Potential Roles for Demand Response in High-Growth Electric Systems with Increasing Shares of Renewable Generation

Elaine Hale, Lori Bird, Rajaraman Padmanabhan, and Christina Volpi

National Renewable Energy Laboratory

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List of Abbreviations and Acronyms

C&I	commercial and industrial
CPP	critical peak pricing
CPR	critical peak rebate
CSIR	Council for Scientific and Industrial Research
DER	distributed energy resource
DLC	direct load control
DOE	Department of Energy
DSM	demand-side management
DRAM	Demand Response Auction Mechanism
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
EV	electric vehicle
FERC	Federal Energy Regulation Commission
FP&L	Florida Power & Light
HVAC	heating, ventilation, and air conditioning
ISO	independent system operator
LBNL	Lawrence Berkeley National Laboratory
MISO	Midcontinent Independent System Operator, Inc.
MWh	megawatt-hour
NE	New England
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
PURPA	Public Utilities Regulatory Policy Act
PV	photovoltaic
REIPPPP	Renewable Energy Independent Power Producer Procurement Programme
REV	Reforming the Energy Vision
RTP	real-time pricing
ToU	time-of-use
TSO	transmission system operator
VPP	variable peak pricing

Abstract

Many countries around the world are experiencing rapid economic development while simultaneously deploying more wind and solar generators. This report explores potential roles for demand response—the modification of electricity load operations to provide grid services—to support these countries' development goals through enhancing grid reliability and assisting with renewable energy integration in the power sector. After reviewing current demand response programs types, which include wholesale and retail market offerings, as well as broader distributed energy resource (DER) aggregation programs, we reflect on the historical trajectory of demand response as a grid resource and on recent findings from renewable integration studies. The reviewed literature suggests that some types of demand response programs are likely to be more supportive of high-economic growth, high-renewable contexts than others. We conclude by outlining best practices for the design of new demand response programs that build on the historical lessons learned and are well suited to accommodate expected future changes in generation and load patterns.

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1 Introduction

Demand response, the adjustment of electrical load operations to provide grid services, has been used for decades to make utility operations and planning more efficient and less capital intensive. However, the role of demand response has changed with experience, technological improvements, and power market restructuring. For example, in recent years demand response resources have begun to actively bid energy, capacity, and ancillary services into wholesale power markets in the United States (Murtaugh et al. 2017; ERCOT 2017; ISO-NE IMM 2017; Potomac Economics 2017; Patton, LeeVanSchaick, and Chen 2017; McAnany 2017; Lee et al. 2016). In retail markets, dynamic pricing programs have been piloted and in some cases made permanent (EPRI 2012). Both of these methods for eliciting demand response are aided by recent and still emerging advances in communications and control technology (gtmresearch 2017).

Historically, demand response programs have been initiated during high energy growth periods to help manage system peaks (Hurley, Peterson, and Whited 2013). This and technological changes that have enabled a variety of automatic, dependable demand response control types and their integration into power system operations imply that demand response resources could be a low-cost, flexible, and efficient source of electricity services in emerging economies. Furthermore, relative to new generation and transmission resources, demand response can be deployed quickly. For example, after accepting responses to its request for proposals in January 2004, Independent System Operator (ISO) New England (NE) was able to award a demand response contract for Southwestern Connecticut that was operational by June 2004 (Electric Light & Power 2008; ISO-NE 2004). The flexibility of demand response can act as a complement to wind and solar photovoltaic (PV) generation (Cappers et al. 2011), which is rapidly being adopted around the world in response to carbon reduction goals and falling costs (REN21 2017).

In this report, we explore the potential for demand response to mitigate costs associated with rapid growth in load, and with renewable energy integration. First, we discuss the variety of roles demand response has fulfilled in wholesale and retail markets both within the United States and internationally. Second, we describe a set of pilot and fully-implemented demand response programs and in China, India, and South Africa—markets that are all experiencing rapid load growth and expanded use of renewable energy generation. The report concludes with a discussion of key considerations for the design and implementation of new demand response programs in wholesale and retail markets.

2 Roles for Demand Response

Historically, demand response was largely used to provide peak load management in the US—specifically, load reduction during contingency events. However, with electricity market restructuring, regulatory reform, and the accelerating adoption of advanced metering and other enabling technologies, demand response in several United States jurisdictions has recently evolved to provide additional system services; in some regions demand response provides a full suite of energy, capacity, and ancillary services. These new services are helping to address operational challenges associated with aging transmission and distribution infrastructure, retirement of older thermal generating units, and increasing penetrations of variable generation. In the future, such services could be provided in other jurisdictions or expanded to provide additional flexibility to aid in the integration of additional variable resources and new technologies such as electric vehicles (Feldman and Lockhart 2014).

The rest of the world has not relied as much on demand response resources as has the United States, even for peak-load management. Given the cost-effectiveness of this traditional role, as well as the maturation of a wider variety of demand response control and service types that can respond to the system needs outlined above, there are new market opportunities for demand response. Feldman and Lockhart (2014) estimate that the global market for demand response-enabling technologies could grow to $9.7 billion by 2023 (Figure 1). The Asia-Pacific region in particular is expected to see rapid growth as its electricity markets allow load participation in the provision of energy and ancillary services.

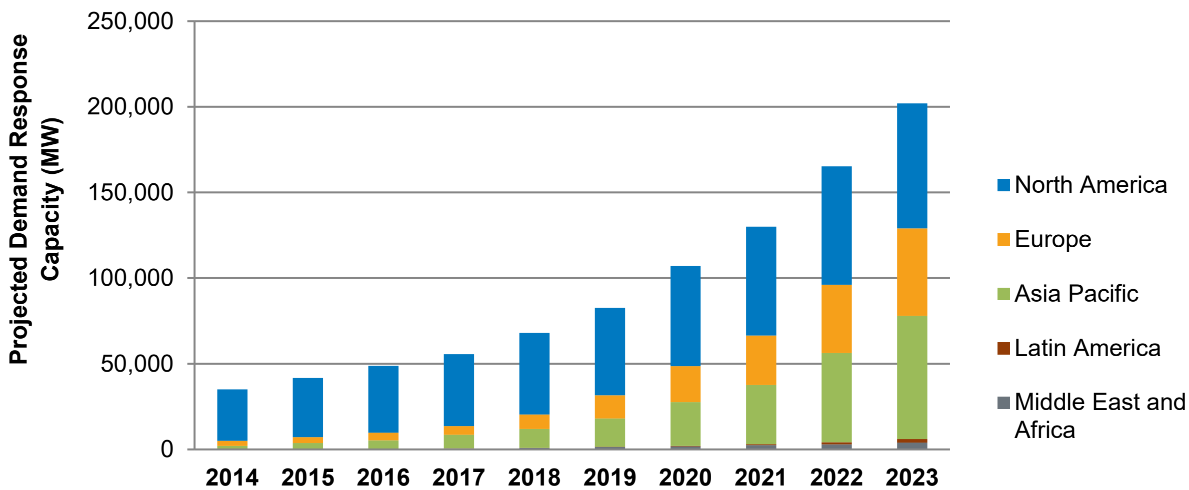

Figure 1. Global demand response market forecast (Feldman and Lockhart 2014)

Depending on context, demand response programs may be implemented in wholesale or retail markets. There are also leading jurisdictions conscientiously working to construct next-generation power systems with an emphasis on variable generation, load flexibility, and other supporting technologies. Utilities and system operators seeking to integrate demand-side resources for the first time or in new ways can benefit from learning about the wide variety of approaches and experiences that have come before.

2.1 Demand Response in Wholesale Electricity Markets

Demand response has been implemented in wholesale electricity markets through regulations and market rules that allow demand response resources to participate side-by-side with supply-side resources in energy, ancillary service, and capacity markets. In these markets, demand response has been implemented primarily by allowing load aggregators, that is, traditional load-serving entities or third-party companies focused on providing demand response solutions, to submit load modification or other grid service offers directly into the wholesale market on behalf of their customers. Large customers can also offer load resources directly into markets in some regions, but this practice is less common.

Demand Response in Energy Markets

There are two potential routes for commercial and industrial (C&I) facilities to reconcile their marginal value of electricity consumption with market conditions. Very large commercial and industrial (C&I) facilities may be able to directly bid their load into the wholesale electricity markets; some utilities and competitive retail providers offer real-time pricing (RTP) via contracts that directly pass through the wholesale electricity price to C&I customers. The latter option, when available, is often the only option for smaller C&I customers, because of either explicit market rules on participant size or implicit barriers related to market participant costs. Australia's National Electricity Market is an example of a market in which no direct bidding of large C&I load is allowed, but utilities do offer RTP contracts (AEMC 2009; Crossley 2011).

Currently, the rules for demand bidding in energy markets vary markedly from market to market. In some energy markets, demand resource bidding is restricted to the day-ahead market (NYISO 2017). In others, demand resources are allowed to participate in both day-ahead and intraday markets (PJM 2017). ISO New England is going through a transitional phase where demand response resources are allowed to place load reduction bids in response to day-ahead locational marginal prices and are then settled at those prices for their bids and real-time prices for any deviations (ISO-NE IMM 2017). In this case, demand response has no effect on the day-ahead prices but does impact the real-time load forecast.

The recent experiences of the California ISO and PJM Interconnection demonstrate how demand bidding in energy markets is still being worked out in practice as a complement to other demand response services rather than as a primary driver. In 2016, the California ISO appeared to experience a shift from most demand response bidding being in the day-ahead market to most being in the real-time market offered at or near the market cap of $1,000 per megawatt-hour (MWh) (Murtaugh et al. 2017). In PJM Interconnection, demand response participating in the PJM energy markets (so-called "economic" demand response) comprised less than 5% of all demand response revenues for each of the fiscal years 2014-2016.[1] Thus demand response based solely on the economics of buying energy (as opposed to energy bundled with some form of capacity payment) tends to be smaller than what demand response provides in terms of ancillary services and capacity (McAnany 2016, 2017).

[1] In 2015, total economic demand response revenues were about $8 million out of a total demand response market size of $800 million. In 2016, they were about $3 million out of total market of around $650 million. Economic demand response made up a larger proportion of 2014 revenue, but that still amounted to less than 5% of the total.

Demand Response in Ancillary Service Markets

Several wholesale electricity markets in North America, Europe, Singapore, and New Zealand allow demand response resources to participate in the provision of ancillary services. Such markets allow demand response resources to directly compete with supply-side resources to provide contingency reserves and frequency regulation services. Demand response resources provide a substantial portion of reserves in several of these markets; for instance, demand response consistently comprises over 50% of the responsive (i.e., spinning) reserves in the Electric Reliability Council of Texas (ERCOT) market—the maximum allowed by market rules (Potomac Economics 2016).

Compensation for demand response providing contingency reserves varies from market to market. In some markets, demand response resources receive capacity payments based on their participation in contingency reserve markets. In others, demand response resources are required to participate in contingency reserve/emergency load shedding markets based on their status as a capacity resource that has cleared a capacity market. The Loads as a Resource (LaaR) program in ERCOT (ERCOT 2006) and the U.K. National Grid system operator's Short Term Operating Reserve program (Curtis 2015) are examples of the former; PJM's capacity performance products are examples of the latter.

Although less common than the inclusion of demand response in contingency resources, a number of system operators (e.g., ERCOT, the Alberta Electric System Operator, and systems in the U.K. and Australia) have programs for under-frequency load shedding, which automatically disconnects select loads when a minimum frequency threshold is violated (ERCOT 2017; Ritter 2011; Heffner et al. 2007). This is sometimes a standalone ancillary service, similar to generator governor controls, that operates through fast automatic control rather than market dispatch. In the case of ERCOT, under-frequency load shedding is the mechanism through which many load resources participate in the ancillary service markets (ERCOT 2006, 2017).

In general, demand-side resources are more likely to provide something akin to spinning contingency reserves rather than regulation reserves. In ERCOT in August of 2017, for example, of the 28,970 MW-h of ancillary services provided by demand response, 28,219 MW-h were for responsive reserves (the spinning reserve product mentioned above) and only 751 MW-h were for regulation reserves.[2] Similarly, in PJM in 2016 demand response provided 67,801 MW-h of regulation reserve, compared to 827,091 MW-h of synchronous (contingency) reserve. However, a wide variety of equipment types are registered to provide regulation services in PJM—water heaters, batteries, HVAC, manufacturing, and refrigeration—which demonstrates an increasing level of sophistication in the requisite communication and control technology (McAnany 2017).

[2] See "Monthly ERCOT Demand Response from Load Resources" (http://mis.ercot.com/misapp/GetReports.do?reportTypeId=13242&reportTitle=Monthly%20ERCOT%20Demand%20Response%20from%20Load%20Resources&showHTMLView=&mimicKey), which is available from "Load Resource Participation in the ERCOT Markets," ERCOT, http://www.ercot.com/services/programs/load/laar. The Responsive Reserve Service is listed as RRS, regulation appears as RegUp and RegDown.

Demand Response in Capacity Markets

The main role of demand response in wholesale markets is as a capacity resource (Lee et al. 2016). In formal capacity markets, demand response resources receive capacity payments for being available for curtailment on request. Capacity auctions that allow demand response participation are regularly held by in the United States by PJM, ISO-NE, New York Independent System Operator (NYISO), and the Midcontinent Independent System Operator, Inc. (MISO).[3] Capacity auctions were held for the second time in the U.K. in 2015 (National Grid 2015). Table 1 summarizes various capacity markets in the United States and the U.K. along with the results for demand response resources in recent auctions (Cappers, Goldman, and Kathan 2010; SEDC 2015; Indo-German Energy Programme 2015).

Table 1. Comparison of Demand Response Participation in Different Capacity Markets

System Operator	Capacity Market Name and Type	Recent Capacity Auction Results	Demand Response Cleared	Remuneration
PJM (U.S.)	Reliability Pricing Model (RPM); Capacity obligation	167,305.9 MW for the 2019–2020[a] delivery period	10,348 MW	Capacity payment based on performance (fast responsiveness), with severe penalties
MISO (U.S.)	Resource Adequacy Requirement (RAR); Capacity obligation	135,483 MW for the delivery period 2016–2017[a]	5,819 MW	Capacity payment based on auction clearing price
ISO-NE (U.S.)	Forward Capacity Market (FCM); Capacity auction	35,567 MW for the 2019–2020[**] delivery period	2,746 MW	Monthly capacity payment based on auction clearing price
National Grid (U.K.)	Electricity Market Reform (EMR); Capacity auction	46,350 MW for the 2019–2020 delivery period	450 MW (8 MW proven demand response)	Monthly capacity payment based on auction clearing price

[a] The delivery period is from June 1–May 31 of the specified years.

Several locations (e.g., Western Australia, France, Ireland, Northern Ireland, Italy, Spain, Greece, and South Korea) have capacity markets in place that do not seem to have explicit demand-side provisions (Spees and Newell 2014; RTE France 2014; Indo-German Energy Programme 2015; SEDC 2015). Capacity market mechanisms are emerging in the Nordic countries,[4] and transmission system operators (TSOs) in different European countries are looking at different procurement mechanisms for demand-side participation in the long term. Taking the grid-interconnected Nordic countries as an example, Finland and Sweden manage capacity with strategic reserve or peak load reserve strategies, which are similar to contingency reserves and involve holding a certain amount of capacity that is activated only when the energy market, Elspot, demonstrates a capacity shortage. Denmark has recently initiated a similar strategy.

[3] In light of recent rules implemented at PJM that require all cleared capacity to be part of a new capacity performance product available year-round, participation of demand response resources could be affected in future auctions. Demand response aggregators can combine different seasonal demand response resources to create a year-round capacity resource; it is unclear how much demand response capacity will be unmatchable in this new scheme.
[4] Excluding Iceland, which has a unique, islanded power system consisting of hydro and geothermal generators.

Norway manages capacity needs through a tertiary balancing market that provides capacity through seasonal and weekly auctions. All these mechanisms allow demand-side participation, but increasing the share of demand response may be difficult because of performance requirements and low electricity prices. For example, Sweden initially had a goal to replace the strategic reserve with an all demand-side market mechanism by 2020, but has since dropped the goal of phasing out generators from providing that service (THEMA Consulting Group 2015).

2.2 Retail Demand Response Programs

Many countries that have not undergone electric market restructuring and do not operate wholesale electricity markets nevertheless have utilities that offer demand response opportunities to residential, commercial, and industrial consumers at the retail level, mostly through time-based tariffs, dynamic pricing programs, interruptible load tariffs, and direct load control programs.

Time-based tariffs and dynamic pricing programs incent customers to shift electricity use from on-peak to off-peak times by exposing them to time-varying price signals. Dynamic pricing programs especially come in a variety of forms. Altogether, the major time-varying price schemes are time-of-use (ToU) tariffs, real-time pricing (RTP), critical peak pricing (CPP), critical peak rebates (CPR), and variable peak pricing (VPP) (Table 2).

Table 2. Description of Retail Demand Response Programs Based on Time-Varying Tariffs

Pricing Mechanism	Description
Time-of-use pricing	As one of the earliest pricing techniques used for decades, ToU pricing consists of a stepped rate structure that includes a peak rate, an off-peak rate (and perhaps a shoulder-peak rate) for predetermined blocks of time. The definition of peak times and the associated rates often varies seasonally.
Real-time pricing	Real-time pricing is a dynamic pricing scheme that reflects the variation of wholesale electricity prices. Customers enrolled in RTP schemes are exposed to the actual cost of energy for each hour of the day as determined in a wholesale day-ahead market, in a utility's day-ahead unit commitment algorithms, or (less commonly) in a wholesale real-time market.
Critical peak pricing	Critical peak pricing is a tariff that adds a time-dependent rate to the normal rate (or ToU rate) based on day-ahead demand forecasts so that the energy prices are sufficiently high during actual peak demand hours to induce reduced consumption. The number of days in which CPP rates are applied is usually limited, and the activation of these rates can range from one day ahead to a few minutes prior to the peak load event.
Critical peak rebate	With a critical peak rebate program, the peak demand periods or emergency events are anticipated by the utility are relayed to their customers, and the provision of load curtailments by customers during those periods are remunerated pro rata at a predefined rate offered by the utility.
Variable peak pricing	Variable peak pricing is a combination of ToU and RTP where the on-peak and off-peak periods are defined in advance (based on anticipated peak demand periods), but the on-peak prices vary based wholesale market prices or system lambdas.

These mechanisms differ with regards to the amount of and frequency with which information must be exchanged between utilities and customers. For a long time, RTP schemes have been held up as the ideal for achieving alignment between customer incentives and system needs so as to reduce overall electricity costs for non-participants as well as participants (Borenstein 2005; FERC et al. 2009). However, implementing an RTP requires constant communication between system operators and customers. In contrast, ToU tariffs are calculated and communicated well ahead of time; and CPP, CPR, and VPP only require communication during peak load times. These mechanisms therefore carry much lower informational burdens that can be satisfied with messages conveyed to customers via mail, e-mail, or text message and interval metering of electricity use.

Table 3 summarizes several recent implementations of time-varying pricing programs by utilities. We choose to highlight examples that engaged fairly large proportions of customers within the affected utility service territories. Italy instituted ToU pricing for all customers after it rolled out smart meters in 2011, but it experienced relatively modest customer load shifting because of a relatively modest difference in peak and off-peak pricing. This was exacerbated by substantial growth in PV during early implementation (nearly 17 gigawatts [GW] of PV were installed by 2013), which further drove down the price difference between on-peak and off-peak prices. The Baltimore Gas & Electric critical peak rebate program in Maryland resulted in significant shifts in consumer demand (on the order of 30% reduction in load) during emergency events. A study of the Commonwealth Edison (ComEd) program showed maximum hourly prices were lower in the market after ComEd implemented their real-time pricing pilot. These examples demonstrate that there are a range of options for implementing programs and success can depend on implementation and design details.

Table 3. Case Studies of Retail Dynamic Pricing Programs

Case Study	Program Background	Consumer Response and Impact
ToU Rates: Italy	After completing the rollout of smart meters to all customers in 2011, Italy introduced a mandatory ToU tariff for nearly 20 million residential customers with on-peak prices from 8:00 a.m. to 7:00 p.m. on weekdays, and lower off-peak prices at other times. The difference between on- and off-peak prices was modest. The rapid increase in adoption of PV at this time contributed to the lack of substantial price difference (Maggiore et al. 2013)	The energy cost savings achieved by all residential customers from July 2010 to June 2012 was estimated at 6.45 million euros (~1 Euro cents(c€) per customer-month). A monthly average load shifting of less than 1% was observed from peak to off-peak hours. No significant difference between average load shifting occurred between on-peak and off-peak hours (Maggiore et al. 2013). Another study of the program, focused on the Trentino province, found that the introduction of the two-part ToU tariffs (*tariff bioraria*) exacerbated the peak load and increased energy consumption by nearly 14% (Torriti 2012).
RTP: Commonwealth Edison (ComEd), Illinois	After a three-year pilot program, in 2007, ComEd offered a voluntary RTP program to all residential customers. The hourly pricing program allows customers to have access to hourly energy prices and the ability to adjust usage accordingly. Varying factors such as weather, market conditions, and usage habits determine the customer's monthly electricity bill (Commonwealth Edison Company 2017).	More than 10,000 customers enrolled in the full program. Customers saved \$9–\$12/month on average (about 15%–20% of their monthly bill) by shifting energy use to low price hours. During the pilot program (2003–2006), the maximum hourly price was 12 cents per kilowatt-hour (kWh), compared to 38 cents/kWh during the Illinois energy crisis 2000–2002 (Star, Isaacson, and Kotewa 2014).
Critical Peak Rebate Program: Baltimore Gas & Electric (BG&E), Maryland	BG&E's Smart Energy Rewards CPR program is designed to encourage residential load shifting during peak hours on selected Energy Savings days. The program informs customers of a peak load event the day before it occurs and offers a rebate for reducing demand. BG&E submits load curtailment offers to the PJM wholesale market and the incentives are shared with participants. The average rebate offered at program launch in 2013 was \$1.25/kWh, or nearly 10 times the average residential electricity price. Residential customers with smart meters are defaulted into the program (Harbaugh 2015).	In its pilot from 2008 to 2011, the CPR program saw an average load reduction between 20%–30% during emergency events, and customers earned between \$6–\$10 per day during these events (Faruqui and Sergici 2011; EPRI 2012; Harbaugh 2015). In 2013, the program had 300,000 participants who contributed to an average load reduction of 15% during the four emergency events in that year. BG&E expanded its program to all its residential customers, and as of 2015, nearly one million residential customers were enrolled and many saved \$5–\$8 on each Energy Savings day (Harbaugh 2015).

Direct load control and interruptible load tariffs are also important ways utilities obtain demand response service through retail markets. Table 4 summarizes two examples of direct load control programs recently implemented by utilities.[5] First, Florida Power & Light (FP&L) offers its residential, commercial, and industrial customers incentives for granting FP&L direct control over air conditioners, water heaters, space heaters, pool pumps, and miscellaneous C&I equipment deemed suitable and acceptable during a site visit.[6] Under this program and others like it, participants get a yearly payment in return for the utility being allowed to exercise control over enrolled equipment during times of peak load, with contractual limitations on event frequency and duration. Second, Table 4 describes a pilot project in which BMW and Pacific Gas & Electric teamed to encourage groups of electric vehicle (EV) chargers to shift their demand in response to utility needs. Because of the success of the first phase of the EV program, a second phase is currently being planned.

Table 4. Case Studies of Retail Load Control Programs

Program Background	Consumer Response and Impact
Full-Scale Direct Load Control Program, Florida Power & Light (FP&L), Florida	
FP&L maintains large direct load control programs for all customers. It provides incentives for residential customers to allow the utility to temporarily shut off or modify the operations of electric water heaters, air conditioners, space heaters, and pool pumps during system emergencies. Commercial customers can enroll air conditioners in a similar program. The utility will also install direct load controllers on equipment types determined during site visits as part of their C&I demand reduction program, which is incented on a dollars-per-kW basis (FPSC 2015).	FP&L estimates taken altogether, their energy efficiency and demand response programs have superseded about 6,000 MW of capacity, of which about a third is attributable to demand response (FPL 2016).
Electric Vehicle Direct Load Control Program, Pacific Gas and Electric (PG&E), California	
The ChargeForward pilot program established by BMW and PG&E explores EV charging demand response. Phase I of the pilot ran from July 2015 to December 2016, and Phase II will run from 2018 to 2020. During Phase I, PG&E sent signals to BMW requesting a load reduction of up to 100 kW. In response, BMW selected participating vehicles to delay charging. One hundred BMW i3 owners participated and were paid $1,000 up front plus an additional payment up to $540 based on the level of participation. Customers were notified by BMW of the charging delay, and the customer could participate or opt-out. BMW is also using a back-up storage supply to respond to PG&E demand response requests (BMW Group and Pacific Gas and Electric Company 2017).	Phase I of the ChargeForward program resulted in nearly 200 demand response events taking place over the 18-month period, 94% of which reached the grid reduction target of 100 kW. From July 2015 to August 2016, more than 19,000 kWh of load was shifted from at-home EV charging to compensate for the grid demand. And, 92% of participants indicated they were satisfied with the program (Pacific Gas and Electric Company 2016).

[5] A running list of such programs in the United States is maintained at "Residential Demand Response Programs," ClearlyEnergy, https://www.clearlyenergy.com/residential-demand-response-programs, last updated October 10, 2016.

[6] In general, C&I traditional interruptible load tariffs are evolving to resemble the newer direct load control programs with regards to being implemented via reliable, automated controls.

Overall, these tariff and incentive programs vary in the extent to which they can align customer prices with system costs and in the amount of complexity and risk experienced by individual customers. Figure 2 illustrates these trade-offs. Although RTP appears to have the most potential to align customer and system incentives, at a minimum its implementation requires advanced metering infrastructure and it has the potential to expose customers to a high degree of price risk. At the other extreme, ToU tariffs are much simpler to implement and less risky to customers, but only provide a very blunt (season and time-of-day) and static (determined a year or more ahead of time) price signal that may not be sufficient to alleviate the worst peak load conditions. Interruptible tariffs, direct load control (DLC) programs, and programs aimed directly at peak load conditions (i.e., CPP/CPR and VPP) represent an interesting middle ground.

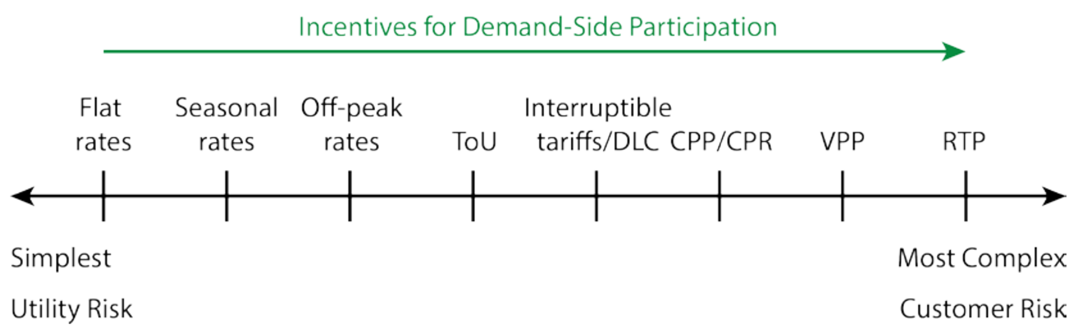

Figure 2. Comparison of different dynamic pricing schemes

2.3 Distributed Resource Aggregations Providing Demand Response

In the United States, the states of California and New York have recently developed initiatives to promote demand response programs that include distributed energy resource participation in wholesale markets to better facilitate renewable energy resource integration and to manage power flows in the distribution system (CPUC 2015; NYPSC 2016). These efforts are designed to support distributed energy resource deployment and bring more demand-side aggregations into the wholesale markets for effective side-by-side participation with supply resources. New York has an additional goal of facilitating the engagement of customers in energy transactions. California's efforts are more directly focused on supporting their greenhouse gas reduction goals, which have already had significant impacts on the state's generation mix (Lyons and Kassakhlan 2016).

California's Demand Response Auction Mechanism (DRAM) (CPUC 2015), which began accepting bids in late 2015, is one such initiative where load aggregations greater than 100 kW are procured by the three large investor-owned utilities in the state (Pacific Gas & Electric, San Diego Gas & Electric, and Southern California Edison) to provide increased flexibility for the system. California's DRAM is intended to expand the demand response markets by allowing the aggregation of distributed energy resources that can provide load response (e.g., smart thermostats, EV charging, behind-the-meter batteries, and commercial and industrial responsive loads). Under the program, load aggregators can make offers (of at least 100 kW) into the California ISO day-ahead market through the Proxy Demand Resource Program. The revenue for load curtailments in the DRAM mechanism will be entirely shared with participating customers. The initial DRAM pilot auction had a minimum target of 22 MW (10 MW each for Pacific Gas

& Electric and Southern California Edison, and 2 MW for San Diego Gas & Electric), and at least 20% of the capacity must come from the residential sector. In its opening auction in 2015, the three investor-owned utilities procured more than 40 MW of total capacity, exceeding their minimum targets. A second auction in 2016 yielded another 82 MW of capacity (St. John 2016). The second round of auction participants will be able to participate in both day-ahead and real-time energy markets in 100-kW increments, as well as bid 500 kW increments into the real-time Reliability Demand Response Resource program (St. John 2016). Several load aggregator startups and new markets for smart thermostats and other smart devices also emerged as a result of this initiative.

New York has been implementing electric sector reforms under its Reforming the Energy Vision (REV) initiative, which is designed to empower customers and facilitate distributed energy resources and the integration of clean energy resources into the electric system. The state has a renewable portfolio standard goal of 50% renewable penetration by 2030.

In line with the REV objectives, the New York Independent System Operator (NYISO) initiated a road-mapping process and a pilot program to allow aggregations of distributed energy resources (DERs) to participate in the wholesale electricity market. The resulting roadmap called for the aggregation rules to be technology agnostic, so that a DER aggregation could consist of different technologies (e.g., storage, distributed generation, and demand reduction) that are collectively able to follow dispatch instructions. The aggregations will be at least 100 kW in size and must be comprised of resources that are connected at the same transmission node. The aggregations can be coordinated by a customer, a distribution system platform provider, or a third-party. DERs could potentially have dual participation in retail and wholesale markets (Pigeon 2017). The NYISO is in the process of implementing a pilot program that is scheduled for 2018 to demonstrate the dispatchability of the DERs and ensure they can meet performance standards (Yung 2017).

2.4 Summary

There are many types of demand response programs distinguished by the markets in which they operate, whether participation is obtained through direct incentives or time-dependent pricing, and their sectoral or end-use specificity. The effectiveness of most demand response programs also depends on the degree to which response is automated. Demand response programs are starting to grapple with their compatibility with increasing amounts of wind and solar generation; California and New York are explicitly working to ensure demand response supports their renewable energy goals, and Italy has had the experience of a ToU structure quickly becoming out of date because of a rapid increase in PV capacity.

In Table 3, we qualitatively summarize the characteristics of different demand response program types with regard to:

- The quality of the response they can provide in terms of certainty, magnitude, and speed
- How robust they are to changing conditions (e.g,, increases in wind and solar penetration)
- How difficult they are to establish in terms of infrastructure requirements, time to establish, and cost to establish

- How acceptable they are likely to be to customers based on intrusiveness and customer price risk

This qualitative assessment was assembled based on the examples described above, as well as other relevant reviews, including EPRI (2012), Cappers et al. (2011), Faruqui, Sergici, and Sharif (2010), Faruqui and Sergici (2010), and Barbose, Goldman, and Neenan (2004).

Table 3. Characteristics of Demand Response Programs

	Bidding Load	Aggregation and Advanced Controllers		Direct Load Control (Incentive or Tariff)		Interruptible Tariff without Direct Load Control	Time-of-use – Basic Controllers		Real-time Pricing – Basic Controllers		Real-time Pricing – Advanced Controllers		Critical Peak Pricing (CPP)		Critical Peak Rebates (CPR)	
Sector	**C&I**	**C&I**	**R**	**C&I**	**R**	**C&I**	**C&I**	**R**	**C&I**	**R**	**C&I**	**R**	**C&I**	**R**	**C&I**	**R**
Certainty of response	◕	◕	◕	●	●	◑	◔	◔	◔	◔	◕	◕	◑	◕	◑	◕
Magnitude of response	◑	◑	◑	◕	◕	◑	◔	◔	◔	◔	◑	◑	◕	◕	◕	◕
Response speed	◑	●	●	●	●	◔	◔	◔	◔	◔	●	●	◔	◔	◔	◔
Robustness to changing conditions	●	◕	◕	◕	◕	◑	○	○	◑	◑	●	●	◑	◑	◑	◑
Infrastructure requirements	□	▪	▮	▮	▙	■	■	■	▙	▙	▪	▪	▙	▙	▙	▙
Intrusiveness	□	▮	▮	▪	▪	▮	■	■	■	■	▮	▮	▮	▮	▮	▮
Customer price risk	■	■	■	■	■	■	▙	▙	□	□	▮	▮	□	□	▪	▪
Time to establish	■	□	□	▮	▮	■	■	■	▮	▮	□	□	▙	▙	▙	▙
Cost to establish	■	▮	▮	▙	▙	■	■	■	▪	▪	□	□	▙	▙	▙	▙

Low — **Medium** — **High**: ○ ◔ ◑ ◕ ●

Less — **More**: ■ ▙ ▮ ▪ □

Large Commercial & Industrial (C&I)	Residential (R)
● (blue)	● (orange)

While old-style demand response programs (i.e., interruptible tariffs not assisted by direct load control implementation, and ToU tariffs) are generally easy and inexpensive to implement, they do not provide responses that are as large, certain, or fast as those assisted by automatic controls and/or enforced by market settlement processes. Time-of-use tariffs especially, and any contract terms that limit events to typical peak (net) load times, are not robust to changes in solar and wind penetration, as the time of peak net load may shift (in the case of more solar) or become more volatile (in the case of more wind). Time-of-use rates can be designed with solar power specifically in mind, as in California's new matinee energy pricing pilots, which will offer lower prices to commercial, industrial, and agricultural customers midday, correlated with times of high production from PV plants (CPUC 2016); however, the variability of wind in particular may preclude the reliable design of a robust ToU rate for high wind penetration systems.

These deficiencies generally point to following the trend for demand response programs that are more formal and automated. With an aggregation or direct load control contract, both the utility or aggregator and the customer are clear about what service is being purchased and at what price, especially as the program ages and experience accumulates. A much-discussed alternative to that paradigm is the real-time pricing tariff, but there are two potential issues to be considered. First, effective response to a real-time pricing signal requires automated controls. Without them, response requires continually monitoring the price of electricity, which is either (1) not worth the time if the utility bill is a small portion of expenses or (2) a stressful and risky burden if energy costs are a large part of the household or company budget. Second, if automated response to real-time prices becomes widespread enough, it becomes imperative for that response to be accounted for in the price formation process. If this is not done, system balancing can become unstable (Roscoe and Ault 2010; Roozbehani, Dahleh, and Mitter 2010).

On the commercial and industrial side, automated control and metrology is generally required for modern demand response programs. These C&I demand response programs vary in the services provided, from emergency or contingency response, to economic dispatch, to regulation reserve. The utilities or system operators generally propose, launch, and revise the programs over time, depending on system needs, load characteristics, enrollment numbers, and performance levels.[7] These programs certainly do not take as long to go from conception to maturity as building new transmission lines does, but the process does typically take several years (Zarnikau 2010). Challenges remain regarding the integration of demand response into markets and utility operations. For example, energy-shifting demand response is likely mis-incentivized in current systems because the make-up energy needed for energy shifting is not factored into day-ahead unit commitment processes.

Automated demand response programs in the residential sector typically take the form of direct load control of appliances such as air conditioners and water heaters. More recently, aggregations of programmable controlled thermostats have been added to the mix, and control of EV charging has been piloted and could be scaled up over the coming decades. All these controllers are operated similarly to modern C&I programs, with either the utility or an aggregator issuing control signals (on/off, setpoint changes, or price signals that can then be factored into user preferences). In the case of third-party aggregators, they may work directly with a vertically integrated utility or bid their aggregated capacity into a wholesale market. These

[7] "Demand Response," PJM, http://www.pjm.com/markets-and-operations/demand-response.aspx

programs have the advantage of being able to respond appropriately to actual power system conditions. On the potentially negative side, they do come with significant hardware and communications requirements, and with the potential to feel intrusive to home owners.

Critical peak pricing programs are interesting as a potential compromise between old-style and newer-style demand response programs. If customers have interval meters, no additional infrastructure is needed to implement a critical peak pricing program, as the utility can declare a critical peak pricing event a day ahead of time through basic e-mail or text messages. Then, if such events are infrequent enough and the incentives large enough, customers may be willing to manually adjust the amount of electricity they use during the declared times. However, a caution similar to that regarding including the response to real-time prices in price formation applies—if enough people participate in a critical peak pricing program, the result may be to simply shift the peak to right before or right after the event window.

3 Demand Response in High-Growth Power Systems with Increasing Shares of Renewable Generation: Current Trajectories and Aspirations

Demand response could play a larger role in countries and regions that are experiencing rapid load growth. In fact, new demand response programs are emerging in Asia, Africa, and other regions for reasons such as growing energy demand, grid congestion, aging infrastructure, and an interest in deferring generation and transmission investments. Goals to increase the use of clean energy resources could drive further interest in the use of demand response in these regions going forward. The following case studies explore efforts to implement demand response and the factors driving emerging programs in China, India, and South Africa.

3.1 China

As a large industrial nation with a forecasted peak load of about one terawatt by 2020 (Lin, Liu, and Karl 2016), China is a potentially large market for demand response. Also, the country has experienced chronic shortages in power availability because of rapid economic growth, a situation that has ebbed in recent years. To manage this mismatch in electricity demand and supply, large industrial customers were instructed to undertake administratively rationed, uncompensated load reductions to reduce peak demand. For example, in 1998, the State Grid Corporation of China established the Demand Response Management Center in the Jiangsu Province, which promoted demand-side management through both energy efficiency and demand response activities. Demand response measures included ToU rate structures, interruptible load programs, and the deployment of energy storage devices (particularly thermal storage for power plants) (Dong, Xue, and Li 2016).

In April 2002, Jiangsu became the first Chinese province to issue its own demand-side management regulations and activate a pilot demand response project that consisted of ToU rate structures, interruptible tariffs, voluntary load shifting, and deployment of storage devices to facilitate load curtailment. With the aim of deferring investments for transmission expansion and the construction of new power plants, the Natural Resources Defense Council conducted demand-side management pilot programs from 2013 to 2015 in four cities in China: Beijing, Tangshan, Foshan, and Suzhou. The main features of these pilot programs are summarized in Table 4 (Stern 2015). Also, Honeywell partnered with the Tianjin Economic-Technological Development Area in 2012 to implement China's first automated demand response (ADR) project (Navigant 2013; Samad, Koch, and Stluka 2016).

Table 4. Overview of Demand Response Pilot Projects in China

	Suzhou, Jiangsu	Beijing	Foshan, Guangdong	Tangshan, Hebei
Programs Offered	Interruptible load programs (real-time and contract demand response)[a]	Interruptible load and peak load pricing[b]	Cooling storage pricing[c]	Interruptible load programs[d]
Load Curtailment Target (2013–2015)	1,000 MW	800 MW	450 MW	400 MW
Targeted Consumers	Industries and municipal facilities	Industrial, commercial, and municipal facilities	Industries and municipal facilities	Industries
Types of Projects	Nearly 400 facilities connected to a DSM-service platform for peak load management	131 projects which targeted 45 enterprises for dynamic pricing	80 energy efficiency projects for industries and 30 projects for peak demand shaving	35 energy efficiency projects for power plants
Actual Response in 2015[e]	2716 customers, total 2037 MW across Jiangsu Province	74 customers, 71 MW	129 customers, 176 MW	NA

[a] Suzhou City Electric Demand Side Management City Pilot Leading Group Office (2015)

[b] Beijing Finance Bureau, Beijing Development and Reform Commission (2013)

[c] Foshan Economic Information Committee (2015)

[d] Tangshan Finance Bureau (2013)

[e] Songsong (2017)

Because the current challenges in China's power system concern over-supply and environmental issues rather than the previous challenges of under-supply, there have been shifts in policy since 2015, starting with State Council Document No. 9 (Pollitt, Yang, and Chen 2017; Dupuy 2016). These shifts include an increased focus on integrated planning and market-based dispatch mechanisms. In accordance with this trend, the government is also encouraging demand-side management pilot regions to employ voluntary price-based mechanisms in place of the conventional quantity-rationing approach (IEA 2017; Liu et al. 2015; Zhao et al. 2015).

3.2 India

Several factors have created potential demand response opportunities in India, including its rapid growth in energy consumption, non-remunerated supply disruptions, and its goals to shift toward cleaner energy sources. Demand response could also help Indian utilities better cover their costs if residential and agricultural consumers shift loads to more favorable times. In recent years, India has faced challenges with supply shortages, including a nearly 3.3% peak load deficit and an energy shortage of 2.1% in fiscal year 2015 (Central Electricity Authority 2016). In addition to rapid growth, changes in its generation mix may also encourage adoption of demand response. India has a capacity target of 175 GW renewable energy by 2022 that expands to 40% non-fossil energy production by 2030.

Currently, time-varying pricing is not widely used in India; time-of-day tariffs are offered to large commercial and industrial customers in some states. Otherwise, electricity is typically supplied at a predetermined tiered tariff structure, with subsidies for agricultural and residential customer classes that often result in financial losses for the distribution utilities (Badiani, Jessoe, and Plant 2012; Komives et al. 2005). Demand response may be able to mitigate these financial pressures by reducing the per-unit cost of electricity, especially if the demand response is incented from the subsidized sectors. Remuneration for loss of service is also more consistent with the idea of universal electricity access, which is now an explicit goal of the Indian government (Singh 2017).

Since 2012, India has conducted a few commercial and industrial demand response pilot programs. Table 5 presents the features of two pilot studies conducted in Mumbai and New Delhi. The project in New Delhi was India's first OpenADR demonstration. That pilot study involved 144 customers with a total coincident peak load of about 25 MW responding to a total of 17 events. By building type, the 75th percentile of responses ranged from 3% in educational buildings to 62% in pumping facilities, with an overall 75th percentile of responses at 10% of total load (Ghatikar et al. 2015). Honeywell estimates that if similar projects were deployed in the commercial and industrial sectors across all of India, the projects could potentially decrease the country's peak electricity demand by around 7.5 GW, or 5% of total peak demand (Poojary et al. 2015).

Table 5. Demand Response Pilot Programs in India

Program Features	Mumbai	New Delhi
Electric Utility	Tata Power Mumbai	Tata Power Delhi Distribution Limited
Demand response provider	Customized Energy Solutions	Honeywell
Type of program	Interruptible load services, energy shifting programs (incentivized)	Interruptible load services
Other features	Interruptible load implemented by reducing air-conditioning load and using thermal storage to shift energy consumption in industrial process-heating applications	OpenADR 2.0b, the latest software version in the United States, was used in tandem with advanced metering infrastructure to communicate with customers and dispatch curtailment requests.
Peak load reduction potential	18 MW (2014)	12 MW (2016)
Target customers	Commercial and industrial consumers (>500 kW capacity)	Commercial and industrial consumers (> 300 kW capacity)

3.3 South Africa

In 2008, South Africa started to experience widespread power outages and increases in electricity prices because of deficiencies in long-term infrastructure planning and investment in prior years. In addition to generally needing to manage for population and economic growth, Eskom, which manages nearly 95% of South Africa's demand, was working with aging assets with deteriorating performance. This resulted in increased outage rates for generators and transmission lines. Distribution performance was also poor (Newbery and Eberhard 2008).

In addition to embarking on a program of refurbishment and new builds, Eskom partnered with demand response provider Comverge in 2011 to pilot test a demand response market in South Africa. In this program, Comverge managed the first open demand response market in South Africa, which led to the procurement of 500 MW of commercial and industrial responsive load. Comverge also procured and managed 300 MW of this resource itself as a curtailment service provider. The demand response pilot program delivered nearly 15,260 MWh of load reduction over its seven months duration, which included 549.5 event hours (Comverge 2014).

Since that time, Eskom has successfully built new capacity and improved plant availability rates. The South African Department of Energy Renewable Energy Independent Power Producer Procurement Programme (REIPPPP) awarded support to 3,915 MW of renewable capacity over three auction windows (Eberhard, Kolker, and Leigland 2014). Also, economic growth has not been as fast as what was anticipated in 2008. As a result, today Eskom has a surplus of capacity and little to no emphasis on demand response (Eskom 2017).

4 Future of Demand Response in High-Growth, Power Systems with Increasing Shares of Renewable Generation

As shown above, demand response can, has, and could play many roles in power systems. In this section, we consider potential roles for demand response in the context of high-growth systems that also have clean energy goals. Such systems are perhaps best exemplified by India and China.

4.1 Comparison of High-Growth Power Systems with Increasing Shares of Renewable Generation with Conditions in the United States When Demand Response Programs Were Originally Introduced

In the United States, demand response programs were initially introduced by vertically integrated utilities in the 1970s, during that period's general energy crisis and when several important factors were at work. Perhaps foremost, the oil embargo in 1973 led to a global increase in energy prices, which, coupled with local intermittent difficulties in purchasing reasonably priced new generators, made the historic electricity demand growth rates of 8%–9% unsustainable, both economically and socially (Bhatnagar and Rahman 1986; U.S. EIA 2016; Hurley, Peterson, and Whited 2013). Centralized air conditioning was widely adopted starting in the late 1960s and early 1970s, which increased peak summer load in many regions. These new load characteristics coupled with the introduction of integrated resource planning in the late 1970s clarified the potential benefits of demand-side management with regard to providing peak capacity and enhanced reliability (Cappers, Goldman, and Kathan 2010). New legislation related to these issues, especially the National Energy Act of 1978, which contained as one of its five statutes the Public Utilities Regulatory Policy Act (PURPA), was instrumental in encouraging more demand-side control, including energy conservation and energy efficiency measures (Alliance to Save Energy 2013).

Programs initiated during that time and into the 1980s were primarily comprised of interruptible, curtailable, or ToU tariffs for large commercial and industrial loads. However, the overall effectiveness of these programs may have been marginal. In some jurisdictions, interruptible and curtailable loads were called on so rarely (e.g., less than once per year) that the tariffs functioned more as an unofficial economic incentive than as peaking capacity. Similarly, the vast majority of ToU customers (approximately 75%), at least as of the early 2000s, did not actually shift load in response to their ToU price structure (Fryer et al. 2002).[8] More recent ToU studies also show mixed results, with multiple pilot programs and natural experiments yielding no or very small (< 5% peak load reductions and elasticities of substitution less than 0.05) impacts (Jessoe and Rapson 2015; EPRI 2012). The old-style interruptible and curtailable rates have at this time largely been replaced by more-reliable alternatives.

Several aspects of the United States electricity industry in the early 1970s, especially the high growth rates and rapid adoption of air-conditioning technologies, are relatable to current conditions in India, China, and similar locales. However, the energy landscape is much different.

[8] Relatedly, Borenstein (2005) finds that under the assumption of equal elasticities (and not accounting for cross-elasticities), time-of-use rates can only be expected to capture 20% of the benefits of real-time rates.

Rather than high fuel costs, in the global energy markets low prices are currently the norm; and nations are planning to shift to use more renewable energy in their electricity sectors. Also, developing nations do not have to forge a completely new path but can build on the experiences of others with demand response and different types of energy markets; they can cooperatively learn with others how to integrate what may turn out to be the 21st century equivalent of the air conditioner: the electric vehicle.

Thus, some of the same drivers for implementing demand response are present, including difficulties building infrastructure fast enough to keep up with increasing demand, the potential for peakier loads driven by air-conditioning, and a desire to provide more reliable service; but, this is against a different energy backdrop of low fuel costs, more variable renewable generators, and the potential for widespread EV adoption. Both the high fuel costs of the 1970s and the clean energy goals of today incentivize less fossil fuel use, but while the implication of the former is basic energy efficiency and reducing peak loads, the latter implies the need to provide flexibility across multiple timescales in support of increasing deployments of wind and solar PV. The demand response innovations of the last several decades, and the potential for emerging technologies such as electric vehicles to be operated flexibly, represent an opportunity to quickly transition to providing reliable electricity service with significantly less pollution intensity by ensuring demand response is implemented to serve as a flexible complement to wind and solar PV generation.

4.2 The Potential for Demand Response to Facilitate Renewable Integration and Emissions Reductions

As numerous grid integration studies have shown, operational flexibility is an important ingredient to successfully adding more variable generation to the supply mix (Brinkman et al. 2015; Paul Denholm et al. 2016; Bloom et al. 2016; Hale, Stoll, and Novacheck 2018). The most important timescales for flexibility are system-dependent (Mills and Seel 2015). Flexibility pinch points can be reduced by enlarging geographic areas of cooperation (Brinkman et al. 2015) and by reducing minimum generation levels and allowing wind and solar generators to provide reserves (Denholm et al. 2016).

As a potential source for supplying increased flexibility, demand response is particularly attractive because of the smaller capital investment required to enable it. However, demand response is not a single homogeneous resource but rather the ability of many kinds of electrical loads to adjust their operations to perform various grid services. This complexity is both an advantage and a disadvantage when it comes to assessing the ability of demand response to integrate more renewables into power systems. It is an advantage because by harnessing multiple types of electrical load, flexibility needs at multiple timescales may be addressed (Barooah, Buic, and Meyn 2015). It is a disadvantage because developing reliable, time-varying, and geographically specific estimates of the technical and economic potential of various end-uses to provide particular grid services is a large effort requiring significant input data. To date, only rough short- to medium-term estimates have been compiled (Olsen et al. 2013, 1; Gils 2014).

Importing demand response potential estimates, imperfect as they are, into large-scale production cost models used for grid integration studies has provided some initial insights into potential roles for demand response in systems with increasing penetrations of wind and solar PV.

First, adding demand response as a resource into any cost-minimizing model of power system operations will always reduce costs, but it will not always reduce emissions, especially if emissions are not factored into dispatch decisions. For example, the case study considered in Hummon et al. (2013, 2), when combined with average coal and natural gas emissions rates,[9] shows that demand response increased carbon emissions compared to the system without demand response. This is in line with what has been seen for storage technologies[10] and has recently been corroborated under a wider variety of conditions simulated for the Florida power system (Hale, Stoll, and Novacheck 2018). For example, Figure 3 shows that for the system studied, adding a 300-MW storage plant increases carbon emissions when wind and solar penetrations are below about 45% on an annual generation basis but decreases them once penetrations are sufficiently high. The mechanism involved is a switch from storage predominantly enabling coal generation at the expense of natural gas generation at low penetrations to storage reducing the curtailment of enough wind and solar generation to eventually decrease overall emissions at high penetrations (Denholm et al. 2013). Demand response has a similar ability to reduce curtailment in high penetration systems, although its capabilities are generally more constrained (Denholm and Margolis 2016). The exact extent to which demand response can reduce curtailment remains an active area of research.

Another role for demand response in integrating renewables is in the supply of additional reserve products needed to support the variability and uncertainty of wind and solar. Such value stacking is clearly shown in Hummon et al. (2013, 2) and Ma et al. (2016). However, it must be cautioned that the amount of reserves needed to integrate wind and solar are not so sizable, such that a large number of new entrants has the potential to quickly saturate ancillary service markets, even at high wind and solar penetrations (Milligan et al. 2010; Hummon et al. 2013; Baker 2016).

[9] "Frequently Asked Questions: How much carbon dioxide is produced when different fuels are burned?" EIA, https://www.eia.gov/tools/faqs/faq.cfm?id=73&t=11
[10] Many types of demand response can be interpreted as, or are mathematically equivalent to, electricity storage. For one example, dynamically adjusting heating and cooling set points to change the power draw of a building relies on the building's inherent thermal storage. For another example, scheduling loads such as clothes washing or EV charging achieves a 100% efficient shift as compared to the less-than-perfect shift achievable by pumped hydro or battery storage.

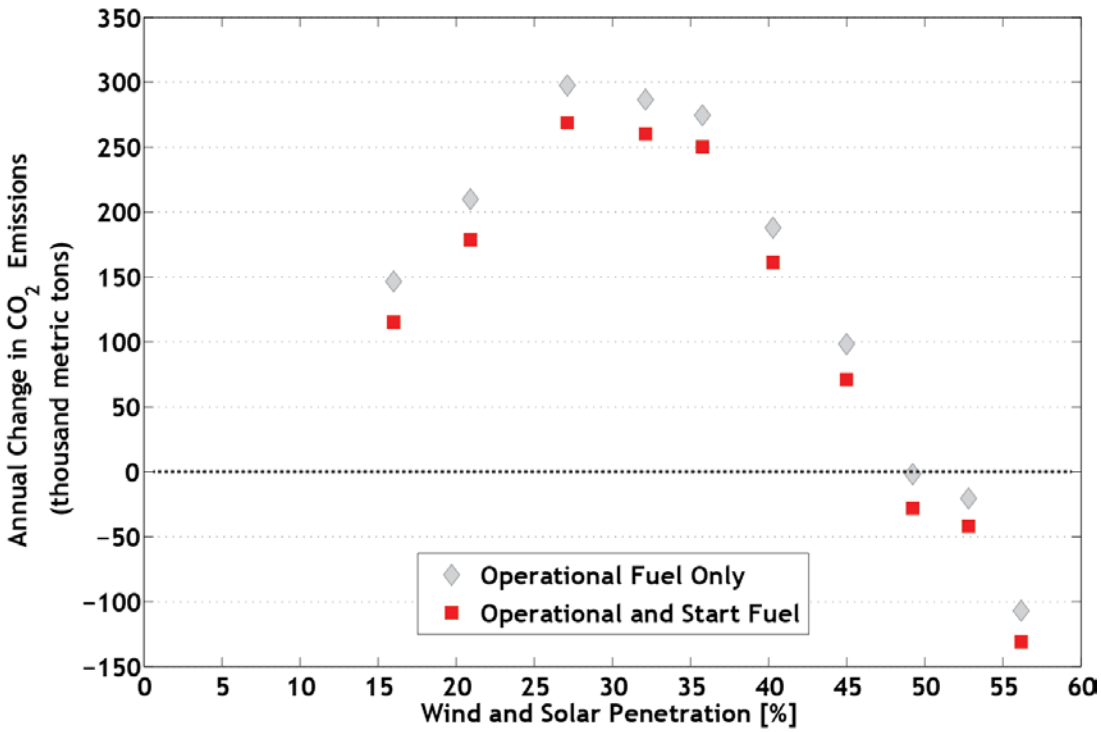

Figure 3. CO_2 emissions associated with adding a 300-MW energy-only storage plant to power system models with a total conventional capacity of 15.8 GW and a varying amount of wind and solar capacity (Denholm et al. 2013)

4.3 Framework for Selecting Demand Response Programs

From the discussion thus far, it is apparent that demand response is currently used to meet several power system needs and that it may be further called on in the future to help integrate wind and solar. These objectives for demand response are summarized in Table 6, which further describes the characteristics needed to meet each objective as well as the types of programs that meet those requirements.

Table 6. Demand Response Objectives and Corresponding Demand Response (DR) Options

DR Objectives	DR Role/Benefits	DR Characteristics Needed	DR Options
Peak load shifting	DR can help shift load at peak periods.	Customers willing to participate several to dozens of times per year Financial viability Reliable response	Bidding load Aggregation Direct load control Interruptible tariff ToU, CPP[a], and RTP
Regulation reserves	DR can provide fast load changes up or down for balancing.	Fast response Binding commitments to provide response Automated control to follow regulation signal	Bidding load Aggregation and advanced controllers Direct load control
Contingency event (emergency response)	DR can respond to infrequent contingency signals.	Need to ensure certainty, speed, and continuous response until the event clears Binding commitments to provide response	Bidding load Aggregation Direct load control Interruptible tariff Frequency sensitive relays
Managing load growth and capacity needs	DR can be included in capacity markets or long-term planning.	Relatively rapid program implementation Need to ensure certainty, speed, and continuous response during peak times Binding commitments	Bidding load Aggregation Direct load control Interruptible tariff ToU, CPP, and RTP
Ramping reserves	DR can help address uncertainty in net-load ramps.	Fast response Binding commitments to provide response Automated control preferred	Bidding load Aggregation Direct load control RTP
Virtual energy storage	DR can help shift load to periods of excess generation (e.g., midday for high-solar systems.)	Customers willing or required to participate Reliable response	Bidding load Aggregation Direct load control ToU and RTP

[a] Whenever CPP is listed, any of CPP, CPR or VPP would be appropriate.

Utilities and regulators serving high-growth systems with increasing shares of wind and solar generation would do well to keep most if not all these objectives in mind, and to go through a detailed planning process to discern which types of demand response might be most valuable to their systems, when, and where. As shown in Figure 4, for the development of effective demand response programs, understanding local conditions is particularly important. Which grid services are most needed? Which loads are significant in size and are (potentially) controllable? The answers to both these questions may change over time. Capacity and peak load reduction have typically been the most important services provided by demand response, but energy shifting, ramping reserve, and regulation may become more important as wind and solar penetrations increase. For now, in many places, applying direct load control to residential air conditioners might not yet make sense, but that could change in coming years. In some areas, focusing on industrial demand response is a natural choice, while in others, commercial loads are dominant. Once the flexible loads and grid service needs have been identified, potential demand response programs can be listed and screened as to whether they are a good fit for providing the services needed with the loads available. When that list is stabilized, it is time to plan for the time it takes to test and revise those potential programs, and to embark on the processes of pilot program design, recruitment, rollout, and analysis. All along the way, there are many examples to study, colleagues to reach out to, and, increasingly, vendors to consider working with to help ensure the establishment of successful programs.

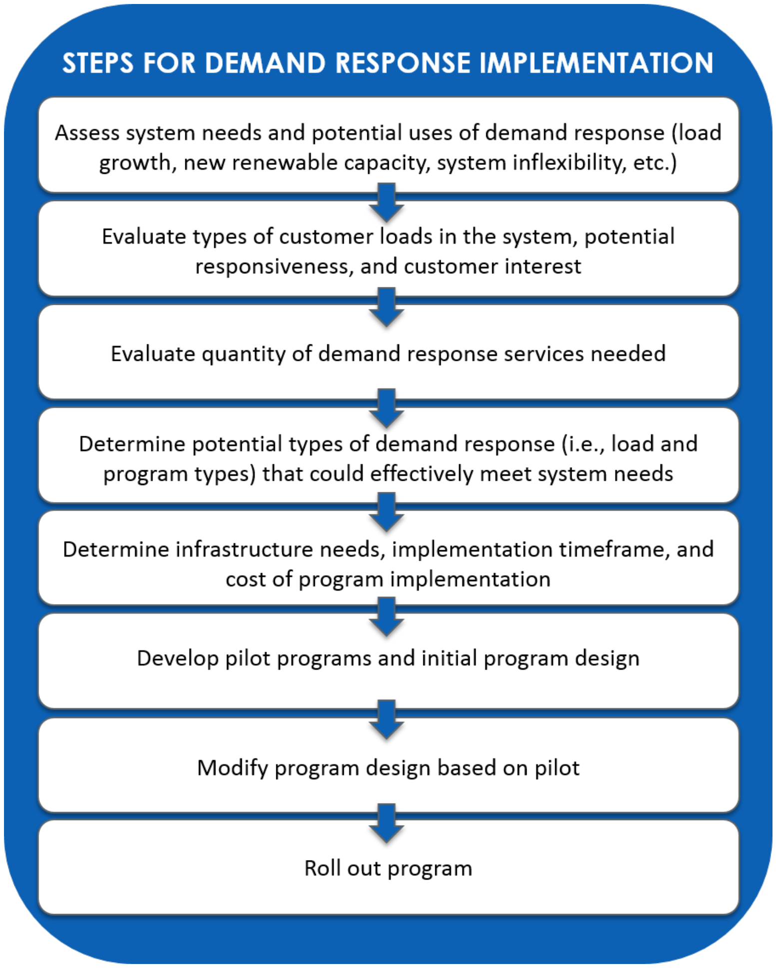

Figure 4. Template of the demand response planning process

Based on the characteristics of various demand response programs and power systems with high penetrations of wind and solar, the types of programs most likely to meet systems' needs for reliable responses under changing conditions include:

- Automated, incentive-based aggregation and direct load control programs
- Real-time prices, or other time-varying prices that are well aligned with system needs, for which the demand-side response is facilitated by automatic control
- Critical peak pricing programs.

Aggregation and direct load control are relatively well understood, reliable when done well, and can be tailored to fit a variety of needs. Real-time pricing programs coupled with automated controls hold promise but have yet to be fully proven, especially with regard to including price-driven responses in the price formation process as is needed to produce reliable grid operations at high penetration. Critical peak pricing programs may be especially useful in the short term, as they can produce significant response at peak times with smaller infrastructure investments, especially for utilities already undertaking advanced metering initiatives.

5 Conclusions

A variety of demand response program types have been used or piloted around the world. On the retail side, interruptible and curtailable tariffs were a common starting point, but they have given way to more robust demand response programs based on direct load control or pay-for-performance. Time-of-use rates are widely available options that do affect some load shifting and peak load reductions but not always as much as one would expect. Recently, other types of dynamic pricing, such as critical peak pricing and real-time pricing have been piloted or introduced as long-term options. Wholesale demand response programs are more recent, but are rapidly expanding to provide a variety of services in several markets.

Traditionally, and even today, demand response is most commonly used to provide capacity that counts toward planning reserves and long-term reliability, and the attendant reductions in load at times near system peak or in emergency conditions as required by such a resource. Demand response thus contributes to both long-term and short-term system reliability, and as a local resource, enhances energy security. Especially with the opening of wholesale markets to demand response, additional services, specifically economic energy shifting, regulation reserve signal following, and other active forms of load balancing are becoming more common in more places. These types of services typically provide additional economic value or cost savings to the system.

Electricity systems with high demand growth and clean energy goals may want to consider accelerating the development of demand response programs specifically tailored to providing additional reliability in the short to medium term, and the ability to help integrate variable generation in the medium to long term. To that end, modern, verifiable forms of emergency demand response from large commercial and industrial customers may be a natural place to start. Residential critical peak pricing programs can also be effective, and they do not require much communication infrastructure. Static ToU tariffs, which already have a mixed record as to how effective they are at shifting load away from peak times, are likely to become even less effective as additional variable generation makes net load curves less predictable and more correlated with weather rather than schedules. Instead, in preparation for deeper forms of demand response on the residential side, utilities and regulators may want to consider which types of appliances and other loads might be able to provide useful services in the future, and what the most effective means of tapping into those resources might be. Advanced metering might be desirable if real-time pricing plus automatic controllers are anticipated, or if the responses of third-party aggregators are to be verified through official meter readings. If other forms of control or verification are anticipated, for instance, direct load control of select appliances plus verification based on a sample of participants, or automatic control of programmable communicating thermostats, widespread investments in advanced meters may be unnecessary.

The ability of demand response to help integrate variable renewable generation has not yet been precisely quantified, but there are two general trends. First, the impact of demand response on emissions is highly system-dependent. For systems at low penetrations of wind and PV and with inexpensive, inflexible coal capacity available, the addition of demand response is likely to increase rather than decrease emissions to the extent that it reduces the operation of natural gas generators in favor of coal generators. However, this trend reverses once wind and PV penetrations increase far enough past the point of requiring system-balancing curtailments. In that case, demand response is used more to reduce renewable energy curtailment, which has a net impact on reducing emissions. Second, demand response can be used to provide regulation and other system balancing reserves that are needed at greater magnitudes as more wind and solar PV are added to the system. However, even in high wind and solar cases, system balancing needs are likely to stay in the range of a few to a dozen percentage points of load. This modest need combined with ancillary services generally being about an order of magnitude less expensive to provide than energy means demand response resources will typically be unable to justify themselves based solely on regulation and other balancing service revenue streams, especially with emerging technologies such as battery storage also competing to provide these services. For this reason, the role of demand response as a capacity resource is likely to remain important.

Future research should provide a better idea of which types of demand response are most valuable when and where. In the meantime, system operators everywhere can investigate how demand response programs might be able to provide additional reliability for their systems, with an eye toward programs that will be robust under swiftly changing net load patterns.

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