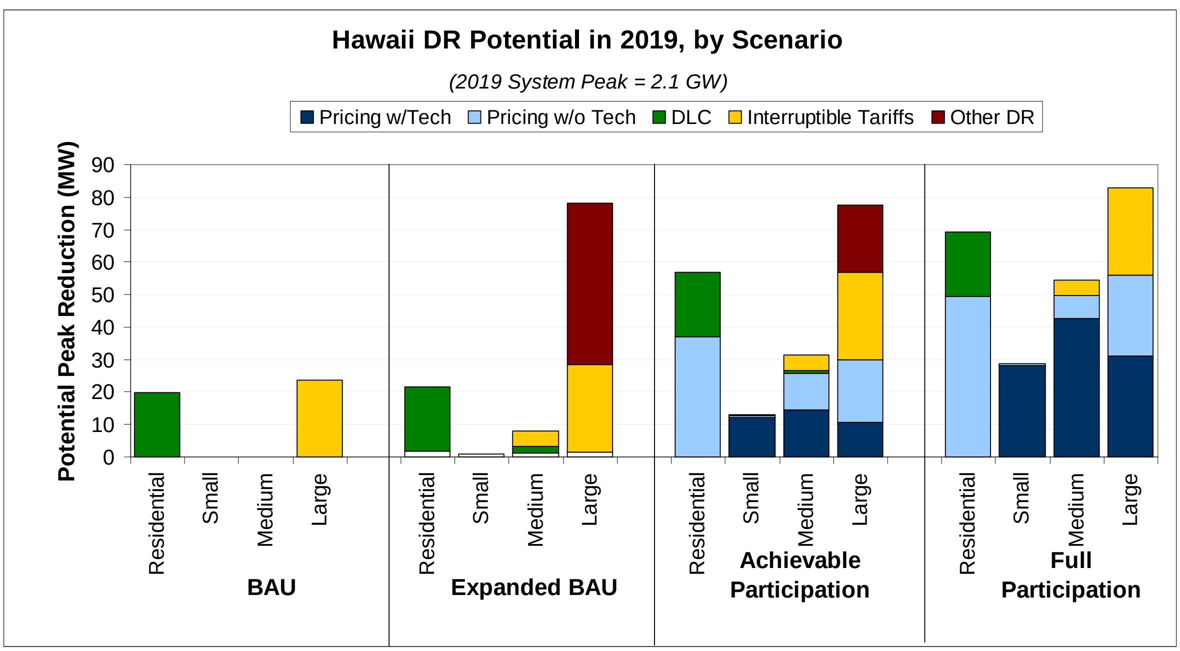
Key drivers of Hawaii's demand response potential estimate include: very low CAC saturation of 17.6 percent, a customer mix that has an above average share of peak demand in the Large C&I (35%), a minimal amount of existing demand response, and the potential to deploy AMI at a faster-than-average rate. Enabling technologies and DLC are cost effective for all the C&I customer classes, however not for the Residential class.

BAU: Hawaii's existing demand response comes from DLC participation in the Residential class and Interruptible Tariff participation in the Large C&I class.

Expanded BAU: Growth in demand response impacts is driven primarily by the Large C&I class. There is a significant increase in Interruptible Tariffs and the addition of Other DR programs. This is due to Hawaii's high share of Large C&I load.

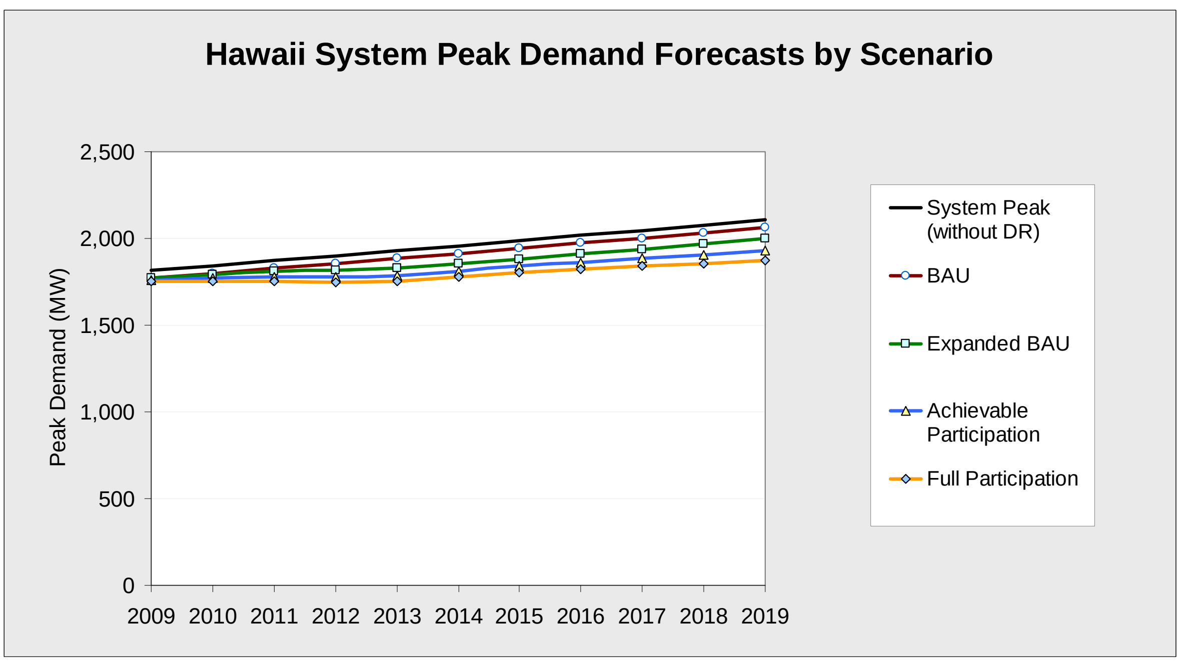
Achievable Participation: Though the Residential class is limited by a low CAC saturation and a lack of enabling technology, there is still growth in potential through pricing programs. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR, while there is moderate growth in the Small and Medium C&I classes.

Full Participation: Similar to the Achievable Participation scenario, there is growing potential across the classes in dynamic pricing, though it is limited in the Residential class due to a lack of enabling technology. Finally, the Large C&I class still exhibits strong potential in Interruptible Tariffs.



Total Potential Peak Reduction from Demand Response in Hawaii, 2019

	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	20	0.9%	0	0.0%	0	0.0%	0	0.0%	20	0.9%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	24	1.1%	24	1.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	20	0.9%	0	0.0%	0	0.0%	24	1.1%	44	2.1%
Expanded 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%	1	0.1%	2	0.1%	5	0.2%
Automated/Direct Load Control	20	0.9%	1	0.0%	2	0.1%	0	0.0%	23	1.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	5	0.2%	27	1.3%	32	1.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	50	2.4%	50	2.4%
Total	22	1.0%	1	0.0%	8	0.4%	78	3.7%	109	5.2%
Achievable Participation										
Pricing with Technology	0	0.0%	12	0.6%	15	0.7%	11	0.5%	37	1.8%
Pricing without Technology	37	1.8%	1	0.0%	11	0.5%	19	0.9%	68	3.2%
Automated/Direct Load Control	20	0.9%	0	0.0%	1	0.0%	0	0.0%	21	1.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	5	0.2%	27	1.3%	32	1.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	21	1.0%	21	1.0%
Total	57	2.7%	13	0.6%	31	1.5%	78	3.7%	179	8.5%
Full Participation										
Pricing with Technology	0	0.0%	28	1.3%	43	2.0%	31	1.5%	102	4.8%
Pricing without Technology	49	2.3%	1	0.0%	7	0.3%	25	1.2%	82	3.9%
Automated/Direct Load Control	20	0.9%	0	0.0%	0	0.0%	0	0.0%	20	0.9%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	5	0.2%	27	1.3%	32	1.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	69	3.3%	29	1.4%	54	2.6%	83	3.9%	235	11.2%



Idaho State Profile

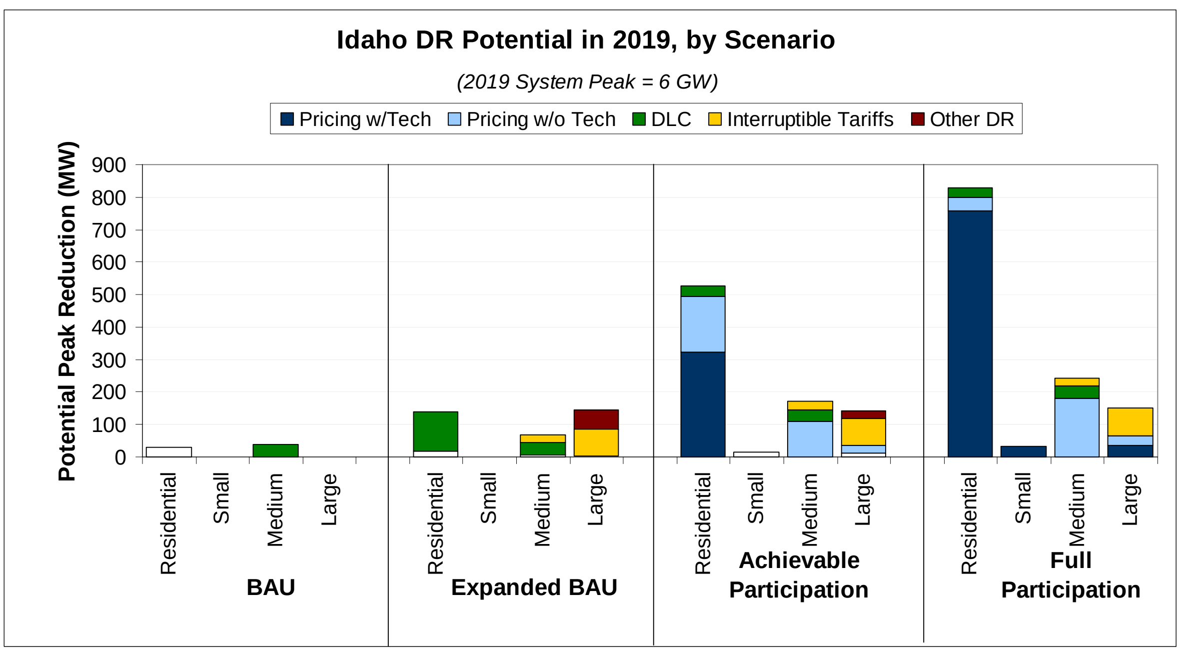
Key drivers of Idaho's demand response potential estimate significant residential CAC saturation of 66.5 percent, a customer mix that has an above average share of peak demand in the Medium C&I classes (39%), a minimal amount of existing demand response, and the potential to deploy AMI at a faster-than-average rate. Enabling technologies and DLC are cost effective for all customer classes in the state except for the Medium C&I segment.

BAU: Idaho's existing demand response comes from DLC programs in the Residential and Medium C&I classes.

Expanded BAU: With a unique customer mix weighted towards the Residential and Medium C&I segments, growth in demand response impacts is spread across these two classes as well as in the Large C&I class. DLC potential has increased for the Residential class, while Interruptible Tariffs and Other DR make up the increase in potential found in the Medium and Large C&I classes.

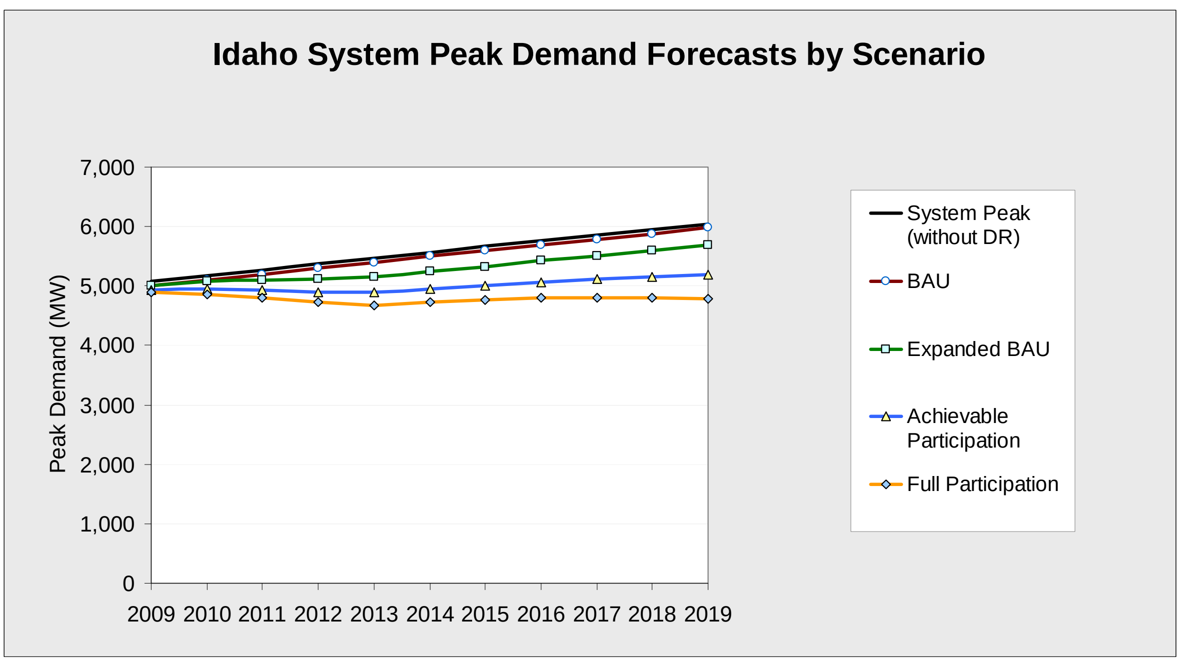
Achievable Participation: High CAC saturation in the Residential sector drives a significant increase in demand response potential through dynamic pricing with and without enabling technologies. The size of the Medium C&I class contributes to the larger role that it plays in the state's total potential.

Full Participation: In the Full Participation scenario, the Residential class exhibits the most potential in dynamic pricing. The Medium and Large C&I classes have moderate increases from the same pricing programs, with potential from Other DR in the Large class dropping off due to an assumption that these customers would instead be enrolled in pricing programs. Potential from the Medium C&I class would be higher, but is mitigated by the lack of enabling technology for dynamic pricing.



Total Potential Peak Reduction from Demand Response in Idaho, 2019

	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	31	0.5%	0	0.0%	37	0.6%	0	0.0%	68	1.1%
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%	0	0.0%	0	0.0%
Total	31	0.5%	0	0.0%	37	0.6%	0	0.0%	68	1.1%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	16	0.3%	0	0.0%	6	0.1%	2	0.0%	24	0.4%
Automated/Direct Load Control	123	2.0%	1	0.0%	37	0.6%	0	0.0%	161	2.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	25	0.4%	84	1.4%	109	1.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	59	1.0%	59	1.0%
Total	139	2.3%	1	0.0%	69	1.1%	144	2.4%	354	5.9%
Achievable Participation										
Pricing with Technology	323	5.3%	14	0.2%	0	0.0%	13	0.2%	350	5.8%
Pricing without Technology	170	2.8%	1	0.0%	108	1.8%	23	0.4%	302	5.0%
Automated/Direct Load Control	32	0.5%	0	0.0%	37	0.6%	0	0.0%	69	1.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	25	0.4%	84	1.4%	109	1.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	24	0.4%	24	0.4%
Total	526	8.7%	15	0.3%	171	2.8%	144	2.4%	855	14.1%
Full Participation										
Pricing with Technology	757	12.5%	33	0.5%	0	0.0%	37	0.6%	826	13.7%
Pricing without Technology	41	0.7%	1	0.0%	180	3.0%	30	0.5%	252	4.2%
Automated/Direct Load Control	31	0.5%	0	0.0%	37	0.6%	0	0.0%	68	1.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	25	0.4%	84	1.4%	109	1.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	829	13.7%	33	0.6%	243	4.0%	150	2.5%	1,255	20.8%



Illinois State Profile

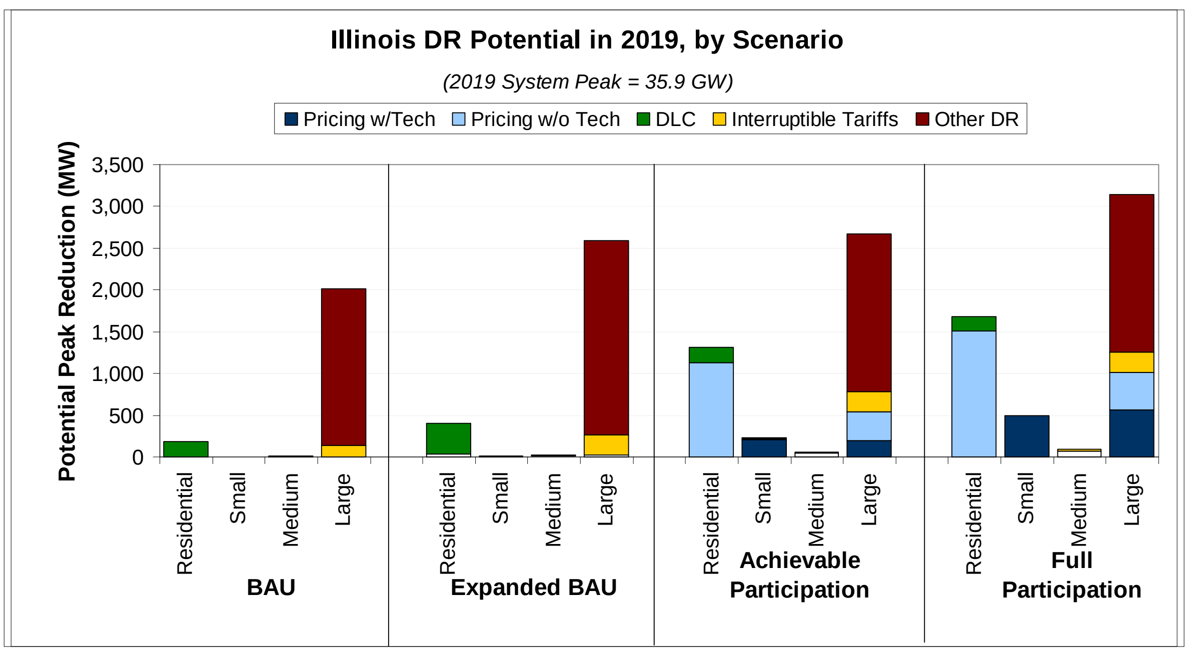
Key drivers of Illinois's demand response potential estimate include: higher-than-average residential CAC saturation of 75 percent, a customer mix that has an above average share of peak demand in the Large C&I class (42%), a moderate amount of existing demand response, and the potential to deploy AMI at a slightly faster-than-average rate. Enabling technologies are cost-effective only for the Small and Large C&I classes. DLC technology is cost-effective for all customer classes in the state.

BAU: Illinois's existing demand response comes primarily from its Large C&I class, namely in the Other DR category. The Residential class contributes minimally with DLC participation.

Expanded BAU: Growth in demand response impacts is driven primarily through the Other DR programs and Interruptible Tariffs for the Large C&I class. Residential DLC exhibits small growth in the existing DLC program.

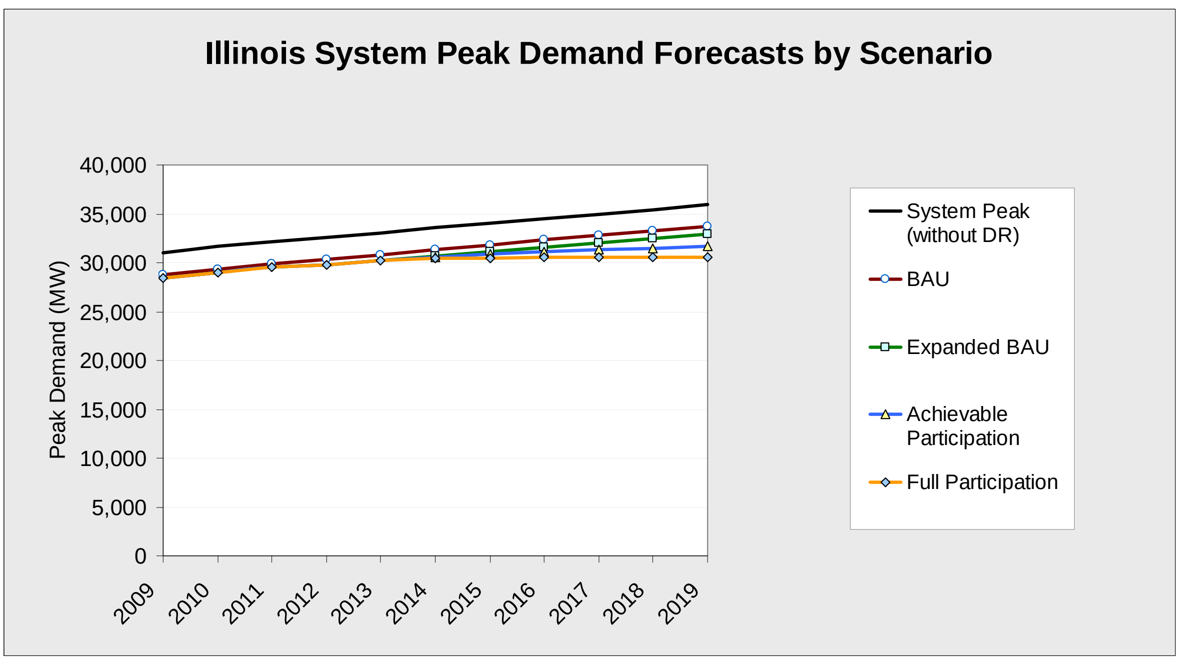
Achievable Participation: High CAC saturation in the residential sector implies significant demand response potential through pricing programs, but this is realized without enabling technology as it is not cost-effective in this class in Illinois. It is, however, cost-effective for the Small and Large C&I classes, and this is reflected in the results. Large C&I demand response potential is slightly higher than in the Expanded BAU scenario due to higher assumed participation in pricing programs.

Full Participation: Potential increases relative to the Achievable Participation scenario due to impacts from pricing programs, limited somewhat by the lack of cost-effective enabling technology in the Residential and Medium C&I classes. The Large C&I class maintains strong potential from Interruptible Tariffs and Other DR as well.



Total Potential Peak Reduction from Demand Response in Illinois, 2019

	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%	0	0.0%	1	0.0%
Automated/Direct Load Control	178	0.5%	0	0.0%	0	0.0%	0	0.0%	178	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	10	0.0%	134	0.4%	144	0.4%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,883	5.2%	1,883	5.2%
Total	179	0.5%	0	0.0%	10	0.0%	2,017	5.6%	2,206	6.1%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	39	0.1%	1	0.0%	2	0.0%	19	0.1%	61	0.2%
Automated/Direct Load Control	369	1.0%	10	0.0%	9	0.0%	0	0.0%	387	1.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	15	0.0%	243	0.7%	258	0.7%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	2,329	6.5%	2,329	6.5%
Total	407	1.1%	11	0.0%	26	0.1%	2,592	7.2%	3,036	8.5%
Achievable Participation										
Pricing with Technology	0	0.0%	210	0.6%	0	0.0%	192	0.5%	402	1.1%
Pricing without Technology	1,131	3.1%	13	0.0%	45	0.1%	349	1.0%	1,537	4.3%
Automated/Direct Load Control	178	0.5%	3	0.0%	4	0.0%	0	0.0%	184	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	15	0.0%	243	0.7%	258	0.7%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,883	5.2%	1,883	5.2%
Total	1,309	3.6%	225	0.6%	63	0.2%	2,667	7.4%	4,265	11.9%
Full Participation										
Pricing with Technology	0	0.0%	492	1.4%	0	0.0%	561	1.6%	1,052	2.9%
Pricing without Technology	1,508	4.2%	8	0.0%	74	0.2%	452	1.3%	2,042	5.7%
Automated/Direct Load Control	178	0.5%	0	0.0%	0	0.0%	0	0.0%	178	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	15	0.0%	243	0.7%	258	0.7%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,883	5.2%	1,883	5.2%
Total	1,686	4.7%	499	1.4%	89	0.2%	3,139	8.7%	5,414	15.1%



Indiana State Profile

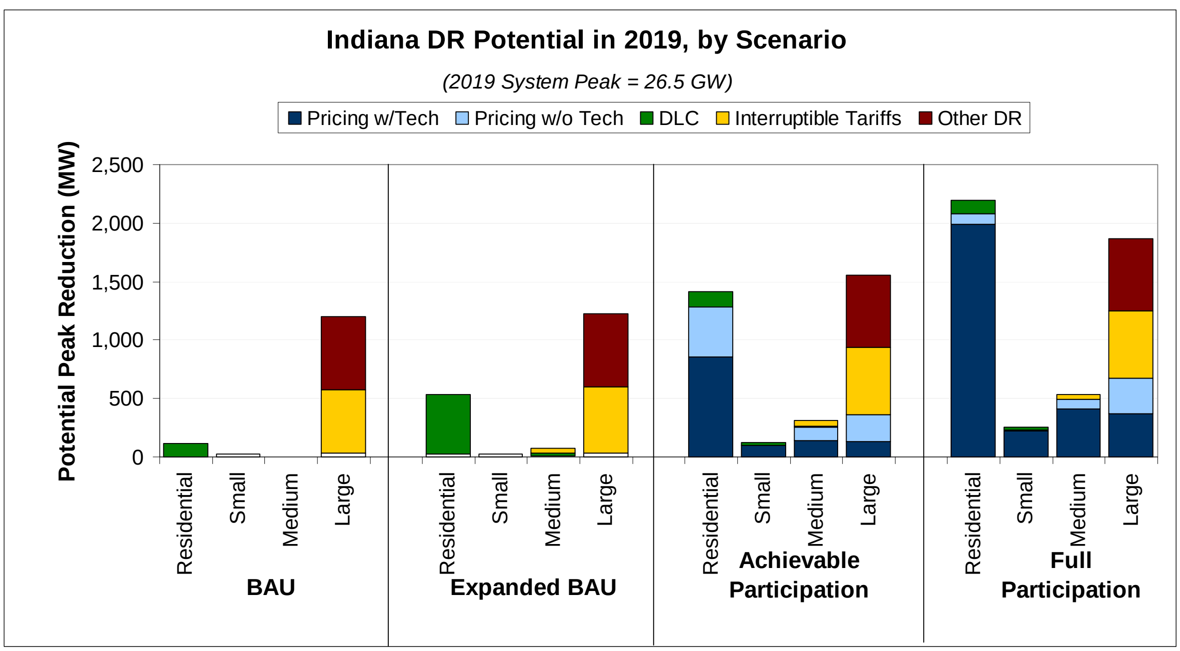
Key drivers of Indiana's demand response potential estimate include: higher-than-average residential CAC saturation of 74 percent, a customer mix that has an above average share of peak demand in the Large C&I class (35%), a moderate amount of existing demand response, and the potential to deploy AMI at an average rate. Enabling technologies and DLC are cost effective for all customer classes in the state.

BAU: Indiana's existing demand response comes primarily from the Large C&I class. BAU demand response for this class is split between Interruptible Tariffs and Other DR.

Expanded BAU: Demand response potential for the Large C&I class remains largely unchanged. However, due to the high Residential CAC saturation, DLC potential in this class has grown significantly.

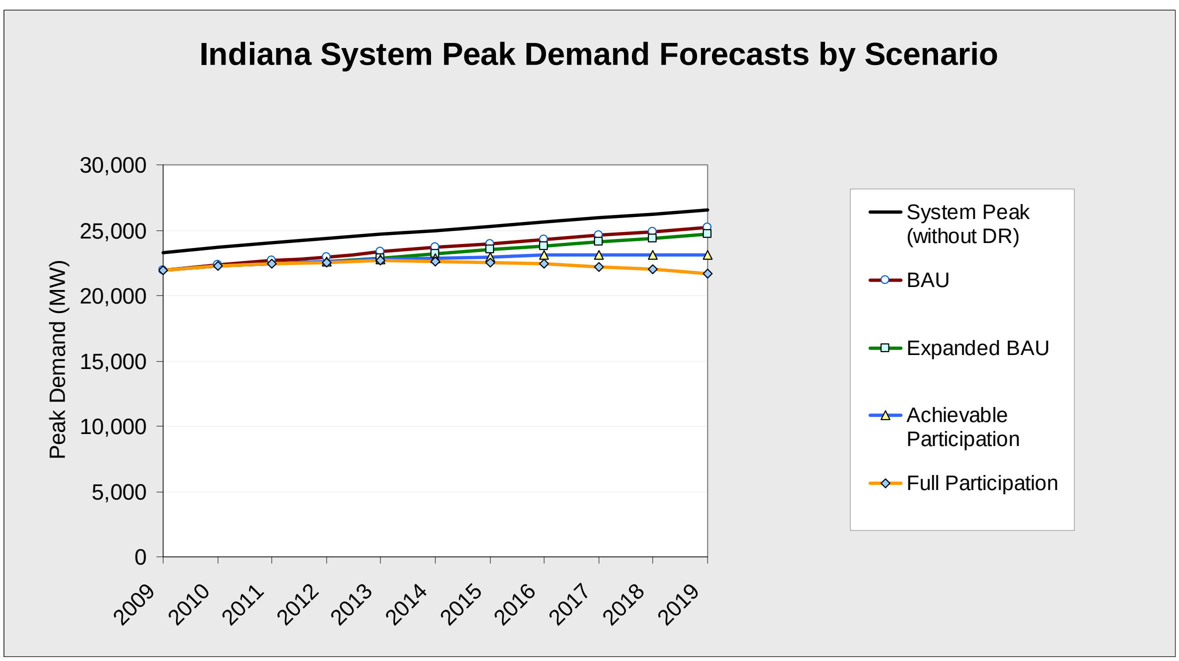
Achievable Participation: High CAC saturation in the residential sector drives a significant increase in demand response potential through dynamic pricing with and without enabling technologies. This is bolstered by the gains across the C&I classes due to pricing programs.

Full Participation: Continuing the trend from the Achievable Participation scenario, high CAC saturation in the residential sector and cost-effective enabling technology drive the increases in impacts from dynamic pricing programs. Potential in the C&I classes grows slightly as pricing program participation increases relative to the other scenarios.



Total Potential Peak Reduction from Demand Response in Indiana, 2019

	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%	29	0.1%	29	0.1%
Automated/Direct Load Control	116	0.4%	23	0.1%	0	0.0%	0	0.0%	139	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	549	2.1%	549	2.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	621	2.3%	621	2.3%
Total	116	0.4%	23	0.1%	0	0.0%	1,199	4.5%	1,338	5.0%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	25	0.1%	0	0.0%	7	0.0%	29	0.1%	61	0.2%
Automated/Direct Load Control	512	1.9%	23	0.1%	24	0.1%	0	0.0%	559	2.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	47	0.2%	575	2.2%	622	2.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	621	2.3%	622	2.3%
Total	537	2.0%	23	0.1%	78	0.3%	1,225	4.6%	1,863	7.0%
Achievable Participation										
Pricing with Technology	852	3.2%	96	0.4%	141	0.5%	128	0.5%	1,218	4.6%
Pricing without Technology	431	1.6%	6	0.0%	113	0.4%	232	0.9%	782	2.9%
Automated/Direct Load Control	131	0.5%	23	0.1%	10	0.0%	0	0.0%	163	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	47	0.2%	575	2.2%	622	2.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	621	2.3%	622	2.3%
Total	1,414	5.3%	125	0.5%	311	1.2%	1,556	5.9%	3,407	12.8%
Full Participation										
Pricing with Technology	1,994	7.5%	225	0.8%	413	1.6%	373	1.4%	3,006	11.3%
Pricing without Technology	85	0.3%	3	0.0%	77	0.3%	301	1.1%	467	1.8%
Automated/Direct Load Control	116	0.4%	23	0.1%	0	0.0%	0	0.0%	139	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	47	0.2%	575	2.2%	622	2.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	621	2.3%	621	2.3%
Total	2,195	8.3%	252	0.9%	538	2.0%	1,870	7.0%	4,855	18.3%



Iowa State Profile

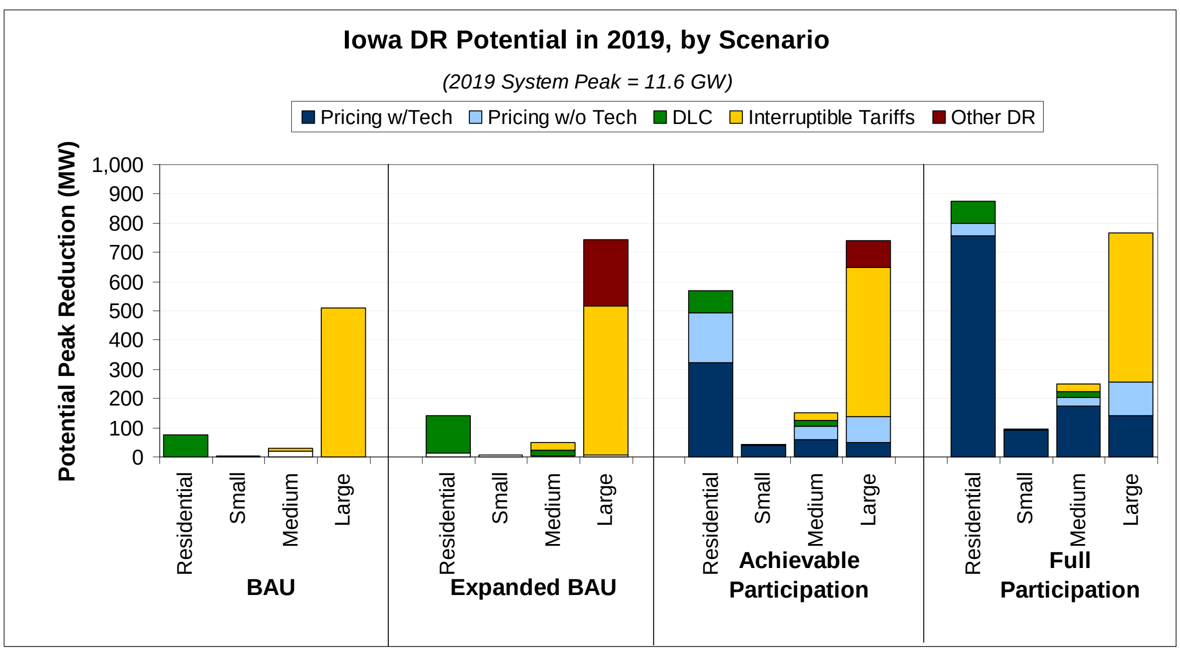
Key drivers of Iowa's demand response potential estimate include: higher-than-average residential CAC saturation of 70 percent, a customer mix that has an above average share of peak demand in the Large C&I class (34%), a small amount of existing demand response, and the potential to deploy AMI at a slightly faster-than-average rate. Enabling technologies are cost effective for all customer classes.

BAU: Iowa's existing demand response comes primarily from Interruptible Tariff and Pricing program participation in the Large C&I class. There is small DLC participation in the Residential and Medium C&I classes as well.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of Other DR programs and growth in Interruptible Tariffs participation for the Large C&I class, with slight growth in the Residential and Medium C&I classes contributing as well.

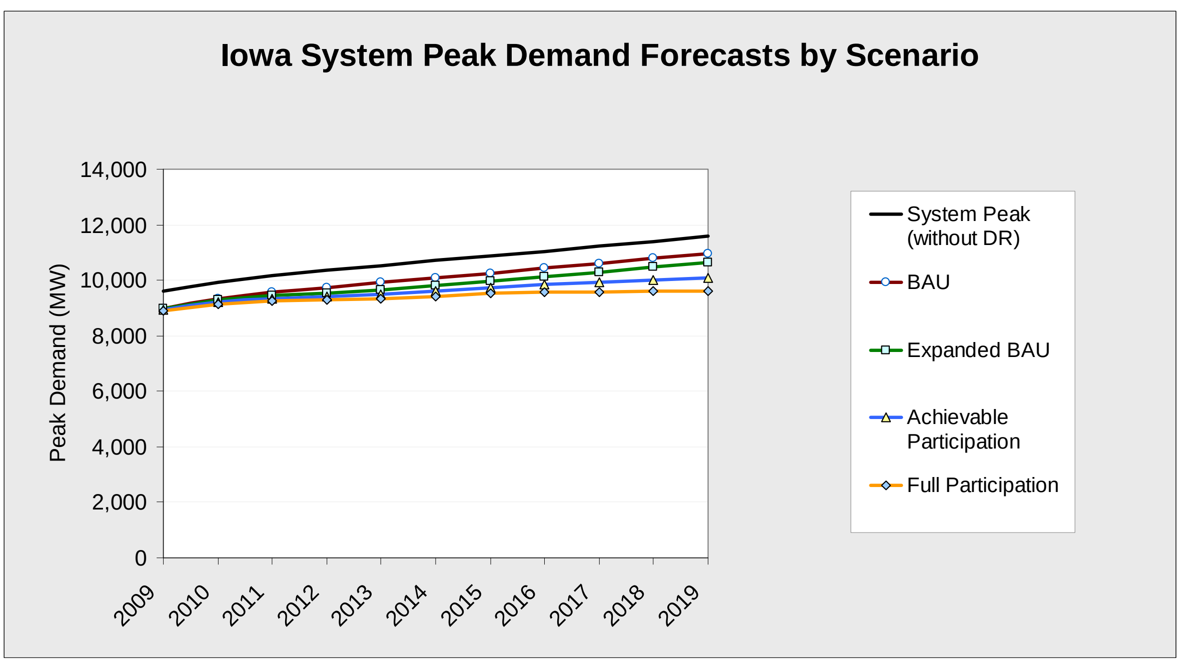
Achievable Participation: High CAC saturation in the residential sector drives a significant increase in demand response potential through dynamic pricing. The Small and Medium C&I classes show some potential, mainly through dynamic pricing. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR.

Full Participation: Similar to the Achievable Participation scenario, growth in the Residential class is driven by pricing with enabling technology. The Small and Medium C&I classes also exhibit an increase in dynamic pricing potential. With pricing making up a larger percentage of assumed participation in the Large C&I class, Other DR does not factor into the total impacts.



Total Potential Peak Reduction from Demand Response in Iowa, 2019

	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	76	0.7%	2	0.0%	19	0.2%	0	0.0%	97	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	10	0.1%	510	4.4%	521	4.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	76	0.7%	2	0.0%	30	0.3%	510	4.4%	618	5.3%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	13	0.1%	0	0.0%	4	0.0%	5	0.0%	23	0.2%
Automated/Direct Load Control	129	1.1%	6	0.1%	19	0.2%	0	0.0%	154	1.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	25	0.2%	510	4.4%	536	4.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	230	2.0%	230	2.0%
Total	142	1.2%	6	0.1%	49	0.4%	745	6.4%	942	8.1%
Achievable Participation										
Pricing with Technology	323	2.8%	40	0.3%	59	0.5%	49	0.4%	471	4.1%
Pricing without Technology	171	1.5%	2	0.0%	47	0.4%	88	0.8%	309	2.7%
Automated/Direct Load Control	76	0.7%	2	0.0%	19	0.2%	0	0.0%	97	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	25	0.2%	510	4.4%	536	4.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	94	0.8%	94	0.8%
Total	571	4.9%	44	0.4%	151	1.3%	742	6.4%	1,507	13.0%
Full Participation										
Pricing with Technology	755	6.5%	93	0.8%	173	1.5%	142	1.2%	1,164	10.1%
Pricing without Technology	43	0.4%	1	0.0%	32	0.3%	115	1.0%	191	1.6%
Automated/Direct Load Control	76	0.7%	2	0.0%	19	0.2%	0	0.0%	97	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	25	0.2%	510	4.4%	536	4.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	875	7.6%	97	0.8%	250	2.2%	767	6.6%	1,988	17.2%



Kansas State Profile

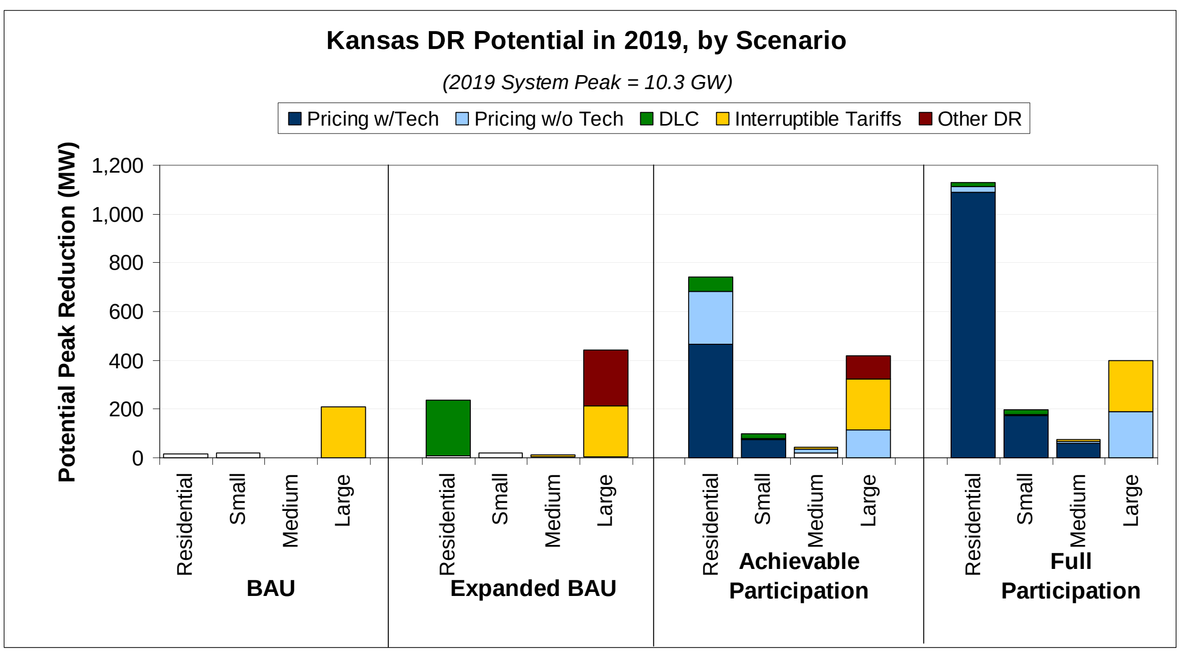
Key drivers of Kansas's demand response potential estimate include: higher-than-average residential CAC saturation of 83.7 percent, a customer mix that has a significant share of peak demand in the Residential and Large C&I classes (44% and 31%, respectively), a small amount of existing demand response, and the potential to deploy AMI at a slower-than-average rate. Enabling technologies are cost effective for all customer classes in the state except for the Large C&I class. DLC technology is cost-effective across all classes.

BAU: Kansas's existing demand response comes primarily from Interruptible tariffs in the Large C&I class and minimal DLC participation in the Residential and Small C&I classes.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of Other DR programs for the Large C&I class, which currently do not exist in the state, as well as growth in the Large C&I class's Interruptible Tariff programs and the Residential class's DLC programs.

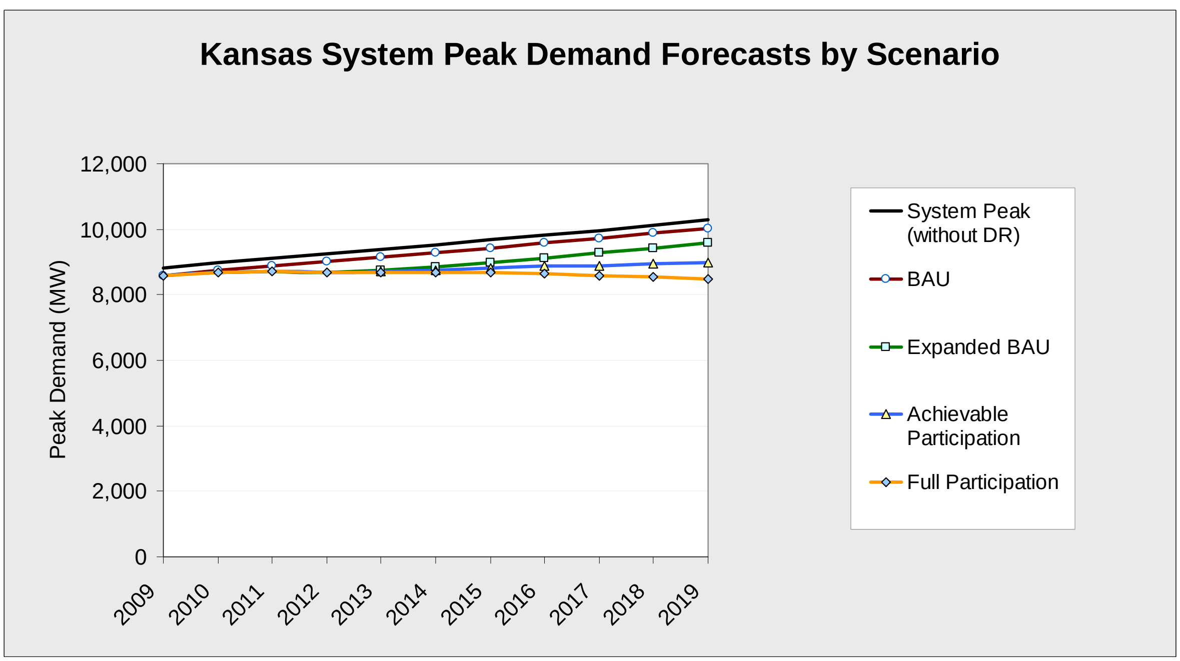
Achievable Participation: High CAC saturation in the residential sector drives a significant increase in demand response potential through dynamic pricing programs. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing without technology relative to Other DR and Interruptible Tariffs.

Full Participation: High CAC saturation combined with a large share of load in the Residential sector drives the increase in impacts. With enabling technology being cost-effective for all but the Large C&I class, there are significant impacts in this category for the Small and Medium C&I classes. The Large C&I class contributes significantly through Interruptible Tariffs and pricing without enabling technology.



Total Potential Peak Reduction from Demand Response in Kansas, 2019

	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	15	0.1%	19	0.2%	0	0.0%	0	0.0%	33	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	211	2.0%	211	2.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	15	0.1%	19	0.2%	0	0.0%	211	2.0%	244	2.4%
Expanded 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%	3	0.0%	13	0.1%
Automated/Direct Load Control	226	2.2%	19	0.2%	4	0.0%	0	0.0%	248	2.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	7	0.1%	211	2.1%	218	2.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	229	2.2%	229	2.2%
Total	236	2.3%	19	0.2%	11	0.1%	443	4.3%	708	6.9%
Achievable Participation										
Pricing with Technology	466	4.5%	75	0.7%	20	0.2%	0	0.0%	560	5.5%
Pricing without Technology	219	2.1%	5	0.0%	16	0.2%	113	1.1%	352	3.4%
Automated/Direct Load Control	57	0.6%	19	0.2%	1	0.0%	0	0.0%	78	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	7	0.1%	211	2.1%	218	2.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	93	0.9%	93	0.9%
Total	742	7.2%	98	1.0%	43	0.4%	417	4.1%	1,300	12.6%
Full Participation										
Pricing with Technology	1,089	10.6%	176	1.7%	58	0.6%	0	0.0%	1,322	12.9%
Pricing without Technology	24	0.2%	3	0.0%	11	0.1%	188	1.8%	225	2.2%
Automated/Direct Load Control	15	0.1%	19	0.2%	0	0.0%	0	0.0%	33	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	7	0.1%	211	2.1%	218	2.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	1,127	11.0%	197	1.9%	75	0.7%	399	3.9%	1,798	17.5%



Kentucky State Profile

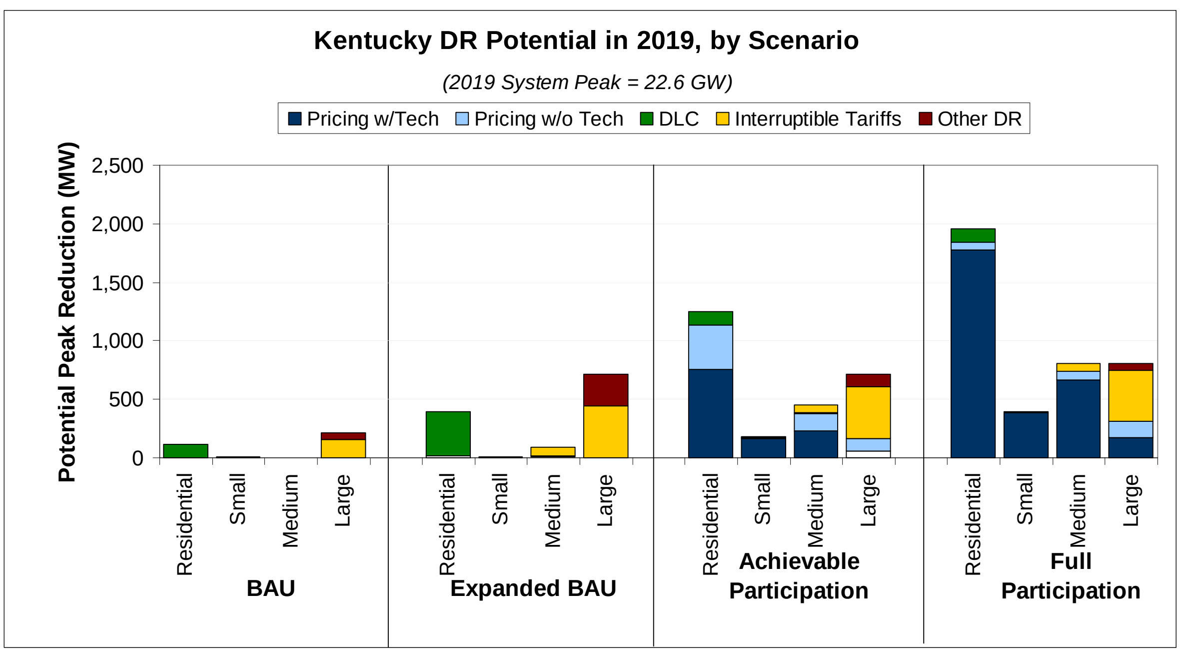
Key drivers of Kentucky's demand response potential estimate include: higher-than-average residential CAC saturation of 76 percent, a fairly typical customer mix with significant load in the Medium C&I class (30%), a minimal amount of existing demand response, and the potential to deploy AMI at a slightly slower-than-average rate. Enabling technologies and DLC are cost effective for all customer classes in the state.

BAU: Kentucky's existing demand response comes from the Residential and Large C&I classes. DLC in the Residential class and an Interruptible Tariff in the Large C&I class make up most of the existing demand response, with Other DR in the Large C&I class also contributing.

Expanded BAU: Growth in demand response impacts is driven primarily through an increase in Other DR programs for the Large C&I class and growth in DLC for the Residential class. The Medium C&I class also gains demand response potential split mainly from an Interruptible Tariff.

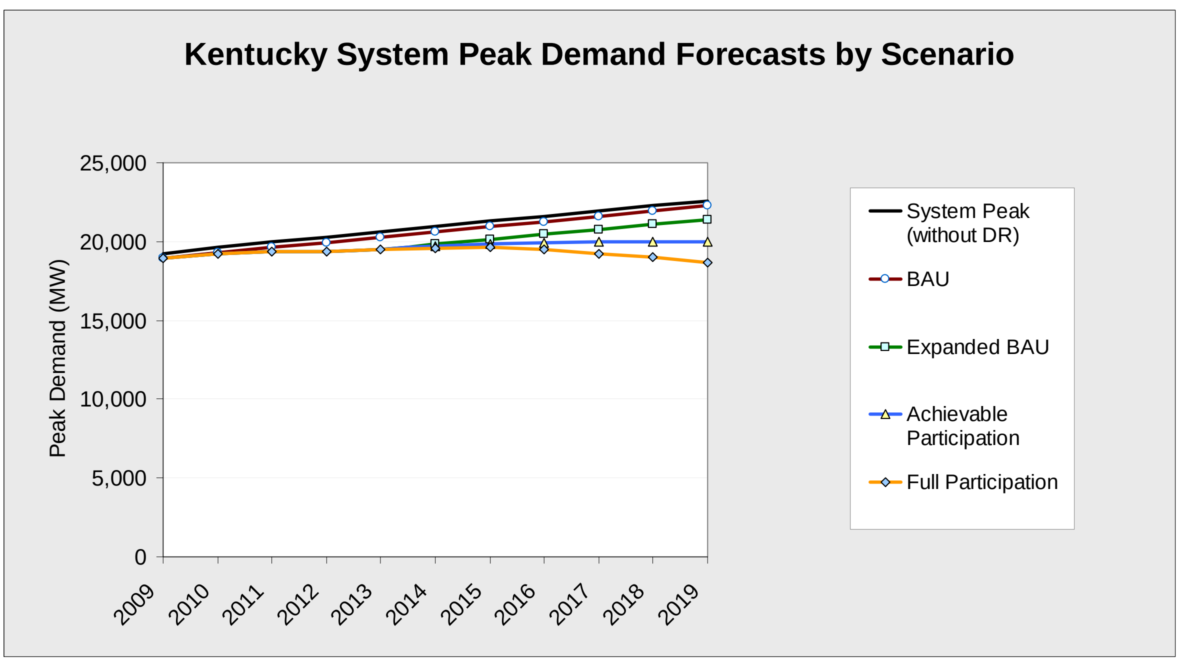
Achievable Participation: High CAC saturation in the residential sector drives a significant increase in demand response potential through dynamic pricing with enabling technologies. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR. There is also significant growth in demand response for the Small and Medium C&I classes driven by dynamic pricing programs

Full Participation: Residential class potential increases due to dynamic pricing. Overall, high CAC saturation across the Residential, Small C&I and Medium C&I classes drives the significant dynamic pricing potential, with the Large C&I class exhibiting significant potential in Interruptible Tariff programs.



Total Potential Peak Reduction from Demand Response in Kentucky, 2019

	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	116	0.5%	6	0.0%	0	0.0%	0	0.0%	122	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	155	0.7%	155	0.7%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	56	0.2%	56	0.2%
Total	116	0.5%	6	0.0%	0	0.0%	211	0.9%	332	1.5%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	18	0.1%	0	0.0%	8	0.0%	4	0.0%	30	0.1%
Automated/Direct Load Control	377	1.7%	6	0.0%	12	0.1%	0	0.0%	394	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	69	0.3%	437	1.9%	506	2.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	272	1.2%	272	1.2%
Total	395	1.7%	6	0.0%	89	0.4%	713	3.2%	1,202	5.3%
Achievable Participation										
Pricing with Technology	759	3.4%	164	0.7%	227	1.0%	59	0.3%	1,209	5.4%
Pricing without Technology	377	1.7%	9	0.0%	151	0.7%	108	0.5%	645	2.9%
Automated/Direct Load Control	116	0.5%	6	0.0%	5	0.0%	0	0.0%	126	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	69	0.3%	437	1.9%	506	2.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	110	0.5%	111	0.5%
Total	1,251	5.5%	179	0.8%	452	2.0%	715	3.2%	2,596	11.5%
Full Participation										
Pricing with Technology	1,774	7.9%	383	1.7%	664	2.9%	174	0.8%	2,995	13.3%
Pricing without Technology	67	0.3%	5	0.0%	73	0.3%	140	0.6%	285	1.3%
Automated/Direct Load Control	116	0.5%	6	0.0%	0	0.0%	0	0.0%	122	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	69	0.3%	437	1.9%	506	2.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	56	0.2%	56	0.2%
Total	1,957	8.7%	394	1.7%	806	3.6%	807	3.6%	3,963	17.5%



Louisiana State Profile

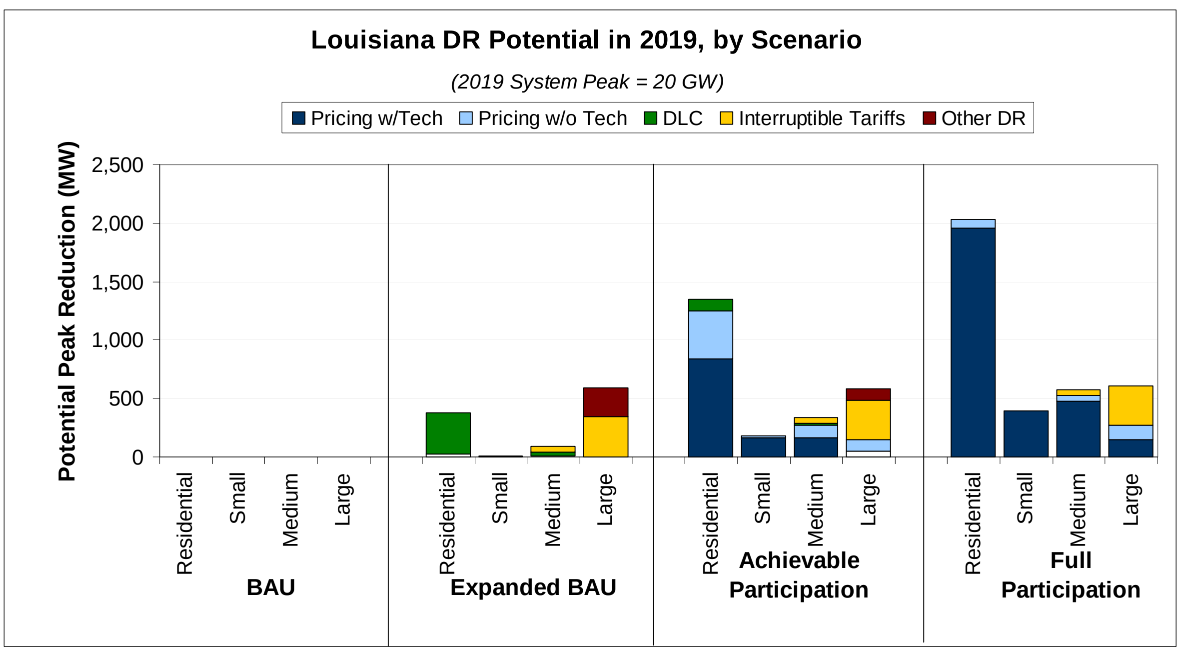
Key drivers of Louisiana's demand response potential estimate include: higher-than-average residential CAC saturation of 75.5 percent, an average customer mix, no existing demand response programs, and the potential to deploy AMI at a slightly slower-than-average rate. Enabling technologies and DLC are cost effective for all customer classes in the state.

BAU: A review of the available data did not identify any existing demand response programs in Louisiana.

Expanded BAU: Growth in demand response impacts under this scenario are driven primarily through the addition of Other DR programs and Interruptible Tariffs for the Large C&I class, and a DLC program for the Residential class. The Residential class has much potential for DLC and dynamic pricing due to its high CAC saturation.

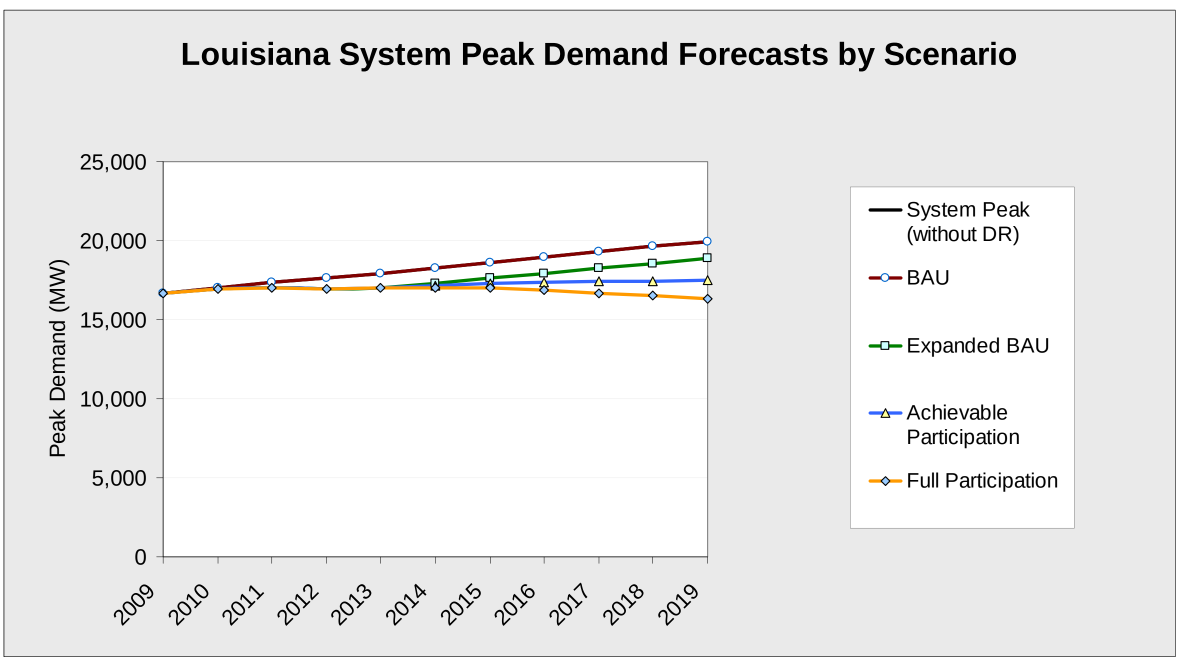
Achievable Participation: High CAC saturation in the Residential sector drives a significant increase in demand response potential through dynamic pricing with and without enabling technologies. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR.

Full Participation: Similar to the Achievable Participation scenario, high CAC saturation combined with a significant share of load in the Residential sector drives the increase in impacts. The impacts are dominated by pricing with enabling technologies, which are cost-effective for all customer classes. Lastly, an Interruptible Tariff in the Large C&I class contributes significantly to Louisiana's demand response potential under this scenario.



Total Potential Peak Reduction from Demand Response in Louisiana, 2019

	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%	0	0.0%	0	0.0%
Total	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	24	0.1%	0	0.0%	7	0.0%	4	0.0%	35	0.2%
Automated/Direct Load Control	356	1.8%	4	0.0%	38	0.2%	0	0.0%	398	2.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	49	0.2%	342	1.7%	391	2.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	244	1.2%	244	1.2%
Total	380	1.9%	5	0.0%	94	0.5%	589	3.0%	1,068	5.4%
Achievable Participation										
Pricing with Technology	837	4.2%	168	0.8%	163	0.8%	51	0.3%	1,220	6.1%
Pricing without Technology	417	2.1%	9	0.0%	109	0.5%	93	0.5%	628	3.1%
Automated/Direct Load Control	91	0.5%	1	0.0%	15	0.1%	0	0.0%	107	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	49	0.2%	342	1.7%	391	2.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	99	0.5%	100	0.5%
Total	1,345	6.7%	179	0.9%	336	1.7%	585	2.9%	2,445	12.3%
Full Participation										
Pricing with Technology	1,959	9.8%	394	2.0%	477	2.4%	150	0.7%	2,979	14.9%
Pricing without Technology	74	0.4%	5	0.0%	53	0.3%	121	0.6%	252	1.3%
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%	49	0.2%	342	1.7%	391	2.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	2,033	10.2%	399	2.0%	579	2.9%	612	3.1%	3,622	18.1%



Maine State Profile

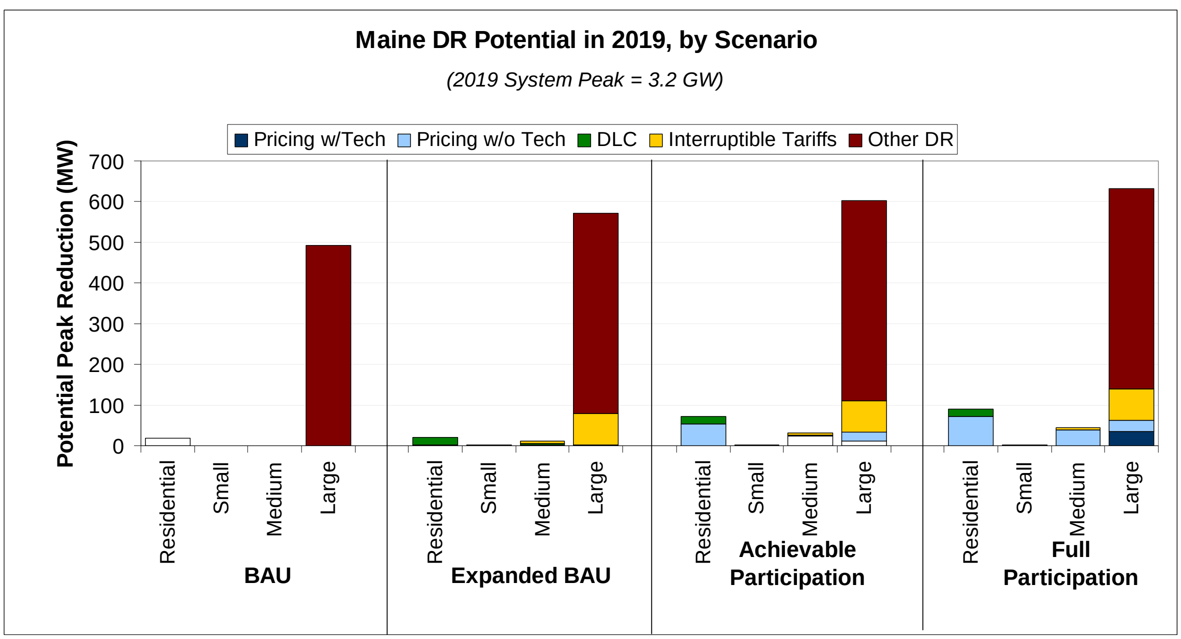
Key drivers of Maine's demand response potential estimate include: lower than average residential CAC saturation of 14%, above average share of peak demand (34%) in the Large C&I classes, and a large amount of existing demand response. Pricing with enabling technologies are only cost effective for the Large C&I class. DLC is cost effective for all classes.

BAU: Maine's existing demand response comes predominantly from the Large C&I class through participation in the ISO New England forward capacity market. These impacts account for over 60% of the total impacts under all scenarios, resulting in smaller incremental differences between BAU and the potential scenarios in comparison to most states.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of interruptible tariffs for the Large C&I class. This is due to Maine's above average share of Large C&I load, which would also allow for some growth in the Other DR category.

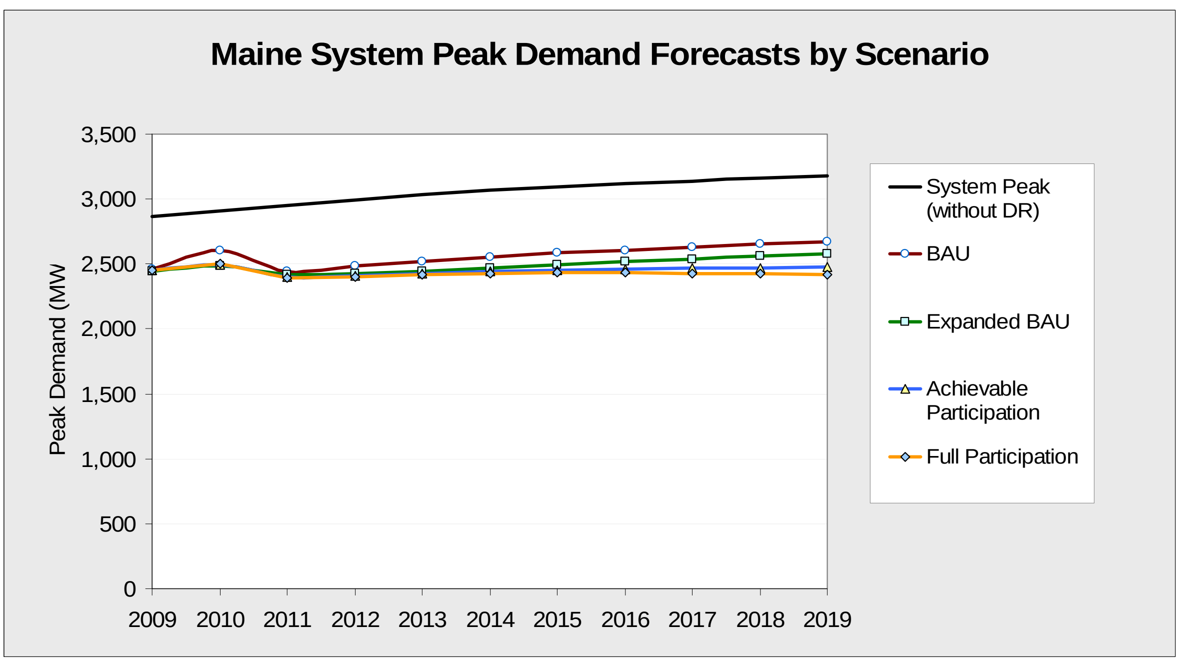
Achievable Participation: The increase in demand response potential comes primarily from dynamic pricing without enabling impacts. Dynamic pricing with enabling technology, which is cost effective for the Large C&I class, contributes additional potential for that customer group.

Full Participation: Similar to the Achievable Participation scenario, the impacts are dominated by pricing without enabling technologies for all customer classes. For the Large C&I class, pricing with enabling technology also contributes to the total potential.



Total Potential Peak Reduction from Demand Response in Maine, 2019

	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	18	0.6%	0	0.0%	0	0.0%	0	0.0%	18	0.6%
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%	492	15.4%	492	15.4%
Total	18	0.6%	0	0.0%	0	0.0%	492	15.4%	510	16.0%
Expanded 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%	1	0.0%	1	0.0%	4	0.1%
Automated/Direct Load Control	18	0.6%	1	0.0%	5	0.2%	0	0.0%	25	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	5	0.2%	78	2.5%	83	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	492	15.4%	492	15.4%
Total	20	0.6%	1	0.0%	12	0.4%	571	17.9%	604	19.0%
Achievable Participation										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	12	0.4%	12	0.4%
Pricing without Technology	53	1.7%	1	0.0%	23	0.7%	21	0.7%	99	3.1%
Automated/Direct Load Control	18	0.6%	0	0.0%	2	0.1%	0	0.0%	21	0.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	5	0.2%	78	2.5%	83	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	492	15.4%	492	15.4%
Total	72	2.2%	1	0.0%	31	1.0%	603	18.9%	706	22.2%
Full Participation										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	34	1.1%	34	1.1%
Pricing without Technology	71	2.2%	1	0.0%	39	1.2%	28	0.9%	139	4.4%
Automated/Direct Load Control	18	0.6%	0	0.0%	0	0.0%	0	0.0%	18	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	5	0.2%	78	2.5%	83	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	492	15.4%	492	15.4%
Total	89	2.8%	1	0.0%	45	1.4%	631	19.8%	766	24.1%



Maryland State Profile

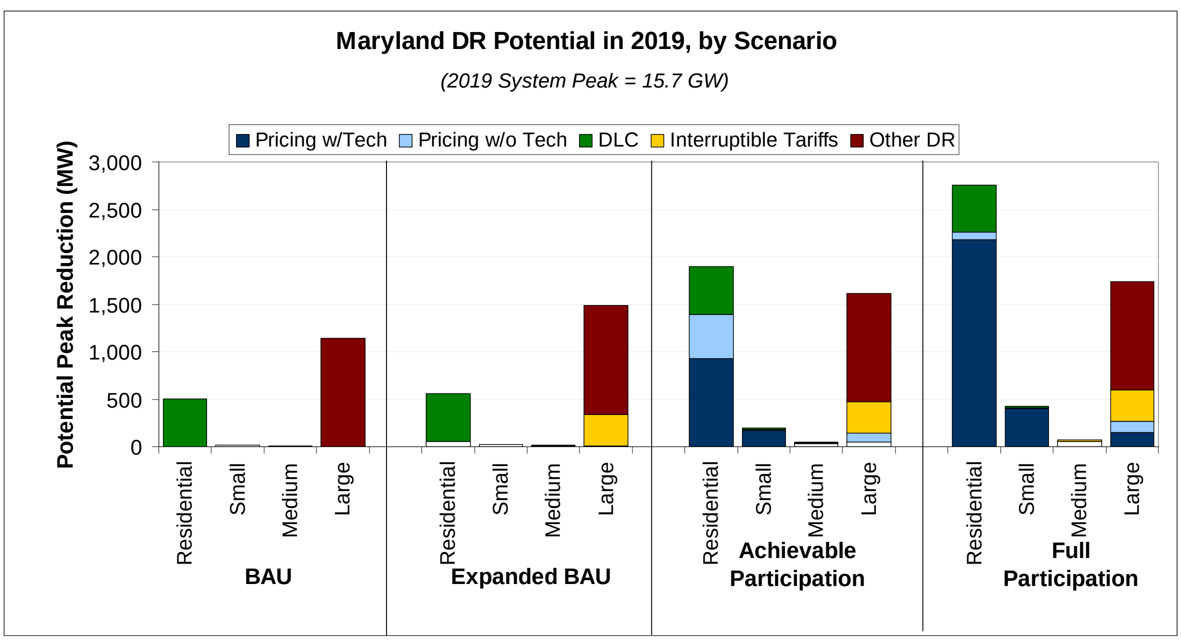
Key drivers of Maryland's demand response potential estimate include: higher-than-average residential CAC saturation of 78%, above average share of peak demand (48%) in the residential class, a large amount of existing demand response, and the potential to deploy AMI at a faster-than-average rate. Pricing with enabling technologies are cost effective for all customer classes, except for the Medium C&I class. DLC is cost effective for all customer classes.

BAU: Maryland's existing demand response comes primarily from residential DLC and Other DR programs for Large C&I customers. The large impacts for Other DR are a due to participation in PJM demand response programs.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of interruptible tariffs for the Large C&I class. The rest of the increase in potential comes from dynamic pricing without enabling technology. Overall, the incremental increase relative to the BAU scenario is small because the state is already achieving significant impacts from non-pricing programs.

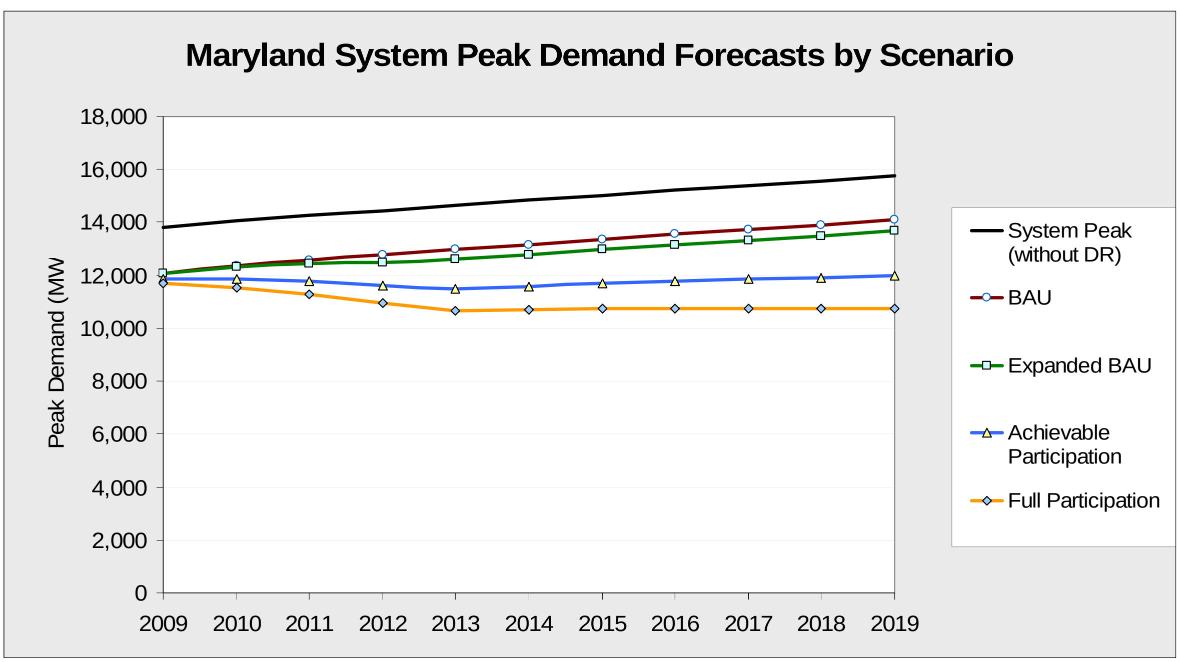
Achievable Participation: High CAC saturation in the residential sector drives a significant increase in demand response potential through dynamic pricing with enabling technologies. Growth in dynamic pricing with enabling technologies occurs for all C&I customers except for Medium C&I, as this is the only class for which the option is not cost effective.

Full Participation: Relative to the Achievable Participation scenario, high CAC saturation combined with a large share of load in the residential sector drives the increase in impacts. The impacts are dominated by pricing with enabling technologies for all customer classes except for Medium C&I customers.



Total Potential Peak Reduction from Demand Response in Maryland, 2019

	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	502	3.2%	13	0.1%	0	0.0%	0	0.0%	515	3.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	9	0.1%	0	0.0%	9	0.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,143	7.3%	1,143	7.3%
Total	502	3.2%	13	0.1%	9	0.1%	1,143	7.3%	1,667	10.6%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	54	0.3%	1	0.0%	2	0.0%	8	0.1%	65	0.4%
Automated/Direct Load Control	502	3.2%	20	0.1%	5	0.0%	0	0.0%	528	3.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	11	0.1%	334	2.1%	345	2.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,143	7.3%	1,143	7.3%
Total	556	3.5%	21	0.1%	19	0.1%	1,485	9.4%	2,081	13.2%
Achievable Participation										
Pricing with Technology	933	5.9%	173	1.1%	0	0.0%	50	0.3%	1,156	7.3%
Pricing without Technology	459	2.9%	10	0.1%	34	0.2%	91	0.6%	593	3.8%
Automated/Direct Load Control	502	3.2%	13	0.1%	2	0.0%	0	0.0%	517	3.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	11	0.1%	334	2.1%	345	2.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,143	7.3%	1,143	7.3%
Total	1,894	12.0%	196	1.2%	47	0.3%	1,618	10.3%	3,755	23.8%
Full Participation										
Pricing with Technology	2,182	13.9%	405	2.6%	0	0.0%	146	0.9%	2,733	17.4%
Pricing without Technology	76	0.5%	5	0.0%	56	0.4%	118	0.7%	255	1.6%
Automated/Direct Load Control	502	3.2%	13	0.1%	0	0.0%	0	0.0%	515	3.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	11	0.1%	334	2.1%	345	2.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,143	7.3%	1,143	7.3%
Total	2,760	17.5%	423	2.7%	68	0.4%	1,741	11.1%	4,991	31.7%



Massachusetts State Profile

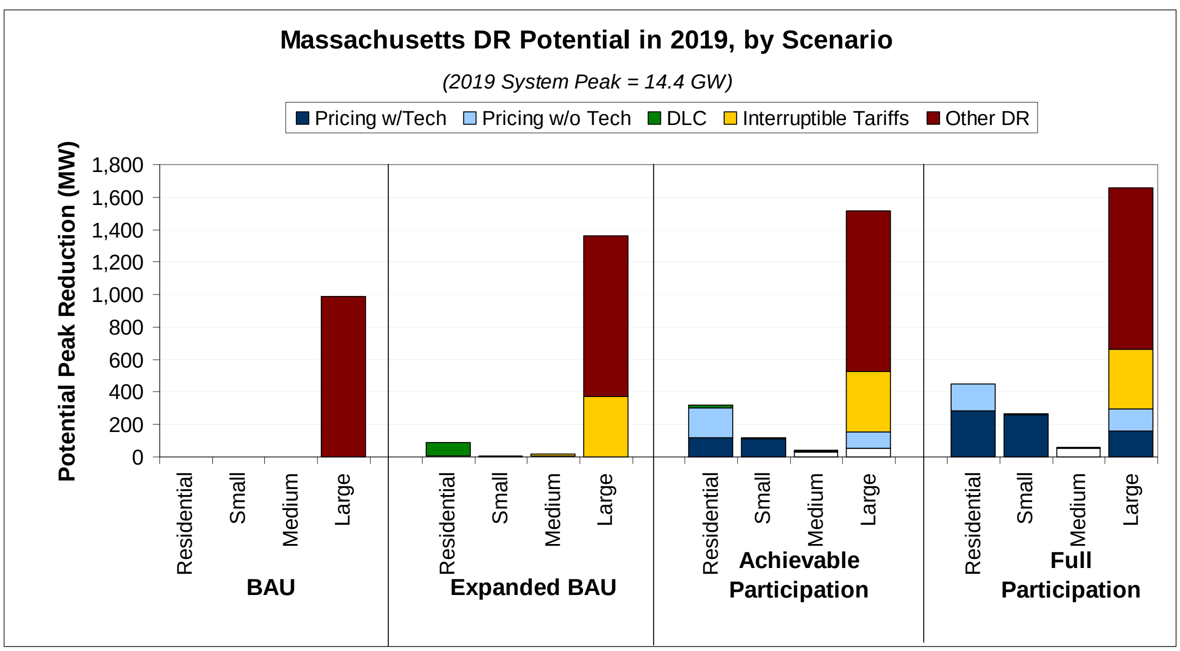
Key drivers of the Massachusetts demand response potential estimate include: significantly lower-than-average residential CAC saturation of 12.7 percent, a customer mix that has an above average share of peak demand in the Large C&I class, a moderate amount of existing Other DR, and an AMI deployment schedule that is anticipated to be slower-than-average. Enabling technologies are cost effective for all classes except the Medium C&I class; DLC technology is cost effective across all customer classes.

BAU: Massachusetts' existing demand response comes entirely from the Large C&I class, which currently has significant enrollment in Other DR, particularly ISO-NE programs.

Expanded BAU: The Expanded BAU scenario includes the addition of an interruptible tariff for the Large C&I class, which can have significant impact due to the high share of Large C&I peak demand in the customer mix. DLC program participation by the Residential class also contributes to Massachusetts' Expanded BAU scenario.

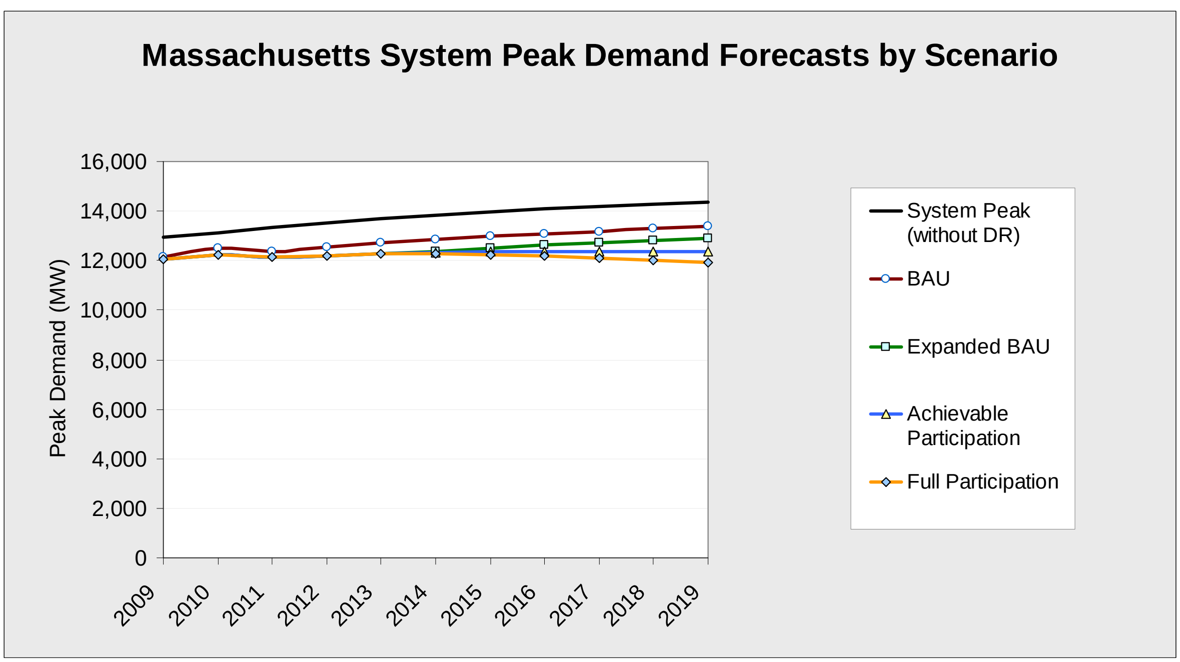
Achievable Participation: Low CAC saturation in the residential sector limits dynamic pricing potential. Furthermore, with enabling technology only cost effective in the Small and Large C&I classes, Other DR in the Large C&I class is still the dominant source of demand response potential.

Full Participation: The Full participation scenario is similar to the Achievable Participation scenario, with incremental increases in dynamic pricing potential. The relatively low incremental difference between the BAU scenario and the Full Participation scenario is driven primarily by low CAC saturation and limited cost-effectiveness for enabling technology.



Total Potential Peak Reduction from Demand Response in Massachusetts, 2019

	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%	0	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%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	990	6.9%	990	6.9%
Total	0	0.0%	1	0.0%	0	0.0%	990	6.9%	991	6.9%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	4	0.0%	1	0.0%	1	0.0%	3	0.0%	8	0.1%
Automated/Direct Load Control	85	0.6%	7	0.0%	8	0.1%	0	0.0%	101	0.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	7	0.1%	371	2.6%	379	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	990	6.9%	990	6.9%
Total	90	0.6%	8	0.1%	16	0.1%	1,364	9.5%	1,478	10.3%
Achievable Participation										
Pricing with Technology	121	0.8%	111	0.8%	0	0.0%	56	0.4%	288	2.0%
Pricing without Technology	179	1.2%	7	0.0%	31	0.2%	101	0.7%	319	2.2%
Automated/Direct Load Control	22	0.2%	2	0.0%	3	0.0%	0	0.0%	27	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	7	0.1%	371	2.6%	379	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	990	6.9%	990	6.9%
Total	322	2.2%	120	0.8%	42	0.3%	1,518	10.6%	2,002	13.9%
Full Participation										
Pricing with Technology	283	2.0%	260	1.8%	0	0.0%	163	1.1%	706	4.9%
Pricing without Technology	169	1.2%	4	0.0%	52	0.4%	131	0.9%	357	2.5%
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%	7	0.1%	371	2.6%	379	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	990	6.9%	990	6.9%
Total	452	3.1%	264	1.8%	60	0.4%	1,655	11.5%	2,432	16.9%



Michigan State Profile

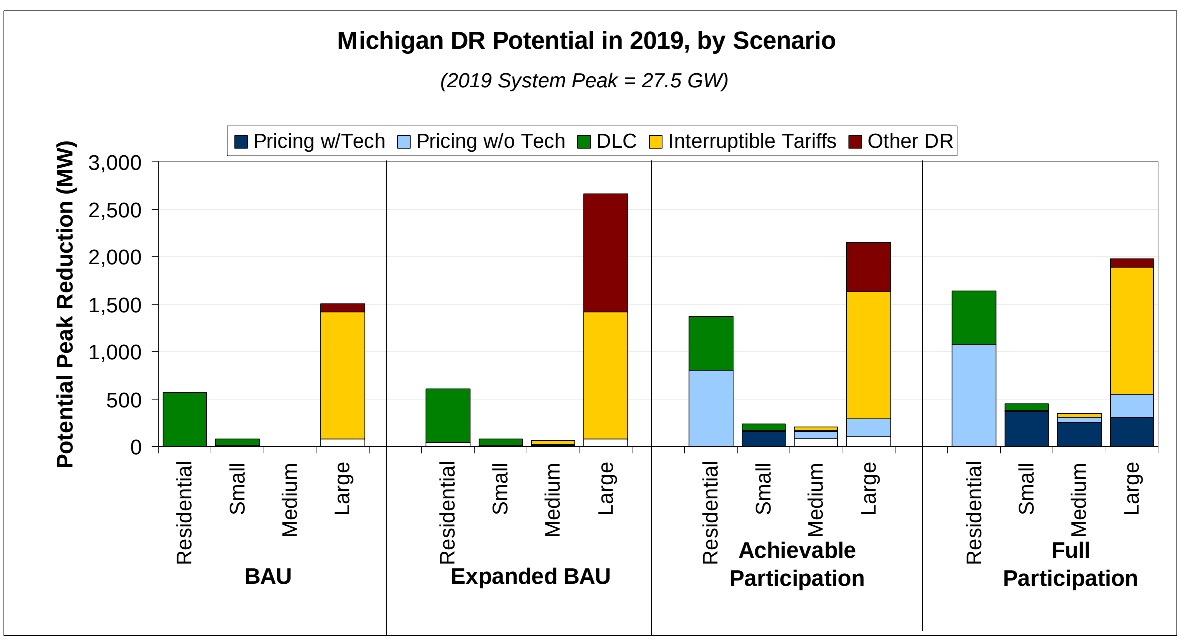
Key drivers of Michigan's demand response potential estimate include: above average residential CAC saturation of 57%, above average share of peak demand (37%) in the Large C&I classes, a large amount of existing demand response, and the potential to deploy AMI at a faster-than-average rate. Pricing with enabling technologies are cost effective for all customer classes, except for the residential class. DLC is cost effective for all customer classes.

BAU: Michigan's existing demand response comes predominantly from interruptible tariffs for the Large C&I class and represents one of the largest interruptible loads in the country. Interruptible tariffs account for at least 30% of the total potential under all other scenarios. The state is also one of the few states that has a significant portion of price induced demand response.

Expanded BAU: Significant growth in Other DR is due to Michigan's above average share of Large C&I load. The rest of the impacts come from Pricing without technology and DLC for the other customer segments.

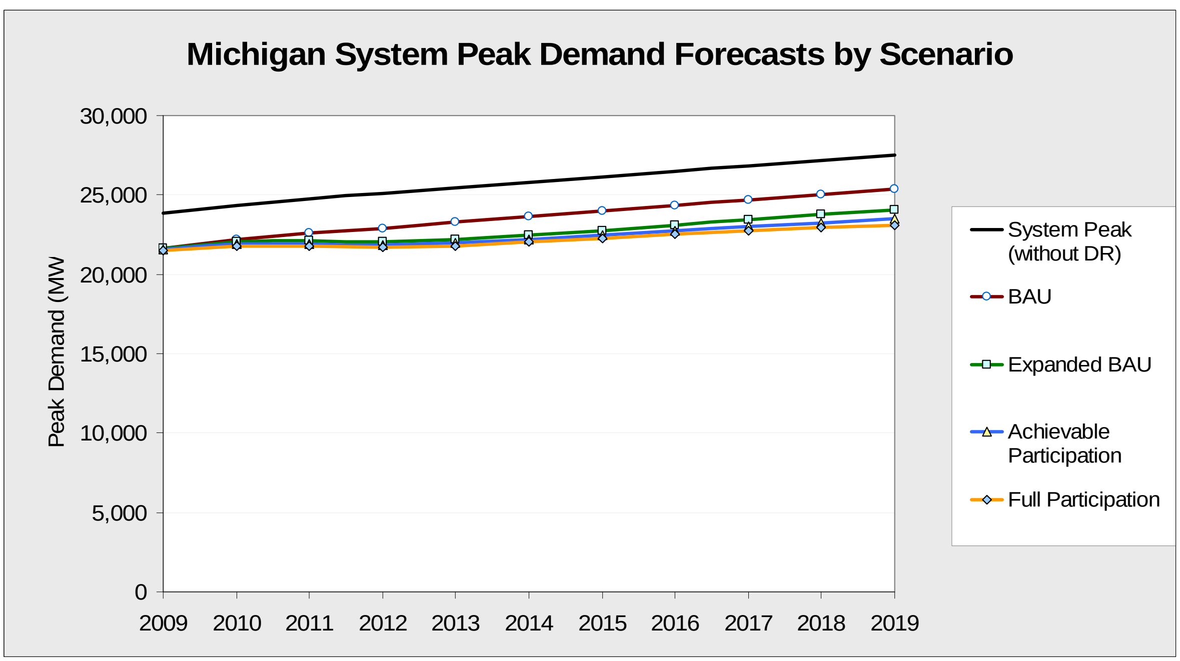
Achievable Participation: The increase in demand response potential comes primarily from dynamic pricing without enabling impacts. Dynamic pricing with enabling technology which is cost effective for all classes except for the residential sector, contributes additional potential for the C&I customers. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing relative to Other DR. The movement of participants in Other DR to pricing also contributes to this effect.

Full Participation: Similar to the Achievable Participation scenario, the impacts are dominated by dynamic pricing without enabling technologies for all customer classes. The lower potential for Large C&I than in the other scenarios is due to participation changes within the different demand response options.



Total Potential Peak Reduction from Demand Response in Michigan, 2019

	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%	6	0.0%	0	0.0%	77	0.3%	83	0.3%
Automated/Direct Load Control	570	2.1%	69	0.3%	0	0.0%	0	0.0%	639	2.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	2	0.0%	1,339	4.9%	1,341	4.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	86	0.3%	86	0.3%
Total	570	2.1%	75	0.3%	2	0.0%	1,502	5.5%	2,149	7.8%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	37	0.1%	6	0.0%	7	0.0%	77	0.3%	127	0.5%
Automated/Direct Load Control	570	2.1%	69	0.3%	18	0.1%	0	0.0%	657	2.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	42	0.2%	1,339	4.9%	1,380	5.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,245	4.5%	1,245	4.5%
Total	607	2.2%	75	0.3%	67	0.2%	2,661	9.7%	3,409	12.4%
Achievable Participation										
Pricing with Technology	0	0.0%	160	0.6%	88	0.3%	105	0.4%	352	1.3%
Pricing without Technology	801	2.9%	10	0.0%	70	0.3%	190	0.7%	1,071	3.9%
Automated/Direct Load Control	570	2.1%	69	0.3%	7	0.0%	0	0.0%	647	2.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	42	0.2%	1,339	4.9%	1,380	5.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	516	1.9%	516	1.9%
Total	1,371	5.0%	238	0.9%	207	0.8%	2,149	7.8%	3,965	14.4%
Full Participation										
Pricing with Technology	0	0.0%	373	1.4%	256	0.9%	306	1.1%	935	3.4%
Pricing without Technology	1,068	3.9%	6	0.0%	48	0.2%	246	0.9%	1,368	5.0%
Automated/Direct Load Control	570	2.1%	69	0.3%	0	0.0%	0	0.0%	639	2.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	42	0.2%	1,339	4.9%	1,380	5.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	86	0.3%	86	0.3%
Total	1,638	6.0%	448	1.6%	345	1.3%	1,977	7.2%	4,409	16.0%



Minnesota State Profile

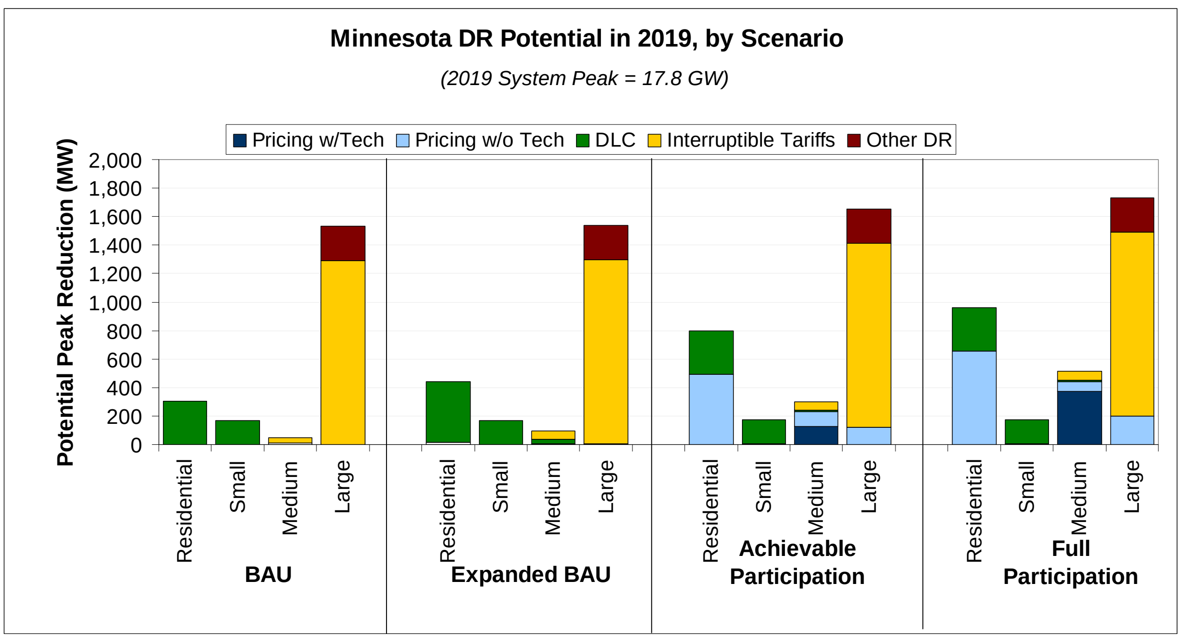
Key drivers of Minnesota's demand response potential estimate include: a substantial amount of existing demand response, above average share of peak demand (30%) in the Large C&I classes and a large residential base. Pricing with enabling technologies is not cost effective for all customer classes, except for the Medium C&I class. DLC is cost effective for all customer classes.

BAU: Minnesota's existing demand response comes primarily from interruptible tariffs and Other DR programs for Medium and Large C&I customers. The savings from interruptible tariffs account for at least 40% of the total impacts under all scenarios, resulting in smaller incremental differences between BAU and the potential scenarios in comparison to most states. The rest of the existing potential comes from direct load control programs for residential and Small and Medium C&I customers.

Expanded BAU: DLC and dynamic pricing without enabling technology account for the growth in potential. Since current participation levels in interruptible tariffs is substantially high, there is not much scope for growth in this program.

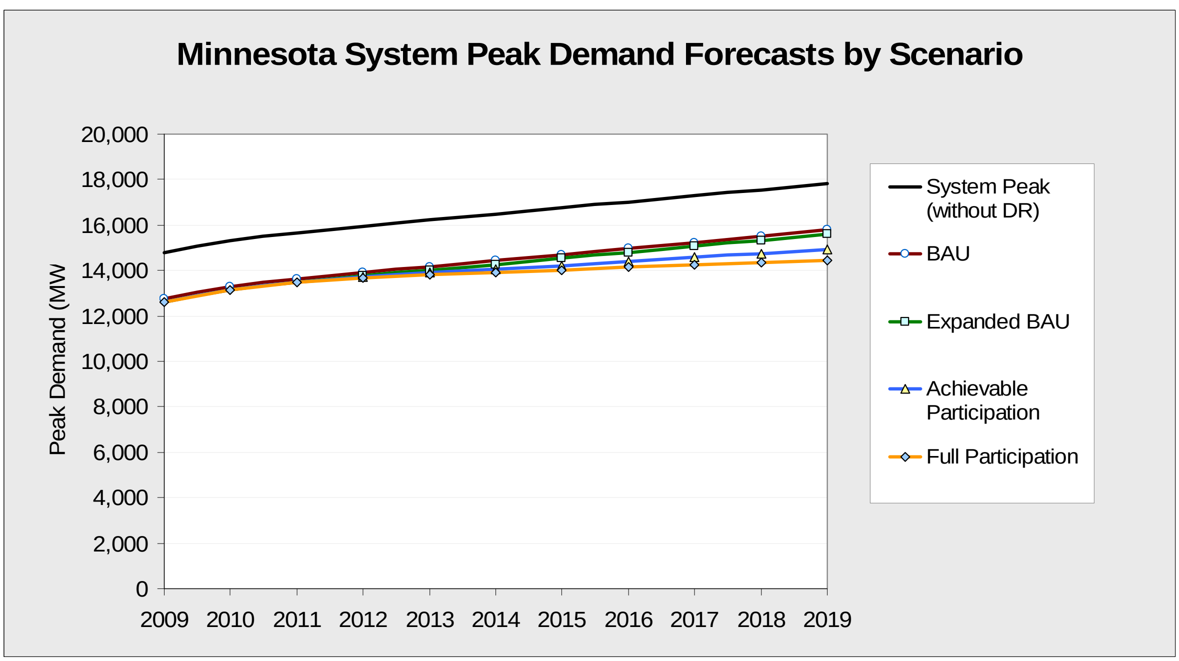
Achievable Participation: The increase in demand response potential comes primarily from dynamic pricing without enabling impacts. Dynamic pricing with enabling technology which is cost effective for the Medium C&I class contributes additional savings.

Full Participation: Similar to Achievable Participation, the incremental impacts come from dynamic pricing.



Total Potential Peak Reduction from Demand Response in Minnesota, 2019

	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%	1	0.0%	1	0.0%
Automated/Direct Load Control	304	1.7%	170	1.0%	11	0.1%	0	0.0%	485	2.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	38	0.2%	1,290	7.2%	1,329	7.4%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	242	1.4%	242	1.4%
Total	304	1.7%	170	1.0%	49	0.3%	1,533	8.6%	2,056	11.5%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	15	0.1%	0	0.0%	7	0.0%	5	0.0%	27	0.2%
Automated/Direct Load Control	428	2.4%	170	1.0%	27	0.2%	0	0.0%	626	3.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	61	0.3%	1,290	7.2%	1,352	7.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	242	1.4%	242	1.4%
Total	443	2.5%	170	1.0%	96	0.5%	1,537	8.6%	2,247	12.6%
Achievable Participation										
Pricing with Technology	0	0.0%	0	0.0%	127	0.7%	0	0.0%	127	0.7%
Pricing without Technology	492	2.8%	3	0.0%	102	0.6%	121	0.7%	718	4.0%
Automated/Direct Load Control	304	1.7%	170	1.0%	11	0.1%	0	0.0%	485	2.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	61	0.3%	1,290	7.2%	1,352	7.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	242	1.4%	242	1.4%
Total	796	4.5%	173	1.0%	302	1.7%	1,653	9.3%	2,924	16.4%
Full Participation										
Pricing with Technology	0	0.0%	0	0.0%	372	2.1%	0	0.0%	372	2.1%
Pricing without Technology	656	3.7%	4	0.0%	69	0.4%	202	1.1%	931	5.2%
Automated/Direct Load Control	304	1.7%	170	1.0%	11	0.1%	0	0.0%	485	2.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	61	0.3%	1,290	7.2%	1,352	7.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	242	1.4%	242	1.4%
Total	959	5.4%	174	1.0%	514	2.9%	1,734	9.7%	3,381	19.0%



Mississippi State Profile

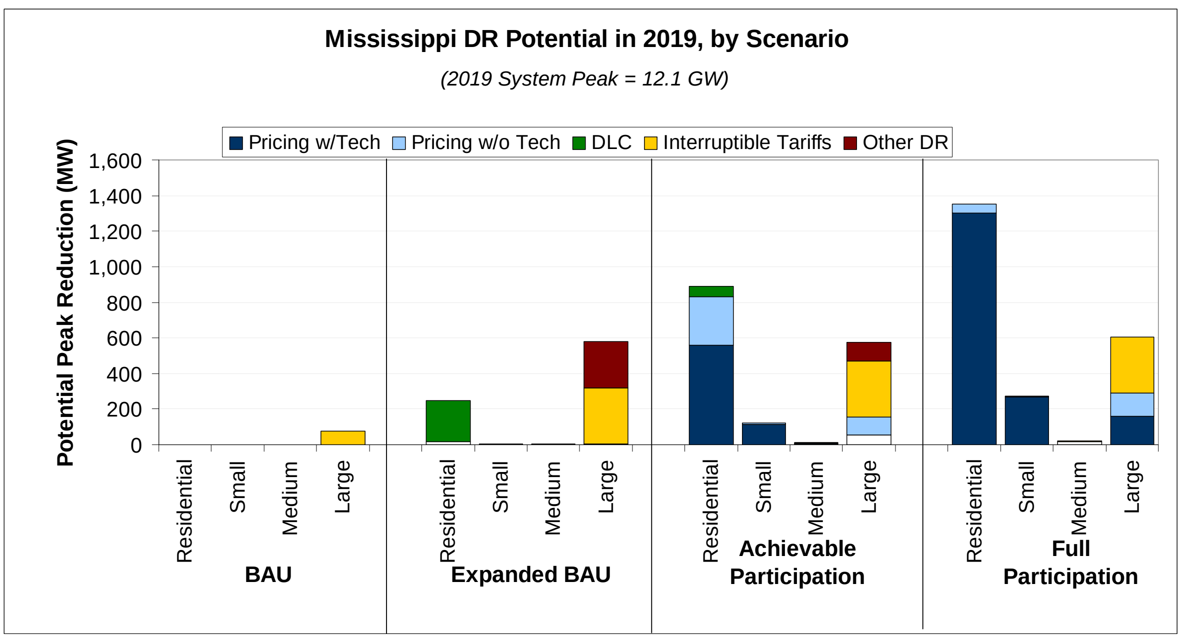
Key drivers of Mississippi's demand response potential estimate include: above average residential CAC saturation of 75% and a customer mix that has an above average share of peak demand in the residential and Large C&I classes (47% and 30%, respectively). Pricing with enabling technologies and DLC are cost effective for all customer classes in the state.

BAU: Mississippi's existing demand response comes solely from interruptible tariffs for the Large C&I class.

Expanded BAU: Growth in demand response impacts is driven through the addition of Other DR programs for the Large C&I class and DLC for the residential class. Growth in the existing interruptible tariffs accounts for the remaining portion.

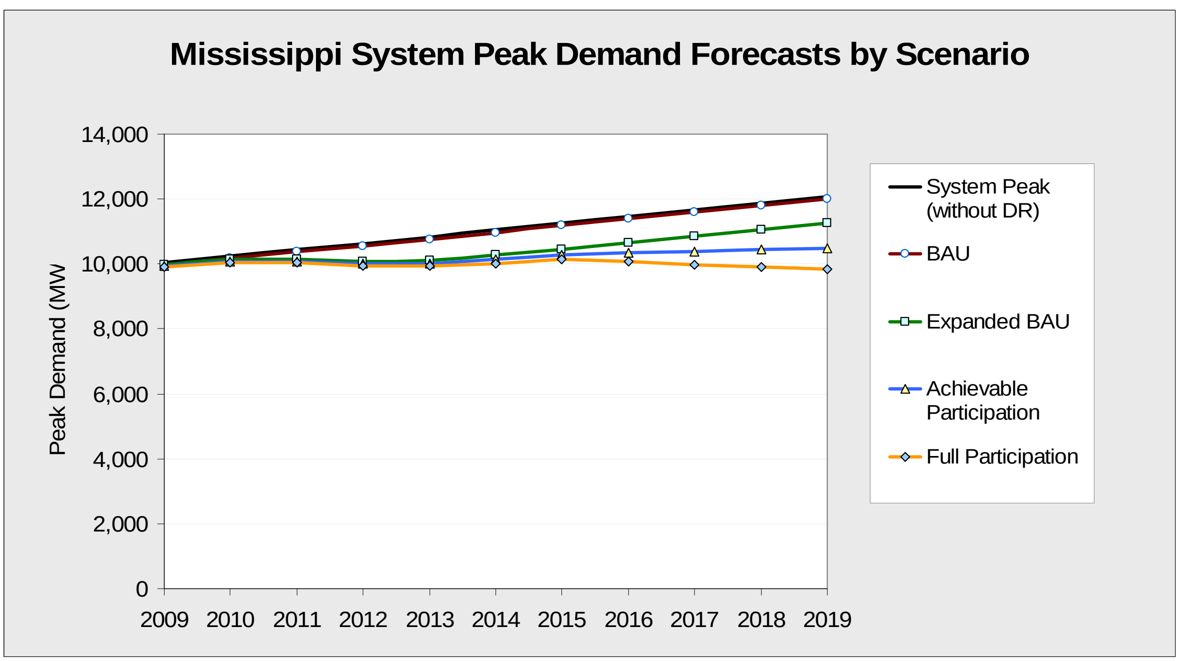
Achievable Participation: Dynamic pricing with enabling impacts accounts for almost 50% of the increase in potential. Dynamic pricing without enabling technology contributes additional savings. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing relative to Other DR. The movement of participants in Other DR to pricing also contributes to this effect.

Full Participation: Similar to the Achievable Participation scenario, the impacts are dominated by the dynamic pricing options for all customer classes. Dynamic pricing with enabling represents over 75% of the potential under this scenario. This has the effect of reducing or eliminating the potential from all of the other demand response options, in particular, DLC and Other DR.



Total Potential Peak Reduction from Demand Response in Mississippi, 2019

	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%	75	0.6%	75	0.6%
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%	75	0.6%	75	0.6%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	17	0.1%	0	0.0%	0	0.0%	5	0.0%	22	0.2%
Automated/Direct Load Control	230	1.9%	5	0.0%	1	0.0%	0	0.0%	236	2.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	2	0.0%	315	2.6%	316	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	262	2.2%	262	2.2%
Total	247	2.0%	5	0.0%	3	0.0%	581	4.8%	836	6.9%
Achievable Participation										
Pricing with Technology	557	4.6%	114	0.9%	6	0.0%	55	0.5%	732	6.1%
Pricing without Technology	277	2.3%	6	0.1%	4	0.0%	100	0.8%	387	3.2%
Automated/Direct Load Control	59	0.5%	1	0.0%	0	0.0%	0	0.0%	60	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	2	0.0%	315	2.6%	316	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	107	0.9%	107	0.9%
Total	892	7.4%	122	1.0%	11	0.1%	577	4.8%	1,602	13.3%
Full Participation										
Pricing with Technology	1,303	10.8%	268	2.2%	17	0.1%	161	1.3%	1,748	14.5%
Pricing without Technology	49	0.4%	3	0.0%	2	0.0%	130	1.1%	183	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%	2	0.0%	315	2.6%	316	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	1,351	11.2%	271	2.2%	20	0.2%	605	5.0%	2,247	18.6%



Missouri State Profile

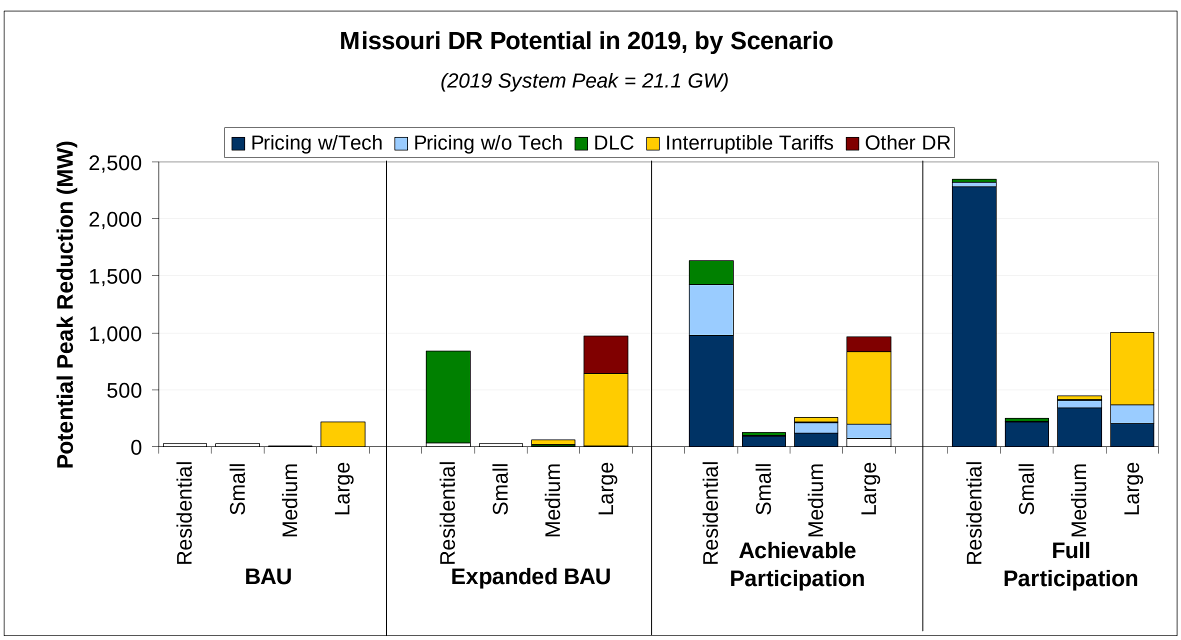
Key drivers of Missouri's demand response potential estimate include: above average residential CAC saturation of 87%, above average share of peak demand (51%) in the residential class, and a moderate amount of existing demand response. Pricing with enabling technologies and DLC are cost effective for all customer classes.

BAU: Missouri's existing demand response comes predominantly from interruptible tariffs for the Large C&I class. Direct load control programs for the other classes account for the remainder.

Expanded BAU: Significant growth in DLC impacts is due to Missouri's above average share of residential load. Growth for the Large C&I class in Other DR and interruptible tariffs account for the remaining portion.

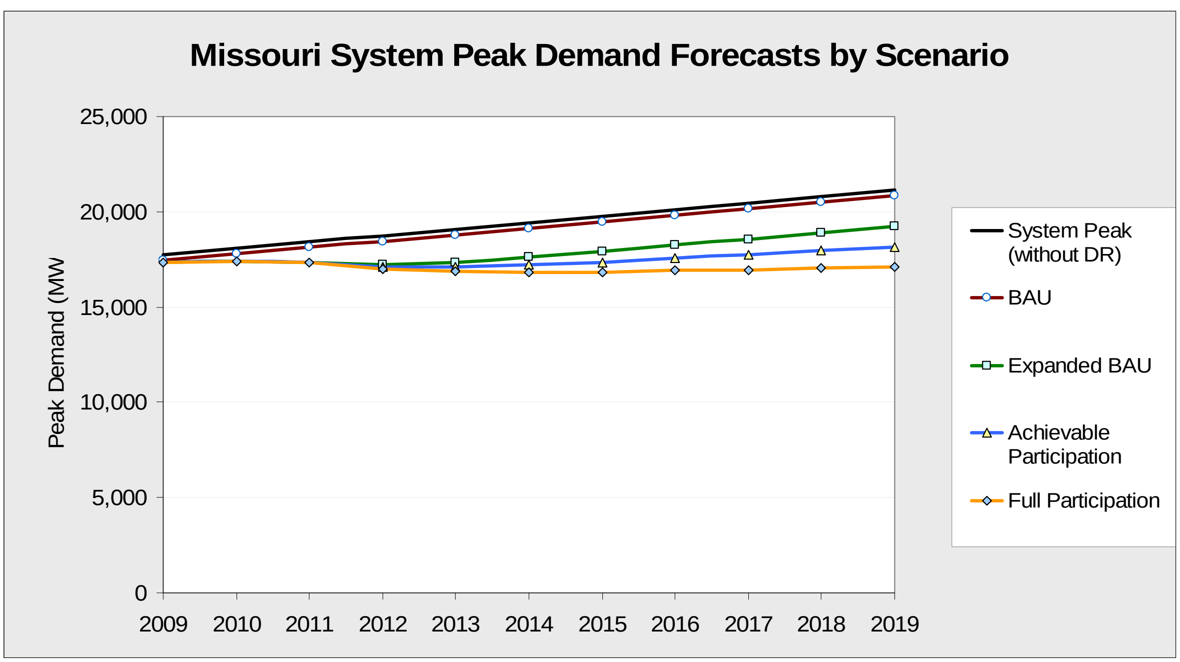
Achievable Participation: The increase in demand response potential comes primarily from dynamic pricing with enabling impacts which is cost effective for all classes. Dynamic pricing without enabling technology contributes additional potential for all customers. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing relative to Other DR. The movement of participants in Other DR to pricing also contributes to this effect.

Full Participation: Similar to the Achievable Participation scenario, the impacts are dominated by the dynamic pricing with enabling option for all customer classes. This has the effect of reducing or eliminating the potential from all of the other demand response options, in particular, DLC and Other DR.



Total Potential Peak Reduction from Demand Response in Missouri, 2019

	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	29	0.1%	29	0.1%	5	0.0%	0	0.0%	63	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	219	1.0%	219	1.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	29	0.1%	29	0.1%	5	0.0%	219	1.0%	282	1.3%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	30	0.1%	0	0.0%	6	0.0%	6	0.0%	43	0.2%
Automated/Direct Load Control	809	3.8%	29	0.1%	13	0.1%	0	0.0%	851	4.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	39	0.2%	638	3.0%	677	3.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	328	1.6%	328	1.6%
Total	840	4.0%	29	0.1%	58	0.3%	972	4.6%	1,899	9.0%
Achievable Participation										
Pricing with Technology	977	4.6%	93	0.4%	117	0.6%	69	0.3%	1,255	5.9%
Pricing without Technology	450	2.1%	6	0.0%	93	0.4%	126	0.6%	674	3.2%
Automated/Direct Load Control	207	1.0%	29	0.1%	5	0.0%	0	0.0%	241	1.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	39	0.2%	638	3.0%	677	3.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	134	0.6%	134	0.6%
Total	1,634	7.7%	127	0.6%	254	1.2%	966	4.6%	2,982	14.1%
Full Participation										
Pricing with Technology	2,285	10.8%	217	1.0%	341	1.6%	202	1.0%	3,045	14.4%
Pricing without Technology	38	0.2%	3	0.0%	64	0.3%	163	0.8%	268	1.3%
Automated/Direct Load Control	29	0.1%	29	0.1%	5	0.0%	0	0.0%	63	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	39	0.2%	638	3.0%	677	3.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	2,352	11.1%	249	1.2%	449	2.1%	1,002	4.7%	4,052	19.2%



Montana State Profile

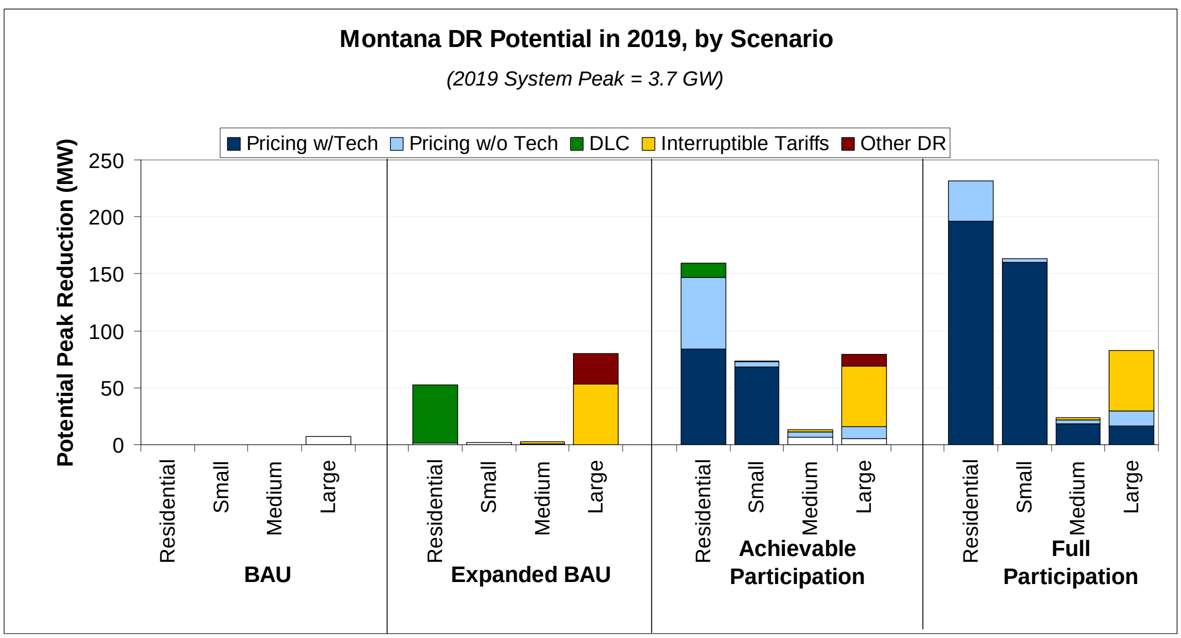
Key drivers of Montana's demand response potential estimate include: a higher than average share of peak demand (53%) in the Small C&I class and a moderate CAC saturation of 42%. Pricing with enabling technologies and DLC are cost effective for all customer classes in the state.

BAU: Montana's existing demand response comes solely from interruptible tariffs for the Large C&I class.

Expanded BAU: Growth in demand response impacts is driven through the addition of Other DR programs for the Large C&I class and DLC for the residential and Small C&I classes. Growth in the interruptible tariffs accounts for the remaining portion.

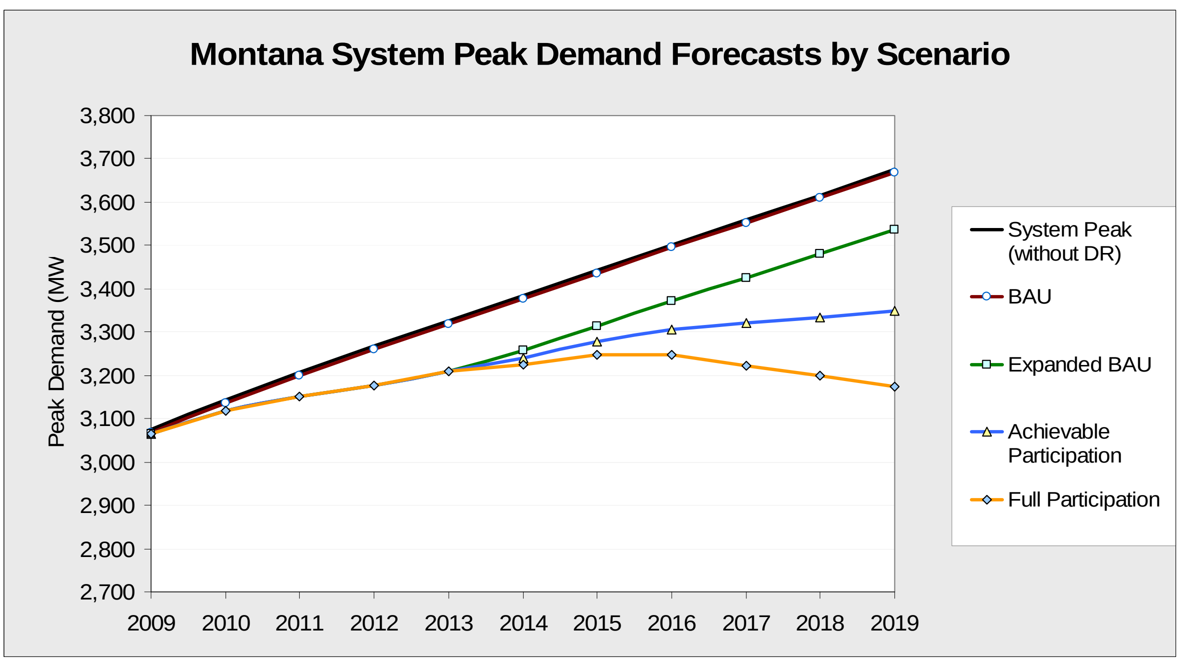
Achievable Participation: Dynamic pricing with enabling impacts accounts for over 50% of the increase in potential, with 20% of this increase due to the potential from Small C&I. Dynamic pricing without enabling technology contributes additional savings.

Full Participation: Similar to the Achievable Participation scenario, the impacts are dominated by the dynamic pricing options for all customer classes. Dynamic pricing with enabling represents almost 80% of the potential under this scenario. This has the effect of reducing or eliminating the potential from all of the other demand response options, in particular, DLC and Other DR.



Total Potential Peak Reduction from Demand Response in Montana, 2019

	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%	7	0.2%	7	0.2%
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%	7	0.2%	7	0.2%
Expanded 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%	0	0.0%	0	0.0%	2	0.1%
Automated/Direct Load Control	51	1.4%	2	0.1%	0	0.0%	0	0.0%	53	1.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	2	0.1%	53	1.4%	55	1.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	27	0.7%	27	0.7%
Total	52	1.4%	2	0.1%	3	0.1%	80	2.2%	137	3.7%
Achievable Participation										
Pricing with Technology	84	2.3%	69	1.9%	6	0.2%	6	0.2%	164	4.5%
Pricing without Technology	63	1.7%	5	0.1%	5	0.1%	10	0.3%	82	2.2%
Automated/Direct Load Control	13	0.3%	1	0.0%	0	0.0%	0	0.0%	14	0.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	2	0.1%	53	1.4%	55	1.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	11	0.3%	11	0.3%
Total	160	4.3%	74	2.0%	13	0.4%	80	2.2%	326	8.9%
Full Participation										
Pricing with Technology	196	5.3%	160	4.4%	18	0.5%	16	0.4%	391	10.7%
Pricing without Technology	35	1.0%	3	0.1%	3	0.1%	13	0.4%	55	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%	2	0.1%	53	1.4%	55	1.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	232	6.3%	163	4.4%	24	0.6%	83	2.2%	501	13.6%



Nebraska State Profile

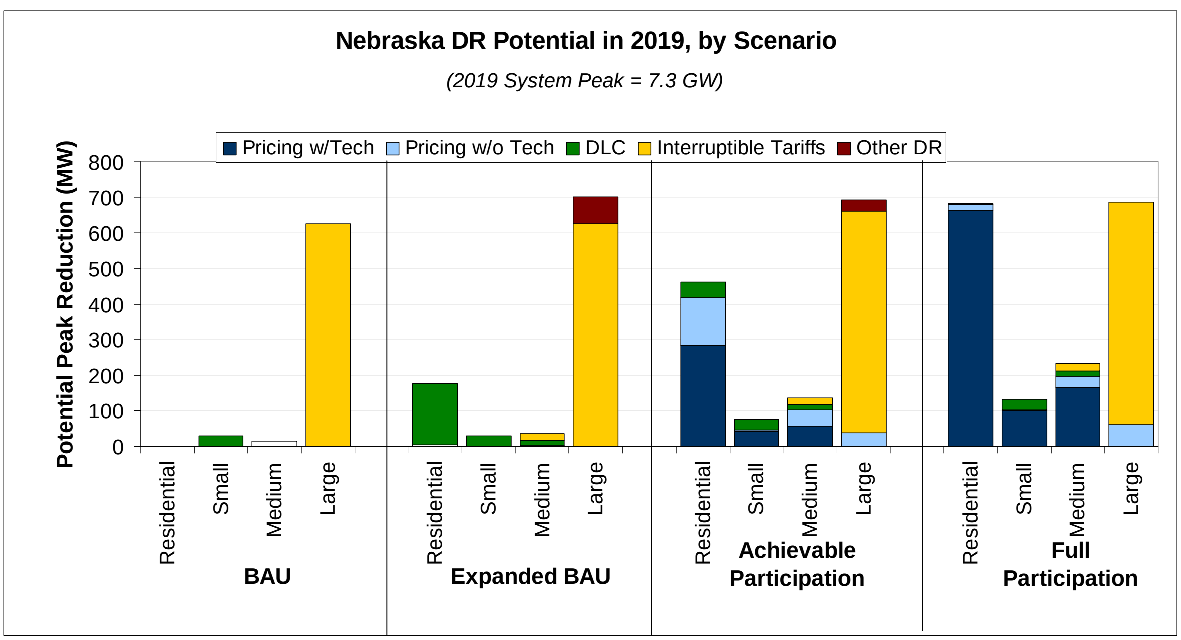
Key drivers of Nebraska's demand response potential estimate include: higher-than-average residential CAC saturation of 83%, a customer mix that has a moderate share of peak demand in the residential and Medium C&I classes (40% and 27%, respectively) and a substantial amount of existing demand response. Pricing with enabling technologies are cost effective for all customer classes, except for the Large C&I class. DLC is cost effective for all customer classes.

BAU: Nebraska's existing demand response comes predominantly from interruptible tariffs for Large C&I customers. The impacts from this option represent at least 30% of the total impacts under all scenarios. DLC for Small & Medium C&I accounts for the remaining portion of existing demand response.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of Other DR for the Large C&I class and DLC for the residential class.

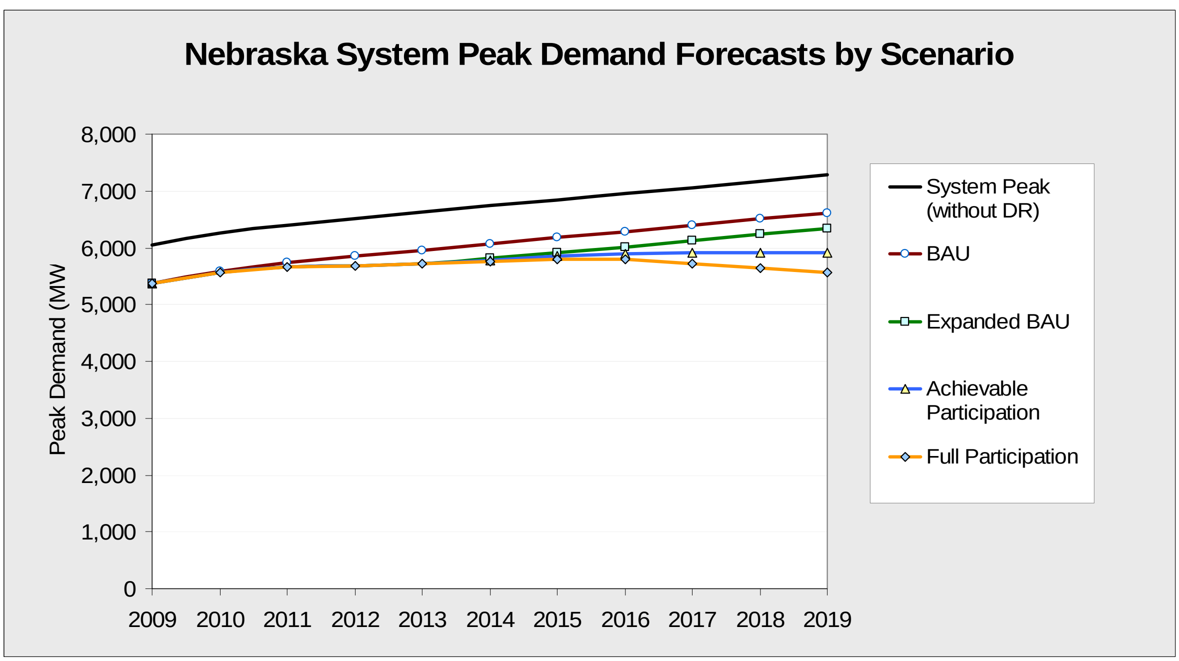
Achievable Participation: High CAC saturation in the residential sector drives a significant increase in demand response potential through dynamic pricing with enabling technologies. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing relative to Other DR. The movement of participants in Other DR to pricing also contributes to this effect.

Full Participation: Similar to the Achievable Participation scenario, high CAC saturation combined with a moderate share of load in the residential sector drives the increase in impacts. The impacts are dominated by pricing with enabling technologies for all customer classes except for the Large C&I customers. The pricing options have the effect of reducing or eliminating the potential from all of the other demand response options, in particular, DLC and Other DR.



Total Potential Peak Reduction from Demand Response in Nebraska, 2019

	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	1	0.0%	30	0.4%	15	0.2%	0	0.0%	46	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	625	8.6%	625	8.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	1	0.0%	30	0.4%	15	0.2%	625	8.6%	671	9.2%
Expanded 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%	1	0.0%	6	0.1%
Automated/Direct Load Control	172	2.4%	30	0.4%	15	0.2%	0	0.0%	217	3.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	19	0.3%	625	8.6%	645	8.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	75	1.0%	75	1.0%
Total	176	2.4%	30	0.4%	35	0.5%	701	9.6%	943	12.9%
Achievable Participation										
Pricing with Technology	284	3.9%	43	0.6%	57	0.8%	0	0.0%	384	5.3%
Pricing without Technology	135	1.9%	3	0.0%	46	0.6%	37	0.5%	220	3.0%
Automated/Direct Load Control	44	0.6%	30	0.4%	15	0.2%	0	0.0%	89	1.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	19	0.3%	625	8.6%	645	8.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	30	0.4%	30	0.4%
Total	462	6.3%	76	1.0%	137	1.9%	693	9.5%	1,367	18.8%
Full Participation										
Pricing with Technology	664	9.1%	100	1.4%	167	2.3%	0	0.0%	931	12.8%
Pricing without Technology	17	0.2%	2	0.0%	31	0.4%	61	0.8%	111	1.5%
Automated/Direct Load Control	1	0.0%	30	0.4%	15	0.2%	0	0.0%	46	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	19	0.3%	625	8.6%	645	8.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	681	9.3%	132	1.8%	232	3.2%	687	9.4%	1,732	23.8%



Nevada State Profile

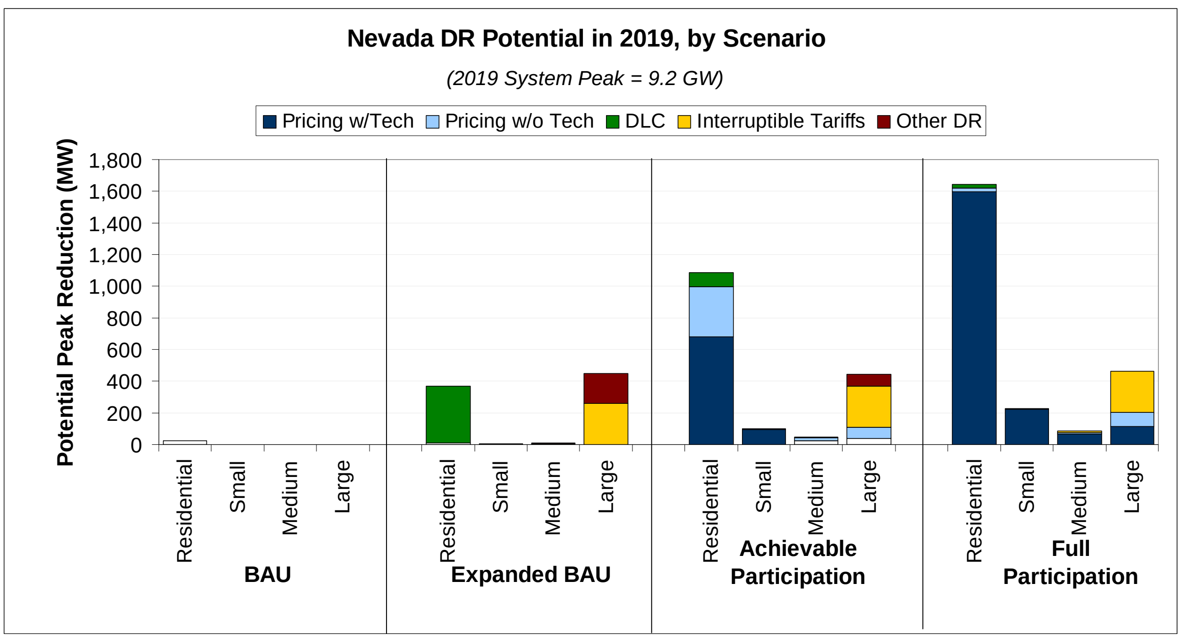
Key drivers of Nevada's demand response potential estimate include: a very high residential CAC saturation of 87%, and a customer mix that has an above average share of peak demand in the residential sector. The rate of AMI deployment is likely to be at a lower-than-average rate. Dynamic pricing with enabling technology and DLC are cost effective for all customer classes in the state. Control of residential air-conditioning load is the key driver of demand response potential in Nevada.

BAU: Nevada's existing demand response comes primarily from residential DLC programs. However, current participation levels are low and there exists scope for significant growth in potential.

Expanded BAU: Growth in demand response impacts is driven primarily through substantial expansion in residential DLC programs due to very high levels of CAC saturation in the state. Impacts also grow due to large C&I participation in 'Interruptible' and 'Other DR' programs.

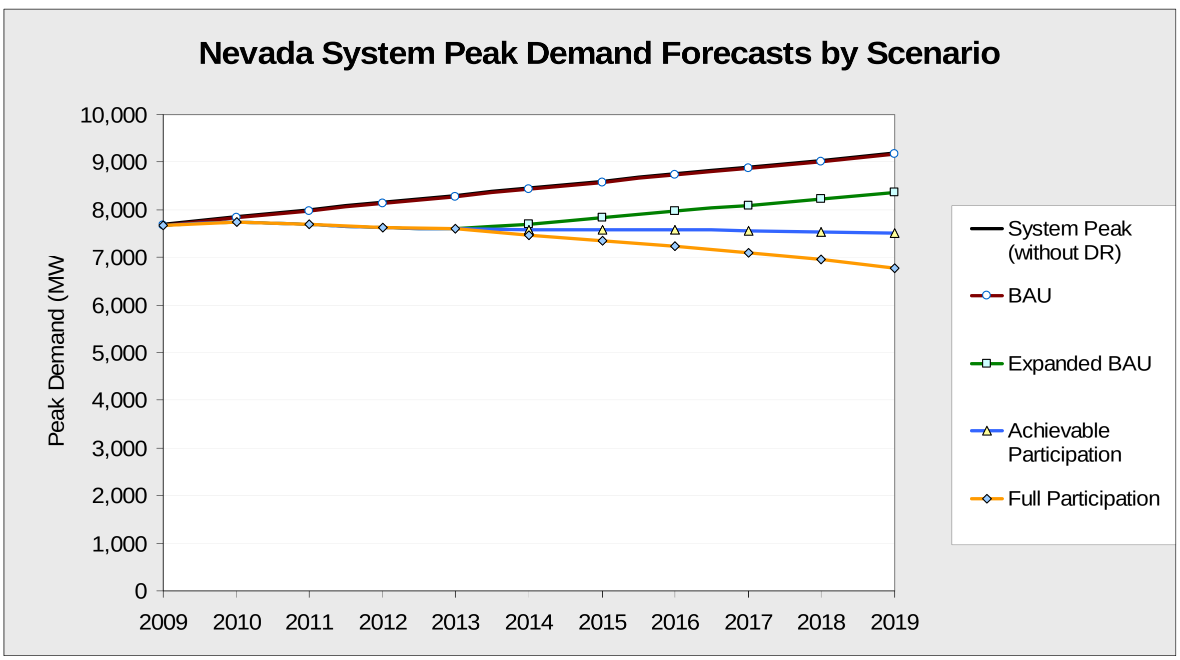
Achievable Participation: High CAC saturation in the residential sector drives a significant increase in demand response potential through pricing programs. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR.

Full Participation: Similar to the Achievable Participation scenario, high CAC saturation combined with a large share of residential load leads to substantial increase in impacts. The impacts are dominated by pricing with enabling technologies. Small and medium C&I potential from pricing programs increase. Large C&I potential is lower than in the Achievable scenario. This is because customers choose dynamic pricing over 'Other DR' programs, leading to a lower level of impacts caused by smaller per-customer impacts from pricing programs relative to 'Other DR'.



Total Potential Peak Reduction from Demand Response in Nevada, 2019

	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	22	0.2%	0	0.0%	0	0.0%	0	0.0%	22	0.2%
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%	0	0.0%	0	0.0%
Total	22	0.2%	0	0.0%	0	0.0%	0	0.0%	22	0.2%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	12	0.1%	0	0.0%	1	0.0%	2	0.0%	14	0.2%
Automated/Direct Load Control	356	3.9%	4	0.0%	2	0.0%	0	0.0%	363	3.9%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	7	0.1%	259	2.8%	267	2.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	186	2.0%	186	2.0%
Total	368	4.0%	4	0.0%	10	0.1%	447	4.9%	830	9.0%
Achievable Participation										
Pricing with Technology	682	7.4%	94	1.0%	23	0.2%	39	0.4%	838	9.1%
Pricing without Technology	313	3.4%	6	0.1%	17	0.2%	71	0.8%	407	4.4%
Automated/Direct Load Control	90	1.0%	1	0.0%	1	0.0%	0	0.0%	92	1.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	7	0.1%	259	2.8%	267	2.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	75	0.8%	75	0.8%
Total	1,085	11.8%	102	1.1%	49	0.5%	444	4.8%	1,679	18.3%
Full Participation										
Pricing with Technology	1,596	17.4%	221	2.4%	67	0.7%	113	1.2%	1,996	21.7%
Pricing without Technology	25	0.3%	4	0.0%	11	0.1%	91	1.0%	131	1.4%
Automated/Direct Load Control	22	0.2%	0	0.0%	0	0.0%	0	0.0%	22	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	7	0.1%	259	2.8%	267	2.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	1,642	17.9%	225	2.4%	85	0.9%	464	5.1%	2,416	26.3%



New Hampshire State Profile

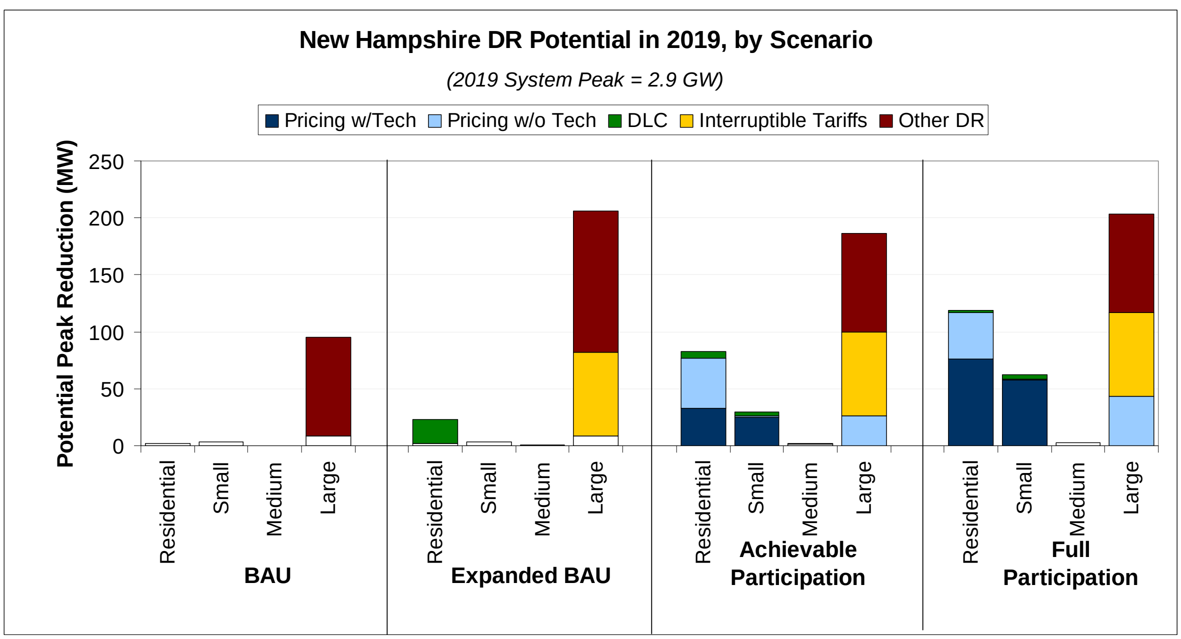
Key drivers of New Hampshire's demand response potential estimate include: a higher than average share of large C&I peak load (33%) and large base of existing load participation in the ISO-NE market. It has a lower than national average residential CAC saturation at 13%, thereby limiting load reduction potential from DLC programs. Dynamic pricing with enabling technology is cost-effective only for residential and small C&I customers. DLC is cost-effective for all customer classes.

BAU: New Hampshire's existing demand response is primarily derived from 'Other DR' programs, due to large C&I load participation in the ISO-NE market.

Expanded BAU: Growth in demand response impacts is driven primarily through the growth of Interruptible programs for large C&I customers. This is due to Rhode Island's high share of large C&I load, which allow for growth in Interruptible programs. Potential for growth in 'Other DR' programs is limited due to current high participation levels. Load reductions from residential DLC programs also grow in this scenario.

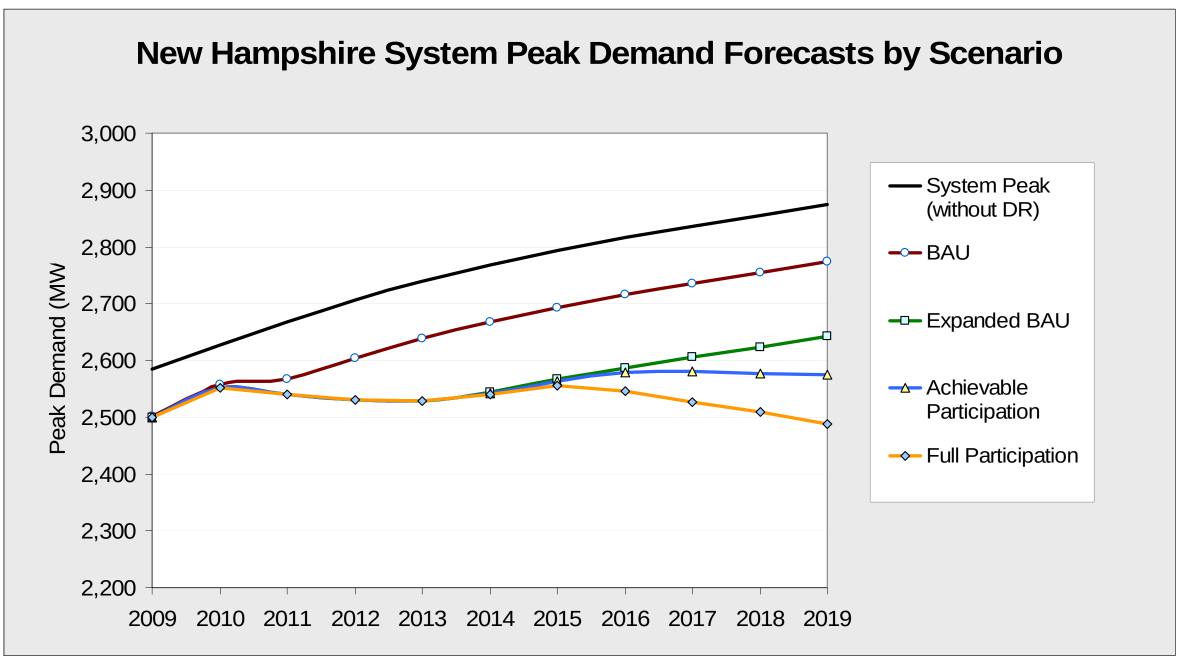
Achievable Participation: Growth in impacts in this scenario is driven by the potential derived through 'pricing without technology' option, primarily from residential and large C&I customers. Growth in impacts from 'pricing with technology' comes from both residential and small C&I customers. 'Other DR' program potential remains at current high levels.

Full Participation: Similar to the Achievable Participation scenario, increase in residential and small C&I customer participation in pricing options drive increase in impacts. Contribution from 'Other DR' and Interruptible programs continues to dominate for large C&I customers.



Total Potential Peak Reduction from Demand Response in New Hampshire, 2019

	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%	9	0.3%	9	0.3%
Automated/Direct Load Control	2	0.1%	3	0.1%	0	0.0%	0	0.0%	5	0.2%
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%	87	3.0%	87	3.0%
Total	2	0.1%	3	0.1%	0	0.0%	95	3.3%	101	3.5%
Expanded 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%	9	0.3%	11	0.4%
Automated/Direct Load Control	21	0.7%	3	0.1%	0	0.0%	0	0.0%	24	0.9%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	74	2.6%	74	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	124	4.3%	124	4.3%
Total	23	0.8%	3	0.1%	1	0.0%	206	7.2%	233	8.1%
Achievable Participation										
Pricing with Technology	32	1.1%	25	0.9%	0	0.0%	0	0.0%	57	2.0%
Pricing without Technology	45	1.6%	2	0.1%	2	0.1%	26	0.9%	74	2.6%
Automated/Direct Load Control	5	0.2%	3	0.1%	0	0.0%	0	0.0%	9	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	74	2.6%	74	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	87	3.0%	87	3.0%
Total	82	2.9%	30	1.0%	2	0.1%	186	6.5%	300	10.4%
Full Participation										
Pricing with Technology	76	2.6%	58	2.0%	0	0.0%	0	0.0%	134	4.7%
Pricing without Technology	41	1.4%	1	0.0%	3	0.1%	43	1.5%	88	3.0%
Automated/Direct Load Control	2	0.1%	3	0.1%	0	0.0%	0	0.0%	5	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	74	2.6%	74	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	87	3.0%	87	3.0%
Total	119	4.1%	62	2.2%	3	0.1%	203	7.1%	387	13.5%



New Jersey State Profile

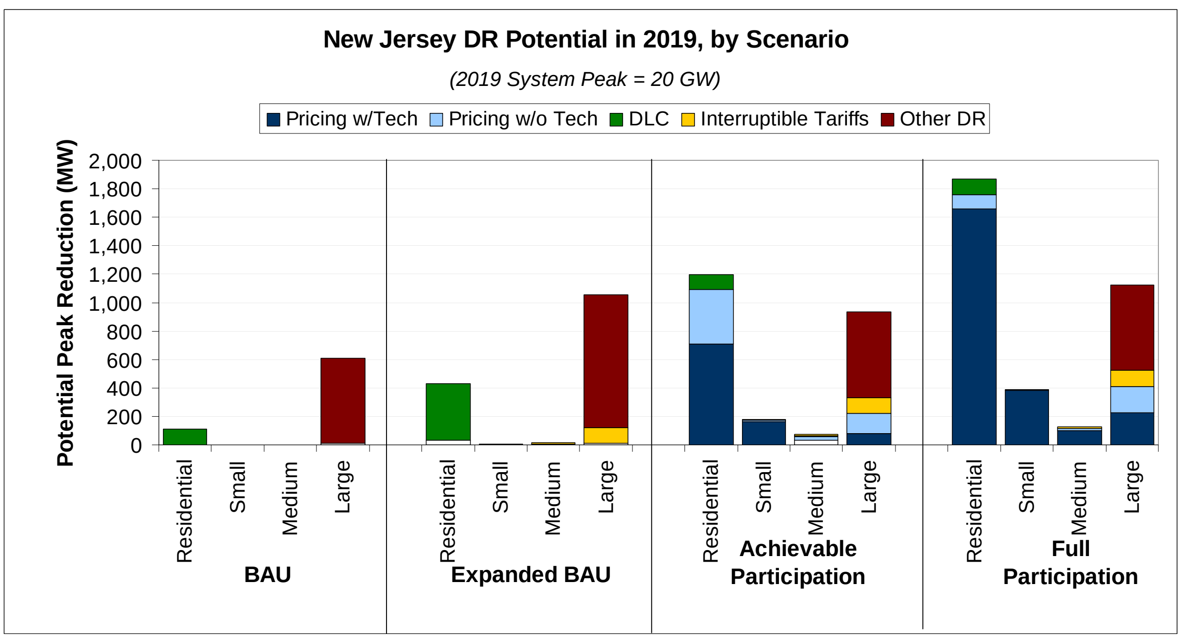
Key drivers of New Jersey's demand response potential estimate include: high levels of large C&I load participation in the PJM market, a customer mix with almost 48% of the load from residential customers and 26% of the load from large C&I customers, and the potential to deploy AMI at a faster-than-average rate. CAC saturation is at a moderate level of 55%. 'Pricing with technology' is cost-effective for all customer classes. DLC is also cost effective for all customer classes in the state.

BAU: New Jersey's existing demand response comes primarily from large C&I load participation in the PJM market. The remaining comes from residential DLC programs.

Expanded BAU: Increase in impacts for this scenario is primarily due to expansion in residential DLC programs and Interruptible programs for large C&I customers, driven by large share in load for these two customer classes. Also, the potential associated with large C&I participation in 'Other DR' programs grows.

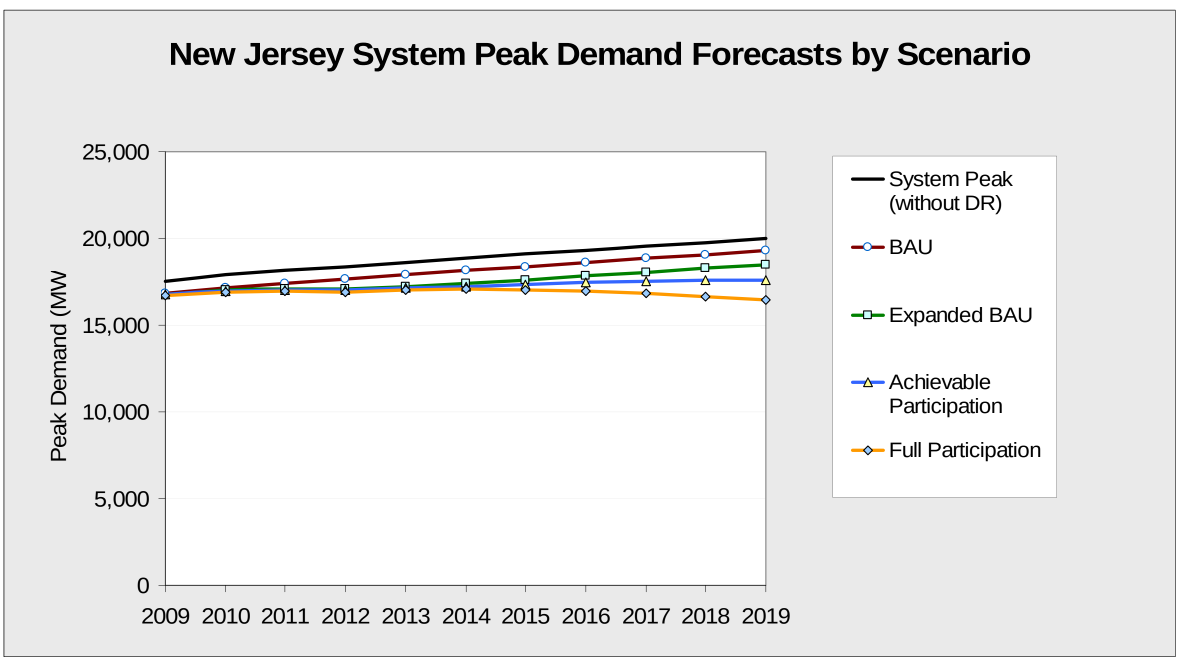
Achievable Participation: A high share of residential load in the total drives a substantial increase in impacts for residential customers through participation in pricing programs. In this scenario, impacts from residential DLC go back to current levels as customers choose pricing over DLC. For C&I customers, additional load reduction is obtained through pricing programs.

Full Participation: Similar to the Achievable Participation scenario, high impacts in this scenario are largely driven by a high level of residential load participating in pricing programs. Also, load reduction from C&I customers participating in pricing programs increases. Large C&I load participation in 'Other DR' programs continues at current high participation levels.



Total Potential Peak Reduction from Demand Response in New Jersey, 2019

	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	108	0.5%	0	0.0%	0	0.0%	0	0.0%	108	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	8	0.0%	8	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	601	3.0%	601	3.0%
Total	108	0.5%	0	0.0%	0	0.0%	609	3.0%	717	3.6%
Expanded 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%	1	0.0%	2	0.0%	9	0.0%	41	0.2%
Automated/Direct Load Control	401	2.0%	7	0.0%	3	0.0%	0	0.0%	411	2.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	11	0.1%	112	0.6%	123	0.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	933	4.7%	933	4.7%
Total	430	2.2%	8	0.0%	17	0.1%	1,054	5.3%	1,508	7.5%
Achievable Participation										
Pricing with Technology	709	3.5%	164	0.8%	34	0.2%	78	0.4%	985	4.9%
Pricing without Technology	381	1.9%	10	0.1%	26	0.1%	142	0.7%	559	2.8%
Automated/Direct Load Control	108	0.5%	2	0.0%	1	0.0%	0	0.0%	111	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	11	0.1%	112	0.6%	123	0.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	601	3.0%	601	3.0%
Total	1,198	6.0%	176	0.9%	73	0.4%	932	4.7%	2,379	11.9%
Full Participation										
Pricing with Technology	1,659	8.3%	384	1.9%	99	0.5%	227	1.1%	2,369	11.9%
Pricing without Technology	100	0.5%	6	0.0%	17	0.1%	183	0.9%	307	1.5%
Automated/Direct Load Control	108	0.5%	0	0.0%	0	0.0%	0	0.0%	108	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	11	0.1%	112	0.6%	123	0.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	601	3.0%	601	3.0%
Total	1,867	9.3%	390	2.0%	127	0.6%	1,124	5.6%	3,508	17.5%



New Mexico State Profile

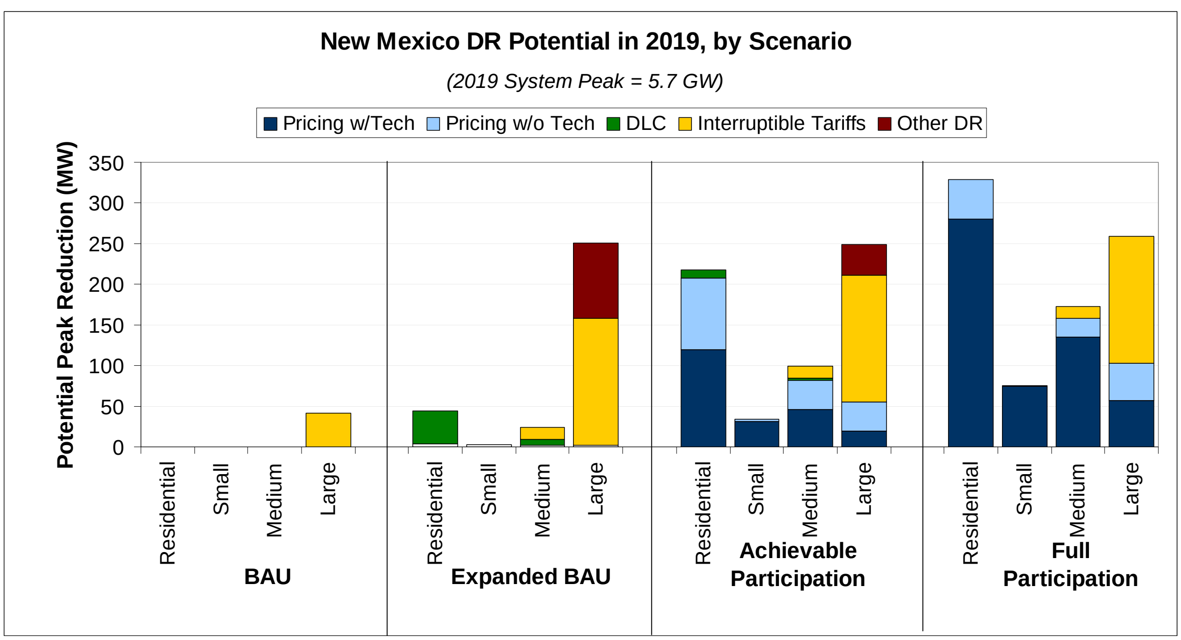
Key drivers of New Mexico's demand response potential estimate include: a customer mix that has an above average share of peak demand for medium C&I customers (50%), and a large share of residential (86%) in the total number of customer accounts. New Mexico has a low level of existing demand response with significant potential for growth across all rate classes. Dynamic pricing with enabling technology is cost-effective for all customer classes. Also, DLC is cost effective for all customer classes.

BAU: The state's existing demand response comes primarily from large C&I participation in Interruptible programs.

Expanded BAU: Growth in demand response potential under this scenario is derived through residential participation in DLC programs, and large C&I load participation in Interruptible and 'Other DR' programs. The potential for expansion is significant, given the low level of existing demand response.

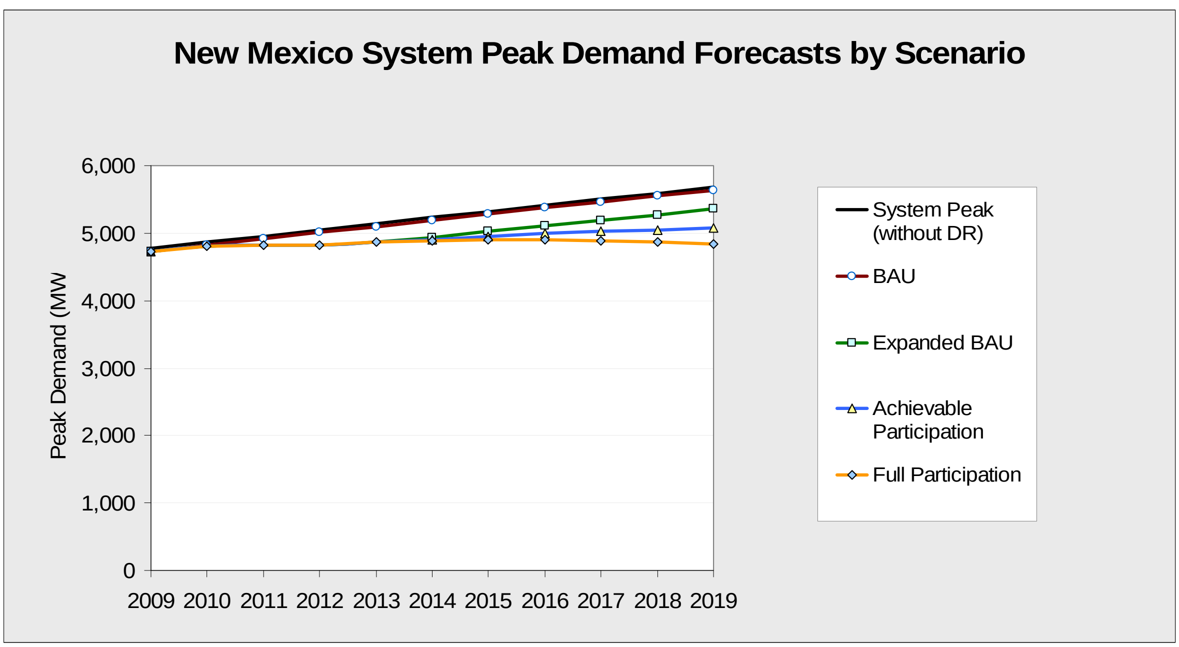
Achievable Participation: The potential increase in this scenario is primarily realized through residential pricing programs. The increase in impacts from the residential class is significant, given its high share in the total account population. Load reduction potential from C&I customers grow due to increased participation in pricing programs. Some of the large C&I customers participating in 'Other DR' programs choose to participate in the pricing programs.

Full Participation: Similar to the Achievable Participation scenario, a very high share of residential accounts in the total number of customer accounts drive increase in impacts from residential pricing programs. For the small and medium C&I classes, impacts are dominated by pricing with enabling technology. However, for the large C&I customers, impacts are dominated by participation in Interruptible programs.



Total Potential Peak Reduction from Demand Response in New Mexico, 2019

	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%	41	0.7%	41	0.7%
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%	0	0.0%	41	0.7%	41	0.7%
Expanded 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%	2	0.0%	1	0.0%	7	0.1%
Automated/Direct Load Control	40	0.7%	2	0.0%	7	0.1%	0	0.0%	50	0.9%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	15	0.3%	157	2.8%	172	3.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	93	1.6%	93	1.6%
Total	44	0.8%	3	0.0%	24	0.4%	251	4.4%	322	5.7%
Achievable Participation										
Pricing with Technology	120	2.1%	32	0.6%	46	0.8%	19	0.3%	217	3.8%
Pricing without Technology	88	1.6%	2	0.0%	35	0.6%	35	0.6%	161	2.8%
Automated/Direct Load Control	10	0.2%	1	0.0%	3	0.0%	0	0.0%	14	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	15	0.3%	157	2.8%	172	3.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	38	0.7%	38	0.7%
Total	218	3.8%	34	0.6%	100	1.8%	249	4.4%	601	10.6%
Full Participation										
Pricing with Technology	280	4.9%	74	1.3%	135	2.4%	57	1.0%	546	9.6%
Pricing without Technology	49	0.9%	1	0.0%	23	0.4%	46	0.8%	119	2.1%
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%	15	0.3%	157	2.8%	172	3.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	329	5.8%	76	1.3%	173	3.0%	259	4.6%	837	14.7%



New York State Profile

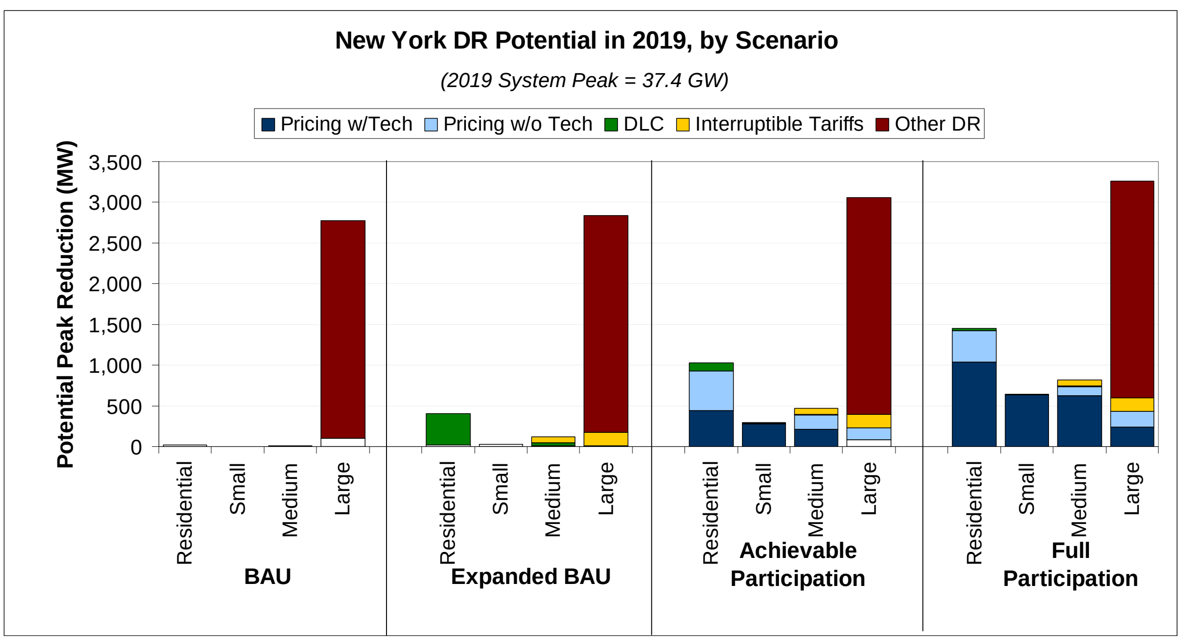
Key drivers of New York's demand response potential estimate include: a very high level of load participating in NYISO demand response Programs, a customer mix with almost 40% of the load from residential customers, and the potential to deploy AMI at a faster-than-average rate. New York has a lower than average residential CAC saturation at 16.7%. 'Pricing with technology' and DLC are cost effective for all customer classes in the state.

BAU: New York's existing demand response comes primarily from large C&I load participation in the NYISO market. This dominates the potential estimated across all scenarios.

Expanded BAU: Since current participation levels in NYISO demand response programs are substantially high, there is not much scope for growth in this program. Increase in impacts for this scenario is primarily derived from an expansion in residential DLC programs and Interruptible programs for large C&I customers.

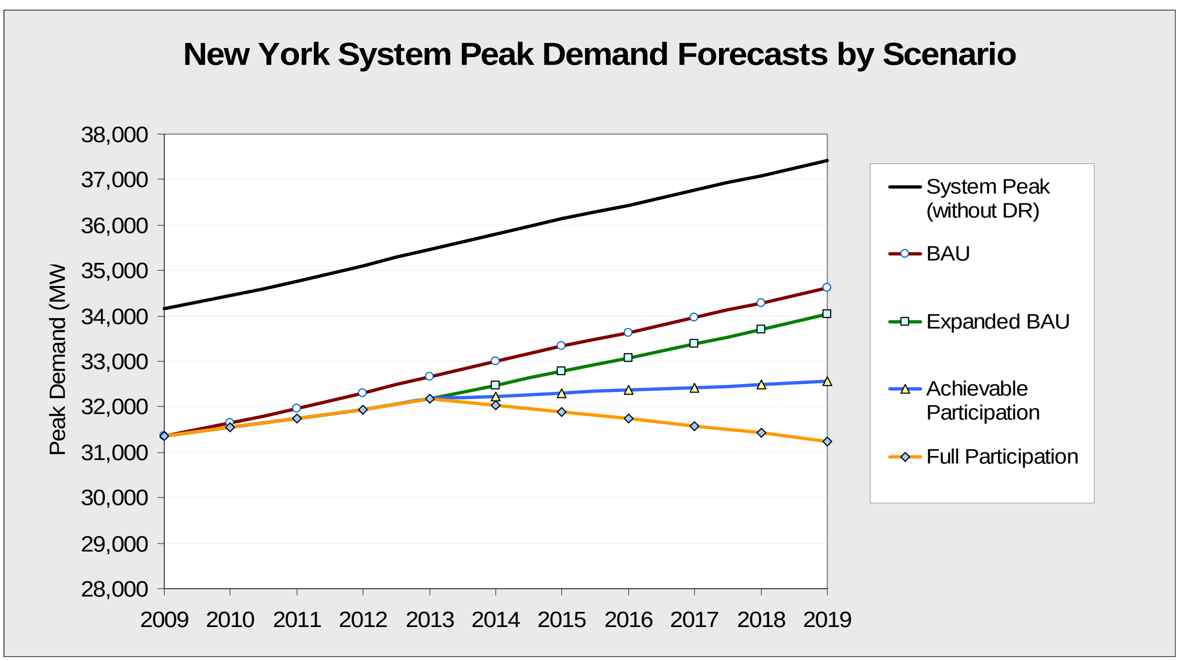
Achievable Participation: A moderately high share of residential load in the total drives a significant increase in demand response potential through pricing programs. For the C&I sector too, additional load reduction is derived through participation in pricing programs. However, impacts from 'Other DR' programs continue to dominate due to persistently high large C&I participation levels in NYISO market.

Full Participation: Higher participation of residential and C&I load (primarily small and medium C&I) in pricing programs drive potential increase in this scenario, as compared to the 'Achievable Participation' scenario. However, the impacts are dominated by high level of large C&I participation in NYISO programs.



Total Potential Peak Reduction from Demand Response in New York, 2019

	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	21	0.1%	0	0.0%	10	0.0%	0	0.0%	31	0.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	104	0.3%	104	0.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	2,668	7.1%	2,668	7.1%
Total	21	0.1%	0	0.0%	10	0.0%	2,772	7.4%	2,803	7.5%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	21	0.1%	1	0.0%	11	0.0%	7	0.0%	39	0.1%
Automated/Direct Load Control	387	1.0%	25	0.1%	35	0.1%	0	0.0%	447	1.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	71	0.2%	164	0.4%	235	0.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	2,668	7.1%	2,668	7.1%
Total	408	1.1%	25	0.1%	117	0.3%	2,839	7.6%	3,389	9.1%
Achievable Participation										
Pricing with Technology	443	1.2%	272	0.7%	215	0.6%	82	0.2%	1,011	2.7%
Pricing without Technology	485	1.3%	17	0.0%	168	0.4%	149	0.4%	818	2.2%
Automated/Direct Load Control	99	0.3%	6	0.0%	14	0.0%	0	0.0%	120	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	71	0.2%	164	0.4%	235	0.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	2,668	7.1%	2,668	7.1%
Total	1,026	2.7%	295	0.8%	467	1.2%	3,063	8.2%	4,852	13.0%
Full Participation										
Pricing with Technology	1,035	2.8%	636	1.7%	627	1.7%	240	0.6%	2,538	6.8%
Pricing without Technology	392	1.0%	10	0.0%	111	0.3%	193	0.5%	706	1.9%
Automated/Direct Load Control	21	0.1%	0	0.0%	10	0.0%	0	0.0%	31	0.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	71	0.2%	164	0.4%	235	0.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	2,668	7.1%	2,668	7.1%
Total	1,448	3.9%	647	1.7%	819	2.2%	3,265	8.7%	6,179	16.5%



North Carolina State Profile

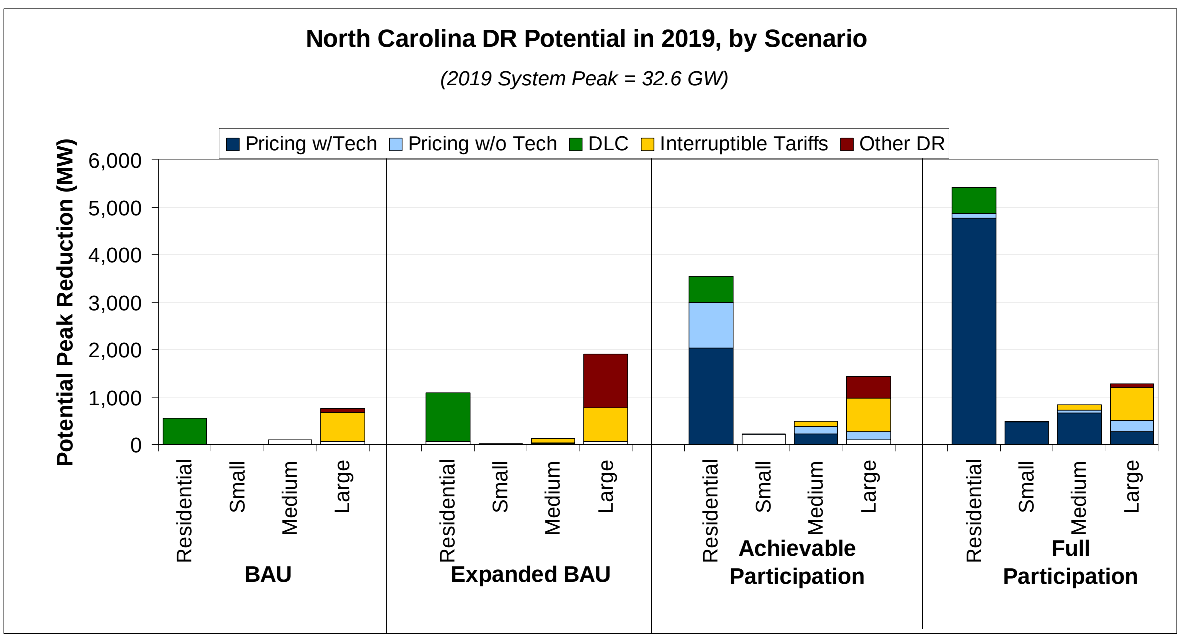
Key drivers of North Carolina's demand response potential estimate include: above average residential CAC saturation of 84%, an above average share of peak demand (51%) in the residential class, and a moderate amount of existing demand response. Pricing with enabling technologies and DLC are cost effective for all customer classes in the state.

BAU: North Carolina's existing demand response comes primarily from residential DLC and interruptible tariffs for the Medium and Large C&I classes. The state is also one of the few states with a significant portion of price induced demand response. Other DR for the Large C&I class accounts for the remaining portion.

Expanded BAU: Growth in demand response impacts is driven through the growth of Other DR programs for the Large C&I class and DLC for the residential class. Growth in dynamic pricing and existing interruptible tariffs account for the remaining portion.

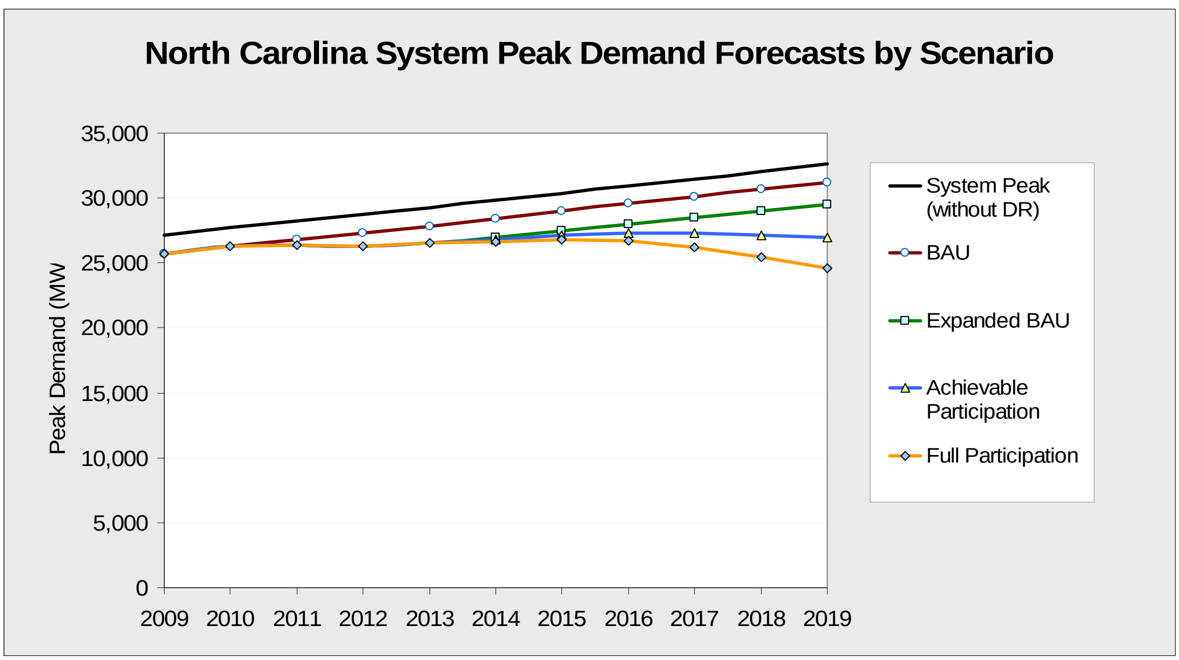
Achievable Participation: Dynamic pricing with enabling impacts accounts for almost 50% of the increase in potential. Dynamic pricing without enabling technology contributes additional savings. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing relative to Other DR. The movement of participants in Other DR to pricing also contributes to this effect.

Full Participation: Similar to the Achievable Participation scenario, the impacts are dominated by dynamic pricing with enabling technologies for all customer classes. This option represents over 75% of the potential in this scenario. The lower potential for Large C&I than in the other scenarios is due to participation changes within the different demand response options.



Total Potential Peak Reduction from Demand Response in North Carolina, 2019

	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%	62	0.2%	62	0.2%
Automated/Direct Load Control	547	1.7%	0	0.0%	0	0.0%	0	0.0%	547	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	93	0.3%	608	1.9%	701	2.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	79	0.2%	79	0.2%
Total	547	1.7%	0	0.0%	93	0.3%	749	2.3%	1,388	4.3%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	67	0.2%	1	0.0%	11	0.0%	62	0.2%	140	0.4%
Automated/Direct Load Control	1,022	3.1%	14	0.0%	12	0.0%	0	0.0%	1,048	3.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	108	0.3%	707	2.2%	814	2.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,134	3.5%	1,134	3.5%
Total	1,089	3.3%	15	0.0%	132	0.4%	1,902	5.8%	3,137	9.6%
Achievable Participation										
Pricing with Technology	2,038	6.2%	203	0.6%	226	0.7%	94	0.3%	2,561	7.9%
Pricing without Technology	952	2.9%	11	0.0%	150	0.5%	171	0.5%	1,285	3.9%
Automated/Direct Load Control	547	1.7%	4	0.0%	5	0.0%	0	0.0%	555	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	108	0.3%	707	2.2%	814	2.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	464	1.4%	465	1.4%
Total	3,537	10.8%	218	0.7%	488	1.5%	1,436	4.4%	5,680	17.4%
Full Participation										
Pricing with Technology	4,768	14.6%	476	1.5%	659	2.0%	275	0.8%	6,178	18.9%
Pricing without Technology	98	0.3%	6	0.0%	73	0.2%	222	0.7%	399	1.2%
Automated/Direct Load Control	547	1.7%	0	0.0%	0	0.0%	0	0.0%	547	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	108	0.3%	707	2.2%	814	2.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	79	0.2%	79	0.2%
Total	5,413	16.6%	482	1.5%	840	2.6%	1,283	3.9%	8,017	24.6%



North Dakota State Profile

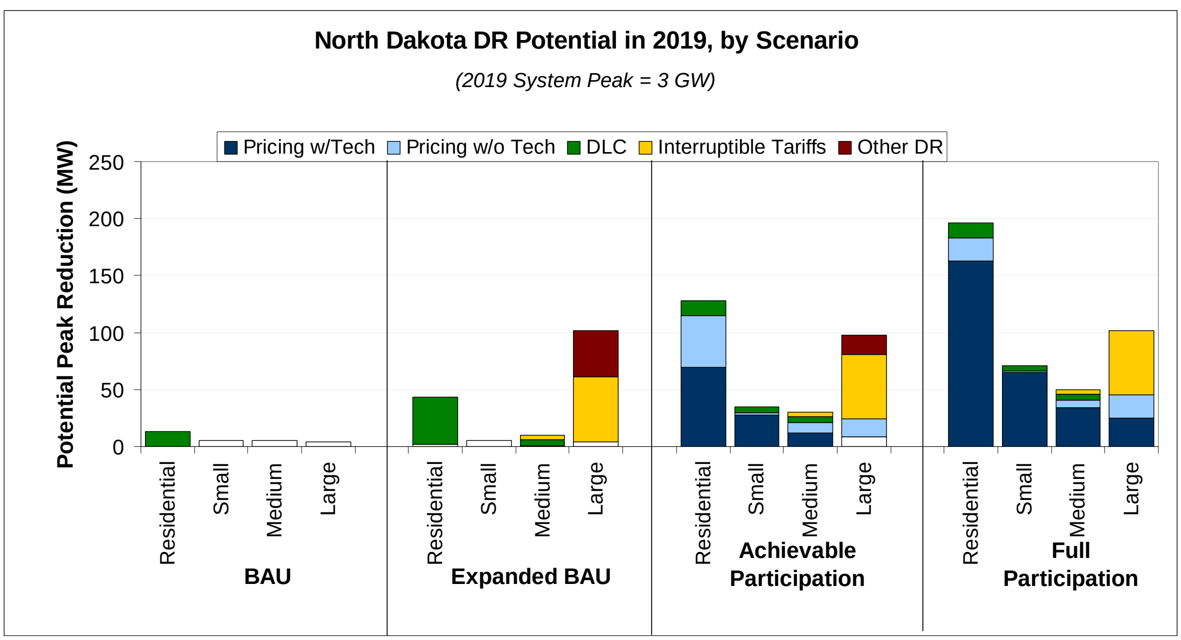
Key drivers of North Dakota's demand response potential estimate include: an above average share of peak demand (27%) in the Small C&I class and a moderate CAC saturation of 51%. Pricing with enabling technologies and DLC are cost effective for all customer classes in the state.

BAU: North Dakota's existing demand response comes primarily from DLC programs for all classes, except for the Large C&I class. Price induced demand response for the Large C&I class accounts for the remaining portion.

Expanded BAU: Growth in demand response impacts is driven through the addition of Other DR programs and interruptible tariffs. Growth in the existing residential DLC programs accounts for the remaining portion.

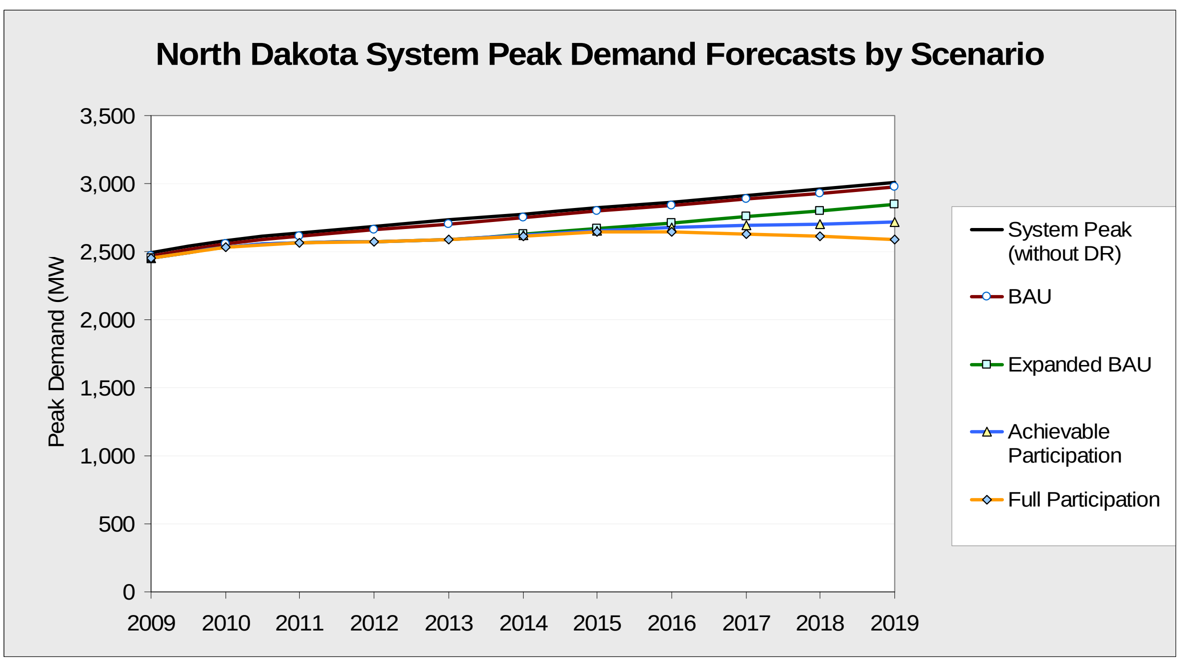
Achievable Participation: Dynamic pricing with enabling impacts accounts for approximately 40% of the increase in potential, with 10% of this increase due to the potential from Small C&I. Dynamic pricing without enabling technology contributes additional savings. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing relative to Other DR. The movement of participants in Other DR to pricing also contributes to this effect.

Full Participation: Similar to the Achievable Participation scenario, the impacts are dominated by dynamic pricing with enabling technologies for all customer classes. This option represents almost 70% of the potential in this scenario. The pricing options have the effect of reducing or eliminating the potential from all of the other demand response options, in particular, Other DR for the Large C&I class.



Total Potential Peak Reduction from Demand Response in North Dakota, 2019

	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%	4	0.1%	4	0.1%
Automated/Direct Load Control	13	0.4%	5	0.2%	5	0.2%	0	0.0%	23	0.8%
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%	0	0.0%	0	0.0%
Total	13	0.4%	5	0.2%	5	0.2%	4	0.1%	28	0.9%
Expanded 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%	4	0.1%	7	0.2%
Automated/Direct Load Control	42	1.4%	5	0.2%	5	0.2%	0	0.0%	52	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.1%	57	1.9%	61	2.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	41	1.4%	41	1.4%
Total	43	1.4%	5	0.2%	10	0.3%	102	3.4%	160	5.3%
Achievable Participation										
Pricing with Technology	70	2.3%	28	0.9%	12	0.4%	9	0.3%	118	3.9%
Pricing without Technology	45	1.5%	2	0.1%	9	0.3%	16	0.5%	72	2.4%
Automated/Direct Load Control	13	0.4%	5	0.2%	5	0.2%	0	0.0%	23	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.1%	57	1.9%	61	2.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	17	0.6%	17	0.6%
Total	128	4.2%	35	1.2%	30	1.0%	97	3.2%	290	9.7%
Full Participation										
Pricing with Technology	163	5.4%	65	2.2%	34	1.1%	25	0.8%	287	9.6%
Pricing without Technology	20	0.7%	1	0.0%	6	0.2%	20	0.7%	48	1.6%
Automated/Direct Load Control	13	0.4%	5	0.2%	5	0.2%	0	0.0%	23	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.1%	57	1.9%	61	2.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	196	6.5%	71	2.4%	50	1.7%	102	3.4%	419	13.9%



Ohio State Profile

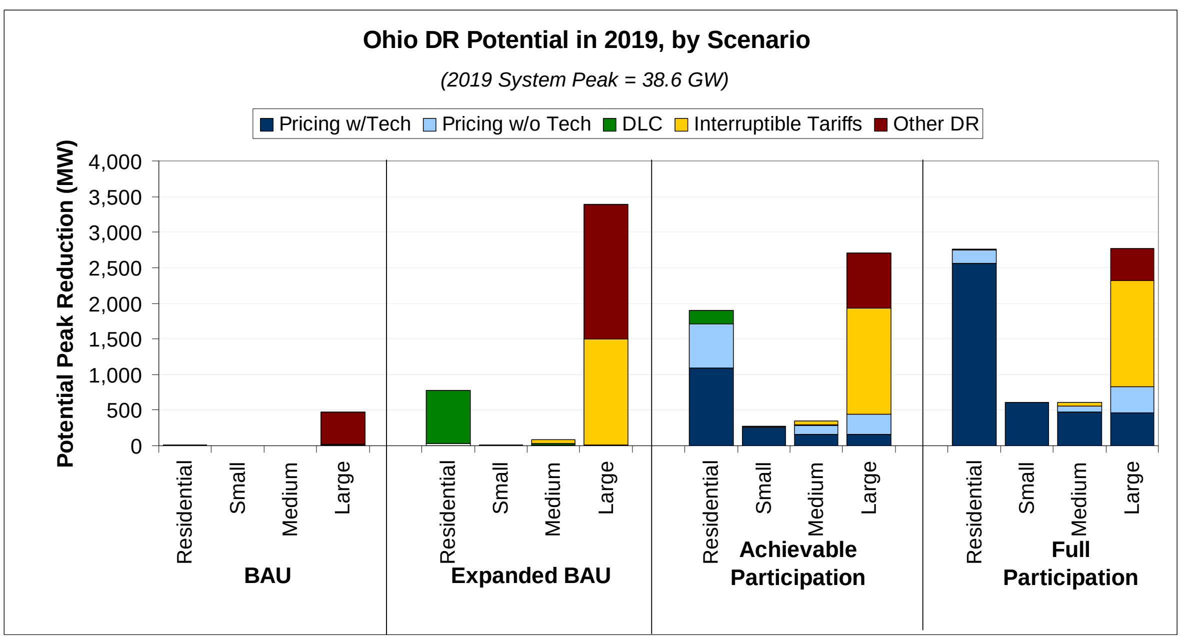
Key drivers of Ohio's demand response potential estimate include: a relatively high number of residential accounts at 5 million, higher-than-average residential CAC saturation of 63%, and a customer mix that has an above average share of peak demand in the large C&I class at 30%. AMI deployment is likely to take place at a lower-than-average rate for the state. 'Pricing with technology' is cost-effective for all customer classes. DLC is cost-effective for all customer classes.

BAU: Ohio's existing demand response comes primarily from large C&I load participation in 'Other DR' programs. Current demand response from DLC and 'Interruptible' programs is low.

Expanded BAU: Growth in demand response impacts is driven primarily through participation in 'Interruptible' and 'Other DR' programs for large C&I customers. Also, there is a significant growth in impacts coming from residential DLC programs. This is due to Ohio's high level of residential accounts with a higher than average CAC saturation.

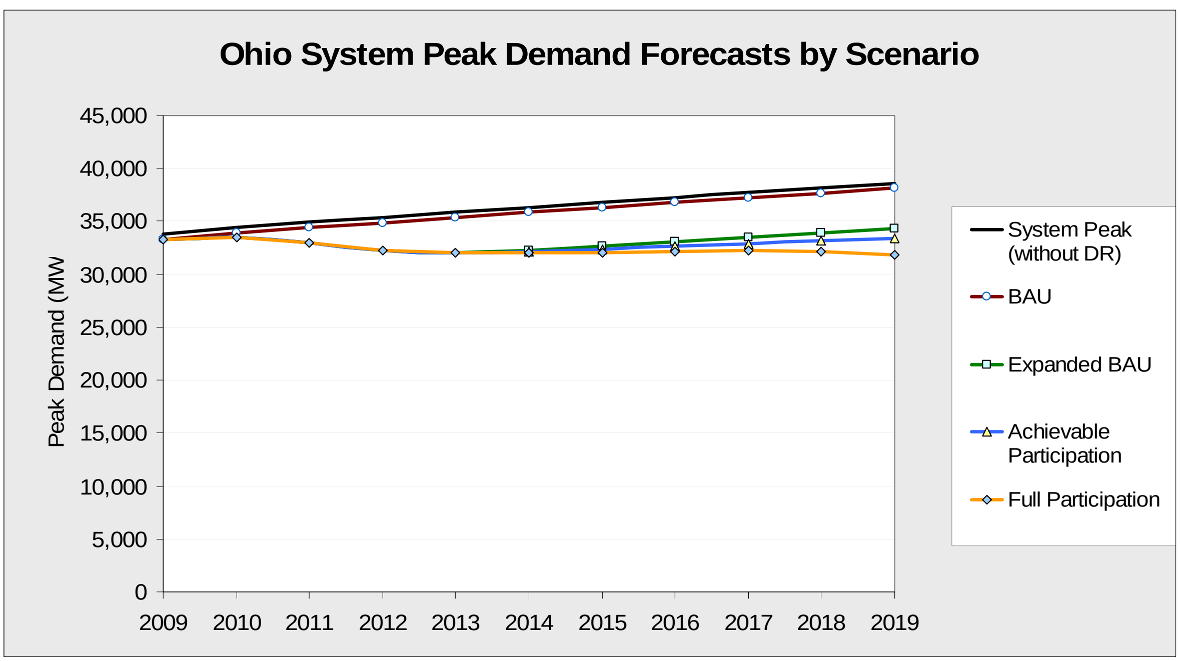
Achievable Participation: High residential customer participation in dynamic pricing options drives the increase in demand response potential for this scenario. C&I customers participate in 'pricing with technology' that also leads to an increase in impacts. Large C&I demand response potential is lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing programs relative to 'Other DR' program impacts.

Full Participation: Similar to the Achievable Participation scenario, increase in potential is driven by a high level of residential and C&I customer participation in 'pricing with technology' option.



Total Potential Peak Reduction from Demand Response in Ohio, 2019

	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	0.0%	13	0.0%
Automated/Direct Load Control	10	0.0%	0	0.0%	2	0.0%	0	0.0%	11	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	8	0.0%	8	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	450	1.2%	451	1.2%
Total	10	0.0%	0	0.0%	2	0.0%	471	1.2%	483	1.2%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	32	0.1%	1	0.0%	7	0.0%	13	0.0%	54	0.1%
Automated/Direct Load Control	747	1.9%	11	0.0%	21	0.1%	0	0.0%	779	2.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	53	0.1%	1,492	3.9%	1,546	4.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,891	4.9%	1,891	4.9%
Total	779	2.0%	12	0.0%	83	0.2%	3,396	8.8%	4,270	11.1%
Achievable Participation										
Pricing with Technology	1,095	2.8%	258	0.7%	160	0.4%	156	0.4%	1,670	4.3%
Pricing without Technology	615	1.6%	16	0.0%	128	0.3%	284	0.7%	1,043	2.7%
Automated/Direct Load Control	190	0.5%	3	0.0%	9	0.0%	0	0.0%	202	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	53	0.1%	1,492	3.9%	1,546	4.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	772	2.0%	772	2.0%
Total	1,900	4.9%	277	0.7%	350	0.9%	2,704	7.0%	5,231	13.5%
Full Participation										
Pricing with Technology	2,562	6.6%	605	1.6%	468	1.2%	457	1.2%	4,091	10.6%
Pricing without Technology	190	0.5%	9	0.0%	87	0.2%	369	1.0%	655	1.7%
Automated/Direct Load Control	10	0.0%	0	0.0%	2	0.0%	0	0.0%	11	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	53	0.1%	1,492	3.9%	1,546	4.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	450	1.2%	451	1.2%
Total	2,761	7.1%	614	1.6%	610	1.6%	2,768	7.2%	6,753	17.5%



Oklahoma State Profile

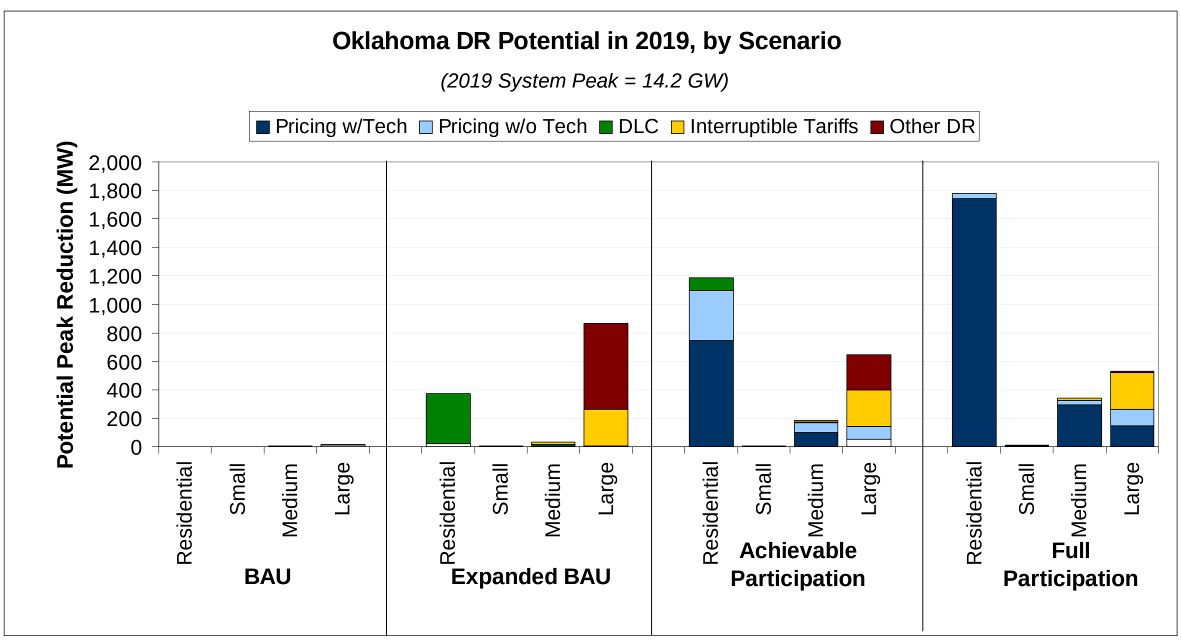
Key drivers of Oklahoma's demand response potential estimate include: higher-than-average residential CAC saturation of 84%, and a customer mix that has an above average share of peak demand in the residential class (50%). The level of existing demand response is low. 'Pricing with technology' is cost-effective for all customers, except for the small C&I class. DLC is cost effective for all customer classes in the state.

BAU: Oklahoma's existing demand response comes primarily from load enrolled in 'Interruptible' and 'Other DR' programs for C&I customers.

Expanded BAU: The residential sector has a high potential for growth due to high CAC saturation level, coupled with a low base of existing programs. In this scenario, growth in demand response impacts is driven primarily through the addition of residential DLC programs and through increase in large C&I load participation in 'Interruptible' and 'Other DR' programs.

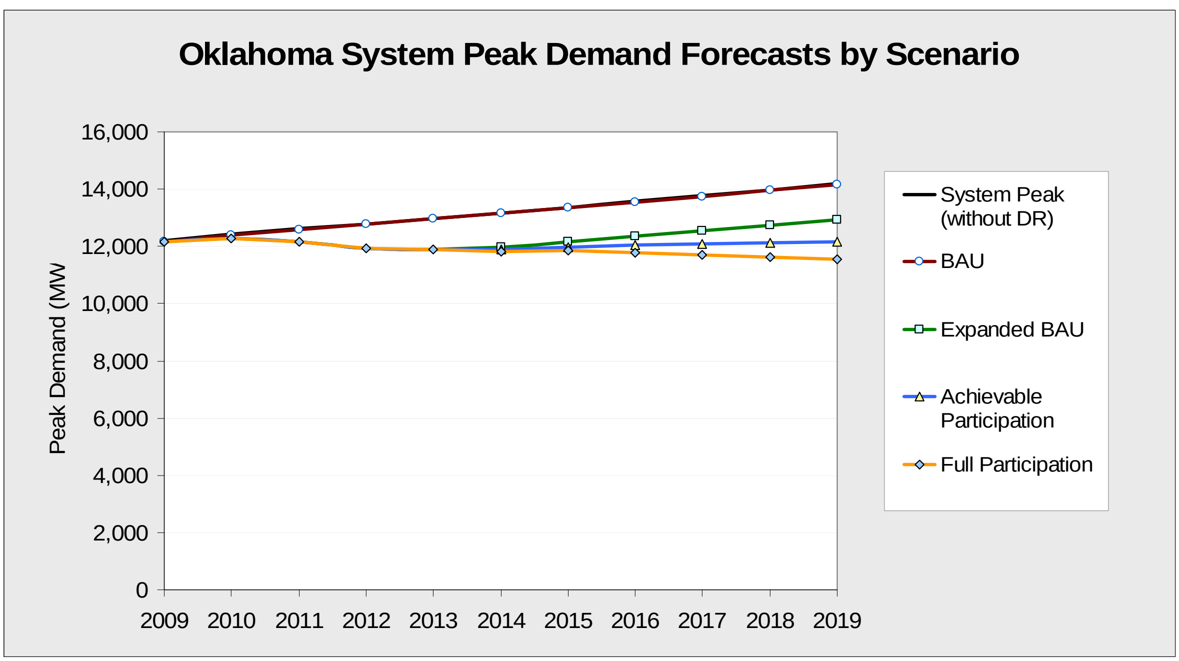
Achievable Participation: High CAC saturation in the residential sector drives a significant increase in demand response potential through 'pricing with technology' option. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing programs relative to Other DR.

Full Participation: Similar to the Achievable Participation scenario, high CAC saturation combined with a large share of load in the residential sector drives increase in impacts. Increase in impacts is dominated by 'pricing with technology', which is cost-effective for all customer classes. Large C&I potential decreases, due to smaller per-customer impacts from pricing programs relative to Other DR.



Total Potential Peak Reduction from Demand Response in Oklahoma, 2019

	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%	1	0.0%	0	0.0%	0	0.0%	1	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	3	0.0%	8	0.1%	11	0.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	10	0.1%	10	0.1%
Total	0	0.0%	1	0.0%	3	0.0%	18	0.1%	22	0.2%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	21	0.1%	0	0.0%	4	0.0%	4	0.0%	30	0.2%
Automated/Direct Load Control	351	2.5%	5	0.0%	13	0.1%	0	0.0%	369	2.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	12	0.1%	258	1.8%	270	1.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	605	4.3%	605	4.3%
Total	372	2.6%	6	0.0%	29	0.2%	867	6.1%	1,273	9.0%
Achievable Participation										
Pricing with Technology	746	5.3%	0	0.0%	101	0.7%	50	0.4%	896	6.3%
Pricing without Technology	350	2.5%	5	0.0%	67	0.5%	91	0.6%	514	3.6%
Automated/Direct Load Control	90	0.6%	1	0.0%	5	0.0%	0	0.0%	96	0.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	12	0.1%	258	1.8%	270	1.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	247	1.7%	247	1.7%
Total	1,185	8.3%	7	0.0%	185	1.3%	646	4.5%	2,023	14.2%
Full Participation										
Pricing with Technology	1,744	12.3%	0	0.0%	295	2.1%	146	1.0%	2,185	15.4%
Pricing without Technology	38	0.3%	7	0.1%	33	0.2%	118	0.8%	196	1.4%
Automated/Direct Load Control	0	0.0%	1	0.0%	0	0.0%	0	0.0%	1	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	12	0.1%	258	1.8%	270	1.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	10	0.1%	10	0.1%
Total	1,782	12.6%	8	0.1%	339	2.4%	532	3.7%	2,662	18.7%



Oregon State Profile

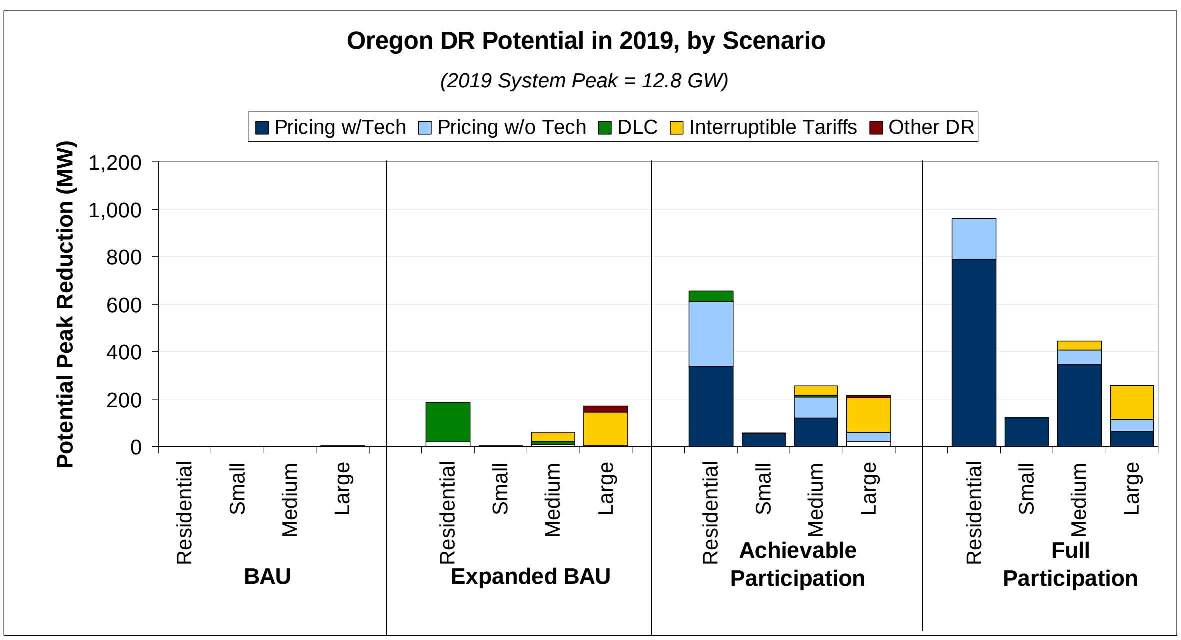
Key drivers of Oregon's demand response potential estimate include: a moderate residential base with 1.6 million accounts, a customer mix that has an above average share of peak demand in the medium C&I class (35%), and the potential to deploy AMI at a faster-than-average rate. Dynamic pricing with enabling technology and DLC are cost effective for all customer classes in the state. Oregon has a moderate residential CAC saturation value of 38%.

BAU: Oregon has a low level of existing demand response, primarily associated with large C&I participation in 'Other DR' programs for one of the IOUs in the region. Dominance on hydro power for generation in the Pacific Northwest region has historically led to low levels of demand response resources.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of DLC programs for residential customers, and through C&I load participation in 'Interruptible' and 'Other DR' programs. The potential for growth is significant, since existing demand response is at a very low level.

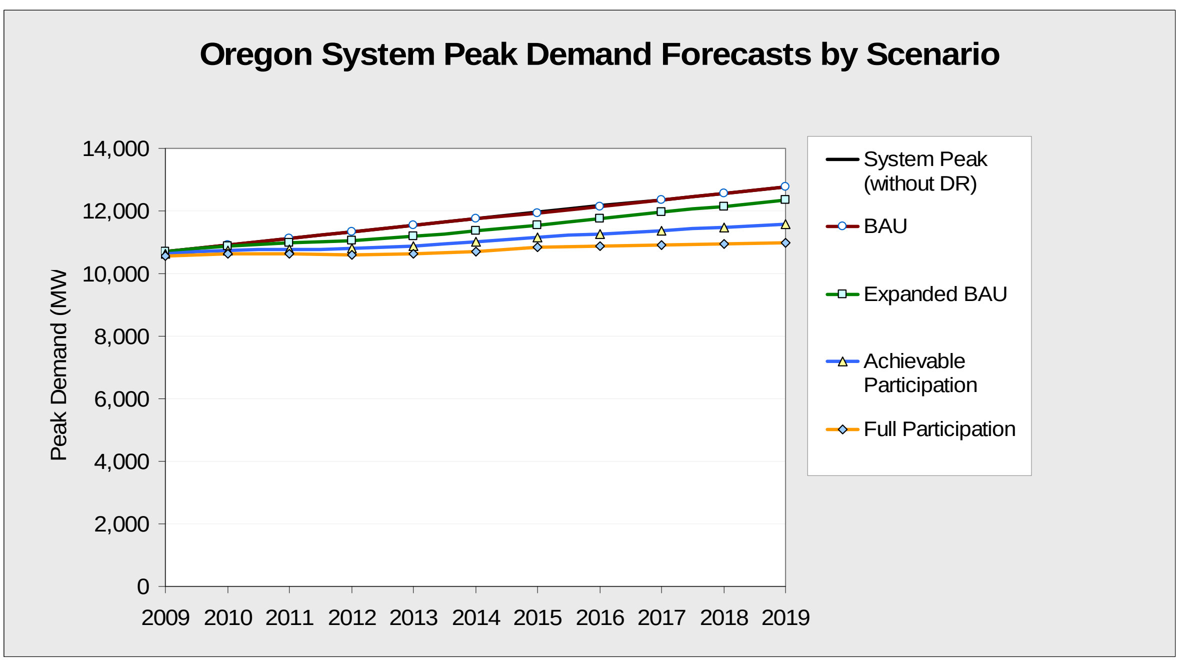
Achievable Participation: The increase in impacts is primarily associated with pricing programs. Participation of residential customers in 'Pricing with technology' option drives a significant increase in demand response potential. Also, impacts from 'pricing without technology' increase across all customer classes.

Full Participation: Similar to the Achievable Participation scenario, impacts are dominated by 'pricing with enabling technology'. Residential impacts grow substantially due to significantly higher participation in pricing programs. Among the three C&I rate classes, medium C&I impacts dominate due to its high share in the overall peak load.



Total Potential Peak Reduction from Demand Response in Oregon, 2019

	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	2	0.0%	0	0.0%	0	0.0%	0	0.0%	2	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%	3	0.0%	3	0.0%
Total	2	0.0%	0	0.0%	0	0.0%	3	0.0%	5	0.0%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	18	0.1%	0	0.0%	8	0.1%	2	0.0%	29	0.2%
Automated/Direct Load Control	168	1.3%	4	0.0%	14	0.1%	0	0.0%	187	1.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	39	0.3%	143	1.1%	182	1.4%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	26	0.2%	26	0.2%
Total	187	1.5%	5	0.0%	61	0.5%	171	1.3%	424	3.3%
Achievable Participation										
Pricing with Technology	336	2.6%	52	0.4%	119	0.9%	21	0.2%	528	4.1%
Pricing without Technology	275	2.2%	3	0.0%	91	0.7%	39	0.3%	408	3.2%
Automated/Direct Load Control	43	0.3%	1	0.0%	6	0.0%	0	0.0%	50	0.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	39	0.3%	143	1.1%	182	1.4%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	11	0.1%	11	0.1%
Total	654	5.1%	57	0.4%	254	2.0%	214	1.7%	1,179	9.2%
Full Participation										
Pricing with Technology	786	6.2%	122	1.0%	347	2.7%	63	0.5%	1,318	10.3%
Pricing without Technology	173	1.4%	2	0.0%	58	0.5%	51	0.4%	284	2.2%
Automated/Direct Load Control	2	0.0%	0	0.0%	0	0.0%	0	0.0%	2	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	39	0.3%	143	1.1%	182	1.4%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	3	0.0%	3	0.0%
Total	961	7.5%	124	1.0%	444	3.5%	259	2.0%	1,788	14.0%



Pennsylvania State Profile

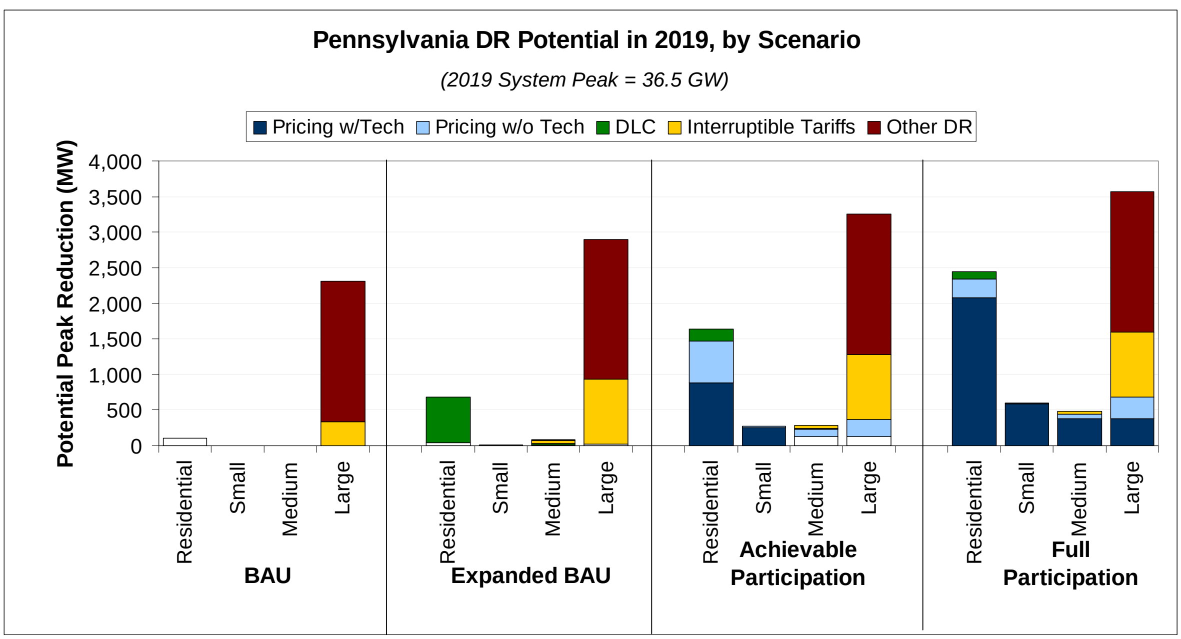
Key drivers of Pennsylvania's demand response potential estimate include: a relatively high level of load participation in the PJM market, a high residential population base with 50% CAC saturation, customer mix that has an above average share of peak demand for large C&I customers, and the potential to deploy AMI at a faster-than-average rate. Pricing with enabling technology and DLC are cost-effective for all customer classes.

BAU: Pennsylvania's existing demand response comes primarily from large C&I load participation in the PJM market. A portion of the existing demand response potential also comes from legacy interruptible programs in the state, along with residential DLC program.

Expanded BAU: Growth in demand response impacts is driven primarily through the increase of 'Other DR' programs for the large C&I class (due to higher load participation in the PJM market), and the expansion of DLC programs for residential customers. Load reduction potential associated with interruptible programs also grows, due to Pennsylvania's high share of large C&I load.

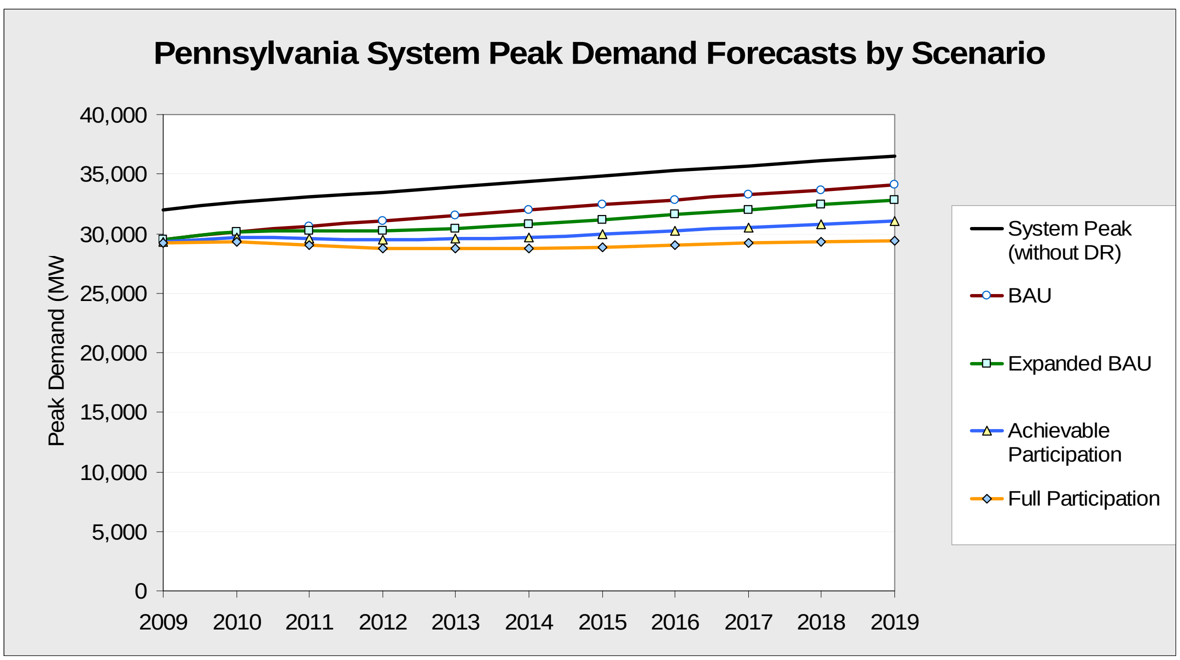
Achievable Participation: For this scenario, growth in residential impacts is associated with the pricing options. C&I customer participation in 'pricing with technology' cause a growth in potential. 'Other DR' programs continue to dominate the load reduction potential for large C&I customers.

Full Participation: Similar to the Achievable Participation scenario, high residential and C&I customer participation in the pricing options (primarily 'pricing with technology') drives the increase in impacts. 'Other DR' programs for large C&I customers maintain their large share in the total potential.



Total Potential Peak Reduction from Demand Response in Pennsylvania, 2019

	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	108	0.3%	0	0.0%	0	0.0%	0	0.0%	108	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	338	0.9%	338	0.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,969	5.4%	1,969	5.4%
Total	108	0.3%	0	0.0%	0	0.0%	2,307	6.3%	2,415	6.6%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	46	0.1%	1	0.0%	10	0.0%	16	0.0%	73	0.2%
Automated/Direct Load Control	641	1.8%	12	0.0%	27	0.1%	0	0.0%	679	1.9%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	43	0.1%	916	2.5%	958	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,969	5.4%	1,969	5.4%
Total	687	1.9%	13	0.0%	79	0.2%	2,901	7.9%	3,680	10.1%
Achievable Participation										
Pricing with Technology	887	2.4%	253	0.7%	129	0.4%	129	0.4%	1,398	3.8%
Pricing without Technology	582	1.6%	16	0.0%	101	0.3%	235	0.6%	934	2.6%
Automated/Direct Load Control	166	0.5%	3	0.0%	11	0.0%	0	0.0%	180	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	43	0.1%	916	2.5%	958	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,969	5.4%	1,969	5.4%
Total	1,635	4.5%	272	0.7%	283	0.8%	3,250	8.9%	5,439	14.9%
Full Participation										
Pricing with Technology	2,075	5.7%	592	1.6%	377	1.0%	378	1.0%	3,422	9.4%
Pricing without Technology	266	0.7%	10	0.0%	66	0.2%	305	0.8%	647	1.8%
Automated/Direct Load Control	108	0.3%	0	0.0%	0	0.0%	0	0.0%	108	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	43	0.1%	916	2.5%	958	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,969	5.4%	1,969	5.4%
Total	2,450	6.7%	602	1.6%	486	1.3%	3,568	9.8%	7,105	19.5%



Rhode Island State Profile

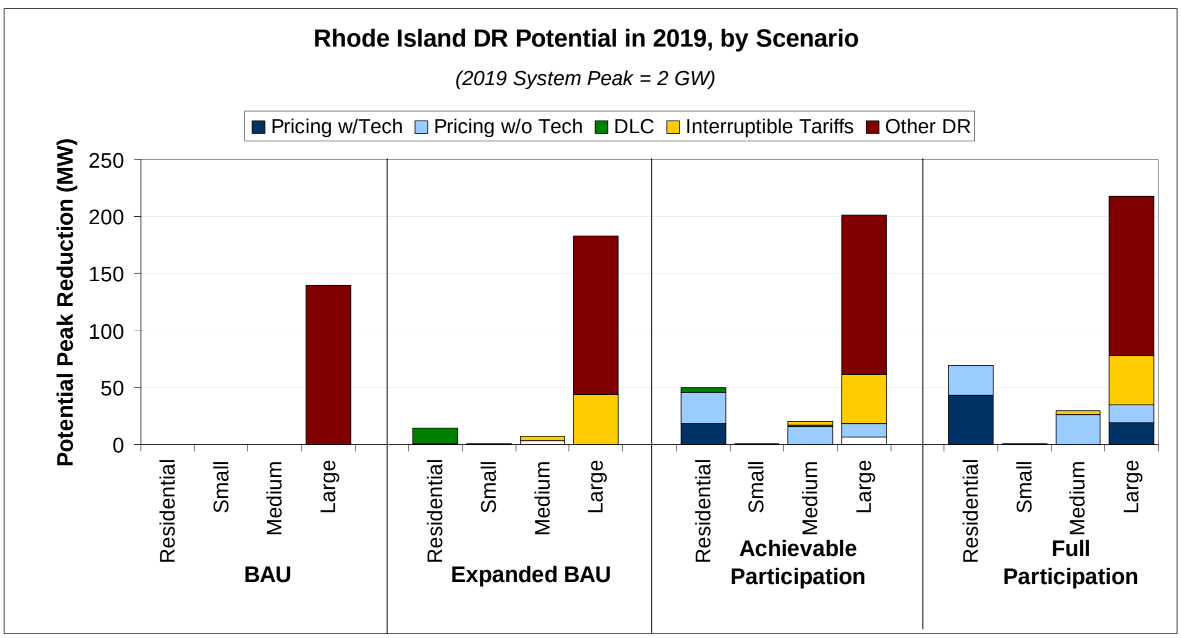
Rhode Island has a higher than average share of large C&I peak load (29%). The state's demand response potential is driven by large C&I load participation in the ISO-NE market. Rhode Island has a lower than average residential CAC saturation at 12%. Dynamic pricing with enabling technology is cost-effective only for residential and large C&I customers, thereby restricting the potential that can be derived from this option. DLC is cost-effective for all customer classes. It has a lower than average AMI deployment rate.

BAU: Rhode Island's existing demand response is derived from 'Other DR' programs, due to large C&I load participation in the ISO-NE market.

Expanded BAU: Growth in demand response impacts is driven primarily through the growth of Interruptible programs for large C&I customers. This is due to Rhode Island's high share of large C&I load, which allow for growth in Interruptible programs. Also, there is a potential for growth in residential DLC programs.

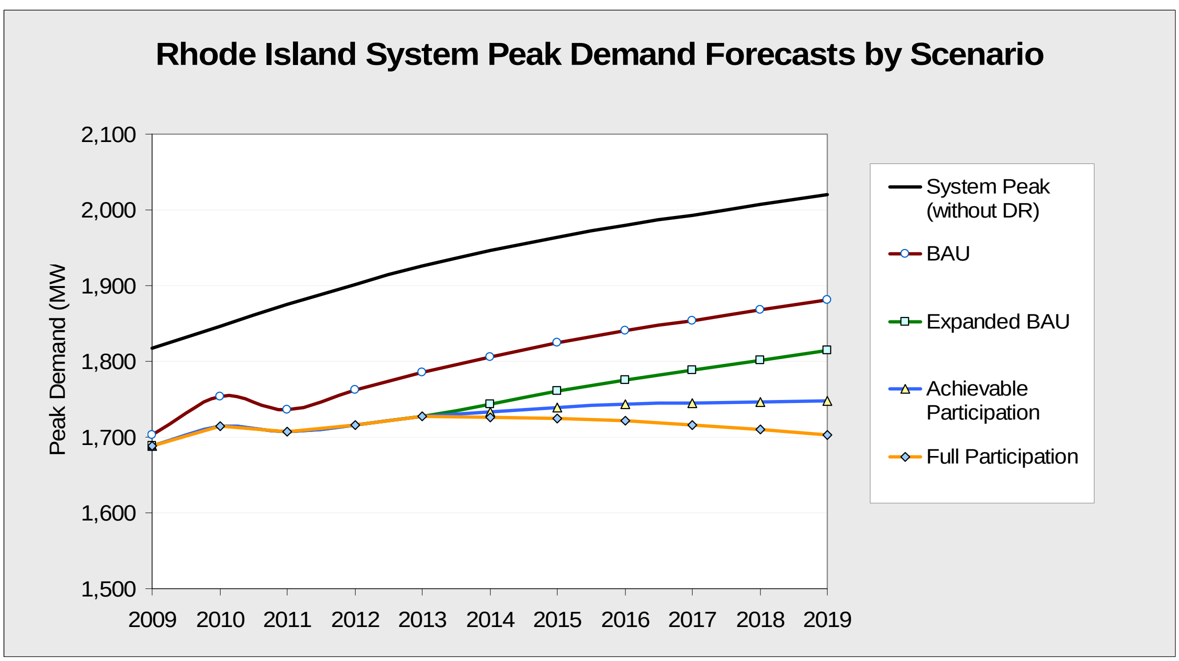
Achievable Participation: Growth in impacts in this scenario is driven by the potential derived from pricing options, primarily from residential customers and to a smaller extent from medium C&I customers. Since 'pricing with technology' is cost-effective only for residential and large C&I customers, there is a low growth in potential associated with this option. Potential through large C&I load participation in the ISO-NE market dominates overall other types of demand response programs.

Full Participation: Similar to the Achievable Participation scenario, increase in customer participation in pricing options, primarily for residential and medium C&I customers, drives the increase in impacts. Similar to the other scenarios, large C&I load maintains high participation levels in the ISO-NE market.



Total Potential Peak Reduction from Demand Response in Rhode Island, 2019

	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%	140	6.9%	140	6.9%
Total	0	0.0%	0	0.0%	0	0.0%	140	6.9%	140	6.9%
Expanded 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%	0	0.0%	1	0.1%
Automated/Direct Load Control	14	0.7%	1	0.0%	3	0.2%	0	0.0%	18	0.9%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.2%	44	2.2%	47	2.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	140	6.9%	140	6.9%
Total	15	0.7%	1	0.0%	7	0.4%	183	9.1%	206	10.2%
Achievable Participation										
Pricing with Technology	19	0.9%	0	0.0%	0	0.0%	7	0.3%	25	1.2%
Pricing without Technology	28	1.4%	1	0.0%	16	0.8%	12	0.6%	56	2.8%
Automated/Direct Load Control	4	0.2%	0	0.0%	1	0.1%	0	0.0%	5	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.2%	44	2.2%	47	2.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	140	6.9%	140	6.9%
Total	50	2.5%	1	0.0%	20	1.0%	201	10.0%	273	13.5%
Full Participation										
Pricing with Technology	44	2.2%	0	0.0%	0	0.0%	19	0.9%	63	3.1%
Pricing without Technology	26	1.3%	1	0.0%	26	1.3%	15	0.8%	68	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%	4	0.2%	44	2.2%	47	2.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	140	6.9%	140	6.9%
Total	70	3.4%	1	0.0%	30	1.5%	218	10.8%	318	15.7%



South Carolina State Profile

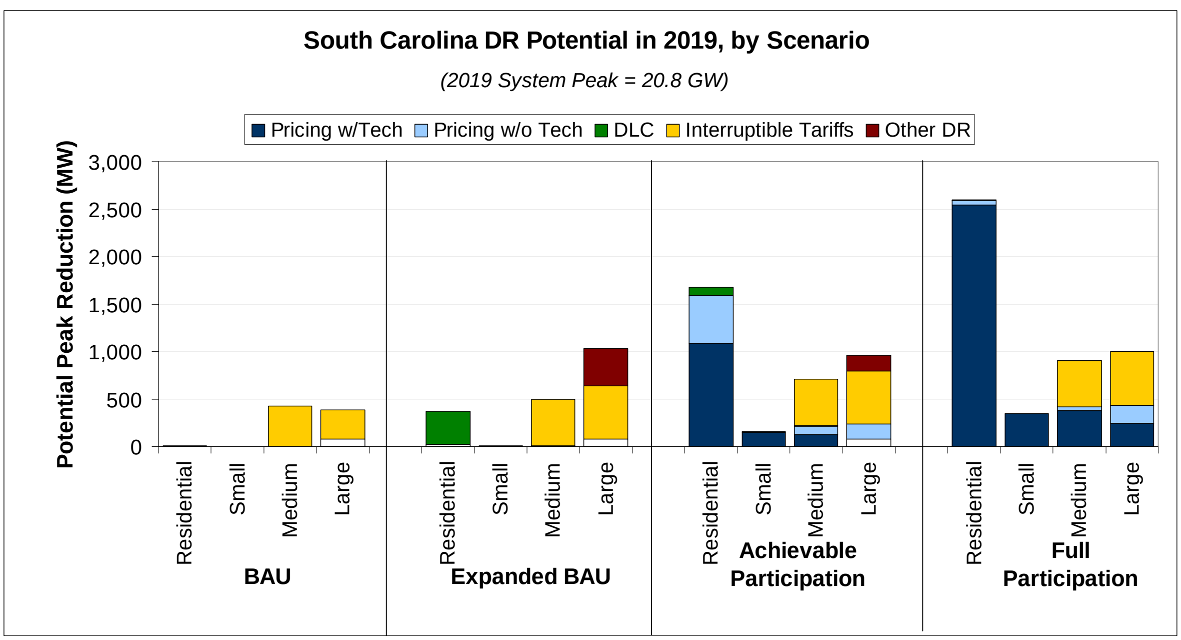
Key drivers of South Carolina's demand response potential estimate include: higher-than-average residential CAC saturation of 84 percent and a moderate amount of existing demand response. An expectation for AMI deployment that slightly lags the national average could lead to less potential demand response. Enabling technologies and DLC are cost-effective for all customer classes in the state.

BAU: South Carolina's existing demand response comes primarily from an interruptible tariff program for both Medium and Large C&I classes. A small amount comes from pricing without technology for the Large C&I class.

Expanded BAU: Growth in demand response impacts are driven through the addition of Other DR programs for the Large C&I class, which currently do not exist in the state. Significant growth also results from residential participation in DLC programs and large C&I customer participation in Interruptible tariffs.

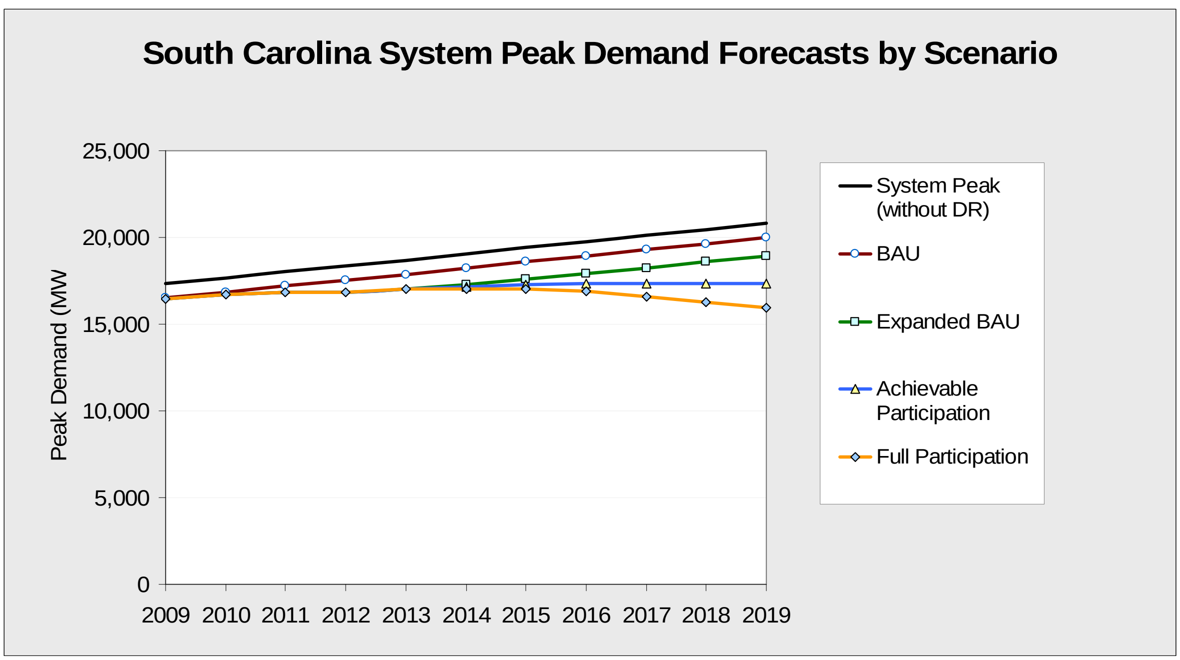
Achievable Participation: High CAC saturation in the Residential sector drives a significant increase in demand response potential through dynamic pricing, with the majority of customers increasing impacts through the use of enabling technologies. Medium C&I demand response potential is slightly increased through the addition of dynamic pricing. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR.

Full Participation: Residential potential demand response increases dramatically due to dynamic pricing with technology reaching more customers. Again, high CAC saturation leads to large demand response potential for the residential sector. Dynamic pricing with technology modestly increases the demand response potential for the remaining sectors.



Total Potential Peak Reduction from Demand Response in South Carolina, 2019

	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%	76	0.4%	76	0.4%
Automated/Direct Load Control	5	0.0%	0	0.0%	0	0.0%	0	0.0%	5	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	423	2.0%	307	1.5%	730	3.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	5	0.0%	0	0.0%	423	2.0%	383	1.8%	811	3.9%
Expanded 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%	5	0.0%	76	0.4%	109	0.5%
Automated/Direct Load Control	343	1.6%	5	0.0%	5	0.0%	0	0.0%	353	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	489	2.3%	563	2.7%	1,052	5.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	394	1.9%	395	1.9%
Total	370	1.8%	6	0.0%	499	2.4%	1,034	5.0%	1,909	9.2%
Achievable Participation										
Pricing with Technology	1,086	5.2%	147	0.7%	129	0.6%	83	0.4%	1,445	6.9%
Pricing without Technology	506	2.4%	8	0.0%	86	0.4%	150	0.7%	750	3.6%
Automated/Direct Load Control	87	0.4%	1	0.0%	2	0.0%	0	0.0%	91	0.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	489	2.3%	563	2.7%	1,052	5.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	161	0.8%	161	0.8%
Total	1,679	8.1%	156	0.8%	706	3.4%	957	4.6%	3,498	16.8%
Full Participation										
Pricing with Technology	2,541	12.2%	344	1.7%	377	1.8%	242	1.2%	3,503	16.8%
Pricing without Technology	50	0.2%	4	0.0%	42	0.2%	195	0.9%	291	1.4%
Automated/Direct Load Control	5	0.0%	0	0.0%	0	0.0%	0	0.0%	5	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	489	2.3%	563	2.7%	1,052	5.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	2,596	12.5%	348	1.7%	907	4.4%	1,000	4.8%	4,851	23.3%



South Dakota State Profile

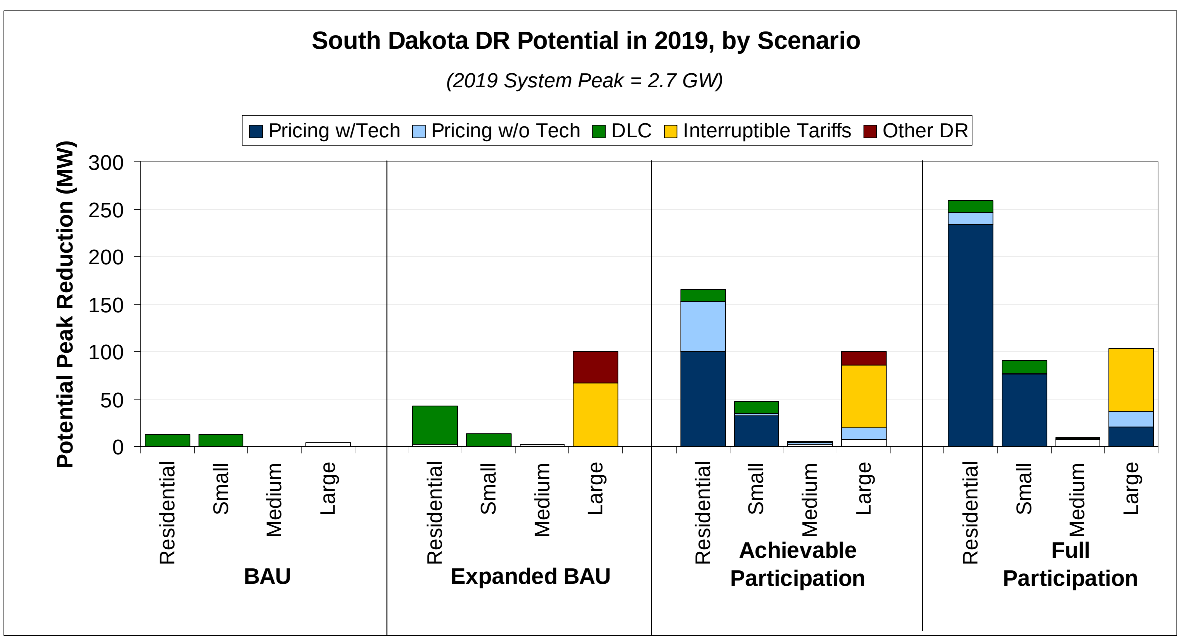
Key drivers of South Dakota's demand response potential estimate include: higher-than-average residential CAC saturation of 71 percent and a small amount of existing demand response. Enabling technologies are cost-effective for all C&I classes and Residential customers. Also, AMI deployment that potentially lags the national average could lead to slower realized demand response potential.

BAU: South Dakota's existing demand response comes primarily from direct load control for both the Residential and Small C&I classes. A small amount of demand response comes from the Large C&I class, in the form of interruptible tariffs.

Expanded BAU: Growth in demand response is driven equally through an interruptible tariff program and other demand response programs for the Large C&I class. The other category of demand response programs does not currently exist in the state. Residential DLC contributes to increased demand response potential, as well.

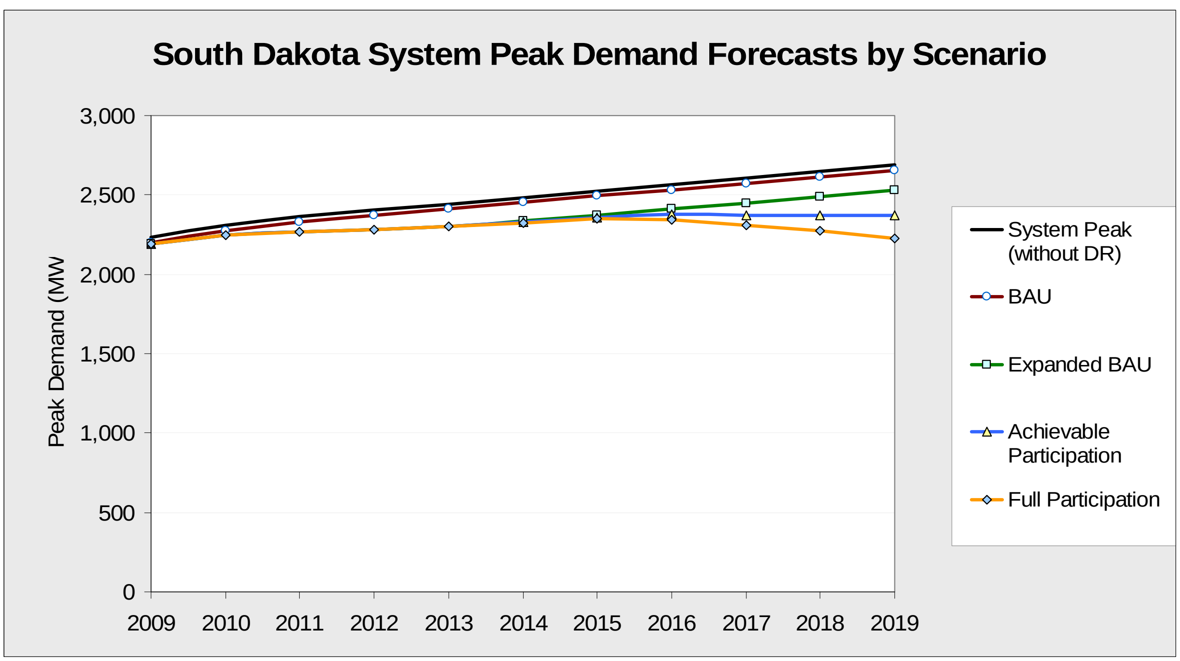
Achievable Participation: Increases in this scenario result from dynamic pricing programs, both with and without enabling technology, primarily through participation of residential and small C&I customers in these pricing programs.

Full Participation: Demand response potential is further realized through increases in both dynamic pricing programs. Large C&I customers that were in other demand response programs have shifted in to both dynamic pricing programs, with the majority enrolling in the with technology option. Again, higher-than-average CAC saturation results in the Residential class having the largest amount of potential demand response, with a very large fraction coming in the form of dynamic pricing with enabling technologies.



Total Potential Peak Reduction from Demand Response in South Dakota, 2019

	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	13	0.5%	13	0.5%	0	0.0%	0	0.0%	26	1.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	4	0.2%	4	0.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	13	0.5%	13	0.5%	0	0.0%	4	0.2%	30	1.1%
Expanded 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%	0	0.0%	3	0.1%
Automated/Direct Load Control	41	1.5%	13	0.5%	1	0.0%	0	0.0%	55	2.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	1	0.0%	67	2.5%	67	2.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	33	1.2%	33	1.2%
Total	43	1.6%	13	0.5%	2	0.1%	100	3.7%	158	5.9%
Achievable Participation										
Pricing with Technology	100	3.7%	33	1.2%	2	0.1%	7	0.3%	142	5.3%
Pricing without Technology	53	2.0%	2	0.1%	2	0.1%	13	0.5%	69	2.6%
Automated/Direct Load Control	13	0.5%	13	0.5%	1	0.0%	0	0.0%	26	1.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	1	0.0%	67	2.5%	67	2.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	14	0.5%	14	0.5%
Total	165	6.2%	48	1.8%	6	0.2%	100	3.7%	318	11.8%
Full Participation										
Pricing with Technology	234	8.7%	76	2.8%	7	0.3%	20	0.8%	337	12.6%
Pricing without Technology	13	0.5%	1	0.0%	1	0.0%	16	0.6%	31	1.2%
Automated/Direct Load Control	13	0.5%	13	0.5%	0	0.0%	0	0.0%	26	1.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	1	0.0%	67	2.5%	67	2.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	259	9.6%	90	3.4%	9	0.3%	103	3.8%	462	17.2%



Tennessee State Profile

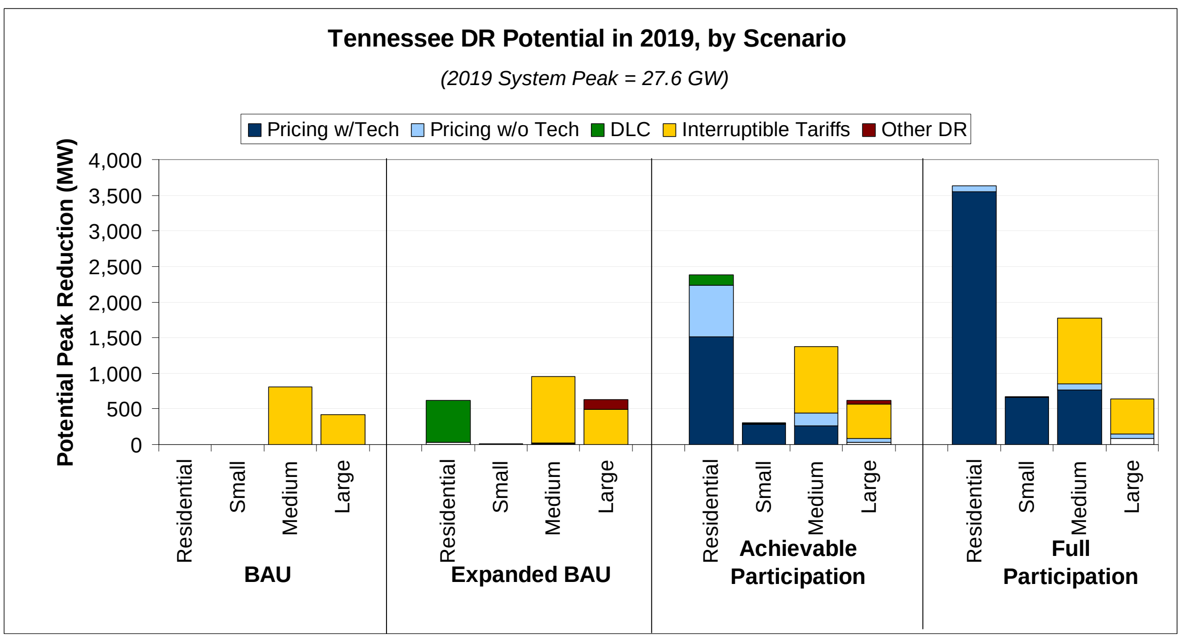
Key drivers of Tennessee's demand response potential estimate include: higher-than-average residential CAC saturation of 81 percent and a moderate amount of existing demand response. Dynamic pricing with enabling technologies are cost-effective for all customer classes. AMI deployment that potentially lags the national average could lead to slower realized demand response potential. Large C&I represents a significantly smaller-than-average share of peak (6%), resulting in a smaller state-wide impact for this class.

BAU: Tennessee has existing demand response for Medium and Large C&I classes, through participation in Interruptible tariffs. A smaller impact comes from Large C&I due to this class representing a smaller portion of overall peak.

Expanded BAU: Demand response potential increase is driven by DLC for Residential customers. Smaller increases result Interruptible and 'Other DR' programs, for the remaining classes.

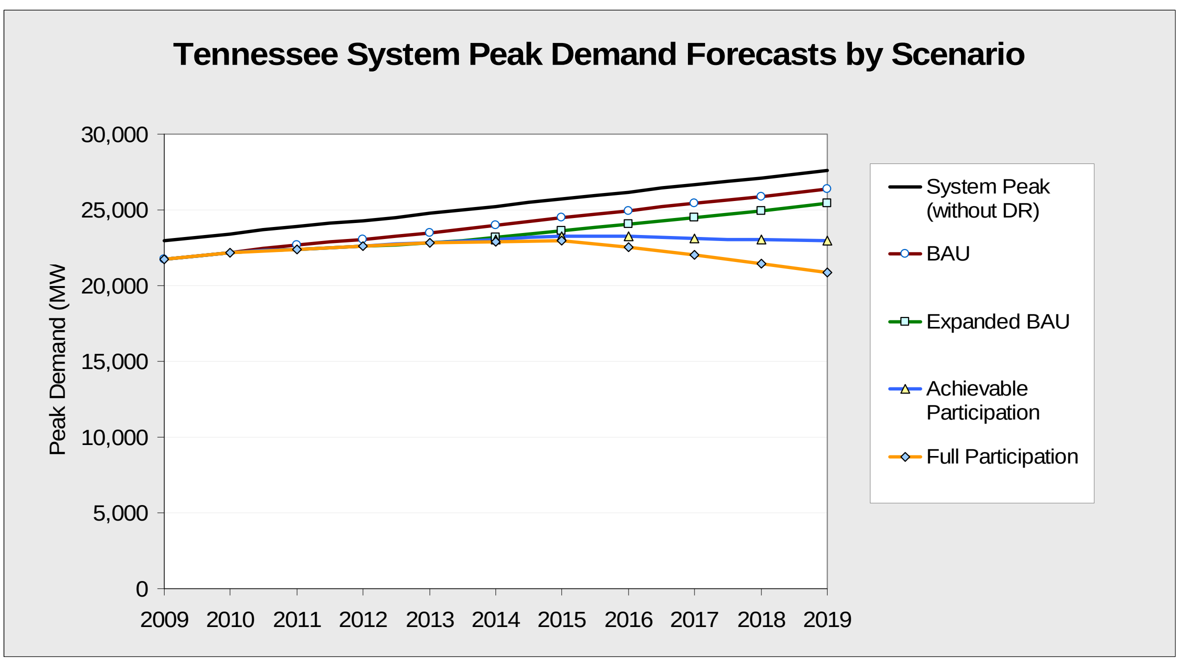
Achievable Participation: Significant potential comes from the two pricing programs, mostly for the residential class of customers. Residential potential demand response is driven by high CAC saturation, leading to this class representing a large share of system peak.

Full Participation: Demand response potential increases are driven mostly by pricing with enabling technology, for all customer classes. This is most pronounced for the residential customers who switch from DLC programs in to pricing with technologies. Again, high CAC saturation drives most of the potential impact for this class of customers.



Total Potential Peak Reduction from Demand Response in Tennessee, 2019

	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%	809	2.9%	425	1.5%	1,234	4.5%
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%	809	2.9%	425	1.5%	1,234	4.5%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	30	0.1%	1	0.0%	8	0.0%	2	0.0%	41	0.1%
Automated/Direct Load Control	586	2.1%	9	0.0%	13	0.0%	0	0.0%	608	2.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	930	3.4%	488	1.8%	1,418	5.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	137	0.5%	137	0.5%
Total	617	2.2%	10	0.0%	951	3.4%	627	2.3%	2,204	8.0%
Achievable Participation										
Pricing with Technology	1,515	5.5%	282	1.0%	262	0.9%	29	0.1%	2,087	7.6%
Pricing without Technology	717	2.6%	16	0.1%	174	0.6%	52	0.2%	959	3.5%
Automated/Direct Load Control	149	0.5%	2	0.0%	5	0.0%	0	0.0%	156	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	930	3.4%	488	1.8%	1,418	5.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	55	0.2%	56	0.2%
Total	2,381	8.6%	300	1.1%	1,370	5.0%	624	2.3%	4,676	16.9%
Full Participation										
Pricing with Technology	3,544	12.8%	660	2.4%	765	2.8%	83	0.3%	5,053	18.3%
Pricing without Technology	85	0.3%	8	0.0%	84	0.3%	67	0.2%	245	0.9%
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%	930	3.4%	488	1.8%	1,418	5.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	3,629	13.1%	668	2.4%	1,779	6.4%	639	2.3%	6,715	24.3%



Texas State Profile

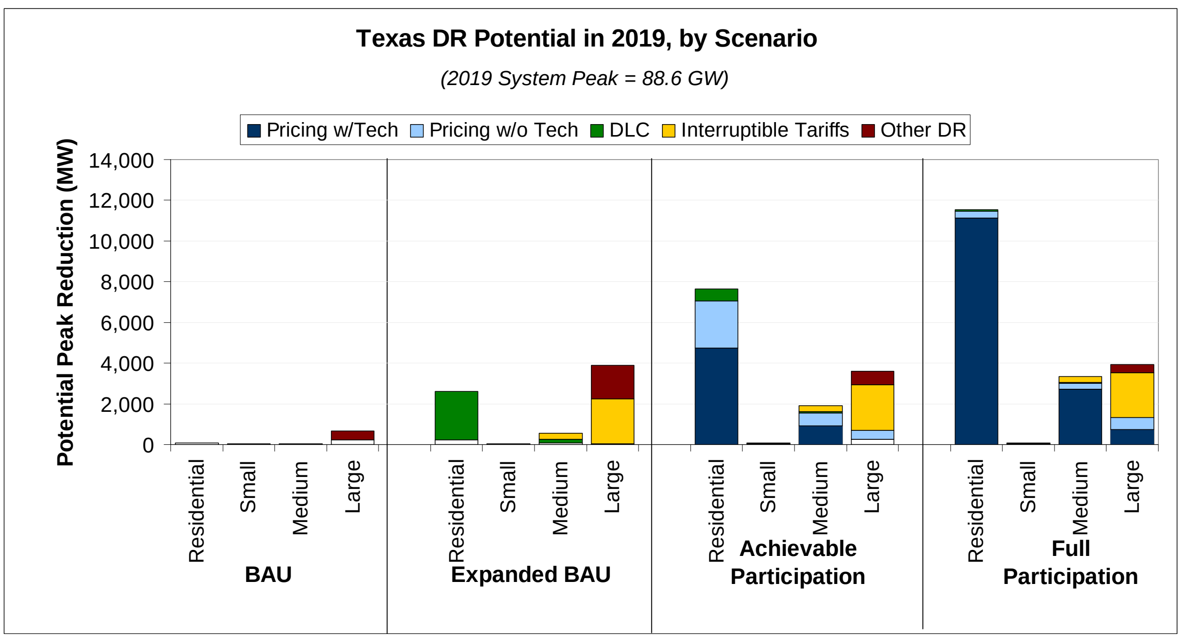
Key drivers of demand response potential in Texas include: higher-than-average residential CAC saturation of 80 percent and very little existing demand response. Enabling technologies are cost-effective for all customer classes, except for small C&I customers. Also, potential AMI deployment significantly leads the national average and could lead to faster realization of potential demand response.

BAU: The majority of Texas's current demand response comes from the Large C&I class, through participation in Interruptible tariffs and 'Other DR' programs in the ERCOT market. The state has a small amount of direct load control for the other customer classes.

Expanded BAU: High CAC saturation leads to growth in residential demand response potential through direct load control. Most of the remaining growth in potential comes from the Large C&I class, through participation in Interruptible and 'Other DR' programs.

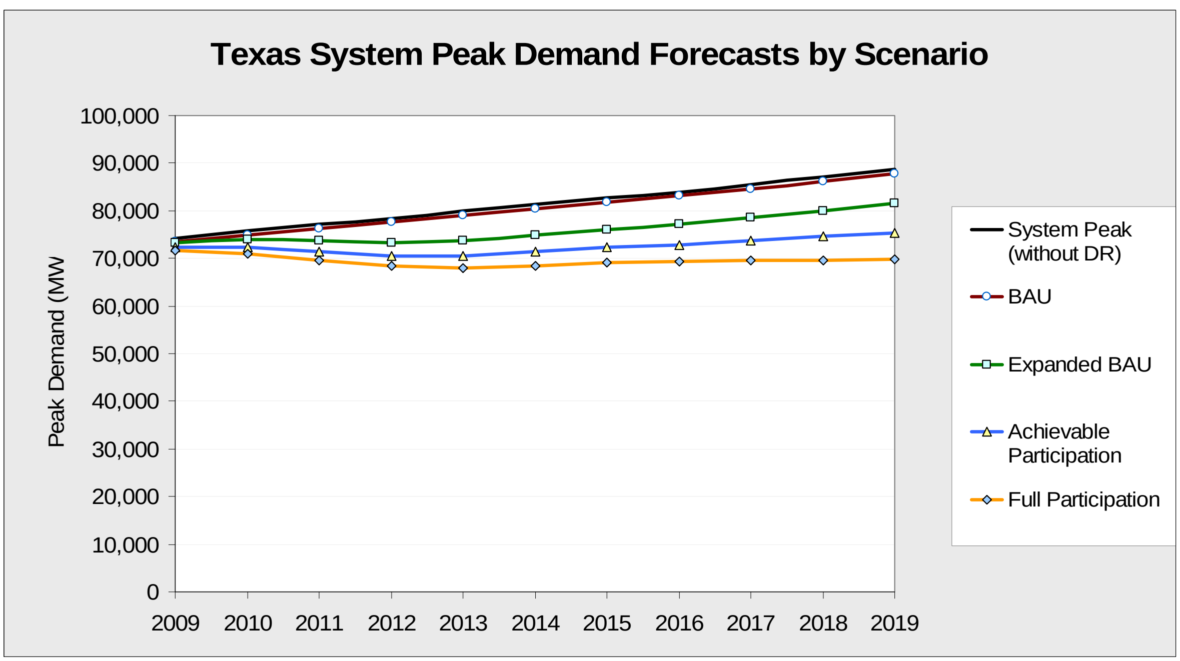
Achievable Participation: High CAC saturation coupled with faster-than-average AMI deployment lead to significant potential acceptance of dynamic pricing for the Residential class. Some residential growth results from customers shifting from DLC programs in to the two dynamic pricing programs. Small increases in demand response potential result from medium and large C&I customers enrolling in both dynamic pricing programs.

Full Participation: Significant demand response potential comes from the Residential class, driven primarily by high CAC saturation and a faster-than-average AMI penetration rate. Both Medium and Large C&I classes show growth in demand response through increased enrollment in dynamic pricing with enabling technology.



Total Potential Peak Reduction from Demand Response in Texas, 2019

	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	79	0.1%	39	0.0%	48	0.1%	0	0.0%	166	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	232	0.3%	232	0.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	413	0.5%	413	0.5%
Total	79	0.1%	39	0.0%	48	0.1%	645	0.7%	810	0.9%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	236	0.3%	1	0.0%	70	0.1%	35	0.0%	343	0.4%
Automated/Direct Load Control	2,371	2.7%	39	0.0%	190	0.2%	0	0.0%	2,599	2.9%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	280	0.3%	2,218	2.5%	2,498	2.8%
Other DR Programs	0	0.0%	0	0.0%	3	0.0%	1,640	1.9%	1,643	1.9%
Total	2,607	2.9%	40	0.0%	543	0.6%	3,894	4.4%	7,083	8.0%
Achievable Participation										
Pricing with Technology	4,758	5.4%	0	0.0%	925	1.0%	250	0.3%	5,932	6.7%
Pricing without Technology	2,289	2.6%	27	0.0%	615	0.7%	454	0.5%	3,386	3.8%
Automated/Direct Load Control	614	0.7%	39	0.0%	79	0.1%	0	0.0%	732	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	280	0.3%	2,218	2.5%	2,498	2.8%
Other DR Programs	0	0.0%	0	0.0%	1	0.0%	680	0.8%	681	0.8%
Total	7,661	8.6%	66	0.1%	1,900	2.1%	3,602	4.1%	13,230	14.9%
Full Participation										
Pricing with Technology	11,129	12.6%	0	0.0%	2,703	3.1%	730	0.8%	14,562	16.4%
Pricing without Technology	318	0.4%	37	0.0%	298	0.3%	588	0.7%	1,241	1.4%
Automated/Direct Load Control	79	0.1%	39	0.0%	48	0.1%	0	0.0%	166	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	280	0.3%	2,218	2.5%	2,498	2.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	413	0.5%	413	0.5%
Total	11,525	13.0%	75	0.1%	3,330	3.8%	3,949	4.5%	18,880	21.3%



Utah State Profile

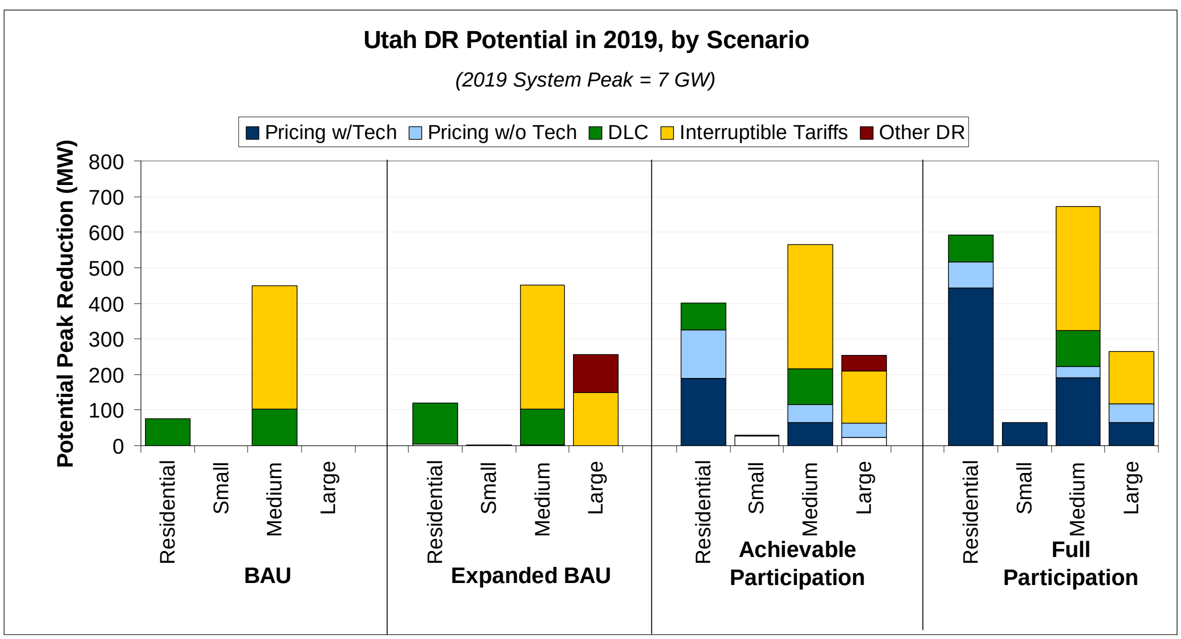
Key drivers of Utah's demand response potential estimate include: lower-than-average residential CAC saturation of 42 percent and a fair amount of existing demand response. Enabling technologies are cost-effective for all customer classes. The state has a smaller-than-average Residential class and AMI deployment that potentially lags the national average, potentially leading to slower realized demand response potential. The state is characterized by a larger-than-average Medium C&I class that has significant amounts of existing demand response.

BAU: Utah's existing demand response is characterized by a large interruptible tariff program for the Medium C&I class. The rest of the existing demand response is through direct load control programs for the Residential and Medium C&I classes.

Expanded BAU: The majority of the growth in demand response potential is driven by interruptible tariffs and other demand response for the Large C&I class.

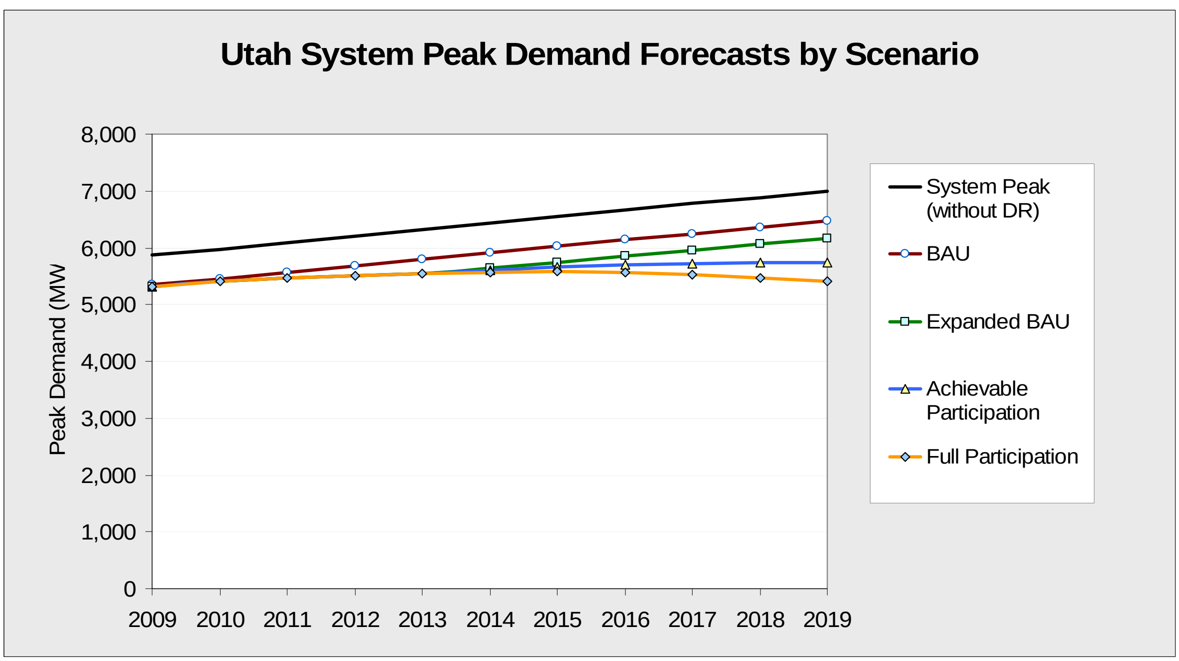
Achievable Participation: Demand response potential for this scenario comes mostly through the two dynamic pricing programs, with the majority utilizing enabling technologies. Enabling technologies are cost-effective for all customer classes.

Full Participation: Under this scenario, dynamic pricing with enabling technology continues to grow for all customer classes. Demand response potential for the Large C&I class decreases slightly, as customers switch from other demand response programs to the dynamic pricing programs, which have smaller per-customer impacts.



Total Potential Peak Reduction from Demand Response in Utah, 2019

	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	75	1.1%	0	0.0%	102	1.5%	0	0.0%	177	2.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	347	5.0%	0	0.0%	347	5.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	75	1.1%	0	0.0%	449	6.4%	0	0.0%	524	7.5%
Expanded 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%	2	0.0%	1	0.0%	7	0.1%
Automated/Direct Load Control	115	1.6%	2	0.0%	102	1.5%	0	0.0%	219	3.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	347	5.0%	148	2.1%	495	7.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	107	1.5%	107	1.5%
Total	119	1.7%	2	0.0%	451	6.4%	256	3.7%	828	11.8%
Achievable Participation										
Pricing with Technology	190	2.7%	27	0.4%	65	0.9%	22	0.3%	304	4.4%
Pricing without Technology	136	1.9%	2	0.0%	50	0.7%	40	0.6%	228	3.3%
Automated/Direct Load Control	75	1.1%	1	0.0%	102	1.5%	0	0.0%	178	2.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	347	5.0%	148	2.1%	495	7.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	43	0.6%	43	0.6%
Total	401	5.7%	30	0.4%	564	8.1%	254	3.6%	1,249	17.9%
Full Participation										
Pricing with Technology	444	6.3%	64	0.9%	191	2.7%	65	0.9%	763	10.9%
Pricing without Technology	72	1.0%	1	0.0%	32	0.5%	52	0.7%	158	2.3%
Automated/Direct Load Control	75	1.1%	0	0.0%	102	1.5%	0	0.0%	177	2.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	347	5.0%	148	2.1%	495	7.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	591	8.5%	65	0.9%	671	9.6%	266	3.8%	1,593	22.8%



Vermont State Profile

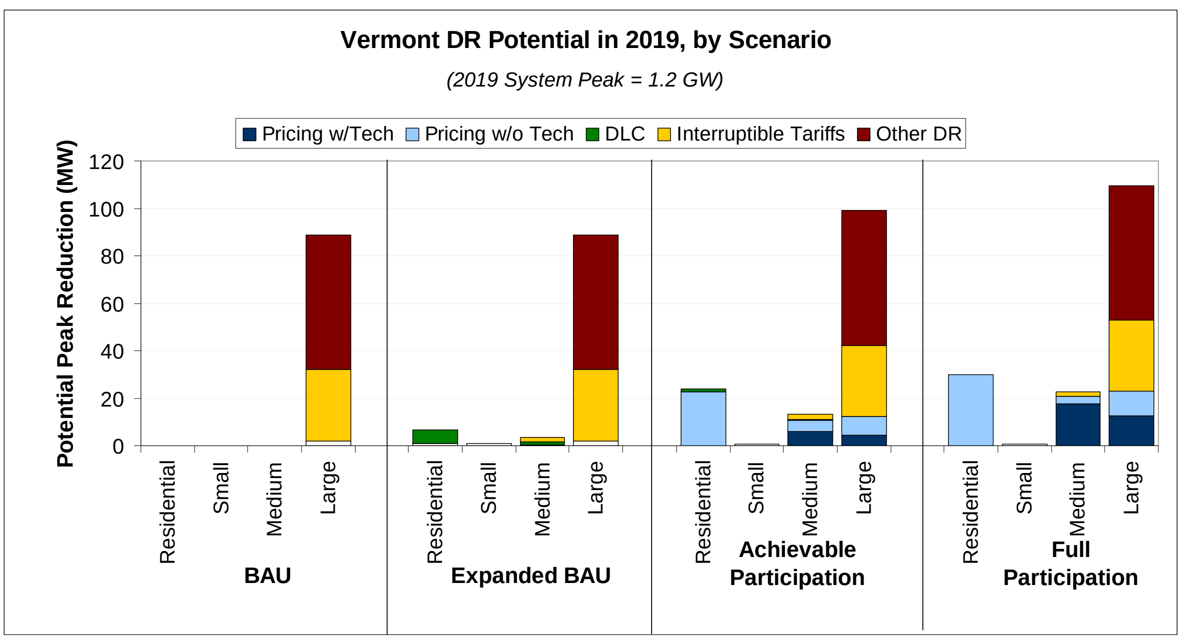
Key drivers of Vermont's demand response potential estimate include: significantly lower-than-average CAC saturation of 7 percent and enabling technologies that are cost-effective for only the Medium and Large C&I classes. Vermont's potential AMI deployment could lead the national average and result in faster realized demand response potential. However, the key driver of this state's demand response potential is very low residential CAC saturation and enabling technologies not being cost-effective for this class, leading to fairly small incremental potential relative to the BAU scenario.

BAU: Vermont has a large amount of existing demand response for the Large C&I class, through interruptible tariffs and other demand response.

Expanded BAU: Small demand response potential increases occur for the Large C&I class, through interruptible tariffs and other demand response. The Residential class shows a small amount of potential demand response through participation in DLC programs.

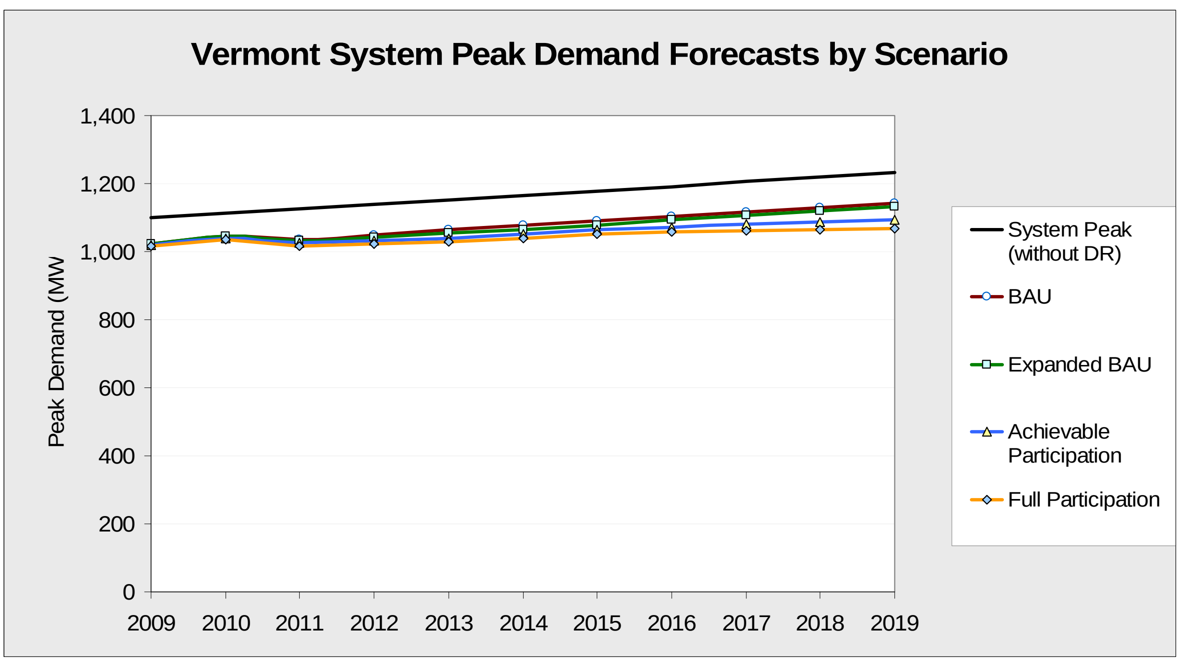
Achievable Participation: Residential and Medium and Large C&I classes show slight increases in dynamic pricing programs. The residential class has a much smaller-than-average demand response potential due to very low CAC saturation and enabling technologies not being cost-effective for this class.

Full Participation: Small increases in potential demand response result for all classes of customers. Overall the state shows a small amount incremental demand response potential driven primarily by low CAC saturation and enabling technologies not being cost-effective for both Residential and Small C&I classes.



Total Potential Peak Reduction from Demand Response in Vermont, 2019

	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	0.2%	2	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%	30	2.4%	30	2.4%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	57	4.6%	57	4.6%
Total	0	0.0%	0	0.0%	0	0.0%	89	7.2%	89	7.2%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	1	0.1%	0	0.0%	0	0.0%	2	0.2%	3	0.3%
Automated/Direct Load Control	6	0.5%	1	0.1%	1	0.1%	0	0.0%	8	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	2	0.2%	30	2.4%	32	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	57	4.6%	57	4.6%
Total	7	0.5%	1	0.1%	4	0.3%	89	7.2%	100	8.1%
Achievable Participation										
Pricing with Technology	0	0.0%	0	0.0%	6	0.5%	4	0.4%	10	0.8%
Pricing without Technology	23	1.8%	1	0.0%	5	0.4%	8	0.6%	36	2.9%
Automated/Direct Load Control	1	0.1%	0	0.0%	0	0.0%	0	0.0%	2	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	2	0.2%	30	2.4%	32	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	57	4.6%	57	4.6%
Total	24	1.9%	1	0.1%	13	1.1%	99	8.0%	137	11.1%
Full Participation										
Pricing with Technology	0	0.0%	0	0.0%	18	1.4%	13	1.0%	30	2.5%
Pricing without Technology	30	2.4%	1	0.1%	3	0.3%	10	0.8%	44	3.6%
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%	2	0.2%	30	2.4%	32	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	57	4.6%	57	4.6%
Total	30	2.4%	1	0.1%	23	1.8%	110	8.9%	163	13.2%



Virginia State Profile

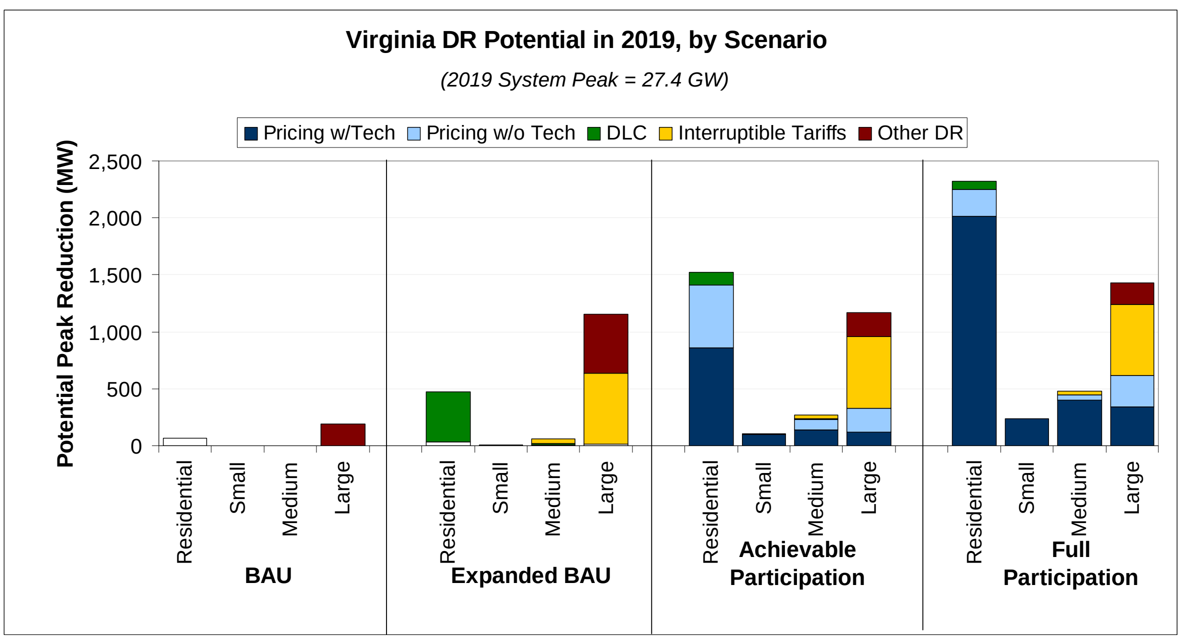
Key drivers of Virginia's demand response potential include lower-than-average residential CAC saturation (50 percent) and a small amount of existing demand response. Enabling technologies are cost-effective for all customer classes. Also, potential AMI deployment slightly leads the national average. A Large C&I class with a higher than average share of the system peak results in the class representing a significant amount of the state's overall demand response potential.

BAU: Virginia's small amount of existing demand response comes from DLC programs for residential customers and large C&I customer participation in 'Other DR' programs.

Expanded BAU: Growth in potential demand response is the result of higher than average peak demand in the large C&I class, resulting in large impacts from both interruptible tariffs and other demand response. The Residential class has a significant growth in load reduction coming from DLC programs.

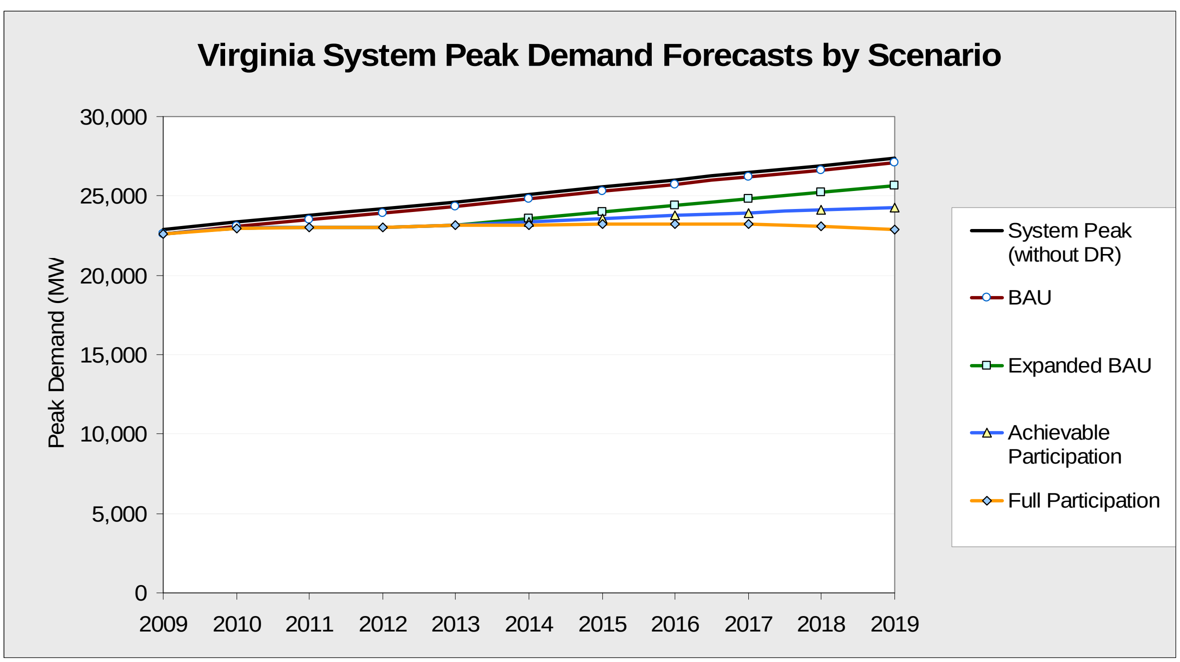
Achievable Participation: Enabling technologies are cost-effective for all customer classes, resulting in large dynamic pricing potential growth from these technologies. The Residential and Small C&I classes show customers enrolling in to the two dynamic pricing programs rather than in DLC programs.

Full Participation: The cost-effectiveness of enabling technology leads to significant growth in dynamic pricing for all classes, especially residential customers. The Residential and Large C&I classes account for most of the peak load, resulting in the majority of the demand response potential coming from these two classes.



Total Potential Peak Reduction from Demand Response in Virginia, 2019

	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	68	0.2%	0	0.0%	0	0.0%	0	0.0%	68	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	1	0.0%	2	0.0%	3	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	189	0.7%	189	0.7%
Total	68	0.2%	0	0.0%	1	0.0%	191	0.7%	260	1.0%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	32	0.1%	0	0.0%	7	0.0%	11	0.0%	50	0.2%
Automated/Direct Load Control	439	1.6%	8	0.0%	14	0.1%	0	0.0%	461	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	37	0.1%	625	2.3%	662	2.4%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	519	1.9%	519	1.9%
Total	471	1.7%	8	0.0%	57	0.2%	1,154	4.2%	1,691	6.2%
Achievable Participation										
Pricing with Technology	861	3.1%	100	0.4%	137	0.5%	117	0.4%	1,215	4.4%
Pricing without Technology	550	2.0%	5	0.0%	91	0.3%	213	0.8%	859	3.1%
Automated/Direct Load Control	112	0.4%	2	0.0%	6	0.0%	0	0.0%	120	0.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	37	0.1%	625	2.3%	662	2.4%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	212	0.8%	212	0.8%
Total	1,523	5.6%	107	0.4%	270	1.0%	1,167	4.3%	3,068	11.2%
Full Participation										
Pricing with Technology	2,015	7.4%	233	0.9%	400	1.5%	342	1.2%	2,990	10.9%
Pricing without Technology	238	0.9%	3	0.0%	44	0.2%	276	1.0%	560	2.0%
Automated/Direct Load Control	68	0.2%	0	0.0%	0	0.0%	0	0.0%	68	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	37	0.1%	625	2.3%	662	2.4%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	189	0.7%	189	0.7%
Total	2,321	8.5%	236	0.9%	480	1.8%	1,431	5.2%	4,468	16.3%



Washington State Profile

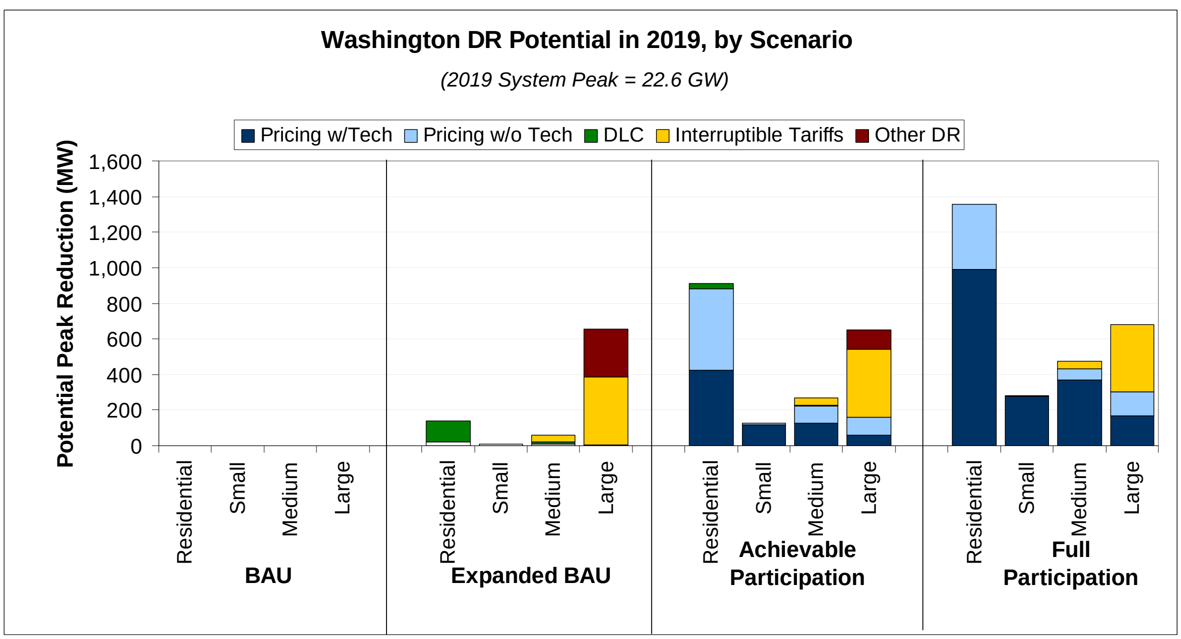
Key drivers of Washington's demand response potential estimate include: lower-than-average residential CAC saturation of 29 percent and no existing demand response. Enabling technologies are cost-effective for all classes. Also, the state's potential AMI deployment slightly leads the national average. Low CAC saturation and non-existent demand response are the key drivers for the state.

BAU: Currently, the state has no demand response. Historically, low energy prices and a surplus of hydro capacity have made demand response seemingly less attractive in this region.

Expanded BAU: The majority of the potential demand response is from Large C&I, through interruptible tariffs and other demand response. Some Residential demand response potential comes from DLC and dynamic pricing.

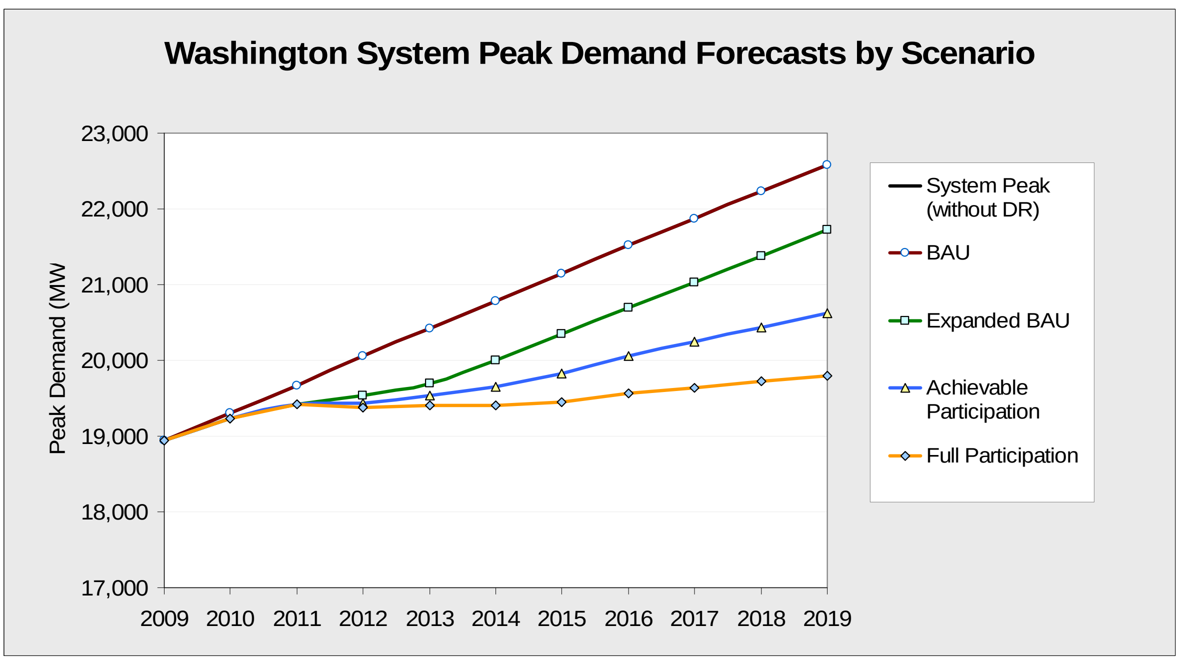
Achievable Participation: Demand response potential is driven by dynamic pricing with and without enabling technology. Many of the residential customers enrolled in DLC programs under the EBAU scenario would instead be expected to enroll in dynamic pricing with enabling technology under this scenario. Relative to the EBAU scenario, Large C&I customers would be enrolled more heavily in dynamic pricing than in interruptible tariff and other demand response programs.

Full Participation: Dynamic pricing programs dominate the demand response potential for this scenario, primarily those utilizing enabling technologies. The largest amount of load reduction can be potentially derived from residential customers. Enabling technologies are cost-effective for all customer classes. Some interruptible tariff demand response remains for both Medium and Large C&I.



Total Potential Peak Reduction from Demand Response in Washington, 2019

	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%	0	0.0%	0	0.0%
Total	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	21	0.1%	0	0.0%	7	0.0%	5	0.0%	33	0.1%
Automated/Direct Load Control	118	0.5%	8	0.0%	12	0.1%	0	0.0%	138	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	41	0.2%	381	1.7%	422	1.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	271	1.2%	271	1.2%
Total	139	0.6%	9	0.0%	60	0.3%	657	2.9%	864	3.8%
Achievable Participation										
Pricing with Technology	424	1.9%	118	0.5%	127	0.6%	57	0.3%	725	3.2%
Pricing without Technology	457	2.0%	8	0.0%	97	0.4%	104	0.5%	665	2.9%
Automated/Direct Load Control	30	0.1%	2	0.0%	5	0.0%	0	0.0%	37	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	41	0.2%	381	1.7%	422	1.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	111	0.5%	111	0.5%
Total	911	4.0%	128	0.6%	270	1.2%	652	2.9%	1,960	8.7%
Full Participation										
Pricing with Technology	991	4.4%	275	1.2%	370	1.6%	167	0.7%	1,803	8.0%
Pricing without Technology	365	1.6%	5	0.0%	62	0.3%	134	0.6%	567	2.5%
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%	41	0.2%	381	1.7%	422	1.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	1,357	6.0%	280	1.2%	473	2.1%	682	3.0%	2,792	12.4%



West Virginia State Profile

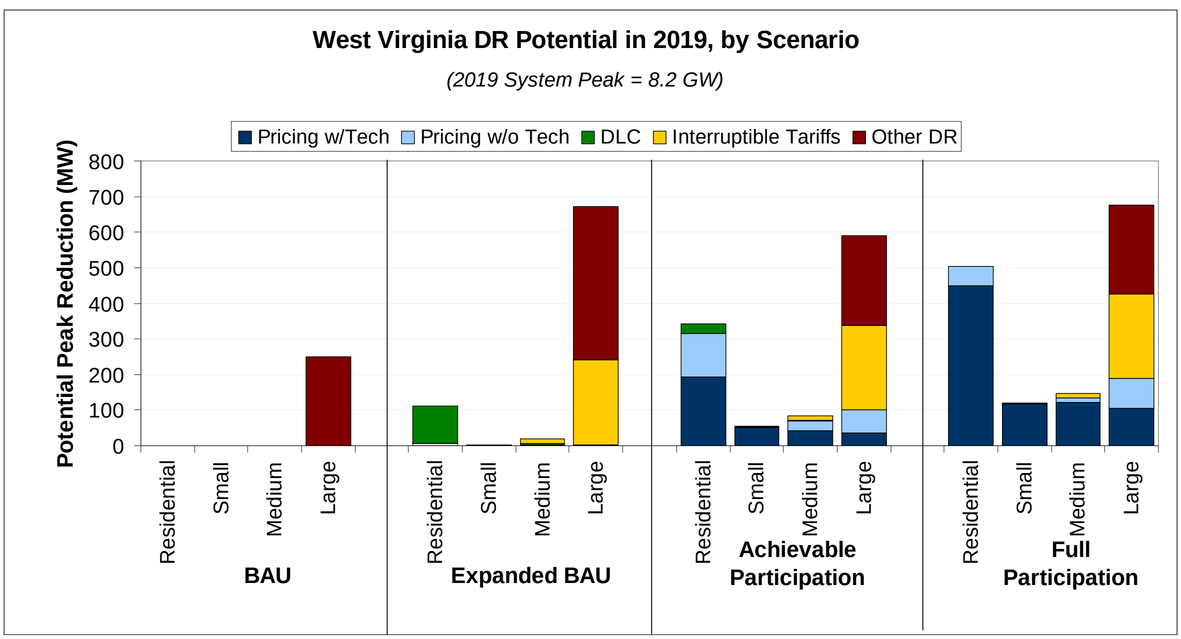
Key drivers of West Virginia's demand response potential estimate include: a CAC saturation of 50 percent and a moderate amount of existing demand response, and a larger-than-average Large C&I class (32%). Enabling technologies are cost-effective for all classes of customers. Also, potential AMI deployment slightly leads the national average. The larger-than-average Large C&I class, with significant existing demand response, is the primary driver for the state.

BAU: West Virginia has a significant amount of existing demand response for the Large C&I class, but none for the remaining classes.

Expanded BAU: Demand response potential comes primarily from the Residential and Large C&I classes. Residential demand response potential is in DLC programs, while the incremental increase in Large C&I potential is in interruptible tariff and 'Other DR' programs.

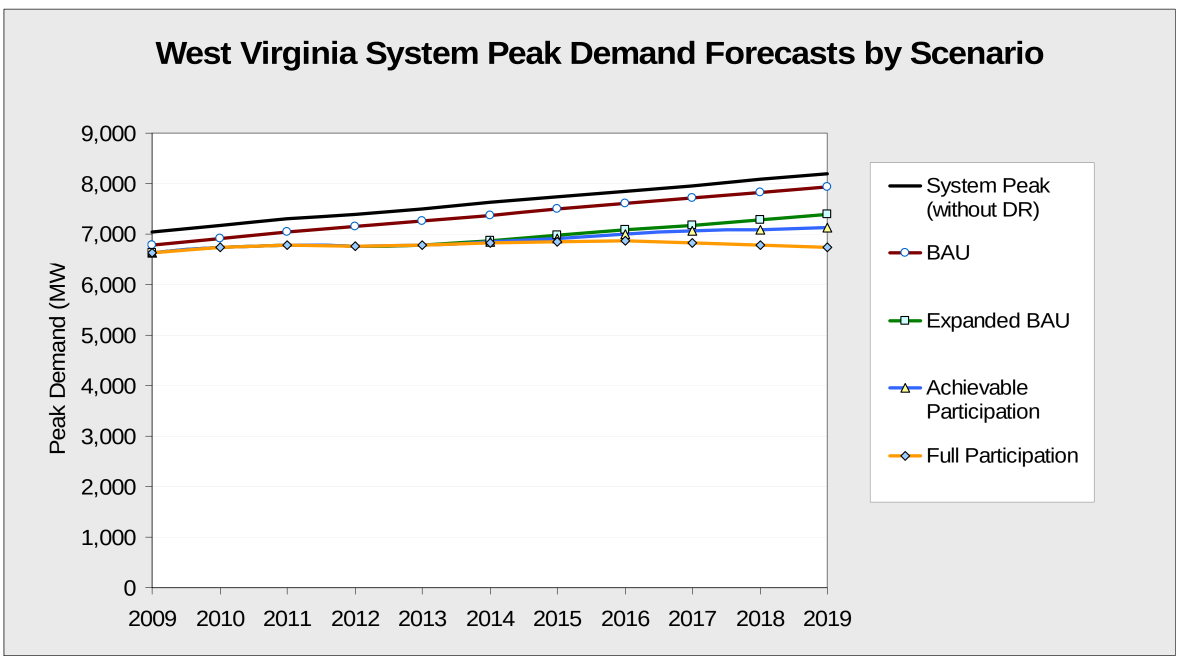
Achievable Participation: The main driver of demand response potential in this scenario is through dynamic pricing, with a significant amount of impact coming from the use of enabling technologies. Enabling technologies are cost-effective for all customer classes. The Large C&I class continues to dominate demand response potential because of its larger-than-average share of system peak load.

Full Participation: Demand response potential from dynamic pricing with enabling technology is largest under this scenario, with all customer classes exhibiting incremental increases in demand response potential relative to the other scenarios. For large C&I customers, potential from Interruptible tariffs and 'Other DR' programs continue to dominate.



Total Potential Peak Reduction from Demand Response in West Virginia, 2019

	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%	250	3.1%	250	3.1%
Total	0	0.0%	0	0.0%	0	0.0%	250	3.1%	250	3.1%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	7	0.1%	0	0.0%	2	0.0%	3	0.0%	12	0.1%
Automated/Direct Load Control	104	1.3%	3	0.0%	5	0.1%	0	0.0%	112	1.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	13	0.2%	238	2.9%	251	3.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	431	5.3%	431	5.3%
Total	111	1.4%	3	0.0%	19	0.2%	672	8.2%	806	9.8%
Achievable Participation										
Pricing with Technology	192	2.3%	50	0.6%	42	0.5%	36	0.4%	320	3.9%
Pricing without Technology	123	1.5%	3	0.0%	28	0.3%	65	0.8%	219	2.7%
Automated/Direct Load Control	27	0.3%	1	0.0%	2	0.0%	0	0.0%	29	0.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	13	0.2%	238	2.9%	251	3.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	250	3.1%	250	3.1%
Total	342	4.2%	54	0.7%	84	1.0%	589	7.2%	1,069	13.1%
Full Participation										
Pricing with Technology	450	5.5%	118	1.4%	121	1.5%	104	1.3%	794	9.7%
Pricing without Technology	54	0.7%	1	0.0%	13	0.2%	84	1.0%	153	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%	13	0.2%	238	2.9%	251	3.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	250	3.1%	250	3.1%
Total	504	6.2%	119	1.5%	147	1.8%	677	8.3%	1,448	17.7%



Wisconsin State Profile

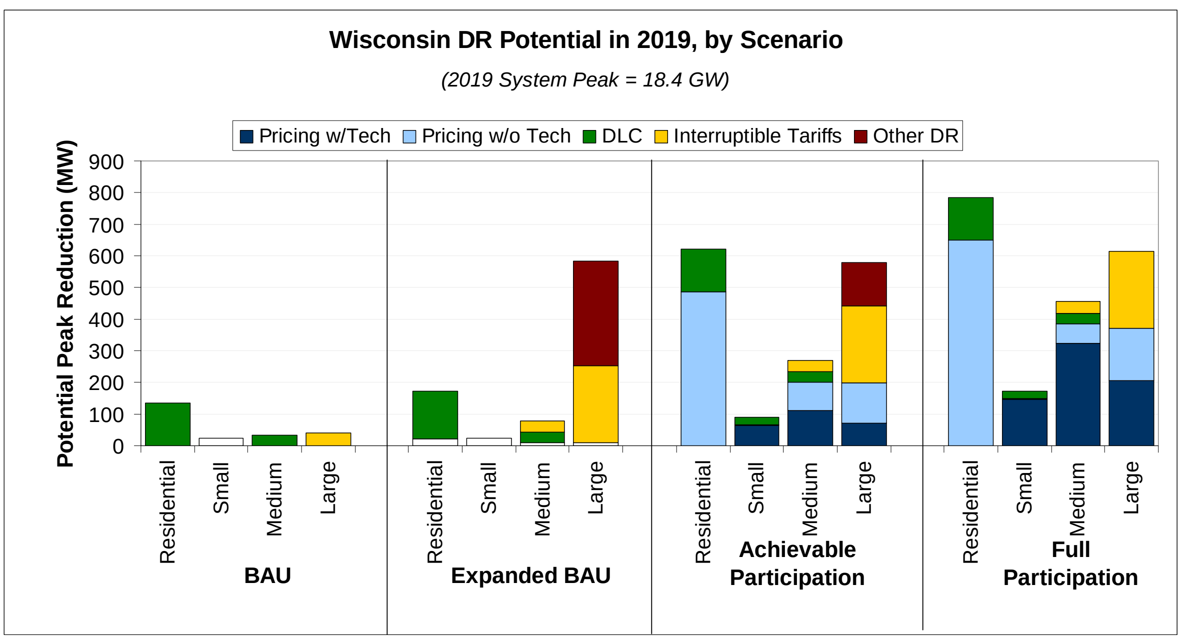
Key drivers of Wisconsin's demand response potential estimate include: a significant level of CAC saturation at 62 percent and a small amount of existing demand response. Enabling technologies are cost-effective for all C&I classes, but not for the Residential class. Also, a potential AMI deployment schedule that leads the national average could lead to faster realized demand response potential.

BAU: Wisconsin has existing demand response for Large C&I through an interruptible tariff program. DLC programs are in place for the remaining customer classes, with the Residential class exhibiting the largest impacts.

Expanded BAU: The Large C&I class exhibits significant demand response potential, which is driven by enrollment in new interruptible tariff and other demand response programs. Dynamic pricing plays a very small role relative to DLC impacts for Residential customers in this scenario

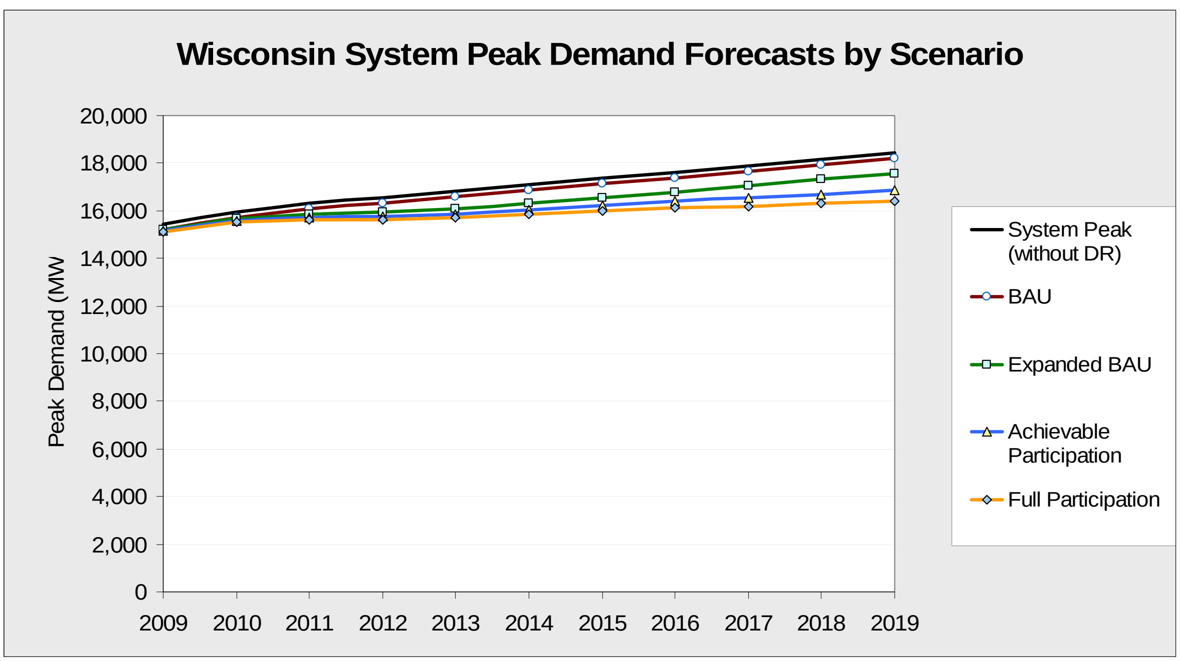
Achievable Participation: The majority of the incremental increase in demand response potential is due to dynamic pricing. Pricing with enabling technologies appears for all classes, except for the Residential class for which it is not cost effective. Still, the Residential class exhibits significant potential through participation in dynamic pricing programs without enabling technology. Total potential demand response decreases for the Large C&I class as a result of customers shifting to dynamic pricing programs, which produce smaller per-customer impacts.

Full Participation: Potential demand response continues to grow through increased enrollment in dynamic pricing programs. Large C&I customers are more heavily enrolled in dynamic pricing programs, slightly decreasing potential impacts from this class.



Total Potential Peak Reduction from Demand Response in Wisconsin, 2019

	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	135	0.7%	24	0.1%	33	0.2%	0	0.0%	191	1.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	40	0.2%	40	0.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	135	0.7%	24	0.1%	33	0.2%	40	0.2%	231	1.3%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	21	0.1%	0	0.0%	9	0.0%	9	0.0%	39	0.2%
Automated/Direct Load Control	151	0.8%	24	0.1%	33	0.2%	0	0.0%	207	1.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	37	0.2%	244	1.3%	281	1.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	331	1.8%	331	1.8%
Total	172	0.9%	24	0.1%	79	0.4%	583	3.2%	858	4.7%
Achievable Participation										
Pricing with Technology	0	0.0%	63	0.3%	111	0.6%	70	0.4%	244	1.3%
Pricing without Technology	487	2.6%	4	0.0%	89	0.5%	128	0.7%	707	3.8%
Automated/Direct Load Control	135	0.7%	24	0.1%	33	0.2%	0	0.0%	191	1.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	37	0.2%	244	1.3%	281	1.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	137	0.7%	137	0.7%
Total	621	3.4%	90	0.5%	270	1.5%	579	3.1%	1,560	8.5%
Full Participation										
Pricing with Technology	0	0.0%	147	0.8%	324	1.8%	205	1.1%	677	3.7%
Pricing without Technology	649	3.5%	2	0.0%	61	0.3%	166	0.9%	878	4.8%
Automated/Direct Load Control	135	0.7%	24	0.1%	33	0.2%	0	0.0%	191	1.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	37	0.2%	244	1.3%	281	1.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	784	4.3%	173	0.9%	455	2.5%	615	3.3%	2,027	11.0%



Wyoming State Profile

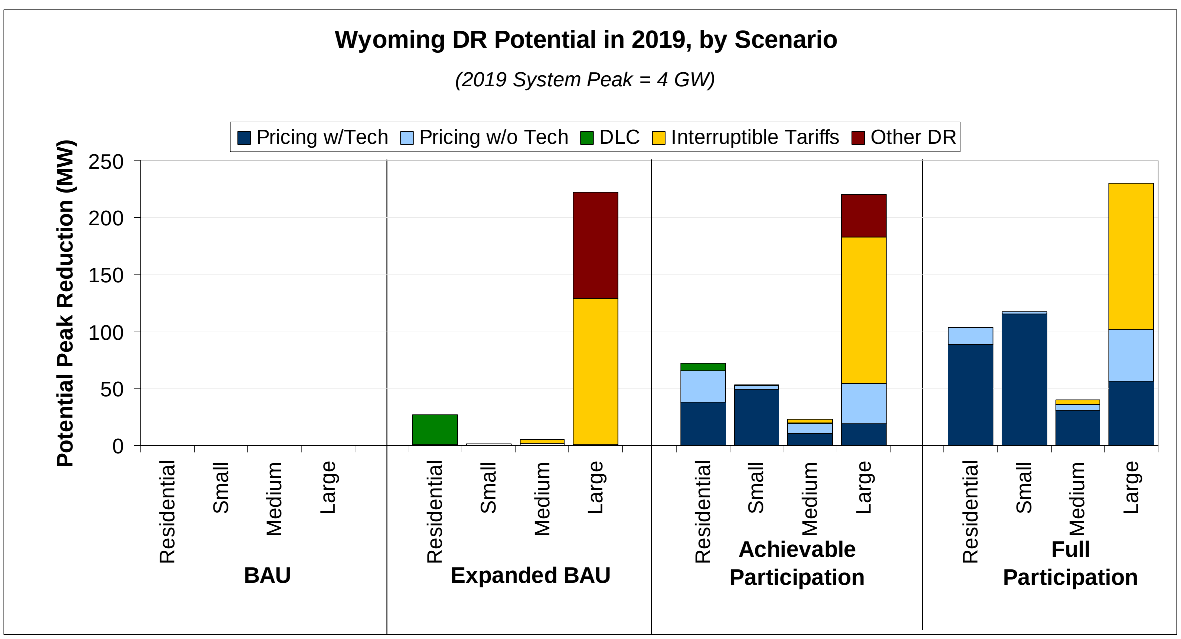
Key drivers of Wyoming's demand response potential estimate include: lower-than-average residential CAC saturation of 42 percent and no existing demand response. Enabling technologies are cost-effective for all C&I classes and for residential customers. Also, potential AMI deployment that lags the national average could lead to slower realized demand response potential. The larger-than-average Large C&I class (36%) is the main driver of demand response in the state.

BAU: Currently, Wyoming has no existing demand response.

Expanded BAU: The Large C&I class represents the vast majority of demand response potential in the state, through enrollment in both interruptible tariff and other demand response programs. A moderate amount of demand response potential exists in residential DLC programs.

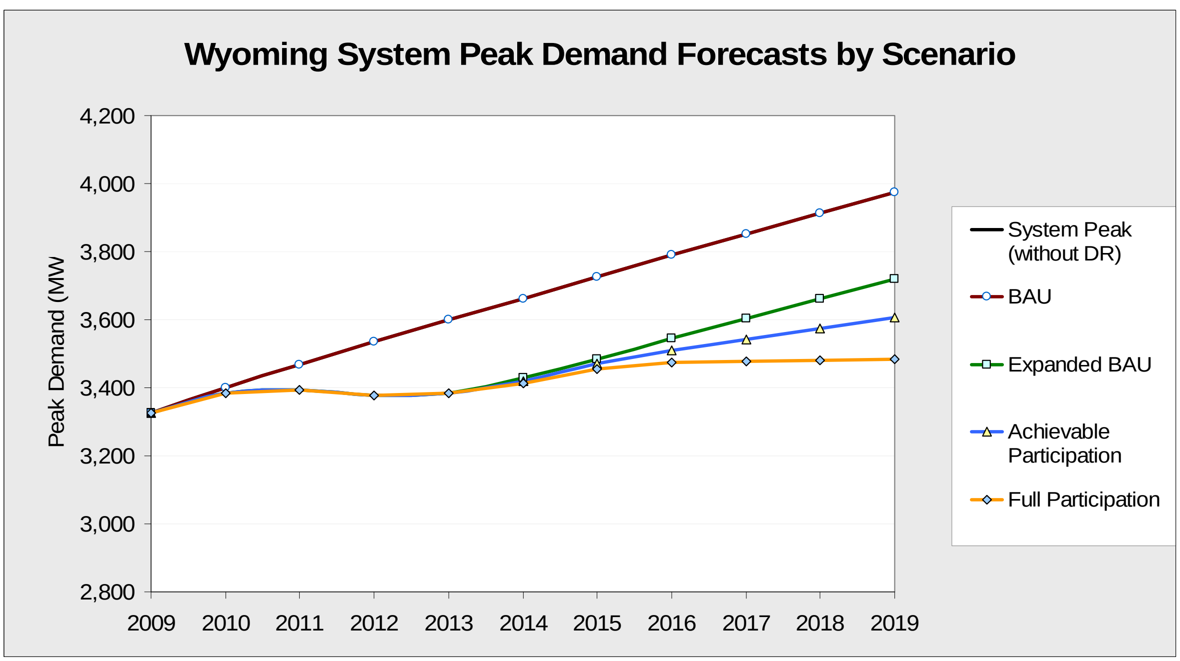
Achievable Participation: Impacts from dynamic pricing are relatively small compared to demand response potential in Other DR and Interruptible tariffs. All classes adopt enabling technologies. Total demand response potential decreases slightly for the Large C&I class due to customers shifting from other demand response programs in to pricing programs, which have smaller per- customer peak impacts.

Full Participation: Incremental demand response potential is highest for the residential, small, and medium C&I classes under this scenario. The Large C&I class drives total potential demand response in the state.



Total Potential Peak Reduction from Demand Response in Wyoming, 2019

	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%	0	0.0%	0	0.0%
Total	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Expanded 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%	1	0.0%	2	0.0%
Automated/Direct Load Control	26	0.7%	1	0.0%	1	0.0%	0	0.0%	29	0.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	3	0.1%	129	3.2%	132	3.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	93	2.3%	93	2.3%
Total	27	0.7%	1	0.0%	5	0.1%	222	5.6%	256	6.4%
Achievable Participation										
Pricing with Technology	38	0.9%	49	1.2%	11	0.3%	19	0.5%	117	2.9%
Pricing without Technology	28	0.7%	3	0.1%	8	0.2%	35	0.9%	74	1.9%
Automated/Direct Load Control	7	0.2%	0	0.0%	1	0.0%	0	0.0%	8	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	3	0.1%	129	3.2%	132	3.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	37	0.9%	37	0.9%
Total	72	1.8%	53	1.3%	23	0.6%	220	5.5%	368	9.3%
Full Participation										
Pricing with Technology	88	2.2%	115	2.9%	31	0.8%	56	1.4%	291	7.3%
Pricing without Technology	15	0.4%	2	0.1%	5	0.1%	45	1.1%	68	1.7%
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%	3	0.1%	129	3.2%	132	3.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	104	2.6%	117	3.0%	40	1.0%	230	5.8%	491	12.4%



APPENDIX B. LESSONS LEARNED IN DATA DEVELOPMENT

Development of state-level data for a bottom-up demand response potential assessment is a complex and challenging task. Data had to be developed for each state and D.C. by type of end-use customer, by type of demand response program, and by demand response potential estimation scenario, with an analysis timeframe spanning 2009-2019. The data development process drew upon information from a variety of different sources. There were challenges faced in compiling information, often not uniformly available across sources, to arrive at data required for potential estimation for all states. This section briefly discusses some of the challenges related to data development and scope for future improvements that are likely to address these challenges. It is intended to serve as a guide for making future updates to the analysis.

Nature of utility data reporting

<u>Challenges</u>
In developing some of the key data items required for potential estimation, utility data was aggregated to come up with state level estimates. Very often, it was found that for utility companies with service territories across multiple states, the reporting of data is at the operating company or entity level and is not disaggregated at the state level for these companies. This posed difficulties in directly aggregating the data to come up with state level estimates. Examples of data items where this difficulty was encountered are: state level estimates that show number of accounts by rate class, sales by rate class, and state peak load forecasts. In such cases, entity level data was disaggregated to the state based on other utility-level parameters reported by the operating company.

<u>Scope for future improvements</u>
Alteration of the nature of utility data reporting for those with service territories across multiple states is likely to address this problem. If utilities report data at the operating state level, instead of aggregate data at the entity level, it will make state level estimations easier.

Incomplete and non-uniform information availability for key data items

<u>Challenges</u>
Difficulties were posed by lack of availability of information related to key data items for potential estimation. Also, often when information was available, it was available from a wide variety of sources, and thus not uniformly characterized.

Examples of key data inputs where such challenges were faced are CAC saturation for residential customers and unit impact estimation for residential DLC programs. In the case of residential CAC saturation estimation across states, there were only very few states where information was available from statewide saturation surveys and other similar sources. Often, it was necessary to compile individual utility-level information and use that as the basis for arriving at state level estimates. There were a few states where data was available from housing surveys for certain metropolitan areas in the state. Also, data availability was for different years. Additionally, there were some states where it was difficult to source the data directly from any state level estimate. In such cases, regional values from appliance saturation surveys (e.g. Residential Appliance Saturation Survey conducted by EIA) were used to derive the state estimate.

Scope for future improvements
Development of comprehensive databases for key items with uniform level of information availability is likely to address this problem. For example, for residential CAC saturation data, a central repository of information from different sources to arrive at state level estimates could be compiled and periodically updated.

Data coverage by utility ownership

Challenges
During the process of developing aggregate state level estimates from utility data, there were difficulties due to lack of data from non-IOUs in the states. For example, FERC Form No.1 data reporting served as the basis for developing distribution of C&I customers by rate class (small, medium, and large).[71] But the FERC Form No. 1 data is available only for Investor-Owned Utilities (IOUs). In the absence of any such similar data reporting from non-IOUs, it was assumed that the distribution for IOUs was applicable to the non-IOUs in the state as well. Also, there were cases where data was not available for all IOUs in the state. Therefore, in all such cases, the estimations from the limited utility data set were assumed to be representative for the state.

Scope for future improvements
Systematic and uniform data collection from all utilities, across different ownership types, is likely to address this problem.

Level of data availability

Challenges
In developing some of the data items, it was necessary to apply regional estimates as proxy for state level data, wherever information at the state level was difficult to obtain. In cases where regional estimations could not be directly applied, the regional data was disaggregated to provide state level estimates based on related data available by state. For example, system peak load forecast from NERC was available only at the NERC regional level, which had to be disaggregated to arrive at state level system peak values. The methodological framework for doing that is described under the 'Data Development' section in the Appendix. Another example is application of regional estimates for growth rate in C&I accounts for all states in a particular census region, since variation by state for this particular item was difficult to estimate.

Scope for future improvements
Wherever information is available only at the regional level, future efforts could be directed towards systematically developing information at the state level by encouraging relevant agencies to report state-level information.

Difficulties related to data development by C&I rate classes

Challenges
A key challenge in developing data related to demand response potential estimation was in developing data for the three rate classes (small, medium, and large) for the C&I sector. Almost all key data inputs for potential estimation had to be developed at the rate class level. However, there was no source from where the information could be directly procured for the commercial rate classes. FERC Form No. 1 data, where individual utilities (IOUs only) report information by rate schedule, was used as the primary basis for developing data by rate class. But use of the FERC Form No. 1 data

[71] FERC Form-1 data was the best, most recently available information among possible data sources, including EIA, USDA Rural Utilities Service (RUS) and other entities that compile databases, etc.

for data estimation by rate class, in turn posed challenges that was inherent to the nature of the FERC Form No. 1 data availability and reporting requirements.

For example: FERC Form No.1 data is reported only by IOUs, and therefore the distribution of C&I customers by rate class applied only to IOUs. In the absence of similar data availability for non-IOUs, we applied the distribution from FERC Form No. 1 to all utilities in a state to arrive at the state level distribution, thereby assuming that the distribution of C&I customers by rate class for IOUs applies to non-IOU utilities as well. For utilities that operate in multiple states, it was necessary to assume that the same mix of C&I customers applies to all states in which a utility operates. In addition, FERC Form No. 1 data was not available for all IOUs across states.

Scope for future improvements

Data availability from utilities, which indicates the classification of customers by peak load, is likely to address this problem. This will enable categorizing C&I customers into different peak load size ranges. Also, information should be available from utilities across different ownership types.

APPENDIX C. DETAIL ON BARRIERS ANALYSIS

A number of barriers are preventing demand response from reaching its full potential in the United States. Some of these barriers are regulatory in nature, stemming from existing policies and practices that are not designed to facilitate the use of demand response as a resource. These barriers exist in both wholesale and retail markets. Other barriers are economic in nature. Finally, certain technological limitations are also standing in the way. In total, there are some 24 barriers to demand response. This appendix includes a discussion of existing demand response barriers, organized into four categories: (1) Regulatory barriers (general, retail and wholesale), (2) economic barriers, (3) technological barriers, and (4) other barriers.

Regulatory Barriers

Regulatory barriers are impediments to demand response caused by a particular regulatory regime, market design, market rules, or the demand response programs themselves.[72] Regulatory barriers constitute the largest group of barriers in this analysis. Below is a summary of the major regulatory barriers, divided into three sub-categories: general, retail-level, and wholesale-level.

General Regulatory Barriers

Retail and Wholesale Price Disconnect

Principal among the regulatory barriers is the lack of a direct connection between retail and wholesale electricity prices. This refers specifically to the lack of dynamic pricing in retail markets.[73] Simply put, most of today's retail tariffs do not reflect the time variation in the cost of electricity supply. As a result, customers are not provided with the appropriate price signals to promote efficient electricity consumption and may over-consume power during expensive peak periods and under-consume power during inexpensive off-peak periods.

Retail customers are essentially provided a full requirements contract in which suppliers bear all the volumetric and price risk. Such fully hedged rates dominate the marketplace, particularly for residential customers. Dynamic pricing rates are not provided as universal service rates nor are they offered as the default service to residential customers of any utility in the US. Indeed, in most parts of the country, dynamic pricing rates are not even available on an elective basis to residential customers. One often cited reason is that the necessary metering technology is not widely deployed to this class of customers.[74] But there are other reasons as well, including a perception that customers do not like price volatility.

While it is true that time-of-use (TOU) rates are the default rate for large commercial and industrial (C&I) customers at some utilities, these rates do not fully reflect the dynamics of power markets or electricity supply costs. Larger C&I customers in restructured power markets such as Connecticut, Illinois, Maryland, Michigan, New England, New Jersey and New York commonly face default real-time pricing

[72] Barriers related to customer attitudes, which sometimes fall into this category, are addressed in the "Other Barriers" section.

[73] In this discussion, we distinguish between two types of time-varying pricing, dynamic and static. Traditional TOU rates, in which prices typically vary by rate period, day of week and season, have higher prices during all peak rate periods and lower prices during all off-peak rate periods. Since TOU price levels and the timing of the periods are known with certainty, they are static time varying prices. Dynamic prices have some degree of uncertainty associated with them, either concerning when certain prices are in effect, or what price levels are in each time period. Critical peak pricing is a dynamic rate in which the prices on certain days are known ahead of time, but the days on which those prices occur are not known until the day before or day of. Real time pricing is another form of dynamic pricing, in which prices in effect in each hour are not known ahead of time.

[74] However, time-varying rates are an option for some residential customers. For example, Arizona Public Service and Salt River Project offer widely-adopted residential TOU rates. Georgia Power offers a residential critical peak pricing (CPP) rate.

(RTP) rates.[75] However, even these rates typically do not reflect the full time variation in supply costs, as they do not incorporate long-run capacity costs in peak period prices.

In July 2008, there was a decision by the California Public Utilities Commission (CPUC) to make dynamic pricing the default rate offering for all customer classes in the state.[76,77]

Measurement and Verification (M&V) Challenges

To accurately assess the benefits of demand response, it is necessary to have standardized practices for quantifying demand reductions. Currently, these practices are often unclear, inaccurate, and inconsistent across utilities, states and ISOs. This has negative impacts on three specific areas: demand response contract settlement, operational planning, and long term resource planning. To date, the focus has generally been on developing M&V practices for settlement purposes, and determining the appropriate level of demand response that should be compensated. However, operational and long term planning have not been key factors in that development process. Both deserve more attention. Operational methods need to be developed to better predict the short term (i.e. day-ahead) impacts of demand response resources. M&V is important to the long-term planning process to the extent that it will influence generation, transmission, and distribution investment decisions.

In April of this year, the California Public Utilities Commission adopted a set of load impact protocols that California's IOUs must use to develop both ex post and ex ante impact estimates for all of their demand response programs.[78] These protocols are designed primarily to support long term resource planning and to asses progress toward meeting resource adequacy requirements in California. They set minimum requirements in terms of the type of information that must be provided for each demand response resource (e.g., impact estimates for each hour on a typical event day) and the factors that must be taken into consideration when developing impact estimates (e.g., ex ante impact estimates must be developed for weather conditions representing 1-in-2 and 1-in-10 weather years). Each year, California's utilities are required to produce ex post impact estimates for each program for the prior year and to update ex ante impact estimates for the subsequent five year period. The protocols were used by each of California's three major IOUs in their recent demand response program applications.[79] In conjunction with these applications, thousands of Excel spreadsheets were filed with the CPUC showing ex post and ex ante impact estimates for roughly a dozen different types of demand response resources and various customer segments. These tables are good examples of the type of information resource that can be developed in the industry when regulators and other stakeholders establish good M&V standards and protocols.

Another example of useful work in the M&V area is represented by recent work being done by the North American Electric Reliability Corporation (NERC) initiated an effort to improve its data collection process for evaluating existing demand response resources at the NERC region level.[80] The effort will specifically focus on expanding and more accurately defining the sources of demand response that are reported, as well as improving the methodology that utilities will use to collect and report data on their demand-side management (DSM) programs.

Much of NERC's initiative will be coordinated with work that is being done by the North American Energy Standards Board (NAESB) to create M&V standards for wholesale markets. This work will focus

[75] FERC, "2007 Assessment of Demand Response and Advanced Metering," September 2007.
[76] Decision adopting dynamic pricing timetable and rate design guidance for Pacific Gas & Electric Company, D. 08-07-045, July 31, 2008.
[77] The residential class is an exception, where legislation (Assembly Bill 1X) freezes the rates for 130 percent of baseline usage until the power purchase contracts that were signed by the state during the energy crisis of 2001 have expired.
[78] CPUC D.08-04-050 issued on April 28, 2008 with Attachment A.
[79] See, for example, Stephen S. George, Josh Bode and Josh Schellenberg. Load Impact Estimates for Southern California Edison's Demand Response Program Portfolio, September 25, 2008. Filed in conjunction with SCE's Demand Response Program Application for 2009-2011.
[80] NERC, "Data Collection for Demand-Side Management for Quantifying Its Influence on Reliability: Results and Recommendations," December 2007.

on developing voluntary demand response standards that would have both wholesale and retail components.[81] Meetings are currently being held to bring industry leaders together to focus on specific recommendations for these standards.

A related barrier to measurement and verification – disagreement on cost-effectiveness analysis – is discussed in the "Retail Regulatory Barriers" section.

Shared State and Federal Jurisdiction
Another barrier to demand response is that of shared state and federal jurisdictions. State commissions regulate retail sales in their own jurisdictions, but do not regulate wholesale markets or transmission. FERC, on the other hand, regulates wholesale markets, but has no direct control over retail tariffs.[82] To the extent that these regulatory bodies have conflicting policy objectives, lack of a coordinated effort can pose a serious barrier to demand response. This concept can also be extended to include state-level interactions with RTOs and ISOs, where a coordinated effort across multiple states is needed to maximize the reliability value of utility-operated demand response programs. At the recent FERC Technical Conference on demand response in organized markets, a representative from Dominion Electric Cooperative cited this as a major barrier to their demand response efforts, specifically indicating that no consensus for the demand response "end game" has been reached, and that a single roadmap is needed to move forward and address the "intertwining between federal and state jurisdictions."[83]

Perception of Gaming
The perception that some participants in demand response programs will "game" the system has become a barrier for demand response programs that require the estimation of a participant's baseline consumption level. This can apply at both the wholesale and retail levels. For example a large industrial customer that is bidding demand reductions into a wholesale demand response program would have the incentive to increase its baseline in order to appear to provide larger demand reductions. A similar incentive would exist in retail programs such as peak-time rebates (PTR) for residential customers, where customers are paid based on how much they lower their usage with reference to an unobserved baseline. RTOs such as PJM are currently examining methods for reducing the ability of participants to artificially inflate their baselines.

Considerable attention was paid to this topic at the FERC Technical Conference on demand response in organized markets. Participants identified ongoing efforts to address the baseline gaming issue in both California and PJM. Further, ISO New England (ISO-NE) and New York ISO (NYISO) were identified as discussing a new proposed method of estimating baselines.[84] A number of suggestions were proposed for addressing this issue, including using different estimation methods for different customer types (e.g., making a distinction between weather-responsive and non-weather-responsive customers) and relying on an entire season of historical load data.[85]

Lack of Sufficient Real Time Information Sharing Between ISOs and Utilities
When responding to an emergency event on the system, ISOs are not always aware of how much of a particular demand response resource is available, or even when it has been called by the utilities. This lack of real time communication among ISOs, utilities, and aggregators limits the value of demand response to ISOs for operational planning purposes and potentially leaves valuable demand response resources sitting idle at a time when they are needed most. According to the FERC 2007 Demand Response Assessment, this was found to be an issue during heat waves in the summer of summer 2006 in both California and the Midwest ISO.[86]

[81] NAESB comments to FERC Technical Conference on Demand Response in Wholesale Markets, April 2007.
[82] An exception to this is ERCOT which is not subject to FERC jurisdiction because it is wholly contained within the state of Texas and only has asynchronous transmission connections with other states.
[83] Proceedings to FERC Technical Conference on Demand Response in Organized Electric Markets, May 21, 2008, p. 136.
[84] Proceedings to FERC Technical Conference on Demand Response in Organized Electric Markets, May 21, 2008, p. 17.
[85] *Ibid.*, p. 65.
[86] FERC, "2007 Assessment of Demand Response and Advanced Metering," September 2007.

Lack of Reliability and Predictability of Demand Response
For demand response to be valuable as a resource, it must be dependable and predictable. In other words, when a program operator "pushes the button" they need to know that they will get the amount of demand reduction that they are expecting. Today, there are concerns that demand response is not as reliable as a supply-side resource. This is largely due to a lack of historical evidence (or at least data) showing consistent impacts from demand response resources or estimates of what demand response resources will provide under various event conditions. This is particularly true for economic programs such as dynamic pricing, for which there have been many robust pilots that have quantified the impacts, but for which there is not yet a significant history of full scale deployment. This shortcoming should decline over time as more empirical evidence is developed and made available to the industry, such as the load impacts recently filed by California's IOUs that were referenced above.

At the wholesale level, in ISO-NE the results of a small pilot showed that the aggregate performance of demand response assets varied from 30 percent to 90 percent of the expected reduction from one demand response event to the next. Efforts are underway to expand the size of these pilots and develop more robust results.[87]

This barrier may be derived partly from the voluntary nature or many demand response programs. These programs do not require that enrolled customers provide peak reductions during critical events – they simply offer payments if the customers respond. By putting control of the program in the hands of the participant, there is no guarantee that the load reduction will be provided. However, a noteworthy counterargument to be made is that while a specific customer may or may not respond to an event on any given day, what matters is the aggregate response from all customers enrolled in a program. To the extent that this aggregate number is statistically predictable, then the program does serve as a reliable resource.

Retail Regulatory Barriers

Policy Restrictions on Demand Response
One of the single biggest barriers to demand response at the retail level is policy restrictions that have the unintended consequence of limiting or even prohibiting certain types of demand response. This most commonly occurs in the form of restrictions on rate design. One such example is California's Assembly Bill 1X, which has been interpreted by the CPUC as a rate freeze for the first two tiers of each residential customer's usage.[88] This effectively prohibits utilities from offering time-of-use or dynamic rates to residential customers on a default basis because they would raise prices in the first two tiers for peak periods. Because of this constraint, the utilities in California have proposed the use of Peak Time Rebates (PTR) for all residential customers. A PTR is a "carrot only," pay for performance program that pays customers a certain amount for each kWh reduced during peak periods on high demand days.

Utilities in New York currently face a similar problem. In New York, state law prohibits utilities from placing residential customers on mandatory or default time-of-use-rates, forcing them to provide these rates on an opt-in basis and effectively reducing the participation rate. In Maine, current restrictions on the form of Standard Offer Service that can be offered through regulated utilities significantly inhibit (some have argued prevent) the ability to offer peak time rebates or critical peak prices to customers that do not switch to competitive suppliers.

Ineffective Demand Response Program Design
Ineffective demand response program design can lead to low enrollment and/or low impacts for demand response programs. One such example is the Puget Sound TOU pricing pilot of 2002.[89] The pilot tested a TOU rate with a very small peak-to-off peak price differential. Due to this design, customers who shifted significant amounts of load from the peak period to the off peak period saw only small bill savings, and

[87] Proceedings to FERC Technical Conference on Demand Response in Organized Electric Markets, May 21, 2008, p. 132.
[88] See, for example, CPUC Decision 04-04-020.
[89] Ahmad Faruqui and Stephen S. George, "Demise of PSE's TOU Program Imparts Lessons," Electric Light and Power, January 2003.

lost interest in participating as a result. As large numbers of customers exited the program, it created a public relations problem for the utility and the program was shut down.

Another characteristic of poor demand response program design is a short expected program life. When programs are implemented as trial programs, there can be hesitancy on the part of customers to invest in the equipment, systems, and training necessary to make the program a success. Other characteristics of the program must also be designed with the intent to balance operational needs with customer ability to respond. For example, if the lead time to respond to demand response events is short (e.g., day-of) and customers are not equipped with enabling technologies to automate load reductions, then their ability to respond will be limited.[90] The duration and frequency of demand response events will also influence the participation level of customers. Ultimately, demand response programs must be designed to find an attractive balance between the reward that customers receive and the inconvenience (or cost) that they incur by participating.

Other examples of ineffective program design include disconnects between event triggers and operational needs (e.g., calling CPP events too late in the day to influence day ahead bids and dispatch schedules), telemetry requirements that may not be relevant for demand resources, and paying incentives that are significantly lower than avoided capacity costs and therefore limiting program participation.

Financial Disincentives for Utilities

Without certain regulatory mechanisms in place, utilities generally have a disincentive to pursue programs that will reduce sales. While this problem is most pronounced with energy efficiency programs, it is also present with programs to encourage demand response. Ultimately, the reduction in sales that results from demand response programs will cause the utility to fall short of recovering the fixed revenue requirement that would otherwise be recovered in the absence of the sales reduction.

The lost revenue disincentive associated with demand response is particularly relevant with respect to TOU rates and dynamic pricing. These rates are designed to be revenue neutral assuming no change in the pattern of energy use, but they ultimately are expected to change the pattern of use. If customers are on TOU pricing, revenue is expected to fall as a result of the change in consumption. With dynamic pricing there is also an issue that a significant amount of revenue is being collected through prices during the peak periods of a few “critical” days. To the extent that critical events are not triggered on those days and the critical prices are not dispatched, the utility would fall short of its revenue requirement.

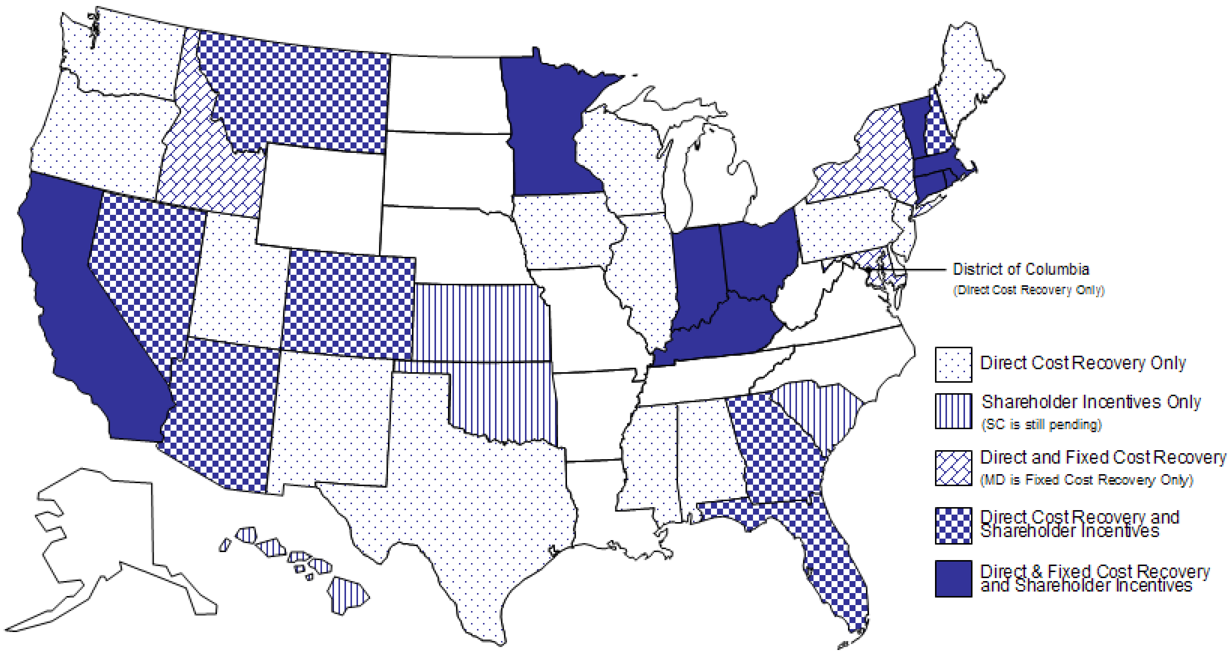
To address this, some states have regulatory incentives in place to either remove this disincentive, or provide a financial incentive to pursue demand-side programs. The regulatory mechanisms fall into three categories:

- Direct cost recovery: This is the most common form of regulatory incentive. It allows utilities to recover the DSM program implementation costs in a timely manner. It is also the weakest of the three mechanisms for promoting DSM.
- Fixed cost recovery: This category includes “decoupling.” Essentially, the link between sales and revenue is removed and utilities are allowed to true-up their rates between rate cases to recover the lost revenues associated with the decreased electricity sales.
- Shareholder incentives: This includes all models that are designed to provide utilities with a financial incentive above and beyond their normal rate of return on investments. A recent example is California’s Shared Savings model, which shares the net benefits of DSM impacts between the utility and the consumer. The Duke Save-a-Watt model is another such example, although it has not yet been adopted.

[90] This has recently been observed in the ComEd residential RTP program.

Many states have adopted various forms of these regulatory incentive mechanisms, as illustrated in Figure C-1.

Figure C-1: Regulatory Mechanisms for Promoting DSM at Electric Utilities



Source: National Action Plan for Energy Efficiency Leadership Group, "Aligning Utility Incentives with Investment in Energy Efficiency," November 2007. Includes additional information to reflect recent regulatory changes. Note that Direct Cost Recovery mechanisms include: rate case, system benefits charges, and tariff rider/surcharges; Fixed Cost Recovery mechanisms include: decoupling and lost revenue adjustment mechanisms. Shareholder Incentives include performance incentives.

However, it is important to note that some of these regulatory mechanisms only apply to energy efficiency measures and do not include impacts from demand response.

Disagreement on Cost-Effectiveness Analysis

Accurate estimation of the financial value of peak reductions induced by demand response is essential to understanding and quantifying demand response benefits. Currently, there is significant disagreement as to what should and should not be included in such benefits assessments. For example, wholesale electricity price reductions are widely cited as a benefit of increased demand response efforts. However, as this is often considered a short-term benefit, it is unclear as to the time horizon over which these benefits should be included. Further, others argue that this benefit is simply a transfer of wealth from generators to consumers and should not be included as a benefit of demand response at all. This was the topic of a recent workshop sponsored by the Mid-Atlantic Distributed Resources Initiative (MADRI).[91]

In addition to which types of benefits should be included in an accurate cost effectiveness assessment, there are also issues concerning the valuation of avoided costs. For example, one major source of financial benefit from demand response is avoided generating capacity cost. However, there is significant disagreement over what should be used as the avoided capacity price. Utilities in California have agreed that the full cost of a peaking plant should be derated to account for revenues that it will earn through sales to the market, as well as to account for a lack of certainty that a demand response program will effectively reduce demand at the time of system peak. However, there is disagreement as to how this adjustment should be calculated. Further disagreement arises as to the level of avoided transmission and distribution (T&D) capacity that should be accounted for by demand response. Some cost-effectiveness tests have been developed in California, although no standard has yet been set. The issue is being

[91] Newell, Sam and Frank Felder, "Quantifying Demand Response Benefits in PJM," Study Report Prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative (MADRI), January 29, 2007.

examined in an ongoing CPUC proceeding (R.07-01-041). Standards for cost effectiveness are also the topic of the previously mentioned NAESB effort in this area.[92]

Lack of Retail Competition
According to some analysts, lack of retail competition is another barrier to demand response. In regions without significant competition at the retail level, providers of demand response programs may not have the same incentive to minimize costs and offer services that are as robust as if there were firms offering competing services. Increased competition from third party aggregators could be a way of introducing innovative program designs and marketing channels. In fact, FERC issued its Wholesale Competition Final Rule (or Order No. 719) which addresses this issue.[93] Order No. 719 requires all RTOs and ISOs to permit aggregators of retail customers to bid demand response on behalf of retail customers directly into the organized energy market, unless the law or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate.[94]

Wholesale Regulatory Barriers

Market Structures Oriented Toward Accommodating Supply Side Resources
Supply-centric market structures limit the participation of demand response resources in several ways. These limitations can include demand response not being allowed to participate in certain markets or overly restrictive market rules that make participation prohibitively expensive or otherwise extremely difficult, restrictions on who can bid demand response into the market, restrictions on suppliers of standard offer service to provide demand response, and lack of a capacity payment for demand response.

Wholesale electricity markets have reliability rules that are specific to the limitations of generators, but not necessarily to demand response resources. For example, rules such as minimum run times would apply to supply side resources, but there are not also maximum run time rules(bidding parameters, as that term is used in Order No. 719), which would accommodate demand response resources.[95] Accommodating these limitations and developing more robust market rules could increase demand response participation in wholesale markets. FERC addressed this issue in its Order No. 719 in requiring each RTO or ISO to accept bids from demand response resources, on a basis comparable to any other resources, for ancillary services that are acquired in a competitive bidding process, if the demand response resources: (1) are technically capable of providing the ancillary service and meet the necessary technical requirements; and (2) submit a bid under the generally-applicable bidding rules at or below the market-clearing price, unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate.[96] Indeed, growing participation of demand response resources in ancillary services markets has been observed, particularly in ISO-NE.[97]

There is also sometimes confusion as to who can actually participate in wholesale markets as a provider of demand response. Andrew Ott of PJM recently indicated that this is a particular barrier to demand response in PJM. Specifically, he noted that “there’s really no established process in the PJM tariff today to allow us to determine whether end users within its jurisdiction in certain customer classes should or should not be able to participate significantly in PJM’s wholesale market. There’s ambiguity.”[98]

There are other markets where demand response is not allowed to compete at all.[99] For example, demand response is not allowed to bid in the operating reserve markets of ISO-NE. This was cited as a major

[92] Draft Agenda to NAESB DSM-EE meeting on October 3, 2008.
[93] Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, 73 Fed. Reg. 64, 100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 61,071 (2008), p. 3 and 154-164.
[94] Id. at p. 3 and 154-164.
[95] FERC, “2006 Assessment of Demand Response and Advanced Metering,” August 2006, p. 117 - 118.
[96] Order No. 719, FERC Stats. & Regs. ¶ 61,071, p. 3 and 47.
[97] FERC, “2007 Assessment of Demand Response and Advanced Metering,” September 2007.
[98] Proceedings to FERC Technical Conference on Demand Response in Organized Electric Markets, May 21, 2008, p. 127.
[99] A summary of the markets in which demand response can and cannot compete is provided in the Policy Options section of this memorandum.

barrier to demand response adoption in wholesale markets by Eric Woychik of Comverge in the FERC Technical Conference on demand response in organized markets.[100]

The full value of demand response should be recognized. For example, demand response has an "option" value in the sense that, regardless of whether it is used, it can be depended upon for reliability and planning purposes. As a result, it should be allowed to compete with supply side resources in planning processes. In regions without a capacity market, or where demand response cannot participate in capacity markets, this can pose a challenge and lead to undervaluing the resource. ISO-NE is an example of a market that allows demand response to compete in its Forward Capacity Market (FCM) up to a limit. In the past four auctions, 2,500 MW of demand response have cleared the market representing roughly nine percent of the resource base in 2010.[101] In fact, Henry Yoshimura of ISO-NE recently indicated that "demand resources are no longer facing barriers in the capacity markets."[102] PJM also allows demand response in its capacity market, and 7,047 MW of demand response cleared in its auction held for 2012/2013.[103]

Economic Barriers

Economic barriers refer to situations where the financial incentive for utilities or aggregators to offer demand response programs, and for customers to pursue these programs, is limited. These barriers are described below.

Inaccurate Price Signals
Inaccurate prices are a barrier to programs in which demand responds to price signals. An inaccurate price could cause a resource to reduce demand when the underlying energy value is low, or raise it when the value is high, which would impair the economic efficiency of the energy market. FERC recognized in Order No. 719 that prices that fail to accurately reflect the value of energy may inhibit and deter entry of demand response and thwart innovation.[104]

Lack of Sufficient Financial Incentives to Induce Participation
For some customers, demand response programs may not provide a sufficient financial incentive to participate. If customers place a high enough value on being able to consume as much electricity as they want, when they want it, then the financial incentives to participate in demand response programs may not be large enough to justify their participation. Of course, higher payments are likely to result in increased participation. For example, Southern California Edison (SCE) offers one of the most financially attractive residential air conditioner direct load control (DLC) programs, with an annual payment of between $100 and $200[105] for participants who sign up for 100% cycling and unlimited interruptions. This is likely one of the factors that has led to enrollment of over 325,000 residential customers in SCE's program, with almost 90% of them selecting the 100% cycling option.

Additionally, dynamic rates by definition will result in some customers experiencing bill increases due to their peakier-than-average consumption patterns, and these customers may not opt-in to such a rate if it is only offered on a voluntary basis. However, when accounting for moderate shifting of load from peak to off-peak periods, such rates could become financially attractive for a larger segment of customers. Further, it has been argued that there is a hedging cost implicit in a flat retail electricity rate, and that by

[100] Proceedings to FERC Technical Conference on Demand Response in Organized Electric Markets, May 21, 2008, p. 13.
[101] *Ibid.*, p. 130.
[102] *Ibid.*, p. 131.
[103] 2012/2013 Base Residual Auction Report Document, http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2012-13-base-residual-auction-report-document-pdf.ashx.
[104] Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, 73 Fed. Reg. 61,400 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281 (2008), reh'g pending, at P 192.
[105] The payment varies depending on the number of tons of air conditioning a customer has. For more details, see Stephen S. George, Josh Bode and Josh Schellenberg. *Load Impact Estimates for Southern California Edison's Demand Response Program Portfolio*, September 25, 2008.

passing price volatility through to customers in the form of dynamic pricing, electric utilities would avoid this cost and, as a result, should be able to reduce rates by the amount of the risk premium.[106] Accounting for this would further expand the share of customers for whom dynamic rates would be financially attractive. Commonwealth Edison has taken this approach in order to increase consumer interest in its residential RTP program.

Alternatively, some utilities have had success with programs that offer no financial incentive but simply appeal to the customer's desire to help avoid large scale brownouts or blackouts or to improve the environment. A respondent to a recent survey on the barriers to demand response indicated that some of his large commercial customers were happy to respond to phone calls on critical days by reducing load, even without any financial incentives. At the same time, they did not want to formally participate in a demand response program because the paperwork and other requirements were very costly and the savings were not proportionately large.[107] PG&E's air conditioning load control program is another example of how consumers are willing to help out in emergencies for little financial remuneration, and a significant contrast to SCE's program. PG&E has enrolled roughly 75,000 customers in its Smart AC air conditioning cycling program based on a one-time payment of $25 and an appeal indicating that participation would be "doing one small thing" that would "actually help prevent power interruptions and protect the environment."[108]

Technological Barriers

Potential technological barriers to rapid implementation of demand response include the need for new types of metering equipment, metering standards, or communications technology.

Lack of Advanced Metering Infrastructure (AMI)

The lack of AMI poses a very significant barrier to implementing price-based demand response. Currently, there is only one utility in the United States (PPL) that has the metering capability and meter data management systems (MDMS) in place that are necessary to put all of its customers on default dynamic pricing. While there are many millions of meters currently installed that can be read remotely by fixed network, automated meter reading (AMR) systems (which actually transmit data quite frequently), the vast majority of these systems would require significant upgrades to support daily delivery of billing quality, interval data and extensive investment in MDMS and billing systems to support large scale participation in dynamic pricing tariffs. Even in places where a commitment to full interval metering and data management exists, such as California, we are still several years away from being able to place large numbers of customers on default dynamic pricing.

However, progress has been made in terms of developing plans for AMI deployment. In addition to California's decision to equip customers with AMI, the state of Connecticut passed a bill requiring utilities to begin to deploy AMI by 2009. Texas regulators are also moving toward mandatory AMI metering for all customers. Many utilities are planning AMI deployment, or actively analyzing it, including Portland General Electric in Oregon, Central Vermont Public Service in Vermont and Baltimore Gas & Electric, to name just a few. Northeast Utilities is developing a pilot to test the potential impacts of rates that the new smart meters will enable them to provide. Additionally, there are currently ongoing dynamic pricing pilots in Maryland (BGE) and Washington, DC (Pepco). With the requirement in the Energy Policy Act of 2005 (EPAct 2005) that all states investigate time-based metering, cost-effectiveness analyses have been conducted by many other utilities across the US as well.

[106] The lower cost can be estimated by using a well-known formula, which expresses the "risk premium" as an exponential function of retail load volatility, wholesale price volatility and retail load-wholesale price correlation. Monte Carlo simulations under a variety of plausible assumptions yield a median value of 6 percent. See "Rethinking Rate Design," prepared for the Demand Response Research Center, August 2007.

[107] Ahmad Faruqui and Ryan Hledik, "The State of Demand Response in California," prepared for the California Energy Commission, April 2007.

[108] Quote taken from the PG&E direct mail offer letter.

Lack of Cost-Effective Enabling Technologies

There is a diverse menu of technologies that can improve customers' ability to provide demand response, but these technologies are not yet all cost-effective. Examples of enabling technologies include smart thermostats that respond to high prices with an automated adjustment to their setting, whole house gateway systems that allow multiple devices to be similarly made price sensitive, advanced energy management systems in commercial buildings and process control systems in industrial facilities that can reduce load when needed. Customer awareness of these technologies is low and given the low level of market penetration, the cost of the technologies is high, creating a Catch-22 situation.[109] It has also been argued that the marketing infrastructure (the value chain from the equipment manufacturer to the retailer and the installing contractor) is in its infancy. A "market transformation" initiative akin to that pursued in the energy efficiency business may be needed to allow rapid penetration of smart (price sensitive) control technologies in customer premises that would allow them to see the full benefits of demand response.

Concerns about Technological Obsolescence and Cost Recovery

Despite increasing investment in AMI, some regulators and decision makers still have concerns about the useful life of smart meters, as well as the risks that the technology could shortly be replaced with something better.[110] Concerns about technological obsolescence also extend to the previously described enabling technologies, many of which are still in the development phase. Ultimately, these concerns contribute to doubts about the ability to recover the cost of these investments before they need to be replaced. As there is uncertainty surrounding whether state commissions will allow the cost of AMI or enabling technologies to be rate-based, this poses a barrier to increased investment.[111]

Lack of Interoperability and Open Standards

Interoperability and open standards refer to the manner in which various technologies, such as meters and in-home enabling technologies, communicate. If advanced meters contain communication chips based on open communication standards, such as ZigBee, it might be possible for consumers to purchase in-home control and information devices that would automatically communicate with their meter and that, in turn, would help automate or otherwise increase demand response. Open standards might also reduce costs by encouraging competition among technology providers to obtain large scale meter and other technology contracts. A number of jurisdictions and/or utilities are building open communications standards into the functional specifications for AMI systems that they will consider. On the other hand, some have questioned whether the meter should serve as the gateway to Home Area Networks (HAN) and other devices, because this might allow utilities to control the technology and access to meter data by third parties could be limited.

The need for appropriate technical protocols and standards was a key issue at a recent PJM Symposium on Demand Response. The symposium identified a number of topics requiring further development, including region-wide communications protocols, meter data reporting standards, and open access to meter data.[112] More recently, the National Institute of Standards and Technology has contracted with EPRI to develop an interim road map that will serve as a guide to inventory existing standards, and identify the need to resolve differences in standards or create new standards entirely. These standards are scheduled to be submitted to FERC by the end of 2009.

Other Barriers

Some additional barriers do not fall into the categories described above. These barriers are summarized here. These are generally related to customer perceptions of demand response programs and a resulting limited willingness to enroll.

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[109] However, the cost of the technologies is rapidly decreasing. The cost of smart thermostats in particular has fallen to less than one-third of the price three years ago.
[110] FERC, "2007 Assessment of Demand Response and Advanced Metering," September 2007.
[111] *Ibid.,* p. 128-129.
[112] Energetics Incorporated, "Proceedings to PJM Symposium on Demand Response," June 8, 2007.

Lack of Customer Awareness and Education

A deficiency of customer education regarding demand response and its benefits has served as a major barrier to further participation in demand response programs. To a large extent, this is evident in a lack of simple customer awareness of demand response programs, which was cited by Toronto Hydro Energy Services as a market transformation barrier for demand response.[113] Inertial behavior also contributes to low participation rates in voluntary programs. Part of this disparity reflects the challenge of creating customer awareness about options, part reflects inertia and still another part reflects uncertainty about the potential benefits of selecting each option. Due to limited customer experience with price-based demand response, and limited utility experience with marketing these programs, a focus on customer education and customer awareness will be key in overcoming this barrier.

Risk Aversion

A significant barrier to customer participation in dynamic pricing options is risk aversion. The Momentum Market Intelligence study cited above also showed that, when selecting a pricing option, customers focus more on the downside risk that their bills might go up if they go on the rate, than on the upside potential that they can save money either by virtue of having a favorable load shape already or by reducing or shifting load from high cost to low cost periods, or both. This risk aversion is one of the primary reasons why default pricing options will lead to much higher customer enrollment than will opt-in enrollment. Research also shows that customers who experience time varying rates have high levels of satisfaction and, when offered the option of staying on such rates, most will do so and will also recommend such tariffs to their friends.[114] Combined, the above research suggests strongly that default, time-based pricing could not only lead to very high participation in such tariffs, but high satisfaction, which is quite contrary to the fears that many express when such notions are suggested.

Fear of Customer Backlash

This has been cited as a concern by some utilities who feel that heavily-used dynamic pricing could cause customer fatigue, cause them to feel exploited if bill savings were small, or trigger a “revolt” in response to the higher critical peak prices. However, others feel that a well designed program, coupled with effective marketing and educational efforts, could prevent this from becoming a significant barrier.[115] The research cited above also strongly suggests that such fears are largely unfounded.

Perceived Lack of Ability to Respond

Some customers feel that they have already done all they can do to become efficient consumers of electricity. This is particularly true in states with highly successful energy efficiency programs. In California, large customers on mandatory TOU rates feel they have already shifted as much of their peak usage to off-peak periods as they can, given the constraints of their business. If these customers were enrolled in a dynamic rate or an additional demand response program, the argument is that they would not know what to do to further reduce peak demand. This is another issue of customer education, where information on cost-effective means for further reducing peak load could facilitate participation in demand response programs for these customers. This barrier is also related to the issue of determining the appropriate financial incentive – given a high enough payment, it could become cost-effective for these customers to curtail consumption for certain end-uses that they otherwise would not do.[116]

Concern Over Environmental Impacts

There is some concern that demand response programs could shift load to off peak hours when coal plants are on the margin, resulting in an increase in emissions. This depends both on the capacity mix in the region and on the impact of demand response on customer consumption patterns. For example, in a

[113] Toronto Hydro Energy Services. Development of an Electricity Demand Management and Demand Response Program for Commercial Buildings: Report on Design Charette. November 28, 2003.

[114] See Dean Schultz and David Lineweber, Real Mass Market Customers React to Real Time-Differentiated Rates: What Choices Do They Make and Why? 16th National Energy Services Conference. San Diego, CA. February 2006. See also Momentum Market Intelligence, Statewide Pricing Pilot: End-of-Pilot Participant Assessment. December 2004.

[115] Ahmad Faruqui and Ryan Hledik, “The State of Demand Response in California,” prepared for the California Energy Commission, April 2007, p. 28

[116] *Ibid*., p. 27.

region where natural gas plants are almost always the “marginal” units, or for demand response programs that simply reduce consumption during peak periods (without shifting load to off peak periods), negative environmental impacts should not be a concern. However, in a region where, say, a natural gas-fired plant is the marginal unit during peak periods and a coal plant is the marginal unit during off peak periods, if a customer were to respond to a demand response program by shifting load from the peak period to the off-peak period, the net result would be an increase in generation from a plant with higher emissions levels.

Perceived Temporary Nature of Demand Response Impacts

Often, demand response impacts are seen as a deferral of supply side investments rather than as a substitute. In other words, the peak demand reductions from a demand response program could delay necessary investment in, say, a new transmission line, but to the extent that there is still load growth in the region, the transmission line will ultimately need to be built. There may be an expectation that once the transmission line is built, the demand response program will no longer be necessary and will be dropped. This perceived temporary nature of the demand response program could limit willingness of a utility to invest in it, or willingness of customers to participate in it.

APPENDIX D. DATABASE DEVELOPMENT DOCUMENTATION

This appendix provides a detailed summary of the data development process that was used to create the model inputs for the demand response potential assessment. Figure D-1 illustrates how the different data elements were developed. The straight arrows depict relationships between the model inputs, while the dashed arrows show key data sources used in determination of the data elements.

The data elements developed for the assessment and described in this appendix can be broadly classified into two categories:

1. Market characteristics data
    a) Number of customer accounts by rate class by state
    b) Electricity sales by rate class by state
    c) System peak load forecast by state
    d) Average peak load per customer by rate class by state
    e) Growth rate in per customer peak load
    f) Central Air Conditioning (CAC) market saturation data
    g) Advanced Metering Infrastructure (AMI) deployment schedule by state
2. Demand response program related data
    a) Business-As-Usual (BAU) Demand Response Potential estimation
    b) Current participation in demand response programs
    c) Impacts from non-pricing programs
    d) Impacts from pricing programs
    e) Cost-effectiveness analysis

This section describes how each of the data elements listed here was developed.

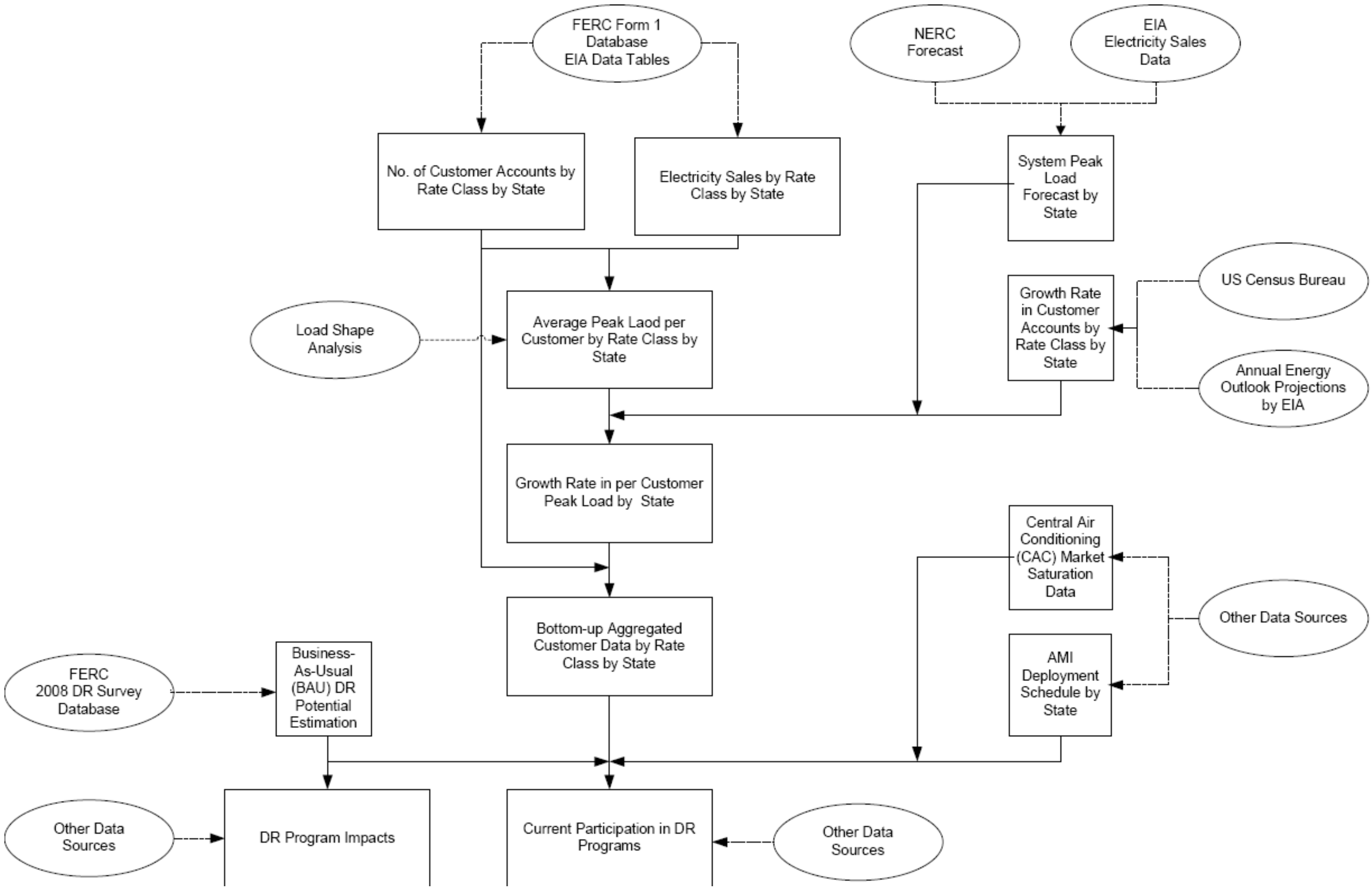


Figure D-1: Data Development for Model Inputs – Relationships Between Data Elements and Key Information Source

Market Characteristics Data

a) Number of Customer Accounts by Rate Class by State

Four rate classes were considered in the model:
1. Residential,
2. Small commercial and industrial (C&I),
3. Medium C&I, and
4. Large C&I.

State-level data, published by EIA[117], provides the number of customers and electricity sales for the residential, commercial, and industrial sectors. Therefore, the number of residential accounts in each state was readily available from the EIA database. However, since the EIA only reports values for the commercial and industrial sectors as a whole, further analysis using FERC Form No. 1[118] data was required in order to determine the breakdown of small, medium, and large C&I accounts for each state. The following steps describe the process undertaken to estimate the number of C&I accounts by rate class for each state.

1. Electricity Sales by Rate Schedule: FERC Form No. 1 data provides the number of accounts and corresponding electricity sales for customers on different rate schedules. FERC Form No. 1 is reported only by IOUs. These data were evaluated and used to calculate electricity sales per customer for each rate schedule.

2. Initial Customer Classification into residential and C&I customers: Customers were then classified into the residential and C&I segments based on the label of the rate schedule provided in FERC Form No. 1. To the extent possible, rate schedule descriptions from utility tariff books were obtained to validate the classifications.

3. Further C&I Customer Classification: The next step was to apply average load factors by rate class to estimate peak load per customer for each rate schedule. The average load factors assumed for the three C&I rate classes were:
   - Load factor for small C&I: 0.6,
   - Load factor for medium C&I: 0.7, and
   - Load factor for large C&I: 0.7.[119]

   These load factors were applied to the electricity sales per customer (Step 1) for each C&I rate schedule in FERC Form No. 1 (Step 2) to estimate peak load per customer. Based on the calculated value of peak load per customer, the C&I rate schedules were grouped into the three C&I rate classes: small, medium, and large. The classification was based on the following ranges for peak load:
   - Small: 0 to 20 kW;
   - Medium: Greater than 20 to 200 kW; and
   - Large: Greater than 200 kW.

   For each utility that reported FERC Form No. 1 data, these first three steps provided an estimation of the percentage of total C&I customers falling into each of the three C&I rate classes.

4. C&I Adjustments for Multi-State Operation by Utilities: Adjustments were then made to C&I data for utilities that had operations in multiple states. For these utilities, the FERC Form No. 1 data on the number of customers and sales were apportioned to all states in which the utilities operate using

[117] http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html
[118] FERC Form 1 Database - Electric Utility Annual Report; survey data collected from FERC Form 1 – "Annual Major Electric Utilities, Licensees, and Others." http://www.ferc.gov/docs-filing/eforms/form-1/viewer-instruct.asp
[119] The load factor assumptions are based on the team's extensive experience working with load shape data and undertaking load shape analysis.

information reported in EIA Form-861. Thus, it was possible to disaggregate the multi-state, utility-reported FERC Form No. 1 data into information for each state in which a given utility operates. This provided a more accurate representation of the number of C&I accounts and sales for each rate class by utility and by state.

5. State-Level Aggregation of Utility Data for C&I Accounts: Multiple utility data for each state were aggregated to arrive at the distribution of small, medium, and large C&I accounts for each state. This assumed that the distribution obtained from FERC Form No. 1 is representative for the state as a whole, with the implicit assumption that the distribution applies to IOUs and non-IOUs as well. Nebraska was the only state for which FERC Form No. 1 data were not available. Since Nebraska's characteristics were assessed to be similar to that of Idaho, Idaho's data were used as a proxy for assuming the C&I distribution for Nebraska.

6. Number of C&I Accounts by Rate Class and State: The final step in estimating the number of C&I accounts by rate class was to apply the percentage distribution for account population by rate class (derived from the previous steps) to the total number of C&I accounts by state (obtained from EIA Form-861 state-level data). This provided the number of C&I accounts by rate class for each state.

Table D-1 lists the resulting number of accounts by state for the residential, small C&I, medium C&I, and large C&I rate classes.

Table D-1: Number of Accounts by Rate Class

State	Number of accounts by rate class			
	Residential	Small C&I	Medium C&I	Large C&I
Alabama	2,077,677	362,448	12,354	3,801
Alaska	266,671	45,183	3,270	62
Arizona	2,567,749	280,527	15,965	1,381
Arkansas	1,301,517	199,604	6,629	3,442
California	12,971,924	1,567,550	301,662	17,772
Colorado	2,068,055	282,139	88,021	1,531
Connecticut	1,449,983	141,998	11,261	8,044
Delaware	390,239	47,323	1,475	374
District of Columbia	206,047	24,506	1,842	1,229
Florida	8,615,249	921,368	224,874	9,195
Georgia	4,039,005	483,576	66,628	11,363
Hawaii	409,581	55,808	7,482	632
Idaho	647,581	65,923	55,692	928
Illinois	5,054,895	541,263	26,791	21,435
Indiana	2,734,788	286,888	65,468	8,038
Iowa	1,320,241	183,320	30,471	3,507
Kansas	1,213,189	221,809	10,962	7,594
Kentucky	1,918,247	272,458	27,771	3,050
Louisiana	1,870,160	196,805	89,052	3,192
Maine	693,400	75,666	13,927	1,065
Maryland	2,187,996	230,938	17,496	4,054
Massachusetts	2,631,568	367,459	22,605	4,510
Michigan	4,336,390	485,729	44,172	10,836
Minnesota	2,283,083	189,477	75,091	10,044
Mississippi	1,222,047	228,202	1,565	2,228
Missouri	2,670,172	347,394	25,739	4,651
Montana	456,112	103,892	890	238
Nebraska	787,312	178,123	10,854	2,889
Nevada	1,079,306	145,469	4,497	1,963
New Hampshire	600,399	102,868	831	1,875
New Jersey	3,414,289	461,304	10,998	10,375
New Mexico	829,100	122,560	16,755	1,296
New York	6,855,544	958,009	66,351	5,265
North Carolina	4,128,231	619,832	29,169	3,277
North Dakota	310,222	54,365	2,211	699
Ohio	4,908,791	569,999	59,607	13,010
Oklahoma	1,629,818	243,831	30,398	3,097
Oregon	1,610,829	220,262	36,132	1,521
Pennsylvania	5,217,010	618,439	75,656	10,577
Rhode Island	432,307	48,623	8,614	864
South Carolina	2,028,361	326,244	15,666	2,327
South Dakota	355,714	66,375	658	875
Tennessee	2,660,110	428,663	30,312	3,735
Texas	9,397,317	1,269,490	411,961	5,756
Utah	911,744	103,864	16,754	791
Vermont	310,842	46,230	3,075	313
Virginia	3,170,126	369,208	32,352	7,886
Washington	2,762,275	345,256	26,145	3,568
West Virginia	855,919	135,823	11,181	1,199
Wisconsin	2,581,840	290,192	44,419	4,518
Wyoming	245,648	61,758	3,587	585
Total	**118,473,006**	**15,108,276**	**2,159,118**	**223,764**

b) Electricity Sales by Rate Class by State

The distribution of electricity sales by rate class was determined using the same approach as described above for estimating the number of accounts by rate class. As before, the electricity sales data were readily available for residential accounts from EIA. However, the small, medium, and large C&I sales data had to be developed from FERC Form No. 1 data. FERC Form No. 1 data contains electricity sales data by rate schedule along with number of accounts for IOUs. An analogous estimation methodology to the one already outlined for the number of accounts (see steps 1-6 in the previous section) was used to develop the C&I sales data. The result was state-level aggregate sales data for each of the four rate classes.

Table D-2 lists the resulting electricity sales by state for the residential, small C&I, medium C&I, and large C&I rate classes.

Table D-2: Electricity Sales by Rate Class

State	Electricity Sales by Rate Class (GWh)			
	Residential	Small C&I	Medium C&I	Large C&I
Alabama	32,870	26,023	13,385	19,534
Alaska	2,204	1,575	2,030	524
Arizona	33,897	20,352	13,897	7,493
Arkansas	17,788	8,510	3,427	18,824
California	93,402	28,440	73,061	73,567
Colorado	17,752	2,745	20,932	9,767
Connecticut	13,204	2,903	4,336	11,843
Delaware	4,330	3,794	1,118	2,544
District of Columbia	1,853	1,214	1,750	6,509
Florida	119,013	13,879	54,139	45,492
Georgia	55,433	12,525	22,410	46,961
Hawaii	3,309	1,373	2,189	3,944
Idaho	8,438	1,232	9,729	4,051
Illinois	47,145	22,662	4,851	71,030
Indiana	32,818	9,432	20,575	45,653
Iowa	13,723	4,039	8,854	17,897
Kansas	13,886	7,095	2,808	17,045
Kentucky	26,425	14,356	28,538	20,483
Louisiana	29,304	14,262	19,889	17,188
Maine	4,432	915	2,715	4,537
Maryland	27,356	15,727	3,369	17,477
Massachusetts	19,988	12,250	3,494	21,148
Michigan	35,192	15,783	12,829	47,081
Minnesota	22,531	3,252	19,154	23,629
Mississippi	18,612	9,582	693	18,651
Missouri	34,841	8,667	16,457	24,274
Montana	4,602	6,871	858	1,890
Nebraska	9,557	4,182	8,313	5,967
Nevada	12,544	7,982	2,766	12,326
New Hampshire	4,482	2,601	163	4,126
New Jersey	29,594	17,322	5,143	29,307
New Mexico	6,293	3,071	6,164	6,514
New York	50,072	28,910	32,902	30,992
North Carolina	53,736	16,586	27,852	31,033
North Dakota	3,962	2,776	1,737	3,076
Ohio	52,221	25,608	23,471	56,129
Oklahoma	22,610	4,793	12,616	17,143
Oregon	19,731	5,389	16,687	7,474
Pennsylvania	53,550	26,874	19,677	48,843
Rhode Island	3,064	731	1,724	2,475
South Carolina	29,017	11,640	14,959	26,889
South Dakota	4,166	3,290	351	2,524
Tennessee	41,565	22,932	31,213	9,555
Texas	132,220	24,047	115,175	85,287
Utah	8,621	2,587	8,523	7,374
Vermont	2,182	729	1,109	1,921
Virginia	43,624	8,633	16,925	39,493
Washington	35,806	12,788	18,393	20,241
West Virginia	11,199	4,419	5,191	12,151
Wisconsin	22,138	6,646	17,059	25,843
Wyoming	2,585	4,822	1,428	6,490
Total	**1,388,887**	**518,818**	**757,030**	**1,092,209**

c) System Peak Load Forecast by State

System peak demand forecast values are readily available from NERC at the regional level.[120] The NERC peak demand forecast is provided for eight NERC Regions (excluding Alaska and Hawaii) and several sub-regions for four of the NERC regions. Only data for New York are available at the (sub-region) state level. Because the model in the study requires state-level forecast values to serve as a reference point for the demand response impacts, the NERC regional data had to be segmented by state.

The NERC forecast was divided among the states (except for New York, Alaska and Hawaii) according to the percentage of total electric sales for each state[121]. This methodology helps establish consistency between the state system peak forecast and the bottom-up aggregated peak load estimate for a state using customer class data by rate class for number of accounts and average peak load per customer. NERC peak demand data for New York was used directly since it was reported at the state level[122]. Since NERC des not provide values for Alaska and Hawaii, summer peak values for these states were obtained from EIA Form-861 data.

There were limited data sources available for benchmarking the state values. Where available, state values were compared and modified to reflect state filings and planning studies. We also benchmarked national level estimates with data from other sources.[123]

Table D-3 provides the system peak load forecast by state for the time horizon being considered in this study.

[120] 2008 Long Term Reliability Assessment 2008-2017, North American Electric Reliability Corporation, October 2008

[121] Electric Sales, Revenue, and Price, Table 2. Sales to Bundled and Unbundled Consumers by Sector, Census Division, and State, 2006, Energy Information Administration, http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

[122] Comparing the NERC peak demand data for New York with that obtained using the same approach followed for other states reveals that the NERC data is about 10% higher. Nevertheless, it was deemed more accurate to use the NERC data directly in this case.

EIA Form-861 provides utility reported peak values. This EIA data was used to arrive at a national estimation of peak load by aggregating the utility reported peak values in the database. The EIA data was also used to arrive at state peak values by aggregating utility peak data for a state. A comparison of the peak values at the national level showed that the peak value estimated from the EIA data was significantly higher than the total peak load forecast reported by NERC. A comparison of peak estimates at the state level across the two datasets revealed differences. There were some states where peak load estimation using EIA data came close to the NERC forecasted values. But for other states, the peak values from EIA and NERC forecast were different. Differences in state peak estimates can be explained by the nature of utility data reporting in EIA. In the EIA database, utilities with service territories across multiple states, report their peak loads only against one particular state (most likely the state of their mailing address) and do not provide the state-level break-up of their peak. This leads to an inaccurate estimation of the state level peak by simply aggregating the utility reported data.

Table D-3: Peak Demand Forecast by State: [124]

State	Peak demand forecast by state (MW)										
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018 (projected)
Alabama	19,000	19,410	19,817	20,191	20,544	20,921	21,344	21,751	22,140	22,536	22,939
Alaska	1,417	1,438	1,459	1,481	1,503	1,526	1,549	1,572	1,596	1,620	1,644
Arizona	18,456	18,862	19,219	19,585	19,964	20,324	20,676	21,030	21,380	21,721	22,067
Arkansas	9,875	10,089	10,296	10,479	10,652	10,836	11,038	11,236	11,426	11,622	11,821
California	57,137	58,395	59,479	60,606	61,814	62,930	64,052	65,183	66,326	67,404	68,500
Colorado	10,837	11,076	11,281	11,495	11,724	11,936	12,149	12,363	12,580	12,785	12,992
Connecticut	7,524	7,658	7,785	7,905	8,016	8,116	8,202	8,277	8,343	8,401	8,459
Delaware	2,503	2,545	2,593	2,630	2,661	2,698	2,734	2,768	2,804	2,836	2,869
District of Columbia	2,403	2,443	2,489	2,524	2,554	2,589	2,625	2,657	2,691	2,723	2,754
Florida	49,453	50,296	51,242	52,470	53,721	54,909	55,952	57,217	58,498	59,788	61,106
Georgia	28,215	28,824	29,428	29,984	30,508	31,068	31,696	32,300	32,878	33,466	34,064
Hawaii	1,790	1,816	1,844	1,871	1,899	1,928	1,957	1,986	2,016	2,046	2,077
Idaho	4,962	5,072	5,166	5,264	5,369	5,465	5,563	5,661	5,760	5,854	5,949
Illinois	30,465	31,019	31,631	32,120	32,552	33,043	33,553	34,033	34,517	34,980	35,449
Indiana	22,890	23,266	23,709	24,043	24,328	24,664	25,000	25,311	25,635	25,933	26,236
Iowa	9,169	9,607	9,945	10,176	10,357	10,527	10,705	10,877	11,045	11,221	11,400
Kansas	8,630	8,820	8,990	9,127	9,256	9,395	9,535	9,678	9,821	9,971	10,124
Kentucky	18,889	19,251	19,637	19,963	20,259	20,588	20,941	21,275	21,605	21,929	22,258
Louisiana	16,332	16,686	17,031	17,341	17,634	17,947	18,293	18,629	18,953	19,283	19,619
Maine	2,812	2,862	2,909	2,954	2,996	3,033	3,065	3,093	3,118	3,140	3,161
Massachusetts	12,695	12,922	13,134	13,337	13,525	13,693	13,839	13,966	14,077	14,175	14,273
Minnesota	14,123	14,798	15,318	15,674	15,952	16,214	16,489	16,753	17,013	17,284	17,559
Missouri	17,362	17,739	18,102	18,424	18,728	19,053	19,408	19,755	20,090	20,434	20,783
Nebraska	5,771	6,047	6,260	6,405	6,519	6,626	6,738	6,846	6,952	7,063	7,175
New Hampshire	2,539	2,585	2,627	2,668	2,705	2,739	2,768	2,794	2,816	2,835	2,855
New Mexico	4,671	4,774	4,863	4,953	5,050	5,139	5,230	5,321	5,413	5,500	5,589
North Carolina	26,548	27,120	27,689	28,212	28,706	29,232	29,823	30,392	30,936	31,489	32,051
Ohio	33,238	33,799	34,443	34,931	35,351	35,843	36,335	36,794	37,270	37,715	38,165
Oregon	10,476	10,706	10,905	11,112	11,333	11,538	11,744	11,951	12,160	12,358	12,559
Rhode Island	1,785	1,817	1,847	1,875	1,902	1,926	1,946	1,964	1,979	1,993	2,007
South Dakota	2,128	2,229	2,308	2,361	2,403	2,443	2,484	2,524	2,563	2,604	2,645
Texas	72,723	74,203	75,734	77,169	78,381	79,898	81,259	82,637	83,881	85,433	87,014
Vermont	1,085	1,099	1,112	1,125	1,139	1,152	1,165	1,178	1,192	1,205	1,218
						24,617	25,097	25,557	26,000	26,447	26,902
Washington	18,538	18,946	19,298	19,663	20,055	20,417	20,782	21,149	21,519	21,869	22,225
West Virginia	6,916	7,042	7,181	7,295	7,396	7,510	7,630	7,744	7,857	7,967	8,078
Wisconsin	14,845	15,458	15,951	16,292	16,562	16,825	17,099	17,362	17,622	17,887	18,157
Wyoming	3,236	3,326	3,401	3,469	3,536	3,599	3,662	3,725	3,789	3,850	3,912
Total	**793,121**	**809,926**	**826,192**	**840,838**	**854,547**	**868,879**	**883,359**	**897,672**	**911,725**	**925,880**	**940,267**

[124] The peak load numbers are based on the NERC report titled '2008 Long Term Reliability Assessment 2008-2017', October 2008. The NERC report provides the peak demand forecast for eight NERC regions (excluding Alaska and Hawaii). Peak demand values for Alaska and Hawaii were obtained from EIA Form-861 data and added to the NERC total to arrive at the total peak demand estimates for the whole U.S.

d) Average Peak Load per Customer by Rate Class by State

One of the key inputs to demand response potential estimation is average electricity use per customer per hour during time periods when demand response programs are likely to be used but before any demand response occurs. We refer to the time period representing when demand response has a high probability of being used as the "peak period" on a "typical event day" and represent that period by the hours between 2 and 6 pm on the top 15 system load days in each state. Note that average energy use across the top 15 system load days will produce demand response load impact estimates that are significantly lower than if they were based on the single hour of system peak or based on fewer than the top 15 system load days. Utility and/or ISO system load data were used to identify top system load days in each state.

Hourly load data are not available for all utilities and states or for all customer segments within states. Indeed, no data at all were found that distinguished between residential customers with and without central air conditioning. Fortunately, hourly load data were available on a large enough cross section of utilities that it was possible to use regression analysis to estimate normalized load shapes for each relevant customer segment and to use these models to develop load shapes for all other states and customer segments. Table D-4 summarizes utilities from which hourly load data was used by state and customer segment. Following Table D-4 is a list of the data sources for each utility.

Table D-4: Summary of Utility Data Used in Regression Analysis

Summary of Utility Data Used in Regression Analysis				
State	**Residential**	**Small C&I**	**Medium C&I**	**Large C&I**
California	PG&E, SCE & SDG&E	PG&E, SCE & SDG&E	PG&E, SCE & SDG&E	PG&E, SCE & SDG&E
Connecticut	United Illuminating Company	United Illuminating Company	United Illuminating Company	United Illuminating Company
District of Columbia	Pepco	Pepco	Pepco	Pepco
Idaho	Idaho Power	Idaho Power	Idaho Power	Idaho Power
Illinois	Amaren, ComEd	Amaren	Amaren	Amaren
Indiana	Duke Energy	Duke Energy	Duke Energy	Duke Energy
Massachusetts	National Grid	National Grid	National Grid	National Grid
Maryland	Pepco, BG&E	Pepco, BG&E	Pepco	Pepco
Maine	Central Maine Power	Central Maine Power	Central Maine Power	Central Maine Power
Michigan	Detroit Edison	Detroit Edison	Detroit Edison	Detroit Edison
Missouri	Amaren	Amaren	Amaren	Amaren
North Carolina	Duke Energy	Duke Energy	Duke Energy	Duke Energy
New Hampshire	National Grid	National Grid	National Grid	National Grid
New Jersey	JCPL, PSEG	JCPL	JCPL	JCPL, PSEG
New York	National Grid	National Grid	National Grid	National Grid
Ohio	Duke Energy	Duke Energy	Duke Energy	Duke Energy
Pennsylvania	MetEd, Penelec	MetEd, Penelec	MetEd, Penelec	MetEd, Penelec
Rhode Island	National Grid	National Grid	National Grid	National Grid
South Carolina	Duke Energy	Duke Energy	Duke Energy	Duke Energy
Texas	Ercot	Ercot	Ercot	Ercot
Vermont	Burlington Electric	Burlington Electric	Burlington Electric	Burlington Electric

Utilities List with Sources

- **PG&E**: http://www.pge.com/nots/rates/tariffs/energy_use_prices.shtml
- **SCE**: http://www.sce.com/AboutSCE/Regulatory/loadprofiles/loadprofiles.htm
- **SDGE**: FSC Internal
- **United Illuminating Company**: http://www.uinet.com/uinet/connect/UINet/Top+Navigator/About+UI/Doing+Business+With+UI/Suppliers+-+Aggregators/Load+Profiles/
- **Pepco**: https://suppliersupport.pepco.com/suppliersupport/suppliersupportframe.htm
- **Idaho Power**: GEP Internal
- **Ameren**: http://www.ameren.com/IlChoice/adc_cc_profile_select.asp
- **ComEd**: FSC Internal
- **Duke Energy**: FSC Internal
- **National Grid MA**: https://www.nationalgridus.com/masselectric/energy_supplier/index.asp
- **National Grid RI**: https://www.nationalgridus.com/narragansett/energy_supplier/index.asp
- **National Grid NH**: https://www.nationalgridus.com/granitestate/energy_supplier/index.asp
- **National Grid NY**: http://www.nationalgridus.com/niagaramohawk/energy_supplier/elec_load_profile.asp
- **BG&E**: http://supplier.bge.com/LoadProfiles_EnergySettlement/historicalloaddata.htm
- **Central Maine Power**: FSC Internal
- **Detroit Edison**: http://www.suppliers.detroitedison.com/internet/infocenter/custdata/loadprofiles/profiles.jsp
- **JCPL**: http://www.firstenergycorp.com/supplierservices/New_Jersey/Load_Profiles.html
- **PSEG**: http://www.pseg.com/customer/energy/energy_profiles.jsp
- **Penelec**: http://www.firstenergycorp.com/supplierservices/Pennsylvania/Met-Ed_and_Penelec/ME_and_PN_Load_Profile.html
- **MetEd**: http://www.firstenergycorp.com/supplierservices/Pennsylvania/Met-Ed_and_Penelec/ME_and_PN_Load_Profile.html
- **Ercot**: http://www.ercot.com/mktinfo/loadprofile/
- **Burlington Electric**: FSC Internal

Data from the utilities identified in Table D-4 were used to estimate regression models that relate normalized hourly load to a variety of variables that influence load in each hour, including weather, central air conditioning saturation and seasonal, monthly, day-of-week and hourly usage patterns. This statistical analysis was used to separate weather sensitive and non-weather sensitive load for residential customers. The normalized load shapes were then combined with estimates of average annual energy use and central air conditioning saturation by customer segment for each state and state-specific weather data to produce hourly load estimates for each customer segment and state. The average, hourly energy use between 2 and 6 pm on the top 15 system load days was used as the basis for estimating load impacts for price-based demand response options for each customer segment. The outcome of this estimation process is summarized in Table D-5.

Table D-5: Average Energy Use per Hour (2 - 6 pm) on Top 15 System Peak Days

Average Energy Use per Hour Between 2 and 6 pm on Top 15 System Peak Days (kWh/hr)					
State	Residential No CAC	Residential with CAC	Small C&I (<20kW)	Medium C&I (20-200kW)	Large C&I (>200kW)
Alabama	1.88	4.29	15.06	192.09	747.82
Alaska	0.89	0.94	4.48	79.82	1029.24
Arizona	1.56	4.18	16.88	165.50	822.41
Arkansas	1.62	3.80	9.09	92.64	800.59
California	0.83	1.79	3.18	37.63	555.49
Colorado	1.01	2.11	1.91	40.05	901.10
Connecticut	1.01	3.35	3.89	63.37	205.70
Delaware	1.27	2.53	15.17	125.09	951.18
District of Columbia	1.03	2.10	9.52	158.33	744.54
Florida	1.64	3.21	2.90	40.13	695.77
Georgia	1.63	3.73	5.44	59.68	601.70
Hawaii	0.89	1.49	4.20	45.07	841.74
Idaho	1.54	3.56	3.95	30.98	636.35
Illinois	1.07	1.84	7.31	28.29	449.82
Indiana	1.38	2.78	6.32	52.36	798.43
Iowa	1.19	2.27	4.11	47.31	709.25
Kansas	1.38	3.07	6.38	43.67	317.52
Kentucky	1.64	3.45	10.51	176.00	958.65
Louisiana	1.86	3.99	14.62	38.52	771.32
Maine	0.71	1.71	2.04	29.65	570.85
Maryland	1.43	2.92	13.09	32.10	606.14
Massachusetts	0.84	2.42	5.98	24.48	641.85
Michigan	0.93	1.85	6.18	48.07	608.74
Minnesota	1.13	2.17	3.21	41.64	327.42
Mississippi	1.81	4.10	8.76	78.15	1214.63
Missouri	1.55	3.33	5.03	110.37	748.32
Montana	1.19	2.27	12.28	156.79	1100.58
Nebraska	1.40	2.82	4.55	127.93	291.10
Nevada	1.38	3.39	12.07	112.40	930.63
New Hampshire	0.83	2.65	4.73	32.07	305.90
New Jersey	0.95	3.24	7.11	77.16	394.96
New Mexico	0.90	1.78	4.81	61.23	707.20
New York	0.80	2.65	5.67	81.14	819.98
North Carolina	1.55	3.48	5.57	168.27	1373.15
North Dakota	1.47	2.85	9.65	129.07	614.41
Ohio	1.22	2.43	8.53	65.09	603.86
Oklahoma	1.67	3.61	3.84	69.80	777.67
Oregon	1.45	2.68	4.52	74.62	679.85
Pennsylvania	1.18	2.32	8.18	42.74	644.24
Rhode Island	0.78	2.29	2.72	31.84	392.99
South Carolina	1.70	4.01	7.64	171.79	1696.41
South Dakota	1.35	2.57	9.28	87.11	401.63
Tennessee	1.86	4.41	11.51	185.85	376.15
Texas	1.69	3.71	3.73	47.23	2086.24
Utah	1.11	2.34	4.91	86.14	1322.23
Vermont	0.78	2.12	2.19	48.54	772.87
Virginia	1.58	3.32	4.58	88.22	708.11
Washington	1.53	2.60	6.50	109.94	771.14
West Virginia	1.50	3.13	6.34	78.07	1431.48
Wisconsin	0.99	1.72	4.08	60.61	781.90
Wyoming	1.24	2.46	14.86	65.71	1550.80

The statistical models underlying the estimates in Table D-5 were estimated using panel regressions. Each load profile represented an individual panel (broken down by utility, region, state and customer class). Each panel contained data in hourly form, for at least one consecutive year's worth of data (8,760 hourly observations), with some panels containing several years of data. The regression models were designed to accurately predict normalized hourly load for electricity customers nationwide given the time of day, day of week, and month, with a focus primarily on the accuracy of the predictions in the months and hours of the day when a demand response event is likely to be called. Hourly loads were estimated for the four customer classes: Residential and Small, Medium and Large commercial and industrial. Separate models were estimated for residential customers in the New England states and non-New England states. This segmentation was intended to reflect inherent differences in the housing stock. Homes in the New England states are typically older, smaller and have a much lower CAC penetration due to a lack of centralized vents. This also typically results in a much higher concentration of room air conditioners, a variable for which there is no reliable data source. With the effect of the temperature-based variables in the model scaled directly by CAC penetration, segmenting the residential class ensures appropriate coefficients for these variables. Without the segmentation, the model produced biased estimates at the low end of the saturation of central air conditioning due to the bias in the New England states.

For each customer segment, functional form was closely considered and then several specifications were tested using a fixed-effects panel regression model. This approach controls for auto-correlation in the errors and ensures correct standard errors. The selection of the final regression model was based on its accuracy under normal and extreme weather conditions, and on its theoretical consistency. The same specification was used for all customer segments, with the main difference being that CAC penetration varies in the residential segment, while it is held constant for the C&I segments. With C&I load much less dependent on CAC load, and variation in CAC penetration significantly lower in these segments, this is a valid approach.

The final models depict normalized energy use for customers across states and classes as a function of variables that capture typical load shapes associated with operational schedules, and, for the residential model, variables designed to capture central air conditioning load based on central air conditioning penetration and cooling-degree-hours. The dependent variable in each regression consisted of normalized hourly energy use, and the explanatory variables for the residential model were:

- Hourly binary variables to define the typical load profile for a day;
- Monthly binary variables to capture seasonal variation;
- Day-of-week binary variables to capture variation in energy use throughout the week;
- A weekend & holiday binary variable interacted with hourly binary variables to capture the different hourly load profile typically found on weekends or holidays;
- A Monday or Friday binary variable interacted with hourly binary variables to capture the different hourly load profiles found on Mondays and Fridays;
- Cooling-Degree-Hours * Central Air Conditioning Penetration interacted with hour binary variables to capture the impact of air conditioning load across the hours;

Mathematically, the regressions can be expressed by:

$$normalizedkW_{xt} = a_x + \sum_{i=5}^{9} b_i \cdot Month_i + \sum_{k=1}^{7} c_k \cdot Dayofweek_k + \sum_{j=1}^{24} d_j \cdot Hour_j + \sum_{j=1}^{24} e_j \cdot Hour_j \cdot Weekendholiday + \sum_{j=1}^{24} f_j \cdot Hour_j \cdot MondayOrFriday + \sum_{j=1}^{24} g_j \cdot Hour_j \cdot CoolingDegreeHours \cdot CACpenetration + U_{xt}$$

In this equation,

$normalizedkW_{xt}$ represents the normalized hourly usage for state or utility x at time t;

a - g are estimated parameters;

$Month_i$ is a dummy variable for month i;

$Dayofweek_k$ is a dummy variable for day of week k;

$Hour_j$ is a dummy variable for hour j;

Weekendholiday is a dummy variable specifying the day as either a weekend or holiday;

MondayOrFriday is a dummy variable specifying the day as either a Monday or Friday;

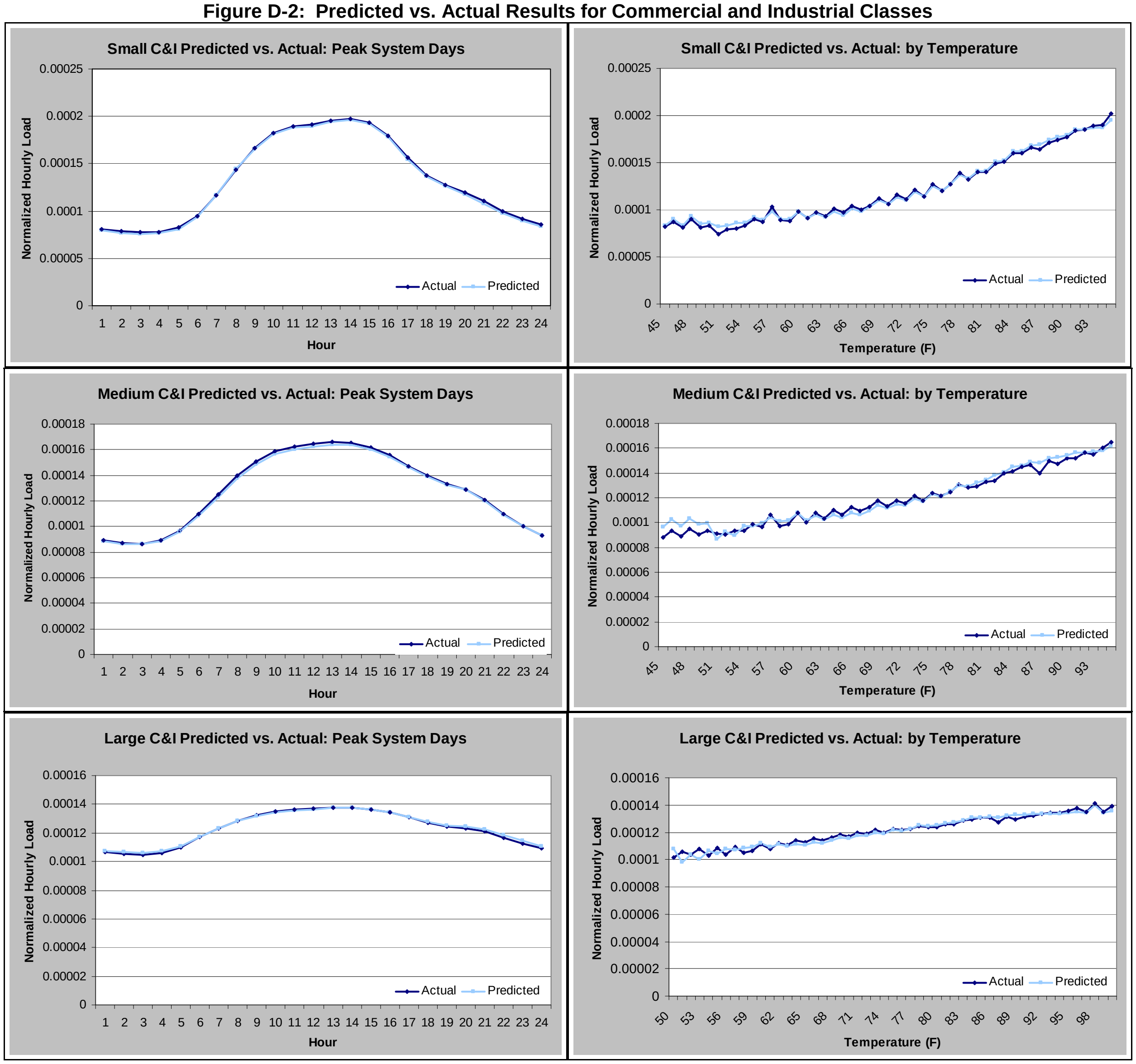
CoolingDegreeHours is the cooling degree hours measured as the maximum of 0 or temperature - 65

U_{xt} is the error term;

The accuracy of the models' predictions across all the states hinges on the amount of variation in the load profiles used as inputs. As indicated in Table D-4, load data underlying the regressions span a wide range of geographic regions and include hot and cold climates, humid and dry climates, and a wide variation in central air conditioning saturation.

An analysis of the Predicted vs. Actual loads shows that the models predict well for all customer classes across various metrics. Figure D-2 shows the predicted vs. actual results for the commercial and industrial classes. Model accuracy is excellent even at the high end of the temperature spectrum and across all hours of the day during peak (top 15) system load days.

Figure D-2: Predicted vs. Actual Results for Commercial and Industrial Classes



Figures D-3 and D-4 compare predicted and actual values for the residential model. As with the C&I models, the residential models predict well across the temperature spectrum. When comparisons are made for states grouped according to CAC saturation, it is evident that even with the segmented models, the predicted values are low at high temperature values for states with lower CAC saturations. Indeed, the average under-prediction across all states for the peak period on the top 15 system load days is 8.5 percent. While not ideal, this under prediction means that the price-based, demand response potential estimates are conservative. Furthermore, predictions are very accurate for the higher CAC quadrants, even at high temperatures, which is where the majority of residential demand response potential will come from.

Figure D-3: Residential Actual vs. Predicted by Temperature

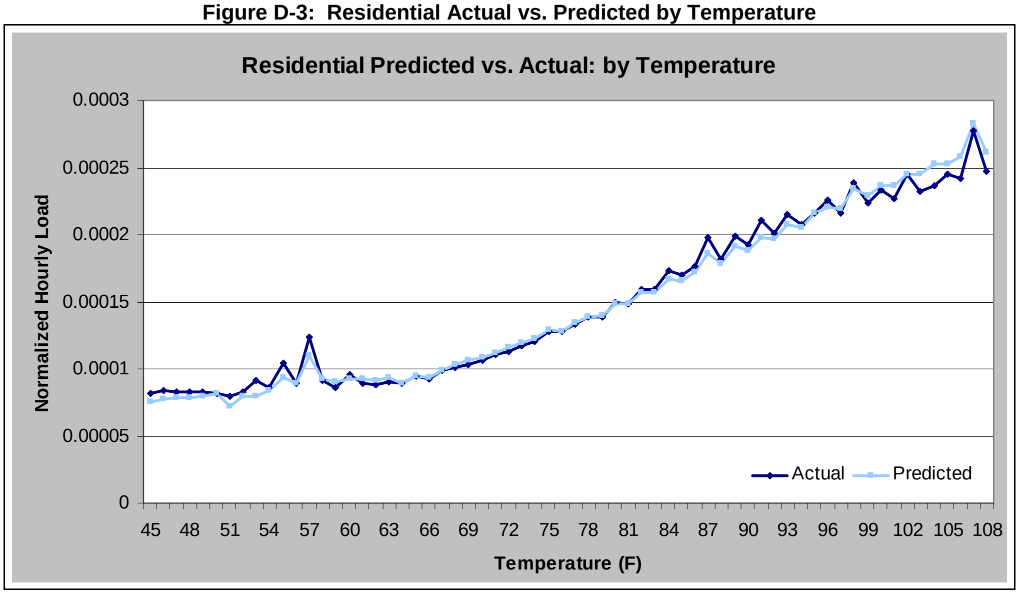


Figure D-4: Residential Actual vs. Predicted by Temperature; CAC Quadrant

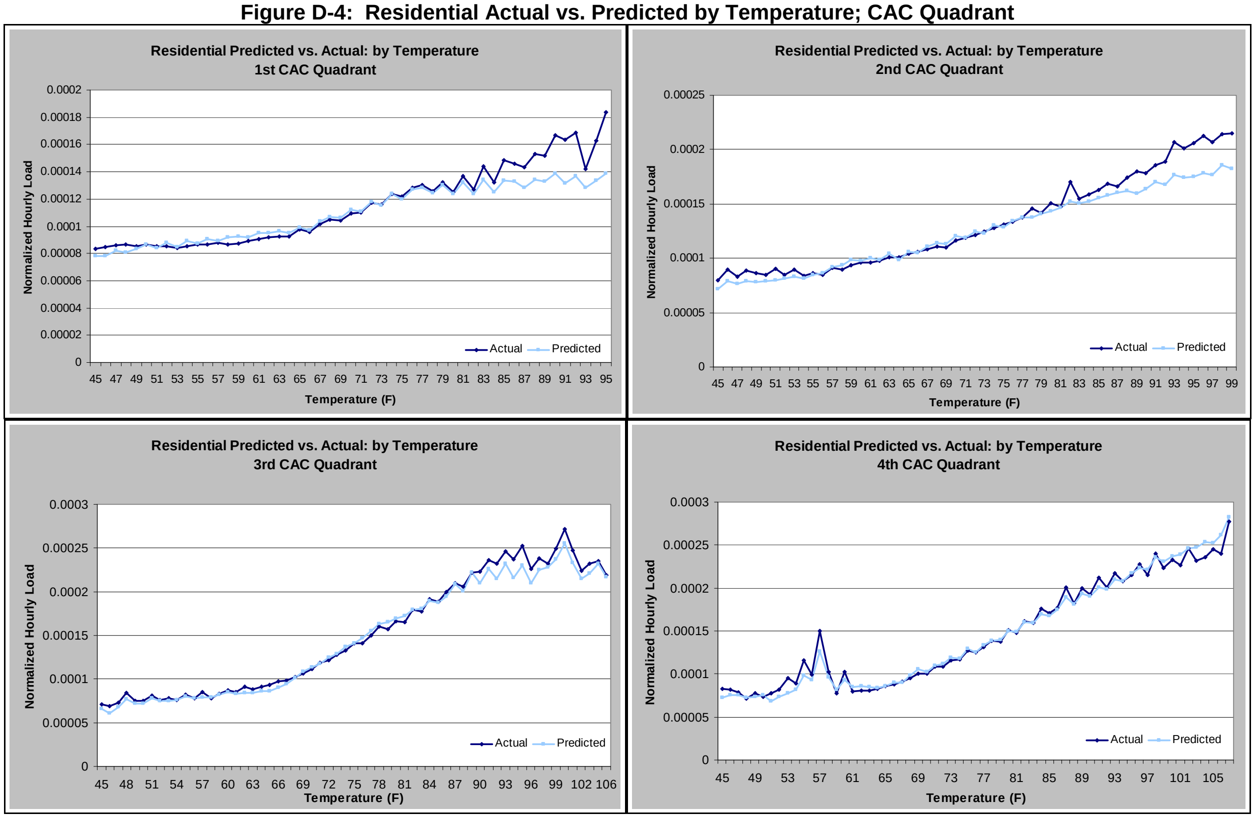


Table D-6 provides the average per-customer peak load by state.

Table D-6: Average Per-Customer Peak Load by Rate Class

State	Average peak load per customer (kW)			
	Residential	Small C&I	Medium C&I	Large C&I
Alabama	3.4	15.1	192	748
Alaska	0.9	4.5	80	1,029
Arizona	3.8	16.9	165	822
Arkansas	2.8	9.1	93	801
California	1.2	3.2	38	555
Colorado	1.5	1.9	40	901
Connecticut	1.6	3.9	63	206
Delaware	1.9	15.2	125	951
District of Columbia	1.6	9.5	158	745
Florida	3.1	2.9	40	696
Georgia	3.4	5.4	60	602
Hawaii	1.0	4.2	45	842
Idaho	2.9	3.9	31	636
Illinois	1.7	7.3	28	450
Indiana	2.4	6.3	52	798
Iowa	1.9	4.1	47	709
Kansas	2.8	6.4	44	318
Kentucky	3.0	10.5	176	959
Louisiana	3.5	14.6	39	771
Maine	0.8	2.0	30	571
Maryland	2.6	13.1	32	606
Massachusetts	1.0	6.0	24	642
Michigan	1.5	6.2	48	609
Minnesota	1.7	3.2	42	327
Mississippi	3.5	8.8	78	1,215
Missouri	3.1	5.0	110	748
Montana	1.6	12.3	157	1,101
Nebraska	2.6	4.5	128	291
Nevada	3.1	12.1	112	931
New Hampshire	1.1	4.7	32	306
New Jersey	2.2	7.1	77	395
New Mexico	1.3	4.8	61	707
New York	1.3	5.7	81	820
North Carolina	3.2	5.6	168	1,373
North Dakota	2.2	9.7	129	614
Ohio	2.0	8.5	65	604
Oklahoma	3.3	3.8	70	778
Oregon	1.9	4.5	75	680
Pennsylvania	1.7	8.2	43	644
Rhode Island	1.0	2.7	32	393
South Carolina	3.6	7.6	172	1,696
South Dakota	2.2	9.3	87	402
Tennessee	3.9	11.5	186	376
Texas	3.3	3.7	47	2,086
Utah	1.6	4.9	86	1,322
Vermont	0.9	2.2	49	773
Virginia	2.5	4.6	88	708
Washington	1.8	6.5	110	771
West Virginia	2.3	6.3	78	1,431
Wisconsin	1.4	4.1	61	782
Wyoming	1.7	14.9	66	1,551

e) Growth Rate in per Customer Peak Load

In estimating the growth rate in peak load per customer, the analysis started with base year values for the following items:

1. Growth rate in number of accounts by rate class,
2. Average peak load per customer account by rate class, and
3. State peak forecast.

In order to estimate the growth rate in critical peak per customer, it is first necessary to estimate the growth rate in account population by rate class. For the residential sector, the population forecast for each state was readily obtained from the U.S. Census Bureau and this was assumed to apply directly to the growth rate of residential accounts. In order to estimate the growth rate in accounts for all C&I rate classes, growth rates in 'Commercial sq.ft.' were used as a proxy (obtained from Supplemental Tables to the Annual Energy Outlook 2008 that provides projections on Commercial Sq.ft. by census division)[125], since better estimates were not available.

The overall peak load for a particular rate class is arrived at by aggregating the product of critical peak load per account and the number of accounts by rate class. It is assumed that the overall peak load for each rate class grows at the same rate as the system peak, obtained from NERC forecast values (as explained in the previous section). Therefore, in the final step, the underlying assumptions related to growth rate in number of accounts by rate class on the growth in aggregate peak load by rate class were used to ascertain the implicit critical peak growth rates per customer by rate class.

Table D-7 lists the population and critical peak growth rate values for each state.

[125] 'Supplemental Tables to the Annual Energy Outlook 2008" – http://www.eia.doe.gov/oiaf/archive/aeo08/supplement/index.html

Table D-7: Growth Rate in Population and Critical Peak Load by Rate Class

State	Population growth rate (%)				Critical peak growth rate (%)	
	Residential	Small C&I	Medium C&I	Large C&I	Residential	All C&I
Alabama	0.3	1.3	1.3	1.3	1.6	0.6
Alaska	1.1	1.3	1.3	1.3	0.4	0.2
Arizona	1.6	1.7	1.7	1.7	0.2	0.1
Arkansas	0.6	1.5	1.5	1.5	1.2	0.3
California	1.1	1.5	1.5	1.5	0.8	0.4
Colorado	0.9	1.7	1.7	1.7	0.9	0.1
Connecticut	0.3	0.8	0.8	0.8	0.9	0.4
Delaware	0.9	1.3	1.3	1.3	0.4	0.1
District of Columbia	-0.1	1.3	1.3	1.3	1.5	0.1
Florida	2.0	1.6	1.6	1.6	0.2	0.6
Georgia	1.3	1.6	1.6	1.6	0.6	0.3
Hawaii	0.6	1.3	1.3	1.3	0.9	0.2
Idaho	1.4	1.7	1.7	1.7	0.4	0.1
Illinois	0.3	1.1	1.1	1.1	1.3	0.4
Indiana	0.4	1.1	1.1	1.1	1.0	0.3
Iowa	0.6	1.1	1.1	1.1	1.6	1.1
Kansas	0.3	1.1	1.1	1.1	1.3	0.5
Kentucky	0.4	1.3	1.3	1.3	1.3	0.4
Louisiana	0.3	1.5	1.5	1.5	1.6	0.4
Maine	0.4	0.8	0.8	0.8	0.7	0.4
Maryland	1.0	1.3	1.3	1.3	0.4	0.1
Massachusetts	0.3	0.8	0.8	0.8	0.8	0.4
Michigan	0.3	1.1	1.1	1.1	1.2	0.4
Minnesota	0.9	1.1	1.1	1.1	1.3	1.1
Mississippi	0.3	1.3	1.3	1.3	1.6	0.6
Missouri	0.5	1.1	1.1	1.1	1.3	0.7
Montana	0.6	1.7	1.7	1.7	1.3	0.2
Nebraska	0.6	1.1	1.1	1.1	1.6	1.1
Nevada	1.6	1.7	1.7	1.7	0.2	0.1
New Hampshire	1.0	0.8	0.8	0.8	0.2	0.4
New Jersey	0.5	0.7	0.7	0.7	0.8	0.7
New Mexico	0.6	1.7	1.7	1.7	1.2	0.1
New York	0.1	0.7	0.7	0.7	0.8	0.3
North Carolina	1.4	1.6	1.6	1.6	0.5	0.3
North Dakota	0.6	1.1	1.1	1.1	1.6	1.1
Ohio	0.1	1.1	1.1	1.1	1.3	0.3
Oklahoma	0.4	1.5	1.5	1.5	1.2	0.1
Oregon	1.1	1.5	1.5	1.5	0.7	0.4
Pennsylvania	0.2	0.7	0.7	0.7	1.2	0.7
Rhode Island	0.4	0.8	0.8	0.8	0.8	0.4
South Carolina	0.9	1.6	1.6	1.6	1.0	0.3
South Dakota	0.6	1.1	1.1	1.1	1.6	1.1
Tennessee	0.9	1.3	1.3	1.3	1.0	0.6
Texas	1.5	1.5	1.5	1.5	0.3	0.3
Utah	1.4	1.7	1.7	1.7	0.4	0.1
Vermont	0.6	0.8	0.8	0.8	0.6	0.4
Virginia	1.1	1.6	1.6	1.6	0.7	0.3
Washington	1.2	1.5	1.5	1.5	0.6	0.4
West Virginia	-0.1	1.5	1.5	1.5	1.6	0.1
Wisconsin	0.5	1.1	1.1	1.1	1.5	0.9
Wyoming	0.3	1.7	1.7	1.7	1.6	0.2

f) Central Air Conditioning (CAC) Market Saturation Data

As a first step in determining the saturation of CAC equipment in the residential sector, CAC saturation values were compiled from a combination of primary and secondary information sources for each state. These multiple sources included EIA Regional Energy Consumption Survey (RECS) data, American Housing Survey data, utility reports, specific reports on state-level appliance saturation surveys, and information obtained from utilities through direct contacts (indicated in Table D-8).

For states with data from multiple sources, professional judgment was used to determine the data that provided the closest approximation to the state level value in order to estimate the default saturation value for each state. The estimation approach varied by state; sometimes a single best source value was used as the default estimate, while at other times CAC saturation values were obtained from multiple sources. The specific methodology used for estimating the default value for each state is indicated in Table D-8.

For the C&I sector, CAC saturation values were obtained from the Commercial Building Energy Consumption Survey (CBECS) data provided by EIA.[126]

Table D-8 summarizes the residential CAC saturation values and how they were derived.

[126] Please refer to Table B41, 'Cooling Equipment Floorspace for Non-Mall Buildings". http://www.eia.doe.gov/emeu/cbecs/cbecs2003/detailed_tables_2003/2003set8/2003excel/b41.xls, published by EIA. The table provides cooling saturation by building floorspace for the four census regions. We assume that small C&I buildings have floor space less than 25,000 sq.ft., For medium C&I customers, we assume that the floor space area ranges between 25,000 to 250,000 sq.ft. This data is available only at the Census region level. All states falling within a census region are assumed to have the same saturation value.

Table D-8: Residential CAC Saturation Values by State

State	Default CAC Saturation Value	Derivation of Default CAC Saturation Value	Residential CAC Saturation Value	Detailed reference
Alabama	62.0%	Used higher value based on CDD compared to other states in census division.	55.1%	2005 RECS data from EIA for East South Central Division, Table HC13.6.
			62.0%	Southern Company Residential Saturation Survey, Dec. 2007. Provided by Lincoln Wood.
Alaska	2.5%	One data source	0.0%	Information from Todd Hoener at Golden Valley Electric Assn.
		Average of two sources	5%	BC Hydro 2003 Residential End Use Study (Northern Region)
Arizona	86.8%	Used value obtained from APS -more current than AHS data	86.8%	Information from Jim Wantor at Arizona Public Service (APS). Based on a saturation study: 75% of residential customers are in the desert and 99% of them have CAC, while 25% of customers are not in the desert and half of them have CAC.
			92.1%	American Housing Survey (AHS) for the Phoenix Metropolitan Area: 2002, U.S. Census Bureau.
Arkansas	54.6%	One data source	54.6%	Association of Electric Cooperatives of Arkansas (AECC): Appliance Saturation Survey indicates that in 2006 approximately 54.6% of the electric cooperatives' residential consumers in Arkansas had electric central air conditioning.
California	41.0%	RASS data was used as the default data source	41.0%	California Statewide Residential Appliance Saturation Study (RASS), June 2004.
			79.9%	American Housing Survey (AHS) for the Sacramento, CA Metropolitan Area: 2004, U.S. Census Bureau.
			47.4%	American Housing Survey (AHS) for the Santa Ana, CA Metropolitan Area: 2002, U.S. Census Bureau.
			38.7%	American Housing Survey (AHS) for the Los Angeles, CA Metropolitan Area: 2003, U.S. Census Bureau.
			70.5%	American Housing Survey (AHS) for the San Bernardino-Ontario, CA Metropolitan Area: 2002, U.S. Census Bureau.
			34.5%	American Housing Survey (AHS) for the San Diego, CA Metropolitan Area: 2002, U.S. Census Bureau.
			45.0%	2005 RECS data from EIA.
Colorado	47.2%	Average of PSC and AHS values. Tri-state data seems low compared to other values.	45.0%	Information from Bruce Nielson at the Public Service Co (PSC) of Colorado. Information provided is for 2006.
			49.5%	American Housing Survey (AHS) for the Denver Metropolitan Area: 2004, U.S. Census Bureau.
			22.6%	Tri-State: Jim Spiers provided data for Tri-State's 4 states from a "recent residential end-use survey of our 44 Members in Colorado, Wyoming, Nebraska and New Mexico."
Connecticut	26.9%	One data source	26.9%	American Housing Survey (AHS) for the Hartford Metropolitan Area: 2004, U.S. Census Bureau.
Delaware	53.0%	One data source	53.0%	PHI AMI business case filing
District of Columbia	56.0%	One data source	56.0%	PHI AMI business case filing
Florida	91.0%	RECS data	93.0%	Information from John Haney at FPL.
			84.9%	American Housing Survey (AHS) for the Miami/Ft Lauderdale Metropolitan Area: 2002, U.S. Census Bureau.

State	Default CAC Saturation Value	Derivation of Default CAC Saturation Value	Residential CAC Saturation Value	Detailed reference
			91.0%	2005 RECS data from EIA.
			68.0%	Southern Company Residential Saturation Survey, Dec. 2007. Provided by Lincoln Wood.
Georgia	82.2%	Average of all data - SoCo is current, but low compared to AHS value.	91.5%	American Housing Survey (AHS) for the Atlanta Metropolitan Area: 2004, U.S. Census Bureau.
			73.0%	Southern Company (SoCo) Residential Saturation Survey, Dec. 2007. Provided by Lincoln Wood.
Hawaii	17.6%	Weighted average based on number of households for each utility	22.5%	Hawaiian Electric Co.: 2007 REEPs.
			4.1%	Maui Electric Co.: Residential Appliance Survey, 7/03.
			1.2%	Hawaii Electric Light Co.: 2007 Residential Appliance Saturation Survey.
Idaho	66.5%	One data source	66.5%	Information from P. Werner at Idaho Power Co. According to him, in the last residential end-use survey of Idaho Power's service territory (not the state) in 2004, the central AC saturation including heat pumps was 60.6%. The current saturation is an estimate.
Illinois	75.0%	Average of AHS and Xcel Energy value - including MEEA data raises average to 81% which seems out of line compared to other states in census division.	60.0%	American Housing Survey (AHS) for the Chicago Metropolitan Area: 2003, U.S. Census Bureau.
			90.0%	Midwest Residential Market Assessment and DSM Potential Study, Xcel Energy, 2006.
			94.3%	Claire Saddler, ComEd, wrote that MEEA conducted 309 SF home survey in 2003. This research found that 94.3% of those sampled had central A/C.
Indiana	74.4%	Average of all data - factors in the more current Xcel Energy value and the AHS data for the Indianapolis area.	82.8%	American Housing Survey (AHS) for the Indianapolis Metropolitan Area: 2004, U.S. Census Bureau.
			66.0%	Midwest Residential Market Assessment and DSM Potential Study, Xcel Energy, 2006.
Iowa	70.0%	One data source	70.0%	IPL Energy Efficiency Plan Vol. II Appendix D (Iowa Utility Assoc. State-Wide Savings Potential Study 8/2/07).
Kansas	83.7%	One data source	83.7%	American Housing Survey (AHS) for the Kansas City Metropolitan Area: 2002, U.S. Census Bureau.
Kentucky	76.0%	One data source	76.0%	Midwest Residential Market Assessment and DSM Potential Study, Xcel Energy, 2006.
Louisiana	75.5%	One data source	75.5%	American Housing Survey (AHS) for the New Orleans Metropolitan Area: 2004, U.S. Census Bureau.
Maine	14.0%	One data source	14.0%	Data obtained from FSC.
Maryland	78.0%	One data source	78.0%	BGE AMI business case filing
Massachusetts	12.7%	One data source	12.7%	2005 RECS data (New England Division); Table HC11.6.
Michigan	57.2%	Average of all data - values are fairly close	56.0%	Electric Demand Comparison, Consumers Energy 6/22/06 (2008 value).
			60.9%	American Housing Survey (AHS) for the Detroit Metropolitan Area: 2003, U.S. Census Bureau.
			52.0%	Consumers Energy Demand Response program plan
			60.0%	Midwest Residential Market Assessment and DSM Potential Study, Xcel Energy, 2006.
Minnesota	51.2%	Average of all data - values are fairly close	48.3%	Great River Energy Planning Study, 2003.
			54.0%	Midwest Residential Market Assessment and DSM Potential Study, Xcel Energy, 2006.

State	Default CAC Saturation Value	Derivation of Default CAC Saturation Value	Residential CAC Saturation Value	Detailed reference
Mississippi	74.7%	Average of all data - SoCo data is more current, but low compared to AHS data.	81.4%	American Housing Survey (AHS) for the Memphis Metropolitan Area: 2004 (also including parts of AR, MS), U.S. Census Bureau.
			68.0%	Southern Company (SoCo) Residential Saturation Survey, Dec. 2007. Provided by Lincoln Wood.
Missouri	87.5%	Average of all data - values are fairly close	92.0%	2006 Missouri Statewide Residential Lighting and Appliance Efficiency Saturation Study, 2006.
			85.0%	Midwest Residential Market Assessment and DSM Potential Study, Xcel Energy, 2006.
			85.5%	American Housing Survey (AHS) for the St. Louis Metropolitan Area: 2004 (also including part of IL), U.S. Census Bureau.
Montana	42.1%	One data source	42.1%	2005 RECS data (Mountain Division); Table HC14.6.
Nebraska	82.8%	Used NPPD data - Tri-State data seems low compared to other mid-west saturation rates.	82.8%	Information from Joel Young at Nebraska Public Power District (NPPD). He mentioned that Res. Central A/C penetration in NPPD’s service area was 82.8% in 2006.
			22.6%	Tri-State: Jim Spiers provided data for Tri-State's 4 states from a "recent residential end-use survey of our 44 Members in Colorado, Wyoming, Nebraska and New Mexico."
Nevada	86.8%	Assume same as AZ based on CDD	42.1%	2005 RECS data (Mountain Division); Table HC14.6.
New Hampshire	12.7%	One data source	12.7%	2005 RECS data (New England Division), Table HC11.6.
New Jersey	55.0%	Used Brattle data - more current	55.0%	Atlanta City Electric AMI business case filing
			45.7%	American Housing Survey (AHS) for the Northern New Jersey Metropolitan Area: 2003, U.S. Census Bureau.
New Mexico	42.0%	One data source	42.0%	2005 RECS data (Mountain Division), Table HC14.6.
New York	16.7%	Average of all data	12.0%	Source: Knowledge Networks, 2007 Electric Forecasting Residential Customer Research, Summer 2007, Prepared for ConEdison, p. 19.
			23.6%	American Housing Survey (AHS) for the Buffalo, NY Metropolitan Area: 2002, U.S. Census Bureau.
			16.4%	American Housing Survey (AHS) for the NY City Metropolitan Area: 2003, U.S. Census Bureau.
			15.0%	2005 RECS data from EIA.
North Carolina	84.4%	One data source	84.4%	American Housing Survey (AHS) for the Charlotte Metropolitan Area: 2002 (also including part of SC), U.S. Census Bureau.
North Dakota	51.0%	Average of RECS and Minnesota CAC % - using only RECS data seems high compared to CDDs. Minnesota has similar CDDs data.	70.9%	2005 RECS data (West North Central Division), Table HC12.6.
Ohio	62.9%	Average of all data - factors in all values given the range of values.	51.3%	American Housing Survey (AHS) for the Cleveland Metropolitan Area: 2004, U.S. Census Bureau.
			75.3%	American Housing Survey (AHS) for the Columbus, OH Metropolitan Area: 2002, U.S. Census Bureau.

State	Default CAC Saturation Value	Derivation of Default CAC Saturation Value	Residential CAC Saturation Value	Detailed reference
			62.0%	Midwest Residential Market Assessment and DSM Potential Study, Xcel Energy, 2006.
Oklahoma	84.2%	One data source	84.2%	American Housing Survey (AHS) for the Oklahoma Metropolitan Area: 2004, U.S. Census Bureau.
Oregon	38.0%	Used PGE Customer Data - more current	28.0%	American Housing Survey (AHS) for the Portland, OR Metropolitan Area: 2002, U.S. Census Bureau.
			38.0%	PGE Customer Data 2007.
Pennsylvania	49.8%	Weighted average based on AHS housing stock from each area	48.4%	American Housing Survey (AHS) for the Philadelphia Metropolitan Area: 2003, U.S. Census Bureau.
			52.3%	American Housing Survey (AHS) for the Pittsburg Metropolitan Area: 2004, U.S. Census Bureau.
Rhode Island	12.5%	One data source	12.5%	American Housing Survey (AHS) for the Providence, Pawtucket, Warwick Metropolitan Area: 1998, U.S. Census Bureau.
South Carolina	84.4%	One data source	84.4%	American Housing Survey (AHS) for the Charlotte Metropolitan Area: 2002 (also including part of SC), U.S. Census Bureau.
South Dakota	70.9%	One data source	70.9%	2005 RECS data (West North Central Division); Table HC12.6.
Tennessee	81.4%	One data source	81.4%	American Housing Survey (AHS) for the Memphis Metropolitan Area: 2004 (also including parts of AR, MS), U.S. Census Bureau.
Texas	80.0%	RECS data	77.9%	American Housing Survey (AHS) for the San Antonio Metropolitan Area: 2004, U.S. Census Bureau.
			92.1%	American Housing Survey (AHS) for the Dallas, TX Metropolitan Area: 2002, U.S. Census Bureau.
			87.0%	American Housing Survey (AHS) for the Arlington, TX Metropolitan Area: 2002, U.S. Census Bureau.
			80.0%	2005 RECS data from EIA.
Utah	42.1%	One data source	42.1%	2005 RECS data (Mountain Division), Table HC14.6
Vermont	7.2%	One data source	7.2%	FSC study
Virginia	50.2%	One data source	50.2%	2005 RECS data (South Atlantic Division), Table HC13.6.
Washington	28.6%	Average of all data - Northwest Energy value is for the entire NW area, not by state.	50.0%	Single Family Residential Existing Stock Assessment, Northwest Energy Efficiency Alliance, Aug 2007.
			7.2%	American Housing Survey (AHS) for the Seattle-Everett Metropolitan Area: 2004, U.S. Census Bureau.
West Virginia	50.2%	One data source	50.2%	2005 RECS data (South Atlantic Division), Table HC13.6.
Wisconsin	62.0%	Average of all data - factors in all values given the range of values. CDDS in WI is on the low end.	72.0%	Central Air Conditioning in Wisconsin, Energy Center of Wisconsin, May 2008.
			51.0%	Midwest Residential Market Assessment and DSM Potential Study, Xcel Energy, 2006.
			53.1%	American Housing Survey (AHS) for the Milwaukee, WI Metropolitan Area: 2002, U.S. Census Bureau.
			72.0%	Information from Harvey Dorn at Alliant Energy. Note that this data is for SF homes only.

State	Default CAC Saturation Value	Derivation of Default CAC Saturation Value	Residential CAC Saturation Value	Detailed reference
Wyoming	42.0%	One data source	42.0%	2005 RECS data (Mountain Division), Table HC14.6.

g) AMI Deployment Schedule by State

Advanced metering is a necessary technology to support price-responsive demand response for mass-market customers. However, having advanced meters is a necessary but not sufficient condition to support price-responsive demand response—a utility also needs a meter data management system (MDMS) and billing system that will support price-responsive demand response options. Quite often, utilities install meters that qualify as advanced meters in that they gather hourly or sub-hourly data daily, but use them as an AMR system to produce monthly meter reads—they do not install the MDMS and billing systems needed to support wide scale price-responsive demand response. A notable example is PPL, which completed its AMI deployment around 2004 and, until recently, had the only large scale AMI system in the country that was generating hourly data on all customers on a daily basis. However, it wasn't until 2008 that the company installed an MDMS system capable of supporting widespread use of price-responsive demand response. Similarly, many small cooperatives and municipalities have AMR or AMI meter systems that can deliver hourly data (although not necessarily daily) but, currently, these systems are almost universally being used only to support monthly meter reads. Without an MDMS system designed to clean and manager hourly data, these small installations can not support wide spread use of price-responsive demand response. The AMI deployment scenarios described below recognize that more than just metering is needed to support price-responsive demand response. The deployment time lines for each scenario are based on the understanding that only systems that have MDMS and billing systems are considered AMI for purposes of supporting demand response potential.

Two AMI deployment scenarios were developed for each state.

- The "Full Deployment" scenario is used to support the Achievable Participation and Full Participation demand response scenarios and assumes that all utilities will have AMI meters in place for all customers, along with the MDMS and billing systems required to support price-based demand response, by the end of the forecast horizon, 2019. Deployment timing is based on a set of assumptions described below, and varies significantly across states based on current plans, the mix of utilities in each state, and other factors.
- The "Partial Deployment" scenario is used to support the Expanded BAU potential scenario and includes AMI deployment plans for each state based largely on a continuation of current trends. It includes utilities that already have or are currently deploying AMI systems and other utilities that, based on a variety of data sources summarized below, have expressed interest in or are believed to have a higher probability of installing such systems over the next ten years.

These two alternative scenarios should not be considered forecasts of actual AMI meter and system deployment. The full deployment scenario is predicated on the assumption that all customers will have smart meters by the end of the ten-year forecast horizon. This assumption is combined with a variety of information and assumptions that drive the likely sequence of installations across utilities in a state and across states that are described below. The partial deployment scenario is probably closer to what might actually occur, but it is not a true forecast, since a true forecast would require conducting business cases on hundreds or perhaps thousands of utilities and an assessment of the likely political and other barriers to deployment in each state. Such work is significantly beyond the scope of this analysis. Even if such work could be completed, it would be subject to change frequently due to some of the factors outlined below. The AMI deployment scenarios presented here should be considered a reasonable starting point for each state based on expert judgment and publicly available information about plans and interest. The demand response potential model has been intentionally set up so that alternative deployment scenarios can easily be substituted.

In addition to limited time and money, one of the primary reasons why the demand response potential estimates are based on AMI deployment scenarios rather than forecasts is that the experience over the last five years illustrates well how difficult it is to forecast AMI activity. The rate of AMI investment depends on a wide variety of factors that are constantly in flux, including federal tax and grant policy, state regulatory policy, technology evolution and testing, and fundamental business case economics, among others. The key forecasting challenges include, but are not limited to:

1. Actual deployment of AMI systems depends importantly on state regulatory policy. Unless regulated utilities anticipate that AMI investments will reduce overall revenue requirements, they will be reluctant to undertake those investments without firm indications from state regulators that such investments will be considered prudent. Thus, regulatory commissions can retard or advance the deployment of AMI within a state by the prudence and clarity they provide. However, forecasting state regulatory commission viewpoints on AMI is extremely difficult because most states have not formulated firm policy and because policy goals within each state are evolving, causing regulatory positions to fluctuate.

2. Federal policy can and does operate to change the basic revenue requirements of AMI. The 2007 change in tax code to identify AMI assets as ten-year, instead of twenty-year, property for tax purposes had a significant impact on improving business case economics. By authorizing funds to support up to 50 percent matching investment funds for Smart Grid and AMI projects, the Federal government has provided further stimulus in the recent American Recovery and Reinvestment Act of 2009. However, future federal AMI initiatives are tied to the economic situation, policies toward greenhouse gas emissions, and transmission grid management policies, and are extremely difficult to anticipate in the future years leading up to 2019.

3. There are a variety of AMI technologies available in the market place, but some of the features and dimensions of these technologies are currently evolving. This on-going evolution makes it difficult for utilities that want to see a fully-deployed system in operation to make a decision to proceed, even if their interest is strong. For example, home-area-networking to support in-home displays and integrated under-glass service disconnection switches are of increasing interest to utilities, but large-scale deployments of these AMI capabilities are not yet observable. Consequently, translating utility stated interests into expected AMI deployment dates is very difficult and depends on specific utility risk profiles.

4. The fundamental economics of AMI deployment varies significantly from utility to utility. Some of the key factors that influence the cost-effectiveness of demand response are:

    a. The higher the current meter reading costs, the more likely utilities are to adopt AMI, but current meter reading costs vary significantly from utility to utility as a result of automation capital currently invested (e.g., drive-by or fixed network AMR), the presence or absence of associated natural gas meters, the prevailing wage levels in the service territory, and the observed meter density (meters per square mile) in the service territory.

    b. Some utilities have substantial field activity related to off-cycle billing reads and service connections and disconnections, while other utilities have minimal field activities in these areas. AMI systems can create dramatic cost savings in these areas. Thus, this activity can be extremely significant in creating benefits to offset AMI costs so it creates important variability in the business case analysis.

    c. Theft of service can be a major consideration for some utilities, and AMI can be very helpful in identifying and reducing theft. For these utilities where theft is important, and where AMI can be used to reduce theft, the cost/benefit calculation will be much more positive, raising the chances that AMI will be implemented.

    d. All utilities seek to reduce estimated and delayed bills, and AMI can help with this goal in a very significant way. However, the number and percentage of estimated and delayed bills varies significantly from utility to utility, as does the importance of reducing them, so that it can be very difficult to predict specific utilities that will gain the most from AMI.

Because the benefits and costs of AMI can be so utility-specific, it is difficult to forecast where positive business cases will be found without detailed, utility-specific analysis, which in turn makes it difficult to forecast which utilities will proceed to implement AMI first. The alternative approach taken here involves the following steps:

1. Six data sources were obtained and examined to determine the most current status of or interest in AMI by hundreds of utilities in the United States. The data sources are listed below:

    a. In a report to the GridWise Alliance (The U.S. Smart Grid Revolution: KEMA's Perspectives for Job Creation, December 23, 2008), KEMA summarized their assessment of major AMI projects and their respective deployment schedules.

    b. In a 2008 survey of utilities, FERC asked a series of questions designed to identify current installations and future interest and plans for installing AMI.

    c. In a January 2008 evaluation of AMI initiatives Utilipoint compiled a list of utilities either implementing or in the process of implementing AMI.

    d. The Enernex Smart Meter Data for the California Energy Commission is a compilation of utilities with active projects or interest in AMI, using a map database format created by the Energy Retail Association.

    e. FERC's annual staff reports on Demand Response and AMI identify particular utilities with plans to deploy AMI systems (Assessment of Demand Response and Advanced Metering 2007, September, 2007, and Assessment of Demand Response and Advanced Metering, December, 2008).

    f. The Institute for Electric Energy Efficiency has released their recent survey of Smart Meter Deployment, Utility-Scale Deployment of Smart Meters, April, 2009.

2. Relevant information from all six data sources was merged into the Form EIA-861, File 2 database, which essentially provides a complete census of all utilities in the country and a mapping of utilities into states. The File 2 data were also used to categorize utilities into size strata and to identify any utilities where no information about AMI status or interest was contained in any of the other data sources.

3. The merged data from step 2 provided a profile of the AMI status of each utility and also a convenient way of identifying situations where different data sources provided contradictory information. In situations where there were internal contradictions, the expert knowledge of the team was used to judge which data was likely to be most accurate.

4. Based on the information above, each utility was assigned to one of the eight classification groups described in Table D-9.

Table D-9: Classification of Utilities by AMI Status

Classification of Utilities by AMI Status		
Category	**Utilities**	**Customers**
Utilities with more than 100,000 customers (or their affiliates) that appear to be committed to deploying AMI within two years	5	2.9 million
Utilities with more than 100,000 customers (or their affiliates) that appear to be committed to deploying AMI over the next five years.	32	34.9 million
Utilities with more than 100,000 customers (or their affiliates) that have fixed-network AMR systems in place	28	15.6 million
Utilities with more than 100,000 customers (or their affiliates) that appear to have some interest in deploying AMI	63	39.6 million
Utilities with more than 100,000 customers that have given no indication of having interest in deploying AMI	85	20.9 million
Utilities with 10,000-100,000 customers that indicated interest in AMI in the FERC survey	122	3.9 million
Utilities with 10,000 – 100,000 customers that did not indicate interest in AMI in the FERC survey	660	17.5 million
Utilities with less than 10,000 customers	2,540	5.8 million
All Categories	**3,535**	**140.0 Million**

5. The final step in the process involved producing judgmental assessments of the likelihood that each utility will deploy AMI and the time period over which it is likely to be deployed in each of the two deployment scenarios. The probabilities and deployment schedules for each category are summarized in Table D-10.

Table D-10: Assumed Probability and Schedule for Utilities Underlying Each AMI Deployment Scenario

Assumed Probability and Schedule for Utilities Underlying Each AMI Deployment Scenario				
Category	**Full Deployment**	**Partial Deployment**	**Deployment Start**	**Deployment End**
Utilities with more than 100,000 customers (or their affiliates) that appear to be committed to deploying AMI within two years	100%	100%	2009	2011
Utilities with more than 100,000 customers (or their affiliates) that appear to be committed to deploying AMI over the next five years.	100%	100%	2009	2013
Utilities with more than 100,000 customers (or their affiliates) that have fixed-network AMR systems in place	100%	67%	2014	2019
Utilities with more than 100,000 customers (or their affiliates) that appear to have some interest in deploying AMI	100%	50%	2014	2019
Utilities with more than 100,000 customers that have given no indication of having interest in deploying AMI	100%	25%	2014	2019
Utilities with 10,000-100,000 customers that indicated interest in AMI in the FERC survey	100%	50%	2014	2019
Utilities with 10,000 – 100,000 customers that did not indicate interest in AMI in the FERC survey	100%	25%	2016	2019
Utilities with less than 10,000 customers	100%	5%	2017	2019

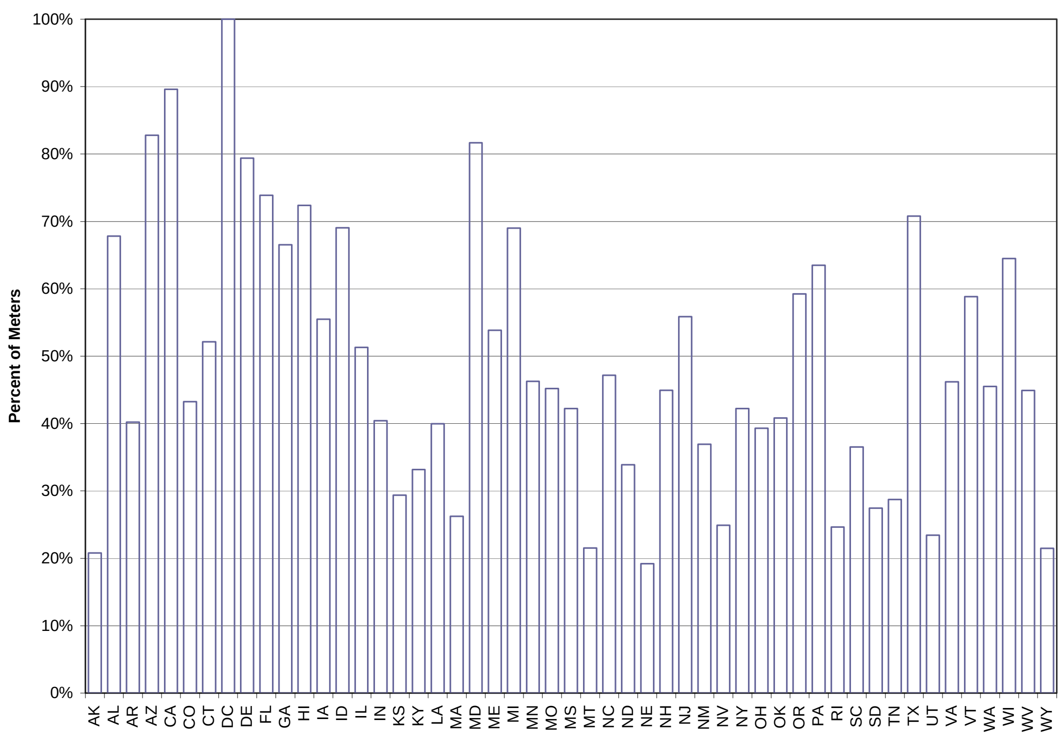
For utilities with automated meter reading systems in place, we assigned a start year and an end year for AMI deployment specific to each utility, based on the age of the automated meter reading system currently in place.

The information and assumptions summarized above lead to different meter deployments for each state and different rates of deployment nationally across the scenarios. Table D-11 shows the annual and cumulative deployment for each forecast year for the two scenarios. Figure D-5 shows the percent of meters in each state that would be AMI meters by the by the end of the forecast period for the partial deployment scenario.

Table D-11: Annual and Cumulative Deployment for Each Forecast Year under EBAU and AP/FP Scenarios

	Partial Deployment Scenario (Used in Expanded BAU Potential)		Full Deployment Scenario (Used in Achievable & Full Participation Scenarios)	
Year	**Annual Installations**	**Cumulative Installations**	**Annual Installations**	**Cumulative Installations**
2009	7,949,249	7,949,249	7,949,249	7,949,249
2010	8,157,557	16,106,806	8,260,157	16,209,405
2011	8,157,557	24,264,363	8,260,157	24,469,562
2012	8,197,899	32,462,262	8,796,464	33,266,026
2013	8,197,899	40,660,160	8,796,464	42,062,490
2014	6,180,478	46,840,638	13,241,914	55,304,404
2015	6,039,977	52,880,615	13,032,212	68,336,616
2016	6,231,172	59,111,787	16,053,354	84,389,970
2017	6,895,117	66,006,904	19,005,862	103,395,832
2018	7,002,218	73,009,122	18,846,010	122,241,842
2019	6,827,310	79,836,432	18,744,805	140,986,647

Figure D-5: Percent of Meters in State That Are AMI Meters in 2019



Demand Response Program Related Data

a) Business-As-Usual (BAU) Demand Response Potential Estimation

The demand response potential estimation for the Business-As-Usual (BAU) scenario was developed with 2008 FERC Demand Response Survey data[127] , using the following four steps:

1. Classification of Programs: The first step was to classify programs reported in the FERC Survey database to the program categories being considered in estimation of the potential: Direct Load Control (DLC) Programs, Interruptible Programs, Pricing Programs, and 'Other Types of DR Programs'. This classification was based on information provided in the FERC survey related to 'Program Name' and 'Program Description'.

2. Assignment of Programs to C&I Rate Classes: The next step was to assign demand response programs targeted toward C&I customers to the small, medium, and large rate classes. The survey database indicated whether a demand response program was being offered to commercial and/or industrial customers. For all such programs being offered to C&I customers, peak load per customer was estimated using program enrollment data in the survey. The survey database reported the 'Number of customers enrolled' and the 'Load enrolled' for each demand response program. This data was used to calculate the load enrolled per customer. If the per customer load enrolled was less than or equal to 20 kW, the program was assigned to the small C&I rate class. For medium C&I customers, the enrolled load per customer ranged between 20-200 kW, while for large C&I customers the value was greater than 200 kW.

3. Aggregation of Survey Data: The Survey database provides data on 'No. of Customers Enrolled', 'Load Enrolled', and 'Potential Load Reduction' for demand response programs reported by utilities. Data for these items were aggregated to the state level to come up with estimates for these items by rate class and program type[128]. Certain adjustments were made to the 2008 Survey data to obtain the BAU estimate of the load reduction potential. These adjustments are described in Chapter III of the report in a sidebar titled 'Benchmarking the BAU Estimate'. In addition, the total load reduction potential reported by ISO-NE and PJM in the FERC Survey database had to be allocated to the states served by these entities.[129]

The BAU potential estimation results are included in 'Table 5- Known DR Participation', which appears in the 'Inputs Database' worksheet of the Demand Response Potential Estimation model.

[127] For details related to the FERC 2008 Demand Response Survey, please refer to the FERC Staff Report titled '2008 Assessment of Demand Response and Advanced Metering'. It should be noted that only those programs that reported a positive 'Potential Load Reduction' in the database were included in developing the BAU forecast.

[128] It should be noted that only those programs that reported a positive 'Potential Load Reduction' in the database were included in developing the BAU forecast.

[129] In the FERC survey database, ISO-NE and PJM reported their entire load reduction potential only against a particular state. ISO-NE reported its entire potential against Connecticut, while PJM reported its entire potential against DC. For ISO-NE, the potential reported was allocated across all states falling under ISO-NE's jurisdiction, based on actual data obtained from ISO-NE. For PJM, the load reduction potential was distributed across all states served by PJM, in the proportion of load served by PJM for these states.

b) Current Participation in Demand Response Programs

The methodology for determining current participation rates in demand response programs varied by type of program. For estimating participation rates in Residential Direct Load Control programs (CAC cycling only), a distinct approach was used as compared to what was followed for the remaining demand response program types considered in our analysis.

The bullet points below describe the approaches used for: 1) residential DLC programs; 2) other remaining demand response programs.

- **Participation Rate Estimation for Residential DLC Programs**: The FERC survey database was used as the primary source of information for estimating current participation rates in residential DLC programs (for the case of CAC only). For each state, the total 'Number of Customers Enrolled' for a particular demand response program type was obtained by aggregating utility data for the state. This was then divided by the 'Total Number of Customers' developed for each state by rate class to arrive at participation rate estimates by program type and rate class for each state.

  An assessment was also carried out to determine how representative the FERC survey data were for estimating 'Participation Rate' for the entire state. If more than 50% of the state's residential population was being covered by the FERC survey, the FERC survey data were considered to be representative of the state. On the other hand, if less than 50% of the residential customer population was represented, information from outside sources was obtained to arrive at 'best' estimates for a state. Outside information sources included utility websites, utility program reports and regulatory filings, and direct contact with utilities.

- **Participation Rate Estimation for all other Demand Response Programs**: The estimation of participation rates for all other demand response programs relied on FERC survey data, wherever information was available on number of customers enrolled in different demand response programs. The participation rate was estimated both as 'percentage of customers' as well as 'percentage of load'. Participation rate as 'percentage of customers' was obtained by aggregating 'No. of Customers Enrolled' data from the FERC survey for a particular type of demand response program and dividing that by the corresponding 'Total No. of Customers' in the state by rate class. Similarly, participation rate as 'percentage of load' was obtained by aggregating 'Total load enrolled' data from the FERC survey for a particular type of demand response program and dividing that by the corresponding 'Total Load' in the state by rate class.

Participation rate estimations by demand response program type and by Rate Class appear in the 'Inputs Database' worksheet of the Demand Response Potential Estimation model.

c) Impacts from Non-pricing Programs

The methodology used to estimate impacts of demand response programs varied by the type of program. The bullet points below describe the approaches used for: 1) DLC programs (CAC control only); 2) Interruptible and 'Other DR' programs;

1) Impact Estimation for DLC Programs (CAC control only): For arriving at 'best estimates' of unit load reduction impacts for residential DLC programs, a combination of information sources was employed. The sources included FERC survey database information, which was used for estimating impacts by dividing the 'Potential Load Reduction' value by the 'Number of Customers Enrolled'. In addition, specific estimates from utility programs outside the FERC survey database were obtained along with DLC program evaluation reports. For states where information was missing, a default value of 1 kW reduction per customer was assumed. Per-customer load reduction impacts for C&I customers from DLC programs were estimated by applying a multiplier to the per customer impact for residential customers.[130]

2) Impact Estimation for Interruptible and 'Other DR' programs: For these programs, the FERC survey database information was used for arriving at load reduction estimates. The 'Potential Load Reduction' as a percentage of the 'Enrolled Load' by demand response program type was used to estimate demand response program impacts.

d) Impacts from Pricing Programs

The Achievable Participation and Full Participation potential estimates rely heavily on price-based demand response options, specifically on dynamic tariffs that deliver high price signals on relatively few high-demand days when demand response benefits are greatest. Estimates of the load impact associated with pricing options are based on variables known as price elasticities. Economists define the "own" price elasticity as the percentage change in the quantity purchased of a good or service divided by the percentage change in the price of that good or service. There is a similar concept, known as the elasticity of substitution, which summarizes the relationship of two goods or services that are substitutes for each other. The elasticity of substitution is equal to the percentage change in the ratio of the quantities purchased of two goods to the ratio of the prices of the two goods. Put another way, the elasticity of substitution summarizes the rate at which consumers substitute one good for another based on the relative prices of the two goods.

In the case of electricity demand, if prices are higher at one time of day relative to another, consumers may be willing to shift their load from the high priced to the low priced period. An example would be a consumer shifting the timing of their laundry from the peak to the off peak period. Alternatively, or in addition, a consumer might just forgo some energy use during the high price period. An example would be switching off lights during high priced periods—consumers don't use more lighting during low priced periods because they used less during high priced periods.

One approach to estimating how electricity demand would change in response to time varying prices involves estimating a two-equation demand system, where 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. In combination, the two equations can predict the change in energy use in each time period as consumers move from non-time varying to time-varying prices. This is the approach that underlies the estimates of time-based price response in the demand response potential model.

A variety of pricing experiments and other studies have been conducted that allow for estimation of demand models and price elasticities such as those described above. These studies show that price responsiveness for residential customers varies across regions based in part on differences in the use of air conditioning. Climate differences can also impact price responsiveness, as can the presence or absence of enabling technology such as programmable communicating thermostats and other load control devices. Price responsiveness also differs between residential and non-residential customers with residential customers generally being more price responsive than non-residential customers. These factors have been taken into account in developing estimates of price response that reflect variation in the characteristics of customers across states. The remainder of this section summarizes how state-specific estimates of price response were developed in this project.

Residential

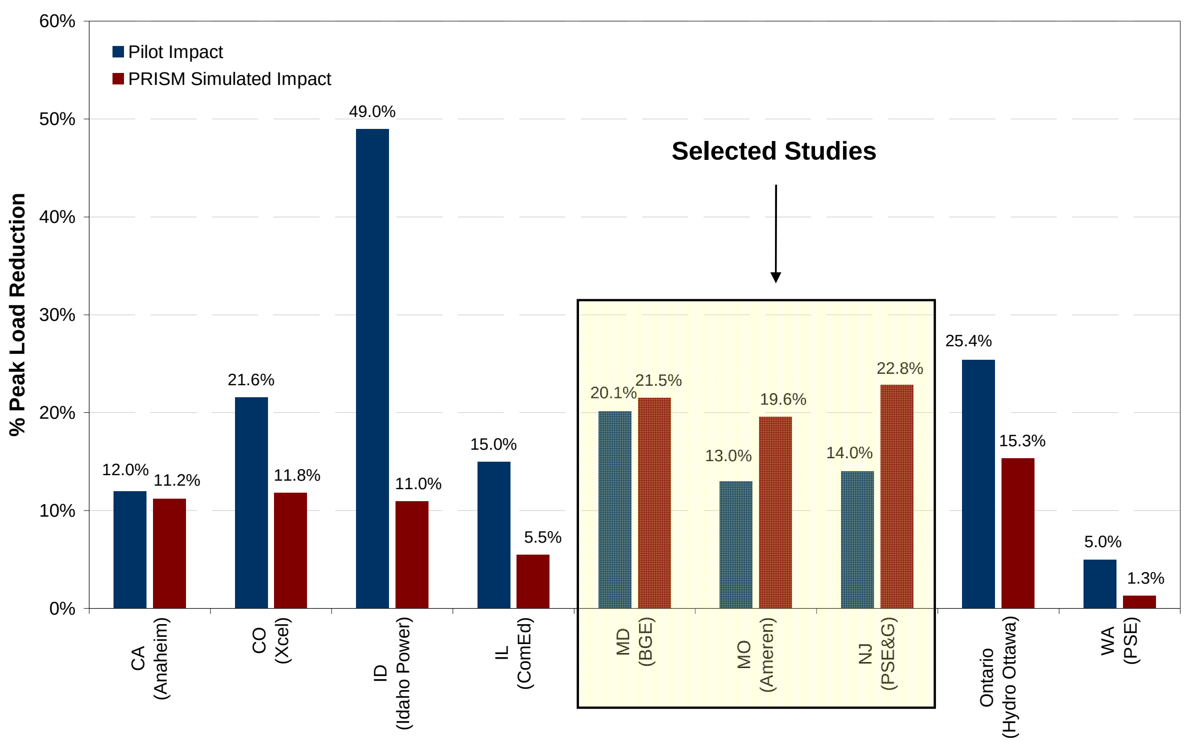
The California Statewide Pricing Pilot (SPP) produced estimates of price elasticity for residential customers that captured variations in customer price responsiveness across four different climate zones in the state. These estimates were codified in the Pricing Impact Simulation Model (PRISM) which allows

[130] This multiplier was based on estimations of the number of cycling switch devices required for Direct Load Control for C&I customers.

price elasticities to vary as a function of a zone's saturation of central air condition (CAC) equipment and weather conditions.[131] Specifically, it was found that zones with higher CAC saturation (which were also the hotter climate zones) were more price elastic than zones with low CAC saturations (which were also the milder climate zones). CAC saturation was found to be a key driver of differences in price responsiveness across the zones. These findings made it possible to express price elasticity as a function of CAC saturation, allowing the PRISM results to be projected to other regions of the country.

However, this projection needs be interpreted as the first step in a two-step process. Dynamic pricing pilots have been conducted in several locations and when the results of PRISM, calibrated to the CAC saturations were compared with those of pilots conducted in those regions, it was found that PRISM did not explain all the variation in pilot results. Figure D-6 summarizes a comparison for nine recent residential dynamic pricing pilots.[132]

Figure D-6: Comparison of Impacts from Recent Pricing Pilots to Calibrated PRISM Simulations



It is apparent that, even when accounting for CAC saturation and the price ratio tested in a given pilot, PRISM does not exactly replicate the pilot's results. Given the state-specific nature of this study, it is necessary to capture these regional differences. However, while each of the pilots in Figure D-6 draws some valuable conclusions about customer price response, some judgment must be exercised in determining whether to extrapolate their findings to a larger population beyond the participants of the pilot. The details of each pilot were carefully reviewed to determine which should be considered when adjusting the PRISM simulated impacts to account for regional differences. Ultimately, six of these nine

[131] The experiment also identified the relationship between price elasticity and average temperature. However, the effect of temperature on price response is much less significant than that of CAC saturation. For the purposes of this study, the temperature effect is held constant across regions.

[132] For more information on the key findings of recent dynamic pricing pilots, see Ahmad Faruqui and Sanem Sergici, "Household response to dynamic pricing of electricity: A survey of the experimental evidence," January 10, 2009. http://www.hks.harvard.edu/hepg/Papers/2009/The%20Power%20of%20Experimentation%20_01-11-09_.pdf.

pilots were excluded from the analysis. Reasons for excluding these pilots are summarized in Table D-12.

Table D-12: Pilot Impacts Excluded from Assessment

Pilot	Reason for Exclusion
California (Anaheim Public Utilities)	Results of the more comprehensive California SPP are being used for California, and the Anaheim impacts are very similar
Colorado (Xcel)	The study identifies issues with self-selection bias which potentially result in an overstatement of the impacts
Idaho (Idaho Power)	The mix of pilot participants was not considered to be representative of the larger population of utility customers
Illinois (ComEd)	Impacts are based on a residential RTP rate and there is not enough available data to accurately determine the impact on average critical peak consumption (results presented in Figure D-6 are during the single highest hour of peak demand)
Ontario (Hydro Ottawa)	For the purposes of this state-specific study, pilots are limited to those conducted in the United States; this pilot could be included in studies of a broader geographical scope but the large standard errors reported in the pilot may preclude extrapolation of results to other regions
Washington (PSE)	The pilot tested a non-dynamic, traditional TOU and that too with a very low peak-to-existing price ratio (1.17), preventing the results to be used in this study

Based on this review, impacts from three of the nine pilots on which data were available were used to further refine the simulations derived from PRISM. Those pilots were conducted in Maryland by BGE, in Missouri by Ameren, and in New Jersey by PSE&G. In each of these pilots, actual customer price response was found to be lower than that simulated by PRISM. A likely explanation for this is that PRISM does not account for the effect of humidity. The California SPP was conducted across zones with a wide range of average temperatures but all the zones lay in a state with relatively low humidity. As a result, the model results would not reflect the likely conclusion that customers in more humid regions would be less responsive to dynamic pricing given the higher loss of comfort that they would experience by turning down their air conditioner on hot summer days.

In Maryland, Missouri, and New Jersey, PRISM-simulated peak demand reductions were scaled back to equal the lower impacts that were observed in these three pilots. In addition, adjustments were made for all states east of the Rocky Mountains to account for the humidity effect observed in the three pilots. PRISM-simulated residential impacts for these states were derated by 20 percent, which is the approximate midpoint of the difference between the California SPP impacts and that of the three previously described pilots.

PRISM allows separate impact estimates to be developed for customers who are offered dynamic pricing in conjunction with enabling technologies. Specifically, for the purposes of the Achievable and Full Participation demand response scenarios, it is assumed that residential customers would be offered a programmable communicating thermostat whenever the incremental effect of this enabling technology is likely to be large enough to make such a device cost effective. The California SPP captured the price elasticity of customers who were both enrolled in dynamic pricing and equipped with programmable communicating thermostats. As a result, these elasticities were used in California and in states west of the Rockies. The PRISM simulations were scaled back for states east of the Rocky Mountains in the same manner as for those customers who did not have the enabling technologies.

Small and Medium C&I

Price elasticities for Small and Medium C&I customers were also estimated during the California SPP. Small C&I customers provide peak reductions of less than one percent even at high price ratios. Medium C&I customers were found to be somewhat more responsive, but less so than residential customers. There are no results from other studies upon which to base any regional variation in these impacts and so the California SPP results were held constant across the states. Price elasticity with enabling technology also comes directly from the California SPP. For both the Small and Medium C&I classes, customers are assumed to be offered programmable communicating thermostats.

Large C&I

Large C&I customers were not included in the California SPP nor are they included in any other pricing pilots. Therefore, price elasticity data for this customer class is limited to a few full-scale implementations in the Northeastern U.S. Much of this information was summarized in a recent study carried out by the Demand Response Research Center.[133] According to this study, the elasticity of substitution could be as high as -0.15 and the daily elasticity could be as high as -0.20. Both estimates varied greatly by sector and rate offering. There is a significant amount of uncertainty in these estimates and they are based on a limited number of participants, so for the purposes of the Assessment they have been scaled down to avoid potentially overstating the impacts.[134] This is an area in which further research is warranted.

There is very limited information on the potential for demand response when customers in this class are equipped with enabling technologies. For the purposes of the Assessment, it is assumed that these customers would be offered automated demand response, a technology that would allow for a coordinated, automated curtailment of electricity consumption at a number of customer end uses. The best available information on the potential impacts of automated demand response comes from a recent study by the Demand Response Research Center.[135] Large C&I customers at all three of California's investor-owned utilities were equipped with the technology, and on average the incremental additional reduction in peak demand was found to be at least 13 percent, or an 86 percent increase over the anticipated response to dynamic pricing in the absence of the technology. It is this incremental increase of 86 percent that was used to represent the incremental impact of enabling technology for the Large C&I class in the Assessment.

It should be noted that, while the DRRC study represents the best available information on this topic, the findings are based on a technology demonstration project rather than on the results of a scientific experiment. As a result, there is significantly more uncertainty in these estimates. This is also an area where further research is warranted.

Assumed Elasticities

The final elasticities used in the Assessment are presented in Table D-13.

Table D-13: Assumed Elasticities by Customer Class

	Type of Elasticity	Res (No CAC)	Res (CAC)	Small C&I	Medium C&I	Large C&I
Without Enabling Technology	Critical Day Substitution	-0.0472	-0.1383	0.0000	-0.0412	-0.0500
	Critical Day Daily Elasticity	-0.0330	-0.0487	0.0000	-0.0250	-0.0200
	Normal Weekday Substitution	-0.0425	-0.1336	0.0000	-0.0493	-0.0500
	Normal Weekday Daily Elasticity	-0.0354	-0.0511	0.0000	-0.0250	-0.0200
	Weekend Daily Elasticity	-0.0354	-0.0511	0.0000	-0.0250	-0.0200
With Enabling Technology	Critical Day Substitution	-0.0472	-0.3523	-0.0892	-0.0815	N/A
	Critical Day Daily Elasticity	-0.0330	-0.0677	-0.0250	-0.0250	N/A

133 Goldman, C., Hopper, N., Bharvirkar, R., Neenan, Cappers, P. August 2007. A Methodology for Estimating Large-Customer Demand Response Market Potential, Lawrence Berkeley National Laboratory Report No. LBNL-63346, presented at: IEPEC Conference, Chicago.

134 These elasticities were recently used in a study for the Demand Response Research Center and are further discussed in: Ahmad Faruqui, Ryan Hledik, and John Tsoukalis, "The Power of Dynamic Pricing," *The Electricity Journal*, April 2009.

135 See "Automated Demand Response for Commercial and Industrial Facilities: A Progress Report to the CPUC," prepared by the Demand Response Research Center, December 2007. Also, Wikler, G., et. al., "Enhancing Price Response through Auto-DR: California's 2007 Implementation Experience," Proceedings of the ACEEE Summer Study on Energy Efficiency in Buildings, August 2008

For states east of the Rockies, residential impacts derived from PRISM with and without technology are scaled back by 20 percent. Impacts for Maryland, Missouri, and New Jersey are scaled back by seven percent, 34 percent, and 39 percent, respectively, to equal results determined by pilots in those states (see discussion above). Large C&I impacts are increased by 86 percent to represent the impacts of automated demand response.

The price elasticities summarized above for residential customers produce quite different percent reductions across states as a function of the variation in climate and air conditioning saturations. There are also differences in the estimated percent reduction in peak period energy use based on differences in the assumed ratio of prices during the peak period. The percent reduction in peak period energy use for residential customers for each state and two price ratios are shown in Table D-14. Note that the relationship between price and energy use is not linear. That is, while the price ratio doubles going from 4 to 1 to 8 to 1, the percent reduction in peak demand increases by less than 100 percent. For example, the doubling of the price ratio in California leads to a 57 percent decrease in peak period energy use.

Table D-14: Percent Reduction in Peak Period Energy Use for the Average Residential Customer

State	CAC Saturation	Percent Peak Period Reduction for 4 to 1 Price Ratio	Percent Peak Period Reduction for 8 to 1 Price Ratio
Alabama	62.00%	9.67%	15.18%
Alaska	2.50%	6.64%	10.57%
Arizona	86.80%	14.28%	22.33%
Arkansas	54.60%	9.15%	14.38%
California	41.00%	10.25%	16.13%
Colorado	47.24%	10.79%	16.97%
Connecticut	26.91%	7.20%	11.37%
Delaware	53.00%	9.04%	14.20%
District of Columbia	56.00%	9.25%	14.53%
Florida	91.00%	11.72%	18.32%
Georgia	82.25%	11.10%	17.37%
Hawaii	17.55%	6.55%	10.36%
Idaho	66.50%	12.49%	19.58%
Illinois	75.00%	10.59%	16.59%
Indiana	74.39%	10.55%	16.52%
Iowa	70.00%	10.24%	16.05%
Kansas	83.68%	11.20%	17.53%
Kentucky	76.00%	10.66%	16.70%
Louisiana	75.49%	10.62%	16.64%
Maine	14.00%	6.30%	9.98%
Maryland	78.00%	12.56%	19.66%
Massachusetts	12.70%	6.20%	9.83%
Michigan	57.22%	9.34%	14.66%
Minnesota	51.15%	8.91%	14.00%
Mississippi	74.72%	10.57%	16.56%
Missouri	87.50%	9.46%	14.80%
Montana	42.10%	10.34%	16.28%
Nebraska	82.80%	11.14%	17.43%
Nevada	86.80%	14.28%	22.33%
New Hampshire	12.70%	6.20%	9.83%
New Jersey	55.00%	7.00%	11.00%
New Mexico	42.00%	10.33%	16.26%
New York	16.75%	7.32%	11.56%
North Carolina	84.35%	11.25%	17.60%
North Dakota	51.00%	8.90%	13.99%
Ohio	62.86%	9.74%	15.27%
Oklahoma	84.16%	11.24%	17.58%
Oregon	38.00%	9.98%	15.72%
Pennsylvania	49.75%	8.81%	13.85%
Rhode Island	12.49%	6.19%	9.81%
South Carolina	84.35%	11.25%	17.60%
South Dakota	70.90%	10.30%	16.14%
Tennessee	81.44%	11.04%	17.29%
Texas	80.00%	10.94%	17.13%
Utah	42.10%	10.34%	16.28%
Vermont	7.20%	5.82%	9.24%
Virginia	50.20%	8.84%	13.90%
Washington	28.62%	9.16%	14.45%
West Virginia	50.20%	8.84%	13.90%
Wisconsin	62.03%	9.68%	15.18%
Wyoming	42.00%	8.27%	13.01%

e) Cost effectiveness analysis

For the purposes of economic screening, the five demand response programs being considered in the analysis can be divided into two broad categories – those that do not require an enabling technology for participation and those that do. The demand response options that do not require an enabling technology for participation were deemed to be cost-effective for all states. For the demand response options that do require an enabling technology for participation, a measure-level economic screen was conducted to assess their cost-effectiveness in each state. The purpose of this preliminary analysis is to determine which states have the critical peak customer loads which would justify the initial costs of enabling technology irrespective of participant rates. The two types of options for which an economic screen was conducted are: 1) Dynamic Pricing with Enabling Technology, and 2) Direct Load Control. This section describes the methodology and the results associated with the economic screening of these two types of demand response options.

Methodology

The economic screen uses a simple version of the Total Resource Cost (TRC) Test that compares the lifetime benefits of the demand response option (i.e., avoided capacity costs) relative to the associated costs to enable each option (i.e., costs related to technology adoption, implementation and delivery, etc.) on a per-participant basis. Inputs for the economic screen include impact estimates per participant by state, capacity costs, equipment costs and implementation costs, as well as economic parameters such as discount and cost escalation rates. The benefits are obtained by multiplying the unit demand reduction for each technology by avoided capacity costs ($/kW) over the ten year time horizon and discounting the dollar savings to a present value equivalent basis. The costs are equal to the equipment and implementation costs per participant.[136] If the benefit-cost ratio is 1.00 or greater, the demand response option is considered cost-effective and is included in the state's Full Participation potential results.

To determine cost-effectiveness associated with the two demand response options, the impact estimates already developed as part of demand response potential estimation were used. The Dynamic Pricing Option without enabling technology is deemed to be cost-effective. Hence this analysis considers only the benefits and costs attributable to the technology component. The enabling technologies included in the analysis are:

- Programmable Communicating Thermostats and remotely-controlled switches for the small and medium load customers, and
- Automated Demand Response technologies for the large load customers.

The equipment type and associated costs are summarized in Table D-15 for the two demand response options by customer class. An additional 15% was added to the equipment costs to represent up-front costs for program development and ongoing costs for implementation and delivery.[137]

Table D-15: Enabling Technology Equipment Costs[138]

Customer Type	Dynamic Pricing		Direct Load Control	
	Equipment	Unit Cost	Equipment	Cost
Residential	PCT	$200	Switch	$200
Small C&I	PCT	$350	Switch	$350
Medium C&I	PCT	$1,050	Auto-DR	$1,050
Large C&I	Auto-DR	$13,500	N/A[139]	N/A

An avoided capacity cost of $75 per kW (representing the investment cost of a gas-fired combustion turbine-generator) was used to derive the avoided cost benefits. This value was escalated at 3% per year for each year beyond 2009. The projected avoided costs were discounted to present value equivalents using a discount rate of 5%.[140]

[136] The cost-effectiveness is not performed at the program-level, therefore the effects of incentives and participation rates are not included in this analysis.
[137] This percentage is commonly used for these types of studies and it based on benchmark experience from actual demand response program implementation nationwide.
[138] The costs are based on vendor estimates and utility program cost data for programs with similar demand response options.
[139] Note that Direct Load Control for large C&I customers was not considered in the analysis.
[140] The assumptions related to avoided capacity costs, cost escalation rates, and discount rates represent commonly accepted estimates for similar analyses conducted in the industry.

Summary of Results

A demand response option with enabling technology is cost-effective and as such passes the economic screen if the benefit-cost (B/C) ratio is 1.00 or higher. Summary results of the economic screen are included in Tables 16 and 17 for Dynamic Pricing with Enabling Technology and Direct Load Control, respectively. The tables list the B/C ratios for each state and indicate the states where the demand response options are cost-effective.

The economic screening results show that Dynamic Pricing with Enabling Technology is a cost-effective option for the majority of states. However, there are a number of states for which it fails the economic screen. The results vary by customer type. Dynamic Pricing with Enabling Technology for residential customers is cost-effective for 42 states (84% of states). The option for small C&I customers is cost-effective for 40 states (80% of states) as well as for the District of Columbia. For the medium C&I customers, the option is cost-effective for 43 states (86% of states) and the District of Columbia, while for the large C&I category it is cost-effective for 45 states (90% of states) and the District of Columbia. The results indicate that Dynamic Pricing with Enabling Technology is cost-effective primarily for those states with high critical peak loads associated with large cooling or other end-use requirements. In particular, this option is highly cost-effective in Arizona and Nevada.

Notable results and observations from the Dynamic Pricing with Enabling Technology screen:

- A state not passing the cost-effectiveness screen does not suggest these programs should not be pursued in that state. The estimates are based on price response using class-average load shapes. Many of the states that did not pass in fact have varying weather characteristics that would lead to different impacts. Some regions might have higher impacts and thus these programs may indeed be cost-effective.
- As the customer class size increases and approaches the large C&I class (starting with the small C&I), more states become cost-effective.
- These trends suggest that as dynamic pricing tariffs are introduced across the country, utilities that are considering adopting one of their own might consider starting with the larger customer classes and gradually introduce the tariffs to the smaller classes once more information is available.
- Careful attention should be given to the economic analysis for these types of programs, particularly when looking at the residential class, which in some regions of the country may not provide the needed level of savings to justify the cost of enablement technologies such as programmable communicating thermostats and automated demand response.

Direct Load Control is a cost-effective demand response option for most states because of the higher per participant savings associated with this option. The analysis showed that Direct Load Control is cost-effective for residential customers in 48 states (96%) and the District of Columbia. The only states for which it is not cost-effective for residential customers are Alaska and Hawaii. Among both small and medium C&I customers, Direct Load Control is cost-effective for all states and the District of Columbia.

Notable results and observations from the Direct Load Control with Enabling Technology screen:

- Most states passed the economic screen. However, for those states that failed the screen, methods of direct load control other than air conditioning might be viable.
- Methods to control water heating and pumping loads may be more viable in these regions.

Table D-16: Economic Screen Results for Dynamic Pricing with Enabling Technology

Dynamic Pricing with Enabling Technology															
Residential				Small C&I				Medium C&I				Large C&I			
Pass	B/C	Fail	B/C	Pass	B/C	Fail	B/C	Pass	B/C	Fail	B/C	Pass	B/C	Fail	B/C
AL	1.93	AK	0.53	AK	1.13	CA	0.80	AK	2.46	ID	0.96	AK	3.04	CT	0.61
AR	1.71	DC	0.95	AL	3.81	CO	0.48	AL	5.93	IL	0.87	AL	2.21	KS	0.94
AZ	2.35	HI	0.67	AR	2.30	CT	0.98	AR	2.86	MA	0.76	AR	2.36	MN	0.97
CA	1.01	IL	0.83	AZ	4.27	FL	0.73	AZ	5.11	MD	0.99	AZ	2.43	NE	0.86
CO	1.18	ME	0.77	DC	2.41	ME	0.52	CA	1.16	ME	0.91	CA	1.64	NH	0.90
CT	1.51	MI	0.83	DE	3.84	MN	0.81	CO	1.24	NH	0.99	CO	2.66		
DE	1.14	MN	0.98	GA	1.38	OK	0.97	CT	1.96	RI	0.98	DC	2.20		
FL	1.44	VT	0.96	HI	1.06	RI	0.69	DC	4.89			DE	2.81		
GA	1.68	WI	0.77	IA	1.04	TX	0.95	DE	3.86			FL	2.05		
IA	1.02			ID	1.00	VT	0.55	FL	1.24			GA	1.78		
ID	2.00			IL	1.85			GA	1.84			HI	2.48		
IN	1.25			IN	1.60			HI	1.39			IA	2.09		
KS	1.38			KS	1.62			IA	1.46			ID	1.88		
KY	1.55			KY	2.66			IN	1.62			IL	1.33		
LA	1.80			LA	3.70			KS	1.35			IN	2.36		
MA	1.09			MA	1.51			KY	5.43			KY	2.83		
MD	1.53			MD	3.31			LA	1.19			LA	2.28		
MO	1.24			MI	1.56			MI	1.48			MA	1.89		
MS	1.84			MO	1.27			MN	1.28			MD	1.79		
MT	1.28			MS	2.22			MO	3.41			ME	1.69		
NC	1.57			MT	3.11			MS	2.41			MI	1.80		
ND	1.28			NC	1.41			MT	4.84			MO	2.21		
NE	1.27			ND	2.44			NC	5.19			MS	3.59		
NH	1.19			NE	1.15			ND	3.98			MT	3.25		
NJ	1.11			NH	1.20			NE	3.95			NC	4.05		
NM	1.00			NJ	1.80			NJ	2.38			ND	1.81		
NV	1.91			NM	1.22			NM	1.89			NJ	1.17		
NY	1.19			NV	3.06			NV	3.47			NM	2.09		
OH	1.10			NY	1.44			NY	2.50			NV	2.75		
OK	1.62			OH	2.16			OH	2.01			NY	2.42		
OR	1.51			OR	1.14			OK	2.15			OH	1.78		
PA	1.04			PA	2.07			OR	2.30			OK	2.30		
RI	1.03			SC	1.93			PA	1.32			OR	2.01		
SC	1.80			SD	2.35			SC	5.30			PA	1.90		
SD	1.16			TN	2.91			SD	2.69			RI	1.16		
TN	1.98			UT	1.24			TN	5.74			SC	5.01		
TX	1.67			VA	1.16			TX	1.46			SD	1.19		
UT	1.32			WA	1.65			UT	2.66			TN	1.11		
VA	1.49			WI	1.03			VA	2.72			TX	6.16		
WA	1.46			WV	1.60			VT	1.50			UT	3.90		
WV	1.41			WY	3.76			WA	3.39			VA	2.09		
WY	1.11							WI	1.87			VT	2.28		
								WV	2.41			WA	2.28		
								WY	2.03			WI	2.31		
												WV	4.23		
												WY	4.58		

Table D-17: Economic Screen Results for Direct Load Control

Direct Load Control											
Residential				Small C&I				Medium C&I			
Pass	B/C	Fail	B/C	Pass	B/C	Fail	B/C	Pass	B/C	Fail	B/C
AL	5.41	AK	0.00	AK	3.87			AK	3.87		
AR	3.37	HI	0.93	AL	6.18			AL	6.18		
AZ	3.11			AR	3.85			AR	3.85		
CA	1.49			AZ	3.55			AZ	3.55		
CO	1.71			CA	4.90			CA	4.90		
CT	3.30			CO	4.15			CO	4.15		
DC	2.98			CT	3.77			CT	3.77		
DE	2.50			DC	3.41			DC	3.41		
FL	4.11			DE	2.86			DE	2.86		
GA	3.85			FL	4.70			FL	4.70		
IA	1.67			GA	4.40			GA	4.40		
ID	3.14			HI	2.48			HI	2.48		
IL	1.20			IA	6.15			IA	6.15		
IN	3.06			ID	3.59			ID	3.59		
KS	2.71			IL	3.23			IL	3.23		
KY	3.13			IN	3.50			IN	3.50		
LA	3.11			KS	3.10			KS	3.10		
MA	3.11			KY	3.57			KY	3.57		
MD	2.38			LA	3.55			LA	3.55		
ME	1.55			MA	3.55			MA	3.55		
MI	1.43			MD	2.72			MD	2.72		
MN	3.15			ME	3.55			ME	3.55		
MO	4.18			MI	3.90			MI	3.90		
MS	3.11			MN	3.60			MN	3.60		
MT	3.11			MO	4.78			MO	4.78		
NC	3.21			MS	3.55			MS	3.55		
ND	3.11			MT	3.55			MT	3.55		
NE	3.11			NC	3.67			NC	3.67		
NH	3.11			ND	3.55			ND	3.55		
NJ	2.58			NE	3.55			NE	3.55		
NM	1.38			NH	3.55			NH	3.55		
NV	4.02			NJ	2.95			NJ	2.95		
NY	4.25			NM	3.55			NM	3.55		
OH	3.04			NV	4.60			NV	4.60		
OK	3.11			NY	4.86			NY	4.86		
OR	3.11			OH	3.47			OH	3.47		
PA	3.11			OK	3.55			OK	3.55		
RI	3.11			OR	3.55			OR	3.55		
SC	2.31			PA	3.55			PA	3.55		
SD	1.90			RI	3.55			RI	3.55		
TN	3.11			SC	2.64			SC	2.64		
TX	3.44			SD	6.04			SD	6.04		
UT	3.11			TN	3.55			TN	3.55		
VA	3.11			TX	3.93			TX	3.93		
VT	3.11			UT	3.55			UT	3.55		
WA	1.65			VA	3.55			VA	3.55		
WI	1.14			VT	3.55			VT	3.55		
WV	3.11			WA	4.26			WA	4.26		
WY	3.11			WI	3.43			WI	3.43		
				WV	3.55			WV	3.55		
				WY	3.55			WY	3.55		

APPENDIX E. UNCERTAINTY ANALYSIS

The data and assumptions in this Assessment are based on the results of a detailed survey of demand response programs and a comprehensive review of previous research on demand response potential. However, as with any forward-looking assessment, the data and assumptions are uncertain. To represent the magnitude of the impact of this uncertainty, sensitivity analysis has been conducted on the variables that are the key drivers of the potential estimates.

A number of factors contribute to the overall potential for demand response. However, at the highest level the calculation of potential boils down to the following simple equation:

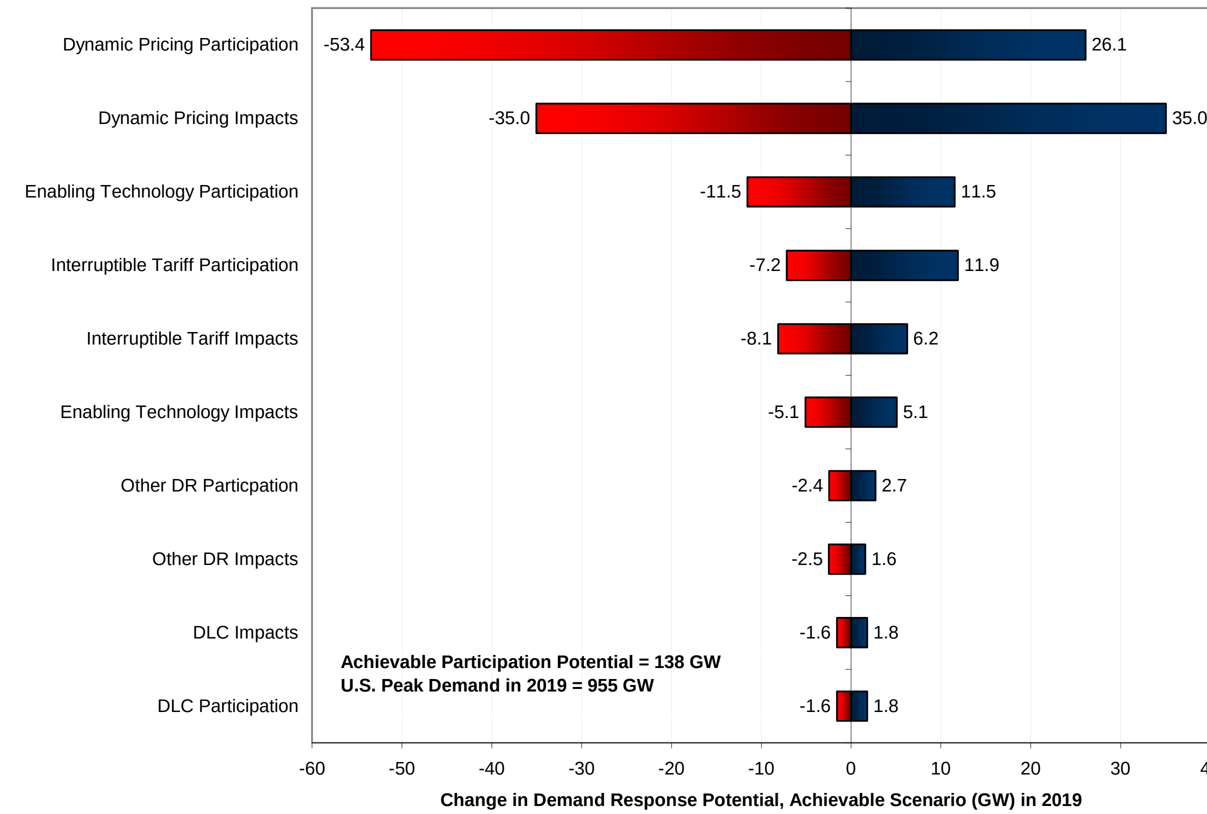
Total demand response potential = # of customers participating in demand response programs ***x*** *peak reduction per participant*

Thus, to develop an understanding of the level of uncertainty in the potential estimates in this Assessment, the two components on the right-hand side of the above equation were chosen as the variables to be tested through sensitivity analysis. For each of the five categories of demand response programs, a high and a low value were chosen for the assumed per-customer impacts and the participation rates. In total, this amounts to twenty new assumptions to be run through the model: 5 program types x 2 values (high and low) x 2 variables (impacts and participation).

To determine the high and low values, each of the model inputs described above were increased by 50 percent (representing the high value) and decreased by 50 percent (representing the low value). This allowed for a consistent comparison across each of the variables in assessing their relative contributions to the uncertainty in the overall potential estimate. The one exception to this is the assumption regarding dynamic pricing participation. Because dynamic pricing is a newly developing program and does not yet have an established history of participation like the other demand response program types, a wider range of uncertainty was used. In the Achievable Participation scenario, the high value for participation was assumed to be 100 percent (representing a scenario where dynamic pricing is the universal rate) and the low value was assumed to be five percent (representing a scenario where dynamic pricing is voluntary and few customers choose to enroll).

The 20 sensitivity assumptions were each run through the model one-at-a-time, while holding all other modeling assumptions constant. The analysis was only conducted for the Achievable Participation scenario, but the approach could be expanded to apply to the other scenarios as well. The results of the model runs can be summarized in a “tornado diagram” as illustrated in Figure E-1.

Figure E-1: Results of Uncertainty Analysis for the Achievable Potential Scenario in 2019



As expected, Figure E-1 shows that dynamic pricing assumptions contribute the most heavily to uncertainty in potential demand response impacts under the Achievable Participation scenario. With low participation in dynamic pricing, the Achievable Participation potential of 138 GW would be reduced by 53 GW to 85 GW, representing a reduction of 39 percent. Higher participation could increase the impacts by 26 GW. The assumed customer response to dynamic pricing also contributes significantly to the overall uncertainty. If customers were found to be more or less responsive to dynamic rates than was assumed in this analysis, total demand response potential could increase or decrease significantly. At the low end, direct load control and Other DR programs do not contribute as significantly to the overall uncertainty.

To put the results of the uncertainty analysis in context it is helpful to know the share of total Achievable Participation potential that is held by each demand response program type. This is illustrated in Figure E-2. It is generally the case that those programs with a larger share of the potential also contribute a large share of the uncertainty.

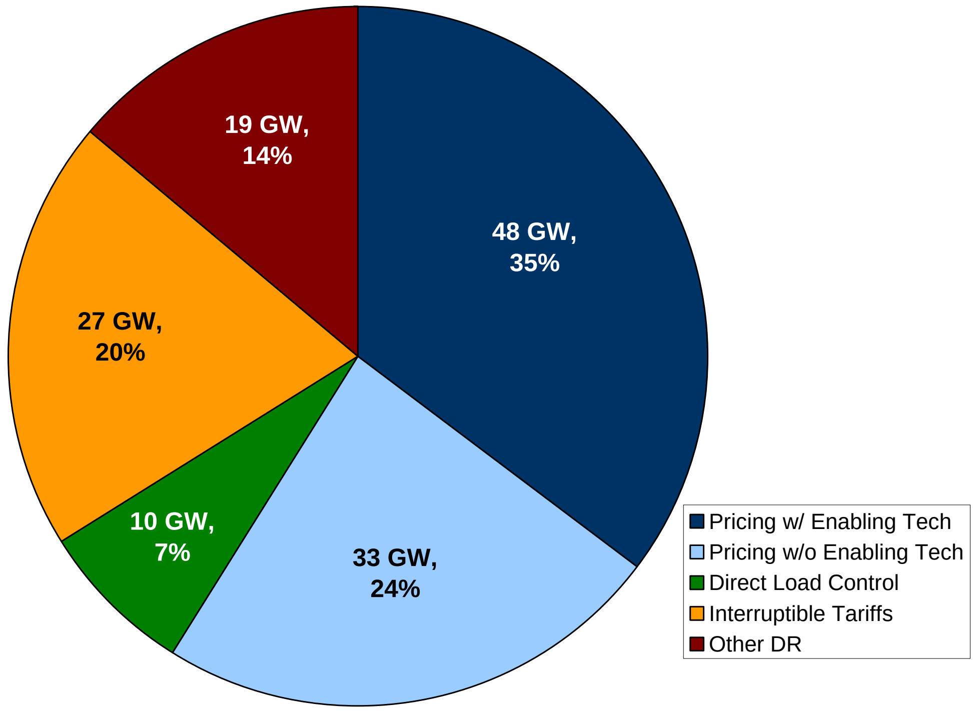


Figure E-2: Share of Achievable Participation Potential for Each Demand Response Program Type, 2019

APPENDIX F. ENERGY INDEPENDENCE AND SECURITY ACT OF 2007, SECTION 529

Energy Independence and Security Act of 2007

TITLE V—ENERGY SAVINGS IN GOVERNMENT AND PUBLIC INSTITUTIONS
Subtitle C—Energy Efficiency in Federal Agencies
SEC. 529. ELECTRICITY SECTOR DEMAND RESPONSE.

(a) IN GENERAL.—Title V of the National Energy Conservation Policy Act (42 U.S.C. 8241 et seq.) is amended by adding at the end the following:

"PART 5—PEAK DEMAND REDUCTION

"SEC. 571. NATIONAL ACTION PLAN FOR DEMAND RESPONSE.

"(a) NATIONAL ASSESSMENT AND REPORT.—The Federal Energy Regulatory Commission ('Commission') shall conduct a National Assessment of Demand Response. The Commission shall, within 18 months of the date of enactment of this part, submit a report to Congress that includes each of the following:

"(1) Estimation of nationwide demand response potential in 5 and 10 year horizons, including data on a State-by-State basis, and a methodology for updates of such estimates on an annual basis.

"(2) Estimation of how much of this potential can be achieved within 5 and 10 years after the enactment of this part accompanied by specific policy recommendations that if implemented can achieve the estimated potential. Such recommendations shall include options for funding and/or incentives for the development of demand response resources.

"(3) The Commission shall further note any barriers to demand response programs offering flexible, non-discriminatory, and fairly compensatory terms for the services and benefits made available, and shall provide recommendations for overcoming such barriers.

"(4) The Commission shall seek to take advantage of preexisting research and ongoing work, and shall insure that there is no duplication of effort.

"(b) NATIONAL ACTION PLAN ON DEMAND RESPONSE.—The Commission shall further develop a National Action Plan on Demand Response, soliciting and accepting input and participation from a broad range of industry stakeholders, State regulatory utility commissioners, and non-governmental groups. The Commission shall seek consensus where possible, and decide on optimum solutions to issues that defy consensus. Such Plan shall be completed within 1 year after the completion of the National Assessment of Demand Response, and shall meet each of the following objectives:

"(1) Identification of requirements for technical assistance to States to allow them to maximize the amount of demand response resources that can be developed and deployed.

"(2) Design and identification of requirements for implementation of a national communications program that includes broad-based customer education and support.

"(3) Development or identification of analytical tools, information, model regulatory provisions, model contracts, and other support materials for use by customers, States, utilities and demand response providers.

"(c) Upon completion, the National Action Plan on Demand Response shall be published, together with any favorable and dissenting comments submitted by participants in its preparation. Six months after publication, the Commission, together with the Secretary of Energy, shall submit to Congress a proposal to implement the Action Plan, including specific proposed assignments of responsibility, proposed budget amounts, and any agreements secured for participation from State and other participants.

"(d) AUTHORIZATION.—There are authorized to be appropriated to the Commission to carry out this section not more than $10,000,000 for each of the fiscal years 2008, 2009, and 2010.".

(b) TABLE OF CONTENTS.—The table of contents for the National Energy Conservation Policy Act (42 U.S.C. 8201 note) is amended by adding after the items relating to part 4 of title V the following:

"PART 5—PEAK DEMAND REDUCTION

"Sec. 571. National Action Plan for Demand Response.".

APPENDIX G. GLOSSARY OF TERMS

- Ancillary Service Programs: Customers bid load curtailments into various ancillary services markets and agree to be on standby if their bid is accepted. They receive a payment if they are called by the ISO/RTO.

- Capacity Programs: Customers offer load curtailments as a replacement to existing generation in the market. They are generally notified during the day when curtailment is needed. Large penalties are often assessed in the event of non-compliance.

- Critical Peak Pricing: Prices vary by time-of-day and are known to the customer for all pricing periods except that the customer does not know when prices in the critical-peak period may be called. These prices are called on a day-ahead or day-of basis.

- Demand Bidding/ Buyback (Day-ahead): Customers bid load curtailments in the day-ahead market in competition with supply-side resources.

- Demand Bidding/ Buyback (Day-of): Customers bid load curtailments in the day-of market in competition with supply-side resources.

- Direct Load Control: In return for a financial incentive, customers agree to have their end-uses such as air conditioners and water heaters to be controlled by the utility via switches or programmable communicating thermostats.

- Demand Response through Load Aggregators: Load aggregators combine the load reductions of smaller participants and submit these reductions to capacity or other emergency or economic demand response programs.

- Emergency Demand Response Program: Emergency demand response programs provide incentive payments to customers for reducing their loads during reliability-triggered events, but curtailment is voluntary.

- Economic Demand Response Program: Economic demand response programs provide incentive payments to customers for reducing their loads during economic-triggered events, but curtailment is voluntary.

- Emergency Generation: When system's reliability is threatened, system operator may automatically dispatch the generation source at customer's site.

- Interruptible General Service: Customers pay a lower rate in return for agreeing to interrupt their processes to a pre-specified level. This program requires the specification of a baseline or normal usage.

- Load curtailment (a nominated load or a contracted firm demand): Customers are paid a specified amount per MWh curtailed in response to a call that is made on a day-of basis. This requires the specification of a baseline or normal usage.

- Peak Time Rebate: Customers receive a cash rebate for each kWh of load that they reduce below their baseline usage during the event hours instead of paying higher rates during the critical event hours.

- Peak Shed Programs: Peak shed programs are generally implemented through automating technologies to reduce the load from certain end-use devices and reduce demand charges that will be paid by the customer.

- Peak Shaving via Owned Generation: This is similar to the interruptible/curtailable rate programs except that when the load is curtailed or interrupted, it is replaced by the power from own generation resources.

- Peak Day Credit: program provides qualifying customers with bill credits on all on-peak charges in exchange for an average load reduction of a pre-determined level in consumption across all critical event days within a billing cycle.

- Prepay Programs: Customers prepay for their electricity and have in-home displays that provide information on consumption. While not a demand response program per se, it's observed that prepay programs increase the effectiveness of time-varying rates.

- Real Time Pricing (Day-ahead): Prices may vary on an hourly and sometime on a semi-hourly basis. Customers are provided the prices on a day-ahead basis.

- Real Time Pricing (Day-of): Prices may vary on an hourly and sometime on a semi-hourly basis. Customers are provided the prices on an hour-ahead basis.

- Thermal Storage Program: In this program, customers have electric thermal storage units installed on electric heaters which operate during off peak hours and agree to curtail electric heat during on peak winter periods.

- Time-of-Use Pricing: Prices vary by time-of-day and are known to the customers.

- Utility Controlled Interruptible Rates: Customers pay lower rates in return for agreeing to their service being interrupted by the utility.