Executive Summary
States across the country are confronting a shift to a “peakier” pattern in the use of electricity—meaning the highest levels of daily demand are increasingly greater than the average level of daily demand—that is driving up overall power costs. The most pronounced shift has occurred in New England, where a peak-to-average difference of 52 percent in 1993 grew to 78 percent in 2012; the difference also grew over that same period in California, New York, Texas and the Mid-Atlantic and Midwest regions. This shift reflects a transition from an industrial to a service-oriented economy and other changes in how electricity is generated and used. For instance, while peak demand has remained relatively flat in many areas, average energy demand has declined so the gap between the two has grown. Governors may be concerned about the increasing peakiness of the electricity system and how it affects reliability and affordability for several reasons:

- Serving peak load can be up to seven times more expensive than serving average “base” load;
- Peaking plants sit idle most of the year, causing utilities to face greater excess capacity (lower utilization rates) during off-peak times and higher costs; and
- Aging transmission and distribution infrastructure is further stressed when demand becomes peakier.

In addition, states experiencing a rapid growth in the use of energy resources with variable supply, such as residential solar photovoltaic (PV) power, may face the additional challenge of addressing residential net demand levels that surge when on-site solar power is unavailable. Residential demand levels typically are not in sync with electricity produced from solar, with residential energy consumption peaking in the early morning and in the evening, both before and after solar PV reaches its production peak.

States have been using demand response measures, which provide incentives for customers to reduce their usage at peak times (when the incentives cost less than generation) to help address the peakiness problem. Meanwhile, some states are also exploring how to design energy efficiency measures, which target reductions in overall energy use, to also address peak demand concerns (focusing on economic sectors and end-uses with high peak demand levels) and some recent efforts in the New England and the Mid-Atlantic regions are showing promise in energy efficiency’s ability to reduce peakiness. However, efforts to coordinate the delivery of demand response and energy efficiency are not generally pursued. Therefore, states may be missing out on opportunities to leverage each type of measure.

To support better alignment, and achieve cost savings and reliability benefits, governors can pursue the following steps with their legislatures, public utility commissions and others:

- When designing new, or evaluating existing, energy efficiency and demand response programs, measure the peak or time-differentiated value of both demand response and energy efficiency savings;
• Support energy data collection to better understand patterns of electricity use and savings while addressing concerns about privacy and access;
• Launch pilots that integrate energy efficiency and demand response at state facilities;
• Encourage alignment or integration of residential and commercial demand response and energy efficiency programs;
• Integrate demand response and energy efficiency into grid modernization efforts;
• Explore the deferral or avoidance of capital investments by geographically targeting investments in energy efficiency and demand response where energy supply costs or grid congestion are highest; and
• Consider setting goals for energy efficiency that include peak load reduction targets.

Background
Over the past two decades, many areas of the country have experienced an increased difference between their annual average hourly demand for electricity and their annual highest peak-hour demand. Generally, increasing “peakiness” has been due to average demand levels decreasing and peak demand levels remaining constant or increasing. The growth in the difference between average demand and peak demand varies by region and has been more pronounced in the New England area, as shown in Table 1 on page 3, where a difference of 52 percent in 1993 grew to 78 percent in 2012. The span is also growing in California, New York, Texas and the Mid-Atlantic and Midwest regions. Three major factors reflecting this trend include a shift from an industrial to a service-oriented economy that is less energy-intensive, new and emerging patterns in residential electricity demand—led by a 30 percent increase in air conditioning since 1993—substantially increased consumer electronics or “plug loads” and the growth in the use of distributed energy resources.

The “greater peakiness” phenomenon affects the reliability and affordability of the electricity system in several ways that may be of concern to governors:

• **Meeting peak load can be up to seven times more expensive than serving base load** since electricity-generating plants used to meet peak load are very costly to operate. Natural gas combustion turbine plants which can be activated quickly in response to increased demand can be considerably more expensive to operate than coal, combined cycle natural gas and nuclear units that are typically used to meet base load.

• **Peaking plants sit idle most of the year, causing utilities to face greater excess capacity (lower utilization rates) during off-peak times and higher costs.** The electric power industry is required to maintain sufficient capacity to meet all power demand, which includes peak load plus a reserve margin. Over the course of a year, most peaking plants are only put into use for a relatively small number of hours, during which they must recover their entire costs. When average demand drops and the gap between average and peak demand grows, the relatively higher amount of excess capacity drives up costs per kilowatt-hour (kWh) as generators have fewer hours over which they can receive energy-related payments.

• **Aging transmission and distribution infrastructure is further stressed when demand becomes peakier.** According to some studies, high levels of peak demand and significant daily fluctuations in demand result in more power disruptions and repairs.

Growth in variable generation and other forms of distributed energy resources (DER), such as residential solar photovoltaic (PV) power, can provide customer and grid benefits, but, if not managed properly, can add to the challenge of peak demand. Net load (baseload electric system demand minus DER)
Table 1. Ratio of Peak to Average Electricity Demand in Different Regions\(^\text{12}\)

<table>
<thead>
<tr>
<th>Region*</th>
<th>1993</th>
<th>Mid-Data Point**</th>
<th>2012</th>
<th>Trend</th>
</tr>
</thead>
<tbody>
<tr>
<td>New England</td>
<td>52%</td>
<td>73%</td>
<td>78%</td>
<td>Peak and average load levels steadily increased from 1993 to 2005. Beginning in 2006, average load levels have declined while peak levels remained about the same.</td>
</tr>
<tr>
<td>New York</td>
<td>64%</td>
<td>69%</td>
<td>75%</td>
<td>Average hourly demand levels steadily increased from 1993 to 2005. Beginning in 2006, average hourly demand levels have remained flat to slightly declining. Peak hour demand levels have remained roughly flat from 2006 on.</td>
</tr>
<tr>
<td>Mid-Atlantic and Midwest (PJM)</td>
<td>59%</td>
<td>65%</td>
<td>74%</td>
<td>Both peak and average hourly demand levels have remained on an upward trend through 2012, though average demand has slightly decreased in 2011 and 2012.</td>
</tr>
<tr>
<td>Midwest (MISO)</td>
<td>62%</td>
<td>67%</td>
<td>76%</td>
<td>Both peak and average hourly demand levels steadily increased from 1993 to 2006. Average hourly demand levels remained relatively flat until 2008, when they dropped significantly.</td>
</tr>
<tr>
<td>Southern California</td>
<td>69%</td>
<td>85%</td>
<td>84%</td>
<td>Both peak and average hourly load levels increased steadily in Northern and Southern California from 1993 to 2006, followed by a flat-to-declining trend in both peak and average loads in the years after.</td>
</tr>
<tr>
<td>Northern California</td>
<td>65%</td>
<td>73%</td>
<td>73%</td>
<td>Both peak and average hourly load levels increased steadily in Northern and Southern California from 1993 to 2006, followed by a flat-to-declining trend in both peak and average loads in the years after.</td>
</tr>
<tr>
<td>Texas</td>
<td>74%</td>
<td>75%</td>
<td>80%</td>
<td>Steady increases in both peak and average hourly demand levels led to a slightly increasing peak-to-average demand ratio throughout the 1993-2012 period.</td>
</tr>
<tr>
<td>Southeast (SPP)</td>
<td>82%</td>
<td>70%</td>
<td>75%</td>
<td>Peak and average demand levels rose in tandem fairly steadily from 1993 to 2007. In 2008 and 2009 peak and average demand fell, then rebounded in 2012 and remained relatively flat thereafter.</td>
</tr>
<tr>
<td>Northwest</td>
<td>63%</td>
<td>59%</td>
<td>47%</td>
<td>Peak and average hourly demand levels were both flat from 1993 to 2012, aside from short-term year-to-year fluctuations due to weather or economic conditions.</td>
</tr>
</tbody>
</table>

* Regions correspond to the footprints of regional system operators (RTOs)/independent system operators (ISOs) in Figure 1 on page 4, plus the Northwest Power Pool (all or major parts of Idaho, Montana, Nevada, Oregon, Utah, Washington and Wyoming) (see: [http://www.ferc.gov/market-oversight/mkt-electric/northwest.asp](http://www.ferc.gov/market-oversight/mkt-electric/northwest.asp)). The California ISO is split into north and south.

** Mid-points in the data occur from 1993 to 2003 and illustrate the middle of the trend line. Data for all years 1993 to 2012 along with associated trend lines are contained in graphs for each region in the EIA source.
declines in the mid to late morning as solar generation picks up, and rapidly increases in the late afternoon as solar production drops off and residential demand increases. States experiencing rapid growth in the use of residential PV power, such as Arizona, California, Hawaii and Nevada, face additional challenges in addressing high residential peak demand levels.¹³

- **California**’s independent system operator analyzed daily projected statewide demand from 2012 to 2020. The results indicated a growing need for flexible electricity resources to serve peak afternoon loads but also found distribution-level costs from over-generation, when more electricity is supplied from DER than is needed.¹⁴ The disparity is illustrated by the so-called “duck curve” shown in Figure 2 on page 5.

- In **Hawaii**, residential solar PV installations tripled in MW capacity between 2012 and 2015.¹⁵ Utilities are looking at circuit level hosting capacity and system level hosting capacity to evaluate safe and reliable levels for grid interconnection and related needs for equipment upgrades.¹⁶

**State Actions to Address Peak Demand: Demand Response, Energy Efficiency and Ideas for Alignment**

To address concerns about the growing peak-to-average electricity demand ratios, states are working with utilities, other private-sector actors and interested stakeholders to deploy demand response programs. Meanwhile, states are supporting a range of approaches to increase energy efficiency. Both demand response and energy efficiency efforts help customers manage their electricity consumption and reduce costs. Demand response programs generally shift electricity consumption away from periods of high demand and high cost to periods of lower demand and lower cost.

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**Figure 1. Map of Centrally-Organized Markets (Regional Transmission Operators/Independent System Operators)**¹⁷
Energy efficiency programs target reductions in overall energy use (and, in some instances, peak energy use), which lower participating consumers’ bills. Both demand response and energy efficiency measures also can reduce congestion on the transmission grid which helps maintain reliability and decrease wholesale electricity costs even for non-participants.\(^{19}\) However, generally, demand response and the energy efficiency efforts are not coordinated, which means states may be missing out on opportunities to leverage the use of demand response to achieve additional energy efficiency gains and to direct energy efficiency efforts to play a more targeted role in lowering peak demand. Governors can promote additional alignment by encouraging state public utility commissions, energy offices and third-party providers to coordinate strategies.

**Demand Response and Pricing Programs Designed to Reduce Peak Electricity Demand**

Demand response programs provide financial incentives or contractual payments to electricity customers to reduce their energy use during times of peak demand. Historically, utility-run demand response programs relied solely on remotely activated load control switches to cycle air conditioners, water heaters and industrial lighting during energy emergencies in order to reduce the need for expensive generation, transmission and distribution capacity. Technological advances—such as advanced metering infrastructure and smart building controls that are part of the move to a “smart grid” -- mean demand response programs are now more automated and can be used by utilities or grid system operators for real-time relief from peak demand or to provide grid services, such as frequency regulation. Demand response programs in 2013 provided a total of 28,798 MW or 6.1 percent in peak reduction potential on average, with programs contributing from 2.9 percent to 10.2 percent, depending upon the region.\(^{20}\)

Demand response programs operate in both the wholesale and retail electricity markets.\(^{21}\) About half of demand response reductions in the United States come from wholesale power markets. Those have grown rapidly in the eastern parts of the country over

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\(^{18}\) Source: CalISO

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**Figure 2. Load Shape for California 2012 to 2020 (projected)**

![Graph showing load shape for California 2012 to 2020](image-url)
the last decade. Wholesale market demand response is overseen by the Federal Energy Regulatory Commission (FERC) in conjunction with regional transmission operators (RTOs) and independent system operators (ISOs). In addition, most vertically-integrated utilities operate their own demand response programs at the retail level.

Two types of voluntary (“opt-in”) demand response programs allow utilities and third parties to cycle load for retail customers in exchange for a financial incentive. Direct load control programs remotely adjust customers’ electrical equipment (such as air conditioners, water heaters and lighting) in response to an emergency peak event. Flexible programs automate adjustment (directly or through a third-party) of equipment operation to meet grid ancillary services (for example, frequency regulation).

In addition, a variety of dynamic pricing programs are tied to advanced metering infrastructure installations that combine new software and control technologies and time-based rates to shape energy use. These programs are emerging in a number of states, with over 4 million households now participating in some form of dynamic pricing structure. Examples of dynamic pricing programs include:

- Time-of-use rates, which provide a schedule of rates for different hours of each day;
- Critical peak pricing, which applies a higher rate to seasonal peaks when wholesale prices are highest or the grid is stressed;
- Peak time rebates, which pay participants for load reductions during peak times; and
- Real time pricing, which charges customers the actual price set in wholesale markets or short-run marginal generation costs (for vertically integrated utilities).

### Energy Efficiency Programs Designed to Reduce Energy Use

Energy efficiency programs focus on reducing and managing energy use while maintaining the same level of service. Ideally, energy efficiency programs combine quicker payback investments and longer-term investments for greater energy savings impacts. Examples of measures that an energy efficiency program could include:

- Enhanced insulation, improved lighting and upgraded appliances in homes and businesses;
- Improved industrial equipment (e.g., industrial fans or motors); and
- Optimized systems for heating, ventilation and air conditioning.

While most energy efficiency programs provide customers with technical assistance, incentives or financing assistance to reduce demand overall, some programs’ energy efficiency measures also reduce peak demand, such as more efficient air conditioning units.

### Concerns about Demand Response and Increased Total Emissions

In some cases, demand response programs may induce greater use of back-up generation, in particular on-site diesel generation, which has raised air quality concerns due to increased emissions. However, a recent decision by the U.S. Court of Appeals rejecting a proposed rule to allow small back-up generators to operate for longer periods without air pollution controls partially mitigates this concern, although a significant increase in customer participation in such programs could still worsen air quality.
that reduce peak use on hot summer days. In the United States in 2014, utility-directed energy efficiency programs achieved 24 million megawatt hours (MWh) in electricity savings which contributed an estimated 5,591 MW in capacity savings. These savings represent about 20 percent of the peak reduction potential attributed to demand response programs. While small, this amount points to the potential for additional benefits. Some recent efforts in the New England and the MidAtalantic regions are showing promise in energy efficiency’s ability to reduce peakiness and leading to reduced forecasts in peak demand.

Aligning Demand Response Programs and Energy Efficiency Programs to Address Peak Electricity Demand and Achieve Demand Reduction Goals

Demand response and energy efficiency programs generally have been pursued separately, each aimed at specific outcomes. Under that type of uncoordinated effort, limited studies have indicated demand response programs provide a small amount of coincidental energy efficiency benefits. For instance, one study estimates that the energy efficiency co-benefits of dynamic pricing (one approach to demand response) have achieved energy savings of from 1 to 3 percent. A recent analysis of potential peak demand reduction strategies noted that customers who receive load control devices and energy management systems also achieve non-event day energy savings if they get in the habit of using them effectively. For this reason, emerging efforts in some states have begun to more deliberately align demand response and energy efficiency. Utilities and others are also being encouraged to make use of both strategies to address increasing peak demand levels while managing overall consumption. The following examples provide suggestions for governors to pursue in collaboration with their legislatures, public utility commissions, energy offices and others.

Measure the value of both demand response and energy efficiency savings

Demand response programs typically examine only a reduction in energy use for a specified period. Programs are not designed to discover whether the short term reduction attributed to the program was simply followed by a shift in load to another period or if there was a reduction in total energy consumption. Neglecting any reduction in total energy use misses the opportunity to better understand the overall longer-term impact of demand response programs on energy consumption. Similarly, measurements of energy reductions from efficiency measures should include coincident peak-demand reduction. In addition, recording the geographic location of energy efficiency achievements can provide the necessary information to offer incentives based on the contribution to demand reduction in specific locations (i.e., closer to how demand response is compensated). California’s Public Utilities Commission (CPUC) historically has included utility-level peak reduction valuation in its policies and programs, but more recently the state legislature has directed that forecasts, planning and offerings reflect more granular geographic, seasonal and hourly valuations. California is also undergoing a process to value DER resource for their ability to contribute to grid reliability as well as to support greenhouse gas reduction goals. The Illinois Commerce Commission requires the state’s major utilities to calculate how much energy efficiency programs reduce energy use overall and at peak periods. The state also quantifies the value of avoided peak electricity demand. In Massachusetts, the Department of Energy Resources is working with utilities to support a commitment in their 2016-2018 Energy Efficiency Plans to incorporate demand reduction demonstration and assessment into their energy efficiency analysis and planning process.

Support the collection of data

Data about when and how electricity is used or saved is important in order to better manage peak demand programs. Advanced metering infrastructure (AMI)—which comprises smart meters, communication networks and information management systems—provides utilities and third parties with this type of data. In 2009, federal investment helped kick-start the deployment of AMI; by the end of 2015, nearly
65 million AMI units were deployed, representing one-third of all homes and businesses in the United States. However, deployment of AMI is only the first step to realizing the system's full energy and cost saving potential. Policymakers and utilities must determine how best to make the information provided by AMI accessible to customers and third-party service providers. Although AMI brings concerns about data privacy, states can establish protocols to ensure that individual customer information is not used inappropriately (for instance through provisions concerning customer consent, data aggregation and opt-out options) and ensure that third-party providers have equitable access to consumer data. The Minnesota Public Utilities Commission, for example, requires utilities to develop security protocols meeting National Institute of Standards and Technology standards for customers’ personally identifiable information collected through smart meters. This data may not be sold by utilities but may be shared with third parties for regulated purposes, provided the third party maintains equally stringent protection and utilities maintain responsibility for the data. In California, the CPUC in the past authorized cost recovery for AMI electric and gas meters generally. More recently it authorized demand response pilots using Home Area Network-enabled devices (with costs recovered through rates). The CPUC has two open proceedings: one that is assessing the local capacity for and net benefits from incorporating distributed resources at the local grid level and another that is developing a framework for how to solicit alternative distributed resources to meet targeted grid needs.

**Launch pilots at state facilities that integrate energy efficiency and demand response**

States are using energy efficiency and demand response measures to manage their own energy use and to control costs of building operations. In 2010, the Massachusetts Department of Energy Resources signed a multiyear contract with a third-party aggregator to integrate demand reduction and energy efficiency measures for a significant portion of its state building portfolio and create a system for state employees to better visualize and manage energy usage for individual buildings. A new three-year agreement with the same company was signed in 2016. The program is expected to save between 5 and 15 percent of energy expenses at the buildings enrolled in the effort. New York has launched a $25 million network operations center that uses smart meter data to track savings from energy efficiency and demand response in its buildings.

**Align residential and commercial demand response and energy efficiency programs**

States can encourage their utilities to pilot programs in the residential sector with a coordinated set of offerings that align demand response and energy efficiency programs. In Nevada, NV Energy has deployed a program to optimize energy efficiency and demand response efforts in the residential sector. The program provides and installs smart thermostats. Using continuous monitoring and thermal profiles, the thermostats give NV Energy the ability to precool homes before a DR event in order to balance load impact against customer comfort. Customers are also able to control their thermostats via a smartphone and the internet. NV Energy had 33,400 customers enrolled and 51,000 smart thermostats installed in its southern service territory and 2,800 customers enrolled and 3,500 smart thermostats installed in its northern service territory as of March 2016. Preliminary results indicate an average peak reduction of 3.0 kW per home in the south and 1.8 kW per home in the north during the first hour of a demand response event and electric energy savings of 580 kWh per household per year on average in the south and 320 kWh per household in the north. In New York, Con Edison combines its end use programs under one department, which enables customers to consider their own combination of demand response and energy efficiency measures.

**Integrate demand response and energy efficiency into grid modernization efforts**

A number of states, including California, Hawaii,
Illinois, Massachusetts, Minnesota and New York, are using utility proceedings to explore the future of the electric grid. Those efforts focus on utility rates and compensation, pricing, DER and the associated implications for transmission and distribution infrastructure. For example, at the direction of New York Governor Andrew Cuomo, the New York Public Service Commission (PSC) released a plan to modernize its electric utility sector, called Reforming the Energy Vision (REV).\textsuperscript{40} Under REV, demand response programs approved by the New York PSC must be available statewide by July 2016.

New York and other states have taken this a step further by geographically targeting energy efficiency to defer or avoid capital infrastructure investments that would otherwise be needed to accommodate increased load. One example is a partnership between the New York State Energy Research and Development Authority and the Con Edison utility to decrease electricity demand by up to 125 MW in New York City by increasing energy efficiency, reducing peak demand and applying combined heat and power (CHP) at high-usage distribution nodes in New York City and Westchester County.\textsuperscript{41} Another groundbreaking effort, also involving Con Edison, is the Brooklyn-Queens Demand Management program. It combines demand response and energy efficiency measures to defer the need for a $1 billion substation by eight years or longer, using half that amount for investments in demand management, energy efficiency and infrastructure upgrades.\textsuperscript{42} In Massachusetts, the National Grid utility has proposed a Non-Wires Alternative program for Nantucket island. The proposal bundles solutions including enhanced energy efficiency, demand reduction and peak load shifting with the goal of deferring transmission and distribution investment for the island for seven years.\textsuperscript{43} Other states pursuing energy efficiency investments to reduce demand and avoid defer or avoid future transmission and distribution investments include California, Maine, Nevada, Oregon, Rhode Island and Vermont.\textsuperscript{44} Consider setting statewide goals for energy efficiency that include peak load reduction targets. As of April 2015, 24 states have goals for energy efficiency, approximately one-third of which include peak reduction targets. While it is difficult to design a program around a “one size fits all” target influenced by exogenous factors, as some states apply top-down goals, promising results in at least one state indicate that well-designed and implemented efforts can reduce peak load.\textsuperscript{45} In 2006, Colorado passed a law requiring utilities to achieve a 5 percent reduction from 2006 electricity sales and a 5 percent reduction from 2006 peak demand by 2018.\textsuperscript{46} To help meet the demand response portion of the state goal, Xcel Energy contracted with a third-party in 2009 to administer the utility’s DR program. This led to a residential demand response pilot program that tested consumer response to energy consumption information delivered when the temperature was higher than 94 degrees. Program participation resulted in average net participant savings of 3 percent.\textsuperscript{47} Building on earlier efforts, Xcel Energy has proposed implementing a $92 million program that is expected to save 506 gigawatt hours per year (1.8 percent of total electricity consumption) and achieve a peak demand reduction of 56 MW at the end of the five-year buildout (during 2015 to 2020).\textsuperscript{48}

**Looking Ahead**

Governors will want to monitor the following new and pending regulatory and legal actions that are expected to affect the market for both demand response and energy efficiency:

- A January 2016 decision by the Supreme Court that upheld Order 745 of the FERC. The order had two important results: It reinforced the ability of demand response programs to participate in wholesale markets, and it required compensation to be equivalent to generation.\textsuperscript{49} The decision brings clarity and regulatory certainty to the market and should support increased interest in and use of demand response to meet peak load.
• The Clean Power Plan, released in August 2015 by the Environmental Protection Agency, requires states to submit compliance plans for reducing greenhouse gas emissions from the power sector. Implementation of the rule was stayed by the Supreme Court in February 2016, pending the outcome of legal challenges, adding uncertainty to the timing and ultimate status of the rule. The rule acknowledges that demand response may produce energy savings as well as reduce energy demand. The ability of demand response and energy efficiency to lower the cost of reducing emissions will depend upon what kind of generation is reduced at the times when an EE measure is saving energy or when a DR program is able to reduce load. Where states are moving forward with their planning or related complementary steps, governors may want to consider how their approach to the Clean Power Plan can benefit from efforts around demand response and energy efficiency.

• The Quadrennial Energy Review 1.1 (QER), led by the U.S. Department of Energy (DOE), includes discussions on how demand response and energy efficiency can complement rooftop solar and other distributed energy resources to reduce transmission constraints. Governors may wish to continue to promote dialogue within their state with state officials, utilities, third-party providers, consumers and the federal government to develop the ideas presented in the QER 1.1. DOE is now accepting stakeholder comments to inform the second installment of the QER, which will more directly study electricity systems.50

Endnotes
1 A peak-to-average demand ratio measures the highest peak-hour of demanded power compared with the average hourly power demanded in a particular region over a period of time. If there were no difference, the ratio would be 1.0, or a 0 percent difference. A higher peak-to-average ratio indicates a peakier system in which a greater share of capacity is needed solely for the purpose of meeting the peak. A ratio of 1.78 means that the peak level was 78 percent higher than the average level. U.S. Energy Information Agency, “Today in Energy: Peak-to-average electricity demand ratio rising in New England and many other U.S. regions,” February 18, 2014 (accessed on May 5, 2016) http://www.eia.gov/todayinenergy/detail.cfm?id=15051#tabs_SpotPriceSlider-2.
3 The nature of efficiency and demand response “program” delivery typically reflects the siloed knowledge and business focus of contractors and installers (e.g., separate insulation companies, lighting contractors or demand response providers focused on automation and controls).
7 The use of natural gas combustion turbine plants to meet peak load is illustrated further by EIA in its article “Natural gas-fired combustion turbines are generally used to meet peak electricity load,” https://www.eia.gov/todayinenergy/detail.cfm?id=13191 (accessed December 6, 2015).
8 While this paper is focused on electricity demand, natural gas has also experienced increasing peaks due to periods of high demand. Demand response and energy efficiency programs can benefit natural gas markets.
9 On average, variable operations and maintenance costs – which include fuel costs – for natural gas combustion turbine plants are on the order of $79.60 to $94.60 per megawatt hour (MWh) compared with natural gas combined cycle ($53.60 to $57.80 per MWh), coal ($29.40 to $30.70 per MWh) and nuclear units ($12.02 per MWh). See the Energy Information Administration’s “Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2015,” https://www.eia.gov/forecasts/aeo/electricity_generation.cfm (accessed December 6, 2015). This is significant for generators in a centrally-organized market (with a regional transmission operator/ independent system operator) where lower energy payments reduce revenues and increase the need for capacity payments. In all markets, the excess capacity can include generation, transmission and distribution capacity.
10 In California, “DER” includes demand response and energy efficiency programs.
11 A peak-to-average demand ratio measures the highest peak-hour of demanded power compared with the average hourly power demanded in a particular region over a period of time. If there were no difference, the ratio would be 1.0, or a 0 percent difference. A higher peak-to-average ratio indicates a peakier system in which a greater share of capacity is needed solely for the purpose of meeting the peak. A ratio of 1.78 means that the peak level was 78 percent higher than the average level. U.S. Energy Information Agency, “Today in Energy: Peak-to-average electricity demand ratio rising in New England and many other U.S. regions,” February 18, 2014 (accessed on May 5, 2016) http://www.eia.gov/todayinenergy/detail.cfm?id=15051#tabs_SpotPriceSlider-2.
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10 In California, “DER” includes demand response and energy efficiency programs.
13 Distributed Energy Resource (DER) technologies are power generation and storage resources typically located on an end-use customer’s premises and operated for the purpose of supplying all or a portion of the customer’s electric load. They may also be capable of injecting power into the transmission and/or distribution system or into a non-utility local network in parallel with the utility grid. They include solar PV, batteries, combined heat and power (CHP), local natural gas generation, electric vehicle home chargers and home automation platforms. In California, “DER” includes demand response and energy efficiency.
15 Information provided by Mark Glick, Hawaii State Energy Office, March 31, 2016; based on Hawaii Electric Company (HECO) annual NEM reports; installed capacity increased from 127.4 MW in 2012 to 382.6 in 2015.
18 Energy efficiency is distinct from energy conservation, which involves undertaking measures to use less energy such as turning down a thermostat to use less heating.
19 Covers participation in RTO and ISO programs only (see map). Assessment of Demand Response and Advanced Metering: Staff Report (Federal Energy Regulatory Commission, December 2014) Table 3-3, page 11. The “potential” reflects the amount that would be provided if all demand response programs are fully utilized or “called upon.”
20 The wholesale market involves sales of electricity for resale while the retail market involves sales to customers for consumption.
21 Mark Dyson et al., The Economics of Demand Flexibility: How “flexiwatts” create quantifiable value for customers and the grid (Rocky Mountain Institute, August 2015), http://www.rmi.org/Knowledge-Center/Library/RMI-TheEconomicsofDemandFlexibilityFullReport (accessed May 5, 2016).
22 Ibid.
23 United States Court of Appeals, District of Columbia Circuit, Delaware Department of Natural Resources v. EPA, 13–1093, 13–1102, 13–1104 (May 1, 2015).
Using cost-effectiveness metrics, program incentives typically are set with a maximum value relative to avoided costs, including peak value where they are utilized.


27 For generation (MWh) savings, see 2014 State of the Energy Program Industry, (Consortium for Energy Efficiency, May, 2015), page 44 and see page 46 for capacity (MW) savings from utility-sponsored energy efficiency programs. See footnote 16 above for potential demand reduction potential.


29 Mark Dyson et al., The Economics of Demand Flexibility: How “flexiwatts” create quantifiable value for customers and the grid (Rocky Mountain Institute, August 2015), http://www.rmi.org/Knowledge-Center/Library/RMI-TheEconomicsofDemandFlexibilityFullReport (accessed May 5, 2016).

30 Peak Demand Reduction Strategy (Navigant Consulting for Advanced Energy Economy, October 2015), 45.


34 Information provided by Jerryllyn Huckabee, Massachusetts Department of Energy Resources, April 4, 2016.


38 Information provided by Jerryllyn Huckabee, Massachusetts Department of Energy Resources, April 4, 2016.


44 Information provided by Jerryllyn Huckabee, Massachusetts Department of Energy Resources, April 4, 2016.

45 In top-down goals, such as those requiring total reductions in electricity sales or peak demand by a specified date (e.g., 20 percent by 2020), care must be taken to account for the impacts of weather, economic activity and other factors outside of the influence of program administrators. For example, a program may gain significant participation but come up short on peak demand reduction goals due to unusually warm summer weather or an increase in state economic activity. California, in contrast, sets its goals using bottom-up potential studies, setting goals based on economic principles and assessing costs by economic sector, building types, end uses of energy and equipment and program costs. As a result, these incremental goals are set for kWh, peak KW and gas therms over a 10-year period and set individually by utility service area.

46 Section 40-3.2-104, C.R.S. further directs the commission to: establish energy savings and peak demand reduction goals to be achieved by an investor-owned electric utility, taking into account the utility’s cost-effective DSM potential, the need for electricity resources, the benefits of DSM investments and other factors as determined by the commission. The energy savings and peak demand reduction goals shall be at least 5 percent of the utility’s retail system peak demand measured in megawatts in the base year and at least 5 percent of the utility’s retail energy sales measured in megawatt-hours in the base year.


49 In 2011, FERC issued Order 745, which allowed demand response programs to participate in the wholesale market and required wholesale energy markets to compensate cost-effectiveness programs using the same locational marginal price provided to generators. The case, Federal Energy Regulatory Commission (FERC) v. Energy Power Supply Association, was argued before the Supreme Court in October 2015. The opinion in the case, in favor of FERC 6-2, was issued in January 2016, see: https://www.supremecourt.gov/opinions/15pdf/14-840_k537.pdf.

50 More information can be found at http://energy.gov/epsa/quadrennial-energy-review-ger Stakeholders can submit their comments via an online portal here: (QER Second Installment Public Comments Form) http://energy.gov/epsa/office-energy-policy-and-systems-analysis (accessed June 20, 2016).