Title

Time-varying value of electric energy efficiency

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Disclaimer

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Acronyms and Abbreviations

CAISO	California Independent System Operator
CEC	California Energy Commission
CPUC	California Public Utilities Commission
DOE	U.S. Department of Energy
ELCAP	End Use Load and Consumer Assessment Program
EPRI	Electric Power Research Institute
EULR	End-use load research
ISO-NE	New England Independent System Operator
NAPEE	National Action Plan for Energy Efficiency
NEEA	Northwest Energy Efficiency Alliance
NEEP	Northeast Energy Efficiency Partnership
PNNL	Pacific Northwest National Laboratory
RBSA	Residential Building Stock Assessment

Glossary

Capacity-related time-varying value: For the purposes of this study, the capacity-related time-varying value is comprised of the following values: avoided generation, transmission and distribution capacity, and reserves or ancillary services.

Coincidence factor: The ratio of the simultaneous maximum demand of two or more loads within a specified period to the sum of their individual maximum demand within the same period. The ratio may be expressed as a numerical value or as a percentage. The coincidence factor is the reciprocal of the diversity factor and is always less than or equal to one. As used in this study, a coincidence factor is the ratio of the observed reduction in system peak demand to the total non-coincident demand savings of all of the measures installed in an efficiency program by participants at the time of the system peak to their non-coincident peak demand.

Diversity factor: The ratio of the maximum demand of two or more loads to the sum of all their individual maximum demand. As used in this study, the diversity factor accounts for the fact that an individual efficiency measure may save a certain amount of demand, but across an entire program not all of the locations where the measure was installed operate at the same time.

End-use load shape: Hourly consumption of an end use (e.g., residential lighting, commercial HVAC) over the course of one year.

Energy-related time-varying value: For the purposes of this study, the energy-related time-varying value is comprised of the following values: avoided energy, risk reduction, carbon dioxide emissions, avoided renewable portfolio standard compliance, and demand reduction induced price effect (DRIPE).

Energy savings shape: The difference between the hourly use of electricity in the baseline condition and the hourly use post-installation of the energy efficiency measure (e.g., the difference between the hourly consumption of an electric resistance water heater and a heat pump water heater, or the difference between the hourly lighting use in a commercial building pre- and post-installation of daylighting controls or occupancy sensors) over the course of one year.

Total time-varying value: For the purposes of this study, the total time-varying value of energy efficiency is the sum of the following avoided cost components: energy, risk, carbon dioxide emissions, avoided renewable portfolio standard compliance, DRIPE, generation, transmission, distribution capacity, and reserves or ancillary services.

Executive Summary

Electric energy efficiency resources save energy and may reduce peak demand. Historically, quantification of energy efficiency benefits has largely focused on the economic value of energy savings during the first year and lifetime of the installed measures. Less emphasis has been placed on the larger grid system. This study reviews existing literature on the time-varying value of energy efficiency savings, provides examples in four geographically diverse locations of how consideration of the time-varying value of efficiency savings impacts the calculation of power system benefits, and identifies future research needs to enhance the consideration of the time-varying value of energy efficiency in cost-effectiveness screening analysis. Findings from this study include:

- The time-varying value of individual energy efficiency measures varies across the locations studied because of the physical and operational characteristics of the individual utility system (e.g., summer or winter peaking, load factor, reserve margin) as well as the time periods during which savings from measures occur.
- Across the four locations studied, some of the largest capacity benefits from energy efficiency are derived from the deferral of transmission and distribution system infrastructure upgrades. However, the deferred cost of such upgrades also exhibited the greatest range in value of all the components of avoided costs across the locations studied.
- Of the five energy efficiency measures studied, those targeting residential air conditioning in summer-peaking electric systems have the most significant added value when the total time-varying value is considered.
- The increased use of rooftop solar systems, storage, and demand response, and the addition of electric vehicles and other major new electricity-consuming end uses are anticipated to significantly alter the load shape of many utility systems in the future. Data used to estimate the impact of energy efficiency measures on electric system peak demands will need to be updated periodically to accurately reflect the value of savings as system load shapes change.
- Publicly available components of electric system costs avoided through energy efficiency are not uniform across states and utilities. Inclusion or exclusion of these components and differences in their value affect estimates of the time-varying value of energy efficiency.
- Publicly available data on end-use load and energy savings shapes are limited, are concentrated regionally, and should be expanded.

To understand the impact of a given energy reduction measure, the time-varying value of electricity needs to be combined with end-use load shape or energy savings shape data. Consideration of the impact of energy efficiency on peak demand reduction (i.e., capacity savings) has been limited, in part due to the lack of publicly available research on the load shape (i.e., the hourly or seasonal timing of electricity savings) of energy efficiency. Until very recently, publicly available end-use load shape data gathering efforts have been most concentrated in the West Coast and New England. In addition, publicly available energy savings shape data are extremely limited. Such data will become increasingly important as a growing share of energy savings are from improved controls which are explicitly intended to modify the duty-cycle or hours of operation of end use consumption (e.g., occupancy controls on lighting).

Most energy efficiency measures produce energy savings that vary over the course of a year. The value of the hourly electricity savings also varies over the course of a year because the avoided cost of generating, transmitting, and distributing electricity during peak demand periods may be significantly higher than during off-peak, or lower load hours. To properly calculate the value of electricity savings to the utility system, it is necessary to account for variations in hourly energy savings, hourly avoided energy cost, and the deferral of capital investment in new generation, transmission, and distribution infrastructure, among other factors. In those power systems that are required to meet renewable portfolio standards, and where such standards are a function of annual retail sales (or fraction of installed capacity), the value of avoided investments in new renewable resources should also be taken into account. Similarly, avoided emissions should be considered on a time-sensitive basis. Finally, in organized markets, the impact of reduced energy and capacity demands on market prices, referred to as *demand reduction induced price effects* (DRIPE), is typically accounted for as an energy efficiency resource value.

In this study, the time-varying value of five efficiency measures was calculated in four locations in the United States: the Pacific Northwest, California, Massachusetts, and Georgia. These areas were selected based on their differing power system load shapes, market structures, approach to and experience with energy efficiency valuation, and availability of data. Only publicly available data was used to calculate the values.[1] The five efficiency measures were chosen because they follow the shape of the end use and illustrate the difference in value for summer and winter peaking electric systems.

Appendix B describes the methods used to apply end-use load shape data in utility resource and demand side management planning in the four locations reviewed in this study. The description of each location's approach to the valuation of energy efficiency is organized into four areas:

- Energy efficiency policy and regulatory context;
- Resource needs assessment process (i.e., how the utility establishes future needs for energy and capacity resource acquisitions are established);
- Cost-effectiveness determination process and criteria; and
- Derivation of time-varying value of energy efficiency measures for this study.

Figure ES-1 through Figure ES-4 show the contribution of the publicly available elements of avoided cost on the total economic value for each load shape selected for four of the locations considered in this study. The vertical axis in these figures shows the total time-varying value of energy efficiency savings by load shape. The contribution of each element of the total avoided cost appears as a component of each bar. Depending on the location and market structure, other avoided utility system costs might include avoided cost of compliance with carbon dioxide (CO_2) and other emissions regulations, avoided

[1] In Georgia, where publicly available data did not include avoided transmission and distribution system values, the time-varying value of efficiency appears much lower for all measures evaluated.

renewable portfolio compliance costs, risk mitigation costs, and DRIPE.[2] The Pacific Northwest, California, and Massachusetts include avoided cost for energy, capacity, deferred transmission, distribution and CO_2 emissions. The data for Georgia only includes the publicly available avoided cost values for energy and capacity. DRIPE data is only shown for Massachusetts and data to quantify the value of reduced requirements for ancillary services (i.e., spinning and operating reserves) is shown only for California. Based on our analysis of end-use load shape, savings load shape and avoided cost data by location, some of the largest capacity benefits from energy efficiency are derived from the deferral of transmission and distribution system infrastructure upgrades. However, the deferred cost of transmission and distribution infrastructure upgrades also exhibited the greatest range in value of all the components of avoided cost across the locations studied.

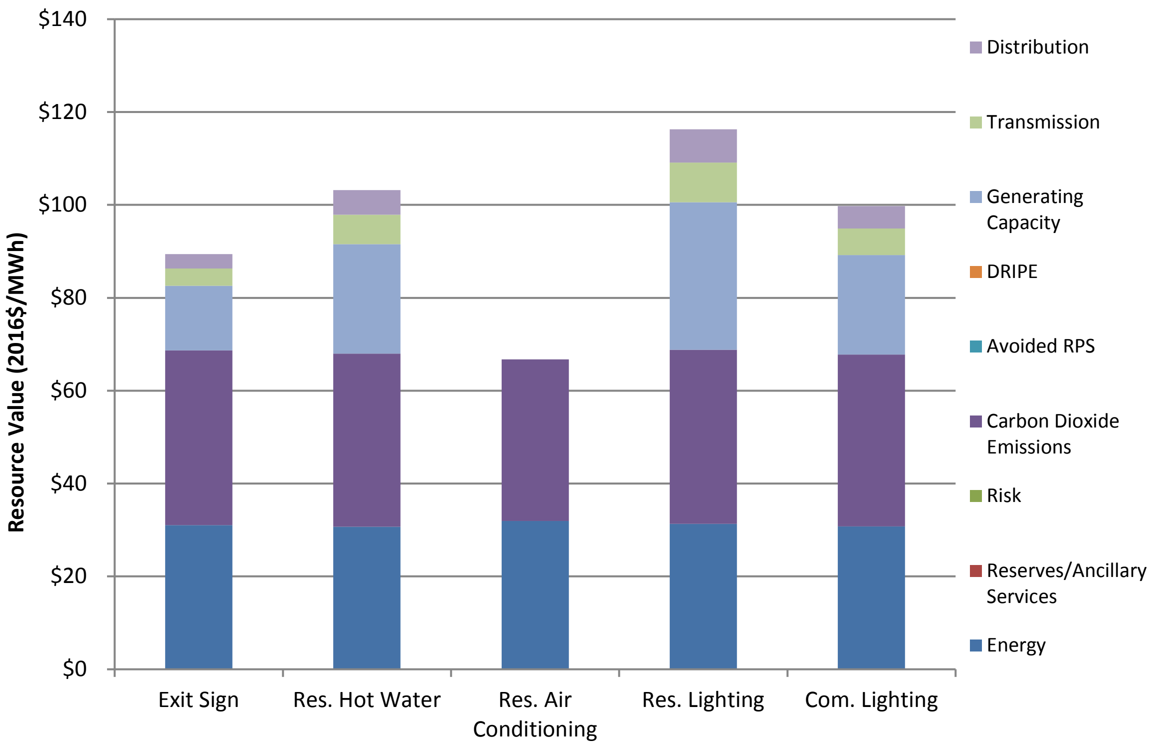

Figure ES-1.Time-varying value of energy efficiency savings by load shape in Pacific Northwest

[2] DRIPE refers to the reduction in wholesale market prices for energy and/or capacity expected from reductions in the quantities of energy and/or capacity required from those markets during a given period due to the impact of efficiency and/or demand response programs. Thus, DRIPE is a measure of the value of efficiency received by all retail customers during a given period in the form of expected reductions in wholesale prices. The avoided cost value of DRIPE during a given time period is equal to the projected impact on the wholesale market price during that period, expressed as a $ per unit of energy, multiplied by the quantity of energy purchased at rates or prices tied directly to that given market price. (Hornby et al., 2015).

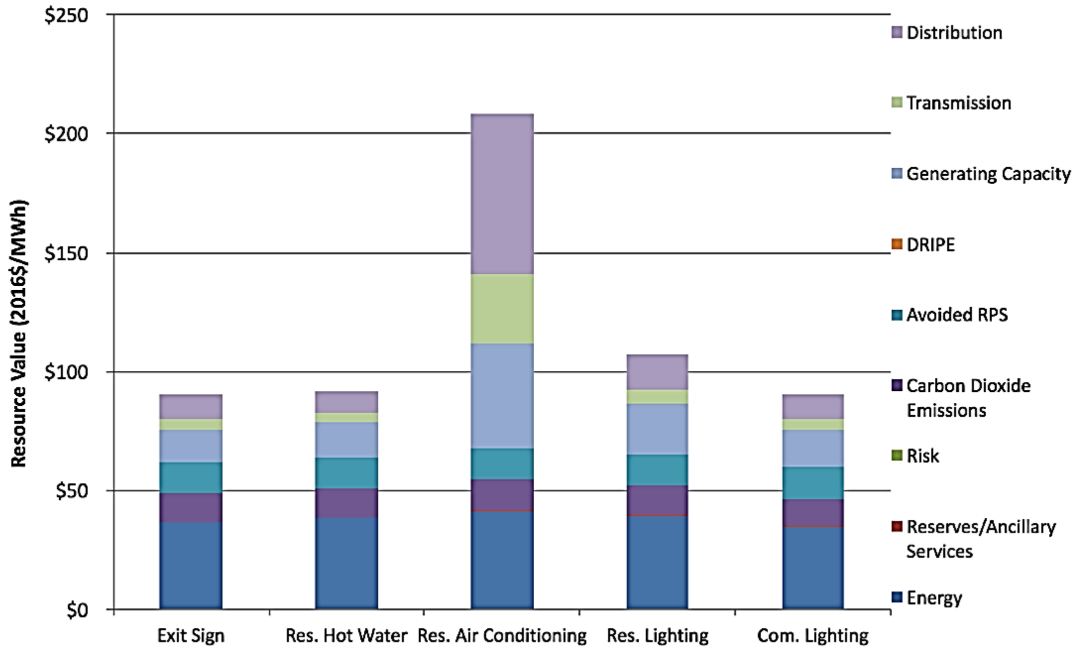

Figure ES-2. Time-varying value of energy efficiency savings by load shape in California

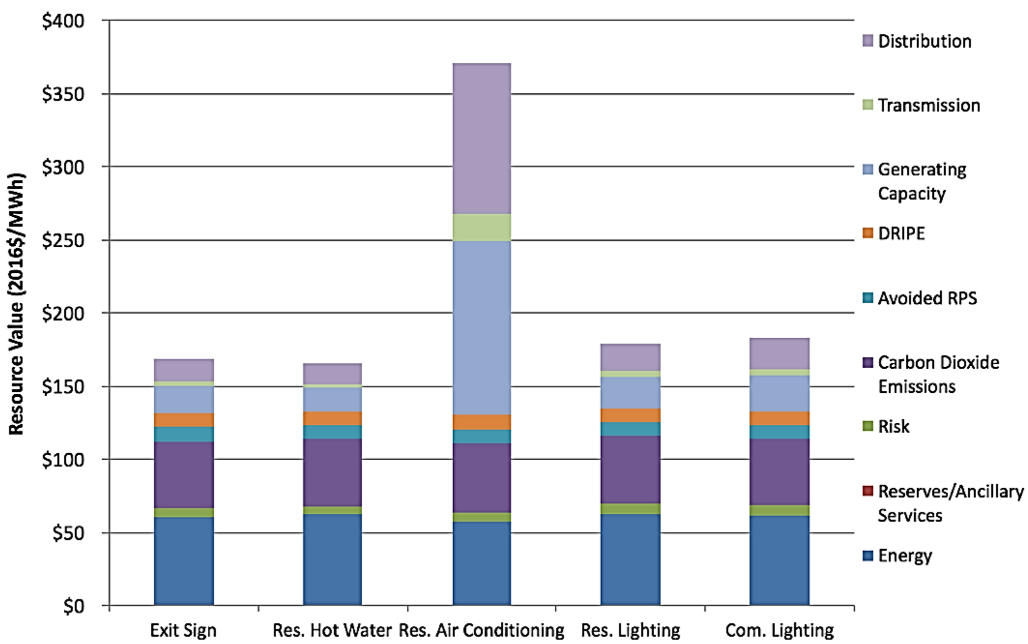

Figure ES-3. Time-varying value of energy efficiency savings by load shape in the Massachusetts

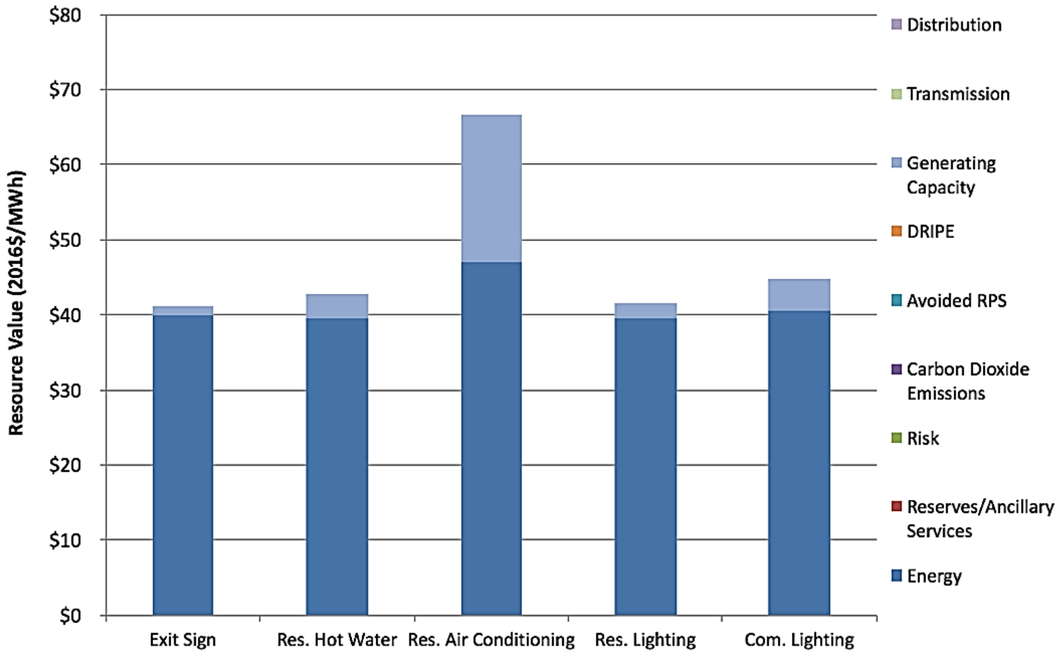

Figure ES-4. Time-varying value of energy efficiency savings by load shape in Georgia[3]

A comparison of Figure ES-1 through Figure ES-4 reveals that the time-varying value of energy savings varies by measure type and location. For example, in both California (Figure ES-2) and Massachusetts (Figure ES-3), savings with a residential air conditioning load shape have significantly more value than measures with other load shapes. In Georgia, (Figure ES-4) savings with a residential air conditioning load shape also have more value than other measures. In contrast, savings with residential air conditioning load shapes in the Northwest (Figure ES-1) have the lowest value relative to measures with other load shapes reviewed in this study. One of the underlying causes of these differences is that the California, Massachusetts, and Georgia utility systems experience their peak demands in the summer, while the Northwest electricity system peaks during the winter.[4]

Figure ES-5 and Table ES-1 show the ratio of the **total** time-varying value of electric efficiency measures (i.e., energy avoided cost plus the avoided cost of capacity) to the energy-related value of savings for the five energy efficiency measures included in this study.[5] As Figure ES-5 and Table ES-1 show, accounting for both the seasonal time-varying value of energy savings and its impact on the need to invest in additional capacity can significantly affect the value of energy savings.

[3] In Georgia, where publicly available data did not include avoided transmission and distribution system values, the time-varying value of efficiency appears much lower for all measures evaluated.

[4] As a region, the Northwest is a winter peaking system, however, individual utilities within this region can be summer peaking (e.g., Idaho Power Company) or experience nearly equal summer and winter peak demands (e.g. Portland General Electric).

[5] The ratios in Table ES-1 are calculated by dividing the total time-varying value by the energy-related value subtotal. See Table 6 through Table 10 for actual values.

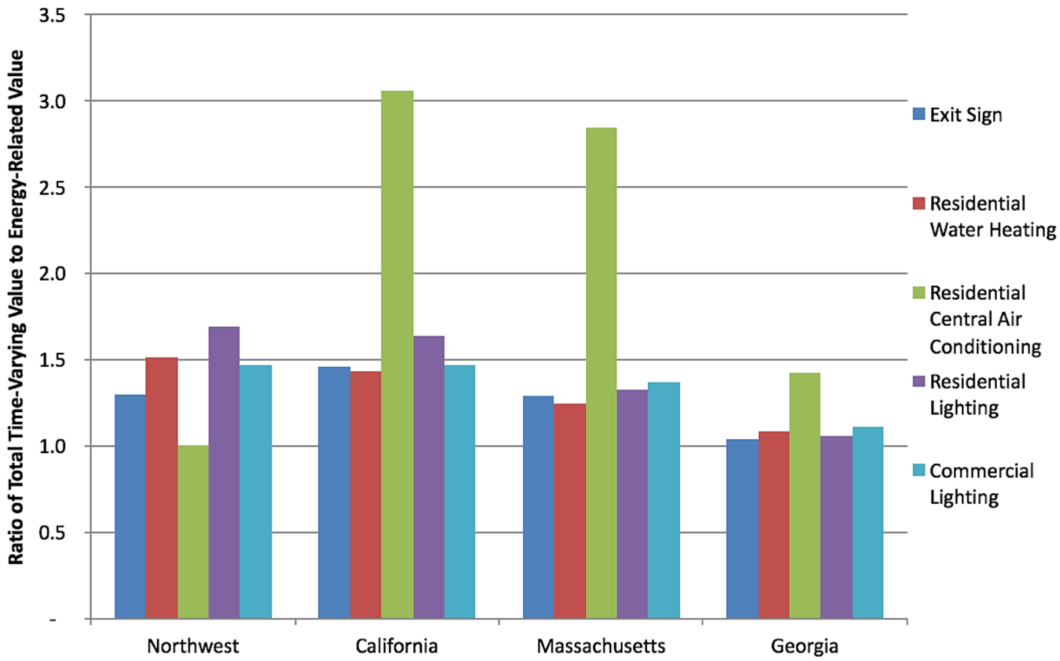

Figure ES-5. Ratio of total time-varying value of energy savings to energy-related savings value by end-use load shape and location[6]

Table ES-1 also shows that the magnitude of this increased value varies by both load shape within a single location and across locations. For example, in California, the avoided capacity benefits of savings from improving the efficiency of residential air conditioning make such measures about 3.1 times more valuable than their annual energy savings alone. In contrast, in the Pacific Northwest, savings from residential air conditioning measures provide no additional capacity benefits. This difference occurs because savings from residential air conditioning offset the summer peak demand for electricity in California, which historically has driven the need for new capacity in that location, while residential air conditioning savings in the Pacific Northwest, which experiences its peak demand in the winter, does not provide capacity benefits.[7] This illustrates that the magnitude of the additional value provided by energy efficiency is directly related to both the measure's impact on the need for additional capacity and the avoided cost of that capacity.

[6] In Georgia, where publicly available data did not include avoided transmission and distribution system values, the time-varying value of efficiency appears much lower for all measures evaluated.

[7] The historical system load shapes of both California and the Northwest are changing. With the increased penetration of renewable resources in California, particularly solar photovoltaic systems, the net utility system loads during summer afternoons are decreasing. In contrast, due to the increased saturation of air conditioning in the Northwest and the diminishing penetration of electric space heating, this region's summer peak demands are forecast to match its winter peaks over the next decade.

Table ES-1. Ratio of total time-varying value of energy savings to energy-related savings value by load shape and location

Load Shape	Location			
	Northwest	California	Massachusetts	Georgia[8]
Flat/Uniform Across All Hours	1.3	1.5	1.3	1.0
Residential Water Heating	1.5	1.4	1.2	1.1
Residential Central Air Conditioning	1.0	3.1	2.8	1.4
Residential Lighting	1.7	1.6	1.3	1.1
Commercial Lighting	1.5	1.5	1.4	1.1

[8] In Georgia, where publicly available data did not include avoided transmission and distribution system values, the time-varying value of efficiency appears much lower for all measures evaluated.

1. Introduction

Quantifying the time-varying value of energy efficiency is necessary to properly account for all of the costs and benefits of energy efficiency, and to identify and implement efficiency resources that contribute to a low-cost, reliable electric system (U.S. EPA 2006; Boomhower and Davis 2016). Historically, most quantification of energy efficiency's benefits has focused largely on the economic value of annual energy reduction. Due in part to the lack of publicly available research on end-use load shapes (i.e., the hourly or seasonal timing of electricity savings) and energy savings shapes, consideration of the impact of energy efficiency on peak demand reduction (i.e., capacity savings) has been more limited. End-use load research and the hourly valuation of efficiency savings are used for a variety of electricity planning functions, including load forecasting, demand-side management and evaluation, capacity and demand response planning, long-term resource planning, renewable energy integration, assessing potential grid modernization investments, establishing rates and pricing, and customer service (KEMA 2012).

This study seeks to advance consideration of the value of energy efficiency during times of peak electricity demand and high electricity prices. Using publicly available end-use load shapes and electric avoided costs, this study quantifies the time-varying value of energy and demand impacts for five types of electric efficiency measures in four geographic locations in the United States.

Chapter 2 reviews the state of end-use load research and databases in the United States, drawing on prior research conducted on the topic in Massachusetts and the Northwest, and also summarizes major concerns with existing end-use load research.

Chapter 3 describes the two general approaches used to characterize the time-varying value of electricity savings. Method 1 uses daily or seasonal load shape data, or both, to allocate energy savings into peak periods and off-peak periods and uses coincidence factors to estimate peak impacts. Method 2 uses annual hourly data on both energy savings and avoided costs (Stern 2013).[9] Both approaches require data on the end-use load shape, utility system load shapes, and utility system avoided costs. The primary differences between the two methods are the fidelity or granularity of their data requirements and the method used to determine peak reduction impacts of efficiency measures.

In addition, we also discuss the scope of the costs that are avoided by the energy efficiency measure's energy and capacity savings for each location. Chapter 3 provides examples of the time-varying values for five efficiency measures in four U.S. locations (California, Massachusetts, Pacific Northwest and Georgia), including a description of the assumptions used to calculate each measure's peak demand impacts. The sources for system load shape, end-use load shape and avoided cost data that was used in this study is summarized in Table 1-Table 3.

[9] See Stern (2013) for a more detailed explanation of alternative approaches that can be used to estimate peak energy savings; some of these approaches do not rely on end-use metered data.

Table 1. Data sources for system load shapes, by location

Location	Source	Year of Data
California	CAISO	2016
Georgia	FERC Form 714	2016
Massachusetts	NE-ISO	Average of 2013–2015
Pacific Northwest	Northwest Power and Conservation Council	2015

Table 2. Data sources for end-use load shapes, by location[10]

Location	End-Use Load Shape	Source	Year of Data
California	Residential lighting, water heating, central air conditioning, commercial lighting	DEER end-use load shapes for Pacific Gas and Electric (PG&E)	2016
Georgia	Residential water heating, residential central air conditioning, commercial lighting	EPRI Load Shape Library 4.0; Southeast Electric Reliability Corporation reliability area	Submissions to EPRI from utilities; metered data.
Georgia and Massachusetts	Residential lighting	U.S. DOE Building America simulations	Typical Metrological Year (TMY) Version 3 (1991–2005)
Massachusetts	Residential water heating, residential central air conditioning, commercial lighting	EPRI Load Shape Library 4.0; Northeast Power Coordinating Council, New England reliability area	Submissions from utilities to EPRI; metered data
Pacific Northwest	Residential lighting, water heating, and air conditioning	Residential Building Stock Assessment (RBSA) metering	2014
Pacific Northwest	Commercial lighting	End Use Load and Consumer Assessment Program (ELCAP)	1987–1989

Note: DEER = Database for Energy Efficient Resources

[10] Exit signs were assumed to operate every hour of every day, and do not have source data.

Table 3. Data sources for avoided costs, by location

Location	Source	Year of Data
California	E3 Energy Efficiency Calculator, with PG&E end-use load shapes	2016
Georgia	Georgia Power Company Solar and Non-Solar Avoided Cost filing, 2016	2016
Massachusetts	National Grid cost-benefit calculator, 2016	2016
Pacific Northwest	Northwest Power and Conservation Council's 7th Power Plan	2016

The time-varying value for each efficiency measure varies by location due to: (1) the economic value of electricity savings of efficiency measures (i.e., avoided resource cost), (2) differences in an efficiency measure's impact on the underlying power system's load shape, (3) the scope, methods and assumptions used to derive their values (e.g., whether avoided transmission and distribution costs are considered).

Chapter 4 summarizes the main results and Chapter 5 offers recommendations for future research directions. Appendix A provides a tabular summary of end-use load research studies that have been conducted in the United States, building from information in Chapter 2. Appendix B provides case studies of the four locations included in this study, including a description of their market structure, approach to and experience with energy efficiency, availability of data, and methods used to apply end-use load shape data in utility resource and demand side management planning. Appendix C provides the total time-varying value of energy efficiency by measure, grouped by location.

Finally, this study raises a number of interesting research questions which are outside the scope of this analysis, including: the source of the variations in the end-use load shapes used in this study,[11] identification of best practices for derivation of the value of components of avoided costs,[12] best practices for hourly or interval end-use metering, transferability of end-use load shapes from one location to another location, and changes in the time-varying value of energy efficiency if more granular avoided costs are used.[13]

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[11] As shown in Table 2, the data sources for the end-use load shapes came from DEER, U.S. DOE, RBSA and ELCAP. It was outside the scope of this study to review the data sources to identify or explain anomalies or patterns.

[12] See Lazar and Colburn (2013) for a more robust discussion of this topic.

[13] For example, if more disaggregated locational transmission and distribution charges were used, the time-varying value of the energy efficiency measures would change. See Lazar and Colburn (2013) for a more detailed discussion of this topic.

2. Overview of End-Use Load Shape Data for Forecasting Energy and Demand Impacts

Understanding the difference between end-use load shapes and savings load shapes is critical to accurately quantifying the value of energy efficiency. All calculations of the time-varying value of electric energy efficiency require data on what devices (e.g., appliances, equipment, lights) are consuming electricity and the hourly and seasonal pattern of their consumption. These data are obtained through end-use load research, which involves measuring electricity consumption of an individual appliance or piece of equipment to obtain information on its demand on a sub-hourly, hourly, daily, weekly, monthly, seasonal, or annual basis.

End-use load research is used for a variety of other electricity planning functions, including: load forecasting, demand-side management and evaluation, capacity planning and demand response, integrated resource planning, renewable energy integration, smart grid investments, rates and pricing and customer service (KEMA 2012). End-use load research data can also serve as critical input to state and federal appliance and equipment standard development processes by providing actual field usage information that can inform both testing procedures and economic analysis.

2.1 End-use load shapes and energy savings shapes from efficiency measures

This study focuses on both end-use load shapes and energy savings shapes. Figure 1 shows the potential inaccuracy introduced in the calculation of the time-varying value of an efficiency measure if an end-use load shape, rather than the energy savings shape, is used. Figure 1 shows the end-use load shape for an electric resistance residential water heater and the shape of the savings resulting from its conversion to a heat pump water heater. The red line represents the electric resistance load shape, and the green line represents the saving shape of a heat pump water heater. Figure 1 illustrates that both the “peak” and “off-peak” savings from the conversion to a heat pump water heater do not follow the load shape of electric resistance water heating. Peak savings occur three hours earlier in the morning and nearly three hours earlier in the evening than would be estimated using the resistance water heating load shape.

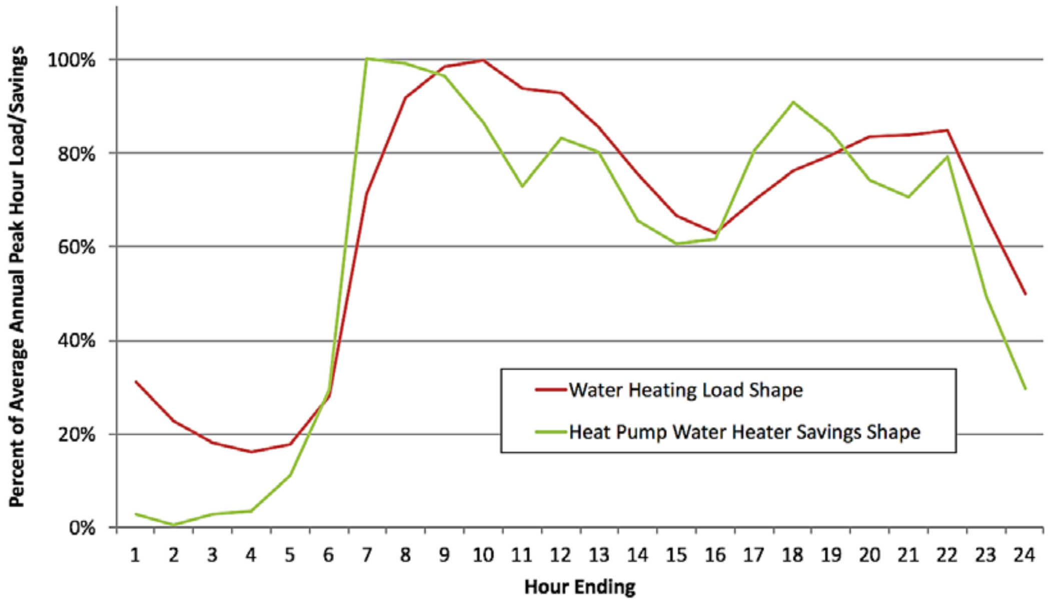

Figure 1. Comparison of a residential water heating load shape with a heat pump water heating savings load shape (Eckman 2014a)

To further illustrate the idea of end-use load shapes and electric savings load shapes, it is useful to consider the three ways that energy efficiency measures can reduce energy and peak demands: improved efficiency of end-use technology, controls, or a combination of improved end-use technology and controls.

- **Improved End-Use Technology:** These are energy efficiency measures that reduce the energy needed to accomplish a given task (e.g., use of LED lamps that require 12 watts to produce the same lumen output as 75 watt incandescent lamps). The savings from technology that reduces the energy required to accomplish a specific end-use task typically have the same shape as the end-use load shape. Higher efficacy lighting and high efficiency motors are examples of efficiency measures that produce savings which follow their end-use load shape.

- **Controls:** Controls often reduce the hours of operation of equipment (e.g., use of occupancy sensors to switch off lights in unoccupied spaces). The shape of the savings from controls are typically different than the underlying end-use because the savings result from modifying the duty cycle (i.e., changing the hours of operation)—not simply reducing the wattage used to perform the desired task.

- **Improved End-Use Technology and Controls:** These are efficiency measures that apply a combination of both energy reduction and reduced hours of operation (e.g., use of daylighting controls to reduce wattage and to switch off lighting when natural lighting is adequate, adding sensors and software to power down computers or televisions to standby mode when not in use). As with controls, the energy savings occur from modifying the end use duty-cycle (i.e., hours of use) so the savings load shape is not typically the same as the end-use load shape.

End-Use Load and Consumer Assessment Program (ELCAP)

ELCAP is one of the most comprehensive studies on residential and commercial end use in the United States. The Bonneville Power Administration gathered hourly and sub-hourly data from 1986 to 1989 from almost 500 residential sites and 140 commercial sites to create end-use and measure load shapes. In 2012, the Regional Technical Forum, an advisory committee to the Northwest Power and Conservation Council compiled the ELCAP data and reports into one location. The online database contains hourly site level meter data for 458 residential and commercial sites. Jenniges et al. (2012).

To summarize, the time pattern of savings from substitution of a more efficient technology does not always mimic the end-use load shape. First, some high-efficiency technologies affect both the wattage and hours required to perform a task. For example, converting electric resistance water heaters to heat pump water heaters, or electric resistance heating to ductless heat pumps, will produce savings that are shaped differently than the underlying end-use load shape (Figure 1). Second, the shape of the savings for improvements in technology that interact with other end uses (e.g., lighting efficiency improvements and space conditioning) produce total impacts on the power system that are different than either of the end-use shapes affected by the measure.[14] Third, the shape of the savings from efficiency improvements that involve technologies that are known to interact with factors in a non-linear fashion (e.g., heat pumps and air conditioners with outside temperatures and humidity) will differ from their end-use load shapes. For example, residential weatherization affects furnace run time by changing how long the interior of the building stays warm between furnace cycles. To accurately represent the impact of these measures on peak demands, their hourly energy savings shapes should be represented by the differential in end-use load shapes between the inefficient and efficient end-use technologies (i.e., the shape of the savings, not the shape of the load).

Currently, energy efficiency evaluation, measurement, and verification (EM&V) impact studies are the primary source for electric savings load shapes. However, to know if an energy efficiency measure has the same load shape as an end-use load shape, the evaluator must measure loads before and after the installation of the energy efficiency measure. A handful of measures are commonly monitored pre- and post-installation, including: lighting sweep controls/Energy Management System/time clocks, occupancy sensors, and building automation systems (Carlson 2012; Texas Public Utility Commission 2017).

2.2 Existing end-use load shape analyses: literature review

Three meta-studies have identified most, if not all, publicly available end-use load research in the United States. In a 2009 study co-funded by the Northwest Power and Conservation Council's Regional Technical Forum and the Northeast Energy Efficiency Partnerships (NEEP), KEMA (now DNV-GL)

[14] In addition to studying energy use, other factors of interest to power system planning and operation could be measured, such as power quality and harmonics. For example, the NEEA RBSA metering study measured the power factor for residential single family homes, in addition to the electricity demand (Ecotope 2014). These topics are outside of the scope of this study.

identified 110 compilation,[15] load research,[16] and evaluation[17] studies that gathered end-use load data in the United States from 1980–2009 (KEMA 2009). In 2012, KEMA updated their report with a focus on the Pacific Northwest (KEMA 2012). In 2016, a report for the Northwest Energy Efficiency Alliance (NEEA) built on the KEMA reports and identified an additional 55 end-use data studies in the United States that have been published since 2009 (James and Clement 2016). NEEA categorized the studies as direct measurement,[18] disaggregation/non-intrusive interval monitoring,[19] and end-use documentation.[20] Appendix A lists the 165 studies that were identified by NEEA.[21]

The reports have several important findings:

- Commercial and residential *end use* data are limited due to age and geographic representation. Commercial and residential energy *savings shape* data are extremely limited across both measures and geographic representation. (KEMA 2009; Grist 2016; Stern 2013; James and Clement 2016). The exception to this is in the Pacific Northwest, where data on residential end-use load shapes and limited energy savings shapes has been collected.
- End-use load shape and energy savings shape data are not being collected in the United States in an organized or methodical way. It is occurring regionally, on an ad-hoc basis, and there are few comprehensive end-use load studies (KEMA 2009; James and Clement 2016).
- Most end-use load data studies in the United States focus on specific end uses (James and Clement 2016). Direct measurement or end-use documentation are the most common sources of information for specific end uses (James and Clement 2016). Of the end-use load data efforts that are broader than one end use, non-intrusive load monitoring using smart meter data disaggregation is common (James and Clement 2016).
- There is a greater need for non-residential end-use data than for residential end-use data. There has been little non-residential end-use data research since the ELCAP study (KEMA 2009; James and Clement 2016).
- There is low transferability of weather-sensitive end-use data from one region to another for the majority of load in both the residential and non-residential sector (KEMA 2009; James and Clement 2016).

[15] Studies that "compiled primary interval data from other studies and used either DOE-2 modeling or statistical modeling techniques to produce average end-use load shapes." (KEMA 2009)

[16] Load research studies "utilized long-term end-use power metering to develop average end-use load shapes. The samples were typically selected to define end-uses at the tariff class level with little or no customer-specific data collected other than interval power data." (KEMA 2009)

[17] Evaluation studies "primarily focused on evaluating savings impacts for energy efficiency measures or demand response programs." (KEMA 2009)

[18] "Direct measurement requires the installation of current transformers on each circuit to monitor the load. The benefit of this approach is measuring actual data at the circuit level." (Hewitt 2015)

[19] "Non-Intrusive Load Monitoring analyzes changes in voltage and current going into a house and deducing what appliances are used in the house as well as their individual energy consumption." (James and Clement 2016)

[20] End use documentation studies "document various end-uses in residential and commercial locations, but they do not capture any load shape data for these end-uses." (James and Clement 2016)

[21] EPRI Load Shape Library is in version 4.0, and the NEEP catalog has been updated since the James and Clement 2016 paper was published.

2.3 Planned end-use load shape studies and databases

Since the NEEA report was published, California, New England, and the Pacific Northwest are in the process of conducting additional end-use load research. There are four major projects planned, or currently under way, intended to update and expand the available end-use load research data. These projects are described below.

- The California Energy Commission (CEC) issued a Request for Proposals in April 2016 for a market analysis on existing and future electricity load, including end-use load shape characterizations from existing electricity technologies, and analyzing how load shape may change over time due to changes in technology mix or end-user consumption patterns (CEC 2016). In May 2016, the CEC staff issued a notice of proposed award recommending ADM Associates be selected to conduct the work (CEC 2016).
- In 2016, PG&E's Codes and Standards team identified a need for updated end-use load research data. After evaluating the results of NEEA's Residential and Commercial Building Stock Assessment projects, PG&E found that NEEA's data were not completely relevant to California. However, PG&E determined that a California-specific study that is modeled after NEEA's studies could provide a robust dataset. PG&E is structuring the research such that the California data will be easily combined with the NEEA data. Together, these data will provide end-use load research for 8 percent of the U.S population. PG&E will place 36 end-use meters in approximately 150 homes throughout their service territory. Meter installation is anticipated to be complete in late 2017.
- NEEA anticipates collecting additional end-use load data in 2018 as part of a project to continuously update and expand end-use load data in the Pacific Northwest. The project will collect residential and commercial energy consumption data at the circuit level, with a focus on heating, ventilation, air conditioning, and water heating data. Both the residential and commercial data gathering efforts will occur for five years, with new homes or buildings added each year.
- NEEP identified several areas for research in the Load Shape Catalog, including updating data for small business and commercial and industrial (C&I) heating, ventilation and air-conditioning (HVAC) load shapes, lighting controls pre-installation data (to identify the energy savings shape), and C&I LED light load shapes.[22]

2.4 Issues with existing end-use data

The majority of reports evaluating publicly available end-use load research express four concerns: (1) lack of end-use and energy savings shape data, (2) low transferability of data from one geographic region to another, (3) the use of obsolete or unreliable data, and (4) use of potentially inaccurate end-use measure and electric savings load shapes.

[22] See the NEEP Loadshape Report and Catalogue: http://www.neep.org/loadshape-report-and-catalogue

2.4.1 Limited end-use and energy savings shape data

Most reports conclude that there is limited reliable end-use load shape data available (KEMA 2009; Grist 2016; James and Clement 2016). There is even less data on energy savings shapes (KEMA 2009; Grist 2016; Stern 2013). The two most recent reports on the topic—the KEMA study and the NEEA study—both concluded that significant gaps remain in the residential and commercial end-use load research (KEMA 2009; James and Clement 2016).[23] While other end-use load shape studies have been completed since the seminal ELCAP study in the late 1980s, there are few, if any, studies that address the vast array of building types and end uses found in commercial buildings. Moreover, the residential studies that have been conducted largely focus on specific end uses and have limited sample sizes that do not address energy savings shapes (James and Clement 2016).

Location, Location, Location

The transferability of heating/cooling load shapes is limited even across locations with similar heating and cooling degree days. For example, using heating load shapes for locations with long mild heating seasons (e.g., Astoria, Oregon/Seattle, Washington), versus those with shorter, more intense heating season (e.g., Columbia, Missouri/ Kansas City, Missouri) could produce significant errors in estimating both energy and peak demand impacts. While these locations have roughly equivalent annual heating degree day base 65°F, they have significantly different annual heating degree days at base 60°F, and the shape of the heating seasons differs considerably. As a result, both the annual energy and peak demand of the saving for upgrading a heat pump would vary significantly between these locations.

2.4.2 Low transferability of data across regions

Several studies have suggested the option of transferring end-use load shapes from one region to another (KEMA 2009; KEMA 2012; James and Clement 2016). Based on the schedule variability (low being the easiest to transfer), and weather variability (low being the easiest to transfer), the 2009 KEMA study concluded that residential kitchen and laundry appliances, refrigerators, interior and exterior lighting, and plug load end uses have the highest data transferability from one U.S. region to the next (Table 4). KEMA rated non-residential end uses such as laundry appliances, data center equipment, compressed air, food service equipment, and lighting as being highly transferrable across regions (Table 5).

However, some of the largest building end-uses, such as HVAC data, have low transferability. In the residential sector, HVAC accounts for about 47 percent of household energy consumption, and 33 percent of non-residential consumption (EIA 2013; EIA 2016). The KEMA report also concluded that, while there are some usable end-use data sets available, "limitations on transferability imposed not by inconsistency of methodology and data format, but by heterogeneity of critical determinants of load shape" created significant limitations on transferability of data (KEMA 2009: KEMA 2012).

[23] Since the KEMA study, NEEA did close some of the single family residential load research gap by completing its Residential Building Stock Assessment, but did not address gaps in end-use load research in multifamily or manufactured homes, or in commercial buildings. Accordingly, NEEA is undertaking its new end-use load research efforts discussed above.

Table 4. Residential analysis groups transferability ratings (KEMA 2009)

Analysis Group	Schedule Variability	Weather Variability	Transferability Rating
Appliances - Kitchen	Medium	Low	High
Appliances - Laundry	Medium	Low	High
Appliances -Refrigerators	Low	Medium	High
Domestic Hot Water	Low	Medium	Medium
HVAC – Cooling	Medium	High	Low
HVAC – Fan Energy	Medium	High	Low
HVAC - Heating	Medium	High	Low
HVAC - Ventilation	Medium	Medium	Low
HVAC - Other	Medium	High	Low
Lighting - Exterior	Medium	Low	High
Lighting - Interior	Low	Low	High
Plug Load	Low	Low	High
Pool Pump	Low	Medium	Medium

Table 5. Non-residential analysis groups transferability ratings (KEMA 2009)

Analysis Group	Schedule Variability	Weather Variability	Transferability Rating
Agricultural - Process	Medium	Medium	Medium
Agricultural - Pumping	Medium	Medium	Medium
Appliances - Laundry	Low	Low	High
Clean Room	Low	High	Low
Compressed Air	Low	Low	High
Data Center Equipment	Low	Low	High
Data Center Cooling	Medium	High	Low
Food Service Equipment	Low	Low	High
HVAC - Cooling	Low	High	Low
HVAC - Fan Energy	Low	High	Low
HVAC - Heating	Low	High	Low
HVAC - Other	Low	High	Low
HVAC - Reheat	Medium	High	Low
HVAC - Ventilation Only	Low	High	Low
Industrial - Process	Medium	Medium	Medium
Lighting - Exterior	Low	Low	High
Lighting - Interior	Low	Low	High
Motors - Drives	Medium	Medium	Medium
Plug Load (Electronics)	Low	Medium	Medium
Pump	Low	Medium	Medium
Refrigeration	Low	High	Low
Water Heating	Low	Medium	Medium

2.4.3 Obsolete and unreliable data

Several reports identified concerns with use of obsolete data, and the potential for inaccuracy (KEMA 2009; KEMA 2012; James and Clement 2016). For example, Figure 2 shows the difference in hourly load shape between the stock of electric resistance water heaters in use in 1990 and a large sample of heat pump water heaters, as well as the current (2014) system winter weekday demand across the Pacific

Northwest. Reliance on the outdated 1990 electric water heating load shape could lead to errors in estimating the impact of heat pump water heater efficiency measures on peak demand.

The Pacific Northwest system has both a morning and evening winter peak (Figure 2). The horizontal axis on this graph plots the hour of the day with hour 1 equal to hour between midnight and one AM. The vertical axis plots the percent of maximum (i.e., peak) hourly demand that occurs at each hour of the day. The morning peak generally occurs between hours 8 and 9, while the evening peak generally occurs between hours 18 and 19. In 1990, peak demand for the electric resistance water heaters occurred between hours 7 and 8, while the peak demand for heat pump water heaters occurs between hours 10 and 11. During the evening system peak hour, the demand of the 1990 stock of resistance water heaters was just under two-thirds of its daily maximum, while the demand of heat pump water heaters was around 75 percent of its daily maximum. Even after adjusting for their higher efficiency, the use of the 1990 load shape data for a heat pump water heating efficiency measure would understate capacity savings during the morning system peak and overstate capacity savings during the evening peak hour.[24]

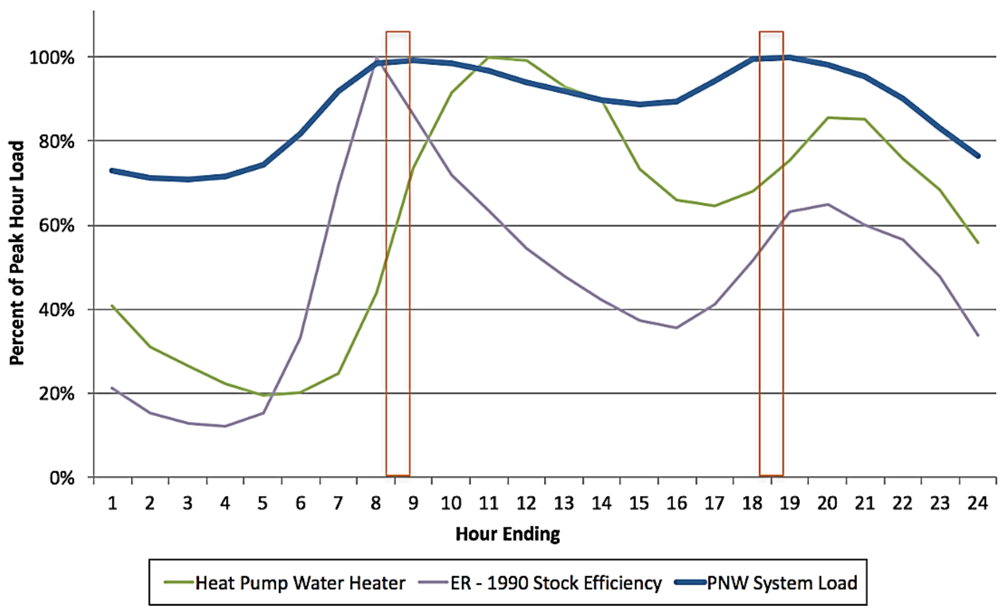

Figure 2. Annual hourly load shapes for two vintages of electric water heaters

Recent efforts to update obsolete data have used non-intrusive load monitoring devices and software. Non-intrusive load monitoring systems are designed to "measure total house electricity use at a single point and then to disaggregate individual load energy via various approaches" (Larson et al. 2016). There are many companies that offer technology to disaggregate whole home energy data (obtained with non-invasive load monitoring, direct use, or otherwise) including Bidgely, PlotWatt, Smappee, Neurio, Navetas, Belkin, and Intel (Greentech Media 2015). Unfortunately, research on the accuracy of

[24] Based on end-use metered data, the maximum daily winter weekday peak demand measured for heat pump water heaters was 0.43 KW, while the comparable value for the stock of electric resistance water heaters measured in ELCAP between 1987 – 1989 was 1.19 KW.

disaggregation techniques found that the devices and software were able to accurately record total home energy load, and some major end uses (e.g., space and water heating) but could not accurately estimate other end-use loads (Baker et al. 2016; Mayhorn et al. 2015).

Both NEEA and the Pacific Northwest National Laboratory (PNNL) recently evaluated the accuracy of non-intrusive load monitoring systems. NEEA commissioned a study to evaluate the accuracy of non-intrusive load monitoring devices by comparing three non-intrusive load monitoring platforms to measured household energy consumption data (Larson et al. 2016). PNNL conducted analysis on the same non-intrusive load monitoring devices (Mayhorn et al. 2015). In both the NEEA and PNNL studies, the data from the non-intrusive load monitoring platforms was compared to NEEA's Residential Building Stock Assessment Metering (RBSA) project, which measured major energy end uses, including "heating, air-conditioning, hot water, appliances, televisions and television accessories, and computers and computer accessories" in 101 homes in the Pacific Northwest (Larson et al. 2016). However, this finding should not be used to discourage the development of non-intrusive load monitoring and disaggregation technologies, but rather to help inform and improve the research (BPA 2014).

2.4.4 Use of engineering estimates to create end-use load shapes

In lieu of end-use metering data, building energy simulation models have been employed to create end-use load and energy savings shapes. There are concerns that the use of end-use load shapes developed through these building simulation models exhibit large discrepancies between the model's prediction of energy consumption and actual energy consumption. Specifically, as it relates to characterizing the end-use load shapes or energy savings shapes at the utility system level, simulation modeling requires inputs that reflect the actual diversity in operating schedules across the population of buildings with an end-use or efficiency measure installed. Other concerns identified with use of building simulation data include: extrapolation of short term meter data into an entire year of usage data, inability to predict occupant behavior, under- or over-accounting for the impacts from weather, internal heat gains, operation and maintenance changes, changes in building equipment, and changes in the building interior conditions (KEMA 2009; Sun et al. 2015).

3. Time-Varying Energy and Demand Impacts of Electric Efficiency Measures

End-use load research provides annual hourly energy and capacity data that enhances the accuracy of efficiency valuation. To properly calculate the utility system value of electricity savings, it is necessary to account for both variations in hourly savings and variations in hourly avoided cost. This section describes the general methodology required to account for the time-varying value of electricity savings to the utility system and provides five examples of efficiency measures that illustrate how the time-varying values might be derived in four geographically diverse areas of the United States.

How are diversity factors and coincidence factors used to estimate utility system peak reductions from energy efficiency savings?

A **diversity factor** accounts for the fact than an individual efficiency measure may save a certain amount of demand, but across an entire program not all of the locations where the measure was installed operate at the same time. For example, if a maximum of 6 of 10 installed LEDs are on at any given time, then the **diversity factor** for this measure is 0.6. The product of the diversity factor and the maximum demand reduction from all installations is referred to as the *diversified demand*.

A coincidence factor accounts for whether or not an end use efficiency measure is reducing use at the same time as the electric system peak. The diversified demand for an end use may or may not align exactly with the utility system peak. For example, if only 2 of the 6 installed LEDs are typically on at the time of the system peak (i.e., their use occurs simultaneously with the system peak), then this measure's savings have a **coincidence factor** of 2/6 or 0.33. Thus, the peak demand savings for an efficiency measure is calculated as the product of the coincidence factor, diversity factor, and maximum demand at individual sites.

3.1 Methods used to estimate time-varying energy and capacity impacts

There are two general approaches for capturing the time-varying value of electricity savings. The most common method (Method 1) uses daily or seasonal load shape data, or both, to allocate energy savings into peak periods and off-peak periods, and uses coincidence factors (see the glossary and text box above) to estimate peak impacts. Method 2 uses annual hourly data on both energy savings and avoided costs (Stern 2013).[25] Both approaches require data on the load shape of efficiency measure savings, utility system load shapes, and utility system avoided costs. The primary differences between the two methods are the fidelity or granularity of their data requirements and the method used to determine peak reduction impacts of efficiency measures.

Method 1 is based on "typical daily" load profiles for peak and off-peak periods (e.g., a typical summer weekday or a typical winter weekday). To reduce data requirements, rather than computing the value

[25] See Stern (2013) for a more detailed explanation of alternative approaches that can be used to estimate peak energy savings; some of these approaches do not rely on end-use metered data.

of energy savings at hourly intervals, data are first aggregated into at least two periods: one that represents the energy savings and avoided cost during peak hours, and a second that represents the energy savings and avoided cost during off-peak hours. Additional time periods may be added to increase the fidelity of the analysis by subdividing the peak and off-peak hours into smaller time segments such as summer peak hours, summer off-peak hours, winter peak hours, and winter off-peak hours. Regardless of the number of periods used, the time-varying value of efficiency savings is calculated by multiplying the share of annual energy savings occurring in each time period and the avoided cost for that same period; then the value across all periods is summed.

The timing of savings from each site where efficiency measures are installed are not necessarily aligned exactly with the utility system peak—which is how the avoided peak demand is defined—so this approach requires an estimate of the reduction in electricity demand (expressed in kilowatts, kW) produced by an efficiency measure that is coincident with a utility system's peak load. The metric that represents the fraction of the peak demand reduction from an efficiency measure, across all installations, that occurs at the time of a utility system's peak is referred to as the measure's *coincidence factor*[26] (see the text box for an additional explanation of how system peak demand reductions are derived).

The peak demand impact of an efficiency measure using this approach is computed by multiplying the peak coincidence factor of a measure's savings times the average peak reduction across all program participants. This is done to determine the amount of demand reduction from a measure or program that occurs simultaneously with the utility system's annual peak demand. If multiple peak periods occur across the year, coincidence factors specific to each period are used. The value of these savings is calculated as the coincident peak demand savings (in kW or megawatts, MW), and the avoided cost of new generating, transmission, distribution, and other avoided cost associated with peak demands. Installation of energy efficiency measures, demand response and other new electric energy technologies (e.g., solar PV, EVs) will move peak load hours earlier or later in the day, so coincidence factors must be updated regularly.

[26] In some cases, *coincidence factor* is defined as the ratio of peak demand to *maximum* demand, rather than *diversified* demand. In the example in the text box, the maximum savings is for all 10 LEDs installed. However, if only 3 LEDs are operating during the system peak, then under this definition this measure's savings would have a coincidence factor of 3/10 or 0.3. This definition of coincidence factor automatically accounts for diversity factor, and only the coincidence factor is necessary to determine peak demand reductions. However, both applications of the coincidence factor result in identical demand savings. The second definition simply incorporates the diversity factor adjustment in the derivation of coincidence factor.

Sources of Time-Varying Avoided Costs

The deployment of efficiency measures and programs can, in the near term, reduce fuel costs, and over time defer the need to add generation, expand transmission and distribution infrastructure, and decrease the requirement for additional ancillary services. Therefore, its economic value depends on the cost, timing, and magnitude of required investments in these utility system assets. As a result, the methodology for deriving the time-varying value of electric savings using hourly data is often implemented through an integrated resource plan (IRP) process or other similar long-term system resource expansion modeling. While IRPs are typically done by vertically integrated utilities, similar long-term system resource expansion modeling may be carried out through processes used to establish avoided costs in organized markets. For example, both New England and California publish avoided cost studies for use in evaluating the cost-effectiveness of energy efficiency, which model the characteristics of specific generating resources as a proxy for cost avoided by energy efficiency savings.

The primary difference between IRP processes and avoided cost studies is that IRPs are designed to evaluate and select the most economic and reliable resources to meet both energy and peak capacity needs by considering the full range of resource alternatives in order to provide adequate and reliable service to electric customers at the lowest system cost. These include new grid-scale generating capacity, power purchases, energy efficiency, demand response, cogeneration and district heating and cooling applications, and non-grid-scale distributed energy resources, including renewable energy. If using best practices, the IRP modeling will allow energy efficiency to compete directly with supply side (i.e., generation) alternatives and distributed resources (DR) so that the most economical solution to both energy and capacity resources needs can be identified. In such analysis, both the energy and capacity characteristics of efficiency measures are modeled. In contrast, most avoided cost studies select one or more representative supply side resources. For example, simple cycle combustion turbines are often selected to serve as a proxy for the cost of supplying new peaking capacity, and combined cycle combustion turbines are used as a proxy for the cost of supplying base load energy.

The use of coincidence factors to compute the time-varying value of electricity savings does not directly involve hourly load shape data, although such data are required to derive the diversity factors and coincidence factors used in such calculations. The primary difference is that the hourly load shape data used to derive diversity factors and coincidence factors need only reflect typical hourly load shapes during peak and off-peak periods. This approach also requires data on the proportion of an efficiency measure’s annual energy savings that occurs within peak and off-peak periods during the year. Coincidence and diversity factors, as well as data on the proportion of savings occurring during peak and off-peak periods, are most accurately obtained through interval or end-use metering analysis. However, such data can be ascertained through alternative approaches, such as engineering algorithms, building simulation modeling, and billing analysis (Stern 2013).

Method 2 is more data intensive and derives the time-varying value of electric efficiency savings using hourly data over the year. This method requires hourly load shapes of the savings from energy efficiency measures that are representative of their system-level impact over an entire year (i.e., the diversified impact of the entire population of program participants or potential program participants).[27] In Method 2, to compute the time-varying value of electricity savings, we multiply an efficiency measure's estimated savings for each hour of the year by the hourly avoided cost for that same hour and then sum these over all hours of the year. Rather than use coincidence factors to estimate peak demand impacts, the demand impacts for each hour are derived directly from the efficiency measure's load profile.

Method 2 offers more flexibility for accounting for future changes in the net load shape of power systems than Method 1 does. This is because Method 1 determines the peak impacts of energy efficiency savings through the use of historical coincidence factors or diversity factors to calculate the value of efficiency. It is reasonably accurate; however, the coincidence or diversity factors will need to be modified as the net load shape of the power system changes through time. For example, an electric system with a high saturation of distributed photovoltaic generation may have a peak period that shifts to later in the day, so savings from commercial air conditioning based on today's coincidence factors will no longer be accurate. Use of historic coincidence factors to estimate an energy efficiency measure's peak impacts will require additional load research to determine new coincidence factors, or modification of existing coincidence factors to remain accurate as system load shapes change. In contrast, in Method 2, the use of hourly data only requires that the net system hourly load shape and hourly avoided cost be used in the calculation; no new load research is required.

Variation in Avoided Costs

The values for avoided costs are typically derived through IRP or similar long-range resource capacity expansion modeling processes or avoided cost studies (see text box above). Individual entities will have differing components and input values for each component of avoided cost, due to specific utility system resource needs, as well as the need to consider other non-energy costs and benefits.

Regardless of which method is used, a determination must be made regarding the scope of the costs that are "avoided" by the energy efficiency measure's energy and capacity savings. This study focuses primarily on the utility system avoided cost resulting from energy and capacity savings.[28] The cost includes avoided investments in energy generation (including both fuel and capital cost), avoided capital investments in peak capacity, deferred

[27] The hourly shape of the measure savings must be representative of the diversity of operation across all installations of the measures. For example, a residential lighting savings load shape should reflect the fraction of all lamps in all homes that are on during each hour, rather than the fraction of all lamps that are on in an individual residence.

[28] This paper intentionally focuses on the electric utility system value of electric energy efficiency savings. If non-energy benefits (NEBs) are constant throughout the year/day, then they simply add a uniform value across all hours. However, if the value of a NEB varies significantly with time of day or season of the year then its time -varying value could also be added to the time-varying value of utility system benefits. See Lazar and Colburn (2013) for a more extensive treatment of both utility system and non-utility system benefits of energy efficiency savings.

investments in transmission and distribution capacity, and reduced requirements for additional ancillary services such as spinning and operating reserves. Depending on the location and the market structure, other avoided utility system costs might include avoided cost of compliance with CO_2 and other emissions regulations, avoided renewable portfolio compliance costs, risk mitigation costs, and DRIPE.

The following is a brief summary of each of the avoided costs. More detailed information, including the derivation of time-varying value of energy efficiency measures for this study is available about the avoided costs for each of the four locations in Appendix B.

- **Energy-related cost:** Levelized cost by time segment (e.g., hourly, by peak or off-peak period) of additional energy (kilowatt-hour, kWh) supplies.[29] In a vertically integrated utility system, these costs are typically represented by the levelized cost of energy from a new power plant, including fuel, capital, fixed operation and maintenance cost and periodic capital replacement cost. In organized markets (e.g., PJM, MISO, ISO-NE) and in areas where utilities have access to wholesale electricity markets, avoided energy costs are typically represented by the forecast of future market prices.
- **Generation capacity-related cost:** Levelized cost by time segment ($/kWh) or present value cost by time segment ($/kW-yr.) of deferred peaking capacity, including fuel, capital, fixed operation and maintenance cost, and periodic capital replacement cost. Depending on the location and avoided cost methodology, this value may be determined by a proxy generating unit or the marginal capacity value of the system.[30]

[29] Levelized cost of energy is "the per kilowatt-hour cost (in discounted real dollars) of building and operating a generating plant over an assumed financial life and duty cycle." EIA 2017. Use of levelized cost allows for comparisons in the cost or value of energy resources which vary in size and lifetime. All energy and capacity related levelized avoided cost specified in KW-year were converted to levelized cost per kilowatt-hour based on assumed site annual savings of 1,000 kWh (1 MWh) distributed across each hour (or season) based on load shape of the specific end use. For example, for the Exit sign (i.e., flat) load shape, savings in each hour were 0.114 kWh (1000 kWh/8760 hours). For a levelized cost of $100 KW-yr. this translates into a levelized value of $0.014/kWh for this load shape.

[30] In California and Massachusetts, energy efficiency calculators were used to determine the avoided cost of the energy efficiency measures. Both calculators rely on a simulated dispatch cost for a new generator entering the wholesale market.

- **Transmission capacity-related cost:** Levelized cost by time segment ($/kWh) or present value cost by time segment ($/kW-yr.) of transmission system expansion avoided or deferred as a result of peak demand savings.
- **Distribution capacity-related cost**: Levelized cost by time segment ($/kWh) or present value cost ($/kW-yr.) of distribution system expansion avoided or deferred as a result of result of peak demand savings.
- **Ancillary services:** Reduced requirements for spinning and operating reserve capacity, if not captured in generation capacity cost ($/kW-yr).
- **Carbon dioxide (CO_2) cost:** Levelized cost of CO_2 emissions by time segment ($/kWh) if applicable (e.g., Regional Greenhouse Gas Initiative (RGGI), California CO_2 cap and trade) or compliance costs.
- **Renewable resource cost:** Reduced development obligation by time segment ($/kWh). Applicable where Renewable Resource Portfolio Standards (RPS) obligations exist.
- **Risk mitigation cost:** Value of reducing exposure to fuel price, technology change, and other stochastic variation in planning assumptions ($/kWh).
- **Demand-reduction induced price effect (DRIPE):** Value by time segment of reductions in wholesale market prices for energy, capacity, and cross-fuel from reduced demand for energy or capacity ($/kWh or $/kW).[31]

Some jurisdictions and utilities have developed "calculators" designed to establish the time-varying value of efficiency resources using both Method 1 and 2. These calculators use forecasts of locally applicable avoided cost, along with end-use load shape data to compute the time-varying value of efficiency savings. For example, a calculator developed by National Grid based on the New England avoided cost study implements Method 1. This calculator uses four periods (summer on and off peak and winter on and off peak) for valuing energy savings. It includes the avoided cost of energy, capacity, transmission, distribution, CO_2, and DRIPE. To determine peak capacity impacts, the National Grid calculator uses two periods (winter and summer) with coincidence factors specific to those seasons (National Grid 2016). In contrast, the calculator prepared for use by investor-owned utilities in California uses Method 2 (E3 2015).

3.2 Examples of the time-varying value of electric energy savings

The economic value of electricity savings varies across measures and across regions of the country due to differences in a measure's impact on the underlying power system's load shape, the avoided resource costs, and the methods and assumptions used to derive their values (e.g., whether avoided transmission and distribution costs are considered). In this section, we provide examples of the time-varying values for five efficiency measures in four U.S. locations and describe the assumptions used to

[31] DRIPE refers to the reduction in wholesale market prices for energy and/or capacity expected from reductions in the quantities of energy and/or capacity required from those markets during a given period due to the impact of efficiency and/or demand response programs. Thus, DRIPE is a measure of the value of efficiency received by all retail customers during a given period in the form of expected reductions in wholesale prices. The avoided cost value of DRIPE during a given time period is equal to the projected impact on the wholesale market price during that period, expressed as a $ per unit of energy, multiplied by the quantity of energy purchased at rates or prices tied directly to that given market price. (Source: Avoided Energy Supply Costs in New England: 2015 Report, Prepared for the Avoided-Energy-Supply-Component (AESC) Study Group. March 27, 2015 (Revised April 3, 2015).

calculate each measure's peak demand impacts. We compare the time-varying value of the five measures to their value as determined by using annual savings and average annual avoided cost. This approach provides a baseline upon which to judge the impact of valuing efficiency savings based on the energy savings shape.

3.2.1 Examples of end-use load shapes

The five measures chosen to illustrate time-varying impact were selected based on when they save energy, in two different ways. First, the savings are assumed to follow the load shape of one of five end uses, and second, they illustrate the difference in value for winter and summer peaking electric systems.

- **Exit sign:** This measure is representative of measures that operate all hours of the year, and has a uniform (i.e., flat) savings across all hours of the year. This load shape does not vary across geographic location, so its value is not affected by differences in end-use load shape by location.
- **Residential electric high-efficiency water heating and air conditioning:** These measures are representative of measures that are highly coincident with peak demands (e.g., water heating in the Pacific Northwest, air conditioning in the summer in other U.S. locations).
- **Residential lighting:** These measures are representative of a measure that may contribute differing amounts toward peak demands depending upon the season of the year and location. They are often the largest share of savings in energy efficiency programs.
- **Commercial lighting:** These measures are representative of a measure that is similar across all locations and highly coincident with peak demands. They typically represent a significant share of efficiency program savings.

The four locations selected for comparison are the Pacific Northwest, California, Massachusetts, and Georgia. Appendix B describes the methodologies used to apply end-use load shape data in utility resource and demand side management planning gin the four locations reviewed in this study.[32] These areas were selected based on their differing power system load shapes, market structures, approach to and experience with energy efficiency valuation, and availability of data. Two of the locations (New England and California) have organized markets and two locations (Georgia and the Pacific Northwest) retain vertically integrated utility systems. ISO-NE's wholesale market encompasses multiple states and includes a forward capacity market. The California Independent System Operator (CAISO) does not have a forward capacity market. The Pacific Northwest region is unique because it has the only federally established regional integrated planning process. Moreover, nearly 40 percent of its power is provided by the Bonneville Power Administration, a federal power marketing agency. Georgia retains the traditional vertically integrated utility business model, and has an IRP requirement for Georgia Power Company, but does not have an energy efficiency resource standard.

[32] The description of each location's approach to the valuation of energy efficiency is organized into four areas: (1) energy efficiency policy and regulatory context; (2) resource needs assessment process (i.e., how future needs for energy and capacity resource acquisitions are established); (3) cost-effectiveness determination process and criteria; and (4) derivation of time-varying value of EE measures for this study.

If end-use load shape data are so limited, what's the source of the load shapes used in this study?

Hourly end-use load shape data was not available for all locations included in this study. End-use load research and hourly load shapes are available for the Pacific Northwest for all five end uses as a result of the ELCAP project and NEEA's Residential Building Stock Assessment. Load shapes for California are from the E3 Energy Efficiency Calculator, using the DEER database end-use load shapes for PG&E. The end-use load shapes shown in Figures 6–12 for Massachusetts and Georgia are based on hourly load shapes data obtained from EPRI's Load Research Library 4.0 (http://loadshape.epri.com/enduse), except for residential lighting, which are based on Building America simulations (http://en.openei.org/datasets/files/961/pub/). Load shapes for residential water heating, air conditioning, and commercial lighting for New England are based on EPRI's data for the Northeast Power Coordinating Council – New England reliability area. End-use load shapes for Georgia are based on EPRI's data for the Southeast Electric Reliability Corporation reliability area.

EPRI clearly states that while the Load Shape Library presents best-available data, it does not represent statistically valid usage. EPRI cautions that users should treat the Load Research Library data as a sample reference since the confidence and precision levels of the data are unknown.

Appendix B provides an explanation of the data and methods used in the calculation of the time-varying value of savings shown in this report.

Figure 3 shows annual monthly system load shape for each of these locations. The vertical axis shows the peak monthly demand as a percent of annual system peak month's demand, where 100 percent is the month of the yearly system peak. The Pacific Northwest has a winter peaking system, and 100 percent of the peak monthly demand occurs in December and January. California, Georgia and Massachusetts have more traditional system shapes that peak in the summer months (i.e., July or August reach 100 percent), driven by air-conditioning loads. The summer peak demands for these three areas are also significantly higher than their winter peaks.

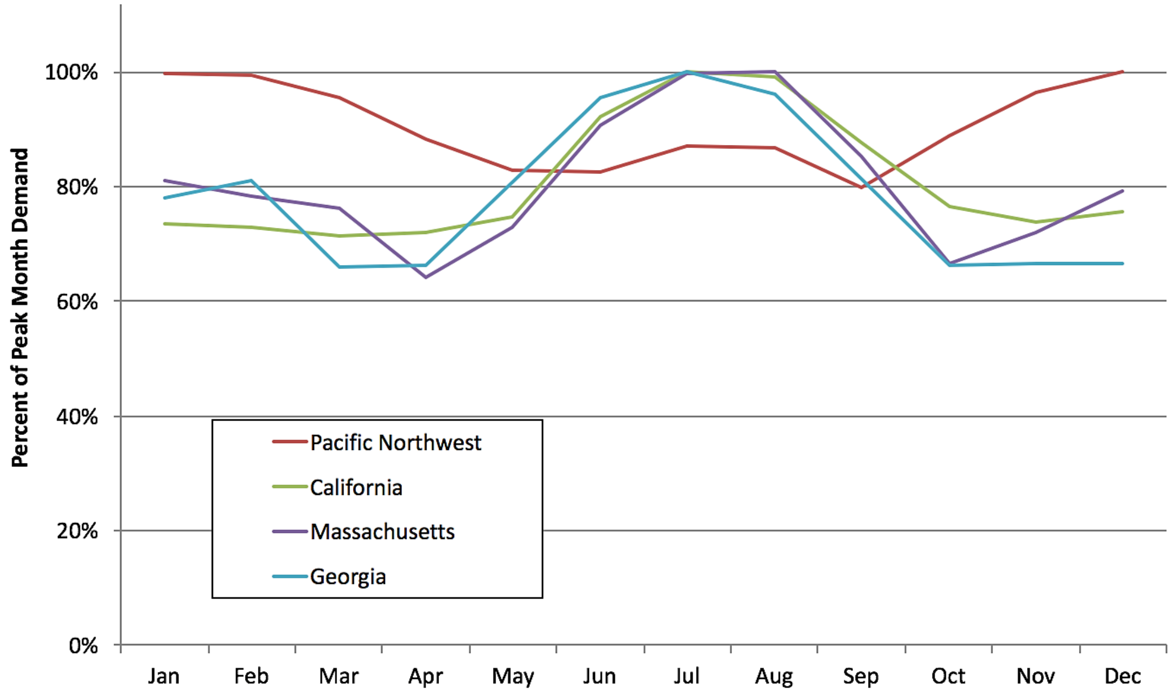

Figure 3. Annual monthly system load shape for the Pacific Northwest, California, Massachusetts, and Georgia

Figure 4 and Figure 5 show the daily summer and winter hourly system load shape, respectively, for these four locations. The horizontal axis on these figures plots the hour of the day with hour 1 equal to the hour between midnight and 1 AM. The vertical axis plots the percent of maximum (i.e., peak) hourly demand that occurs at each hour of the day. For example, Figure 4 shows that the peak hour demand (i.e., when the percent of peak hour load equals 100 percent) on a summer day in California is hour 16, and that at hour 5 system loads are only 60 percent (i.e., the percent of peak hour load equals 60 percent) of the day's peak demand. In contrast, the maximum peak hour demand for the Pacific Northwest is between hour 16 and 17, but even at that hour it is only about 90 percent of annual hourly peak demand, which occurs in the winter.

Summer peak demands in California, Georgia, and Massachusetts occur during the middle of the afternoon (see Figure 4). The difference across locations in their summer load shapes is driven by both climate and the prevalence of air conditioning. For example, in California, hourly loads increase more slowly than in Massachusetts and Georgia, where nighttime temperatures and humidity remains higher than in California. In contrast, in the Pacific Northwest, which has a more temperate climate and lower saturation of air conditioning, summer loads rise gradually until around 11 AM (hour 11) and remain at roughly the same level until very slowing declining after 6 PM (hour 18).

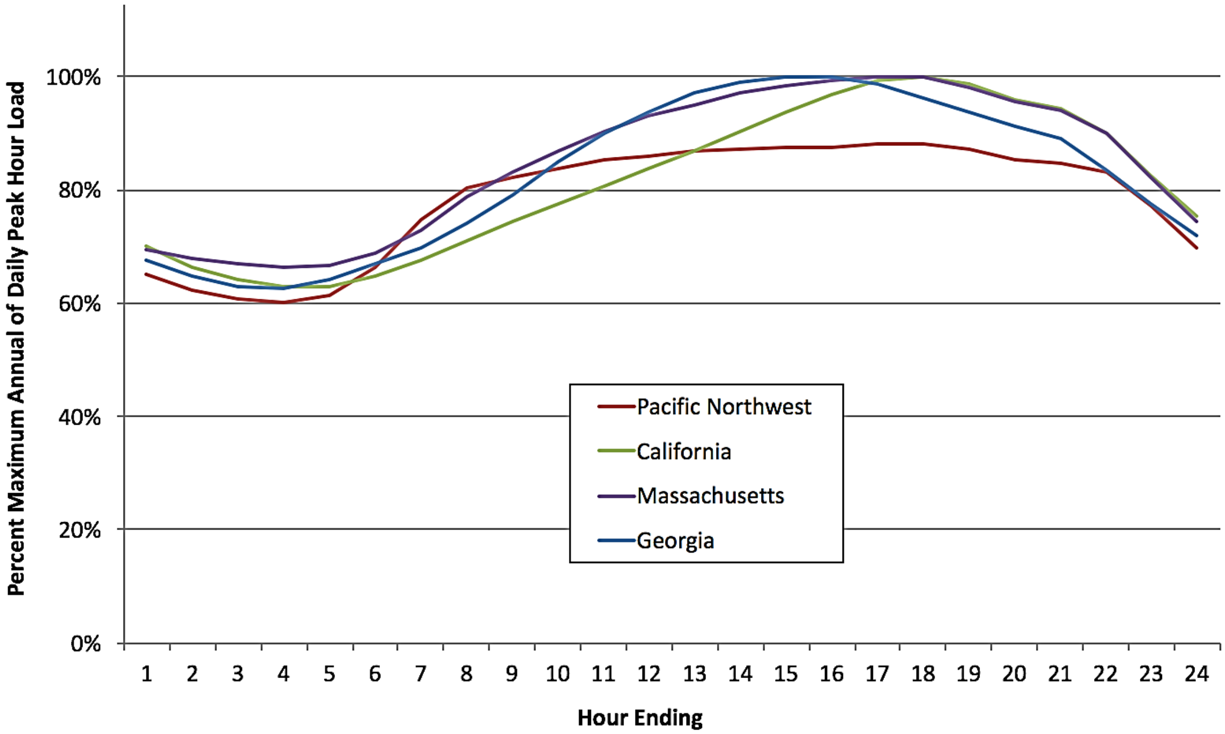

Figure 4. Hourly load shape on a typical summer day for the Pacific Northwest, California, Massachusetts, and Georgia systems

Figure 5 shows that the Pacific Northwest, California, and Georgia systems have nearly equal winter peaks in both the morning and evening, while in Massachusetts the evening peak is ten percent higher than the morning demand. Figure 5 also shows that even at the peak hour on a winter day, the maximum demand on the California and Georgia systems are around 70 to 75 percent of their annual peak hourly summer demand. In 2016, Massachusetts's peak day hourly winter demand is within 10 percent of its summer peak day hourly demand.

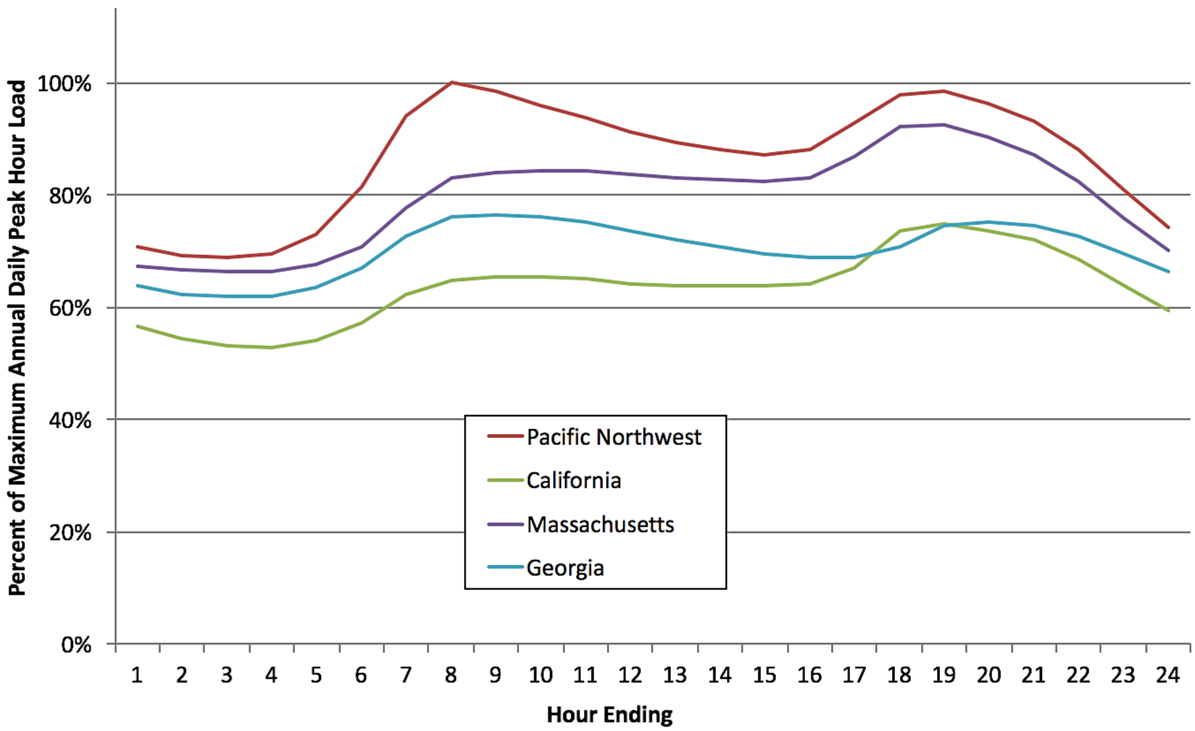

Figure 5. Hourly load shape on a typical winter day for the Pacific Northwest, California, Massachusetts, and Georgia systems

Figure 6 through Figure 12 show the hourly load shapes for summer and winter days for the four efficiency measures with varying hourly loads (i.e., the exit sign representing the flat load shape is excluded) for each of the four locations.[33]

The general pattern of residential water heating use across the four locations is similar, although they are not identical (Figure 6). The daily summer peak demands for residential water heating do not align with the summer peak hourly demand of any of the four power systems considered in this study. For example, Figure 4, shows that the peak hourly demand in the summer in all four power systems occurs in the afternoon between hour 16 and hour 18. However, during the summer months, the peak demand for residential water heating occurs between hour 8 and hour 11 (Figure 6). At hour 16, residential water heating demands are at or below 80 percent of their daily peak demands. In other words, only 80 percent of residential water heating savings peak demand reduction impact is coincident with the summer peak demands of these systems.

[33] No significant air conditioning occurs during winter peak days in these locations, so there is not a winter day load shape shown for this end use.

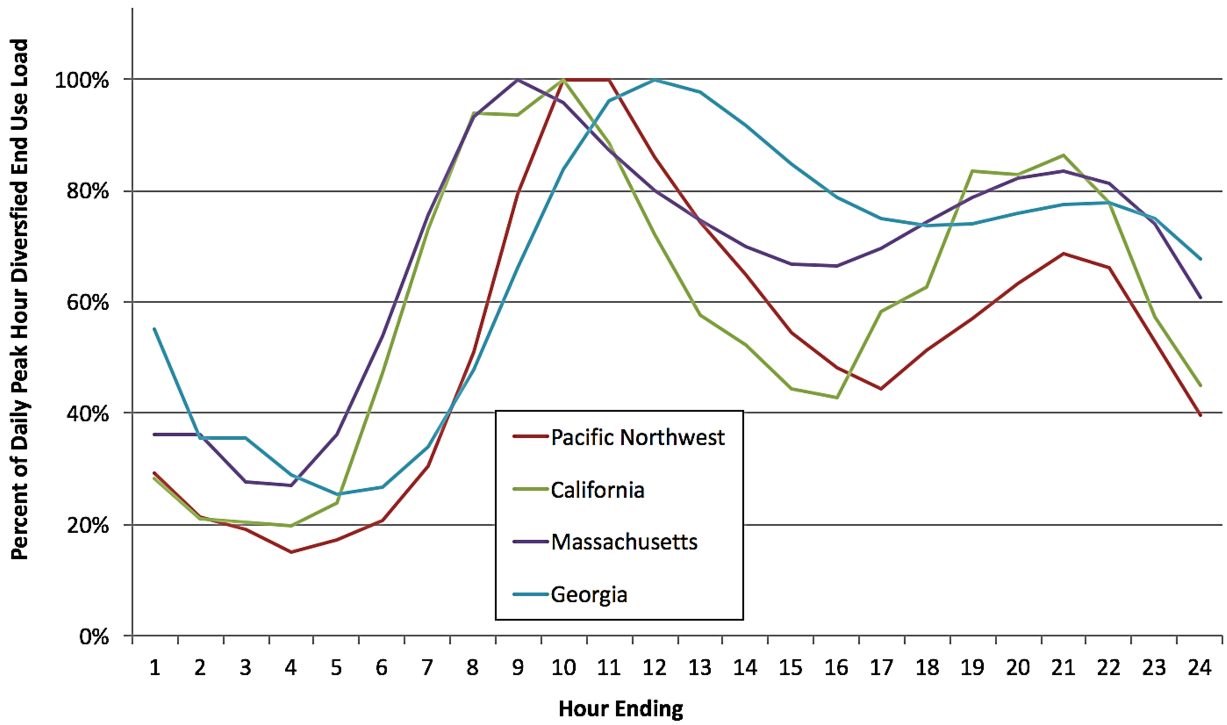

Figure 6. Typical summer day hourly load shapes for residential water heating for the Pacific Northwest, California, Massachusetts, and Georgia systems

Figure 7 shows the winter day hourly load shape for residential water heating. Water heating demands have similar patterns during both summer and winter days, although the afternoon water heating demands are slightly higher in the winter than they are in the summer (figures 6 and 7). However, unlike summer, the winter day residential water heating loads are highly coincident with winter power system peaks in all four locations considered in this study. A comparison of Figure 5 and Figure 7 shows that residential water heating demands are highest between hours 9 and 11, which are the same times as the peak demand occurs on the power system during winter days. This implies that in areas like the Pacific Northwest, where winter peaking demands can drive investments in additional capacity, the capacity savings associated with efficiency improvements in residential water heating will be more valuable.

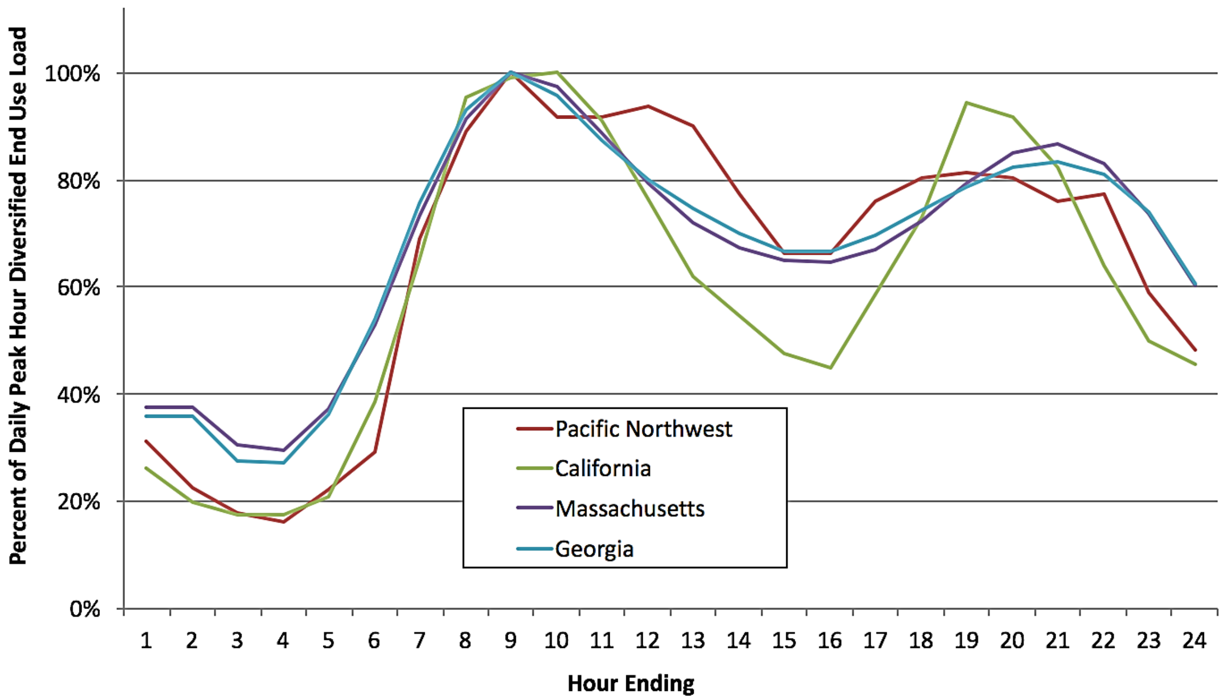

Figure 7. Typical winter day hourly load shapes for residential water heating for the Pacific Northwest, California, Massachusetts, and Georgia systems

The influence of longer daylight hours during the summer season can be seen in the residential lighting load shape. The demand for residential lighting on a peak summer day does not occur until after the power system peaks, with maximum demand occurring between hour 21 and hour 22 (Figure 8). Indeed, throughout most of the day, residential lighting loads operate at or below 40 percent of peak daily demands. Therefore, improving the efficiency of residential lighting does not significantly alter utility system summer peak day demands.

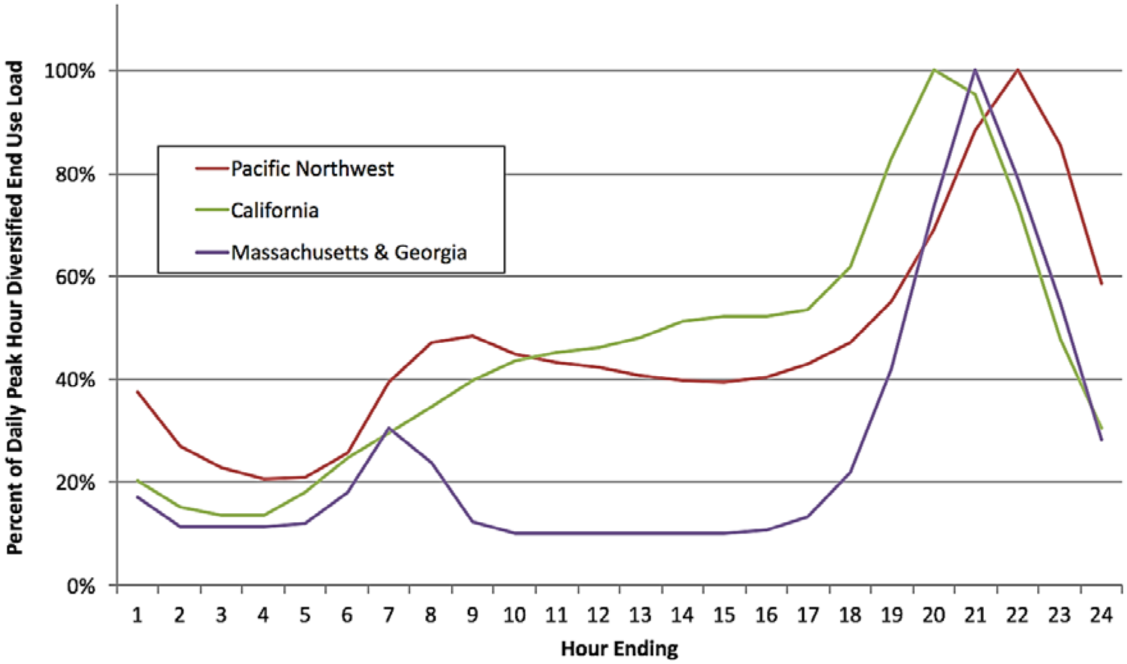

Figure 8. Typical summer day hourly load shapes for residential lighting for the Pacific Northwest, California, Massachusetts, and Georgia systems[34]

The pattern of residential lighting loads changes between winter and summer days due to shorter daylight hours. During the winter, residential lighting loads have a small peak during the morning hours when loads reach about 60 percent of their daily maximum, before peaking between hours 18 and 22 (Figure 9). Residential lighting load increases during the winter, and the timing of its peak demand coincides with winter power system peak demands in most locations, as these also peak between hours 18 and 22. As was the case with residential water heating, this implies that in areas like the Pacific Northwest, where winter peaking demands can drive investments in additional capacity, the capacity savings associated with energy efficiency improvements in residential lighting will be more valuable.

[34] Residential lighting loads for Georgia and Massachusetts are identical based on the Building America simulations, so they are shown as a single line.

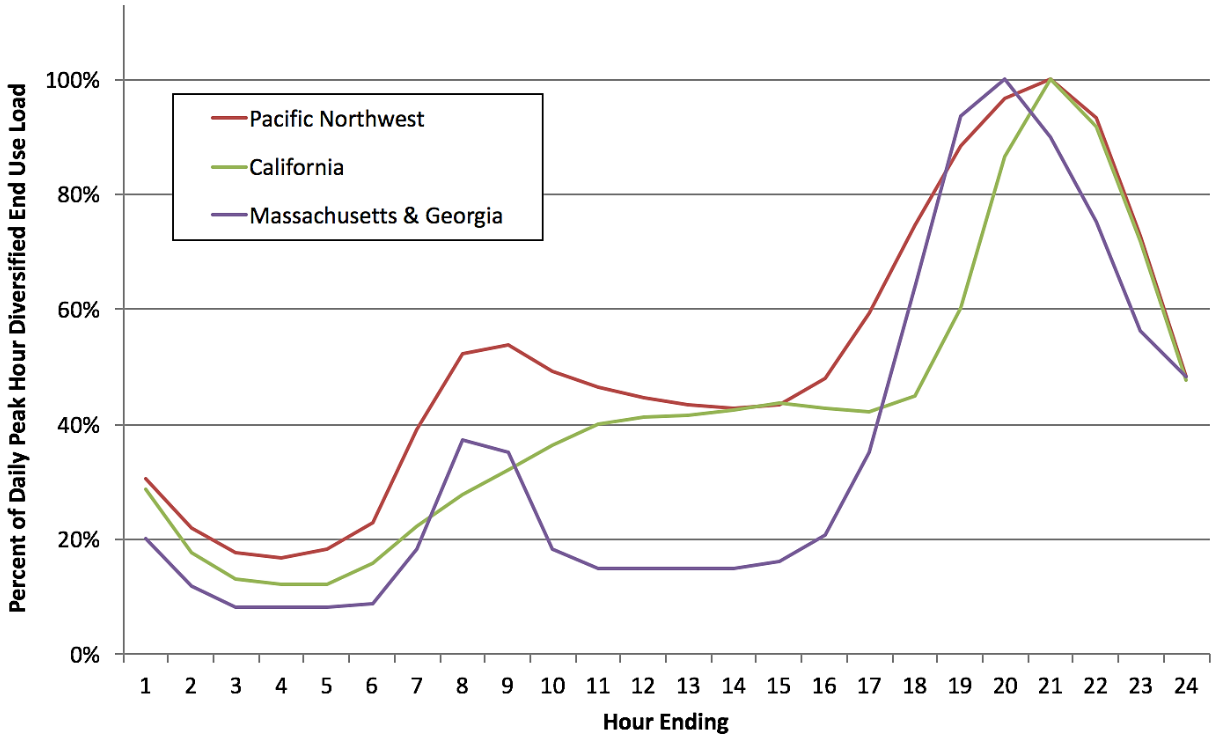

Figure 9. Typical winter day hourly load shapes for residential lighting for the Pacific Northwest, California, Massachusetts, and Georgia systems

In contrast, residential central air conditioning loads are a primary contributor to the daily summer peak loads of the four power systems considered in this study (Figure 10). Depending upon the power system, residential air conditioning demands peak between hour 16 and hour 19, which are coincident with utility system peak demands. More important, the peak demands for air conditioning remain nearly constant between hour ending 16 and 19 in all but the Pacific Northwest system.

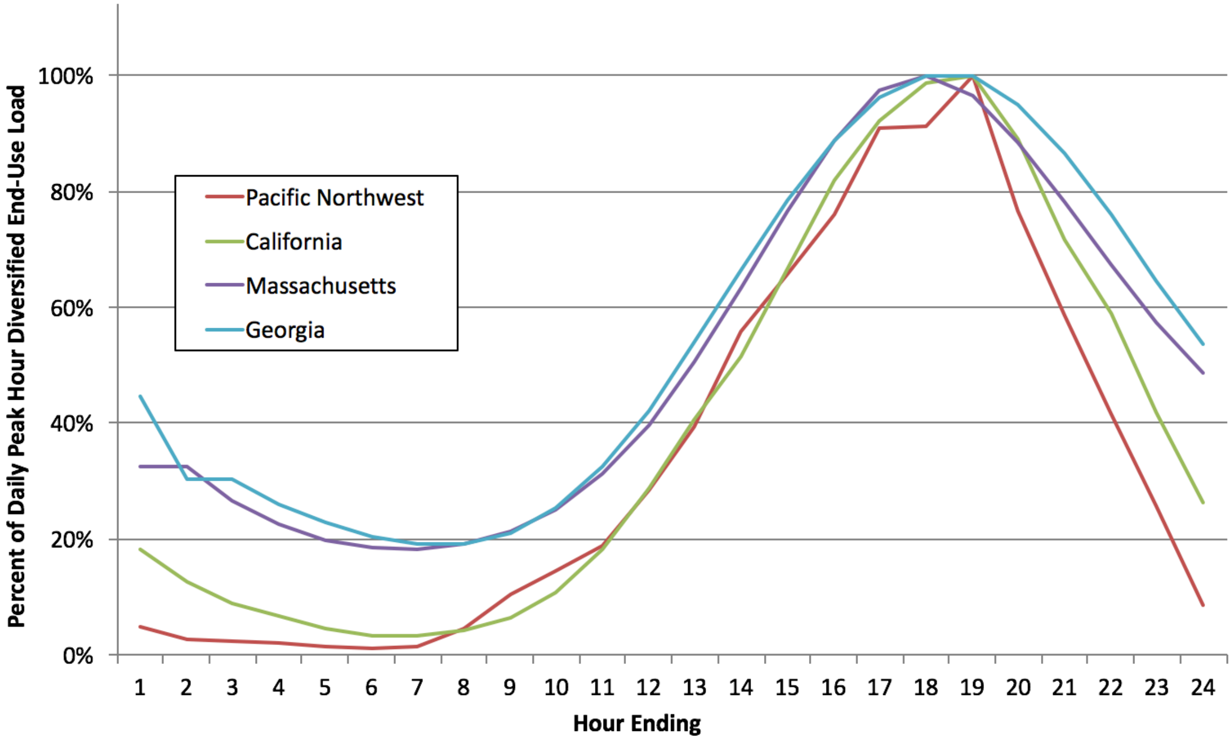

Figure 10. Typical summer day hourly load shapes for residential central air conditioning for the Pacific Northwest, California, Massachusetts, and Georgia systems

Figure 11 shows the peak summer day load shape for a typical commercial office building. The demand for lighting in commercial office buildings is highly correlated with typical business hours. Interior building lighting demand rapidly increases between hours 6 and 9, remains constant throughout the day, and then declines rapidly starting around hour 16 or 17. Because commercial office building lighting loads are still high during late afternoon hours, they contribute significantly to power system summer peak demands, making commercial lighting efficiency improvement that produce capacity reductions more valuable.

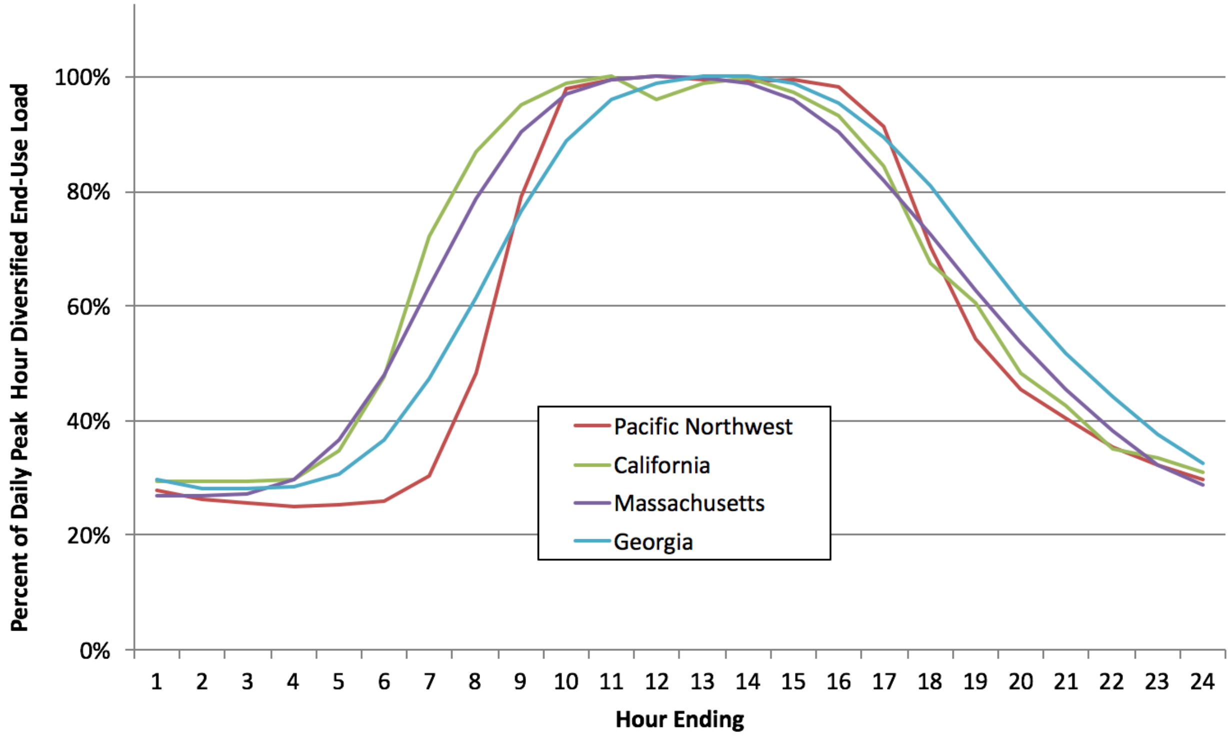

Figure 11. Typical summer day hourly load shapes for commercial office building lighting for the Pacific Northwest, California, Massachusetts, and Georgia systems

A comparison of summer (Figure 11) and winter (Figure 12) daily load shapes for commercial office building lighting reveals very little difference. While the "ramp up" and "ramp down" periods extend over slightly more hours, the peak demands are still highly correlated with typical business hours. However, although the load shape of commercial office building lighting does not change materially between summer and winter, the load shapes of the power system that supply these buildings do, as shown in Figure 4 and Figure 5. The four locations included in this study experience nearly equal peak demand in the morning and afternoon/evening hours during the winter months. As a result, the lighting in commercial office buildings contributes to both peaks, making energy efficiency improvements in this end use valuable.

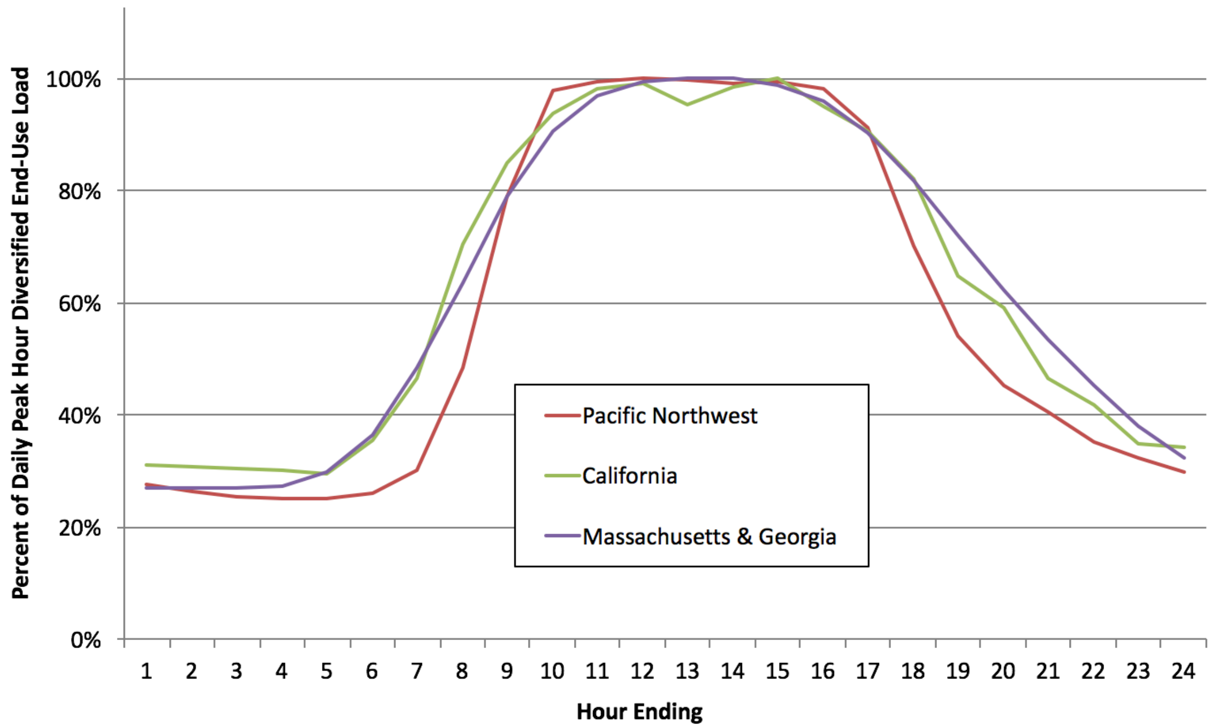

Figure 12. Typical winter day hourly load shapes for commercial office building lighting for the Pacific Northwest, California, Massachusetts, and Georgia systems

3.2.2 Value of energy efficiency savings by location

There are several reasons that the value of the same energy efficiency measure differs across power systems:

- **Load shape of the electric system:** The difference in load shapes across electric systems is an underlying factor that can result in significant differences in the time-varying value of the same energy efficiency measure. This can be driven by differences in customer mix, building stock, and climate.
- **Inclusion or exclusion of types of avoided costs:** Significant differences in the value of energy savings can result from the type of benefits that are considered and estimated in avoided cost methods by states (Lazar and Colburn 2013).
- **Resource need:** Each electric system is in a different position with respect to its need for additional generation, distribution, and transmission resources.
- **Resource availability:** Each utility also has access to different resource options (e.g., wind resources in the Great Plains, solar in the desert Southwest, or market purchases in organized markets). These differences translate into determinations of the avoided resource cost. For example, inadequate access to natural gas pipeline capacity may make gas-fired generation less competitive than coal-fired generation in certain areas. Similarly, wind resources across the Great Plains states will likely be more cost-competitive options for meeting renewable resource portfolio requirements than areas where wind regimes are less favorable. As a result, each system has a unique set of avoided costs (and risk).

Table 6 through Table 10 show the time-varying value of savings for five efficiency measures in the four locations studied. The first five rows of each table display the energy-related levelized values of each measure, and the sixth row is the energy-related value subtotal.[35] The levelized value shown in the first row is the value of the efficiency measure over an assumed useful life of 15 years, considering only the shape of the energy savings over the course of the year (i.e., the annual average value of a megawatt-hour of savings).[36] Efficiency also can reduce economic risk. For example, future generating fuel prices might be higher or more volatile than forecast. The estimated risk mitigation value of efficiency is shown on row two.[37] The third row shows the value of CO_2 reduction. This value can be the market value in states that have established carbon prices (e.g., California and the RGGI that includes Massachusetts) or it may represent a "virtual" price used to reflect public policy (e.g., the Pacific Northwest value uses the federal Interagency Working Group on the Social Cost of Carbon as a proxy for the value of reduced carbon emissions).[38] Another approach to value avoided emissions is to use the cost of emissions control equipment at electric generating plants. Using this approach, energy efficiency displaces emissions of nitrogen oxide, sulfur dioxide, mercury, and particulate matter.

Row four shows the levelized value of reducing the need to acquire renewable resources in those states that have a renewable portfolio standard (RPS). If an RPS is based on supplying a minimum amount of retail sales with renewable resources, then energy efficiency reduces the growth in retail sales, and thus the amount of renewable resources required to satisfy a utility's RPS obligations will be lower. Row five shows the levelized value of DRIPE. In very simplified terms, DRIPE is the value of reducing the cost of supplying electricity in an organized market as a result of placing lower demands on the market. This value is applicable in areas with an organized wholesale market (e.g., ISO-New England).

Rows seven through ten in each table display the capacity-related levelized values for each of the efficiency measures. The seventh row shows the levelized value of avoided generating capacity resulting from the reduction in system peak demand due to the measure. The eighth and ninth rows show the levelized value of deferring transmission and distribution system expansion resulting from reducing the rate of growth in peak demands. By reducing the need for additional generation capacity, efficiency savings also reduce the requirement to add reserves and other ancillary services for that capacity. The value of this benefit may be shown separately on row ten, or for some locations is captured in the value of deferred generation (see row seven in the tables). Row eleven is the capacity-related value subtotal.

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[35] The breakout of energy value in Tables 6 through 10 is not the traditional definition of avoided energy cost. However, it is included in these tables because the values are related to electricity, not peak demand. In addition, in the Pacific Northwest, California, and Massachusetts, these values are included in the calculation of energy efficiency cost-effectiveness.

[36] These levelized values are based on electricity savings at the generator (i.e., they include transmission and distribution system losses). They do not reflect the "source" energy (i.e., the BTU input) required to produce a kWh).

[37] There is not a risk mitigation factor listed for the Pacific Northwest because the risk mitigation values are embedded in the energy and capacity cost values. The other locations do not have risk mitigation factors and are accordingly listed as zero.

[38] Another approach to value avoided emissions that have primarily local and/or regional impacts is to use the cost of emissions control equipment at electric generating plants. Using this approach, energy efficiency displaces emissions of nitrogen oxide, sulfur dioxide, mercury and particulate matter.

Row twelve shows the **total** time-varying value of electricity savings. Row twelve may or may not represent the total resource value of the electricity savings from efficiency measures because it potentially excludes non-energy values (e.g., water savings) which are not shown in Table 6 through Table 10.

The exit sign is representative of measures that save a uniform amount of energy each hour and have the exact same load shape across all locations. Thus, the range in time-varying values for this measure is due solely to the avoided cost of the system and the factors (e.g., avoided energy, capacity, transmission, distribution, and avoided CO_2 emissions) considered in the savings valuation. Savings with a uniform load shape (i.e., exit sign) have a levelized value of energy savings that ranges from \$31/MWh to \$60/MWh (see Table 6, Row 1). When the capacity value of savings with a load shape like an exit sign are considered, the total time-varying value of this measure is significantly higher, and ranges from a low of around \$41/MWh to a high of about \$169/MWh (see Table 6, Row 12).

Table 6. Time-varying value for an exit sign load shape (2016\$/MWh)[39]

Row	Resource Benefit	Pacific Northwest (\$)	California (\$)	Massachusetts (\$)	Georgia[40] (\$)
1	Energy	31	37	60	40
2	Risk	0	0	6	0
3	CO_2 Emissions	38	12	46	0
4	Avoided RPS	0	13	10	0
5	DRIPE	0	0	9	0
6	**Energy-Related Value Subtotal**	**69**	**62**	**131**	**40**
7	Generation Capacity	14	14	19	1
8	Transmission	4	4	3	0
9	Distribution	3	10	16	0
10	Reserves/Ancillary Services	0	<1	0	0
11	**Capacity-Related Value Subtotal**	**21**	**29**	**38**	**1**
12	**Total Value**	**89**	**90**	**169**	**41**

Totals may not sum due to rounding.

A comparison of the total time-varying value of savings from residential water heating in Table 7 reveals that its value is greater than the value of constant hourly savings (i.e., flat load) in the Pacific Northwest, about the same in California and Georgia, and lower in Massachusetts. The time-varying values for residential water heating efficiency measures depend on the coincidence of the savings with

[39] See Appendix B for additional information on each location's resource benefits.
[40] Avoided transmission and distribution costs are included in Georgia Power's energy efficiency evaluations, but are not a part of the publicly available PURPA avoided cost filing.

a particular utility system peak demand. For example, comparing the load shape of electric water heating (Figure 6 and Figure 7) with the system load shapes (Figure 1 and Figure 5 it can be observed that water heating loads peak at, or very near, the time of winter peak in the Pacific Northwest, which drives the need for new capacity. In contrast, residential water heating peak demands are after the summer peaks in the other locations, where summer peaks drive the need for new capacity. Therefore, savings from an electric water heater efficiency improvement would be more valuable in the Pacific Northwest than in other locations, due to their higher coincidence factor.

Table 7. Time-varying value of residential water heating load shape (2016$/MWh)

Row	Resource Benefit	Pacific Northwest ($)	California ($)	Massachusetts ($)	Georgia ($)
1	Energy	31	38	62	39
2	Risk	0	0	6	0
3	CO_2 Emissions	37	12	46	0
4	Avoided RPS	0	13	10	0
5	DRIPE	0	0	9	0
6	**Energy-Related Value Subtotal**	**68**	**64**	**133**	**39**
7	Generation Capacity	24	14	16	3
8	Transmission	6	4	3	0
9	Distribution	5	9	14	0
10	Reserves/Ancillary Services	0	<1	0	0
11	**Capacity-Related Value Subtotal**	**35**	**28**	**33**	**3**
12	**Total Value**	**103**	**92**	**166**	**43**

Totals may not sum due to rounding.

In Table 8 (row 1), we see that the total time-varying value of energy savings from residential air conditioning is greater than the value of constant hourly savings (i.e., flat load) of savings in California, Massachusetts, and Georgia (see Table 6). In contrast, the total time-varying value of energy savings from central air conditioning in the Northwest is below the value of measures with constant hourly savings (i.e., an exit sign, or flat load) for that location ($67/MWh versus $89/MWh). The reason for the lower value of savings is that savings from central air conditioning in the Pacific Northwest do not reduce the need for additional generation, transmission, or distribution capacity. However, the total time-varying value of savings for residential central air conditioning efficiency improvements in California and Massachusetts is far larger than any of the other measures included in this study. For example, in California, the total value for efficiency improvements in residential central air conditioning is $208/MWh, which is twice as high as the total value for commercial and residential lighting ($107/MWh and $92/MWh, respectively). We observe a similar phenomenon in Massachusetts, where the total value of residential air conditioning to the utility system is $371/MWh, which is also twice as high as the total value for residential and commercial lighting ($179/MWh and $182/MWh, respectively).

Table 8. Time-varying value of residential air conditioning load shape (2016$/MWh)

Row	Resource Benefit	Pacific Northwest ($)	California ($)	Massachusetts ($)	Georgia ($)
1	Energy	32	41	57	47
2	Risk	0	0	6	0
3	CO_2 Emissions	35	13	48	0
4	Avoided RPS	0	13	10	0
5	DRIPE	0	0	10	0
6	**Energy-Related Value Subtotal**	**67**	**68**	**130**	**47**
7	Generation Capacity	0	44	119	20
8	Transmission	0	29	19	0
9	Distribution	0	67	103	0
10	Reserves/Ancillary Services	0	<1	0	0
11	**Capacity-Related Value Subtotal**	**0**	**140**	**240**	**20**
12	**Total Value**	**67**	**208**	**371**	**67**

Totals may not sum due to rounding.

A comparison of the total time-varying value of savings from residential lighting in Table 9 reveals that its value is significantly greater than the value of a measure with constant hourly savings (i.e., exit sign) in the Pacific Northwest ($116/MWh versus $89/MWh) and somewhat higher in California, Massachusetts, and Georgia.

Table 9. Time-varying value of residential lighting load shape (2016$/MWh)

Row	Resource Benefit	Pacific Northwest ($)	California ($)	Massachusetts ($)	Georgia ($)
1	Energy	31	39	63	39
2	Risk	0	0	7	0
3	CO_2 Emissions	37	13	46	0
4	Avoided RPS	0	13	10	0
5	DRIPE	0	0	10	0
6	**Energy-Related Value Subtotal**	**69**	**65**	**135**	**39**
7	Generation Capacity	32	21	21	2
8	Transmission	9	6	3	0
9	Distribution	7	15	19	0
10	Reserves/Ancillary Services	0	<1	0	0
11	**Capacity-Related Value Subtotal**	**47**	**42**	**44**	**2**
12	**Total Value**	**116**	**107**	**179**	**42**

Totals may not sum due to rounding.

Comparing the load shape of residential lighting (Figure 8 and Figure 9) with the system load shapes (Figure 4 and Figure 5) it can be observed that residential lighting peaks at or near the time of winter peaks in the Northwest, but occurs well after the summer peaks in California, Georgia, and Massachusetts. Therefore, even though the value is highest in Massachusetts, the savings from residential lighting efficiency improvements are more valuable in the Northwest than they are in these other locations due to their higher coincidence factor (see ratios in Table ES-1).

A comparison of the total time-varying value of savings from commercial lighting in Table 10 with Table 6 reveals that their value is greater than the value of measures with uniform (flat) hourly savings in the Pacific Northwest, Massachusetts, and Georgia, and approximately the same in California. Comparing the load shape of commercial lighting (Figure 11 and Figure 12) with the system load shapes (Figure 4 and Figure 5), it can be observed that commercial lighting peaks closer to the winter morning peaks in the Pacific Northwest, but after the summer peaks in California. Therefore, savings from commercial lighting efficiency improvements are slightly more valuable in the Pacific Northwest, Massachusetts, and Georgia than they are in California due to their higher coincidence factor.

Table 10. Time-varying value of commercial lighting load shape (2016$/MWh)

Row	Resource Benefit	Pacific Northwest ($)	California ($)	Massachusetts ($)	Georgia ($)
1	Energy	31	35	62	40
2	Risk	0	0	6	0
3	Carbon Dioxide Emissions	37	12	46	0
4	Avoided RPS	0	13	10	0
5	DRIPE	0	0	9	0
6	**Energy-Related Value Subtotal**	**68**	**60**	**133**	**40**
7	Capacity	21	16	25	4
8	Transmission	6	4	4	0
9	Distribution	5	10	21	0
10	Reserves/Ancillary Services	0	<1	0	0
11	**Capacity-Related Value Subtotal**	**32**	**31**	**50**	**4**
12	**Total Value**	**100**	**90**	**183**	**45**

Totals may not sum due to rounding.

Table 6 through Table 10 show the significant differences in the time-varying value of saving for the four measures within the same power systems. These differences are primarily due to the relationship between the load shape of the measure's savings load and the system load shape. For example, in California and Massachusetts, the time-varying value of residential central air-conditioning savings, which is highly coincident with that system's summer peak demand, is nearly twice that of residential lighting, which peaks much later in the day ($208/MWh versus $107/MWh in California and $371/MWh versus $179/MWh in Massachusetts). Similarly, in the Pacific Northwest, which has a winter peak, the value of residential lighting is nearly twice that of residential air conditioning ($116/MWh versus $66/MWh). In Georgia, where publicly available data did not include avoided transmission and distribution system values, the time-varying value of efficiency appears much lower for all measures evaluated.

4. Conclusions

The time-varying value of energy efficiency savings is important because, when calculating the benefits to the power system produced by energy efficiency savings, that value will be determined by the season and hour of the day that the energy reductions occur. End-use load shape or energy savings shape data is necessary to determine the time-varying value of electric energy efficiency. Consideration of the impact of energy efficiency on peak demand reduction (i.e., capacity savings) has been limited, in part due to the lack of research on the load shape (i.e., the hourly or seasonal timing of electricity savings) of energy efficiency measures.

Until recently, publicly available end-use load shape data gathering efforts have been scattered and modest, and limited to the West Coast and New England. Such data will become increasingly important in the future as a growing share of energy savings are projected to come from improved controls which are explicitly intended to modify the duty-cycle or hours of operation of end-use consumption (e.g., occupancy controls on lighting). Consequently, the load shape of the affected end-use(s) will no longer serve as a valid proxy for estimating the capacity benefits of such energy efficiency measures.

Based on the case studies reviewed in this study, some of the largest capacity benefits from energy efficiency come from the deferral of transmission and distribution system infrastructure upgrades. Therefore, to properly calculate the value of electricity savings to the utility system it is necessary to account for variations in hourly energy savings, variations in hourly avoided energy cost, and the deferral of capital investment in new generation, transmission, and distribution infrastructure.[41] In those power systems that are required to meet renewable portfolio standards, and where such standards are a function of annual retail sales, or a fraction of installed capacity, the value of avoided investments in new renewable resources should also be taken into account. Similarly, consideration of avoided emissions costs should be done on a time-sensitive basis. Finally, in organized markets, the impact of DRIPE should be accounted for as a resource value.

Two general approaches are used to capture the time-varying value of electricity savings. The most common method (Method 1) uses daily and/or seasonal load shape data to allocate energy savings into peak periods (high load hours) and off-peak periods (low load hours), and coincidence factors to estimate peak impacts. Method 2 uses annual hourly data on both energy savings and avoided costs.[42] Both approaches require data on the load shape of efficiency measure savings, utility system load shapes, and utility system avoided costs. The primary differences between the two methods are the fidelity or granularity of their data requirements, and the method used to determine peak reduction impacts of efficiency measures.

[41] Energy efficiency programs that are appropriately geographically targeted, as well as efficiency programs that reduce the pace of load growth across the entire distribution network, can result in deferral of distribution investments.

[42] See Stern (2013) for a more detailed explanation of alternative approaches that can be used to estimate peak energy savings, some of which do not rely on end-use metered data.

Method 2 offers the greatest flexibility for accounting for future changes in the net load shape of power systems. Valuation methodologies that determine the peak impacts of energy efficiency savings through the use of historical coincidence or diversity factors to identify the value of efficiency, while reasonably accurate, are less flexible because these factors will need to be modified going forward as the net load shape of the power system changes through time. For example, an electric system with a high saturation of distributed photovoltaic generation may have a peak period that shifts to later in the day, so savings from commercial air conditioning based on today's peak coincidence factors will no longer be accurate. Similarly, widespread adoption of electric vehicles, distributed storage and deployment of demand response or grid responsive technologies will all change the size and timing of peak loads from today's norm. Use of historic coincidence factors to estimate an energy efficiency measure's peak impacts will require additional load research to determine new coincidence factors, or modification of existing coincidence factors to remain accurate as system load shapes change. In contrast, the use of hourly data only requires that the new net system hourly load shape and hourly avoided cost be used in the calculation; no new load research is required.

Accounting for the total time-varying value of energy efficiency increases the resource value of various measures. Accounting for the capacity value of energy efficiency increased resource value by 10 to 300 percent, compared to the energy-related savings alone (Table 11). Table 8 also shows that the magnitude of this increased value varies by both load shape within a single location and across locations. For example, in California, the avoided capacity benefits of savings from improving the efficiency of residential air conditioning make such measures about 3.1 times more valuable than their annual energy savings alone. In contrast, in the Pacific Northwest savings from residential air conditioning measures provide no additional capacity benefits. This difference occurs because savings from residential air conditioning offset the summer peak demand for electricity in California, which historically has driven the need for new capacity in that location, while residential air conditioning savings in the Pacific Northwest, which experiences its peak demand in the winter, does not provide capacity benefits.[43] This illustrates that the magnitude of the additional value provided by energy efficiency is directly related to both the measure's impact on the need for additional capacity and the avoided cost of that capacity.

[43] The historical system load shapes of both California and the Northwest are changing. With the increased penetration of renewable resources in California, particularly solar photovoltaic systems, the net utility system loads during summer afternoons are decreasing. In contrast, due to the increased saturation of air conditioning in the Northwest and the diminishing penetration of electric space heating, this region's summer peak demands are forecast to match its winter peaks over the next decade.

Table 11. Ratio of total time-varying value to energy-related value of energy savings by load shape and location

Load Shape	Location			
	Northwest	California	Massachusetts	Georgia
Flat/Uniform Across All Hours	1.3	1.5	1.3	1.0
Residential Water Heating	1.5	1.4	1.2	1.1
Residential Central Air Conditioning	1.0	3.1	2.8	1.4
Residential Lighting	1.7	1.6	1.3	1.1
Commercial Lighting	1.5	1.5	1.4	1.1

In calculating the time-varying value of efficiency for the four locations, we found that the time-varying values for energy efficiency savings, specifically for transmission and distribution, appear to be higher in Massachusetts than the other locations. One reason is that Massachusetts includes urban, congested areas where distribution system investments are expensive. California and the Pacific Northwest provide clear examples of how time-varying value of end uses or energy savings shapes is influenced by the timing of the system peak demand (e.g., summer versus winter) and variations in hourly savings through the residential air conditioning and residential hot water measures. The value of residential air conditioning on the Pacific Northwest's winter peaking system is low, and vice versa with residential hot water on California's summer peaking system. Finally, publicly available data on hourly avoided cost are limited in Georgia, producing time-varying value that appears low, but actually are incomplete in comparison to other locations, as these ratios do not include avoided transmission, distribution, reserves/ancillary services, RPS compliance, risk, and CO_2 emissions values.

5. Recommendations

State utility regulators, utilities, and energy efficiency program administrators should consider the following opportunities to improve estimates of the time-varying value of energy efficiency:

At a utility, state, or regional level:

- Collect metered data on a variety of end-use load and energy savings shapes for the state or region at least at the hourly level and make the data publicly available in a format that can be readily used in planning processes.
- Account for variations in the time-varying value of energy savings and avoided costs.
- Periodically update estimates of the impact of energy efficiency measures on utility system peak demands to accurately reflect changing system load shapes.
- Study transferability of end-use load shapes from one climate zone to another climate zone.

At a regional or national level:

- Identify best practices for establishing the time-varying value of energy efficiency in integrated resource planning and demand-side management planning to ensure investment in a least-cost, reliable electric system.
- Establish protocols for consistent methods and procedures for developing end-use load shapes and load shapes of efficiency measures.
- Establish consistent methods for assessing the time-varying value of energy savings, including values that are often missing, such as deferred or avoided transmission and distribution investments.

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Appendix A: End-Use Load Research Studies

Table A-1. Major U.S. End-Use Load Research Studies (James and Clement 2016)[44]

STUDY	Location	YEAR	RES	COM	Direct Measurement	Disaggregation/ NILM	End-Use Documentation	LINKS
End-use Load and Consumer Assessment Program (ELCAP)	NW U.S.	1989	x	x	x			LINK
DOMESTIC STUDIES								
California Commercial End-Use Survey (CEUS) UPDATE	CA	2017		x		x	x	
California Residential End-Use Survey	CA	2016?	x			x	x	LINK
Fort Collins DSM Program (AC, DWH)	CO	2016	x		x			LINK
NEEA Next Step Homes								
NEEP Project Load Shape Database	VT, NH, MA, RI, CT	2016?	x	x	x	x	x	LINK
EPRI End Use Load Shape Library 3.0	U.S.	2016	x	x	x	x	x	LINK
National Grid Usage Data	RI, NH, VT, CT	2015+	x	?	x	x	x	LINK
Hourly Data for MHP Customers	NY, NJ	2015+		x		x	x	LINK
Market Analysis and Information System Databases (MAISY®)	U.S.	2015	x	x				LINK
NYSERDA End-use Load Project[a]	New York	2015	x			x	x	
Commercial Refrigeration Loadshape Report	NE U.S.	2015		x	x			LINK
NEEA Heat Pump Water Heater Model Validation Study	NW U.S.	2015	x		x			LINK
Residential Building Stock Assessment Metering (RBSAM)	NW U.S.	2012–14	x		x			LINK
NEEP Ductless Heat Pump Meta-Study	NE U.S.	2014	x		x			LINK
ME Appliance Rebate and Lighting Evaluations	ME	2014	x		x		x	LINK
Central Air Conditioning Impact and Process Evaluation	CT	2014						LINK
Connecticut Ground Source Heat Pump Impact Evaluation and Market Assessment	CT	2014	x		x			LINK
Commercial Building Stock Assessment (CBSA)	NW U.S.	2014		x			x	LINK
PA Commercial & Residential Lighting Study	PA	2014	x	x	x			LINK
NEEP Variable Speed Drive Load-shape Study	NE U.S.	2014		x				LINK
EmPOWER C&I Lighting Evaluation	MD	2014		x	x	x	x	LINK
FPL NEST Thermostat Field Test	FL	2014	x			x		
ETO Nest Heat Pump Pilot	OR	2014	x			x		LINK
TVA NILM Field Trial[b]	KY	2014	x		x	x	x	LINK

[44] "It is likely that there are additional small, single-end use studies and evaluations, especially with regard to lighting and smart thermostats, this list represents what we have been able to find to date and what appears to be major studies conducted in the recent past." (James and Clement 2016).

Table A-1. (continued)

STUDY	Location	YEAR	RES	COM	Direct Measurement	Disaggregation/ NILM	End-Use Documentation	LINKS
Western Exterior Occupancy Survey for Exterior Adaptive Lighting Applications	Western U.S.	2014		x	x	x	x	LINK
Michigan Statewide Commercial and Industrial Lighting Hours-of-Use Study	MI	2013		x	x			LINK
Northeast Residential Lighting HOU	CT, MA, NY, RI	2013	x		x		x	LINK
Florida Power and Light (FPL) Electric Vehicle Pilot[c]	FL	2013	x		x			
The EV Project	U.S.	2013	x	x	x			LINK
American Housing Survey (AHS)[d]	U.S.	2013					x	LINK
BPA Evaluation of Site-Specific Savings Portfolio	NW U.S.	2013		x	x	x		LINK
Residential Building Stock Assessment (RBSA)	NW U.S.	2012	x				x	LINK
Duke Energy Smart $aver® Impact Evaluation	OH, KY	2012	x		x	x		
Delaware C&I End-use & Saturation Study	DE	2012		x			x	LINK
Florida Power and Light (FPL) Smart Appliance	FL	2012	x		x			
Commercial Buildings Energy Consumption Survey (CBECS)[e]	US	2012		x			x	LINK
Michigan CFL Hours of Use Study	MI	2012	x		x			LINK
NEEP C&I Unitary HVAC Load Shape Project	NE U.S.	2011		x		x	x	LINK
NEEP C&I Unitary Lighting Load Shape Project	NE U.S.	2011		x		x	x	LINK
NEEA Heat Pump Water Heater Test	NW U.S.	2011						
EmPOWER Maryland Res Lighting & Appliances Evaluation	MD	2011		x	x	x	x	LINK
BPA Water Heater and Heat Pump Water Heater Field Work	NW US	2011	x					
Glasgow Electric Plant Board (GEPB) Smart Appliance	KY	2011	x		x			LINK
California Commercial End-Use Survey (CEUS)	CA	2010?		x		x	x	LINK
ISO New England End Use Study	New England	2010	x	x		x		
WRAP/UI Helps Impact Evaluation[f]	CT	2010	x		x			LINK
Energy Opportunities Impact Study[g]	CT	2010		x	x			LINK
Southern Company End Use Metering Evaluation Project[h]	GA	2010	x		x		x	LINK
FL Electricity Loads and Appliance Energy Usage Profiles	FL/U.S.	2009	x			x	x	LINK
XCEL Energy Savers Switch program evaluation.	CO/MN	2009	x				x	LINK
Residential Energy Consumption Survey (RECS)[i]	U.S.	2009	x				x	LINK
California Residential Lighting Metering Study[j]	CA	2009	x	x		x	x	LINK
Assessment of the Feasible and Achievable Levels of Electricity Savings	TX	2008	x	x		x	x	LINK
Puget Sound Energy Commercial & industrial Lighting	WA (PSE)	2007		x	x			

Table A-1. (continued)

STUDY	Location	YEAR	RES	COM	Direct Measurement	Disaggregation/ NILM	End-Use Documentation	LINKS
Seattle City Light Space Heat Thermostat Metering Study	WA (SCL)	2006	x		x			
INTERNATIONAL STUDIES								
Saudi Arabia Electricity Efficiency Study	Saudi Arabia	2016	x	x	x	x	x	LINK
Energy Rate (Australia/New Zealand)[k]	AUS/NZ	2011						LINK
BC Hydro's Residential End-Use Metering Project (REUMP)[l]	BC	2009	x		x			
BC Hydro Load Monitoring Project	BC	2009	x		x			LINK
Residential Monitoring to Decrease Energy Use and Carbon Emissions in Europe (REMODECE)[m]	Europe	2008	x		x			LINK

Notes: NILM = non-intrusive load monitoring; AC = air conditioning; DWH = data warehouse; NYSERDA = New York State Energy Research and Development Authority; NEEA = Northeast Energy Efficiency Alliance; ETO = Energy Trust of Oregon; TVA = Tennessee Valley Authority; HOU = hours of use; BPA = Bonneville Power Administration; C&I = commercial and industrial; ISO = independent system operator; WRAP/UI = Weatherization Residential Assistance Partnership / United Illuminating Company.

[a] Pilot, then 1,000–1,200 customer scale up.

[b] Thirty-site field evaluation of residential NILMs to assess accuracy in the field and document the practical issues with a field deployment.

[c] Sample of 50 homes was directly measured, and disaggregated EV charging.

[d] Used to develop the DOE Residential Lighting End-Use Consumption Study.

[e] Used to develop the DOE Residential Lighting End-Use Consumption Study.

[f] Ninety-two site visits with a partial-year time frame.

[g] Fifty-five lighting sites and 25 non-lighting sites.

[h] Monitored three sites using Echelon End Use Modules and TED 500 Google Power Monitors.

[i] Used to develop the DOE Residential Lighting End-Use Consumption Study.

[j] Household characteristics and lighting inventories were collected onsite from a random sample of more than 1,200 residences. In addition, end-use metering data were collected for a random sample of up to seven lighting fixtures.

[k] Stage 1 was a proof-of-concept involving end-use monitoring in five Melbourne households to develop a comprehensive and practical assessment of end-use metering hardware and software over an extended period. Stage 2—expansion of the project—has not been completed, and its current status is unclear.

[l] The initial sample of 12 homes could be expanded to 300 in the future.

[m] The study included 100 households in each country—Belgium, Bulgaria, Czech Republic, Denmark, France, Germany, Greece, Hungary, Italy, Portugal, Romania, and Switzerland—where 24 end uses were monitored in 10-minute intervals over two weeks.

Table A-2. Other, older studies identified in a 2009/12 KEMA study (James and Clement 2016)

Region	Name of Study	Utility/Agency	End Date	Usability Rating
South	AEC System Load Research Study	AEC	2008	D
South	Electric Tankless Water Heater	Alabama Power Company	2007	D
Midwest	Indiana Electric Water Heater Study	American Electric Power	1986	D
NW	Load Monitoring Project (LMP)	BC Hydro - LMP	2009	B
NW	Power Smart Residential End-use Study	BC Hydro - Power Smart	unknown	IP
Mid-Atlantic	Demand Response Infrastructure Pilot Program	BGE	2007	B
Mid-Atlantic	Water Heater and Residential AC studies that supported the PJM collaborative evaluation that RLW performed. Also Commercial AC	BGE	unknown	B
NW	End-Use Load and Conservation Assessment Program (ELCAP)	BPA	1990	B
NW	Multifamily Metering Study	BPA	1994	D
NW	Limited Hourly Metering Pilot	BPA	2006	D

Table A-2. (continued)

Region	Name of Study	Utility/Agency	End Date	Usability Rating
NE	Municipal Impact Study	Cape Light Compact	2004	B
CA	California Residential Appliance Saturation Survey (RASS)	CEC	2003	B
CA	Inventory of CEC Forecast Load Shapes - Other Sectors (Agriculture and Water Pumping, Transportation and Communications, Street Lighting)	CEC	n/a	D
CA	Inventory of CEC Forecast Load Shapes - Commercial	CEC	n/a	D
CA	California Commercial End Use Survey (CEUS)	CEC	2002	B
CA	Inventory of CEC Forecast Load Shapes - Residential	CEC	n/a	D
CA	Inventory of CEC Forecast Load Shapes - Industrial	CEC	n/a	D
CA	DEER 2001	CEC	2001	A
CA	California Industrial End Use Survey (IEUS) - In progress	CEC	2007	D
CA	Residential Plug Load Study	CEC	2007	A
NE	Municipal Impact Study 2006	CL&P	2006	B
Midwest	Dehumidifier Study	Consumer Powers	1982	D
Midwest	Clothes Washer and Electric Clothes Dryer Study	Consumers Power	1983	D
Midwest	Electric Range/Microwave Oven Study	Consumers Power	1982	D
Midwest	Freezer Study	Consumers Power	1981	D
Midwest	Microwave Ovens Study	Consumers Power	1978	D
Midwest	Frost-Free Refrigerator Study	Consumers Power Company	1984	D
CA	DEER 2004–5 Database Update	CPUC	2005	A
CA	DEER 2004–5 MAS Tool	CPUC	2005	A
Mid-Atlantic	Critical Peak Pricing Pilot	Dominion	2009	D
NE	Efficiency Maine Residential Lighting Impact Study	Efficiency Maine	2007	B
NE	Efficiency Maine Low Income Light and Appliance Impact Study	Efficiency Maine	2007	B
NW	Solar Pool Heater	Energy Trust of Oregon	2000	D
Other	Center for Electric End Use Data	EPRI, participating utilities	1998	D
CA	eShapes - Industrial	Itron	n/a	C
CA	eShapes - Residential	Itron	n/a	C
CA	eShapes - Commercial	Itron	n/a	C
CA	LBL End-Use Disaggregation Algorithm (EDA)	LBL	0	D
Midwest	General Load Research Program	MidAmerican Energy Company	0	D
NE	EI and C&I Lighting Impact Study	National Grid	2000	B
NE	Design2000 Plus Lighting Study	National Grid	2008	B
NE	Custom Lighting Impact Study	National Grid	2007	B
NE	Custom HVAC Impact Study	National Grid	2008	B
NE	Lighting Controls Impact Study	National Grid	2007	B
NE	SBS Custom Impact	National Grid	2006	B
NE	EI & Design2000 Plus Lighting Impact Study	National Grid	2005	B
NE	Small C&I Unitary HVAC Pilot Impact Study	National Grid	2003	B
NE	Residential AC Impact Study	National Grid	2008	B
NE	NH Lighting Impact Study	NGRID	2003	B
NE	NH Small Business Lighting Study	NH Electric Coop	2004	B
NW	Ductless Heat Pump Pilot	Northwest Energy Efficiency Alliance	2012	IP
NW	Distribution Efficiency Initiative	Northwest Energy Efficiency Alliance	2006	D
NW	ENERGY STAR Homes NW Impact Evaluation	Northwest Energy Efficiency Alliances	2009	IP
NE	MA, RI, and VT Residential Lighting Impact 2005	NSTAR Electric	2005	B
NE	BSCS Lighting Impact Study	NSTAR Electric	2009	B
NE	BSCS Non-Lighting M&V Impact Study	NSTAR Electric	2008	B
NE	BSCS Impact Study	NSTAR Electric	2007	B
NE	SBS Impact Study	NSTAR Electric	2005	B
NE	Custom Services (CS) Impact Study	NSTAR Electric	2004	B

Table A-2. (continued)

Region	Name of Study	Utility/Agency	End Date	Usability Rating
NE	SBS Impact Study - Lighting and Cooler Controls	NSTAR Electric	2003	B
NE	C & I Retrofit Impact Study	NSTAR Electric	2003	B
NE	Small C&I Retrofit Logger Study	NSTAR Electric	2002	B
NE	C&I New Construction Retrofit Impact Study	NSTAR Electric	2001	B
NE	NYLE Heat Pump Water Heater Evaluation	NU	2002	B
NE	NU/UI Catalog POP Impact Study	NU and CL&P	2003	B
NE	NU/UI ENERGY STAR Homes Impact Study	NU and CL&P	2002	B
NE	Municipal Impact Study 2004	NU and CL&P	2004	B
West	End Use Load Shape Project	NV Energy (fka Sierra Pacific Power Company)	1996	C
NW	Industrial Supply Curves	NWPPC	2009	D
Other	2008 Every Kilowatt Counts Impact Evaluation	Ontario Power Authority	2009	D
NW	Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources	PacifiCorp	2007	D
CA	Small Commercial CFL Monitoring Study	PG&E	2005	B
CA	2004–05 Savings By Design EM&V - PG&E Procurement Add-on Study	PG&E	2007	C
CA	PG&E CEUS 1997	PG&E	1994	C
CA	2004–05 ENERGY STAR Homes EM&V	PG&E	2005	C
CA	Residential End-Use Load Research Study	PG&E	2001	A
CA	Residential End-Use Metered Data to Improve Forecasts	PG&E / CEC	1993	D
CA	Compressed Air Management Program	PG&E and others	ongoing	B
CA	2006–08 CPUC Residential New Construction Evaluation	PG&E/CPUC	2010	B
CA	2004–05 ENERGY STAR New Homes Evaluation	PG&E/CPUC	2006	B
NW	2005 PSE Lighting Program Evaluation	Puget Sound Energy (PSE)	2006	D
CA	Load Research Annual Class and General Service Study	Roseville Electric	annual	D
CA	Air Conditioner Cycling Summer Discount Program	SCE	2006	D
CA	2002–03 Smart Thermostat Impact Evaluation	SCE	2004	C
CA	Small Commercial End-Use Load Research Study	SCE	1996	C
CA	Pool Pump Study	SCE	2001	D
CA	Refrigerator Recycling Study	SCE	2005	A
CA	2003, 2004, 2005 Energy Smart Thermostat Study	SCE	2005	C
CA	2004–05 Savings by Design Evaluation	SCE/CPUC	2006	B
CA	2006–08 CPUC Savings by Design Evaluation	SCE/CPUC	2011	B
CA	Demand Response, Spinning Reserve Demonstration	SCE/LBNL-CERTS	2006	C
CA	Residential Air Conditioner Metering Project	SDG&E	ongoing	B
CA	In installation phase: Residential and Small Commercial CAC	SDG&E	2006	C
CA	Smart Thermostat for Residential CAC	SDG&E	ongoing	C
CA	Residential CFL Load Shapes by Room Type	SDG&E	2004	A
CA	Hours of Operation (Super Saver)	SDG&E	2006	C
CA	Hours of Operation (Express Efficiency)	SDG&E	2006	B
CA	Statewide Investor Owned Utility Ceiling Fan Study	SDG&E	2001	D
CA	Commercial End-Use Load Research Sample	SDG&E	ongoing	C
CA	Load Shape Disaggregation	SDG&E	1995	D
CA	SDG&E 1995 & 1996 Nonresidential New Construction Evaluation	SDG&E	1996	C
CA	SPP Pilot - Residential customers with CAC	SDG&E	ongoing	C
CA	Analysis of Residential CAC load for the AMI Pilot	SDG&E	2003	D
NW	Space Heat Thermostat Metering Study	Seattle City Light	2006	B
CA	2007 Residential HVAC Program Evaluation	SMUD	2007	B
NE	SPWG Lighting Coincidence Factor Study for the ISO Forward Capacity Market	SPWG and many others	2007	A
NE	SPWG Lighting Coincidence Factor Study for the ISO Forward Capacity Market	SPWG and many others	2007	A
NE	CT School Lighting Baseline Study	UI, CL&P, Western MA	2006	B
NE	CFL Markdown Impact Study	United Illuminating and other utilities	2008	B
NE	CT and MA Ductless Heat Pump Impact Study	United Illuminating	2008	B

Table A-2. (continued)

Region	Name of Study	Utility/Agency	End Date	Usability Rating
NE	2005 Coincidence Factor Study	United Illuminating and CL&P for the ECMB	2007	B
NE	MassSAVE Impact Study	Unitil	2007	B
Other	End-use database	Florida Solar Energy Center	2000	C
Other	End-use database	Florida Solar Energy Center	2000	C
Other	Residential end-use database	Austin Energy	early 1990s	D

Note: Usability rating is a subjective ranking system as follows: (A) meets capacity market standards (for defined region, measure(s)), and is usable as a stand along study within a region; (B) meets efficiency planning standards (for defined region, measure(s)), and is usable as part of a compilation study; (C) has some issues (e.g. low sample size or data is older), but could be used as last resort or to guide modeling efforts; (d) study should not be used (or data not available to be used); (IP) study is in progress (during KEMA 2009 study). Source: KEMA 2009.

Appendix B: Application of Load Shape Data in Integrated Resource Plans (IRPs) and Demand Side Management (DSM) Plans

Appendix B describes the methodologies used to apply end-use load shape data in utility resource and demand side management planning in the four locations reviewed in this study. These areas were selected based on their differing power system load shapes, market structures, approach to and experience with energy efficiency valuation, and availability of data. These include two areas with organized markets (New England and California) and two areas (Georgia and the Pacific Northwest) that retain vertically integrated utility systems.

The description of each location's approach to the valuation of energy efficiency is organized into four areas:

- Energy efficiency policy and regulatory context;
- Resource needs assessment process (i.e., how future needs for energy and capacity resource acquisitions are established);
- Cost-effectiveness determination process and criteria; and
- Derivation of time-varying value of energy efficiency measures for this study.

Pacific Northwest

Energy efficiency policy and regulatory context

The Pacific Northwest was chosen as a case study for this study because it has a long-standing history of implementing energy efficiency on a regional basis, and through an IRP process. The Pacific Northwest region is unique because it has the only federally established regional integrated planning process. Moreover, nearly 40 percent of its power is provided by the Bonneville Power Administration, a federal power marketing agency. The Northwest Power Planning Council (Council) is an interstate compact between the states of Idaho, Montana, Oregon, and Washington authorized by the U.S. Congress in the Northwest Electric Power Planning and Conservation Act of 1980 (Power Act) (Northwest Power Act 1980). The Council's role is to ensure that the Pacific Northwest's electric power system will provide adequate and reliable energy at the lowest economic and environmental cost to its citizens. Congress charged the Council with developing integrated electric power plans for the Pacific Northwest region. Under the Power Act, the Council's IRPs are to rely on the least cost resources to meet the region's future power needs. Under the statute, energy efficiency is defined as a resource, and given first priority for development when its cost is less than 110 percent of the next similarly available and reliable supply side resource (Northwest Power Act 1980). The Council is required to review and update its IRP every five years. Its most recent IRP, the Seventh Regional Conservation and Electric Power Plan (Seventh Power Plan), was adopted by the Council in February 2016 (Northwest Power and Conservation Council 2016).

As has been the case in all of the Council's prior plans, the Seventh Power Plan relies heavily on cost-effective energy efficiency to meet the growth in electricity demand over the next 20 years. In more than 90 percent of future conditions, cost-effective efficiency is forecast to meet all electricity load growth through 2030 and in more than half of the futures for all load growth through 2035. The Seventh Power Plan also found that efficiency contributes to meeting future energy requirements, and provides capacity during peak load periods. The efficiency improvements that yield just over 38,000 gigawatt-hours (GWh)/year by 2035 are also forecast to reduce peak hour demands by nearly 9,100 megawatts (MW) during the winter months.[45]

Resource needs assessment process

The Council uses the IRP process to assess the need for, and value of all resources—including energy efficiency—to meet future demands. The first step in the Council's process is to identify the potential need for new resources to ensure that the region maintains an adequate power supply. The Council uses a probabilistic approach to determining whether the region has sufficient resources to meet a 5 percent Loss of Load Probability (LOLP) standard.[46] The LOLP is measured by performing a chronological hourly simulation of the power system's operation over many different combinations of water supply, temperature (load variation), wind generation, and resource forced outages. Any hour in which load cannot be served is recorded as a shortfall. The results of the resource adequacy assessment are then used in the Council's Regional Portfolio Model to establish the minimum capacity and energy reserve margins required to maintain the minimum LOLP.[47]

The Council models energy efficiency as one of the resources available to meet both energy and capacity needs in the Regional Portfolio Model. This means that in the Regional Portfolio Model, energy efficiency resource directly competes with generating resources and market power purchases based on availability, levelized cost, and load shape. As a result, both capacity and energy contributions are considered when determining which resources can supply future needs at the lowest cost and at an acceptable level of economic risk. The Council uses the Regional Portfolio Model to evaluate the cost

[45] Chapter 12 of the Seventh Northwest Conservation and Electric Power Plan, Northwest Power and Conservation Council. Document 2016-2 (February 2016) contains a description of how the capacity savings of energy efficiency measures are estimated (http://www.nwcouncil.org/media/7149926/7thplanfinal_chap12_conservationres.pdf). Chapter 11 of the Seventh Power Plan contains a description of how the system level capacity savings, or associated system capacity contributions, of energy efficiency and generation resources are estimated (http://www.nwcouncil.org/media/7149927/7thplanfinal_chap11_systemneedsassess.pdf).

[46] Loss of load occurs when the system load exceeds the generating capacity available for use. Loss of Load Probability (LOLP) is a projected value of how much time, in the long run, the load on a power system is expected to be greater than the capacity of the available generating resources. It is defined as the probability of the system load exceeding the available generating capacity under the assumption that either energy or peak loads exceed available capacity for a specified period of time.

[47] See Chapter 11 of the Council's 7th Power Plan for a more detailed discussion of the resource adequacy assessment process. Available at: http://www.nwcouncil.org/media/7149927/7thplanfinal_chap11_systemneedsassess.pdf.

and economic risk of hundreds of alternative resource portfolios[48] across 800 different future conditions that reflect a wide range of load growth, electricity and natural gas market prices, hydropower availability, and carbon regulation policies.[49]

The Regional Portfolio Model identifies resource portfolios that have the lowest cost for a given level of economic risk while meeting regional reliability standards for both energy and peak loads.[50] The principle advantage of allowing energy efficiency to compete with other supply side resources in the Regional Portfolio Model is that the model finds the lowest cost solution to both the energy and capacity needs. That is, the model solves both capacity and energy needs simultaneously by testing the cost and economic risk associated with each resource's energy and capacity contribution to the existing power system. For example, when the Regional Portfolio Model identifies a need to add only capacity, then resources that provide only or mostly capacity, such as demand response, are a better match to system requirements.

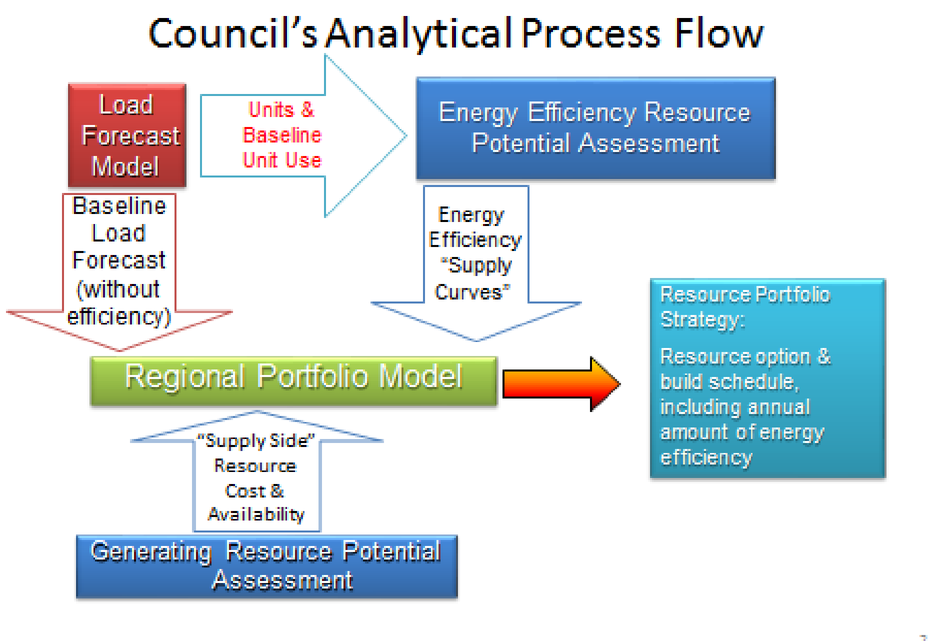

Figure B-1. Northwest Power and Conservation Council integrated resource planning analytical process flow (Eckman 2014b)

[48] A *resource portfolio* consists of a specific resource mix, the timing of the decision to build each resource, and the amount of each resource to develop.

[49] The Council evaluated over two dozen different scenarios, including ones that varied carbon costs, others that set limits on demand response and energy efficiency development or required expanded use of renewables. A least cost, lowest risk resource portfolio was identified for each of these scenarios through analysis across the same set of 800 future conditions. See Chapter 3 of the 7th Power Plan for a more detailed discussion of these scenarios and there results. Available at: http://www.nwcouncil.org/media/7149935/7thplanfinal_chap03_resstrategy.pdf

[50] The RPM is a resource expansion and risk analysis model developed by the Council. See Appendix L of the Seventh Power Plan for a more detailed explanation of the Regional Portfolio Model, model logic and modeling process. (http://www.nwcouncil.org/media/7149906/7thplanfinal_appdixl_rpm.pdf)

Cost-effectiveness determination process and criteria

Based on the outputs of the Regional Portfolio Model analysis, the Council selects a resource portfolio that minimizes the present value system cost, taking into account economic risk (i.e., the *least cost* portfolio with acceptable risk). This portfolio determines the amount and pace of development for all resources, including energy efficiency. The amount of energy efficiency included in this portfolio is judged to meet the Power Act's definition of cost-effectiveness.[51] Because, the Regional Portfolio Model models aggregate bins of energy efficiency, the final step in the Council's process is to specifically consider the impact of the time-varying value of the cost-effectiveness of each of the energy efficiency measures included in the Seventh Power Plan on the preferred resource portfolio.[52]

This process requires that a cost-effectiveness limit for individual measures be set at a level that provides total savings across all measures equivalent to that identified in the Regional Portfolio Model's analysis of 800 different future conditions. The Regional Portfolio Model's wide range of market prices used across these 800 futures are determined stochastically. Rather than attempting to calculate each measure's cost-effectiveness across the full range of market prices, the Council uses the forecast for the variable cost of dispatching the marginal in-region resource for its measure level cost-effectiveness analysis. Other inputs, including the value of deferred generating capacity, deferred transmission and distribution, and carbon costs are assumed to be identical to those used in the preferred resource portfolio. The value of "risk" which is determined through the analysis in the Regional Portfolio Model, serves as the "calibrating" variable. That is, a value for risk is added to ensure that the individual measure cost-effectiveness limit is set at a level that produces savings across all measures equivalent to the amount identified in the analysis in the Regional Portfolio Model.

The Seventh Power Plan explicitly incorporates the value of deferred generation, including the reduced requirements for spinning and operating resources and avoided RPS compliance cost, transmission, and distribution capacity into its cost-effectiveness determinations for measures and programs. Each efficiency measure analyzed by the Council has a unique load shape, and thus has a different impact on the Northwest regional power system's peak demands. This affects its value as a resource option; resulting in different time-varying cost-effectiveness limits for each measure. The Council determines the time-varying cost-effectiveness for individual measures and programs using a software program (ProCost) developed by the Council that accounts for the time-varying value of each energy efficiency measures load shape.[53]

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[51] The Power Act's definition of cost-effectiveness is: "*cost-effective," when applied to any measure or resource referred to in this chapter, means that such measure or resource must be forecast to be reliable and available within the time it is needed, and to meet or reduce the electric power demand, as determined by the Council or the Administrator, as appropriate, of the consumers of the customers at an estimated incremental system cost no greater than that of the least-cost similarly reliable and available alternative measure or resource, or any combination thereof.* Northwest Power Act, supra note 1, at §3(4) (A) (ii), 94 Stat. 2698.

[52] See Appendix G of the 7th Power Plan for a more detailed discussion of the time value of efficiency. Available at: http://www.nwcouncil.org/media/7149911/7thplanfinal_appdixg_consresources.pdf.

[53] The Council's ProCost model is available at: https://nwcouncil.box.com/s/m6q9jqhtgoeehn4pm1rtuk1eoozubzaf. The supporting input file with load shapes and avoided cost is available at: https://nwcouncil.box.com/s/gacr21z8i89hh8ppk11rdzgm6fz4xlz3.

Derivation of time-varying value of efficiency measures for this study

The Council's ProCost cost-effectiveness model, with avoided cost input drawn from the Seventh Power Plan, was used to generate the time-varying value of savings in this study. The ProCost model was run in iterative fashion to establish the total levelized value of all the components of avoided cost (e.g., energy, capacity, deferred transmission and distribution) for each end-use load shape. One ProCost model run used the average avoided cost across all 800 futures tested during the development of the Council's Seventh Power Plan. The avoided cost in this run assumed that a carbon dioxide cost equivalent to the Interagency Working Group on the Social Cost of Carbon's estimate of the damage cost of global warming using a 3 percent discount rate was imposed. A second ProCost model was run using avoided cost that assumed no carbon dioxide cost. The difference in avoided energy cost between these two ProCost runs was used to determine the net cost of carbon dioxide emissions.

California

Energy efficiency policy and regulatory context

California was selected as a case study for this study because of its inclusion of time-varying value of efficiency in its state building energy codes, efficiency program cost-effectiveness, energy efficiency resource standard, and utility shareholder performance incentives (E3 2016; CPUC 2013; Steinberg and Zinaman 2014).

California has a long history of employing the time-varying value of efficiency in electric system planning, and it is the resource of first choice for future energy needs (Navigant 2015). The California Public Utilities Commission (CPUC) is charged with meeting "unmet resource needs with all available energy efficiency and demand reduction that is cost-effective, reliable, and feasible." (California Public Utility Code, accessed June 2017). The CPUC sets efficiency goals for investor-owned utilities through a regulatory proceeding which typically occurs every three years, using a statewide energy efficiency potential study to guide the goals.[54] The goals set by the CPUC are used in "transmission and procurement planning efforts of the Commission, the California Energy Commission and the CAISO; Assembly Bill (AB) 32 greenhouse gas reduction planning; and the Commission's Energy Efficiency Strategic Plan" (CPUC 2015). The electric efficiency goals established for 2016–2024 range from 1,875–2,864 GWh, and 301–550 MW of savings each year for all three investor-owned utilities (CPUC 2016a). In the same docket, the CPUC ruled that utility energy efficiency program administrators in California would submit energy efficiency business plans that describe how they will cost-effectively achieve their efficiency goals by January 2017.

[54] In 2013, the CPUC decided to transition to a rolling review of energy efficiency programs (CPUC 2015).

Resource needs assessment process

California now requires utilities to complete long-term procurement plans, but recently the state has shifted to requiring integrated resource plans for load serving entities in the state.[55] Currently, the CPUC, California Energy Commission (CEC), the California Independent System Operator (CAISO), and the investor-owned utilities all contribute to the development the energy efficiency goals included in long-term electric planning. *The 2015 California Energy Efficiency Potential and Goals Study*, a study developed by Navigant Consulting and funded by the CEC and CPUC, guides many of the decisions in California energy efficiency investments, which are discussed in more detail below. The 2015 energy efficiency potential report is in the process of being updated for 2018, and will include methodological changes from the 2015 study which are currently being discussed in the CPUC's Demand Analysis Working Group (Navigant 2015).

The CEC is responsible for creating the annual energy demand forecast, which is updated each year. The 2017 energy demand forecast was approved in January 2017 (CEC 2017). The CEC draws upon the efficiency potential study to set the utilities' efficiency goals to account for efficiency that is reasonably expected to occur, and reflects those savings in the load forecast. In addition to the efficiency potential study, the CEC considers "committed efficiency" in its load forecast (CEC 2016b).

Cost-effectiveness determination process and criteria

In California, efficiency cost-effectiveness for utility efficiency programs is determined by the *California Standard Practice Manual.* The avoided cost, an input used in all the manual's cost-effectiveness tests, is determined by a methodology that the CPUC established in 2005 to develop avoided costs in a consistent and coordinated manner across Commission proceedings. The avoided cost methodology incorporates market price effects, including the value of reliability through ancillary services and the disaggregation of the avoided costs to time (hour, month, or time-of-use period) and to California climate zones. The use of the time-varying value for avoided cost grew from the California Energy Commission's use of time dependent valuation in evaluating the cost-effectiveness of the state building energy codes (known as Title 24) (E3 2015). California's energy efficiency resource standard goals are also embedded in the utilities' efficiency goals, meaning that the statewide energy efficiency resource standard also considers the time-varying value of efficiency.

Since 2005, this methodology has been updated several times, most recently in 2016 (CPUC 2016b). The avoided cost methodology, and updates to it, are documented extensively, currently through the integrated distributed energy resources proceeding.[56] California has strived for transparency in the calculation of time-varying value of efficiency. E3, a CPUC contractor, developed the avoided cost

[55] In the context of CA SB 350, which requires the CPUC to adopt a process by 2017 for all jurisdictional load-serving entities (LSEs) to submit IRPs to ensure that the LSEs' planning and procurement efforts: (1) meet portfolio optimization requirements in a least-cost/best-fit manner and (2) are on track to meet state electricity sector's targets for greenhouse gas emissions reductions, and by 2030 to meet the requirement to double energy efficiency savings and achieve a 50 percent renewable portfolio standard.

[56] Integrated Distributed Energy Resources docket (http://www.cpuc.ca.gov/General.aspx?id=10710)

calculator that was updated in 2016 to provide hourly efficiency avoided cost values. All of the calculators, user manuals, and model updates are available publicly, for free on the CPUC's website.[57]

Derivation of time-varying value of efficiency measures for this study

For this study, end-use load shapes were obtained from two sources in California: the Hourly Electric Load Model (HELM) maintained by the CEC and the Database for Energy Efficient Resources (DEER). The CEC uses the HELM model to create 8,760 load shapes to forecast peak demands by sector (e.g., residential, commercial) for each investor-owned utility in the state as well as for the entire state. This study used the CEC data from HELM to represent the power system load shape for Pacific Gas and Electric (PG&E). The load shapes contained in the DEER database are IOU-specific and are required for use in their efficiency portfolio planning and cost-effectiveness evaluations.

A final E3 Energy Efficiency Calculator for PG&E, using the most recent (2016) avoided cost, was not available for use in this analysis. However, this study attempted to mimic the methodology used in the E3 Energy Efficiency Calculator using the DEER database end-use load shapes for PG&E (climate zone 13) and obtained avoided costs from the 2016 version of the E3 Avoided Cost Calculator.[58] Following the method used in the E3 calculator, the time-varying values for energy savings for this study were computed by multiplying the hourly (8,760) levelized value/MWh of the avoided cost for energy, capacity, ancillary services, transmission and distribution, carbon dioxide emissions, and RPS compliance costs by each hourly demand for each efficiency measure. Efficiency measures were assumed to be installed in 2017 in PG&E's service area (California climate zone 13) and have an expected useful life of 15 years. The sum of the hourly values for each of these components is then the hourly demand weighted value for each end-use across all hours in a year, or the time-varying value for each load shape.

Massachusetts

Energy efficiency policy and regulatory context

Massachusetts was selected as a case study for this study because the region participates in a wholesale electric market that is administered by ISO New England (ISO-NE), and the states participating in this market all have a long history of significant energy efficiency resource development. The ISO-NE has three goals: (1) to keep electricity supply and demand in balance, (2) to oversee the wholesale electricity market in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont, and (3) to conduct power system planning for the region. ISO-NE allows energy efficiency to participate in the wholesale electricity market through the Forward Capacity Market. The New England market structure differs from the California market structure in several respects. First, ISO-NE has

[57] Integrated Distributed Energy Resources docket (http://www.cpuc.ca.gov/General.aspx?id=10710)
[58] E3 calculator (2015).

established a forward capacity market, while the CAISO has not. Second, the ISO-NE operates across multiple states, while the CAISO currently operates only within a single state.[59]

Resource needs assessment process

ISO-NE creates its efficiency forecast by projecting the cost of energy savings, and projecting the amount of funding that each of the states in the ISO-NE region will spend. Together these estimates create the efficiency load forecast (ISO-NE 2016). The ISO-NE relies on information from the states to ensure that it creates an accurate forecast, including efficiency budgets, production costs, and a ratio of peak demand to annual savings in energy use (ISO-NE 2016).

To avoid double counting, ISO-NE's load forecast does not take into account new energy efficiency resources, as those are resources that can bid in the auction. The load forecast does take into account energy efficiency that has been accepted in prior auctions, or that continues to have a capacity supply obligation. To ensure accuracy, a thorough measurement and verification protocol is used to determine energy efficiency impacts.

ISO-NE determines the amount of efficiency through its Forward Capacity Market.[60] ISO-NE determines the amount of resources that are necessary to meet its summer peak load forecast and then sets the minimum amount of supply and demand resources that it will purchase and the maximum price it will pay for the quantity of resources.

Cost-effectiveness determination process and criteria

The states participating in ISO-NE have differing processes and criteria for determining cost-effectiveness, although most use a version of the Total Resource Cost test.[61] However, they all use a regional analysis of avoided cost in their calculations of the value of energy savings (Hornby et al. 2015). The *Avoided Energy Supply Costs in New England: 2015 Report* (Hornby et al. 2015) provides estimates of avoided costs for program administrators throughout New England to support their internal decision-making and regulatory filings for energy efficiency program cost-effectiveness analyses. The AESC 2015 includes avoided cost for energy, capacity, transmission, distribution, carbon dioxide emissions, RPS compliance, and DRIPE, as well as other resource data.

Derivation of time-varying value of efficiency measures for this study

In this project, the system load shape data was obtained from the ISO-NE. The ISO-NE system load data was downloaded through its energy, load, and demand reports webpage.[62] Historical hourly real-time system demand was downloaded and compiled into annual hourly data.

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[59] CAISO is in the process of expanding its operations and governance beyond California to better serve the need for energy imbalance market services across the West to meet increased balancing and flexibility reserve requirements resulting from expanding use of renewable resources. http://www.caiso.com/Documents/RegionalEnergyMarket-FastFacts.pdf

[60] ISO-NE Forward Capacity Market: https://www.iso-ne.com/markets-operations/markets/forward-capacity-market

[61] See the ACEEE State Energy Efficiency Scorecard at: http://aceee.org/state-policy/scorecard.

[62] ISO-NE Energy, Load, and Demand Reports: https://www.iso-ne.com/isoexpress/web/reports/load-and-demand

The time-varying value of energy efficiency calculation for Massachusetts was done for Massachusetts using the National Grid cost-benefit calculator (National Grid 2016). This calculator uses the avoided cost developed through a regional analysis, the *Avoided Energy Supply Costs in New England: 2015 Report* (Hornby et al. 2015). The coincidence factors and seasonal distribution of energy savings for each end-use load shapes used were those that were assumed in the National Grid cost-benefit calculator.

Georgia

Energy efficiency policy and regulatory context

Georgia was chosen as an example for this study because it represents a traditional vertically integrated, regulated utility in a region without an organized wholesale market. Georgia Power generates about 68 percent of Georgia's electricity. Georgia retains the traditional vertically integrated utility business model, and has an IRP requirement but does not have an energy efficiency resource standard or other policy mandating/encouraging energy efficiency.[63]

Resource needs assessment process

The Georgia Public Service Commission regulates Georgia Power, and approves its IRP and DSM plans on a three-year cycle. Georgia Power's DSM plan is developed over an 18-month period, in collaboration with diverse stakeholders. The company uses an efficiency potential study that is updated every three years to identify the technical, economic, and achievable potential that is available in its service territory. After identifying the efficiency potential, the company develops DSM plans for an efficiency target that "minimize upward pressure on rates and maximize economic efficiency" (Georgia Power Company 2016). The Georgia Public Service Commission reviews the efficiency potential study, the DSM plans, and the proposed efficiency target, and approves them as part of the larger IRP process. The efficiency targets are used as a load reduction in the IRP (Georgia Power Company 2016).[64]

Cost-effectiveness determination process and criteria

All efficiency measures that pass qualitative screening then undergo economic screening (using hourly load shapes and Southern Company Service's proprietary model, PRICEM). Measures that pass the Total Resource Cost test are available to be included in energy efficiency program plans. The value of the energy efficiency impacts that are used in the DSM plans are calculated hourly, using hourly avoided costs. However, Georgia Power does not provide the load shapes or hourly avoided cost as publicly available data. As discussed in Section 4, calculating the hourly avoided cost associated with energy efficiency measures is a best practice. However, due to the company's request that this information be classified as confidential data, we were unable to verify or review the company's methodology and data.

[63] All figures from 2015. *Georgia Power Company 2015 Annual Report.* https://www.georgiapower.com/docs/about-us/2015GPCAnnualReport.pdf, page 7; Energy Information Administration. Georgia Electricity Profile 2015. https://www.eia.gov/electricity/state/georgia/

[64] Georgia Public Service Commission Docket No 40162.

Unlike the other locations in this study, the Georgia Public Service Commission considers the Ratepayer Impact Measure cost-benefit test when determining "upward pressure" on rates. This cost-benefit test takes into consideration lost revenues when determining cost-effectiveness.

Derivation of time-varying value of efficiency measures for this study

For this analysis, neither hourly load shapes nor hourly avoided cost were available for Georgia Power's service area, as the company considers these proprietary data. However, Georgia Power does publish a publicly available Technology Catalog that is used to develop its technical, economic, and achievable demand side management potential.[65] For this study, the peak kilowatt savings, identified in Georgia Power's Technology Catalog for the five measures were used to calculate their capacity values.[66] Load shape data from the Building America simulations (http://en.openei.org/datasets/files/961/pub/) for Atlanta were used to allocate hourly energy savings to peak and off-peak avoided cost periods. To compute the time-varying value of savings, this study used Georgia Power's seasonal peak and off-peak avoided costs developed for its Public Utility Regulatory Policies Act (PURPA) compliance filing.[67] The avoided cost values for peak and off-peak hours, as defined in that study, were used to derive the seasonal peak and off-peak value of savings for each of the energy efficiency end-uses. No avoided costs are included in this study for transmission, distribution, reserves/ancillary services, RPS compliance, risk, and carbon dioxide emissions.

Data from Federal Energy Regulatory Commission (FERC) Form 714 was used to develop Georgia Power's annual hourly load shape. FERC Form 714 provides data in the central time zone, so hourly data was shifted backwards one hour to develop the load shapes to reflect the savings occurring in the Eastern Time zone.

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[65] Georgia Public Service Commission Docket No. 40162.

[66] All energy and capacity savings were first normalized to a measure with assumed annual energy savings of one megawatt-hour (1,000 kWh).

[67] Georgia Power Company. 2016 Avoided Cost and Solar Avoided Cost Projections; Georgia Public Service Commission Docket Nos. 4822 and 16573. http://facts.psc.state.ga.us/Public/GetDocument.aspx?ID=166300

Appendix C: Time-Varying Value of Energy Efficiency by Measure and Location

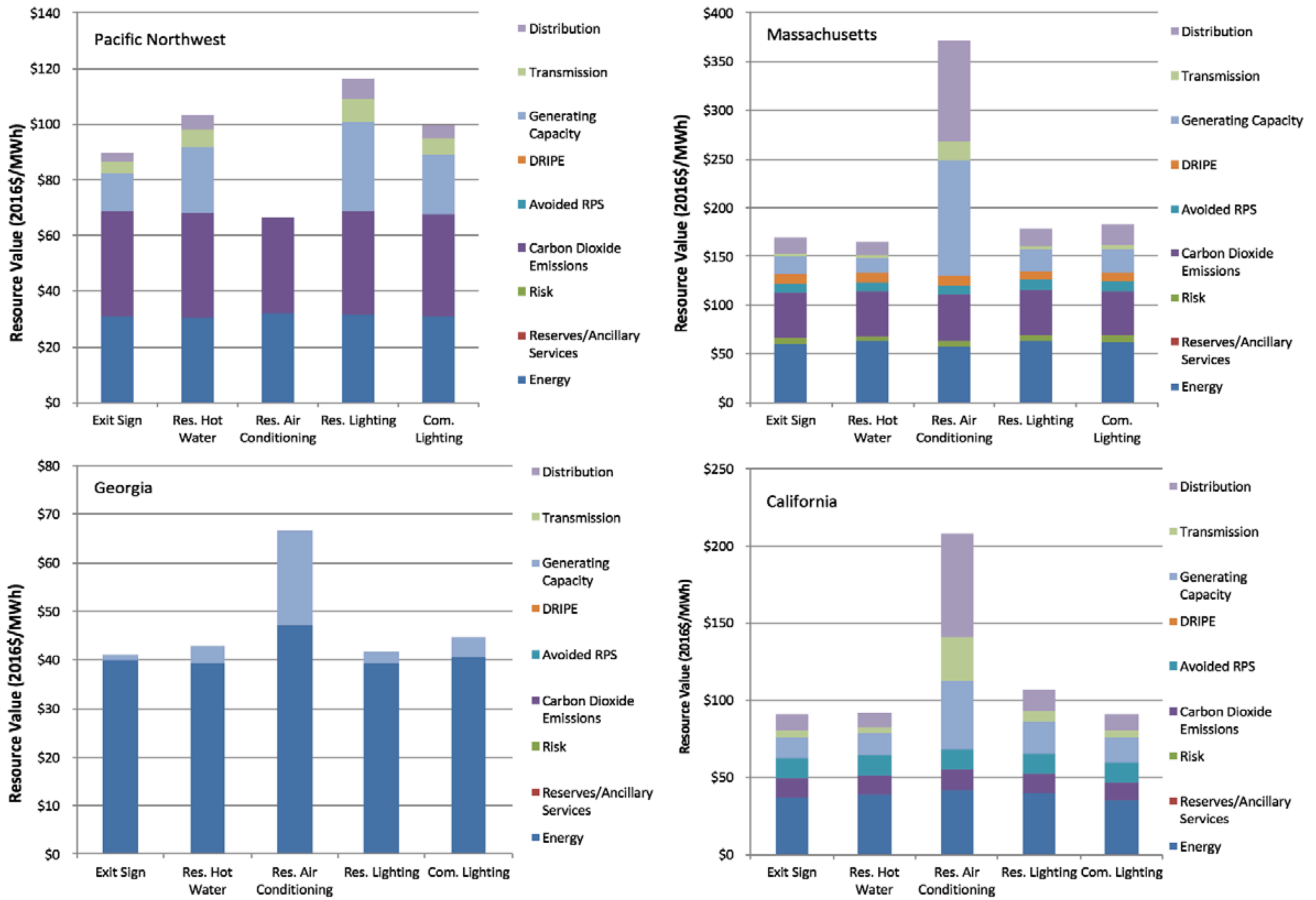

Figure C-1. Time-Varying Value of Energy Efficiency by Measure and Location