Performance Incentive Mechanisms for Strategic Demand Reduction

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Executive Summary

Key Takeaways

This report characterizes performance incentive mechanisms (PIMs) for strategic demand reduction (SDR). These are megawatt reductions comprised of energy efficiency and demand response that aim to minimize system costs by displacing the need for services traditionally provided by the supply side.

- A new generation of SDR PIMs is on the rise, driven by a need for flexibility at times of peak demand and a shift toward more variable generation. Thirteen states have an SDR PIM in place for at least one utility, and two states have early-stage SDR PIM proposals.
- Although we find that PIMs are an effective strategy for incentivizing SDR where they are used, this potential remains largely untapped. Of the seven cases of existing SDR PIMs we studied, five have available results and four administrators met or exceeded their targets. Administrators earned incentives of about 2–25% of their program spending and saved about 0.69–6.5% of total peak demand, while creating customer benefits with benefit–cost ratios of 2 and above.
- SDR PIMs are currently focused on long-term adaptation of customer demand in response to prices and efficiency measures (called shape services) and traditional utility and wholesale market demand response programs (called shed services). They have yet to focus on moving demand from one time of day to another and on grid-balancing measures targeting ramping services (called shift services) that can better support distributed resources and renewables integration.
- Incentive mechanisms should be designed with consistent, continuous improvement in mind. This will enable them to reap the benefits of several review cycles as well as secure buy-in from (a) utilities seeking regulatory certainty and stability, and (b) regulators who seek to protect ratepayer interests and motivate superior utility performance.
- Although PIMs alone can encourage SDR, the cases in this report show that successful states have complementary policies. These include energy efficiency and other clean energy targets; business model reforms, such as decoupling and energy efficiency PIMs; independent evaluation, measurement, and verification (EM&V); and valuation mechanisms in wholesale markets, rate design, and distribution resource planning.

Strategic Demand Reduction

Electricity demand reduction, which includes energy efficiency and demand response, is an essential tool to affordably and rapidly drive down the cost and greenhouse gas (GHG) emissions of electricity systems. Strategic demand reductions (SDR) comprise a subset of energy efficiency and demand response measures, reducing demand at specific times to optimize the electricity system. SDR minimizes system costs by displacing the need for services that are traditionally provided by the supply side, i.e., generation, transmission, and distribution, typically measured in megawatts (MW) of capacity. SDR is emerging as a key tool to increase system flexibility, which is increasingly important with high penetration of variable generation from renewable energy.

Lawrence Berkeley National Lab (LBNL) provides a helpful taxonomy of four services that SDR can provide along different timescales to complement a low-carbon grid. As figure ES1 shows, these services are shape, shed, shift, and shimmy (Alstone et al. 2017). We use this taxonomy throughout this report.

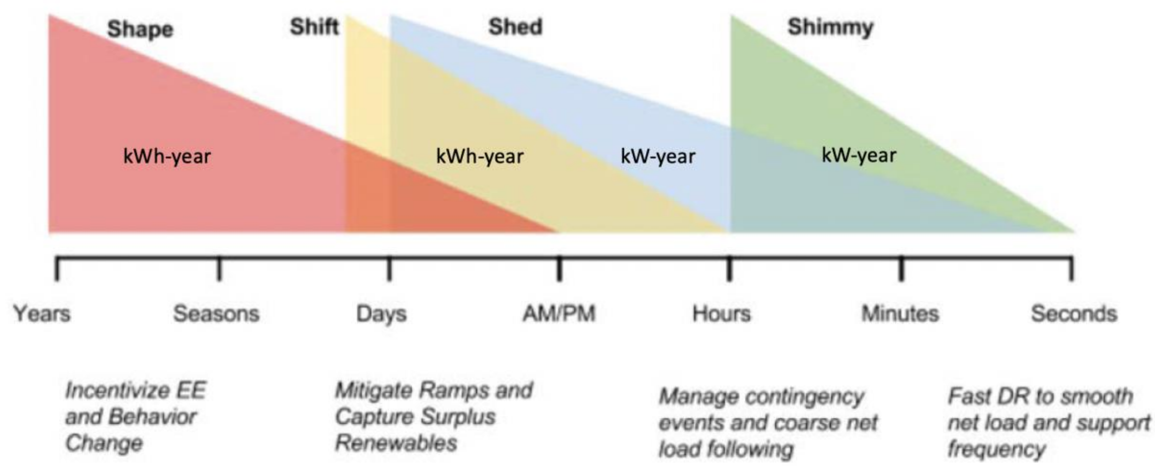

Figure ES1. Timeframes of demand-side management services. *Source:* Alstone et al. 2017.

Overcoming Barriers to SDR

Despite clear evidence of SDR's value to the electricity system and society, utilities are still only scratching the surface of integrating it into system planning, operations, rate design, and investment strategies. Three major barriers account for this delay. First, the regulatory structure is such that retail customers do not see prices that reflect the marginal cost of producing energy, limiting the benefit they derive from reducing demand at times of system stress (Aggarwal et al. 2019). Second, energy markets may also fail to value load reduction as a resource, as steep transaction costs and minimum bid sizes preclude small- and mid-size customers from participating and delivering resources like energy efficiency and demand response, even with aggregation (FERC 2011; Orvis and Aggarwal 2017). In addition, many retail SDR programs lack visibility to grid operators.

Third, utilities generally lack a business model that encourages SDR, which exacerbates these barriers. While utilities depend on increasing capital investment and sales to drive shareholder returns (Kihm et al. 2015), SDR can obviate the need for distribution, transmission, and generation services, as its resources (such as energy efficiency and customer-owned solar) decrease sales to the utility.

One emerging solution to this dilemma is to use performance incentive mechanisms (PIMs) that reward utilities for developing strategic demand management programs that reduce costs for all customers. PIMs help align policy, utility, and customer goals by creating the opportunity for utilities to earn incentives if they meet the specific, measurable goals identified by regulators.

SDR PIMs Landscape

We found 13 examples of existing SDR PIMs across the country. Some of these incentives focus on long-term adaptation of customer demand in response to prices and efficiency measures (shape), while others focus on traditional utility and wholesale market demand response programs (shed). Figure ES2 shows the current SDR PIM landscape by type of incentive structure.

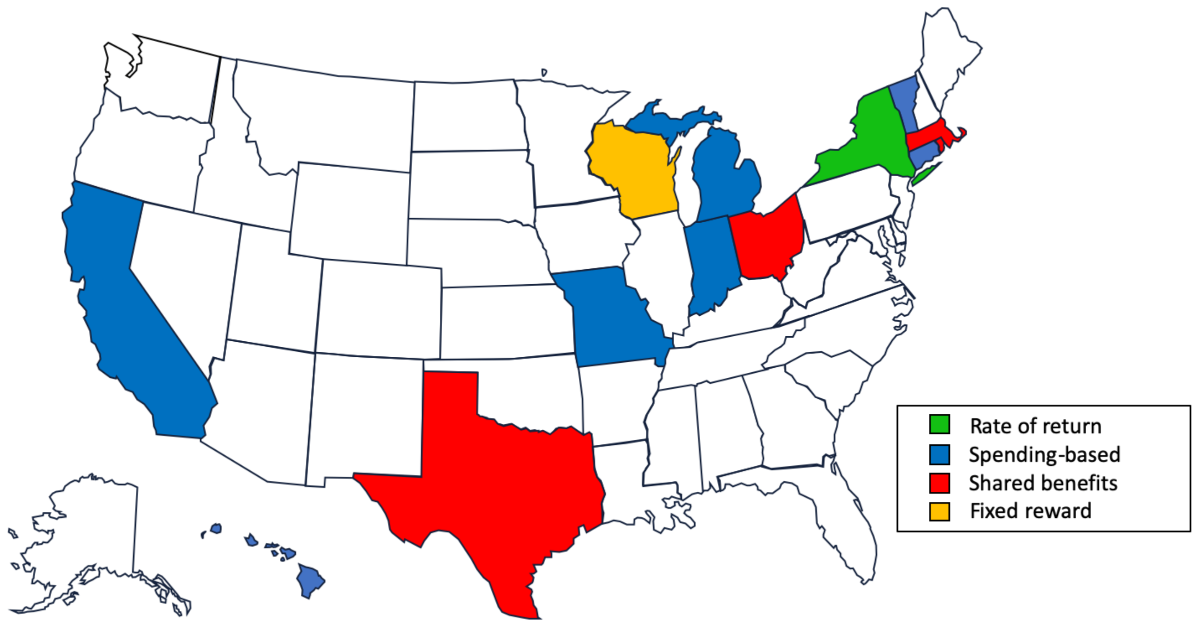

Figure ES2. SDR PIMs by type

This report concentrates on 7 of the 13 PIMs; table ES1 lists their design features. These seven PIMs reflect a meaningful cross section of SDR PIMs, including traditional utility procurement approaches to peak demand reduction in Hawaii and Texas, and newer ways to encourage SDR by compensating the utility for a mix of actions and outcomes in New York and Rhode Island.

Table ES1. Key design features of case study PIMs

State	Key design features	Maximum available incentive*	Performance period; duration of PIM
Hawaii	Initial, one-time incentive based on achievement of peak demand reduction target through direct procurement.	Lesser of 5% of aggregate annual contract value or $500,000	One year
Michigan	Up to 15% of demand response costs on a sliding scale based on demand response capacity, achieved growth rate, and nonwires alternatives assessment costs	15% of demand response spending	One-year cycle (approved for 2019 only)
Texas	1% of net benefits for every 2% of demand reduction goal exceeded	10% of net benefits	One-year cycle
Vermont	Percentage of total approved budget based on performance on several outcomes, including winter/summer peak demand reduction	2.5% of total approved budget	Three-year cycle
Rhode Island	Cash reward based on achievement of peak demand reduction, structured as a shared savings mechanism exempt from utility return-on-investment cap	45% of net benefits	Three-year cycle
New York	Up to 100 basis points added to ROE for PIMs in aggregate; peak demand reduction achievements receive a portion	A portion of 100 basis points for SDR performance (currently approved at 65–70 total basis points)	Three-year cycle
Massachusetts	Portfolio-wide incentive based on performance from 75–125% of the PIM goals	5.4% of cumulative budget for program costs	Three-year cycle

*This is based either on the most recently complete performance period or the current performance period, depending on the age of the incentive.

We review each state's policy drivers, PIM structure, and utility performance to date. Table ES2 provides key data points that evaluate each PIM's effectiveness (where available) including the utility's overall results; the peak demand savings as a percentage of the covered entities' total peak demand; and whether the PIM's target was missed, met, or exceeded.

Table ES2. PIM details and results from states studied

State	Result for utilities	Achieved peak demand savings as a % of peak demand	Type of SDR	Missed, met, or exceeded
Hawaii	PIM was not met, and utilities did not receive payment	N/A	Shed and shimmy	Missed
Michigan	Results available in 2020	N/A	Shed	N/A
Texas	Utilities kept an average of 24% of 2015–2017 program spending.	0.82% of summer peak demand in 2017	Shape	Exceeded
Vermont	The utility earned the maximum reward in the 2015–2017 cycle.	1.8% of summer peak for 2015–2017	Shed	Exceeded
Rhode Island	Results from the first cycle will be available in 2021.	N/A	Shed	N/A
New York	ConEd's reward was approximately 5.2% of 2018 spending.	0.69% of summer peak in 2018	Shape and shed	Met
Massachusetts	Utilities earned an average of 6.5% of 2016–2018 program spending.	4.4% of summer peak for 2016–2018	Shed	Exceeded

Findings

PIMs are an effective tool for unlocking SDR. SDR potential remains largely untapped, reaching nowhere near the potential cost-effective load flexibility. Nonetheless, a review of these case studies demonstrates that PIMs can be an effective strategy for incentivizing SDR. Of the five cases studied that had available results, four administrators (in Massachusetts, New York, Texas, and Vermont) met or exceeded their targets, which varied in savings thresholds and consumer benefits.

Multiple resources can support SDR. Diverse resources including energy efficiency, demand response, and storage can provide SDR. Traditional energy efficiency and demand response are the most common resources currently providing SDR as part of PIMs. However some states, including Massachusetts and New York, have created a technology-neutral structure for their SDR PIMs and include participation from distributed solar PV and storage.

SDR PIMs currently focus on shape and shed and have opportunities to capture additional shift value. Although SDR PIMs primarily focus on peak demand reduction via shed and shape, states are beginning to implement PIMs that explicitly reward other SDR services, particularly shifting. For example, Massachusetts created a PIM to deliver "active demand management" that includes demand shifting to help support renewables integration.

Durable, long-term incentives with periodically updated performance cycles support continuous improvement. Our case study review and analysis found that incentives that combine a consistent policy signal over a long time period (often a decade) and multiple program cycles tend to elicit the most SDR. Examples include Massachusetts, Texas, and Vermont. These multiyear programs properly incent utilities to integrate SDR technology and policy on an infrastructure investment timescale. They also periodically revisit the PIMs, updating targets and incentives every one to three years.

Complementary state and regional policies are needed to maximize SDR PIM effectiveness. While PIMs encourage SDR, the cases illustrated here show that successful states also have complementary policies in place. These policies include energy efficiency and other clean energy targets; business model reforms, such as decoupling and energy efficiency PIMs; independent EM&V; and valuation mechanisms in wholesale markets, rate design, and distribution resource planning. Many of these reforms are included in the grid modernization proceedings underway in states across the country.

Background

GRID TRANSITION

The electricity sector is in a period of rapid technological and policy disruption. New renewable energy is now the cheapest source of electricity on a levelized cost basis (Mahajan 2018). Wind and solar are also cheaper per megawatt-hour (MWh) than three-quarters of existing coal-fired generation (Gimon et al. 2019). Clean energy portfolios (combining energy efficiency, demand response, wind, solar, and storage) are cheaper than 90% of the currently proposed new natural-gas-fired power plants. Energy efficiency and demand response are critical for these emerging portfolios; ignoring the value of these resources shrinks by 70% the near-term market for clean energy portfolios to replace new gas (Teplin et al. 2019).

At the same time, policymakers in states and localities across the United States are taking action to address the impacts of greenhouse gas (GHG) emission and mitigate climate change. These environmental concerns combined with changing economics are rapidly creating a renewables-centric grid (Barbose and Galen 2019). This evolving grid will be increasingly dependent on cheap, abundant, variable, weather-dependent resources—particularly wind and solar—and will require the cost savings and flexibility of energy efficiency, demand response, and other flexible resources to manage the transition. This evolving tableau creates new challenges, as well as new opportunities for electric utilities to innovate.

ENERGY EFFICIENCY AND DEMAND RESPONSE

Utilities can drive down system and customer costs and GHG emissions through reductions in demand via energy efficiency and demand response. Although often invisible, efficiency is now the third largest resource in the electricity sector, delivering 18% of US electricity services in 2016 (Molina, Kiker, and Nowak 2016). Those demand reductions have driven tremendous GHG savings. As figure 1 shows, the majority of the power sector's 2000–2017 emissions reductions came from lower demand growth, including from energy efficiency.

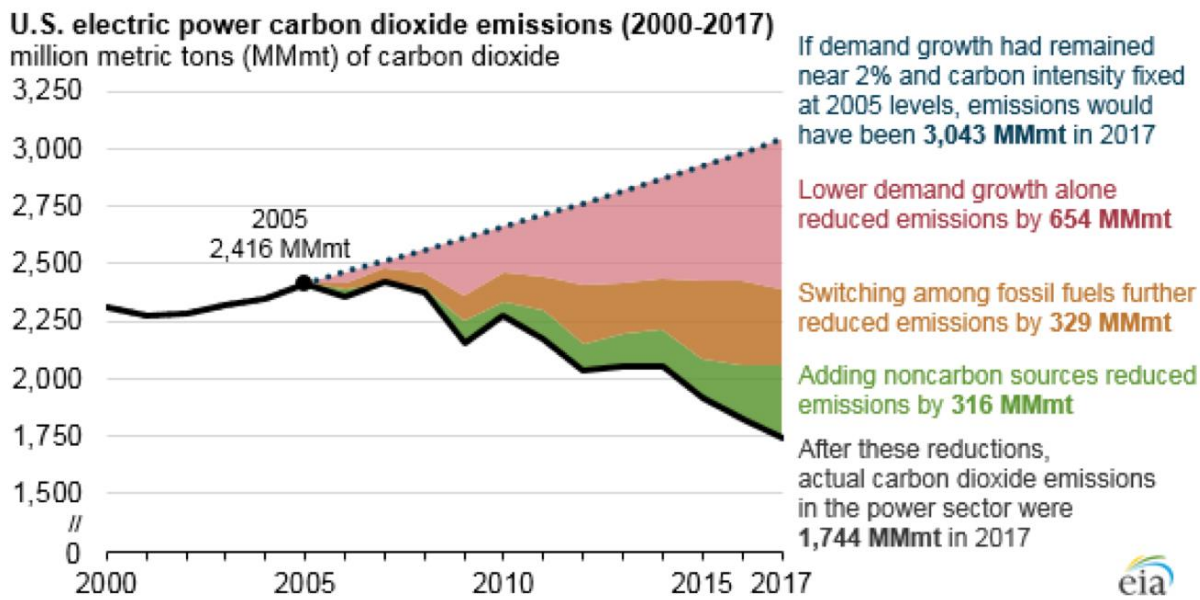

Figure 1. US electric power carbon dioxide emissions (2000–2017). *Source:* EIA 2018.

Traditional utility and wholesale market demand response programs aim to reduce demand during the highest-cost hours, which correlate with peak demand.[1] The economic and environmental benefits of such programs are apparent through both specific cost–benefit analyses and their robust competitive market participation. However there is less information available to quantify demand response's annual and cumulative impact on cost and air pollution to date (Dahlke and McFarlane 2014; AEE 2015; FERC 2018).

Strategic Demand Reduction

Electricity demand reduction, which includes energy efficiency and demand response, is an essential tool to affordably and rapidly drive down electricity system costs and GHG emissions. SDR comprises a subset of energy efficiency and demand response measures that reduce demand at specific times to optimize the electricity system. SDR, which is typically measured in MW of capacity, minimizes system costs by displacing the need for supply-side services (generation, transmission, and distribution).

[1] Peak demand represents the hours electricity prices tend to be most expensive. For example, in Massachusetts from 2013 to 2015, the top 1% most expensive hours (correlated with system peak) accounted for 8% of customers' annual spending on electricity ($650 million). Reducing peak demand through energy efficiency and demand response avoids new long- and short-term costs for customers.

Electric Vehicles and Building Electrification as SDR

New electric end uses (e.g., electric vehicles [EVs], space and water heating, and indoor agriculture) are on the rise and are critical to decarbonization in parallel with the growth of zero-carbon electricity generation. These electrification resources can also offer significant SDR potential, such as through the managed charging of EVs (Fitzgerald, Nelder, and Newcomb 2016). Although few of these PIM frameworks currently include electrification resources, more are likely to do so in the future.

In 2018, for example, EVs provided SDR under ConEd's PIM. The PIM is currently technology neutral, and complementary load-building strategies such as fuel switching (from gasoline to electrically fueled vehicles or through heat pump adoption, for example) can help improve the utility's load factor. Beneficial electrification is also incorporated into the baselines for outcome-based energy intensity SDR PIMs, to avoid undercutting the rewards for efficiency measures.

Newly electrified end uses are important for decarbonization and offer significant SDR potential, but they differ in crucial ways from energy efficiency and demand response on existing end uses. Increases in volumetric sales make utilities less antagonistic to beneficial electrification than to SDR. Utilities should incorporate strategies to capture SDR as these resources come onto the system, but different regulatory approaches may be required. Still, PIMs can help ensure SDR becomes and stays a core utility business function as new sectors electrify.

SDR is a resource that can reduce costs, integrate variable resources, and improve grid reliability (Golden, Scheer, and Best 2019). It reduces costs by shifting or reducing customer consumption during expensive hours, which often correlate with system peak demand. SDR can also support variable renewable energy integration by providing ramping services or by soaking up excess renewable energy that might otherwise be curtailed (Silverstein, Gramlich, and Goggins 2018). Depending on how it shifts energy consumption, SDR can also reduce GHG emissions.

Lawrence Berkeley National Lab (LBNL) provides a helpful framework for four different types of load management:

- Shape
- Shed
- Shift
- Shimmy

Utilities and system operators use energy efficiency measures and price signals to shape customer demand over the long term (*shape*). Some energy efficiency measures deliver savings at peak or net peak times, shaping customer demand and reducing system costs by displacing supply-side needs. Other measures deliver average savings and displace generation across the year but may not offer value at peak. Traditional demand response programs, typically targeted to industrial and large commercial customers, implement load-reduction measures to reduce demand during highest-cost hours (*shed*). *Shift* moves demand away from peak times to other times of day.[2] Advanced SDR techniques supported by demand-side resources such as storage offer load-following demand shaping in real time (*shimmy*) (Alstone et al. 2017). Figure 2 shows the timeframes of these measures.

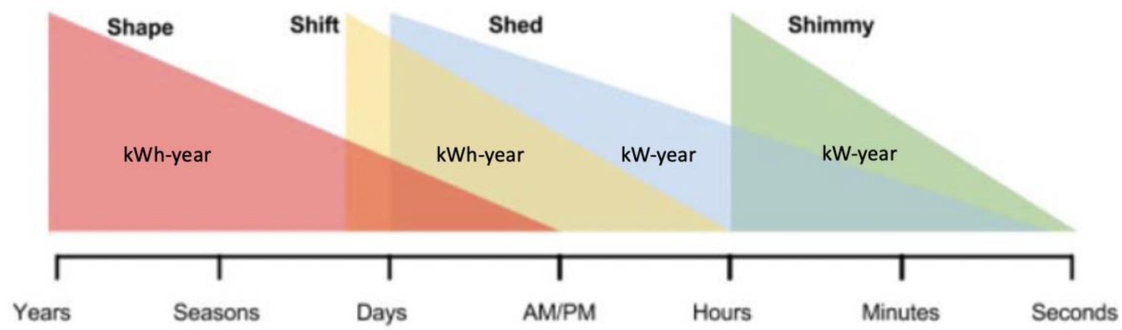

Figure 2. Timeframes of demand-side management services. *Source:* Alstone et al. 2017.

While shape and shed are more common and well understood, integrating shift and shimmy from SDR into the electricity system will require new technologies and regulatory frameworks. These frameworks include wholesale market participation rules that allow demand-side resources to provide these services and more sophisticated rates or compensation schemes that better reflect the energy's locational and time-varying values. In terms of new technologies, SDR will require distributed energy resource management systems (DERMS) and software platforms that optimally integrate distributed energy resources into the grid to provide shift and shimmy services (particularly locational ones). While shift represents massive untapped flexibility value paired with variable renewable generation (Hledik et al. 2019), shimmy services face a relatively shallow market, reflecting much less value to a low-carbon grid (Alstone et al. 2017).

Making Demand Reduction Strategic

To maximize potential GHG reductions, we must maximize cost-effective efficiency and traditional demand response, but we still can do more. SDR services from efficiency investments and rate designs can target certain load shapes and thereby avoid customer consumption when it is most expensive and carbon-intensive. Demand-side resources can also provide more dynamic shifting, complementing renewable energy with services such as ramping. Combining these strategies improves on existing efficiency and demand response approaches.

As reliance on low-cost renewable energy increases, the highest-cost hours of electricity generation will accordingly occur when wind and solar resources become scarce, while hours in which the marginal cost of electricity is zero or near-zero will also continue to

[2] Demand shifting is not necessarily a net reduction, but rather is a net decrease at one time offset by an increase at another time.

increase. This already occurs in California, where the abundance of solar drives down the cost and carbon footprint of midday electricity but prices spike higher than $1,000/MWh as the sun sets and natural gas power plants ramp up to meet evening peak (CAISO 2019). Such price fluctuation already makes certain kinds of demand reduction extremely valuable for reducing GHG emissions and saving money (Golden, Scheer, and Best 2019). For example, more-efficient HVAC units and tighter building envelopes will yield savings during the hottest and coldest parts of the day, whereas more-efficient water heaters and other appliances will yield savings at other times and over different timescales. Further, advanced metering technology allows program administrators to measure the time-varying impacts of efficiency measures and SDR resources and receive compensation for this demand reduction value. Despite the growth in advanced metering technology, these advanced rate designs have been slow to materialize. Figures 3 and 4 illustrate these patterns.

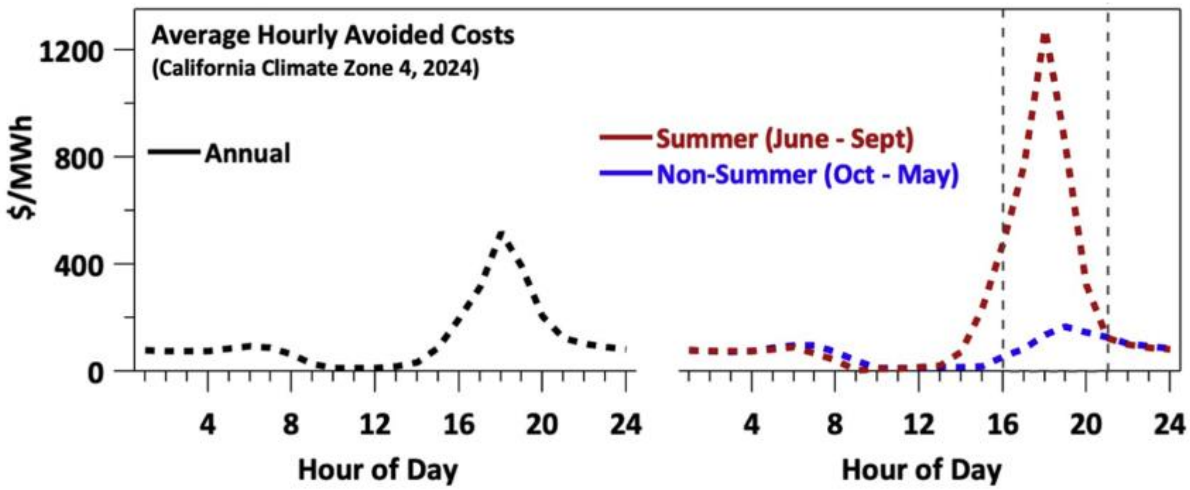

Figure 3. Forecasted 2024 average hourly avoided costs for a representative climate zone in Pacific Gas & Electric's service territory. *Source:* California Efficiency and Demand Management Council 2019, cited in Golden, Scheer, and Best 2019.

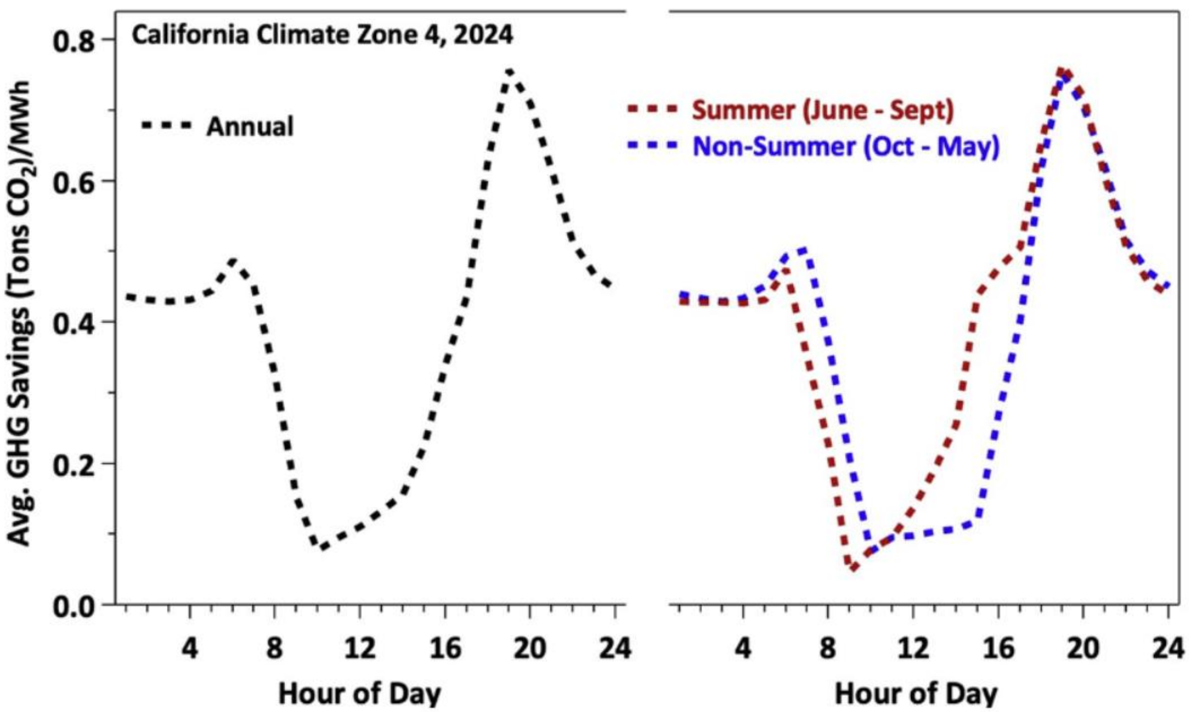

Figure 4. Forecast of average hourly marginal CO_2 intensities on annual (left panel) and seasonal (right panel) bases. California Climate Zone 4 is taken as an example. Values are on an average hourly marginal basis and are computed using the California Public Utilities Commission's avoided cost calculator. *Source:* Golden, Scheer, and Best 2019.

Utilities and grid operators have yet to realize demand reduction's immense potential to cost-effectively provide substantial additional flexibility in meeting ramping and peak needs compared to a continued reliance on coal, natural gas, and (increasingly) battery storage (Alstone et al. 2017).

Barriers to SDR

SDR has significant untapped economic potential. A Brattle Group analysis finds that nearly 200 gigawatts (GW) of cost-effective load flexibility (defined as peak demand reduction, load shifting, and system balancing) will exist in the United States by 2030 (Hledik et al. 2019). It also estimates that load flexibility's economic benefits could exceed $15 billion per year.

Electric utilities and state regulators oversee demand management programs and control access to customer data, holding tremendous sway over whether demand reduction is deployed and scaled strategically. Despite clear evidence of SDR's value to the electricity system and society, however, utilities are still merely scratching the surface of integrating it into system planning and investment strategies. Three major barriers account for this delay.

Customer-Facing Electricity Rates

Even with regulatory mandates for utilities to serve customers at least cost, retail prices leave customers with limited benefit for reducing demand at specific times of system stress. Retail residential and commercial customers (particularly smaller ones) do not see prices that reflect the time-varying marginal cost of producing energy. For the vast majority of residential electricity customers, the default rate reflects only the average cost of generating electricity over the course of an entire year (flat) and varies only with the amount of energy consumed (volumetric). Commercial and industrial rates are more complex, but even those often fail to directly track electricity's real-time cost and are slow to change over time as system needs evolve (Aggarwal et al. 2019).

Time-varying rates (TVR) give customers higher prices when wholesale power and delivery is more expensive and lower prices when power is cheap; they are thus effective tools for SDR, yet only about 2% of residential customers were on TVR as of 2016 (Faruqui 2016). On average, customers on TVR save money, while reducing peak demand by at least 10% on average (Faruqui 2016). This response is magnified when there is a higher differential between peak prices and off-peak rates, and customer-facing technology such as a programmable controlled thermostat further enhances the response and associated savings (Faruqui 2016). Despite being a key tool to elicit SDR, TVR face resistance from utilities and regulators and are still greatly underutilized.

Wholesale Markets

Wholesale markets may also fail to value load reduction as a resource and create barriers to market participation. Federal Energy Regulatory Commission (FERC) Order 745 required wholesale market operators to allow energy efficiency and demand response to bid directly into energy markets, but participation remains small, with steep transaction costs and minimum bid sizes that preclude small- and mid-size customer participation and aggregation in those markets (FERC 2011; Orvis and Aggarwal 2017). Furthermore, utilities have jurisdiction to propose retail rates for regulatory approval and can help maintain substantial barriers to customer participation in wholesale markets through their tariffed provisions.

Demand response participates in limited nonenergy markets for capacity and emergency demand response programs, while efficiency plays a smaller role. Emergency demand response is a long-trusted resource that can reduce system stress and avoid blackouts when demand threatens to outstrip supply. But beyond these capacity-type resources (a limited subset of shed resources), there are few opportunities to participate in energy markets due to market rules.

Traditional Utility Business Model

SDR conflicts with the conventional utility business model. In general, utilities see little upside to making the most of SDR, mainly because they lack the financial incentive to pursue it. Utilities depend on increasing capital investment and sales to drive shareholder returns (Kihm et al. 2015). This creates bias toward capital expenditures (capex) and is a powerful disincentive to meaningfully invest in SDR. By obviating the need for distribution, transmission, and generation services, SDR undermines the utility business model, essentially punishing utilities for managing demand in a way that reduces costs overall.

Some SDR resources, such as energy efficiency and customer-owned solar, also decrease a utility's electricity sales. In states without decoupling,[3] utilities have an incentive to increase sales in the short term, because those increased sales will increase short-term profits.[4] Generally, utilities recover some of their fixed costs through volumetric charges. So, when sales increase, utilities may collect more than their authorized fixed costs and return, creating windfall profits from customer bills. This throughput incentive creates a bias toward higher sales and against demand reduction resources that decrease sales.[5]

Although these dynamics are present for all customer- or third-party-owned resources, the business models and market structures of electric utilities may encourage them to favor procuring some demand reduction resources over others. For example, vertically integrated utilities will be more resistant to efforts to procure SDR to offset the need for new power plants, while both distribution-only utilities and vertically integrated utilities will seek to sell more power that increases sales and justifies new spending on poles and wires.[6]

SDR Performance Incentives

In the face of these barriers, several policies can operate in concert to promote SDR, including improved market access for demand-modifying resources, TVR, and nonwires alternatives (NWA) programs. One of the most important steps—and the subject of this paper—is to offer utilities financial incentives for developing SDR programs. In conjunction with strong oversight and superior program design, SDR proponents can leverage performance incentive mechanisms (PIMs) to reward utilities for customer demand reduction. PIMs can address utilities' opportunity cost of pursuing SDR by creating earnings opportunities in return for delivering demand reduction aligned with the public interest. In other words, PIMs align customer and shareholder value (Kihm et al. 2015). Designed well, they shift the model from an input-based cost-of-service structure to one that aligns utility behavior with desired policy outcomes.

This Report

The following sections provide an overview of the US landscape of SDR PIMs, then examine state and utility SDR PIM examples in Hawaii, Michigan, Texas, Vermont, Rhode Island,

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[3] Decoupling, sometimes known as revenue regulation, fixes the amount of revenue to be collected and allows the rate (price) to float up or down between rate cases to adjust for variations in sales volume. In some cases, this revenue target is allowed to increase on the basis of inflation adjustors or the number of customers served (Lazar et al. 2016).

[4] The rare exception would be if utilities could not serve increased usage with existing facilities, and if operating and fuel costs were higher than retail rates.

[5] States typically address this through ratemaking tools such as decoupling and lost revenue recovery, although some (such as Michigan) provide strong PIMs to address this bias. However addressing this throughput incentive is not the focus of this report; see Lazar et al. 2016 for a guide to this topic.

[6] Given their capex bias and, in some states without decoupling, their throughput bias, electric utilities are likely to pursue resources that increase volumetric sales, such as those from vehicle and building electrification. Depending on the magnitude of the capex bias, utilities may also work to include such resources in their system without exacerbating peak demand, which can drive up costs. The incentive to manage these resources well will be balanced against the bias to build infrastructure to address peaks or ramps. Over time, once electrification has occurred, SDR PIMs may increase in importance as a tool to continuously encourage load management.

New York, and Massachusetts. Although the case studies are not comprehensive, they sample a diverse set of mechanisms, and we believe they represent the majority of utility incentives for SDR. Further, while technology and service providers are important to supporting SDR, the case studies are confined to utilities and utility program administrators because of their unique gatekeeper role in identifying value where and when SDR can reduce system costs. Utilities can also uniquely reach all customers in their service territory, and, as load-serving entities, are positioned to procure demand reduction on behalf of the system as a whole.

All seven cases focus on performance-based regulation and specifically on PIMs and their effectiveness. Other ways to incentivize SDR on the customer side are outside the scope of this paper; they include rate design, payments to demand-side resources through wholesale markets, and mandated demand-side resource procurement. PIMs may reduce the friction associated with these complementary measures and thereby enhancing their effectiveness.

Taken together, these case studies and the accompanying analysis provide insights for policymakers, utilities, stakeholders, and market participants into how to design PIMs and stimulate the SDR market.

Methodology

We surveyed subject matter experts both to identify states to highlight and to determine an initial set of PIMs to research. Next, we pulled data and information from publicly available documents such as utility commission orders, legislative documents, and utility filings. Finally, we worked with key contacts in these states to confirm the data and research.

The PIMs Landscape

As utilities face new expectations and circumstances, including the rising need to address carbon reduction, reliability, and the deployment of distributed energy resources, an increasing number of states are considering PIMs for demand reduction. We found 13 examples of SDR performance incentives currently in place across the country. To be considered a performance incentive, the mechanism must require the administrator to meet an SDR target or threshold measured in megawatts (MW). Once a mechanism meets this threshold, we identified four ways that it can reward SDR resources:

- *Rate of return*. Utilities' SDR performance impacts their earnings through an adjustment to their regulated return on equity (New York)[7]
- *Spending-based*. Utilities can earn a percentage of their SDR spending, typically on a sliding scale (California,[8] Connecticut, Hawaii, Indiana, Michigan, Missouri, Vermont).
- *Shared net benefits*. Utilities can earn a percentage of the benefits from successful SDR programs or procurement, sharing part of the savings with customers (Massachusetts, Ohio, Texas, Rhode Island).
- *Fixed reward.* Utilities can earn a fixed amount for successful administration of SDR programs (Wisconsin).[9]

Figure 5 shows states where at least one utility has an SDR performance incentive mechanism.

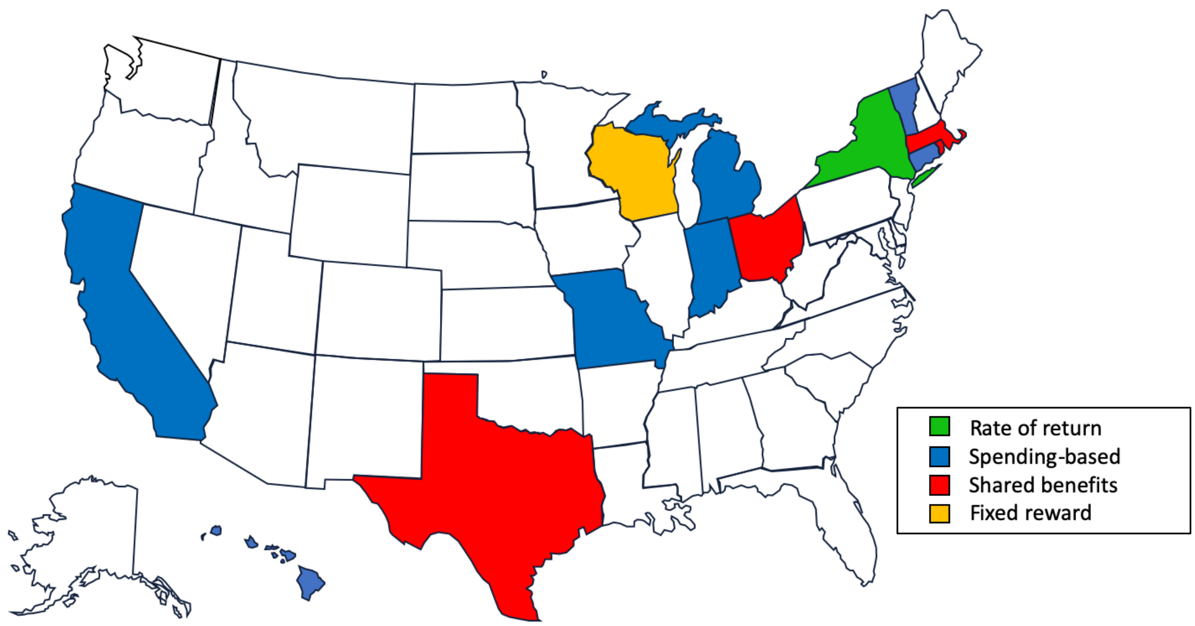

Figure 5. SDR PIMs by type

[7] New York's earnings adjustment mechanisms (EAMs) are scaled as adjustments to the utility's rate of return on its capital investments before the performance period, then are fixed as cash rewards. As a result, the EAMs do not change if the size of utility rate base changes throughout the performance period.

[8] California's PIM is designed to reward utilities based on their program budget rather than actual spending, up to a 9% cap. For more information, see: docs.cpuc.ca.gov/PublishedDocs/Published/G000/M076/K775/76775903.PDF.

[9] The contract for Wisconsin's energy efficiency program administrator states that the organization can earn $100,000 for meeting a minimum of 40% of the MMBTU savings goal by 2020 and can earn $150,000 for meeting 102% by 2022 (apps.psc.wi.gov/pages/viewdoc.htm?docid=%20368272). We do not include a case study on this type of PIM because it is the only one of its kind.

Some states value having diverse programs, measures, or types of DERs that contribute to meeting SDR goals. Such states may create a carve-out within their PIMs for various types of measures or programs (e.g., those that provide more first-year versus lifetime savings), types of DERs (e.g., energy efficiency, demand response) or types of SDR (e.g., shape versus shed, or winter versus summer shed). For example, the Massachusetts PIM rewards program administrators for achieving goals to provide reductions at summer and winter peaks through efficiency (known as passive demand savings in Massachusetts and ISO New England (ISO-NE)). It is also designed to encourage the program administrators to pursue demand response at peak times (known as active demand savings in the region) (MA EEAC 2018b). In addition to Massachusetts, other states that incentivize such diversity include Hawaii, Missouri, New York, Rhode Island, and Vermont.

SDR PIMs vary in design. The most prevalent mechanisms calibrate the performance reward in terms of some percentage of the utility's spending. Seven states use that approach. In contrast, New York currently rewards SDR resources with a rate of return.

We do not consider additional mechanisms that implicitly reward or otherwise value SDR resources to be performance incentives, because they do not explicitly encourage or reward demand reductions. For example, states with an energy efficiency performance incentive based on shared net benefits almost always value avoided capacity costs in the net benefits calculation. Some states, such as Arizona, Minnesota, and New Mexico, also include demand response or load-management spending or energy usage savings from load management when calculating an energy efficiency PIM.

We also do not include states in which wholesale markets can provide payments to demand reduction resources (such as California's Demand Reduction Auction Mechanism), although those can be a type of performance incentive. In these markets, entities (typically utilities, large customers, and aggregators) bid demand reduction resources such as energy efficiency, demand response, and price-responsive demand into the wholesale or demand response auction and are paid the clearing price by demonstrating performance through delivery of those resources. Utilities also receive some benefit of reduced wholesale market costs through regulatory lag.

Evaluating PIM Design

Performance incentives have been used in electric utility regulation for decades, and their most common application is for energy efficiency. Nowak et al. (2015) and Whited, Woolf, and Napolean (2015) provide an overview of how these incentives are structured and how effective they are at encouraging energy efficiency investment and savings. These resources identify several principles for PIM effectiveness, all of which apply to SDR (Whited, Woolf, and Napoleon 2015; ACEEE 2018). PIMs should

- Link the metrics, or standards of measurements for performance tracking and reporting, to policy goals. This might include helping influence the utility to do what it might otherwise not be inclined to do under traditional regulation, recognizing that inherent utility preferences should guide whether (and what amount of) a performance incentive might be required.
- Guide the utility's actions toward specific desired outcomes

- Encourage strong effort beyond the baseline toward desired outcomes, but also establish metrics that are within the utility's control
- Provide transparent tracking that can be easily interpreted and accountability regarding utility performance
- Be structured in a way that is fair and reasonable for ratepayers

Incentives need to be large enough to drive utilities to reach a desired outcome, but should strike a balance between producing customer benefits and providing sufficient utility incentives (Whited, Woolf, and Napolean 2015). To assess whether PIMs effectively lead to desired outcomes, past studies have compared overall energy savings as a percentage of sales and energy efficiency spending as a percentage of revenue in states with and without PIMs in place (Nowak et al. 2015).

In the following sections, we provide detailed examples of SDR PIMs in seven states. These seven examples offer a meaningful cross section of SDR PIMs, moving from traditional utility procurement approaches to peak demand reduction in Hawaii and Texas, to newer methods of incenting SDR by compensating the utility for outcomes in New York and Rhode Island. Table 1 below lists the available incentive as a percentage of overall SDR spending for each case. While the table is not a perfect proxy for evaluating PIM design and whether its earning opportunity is sufficient to motivate performance, it does provide a comparison of the relative size of earning opportunities across the PIMs.

Where available, the case studies provide a few key data points to assess PIM design in relation to the effectiveness principles listed above. For example, where available, we provide information on the amount of incentive earned per MW of saved peak demand. Our discussion section at the end of the report provides additional information on whether utilities achieved targeted performance, including a calculation of peak demand savings as a percentage of peak demand.

State Case Studies

The following sections present examples of states with a range of demand reduction PIMs. For the most part, the case studies start with those that are most similar to traditional energy efficiency PIMs and then move on to newer approaches.[10] For each example, we provide information on the background and drivers for implementing the PIM, how the state defines demand reduction, the PIM's structure, and performance data (if available).

Table 1 lists the case study PIMs' key design features and maximum available incentive as a percentage of SDR spending.

[10] Although it has one of the largest programs, California is not included as a case study in this white paper as California and Michigan have very similar demand reduction PIMs; to reduce repetition and increase geographic diversity, we decided to include only the Michigan case study.

Table 1. Key design features of case study PIMs

State	Key design features	Maximum available incentive*
Hawaii	Initial, one-time incentive based on achievement of peak demand reduction target through direct procurement	Lesser of 5% of aggregate annual contract value or $500,000
Michigan	Up to 15% of demand response costs on a sliding scale based on demand response capacity, growth rate achieved, and NWA assessment costs	15% of demand response spending
Texas	1% of net benefits for every 2% of demand reduction goal exceeded	10% of net benefits
Vermont	Percentage of total approved budget based on performance on several outcomes, including winter/summer peak demand reduction	2.5% of total approved budget
Rhode Island	Cash reward (exempt from utility ROE cap) based on achievement of peak demand reduction, structured as a shared savings mechanism	45% of net benefits
New York	Up to 100 basis points added to ROE for PIMs in aggregate; peak demand reduction achievements receive a portion	A portion of 100 basis points for SDR performance (currently approved at 65–70 basis points total)
Massachusetts	Portfolio-wide incentive; incentive based on performance from 75% to 125% of the PIM goals	5.4% of cumulative budget for program costs

*This is based either on the most recently complete performance period or the current performance period, depending on the age of the incentive.

Hawaii

Background and Drivers

In January 2018, the Hawaii Public Utilities Commission (HIPUC) established an initial, one-time PIM for the prompt acquisition of cost-effective demand response from a shortlist of approved vendors and projects. In its order approving the Hawaiian Electric Companies (the HECO Companies) demand response portfolio, HIPUC recognized demand response's contribution to grid flexibility, efficiency, and reliability as the state's grid shifts to a more decentralized system with high DER penetrations.

This PIM was separate from the docket investigating the performance-based regulation (PBR), but it was intended to be consistent with the PBR approach, which prioritizes delivering value for customers over utility capital investment and sales volume (HI PUC 2019c; Energy Innovation 2019). HIPUC noted at the outset that it intends to create additional outcome-based PIMs as the demand response portfolio evolves, but that it was first implementing this PIM to reward the utility for getting demand response projects operational.

How It Defines Demand Reduction

HIPUC defines cost-effective demand reduction as MW of customer-side resources that provide four different kinds of grid services: capacity (shed); and fast frequency response, regulating reserve, and replacement reserves (collectively, shimmy).

Performance Incentive Structure

This is a spending-based PIM that rewards the HECO Companies for acquiring demand response projects that fulfill the four different grid services listed above (HI PUC 2019a). Each service is part of a demand response portfolio through which the utility may administer customer incentives, either directly or indirectly through aggregators.

The services sought in the demand response RFP totaled 21 MW of targeted grid services (HI PUC 2019b). To qualify, the HECO Companies had to acquire resources for prices lower than the avoided cost of acquiring these services through traditional infrastructure. To count toward the PIM, projects had to be operational before the end of 2018.

The one-time PIM had a limit of 5% of the aggregate annual demand response contract value, with a cap of $500,000. Since the projects were already selected and deemed to be cost effective, the HIPUC determined the size of this PIM to incent quick implementation of the demand response projects.

Performance

The HECO Companies did not achieve the December 31, 2018 milestone, so they did not receive the incentive payment. A key reason for this was that contract negotiations between the HECO Companies and the demand response aggregators continued until February 2019, which resulted in a delay in bringing the demand response projects online (HI PUC 2019b). The commission acknowledged that the HECO Companies were unable to meet the PIM milestone. In August 2019, the HIPUC filed a new order that announced a successor PIM; this demand response adjustment clause will essentially offer a multiyear shared savings incentive for grid services contracts that come in below the service's value (similar to the avoided cost for that service), which will be evaluated on a quarterly basis (HI PUC 2019b). The details have not yet been finalized, but stakeholders expect HIPUC to move forward with a PIM structured in this fashion.

Michigan

Background and Drivers

Michigan's electric utilities are subject to statutory energy savings requirements based on the state's energy efficiency resource standard (EERS). Michigan's energy optimization standard, which was later renamed the energy waste reduction (EWR) standard, began in 2009. In 2016, the state passed legislation that extended the EWR targets until 2021 in order to create financial savings for residents and to promote more efficient grid use (Kushler 2016). Michigan's concerns about resource adequacy may be growing as the regional transmission organization identified a need for capacity imports into the state, and research shows a projected peak demand increase of 2,000 MW in Michigan by 2026 (AEE 2017).

In response to the 2016 legislation, which also required utilities to do integrated resource planning (IRP), the Michigan Public Service Commission (MI PSC) initiated a proceeding on regulatory frameworks for demand response. In that proceeding, the MI PSC noted that a financial incentive for demand response would be reasonable (DTE 2019).

How It Defines Demand Reduction

This PIM focuses on demand response or load management, defined as "measures or programs that target equipment or behavior to result in decreased peak electricity demand such as by shifting demand from a peak to an off-peak period" (Michigan Legislature 2016). In other words, the Michigan program focuses only on peak demand reduction (shed).

Performance Incentive Structure

The MI PSC approved a financial incentive for demand response for Consumers Energy on July 18, 2019. This is a spending-based PIM. The incentive applies to demand response capacity and growth achievements based on goals approved in the company's IRP. The incentive is capped at 15% of costs. The state has a separate energy-efficiency-specific PIM that allows a higher incentive of 20% of costs for efficiency achievements. The approved mechanism comprised of an annual payment as follows:

- Up to 13% of noncapital demand response costs on a sliding scale:
  - No incentive for achievement of less than 50% of its demand response capacity growth target (based on the company's IRP)
  - 0.26% of its demand response costs for every 1% above 50% of its demand response capacity growth target (based on the company's IRP) up to 13%
- 2% of costs for assessment of demand response within potential NWAs.[11] This payment is dependent on the company assessing demand response in five NWA projects.

The commission notes that incentives should be reviewed periodically and can be tweaked (Neme 2019).

Performance

Michigan's utilities have a long history of earning their full energy efficiency performance incentives (see Nowak et al. 2015). However there is not yet data on their achievement toward the demand response PIM, as the mechanism will apply to calendar year 2019 achievements.

TEXAS

Background and Drivers

Texas monopoly distribution utilities operate in the Electric Reliability Council of Texas (ERCOT) wholesale market and in a state that has been uniquely focused on managing load growth for decades. Texas became the first state to implement an EERS in 1999, while the state's electricity markets were simultaneously deregulating. The state's EERS requires electric utilities to acquire energy efficiency resources to offset a percentage of load growth,

[11] NWAs use DERs such as distributed generation technologies, battery storage, demand response, and/or energy efficiency to defer or avoid the need to upgrade transmission or distribution infrastructure to meet increasing demand (Baatz, Relf, and Nowak 2018).

with an emphasis on reducing peak demand growth. In 2019, ERCOT set a new record peak demand and called an Energy Emergency Alert during a heat wave that caused reserve margins to fall and capacity prices to spike to $9,000/MWh (Walton 2019). During such events, ERCOT can call on all available resources to meet demand.

How It Defines Demand Reduction

This PIM defines demand reduction as a reduction in summer peak demand (shed). As of 2013, the eight regulated distribution utilities are required to reduce summer peak demand by at least 30% of annual projected residential and commercial peak demand growth, based on the utility's previous five weather-adjusted peak demands. If 30% of peak demand growth is greater than or equal to 0.4% of the previous year's summer peak demand, 0.4% reduction based on the previous year's peak demand becomes the new goal. Goals may not be lower than the previous year (Texas Legislature 2013).

Investor-owned transmission and distribution utilities are the obligated entities, but they are not legally allowed to deliver energy efficiency directly to customers other than cities and schools. For this reason, utilities use third-party contractors to administer most of their programs, which can include energy efficiency, load management, and solar programs (Texas Energy Efficiency 2019a).

The state's savings goals also have a carve-out for low-income customers and energy efficiency as a peak demand reduction resource. Utilities must meet at least 5% of their goal with savings from hard-to-reach sectors, defined as residential customers with annual income at or below 200% of the federal poverty level (Texas Legislature 2013). Utilities also must meet an energy savings goal through peak demand reduction. Program spending is limited based on a specified per-kWh amount for each rate class.

Performance Incentive Structure

The Texas PIM, called a performance bonus, was enacted in 2008, and is a shared benefits PIM calculated as a percentage of net benefits of the administrator's programs. Net benefits are calculated as the present value of the avoided capacity and energy costs, minus the total program costs.

To be eligible for the bonus, utilities must exceed both their demand and energy reduction goals without exceeding the cost cap. Once those thresholds are met, the incentive is calculated based on demand reduction performance. Utilities can earn 1% of their net benefits for every 2% that they exceed their goal, with a maximum of 10% of the calculated net benefits.[12] Recovery of the bonus occurs in the filing the year following verification of the savings by a commission-hired entity; for example, 2014 achievements were verified in 2015 using an approved evaluation, measurement, and verification (EM&V) approach, with recovery occurring in 2016. The commission retains the right to reduce the bonus if the

[12] The primary Texas energy efficiency benefit–cost analysis test is the Utility Cost Test, which includes utility measure costs, program administration costs, EM&V costs, and shareholder incentive costs. As benefits, it includes avoided energy costs, avoided capacity costs, and potentially avoided line loss costs (NESP 2019).

utility has a lower goal, a higher administrative spending cap, or a higher cost cap (Texas Legislature 2013).

Initially, load-management (demand response) programs were limited to 15% of their contribution to demand reduction goals. This was increased to 30% in 2005 due to ERCOT's concerns over declining reserve margins. Utilities can count load-management measures as having a one-year measure life; that is, they can count the same loads toward their goal each year rather than having to add new load-reduction measures.

Performance

Utilities in Texas have had success in reducing demand and earning performance bonuses. Figure 6 shows demand reduction performance by Texas investor-owned utilities for 2002–2015.

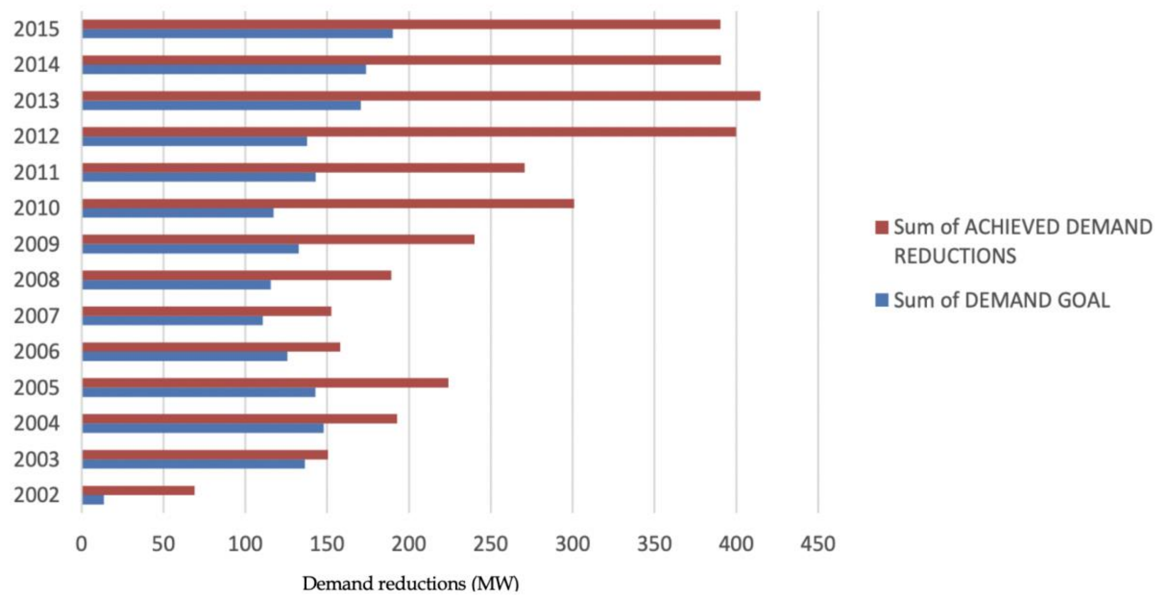

Figure 6. Demand reduction by Texas investor-owned utilities for 2002–2015. *Source:* Herbert 2019.

Each year from 2002 to 2017, utilities exceeded their demand reduction goals. Over the past three years, they earned incentives ranging from 13% to 33% of program spending, with an average of 24%. In absolute figures, incentives ranged from about $660,000 to $9.4 million—or about $50,000–96,000/MW in 2017 (Texas Energy Efficiency 2019b). This high achievement level indicates that goals could be much more stringent, especially since many of them have remained the same across multiple years, even as achievement has gone up (Reed 2018). These programs achieved benefit–cost ratios of 2.57–4.00 in 2017, as assessed for their performance incentive calculation.

Vermont

Background and Drivers

Vermont Energy Investment Corporation (VEIC), established in 1986, is a nonprofit sustainable energy company that administers Efficiency Vermont's regulated energy efficiency utility (EEU) under an Order of Appointment from the Vermont Public Utility Commission (PUC) (VEIC 2019). This is a departure from the traditional utility business model, in which demand-side management is performed by an entity that is split off from the investor-owned utility in order to reduce business model conflict and better achieve energy efficiency goals.

How It Defines Demand Reduction

Efficiency Vermont's energy efficiency programming includes passive summer and winter peak demand reduction (MW shed), where peak times are specified according to the seasonal system peak periods of ISO-NE. Since Energy Vermont launched in 2000, statewide summer and winter peak demand reduction goals have been part of its performance metrics. Under VEIC's Order of Appointment, Efficiency Vermont is permitted to collaborate with third-party demand response providers as part of its comprehensive treatment of customers (Vermont PUC 2016).

Performance Incentive Structure

This is a spending-based PIM. VEIC's performance goals are set by the PUC, Vermont's utility regulator, and they are tied to VEIC's compensation.

VEIC's performance compensation structure is based on the achievement of a broad set of quantifiable performance indicators (QPIs). These metrics and targets include both performance indicators, which create the opportunity for VEIC to earn performance compensation, and minimum performance requirements, through which VEIC would be assessed financial penalties if it does not achieve its targets. For the 2018–2020 performance period, Efficiency Vermont's QPIs include a total of 19 metrics, 7 of which are performance indictors and 12 of which are minimum performance requirements.

VEIC's performance metrics (on behalf of Efficiency Vermont) are established for three-year performance periods, with progress toward these performance metrics evaluated annually by the Vermont Department of Public Service (DPS). Upon completing its annual evaluation process, the DPS certifies the evaluation's results to the PUC. Establishing QPIs for each performance period is accomplished through a demand resources plan (DRP) regulatory proceeding. The DRP process begins partway through a given performance period with the objective of finalizing performance metrics for the next performance period before that period starts. The most recent DRP proceeding for Vermont's EEUs was initiated in August 2019 pursuant to Case 19-3272-PET: Petition of Vermont Department of Public Service to open a proceeding to initiate an EEU DRP proceeding for the 2021–2023 performance period.

With respect to demand response activities, VEIC primarily provides information and support for customers working with demand response providers. VEIC may claim energy (MWh) and demand (kW) savings resulting from measures that are part of an integrated package of efficiency and demand response measures toward achievement of its QPIs for which VEIC has provided technical and/or financial assistance.

Table 2 lists Efficiency Vermont's five electric QPI performance indicators and related targets for the 2018–2020 performance period.

Table 2. Efficiency Vermont electric QPI performance indicators

QPI	Indicator	Performance indicator/milestone	100% $ target
1	Total resource benefits	Present worth of lifetime electric, fossil, and water benefits	$318,107,900
2	Annual electricity savings	Annual incremental net megawatt-hour (MWh) savings	357,400
3	Statewide summer peak demand savings	Cumulative net summer peak demand kilowatt (kW) savings	45,900
4	State winter peak demand savings	Cumulative net winter peak demand kW savings	62,400
5	Lifetime electricity savings	Lifetime incremental net MWh savings	3,582,000

Source: Efficiency Vermont 2017

Performance

Figure 7 shows Efficiency Vermont's 2018 performance relative to progress toward the three-year performance goals in table 2.

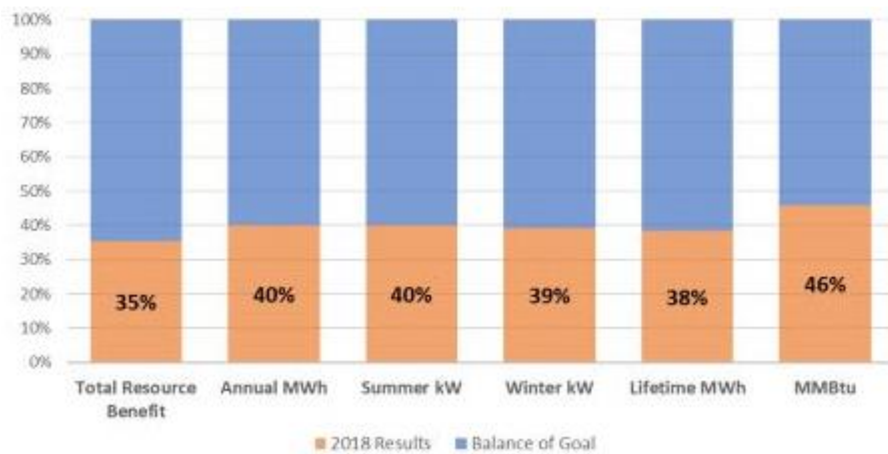

Figure 7. Efficiency Vermont's 2018 performance as % of 2018–2020 goals.
Source: Efficiency Vermont 2019.

Considering only the 2018 performance in the current three-year performance period (2018–2020), Efficiency Vermont is on track to meet its current triennial energy savings goals, including statewide summer and winter peak demand reduction goals. In the previous triennial cycle (2015–2017), it reached 110% of its statewide summer peak kilowatt (kW) demand reduction goal as well as 130% of its statewide winter peak kW demand reduction goal (Efficiency Vermont 2018). Additionally, in that 2015–2017 cycle, Efficiency Vermont achieved a two-to-one ratio of gross electric benefits-to-spending for its full portfolio, including the summer and winter demand reduction resources (Efficiency Vermont 2018). Efficiency Vermont earned about $62,000 per MW of peak demand reduction.[13]

Rhode Island

Background and Drivers

In October 2018, Rhode Island adopted a modified version of National Grid's proposed System Efficiency Incentive, which is a demand reduction PIM (Rhode Island PUC 2018). National Grid proposed the incentive as part of its power-sector transformation proposal to the Rhode Island Public Utilities Commission (RIPUC) in parallel to filing a rate case. In the end, the two parallel proceedings were combined and considered as one; the RIPUC ultimately only approved a PIM for peak demand reduction.

These performance incentives were launched in the context of a wider multistakeholder push for new utility regulatory models that began in 2016 to facilitate decarbonization and grid modernization in Rhode Island. This discussion occurred in a power sector transformation process led by the consumer advocate, energy department, and RIPUC and culminating in a Phase I report to Governor Gina Raimondo. Among the key recommendations in that report were to "shift to a pay for performance [utility] model by developing PIMs for system efficiency, DER, and customer and network support" in order to optimize DER and achieve rapid decarbonization (Rhode Island PUC, DPUC, and OER 2017).

How It Defines Demand Reduction

The primary incentive metric is MW of annual peak capacity savings (shed) across all customer categories, with capacity defined as a reduction in total demand in the annual peak hour of demand for ISO-NE. The metrics are set and reported annually for a three-year performance period.

Performance Incentive Structure

This is a shared net benefits PIM; the potential earnings for the utility are 45% of the quantified net benefits of achieving the metrics, with the remaining 55% of the benefits going back to National Grid customers in Rhode Island. National Grid proposes a budget to achieve the system efficiency target as a separate carve-out in the annual electric energy efficiency plan.

PIM earnings are exempted from Rhode Island's Earnings Sharing Mechanism, which otherwise limits the maximum utility return. To illustrate the fiscal impact of these incentives, National Grid converts the incentive dollar amounts into basis points (National Grid 2018a).

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[13] Cost-effectiveness information for these programs is not available.

Eligible resources to meet the annual MW capacity savings include the following:

- Demand response, currently including residential smart thermostats that receive deemed MW-reduction credit (other demand responsive appliances can be added in future program iterations)
- Observed demand savings during demand response events for commercial and industrial customers
- Incremental net-metered behind-the-meter solar PV distributed generation greater than company forecast levels, which receive deemed MW-reduction credit
- Incremental installed energy storage capacity
- Any additional actions that National Grid can identify to reduce peak demand, including
    - NWAs expected to reduce system peak, but not already accounted for in this PIM or other metrics
    - Partnerships with third parties to help meet peak demand reduction targets

Table 3 shows annual savings and earnings targets.

Table 3. National Grid Rhode Island annual MW capacity savings: targets and maximum earnings opportunity

	CY 2019	CY 2020	CY 2021
Minimum	14	17	21
Target	17	21	24
Maximum	20	25	29
Earnings at maximum	$362,085	$622,370	$944,141

Source: National Grid 2018a

Performance

National Grid estimates that it has already procured more than 33 MW of eligible peak demand reduction, overwhelmingly from commercial and industrial demand response (National Grid 2019). Table 4 shows that residential thermostats make a small contribution, while residential storage makes virtually no contribution. More reporting and associated data will be required to determine the overall success of this program.

Table 4. National Grid estimate of peak demand reduction procured as of September 2019

Resource type	Customers enrolled	Estimated capacity curtailment (MW)
Residential thermostat demand response (DR)	2,533	1.390
Residential battery	1	0.004
Commercial & industrial (C&I) DR	77	32.000
Total	2,611	33.394

Source: National Grid 2019

NEW YORK

Background and Drivers

New York's Reforming the Energy Vision (REV), initiated in 2014, outlines how utilities will become drivers of decarbonization by animating more participation from third-party providers to optimize customer energy use. In this context, the PSC adopted new energy savings targets in 2018 alongside existing decoupling policies for electric and gas utilities (ACEEE 2019).

In order to achieve these goals, the REV proceedings aim to change many aspects of the utility business model, including moving toward performance-based ratemaking.

In 2019, New York passed legislation requiring the state to create a plan to achieve net zero GHG emissions by 2050. This plan informs the many reforms underway in New York's electric utility sector and will likely increase the PSC's focus on the interaction between demand reduction, carbon reduction, and cost. In particular, the PSC has stated that the objectives for its ratemaking changes are to make a modern power system that is clean, adaptable, efficient, and transactive. It emphasizes improving system efficiency and reducing peak demand as a way to achieve these goals (New York DPS 2016).

How It Defines Demand Reduction

Utilities in New York are focused on reducing demand that coincides with system peak (shed) and improving overall system efficiency and load factor (shape and shed), which it defines as total system costs divided by sales units. The PSC originally proposed a system peak demand reduction target based on the bulk system's average load on the top 10 peak days, aiming to reduce load on the top 100 peak hours (New York DPS 2016). However the commission ultimately left it to the utilities to propose their own performance goals to be determined in each rate case.

Performance Incentive Structure

As a step toward performance-based ratemaking, utilities can propose and earn financial awards, or earnings adjustment mechanisms (EAMs), for achieving targets approved by the utility commission. The EAMs are broken into program-achievement and outcome-based EAMs to incentivize high-performing energy efficiency and demand shaping programs and to incentivize broader outcomes for the utility's territory. The EAMs allow utilities to earn up to 100 basis points for achievements across system efficiency and other public interest outcomes. In practice, the available incentives are set in rate cases as a fixed dollar amount, and have reached maximums in the 65–70 basis point-equivalent range (Jason Hochman, senior specialist, Regulatory Strategy and Stakeholder Engagement, ConEd, pers. comm., December 5, 2019). The available basis points for each initiative within the total, including any related to SDR, vary based on expected outcomes and costs. Compensation varies based on the utility, which must propose its own EAMs and report on them annually. These EAMs are rate-of-return PIMs.

New York's outcome-based peak demand reduction (shed) and load factor (shape and shift) EAMs are unique in that they allow utilities flexibility in meeting the goals. Efforts to meet these targets can reduce overall load through targeted efficiency (shed) or shift load to off-peak times (shift or shed); they can also include complimentary load-building strategies such as electrifying heat pumps or increasing electric vehicle (EV) adoption (shape). The EAMs encourage a wide range of efforts to reduce system peak demand including demand response, energy efficiency measures with demand impacts, interconnection of distributed generation, rate promotion, and building code development.

Consolidated Edison (ConEd) has program- and outcome-based EAMs for efficiency and SDR programs that it funds through two mechanisms: an energy efficiency transition implementation plan (ETIP) and its rate case. The programmatic EAMs incentivize energy savings and system peak demand reductions, while the outcome-based EAMs are based on DER utilization[14] and energy intensity. Starting in 2020, the system peak demand reduction EAM will transition to an outcome-based EAM awarded based on actual weather-normalized coincident system peak (ConEd 2019b).

Other New York utilities have similar EAMs in place. National Grid has peak reduction and DER utilization EAMs that the company aims to meet through demand response, peak-focused energy efficiency, off-peak EV charging, heat electrification, and other programs (National Grid 2018b).

Performance

In 2018, ConEd (the first utility to file for EAMs) earned its maximum program-based incentive for peak demand reduction: $5.36 million for 85 MW of peak demand reduction achieved through multiple programs run at a cost of about $103 million (ConEd 2019a).[15] This is about $63,000/MW. In 2017, the company also earned the maximum amount ($3.46 million) for its 60 MW of peak demand reduction (ConEd 2019c). ConEd achieved these reductions through many programs that are standard in utility energy efficiency portfolios, including commercial direct install programs, lighting rebates, and home energy reports. In addition, the company offered incentives for off-peak EV charging, which contributed to less than 1% of the demand reduction.

ConEd also has a specific system peak reduction demand management program offering customers incentives for advanced technologies that reduce coincident peak demand. These technologies include battery storage, thermal storage, demand response enablement, building management systems and controls, HVAC and chillers, and fuel switching (such as from gasoline to electrically fueled vehicles or adoption of ground source heat pumps). Of these advanced technologies, thermal storage and fuel switching produced the greatest peak demand reductions (ConEd 2018). Demand response and EVs also contributed to ConEd's outcome-based EAM for DER utilization, measured in MWh. Cost-effectiveness information was not available for this program.

[14] ConEd's DER utilization EAM aims to increase DERs on the system by incentivizing the utility to work with customers and providers on expanding solar, combined heat and power, fuel cell, demand response, thermal storage, heat pump, and EV charging technologies. The EAM is measured based on the technologies' annualized MWhs of production, consumption, discharge, or reduction (ConEd 2019a).

[15] Cost-effectiveness information for these programs is not available.

MASSACHUSETTS

Background and Drivers

Massachusetts' state EERS establishes clearly defined, long-lasting program administrator (utility) targets for energy savings (ACEEE 2019). It requires state program administrators to file an energy-saving and demand management plan with the Energy Efficiency Advisory Council (EEAC) and the Department of Public Utilities (DPU) every three years. The 2019–2021 plan includes a statewide active demand reduction PIM.

This latest plan added a focus on active demand response and fuel switching, which is swapping out oil- and propane-powered heat and hot-water systems for electric heat pump versions. This is consistent with the Act to Advance Clean Energy, a 2018 update to the Green Communities Act (2008), which originally created the EERS (General Court of Massachusetts 2008, 2018).

How It Defines Demand Reduction

The SDR component of the demand reduction PIM measures and rewards program administrators for achieving summer and winter peak demand reductions (shed) through efficiency (called passive demand savings in Massachusetts and ISO-NE). It also has an additional specific component called active demand savings, which is designed to encourage program administrators to pursue demand response (also defined as peak demand reduction) (MA EEAC 2018b). That the peak demand reduction must be acquired for both summer and winter capacity reflects the ISO-NE wholesale market's movement toward a seasonal capacity market, with future projected winter peaks as Massachusetts electrifies its vehicles and buildings (MA EEAC 2018a).

Performance Incentive Structure

The PIM, a shared net benefits energy efficiency and demand reduction mechanism, has two primary components: the savings component, intended to reward administrators for achieving lifetime energy and peak demand savings; and the value component, intended to reward administrators for seeking cost-effective savings and nonenergy benefits (Mass Save 2018). The newest addition, the active demand reduction PIM, has a separate pool of incentive money from the efficiency incentive—$5 million in the current performance period—but falls under the savings component.

The entire performance incentive pool is allocated to each individual program administrator in proportion to that administrator's planned net benefits. The performance incentive is applied and earned at the portfolio level (that is, across all factors) for the three-year cycle and is based on the actual performance compared to planned benefits.

Three levels of incentive earnings provide a minimum and maximum. The earnings scale linearly within the following three bounds:

- *Threshold:* a minimum of 75% of benefits achieved to receive performance incentive (PI).
- *Design:* equal to 100% of the PI pool.
- *Exemplary*: a maximum 125% amount of PI, set as a percentage of design.

Table 5 shows each of the components of the performance incentive, with the total amount of potential earnings in each component for program administrators.

Table 5. 2019 long-term plan goals

<table>
<tr><th>PIM component</th><th colspan="2">Electric performance incentive totals ($ millions)</th></tr>
<tr><td>Value: energy efficiency, passive and active demand</td><td>41.195</td><td rowspan="2">107
(38.5% value and 61.5% savings)</td></tr>
<tr><td>Savings: energy efficiency and passive demand</td><td>65.805</td></tr>
<tr><td>Savings: active demand</td><td>5</td><td></td></tr>
<tr><td>Total</td><td>112</td><td></td></tr>
</table>

Source: MA EEAC 2018c

In aggregate, the 2019–2021 plan sets the summer demand reduction goal at 665 MW (200 MW from active demand and 465 MW from passive demand), and the winter goal at 500 MW (Mass Save 2018). Current demand reduction benefits are calculated as an avoided cost for summer capacity, but stakeholders are currently undertaking a study to quantify winter capacity benefits and determine if the winter capacity savings offer new benefits.

The active demand management program is structured to be technology neutral, meaning that it is not limited to traditional demand response, but also includes load shifting, utilizing renewable energy and storage, and managing electrified end uses. The administrators will report biannually on active demand reduction participation by sector, season, and approach (including without limitation, storage, residential direct load control, and commercial and industrial curtailment).

Performance

According to the Mass Save website, from 2010 through 2018, the energy efficiency programs reduced 1,565 MW of summer peak demand (Mass Save 2019). The graph below also shows planned and achieved demand reductions. Thus far, all demand reductions have come from passive demand management (active demand management was added in 2019). The statewide evaluated benefit–cost ratio for the 2016–2018 cycle was 2.54 across the entire portfolio (MA EEAC 2019).[16] The program administrators earned approximately $51,000 per MW of electric capacity saved. Figure 8 shows net capacity savings in each summer from 2013 to 2017, as well as goals for 2018 to 2021.

[16] The Total Resource Cost (TRC) Test is the primary guideline for determining the cost effectiveness of energy efficiency programs in Massachusetts. It accounts for all benefits and costs associated with the energy system. Benefits accrue from measures such as avoided energy and energy capacity, while costs accrue from program implementation, incentive, and incentive costs (MA EEAC 2011).

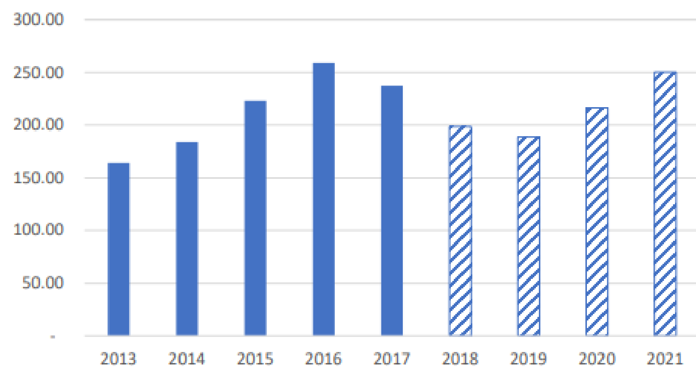

Figure 8. Sum of net summer capacity savings (MW). *Source:* MA EEAC 2018.

Discussion

The case studies here describe a variety of SDR PIMs that have been implemented across the United States. Table 6 includes the design features from table 1 and provides additional key data points where available.

Table 6. PIM details and results from states studied

State	Key design features	Maximum available incentive*	Performance period; duration of PIM	Result for utilities	Achieved peak demand savings as % of peak demand	Type of SDR	Missed, met, or exceeded
Hawaii	Initial, one-time incentive based on achievement of peak demand reduction target through direct procurement.	Lesser of 5% of aggregate annual contract value or $500,000	One year	PIM was not met so the utilities did not receive the payment.	N/A	Shed and shimmy	Missed
Michigan	Up to 15% of demand response costs on a sliding scale based on demand response capacity, growth rate achieved, and NWA assessment costs.	15% of demand response spending	Approved for only a one-year cycle (2019)	Results available in 2020	N/A	Shed	N/A
Texas	1% of net benefits for every 2% of demand reduction goal exceeded.	10% of net benefits	One-year cycle	Utilities kept an average of 24% of 2015–2017 program spending.	0.82% of summer peak demand in 2017	Shape	Exceeded

State	Key design features	Maximum available incentive*	Performance period; duration of PIM	Result for utilities	Achieved peak demand savings as % of peak demand	Type of SDR	Missed, met, or exceeded
Vermont	Percentage of total approved budget based on performance on several outcomes, including winter/summer peak demand reduction	2.5% of total approved budget	Three-year cycle	The utility earned the maximum reward in the 2015–2017 cycle.	1.8% of summer peak for 2015–2017	Shed	Exceeded
Rhode Island	Cash reward based on achievement of peak demand reduction, structured as a shared savings mechanism exempt from utility return-on-investment cap	45% of net benefits	Three-year cycle	Results from the first cycle will be available in 2021.	N/A	Shed	N/A
New York	Up to 100 basis points added to ROE for PIMs in aggregate; peak demand reduction achievements receive a portion.	A portion of 100 basis points for SDR performance (currently approved at 65–70 basis points total)	Three-year cycle	ConEd's reward was about 5.2% of spending in 2018.	0.69% of summer peak in 2018	Shape and shed	Met
Massachusetts	Portfolio-wide incentive; incentive based on performance from 75% to 125% of the PIM goals	5.4% of cumulative budget for program costs	Three-year cycle	Utilities earned an average of 6.5% of program spending from 2016–2018.	4.4% of summer peak for 2016–2018	Shed	Exceeded

The sections below describe the trends emerging from our research and recommend best practices for structuring SDR PIMs.

PIMs are an Effective Tool for Unlocking SDR

SDR potential remains largely untapped, reaching nowhere near the Brattle-estimated potential of 200 GW of cost-effective load flexibility and consumer benefits of $15 billion per year. Nonetheless, our review of several case studies demonstrates that PIMs can be an effective strategy for incentivizing SDR. Of the five cases studied that have available results, four administrators (in the Massachusetts, New York, Texas, and Vermont cases) met or exceeded their targets. Administrators in the seven states reviewed earned incentives ranging from 2% to 25% of their program spending. However this range is meant to illustrate only a possible range as the baseline spending for each utility was calculated in a slightly different manner, as the table describes. Utilities saved about 0.69–6.5% of total peak demand, and each program created consumer benefits, with benefit–cost ratios of 2 and higher.

Although these incentives are generally successful, we found two key design features that require careful consideration: sizing incentives to be both financially meaningful and aligned with the scale of benefits, and maintaining a focus on outcomes relative to process or activities in incentive design.

Regulators face a challenge when sizing an incentive to encourage utility uptake and performance beyond business as usual while also attempting to maximize performance benefits for customers. One consideration in that analysis is goal stringency. If the goals are easily reached, a low incentive could be sufficient. Conversely, if a performance target represents a big departure from business as usual, a larger incentive may be necessary to compensate utilities for the additional risks involved in making major changes to their operations and business model.

Two case studies from Hawaii and Texas, and an additional example from Missouri, illustrate these tradeoffs and the difficulty of assessing whether SDR incentives are sized appropriately. Hawaii's SDR PIM failed to elicit utility performance, which implies that the incentive was not well aligned with the target. Multiple factors were at play, however, including that HECO's SDR PIM lacked recurring annual revenue and faced a difficult timeline. Experience with Ameren Missouri's energy efficiency PIM similarly demonstrated that the incentive alone was not sufficient to motivate the utility to consistently increase its efficiency savings levels (Nowak et al. 2015).

According to our analysis, administrators (mostly utilities) are earning $50,000–62,500/MW of saved peak demand from SDR PIMs. A recent LBNL study evaluated costs borne by program administrators for first-year peak demand savings through energy efficiency programs; these costs ranged from $568,000–2,353,000/MW across the nine states it evaluated. It is important to note that these programs also produce energy savings, which are additional benefits against which these costs can be compared. The states are in different climate zones and have different peak demand periods, which may also affect the cost of saved peak demand (Frick et al. 2019). Despite the difficulty of comparing heterogeneous SDR programs, the cost figures do provide some helpful context. For example, in Texas, the incentive earned is equal to about 6.8–13% of the cost per peak MW saved. In Massachusetts, the incentives are higher, but the costs are also higher—equal to about 6.5% of the cost per peak MW saved. These figures are similar to conventional energy efficiency performance incentives, which are typically 3–15% of program spending (Relf and Nowak 2018).

Additionally, an incentive structure with a cap or ceiling can encourage performance up to that cap but not beyond it. For example, ConEd achieved its full peak demand reduction PIM by acquiring about 85 MW of peak demand reduction, just over its approved maximum target of about 82 MW. In contrast, Texas utilities regularly exceed their performance targets and have no incentive cap. However the Texas program's high achievement level indicates that the demand reduction performance thresholds could be increased; they have held constant for nearly two decades.

Table 6 above attempts to show each incentive's relative size by evaluating the percentage of SDR program spending in the "Results for utilities" column. For the newer PIMs, these may need to be recalibrated over time, as it may take one to two cycles to calibrate and size an incentive (Whited, Woolf, and Napolean 2015). While it is not ideal to change investment expectations for targets or incentives set in the first performance period, the second performance period should certainly learn from the first. Additionally, states wary of misappropriating ratepayer dollars can create a measurement-only period to find a baseline from which to work—an approach taken by the Minnesota PUC in its proceeding to develop metrics that support future PIMs (MN PUC 2019).

With the exception of the performance incentives for VEIC in Vermont, the SDR PIMs studied here are upside-only for the utility.[17] PIMs can be designed as upside-only, downside-only, or symmetrical, with penalties for poor performance and rewards for excellent performance. This range of design choices is not theoretical; many reliability or safety PIMs are negative-only, while many cost risk-sharing PIMs are symmetrical (Whited, Woolf, and Napolean 2015). Upside-only PIMs provide benefits for new SDR programs without much downside for poor performance, and they introduce little new risk to utility shareholder returns. These upside-only PIMs are useful incentives in an environment such as SDR, where significant technology risk might lead to worse than expected performance. They also aim to compensate the utility for missed capex earnings opportunities.

To make SDR a core part of the utility business model, incentives and other policies can continue to strengthen the link between utility performance on SDR and investor returns. Doing so may fundamentally shift investor attitudes about utility risk, depending on how the PIMs are structured and sized. As confidence builds around utility performance on SDR, regulators will have the opportunity to iterate and expand compensation mechanisms, try new compensation structures that introduce additional upside and downside risks, increase the stringency of performance targets, and try innovative new metrics. Creating adaptive processes that promote continuous improvement is key to growing SDR as utilities gain experience promoting this important resource.

Multiple resources can support SDR

Traditional energy efficiency and demand response are the most common resources currently providing SDR as part of PIMs, but other resources, such as behind-the-meter battery and thermal storage, fuel switching, and solar PV, are emerging in several states.[18]

Incentives that focus on outcomes (the effect of the utility's activities) rather than process (which activities were required of the utility) often enable a technology-neutral approach, while also providing more clarity and transparency to stakeholders on the benefits that were actually achieved (O'Boyle and Aggarwal 2015). Rhode Island's peak demand reduction PIM exemplifies outcome-based measurement and compensation. The PIM measures annual peak capacity savings, and allows for diverse approaches to meet this goal including distributed solar PV and storage. Utilities and customers split the benefits, measured as

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[17] VEIC's performance compensation is based on the achievement of a broad set of QPIs that includes some minimum performance requirements that assess financial penalties if targets are not achieved.

[18] As described above, utilities may have different inherent incentives to pursue fuel switching or utility-owned storage; we have yet to see SDR PIM designs account for these nuances.

avoided-capacity market and transmission tariff costs. The active demand component of Massachusetts' PIM is also technology neutral.

Likewise, New York's SDR EAM encourages utilities to partner with third parties and customers to use whichever technology can deliver the results in a cost-effective manner. ConEd included a wide range of resources in its system peak reduction program; thermal storage and fuel switching provided the greatest peak reductions, with additional contributions from demand response and EVs. In Michigan, the MI PSC has indicated that it may move to an outcome-based metric that includes demand response in NWAs, rather than rewarding utilities for consideration of specific resources, whether or not they were actually deployed. These outcome-based metrics include potential challenges, however, including the administrative costs in setting up and accurately defining the metrics and ongoing challenges with measuring success with uncertain baselines. Regulators will also need to avoid double-counting with any existing activity- or program-based metrics.

SDR PIMs currently focus on shape and shed

Current SDR PIMs focus primarily on long-term adaptation of customer demand in response to prices and efficiency measures (shape) and traditional utility and wholesale market demand response programs (shed). Most SDR PIMs have yet to focus on enabling daily changes to consumption by moving demand from one time of day to another and on grid-balancing measures targeting ramping services (shift) that can better support renewables integration. Over time, these resources will require PIMs to account for time and locational value, and they may also require new metrics for assessing success.

An exception to this focus on shape or shed services is Massachusetts, which has created a PIM to deliver active demand management, which would provide shed and shift demand reductions to support renewables integration. New York's load-factor reduction PIM also begins to get at valuing shift as well as shed and shape, although it is an inherently approximate measurement of SDR. Some states, including New York, Vermont, and Rhode Island, are also implementing financial incentives for NWAs that reward utility procurement of locational SDR as well, though only a handful of demonstration projects exist.[19]

Most of these states provide greater incentives for the shape services provided by some energy efficiency investments, which face both throughput and capex bias, than SDR focused on shed and shift, which primarily faces the capex bias. In designing PIMs, regulators are analyzing the costs and benefits of different SDR services and resources, and balancing those costs and benefits against the underlying incentives utilities have to deliver SDR with different resources. This follows the principle that PIMs should help influence the utility to do what it might not otherwise be inclined to do under traditional regulation. Utilities are more inclined to shift and reduce demand when sales remain constant.

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[19] See generally rmi.org/insight/non-wires-solutions-playbook/, page 25: "A number of states—including California, Maine, New Hampshire, New York, Rhode Island, and Vermont—require utilities to consider distribution level non-wires solution projects that meet defined screening criteria. "

In the three states we examined with demand incentives focused on shed or shift services, the available incentives for energy efficiency and shape services are higher than for active demand reduction from shed and sometimes shift. In Michigan, utilities can earn up to 20% of their spending for energy efficiency, but a maximum of 15% for demand response, specifically for shedding services. In the proceeding to determine Consumer Energy's incentive, staff and NRDC recommended a lower incentive for demand response than the one proposed by Consumers Energy, which would have included the opportunity to earn up to 20% of spending for demand response. The administrative law judge agreed, noting that energy efficiency results in significantly more lost revenue for the utility since it operates year-round and not simply in the few annual on-peak hours; the commission ultimately adopted the lower incentive (15% of spending) for demand response (MI PSC 2019). In Massachusetts, the difference is more stark: more than $65 million is available for what it calls passive demand reductions (that is, shape demand reduction), while only $5 million is available for active demand reductions (shed and possibly shift).

Durable, long-term incentives with periodically updated performance cycles support continuous improvement

In our case study review and analysis, the incentives that combined a consistent policy signal over a long period (at least a decade) and included regular, sequential program cycle updates (such as those in Massachusetts, Texas, and Vermont) tended to elicit the most SDR. Most of the examples we reviewed were relatively long term. However Hawaii's one-time PIM stood out as a short-term, nonrecurring PIM; in it, the utility was not successful in receiving the incentive. Utilities, which plan and invest over long time horizons, likely need a multiyear program to properly incent them to integrate SDR technology and policy.

We also found that the best-performing PIMs were revisited through interim policy updates (anywhere from annual to triennial). Without an opportunity for iterative updates, commissions and utilities cannot fine-tune the program over time or adjust to new technology. Synapse's *Utility PIMs* report notes that incentives "may need to be adjusted over time"; targets and metrics may also require adjustment. For example, many of our case studies evolved from energy efficiency programs and mechanisms and incorporated elements of demand response (called active demand management in some states), and they were able to do this in cycle updates.

Reporting and data collection should be available to the public for accountability and transparency in the regulatory process. Synapse's report suggests that, to report and track key data, commissions should create dashboards that are accessible, contextualized, clear and concise, comprehensive, and up-to-date (Whited, Woolf, and Napoleon 2015). Incentives that allow for regulatory certainty, adaptation, and transparency prove to be the most effective in producing results.

Durable, long-term incentives also relate to the contract terms and details of the incentive itself. If contract terms are reduced to short time frames, utilities may not have the incentive to acquire new resources. Until 2006, load-management programs in Texas were required to have a standard minimum measure life of 10 years like other efficiency measures, with annual incentive payments for a 10-year contract term. As a result, new load resources would have to be added each year to those already under contract in order for utilities to capture additional demand reduction credit. With changes to allowable measure lives from these programs and no change to the PIM, utilities were effectively able to use the same loads every year to apply to their demand savings, increasing their opportunity to earn the incentive without increasing demand reduction investment (Beville and Howell 2017).

STATE AND REGIONAL POLICIES CAN COMPLEMENT PIMS

Although PIMs can encourage SDR, the cases illustrated here show that successful states also have complementary policies in place. These include energy efficiency and other clean energy targets; business model reforms, such as decoupling and energy efficiency PIMs; independent EM&V; and valuation mechanisms in wholesale markets, rate design, and distribution resource planning. Many of these reforms fall under grid modernization proceedings underway across the country.

Research shows that utilities require program cost recovery, decoupling of revenue from sales to remove the throughput incentive, and performance incentives to achieve robust energy savings (Molina and Kushler 2015). Additionally, EERS, renewable portfolio standards (RPS), and other clean energy requirements mandate procurement of certain resources and stimulate market growth in those sectors, driving down costs and increasing availability. Such business model reforms can help to facilitate a cultural shift toward incorporating clean energy as a core part of business operations. Of the seven states studied, all have an energy efficiency PIM, an RPS, and an electric EERS in place. Five have electric decoupling.

Beyond PIMs, rate design can further incentivize investment in SDR. Currently, few customers receive price signals through their rates that reflect SDR's value. TVR, such as time-of-use and critical peak pricing rates, can provide price signals to customers that encourage energy efficiency and SDR on a granular time and locational basis. Of the states studied in this paper, at least one utility in five of the states has a residential time-of-use rate in place.

Wholesale markets provide another opportunity to realize additional SDR value and can also help to inform demand reduction PIM design. This is the case in Rhode Island, New York, and Massachusetts, where peak demand reductions are defined within the context of bulk power system peak. The wholesale market also provides a market-based price signal for SDR resources' value; this price signal is used to compensate resources in a value-stacking reward mechanism, like that in New York. Further evolutions in wholesale market design, including participation models for aggregated distributed energy resources,[20] will provide new pathways for customers to provide and be paid for SDR.

Value streams beyond PIMs are important drivers for investment in SDR resources. Many states do not have a specific PIM in place for SDR resources, but utilities can be rewarded for their performance by bidding SDR resources into a wholesale market and sharing some of the savings. For example, demand resources are growing as a part of the PJM capacity

[20] As of this writing, FERC is assessing DER participation models in Docket No. RM18-9. See generally www.ferc.gov/CalendarFiles/20180215200832-RM18-9-000.pdf.

market, which does not have specific SDR PIMs in place (Relf and Baatz 2017). Capacity payments can be considered a kind of PIM, although capacity costs are typically passed through to retail customers. In the most recent PJM auction, payments to demand-side resources were more than $820 million. In contrast, states in ISO-NE are stacking wholesale market payments with SDR PIMs and have been successful at achieving SDR. Additional research may be necessary to determine the interactive effects of wholesale market payments with PIMs. This is an ongoing question in Maryland, where the commission has held off on setting SDR targets for utilities due to questions about changes to PJM's market structures and uncertainty about the current market saturation of direct load-control programs.[21]

Wholesale markets capture locational value on a subregional scale; including SDR in distribution system planning can capture locational value on an even more granular level. As discussed above, PIMs can help to incentivize use of SDR in NWAs (as in Michigan and New York). States can also require the consideration of distribution system planning to evaluate SDR resources and NWAs as another way to capture this value and ensure that all resources are being evaluated on a level playing field. Coordinated system planning helps to improve overall system efficiency, which is often a desired outcome of SDR and SDR PIMs.

Utilities and grid operators are also paying increased attention to distribution system planning due to new loads coming online on the customer side of the meter, including from electrification. Electrification, that is, fully or partially switching from technologies that directly use fossil fuel to those that use electricity, is critical to achieving long-term GHG reduction goals, and it will require more grid capacity although it also provides more load flexibility (Williams et al. 2015; Jadun et al. 2017). Electrification measures create grid flexibility by providing an opportunity to shift large aggregate loads, such as vehicles and space conditioning, to provide SDR that complements renewable energy. However utilities and customers may not take advantage of that inherent flexibility absent requirements or motivation to do so. As utilities and states pursue electrification, they should incorporate strategies such as smart charging to strategically manage new loads in a way that does not exacerbate peak demand and that reduces system costs. Policy should require that utilities optimize new load growth and strategically deploy energy efficiency and SDR when and where it is needed most alongside electrification. However utilities are likely to pursue electrification to increase volumetric sales, and thus may not require the same scale of performance incentives to pursue SDR for new electric end uses.

All of the complementary strategies discussed above require robust EM&V that creates confidence in achievements and provides both information on possible improvements and data for additional analysis. This is important for SDR PIMs as well.

[21] www.psc.state.md.us/search-results/?keyword=9154+&x.x=19&x.y=8&search=all&search=case

Conclusions

State commissioners, regulators, and utilities are experimenting with newer forms of SDR PIMs to achieve what traditional cost-of-service regulation has not: load flexibility, load shaping, and load responsiveness. To achieve the estimated economic benefits of more than $15 billion annually from load flexibility, legislators and regulators need to use the many tools at their disposal to encourage utilities to integrate SDR as a core part of their business operations (Hledik et al. 2019). The states studied in this report show a growing interest in and experience with SDR to achieve a variety of goals, including cost savings for consumers and reducing GHG emissions.

Within the next wave of states considering changes to the utility business model, many are considering incentivizing SDR. New Hampshire is currently considering updates to its performance incentives, and its commission staff members have put forth a proposal that includes incentives for demand reductions (New Hampshire Performance Incentive Working Group 2019). Recent legislation in Washington opens the door for demand reduction PIMs, as it explicitly calls for demand response targets and establishes authority to create performance-based rates (Washington Legislature 2019). Minnesota's performance-based metrics proceeding highlights the "cost-effective alignment of generation and load" as a key policy outcome (MN PUC 2019). Hawaii selected DER asset effectiveness as a key outcome in its PBR docket (HIPUC 2019d). Michigan's DTE has proposed a demand response PIM that has not yet been approved by the commission (DTE 2019). California utilities are piloting "pay-for-performance" efficiency programs that target SDR applications and place requirements on customers for achieving greater value through energy efficiency (St. John 2019).

This research highlights successful elements of SDR PIMs for consideration as more jurisdictions move toward performance-based regulation. Regulatory reform in conjunction with robust programs can reduce demand strategically to transition to an affordable, resilient, and clean electricity system. Complementary policies can help to reduce SDR conflicts with the cost-focused utility business model. It is also important to continuously evaluate what each PIM is incentivizing and how effectively it is delivering benefits to customers. Well-designed SDR PIMs can help move utility behavior to align with desired policy outcomes including reduced customer costs, improved reliability, and reduced environmental impacts during a time of rapid change in the energy sector.

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