Everyone Benefits: Practices and Recommendations for Utility System Benefits of Energy Efficiency

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June 2015

Report U1505

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Acknowledgments

This report was made possible through the generous support of Sempra Energy, Pacific Gas & Electric, and the United States Environmental Protection Agency. The author gratefully acknowledges external reviewers, internal reviewers, colleagues, and sponsors who supported this study. External expert reviewers included Jim Lazar from the Regulatory Assistance Project, Joe Loper from Itron, Kenji Takahashi from Synapse Energy Economics, Luke Nickerman from Pacific Gas & Electric, and Daniel Rendler from Southern California Gas Company. External review and support does not imply affiliation or endorsement. Internal reviewers included Maggie Molina, Steve Nadel, R. Neal Elliott, Annie Gilleo, Jim Barrett, and Marty Kushler. The author also gratefully acknowledges the assistance of Byron Boyle and Bryan Ward from the Cadmus Group. Last, I would like to thank Fred Grossberg for managing the editorial process, Kate Hayes and Roxanna Usher for copy editing, Eric Schwass for the publication design, and Patrick Kiker for his help in launching this report.

Executive Summary

The benefits of energy efficiency to a utility system are substantial and far reaching. These benefits reach all customers in the system, program participants and nonparticipants alike. We define utility system benefits as the energy and nonenergy benefits accruing to a utility system from the implementation of energy efficiency programs. These benefits go beyond traditional avoided costs of energy to include other economic benefits. They reduce utility costs over time and translate into reduced rates for customers.

This report focuses on the electric utility system benefits of energy efficiency. Our goal is to describe the benefits administrators are including in energy efficiency evaluation and program screening, and to understand how they are quantifying them. We also aim to analyze the economic benefits of energy efficiency in utility system resource planning. Both program screening and resource planning involve the forecasting of future benefits. These two perspectives are critical because they guide the level of energy efficiency implementation in a utility service territory.

METHODOLOGY

For this study we reviewed publicly available energy efficiency planning and evaluation materials and integrated resource planning studies in over half of the US states. Although we did not try to collect data from every state, we covered program administrators in nearly every region of the country. Our review focused on information and data specific to the benefits calculated for energy efficiency programs. We also examined relevant state public service commission orders and recent national studies. Based on our findings, we discuss each utility system benefit of energy efficiency in detail, specifically how prevalent it is in program screening and the methodology used to estimate it.

We also examined the effect of excluding benefits in program screening. To do this, we created a hypothetical program and performed cost-benefit tests on it using various assumptions about benefits. We also tested the program under different discount-rate assumptions. Finally, we reviewed four integrated resource plans to examine the economic impact on a utility system of including energy efficiency.

HIGH LEVEL FINDINGS

Table ES1 lists the utility system benefits examined in this report.

Table ES1. Utility system benefits of energy efficiency

Benefit	Description
Avoided cost of energy	Avoided marginal cost of energy produced
Avoided cost of capacity	Avoided cost of generating capacity
Avoided cost of transmission and distribution	Value of avoiding or deferring the construction of additional transmission and distribution assets
Avoided cost of ancillary services	Value of avoided ancillary services (e.g., spinning reserves) required to operate
Avoided cost of environmental compliance	Avoided cost of compliance with existing and future environmental regulations

Benefit	Description
Demand reduction induced price effects (DRIPE)	Value of energy or capacity market price mitigation or suppression resulting from reduced customer demand
Utility nonenergy benefits	Value of cost savings to a utility stemming directly from energy efficiency programs, e.g., reduced arrearage carry costs, insurance premiums, cost of reconnections
Avoided cost of renewable portfolio standards	Value of a reduced cost of compliance with renewable portfolio standards as electricity sales decrease

Based on our review of state practices, we found wide diversity in the benefits included in energy efficiency program screening and how these benefits are calculated. This lack of consistency is evident not only among different states, but also among program administrators within states. We also found a lack of transparency in the reporting of benefits used to screen efficiency programs and the methodologies used to calculate them. This was one of the limiting factors in our review of state practice and methodology.

Many program administrators exclude significant benefits from energy efficiency program evaluation. For example, avoided transmission and distribution (T&D) is a significant benefit of implementing energy efficiency and should always be considered when screening programs. However 6 of 45 program administrators in the jurisdictions we reviewed did not include avoided cost of T&D. This trend was also true of other benefits. Of the 14 states that could include the program benefit of wholesale market price suppression, only 6 are currently including it.

In addition, most states and jurisdictions do not include utility-specific nonenergy benefits or avoided cost of renewable portfolio standard compliance. Both of these benefits have been studied in detail and should be included in program cost screening. While the utility nonenergy benefits can be difficult to quantify, research has shown that these benefits are not zero and so should be included when examining measure eligibility for programs.

Best Practices in Estimating Utility System Benefits

Our review offers decision makers some insight into best practices for including and calculating energy efficiency benefits. First, program administrators should include all benefits of implementing energy efficiency as a utility resource. Administrators tend to exclude benefits that may be more difficult to quantify. However, as many states have proven, these benefits can and should be quantified and included in program evaluation and program planning.

Second, when quantifying benefits—especially more significant benefits—program administrators should estimate them at the most reasonable level of detail possible, given limited resources. For example, the avoided cost of energy should reflect differences in both hourly and seasonal changes in energy costs. The avoided cost of capacity should also reflect changes in short-term versus long-term resource planning decisions.

Third, program administrators should consider multiple natural gas price forecasts when estimating the avoided cost of energy to mitigate the risk of relying on a single forecast.[1]

Finally, administrators should pay careful attention to the discount rate used in screening programs. A high discount rate that is not reflective of a utility's decreased level of risk associated with energy efficiency can have an adverse effect on program screening, especially on programs with longer measure lives.

COST-EFFECTIVENESS SCREENING

We conducted cost-effectiveness testing on a hypothetical program as part of our review of utility system benefits. The results showed how important each benefit is to efficiency program planning. Our hypothetical program did not produce positive net benefits until over half of the benefits were included. We also examined net benefits under several discount rates used by program administrators. As expected, net benefits decrease as the discount rate increases.

INTEGRATED RESOURCE PLANNING

Integrated resource plans are planning studies produced by electric utilities to determine resource needs over a given period of 10 to 20 years. They seek to optimize resource options, typically with a focus on least-cost service to customers. While energy efficiency is included in most resource plans, the methodology for including it and the level of efficiency vary by plan. In our review of four recent integrated resource plans, we found that energy efficiency plays a significant role in reducing both system costs and risk, translating into significant cost savings and risk mitigation for all utility customers. For example, Ameren Missouri's energy efficiency scenario reduced its integrated resource plan costs by approximately $2 billion (in present value terms) over a 20-year period. Tennessee Valley Authority's 2011 integrated resource plan produced similar results. Northern Indiana Public Service Company's plan reduced costs by over $325 million over the planning period by including only five energy efficiency programs in its resource portfolio. Although none of the integrated resource plans we reviewed pursued high levels of energy efficiency, even modest efficiency efforts produced substantial economic benefits in the form of lower costs to customers.

CONCLUSION

Energy efficiency provides many benefits to all of the customers in a utility system. Implementation of energy efficiency programs produces positive net benefits, reducing costs for all ratepayers. Utilities should quantify and include all the utility system benefits of energy efficiency in program planning to ensure consideration of all cost-effective measures and programs.

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[1] K. Costello. "How Regulators Should Use Natural Gas Price Forecasts." National Regulatory Research Institute. Presentation at the 2010 NARUC Summer Committee Meetings. http://www.narucmeetings.org/Presentations/Presentation%20on%20the%20Use%20of%20Gas%20Price%20Forecasts%20NARUC%20Meeting.pdf.

State utility commissions should move toward policies that promote the transparency of utility system benefit methodologies and practices. States that have been successful in energy efficiency implementation are those with methodologies and policies that favor consistency, transparency, and the inclusion of all relevant benefits. Because of different regulatory structures and state policies, there is no one-size-fits-all approach to determining benefits. However this should not discourage states from including all benefits relevant to energy efficiency.

Introduction

The benefits from utility-sector energy efficiency programs have been well documented over the past three decades. Yet there is a common misconception that customers who participate in these programs are the only beneficiaries. In fact, efficiency programs benefit the entire utility system and therefore all its ratepayers.

We define utility system benefits as the energy and nonenergy benefits accruing to all customers in a utility system from the implementation of energy efficiency programs. Utility system benefits reduce revenue requirements and so avoid rate increases for both program participants and nonparticipants.[1] They also reduce risk for the utility and its customers by pursuing investments in energy efficiency instead of traditional energy supply resources.

Energy efficiency is almost always the least-cost resource available to a utility system (Molina 2014). Utilities may implement energy efficiency programs as an alternative to constructing a new power plant and to avoid or defer transmission and distribution (T&D) investments. All ratepayers, including nonparticipants in programs, will enjoy the cost savings from a lower-cost resource. Customers of utilities who do not own generation assets will also receive benefits. If a distribution company reduces demand by implementing efficiency programs, it should lower market energy and capacity prices for all ratepayers in the system.

It is true that participants are likely to benefit most from energy efficiency programs. They receive the immediate benefits of bill reductions, improved comfort, higher home or business value, and others. These advantages are on top of the utility system benefits enjoyed by all customers. In return, participants must invest time and take full advantage of financial incentives or technical assistance, and they often must pay additional out-of-pocket expenses.

Few jurisdictions include all utility system benefits when evaluating energy efficiency programs. This may cause utilities to exclude cost-effective programs and pursue higher-cost resources to meet customer demand. We explore the impact of excluding specific benefits later in this report.

Traditionally, administrators should use utility system benefits to screen energy efficiency programs under the utility cost test, or UCT.[2] The benefits are also included in the total resource cost (TRC) test and the societal cost test (SCT). Considering all utility system benefits while screening programs will improve the attractiveness of energy efficiency as an investment and a low-cost resource. The Resource Value Framework (RVF), a framework of cost-effectiveness testing recommendations from a collaborative of energy efficiency professionals, emphasizes the core principle of using the public interest to guide energy

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[1] Utility revenue requirements can be defined as the level of revenue necessary for a utility to collect to properly operate and maintain an electric system to reliably serve customers.

[2] The utility cost test is also known as the program administrator cost test (PACT).

efficiency investments (National Efficiency Screening Project 2014). Pursuing the least-cost resource to meet energy demand is in the public interest.

Avoided cost is often listed as the primary benefit of energy efficiency. The concept of avoided cost originated under the Public Utilities Regulatory Policies Act of 1978. Among other things, this act was designed to encourage independent power production and required electric utilities to purchase energy at avoided cost. A subsequent Federal Energy Regulatory Commission rulemaking defined avoided cost as the "incremental costs of electric energy, capacity, or both" (FERC 1980). Unlike traditional specifications of avoided costs, however, utility system benefits consider all utility-specific benefits, not just avoided energy and capacity.

This report focuses on utility system benefits from an electric utility perspective.[3] We reviewed the methodologies by which various states consider utility system benefits in program screening and evaluation in a sample of jurisdictions. In the process, we uncovered challenges faced by regulators, utilities, and other interested parties in estimating benefits during program screening.

Methodology

We separated the research presented in this report into three phases. For the first phase detailing utility system benefits, we gathered information regarding how states and utilities calculate utility system benefits. We relied on regional or statewide avoided cost studies, utility filings, commission orders, state laws, market potential studies, and other sources of information on the utility, state, and regional level. These data allowed us to gain a better understanding of the various methodologies states and utilities use in different regions to determine benefits. The information also allowed us to understand the differences between states with and without prescriptive methodologies. We did not conduct a comprehensive review of every state practice to determine benefits. Instead, we focused on readily available public data and information in over half the states.

Following our research into the various methodologies and values used in the states, we examined the outcomes of the various approaches on cost-effectiveness screening. To do this, we created a hypothetical energy efficiency program that we screened using various avoided cost assumptions. While the program assumptions were hypothetical, we used actual avoided cost data from Baltimore Gas and Electric's most recent three-year efficiency plan. Using real data and a hypothetical program enabled us to view the impact of each utility system benefit in the construct of cost-effectiveness testing.

In the final phase, we reviewed several integrated resource plans in order to understand the utility system benefits of energy efficiency in an integrated resource planning context. To gauge the full value of energy efficiency to a utility system, we examined the results of various resource plan scenarios and compared system costs among scenarios with and

[3] While the primary focus of this work is electric utility system benefits, many of these benefits may also be found in natural gas programs. For example, natural gas efficiency programs may preclude or defer the construction of new natural gas distribution infrastructure.

without energy efficiency. Some of the resource plans involved multiple levels of energy efficiency deployment. Comparing the cost differences in these scenarios offered insight into the value of energy efficiency to a utility system.

RESEARCH CHALLENGES

We encountered many difficulties as we undertook the research for this project. Transparency of data and methodologies was an obstacle. Many utilities consider avoided cost data and methodology competitive information and do not publicly file this information. Even in regulatory filings detailing cost-effectiveness analysis of potential programs, avoided cost information was often not included. When we were able to gather data on avoided cost, the data were often difficult to dissect. Companies would often include several avoided costs as one value without an explanation of the value of subcomponents. For example, a company might sum together avoided T&D capacity cost with avoided generation capacity cost and label it as avoided capacity cost. Finally, avoided cost figures were often not specified as real or nominal dollars. This uncertainty was further complicated by the fact that many companies used a fixed value to forecast costs out into later years but did not state whether the escalation rate included assumed inflation or was a presumed nominal increase in cost.

Utility System Benefits

OVERVIEW

We define utility system benefits as the energy and nonenergy benefits accruing to the utility system, and all customers in that system. Table 1 illustrates the utility system benefits we discuss in this paper. For example, utility system benefits include traditional avoided costs such as avoided energy and capacity as well as other benefits of implementation of energy efficiency programs. These benefits include avoided or deferred T&D infrastructure, which can be substantial and extend to all ratepayers in a utility system through reduced rates in later years. While avoided energy and capacity costs are a critical component, utility system benefits are more than just these avoided costs.

Table 1. Utility system benefits

Benefit	Description
Avoided cost of energy	Avoided marginal unit of energy produced
Avoided cost of capacity	Avoided cost of generating capacity
Avoided cost of T&D	Value of avoiding or deferring the construction of additional T&D assets
Avoided cost of ancillary services	Value of avoided ancillary services required to operate. A primary example would be spinning reserves.
Avoided cost of environmental compliance	Avoided cost of compliance with existing and future environmental regulations
Demand reduction induced price effects (DRIPE)	Value of energy or capacity market price mitigation or suppression resulting from reduced customer demand
Utility nonenergy benefits	Value of cost savings to a utility from energy efficiency programs. These benefits include reduced arrearage carry costs, reduced insurance premiums, or reduced cost of reconnections
Avoided cost of renewable portfolio standards	Value of a reduced cost of compliance with renewable portfolio standards as electricity sales decrease

AVOIDED COST OF ENERGY

Typically, avoided cost of energy is the avoided cost of a wholesale market energy purchase or the avoided cost of production, generally composed of fuel and avoided variable operations and maintenance cost. In the context of energy efficiency program evaluation, the avoided cost of energy is the marginal cost of production for the incremental unit of energy avoided through an energy efficiency program.[4] There are differences between short- and long-run avoided costs of energy. In the short-run, the avoided cost of energy is the avoided unit cost on the market or unit production cost. Long-run avoided cost of energy may change as the source of avoided energy changes over time. For example, a short-run avoided cost of energy might be based on the marginal cost of production from a simple combustion turbine (CT). This cost is based on the known cost of fuel. A long-run avoided cost of energy might be based on the marginal cost of building and operating a combined cycle gas turbine (CC). A CC has lower variable costs of operation than a CT but a higher capital cost.

Avoided Cost of Energy and Nonparticipants

Assessing the benefits of the avoided cost of energy to nonparticipants is difficult. Most utilities operating outside of wholesale energy markets are able to recover fuel expenses through fuel adjustment mechanisms or clauses. Fuel adjustment mechanisms are a way for a utility to recover fuel costs outside of a rate case and are generally a rider on a utility customer bill. The adjustment allows a utility to recover fuel costs in almost real time to avoid the risk of fuel price spikes. Given that the avoided cost of energy is primarily composed of avoided fuel, the fuel cost adjustment should reflect a decrease in fuel cost when energy efficiency programs are operating. The economic benefits of the decrease in costs collected in the fuel cost mechanism will be reflected in all customer bills, including nonparticipants.

Estimating the benefits to nonparticipants in a competitive market environment is more difficult and relies on specific characteristics of the utility and regulatory environment. For instance, Maryland utilities only own distribution assets and do not make fuel purchases. Avoided electricity in this context is the avoided wholesale market purchases of electricity, which are a direct pass-through to customers. So, in Maryland, if a program participant were able to reduce its electricity usage through participation in a program, other customers (nonparticipants) would likely not see an immediate direct benefit. However a primary energy-related benefit to nonparticipants in competitive market environments is the energy demand reduction induced price effect (DRIPE). This benefit is discussed in greater detail later in the report.

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[4] The concept of avoided cost originated under the Public Utilities Regulatory Policies Act (PURPA) of 1978. Avoided cost of energy in the efficiency context considers the marginal or peak avoided cost. PURPA avoided cost calculations vary and do not necessarily focus on peak periods.

Energy or capacity DRIPE benefits would likely not accrue to a vertically integrated company in a state operating in a wholesale energy market.[5] Utilities in Wisconsin and Indiana, for example, operate in the Midcontinent Independent System Operator (MISO) system but do not rely on wholesale markets to meet customer demand. In Wisconsin and Indiana, rates are not established through wholesale market transactions, as is the case in the Maryland example above, but are based on traditional cost of service rate regulation in which bundled rates are determined through a state public service commission proceeding. Therefore, utilities in these markets do not bill retail customers based on energy market prices. However rate structures vary significantly in different jurisdictions, and specific circumstances must be known to determine whether energy DRIPE benefits are accruing to a utility system.

Methodologies to Estimate Avoided Cost of Energy

All states, jurisdictions, and utilities in our review included avoided cost of energy as a system benefit in cost-effectiveness screening. As expected, the avoided cost of energy values and methodologies differed by company and region; however there are two overarching approaches. First, unbundled utilities operating in wholesale energy market environments typically estimate avoided cost of energy using forward market forecasts and base avoided cost of energy on avoided market purchases. Second, most vertically integrated utilities outside of competitive wholesale markets use integrated resource planning modeling to estimate future avoided energy costs. These companies typically own and operate power plants. Integrated resource planning methodologies rely on comprehensive whole system modeling using assumptions of fuel prices, environmental regulations, weather data, forecasted demand, and other factors to determine future marginal prices.

Significant variance exists between the two overarching methodologies. While all integrated resource planning relies on modeling an entire production system to determine future prices, methodological approaches differ substantially among utilities or regions utilizing this approach, as does the extent to which T&D costs are included. The same is also true for companies and regions forecasting future market prices to estimate the avoided cost of energy. Finally, there are examples of jurisdictions that do not rely on integrated resource planning or wholesale energy market prices. Pennsylvania and New Jersey, for example, use forward projections of natural gas prices to estimate future avoided energy costs.

Other methodological differences exist between jurisdictions. The most significant of these differences are variances of avoided cost of energy based on time of day or season, inclusion or assumptions related to line losses, and inclusion of costs related to compliance of environmental regulations. We discuss each of these differences later in this report. Table 2

[5] Wholesale energy markets include transactions of electricity sales between wholesale buyers and sellers. Buyers generally then sell electricity to retail customers. These markets were established and are regulated by the Federal Energy Regulatory Commission. The markets are competitive, meaning the price is set by the demand in a given market. Therefore, if demand is decreased, wholesale energy prices would be expected to decline as a result.

details several examples of state or utility methodologies for determining avoided cost of energy.

Table 2. State and utility examples of avoided cost of energy methodologies

State or region	Methodology
Pennsylvania	The current avoided energy cost methodology in Pennsylvania was prescribed by the Commission in Phase II of Act 129 (PAPUC 2012). The forecast relies on using PJM zone-specific NYMEX PJM futures for peak and off-peak price points during the first four years of a measure life. In Years 5 through 10 of a given measure life, the methodology relies on using NYMEX natural gas futures prices and a spark-spread calculation to convert gas prices into wholesale energy prices.* The last five-year segment uses the latest Annual Energy Outlook natural gas price forecast or NYMEX futures and a spark-spread calculation to convert gas prices into wholesale energy prices. Heat rates used in the spark-spread calculation are sourced from the Annual Energy Outlook and are updated annually at the beginning of each planning cycle. All three-time periods require the use of a 50% on-peak and 50% off-peak ratio and the use of separate heat rates for peak or non-peak times.
Maryland	Maryland recently completed a statewide avoided cost study for the five utilities participating in EmPOWER Maryland, the state's efficiency statewide effort (Exeter 2014). The basis to estimate the avoided cost of energy was the Ventyx Integrated Power Model (IPM) for 10 zones in the PJM footprint. The IPM is a highly complex model based on least-cost dispatch of generating units in PJM. Wholesale power price projections were modified in two ways to determine the avoided retail electric prices. First, line losses were included. Second, a $0.007 per kWh adder representing the cost of avoided ancillary services, compensation for business risk, and retail supplier margin was added to the per unit price. Line losses were assumed to be 1.5 times the average line losses for each utility to determine the marginal line losses (Exeter 2014).
Texas	In Texas, all utilities operating efficiency programs use the same statewide value for avoided cost of energy. From 2008 to 2012, this was $0.064 per kWh, escalating 2% after year one of measure life. Beginning in 2013, the Public Utilities Commission of Texas has been responsible for updating this number annually. In 2013, the value was $0.104 per kWh and in 2014; it dropped significantly to $0.0462 per kWh. In 2015, it increased again to $0.0532 per kWh (PUCT 2015). The value is calculated using the summer and winter average four-zone nodal market energy prices in ERCOT.
California	The avoided cost methodology for energy efficiency was most recently updated in 2011. The avoided cost of energy forecast consists of short- and long-term values. The short-term values are based on the NYMEX market price forecast. To determine long-run energy prices, a combined cycle unit is modeled in a simulated energy market. The market price is established when the energy market revenues plus the capacity market payments equal the fixed and variable cost of the combined cycle unit. There are other adjustments to the forecasted values based on forecasted natural gas prices and calibrations to ensure the combined cycle does not over- or under-collect revenue. Finally, the annual avoided energy forecast is converted into hourly data using day-ahead locational marginal prices (LMPs) at load aggregation points (E3 2011). Locational marginal prices are whole energy prices in specific locational points comprised of marginal cost of energy, transmission congestion costs, and line losses.
Wisconsin	In Wisconsin, for the purpose of cost-effectiveness testing, avoided cost of energy is calculated at the state level. The methodology relies on forecasted LMP data produced by MISO for various planning scenarios. MISO uses PROMOD IV, an electric market simulation model incorporating generation characteristics, transmission constraints, and market system operations to forecast locational marginal prices. MISO completes this forecast annually, and the forecast covers a 15-year time period.

State or region	Methodology
Indiana	Avoided cost is defined in Indiana code as "the amount of fuel, operation, maintenance, purchased power, labor, capital, taxes, and other cost not incurred by a utility if an alternate supply or demand-side resource is included in the utility's IRP" (170IAC 4-7-1(b)). Indiana requires utilities to also consider the avoided costs of spinning reserves and emission allowances in addition to fuel and O&M. From this guidance, Indiana utilities calculate avoided cost using assumptions and modeling scenarios used in the integrated resource planning process. Indiana would be an example of a state operating in a wholesale market (MISO and PJM) but still using internal data to determine avoided cost benefits. Each utility in Indiana employs different integrated resource planning methods using different assumptions to determine avoided marginal cost.
New England	Every two years, the states in the New England ISO (NE-ISO) conduct an avoided cost study (AESC 2013). This study is among the most comprehensive avoided cost studies in the United States. To determine the avoided cost of energy, a zonal locational marginal price forecasting model is constructed based on specific assumptions regarding fuel prices, demand forecasts, generation forecasts, and other factors. Using load forecasts and hourly load profiles, the model simulates dispatch of generating units at marginal cost. The simulation with other adjustments produces estimates of future LMP values in NE-ISO.
Arkansas	Arkansas recently changed the statewide approach to estimating avoided cost for energy efficiency. The Arkansas Public Service Commission has required utilities to quantify avoided cost of energy to include the value of energy freed by efficiency programs and sold into the wholesale market or avoided energy purchases (APSC 2013). The Commission has also required utilities to differentiate avoided cost of energy by time of day and year to determine the specific value of programs and measures. Utilities still have discretion in terms of specific methodology to determine the avoided cost. In Arkansas, utilities calculated avoided cost of energy in integrated resource planning,

*"Spark price spread" refers to the difference between the price of electricity sold by a generator and the price of the fuel used to generate it, adjusted for equivalent units. The spark price spread can be expressed in $/MWh or $/MMBTUs (or other applicable units). To express it in $/MWh, the spread is calculated by multiplying the price of gas, for example (in $/MMBtu), by the heat rate (in Btu/KWh), dividing by 1,000, and then subtracting from the electricity price (in $/MWh). The heat rate is defined as the ratio of energy inputs used by a generating facility expressed in Btus to the energy output of that facility expressed in kilowatt-hours. See http://moneyterms.co.uk/spark-spread/.

Range of Avoided Energy Cost

We collected 20 observations for avoided cost of energy used in energy efficiency program screening. Figure 1 presents the range of estimated avoided cost from 2015 to 2030 for the 21 observations. The left side of each bar shows the 2015 nominal value; the right side shows the 2030 nominal value. The values are from publicly available data and do not represent a comprehensive list. The figure also does not include values for all examples listed above, as all methodological examples did not include values.

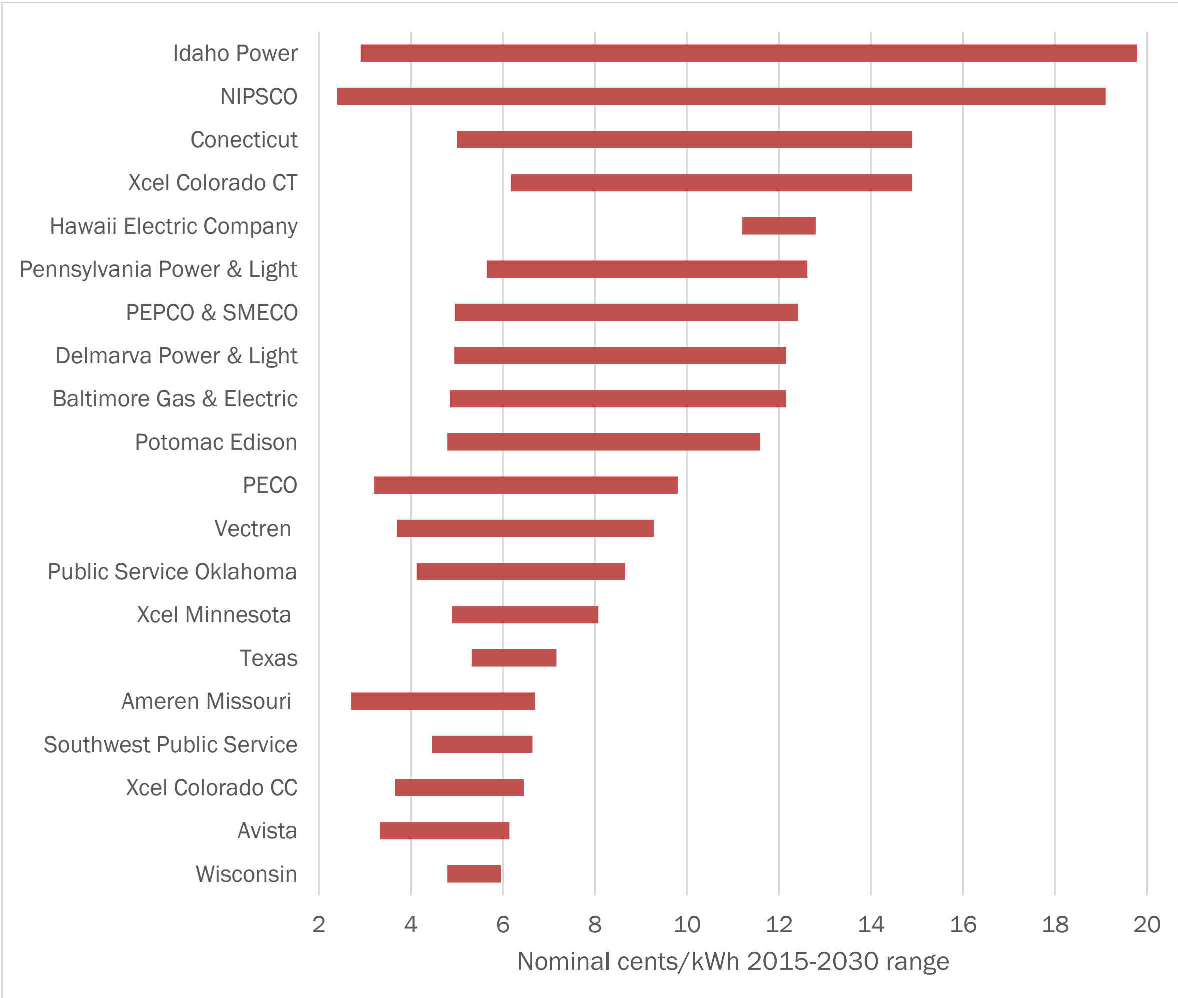

Figure 1. Avoided cost of energy 2015–2030 range for selected states and utilities in cents per kWh. We converted all real dollars to nominal dollars. If values were not clearly labeled, we assumed dollars were nominal. See Appendix A for detailed information on values and data sources.

Some companies or states assume minimal increases in the avoided cost of energy from 2015 to 2030 (those with shorter bars) while most assume substantial increases in the avoided cost of energy over time (those with longer bars). To give a better idea of what the increases were in growth rate terms, the Texas avoided cost of energy was 5.32 cents per kWh in 2015. State law requires companies to use this value with an annual escalation rate of 2%. With this 2% annual escalation, Texas avoided cost of energy increases to 7.16 cents per kWh in 2030.

Time Differentiation of Avoided Energy

The cost of electricity varies throughout the day and year for both regulated and non-regulated utilities. As load grows, more expensive units are dispatched to meet demand. During peak demand hours, the most expensive units on a system will be dispatched to meet demand. For example, figure 2 contains the actual hourly energy prices for the MISO Michigan hub for the calendar year of 2014 (LCG 2015). The prices show strong swings throughout the year with a peak price of just over $1,800 per MWh in January. While most states and utilities we reviewed differentiated avoided energy costs by time of day or year, many did not. Some simply averaged peak and nonpeak values to determine a single avoided cost.

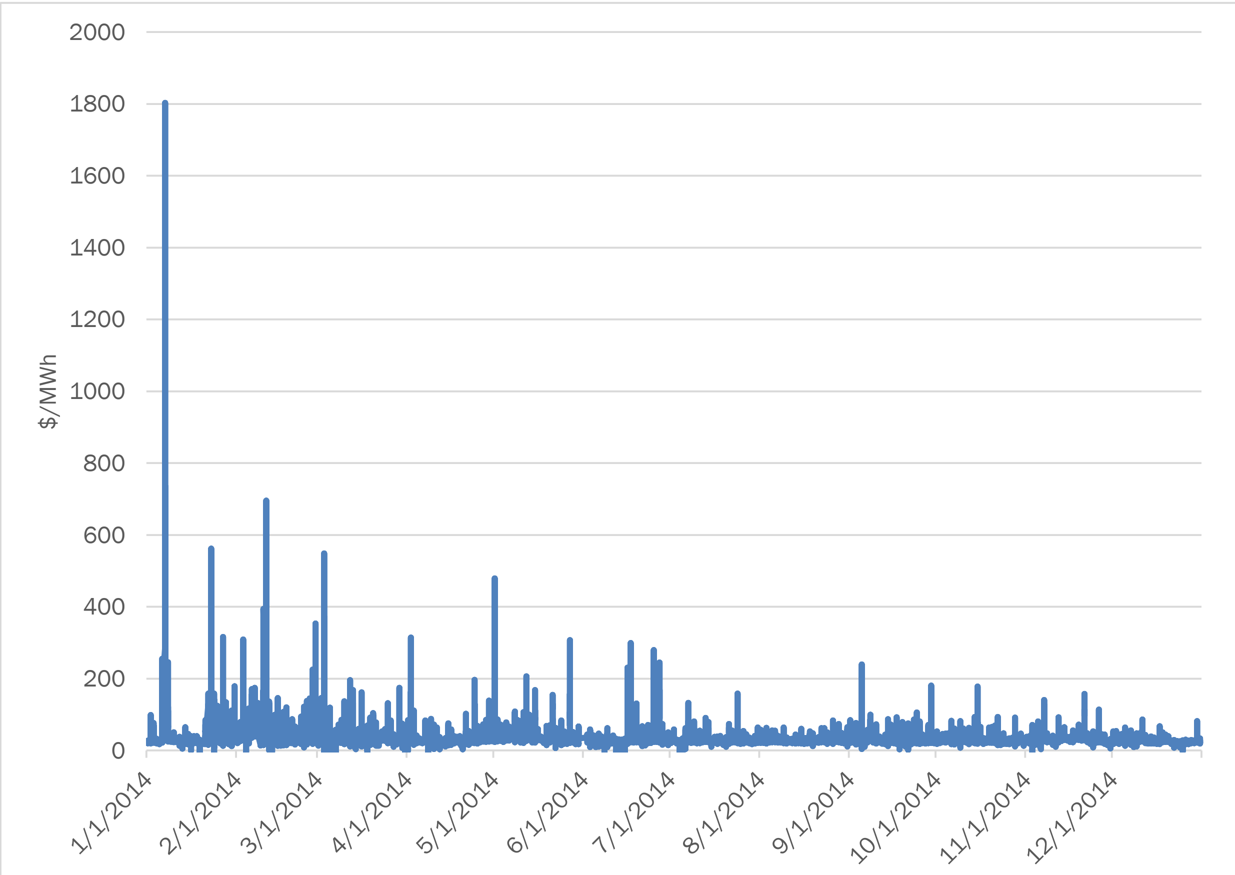

Figure 2. MISO 2014 Michigan hub actual energy prices. *Source:* LCG 2015.

Forecasting Natural Gas in Avoided Cost of Energy

Natural gas price forecasting is the central determinant of the forecasted avoided energy price since it is considered to be the marginal fuel in all approaches. Historically, however, natural gas prices have been volatile and difficult to forecast accurately. This complicates using natural gas price forecasts in utility planning.

Natural gas prices have declined in recent years because of advances in gas extraction technologies. However prices may increase in the future due to changes in demand from increased LNG exports and increases in domestic natural gas power generation (Bentek 2014). Also, as environmental regulations lead to costlier coal-fired generation, demand for natural gas may increase. As a share of electricity production, natural gas power plants are expected to grow from the current 32% to 52% of the US generation mix by 2040 (Pickles 2015). Increased regulations related to hydraulic fracturing may also increase the price of natural gas. The Bureau of Land Management recently proposed new regulations on hydraulic fracturing, which may increase some costs (Cama 2015). Finally, an increase in natural gas exports overseas may have an impact on natural gas prices due to greater demand in a worldwide market (CRA 2013; EIA 2014). Figure 3 illustrates the historic volatility of annual average natural gas prices and the variance in EIA forecasted price.

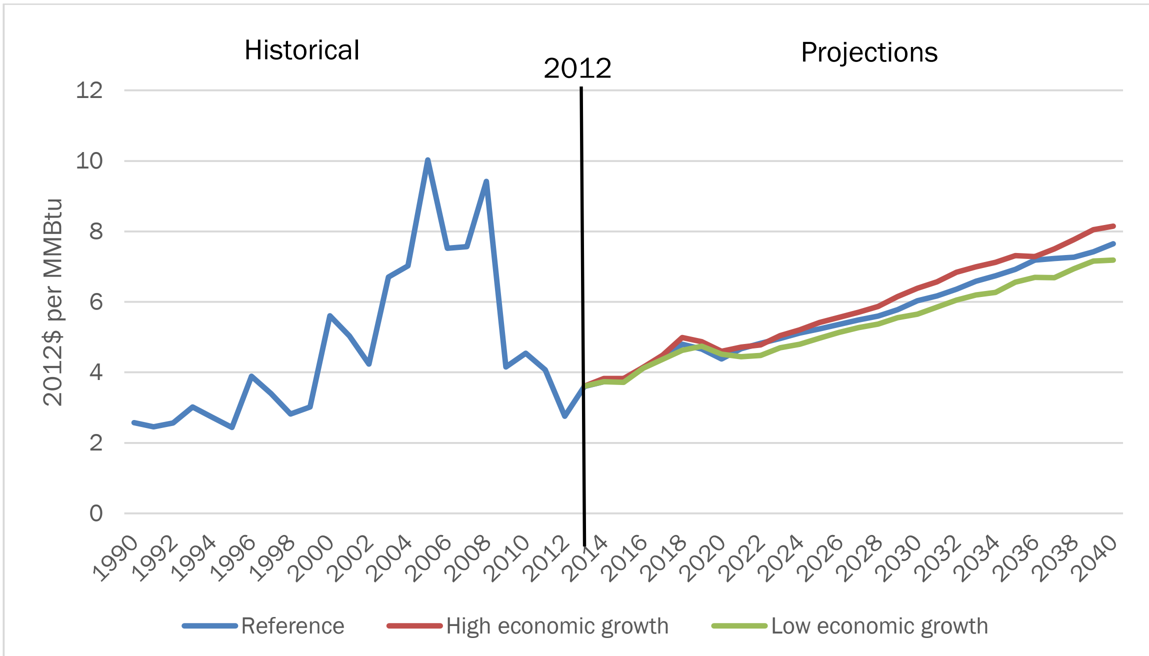

Figure 3. Annual average Henry Hub spot prices for natural gas in three cases, 1990-2040 (2012$/MMBtu). *Source:* EIA 2013.

Given historic volatility and variation among natural gas price forecasts, it can be difficult to use these forecasts when projecting avoided costs of electricity. In a 2010 paper, the National Regulatory Research Institute offered advice to regulators making planning decisions based on uncertain future natural gas prices (Costello 2010). The advice focused on two recommendations. First, regulators should require parties to submit a range of natural gas price forecasts instead of relying on a single best estimate. Second, regulators should require parties to forecast the risk associated with using the price forecasts. The quantification of risk between different forecasts can allow decision makers the opportunity to evaluate the differences under various natural gas price forecasts. Not only are natural gas price forecasts used to estimate future avoided cost of electricity; the forecasts are also used to predict utility-system-wide costs in resource planning as well.

Losses

Energy losses occur during the production and delivery of electricity from a power plant to an end-use customer. These losses are generally referred to as line losses even though some of them occur during the voltage changes in transformers. The variance of line losses is dependent on a number of factors including weather, distance of a transmission or distribution line, and grid infrastructure. Generally, metered losses are not available and must be estimated (Wong 2011). As an efficiency program reduces energy demand, losses are also reduced. The avoided line losses should be included as a benefit to the programs as line loss costs are directly recovered from ratepayers. Avoided line losses are valued a number of different ways but are typically expressed as average line losses for either transmission or distribution, or both. Some utilities also calculate different line loss values for different customer classes.

In our review of avoided cost methodologies, avoided line losses ranged from approximately 2% to 10%. While we found some utilities using marginal line losses, many used average line losses. As presented in a 2011 RAP report, using average line losses in calculating benefits of energy efficiency understates potential benefits of savings. According to the authors, because line losses are exponentially related to load, marginal line losses are greater than average losses, and line losses avoided by efficiency programs are more likely to occur during peak times. The difference between marginal and average line losses can be substantial and change throughout the day depending on load shape. Finally, line losses increase exponentially with load. Therefore, during the highest peak demand, losses are also at the highest point (Lazar 2011).

AVOIDED COST OF CAPACITY

One of the primary goals of energy efficiency programs is to avoid or delay the construction of more-expensive new generation capacity. If energy efficiency obviates the construction of a new power plant, all ratepayers enjoy the savings of the avoided investment. New generation capacity is expensive and risky. It takes several years for a new plant to go from the planning phase to becoming fully operational. Energy efficiency savings come at a much lower cost and lower risk.

Methodologies to Estimate Avoided Cost of Capacity

Avoided capacity cost methodologies vary from state to state. States in regional transmission organizations operating capacity markets often estimate avoided capacity cost using a forecast of forward capacity market prices. For reasons discussed in greater detail later, this can be very difficult. Differences arise among states or utilities on how to forecast the value of capacity beyond the outward auction results. Most other states assume construction costs of a new combined cycle or simple combustion turbine power plant. Table 3 provides some examples of how different states, regions, and utilities determine avoided cost of capacity.

Table 3. Examples of state and utility avoided-cost-of-capacity methodologies

State or region	Description
Maryland	Avoided capacity prices in Maryland are calculated by averaging the capacity values from the last seven capacity auctions for specific PJM load zones. Then, this value is escalated by 7.7% annually to estimate future prices. The escalation factor is based on the five-year compounded annual growth rate of the Handy-Whitman Index for the North Atlantic Region (Exeter 2014, 16). (The Handy-Whitman Index is an annual industry-recognized construction cost index.)

State or region	Description
New England	The 2013 Avoided Energy Supply Cost Study (AESC) utilizes the projected forward capacity market price, adjusted for reserve margin requirements and distribution losses. The 15-year levelized projection of capacity prices in NE-ISO increased from $49.69/kW-year in 2011 to $79.88/kW-year in 2013; both values are 2013 dollars (AESC 2013). The substantial increase in forecasted capacity prices is due to changes to the NE-ISO forward capacity market and environmental regulations forcing some older units into early retirement. The AESC used load forecasts for the ISO-NE territory to develop projected forward capacity market prices. The study made assumptions regarding the retirement of existing generating units, the construction of new transmission projects, generating resource additions, and wholesale market risk premium. Finally, using the load forecasts and future assumptions, the study estimated the forward capacity prices from 2013 to 2024.
Arkansas	Arkansas recently changed the statewide approach to estimating avoided cost for energy efficiency. The Arkansas Public Service Commission has required utilities to quantify avoided cost of capacity to be based on the cost of a combustion turbine modified to account for current market conditions. Utilities in Arkansas have also been directed to include an avoided cost of capacity only in years in which the utility does not have excess capacity. Finally, the commission required utilities to utilize a real economic carrying charge approach to forecast annual avoided capacity costs (APSC 2013).
California	In California, the avoided cost of capacity is based on the hourly dispatch of a new combustion turbine to determine annual market energy revenues. The market revenues earned in the energy and ancillary services markets are subtracted from the fixed and variable costs of an operating combustion turbine to determine the residual capacity value (E3 2011). This residual capacity value is then allocated over the top 250 hours of the CAISO system load. Then, this value is grossed up to account for temperature effects on unit performance, an increase of approximately 8%. The forecasted capacity values ranged from approximately $100 per kW-year in 2013 to $160 per kW-year in 2033.
Texas	In Texas, the avoided cost of capacity value is released annually by the PUCT and is based on the overnight construction costs of a new conventional combustion turbine as defined in the EIA Annual Energy Outlook (EIA AEO). If the EIA AEO estimates of a conventional or advanced combustion turbine are less than $700/kW, the avoided capacity cost is set at $80 per kW. If the EIA estimate is between $700 and $1,000, the avoided capacity cost is set at $100 per kW. Finally, if the estimate is above $1,000, the avoided cost of capacity is set at $120 per kW.
Indiana	Utilities differed in approach to calculating the avoided cost of capacity. Indiana Michigan Power, which operates within PJM, assumed market prices for capacity in the short term but based the long-term avoided cost on a new combustion turbine. Other utilities in Indiana based avoided cost of capacity on the cost of constructing a new combustion turbine. However some assumptions in Indiana differed. Some utilities adjusted avoided capacity cost upward to reflect the reserve margin while some did not.
New Mexico	Southwestern Public Service Company utilized a portfolio approach to determine which type of generation capacity would be displaced by energy efficiency programs. This approach focuses on system-wide resource needs over a 20-year planning period and uses a revenue requirements analysis to determine costs. These costs are then adjusted for inflation annually in a real economic carrying charge approach. Finally, the avoided capacity costs are adjusted for the utility reserve margin and the inclusion of costs to secure space on a regional natural gas pipeline needed to supply fuel to the avoided capacity.

Capacity Avoided

To determine avoided cost of capacity, the program administrator must determine what capacity is actually being avoided by the implementation of energy efficiency programs. Avoided capacity generally falls into three categories: avoiding the construction of a new asset, the purchase of an existing asset, or market purchases for capacity. The following sections explain in greater detail the differences between the three types of avoided capacity. Within the three types, there is variation in long-term and short-term avoided capacity. For example, in the short term, a utility may decide to purchase an existing asset because of the time needed to construct a new asset. But in the long term, a company may decide to build an asset.

Construction of a New Generating Asset

The construction cost of a new power plant is the primary method of determining avoided capacity cost for utilities in jurisdictions not participating in wholesale capacity markets. As energy efficiency is expected to occur at the margin, the marginal generation resource is assumed to be the avoided capacity needed. Many utilities assumed a conventional combustion turbine would be the marginal unit needed to meet peak demand. However combustion turbines operate a limited number of hours per year and in many cases, a combined cycle unit is the marginal unit. Others may use the cost of implementing a demand response program as the cost of capacity for short-duration loads. Table 4 lists recent capital cost estimates for new combined cycle and combustion turbine power plants.

Table 4. Cost estimates of recent natural gas-fired generators

Owner	Plant name	Type*	State	Size (MW)	Cost ($millions)	$/kW	Status
NRG Energy	Carlsbad	CT	California	636	850	1,336	Development
NRG Energy	Bowline 3	CC	New York	775	1,000	1,290	Planned
Calpine	Russell City	CC	California	657	845	1,286	Online 2013
WEPCo	Riverside	CC	Wisconsin	650	775	1,192	Planned
Panda	Panda Sherman	CC	Texas	769	845	1,100	Online 2014
FPL	Port Everglades	CC	Florida	1,250	1,300	1,040	Construction
Indeck Energy	Indeck Wharton	CT	Texas	620	627	1,011	Construction
KU	Green River 5	CC	Kentucky	700	700	1,000	Cancelled
Constellation	Perryman	CT	Maryland	120	120	1,000	Construction
Southern Co.	Jackson County	CT	Texas	920	874	950	Development
Wolverine	Alpine	CT	Michigan	432	410	949	Development
IPL	Eagle Valley	CC	Indiana	671	631	940	Construction

* CT denotes a combustion turbine; CC denotes a combined cycle. *Source:* SNL 2015.

On an annual basis, the Energy Information Administration releases overnight capital cost estimates to construct new generating units. Overnight costs are total costs of construction excluding interest. Figure 4 shows the EIA AEO estimated overnight cost of construction for new natural gas power plants since 2001.

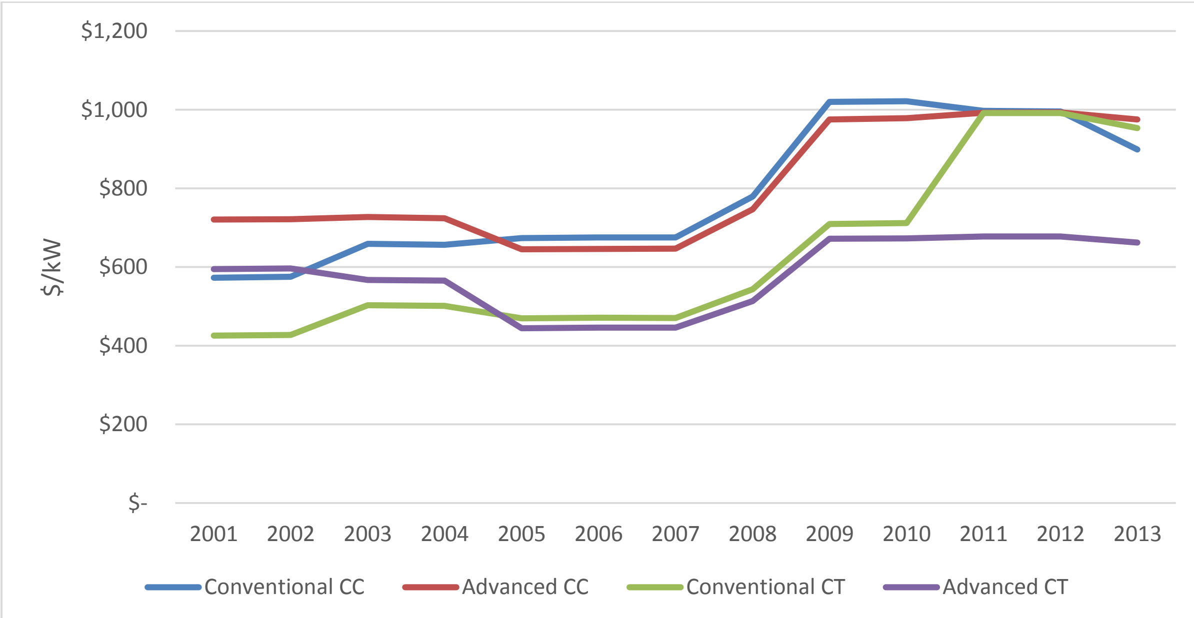

Figure 4. EIA AEO new natural gas unit overnight cost (2014$). ***Source:*** **EIA 2001–2013.**

The data show an increase from 2001 to 2011 in the real cost to build a new natural-gas-fired power plant. Since 2011, the real cost of construction for a combustion turbine has remained relatively flat. Although the Annual Energy Outlook is released annually, it is important to note EIA does not update the generation cost study annually. Prior to the 2013 study, the last study was completed in 2010. In 2013, construction costs for all four types of gas-fired generation decreased slightly.

Other estimates of capital costs for new generation estimates are generally higher than EIA estimates. Other estimates we reviewed listed gas peaking plant total capital costs between $800 and $1,000 per installed kW and gas combined cycle between $1,006 and $1,318 per installed kW (Lazard 2014). EIA estimates are also on the lower end when compared with estimates presented in table 4.

Capacity Procurement through a Wholesale Capacity Market

In the northeastern United States (and parts of the Midwest), generating capacity is procured through organized capacity markets. Estimating the avoided cost of capacity in a market environment is very difficult. There are numerous factors impacting the market price for capacity. A review of capacity market results in PJM, NE-ISO, and NYISO from 2006 to present shows wide variation year to year in capacity markets. Figure 5 shows some of the variability. This variation year to year does not generally show a linear trend of capacity prices, which would lend itself to a simple escalation factor for future prices. Instead, future prices must be modeled based on a number of factors regarding future likely scenarios for transmission builds, generation retirements, generation new builds, and fuel prices.

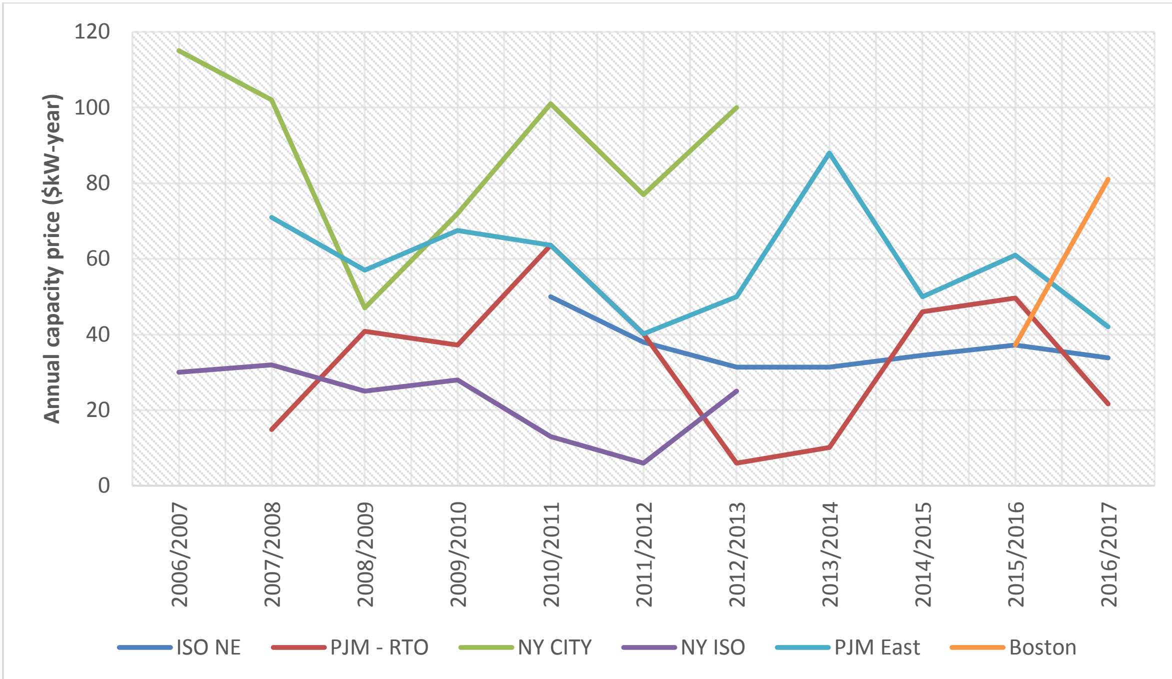

Figure 5. Capacity clearing prices in each RTO and select sub regions for commitment periods 2006–2017. *Source:* FERC 2013.

Purchase of Existing Market Assets

The purchase of existing market assets is also an option for some utilities. There are several factors to consider when purchasing an existing plant on the market. Transmission capacity must be available to move power from the new unit to a company's existing load. The type of fuel used by the existing unit must match the dispatch characteristics needed by the company. For example, a 100-MW wind farm is likely not a workable solution for a company in need of generation to meet peak demand. Finally, an existing unit must fit within the environmental planning process for a given company. For example, Kentucky Utilities is a company primarily relying on coal-fired generation. Recent environmental rules have pressed the company to diversify its generation portfolio, and it would be unlikely for this company to purchase an existing coal-fired power plant.

Existing generation may be less costly than a new build. For example, Dynegy Inc. recently acquired several existing power plants in the Midwest and New England. The Midwest plants were acquired for approximately $450 per kW, and the New England plants were acquired for $575 per kW (Qureshi 2014).[6] However a unit that has operated for many years has a shorter remaining life, and the annualized cost of capacity must take this into account. In another example of a higher-cost unit, the Fox Energy Center, a combined cycle unit in

[6] The Midwest purchase included 11 power plants, of which 55% of capacity was natural gas fired and 45% was coal fired. The New England acquisition included 10 power plants, of which 58% of capacity was natural gas fired and 42% was coal fired. This transaction is currently awaiting final approval from the Federal Energy Regulatory Commission.

Wisconsin, was recently acquired by Wisconsin Public Service Corp for $741 per kW (Qureshi 2013).

Rise in Utility Generation Construction Costs

Over the last 20 years, utility construction costs have increased dramatically (Handy-Whitman 2014). There are several reasons for the increase in construction costs. The cost of skilled labor, raw materials, refined materials, and fabrication capacity has increased in the last decade. This trend is likely to continue as the demand for new power plants continues to grow in the United States and abroad. Aging power plants, environmental regulations, and the low cost of natural gas have forced the US generating fleet to change rapidly. The North American Reliability Council (NERC) is projecting the retirement of 44.6 GW of generating capacity by 2024 for a total of 86 GW of capacity retired since 2011 (NERC 2014).[7] Even with slow load-growth conditions nationwide, NERC projects a need for 96 GW of new capacity in this time period. This increasing demand for new capacity should produce upward pressure on utility construction costs.

The Handy-Whitman Index of Public Utility Construction Costs is an annually published index for trends in utility construction costs. The index is designed to collect publicly available data reported to the Federal Energy Regulatory Commission to be a reasonably accurate measure of the cost of reproducing actual plant. The index is widely used by regulatory bodies, valuation experts, and regional transmission organizations to estimate trends in construction cost. To demonstrate the increase in utility construction costs in recent years, figure 6 graphs the index since 1991 for total steam production plant and gas turbo generators. These two categories represent the likely construction cost trends for an asset that would be avoided. We have also included the GDP deflator to show how these construction cost trends have compared with general inflation trends in the same time period. Figure 6 shows a significant upward trend in utility construction costs since 1991, with a large increase since 2003. The growth rate in construction costs for natural gas turbo generators experienced much higher growth rates than inflation.

[7] NERC is a nonprofit entity responsible for assuring reliability of the bulk electric power system in North America. NERC is overseen by the Federal Energy Regulatory Commission and other regulatory authorities in Canada.

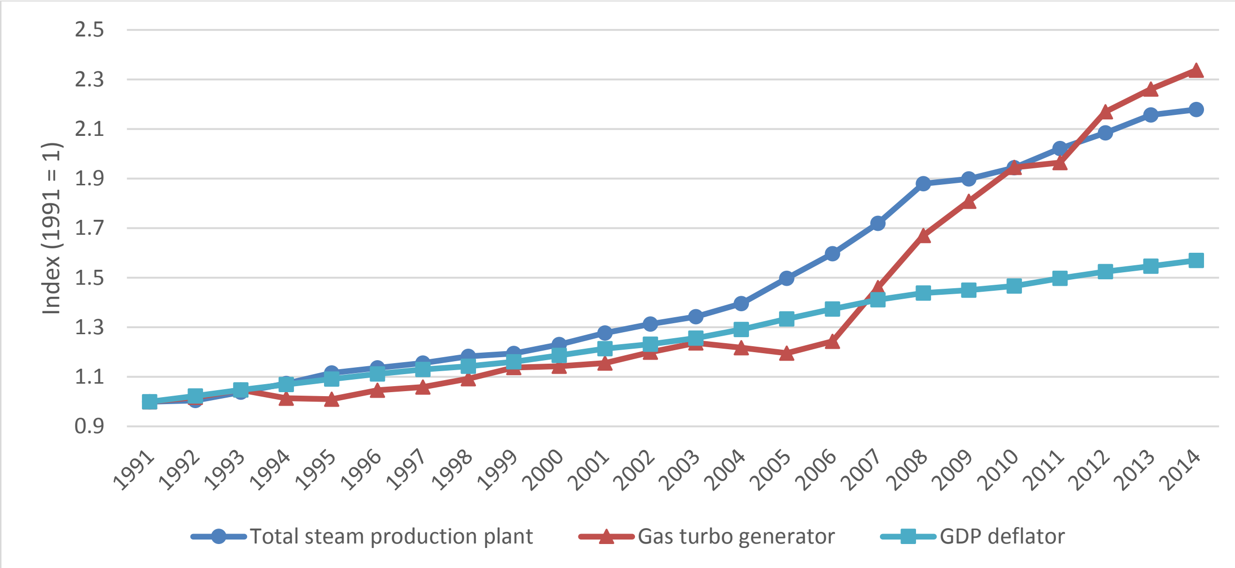

Figure 6. National average of generation construction cost indices. *Source:* Handy-Whitman 2014; BEA 2015.

Planning Reserve Margin and Avoided Cost of Capacity

Reserve capacity is defined as the capacity in excess of that required to carry peak load, available to meet unanticipated demands for power or to generate power in the event of loss of generation (Duke 2004). Excess capacity is required for reliability purposes in the event of planned or unplanned outages to generating units or transmission facilities. The planning reserve margin is the percentage of excess capacity over the forecasted demand. Excess capacity and higher reserve margins increase the reliability of a system. For example, if a utility has a peak demand forecast of 100 MW, it will likely plan to have at least 115 MW of available generating capacity. This would represent a reserve margin of 15%.

NERC conducts an annual assessment of summer reliability. In the 2014 assessment, NERC expressed concern with reserve margins in the MISO and ERCOT regions. Both regions had reserve margins of approximately 15% (NERC 2014). According to NERC, reliability can be compromised if reserve margins fall below this threshold. Reliability disruptions have the potential to cause blackouts resulting in substantial economic costs to society. Other reserve margins are used in different jurisdictions. For example, in the Maryland avoided cost study, reserve margins of 9% are assumed.

If a utility is avoiding securing excess capacity to meet peak demand, it is also avoiding the reserve margin associated with the avoided capacity. Referring to the simple example above, if a utility is able to reduce demand from 100 MW to 90 MW and has a planning reserve margin requirement of 15%, the utility has not only avoided the 10 MW but has also avoided 1.5 MW in addition because of a reduced reserve margin requirement.

Avoided Capacity Cost and Natural Gas Pipelines

Many utilities forecasting avoided cost of capacity assume new construction of either a conventional or advanced combustion turbine. To construct a new natural gas power plant, most utilities also need to construct a new natural gas pipeline to supply the plant with fuel. In our limited review of utility data and methodologies, only one electric utility, Southwestern Public Service Company (SPS), included the avoided cost to transport natural gas to the new plant (SPS 2013). Instead of assuming construction of a new pipeline, SPS assumed the avoided cost of securing capacity on the Northern Natural Gas Pipeline, estimated to be $18.48/kW-year. The cost of securing new pipeline capacity or constructing a new pipeline should be considered in the avoided cost of capacity for a new plant. These costs are real and can be avoided if the plant can be avoided.

Levelized Versus Non-Levelized Avoided Cost of Capacity

In our review of avoided cost of capacity methodologies, we found that some companies use a levelized cost of capacity held constant throughout the forecasted period. Levelized cost of capacity is the present value of capital required to build a new power plant amortized over the life of the plant. This value often includes financing costs such as allowance for funds used during construction, but sometimes does not. Other companies escalate the avoided cost of capacity by a fixed percentage. The escalators would include an assumption for inflation but would also include assumptions regarding the perceived increased real cost of avoided capacity in the future. Also, some methodologies we reviewed only escalated avoided capacity by an assumed inflation rate, thereby assuming no real cost increase in the forecast period for capacity. Finally, some methodologies used a real economic carrying charge approach. This approach values the delay of construction of a new plant by one year at a time. Instead of a levelized cost, it assumes that the value of the asset increases by the level of inflation annually. This approach yields the same net present value of revenue requirements as a nominal levelized approach.

The various approaches can produce very different results. For example, in a real economic carrying charge approach, avoided capacity benefits are much higher in later years than earlier years. This approach may undervalue energy efficiency, as the early years are the lowest cost. This in turn should provide an incentive to focus on measures and programs with longer-measure lives.

Range of Avoided Capacity Cost

We collected avoided cost of capacity data for 17 states or utilities (some jurisdictions, such as Texas, assume a statewide value). Figure 7 shows the results for the avoided cost of capacity data collected.

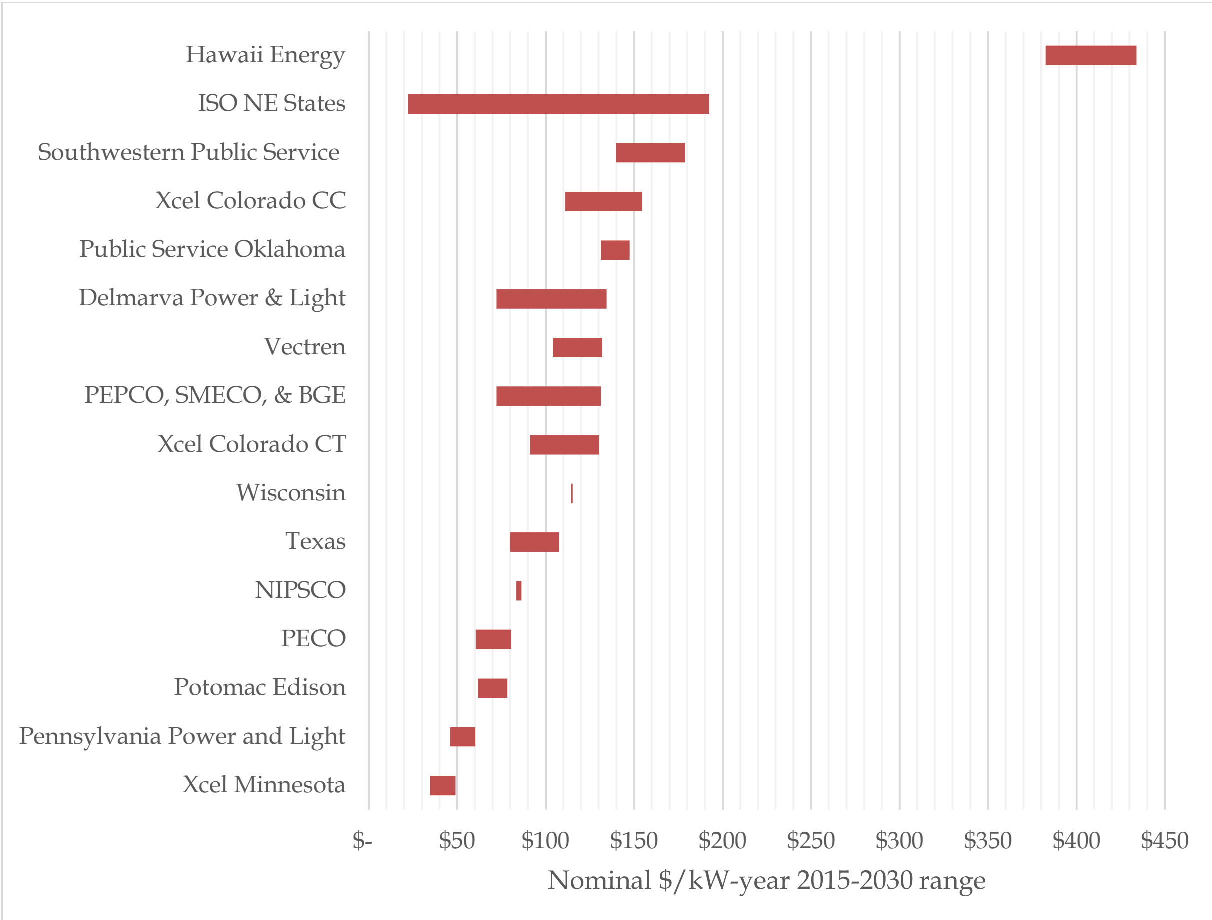

Figure7. Avoided cost of capacity value range 2015–2030 for selected utilities and states. See Appendix B for detailed information on values and data sources.

One challenge in interpreting these data was that when the data were presented in utility filings, it was often not clear if the dollars were real or nominal. For the purpose of this section, if the values were presented as real, we converted them to nominal. We assumed nominal dollars in cases where it was not expressly noted. However, when examining rates of change year to year for the avoided cost streams, we noticed many companies increased the avoided cost value by a fixed (or close to fixed) percentage annually. These values ranged from 1.6% to 2.4%. This led us to believe some of the dollars were, in fact, real and the increased value year to year was to reflect inflation. Several companies used the term "escalation" to describe year-to-year increases in values but did not describe or note if the escalation was specifically related to inflation or real cost increases for new capacity.

AVOIDED TRANSMISSION AND DISTRIBUTION COSTS

Energy efficiency programs have the ability to reduce load in given areas for a utility system. Load reductions may reduce utility investments in T&D facilities over time as upgrades, maintenance, and new construction can be delayed or completely avoided. Avoided T&D costs are important when assessing the benefits of energy efficiency, as the economic value of these benefits can be substantial and are enjoyed by all ratepayers in a utility system, not just those who participate in programs.

Recent Studies

In 2012 the Regulatory Assistance Project published a paper on energy efficiency as a T&D resource (Neme 2012). The paper differentiated between active and passive deferrals of T&D investments due to energy efficiency. Passive deferral describes the deferral of T&D investments due to system-wide efficiency investments. RAP notes that passive deferrals are sometimes reflected in the avoided cost of T&D in efficiency program screening. Active deferrals refer to targeted investment of energy efficiency to defer or avoid building specific T&D facilities. The authors also highlighted the many instances in which energy efficiency programs allowed utilities to defer or completely avoid new T&D investments. In a notable example of a passive deferral, ComEd was able to reduce its projected T&D capital expenditures by nearly $1 billion after adjusting load forecasts to consider the impacts of system-wide energy efficiency efforts. The authors also provide many examples of avoided T&D investments due to geographically targeted energy efficiency efforts.

A 2014 survey of methodologies used to estimate avoided T&D conducted by the Mendota Group on behalf of Xcel energy reveals the wide variation among utilities in making the calculation (Mendota 2014). While there was some commonality, significant differences in methodological approach are apparent. The study concludes there may not be a best practice method to determine avoided cost of T&D because many different methods may be capable of producing a valid estimate. The calculation of avoided T&D benefits is dependent on location, system-wide impacts, and time of day or year. Estimation of these costs requires complex system modeling. The study also notes while energy efficiency has the ability to defer or avoid T&D investments, the measures must be coincident with system peaks to achieve this purpose.

The Mendota report also collected data for 36 companies estimating avoided T&D benefits over the last three years. The estimates span most regions of the country except the southwest. The range of the avoided distribution was found to be $0 to $171/kW-year with an average avoided cost of $48.37. The range of the avoided transmission cost was found to be $0 to $88.64/kW-year with an average avoided cost of $21.21. Most avoided T&D cost estimates were between $40 and $60/kw-year with four companies assuming $0/kw-year.

Methodologies to Estimate Avoided Cost of T&D

Estimating avoided T&D costs can be a highly complex process and is typically more challenging than estimating the avoided cost of capacity or energy. In our review of avoided cost data, several observers commented on the difficulty of including estimates for avoided T&D. Our review found that several companies do not consider avoided T&D cost in program evaluation. For example, Focus on Energy does not include any avoided T&D costs in ex post evaluation estimates of program cost effectiveness (Cadmus 2013). Indiana Michigan Power also does not include this benefit claiming, “It is nearly impossible to determine a transmission-related avoided cost that has real meaning or is reliable for the Company other than on a case-by-case basis” (I&M 2013). Table 5 presents examples of states and utilities methodologies to determine the avoided cost of T&D.

Table 5. State and utility examples of avoided cost of T&D methodologies

State or region	Description
Maryland	Avoided T&D costs in Maryland vary by utility and were not calculated as part of the 2014 Exeter statewide avoided cost study. Baltimore Gas and Electric based its avoided T&D costs on the replacement cost of a distribution substation and the value of importing electricity into its transmission system. Potomac Edison relied on a proxy estimate supplied during the last evaluation of programs of a sister company in Pennsylvania.
New England	The New England Avoided Cost of Supply study does not calculate the avoided cost of T&D. In an earlier version of this study, ICF developed a spreadsheet-based tool that companies in the region still rely on to estimate this cost (AESC 2005). The tool relies on 15 years of historical and 10 years of forecasted T&D investments to determine the marginal T&D capacity cost. The tool also requires other information, mostly found in the FERC Form 1.*
Arkansas	A recent Arkansas Public Service Commission order on avoided cost methodologies directed Arkansas utilities to internally develop long-run marginal avoided T&D cost. Beyond requiring companies to calculate marginal line losses instead of average line losses, the Commission did not require a specific methodology. Entergy Arkansas bases its avoided cost of T&D on a levelized average of the actual cost of completed substation upgrade and line upgrade project costs in the Entergy Electric System over the past five years.
California	California T&D avoided costs were determined independently by each utility prior to the completion of the statewide avoided cost study. The values were then allocated to hours based on climate and weather data. The avoided costs were also escalated at 2% per year nominally and adjusted for losses.
Indiana	Methodology to determine avoided T&D varies significantly among utilities in Indiana. For example, Vectren assumes 10% of the estimated avoided capacity cost as a proxy for avoided T&D. This methodology produces avoided T&D costs, which were much lower than most reviewed in our analysis. In comparison, NIPSCO's avoided cost of T&D was roughly half of the avoided cost of capacity. NIPSCO's specific methodology is unclear. Indiana Michigan Power does not include avoided cost of T&D, citing the difficulties associated with such estimates.
New Mexico	Southwest Public Service Company relied on the Southwest Power Pool 10-year integrated transmission plan to determine the avoided cost of transmission. The company also noted it was only appropriate to apply this benefit to programs reducing peak demand. The company did not include distribution avoided cost and cited the difficulty obtaining values that would be specific to energy efficiency programs.

* The FERC Form 1 is an annual FERC filing requirement, gathering all financial information for all federally regulated US utilities.

Range of Avoided Cost of T&D

We collected 45 data points for estimates of avoided T&D used in efficiency program screening. Most estimates of avoided T&D were presented as a single or levelized value. Figure 8 displays the wide range of estimates for this benefit ranging from $0/kW-year to $200/kW-year. Of the 45 data points, 6 were $0/kW-year, meaning avoided T&D benefits were excluded from program screening. The majority of values were between $25 and $50 per kW-year. Of the estimates reviewed for this study, the highest level of avoided cost of T&D was reported in the northeastern region.

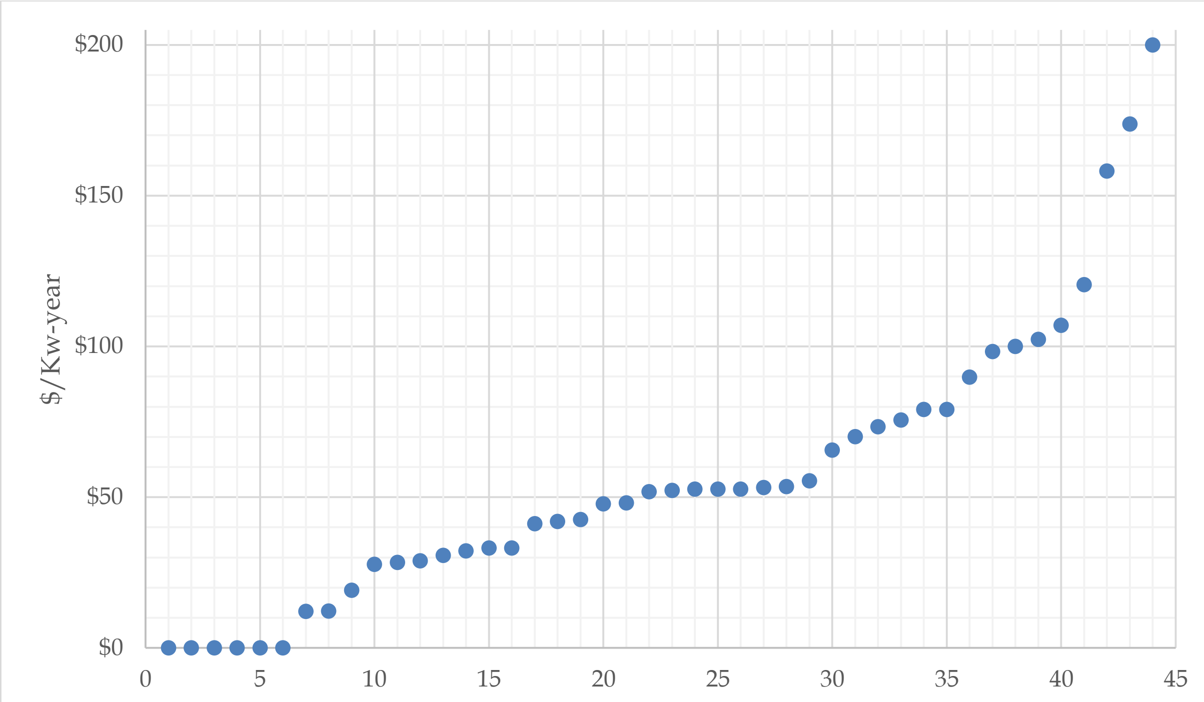

Figure 8. Survey of avoided cost of T&D values. Each point in the graph represents the avoided cost of T&D for a specific company or utility. See Appendix C for detailed information on values and data sources.

Rise in Utility T&D Construction Costs

Similar to recent trends with generation construction costs, utility T&D construction costs have also increased in recent years. Using the Handy-Whitman construction cost index discussed above, figure 9 plots the trend in construction costs for T&D against inflation.

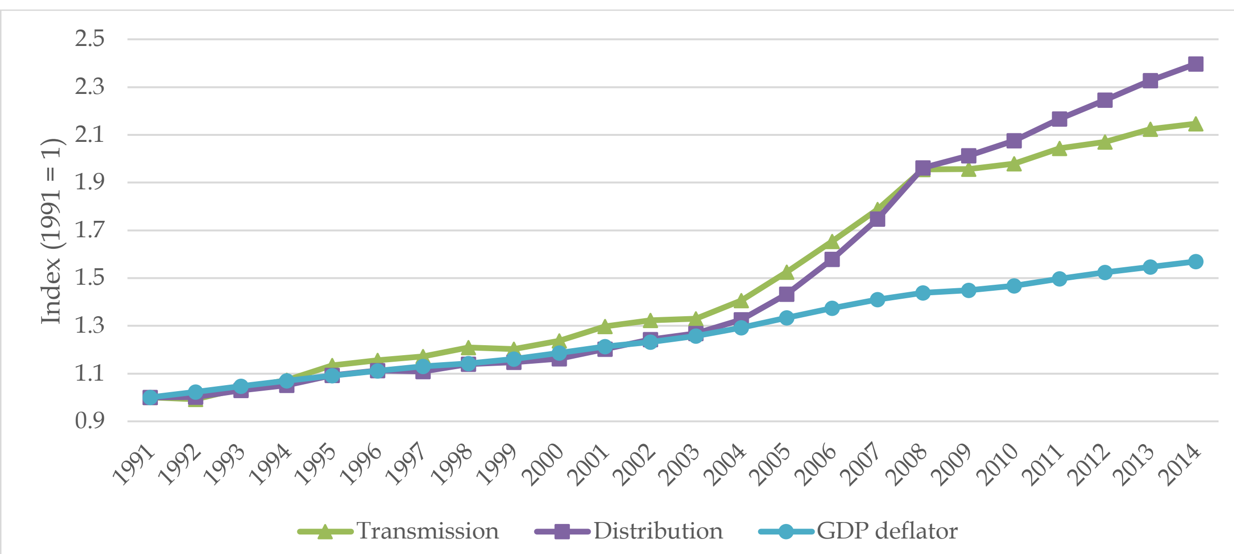

Figure 9. National average of T&D construction cost indices. *Source:* Handy-Whitman 2014; BEA 2015.

The results show a substantial upward trend from 2003 to 2008 with construction costs for T&D far outpacing inflation. The period between 2009 and 2014 seems to have slowed in comparison with the previous five years; distribution construction costs have outpaced inflation by approximately 2% annually. For the same period, transmission construction costs have grown at a similar pace to inflation with only a few years over 1%. The trend in construction costs in this period mirrors the trend in raw material costs as world prices for many commodities, including crushed stone, cement, and copper, declined during the Great Recession. The increase in construction costs may also be partially explained by an increase in construction of underground distribution facilities (EEI 2013).

AVOIDED COST OF ANCILLARY SERVICES

Ancillary services are defined as the services necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operations of a transmission system (PJM 2015). Ancillary services include reactive power and voltage support, spinning reserves, supplemental reserves, generator imbalance, energy imbalance, regulation and frequency response, and schedule, system control, and dispatch (FERC 2007). Energy efficiency, especially programs reducing peak load, have the ability to reduce the demand for ancillary services. The cost of ancillary services is traditionally collected in transmission rates but includes costs associated with generating capacity, energy, and transmission costs. In our limited review, we found jurisdictions that included avoided ancillary service costs in avoided cost of capacity, energy, and T&D.

AVOIDED COST OF ENVIRONMENTAL COMPLIANCE

Existing Regulations

Power plants in United States face environmental regulations from state and federal agencies. Examples of air emissions that are regulated include mercury, sulfur dioxide, nitrogen oxide, particulate matter, and ozone. The Environmental Protection Agency has also recently finalized carbon dioxide emission guidelines for new sources and is in the process of finalizing a rule to limit emissions of carbon dioxide from existing generation sources (EPA 2015a). New and existing power plants must adhere to several laws to reduce emissions. Table 6 describes some of the more significant rules.

Table 6. Selected EPA rules affecting existing power plants

Regulation	Description
Cross State Air Pollution Rule	Limits release of SO_2 and NO_x emissions that cross state lines. There are 28 states in the eastern United States operating under this rule.
Mercury and Air Toxics Standard	This rule targets mercury emissions reductions at new and existing coal- and oil-fired generating units. The rule will likely require existing units to install new pollution control technologies if not already installed to meet the emission limits.
Coal Combustion Residuals Rule	This rule requires specific technical requirements for the disposal of coal ash produced at coal-fired generating stations. Compliance costs for the rule will vary based on the characteristics of specific power plants, but it is expected to add compliance costs to new and existing generating units.
Cooling Water Intake Rule (316b)	This rule requires an estimated 544 power plants to have specific cooling water intake structures installed to reduce fish impingement.

Source: EPA 2015b

The existing rules described in table 6 are all recent regulations. The Cross State Air Pollution Rule began implementation in early 2015 (EPA 2014a). The Mercury and Air Toxics Standard was finalized in 2012 and gives existing power plants four years to comply with emissions standards outlined in the rule. The Cooling Water Intake rule and Coal Combustion Residuals rule were finalized in 2014. These rules have the potential to increase costs for existing power plants, especially coal-fired power plants that are required to install new environmental control technologies. The compliance costs for some of these rules can be substantial and have contributed to decisions to retire older coal-fired power plants.

Energy efficiency has the ability to reduce power plant emissions by reducing electricity generation. Reduced emissions can translate into reduced compliance costs, a utility system benefit of energy efficiency. Quantifying this benefit can be difficult as compliance costs can be borne through emissions allowances, capital costs for new pollution-control equipment, and increased operating costs to sustain pollution control equipment. A recent report from the Regulatory Assistance Project notes it is important to consider most of these costs are internalized in market prices in long-run forecasts and should be handled carefully in avoided cost methodologies to avoid double-counting of benefits (Lazar 2013).

Many of the companies we reviewed considered the avoided cost of environmental compliance in avoided cost calculations. However companies generally only considered the avoided cost of emission allowances associated with SO_2 and NO_x. The avoided cost of emission allowances was based on the historic and projected cost of emission allowances. In all of the studies we reviewed, the avoided cost of emission allowances was included in the avoided cost of energy.

Future Regulations

Utility efforts to estimate the cost of future environmental compliance has been largely focused on the forecasted avoided cost of carbon dioxide emissions and the avoided cost of compliance for the Cross State Air Pollution Rule. As with most avoided cost calculations, companies operating in wholesale market environments utilize different methodologies than traditional vertically integrated companies. In both instances, the avoided cost of compliance with future environmental regulations was usually embedded in the avoided energy costs.

In companies operating in wholesale markets, assumptions on future costs of emissions was usually included in economic simulations to determine wholesale market prices. Therefore, the wholesale market prices produced by these models included the avoided cost of environmental compliance for CO_2, NO_x, and SO_2. Assumptions on future prices of emissions varied and were not uniform among studies we reviewed. For vertically integrated companies, the most common methodology in our review was an assumption of carbon dioxide in dollars per ton to begin in a specific year. Many states and companies we reviewed used a similar methodology with varying assumptions on cost and start date of cost of compliance.

One of the most commonly cited forecasts is the Carbon Price Forecast by Synapse Energy Economics (Synapse 2015). This forecast, released annually since 2012, projects a high, low, and reference price of carbon dioxide over a 30-year time period.[8] Figure 10 shows the most recent forecast.

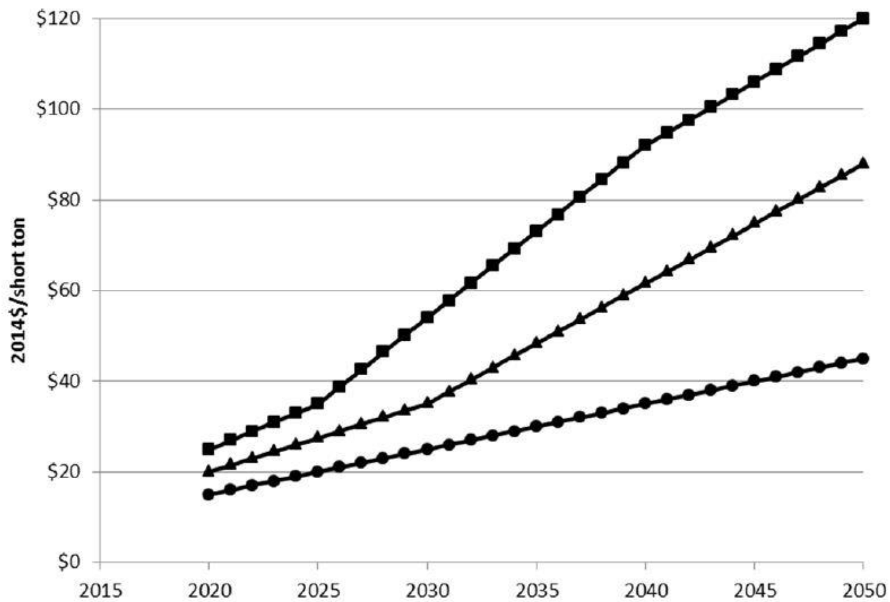

Figure 10. Synapse Energy Economics 2015 carbon price forecast. *Source:* Synapse 2015.

EPA is currently in the process of finalizing rules to limit greenhouse gas emissions from new and existing power plants with final rules expected in summer of 2015. EPA's proposed rule to limit carbon emissions from existing sources, called the Clean Power Plan, will allow states flexibility to meet specific state carbon emission limits (EPA 2014b). States will have the opportunity to pursue different compliance strategies based on four "building blocks," although states are not bound to use the four building blocks in final compliance strategies. One of the four building blocks or central compliance strategies is demand-side energy efficiency. In the proposed rule, EPA stressed the benefits of energy efficiency as a low-cost strategy to reduce carbon emissions. While the value of using energy efficiency as a compliance option is not yet fully known, ICF International projects the net electric system benefits could increase as much as $12.1 per MWh (Pickles 2014). Relative to other compliance options, energy efficiency has the potential to reduce total utility system costs and customer bills.

Demand Reduction Induced Price Effects

Energy efficiency programs also have the ability to reduce wholesale market prices for energy, capacity, and natural gas. When load is reduced in a jurisdiction operating in a wholesale market environment, demand for energy or capacity is also reduced, resulting in price suppression in the associated market. This concept is known as market price

[8] The focus of the Synapse carbon price forecast is estimating the forecasted price of carbon for electric utilities to use in resource planning. The social cost of carbon has been estimated to be higher. For example, the US Government Interagency Working Group on Social Cost of Carbon estimates the social cost to be $39 per ton in 2015 increasing to $76 per ton in 2050 (2011$), assuming a 3% discount rate (EPA 2015c).

mitigation, price suppression, or demand reduction induced price effects (DRIPE). DRIPE benefits can be substantial, and inclusion of these benefits in program cost screening can increase the cost effectiveness of peak-focused programs by up to 15–20% (Synapse 2008). Also, like other utility system benefits, DRIPE benefits accrue to both participants and nonparticipants of utility-sponsored energy efficiency programs.

Currently, electric utilities in 15 states and the District of Columbia operate in competitive wholesale energy markets and rely on market purchases to meet retail customer demand.[9] The total population in these 16 jurisdictions represents nearly half of the total population of the United States. As of late 2014, 6 of the 16 jurisdictions calculate DRIPE benefits and include these benefits in cost-effectiveness screening for programs. Of the remaining 10 states, 9 do not include any DRIPE benefits in cost-effectiveness screening. California previously calculated market suppression effects in avoided cost beginning in 2004, but has not included these effects since 2006. This is due to the change in capacity constraints in California at the time. Evaluation of programs in California never included market suppression benefits in cost-effectiveness testing. For the 2015–2017 three-year program cycle, utilities in Maryland have filed energy and capacity DRIPE as a benefit used for program screening. However the exact values for capacity and energy DRIPE have been contentious in Maryland. The Maryland Public Service Commission is expected to rule on the DRIPE issue sometime in 2015. The New York State Energy Research and Development Authority (NYSERDA) includes DRIPE benefits in impact evaluations following a program year but does not use the benefit in program screening cost-effectiveness testing. Finally, stakeholders in Illinois have recently been engaged in discussions to include DRIPE benefits, but no utilities in the state have included DRIPE to date.

Six states and the District of Columbia are currently including energy or capacity DRIPE benefits in program cost screening. These include:

- Massachusetts
- Rhode Island
- Vermont
- Connecticut
- Delaware
- Maryland
- District of Columbia

DRIPE Benefits and Retail Customers

The level of benefits passed on to retail customers from load-serving entities operating in wholesale energy markets is dependent on several factors, including wholesale power contracts, retail rate-making structures, and energy procurement processes. Wholesale power contracts can require load-serving entities to pay fixed prices for energy for years at a

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[9] There are other states operating in competitive wholesale markets, but they are not unbundled retail choice states. For a utility to calculate DRIPE benefits, it would need to rely on market purchases to enjoy the benefits of reduced wholesale market energy prices. Therefore, utilities in states like Indiana, which serve retail load with self-scheduled generation resources, would not receive DRIPE benefits from energy efficiency.

time without change. Retail rate-making structures often insulate retail customers from large swings in market prices to avoid rate shocks. Finally, energy procurement plans, like those filed in Maryland and Illinois, require utilities to hedge against real-time market prices by entering into fixed-price contracts for short periods of time. Because of this process, retail customers may not see the benefits of DRIPE in rates for at least a year or two. DRIPE benefits can also benefit retail customers in regulated states, to the extent the utilities in these states rely on wholesale energy markets to meet demand. These costs are often collected in fuel-adjustment clauses or regional-transmission organization bill riders.

Methodologies to Calculate DRIPE Benefits

There are very few published methods to calculate DRIPE benefits. The AESC 2013 report relied on statistical methods at the state level based on various factors to determine energy DRIPE coefficients (AESC 2013). This approach allowed the application of a single coefficient as prices change. In Maryland, to determine future DRIPE benefits, market simulation models were used to forecast future energy and capacity values in specific zones located within regional transmission organizations (Exeter 2014). The simulations are conducted with and without energy efficiency to determine the difference in prices. The price difference in the zone is then adjusted to focus on the price difference in a specific utility territory. Statewide price impacts are also determined. One problem with this approach is it does not fully account for imports and exports, which can greatly impact prices.

DRIPE Uncertainty and General Acceptance

The decision whether or not to include DRIPE benefits in cost-effectiveness analysis has not been easy for regulators and stakeholders. For instance, Vermont only recently began including DRIPE benefits in cost-effectiveness screening, even though the results of the AESC showed economic benefits for Vermont ratepayers since 2005 (AESC 2005). In 2011, the Vermont Public Service Board (VPSB) issued a memorandum declining to include DRIPE benefits in cost-effectiveness screening (VPSB 2011). The board stated, "The benefits associated with DRIPE are offset by the reduction in payments to owners of generation resources resulting from lower market clearing prices" (VPSB 2014). The VPSB reversed this decision in 2014, deciding to include 50% of rest-of-pool DRIPE in the societal cost test. The VPSB decided to include only 50% of benefits to recognize the societal cost of reducing wholesale natural gas prices (VSPB 2014).[10] The other 50% is considered a transfer payment from other market actors to consumers.

The calculation of DRIPE benefits has also been a contentious issue in some jurisdictions. The previous example in Vermont highlights some of the issues associated with estimating what the future DRIPE benefits might be using different cost-effectiveness tests (i.e., societal versus utility cost test). Maryland recently completed an avoided cost study for the 2015–2017 three-year program cycle (Exeter 2014). The study included energy and capacity DRIPE

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[10] The VBSB based this conclusion on a 2011 Lawrence Berkley National Labs study filed by the Vermont Department of Public Service. The 2011 study highlighted the costs of reduced wholesale natural gas prices resulting from energy efficiency. These costs included reduced local, state, and federal taxes, as well as reduced payments to landowners.

benefits, but the level of benefits has been debated by the EmPOWER Maryland Planning group following the release of the study. In comments filed on August 18, 2014, the Maryland Office of People's Council (OPC) expressed concern about the final capacity DRIPE values being overstated (Chernick 2015). OPC disagreed with the methodology as presented in the study and took issue with capacity DRIPE values for 2015–2017 because prices for this time period were already being set by the PJM RPM process and therefore unable to be impacted by energy savings implemented then. The Public Service Commission Staff and Potomac Edison filed comments supporting OPC's assertion that capacity DRIPE benefits should not be included until at least 2018 because capacity prices have already been determined by the PJM RPM auction through 2018 (MEA 2014). In a recent order, the Maryland Public Service Commission has asked parties to file comments related to future cost-effectiveness screening (MPSC 2014). As of now, even with a statewide avoided cost study, differences exist between Maryland utilities regarding DRIPE values. For example, Potomac Edison did not include any DRIPE benefits in cost-effectiveness screening, while Baltimore Gas and Electric did include such benefits.

New England States

As part of a regional avoided cost study, several New England states have been calculating DRIPE benefits from energy efficiency programs since 2005. The study provides values for energy DRIPE, capacity DRIPE and, since 2013, natural gas DRIPE. In the 2013 study, energy DRIPE values ranged from $0.001/kWh in Maine during off peak to $0.024/kWh in Massachusetts during the winter and summer peaks.[11] Capacity DRIPE ranged from $0.062/kW-year in Maine to $34.07/kW-year in Massachusetts. Table 7 summarizes the results for the energy and capacity DRIPE for the New England States for 2015 measures.

Table 7. Northeastern United States 2015 vintage measures DRIPE

	Energy				Capacity
State	Winter peak ($/kWh)	Winter off-peak ($/kWh)	Summer peak ($/kWh)	Summer off-peak ($/kWh)	Annual value ($/kW-year)
Connecticut	0.008	0.010	0.008	0.009	16.72
Massachusetts	0.024	0.009	0.024	0.008	34.07
Maine	0.003	0.001	0.003	0.001	5.53
New Hampshire	0.007	0.004	0.007	0.004	6.92
Rhode Island	0.009	0.003	0.009	0.002	5.10
Vermont	0	0	0	0	0.62

Values are in 15-year levelized terms. *Source:* AESC 2013.

In 2013, the AESC study included the calculation of natural gas DRIPE. Natural Gas DRIPE is the economic benefit of reduced natural gas prices associated with reduced natural gas

[11] Vermont energy DRIPE was valued at $0.00/kWh all year. This is due to the fact that Vermont is not a retail choice state and utilities in Vermont are vertically integrated.

demand influenced by energy efficiency programs. The reduction of natural gas could happen at the end-use retail consumer's home or business or at a gas-fired electric generating station. The study estimated a 15-year levelized natural gas DRIPE value of $0.296 per MMBtu of natural gas avoided by a retail gas customer.

Illinois

Regulators in Illinois do not currently require program administrators to include DRIPE benefits in program screening. However recent analysis shows significant energy DRIPE benefits for utilities in the state. Analysis conducted for the Commonwealth Edison and Ameren Illinois service territories estimated the levelized DRIPE energy benefits would be approximately 20–40% of the avoided cost of energy (Chernick and Griffiths 2014). This range is for a measure life of 15 years and includes the effects of existing wholesale power contracts and the decay of energy DRIPE benefits over time. Measures with shorter lives would see even higher benefits. The range of potential benefits is explained by several factors. First, energy prices vary from peak times to off-peak times. Second, modeling assumptions on the geographic scope of the region's impact market prices for a specific company also varied. For example, the analysis produced different results for the energy DRIPE reduction as a percentage of avoided cost for Commonwealth Edison when including all of MISO or just the central region. Results were higher when considering only the central region.

Ohio

Currently, Ohio does not include DRIPE effects as a benefit of energy efficiency programs in cost-effectiveness screening. However a 2013 study analyzed the potential DRIPE effects as a direct result of the EERS in Ohio (Neubauer 2013). As a result of the Ohio EERS, the study estimated total cost-mitigation savings of $878 million between 2010 and 2020 for energy DRIPE. For capacity DRIPE, the study estimated savings of $1.3 billion over only the last four years of the same time period. The substantial DRIPE benefits in Ohio are benefits that would accrue to all ratepayers in the state through reduced market prices.

New York

New York does not currently calculate energy or capacity DRIPE effects as part of the efficiency program screening process. However NYSERDA does calculate price suppression benefits at the end of program years. The price suppression analysis conducted by NYSERDA is part of an analysis to determine the total macroeconomic benefits of all programs in the state. NYSERDA defines price suppression to be "the increased disposable income and lowered production costs to residential and business customers that result from the slightly lower system-wide wholesale electricity prices caused by efficiency installations" (NYSERDA 2011a). These benefits were calculated to be $34,600 per GWh of electricity avoided per year since mid-2006 (NYSERDA 2011a). In another NYSERDA report quantifying the benefits of combined heat and power or distributed generation resources, the agency found capacity DRIPE values to range from $180/kW-year for upstate New York to $600/kW-year for downstate New York. Energy DRIPE values were estimated to be $12.87/MWh (NYSERDA 2011b).

Maryland

Both energy and capacity DRIPE was estimated in the 2014 Maryland avoided cost study. However not all Maryland stakeholders agreed with the methodologies used in the study, and one utility did not include DRIPE benefits in program screening. The energy and capacity DRIPE assumptions in Maryland are currently under review by the Public Service Commission with an order expected later this year. Energy DRIPE values were as high as $14/MWh for Baltimore Gas and Electric. These values were highest in earlier years and decayed over time.

Figure 11 shows the forecasted capacity DRIPE values in Maryland for measures installed in 2015. The initial estimated avoided capacity DRIPE in Maryland is substantial, often exceeding the avoided cost of capacity for most Maryland utilities. Potomac Edison was the only Maryland utility with estimated capacity DRIPE lower than the avoided cost of capacity through 2020.

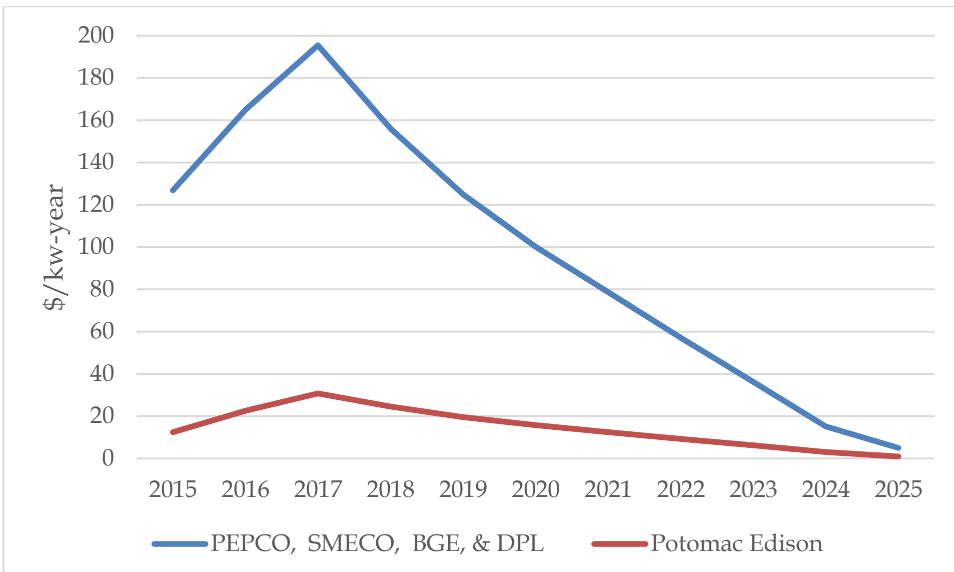

Figure 11. Capacity DRIPE values in Maryland for measures installed in 2015.
Source: **Exeter 2014.**

UTILITY NONENERGY BENEFITS

Nonenergy benefits (NEBs), also known as nonenergy impacts (NEIs) or other program impacts (OPIs), are the benefits of energy efficiency programs not directly related to energy. Significant study and attention has been given to the societal NEBs provided by energy efficiency programs. These benefits include improved comfort, reduced illnesses and deaths from power plant emissions, improved productivity, and many others. In addition, NEBs also accrue to utilities directly in the implementation of energy efficiency programs. These benefits typically include reduced costs associated with service interruptions as low-income customers' reduced utility bills result in fewer situations of nonpayment of an electricity bill. Other utility sector NEBs from utility programs include reduced carrying costs associated with reduced arrearages and longer T&D component life due to lighter loading.

Most utility NEBs are associated with low-income programs. Reduced costs of service interruptions and carrying costs for arrearages are both benefits realized through the implementation of low-income programs.

Very few jurisdictions or states in our review included utility-specific NEBs in program screening. According to our review of existing literature, only Rhode Island, New York, and Massachusetts explicitly calculate utility-specific NEBs (Woolf 2013). Several other states use an adder approach that included NEBs without explicitly quantifying them. This approach adds a fixed percentage of total benefits to assume NEBs. However it is not clear if utility-specific NEBs are considered to be included in the added benefits in this approach. Table 8 summarizes states utilizing the adder approach.

Table 8. Nonenergy benefit adders

State/company	Nonenergy benefit adder
Colorado	10% (25% for low-income programs)
Iowa	10%
DC	10%
Vermont	15%
PacifiCorp	10% for low income (CA, ID, OR, UT, WA, WY)

Source: Daykin 2011; Skumatz 2010

One of the most commonly cited evaluations of utility-specific NEBs was presented in a 2010 report to the California Public Utility Commission conducted by the Skumatz Economics Research Associates (SERA) (Skumatz 2010). The review of existing quantitative literature presented in the report highlighted 13 different utility perspective NEBs. Many of the benefits had been very rarely studied or examined. For some of the benefits (including carrying charges on arrearages, bad debt written off, shutoffs, reconnects, customer calls, and insurance savings), annual per-participant values were presented. The carrying charges on arrearages and bad debt written off were the highest value NEBS for low-income programs ranging from $2 to $100 per participant. The report concluded these benefits were less than 10% of total NEBs in most cases. However the authors note that utility NEBs are not substantial, mainly because many of the categories of potential benefits have not yet been studied.

In Massachusetts, a 2011 statewide study has provided the basis for NEB estimations (NMR 2011). The study relied on thorough literature reviews, company data, and interviews to determine Massachusetts-specific utility NEBs. Almost all of the utility NEBs explored in this study were related to the implementation of low-income programs. The study recommended specific values per participant per year for several NEBs. Table 9 presents the recommended annual values in Massachusetts from the 2011 NMR study.

Table 9. Massachusetts utility NEB value recommendations ($/MWh)

NEB	Annual value
Arrearages	$2.61
Bad debt write-offs	$3.74
Terminations and reconnections	$0.43
Customer calls	$0.58
Collections notices	$0.34
Safety-related emergency calls	$8.43

Source: NMR 2011

A recent study of NEBs in Maryland recommended using a value of 2% of the kWh savings for each low-income weatherization project (Itron 2014). The 2% value only includes reduced utility carry costs associated with arrearages. This estimate was noted to be conservative in that it was at the bottom quartile of estimates in existing literature for reduced arrearages. The recommendation was based on literature reviews and an assessment of the methods used in pervious literature to ensure results would apply to Maryland. The primary method relied on comparing the differences in arrears between a group of customers who participated in the low-income program and those who did not. The Maryland study also noted the results from the 2010 SERA California study were comparable with the results presented in the 2011 Massachusetts study. The Maryland study did not recommend a value to account for any other utility-specific NEBs, but did estimate and recommend values for several other NEBs such as comfort, reduced air emissions, and reduced operations and maintenance costs.

A 2009 evaluation of a low-income weatherization program also demonstrated utility NEBs (Cadmus 2009). The report determined the program was responsible for a reduction of $870,000 in arrearage balances. While the report does not document what the reduced cost to the utility would be from the reduction in arrearage balance, it can be assumed there was a cost associated with carrying this balance.

AVOIDED COST OF RENEWABLE PORTFOLIO STANDARD COMPLIANCE

Thirty states and Washington, DC mandate electric suppliers to obtain a certain percentage of generation from renewable sources. The renewable portfolio standard (RPS) policies differ from state to state. As energy efficiency programs reduce energy demand, the level of energy required from renewable resources in these states will also be reduced. This will allow utilities to avoid some of these costs associated with meeting the RPS goal. While this benefit was not common in our review of avoided costs used in program screening, some states did estimate the avoided cost of RPS compliance.

Avoided RPS compliance costs were included in the 2014 Maryland avoided cost study. The avoided cost was based on estimating the future prices of renewable energy credits (RECs) to Maryland utilities and then multiplying this price by the annual percentage requirement for each type of REC. RECs in Maryland are differentiated by the type of renewable generation. Solar RECs are of the highest value, and then Tier 1 followed by Tier 2. Each

REC represents a MWh of renewable energy. The estimated avoided renewable energy prices are presented in figure 12.

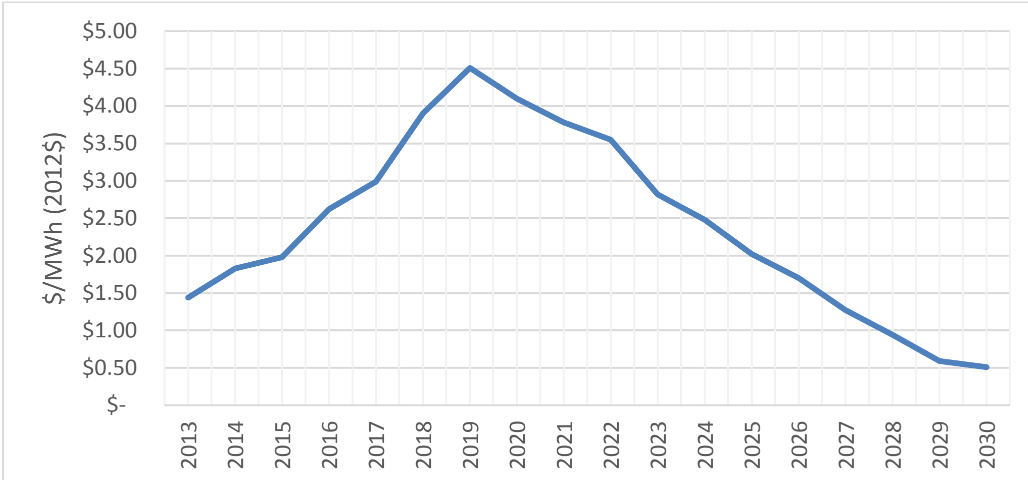

Figure 12. Maryland avoided renewable portfolio standard compliance cost. *Source:* Exeter 2014.

Avoided costs of RPS compliance are also included in the New England Avoided Energy Supply Cost study. This study assumes full compliance with RPS standards for each load-serving entity in the study. Similar to the Maryland avoided cost study, the avoided RPS compliance cost was assumed by multiplying the cost of RECs by the annual percentage of load that must be served using RECs. REC prices are estimated using market prices in 2013 and 2014. For the later years, the incremental cost of new energy for renewable sources is used to determine the projected REC value. The estimated avoided cost of compliance is presented in figure 13 for each state in the AESC 2013 study. Vermont is estimated at $0 because the state does not have a binding RPS.

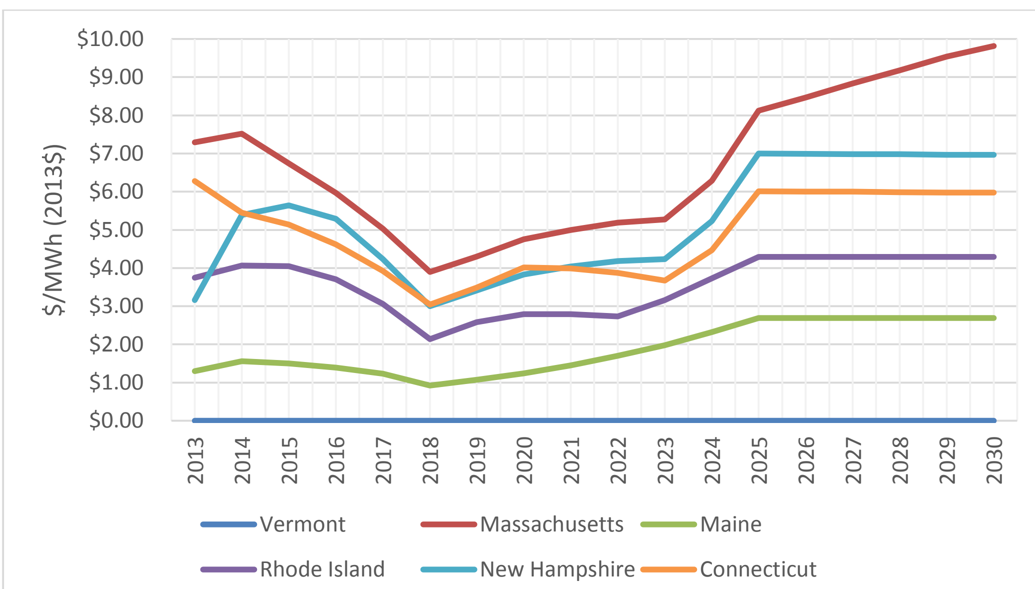

Figure 13. New England avoided renewable portfolio standard compliance cost. *Source:* AESC 2013.

As examples in Maryland and New England demonstrate, there are real avoided costs of RPS compliance in states with such policies. The 30 states that have RPS policies should quantify and include this benefit in program cost-effectiveness screening.

OTHER POTENTIAL BENEFITS

This report is not an exhaustive list of the utility system benefits accruing from efficiency programs. We have attempted to capture different methodologies for the most prevalent benefits being used across the country. Aside from the traditional utility system benefits discussed above, other benefits include increased reliability, reduced levels of risk, and fuel price hedging. Most of the other potential benefits are focused on the reduction of utility risk. A recent report on the risks associated with various utility generation options cited energy efficiency as the option with the least risk (Ceres 2014).

Very few companies include the benefits associated with reduced utility risk in cost-effectiveness screening. No states or companies we reviewed explicitly calculated this benefit. However some states have considered risk benefits when determining the nonenergy benefit adders presented in table 9 and in determining discount rates used for program screening.

Increased Reliability

Energy efficiency savings reduce peak demands and the strain on the utility system during hours of peak demand. The reduced demand on the system can prevent rolling blackouts. While it can be very difficult to quantify the benefits of reliability, the economic costs of power outages, even ones lasting only hours, can be substantial. The 2003 blackout in the northeastern United States resulted in losses of approximately $6.4 billion (Anderson 2003). While this example is of an extreme event, it nonetheless demonstrates the significant economic losses occurring from blackouts. While any system resource could reduce demand to prevent blackouts, energy efficiency can often reduce peak demand at the lowest cost (Molina 2014). No companies or states we reviewed quantified this benefit for cost-effectiveness screening.

Reduced Utility Risk

Energy efficiency programs have the ability to reduce utility risks on several fronts. First, utility risk of construction cost overruns is reduced when new power plants are avoided or deferred. Construction cost overruns for new power plants are not uncommon. Construction cost overruns are also not uncommon in new transmission projects. Energy efficiency investments have the ability to reduce or eliminate this risk if construction projects are avoided or deferred.

Energy Efficiency as a Fuel-Price Hedging Strategy

To avoid the risks associated with exposure to fluctuations in fuel prices, many utilities engage in fuel-price hedging. There are many fuel-price-hedging strategies available to electric utilities. Companies can enter into short- and long-term fuel-price contracts to lock in prices. Companies can also engage directing in natural gas or coal extraction to mitigate market price risks. Energy efficiency can also act as a fuel-price hedge through reduced demand at a known cost.

Energy Efficiency as a Fuel-Supply Risk-Reduction Strategy

Increased energy efficiency has the ability to reduce the level of fuel necessary for a utility at a given time. A demand reduction during peak times reduces the fuel-supply risk some utilities face because of constrained natural gas pipeline capacity. Natural gas pipelines are especially constrained in the Northeast and have led to high wholesale spot prices in the region during high-demand days. For example, PJM experienced significant generator forces outages due to natural gas supply interruptions during the polar vortex of January 2015. Wholesale energy prices increased dramatically partly because of the fuel supply interruptions caused by extreme cold.

Discount Rates

The discount rate used in cost-effectiveness screening can have a significant impact on the evaluation of energy efficiency programs. Discount rates are used to calculate the net present value of benefits for a program or measure producing energy savings over multiple years. Typically, an energy efficiency program will incur all costs in the first year but accrue benefits for several years thereafter. Discount rates are typically assumed to include the time value of money and assumptions regarding future risk of an investment. Discount rates can also be expressed in real or nominal terms. There is no best practice in terms of using nominal or real discount rates, but it is important to ensure the avoided costs are in the same terms as the discount rate.

In cost-effectiveness screening, the most common discount rate for the total resource cost test and the program administrator cost test is the utility weighted average cost of capital (WACC). The WACC is a rate usually set in a utility base-rate case. The rate is calculated using the weighted average of the cost of debt and the cost of equity. The cost of equity is a heavily litigated value and generally represents the perceived risk of investment in a given utility. Utilities receive lower return on equity rates when they are viewed favorably by credit rating agencies and are considered low-risk investments. This is not always the case as the Federal Energy Regulatory Commission often rewards transmission investment with higher return on equity rates.

In a recent report on best practices in energy efficiency program screening, Synapse Energy Economics proposed using a lower discount rate than the WACC to evaluate energy efficiency investments. The authors asserted that efficiency investments are a much lower-risk investment than traditional utility capital investments and should be evaluated as such. They also pointed out financing for efficiency programs typically does not come from traditional utility rate recovery mechanisms but is instead recovered through bill riders, a much less risky alternative. Thus the WACC is not an appropriate discount rate to evaluate efficiency investments. Instead, the authors recommend using the interest rate on long-term US Treasury Bills as the discount rate for the TRC and PAC tests (Woolf 2013, 53).

As stated above, our review found most states and utilities use the utility WACC for the TRC and PAC tests. While the pretax WACC should be used, this is not always the case. Some utilities use the after-tax WACC as well. There was some variation in discount rate, but this was premised on differences in the primary test used to evaluate programs. For instance, in Washington, DC and Vermont the primary test is the societal cost test. Both of these states rely on a lower societal discount rate. New Hampshire relies on the prime rate

(2.46% real), a much lower rate than any utility WACC. Massachusetts relies on the TRC test to screen programs but uses the 10-year treasury rate (0.55% real) instead of the WACC (Woolf 2013).

The utility WACC values are generally much higher than the 10-year treasury rate or the prime rate. Our review found most utility WACC rates were between 5% and 10%. Table 10 presents a sample of some utility WACC values. These show a mix of WACC values including both net of tax and with tax. While the difference among values is only a few percentage points, these can cause significant changes in net benefits calculations.

Table 10. Weighted average cost of capital

Company	WACC
Texas New Mexico Power	9.90%
Consumers Energy	9.78%
Pennsylvania Power and Light	8.14%
Indiana Michigan Power	7.92%
Northern States Power Co. South Dakota	7.79%
Southwestern Public Service	7.48%
Vectren Energy Delivery	7.29%
Northern States Power Co. Minnesota	7.15%
El Paso Electric Company	7.08%
San Diego Gas and Electric	6.87%
Northern Indiana Public Service	6.54%

Conclusions

We are able to draw several conclusions following the collection and review of various state policies and utility practices in avoided cost assumptions and calculations. First, the methodological approach to calculating utility system benefits is diverse. In states lacking specific methodological approaches or even definitions, significant differences exist between utilities. These differences can cause problems with comparability of program results within a state or among utilities in different states. Differences in assumptions, methodologies, and benefits greatly impact the net present value of the benefits in cost-effectiveness testing. While we would expect each utility to differ in avoided cost values because of location, generation mix, and other factors, in order to accurately compare programmatic performance among utilities in a state or nationally, common avoided cost methodologies should be employed.

A second conclusion we draw from this research is that nonparticipants benefit substantially from energy efficiency programs. While nonparticipants do not receive the immediate benefit of a bill reduction like participants do from installing energy efficiency measures, nonparticipants receive the economic benefit of reduced rates in later years because of the decision to pursue the least-cost, least-risk resource of energy efficiency.

A final significant conclusion we draw from this research is that many utilities and states exclude critical, substantial benefits from cost-effectiveness screening of programs. Over the course of our review, we found many occasions in which substantial benefits, such as avoided T&D, DRIPE, and avoided RPS compliance, are not quantified as a benefit of efficiency programs. Exclusion of benefits will adversely affect the program screening process and will result in a utility pursuing higher-cost, less-efficient resources to meet customer demand. This will raise rates on all customers in a utility system.

Best Practices for Utility System Benefit Assumptions

Each state and utility has a different approach to calculating benefits in energy efficiency programs. Some exclude real and valuable benefits in their energy efficiency potential studies and program planning, a practice that can adversely affect optimal program selection. This section offers some best practices and advice to program administrators who are quantifying efficiency program benefits.

- Provide transparent information related to the data and assumptions for the determination all utility system benefits. The assumptions include but are not limited to natural gas price forecasts, avoided capacity costs, real versus nominal dollars, average versus marginal line losses, and discount rates.

- If cost allows, utilize a long-term system-planning approach using dispatch modeling to determine the most accurate avoided cost of energy. While using other estimates such as publicly available price forecasts may be less expensive, a systems modeling approach will produce the most specific values for a specific utility or service territory.

- Calculate energy savings at the generator level using marginal, not average, line losses, to ensure inclusion of all relevant line-loss savings. These savings can be substantial and represent an average of 10% of avoided energy cost. This can be done in addition to publishing premise-level savings estimates, which are often the values used for establishing energy efficiency targets.

- If using locational, marginal price market level data to forecast avoided energy cost, be mindful that line losses are a component in this price. Including additional line losses would be double-counting line losses, but the correct calculation is the marginal loss, not the average loss often used for LMP development.

- Instead of relying on a single natural gas price forecast, utilities should consider several natural gas forecasts to evaluate risks associated with various price forecasts.

- Differences in seasonal and time-of-day energy prices should be accounted for in avoided energy cost to calculate the most accurate avoided cost of energy possible.

- Include the reserve margin adjustment when calculating the avoided cost of capacity. If capacity can be avoided, the reserve capacity for the avoided capacity is also avoided. Reserve margin values often represent 10–15% of the capacity value making the inclusion of this component significantly valuable.

- Calculate the avoided cost of capacity for both the short and long term. In the short term, a combustion turbine may be used as an avoided capacity cost. However, in the long term, a combined-cycle gas turbine may be used. These two units have differing capital and operating costs. A combustion turbine, while less expensive to construct, has higher operating costs and faces limitations in annual operating hours.

- Use best available information to calculate avoided cost of T&D. Although this benefit can be difficult to quantify because of the locational character of the benefits, excluding these benefits excludes substantial real benefits of energy efficiency.

- Include the cost of current and future environmental compliance as a benefit when using the TRC or UCT, unless these costs are already embedded in forecasted energy prices. These avoided costs are real avoided costs to a utility and are expected to increase once 111(d) is implemented.

- As previous literature has shown, the value of utility-specific NEBs is evident, mostly for low-income programs. Companies should include these benefits in cost-effectiveness screening. If the resources are unavailable to complete a jurisdictional specific study, previous estimates assumed from literature reviews can be used, as is the case in Maryland and Massachusetts.[12]

- Choose a discount rate reflecting the reduced risk associated with energy efficiency investments, not the higher risk associated with utility investments. As detailed in the next section, choosing a high discount rate that does not reflect this reality can adversely affect cost-effectiveness screening of programs. Discount rates also should represent the real opportunity cost for the program administrator.

- Assure all calculations are consistent with respect to use of real or nominal values. If using a real discount rate to calculate net present value of benefits, also use real avoided cost data.

Cost Effectiveness and Utility System Benefits

OVERVIEW

The decision as to of which benefits to include in cost-effectiveness testing can have substantial impacts on whether programs pass cost-effectiveness criteria and ultimately which programs are offered. To demonstrate the impacts of the inclusion of various utility system benefits in program screening, we have completed cost-effectiveness testing on a hypothetical program. Our hypothetical program has a measure life of 10 years, 4,500 MWh of annual energy savings, and 616 kW of demand savings. For the cost-effectiveness tests, we used a whole house shell load shape. This type of load shape would be used to measure the benefits of a typical residential retrofit program.

[12] The Maryland values have not yet been approved by the Maryland Public Service Commission.

To calculate the net benefits of our hypothetical program, we utilized the publicly available avoided cost data for Baltimore Gas and Electric presented in the 2014 report *Avoided Costs in Maryland* (Exeter 2014). We used publicly available load shape data for the Baltimore area. As this report has focused on the utility perspective, we present the results from the utility cost test perspective. This test focuses on energy efficiency program costs and benefits from the perspective of the utility system alone.

To determine the impact of each benefit discussed in this report, we calculated the net benefits of our hypothetical program under 10 different scenarios. Each scenario includes different benefits but usually builds on the previous scenario. For example, in the first scenario, we calculated net benefits using only the avoided cost of energy with no assumed line losses. For the second scenario, we added avoided capacity costs but did not include reserve margin adjustments or losses. We calculated the net benefits in this way to determine the impact of each incremental change in which utility system benefits were included in program screening. Table 11 details the benefits included in each scenario.

Table 11. Benefits included in each scenario

Benefit	Scenario									
	1	2	3	4	5	6	7	8	9	10
Avoided energy with no losses	●	●								
Avoided capacity with no losses		●								
Avoided energy & capacity with average losses			●							
Avoided energy & capacity with marginal losses				●	●	●	●	●	●	●
Avoided T&D					●	●	●	●	●	●
Avoided capacity DRIPE						●	●	●	●	●
Avoided energy DRIPE							●	●	●	●
Avoided energy with avoided RPS								●	●	●
2% avoided arrearage adder									●	
10% nonenergy benefit adder										●

RESULTS

The results show substantial increases in the present value of benefits for each change in utility system benefits. Figure 14 presents the net present value of benefits and the cost for each scenario in our hypothetical program. We assume a nominal discount rate of 7%, a common rate used by the utilities in our limited review. Each bar represents the net present value of benefits calculated under each scenario. The orange bar represents the cost of the program. This exercise highlights the importance of several benefits not commonly included in program screening.

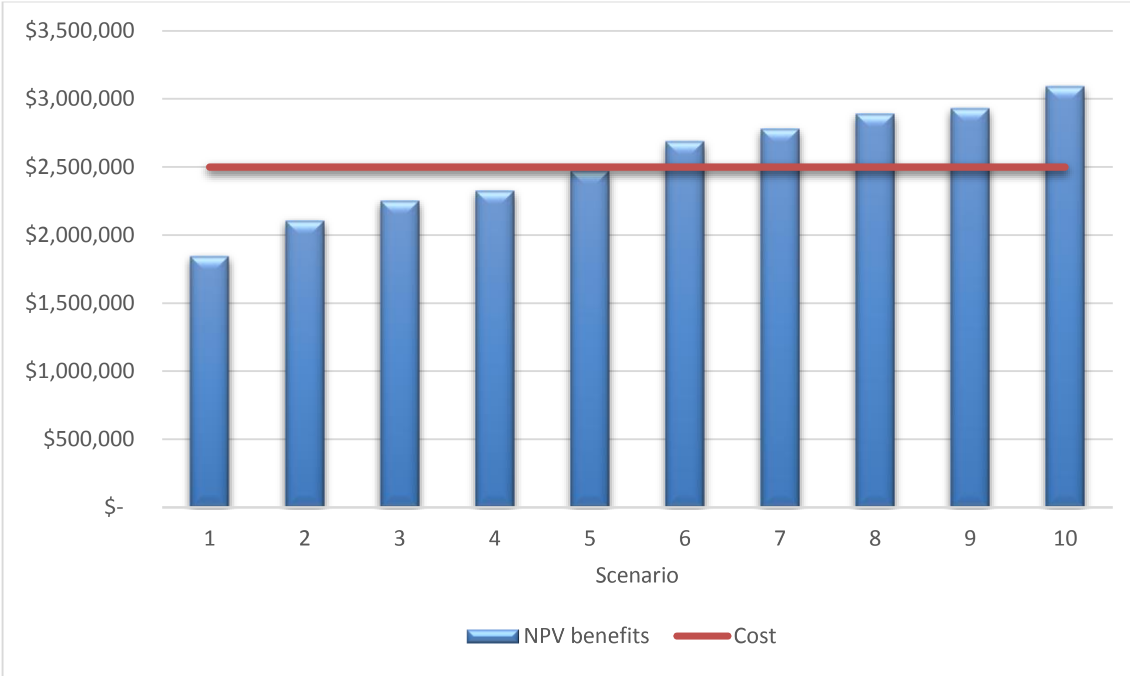

Figure 14. Hypothetical program net present value benefits and cost assuming a 7% discount rate

In our research, we found several companies and states not including avoided T&D benefits in program screening.[13] Including the avoided cost of T&D increased the net present value of benefits by $145,738 in our example. This value represents 5.8% of the total cost of the program. The avoided T&D value used in this example was $31.49 per kW-year and was fixed throughout the analysis period. This value falls in the low range, with 70% of estimates we reviewed with a higher estimated value.

In our review of benefits used to screen programs, not all utilities were using marginal losses but were instead using average losses. The net present value difference between scenarios 3 and 4 is approximately $73,261, or 2.9% of the total cost of the program. The difference between the two scenarios represents the difference between using average and marginal losses. The inclusion of energy and capacity DRIPE benefits also had a large impact on our results. The addition of energy and capacity DRIPE increased the net present value of benefits by $363,518, representing 14.5% of total program cost. Our research found that only 6 out of 14 possible states (including DC) used this benefit in program screening.[14]

Scenarios 9 and 10 are designed to show the difference in cost effectiveness in states using adders for specific programs. For example, scenario 9 included a 2% adder on avoided energy costs to account for the reduction in arrearage costs for a utility (this value would only be applicable to a low-income program). This value was based on a recent

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[13] Our limited review showed six jurisdictions assuming a value of $0 for avoided T&D. These jurisdictions include: Idaho Power, Arizona Public Service, Wisconsin Focus on Energy, Indiana Michigan Power, State of Texas, and Consumers Energy.

[14] Massachusetts, Rhode Island, Vermont, Connecticut, Delaware, Maryland, and the District of Columbia.

recommendation made in Maryland that has not yet been considered by the Public Service Commission (Itron 2014). The marginal benefit of including a 2% adder to avoided energy cost for arrearage costs increased the net present value of benefits by $40,459 from scenario 8. Several states also include a fixed percentage adder to account for all NEBs, including benefits specific to a utility or program administrator. The increase in net present value benefits is $202,297 over scenario 8 when including the 10% adder to avoided energy costs. This change represents 8.1% of total program costs for this example.

The results in figure 14 demonstrate the effect of including different utility system benefits in cost-effectiveness testing. Our hypothetical program would not have passed program screening under scenarios 1 through 5. Only after adding capacity DRIPE did our hypothetical program benefits exceed the costs. This analysis is dependent on values assumed for each benefit.

Discount Rate Sensitivity Analysis

The results presented above were calculated using a nominal 7% discount rate. We also wanted to understand the impact of applying different discount rates to the program under different scenarios. We conducted sensitivity analysis for all 10 scenarios using four discount rates: 2%, 5%, 7%, and 10%. The range of discount rates used in this analysis represents the range of discount rates we observed in our research. For example, a real 2% discount rate mirrors the rate utilized by Focus on Energy in Wisconsin. The 10% rate is approximately what Texas New Mexico Power uses.

Table 12 shows the results of the discount rate sensitivity analysis. This table shows the 10 scenarios under 4 different discount rates. Of the 40 cost-effectiveness outcomes for our hypothetical program, 25 of 40 passed cost-effectiveness testing. To pass cost-effectiveness testing, the cost-benefit ratio of net present value of costs and benefits must be greater than 1. This is indicated in green in table 12. Red indicates the program failed cost-effectiveness testing. The hypothetical program only passed cost-effectiveness testing under the 7% discount rate after including approximately half of the benefits. The program passed without the inclusion of either nonenergy benefit adder. The program did not pass under the 10% discount rate until scenario 7, the inclusion of energy and capacity DRIPE.

Table 12. Hypothetical program benefit cost ratio results under discount rate sensitivities

Scenario	Discount rate			
	2%	5%	7%	10%
1	0.90	0.80	0.74	0.66
2	1.03	0.91	0.84	0.76
3	1.10	0.97	0.90	0.81
4	1.13	1.00	0.93	0.83
5	1.21	1.07	0.99	0.89
6	1.32	1.16	1.07	0.96
7	1.35	1.20	1.11	1.00

Scenario	Discount rate			
	2%	5%	7%	10%
8	1.41	1.25	1.16	1.04
9	1.43	1.26	1.17	1.05
10	1.51	1.33	1.24	1.11

Examining Benefits of Energy Efficiency in Integrated Resource Planning

The economic benefits of efficiency from a utility-planning perspective are substantial. To determine the level of benefits utility systems receive from efficiency programs, we conducted a limited review of recent integrated resource plans. The benefits of energy efficiency are most clearly outlined in utility resource plans that model the total costs of a system with and without efficiency over a given period of time. This approach shows a clear distinction between the two options and provides a specific value of what the cost difference would be for a utility system with and without energy efficiency. In a resource-planning scenario without energy efficiency, a utility must pursue higher-cost resources to meet forecasted customer demand.

WHAT IS INTEGRATED RESOURCE PLANNING?

Integrated resource plans (IRPs) are planning studies produced by electric utilities to determine resource needs over a given planning period. The planning period is generally between 10 and 20 years. Methodologies used in the studies vary but are usually based on system dispatch models to produce the least-cost, least-risk resource balance. IRPs consist of several sub-studies as well. The following list contains a partial summary of some of the studies typically performed as part of an IRP:

- Customer energy and peak demand forecast
- Generation technology cost study
- Energy efficiency market potential study
- Distributed generation feasibility and cost study
- Risk analysis for generation technologies or fuel types
- Reliability studies
- Market price forecasts for energy and capacity

Upon completion of these studies, system dispatch models are run for many resource planning scenarios. Scenarios are often sensitivities of different assumptions. For example, a utility may run several scenarios based on different assumptions in natural gas price changes or changes in load growth. The different scenarios are compared using a net present value of revenue requirements analysis. A revenue requirements analysis presents the total cost of service annually for a utility for the study period. These costs include taxes, return on investment, and other financial considerations of providing electric service. Finally, the scenario annual revenue requirements are presented as a net present value to allow for direct comparison of each scenario. A utility will theoretically choose to pursue the least-cost, least-risk scenario.

MODELING ENERGY EFFICIENCY IN INTEGRATED RESOURCE PLANS

IRPs utilize different approaches in considering energy efficiency or other demand-side resources. Some IRPs will forecast load reductions attributable from energy efficiency and adjust the load forecast downward prior to determining which resources will be necessary to serve future demand. Other IRPs will model the inclusion of energy efficiency on a similar basis to supply-side resources or market purchases. Some IRPs will also model different levels of efficiency at different cost points to evaluate the impact of greater levels of efficiency. Whether energy efficiency is modeled on the supply or demand side, many assumptions must be made to determine the future impact of energy efficiency.

INTEGRATED RESOURCE PLAN CASE STUDIES

In our review, we examined four IRPs to determine the impact of the inclusion of energy efficiency on utility system costs. We reviewed IRPs from Northern Indiana Public Service Company (NIPSCO), Tennessee Valley Authority (TVA), PacifiCorp, and Ameren Missouri (Ameren). The four IRPs were selected because each of the four studies includes results for scenarios with differing levels of energy efficiency deployment. The NIPSCO IRP presents results with and without energy efficiency. The remaining three present results with various levels of energy efficiency. All four IRPs presented results in terms of the net present value of revenue requirements for the system over the planning period.

CONCLUSIONS OF INTEGRATED RESOURCE PLAN REVIEW

We reviewed the impact of energy efficiency on utility resource planning in four IRPs. The IRPs reviewed represent resource planning in jurisdictions in 15 states serving over 12.5 million electric customers. The results presented in the four IRPs above demonstrate that resource plans favoring higher levels of energy efficiency provide the lowest-cost resource strategy with the lowest level of risk for customers in those jurisdictions. The difference in present value of revenue requirements between plans favoring efficiency and those not was substantial, resulting in cost savings to ratepayers over the forecasted time period. Table 13 shows the results of our review.

Table 13. Value of energy efficiency in integrated resource plans

Company	Year	Net value of EE in IRP*
Northern Indiana Public Service	2014	$325 million
Tennessee Valley Authority	2011	$2 billion
Ameren Missouri	2014	$2 billion
PacifiCorp	2013	$190 million

The values presented in the table are in different terms. NIPSCO is in 2013$, TVA 2010$, Ameren Missouri 2013$, and PacifiCorp 2012$. *The value of EE in the PacifiCorp IRP is the value of pursuing an accelerated deployment strategy. The utilities are very different sizes, so the relative savings are not shown. This strategy does not include higher levels of efficiency than others analyzed in the IRP.

The NIPSCO IRP modeled efficiency as a resource in predetermined blocks of capacity. NIPSCO only included efficiency programs from its most recent market potential study, which was not expansive enough to permit measurement of a full range of potential benefits. Even with a very limited level of energy efficiency, the inclusion of five efficiency programs with modest savings produced savings of $325 million in net present value terms. NIPSCO also projected reliance on market purchases in later years that may be offset by increased efficiency.

The 2011 TVA IRP modeled future scenarios based on five different energy efficiency contribution assumptions. Unlike NIPSCO, TVA did not present results of a plan without energy efficiency. In the future scenario relying on the highest level of energy efficiency, TVA analysis projected savings of approximately $2 billion. TVA scenarios with lower levels of energy efficiency were much higher cost than scenarios with lower levels of efficiency.

Ameren Missouri modeled three energy efficiency scenarios, two scenarios from a recent market potential study and one scenario with no new efficiency programs after 2015. The difference between the low scenario from the latest potential study and no new programs after 2015 was a savings of approximately $2 billion for Ameren customers over the study period. The savings were an additional $500 million higher assuming the high scenario from the market potential study. However Ameren ultimately pursued the low scenario from the market potential study still resulting in cost savings to customers of approximately $2 billion in present value terms over the study period.

PacifiCorp has the lowest value of energy efficiency in IRP in table 13. This value is misleading because PacifiCorp did not offer results of modeling scenarios with and without efficiency. Instead, the company compared the results of two energy efficiency scenarios assuming different deployment rates. The accelerated deployment scenario resulted in savings to customers of $190 million in present value terms over the study period. While PacifiCorp did not pursue an accelerated energy efficiency strategy, ratepayers will still see substantial cost savings through the pursuit of energy efficiency.

All four IRP reviews demonstrate the significant value of energy efficiency as a resource that lowers costs for all customers. The IRP results demonstrate that energy efficiency provides real economic benefits to a utility and its customers. These benefits are enjoyed by all ratepayers through the reduction of rates over time as revenue requires decrease.

The results of the IRP review also indicated the short-sightedness of using a ratepayer impact measure test to evaluate programs.[15] The ratepayer impact measure test (RIM) is meant to measure the impact of electric rates resulting in changes to utility revenues from the implementation of efficiency programs. The NIPSCO and Ameren IRPs presented the RIM test results for the programs included in the IRP analysis. For both utilities, no programs passed the RIM, indicating that the implementation of the programs would raise customer bills. In both cases, however, the inclusion of the energy efficiency programs reduced revenue requirements over time, reducing customer bills in the forecasted period. These two studies present strong evidence that the RIM test does not accurately reflect changes in customer rates over time and should not be considered when screening

[15] According to the National Efficiency Screening Project, the RIM test is not recommended as a test to screen energy efficiency resources (National Efficiency Screening Project 2014).

programs. The RIM test is also inconsistent with the way supply-side resources are analyzed in an IRP context.

Further Research

While the limited review of available information on utility system benefits from energy efficiency programs answered many questions regarding the breadth of benefits available, the review also posed many new questions for future research. Little research has been conducted on the direct rate impacts of energy efficiency to nonparticipants of utility programs. This research clearly demonstrates the benefits to nonparticipants, but does not attempt to quantify these benefits in terms of direct rate impacts over time. As our limited review of integrated resource plans demonstrate, the RIM test does not accurately quantify the rate impacts to nonparticipants. While the analysis would be challenging and the results would vary by utility, an examination of this issue through case studies would provide valuable information on the level of benefits received by nonparticipants.

The issue of timing is one challenging factor in estimating the benefits to nonparticipants of utility programs. Participants see immediate benefits in through reduced bills while nonparticipants do not immediately receive the utility system benefits discussed in this report. The slight delay in receiving some benefits may diminish the overall value of the benefits. More research is required to determine the cost of the delay in benefits.

Most jurisdictions do not include all utility system benefits examined in this report in program screening. Even key significant benefits such as avoided T&D were excluded from cost-effectiveness screening for many of the reviewed jurisdictions. Reasons for excluding these benefits likely vary by jurisdiction, but an examination of these reasons would be beneficial to understand why jurisdictions are excluding key benefits. The results of this review could also provide valuable insight to policymakers as they decide which benefits to include in program screening.

Recommendations to State Utility Regulators

Our review of utility system benefits gives rise to several recommendations for state utility regulators. These emphasize the inclusion and transparency of all relevant benefits of energy efficiency. Our review shows that even in the most advanced states, improvements can be made in determining utility system benefits.

First, state utility regulators should require long-run analysis for utilities or program administrators calculating utility system benefits. In the short run, costs may be both variable and fixed, but in the long run, most costs are variable, meaning these costs can be avoided. Resource decisions also change in the long run. Xcel Energy Colorado is an example of one utility considering differences in avoided costs in long-run analysis to determine program benefits.

Second, state utility regulators should require all utilities to be transparent in terms of assumptions, analysis, and calculations of utility system benefits. One of the most significant research difficulties we faced during this project was a lack of transparency from utilities in presenting assumptions, analyses, and calculations. A lack of transparency makes it very difficult for stakeholders to evaluate approaches and assumptions used by utilities.

Third, state utility regulators should be consistent in terms of the discount rate used to determine net benefits of programs. Our research showed some utilities using a net-of-tax WACC, while others were using a with-tax WACC. State commissions should require consistency in terms of the discount rates used by regulated companies. In the UCT, the net-of-tax discount should be used to calculate net benefits.

Finally, state utility regulators should require the inclusion of all quantifiable utility system benefits in the evaluation of energy efficiency programs. Specific guidance should be given to utilities and program administrators to calculate the benefits to ensure consistency among entities in the state. If possible, state or region-wide benefits studies, such as those of California, Maryland, and New England, are the best approach to ensuring consistency. As detailed in this report, utility system losses, accounting for avoided reserve margins, utility system nonenergy benefits, and market-price suppression are all real benefits and should be included.

Conclusion

This review of utility system benefits from energy efficiency programs demonstrates substantial advantages to all ratepayers in the system. Not only do program participants directly benefit through bill reductions, but all ratepayers benefit through reduced utility system costs that translate into lower rates over time. Past studies have demonstrated that these benefits are real and quantifiable. They should be included in program screening to **ensur**e that maximum levels of cost-effective energy efficiency are available for utility resource optimization.

If administrators exclude significant benefits from program screening, they may inadvertently choose not to offer a program which could provide measurable positive net benefits to all ratepayers in a utility system. While the value of some benefits may be uncertain, they are not zero, so administrators should still pursue best estimates. The hypothetical program we analyzed showed positive net benefits only after half of the utility system benefits were included. While this is just one example, it illustrates the effect of adding additional, real benefits to cost-effectiveness screening.

Our review of utility system benefits also highlights some of the difficulties in estimating future benefits of energy efficiency. The volatility of natural gas prices presents an especially difficult challenge to regulators and program administrators. Energy efficiency programs can provide a hedge against swings in natural gas prices, reducing the risks for both a utility and its customers. Efficiency programs that reduce the demand for natural gas also lower its wholesale price, further dampening volatility.

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Appendix A: Avoided Cost of Energy Detail

Table A1. Avoided cost of energy detail (nominal$)

Utility or jurisdiction	Source	Avoided cost of energy ($/kWh)	
		2015	2030
State of Wisconsin	Cadmus 2013	$0.0480	$0.0596
Avista	Avista 2013	$0.0333	$0.0614
Xcel Colorado CC	Xcel CO 2013	$0.0366	$0.0646
Southwest Public Service	SPS 2013	$0.0446	$0.0664
Ameren Missouri	Ameren 2014	$0.0270	$0.0670
State of Texas	Texas 2015	$0.0532	$0.0716
Xcel Minnesota	Xcel MN 2012	$0.0490	$0.0808
Public Service Oklahoma	PSO 2014	$0.0413	$0.0866
Vectren	Vectren 2014	$0.0369	$0.0928
PECO	PECO 2012	$0.0320	$0.0980
Potomac Edison	Exeter 2014	$0.0480	$0.1159
Baltimore Gas & Electric	Exeter 2014	$0.0485	$0.1216
Delmarva Power & Light	Exeter 2014	$0.0494	$0.1216
PEPCO & SMECO	Exeter 2014	$0.0495	$0.1241
Hawaii Energy	Hawaii Energy 2014	$0.1120	$0.1280
Pennsylvania Power & Light	PPL 2013	$0.0565	$0.1294
Xcel Colorado CT	Xcel CO 2013	$0.0617	$0.1490
State of Connecticut	AESC 2013	$0.0500	$0.1490
NIPSCO	NIPSCO 2014	$0.0240	$0.1910
Idaho Power	Idaho Power 2013	$0.0291	$0.1979

Appendix B: Avoided Cost of Capacity Detail

Table B1. Avoided cost of capacity detail (nominal$)

Utility or jurisdiction	Source	Avoided cost of capacity ($/kW-year)	
		2015	2030
Xcel Minnesota	Xcel MN 2012	$34.58	$49.06
Pennsylvania Power and Light	PPL 2013	$45.99	$60.33
Potomac Edison	Exeter 2014	$61.66	$78.36
PECO	PECO 2012	$60.51	$80.54
NIPSCO	NIPSCO 2014	$83.39	$86.36
Texas	Texas 2015	$80.00	$107.67
Wisconsin	Cadmus 2013	$114.30	$114.30
Xcel Colorado CT	Xcel CO 2013	$91.08	$130.20
PEPCO, SMECO, & BGE	Exeter 2014	$72.30	$131.22
Vectren	Vectren 2014	$104.01	$131.97
Delmarva Power & Light	Exeter 2014	$72.30	$134.41
Public Service Oklahoma	PSO 2014	$131.11	$147.43
Xcel Colorado CC	Xcel CO 2013	$111.12	$154.44
Southwestern Public Service	SPS 2013	$139.59	$178.69
ISO NE States	AESC 2013	$22.25	$192.55
Hawaii Energy	Hawaii Energy 2014	$382.50	$433.90

Appendix C: Avoided Cost of Transmission and Distribution Detail

Table C1. Avoided cost of transmission and distribution detail (nominal$)

Utility or jurisdiction	Source	Avoided T&D ($/kW-year)
Idaho Power	Idaho Power 2013	$0.00
Arizona Public Service	Mendota 2014	$0.00
Wisconsin	Cadmus 2013	$0.00
Indiana Michigan Power	I&M 2013	$0.00
State of Texas	Texas 2015	$0.00
Consumers Energy	Mendota 2014	$0.00
Vectren	Vectren 2014	$12.14
Nevada Power	NVE 2012	$12.23
Public Service Oklahoma	PSO 2014	$19.17
Ameren Missouri	Ameren 2014	$27.68
Xcel Energy Colorado	Xcel CO 2013	$28.40
Southwest Public Service	SPS 2013	$28.87
Potomac Edison	Exeter 2014	$30.69
Connecticut Light and Power	AESC 2013	$32.24
Baltimore Gas and Electric	Exeter 2014	$33.15
PGE Oregon	Mendota 2014	$33.20
National Grid Rhode Island	AESC 2013	$41.24
ComEd Illinois	Mendota 2014	$42.00
Consolidated Edison Non Network	Mendota 2014	$42.63
United Illuminating	AESC 2013	$47.82
MidAmerican South Dakota	Mendota 2014	$48.16
MidAmerican	Mendota 2014	$51.86
Northern Indiana Public Service	NIPSCO 2014	$52.25
PacifiCorp Oregon	Mendota 2014	$52.64
PacifiCorp Utah	Mendota 2014	$52.64
PacifiCorp Washington	Mendota 2014	$52.64
Xcel Energy Minnesota	Xcel MN 2012	$53.17
Southern California Edison	Mendota 2014	$53.49
Delmarva Power and Light	Exeter 2014	$55.43
Northwest Utilities	Mendota 2014	$65.59
Public Service New Hampshire	AESC 2013	$70.05
San Diego Gas and Electric	Mendota 2014	$73.32
Pacific Gas and Electric	Mendota 2014	$75.57
PEPCO	Exeter 2014	$79.12
Southern Maryland Electric Coop	Exeter 2014	$79.12
NSTAR	AESC 2013	$89.79

Utility or jurisdiction	Source	Avoided T&D ($/kW-year)
WMECO	AESC 2013	$98.35
Tucson Electric Power	Mendota 2014	$100.00
Unitil New Hampshire	AESC 2013	$102.29
Interstate Power and Light	Mendota 2014	$107.00
Consolidated Edison Network	Mendota 2014	$120.52
Vermont	AESC 2013	$158.15
Unitil Massachusetts	AESC 2013	$173.79
National Grid Massachusetts	AESC 2013	$200.01

Appendix D: Integrated Resource Planning Case Studies

NIPSCO 2014

Overview

NIPSCO is a joint gas and electric company providing service to 821,000 natural gas and 468,000 electric customers in northern Indiana. NIPSCO is required to file an IRP with the Indiana Utility Regulatory Commission every three years and provide updates as needed for other filing requests. The 2013 NIPSCO electric IRP presented several resource portfolio cases modeled on different assumptions.

To determine the level of efficiency to include in the resource planning analysis, NIPSCO first screened potential programs using a discounted cash flow market value analysis to determine the value of each program. Then NIPSCO evaluated the possible combinations of supply- and demand-side resources to meet forecasted future demand for the study period. Several possible scenarios were included in the analysis. The base case scenario was premised on relying on new natural gas generation and market purchases to meet potential future demand. This scenario did not include any energy efficiency programs.

NIPSCO also modeled a scenario including the potential 2015 energy efficiency programs. The 2015 potential programs were assumed to have first-year energy savings of 120 GWh and 47 MW of demand. Demand-side management (DSM) in the context of the NIPSCO IRP is defined as five energy efficiency programs and one residential direct-load control program. NIPSCO also modeled other plans including renewable resources, industrial direct load control, and a non-gas plan focused on increased reliance of coal-fired generation.

Results

In the initial analysis, the scenarios including energy efficiency outperformed those without. Table D1 presents the results of the analysis for the three final scenarios.

Table D1. NIPSCO 2014 IRP net present value of revenue requirements for three most likely scenarios

Plan	PVRR (2013$ millions)	Change from lowest-cost portfolio (millions)	Rank
Gas/DSM	$11,304	$0	1
DSM/gas/renewable	$11,405	$101	2
Gas only	$11,630	$326	3

Source: NIPSCO 2014

As the table shows, the NPVRR for the Gas/DSM plan was $325.5 million less than the Gas only plan. This would indicate the value of including efficiency in NIPSCO's IRP is approximately $325.5 million over the planning period. This scenario only includes a very limited level of energy efficiency, and NIPSCO did not conduct further analysis with higher levels of efficiency. The preliminary analysis did not include any consideration of risk.

Following preliminary analysis, NIPSCO completed sensitivity analyses to determine risk exposure of the three options: Gas/DSM, DSM/gas/renewables, and Gas only. NPVRR was calculated for the three plans under nine different scenarios. Figure D1 shows the results of this analysis. NIPSCO determined that the DSM plans provided the best hedge against risk related to future carbon regulations, load growth, and natural gas prices.

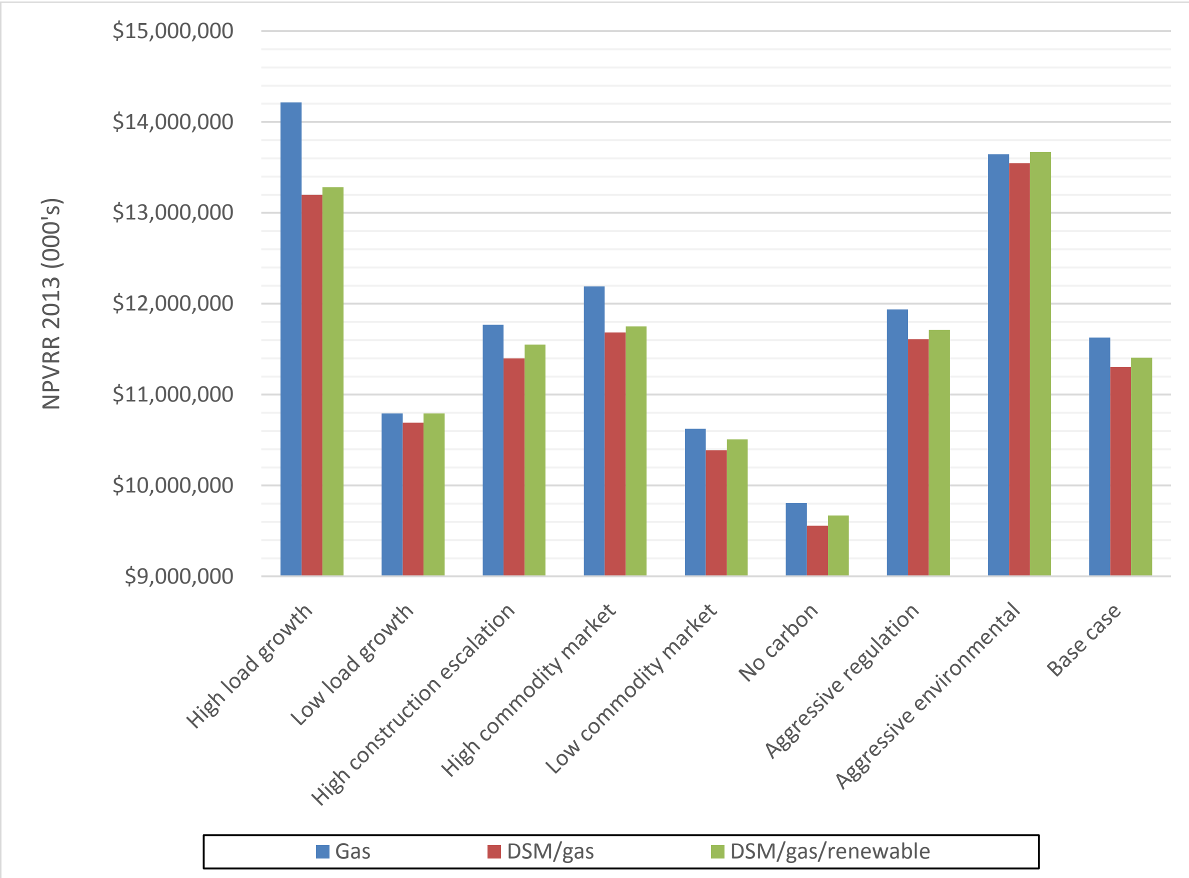

Figure D1. NIPSCO 2014 IRP risk sensitivity analysis results. ***Source:*** **NIPSCO 2014.**

Conclusions

NIPSCO ultimately selected the DSM/Gas plan as the resource plan of choice. This plan was the least-cost strategy with the lowest-risk profile among portfolios analyzed by NIPSCO. The plan results in savings to ratepayers of approximately $325.5 million in NPVRR over the 20-year planning period when compared to the best plan without energy efficiency. However one sensitivity NIPSCO did not model was a scenario with increased energy efficiency efforts. All plans including DSM modeled the same level of energy efficiency resources. It would have been worthwhile to consider scenarios with more aggressive energy efficiency goals.[16]

[16] For the 2014 IRP, NIPSCO modeled the 2015 energy efficiency reductions proposed in a recent one-year plan. This plan is the first NIPSCO energy efficiency plan following the elimination of Indiana's statewide energy

The ratepayer impact measure test (RIM) is meant to measure the impact of electric rates or customer bills resulting in changes to utility revenues from the implementation of efficiency programs. None of the NIPSCO programs included in the IRP analysis passed the RIM test, meaning the implementation of these programs would lead to higher rates for all customers. However the IRP modeling suggests otherwise as rates would actually decrease over time for all customers through the implementation of the programs. This is evident through the difference in NPVRR between the plans with the programs and those without. This result demonstrates potential issues with using a simple test like the RIM to determine real impacts on rates over time in a utility system.

TVA 2011

Overview

TVA is a government-owned corporation providing electricity to nine million customers in Tennessee, Alabama, Georgia, Kentucky, Mississippi, North Carolina, and Virginia. TVA files a new IRP every five years, with the last IRP filed in 2011.[17] The TVA IRP modeled five planning strategies in seven possible scenarios. The seven scenarios represent various outcomes related to economic conditions, carbon dioxide regulations, national energy policies, fuel prices, and possible technological changes impacting load. The five strategies represent various approaches to securing supply-side resources necessary to meet future demand under the seven scenarios. Table D2 details the five strategies with the assumed level of energy efficiency. The five strategies were modeled across the seven scenarios to determine the least-cost, least-risk resource planning option.

Table D2. TVA 2011 IRP energy efficiency levels for strategies

	Strategy	Demand (MW)	Energy (GWh)
A	Limited change	1,940	4,725
B	Baseline plan	2,100	5,900
C	Diversity focused	3,600	11,400
D	Nuclear focused	4,000	8,900
E	EE, DR, and renewables	5,100	14,400

Results

The modeling results showed strategies C and E with the lowest average NPVRR over the seven scenarios. The difference between these two strategies and the next-best resource plan is approximately $2 billion. This result indicates that both strategies, which pursue the highest level of energy efficiency deployment, result in cost savings to customers of approximately $2 billion over the planning period. Strategy E scored well with the lowest NPVRR in five of the seven scenarios. The only scenarios where strategy C scored better

efficiency goals. The 2015 proposed reductions represent approximately half of the energy efficiency savings achieved by NIPSCO in 2014.

[17] TVA is currently in the process of completing the 2015 IRP.

than strategy E was under the assumptions of a prolonged economic recession (scenario 3) and a game-changing technology (scenario 4).[18] The modeling results are displayed in table D3.

Table D3. TVA 2011 IRP net present value of revenue requirements over seven scenarios (2010$ million)

Strategy	Scenario							Average
	1	2	3	4	5	6	7	
A	180	137	116	138	135	109	134	136
B	179	136	114	137	133	107	133	134
C	175	133	114	135	131	105	130	132
D	181	137	115	138	134	103	132	134
E	174	131	115	136	131	104	130	132

The potential resource outcomes were also evaluated on several other criteria besides PVRR, including short-term rate impacts, perceived risk benefits, and risk. Strategies C and E were the top-performing strategies when averaged across all possible planning scenarios. In fact, the performance of the two strategies was so close that the separation between the ranking scores was determined to not be statistically significant. Finally, TVA modeled CO_2 emissions from the potential strategies. Strategy E provided the lowest forecasted CO_2 emissions of any plan over the 20-year planning period.

Conclusions

Ultimately, TVA created a new strategy based on the optimization of various components of the strategies that performed best under the IRP modeling scenarios. The recommended strategy focused on a diverse resource portfolio with a targeted level of energy efficiency comparable to strategies C and E. This approach resulted in similar economic value to strategy C and E in terms of net present value of revenue requirements savings customers approximately $2 billion in net present value of revenue requirements over the course of the planning period.

PACIFICORP 2013

Overview

PacifiCorp is a large western utility serving 1.8 million customers in a service territory spanning six states: Oregon, Washington, California, Utah, Wyoming, and Idaho. Every two years PacifiCorp completes a new IRP with updates as needed. The IRP focuses on a 10-year forecast and a 20-year forecast. The PacifiCorp IRP relies on system-wide modeling based on numerous assumptions to determine the least-cost resource portfolio to meet customer demand. The IRP also considers other factors such as risk, reliability, uncertainty, and specific state policy requirements that impact resource planning decisions. The objective

[18] A game-changing technology is defined in the TVA 2011 IRP as a technology that could dramatically reduce or increase demand.

outlined in the IRP was for PacifiCorp to acquire between 1,425 and 1,876 GWh of cost-effective energy efficiency resources by the end of 2015 and between 2,034 and 3,180 GWh by the end of 2017.

Results

The final analysis demonstrated the two scenarios deploying accelerated energy efficiency resulted in lower net present value of revenue requirements over the study period. The level of energy efficiency deployment in the planning period is the same for all five cases. However, as table D4 shows, the two options including accelerated energy efficiency outperformed the next best option by $190 million in present-value revenue requirements. This means the best performing option would cost ratepayers a total of $190 million in present-value terms over the course of the 20-year planning period. The primary difference between the two top-performing portfolios is the difference in assumptions related to transmission constraints.

Table D4. PacifiCorp 2013 IRP portfolio comparison risk-adjusted present value of revenue requirements for top five cases

Case	Risk adjusted PVRR ($m)	Change from lowest-cost portfolio ($m)	Rank
EG1-C15	$33,293	$0	1
EG2-C15	$33,425	$131	2
EG2-C07	$33,483	$190	3
EG1-C16	$33,536	$243	4
EG1-C03	$33,537	$244	5

Conclusion

PacifiCorp did not pursue either portfolio deploying accelerated energy efficiency because of concerns with cost assumptions for accelerated DSM, untested ramp rate assumptions, and the exclusion of combined-cycle combustion turbine technology from the portfolio models. PacifiCorp did recognize the benefits of acquiring an accelerated level of efficiency and included specific action items to achieve this level of efficiency in the IRP. The final portfolio selected did not recommend a reduced level of energy efficiency resources but did not pursue such resources as aggressively as the accelerated cases. The final portfolio selected forecasted 39% of new generation resources would come from DSM in 2022 and 36% in 2032.

AMEREN MISSOURI 2014

Overview

Ameren Missouri is a vertically integrated utility serving 1.2 million customers in Missouri. Every three years, the company files an IRP with the Missouri Public Service Commission. The Ameren IRP determines the least-cost, least-risk resource mix to serve the company's customer base utilizing whole-system modeling techniques similar to other previously discussed IRPs. While the assumptions and modeling software may differ, the approach is the same, comparing various resource portfolio approaches under several possible scenarios.

The Ameren IRP modeled several different assumptions regarding the future contribution of energy efficiency to the total resource portfolio. The assumptions were based on the results from a recent market-potential study for energy efficiency in Ameren's service territory. Table D5 shows the three modeled energy efficiency scenarios. In an analysis of the levelized cost of energy for all demand- and supply-side options, Ameren found energy efficiency to be the least-cost resource available. Ameren Missouri modeled 19 potential resource scenarios to determine the least-cost plan of action.

Table D5. Ameren Missouri 2014 IRP energy efficiency scenario assumptions

Energy efficiency scenario	Cumulative energy savings
Maximum achievable potential (MAP)	2016 - 510 GWh 2018 - 1,179 GWh 2030 - 5,377 GWh
Realistic achievable potential (RAP)	2016 - 105 GWh 2018 - 426 GWh 2030 - 3,958 GWh
Missouri Energy Efficiency Investment Act (MEEIA) Cycle 1 only	No new efficiency beyond 2015

Results

Resource scenarios with no new energy efficiency beyond 2015 performed substantially worse than plans focused on the inclusion of energy efficiency. The difference in present value revenue requirements between the least-cost plan, focused on maximum achievable potential for energy efficiency, and the highest-ranking plan eliminating energy efficiency in 2015 was $2.5 billion. The $2.5 billion difference represents the cost savings in present-value terms to customers over the time period. Table D6 shows the results for five selected plans.

Table D6. Ameren Missouri resource portfolio scenario results

Plan	Description	PVRR ($million)	Change from lowest-cost plan ($million)	Rank within 19 potential scenarios
G	CC-MAP	$60,842	–	1
R	CC-MAP-Balanced	$61,081	$239	4
I	CC-RAP-Balanced	$61,352	$510	8
K	CC-MEEIA1-Balanced	$63,357	$2,515	14
L	Wind-MEEIA1	$66,973	$6,131	19

Source: Ameren Missouri 2014

Ameren Missouri also completed sensitivity analysis for the five plans in table D6. Each scenario was a sensitivity for the following assumptions: coal retirements, carbon prices, load growth, natural gas prices, project costs, interest rates and return on equity, demand-side management, and coal prices. Under these scenarios, Plan G was the least-cost option 26 out of 27 times. The only scenario in which Plan G did not produce the lowest-cost PVRR was the case of high cost of carbon emissions. In this scenario, Plan L was the least-cost option.

Ameren Missouri, like NIPSCO, included RIM test results for the programs included in the MAP and RAP energy efficiency scenarios. The RAP RIM test result was 0.66 and the MAP RIM test result was 0.60. The RIM test is designed to tell program decision makers if the implementation of a program will increase rates. A score under 1 indicates rates will increase if a program is implemented, and a score over 1 indicates rates will decrease if a program is implemented. The RIM scores of both scenarios presented in the IRP indicate rates will increase if programs are implemented. However the IRP analysis demonstrated that rates would be substantially lower if the programs were implemented. Reduced revenue requirements for a utility should translate directly into lower rates. Finally, Ameren notes both RAP and MAP scenarios result in lower overall costs to customers (Ameren 2014, 11)

Conclusions

Ultimately, Ameren Missouri did not elect to pursue Plan G but instead decided to pursue Plan I. As modeled, Plan I could cost ratepayers $510 million more than Plan G. Ameren pursued Plan I because of consideration of the risk of attaining savings outlined in MAP versus those in RAP. Ameren Missouri also included considerations of participant costs in the comparison between RAP and MAP approaches.