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<https://escholarship.org/uc/item/3mp147d8>

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### Publication Date

2024-01-09

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Peer reviewed

November 2023

# The use of price-based demand response as a resource in electricity system planning

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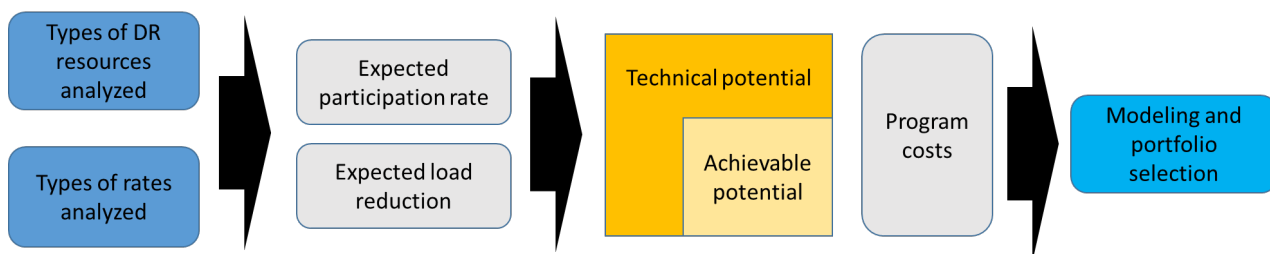
Utilities have conducted IRP for decades to consider both supply- and demand-side resources to meet bulk power system needs. More recently, an increasing number of states are requiring regulated utilities to file plans that identify distribution system needs, including DERs that can avoid or defer certain types of traditional utility investments cost-effectively. Price-based demand response (DR) is an underutilized resource that could substantially contribute to load flexibility. We find that evaluation of price-based DR as a solution to meet identified electricity system needs is uncommon at both planning processes. Where price-based DR is considered as a solution, methodologies are often deficient in the characterization and treatment of this resource. Based on our analysis of utility filings and state requirements, this brief provides recommendations for improving consideration of price-based DR in the context of long-term planning for bulk power and distribution systems.

## Introduction

Decarbonizing electricity systems, including electrifying transportation and buildings, will require high levels of flexibility. Loads can be leveraged as flexible solutions at both the bulk power system and distribution system levels. While traditional demand response (DR) programs such as direct load control will continue to play an important role, load flexibility in the future may depend in large part on price-based DR programs, implemented through time-based rates.

*Integrated resource planning* (IRP) has historically incorporated demand-side resources without a clear connection to (1) the rate structures that underpin them and (2) the potential of underutilized and novel rate structures to drive higher levels of load flexibility. While some utilities began considering DR in *distribution system planning* (DSP) in the 1990s for deferring or avoiding some types of distribution system upgrades — and several jurisdictions now require regulated utilities to consider the locational value of DR and other types of distributed energy resources (DERs) — rate design is not typically considered.

This technical brief focuses on the treatment of price-based DR in IRP, using the framework in Figure 1, and recommends ways to improve consideration of price-based DR as a bulk power system resource. The brief also reviews nascent approaches for including price-based DR in DSP and recommends improvements.



**Figure 1.** IRP framework for price-based DR analysis.

## Background on price-based DR

The U.S. Energy Information Administration (EIA) distinguishes between traditional DR programs and price-based DR in its annual collection of information from utilities. "Demand Response Programs are procedures that encourage a temporary reduction in demand for electricity at certain times in response to a signal from the grid operator or market conditions. Examples are the dimming of lights, turning on backup generators or shutting down industrial processes."<sup>1</sup> In this brief, we define price-based DR as time-based rate programs, also referred to as "time-varying rates" or simply "rates." The EIA refers to these programs as those "designed to modify patterns of electricity usage, including the timing and level of electricity demand."<sup>2</sup>

The EIA uses the following definitions for time-based rate programs:\*

- **Time of Use Pricing (TOU)** is a program in which customers pay different prices at different times of the day. On-peak prices are higher and off-peak prices are lower than a "standard" rate. Price schedule is fixed and predefined, based on season, day of week, and time of day.
- **Real Time Pricing (RTP)** is a program of rate and price structure in which the retail price for electricity typically fluctuates hourly or more often, to reflect changes in the wholesale price of electricity on either a day-ahead or hour-ahead basis.
- **Variable Peak Pricing (VPP)** is a program in which a form of Time-Of-Day (TOD) pricing allows customers to purchase their generation supply at prices set on a daily basis. Standard on-peak and off-peak time-of-day rates are in effect throughout the month. Under the VPP program, the on-peak price for each weekday becomes available the previous day (typically late afternoon) and the customer is billed for actual consumption during the billing cycle at these prices.
- **Critical Peak Pricing (CPP)** is a program in which rate and/or price structure is designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies, by imposing a pre-specified high rate or price for a limited number of days or hours. Very high "critical peak" prices are assessed for certain hours on event days (often limited to 10-15 per year). Prices can be 3-10 times higher than standard during these few hours. Typically, CPP is combined with a TOU rate, but not always.
- **Critical Peak Rebate (CPR)** is a program in which rate and/or price structure is designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies, by providing a rebate to the customer on a limited number of days and for a limited number of hours, at the request of the energy provider. Under this structure, the energy provider can call event days (often limited to 10-15 per year) and provide a rebate typically several times the average price for certain hours in the day. The rebate is based on the actual customer usage compared to its baseline to determine the amount of the demand reduction each hour.

\* Form EIA-861S Annual Electric Power Industry Report

<sup>1</sup> Form EIA-861S Annual Electric Power Industry Report (Short Form) Instructions, page 16, [https://www.eia.gov/survey/form/eia\\_861s/instructions.pdf](https://www.eia.gov/survey/form/eia_861s/instructions.pdf).

<sup>2</sup> *Id.*, page 17.

Utilities use three types of enrollment methods for price-based DR:<sup>3</sup>

- *Opt in*: Customers can choose to participate but are otherwise not enrolled.
- *Opt out*: Customers are enrolled by default but have the option to switch to another rate.
- *Mandatory*: All customers in the designated rate class, or meeting certain criteria (e.g., above a set consumption level), must take service on the rate.

Rate levels or prices influence customer behavior and hence can be used as a resource to achieve operational outcomes in an electric grid. However, prices are also critical to stimulate investment in enabling technologies, a role that is not examined in this paper.

## Current practices for considering price-based DR in IRP

### *Approach*

Berkeley Lab maintains a web-based tool, the Resource Planning Portal, which provides users with information in a consistent format from publicly filed IRPs and other similar planning documents for dozens of U.S. electric utilities.<sup>4</sup> Example uses include comparing planning assumptions across utilities and aggregating capacity of planned new resources across utilities in a particular region. Berkeley Lab has used the information for research for conducting a flexibility assessment, evaluating the accuracy of load forecasts in resource planning, benchmarking carbon costs used in resource plans, and estimating planned reliance on wholesale market transactions by Western U.S. utilities.<sup>5</sup> While the Resource Planning Portal is set up to record price-based DR that utilities include in resource plans, this is Berkeley Lab's first research project focusing on this topic.

The Resource Planning Portal does not include every IRP filed in the U.S., but it does cover all of the major investor-owned and publicly owned utilities that file these plans. For each of these utilities, we screened the most recent IRP filed for inclusion of price-based DR in the main report, appendices, or supplementary studies to develop our sample. All IRPs in the sample were filed in 2019 or later, with most of them filed in 2021. Based on our screening, this brief examines 12 recently filed IRP reports<sup>6</sup> by electric utilities in the Western, Midwest, and Southeast U.S. (Table 1).

Our study identifies and characterizes current IRP practices for capturing the benefits of retail rates as a resource. While our study is not intended to determine how common these practices are across utilities that are required to file IRPs, most of the IRPs in our database do not consider price-based DR.

<sup>3</sup> Chitkara et al. (2016).

<sup>4</sup> The U.S. Department of Energy supports the Resource Planning Portal so that anyone can use it at no charge: <https://resourceplanning.lbl.gov/login.php#q1>.

<sup>5</sup> See publications listed at <https://emp.lbl.gov/projects/utility-resource-planning>.

<sup>6</sup> These reports were the most recent ones as of March 2022, when we finalized our list.

**Table 1. IRPs examined in this study**

Entity	State(s) covered	Plan year	Supplementary information
<b>AES Indiana</b>	IN	2022	DSM market potential study
<b>Arizona Public Service (APS)</b>	AZ	2021	DSM opportunity study
<b>Avista</b>	WA, ID, OR	2021	DR potential assessment
<b>Consumers Energy</b>	MI	2021	DR potential study
<b>DTE Energy</b>	MI	2019	DR potential study
<b>Entergy Louisiana</b>	LA	2019	DR study
<b>Georgia Power</b>	GA	2022	Load and energy forecast appendix
<b>Northwest Power and Conservation Council (NWPC)*</b>	ID, MT, OR, WA	2021	DR appendix
<b>PacifiCorp</b>	UT, OR, WA, ID, CA, WY	2021	DSM conservation potential assessment
<b>Puget Sound Energy (PSE)</b>	WA	2021	DR potential assessment
<b>Sacramento Municipal Utility District (SMUD)</b>	CA	2019	None
<b>Public Service Company of Colorado (Xcel Energy)**</b>	CO	2021	2021-2022 DSM plan

\* The NWPC relies on input data from entities in its footprint and produces its own DR impacts analysis using this data. This brief focuses on the NWPC's methodology and plan outcomes.

\*\* After publishing its 2021 IRP, Xcel Energy commissioned a DR study to assess the cost-effective potential for new DR opportunities in 2030, as Public Service Company of Colorado increasingly relies on non-dispatchable wind and solar generation.<sup>7</sup>

The following sections of this brief characterize price-based DR in IRP according to:

- Types of DR resources studied
- Types of rates analyzed
- Expected customer participation rate
- Expected load reduction per participant
- Technical and achievable potential
- Program costs
- Economic assessment of price-based DR
- Treatment of rate design as a resource

<sup>7</sup> See Hledik et al. June 2022. Primary drivers of achievable incremental potential in that timeframe are default TOU rates for all customer classes, managed charging for electric vehicles (EVs), a targeted peak time rebate for event-based DR beyond TOU impacts, and additional behind-the-meter battery programs.

### *Types of DR resources studied*

In general, we find that utilities implicitly or explicitly characterize DR programs as dispatchable or non-dispatchable resources and treat them differently in the IRP modeling process. Utilities generally consider price-based DR as a non-dispatchable resource, even with event-based rates such as CPP or certain forms of CPR. For example, PacifiCorp's longstanding practice is to categorize DR into several classes, ranging from highest to lowest certainty for available firm capacity. Price-based DR is classified in the third tier, and behavioral programs are in the fourth tier, considered the least predictable. Class 1 resources represent direct load control-type programs, which are not price-based, while Class 2 groups energy efficiency programs.

About a third of the utilities studied deem non-dispatchable resources such as price-based DR to be unsuitable to include as a resource in the IRP due to its unpredictability<sup>8</sup> and relatively low volume (i.e., low customer participation rate). Even when analyzed as part of conservation or DR potential studies and with positive benefit-cost ratios, these utilities excluded price-based DR from the planning process, including modeling.

Almost all IRPs studied incorporate some form of direct load control (DLC) or interruptible loads, which are typically deemed as the most predictable type of DR. Space heating and cooling, water heating, and commercial/industrial interruptible loads are the most common DLC programs offered by all the utilities analyzed. Few of the IRPs analyzed mention smart thermostat and smart appliances even though residential DLC programs are increasingly being provided by these technologies. About a third of the IRPs analyzed explicitly mention DSM programs for EVs, but it is unclear whether they are treated as DLC or price-based DR programs. Emerging DLC programs include battery and thermal storage as well as behavioral programs that provide some form of consumption feedback to the customer.

### *Types of time-based rates analyzed in IRPs studied*

The most common types of time-based rates (price-based DR) analyzed across the 12 IRPs we examined are TOU and CPP. Other time-varying rates — VPP, CPR, and RTP — were less commonly analyzed. Table 2 reports the counts of utilities that include each of the five time-varying rates, by customer market segment. All utilities studied offer traditional C&I rates with a mix of time-based charges and demand charges that are included directly in the baseline load forecast.<sup>9</sup>

<sup>8</sup> Predictability concerns seem to relate to short-term or operational scales, given that customer response to price signals can be erratic and uncertain. Our interpretation of the IRPs reviewed for this study is that utilities consider their predictions of customer adoption of price-based DR to be reasonably accurate for long-term planning purposes.

<sup>9</sup> Demand charges for C&I customers likely contribute to resource adequacy by encouraging them to reduce their peak load. But many demand charge rate structures do not consider the utility system peak, and demand charges may be inferior to time-varying rates as a tool for resource adequacy.

**Table 2. Number of utilities that include price-based DR in IRPs studied, by rate type and customer segment**

Customer segment	Rate types				
	TOU	CPP	VPP	CPR	RTP
<b>Residential</b>	6	4	2	0	0
<b>Commercial</b>	5	4	2	0	2
<b>Industrial</b>	5	2	2	0	3
<b>Irrigation</b>	2	0	0	0	0
<b>Undefined segment</b>	3	0	0	0	0

Some utilities clearly distinguish existing vs. new price-based DR in their plans. For utilities that do, existing rates at current enrollment levels are considered part of the base forecast and are treated as peak load reductions in the base forecast. Unfortunately, most utilities do not make the distinction between existing and new price-based DR, which makes it hard to understand whether new customers adopting existing time-varying rates are considered a load reduction to the forecast model or a resource for planning purposes.

Some IRPs report the expected number of annual events that customers may face on a time-varying rate option. For example, Avista reports that it expects up to 80 event-hours per year for its VPP rate. Utilities reporting CPP events per year include Puget Sound Energy (40 events/yr), Public Service Company of Colorado (15 events/yr), DTE (20 events/yr), and Consumers Energy (14 events/yr). The wide variation from 15 to 40 CPP events per year may be the result of caps set by regulators, but may also reflect the utility’s needs based on the shape of its load duration curve.<sup>10</sup>

At least two utilities screen out rates such as CPP and RTP that require advanced metering infrastructure (AMI) to implement time-based pricing and, in the case of RTP and some forms of CPP, reflect the impacts of prices in real-time. One utility explains that these rates’ “pricing mechanism and communication is not well-established in the DR community.” In most cases, utilities that offer sophisticated rates to a wide range of customers can do so in part because their regulator authorized large-scale deployment of AMI in their service territory that allows for granular tracking of electricity consumption. Utilities that do not have widespread AMI deployment can account for the cost of the meter set-up in their benefit-cost screening, in lieu of rejecting price-based DR as a resource option before performing any analysis. This is especially important considering the low relative cost<sup>11</sup> of price-based DR compared to other forms of DR, as we discuss later in this brief.

In addition to the hours and seasons that characterize rates, the price level and the duration of “event” blocks are also fundamental aspects of price-based DR. Customers’ response to rates depends on their own price elasticity, which in turn depends on the actual price levels as well as their relative difference throughout the day<sup>12</sup>. For TOU rates, the duration and timing of on- and off-peak blocks condition customers’ load reductions (DOE, 2016). Utility resource plans we reviewed included little or no explanation of the detailed design of the time-varying rates considered. Disclosing these

<sup>10</sup> A steep load duration curve would require fewer events per year to achieve a reduction in supply-side capacity needs; a flatter curve would require many more events to achieve the same reduction in supply-side capacity needs.

<sup>11</sup> “Cost” in the context of this brief reflects the utility’s perspective in selecting a least-cost portfolio to meet load. It is implicitly assumed that customers who engage in DR have benefits higher than their own individual costs.

<sup>12</sup> For more information about customer price elasticity in retail rates, see Sergici et al. (2020).

assumptions is important to evaluate the reasonableness of other components of price-based DR, including customer adoption rates and load reduction rates (both of which are examined later).

Finally, several IRPs included some form of interruptible rate that compensates customers on an event-by-event basis for load-shedding actions that meet prescribed durations (typically 1 to 4 hours). Similarly, novel bidding mechanisms are available for C&I customers to bid reductions at desired prices. We do not include these rates in our analysis because they are not time-varying, are generally treated as DR programs rather than rates, and their enrollment is far more limited than those reported in Table 2.

### *Expected participation rate*

Eight out of the 12 IRPs studied report assumed participation rates by rate type and customer segment, with varying precision (see Table 3). Utilities generally specify the fraction of customers in each customer class they assume would adopt a given rate. One utility reported the fraction of “eligible load,” corresponding to a subset of customers with certain enabling technologies such as smart thermostats and electric heating equipment. Only one utility reported adoption rates for opt-in and opt-out separately, finding a five-fold increase in customer participation from defaulting residential customers onto the rate compared to an opt-in approach. Another utility explicitly assumed only opt-in mechanisms, but did not examine an opt-out alternative. All remaining utilities did not explicitly indicate whether they were considering opt-in or opt-out mechanisms. Utilities should clearly indicate their assumptions for how customers enroll in the rate and, if they are considering both opt-in and opt-out approaches, present both sets of results to weigh the benefits of expanded adoption and effectiveness (see Fowlie et al., 2021) in light of concerns raised by utility consumer advocates about opt-out rates, particularly for low-income households.<sup>13</sup>

IRP is characterized by scenario analysis to address the uncertain nature of key variables. However, the IRPs analyzed generally assumed customer participation rates are a fixed value. Only one utility considered a low and a high adoption rate in its IRP.

**Table 3. Participation rate by customer class and rate type for all reporting utilities**

Utility ID	Res-TOU	Res-CPP	Res-VPP	C&I-TOU	C&I-CPP	C&I-RTP
1	13% opt-in; 74% opt-out	-	25%	13% opt-in; 74% opt-out	-	-
2	-	15% eligible load	-	10% eligible load	-	-
3	28% opt-in	17% opt-in	-	13% opt-in	18% opt-in	3-5% opt-in
4	-	-	-	-	~10% (ind)	-
5	30% (low); 75% (high)	-	7% (low); 24% (high)	10% (low); 22% (high)	-	5% (low); 10% (high)
6	27%	-	-	14% (comm); 22% (ind)	-	-
7	~70%	-	-	-	-	-
8	36%-64%	-	-	-	23%-50%	-

*Note: The utility IDs do not correspond to the same utility in each of the tables.*

<sup>13</sup> "While opt-out programs may result in greater participation numbers, opt-in programs for low-income consumers would be more protective by allowing each family to assess whether they can shift a significant amount of electrical load and whether it makes financial sense for the household to try a time-varying rate structure." John Howat and Jennifer Bosco, National Consumer Law Center, in [Advancing Equity in Utility Regulation](#), Future Electric Utility Regulation Report No. 12, 2021. Also see Cappers, et al., 2016, and Sergici et al., 2020.



Expected penetration levels differed substantially across the IRPs studied. TOU rates offer the best comparison, as they are the most common rate considered. Expected residential TOU participation rates ranged from 13% to 75%, while C&I participation rates ranged from 10% to 74%. Despite the wide range, participation rates assumed by most utilities clustered on the lower or higher side. The lack of diversity in values considered within each IRP suggests that there is remarkably similar experience across the country, or that utilities are relying on few actual data points that propagate across IRPs and supplementary DR studies. Utilities that are part of larger holding companies with other utility subsidiaries generally indicate that their participation rate values come from shared experience across these firms. In other cases, data sources for assumed participation rates are not provided.

Utilities in our sample that disclosed their assumed enrollment rates by recruitment strategy reported a 3%–30% range for opt-in recruitment. Only one utility reported its assumed enrollment rate for opt-out recruitment, at 74%. Based on this observation, for utilities that did not disclose a recruitment strategy, we assume the low values reported represent opt-in recruitment and high values represent opt-out recruitment.

We compare these enrollment rates with those reported in the literature. A 2016 DOE-sponsored study that analyzed residential customer adoption of time-based rates for 10 utilities found that the TOU adoption rate was highly contingent on whether customers were “defaulted” into the rate (DOE, 2016). The enrollment rate under such opt-out recruitment was 92%, compared to 15% for opt-in recruitment. Todd et al. (2013) reported similar TOU adoption rate values for a sample of 10 utilities — 84% enrollment for opt-out approach compared to 11% for opt-in recruitment. These enrollment values were consistent across different types of time-based rates. A study by the Brattle Group (Faruqui et al. 2014) determined comparable TOU enrollment rates — an average 85% for opt-out recruitment compared to 28% for opt-in recruitment, as well as similar results across various dynamic price options including CPP, VPP, and RTP. Compared to these three studies, the residential enrollment rates reported in our IRP sample were relatively similar for opt-in recruitment and slightly lower for opt-out recruitment.

A methodological challenge in estimating and reporting expected participation rates is how to account for the dependence across rates for a given customer segment. For example, for the purpose of analysis, a C&I customer may be deemed a TOU, CPP, and RTP potential participant, but cannot adopt all three rates at the same time. Most studies do state that their participation rates are mutually exclusive and do not account for interactions, but make ad hoc corrections when formulating portfolios for technical and achievable potential.

### *Expected load reduction per participant*

Another key component to estimate price-based DR potential is an estimate of the load reduction per participant. Table 4 shows the numerical values used by the seven utilities that reported them. Two utilities report summer- and winter-specific values. One of them is a dual-season peaking utility; the other is a summer-peaking utility that expects the peak load season to shift to winter-peaking during the analysis period.

One utility reports load reduction differentiated by opt-in and opt-out mechanisms, with opt-in mechanisms achieving load reduction levels about 80%-90% higher for residential customers and about 10% higher load reductions for C&I customers, compared to opt-out customers. This utility does not report whether these differences are supported by empirical evidence, but it does indicate

that opt-in customers may have greater economic incentive and be more committed to achieve load reductions than opt-out customers do.<sup>14</sup> One utility conditioned its load reduction values on the use of enabling technologies. Specifically, the utility expected a lower load reduction for customers that do not use a smart thermostat that can be controlled by the utility following a price signal<sup>15</sup>. The utility's control of this device increased expected reductions three-fold for residential customers and 50% for C&I customers.

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<sup>14</sup> Cappers et al. (2022) found that customers most likely to save with price-based DR ("structural winners") with limited demand flexibility have poor enrollment rates but are among the best performers and are the most cost-effective to pursue. Conversely, households with limited flexibility and high enrollment rates do not perform that well.

<sup>15</sup> This is consistent with prior studies of customer response to time-varying rates (DOE, 2016).

**Table 4. Expected load reduction per participant by rate and customer class**

Utility ID	Res-TOU	Res-CPP	Res-VPP	C&I-TOU	C&I-CPP	C&I-RTP
1	4.6% summer; 1% winter					
2	5.7% (opt-in summer); 3.4% (opt-out summer)		10% (summer)	3.1% (opt-in); 2.6% (opt-out)		
3		12% no DLC; 40% with DLC			5% no DLC; 7% with DLC	
4	5.7% summer; 2.9% winter	12.5% summer; 7.5% winter		~3% summer; ~1.5% winter	~7% summer; ~4% winter	~7% summer; ~4% winter
5					20%	
6	12%		10%	5%	20%	13%
7	4% (low); 5.3% (high)					
8		9%			11%	

Expected reductions are consistent across utilities. Residential TOU reductions generally range from 1% to 6%, with one IRP expecting a 12% reduction. C&I TOU reductions are in a similar range: 1.5% to 5%. VPP, CPP, and RTP yield higher load reductions than TOU rates (if they do not include DLC technologies), with one utility expecting up to 20% reduction from C&I CPP.

For most of the IRPs analyzed, utilities inexplicably derated load reductions from price-based DR when determining the impact on the utility's peak demand. One possible explanation is that the load reductions reported by the utilities are not coincident with their system peak demand, but with a territory-wide peak (e.g., system peak for the regional grid operator). Using a supply-side analogy, the DR load reductions are akin to a nameplate capacity rather than a firm capacity. Two utilities that reported differentiated summer and winter load reductions seemed to have estimated the actual capacity contribution of the price-based DR. However, in most cases it is unclear whether the load reductions from price-based DR included in the plan were coincident with utility system peak demand. More generally, it is unclear how assumptions of price-based DR load reductions are incorporated into resource adequacy constructs used in IRP.

As with expected customer participation rates, there is scant information on sources for the expected load reduction values reported by the utilities. In many cases, values are proposed by consultants that develop DR potential studies. They may be using proprietary information collected from other clients that cannot be disclosed. Substantiation of values used is an important area for improvement, especially using empirical analysis of pilot programs, or ideally from full-scale rate deployment.

#### *Technical and achievable potential*

With participation rates and load reduction estimates, utilities calculate the potential of time-varying rates to reduce load as non-dispatchable DR programs. In general, utilities report two potential calculations: technical and achievable. *Technical potential* multiplies expected participation rates and load reduction per participant. *Achievable potential* (sometimes also called *realistic potential*) is typically a qualitative de-rating of the technical potential to recognize the fraction of technical potential that can realistically be acquired during the IRP's study horizon. Among other reasons, these derates recognize the time it takes for price-based DR to ramp up, particularly for new

programs, to begin achieving load reductions as forecasted. Achievable potential does not depend on economic considerations — it does not consider customer acquisition costs or any fixed costs such as utility billing system improvements or AMI.

Potential is reported by utilities in capacity units, typically MW. That makes comparisons more challenging than participation and load reduction rates, which are expressed in percent. We use peak load forecasts reported in the IRPs to normalize reported achievable potential values.<sup>16</sup> When reported by customer segment, we aggregate them into a single value by rate type because most load forecasts are reported in aggregate. Table 5 shows the outcome of this normalization. We find wide variation in the achievable potential across utilities, ranging from low values of 0.1% to 0.25% for all rate types to high values of 3.8% for TOU and 6.6% for VPP. The higher end of these ranges correlates with utilities that reported high customer participation rates. Otherwise, there is not a clear explanation for the up to 20-fold variation in achievable potential across utilities or across similarly structured rates such as VPP and RTP.

**Table 5. Achievable potential normalized as a fraction of peak load, by rate type**

Rate type	Potential range (%)
<b>TOU</b>	Opt-in: 0.25%-3.8% Opt-out: 1%
<b>CPP</b>	0.2%-1%
<b>VPP</b>	0.25%-6.6%
<b>RTP</b>	0.1%

The calculation and reporting of general DR potential could be improved in the following ways:

- *Calculate potential by season, customer segment, rate type, and both opt-in and opt-out mechanisms.* In some cases, two scenarios reflecting different underlying participation or load reduction rates, or both, may be warranted to reflect particularly high uncertainty in these variables.
- *Report potential on a maximum annual basis, in addition to total value.* The maximum annual basis would reflect assumptions on adoption and customer acquisition dynamics that would affect how much price-based DR is available for a utility each year.
- *Do not constrain potential to meet any type of regulatory mandate.* After calculating and reporting potential, the utility may indicate that a fraction of the potential will be tapped to comply with any programmatic requirement. The utility should acquire more DR than required if it is cost-effective to do so.
- *Use empirical data to improve accuracy of potential estimates:* Consider more accurate ways to assess DR potential that use granular customer-level real-time data (see e.g. Glass et al. (2021)).

<sup>16</sup> Most utilities report only achievable potential and do not report technical potential, as well. Hence, we cannot perform this calculation on the technical potential.

### Implementation costs and economic assessment of rates

We group together these two components in part because they complement each other, but also because six out of the 12 IRPs analyzed do not report costs to implement price-based DR. One of these non-reporting utilities screened out price-based DR early in its process (although the utility quantified participation and load reduction rates).

The remaining six IRPs included the following cost components. Costs are deemed “variable” or “fixed” depending on whether they change with the number of customers.

- Variable costs:
  - Operation and maintenance and metering equipment
  - Participant marketing and recruitment
- Fixed costs:
  - One time - price-based DR development and setup
  - Ongoing - administrative costs

Table 6 reports variable and fixed cost assumptions for price-based DR implementation by rate type (TOU vs. other time-varying rates) and utility. In general, no utility assessed equipment costs. The assumption seems to be that AMI to implement time-varying rates already is, or will be, in place. Variable costs are expressed on a per participant basis, with one noted exception, where costs are reported on a per-megawatt basis.

In general, reported implementation costs are in the tens to hundreds of thousand dollars and do not vary much across rates. Customer acquisition costs are relatively small — \$25 to \$175 per customer — with the higher range of values corresponding to C&I customers that require customized strategies for enrollment. The varied cost structure for each utility-rate combination points toward the value of standardization of reporting program costs across utilities.<sup>17</sup>

**Table 6. Per participant program costs for reporting utilities: TOU vs. other time-varying rates**

Utility ID	Subtype*	TOU			VPP/CPP/RTP		
		Fixed - Initial	Fixed - Ongoing	Variable	Fixed - Initial	Fixed - Ongoing	Variable
1	State 1	\$12k	-	\$57.50	\$12k	-	\$175
1	State 2	\$6k	-	\$69			
2	Res				\$150k	\$75k	\$25
2	Com				\$150k	\$75k	\$50
3	-				\$235k		-
4	-	\$150k	\$250k	-	\$150k	\$250k	-
5	-		\$100k	\$5/MW			
6	Res				\$100k	-	\$30
6	Com				\$100k	-	\$30

\* “Subtype” identifies sets of alternate results reported by a utility — in this case, by state or customer segment.

<sup>17</sup> Berkeley Lab has provided templates for standardization of reporting costs for energy efficiency programs. See Rybka et al. (2015) and Hoffman et al. (2016).

Utilities use these implementation costs to determine a levelized cost of capacity (LCOC) that encapsulates fixed and variable costs and achievable potential into a single \$/kW-year value. This value is typically compared with the cost of other DR options, and in some cases to the cost of new entry (CONE),<sup>18</sup> to determine cost-effectiveness of price-based DR. In some cases, utilities calculate a net LCOC that internalizes system-level benefits of price-based DR (e.g., reducing the cost of system flexibility), resulting in some negative values for net LCOC.

Table 7 reports the LCOC for price-based DR. Values for TOU rates range from \$7/kW-year to \$100/kW-year, with the latter being close to the CONE in most areas in the country.<sup>19</sup> This indicates that even the high end of the TOU cost range is most likely cost-effective compared to deploying new generation capacity — especially since CONE does not reflect the incremental cost of transmission. The high-end values are driven by customer marketing and acquisition costs. Unfortunately, the IRPs we studied provided no detail on what these costs entail and why some utilities assume values substantially higher than others do. We compared the LCOC across utilities and rates and determined that load reduction assumptions are the main driver for LCOC. Higher load reduction assumptions typically result in lower costs. Low implementation costs also drive LCOC down.

**Table 7. Levelized cost of capacity by customer class and rate**

Utility ID	Res-TOU	C&I-TOU	Res-CPP	C&I-CPP	Res-VPP	C&I-RTP
1	\$80-\$100/kW-yr				\$33-\$59/kW-yr	
2			-\$3 to -\$8/kW-yr	\$81-\$86/kW-yr		
3				\$22/kW-yr		
4	\$16/kW-yr				\$10/kW-yr	\$8/kW-yr
5	\$7/kW-yr	\$14-\$18/kW-yr				
6	\$14-\$36/kW-yr	\$6-\$8/kW-yr				
7				\$71/kW-yr		

Utility-reported LCOC reveal that no particular rate type has a consistently lower cost compared to others. In Table 7, some TOU, CPP, VPP, and RTP alternatives fall in the relatively narrow -\$3 to \$10/kW-year range.

### *Treatment of price-based DR as a resource in IRP*

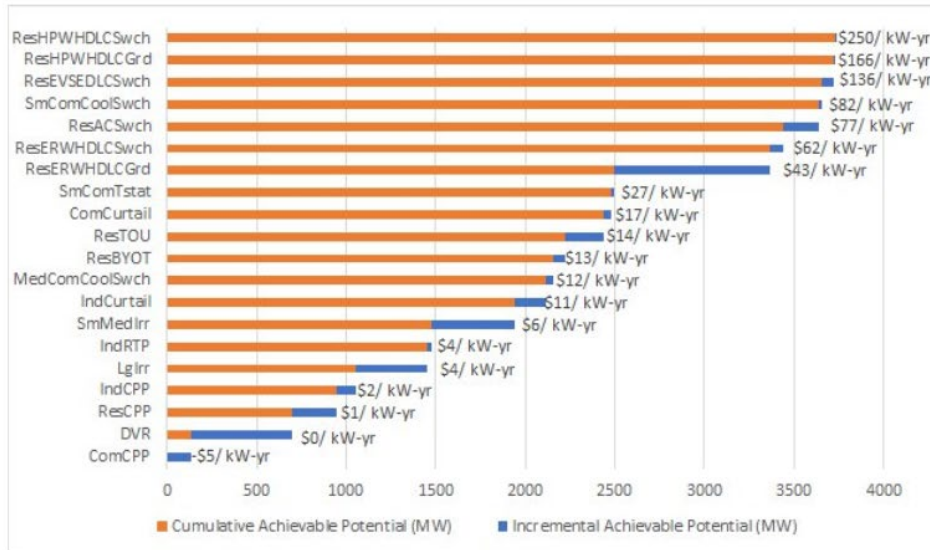
The last component of our analysis reviews how the achievable potential and costs of price-based DR are considered in the IRP analysis process to include this resource in portfolios tested and in the selection of the utility's preferred portfolio. Principles to effectively integrate price-based DR in resource portfolios rely on the concept of a supply curve. When applied to demand response, a supply curve represents the quantity of load reduction that can be obtained at a given cost, in the

<sup>18</sup> The CONE typically reflects the annualized cost of constructing a new power plant. CONE calculations are usually based on a gas combustion turbine. CONE is most commonly used by RTO and ISO that need a reference cost for generation capacity but that do not conduct a generation planning process.

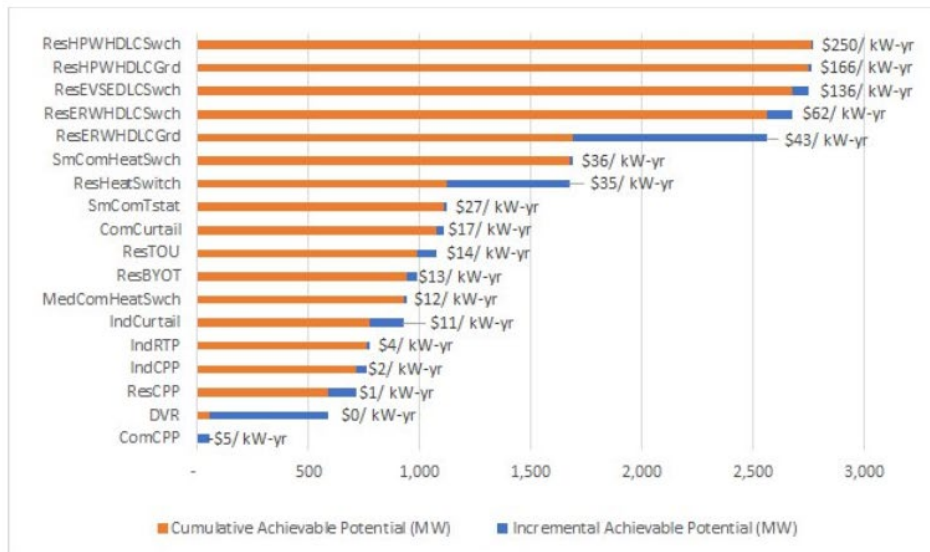
<sup>19</sup> For example, [MISO](#)'s most recent CONE is between \$93 and \$109 per kW-year; [PJM](#)'s is \$183/kW-year, [WPP](#)'s is \$92/kW-year, and [NYISO](#)'s is between \$110 and \$195 per kW-year.

form of DR measures or groups of DR measures with similar characteristics. Figure 2 shows supply curves produced by the NWPC for its 2021 Power Plan. The width of the orange bars represents the cumulative quantity of price-based DR reflected in the curve. To the right of each bar is the price of the incremental offer available or cost of the program. The y-axis shows the DR offer by customer segment analyzed, including a mix of price-based and non-priced-based DR.

**Demand Response Achievable Technical Potential in 2041 with Net Levelized Cost - Summer**



**Demand Response Achievable Technical Potential in 2041 with Net Levelized Cost - Winter**



**Figure 2. Summer and winter supply curve for price-based and non-priced-based DR resources (NWPC 2021).**

A capacity expansion model would traverse the curve, moving from one rate-customer segment "bundle" to the next. The model determines whether the cost of each bundle is below the current capacity cost based on all available resources — supply and demand side. The model selects price-based DR with costs lower than the most expensive supply-side capacity resource selected.

The way price-based DR is considered in the portfolio analysis in IRP reports reviewed is hard to track at best and unclear in general. Despite the highly detailed characterization and evaluation processes for price-based DR described earlier in this brief, utilities inexplicably screened, down-selected, aggregated, or omitted these values in developing their preferred portfolio. Following are examples of common shortcomings in current IRP practices:

- *Lack of transparency in type of DR adopted.* It is unclear how much of the aggregate DR resource incorporated in the preferred portfolio is price-based versus the other types of DR. Without such disaggregation, we cannot confirm how much DR from the potential study the utility adopted in the preferred portfolio.
- *Rationale for level of DR adopted.* It is generally not clear whether adopted levels of DR are the result of optimization in the capacity expansion model, a pre-determined capacity level that the utility deemed economical, or simply fulfilling a regulatory mandate.
- *Treating DR as a load reduction.* In several IRPs reviewed, DR is treated as a load reduction, instead of a resource option the capacity expansion model can select, on a par with treatment of other resource options. When DR is treated as a load reduction, its costs are not directly compared against other resources, which means they will be under-procured given the cost-effectiveness of these resources.<sup>20</sup>
- *Lack of transparency in DR supply curves.* Three of the IRPs reviewed develop a supply curve for price-based and non-price-based DR, but it is unclear if each step in the curve corresponds to a single DR option or multiple DR options with similar cost. It also is unclear whether the analysis assumed diversity in customer adoption and load reduction rates for price-based DR, such that there are multiple entries in the supply curve for a given rate.
- *Low capacity assigned to DR, and amount of DR selected, is unsupported.* In some cases, the firm capacity of price-based DR, as determined in the utilities' technical and achievable potential studies, is inexplicably derated when including the resource in the preferred portfolio. In other cases, the final amount of DR adopted does not comport with the achievable potential identified in the supplementary study, with no explanation for the final value incorporated in any resource portfolio.

Drawing on the IRPs reviewed, prior research, and our own experience, we recommend that best-practice treatment of price-based DR in creating resource portfolios for analysis and selecting the preferred portfolio follow these five principles:

1. Price-based DR should be treated as a resource by creating supply curves with a diverse set of rate options, and not as load reduction in the load forecast used in the capacity expansion model.
2. The cost of price-based DR options should be refined to produce a smooth, positive-sloped supply curve that reflects load reduction and customer participation rates, as well as achievable potential and costs, across customer segments and subsegments (e.g., low vs. high

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<sup>20</sup> This same issue arises with energy efficiency resources. A report by Frick et al. (2021) explains the solution: "Efficiency supply curves are included as resource options that can be selected by the capacity expansion model for development, and not as exogenous reductions to load forecast inputs for long-term capacity expansion models."



income customers, or certain businesses within C&I that would adopt time-varying rate options earlier than other businesses).

3. When building DR supply curves and not explicitly modeling transmission expansion, utilities should recognize that these resources might defer transmission capacity. Ideally, utilities will model generation and transmission expansion that endogenously internalizes the transmission capacity deferral benefits of DR in the model outcome.
4. Utility regulators should make clear that any mandates for DR acquisition are lower bounds for resource planning. Utilities should build supply curves unrestricted by these mandates, apply the mandate as a lower bound constraint in the capacity expansion model, and procure as much cost-effective DR as possible.
5. Like other resources, many aspects of price-based DR are uncertain. Scenario and stochastic analysis are effective tools to assess the firm capacity and cost of price-based DR.

### *Recommendations for incorporating price-based DR in IRP*

This section reiterates and summarizes our recommendations above for incorporating price-based DR in IRP, based on our analysis for this study.

Component	Recommendation
<b>Types of DR</b>	We recommend that IRPs do not screen out price-based DR options due to "unpredictability," which may be no greater than for hourly loads and variable energy resources like wind and solar. At the very least, the utility should demonstrate that the predictability of price-based DR is indeed lower than that of other types of resources, and that mitigating the predictability is infeasible or too costly. Further, utility experience with price-based DR has demonstrated reliable load reductions and cost-effectiveness (Faruqui and Sergici, 2013).
	Evaluate time-varying pricing for EV charging to help meet projected load growth due to electrification.
<b>Types of rates</b>	We recommend that utilities develop a study to understand how customers on existing time-varying rates may reduce or shift their loads with enabling technologies and incorporate these technologies as part of the price-based DR options for IRP modeling. Participation levels and load reductions associated with existing time-varying rates may be increased with new enabling technologies, but existing time-varying rates generally are excluded from DR potential studies as they are deemed part of the base forecast.
	We recommend that IRPs are transparent about their assumptions for customers switching to an existing time-varying rate or to a new time-varying rate. It is not clear how customers that may transition from an existing time-varying rate to a new rate are treated. We do not find any evidence that utilities assume customers may, for example, leave a TOU rate for a CPP or RTP rate.
	Assumptions of rates that may be adopted by customer class remain conservative. For residential customers, options considered in IRPs are almost exclusively TOU and CPP rates. RTP remains a fringe rate, even for C&I, despite its high potential (Faruqui and Sergici, 2013). We recommend exploring a wider range of rates, characterizing their potential DR contribution in the IRP process.
	IRPs should consider rates with effective price differentials or at the very least explicitly report the rate design assumptions behind their price-based DR offers. The structure and price levels of rates are rarely discussed in DR potential studies and IRP reports. However, experience shows the effectiveness of time-varying rates depends substantially on the price differentials across on- and off-peak periods.
<b>Participation rate</b>	The IRP analysis should estimate participation rates for both opt-in and opt-out versions of price-based DR. Opt-out mechanisms may achieve significantly larger impact, but regulators should consider appropriate consumer protections.

<b>Participation rate</b>	<p>When calculating technical vs. achievable potential, some utilities use different participation rates than identified in the DSM study that supports the IRP. Participation rates should be consistently applied and any deviations explained. In addition, participation rates should be identified separately as short- and long-term. Short-term participation rates should be used to inform realistic annual acquisition rates. Long-term participation rates should reveal the likely pool of customers that may adopt the rate and its ultimate technical potential.</p>
<b>Load reduction rate</b>	<p>IRP should clearly report available empirical data from the utility's own rate pilots or full deployments or from experiences of other applicable utilities to inform load reduction rates.</p> <p>Apply the load reduction rate as a probability distribution rather than a deterministic value to recognize that load reduction varies across customers within a customer segment. This method produces more realistic estimates for load reduction potential and informs a distribution of costs that integrates better into a supply curve approach for resource selection.</p> <p>Use a load reduction rate that is consistent with the capacity credit for DR, by customer segment and rate type. At a minimum, determine price-based DR load reductions based on the utility system peak demand or top load hours and apply the appropriate level of technical potential to capacity accreditation. A best practice developed by one utility in our sample was to estimate the effective load carrying capability (ELCC) of each DR bundle to determine the capacity contribution of price-based DR.</p>
<b>Potential</b>	<p>Clearly distinguish between standalone and integrated potential. Standalone is the potential of one rate type should all customers adopt that rate. In reality, customers can be served by only one rate, so utilities need to determine a realistic integrated portfolio of rates that reflect customer choices among the various rate options, without double-counting.</p> <p>Refrain from screening price-based DR — and DR solutions more generally — using traditional cost-effectiveness screening tests. IRP is a process to determine least-cost/least-risk solutions. As such, it does not subject any supply-side resource to a cost-effectiveness test, as cost-effectiveness is an output of the process. Demand-side resources, including price-based DR, should be treated similarly, adjusting technical potential for reasonable assumptions without a screening process that constrains the consideration of DR resources.</p> <p>Avoid rejecting price-based DR as a resource option before performing any analysis. Utilities that do not have widespread AMI deployment can account for the cost of the meter set-up in their benefit-cost screening — if they continue to apply that framework.</p> <p>Clearly report the assumptions and methods utilized to estimate achievable potential from technical potential.</p>
<b>Implementation costs</b>	<p>Use a standard cost structure categorized as initial fixed costs, ongoing fixed costs, and variable per customer costs. Explain clearly the assumptions for each cost component.</p>
<b>Treatment in portfolio process</b>	<p>Price-based DR, and more generally all DR, should be treated on a par with other resources in the portfolio identification process rather than as reductions to the load forecast.</p> <p>DR costs should be refined to produce a smooth, positive-sloped supply curve that reflects load reduction and participation rates, as well as achievable potential and costs, across customer segments and subsegments.</p> <p>Regulators should make clear that any mandates for DR acquisition are lower bounds for analysis, and that utilities should procure as much cost-effective DR as possible.</p> <p>When building supply curves for DR, utilities should account for potential deferral of transmission capacity — for example, by including transmission expansion as a resource in the capacity expansion model.</p> <p>Utilities should use scenario or stochastic analysis to assess the firm capacity and cost of price-based DR.</p>

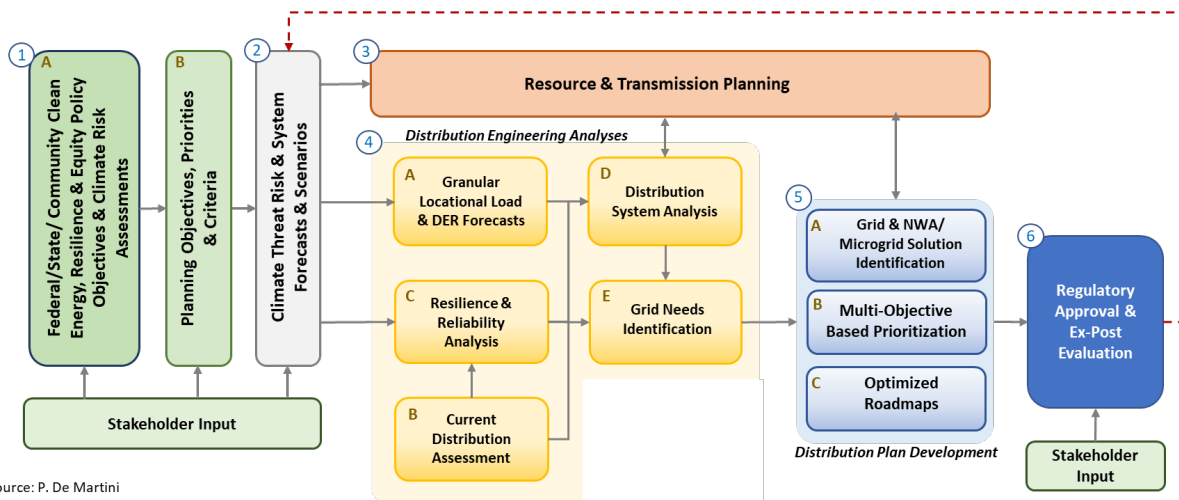
## Incorporating price-based DR in DSP: Current practice and recommendations

Price-based DR for bulk power systems has the potential to reduce capacity upgrade needs for distribution systems, but IRPs typically do not quantify these benefits. Some jurisdictions are working toward better integration of planning for bulk power and distribution systems.<sup>21</sup> In the meantime, any consideration in electricity planning processes of the *locational value* of price-based DR — its value at specific points on the electricity system to help meet distribution system needs — takes place in DSPs.

While utilities have filed IRPs for decades, states only recently began requiring regulated utilities to file DSPs.<sup>22</sup> Filing requirements in many of these jurisdictions require an assessment of the locational value of DERs, including California, Colorado, Delaware, District of Columbia, Hawaii, Maine, Michigan, Minnesota, Nevada, New York, and Rhode Island.<sup>23</sup> How utilities estimate locational value, and how they procure DERs to meet distribution system needs, vary based on regulatory requirements and implementation practices.

The remainder of this brief addresses ways that utilities can incorporate price-based DR in planning for local grids. Specifically, price-based DR should be considered as a potential cost-effective non-wires alternative (NWA) to traditional utility distribution investments that meet suitability criteria for distribution project type, cost, and timeline. To date, most states have considered NWA in the context of third party-owned DERs. But utility-owned NWA — whether a large storage system or time-based pricing tariff — are just as important to evaluate.

Figure 3 illustrates an integrated DSP framework. Identification of NWA solutions occurs in step 5, following grid needs identification. NWA can be procured through pricing, programs, and procurements, including price-based DR tariffs.



Source: P. De Martini

**Figure 3. Integrated distribution system planning framework.** [Integrated Resilient Distribution Planning](#), prepared for U.S. Department of Energy, 2022.

The bulk power system benefits from broader load and resource diversity and interconnectedness than distribution systems. As a result, certainty of load response to pricing is more critical for

<sup>21</sup> See [NARUC-NASEO Task Force on Comprehensive Electricity System Planning](#).

<sup>22</sup> Homer et al. 2017; Cooke et al. 2018; Schwartz and Frick 2022.

<sup>23</sup> Frick et al. 2021; Schwartz and Frick 2022.

distribution systems. Some types of DR programs, like direct load control, may provide more certainty to the utility. However, many programs have override provisions.<sup>24</sup> As with evaluation of price-based DR in IRP, utility distribution planning can address uncertainty in load response by targeting more customers and expected load reduction than needed to defer a specified distribution upgrade, as part of a portfolio of different types of NWAs. Utilities can adjust over time their assumptions for load response to price-based DR, based on experience, or even systematically study customer-level responses to price-based events to bundle reliable-response customers into highly graded DR portfolios with higher payments.

### *Considering the locational value of DR*

Both traditional DR programs and price-based DR can help meet a variety of distribution system needs — including load relief, voltage regulation, and resilience — if DR is geographically targeted.

The potential value of DR at a specific location on the distribution system is determined by its capability to provide needed grid services at that location and the potential costs DR can avoid, compared to the traditional distribution investment the utility would otherwise make.

The primary location-specific benefit is deferral value. That value is tied to DR operating at specific times and at specific locations where there is a risk that distribution capacity is insufficient to meet expected future needs.<sup>25</sup>

In a future with load-growth driven investments in the distribution system for electrification, and increasing hosting capacity needs<sup>26</sup> for distributed generation, accurately valuing all potential distribution system solutions — including both price-based DR and traditional DR programs — is increasingly important for informed decision-making. Utilities can target load management approaches to reduce distribution capacity needs for new loads and better integrate and optimize distributed generation and EV charging, reducing localized strains on the grid. Siting challenges are another driver for considering the locational value of DR. In some cases, it may be difficult to site traditional grid solutions such as new distribution substations. Geotargeting DR, in combination with other DERs, may be a faster and less costly solution.

### *Pricing pilots and tariffs with location-based price signals*

Most distribution system pricing pilots, focused on meeting local grid needs, are technology tests to assess sending prices to devices already in place. They do not determine whether distribution-level pricing encourages customers to adopt price-responsive DR, make related investments in enabling technologies, and successfully contribute to deferrals of distribution system upgrades. For example:

- Southern California Edison's Flexible Pricing Rate Pilot<sup>27</sup> is testing time-differentiated price signals that combine real-time energy market prices, generation capacity needs, and costs and capacity needs for distribution and transmission. The pilot tests the capability of devices to shift electricity to times of day when costs are lower. The dynamic rate is a reflection of

<sup>24</sup> Examples include overrides for residential direct load control programs as well as large customers failing to perform according to agreed-upon tariff provisions for interruptible tariffs. Such tariffs offer lower electricity rates in exchange for agreeing to be interrupted during certain reliability events.

<sup>25</sup> DR that avoids distribution system losses when and where they are highest also reduce transmission system losses and generation capacity needs.

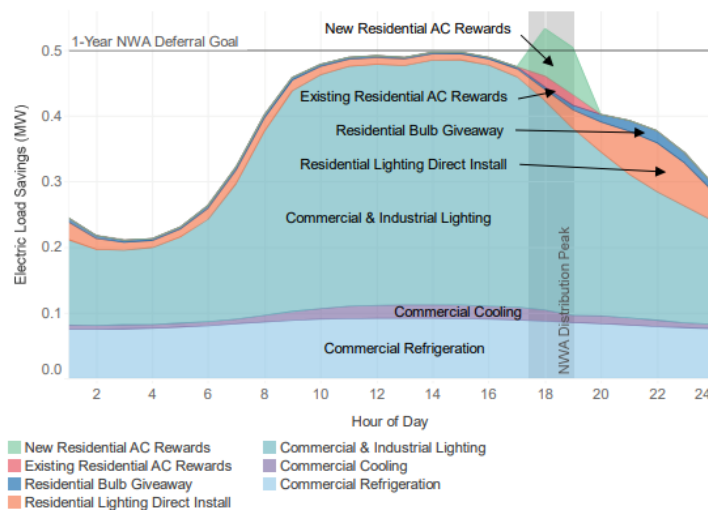
<sup>26</sup> Hosting capacity is the amount of DERs that can be interconnected without adversely impacting power quality or reliability under existing control and protection systems and without infrastructure upgrades.

<sup>27</sup> See <https://www.dret-ca.com/dynamic-rate-pilot/>

local grid conditions. Customers can buy or sell energy to better meet their operational needs considering these conditions.

- San Diego Gas & Electric's Vehicle Grid Integration rate applies to the utility's more than 2,500 Level 2 charging ports at workplaces and multi-family dwellings. The rate is a dynamic, hourly charge that includes a distribution capacity adder for the top 200 hours of distribution circuit loads, with those hours varying by feeder.<sup>28</sup>

Pilots can go beyond prices-to-devices experiments to provide utilities direct experience with DR as a NWA, fine-tuning approaches before full-scale NWA deployment. For example, in Minnesota the Center for Energy and the Environment worked with Xcel Energy to test whether geotargeted DR and energy efficiency programs could defer specific planned investments in the distribution grid (Figure 4). Geotargeting existing energy efficiency and load management programs reduced peak demand by 500 kilowatts to defer an estimated \$4.1 million in distribution system capacity upgrades. These pilots provide insights into customers' interaction with price-based DR and may influence the design of NWA processes in DSP in the future.



**Figure 4. Minnesota pilot testing energy efficiency and DR programs to defer distribution upgrades (Center for Energy Efficiency 2021).**

Some pilots are addressing compensation methods. For example, New York is testing granular location- and time-based compensation for DERs that use automated controls to optimize value for customers and utility systems. Smart home devices provided to pilot participants enable reductions in demand during locally constrained times to reduce peak load on distribution systems. For example, a residential rate under Consolidated Edison's Smart Home Rate Demonstration Project<sup>29</sup> used a daily demand charge and critical peak event charges. The utility declared critical peak events at different system levels — generation, transmission, and distribution.

<sup>28</sup> Pricing also reflects distribution sunk costs, CAISO day-ahead hourly market prices, and an adder for system capacity for the top 150 system load hours.

<sup>29</sup> See Smart Home Rate [here](#) and updated implementation plan [here](#). The utility plans to file a final report on the project by October 31, 2023.

New York's Value Stack tariff<sup>30</sup> provides an example of a rate structure that provides compensation based on the value DERs provide to the utility system. For distribution rate components, each utility uses its annual marginal cost of service study to define two load reduction values: one that is location-specific, and another that is not. The Demand Reduction Value represents subtransmission and distribution costs that the utility avoids as a result of the DER.<sup>31</sup> A higher Locational System Relief Value is available in utility-identified locations where distribution investment needs can be addressed by DERs. Compensation for this additional value targets highly constrained areas which would very likely require distribution system upgrades or other new investments in the absence of increased capacity contributions from DERs.

Portland General Electric's (PGE's) Smart Grid Test Bed<sup>32</sup> tariff explicitly tested price-based DR as a NWA. Beginning in April 2019, PGE began testing a Peak Time Rebate (PTR) to defer infrastructure upgrades for three distribution substation service areas. Participants receive a credit on their next monthly bill of \$1 per kilowatt-hour for reducing electrical demand during two- to five-hour events the utility calls in winter and summer, by shifting energy consumption to non-peak periods or by conserving energy. The utility calculates savings by comparing participants' metered consumption during events to an estimate of their baseline consumption. PTR in the Test Bed area reduced peak demand about 4% in summer and 3% in winter.<sup>33</sup> PGE used an opt-out strategy to target this geographic area. The tariff is now available throughout the utility's service area on an opt-in basis.<sup>34</sup>

The second phase of the Smart Grid Test Bed began in January 2023. It includes an EV charging study in a portion of PGE's service territory. The study uses location-based price signals to achieve load shifting or load reduction goals for a specific feeder or geographic area. Participants receive a one-time enrollment incentive, bill credits twice a year, and monthly incentives through December 2024 for allowing the utility to pause EV charging during times of high demand.<sup>35</sup>

### *Considering price-based DR in distribution system plans*

Price-based DR is typically not addressed in utility DSPs, at least in part for the same reason it usually receives cursory consideration in IRPs. Many utilities lack sufficient experience with time-based rates to be willing to count on it to reduce peak demand. That is particularly an issue for distribution system engineers, who must plan to serve demand at all times and locations, and for all distribution system components. While energy to meet bulk power system needs can be purchased in the market even during the top peak hours of the year,<sup>36</sup> albeit at high prices, utilities must rely on utility assets or customer DERs connected to local grids to meet distribution system needs.

<sup>30</sup> See <https://www.nysedra.ny.gov/All-Programs/Programs/NY-Sun/Contractors/Value-of-Distributed-Energy-Resources>.

<sup>31</sup> In practice, some utilities quantify the costs of incremental transmission and distribution capacity instead of the demand reduction value.

<sup>32</sup> See <https://portlandgeneral.com/about/who-we-are/innovative-energy/smart-grid-test-bed>. Also see Cadmus. 2022. Final Evaluation of PGE's Demand Response Testbed Project. <https://edocs.puc.state.or.us/efdocs/HAD/um1976had9321.pdf>.

<sup>33</sup> See Cadmus 2022. Flex 2.0 Demand Response Pilot Program Impact Evaluation Report. Prepared for Portland General Electric. <https://edocs.puc.state.or.us/efdocs/HAD/um2141had94018.pdf>.

<sup>34</sup> See Portland General Electric Schedule 7: <https://portlandgeneral.com/about/info/rates-and-regulatory/tariff>. Participants make no performance commitment and incur no penalties for energy use above baseline consumption.

<sup>35</sup> See Portland General Electric Schedule 13: <https://portlandgeneral.com/about/info/rates-and-regulatory/tariff>; also see <https://portlandgeneral.com/smart-grid-test-bed-ev-charging-study>. In addition, the second phase of the Smart Grid Test Bed is studying the value of controls on customer-owned smart inverters for Volt/VAR support, increasing distribution hosting capacity for solar PV, and minimizing grid export for distributed solar and storage systems. PGE will recruit customers with qualifying equipment by offering an upfront incentive in addition to an ongoing monthly incentive for continued enrollment throughout the project duration.

<sup>36</sup> Through bilateral transactions or centrally organized wholesale electricity markets.

To the extent utilities have considered price-based DR in DSP, to date it has been addressed in load forecasting, pilots, and NWA analysis.

*Load forecasting.* Utilities can consider the impacts of price-based DR on future loads, both at the system level and the substation circuit level. For example, for the Grid Needs Assessment that is part of the distribution planning process in California, Southern California Edison (SCE) disaggregates "Load-modifying DR" — defined as CPP — at the system level to develop circuit-level forecasts. The utility also estimates circuit-level hourly impacts of TOU rates that shift some energy use to off-peak hours.<sup>37</sup>

Hawaiian Electric's 2023 Integrated Grid Plan<sup>38</sup> evaluates the impact of three residential TOU forecasts (Table 8) on a range of modeling scenarios.<sup>39</sup> The utility used proposed TOU rates from a DER proceeding<sup>40</sup> to develop these forecasts. The TOU rates in the "High" TOU forecast most closely align with the rates approved by the Hawaii Public Utilities Commission. The TOU forecast does not include DER or EV customers, which Hawaiian Electric includes in separate forecast layers. The EV forecast reflects managed charging in response to incentives. In addition, the utility's forecasts assume that approved DR programs (e.g., the Bring-Your-Own-Device Tariff and the Battery Bonus Program), which provide incentives to provide additional capacity during the utility's daily peak period, would provide some grid capacity.

**Table 8. Hawaiian Electric's Assumptions for Residential TOU Load-Shift Sensitivities**

Input	Low	Base	High
Rates	Hawaiian Electric Final ARD Proposal	Hawaiian Electric Final ARD Proposal	DER Parties Final ARD Proposal
Residential customer pool	All non-DER residential customers = residential forecast minus High DER Sch-R forecast	All non-DER residential customers = residential forecast minus Base DER Sch-R forecast	All non-DER residential customers = residential forecast minus Base DER Sch-R forecast
AMI rollout	100% by 2025, straight line from current deployment to 2025	100% by 2025, straight line from current deployment to 2025	100% by 2025, straight line from current deployment to 2025
TOU rollout	Default rate for AMI meters ramps up from 2022 to 2026	Default rate for AMI meters ramps up from 2022 to 2026	Default rate for AMI meters ramps up from 2022 to 2026
Load shift method	Net-zero load shift	Net-zero load shift	Net-zero load shift
TOU opt-out rate (%)	25%	10%	10%
Price elasticity	-0.045	-0.070	-0.070

*Pilots.* In initial grid modernization plans filed by Xcel Energy in Minnesota,<sup>41</sup> the Public Utilities Commission certified and approved a residential TOU rate pilot, called Flex Pricing, to test AMI and a field area network with two-way communication and learn how customers respond to TOU price signals. The utility enrolled customers served by two distribution substations through opt-out recruitment. In summer 2021, the pilot reduced load by more than 2% during the utility's single peak hour of the year.<sup>42</sup>

<sup>37</sup> SCE 2023.

<sup>38</sup> Hawaiian Electric 2023.

<sup>39</sup> See Table 3-16, Hawaiian Electric 2023. Modeling scenarios address loads, DERs, and EVs, among other factors.

<sup>40</sup> Docket No. 2019-0323.

<sup>41</sup> See Docket Nos. E002/M-17-776 and E002/M-17-775.

<sup>42</sup> Xcel Energy, Feb. 25, 2022, compliance filing, Docket No. E002/M-17-775.

Xcel Energy's 2021 Integrated Distribution Plan (IDP)<sup>43</sup> considered two potential new TOU rate structure pilots for general service customers. One has time-varying energy and demand charges, with the demand charge further differentiated by time of year. The other rate pilot combines energy and demand charges into one time-varying volumetric charge, using three time periods. The rate also includes a critical peak pricing component that would allow the utility to call events for up to 75 hours per year, with a much higher per kilowatt-hour charge during these events. The pilots were intended to inform a permanent general service TOU rate tariff to be proposed in a future filing after the pilots are completed and AMI is fully deployed and operational.<sup>44</sup>

The 2021 IDP also discussed the utility's EV Accelerate at Home program,<sup>45</sup> with low pricing for charging EVs during off-peak and mid-peak hours and a higher rate for charging weekdays between 3 p.m. and 8 p.m.<sup>46</sup> In addition, Xcel Energy noted its partnership with the National Renewable Energy Laboratory to explore the impacts of unmanaged EV charging on the distribution system. Managed charging and TOU rates are among the mitigation options included in the study.

In the order approving the 2021 IDP, the Commission required Xcel Energy to host stakeholder meetings on a number of topics before the next IDP is filed, including how to "Develop a methodology for valuing the load-modifying impacts of demand response in load forecasts and present a load forecast that includes demand response contributions."<sup>47</sup>

The first IDP filed by Public Service Company of Colorado<sup>48</sup> discusses its Residential Resiliency and Managed Charging project, a collaborative study with the National Renewable Energy Laboratory examining the impacts of residential EV charging on the distribution grid under various managed charging scenarios, including TOU rates. The utility will use the results of the study to prepare the distribution grid for increasing levels of EV adoption in its service territory. The Project is studying the impacts of EV home charging for customers sharing the same transformer and secondary distribution network under varying load conditions, load diversity, types of distribution system equipment, types of DERs, and TOU rates. The IDP also discusses an EV Load Detection and Disaggregation Pilot, which will inform optimization of EV charging rates.<sup>49</sup>

*Non-wires alternatives.* Utilities can target DERs — including DR — to meet narrowly identified system needs through solicitations for NWA to defer, mitigate, or eliminate the need for a subset of traditional distribution (and transmission) investments.<sup>50</sup> Utilities may consider DR as a NWA for *specific* planned distribution projects, which often focus on a five-year horizon. In addition, utilities can conduct longer term (e.g., ten-year horizon) *systematic* studies of the locational value of DR to better understand where to target time-varying pricing, reducing load growth and the risk that

<sup>43</sup> Northern States Power Company (2021).

<sup>44</sup> The Commission approved the pilot and tariff modifications in Docket No. E002/M-20-86.

<sup>45</sup> See Docket No. E002/M-19-559.

<sup>46</sup> See <https://ev.xcelenergy.com/ev-accelerate-at-home-mn>; Docket No. E002/M-19-559.

<sup>47</sup> Minnesota Public Utilities Commission. In the Matter of Xcel Energy's 2021 Integrated Distribution System Plan and Request for Certification of Distributed Intelligence and the Resilient Minneapolis Project (Docket M-21-694). July 26, 2022, Order, page 14. The Order also stated that "Xcel shall include a discussion of how it plans to encourage more customers with electric vehicles to participate in managed charging" (page 10).

<sup>48</sup> Public Service Company of Colorado 2022.

<sup>49</sup> The IDP also discusses the Charging Perks program, which provides an upfront and annual incentive for utility control of home EV charging.

<sup>50</sup> Depending on market structure, DERs deployed as NWAs also may be able to provide the utility or centrally organized wholesale electricity market with other grid services — energy, generation capacity, and ancillary services.

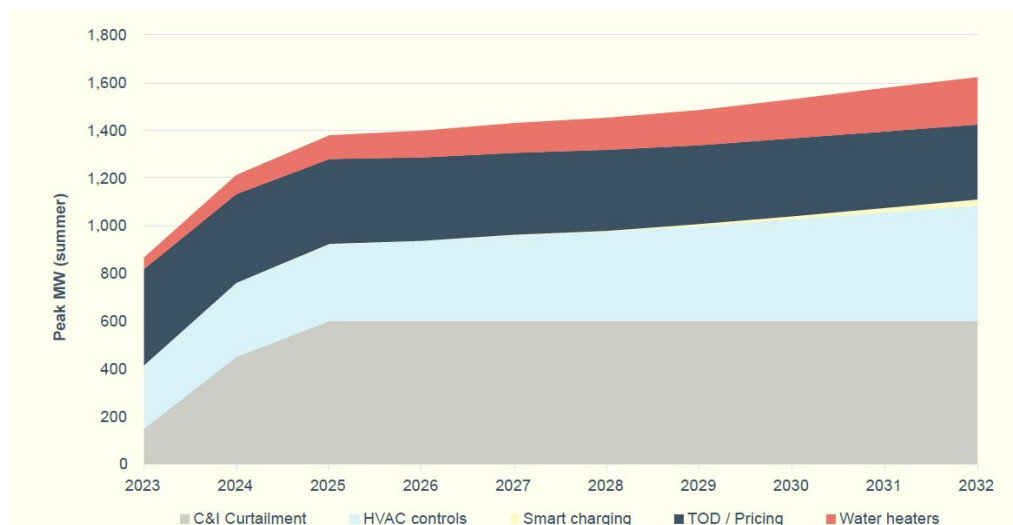


distribution system upgrades will be needed in specific areas of the distribution system. These studies can become a routine part of the utility’s DSP process.

Despite a growing body of NWA evaluations — for tariffs, pilot programs, and DSP processes — consideration of *price-based DR* as NWAs is nascent. That may in part be the result of the solicitation processes for third-party providers that some states require for NWA. Since the utility itself implements price-based DR, the resource does not fit into typical NWA processes in DSP. But clearly, utility analysis of NWAs could include time-based rates, such as TOU or CPP rates for both energy and delivery (in vertically integrated states) or time-differentiated distribution charges, in addition to geotargeting DR and energy efficiency programs for utility customers and utility-owned batteries.

Oregon’s DSP requirements for each of the two largest regulated electric utilities call for evaluation of at least two concept proposals to gain experience and insight into assessing NWAs, particularly to address priority issues such as new capacity needs to serve local load growth and improving power quality in underserved communities.<sup>51</sup> These recent evaluations have included price-based DR.

For example, for PGE’s first DSP, the company evaluated five potential NWA candidates before it developed full concept proposals for two of them.<sup>52</sup> To support the evaluation, PGE sponsored a flexible load potential study for its service area to identify economically achievable flexible load in 2025. According to the study, the achievable potential is 135 MW in summer and 108 MW in winter.<sup>53</sup> Figure 5 illustrates the annual flexible load and DR potential for one of the two NWA concept proposals, for the utility’s planned Eastport substation project. NWAs include existing opt-in Time of Day pricing and PTR.<sup>54</sup> PGE demonstrated conceptually that these price-based DR resources, combined with DR programs, energy efficiency, and distributed solar PV and storage, could meet the identified requirements for providing capacity relief for the Eastport location. Based on both quantitative and qualitative examination, PGE will conduct more detailed NWA planning to consider risk, customer acceptance, and budget impacts.



**Figure 5. Flexible load and DR potential — including price-based DR — for PGE’s Eastport substation (PGE 2022).**

<sup>51</sup> Oregon Public Utility Commission. 2020. Order No. 20-485 (Docket No. UM-2005). <https://apps.puc.state.or.us/orders/2020ords/20-485.pdf>.

<sup>52</sup> PGE 2022.

<sup>53</sup> Cadeo Group 2021. PGE DER and Flexible Load Potential. <https://edocs.puc.state.or.us/efdocs/HAD/um2141had16243.pdf>.

<sup>54</sup> The Company did not incorporate dynamic rates into its DER potential study for the DSP.

### *Recommendations for considering price-based DR in DSP*

The Center for Energy Efficiency study discussed above makes several recommendations for improving consideration of cost-effective DR and other DERs in DSP.<sup>55</sup> Some of these recommendations would expand consideration of price-based DR specifically:<sup>56</sup>

- *Require more comprehensive assessment of potential NWAs* - Specifically, utilities should examine all types of NWAs, including price-based DR alongside DR programs, energy efficiency, distributed generation, storage, and grid management technologies.
- *Expand screening criteria* - In addition to considering DERs for distribution system investment deferrals, include the potential of NWA to reduce distribution capacity needs for new loads, such as a new subdivision, and to better integrate solar generation and EV charging.
- *Consider financial performance incentives* - Performance incentives for utilities to acquire NWAs could be based on the deferred or avoided cost of a planned utility distribution project. Metrics for performance incentives also could be established for using load management to reduce grid costs for hosting distributed generation and charging EVs.
- *Invest in planning tools and grid data* - Insufficient planning tools and granular information about the shape, timing, and location of customer loads and DR behavioral response constrain NWA consideration and implementation. New planning tools with foresight to consider NWA timely for meeting grid needs may be required.
- *Make grid data publicly available* - If utilities identify and define grid constraints — for example, with hosting capacity maps and accompanying information like minimum daytime loads — DER developers and customers can bring forward DER solutions. Some states require utilities to provide data on grid needs in a standardized format through easily accessible data portals.

In addition to the recommendations above, public utility commissions could provide guidance to regulated electric utilities to consider price-based DR in DSP in the following ways:

- *Establish a longer planning horizon* - Short horizons focus planners on near-term dispatchable resources instead of building price-based DR resources over time.
- *Consider price-based DR beyond load forecasting*. Utilities consider the impacts of DR rates and programs in their load forecasts that underpin DSP. Price-based DR also can be considered as part of a portfolio of NWA after the utility's grid needs assessment.
- *Forecasting* - Disaggregate to the distribution substation circuit level the price-based DR assessed at the system level in IRPs.
- *Appropriately bookend assumptions for price-based DR*. Prioritize practical scenarios that can meet the grid need and analysis of key variables that have high impact.
- *Assess the impacts of distribution system upgrades with and without incremental DERs* - Similar to deficiencies with IRP analysis of price-based DR, simply including in the forecast an assumed level of yet-to-be-built DERs does not appropriately value their benefits.

<sup>55</sup> Center for Energy Efficiency 2021.

<sup>56</sup> Other recommendations by Center for Energy Efficiency would improve the NWA process for DERs other than price-based DR: (1) competitive procurement of NWAs and (2) making grid data publicly available, using data portals with standardized information, such as in California ([PG&E](#), [SCE](#), and [SDG&E](#)) and [New York](#).

- *Geotarget existing price-based DR* - If a utility is already implementing time-varying pricing to reduce peak demand on the bulk power system, there may be small incremental costs — and great value — to add to the tariff a dynamic rate for local distribution events.
- *Pilots* - Test price-based DR as a strategy to reduce peak demand for one or more distribution substation service areas, where load growth (e.g., EV charging or a large distribution warehouse) may trigger upgrades in the future, but there is enough lead time for mitigation strategies. In particular, additional studies are needed to better understand the *long-term* impacts of rate structures on customer adoption of DER investments that reduce peak demand. In particular, piloting and evaluating results for EV charging rates are critical to address large unmitigated load growth from transportation electrification.
- *Identify impacts of EV charging tariffs on utility upgrades* - Utilities need confidence that tariffs designed to encourage EV charging during off-peak hours will manage EV loads in ways that can be translated into changes in transformer sizing. At the same time, regulators need to understand how EV-specific tariffs are affecting utility practices for equipment sizing.
- *Locational distribution price signals* - Consider targeted price-based DR tariffs in combination with other NWAs to deferral specific utility distribution projects.
- *Systematic studies of DER locational value* - Require regular studies of the locational value of DERs, including price-based DR, throughout each utility's service territory.
- *Hosting capacity* - Consider price-based DR as a tool to improve hosting capacity for solar PV and EV charging, as well as to reduce interconnection costs in constrained areas on the distribution system. Such pricing would need to reflect distribution system stresses at specific places and times — for example, higher prices for customers on specific feeders at times of high loading. Also, utilities can conduct hosting capacity analysis at the secondary system level to better geotarget price-based DR and other NWA for distribution system deferrals. States also are beginning to require utilities to include EV charging loads in hosting capacity analysis for a more comprehensive understanding of both loads and generation at specific locations on the grid. Among the challenges to hosting capacity analysis are accuracy of underlying data, frequency of updating, and insufficient granularity due to data redaction by utilities to address concerns about cyber and physical security and confidential customer data.

## Conclusion

Utilities have conducted IRP for decades to consider both supply- and demand-side resources to meet bulk power system needs. More recently, an increasing number of states are requiring regulated utilities to file plans that identify distribution system needs and planned projects over a five- to ten-year period and to consider DERs that can avoid or defer certain types of traditional utility investments cost-effectively. Evaluation of price-based DR as a solution to meet identified electricity system needs is uncommon at both planning processes. Where price-based DR is considered as a solution, methodologies are often deficient.

Based on our analysis of utility filings and state requirements, this brief provides recommendations for improving consideration of price-based DR in the context of long-term planning for bulk power and distribution systems:

- *For bulk power system planning*, we generally recommend treating price-based DR as a resource in capacity expansion modeling, which entails a much more granular representation of its potential, costs, and capacity contribution. This also entails avoiding screening price-based DR prior to using it as model input, improving its characterization using empirical recruitment and performance data, and including it in IRP resource adequacy assessments for a proper load carrying capabilities evaluation.
- *For planning local grids*, that includes evaluating price-based DR in NWA analysis both for deferring distribution system investments and meeting new loads, considering financial performance incentives to align utility shareholder and utility customer interests, improving grid data and making it publicly available, applying advanced planning tools, using a longer planning horizon, and conducting additional analyses and studies.

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## Acknowledgements

The authors thank the following experts for reviewing this report (affiliations do not imply that their organizations support or endorse this work): Peter Cappers, Berkeley Lab; Tom Eckman, consultant; Owen Zinaman, U.S. Department of Energy; Naomi Simpson and Joy Wang, Michigan Public Utilities Commission; Brad Borum, Indiana Utility Regulatory Commission; Jamie Barber and John Kaduk, Georgia Public Service Commission; Hanna Terwilliger, Minnesota Public Utilities Commission; Anna Sommer, Energy Futures Group; Josh Bode, Demand Side Analytics; Jeff Loiter, NARUC; Paul DeMartini, Newport Consulting Group; Brian Gerke, Recurve; Jack Smith and Sarah Shenstone-Harris, Synapse Energy Economics; Sean Morash, Telos Energy; Leona Haley, Avista; and Debbie Lew and Carl Linvill, ESIG.

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