TECHNICAL REPORT

HARNESSING THE POTENTIAL OF FLEXIBLE DEMAND RESPONSE IN EMERGING MARKETS

Lessons Learned and International Best Practices

THE WORLD BANK
IBRD • IDA

ESMAP
Energy Sector Management Assistance Program

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ABOUT ESMAP

The Energy Sector Management Assistance Program (ESMAP) is a partnership between the World Bank and over 20 partners to help low- and middle-income countries reduce poverty and boost growth through sustainable energy solutions. ESMAP's analytical and advisory services are fully integrated within the World Bank's country financing and policy dialogue in the energy sector. Through the World Bank, ESMAP works to accelerate the energy transition required to achieve Sustainable Development Goal 7 (SDG7), which ensures access to affordable, reliable, sustainable, and modern energy for all. It helps shape World Bank strategies and programs to achieve the WB Climate Change Action Plan targets.

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Abbreviations

CBL	customer baseline load
CEMIG	Companhia Energética de Minas Gerais
CPP	critical peak pricing
CSP	curtailment service provider
DSB	demand-side bidding
DSO	distribution system operator
EV	electric vehicle
EVN	Viet Nam Electricity
IEA	International Energy Agency
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PV	photovoltaic
RPM	Reliability Pricing Model, PJM's capacity market
RTO	regional transmission organizations
RTP	real-time pricing
RVD	Redução voluntária da demanda (Brazil)
ToU	time-of-use
TSO	transmission system operator
VRE	variable renewable energy
V2G	vehicle-to-grid
VPP	variable peak pricing
VRE	variable renewable energy

All dollar amounts ($ OR USD) are US dollars unless otherwise indicated. The word "cents" refers to US cents, unless otherwise indicated.

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Executive Summary

Demand response is a "short-term, voluntary decrease in electrical consumption by end-use customers that is generally triggered by compromised grid reliability or high wholesale market prices."[1] In demand-response schemes, customers are remunerated for curtailing their loads (Federal Energy Management Program. n.d.). Curtailment can help balance energy supply and demand, ensure adequate capacity during times of stress on the system, and provide ancillary services such as frequency support and management of network congestion.

The role of demand response in power markets is expected to grow significantly in coming years. In its "Net Zero by 2050 Roadmap for the Global Energy Sector," the International Energy Agency (IEA) foresees a need for "flexibility," the components of which are demand response, batteries, and low-carbon flexible power plants to help balance wind and solar with evolving demand patterns (IEA 2021b). In the roadmap, the use of demand response in emerging markets and developing economies grows from a negligible base in 2020 to almost 20 percent of all flexibility by 2050. These global expectations are mirrored in decarbonization pathways for individual countries. For example, the United Kingdom's scenarios for achieving net zero energy by 2050 foresee demand response (including vehicle-to-grid technology) expanding six to eleven times its 2021 levels in terms of capacity, while IEA (2021c) foresees a "massive increase in power system flexibility" being required for India, including between 140 and 200 gigawatts of batteries, supplemented by demand response.

Three factors are contributing to this growth. First, some countries have long used demand response to manage demand fluctuations and support grid security. Continued growth in the deployment of variable renewable energy reinforces those uses by making periods of system stress less predictable and imposing further technical challenges for system operators regarding frequency and voltage control. Second, the electrification of transport and heating and a rapid growth in demand from data centers are changing load profiles across various markets. Demand response offers a cost-effective way to balance supply and demand and manage these developments. Third, smart grid and appliance technology, coupled with internet-based devices that communicate instantaneously, extends the range of potential demand-response providers—right down to individual households.

Maximizing the potential of demand response requires a conducive policy and regulatory framework. Market design and other regulatory barriers can restrict the participation of demand-response providers that would otherwise be cost-effective, increasing the overall cost of electricity supply and slowing the energy transition. Understanding the options available, international lessons learned, and how these can be best applied is therefore valuable for policy makers and regulators seeking to understand how best to leverage the potential of demand response in their power systems.

Demand-response programs can be broadly categorized as indirect price-based approaches or direct quantity-based approaches. Price-based (also known as "implicit") demand-response mechanisms use time-differentiated electricity prices designed to incentivize customers to shift consumption away from peak hours or when the power system is under stress from high demand or low supply. Quantity-based (or "explicit") demand response includes a broad set of solutions designed to shape customer consumption directly through incentive payments. Under quantity-based schemes, the utility, service provider, or grid operator directly contracts for a given quantity of load reduction, typically in exchange for an explicit payment. Certain loads, such as water heaters, air conditioners, lighting, pool pumping, and electric vehicle charging can be shifted with minor inconvenience to end users. With the increasing deployment of smart meters and remote monitoring and control tools, such load control can also be automated and thereby more closely controlled by the contracting entity.

Demand-response programs can be implemented at the retail or wholesale level to support energy and network services. Electricity market retailers[2] may offer time-of-use tariff options for all customer types, provided their metering equipment can support implementation. Distribution system operators (which may be bundled with the local retailer) can also enlist demand-response providers to support local system services such as management of congestion in the distribution network. At the wholesale level, the grid operator can contribute to load control and encourage the use of demand response to achieve wholesale energy balancing, capacity adequacy, and ancillary services. It does so through various market mechanisms and bilateral contracts. Large consumers will often be able to access these demand-response markets directly, while smaller consumers may be required—or prefer for reasons of transaction cost and simplicity—to work via demand-response aggregators.[3] Retail and wholesale mechanisms are complementary.

Policy makers and regulators can encourage innovation and new business models by improving market design and widening access to demand-response mechanisms. Emerging demand-response business models are being designed and piloted to aggregate multiple, fragmented loads and allow the utility or grid operator to control them directly. Demand-response aggregators can build multiple distributed energy resources—including small, fragmented demand-response opportunities—to a scale that can deliver substantial grid services to utilities and system operators. These new companies are equivalent to the energy service companies operating in the energy efficiency space. Such innovation is greatly supported by conducive market design and the adoption and installation of new smart technologies.

While the absolute level of demand response remains low, demand-response instruments have already been widely deployed and tested in many emerging markets, from the large power systems of India, People's Republic of China, and Brazil down to those of small island nations. Assessing global lessons learned and barriers encountered can help other emerging markets understand how best to design and implement their own instruments in line with the local context and with maximum chance of success. Static time-of-use tariffs have been adopted in most of the countries reviewed in the case studies of this report. Still, dynamic pricing (prices that vary in real time in response to prevailing supply-and-demand conditions) has not been mainstreamed, except for some pilots in South Africa and exposures to spot-prices by large customers in Brazil. Quantity-based demand-response schemes exist in People's Republic of China and are relatively well developed in South Africa, which has implemented sophisticated load control systems and business models to manage nonessential loads to mitigate capacity shortages. However, a wide gap in demand-response deployment remains, and performance in those countries is compared in this report with the best demand-response practices in the United States, a global forerunner.

The case studies presented here provide evidence that demand-response programs should be grounded in a country's context, targeting identified power system constraints. Demand-response mechanisms can be well targeted to specific objectives but are likely to be less effective if applied too broadly. As a first step in designing a demand-response program, a system diagnostic will identify the drivers of the need for demand response, which often include variable generation, network constraints, customer demand, and circumstances external to the system, such as a mandate for decarbonization. The driver's location is also essential—that is, how it is dispersed geographically or over time, how immediate it is, and how it affects different customers. Finally, the structure of a country's power system and its experience with demand response will determine possible mechanisms and how they can be adopted.

The benefits of demand response should be identified and evaluated through a cost-benefit analysis. The analysis should be based on a country's enabling conditions, market structure, and available (or soon-to-be-available) technologies. It should plot all demand-response options (including "do nothing") on a "supply curve" based on their net and distributed benefits, allowing them to be ranked in order of preference. After designing the mechanisms, enhancements to pertinent policy, legal, and regulatory frameworks should be accompanied by market education on their potential. Finally, the program should be implemented in accordance with a detailed roadmap and timeline, supported by pilot projects, quick wins, technical assistance for implementing institutions, and systematic monitoring and reviews.

Endnotes

1. "Wholesale market prices" here are driven by the high marginal cost of generation, which would apply equally to a jurisdiction with no active market operating under least-cost dispatch regulations
2. This report uses "retailer" to refer to entities licensed to supply electricity procured at the wholesale level (through wholesale markets, directly from generators, or from a designated single buyer) to end consumers. In many jurisdictions the retailer will remain bundled legally or in accounting terms with the distribution system operator or distribution network owner, in which case it will be referred to as a "local utility" or "distribution company" operating under monopoly price regulation.
3. "Demand-response aggregator" is used as a general term to refer to an entity contracting several demand-response providers. A retailer may also operate as an aggregator—for example, when bidding on demand response in wholesale markets.

ONE
DEMAND RESPONSE AND ITS ROLE IN THE ENERGY TRANSITION

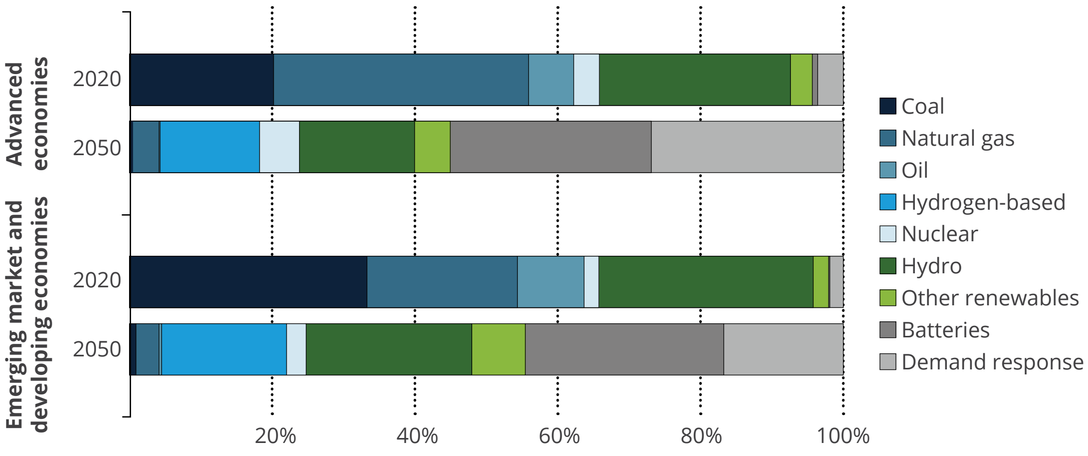
The Need for Demand Response

Supported by new and innovative technologies, demand response is rapidly gaining prominence in power system planning and has the potential to help facilitate the energy transition. The International Energy Agency (IEA) foresees the need for sources of flexibility—defined as the ability to adjust demand and supply when faced with an imbalance in the system—to quadruple by 2050 under a global net zero scenario despite the loss of dispatchable fossil fuel generation (IEA 2021b). Demand response is identified as a critical and significant component for enabling this transition in both developed and emerging markets (IEA 2021a). It should represent about 30 percent of the electricity system's flexibility in advanced economies and almost 20 percent in emerging markets and developing economies, as shown in Figure 1.1. These international projections are replicated in national plans. For example, the United Kingdom's scenarios for achieving net zero energy by 2050 foresee demand response (including vehicle-to-grid technology) to expand to six to eleven times their 2021 levels in terms of capacity, while IEA (2021c) foresees a "massive increase in power system flexibility" being required for India, including between 140 and 200 gigawatts (GW) of batteries, supplemented by demand response (National Grid ESO 2024). Thus, the growing need for flexibility should motivate policy makers and regulators to embrace demand response aggressively.

Flexibility is crucial to increasing the penetration of variable renewable energy in the power system. Flexible resources, such as synchronous generation, storage, and demand response, will become critical elements to balance the system and provide ancillary services.

FIGURE 1.1

Electricity System Flexibility by Source



Source: IEA 2021b.

There are three key drivers behind this acceleration in the deployment of demand response.

- **Very high levels of variable renewable energy (VRE)** are critical to meet global net zero and decarbonization goals. In their 2050 global net zero pathway, IEA estimates solar photovoltaic and wind capacity must grow by around four times between 2020 and 2030 and reach almost 70 percent of all electricity generation by 2050 (IEA 2021b). This rapid expansion will entail significant disaggregation of energy supply, with a much larger share of generation capacity connected at the distribution level both upstream of the meter and behind it. These developments are creating new generation patterns and challenges for achieving supply-demand balance on the grid and for system operators that must manage additional technical challenges in ensuring reliable supply.[1] Energy system flexibility is thus an increasingly essential part of the power system.
- **Structural changes to electricity demand patterns.** Climate change, economic growth in emerging economies, and electrification of end uses (especially transport systems) are changing the intensity and load shape of electricity demand. Cooling represents 10 percent of global electricity demand, and that share is increasing fast, driven by rising temperatures and the adoption of air-conditioning and refrigeration, especially in emerging and developing economies (IEA 2023). Electrification of the transport sector, led by electric vehicles (EVs),[2] is also changing load profiles, as is the rapidly expanding need for energy-intensive data centers. These demand-side factors and associated changes in load profiles are increasing the strain on the grid and the complexity of maintaining reliable operations. Thus, there is an increasing need for flexible resources, including demand response, to manage structural changes in load shape.
- **New technologies are enabling the emergence of fast, cost-effective demand-response schemes.** Digital tools, innovative grid technologies, smart appliances, and other Internet-of-Things devices enable a suite of options to deploy demand response far beyond its historical base of large consumers—even to individual households—thus increasing the ability of system operators to manage loads flexibly and cost-effectively in response to grid conditions. Smart meters, a foundational smart grid technology, are crucial to optimizing price- and quantity-based demand response because they provide granular data on prices and consumption to utilities and customers. Increasing digitalization has allowed more cost-effective coordination and management of distributed resources and their aggregation into virtual power plants that can deliver flexibility to grid operators.

Flexibility, and particularly demand response, thus provides substantial value to power systems by displacing expensive thermal generators and deferring investments in new generation and grid expansion.

Defining Demand Response

Demand response lies within the broader concept of demand-side management. Although the terms are sometimes used interchangeably, demand-side management typically refers to measures designed to shape load profiles in the medium to long term.

In contrast, demand-response programs are focused on changing demand in response to events of shorter duration—and even in real time. Both stand in contrast to energy efficiency, which signifies permanent change in energy consumption, generally with no decrease in service level.

For this report, demand response is defined as encompassing "changes in the electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce. . . lower electricity use at times of high wholesale market prices or when the system reliability is jeopardized" (FERC 2018). This report also considers behind-the-meter forms of energy storage
(domestic battery systems and vehicle-to-grid systems) owing to their similar purpose and their potential for being bundled with providers' demand-response measures.

Demand-Response Applications

Demand-response measures can increase affordability and reliability. They can also aid in decarbonation.

- Demand-response measures can lower generation costs by shrinking the need for expensive thermal plants during peak hours or hours of low VRE output and optimizing the use of the existing generation assets.
- They can make electricity supply more reliable by minimizing the risk of curtailment and outages and helping to alleviate network congestion.
- They can reduce carbon emissions by enabling consumers to shift load away from peak periods (or periods of low VRE output) in situations where the marginal plant is typically carbon-intensive thermal generation.

The objectives are summarized in Figure 1.2.

Many stakeholders can benefit from demand-response programs. Electricity customers who participate in demand-response programs obtain direct financial savings from more efficient usage and may receive compensation for services provided to the grid. Nonparticipating customers will benefit from reduced peak demand, reduced infrastructure costs, and increased grid reliability. The cost of non-served energy is very high, and a more reliable grid mainly benefits people with low incomes who cannot afford backup generators.

Distributional concerns must be considered in the design of demand-response programs. For example, when utilities shift from flat to time-varying tariffs (a practice termed "price-based" demand response in this report), customers who are not adequately informed or able to adjust their consumption profiles may end up paying larger electricity bills, which is especially problematic if they are low-income customers.[3] There are several ways to address this distributional challenge. First, in the design phase of demand-response

FIGURE 1.2

Objectives of Demand Response

Energy balance	**Least-cost energy provision**	Maximizing consumer utility through least-cost matching of supply and cost-reflective demand
Capacity provision	**Capacity adequacy**	Ensuring adequate de-rated capacity available on system for managing system stress events within LOLP limits
Ancillary services	**Reserve provision**	Arresting and restoring system frequency following loss of load
	Frequency regulation	Managing continuous fluctuations in frequency caused by fluctuations in demand and in the supply of renewable energy
	Voltage control	Managing voltage deviations to retain power quality
	Constraint management	Managing network congestion and constraints that otherwise curtail generation in substitution of upgrading or reinforcing the network directly ("non-wire alternative")

Affordability

Meeting system needs at lower cost

Reliability

Reducing system outages

Decarbonization

Facilitating greater penetration of renewable energy

Source: Author's analysis.

Note: Non-wire alternatives address congestion management without expansion of the grid. LOLP = loss of load probability; RES = renewable energy.

programs, a cost-benefit analysis should be carried out to assess the overall impact on rates across all customer categories. Second, tariff design can be fine-tuned so that no one loses at the outset (although this may necessitate diluting the incentive). Third, safety nets can be established for low-income customers. Fourth, the demand-response tariff system can be made optional (on an opt-in or opt-out basis).

Demand Response as a Climate Asset

Demand response's primary focus is to enhance the power system's stability, to address the challenges of meeting peak demands or low VRE output, and to help the system operator manage contingencies. This goal is also significantly aligned with climate-related benefits.

Demand-response programs can help reduce greenhouse emissions in the electricity sector by shifting consumption to off-peak periods or periods of higher renewable energy output. An analysis conducted for several US states in 2017 revealed that, in California, there was a 96 percent difference in emissions between the most and least carbon-intensive hours of the year. The variation in the New York grid was around 25 percent, and the variation in the Midwest was close to 11 percent (Zhou and Trieu 2021). The fact that peak demand is typically met with fossil-fuel-based energy[4] highlights the substantial climate benefits to be had by shifting load away from peak periods toward times when renewables are generating power.

Demand response provides additional flexibility to displace carbon-intensive thermal power plants that provide ancillary services. Fast-response resources can handle sudden variations in solar production or in the ramp-up of EV charging (Conteh et al. 2020). This is important because inverter-based renewables that are not synchronously connected to the grid network reduce the level of rotating inertia in the system, which can cause the grid's frequency to react more rapidly in the event of a supply or demand shock. Fast-responding reserves, such as load control (and batteries), help manage such fluctuations and minimize the need to retain fossil fuel generators (and their associated inertia) on the network. Therefore, demand response enables continued expansion of the VRE base, displacing expensive thermal peaking plants. Box 1.1 offers an example of close alignment of demand response with climate goals.

BOX 1.1

DATA CENTERS AND DEMAND RESPONSE

Driven by the explosion of cloud computing, cryptocurrency mining, and artificial intelligence, power demand from data centers is rising dramatically around the world. The scale and speed of growth in demand is very likely to complicate utilities' efforts to assure grid reliability and decarbonization. In recognition of the challenge, data center companies are increasingly focusing on energy efficiency (largely in relation to processing and cooling) and demand flexibility.

For example, Google's carbon-intelligent computing platform allows Google to shift less urgent computing tasks to times and places where renewable energy is most available, thereby helping lower the company's carbon footprint. Google classifies tasks by their urgency to assess which can be shifted without a substantive impact on user experience or performance (for example, YouTube video processing). The company is applying the intelligent computing system to some of its most prominent super-scale data centers worldwide (Bonifacic 2020).

(*continues*)

BOX 1.1 (*Continued*)

Google has also used the carbon-intelligent computing platform to work with utilities to support grid reliability. During the energy crises in Europe in the winter of 2022–23, the company used the platform to reduce electricity demand during the evening peak period. In the United States, the company reduced data center power consumption in response to extreme weather events to maintain local grid reliability.

Other technology companies and data centers are also testing demand-response initiatives by optimizing their operations. In the face of rapidly growing energy demand, these efforts could yield a very significant demand-side benefit.

Source: Mehra and Hasegawa 2023.

Lastly, demand response has the potential to lower overall electricity use. It is often assumed that demand response is "energy neutral"—that it simply shifts consumption to another period, with no energy savings, but empirical evidence has shown otherwise. Demand-response programs have brought energy savings of 3–6 percent of total energy consumption. The savings are achieved because not all the energy deferred (or not consumed) during peak hours is shifted to other periods. Furthermore, the technologies that enable demand response, such as energy management systems for buildings, can help customers reduce their overall energy consumption (Nemtzow, Delurey, and King 2007).

Demand-response programs have emerged as a critical, flexible tool in the energy transition, offering a range of benefits for grid operators and energy consumers. As the world continues to shift toward a cleaner energy future, demand response will play an increasingly important role in maintaining grid stability, reducing greenhouse gas emissions, and supporting a more sustainable energy system.

Endnotes

1. Specific issues include high ramp rate requirements caused by falling solar photovoltaic output concurrent with the evening peak, a low system inertia increasing the rate of change of frequency in the system following an outage event, and grid system congestion.
2. EVs accounted for 14 percent of all car sales in 2023 in People's Republic of China, Europe, and the United States, up from 5 percent in 2020 (IEA 2023).

3. After hourly pricing for residential customers was introduced in Illinois, a study was conducted to investigate the allocative efficiency and distributional impact of the tariff change (Environmental Defense Fund 2021). Annual savings from the program were $29.8 million. Most of the 344,000 customers reduced their electricity bill, for an average savings of $86.6 per year, but 5,800 experienced increases in their electricity bills of an average of $11 per year.
4. As countries advance on the pathway to net zero and reach very high VRE penetration levels, peak demand will increasingly be met by stored energy. However, this stage is not imminent for the large majority of power systems, large or small.

TWO
CLASSIFYING DEMAND-RESPONSE INSTRUMENTS

A variety of demand-response program designs with differing mechanisms and incentive structures have been implemented around the world. Demand-response interventions can broadly be classified as either indirect price-based mechanisms or direct quantity-based mechanisms. Price-based mechanisms rely on time-differentiated rates to induce customers to shift consumption away from peak hours or during system contingencies. Several types of time differentiation are possible; they vary in how precisely they reflect real-time grid conditions. Various quantity-based mechanisms are designed to shape user consumption in exchange for an incentive payment. Price- and quantity-based demand response is also known as implicit and explicit demand response, respectively.[1]

Each mechanism entails different incentives, business models, and response speeds (seconds, hours, day-ahead) and requires a different level of coordination between the grid operator, utility company, and the demand-response providers (customers or aggregators) that will interact with the market design in which the mechanism is deployed. Figure 2.1

FIGURE 2.1

Types of Demand-Response Mechanisms According to the Nature of Incentives

Price-based (indirect/implicit) *Consumer responds tomarket prices by reducing consumption*	**Time-of-use (ToU)**	Fixed ToU retail tariffs eliciting a demand-response in relation to predictable patterns of system stress (demand peaks and solar peaks)
	Critical peak pricing (CPP)	Narrow and high peak time price incentives to reduce demand reflecting both predictable periods of system stress and network investment drivers
	Variable peak pricing (VPP)	As per CPP but peak price level is variable dependent on level system stress (may be linked to wholesale market prices)
	Real-time pricing (RTP)	Fully flexible pass-through (may be within a hedge) of dynamic pricing to retail tariffs
	Peak-time rebate (PTR)	Payment for reduced consumption relative to baseline at peak periods
Quantity-based (direct/explicit) *Consumer receives a direct payment for reducing load*	**Demand-side energy offers**	Direct bidding/contracting in wholesale energy markets (day-ahead, intraday, balancing; where no market exists via bilateral contract and dispatch rules)
	Demand-side capacity offers	Direct bidding/contracting in capacity markets
	Auto load control/ interruptible load	Remote management of devices (tune or turn off/on) capable of supporting network and system operation services
	Manual load control/ interruptible load	Manual management of devices (tune or turn off/on) capable of supporting network and system operation services

Source: Adapted from Morales-Espana, Martinez-Gordón, and Sijm (2022) and NERC (2013).

Note: Some quantity-based instruments entail the offer of both price and quantity pairs to the system operator or market operator from which least-cost dispatch can be selected (sometimes involving co-optimization between wholesale and ancillary service markets). Here, these are termed quantity-based to differentiate them from pure price-based approaches where there is no explicit offer of a given quantity.

describes the different types of demand-response mechanisms, grouped into price- and quantity-based demand-response mechanisms.

The various demand-response mechanisms are not mutually exclusive. Most can be implemented in conjunction, targeting various customer segments and markets. For example, some countries combine time-of-use (ToU) rates for smaller customers with real-time pricing (RTP) for large customers. Others allow consumers to participate in either mechanism, depending on their preferences. The existence of, and access to, competitive wholesale and retail markets may drive choices and decisions. Small retail customers may have a form of time-differentiated rates and still participate in load control. This option will likely gain momentum with electric vehicles (EVs), because charging patterns are a crucial target for incentivizing demand shifting, while their batteries offer a potentially valuable storage resource. Small customers may be subject to ToU rates and still participate—via aggregators—in several demand-response programs at the wholesale level. Alternatively, large customers can often participate directly in the wholesale market (via market pools or bilateral contracts).

The alignment of each of the above demand-response instruments with the critical objectives of meeting the least-cost supply-demand balance, ensuring capacity adequacy, and delivering the suite of ancillary services to the system operator, is illustrated in Table 2.1.[2]

TABLE 2.1

Spectrum of Demand-Response Interventions

TOOLS	PRICE BASED					DIRECT PAYMENT BASED			
	TOU	CPP	VPP	RTP	PTR	DR ENERGY OFFERS	DR CAPACITY OFFERS	AUTO LOAD CONTROL	MANUAL LOAD CONTROL
Least-cost Energy provision	Yes	Yes	Yes	Yes	Yes	Yes			
Capacity Adequacy							Yes		
Reserve Provision								Yes	Yes
Frequency Regulation								Yes	
Voltage Control								Yes	
Constraint Management		Yes	Yes	Yes	Yes			Yes	Yes

Source: Author’s analysis.

Note: CPP = critical peak pricing; DR = demand response; PTR = peak time rebate; RTP = real-time pricing; ToU = time-of-use; VPP = variable peak pricing.

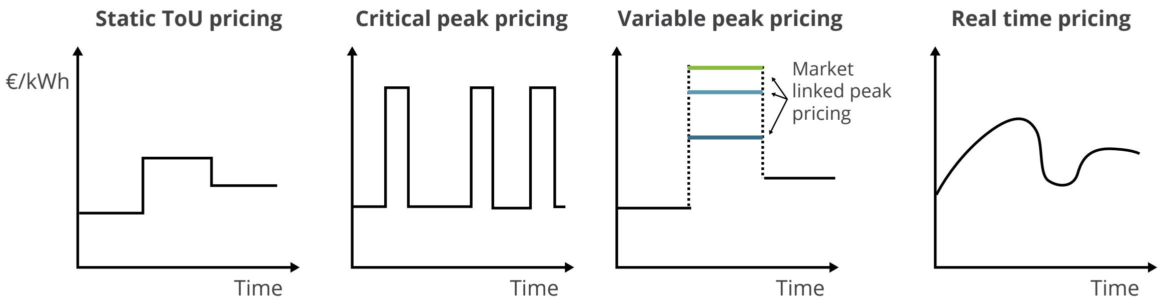
Price-Based Demand-Response Instruments

Price-based mechanisms (or implicit demand response) establish time-differentiated retail electricity rates. Unlike uniform pricing, rates are typically differentiated during peak, valley, and off-peak hours, or with even more granularity.

The four basic types of price-based instruments vary based on how closely they reflect grid and market conditions. Static ToU prices are fixed at predefined intervals typically differentiated during peak, valley, and off-peak hours. At the other end of the spectrum is RTP, which can vary in real time based on grid conditions. Other types of price-based instruments, such as critical peak pricing (CPP) and variable peak pricing (VPP), are somewhere in between (Figure 2.2).

FIGURE 2.2

Types of Price-Based Instruments



Source: IRENA 2019a.

Note: kWh = kilowatt-hour; ToU = time-of-use.

Price-based instruments can reflect time-differentiated costs associated with wholesale electricity generation and electricity network infrastructure. The former is driven by variances in the marginal cost of production as more expensive forms of generation are called upon to meet peak demand or periods of low variable renewable energy output. These variances are best priced in volumetric terms (US dollar per kilowatt-hour, $/kWh), reflecting the variable cost of peak generation plants. Network costs, by contrast, are overwhelmingly fixed and driven by the cost of meeting peak demand ($/megawatt [MW]).

Cost-reflective tariffs, therefore, seek to reflect this pricing structure with volumetric elements that vary with usage and fixed elements represented by standing charges (a flat monthly cost regardless of use) and demand charges priced to reflect contracted capacity or maximum demand. However, fixed costs are frequently recovered in part or in whole through volumetric pricing. Countries may, therefore, use price-based instruments to reflect network costs through a CPP approach or by having customers pay (higher) demand charges ($/MW) focused on usage during peak periods.

Fixed Time-of-Use Tariffs

ToU is a static pricing mechanism, with the price of electricity varying according to preestablished time intervals, which may be daily or, in some cases, seasonal. ToU tariffs may be implemented to reflect the underlying costs of generation and the grid at different times. If the challenge is to meet peak loads, the most common form of ToU is that in which tariffs differ for energy consumed during peak and off-peak hours (volumetric charges), reflecting the difference in generation costs.[3]

ToU tariffs are the most commonly used price-based demand-response instrument and are more frequently applied to commercial and industrial customers (Box 2.1). survey conducted in 2019 by the World Bank in 65 countries (mostly middle- and low-income countries) showed that large industrial and commercial customers in about 40 percent of the countries surveyed are subject to ToU rates. Residential customers, by contrast, were subject to ToU tariffs in less than 10 percent of the countries surveyed (Figure 2.3).

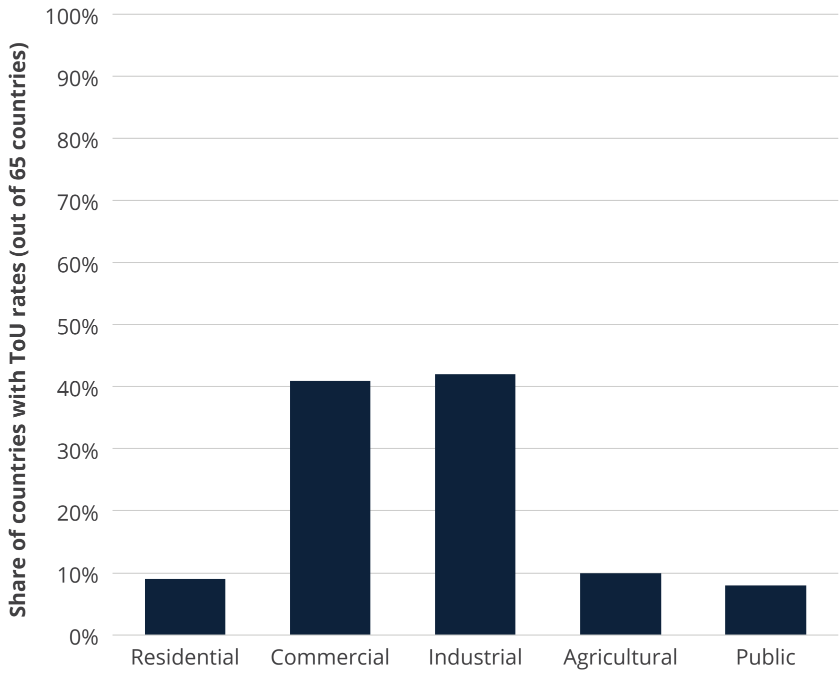
BOX 2.1

TIME-OF-USE TARIFFS FOR COMMERCIAL AND INDUSTRIAL CONSUMERS IN COSTA RICA

Costa Rica has used time-of-use rates, which are targeted to large industrial and commercial customers, with time differentiation for both the energy tariff (in $/MWh) and for the demand charge (in $/MW)—the so-called "two-part tariff." The day is divided into three periods: peak (5 hours per day), valley (9 hours per day), and night (10 hours per day). The ratio of peak to off-peak rates is high by international standards. Demand charges during peak hours are 2.24 times higher than during night hours, and energy charges are 4.4 times higher. This price differentiation strongly incentivizes customers to shift nonessential loads and production schedules from peak to off-peak hours. Despite the lower ratio for demand charges, customers have an extra incentive to control load and avoid peaks because demand is measured over 15-minute intervals; the maximum monthly read-out serves as he basis for the payment of demand charges for the entire month.

FIGURE 2.3

Share of Countries with Time-of-Use Rates, by Customer Class



Source: Foster and Witte 2020.

Note: Based on a database contained in the World Bank Regulatory Indicators for Sustainable Energy, which includes tariff schedules of 65 developed and developing countries: 7 high-income countries, 35 middle-income countries, and 23 low-income countries. ToU = time-of-use.

A 2013 study of US and European utilities showed that ToU is the most prevalent type of price-based demand response. Table 2.2 presents price-based instruments in reviewed European countries and US states. These instruments can be implemented as mandatory, opt-out, or opt-in. The choice of modality will affect adoption rates. Opt-in modalities, which rely on customers choosing to sign up for the program, tend to result in much lower subscription rates than opt-out modalities. Mandatory rates are the most effective for subscriptions. In jurisdictions with competitive retail markets, it is typically the prerogative of the individual retailers to design tariff structures and options that they consider most attractive to their customers, although some regulatory requirements may still apply.

ToU tariffs are generally simple and inexpensive to implement. However, static ToU tariffs do not reflect the system's condition at any given moment, and the flexibility of ToU rates is limited. This may become an increasingly important limitation as the share of VRE grows and periods of system stress become less predictable owing to low wind or high levels of cloud cover, threatening generation shortages outside of peak demand periods.

TABLE 2.2

Time-Differentiated Modalities in Various Energy Markets

ENERGY MARKET	TYPES OF PRICE-BASED INSTRUMENT[a]	MODALITY	ACCEPTANCE (%)
Colorado (Fort Collins)	ToU	Mandatory	100
California (Pacific Gas and Electric, Southern California Edison, San Diego Gas and Electric)	ToU	Opt out (in 2020)	75–90
California (Sacramento Municipal Utility District)	ToU	Opt out	75–90
Michigan (Consumers Energy)	ToU	Opt out (in 2020)	75–90
Spain	Real-time pricing	Opt out	40[b]
Arizona (Arizona Public Service)	ToU	Opt in	57
France	ToU	Opt in	50
Arizona (Salt River Project)	ToU	Opt in	36
Oklahoma (Oklahoma Gas and Electric)	VPP	Opt in	20
Great Britain	ToU	Opt in	13

Source: Adapted from Faruqui and Sergici (2013).

Note: ToU = time-of-use; VPP = variable peak pricing.

[a] These are typically rates applicable to the megawatt-hour (MWh) component (volumetric).

[b] The adoption is low despite opt-out. This is likely because customers were wary of real-time pricing due to the lack of understanding and uncertain impact on the electricity bill.

Critical Peak Pricing Tariffs

CPP involves a dynamic rate wherein prices rise significantly on critical days when there is a risk of low reserves or even blackouts. The energy price during those days may increase several-fold, reflecting the underlying generation costs and providing a significant incentive for customers to adjust their load profiles. Under a CPP structure, the utility notifies customers a day in advance and sometimes even on the day of the event. This tariff applies for a maximum number of critical days per year. Box 2.2 illustrates the case of South Africa, which has a CPP tariff for large clients.

CPP has been applied to a smaller extent in France, Lithuania, Portugal, and Romania (ACER 2016). France has been using the so-called “Tempo” tariff for many years. Under this scheme, each year is divided into three color-coded tariff categories: a maximum of 22 days is considered critical (and the highest tariff applies), 43 days are categorized as requiring attention (high tariff), and at least 300 days are considered standard (regular tariff).

Some US states, such as California, have introduced a type of CPP rate called CPP-variable for which the number and duration of peaks are not set ahead of time. The current

BOX 2.2

SOUTH AFRICA'S EXPERIENCE WITH CRITICAL PEAK PRICING

In South Africa, where electric heaters and stoves drive winter peak consumption, the government implemented the Nightsave program in 2020 to reduce peak loads. On critical days, the energy cost would jump from US¢3.2/kWh to US¢18.2/kWh. The peak–to–off-peak ratio (5.7) is thought to be high enough to motivate customers to change their consumption profiles. South Africa has been working to improve the program's pricing methodology. A new critical peak pricing (CPP) scheme was recently piloted by the state utility Eskom, offering two options for customers: 16 hours per day (06:00−22:00) for 25 critical peak days, or 8 hours per day (06:00−14:00) for 50 critical peak days, up to a maximum of 400 hours per year. The extended duration of the critical periods reflects the constraints that the power sector faces in South Africa. Both programs had excellent uptake, and the business processes for a dynamic tariff have been tested, with critical lessons learned for large-scale implementation of CPP. The 8 hours per day scheme had better uptake. According to initial surveys, customers were able to manage load reductions. But when the number of critical peak days in a week or month was too high, customer fatigue prevented significant load reduction. Therefore, dispatching the 50 days throughout the year requires careful implementation by the system operator. The benefits of CPP depended on Eskom avoiding higher open cycle gas turbine generation costs and reducing the risk of unexpected blackouts.

CPP-variable program for Southern California Edison, for example, provides four months of summer-season bill credits in exchange for customers paying higher electricity prices during 12 to 15 annual CPP events. The substantial difference between peak and off-peak rates is a powerful incentive for customers to react during critical periods (between 4 p.m. and 9 p.m.). Customers are notified a day before a CPP event occurs.[4]

Variable Peak Pricing Tariffs

VPP is a hybrid of ToU and RTP (discussed below). With VPP, as with ToU pricing, peak and off-peak intervals are predetermined, but unlike with ToU, during the peak period VPP customers are charged a rate that varies according to the utility/retailer and usually reflects the wholesale price of electricity. Because peak prices emulate market prices for electricity, VPP rate designs more accurately match the cost of producing and distributing electricity. The risk of high power prices is shifted during peak periods to customers, who can respond by reducing consumption. Box 2.3 describes Oklahoma's VPP scheme.

BOX 2.3

SmartHours VARIABLE PEAK PRICING, 2023

With SmartHours VPP, the daily peak price varies between low, standard, high, and critical rates. Customers can check pricing information or receive day-ahead price notifications via email, phone, or text from Oklahoma Gas & Electric. On occasion, high energy demand may cause a critical event. Although these events are rare, they can occur at any time of day and any time of year and last up to eight hours. Oklahoma Gas & Electric sends critical event notices at least two hours ahead to enable customers to prepare.

In the case of time-of-use (ToU) pricing, peak hours are charged at US¢26. With VPP, off-peak hours are US¢8; standard hours, US¢13 (half of the average ToU); and peak hours, US¢48.

Real-Time Pricing Tariffs

Under RTP, the energy (MWh) component of tariffs to the end users reflects spot-price variations (typically day-ahead) in the wholesale market.[5]

Some countries and regions have been trying a variety of dynamic pricing mechanisms to provide a better linkage between prices at the wholesale and retail levels (Faruqui 2005).[6] For example, in several European markets and New Zealand, energy retailers in competitive markets have offered dynamic RTP tariff options to various customer categories. These offers stand alongside more traditional fixed and static ToU tariff options and are crafted to appeal particularly to owners of solar photovoltaic systems and EVs.

The United States has been trying to implement RTP for a while now, but customer uptake has been slow. Reasons for the slow uptake are several and vary by state. Customers' fear that savings are uncertain is one reason. Their apprehension makes them hesitant to take on the risk of exposure to volatile spot prices. Another reason is that, in some states where retail competition is more active, some commercial and industrial customers are no longer interested in the regulated RTP rates offered by the utility because they can procure energy from alternative suppliers in the nonregulated market. Those customers may still be exposed to—and respond to—spot price variations (Barbose and others 2005).

The essential question is who bears the price risk, the retailer or the consumer? In a competitive retail market with various options available, consumers will self-select the degree of risk they are willing to take in return for the potential to lower their bills through demand response.

Spain has implemented elaborate price-based instruments with a hybrid of RTP and ToU. Generation costs are priced in real time, considering variations in the wholesale energy cost. Grid costs are priced in three differentiated time intervals. A summary of the current system is presented in Box 2.4, with additional information provided in Appendix B.

BOX 2.4

HYBRID PRICE-BASED INSTRUMENTS IN SPAIN

Spain has implemented sophisticated time-differentiated rates for residential customers to better reflect underlying generation and grid costs and encourage customers to change their consumption patterns accordingly. Since 2021, electricity bills have had the following components:

- System access fees to recover regulated costs (network costs and a group of energy- and policy-related costs, such as subsidies for renewables and system operation) are standard for all residential customers.
- A capacity charge is based on the capacity that each customer contracts; it is enforced via automatic disconnection. This component is offered in two options: one is fixed; the other is provided in peak and off-peak intervals keyed to EV evening charging.
- A network access energy component (€/kWh) has three prices—peak, low, and average. The average charge is about 10 times the off-peak price, conveying a powerful signal for load shifting.
- A dynamic hourly price (€/kWh) results from the direct pass-through of the published day-ahead and intraday market prices, plus the cost of ancillary services for the day after.

(*continues*)

BOX 2.4 (*Continued*)

The scheme should lead to savings of around 3.4 percent for 19 million households billed using time-differentiated rates (CNMC 2022). It poses an additional expense of €2 a month for another 8 million households. Changing habits could result in annual savings of €200 to €300 (CNMC 2022). According to consumer organizations, the average customer could save up to €574 per year if appliances were used half the time during the cheapest periods. However, there has been concern that the new methodology will penalize smaller consumers and benefit larger ones.

Source: CNMC 2022.

Effectiveness of Price-Based Demand Response

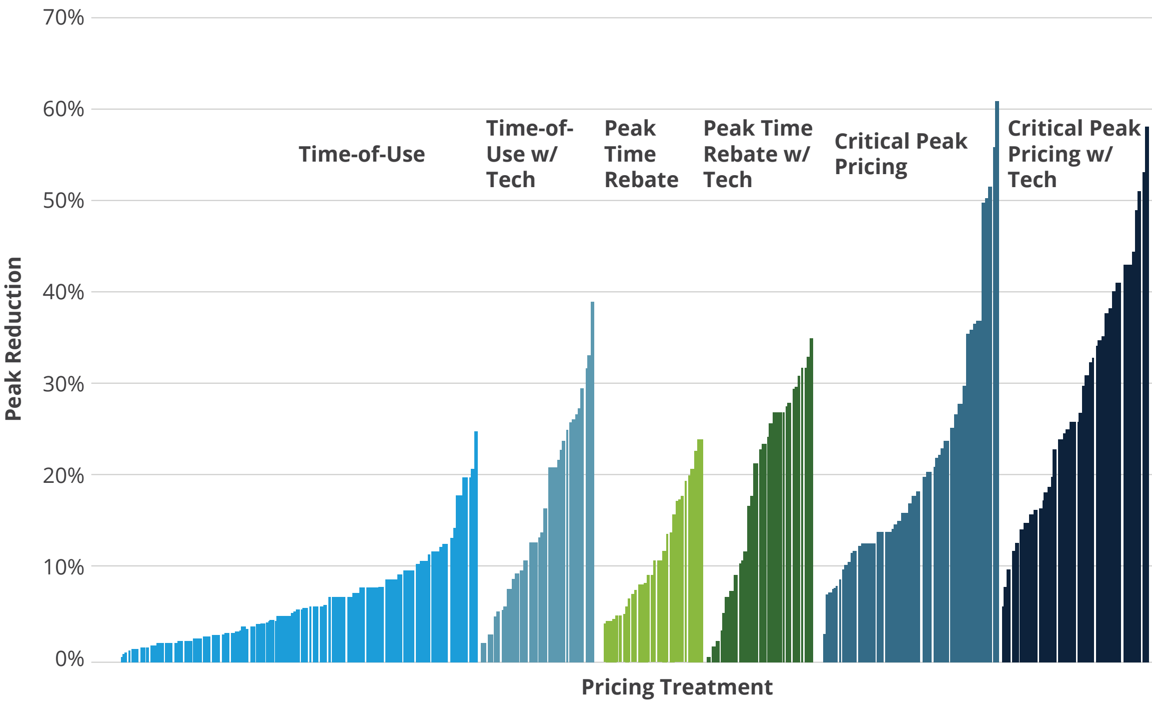
Price-based instruments (optional or mandatory) are essential to foster implicit demand response in the retail market. In 2017, a detailed study (Faruqui, Sergici, and Warner 2017) was conducted to analyze the impact of such mechanisms on electricity consumption. The study included 334 case studies from various parts of the world categorized into six basic pricing categories: ToU, peak-time rebates,[7] and CPP, each with and without the use of technologies to manage consumption during peak hours (Figure 2.4).

The analysis revealed significant variation in performance across the six pricing categories and within each one. The study found that enabling technologies such as smart thermostats can significantly boost the effectiveness of pricing schemes. For instance, in the case of traditional ToU pricing, peak reductions across the sample of projects ranged from virtually zero to about 25 percent, with a median of approximately 7 percent. Still, with the application of technology, the peak reduction ranged from 5 percent to almost 40 percent, with a median of about 16 percent. More sophisticated tariff mechanisms, such as CPP, resulted in peak savings ranging from 2 percent to 60 percent, with an average of 18 percent. When technology is applied, the peak reduction stays within the same range, but the median increases to more than 30 percent.

Several factors explain these significant differences in performance. The main one is the design of the tariff mechanism. Tariff design elements include the price ratio between peak and off-peak periods, the length of the peak period, and the number of pricing periods.

FIGURE 2.4

Average Peak Reduction from Time-Differentiated Rate Pilots



Source: Faruqui, Sergici, and Warner 2017.

Note: "w/ Tech" signifies the application of smart technology.

Quantity-Based Demand-Response Instruments

Several quantity-based instruments exist, encompassing interruptible contracts, direct or automated load control, and demand-side bidding in wholesale energy and capacity markets. These mechanisms may overlap depending on the structure of a particular power sector or market. All such mechanisms explicitly offer a combination of a given quantity level (lower demand relative to baseline) for a given price.

Interruptible Contracts

An interruptible contract is an arrangement in which a transmission or distribution system operator makes a payment to a customer or lowers tariffs in exchange for the ability to reduce or interrupt the customer's electrical service during system contingencies.[8] This enables some level of "dispatchability" (defined as the possibility of load response by the system operator) under the conditions spelled out in the agreement, such as notice period, duration of curtailment, and frequency.

Interruptible contracts are very effective. For example, they proved extremely important for the system operator in managing the 2001 power crisis in California. The rolling blackouts would have been more frequent and widespread without them (Sweeney 2013). South Africa has a negotiated pricing agreement with an aluminum smelter that provides two hours of interruptibility for an agreed maximum number of events per year. In several developing countries, the ability to interrupt large users is an additional balancing resource for the grid operator. Still, it happens ad hoc, without standard protocols for interruptibility or compensation. Interruptible contracts will remain important in future demand-response plans, particularly when operations can be automated, enhancing the speed and value of demand response (Hledik and others 2019).

Load Control

Distribution utilities and power system operators can selectively control loads remotely through direct load control. Load control may be manual (requiring an end-user response) or automated. In the latter case, switches are activated and deactivated without human intervention. Typically, load controls are opt-in mechanisms, and the customer subscribing to the service receives some form of monetary compensation for allowing the utility to control load during critical period "events." Unlike with interruptible tariffs, direct load control does not fit into a particular customer tariff group. Special incentives are set for those users, across customer categories, who subscribe to the utility's load control programs.

In all customer categories several pieces of equipment may be controlled. At the residential level, EVs are strong candidates, alongside cycling, air-conditioning, or heat pumps (controlled via switches or smart thermostats). At the commercial level, air-conditioning and refrigeration can be effectively controlled. Some simple but fast-responding technologies, such as water heaters, can autonomously respond to control signals. At the industrial level, the load control becomes process- and end-use-specific in situations in which loads can be interrupted temporarily or where there is some form of storage in the system (electric or thermal). Load control makes sense because it benefits the system and causes only modest disruption to users. Table 2.3 lists some kinds of loads that can be controlled and classified according to customer segment. One of India's early pilots of load control for medium-sized and large customers is profiled in Box 2.5.

Demand response is a beneficial, cost-effective way to provide many ancillary services, including voltage and frequency regulation, load following, and reserves, compensating for a lack of rotating inertia that most inverter-based renewables cannot provide.

Future demand-response resources should be able to provide an even faster response than traditional demand response (down to milliseconds), with the speed of response ranging

TABLE 2.3

Loads that can be Controlled According to Customer Segment

END-USE TECHNOLOGY	SECTOR		
	RESIDENTIAL	COMMERCIAL	INDUSTRIAL
Electric vehicles	Yes	Yes	
Plug-in hybrids	Yes	Yes	
Air-conditioning and heating	Yes	Yes	
Water heaters	Yes	Yes	
Pool pumps	Yes	Yes	
Lighting		Yes	
Refrigeration		Yes	Yes
Process industry and large facilities			Yes
Agricultural pumping			Yes
Data centers			Yes
Wastewater treatment			Yes

BOX 2.5

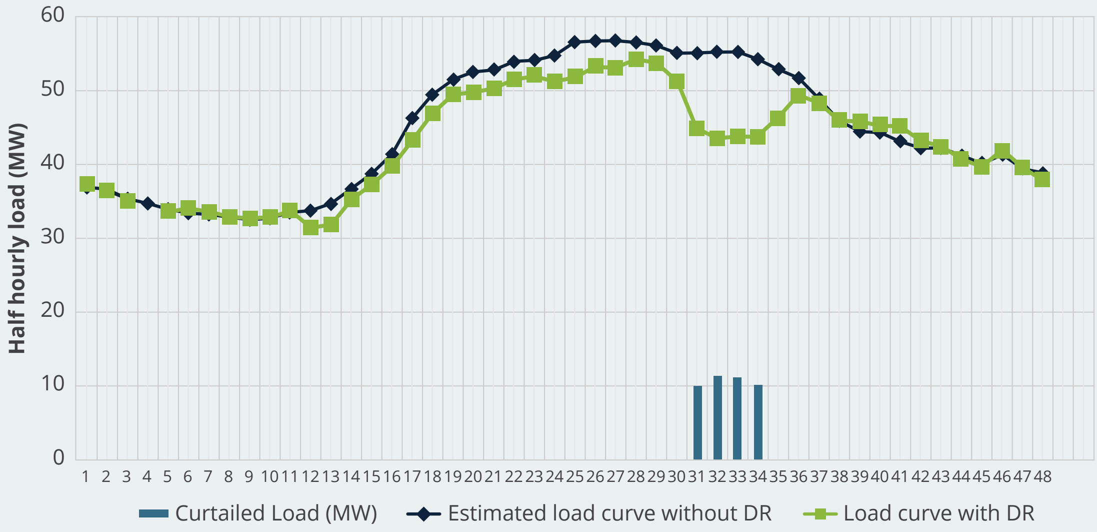
INDIA: LOAD CONTROL FOR LARGE AND MEDIUM CUSTOMERS

India has been implementing several pilots on load control. The first was designed by Tata Power in Mumbai. It was implemented in 2012 to reduce load during peak shortages, transmission line tripping, and generator set tripping, as well as when power purchase costs were high. Demand-response events were limited to a maximum of 2 hours, totaling 100 hours a year. Participation was optional, and customers could opt out at any time. Participating customers included malls, hospitals, municipal sewage plants, IT parks, and airports. The figure below illustrates the load reduction during a demand-response day. The peak load was reduced from about 55 GW to 42 GW, representing a significant contribution of demand response when the actual load is compared to the estimated load if no demand response had occurred.

(*continues*)

BOX 2.5 (*Continued*)

Load Control Pilot Program by Tata Power in Mumbai on a Demand-Response Event Day



Source: Tata Power 2012.

Note: DR = demand response; MW = megawatt.

from a few days in advance (in anticipation of heat waves or forecasted decline in wind production) to 30 minutes or less (e.g., to address system contingencies, sudden variation in PV production, or an increase in EV charging).

Demand-Side Energy Offers

Demand response can also be part of wholesale energy provision. This may include demand-side bidding (DSB) in organized energy pools at day-ahead, intraday, or real-time (balancing) markets to compete with supply-side offers. DSB, in this way, requires a functional wholesale pool market with central dispatch. Where such a market does not exist, demand response must contract via generators or suppliers trading on a power exchange. Should there be no wholesale market of either form, then a bilateral contract with the system operator, dispatching the demand response according to their defined dispatch rules, would be necessary. DSB offers under a merchant market approach (i.e., without long-term contracts committing availability) are essentially voluntary, the only penalty for failure to deliver being the prevailing electricity price. This has led to some system operators not perceiving the mechanism as a flexible, dependable demand-response option to help mitigate expected supply shortages (for example, reductions in generation) or demand increases (for example, during heat waves) (Cappers, MacDonald, and Goldman 2013).

Demand-Side Capacity Offers

Consumers can also participate in demand response in some capacity markets by bidding on contracts for demand reduction. The grid operator instructs winning bidders to reduce load when required. Unlike the DSB mechanism, bidders receive a fixed payment for availability, as grid operators need a “dependable” resource to be available for dispatch when needed. Demand-response mechanisms should be designed to compete on a level playing field with generators, which makes demand response equivalent to a supply resource.

System operators must count on dependable and reliable resources when dispatching power. Some demand-response mechanisms may be beneficial in theory but not considered strong enough to give system operators the assurance that the resources will be available for dispatch when needed. There is a perception that demand-response programs are not as dependable as thermal generation plants, which can presumably be dispatched on demand when necessary.

There are indeed cases when demand-response resources were overestimated and unavailable on request. For example, in 2001 in California, about a third of the resource adequacy requirements met by demand response was not available or directly accessible to the system operator in peak net load hours on days where “Flex Alerts” or system warnings were issued during heat waves (California ISO 2022). The Pennsylvania–New Jersey–Maryland interconnection has encountered similar situations in the winter (FERC 2023). There is a concern that demand-response programs used to meet resource-adequacy requirements are significantly overcounted compared with the actual availability of these resources, particularly during peak net load hours.

The key message is that availability mechanisms should be well designed, with frequent testing for demand response and generation assets and with penalties for nonavailability.

Measurement and Verification

In an explicit demand response scheme, electricity customers can offer to reduce their consumption, individually or through aggregation by an intermediary. However, measuring such a reduction requires the identification of a customer baseline load (CBL). A counterfactual must be established, as only actual consumption can be observed. Such a counterfactual is necessary to measure a demand resource’s effective performance and adequately compensate the provider.

Determining a CBL is challenging and will inevitably involve uncertainty and error. End users' electricity consumption is variable for several reasons unrelated to demand-response interventions. Weather conditions, production schedules, seasonal variations in firms and household needs, holidays, and other factors strongly affect the amount of electricity a customer consumes, independent of any price variation or incentive payment. Attempts to account for these aspects may help reduce (but not eliminate) the related uncertainty and increase efficiency to the extent they do not make the mechanism's design too complex. Conversely, the less predictable consumption is, the greater the scope for error and manipulation in deriving a CBL, thereby reducing the scheme's efficiency.

There are several methodologies for estimating CBL. Their suitability depends on the nature of the demand-response program and local measurement and verification standards. CBL estimations should balance various desirable criteria, including accuracy, simplicity, and integrity. The choice of the best methodology depends on factors such as the function the relevant demand-response mechanism fills in the system, the broader regulatory framework for demand-response participation in wholesale markets, and the characteristics of the demand-response providers.[9] The most common approach is using historical metered data, possibly amended by season and weather, with statistical processing to improve its use as a predictor of future use. The result is an assumed load curve representing the CBL of the consumer, or aggregated set of consumers. An example from Elia, Belgium's transmission system operator, follows.

Elia uses a set of different baseline methodologies to fit the various demand-response applications it deploys, all developed in conjunction with stakeholders to ensure they match the specific delivery characteristics of the providers and applications in question (Elia 2021). For manually instigated reserves, a combination of the last 15-minute interval plus a "high X of Y" approach is used, whereby the latter refers to taking the average of the highest X number of days among a set of Y for the equivalent hours in the preceding Y days. These results are adjusted under a "same-day adjustment" process. This adjustment seeks to account for weather-related impacts, as illustrated in Figure 2.5.

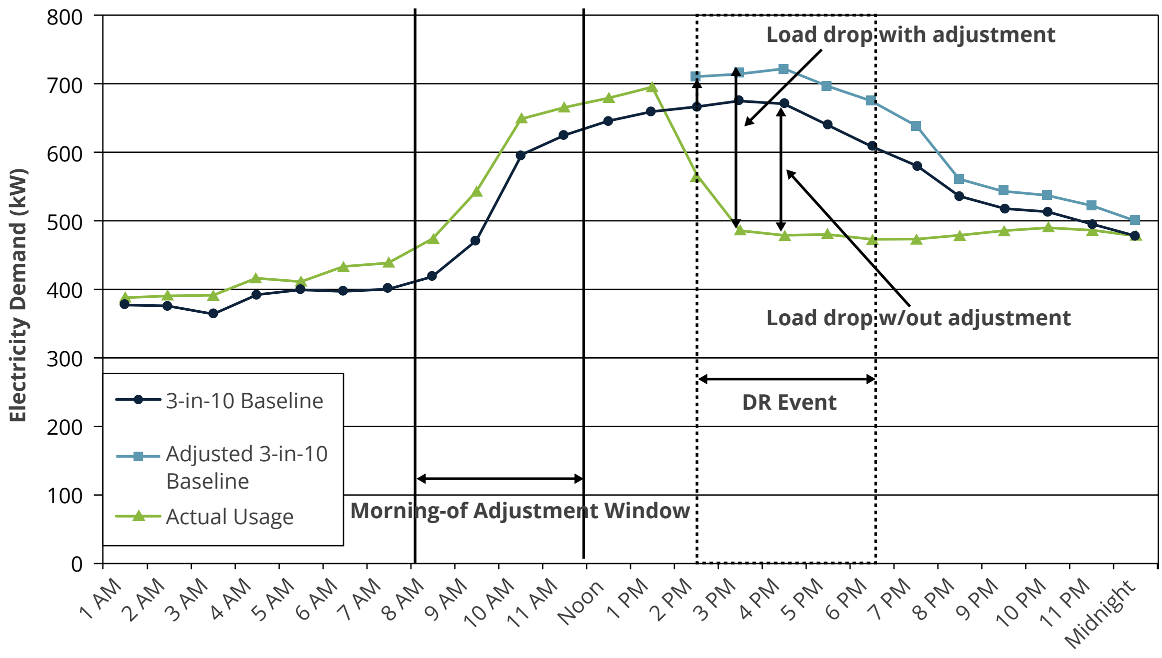
Elia considers its baseline approaches (including a declarative approach for automated frequency response services) broadly in line with best practices internationally. However, considering the diurnal volatility in output and consumption profiles, concerns persist about their future suitability for harnessing residential flexibility.

Endnotes

1. Alternative classifications are often used. For example, behavioral demand response relies on behavioral nudges and incentives to induce customers to shift or shed load. These are cost-effective, as they do not depend on any specific technology investments. Over time, however, they may cause customer fatigue, rendering them less effective.
2. See appendix A for details on ancillary services.

FIGURE 2.5

Elia's Same-Day Adjustment Process

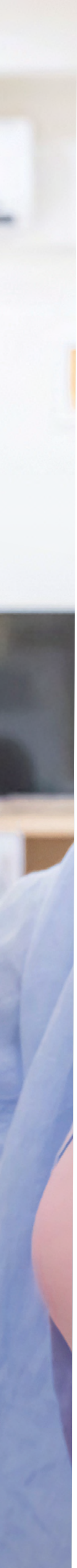


Source: Elia (2021), citing California Independent System Operator.

Note: DR = demand response; kW = kilowatt.

3. These are typically either two-tier or three-tier. Interest in recent years has shifted from simple daytime and night-time splits to a focus on separate pricing for peak demand periods (typically evening).
4. Southern California Edison, https://www.sce.com/business/rates/cpp.
5. Spot prices may be calculated with different levels of granularity, ranging from five minutes to one day depending on the existing settlement rules in the wholesale market. In bilateral contracting markets using self-dispatch, a liquid power exchange may be referenced. Where no wholesale market exists, a shadow price may be derived from the system's short-run marginal cost.
6. In competitive retail markets these tariff options may be offered by individual retailers.
7. Peak-time rebates are monetary incentives offered to customers who reduce their electricity consumption during periods of high-cost electricity. Those customers who do not reduce usage during peak periods are simply charged the rate normally applicable during those periods. The rebates may be considered similar to a static ToU scheme but with a sharp, differentiated peak period, the reward being an explicit payment as opposed to implicit saving.
8. The operator, particularly at the distribution system level, may be bundled with the retail entity, in which case the network tariff is aggregated with energy costs.
9. A detailed analysis of CBL methodologies exceeds the scope of this report.

THREE
INCREASING THE UPTAKE OF DEMAND RESPONSE: ENABLERS AND BARRIERS



The potential for demand response is far more significant than current levels of deployment and utilization suggest. This chapter describes critical enablers and barriers to implementation and uptake. Some enablers are recent, such as new technologies affecting loads that offer demand response. Others refer to remote management, and specifically the communications and data infrastructure for monitoring, processing, and relaying information in real time. The perceptions of system operators, other energy sector entities, and consumers also play a role. Incentives must be aligned for regulated entities, while customer engagement can help overcome consumer fears and produce greater understanding and buy-in.

Enablers

Technology and Data

Technology is a critical enabler of mainstreaming price- and quantity-based demand-response programs. Many technologies already support demand-response programs. New technologies will emerge to support more granular, faster demand response to meet the needs of future power systems amid the expanding penetration of variable renewable energy. Existing technologies include bidirectional communication, smart metering,[1] smart controls, smart thermostats, and energy management systems affecting the end user. Digitalization will strengthen the opportunities for demand response and behind-the-meter generation with smart inverters.

Smart meters deployed in most countries have helped lower losses and operating costs, but they can also support the mainstreaming of demand-response programs. Advanced metering infrastructure tracks the consumption of individual consumers. Smart meters record consumption on hourly, half-hourly, or quarter-hourly bases, allowing retailers to refine tariff structures for energy production and supply costs. They are necessary for market-based pricing schemes. Advanced metering infrastructure enables two-way communication between suppliers and customers. It integrates additional technologies, such as web-based portals, allowing customers to analyze their hourly electricity use, compare their use with that of other local consumers, and gather information about options to manage their electricity consumption better (IRENA 2019b). Smart meters can also help implement remote load control if equipped with relays (on-off switches). A broad range of technology options—including automation equipment, smart devices, storage, smart inverters, and communication infrastructure—are available to support quantity-based demand-response programs with various goals and degrees of complexity.

Ripple control—a load control technology in which a higher-frequency signal (carrier) is superimposed onto the standard 50–60 Hz of the main power signal—enables some equipment to be switched on and off remotely, reducing consumption during peak hours or contingencies on a systemwide or local level. The relatively simple devices required do not require smart metering infrastructure. Protocols and incentives should be agreed upon beforehand with the customer. It is a mature technology; the Czechia and New Zealand started using it in the 1950s. In emerging markets, it has been used in southern Africa for many years.[2] Box 3.1 illustrates the example of water heaters in Botswana. Simple load control switches use one-way communication that cannot be verified. Modern control systems can be web based and benefit from switching on/off features embedded in smart meters.

BOX 3.1

CONTROL OF HOT WATER IN BOTSWANA

Like South Africa (see section 5, under "Demand Response in South Africa," for a detailed discussion), Botswana implemented a hot water ("geyser") load control program in 2010. Prepaid smart meters were installed in key areas, enabling remote load control by the utility, the Botswana Power Corporation. This program reportedly achieved a peak load capacity reduction of 20 MW with an estimated potential of 40 MW.

In 2015, Botswana experienced a supply shortfall caused by deficits in the Morupule B generator and constrained imports from Eskom. In response, the Botswana Power Corporation implemented a load management program to reduce load-shedding events. The program was tasked mainly with lowering demand during the four-hour peak periods of 6–10 a.m. and 6–10 p.m.; the schedule was posted on the Botswana Power website. If the program were called upon, household and small business consumers were required to switch off all nonessential appliances to limit their load to less than 10 amperes. Consumption exceeding 10 amperes would be curtailed by the utility, which would notify the customer via an alarm. The customer would have three minutes to reduce their load below 10 amperes; if the reduction were not achieved, their load would be interrupted for 60 minutes. The 10-ampere limit was set to allow usage of typical 10 CFL lights, refrigerators, televisions, and decoders (BPC n.d.).

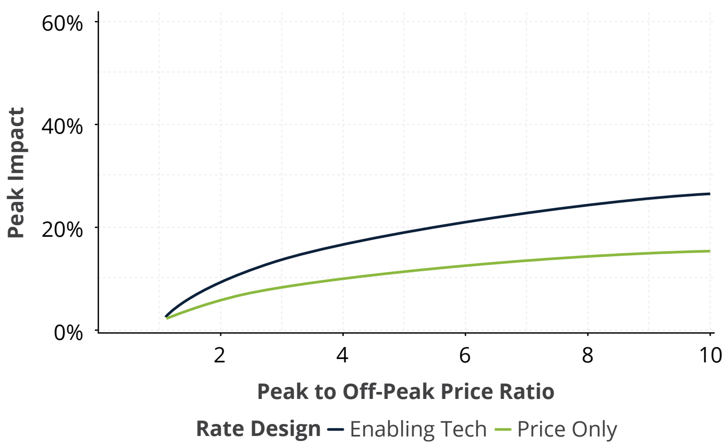
Remotely controlled thermostats evolved from traditional load controls. A new generation of smart thermostats (for example, Nest by Google) can be programmed and controlled online for heating, ventilation, and air-conditioning applications. They rely on two-way communication and can be used for variable load shedding, which allows for more refined control, possibly precooling by the grid operator, in anticipation of a heat wave. Home energy systems enable a comprehensive range of loads to be switched sequentially. The required process entails two-way communication, leveraging behind-the-meter automation.

Smart appliances can work in two ways; their use may be deferred in response to price signals or provide frequency services to the grid. Autonomous responses are critical for reliability and include refrigeration appliances that offer frequency regulation to the system operator. Both approaches are forms of demand response. The incremental cost of building the hardware and software to increase those capabilities is modest (around $20 per refrigerator).[3] More information about load control possibilities is provided in appendix C and Box 3.2 on electric vehicles (EVs) and vehicle-to-grid (V2G).

The use of enabling technologies boosts the impact of tariff mechanisms. Figure 3.1 illustrates the impact of tariff design and enabling technology on peak demand reduction. The graph has two curves. The lower one represents the impact of sending price signals to customers without smart technologies. The vertical axis shows the percentage reduction in peak demand induced by various peak and off-peak prices. Customers respond to higher peak to off-peak ratios by lowering peak demand but at a diminishing rate. For instance, at a price ratio of 2:1, the drop in peak demand is a little more than 5 percent; at 4:1, the reduction is 10 percent; and at 6:1, it is a bit more than 12.5 percent.[4] The upper curve shows the impact on peak response when technology is deployed.

FIGURE 3.1

Price Responsiveness With and Without Emerging Technology



Source: Faruqui, Hledik, and Sergici 2019.

BOX 3.2

ELECTRIC VEHICLES AND VEHICLE-TO-GRID

Electric vehicles (EVs) are a uniquely exciting technology and present a potentially significant source of demand response for power systems. They can make two possible contributions as a resource. The first uses demand response to manage the load by charging batteries off-peak and discharging during peak hours. The second represents an emerging business model that uses EV storage capacity to provide services to the grid.

The EV is typically the most significant individual load among households with an EV. A level-2 charging station, used in most households with EVs, draws 7 kW from the grid. Charging EVs is a sizeable increment in peak consumption, particularly because so many EVs are plugged in as drivers return home in the early evening (peak coincident). Utilities are concerned about the additional investment in peaking plants and grid expansion needed to accommodate this incremental load. In a scenario of growing EV penetration, demand response becomes necessary. The grid will be overloaded if all electric car owners decide to charge simultaneously. The good news is that EV charging has a low-capacity factor (for example, two hours per day), so this charging period can easily be shifted to off-peak hours. Utilities are designing special programs and encouraging customers to participate in demand-response programs. Special price-based instruments, including critical peak pricing and real-time pricing, are being offered, and in some cases, EVs are being treated as separate loads requiring submetering (Southern California Edison 2023). The demand-response process can be automated because most EVs have features that enable them to be programmed to be charged off-peak, making the demand-response program more effective.

EVs as an energy source is a breakthrough in terms of demand-response provision.[a] Vehicle-to-grid (V2G) takes advantage of EVs' large electric battery capacity, which sits idle most of the time. This storage capacity will far exceed the storage capacity in stationary batteries. V2G will increase flexibility and grid resilience (smart grid). This business model entails using parked EVs as a power source for the electric grid during periods of high demand while returning that power to the EVs during times of low demand. Studies have indicated that vehicles are not used for active transportation up to 95 percent of the time

(*continues*)

BOX 3.2 (*Continued*)

(Letendre, Denholm and Lilienthal 2006) and can be used to help the power system. For end users, V2G technology can provide an additional revenue stream. EV owners can discharge the stored energy in their vehicle's battery to the grid during peak demand periods, earning credits or cash payments. Unlike one-way smart charging, bidirectional charging should offer daily flexibility to the grid. V2G offers deep load-shifting benefits and an effective real-time mechanism for mitigating dynamic network constraints. The flexibility generated from V2G-enabled devices has the potential to accelerate the uptake of renewables (Horschig, Özgün, and Jones 2023).

V2G is still under development and testing. Despite its alleged benefits, there are challenges and concerns.[5] V2G has been criticized because its economics may not favor EVs feeding into the grid. Manufacturers and EV owners have expressed concerns that using the battery to provide price arbitrage and peaking power (deep cycles) will reduce the battery life cycle. Using a battery energy storage system to offer other ancillary services to the grid can be explored. Aggregators must consolidate multiple loads and offer them jointly to the utility or the system operator. Some manufacturers are mainstreaming V2G capabilities, and regulators are encouraging behind-the-meter batteries to provide ancillary services to the grid.

[a] Other business models include vehicle-to-home.

Supportive Policy and Regulatory Frameworks

Policies and regulations are essential to enable the adoption of demand-response mechanisms. Developing countries are at various stages of developing price- and quantity-based demand-response mechanisms. Some are still piloting time-of-use (ToU) rates, whereas others are advancing toward dispatchable demand-response mechanisms in the energy market. The nature and intensity of demand-response interventions will depend on various enabling factors, including sector structure, enabling technology, and policy direction. Regulators can support the evolution of appropriate, cost-effective demand-response mechanisms in several ways:

- Propose new pricing mechanisms to foster customer engagement and demand response. Propose new tariff methodologies, starting with ToU rates and evolving toward dynamic tariffs such as critical peak pricing and variable peak pricing. Review barriers and other incentives for customer engagement (for example, opt-in, opt-out, mandatory).

- Define the pace of implementation of new tariff regimes, proposing the development of specific pilots, if necessary. Conduct cost-benefit analysis along the way. Regulations must ensure that, at the institutional level, all roles and responsibilities are adequately defined and assigned to each actor involved.
- Support system and market operators to develop and implement quantity-based demand-response mechanisms, ranging from simple load control to more sophisticated and flexible demand-response product participation in energy markets.
- Identify winners and losers resulting from the implementation of demand-response programs and, if possible, eliminate conflicts of interest and perverse incentives.
- Agree on how enabling technology should be deployed and how customers should pay for it.
- Enable the emergence of new players and innovative business models.

New forms of demand response are being adopted in distribution. Historically, the owners of distribution networks have been largely passive, involved in connections and infrastructure delivery but not active as "system operators" instructing connected entities on load and generation management. This pattern is changing, however, and distribution system operators (DSOs) are discussed throughout this report. As noted above, smart technology can give the DSO and service providers greater real-time network status visibility. The combination of battery storage, EVs with V2G potential, distributed generation such as rooftop solar, and smart meters all enable a DSO to optimize electricity, and potentially energy as a whole, in a future, integrated system. These changes may help bring forward technologies to support decarbonization at the least cost on the one hand. On the other, these technologies face regulatory and market hurdles because the framework has been developed to accommodate traditional fossil fuel power generation. Such barriers can include a default preference by DSOs for wire (rather than non-wire) solutions for managing system constraints because the former contributes to their regulated asset base on which they earn a return.

The European Union is working to ensure its member states address such concerns (European Union 2019). Directive 2019/944 relates to incentives for procuring flexibility services from providers of "distributed generation, demand response or energy storage and promote the uptake of energy efficiency measures." Product categories for such procurement should ensure effective and nondiscriminatory provision. DSOs must also publish a network development plan every two years. This requirement provides transparency both on the flexibility provision in the coming decade and on requirements to integrate EVs in a way that allows for nonnetwork solutions. The development plan architects will need to consult system users for input.

A 2022 report by the Centre on Regulation in Europe, "The Active Distribution System Operator," describes three phases in this evolution of the DSO's role (CERRE 2022):

- **Phase 1:** Unbundling, efficiency-inducing regulation, including better supply continuity and quality.
- **Phase 2:** DSOs incorporating distributed energy resources (smart meters, EVs, photovoltaics, etc.) into their processes.

- **Phase 3:** Active management of these distributed assets to optimize their use and maximize decarbonization.

Demand response is critical in Phases 2 and 3. The right incentives must be in place, however, for the DSO to make this journey. Mechanisms used by regulators have included:

- Mechanisms that allow a portion of capital expenditure to be passed through to consumer bills for the highly uncertain expenditure related to the energy transition (for example, unit costs may be fixed, but volumes passed through—this approach has been used for smart meter rollout).
- Incentivizing better coordination between transmission system operators and DSOs where these are disaggregated data exchange platforms paired with increased digitalization/automation. Such initiatives may allow for better utilization and penetration of distributed generation (often from renewable sources), more system flexibility, and potential deferral or avoidance of network investments.
- Innovation funds and regulatory "sandboxing" (limiting derogations from usual regulatory constraints) to allow pilot processes to be trailed.
- A premium weighted average cost of capital for the allowed returns from certain investments considered high risk.

There is more in chapter 6 on the steps regulators and policy makers could take in accelerating the deployment of demand response, with a focus on developing countries.

Customer Engagement

The willingness of customers to take part in demand-response programs depends on a number of factors driven mostly by incentives and behavioral responses. The perceived net benefits of participation, perceptions of risk or uncertainty, ease of understanding the program, and trust in the program provider all play a role in voluntary participation.

One crucial factor is overcoming customers' fear of new demand-response schemes. Complex combinations of tariff types and load control programs can seem opaque and prevent consumers from choosing more dynamic pricing-based instruments or subscribing to load management programs. Customers are rarely familiar with their load profiles, how their actions may influence consumption, and the impact of all those factors on their electricity bill. Given this uncertainty, people often prefer a risk-averse approach, staying with flat tariffs or, if mandatory, accepting ToU tariffs. Many factors drive customer participation. The first is pricing structures. High peak to off-peak energy price ratios (that is, >4:1) are more effective at changing consumer behavior than low ones (that is, 2:1).[6] Several demand-response programs at the residential and small commercial levels allow customers to opt in or out.

Greater customer engagement addresses these concerns. The first step is ascertaining that proposed demand-response schemes are easy to understand. Information can change behavior because it facilitates the user experience and provides data about consumption patterns and the impact of load controls on customer discomfort. Energy suppliers, distribution companies and system operators, regulators, and trade associations should play a key role in communication. Communication strengthens customer understanding about how bills may change because of new tariff designs. Customers should be given simulation tools to see how their electricity bills change with different consumption profiles. Before the new tariff systems are mainstreamed, well-designed pilot programs should be run to test customer response.

Dynamic tariffs offered to the regulated market must provide a hedge against the most catastrophic price scenarios. Customers may fear events like the 2021 Texas power crisis, caused by intense cold weather, when spot prices skyrocketed to about $10,000/MWh. Customers who had shifted to variable-rate plans were suddenly exposed to spot price volatility and monthly bills exceeding $3,000.[7] Extreme cases amplify customer fear of accepting different tariff regimes, so additional incentives are needed to change the load profile in response to market signals.

As people accept and grow familiar with digitalization and automation in their daily lives, their attitude toward dynamic electricity tariffs may change. In the Republic of Korea, more than 60 percent of survey respondents preferred real-time pricing over less dynamic tariffs such as ToU (Clean Energy Ministerial 2014). The wider prevalence of distributed energy resources, including EVs, engages consumers with their energy use. Therefore, perhaps the biggest hurdle is reaching critical mass and then explaining why dynamic electricity tariffs work (Faruqui, Hledik, and Palmer 2012).

Barriers and Challenges

There are several barriers to the implementation of demand-response programs. Some are the same as those to mainstreaming energy efficiency programs, such as load fragmentation, customer resistance to changing consumption habits, inadequate incentives, and undermotivated policy makers and regulators facing thousands of customers and the need to achieve demand reduction while deploying enabling technologies. This section details the key barriers to demand-response deployment.

Supply-Side Bias

Utilities generally focus on the supply side (for example, building generation or transmission facilities) to meet customers' needs. Utilities are capital-intensive, and customers often have no choice but to buy energy from the local utility. Several other factors compound the supply-side orientation. First, interacting with a few existing supply-side participants seems easier and potentially more cost-effective to the electric power industry than creating new strategies to include the emerging demand-side resource (FERC 2013). Second, traditionally the utility earns a guaranteed return on the asset base, while the profit-sharing mechanism when the utility invests in demand response or energy efficiency is uncertain. There may also be a perception that having the customer help bridge the supply-demand gap will be interpreted as a failure in planning and execution. Consequently, demand-side resources (for example, large-scale deployment of demand response and load management systems) are frequently overlooked.

Customer Fatigue

An important factor in demand-response programs is customer fatigue. Customers may tire of making manual load adjustments or tracking prices over time, making the demand-response program less effective. This is true even for customers who have subscribed to demand-response programs (price or quantity based).

Technology is a crucial element maintaining effective demand-response programs over time. Remote consumption control can mitigate fatigue, make manual adjustments, and make daily decisions about when to activate which appliances. In the residential market, it is expected that management of distributed energy resources (demand response, self-generation, storage, EV charging) for demand response will increasingly be automatic without affecting homeowners. Utilities could be empowered to dispatch equipment remotely or be programmed to automatically react to a critical peak price signal (auto-demand response). In return, the homeowner would receive larger payments.

Fatigue occurs with all types of demand-response mechanisms that require human interference. Pricing mechanisms such as critical peak pricing should be applied to a maximum number of days per year. Otherwise, customers may not respond, and the mechanisms may lose their effectiveness. Likewise, the utility's load controls of smart thermostats are limited to several events per year. Otherwise, customers may override controls.

Behavioral science and "nudges" (subtle changes in the way choices are presented to influence behavior) have become increasingly relevant in the implementation of DR programs in the electricity sector. These can make DR programs more effective by helping utilities engage with consumers by applying principles like social norms, loss aversion, and the framing of incentives. By engaging consumer in a way that is both motivating and convenient, utilities can drive behavior changes that not only reduce electricity demand during peak periods but also promote a more sustainable energy future. With a combination of behavioral insights and technology, DR programs can be more efficient, scalable, and effective at increasing consumer participation.

Privacy and Cybersecurity Concerns

As smart meters multiply, there are concerns about collecting and sharing data, particularly disaggregated consumption data, with utilities and providers of demand-response services. Advanced metering infrastructure has the potential to enable demand response while improving both efficiency and grid reliability. The new generation of fast demand response requires time-disaggregated (nearly real time) data. Still, many are concerned about sharing these data because they reveal consumer habits. Some software (for example, Zigbee)[8] can examine time-disaggregated data (load profile) and determine which equipment was in use, when it was turned on and off, and other information that customers may want to keep private. It is perceived as a window into people's lives.

Cybersecurity is a second concern. Smart meter usage data are transmitted over great distances using communication networks that serve the smart grid. Customers fear that electronic equipment can be hacked, and that unauthorized parties or hackers could intercept this information. A smart house will contain several web-based sensors, equipment (for example, smart thermostats), and energy management systems to interface with the external world. There is also a concern that hackers will target smart meters to attack the grid. If hackers can take control of multiple smart meters, they can cause the load to vary in a regular pattern (oscillation attack), potentially compromising the grid (Latief 2023).

Big Data Management

Smart meters provide vast amounts of data. Compared with a monthly kilowatt-hour bill, the volume and variety of data may be overwhelming. For a typical residential customer, electricity may be metered at 15-minute intervals, including energy and peak consumption. If there is submetering for some special loads, such as EVs, the information doubles. If the customer is under any time-differentiated tariff (price-based demand response), consumption must be valued at each corresponding interval pricing. This meets the classical definition of big data, encompassing information that grows at an increasing rate, the pace at which it is created, and the variety of data points collected. Sorting out these data, extracting relevant information about consumption habits, translating it into useful information, forecasting customer behavior, proposing effective tariff structures, and testing the results are challenges that utilities face when implementing sophisticated demand-response programs.

System Operators and Perception of Dependability of Demand-Response Schemes

System operators are generally hesitant about the effectiveness and dependability of demand-response schemes. Empirical evidence in some US power pools, particularly that of the California Independent System Operator (CAISO), suggests that the potential of demand response can be overestimated, which can harm their reputation with system operators. Demand-response resources were not available when called by the system operator during emergencies, which raises issues about their dependability in the eyes of the system operator. Incentives and penalties should be carefully assessed in the design of demand-response mechanisms; actual demand-response potential should be reassessed periodically.

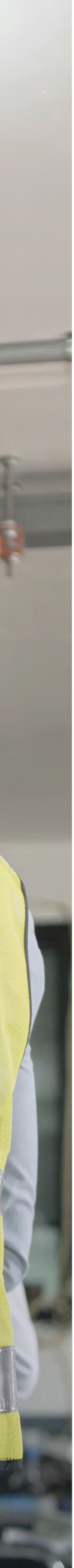
These concerns are particularly strong in relation to typical demand-side bidding (DSB) instruments when customers bid to reduce load (usually the day ahead). Customers may often withdraw their offers in real time without penalties other than the prevailing electricity cost; if removed in real time, those load reductions will not be available for the system operators to control (or dispatch). Furthermore, because customer decisions to bid are based on price, load reductions may take place too slowly to balance the system in the case of a contingency. Therefore, it is argued that DSB mechanisms are not as fast and reliable as a power plant, which may commit the day ahead and be penalized if it withdraws its offers in real time. These drawbacks, which have affected perceptions about the dependability of DSB in particular, could be addressed through automation and/or enforceable penalty provisions. Load control may also be procured in capacity and ancillary service markets, allowing demand response to behave like a power plant and therefore be considered a reliable source by the system operator as a reliable resource.

Endnotes

1. Smart meters have been deployed rapidly around the world. Even though their main aim is to reduce loss and operation costs, most have built-in features to control load and convey granular ToU pricing, supporting more frequent billing.
2. In early applications, the control signal was transmitted via the grid using transmitters with a range of up to hundreds of kilometers. The number of receivers per transmitter is unlimited. Basic load control switches use one-way communication to control load, with no verification.
3. Personal conversation with Edu Chaves, formerly of Whirlpool.
4. While this result is clear in illustrating the increased responsiveness of demand to higher ratios, economic theory would suggest an optimum response is gained through cost-reflective pricing that corresponds to the variation in the marginal cost of supply.
5. Most major original equipment manufacturers have committed to deliver V2G and vehicle-to-everything compatible EVs in this decade, and charge point manufacturers have made a similar commitment. For example, the Renault 5 electric is the first in a long series of cars to come equipped with a bidirectional charger. The innovative architecture integrates hardware such as natively reversible electrotechnical components and electrical-current management software that provides ongoing access to the V2G service while preserving battery capacity. A smart platform, Mobilize PowerBox, communicates with the car and the cloud to determine whether it should recharge the battery or send power back to the grid depending on battery charging needs, domestic needs, and incentives from the energy market and power grid. On the other side of the Atlantic, Ford F-150® Lightning® truck provides backup power to homes (vehicle-to-home) using an 80-ampere charging station. With extended-range batteries, the truck should be able to power a single home for three days.
6. This does not necessarily mean a higher ratio is always desirable; the objective should be cost-reflective pricing to encourage rational consumption decisions.
7. Some electricity providers offer variable-rate plans at the end of a fixed-rate contract, fully exposing customers to wholesale market prices.
8. A standard-based wireless technology developed to provide a low-cost, low-power, wireless machine-to-machine and Internet-of-Things network. Utility companies can use Zigbee on their smart meters to monitor, control, and automate delivery of energy.

FOUR

INTEGRATING DEMAND RESPONSE INTO POWER SYSTEMS



In theory, all market structures, including vertically integrated monopolies, can provide a route for demand response to participate in the electricity sector. However, the prevailing structures will influence the cost efficiency, scope for innovation, and available options. As markets evolve, there are opportunities to integrate demand-response mechanisms into the regulatory framework and the market design for energy provision, capacity, and ancillary services. While functional energy markets exist in many countries, demand is sometimes disregarded due to regulatory constraints, such as specific technical criteria designed around traditional forms of power generation.

This chapter introduces the contracting framework for the providers of price- and quantity-based demand-response mechanisms within the many power sector structures. It shows ways for a demand-response provider to participate in a liquid market (such as a power pool) or through bilateral contracting with a monopoly utility. The various demand-response instruments are introduced and illustrated alongside sample business models. These models may involve “revenue stacking,” which includes service provision and revenue generation from multiple applications. For example, vehicle-to-grid (V2G) and virtual power plants may offer both wholesale and ancillary services and trade in multiple markets.

Contracting Framework: Price-Based Demand Response

An indirect price-based demand response elicits a reduction or shift in demand from consumers in response to an electricity retailer’s time-differentiated tariffs (price-based demand response). The retailer may set appropriate rates considering the time-dependent variable cost of wholesale electricity generation and purchases, as well as network costs, which are driven by peak demand. (See Box 4.1 for the example of the Octopus tailored tariff provider.) Large consumers able to procure directly from any wholesale energy market may face disaggregated energy and network tariffs, each including time-differentiated elements.

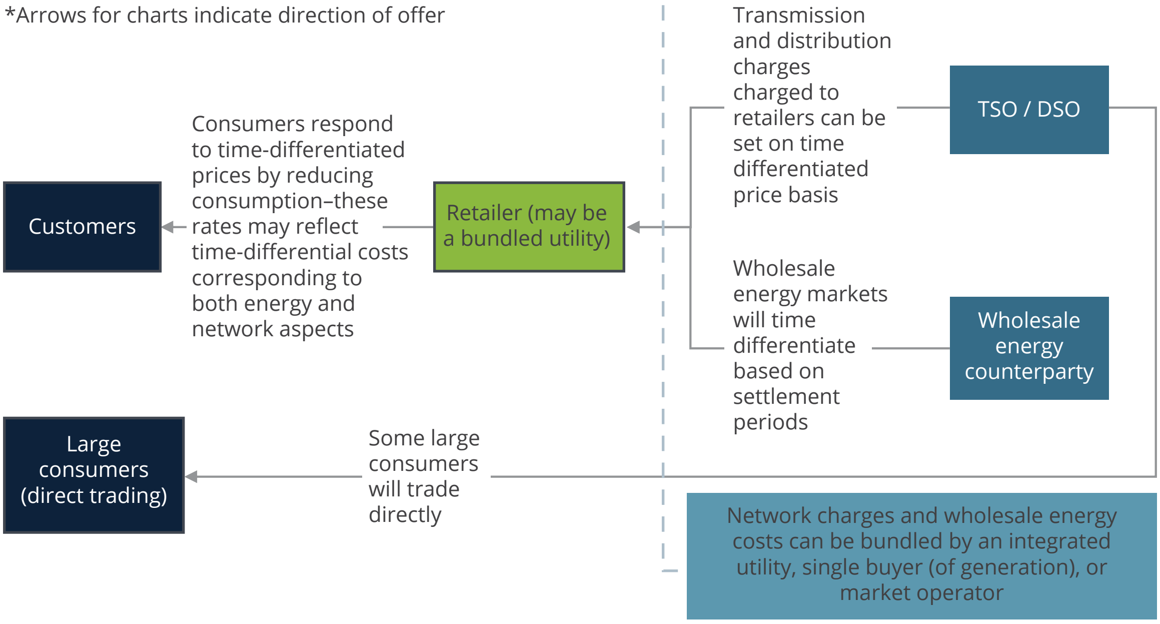
Distribution system operators (DSOs) and transmission system operators (TSOs) bear network costs at the distribution level and transmission level, respectively. How these costs are converted to network charges and levied on consumers relies heavily on the market/system. Where the DSO and the TSO are independent entities, they may levy network charges directly on system users (including generators, retailers, and demand-response aggregators). Alternatively, in a “gross pool” market (that is, one where a single market operator clears all generation and demand bids and offers with centralized dispatch), transmission network charges are often bundled with the wholesale energy price, possibly by location. In contrast, distribution network charges may be bundled with retail costs and may or may not be separately itemized on consumers’ bills. Power systems that have yet to develop active markets may bundle all costs within one vertically integrated utility or a single buyer (also when purchasing from independent power producers).

Even when entities are fully bundled, tariffs will be developed based on cost-of-service assessments and seek to be cost-reflective—meaning pricing principles seek to reflect an efficient market outcome. This means the principles undergirding a price-based demand-response instrument (that is, to reflect energy and/or network costs) can be developed in all cases.

Figure 4.1 illustrates the contracting framework for the provision of a price-based demand response. The arrows run from relevant entities (on the right), which set the applicable tariffs, to consumers (on the left), who respond.

FIGURE 4.1

Contracting Framework for Price-Based Demand-Response Providers



Source: Author's analysis.

Note: DSO = distribution system operator; TSO = transmission system operator.

Contracting Framework: Demand-Side Offers for Wholesale Energy Provision

Demand-response aggregators and large consumers may be regarded as equal to generators in wholesale energy markets (or through bilateral contracting and within dispatch rules where no such market exists). The United States provides an example of demand-response involvement in wholesale energy markets where demand-side bidding (DSB) rules enable customers (typically large consumers in the day-ahead market) to participate. DSB can be an efficient demand-response mechanism, especially if automated, by helping to clear the market at a lower price point as a cheaper demand-response substitutes for the marginal generator (that is, the most expensive generation unit required to meet demand). Integration

BOX 4.1

BUSINESS MODEL: OCTOPUS ENERGY TAILORED TARIFF PROVIDER

Retailers use tailored time-of-use (ToU) tariffs to design a range of packages for their customers. They create an incentive to shift the load to meet the system owner's needs and are based on customer requirements.

Emerging companies perform various roles in the price-based demand-response space. Octopus Energy Group[1] is one retailer that offers a range of innovative, tailored tariffs, including dynamic pricing, leveraging the national introduction of smart meters. The design is tailored to mass-market residential customers.

Octopus started developing a half-hourly ToU tariff that is tied to wholesale prices and updated daily (Agile Octopus); a bespoke tariff for indoor vertical farms; a tariff that falls as wind speeds rise (Fan Club); and has recently introduced the United Kingdom's first vehicle-to-grid tariff (Octopus Power Pack). Recently, Octopus has been offering savings to electric vehicle owners during "plunge pricing" events, when there is excess renewable energy on the grid and wholesale market prices fall. During these periods, discounts of 15–45 percent per kilowatt hour are available on the tariffs for charging electric vehicles, and vehicle owners might even receive payments for charging if wholesale market prices become negative at times. Customers are typically notified of a "plunge pricing" event 24 hours in advance via an app.

Sources: Jackson 2018; Octopus Energy 2023.

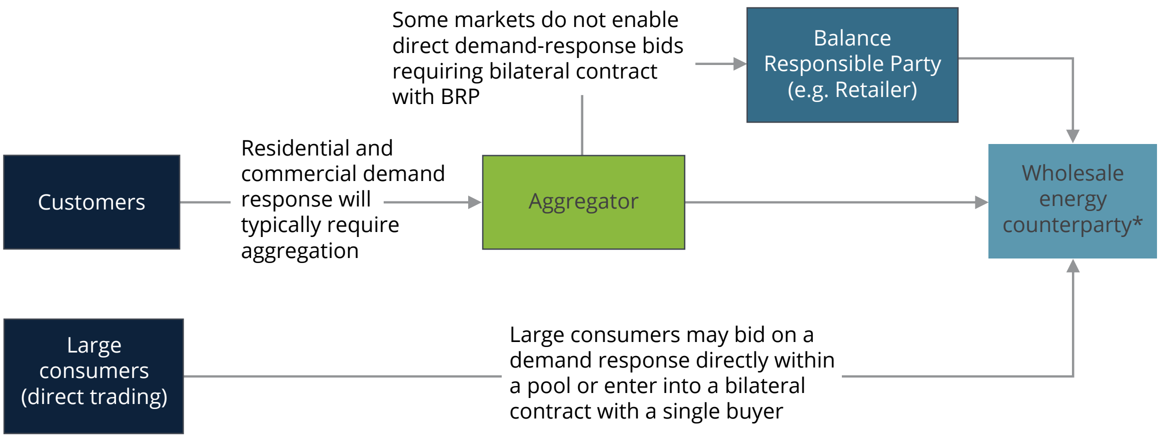
in the market can be complex, however, and weak penalties for failure to deliver can result in perceptions that a provider is not dependable.

In this form, DSB requires a market that is designed around a power pool with central dispatch, whereby a system operator can select and dispatch the least-cost mix of generation and demand response required to satisfy forecasted demand. Where no such pool with central dispatch exists, the demand response must contract through other market players, typically, retailers, to access the wholesale markets.

The specific market or power system structure will define the trade counterparty for a price-based demand response. In a gross pool framework, this would be the market operator. In other systems, it could be the bilateral trade counterparty, relevant power exchange, or a single buyer/integrated utility. A generalized framework is illustrated in Figure 4.2.

FIGURE 4.2

Contracting Framework for Demand-Side Energy Offers



* Counterparty will depend the on market/system structure.

Source: Author's analysis.

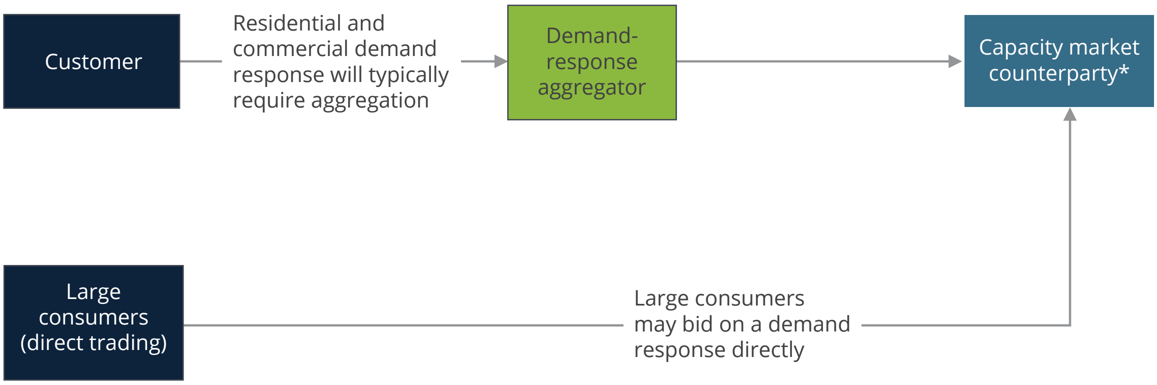
Note: BRP = balance responsible party (an entity responsible to the system operator for imbalances); DR = demand response.

Contracting Framework: Demand-Side Offers for Capacity

Capacity markets seek to instill confidence in system operators and enable them to secure adequate long-term capacity. There are concerns that so-called energy-only market designs—whereby the fixed costs associated with generation facilities are recovered through general volumetric wholesale electricity prices—may not provide sufficient certainty to attract the needed investment in new facilities. Capacity markets seek to address this concern by providing a reliable revenue stream so that generators can recover fixed costs. Such markets either do not exist or are new in many countries, but have become more prevalent, with concerns mounting about insufficient investment in new capacity, especially flexible capacity, to support the energy transition. Demand response in capacity markets offers good opportunities for customers to reduce their electricity costs (through payments) in exchange for a few demand-response events. It benefits the system by providing adequate capacity at a lower cost. Demand-response aggregators, including virtual power plants, can manage participation as shown in Figure 4.3 and discussed in Box 4.2. The financial benefit of the capacity payment (e.g., $150/MW per day) and substantial penalties for failure to pay explain why the participation of demand response in the capacity market can be robust (PJM 2024). If demand-response resources are reliable, they are comparable with generation resources. (See Box 2.6 for a discussion on the California ISO case.)

FIGURE 4.3

Contracting Framework for Demand-Side Capacity Market Offers



* As for the wholesale energy market, different market structures may define a different entity as the capacity market counterparty.

Source: Author's analysis.

BOX 4.2

BUSINESS MODEL EXAMPLE: VIRTUAL POWER PLANTS

In this business model, demand-response capabilities are combined with other behind-the-meter resources to emulate the behavior of conventional generators in the grid. Virtual power plants can offer various products to the grid, including trading in the spot (wholesale) market, network support to alleviate congestion, ancillary services, peak management, and capacity reliability. The existence of new distributed resources (e.g., photovoltaics and storage), combined with a portfolio of intermittent and dispatchable generators integrated with demand-response programs, enables aggregators to offer a broader range of sophisticated products and services in the market, operating like a virtual power plant. For example, slight, infrequent adjustments to the temperature settings of a smart thermostat (two degrees) can provide hundreds or even thousands of megawatts (MW) of peak demand reduction if aggregated across enough participants within a power market (Hledik, Viswanathan, and Peters 2023).

Virtual power plants aggregate small, distributed systems into single, controllable resources. Sunrun's virtual power plant in New England, United States, which

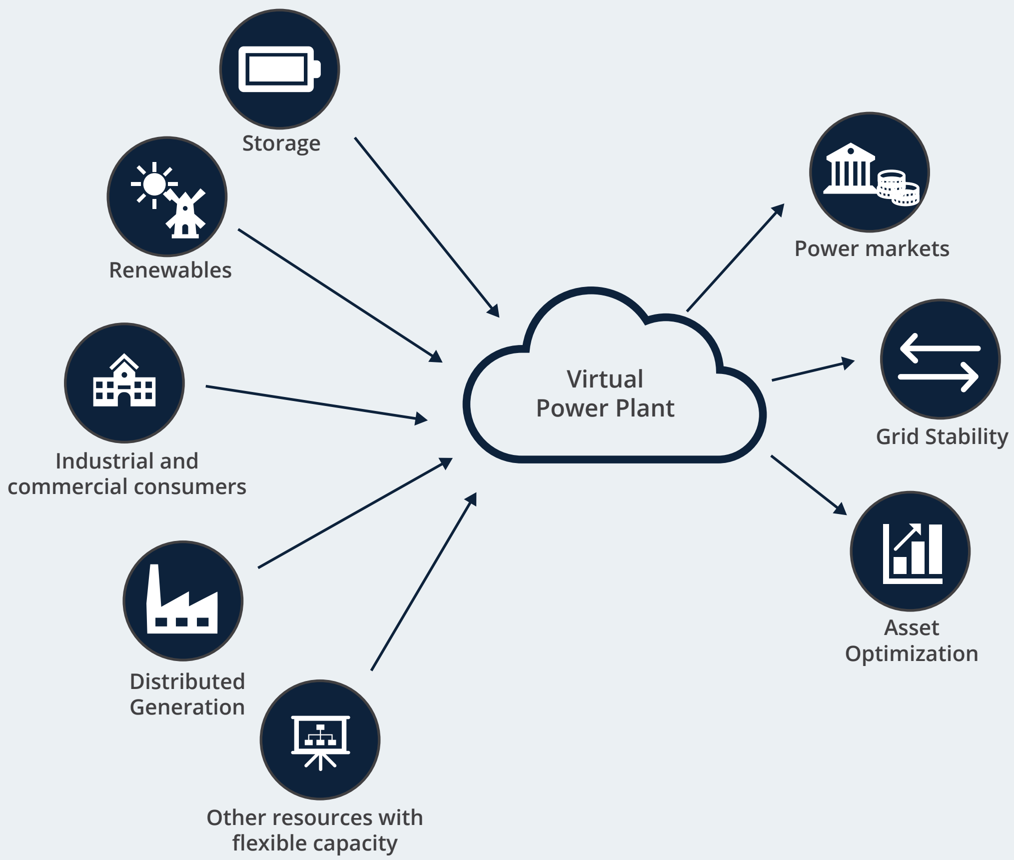
(*continues*)

BOX 4.2 (*Continued*)

encompasses thousands of homes with solar and battery systems, provided 1.8 gigawatt hours of energy over three months of the summer of 2022. AGL Energy's aggregation of battery energy storage systems in 1,000 residential and business properties in Adelaide, Australia, provided 5 MW of capacity between 2016 and 2019. The increased capacity could reduce customers' bills, lower the peak demand on the network, provide a wholesale market arbitrage, and supply frequency control ancillary services and voltage support.

The nature of the services and products can be tailored to meet the sophistication of individual power markets (Burger and others 2016). The figure below illustrates how a virtual power plant and the various behind-the-meter assets can be combined to provide grid services.

Behind-the-Meter Asset Classes in a Virtual Power Plant



Source: Adapted from NEXT (2023).

(*continues*)

BOX 4.2 (*Continued*)

The Brattle Group conducted a study to quantify the benefits of virtual power plants. It concluded that virtual power plants can be significantly beneficial to power systems (Brattle Group and SEPA 2019). A simulation was conducted to compare the cost and reliability of generating 400 MW of power through virtual power plants containing smart thermostats, electric vehicle chargers, smart water heaters, and behind-the-meter batteries. The study explored whether virtual power plants can provide resource adequacy with the same level of reliability as gas plants and utility-scale batteries in a power system with 50 percent renewables. The study suggests that the net cost for a utility to provide resource adequacy from a virtual power plant is about 40–60 percent less than from natural gas peaking plants (peakers) and utility-scale batteries. Deploying 60 gigawatts of virtual power plants could meet future resource adequacy needs of the United States for $15–$35 billion less than the cost of alternative options over the next decade.

Contracting Framework: Demand-Side Offers for Ancillary Services

Ancillary services include, but are not limited to, reserves that are able to respond to any outage event and arrest the associated frequency deviations; ongoing frequency regulation to oversee fluctuations in demand and variable renewable energy input; voltage support services to administer localized deviations; and network constraint services to manage congestion.[2] Large consumers that can reduce their demand quickly—sometimes much faster than any generator can ramp up—should be (and often already are) paid to be ready to do so (an availability-payment equivalent). Provision has little impact on comfort or convenience because events are brief (for example, 30 minutes or less). They are paid in return for being prepared to quickly modify the supply-demand balance of a system. (See appendix A for the main ancillary services.)

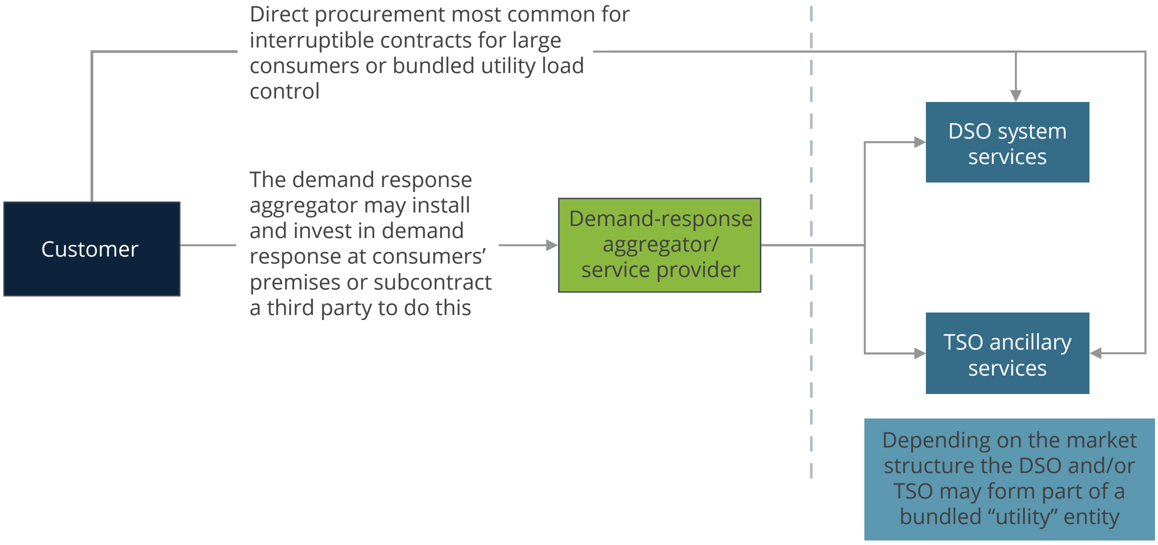
More European countries are participating in demand-response ancillary services through various asset classes, such as home batteries and electric boilers (Belgium), electric heating and boilers (France), and remote control of appliances and electric vehicles (Norway). In some cases, households can participate in an explicit demand response for ancillary services based on the products the TSO defines through aggregation (Slovenia). In other cases, quantity-based demand-response offers are limited to consumers with the technology to record consumption in half-hourly increments.

While both TSOs and DSOs can manage ancillary services, for DSOs, they are typically referred to as "system services" instead. System frequency regulation and reserve procurement and dispatch are generally a TSO's sole responsibilities, since those are systemwide attributes. At the same time, both TSOs and DSOs may contract providers for voltage support and congestion support for their respective networks. A separate market operator can, in some cases, undertake the procurement of some ancillary services at the transmission level to meet stipulated volume requirements. Offers can be co-optimized with energy bids and offered in a pool market to meet the least-cost dispatch.

This contracting framework is summarized in Figure 4.4.

FIGURE 4.4

Contracting Framework for Demand-Side Offers to Ancillary Service Markets



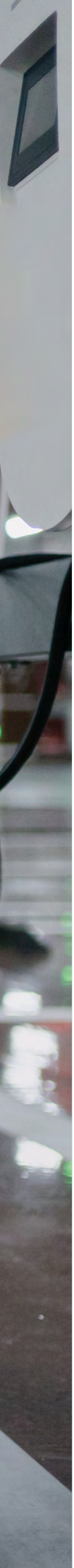
Source: Author's analysis.

Note: DR = demand response; DSO = distribution system operator; TSO = transmission system operator.

Endnotes

1. Octopus is a UK-based company selling electricity services to 5.4 million customers globally through its retail arm. It has also licensed its advanced data and machine learning platform, Kraken, to support millions of customers worldwide.
2. The nomenclature and product definitions associated with these services are market specific but will typically cover these functions. Reserves are typically subcategorized into those that are able to respond quickly (often referred to as "spinning reserves" because, as traditional plants, they are synchronized with the grid) and those with a slower response time, which are called on to free up the faster reserves.

FIVE LESSONS LEARNED FOR DEMAND RESPONSE IN DEVELOPING COUNTRIES



To assess the status of demand-response implementation in developing countries, this chapter looks at programs in five mid-size and large emerging economies—Brazil, People's Republic of China, India, South Africa, and Viet Nam. It also examines the unique challenges faced by small island states or territories, using as a benchmark the United States, one of the most highly developed demand-response markets in the world. In the United States, several states in the mid-Atlantic region and parts of the Midwest are served by PJM Power Pool, one of the most aggressive demand-response markets in the country.

When comparing the five countries (Brazil, People's Republic of China, India, South Africa, and Viet Nam), the study considered the existence and nature of ToU (time-of-use) rates combined with load control and demand response.

Demand Response in India

Historically, demand management received insufficient attention from Indian policy makers as a resource for planning short- and long-term electricity systems. System operators and distribution utilities have responded to changes in customer demand by adjusting generation dispatch, planning for adequate supply reserves, or managing the load through supply interruptions.

India is, in other words, in the early stages of designing and implementing price- and quantity-based demand-response initiatives. The country now recognizes the role played by demand-response mechanisms in meeting power system needs at the national and subnational levels—challenging given the rapid growth in demand for reliable, affordable, 24/7 power supply. Demand-response mechanisms are seen as an efficient means of limiting supply disruptions and contributing to the shift toward cleaner energy sources. Air conditioning is the leading driver of peak power demand in India as per capita income and urbanization cause the use of air conditioning to surge.

In the 2021 grid code, India’s Central Electricity Regulatory Commission recognized the value of demand response in lowering electricity supply costs and supporting reliable grid operations with high levels of variable renewable energy (VRE) (Sasidharan and others 2021). But implementation rests with the distribution companies, which because of technical, economic, and financial barriers have yet to undertake large-scale programs.

Over the past several years most states in India have implemented various ToU tariff designs, focusing on industrial and commercial customers connected to high- and medium-voltage. These tariffs are typically calculated via a surcharge and a rebate applied only to the energy component of the conventional tariff (Table 5.1). Seasonally adjusted implicit peak-to-off-peak ratios vary between 1.3 and 2.0 (with an average of 1.5). These are relatively modest ratios: in Brazil and South Africa ratios may reach 6.0; the ratio in Beijing (People's Republic of China) is 4.3 (Ferriera and others 2013). The impact on the load profile is more significant in states with larger off-peak ratios. Still, unmonitored industrial facilities will hamper efforts to assess the effectiveness of the ToU tariff programs (Chunekar, Kelkar, and Dixit 2014; PwC 2010).

TABLE 5.1

Time-Differentiated Tariffs in India, by State

STATE	TARIFF
Bihar	ToD tariff applies to all high-tension consumers. Surcharge of 20 percent or rebate of 15 percent applicable to energy charges during peak and off-peak periods.
Chhattisgarh	ToD tariff applies to select high-tension consumers. Surcharge of 20 percent or rebate of 15 percent applicable to energy charges during peak and off-peak periods.
Delhi	ToD tariff applies to all consumers (except households) whose sanctioned load or maximum demand indicator (whichever is greater) is 10kW/11kVA or above. ToD optional for household consumers. 20 percent surcharge or rebate is applicable to energy charges.
Gujurat	ToD tariff applies to some high-tension consumers. Surcharge of 10–20 percent applied to energy charges during peak hours. Nighttime concession available to consumers opting to use electricity only at night.
Haryana	Optional ToD tariff applies to high-tension industrial customers from October through March. 19 percent surcharge and 15 percent rebate applicable to energy charges.
Jharkhand	ToD tariff applies to high-tension consumers. 20 percent surcharge and 15 percent rebate applicable to energy charges.
Punjab	Additional charge of Rs. 2/kVAh during peak hours and rebate of Rs. 1.25/kVAh during off-peak hours apply to medium-sized and large industries, nonresidential, and bulk supply customers. Peak tariff applies only June through September; off-peak tariff applies for rest of year.
Kerala	ToD tariff applies to extra-high-tension, high-tension, and low-tension industrial consumers with connected load of at least 20kW. Surcharge of 50 percent and rebate of 25 percent applicable to energy charges during peak and off-peak hours.

Source: Adapted from CERC (2019).

Note: ToD = time of day.

Since 2012, distribution companies in India have initiated commercial and industrial load control pilots. For instance, Tata Power, which controls several distribution companies, has designed and implemented demand-response pilots in Mumbai and New Delhi. One of India's most innovative utilities, Tata is also rolling out India's first smart meter–based pilot program for peak demand and grid stress using automated demand-response management. The pilot relies on real-time communication to share information on the load to the utility and consumers, improving transparency. The utility also conducted a pilot of behavioral demand response that targeted residential customers, demonstrating the potential savings to the utility and customers. With peak demand four times greater than off-peak demand, the targeting shaved off-peak demand.

Similarly, BSES Yamuna Power Limited, a joint venture of the government of Delhi and Reliance Infrastructure Limited, carried out manual demand-response pilots between 2017 and 2019 to assess the benefits of lower peak load costs and flexible load management (Bureau of Energy Efficiency 2023, accessed 2024). The first pilot saw 30 industrial and commercial customers participate with an avoided peak of 17 MW, while the second pilot saw participating entities rise to 60, with 32.5 MW avoided, respectively. Requests were conveyed and confirmation sought through instant messaging services on smartphones to curtail noncritical loads in return for incentive payments.

These pilots confirmed that customers can lower their consumption during peak hours, improving grid reliability (Poojary and others 2023). If load control projects like those described above were deployed in the commercial and industrial sectors across India, the country's peak electricity demand could drop by around 7.5 GW, or 5 percent of total peak demand (Poojary and others 2023). Appendix B contains more information on pilot programs by distribution companies.

Many different sources can provide demand response. For example, direct load control and interruptible pumping programs are possible because feeders supplying energy to agricultural pumping are often segregated from other loads. Nighttime watering occurs during demand-response events. Utility or demand-response providers could curtail reliance on switches or timers or manual demand response by the farmers.

Similarly, as 70 percent of the growth in air conditioning is expected to come from the residential sector alone, it is critical to design demand-response programs targeting this segment. With respect to the uptake of air conditioning, there are three possible demand-response scenarios: (1) switching air conditioners on and off, (2) adjusting thermostat settings, and (3) load cycling. Wifi-enabled smart air conditioners can manage loads by building in capability for demand response. Others could convert to demand response with wifi-enabled plugs (Sasidharan and others 2021).

Despite the success of India's pilot programs and the potential for scale-up of demand response, barriers remain in policy, regulatory, technical, and economic areas. These barriers affect the willingness and ability of distribution companies—the companies responsible for demand-response implementation—to undertake large-scale programs.

A key policy barrier is the subsidization of electricity, which pushes sales below cost-recovery rates. This can prevent the benefits of avoiding or shifting consumption from accruing to financial benefit of the provider. The lack of cost-reflective tariffs is compounded by the small differential between peak and off-peak tariff rates under ToU pricing.

Regulatory barriers are also constraining. In the 2021 grid code, India's Central Electricity Regulatory Commission recognized the value of demand response in reducing electricity supply costs and supporting reliable grid operations with high levels of VRE (Sasidharan and others 2021). Nevertheless, regulations often fail to define the term and focus instead on peak shaving in response to previous supply gaps rather than flexibility for integration of renewables.

Cost-plus[1] regulatory frameworks do not provide incentives to distribution companies to reduce costs. Instead, they link distribution company revenues directly to the volume of energy sold, disincentivizing the adoption of programs to reduce consumption. Taking more of a revenue approach, supported by performance-based incentives that encourage demand-response uptake, could ameliorate this conflicting incentive. The regulatory framework for demand response could be treated on an equal basis from an economic perspective by taking the following steps (Sasidharan and others 2021):

- Ensuring that distribution utilities are incentivized to consider non-wire solutions to network congestion or constraints on a basis equivalent to network upgrades
- Allowing greater flexibility in the design of tariff options for consumers
- Ensuring that demand-response aggregators have access to ancillary service markets
- Integrating the cost of emissions in least-cost dispatch calculations.

KEY TAKEAWAYS

- India recognizes the need for demand response to cope with the expected growth of its economy and power sector, including surging demand for air conditioning.
- Government and some utilities have been developing load control pilots for various customer segments. Customer reaction and pilots have been encouraging.
- Projects offering price-based demand-response can demonstrate potential and build capacity, but to yield full benefits, they must be supported by a follow-up strategy, which requires changes in the regulatory framework.
- The incentives within the regulatory framework for controlling revenues and tariffs will be instrumental in gaining buy-in from distribution utilities to implement demand-response programs.
- Monitoring pilots and programs is essential to ensure that necessary findings can be evaluated and adjustments made to improve results.

Demand Response in People's Republic of China

As a large industrial nation with a forecast peak load of about 1 TW by 2020, China is a large potential market for demand response. Roughly 5 percent of China’s peak electric load, about 60 GW, is met by generators, demonstrating a solid case for demand-side interventions that can lower loads in homes, businesses, factories, and government facilities via price signals or market payments (Liu 2016). Harnessing the full potential of demand response would require the creation of markets to unite customers and grid operators.

Over the past three decades, People's Republic of China has developed a number of demand-response programs. In the early 1990s several programs fostered energy efficiency, reduced consumption, and higher productivity. Some mechanisms were integrated into demand-side management policies, which have become more sophisticated, with a national law on ToU tariffs for industrial customers and additional large-scale demand-response programs.

Since the late 1990s, People's Republic of China has rolled out ToU prices to balance daily electricity use. The initial objective was to encourage industrial users to shift to off-peak periods. Most Chinese jurisdictions have introduced ToU tariffs for industrial consumers in a pilot project or as a permanent solution (Tahir and others 2020), with peak and off-peak rates that rose over time. Time-differentiated tariffs (price-based demand response) are sometimes available to residential customers. People's Republic of China does not have a national ToU policy applicable to all utilities and customer segments. Each city and province defines the type of ToU rates and the ratio of peak to off-peak tariff.

Shanghai was the first large city in People's Republic of China to widely adopt ToU rates, although such rates had already been applied to large industrial customers in other jurisdictions. Beginning in May 2001, the cost of electricity in Shanghai became 50 percent lower at night than during the day. Four hundred thousand households were eligible to opt into time-differentiated tariffs. Estimates show that they could cut their off-peak consumption by 25 percent, reducing their power bills by 12.7 percent. Because so few consumers signed up for these programs, however, the impacts were limited.

Beijing began engaging in ToU primarily for load management in response to escalating peak demand and a sinking load factor. In 1996, after determining which industrial users consumed at least half of their electricity during peak periods, the Beijing electric utility implemented ToU pricing and other demand incentives to shift consumption to off-peak periods. The peak to off-peak ratio is now 4.3:1, enough to direct the load away from peak periods for many.

In 2002, Jiangsu became the first Chinese province to issue demand-side management regulations and activate a pilot demand-response project that combined ToU rate structures, interruptible tariffs, voluntary load shifting, and deployment of storage devices (particularly thermal storage) to facilitate load curtailment and better manage the supply-demand mismatch. Large industrial customers were instructed to undertake administratively rationed, uncompensated load reductions to reduce peak demand. In 2012, the Tianjin Economic-Technological Development Area implemented China's first automated demand-response project (Navigant 2013; Samad and others 2016). The project comprised 33 commercial and public buildings and 31 steel, chemical, and automotive industries as customers with 100 MW of combined load-shedding capacity. The central government paid each participant two renminbi per kilowatt-hour of reduction, and the local Shanghai government spent an additional two renminbi per kilowatt-hour, which adds up to roughly 36 US cents per kilowatt-hour, or four times the local retail price of electricity.

The main features of these pilot programs are summarized in Table 5.2.

TABLE 5.2

Demand-Response Pilot Projects in China

	SUZHOU, JIANGSU	BEIJING	FOSHAN, GUANGDONG	TANGSHAN, HEBEI
Programs offered	Interruptible load programs (real-time and contract demand response)	Interruptible load and peak load pricing	Cooling storage pricing	Interruptible load pricing
Load curtailment target, MW (2013–15)	1,000	800	450	400
Targeted consumers	**Industrial and municipal facilities**	Industrial, commercial, and municipal facilities	Industrial and municipal facilities	Industrial facilities
Types of projects	Nearly 400 facilities connected to a demand-side management service platform for peak management	131 projects targeting 45 enterprises for dynamic pricing	80 energy efficiency projects for industry and 30 projects for peak demand shaving	35 energy efficiency projects for power plants
Actual response in 2015	2,716 customers, a total of 2,037 MW across Jiangsu Province	74 customers, 71 MW	129 customers, 176 MW	Not available

Source: Stern 2015.

KEY TAKEAWAYS

- Policy makers in People's Republic of China acknowledge the importance of interventions on the demand side to avoid load shedding or payment for expensive thermal capacity.
- Proactive identification of energy-intensive consumers with significant potential for time-shifting load can yield benefits, particularly when combined with high ratios of peak to off-peak pricing (although care must be taken that offers not discriminate unnecessarily).
- ToU rates for residential customers have been tried in some jurisdictions, but as in other opt-in programs in the world, customer buy-in is modest.
- Industry represents a good entry point for implementing demand-response programs, owing to greater incentives and capacity for engagement.

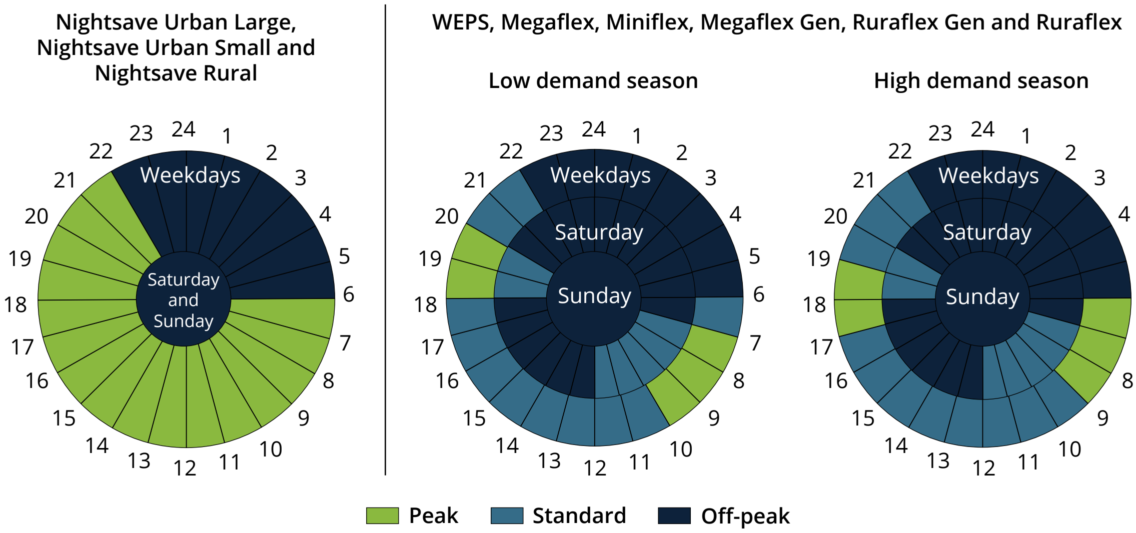
Demand Response in South Africa

South Africa has one of the most comprehensive frameworks for demand response in an emerging market. It combines ToU rates and load control techniques that are applicable nationally. Over many years, the vertically integrated electricity utility, Eskom, has implemented various implicit and explicit (price- and quantity-based) demand-response schemes.

Eskom offers various ToU tariff schemes to its large industrial consumers. Since the early 1990s, about 80 percent of electricity sales have been time-differentiated (Eskom 2020). Figure 5.1. presents the various ToU tariffs available in 2021 and the periods they are based on.

FIGURE 5.1

Time-of-Use Tariffs Available in South Africa



Source: Eskom 2020.

Note: Captions in Figure use Eskom names for ToU programs.

The ToU tariff system constantly evolves to reflect changes in load patterns and system characteristics. Demand patterns change over time. With the deployment of solar PV, net demand became more volatile. As a result, the underlying system costs changed, prompting the operator to propose an overall reform of the ToU tariffs. The peak periods, and the ratios between peak and off-peak prices, were adjusted to reflect the relative difference in system costs.

In addition to standard ToU rates, South Africa has introduced CPP as a pilot, as shown in the tariff schedule (Table 5.3). The CPP system allocates 17 days a year that may be designated as "critical" and have CPP applied, offering a strong price signal. On such critical days, the energy cost may jump from 3.2 US cents/kWh to 18.2 cents/kWh, a significant incentive for customers to adjust their load profile.

TABLE 5.3

Innovative Time-Differentiated Designs in South Africa

		NON-CRITICAL PEAK DAYS (348) (US CENTS/kWh)	CRITICAL DAYS (17)	DEMAND CHARGE (US CENTS/kVA-MONTH
Nightsave urban small critical peak day tariff	High season (June–August)	3.2	18.2	8.1
	Low season (September–May)	2.5	17.5	1.0
Nightsave urban small critical peak day ratios	High season (June–August)	Peak 1.3	Standard 7.3	Off-peak 7.8
	Low season (September–May)	Peak 1.0	Standard 1.0	Off-peak 1.0
Maximum peak-off-peak ratio	High season	5.7		
	Low season	1.0		

Source: Eskom 2020.

Note: Captions in Figure use Eskom names for ToU programs.

South Africa has for many years made extensive use of automated load control and considers it successful. The target appliances for load control are domestic water heaters that can be switched on and off remotely during maximum demand periods. Around 400,000 homes are enrolled, representing 200 MW of capacity. Utilities use specially designed algorithms to control the hot water load to achieve optimum control with minimal interference and discomfort to the customer. In addition to water heaters, these control mechanisms may be applied to nonessential intermittent loads such as pool pumps.

South Africa is experimenting with control systems featuring two-way communication. The greatest challenge is obtaining demand-response technology that is cost-effective with respect to capital and operating costs. A helpful technology should provide beneficial information such as tampering notifications, turning water heaters on and off without verification, the hot water heater temperature, and the energy consumption of the hot water heater.

In 2011, Eskom partnered with demand-response provider Comverge to run a pilot. Comverge managed the first open demand response in South Africa, which involved 500 MW of commercial and industrial loads, which could respond if requested. The program was called the Eskom Demand Response Aggregation Pilot Program (Smart Energy International 2012). Comverge procured and managed nearly 300 MW of demand response from municipalities with so-called ripple control technologies. (Ripple refers to residual periodic variation.) The pilot program with Eskom delivered almost 15 GWh of load reduction over seven months, covering 550 event hours.[2]

Other mechanisms designed by Eskom for large customers are described in appendix B.

Despite considerable efforts on demand response, the country faces recurrent power shortages. The rapidly advancing obsolescence of existing coal plants, poor planning for new capacity, and failure to achieve commercial operation with newly built plants are the main drivers of the current power crisis, so investments in generation have lagged market requirements.

South Africa uses rotational load shedding, under which the number of hours and frequency of interruptions increase depending on the criticality of the system. South Africa has a well-structured load-shedding program; in 2022 load shedding over nearly 3,800 hours of the year (more than 40 percent) dropped over 20 percent of peak load.[3] One interesting aspect of the scheme is that large industrial customers participating in demand-response programs are exempt from the early stages of curtailment.

KEY TAKEAWAYS

- South Africa has a long-established tradition of demand side interventions, including both price- and quantity-based mechanisms.
- South Africa has implemented traditional ToU pricing, refining it to retain cost reflectivity as the generation mix changes, particularly with greater solar PV penetration. South Africa has also effected critical peak pricing in its tariffs.
- On the quantity-based front, control of domestic hot water systems has been operational for many years, offering a strong entry point for automated load control without requiring sophisticated new technology.
- Despite considerable efforts on demand response, the country faces recurrent power shortages due to the rapid obsolescence of its existing coal plants.
- Adopting a mix of demand-response mechanisms tailored to the country’s challenges and consumer profile can strengthen engagement and effectiveness.

Demand Response in Brazil

Brazil implemented ToU tariffs as early as the mid-1980s. The model was based on the French tariff structure (Ferreira and others 2013). Initially, ToU electricity tariffs were differentiated according to peak, off-peak, dry, and wet periods; only large and medium-sized customers participated on a mandatory basis. Over the past few years, smaller customers have been allowed to participate, but as with other opt-in schemes, uptake has been modest, with only 65,000 customers as of September 2021.

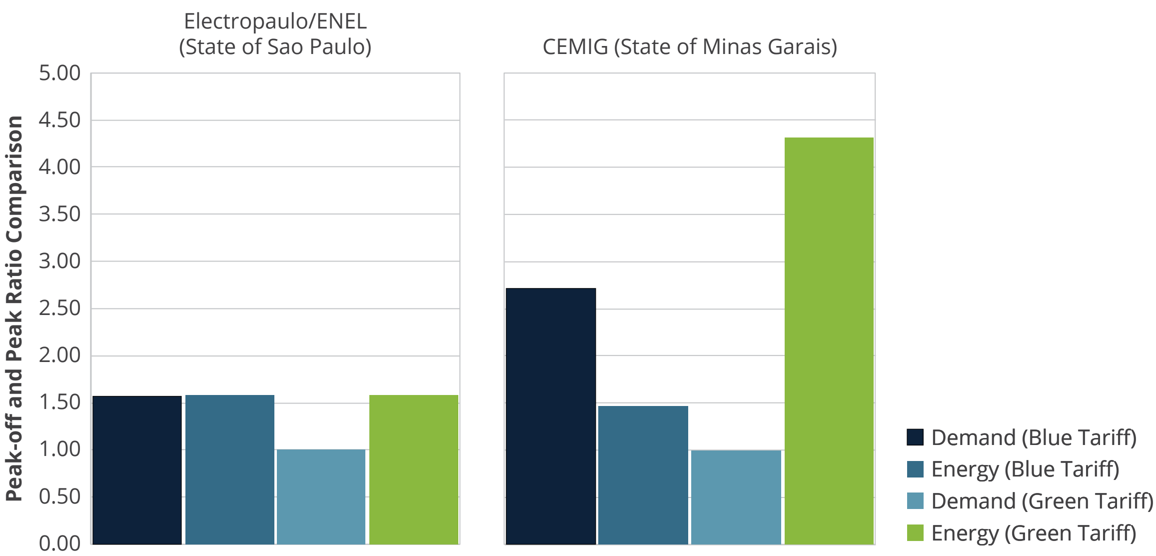
Large customers are typically subject to two-part tariffs for energy and demand. Time-of-day differentiation applies to both energy and demand for large customers (blue tariffs)

In contrast, for medium-sized customers, the time-of-day tariffs apply only to the energy component (green tariffs).

The peak to off-peak ratio varies according to the customer group and utility. Figure 5.2 compares this ratio for Enel (the largest utility in the state of São Paulo) and CEMIG (the utility for Minas Gerais). CEMIG leverages ToU rates to reduce or shift peak load consumption (CEMIG 2021).

FIGURE 5.2

Peak and Off-Peak Comparison of Large, High-Voltage Clients



Source: Enel and CEMIG.

The ToU methodology achieved the initial objective of shifting loads to off-peak periods. It is estimated that ToU tariffs at CEMIG resulted (and still result) in a peak load reduction of 500 MW for high-voltage customers and 700 MW for medium-voltage[4] (about 10 percent in total), for an estimated investment saving of $600 million.[5]

ToU tariffs in Brazil are no longer differentiated seasonally (dry and wet periods). In 2017, Brazil revised its tariff methodology, introducing a tariff surcharge (called "flag tariff") based on the criticality of the power system, ranging from about $5.8/MWh to $19.2/MWh (Enel 2023). The surcharges were designed to help defray some thermal generation costs, such as the fuel required to operate flexible thermal plants during critical supply conditions driven by low rainfall and reservoir levels (ANEEL 2017a).

The flag tariff system was designed to ensure cost-recovery rather than elicit a demand response. Still, it may have a modest impact in terms of energy and peak savings. Considering a peak energy price of about R$392/MWh and a maximum surcharge of R$98/MWh, the tariff increase would be 25 percent. Assuming a price elasticity of

–10 percent, the expected total reduction in energy consumption and peak demand would be about 2.5 percent.

ToU tariffs were (and still are) important in Brazil—but they are a static mechanism. Tariffs are based on predetermined time intervals and rates, which do not vary to respond to the criticality of the system. ToU was applicable when the load profile was predictable, but VRE production and changes in the consumption profile now influence net load. For example, air conditioning loads, which drive the summer peak, tend to occur between 14:00 and 15:00 but may be partially offset by solar production.[6] Other TDR methodologies, such as CPP and RTP, could be helpful but have not been considered, even though customers operating in the free market may be exposed to hourly prices in the wholesale market, enabling some response to prices, which track changes in load profile and VRE volatility more accurately than traditional ToU tariffs (Burger and others 2016).

Brazil has no load control mechanisms of any kind and no plans to introduce them. In 2021, however, the country introduced a simplified form of DSB called *redução voluntária da demanda* (RVD).[7] At the time, the national grid faced a dual energy and capacity constraint. RVD was designed expeditiously, building on lessons learned from two projects piloted by the Agência Nacional de Energia Elétrica a few years earlier. Participation was limited to large industrial companies (>1 MW) or aggregators that could make offers a week or day ahead to shift load from peak to non-peak periods (typically for a four-hour reduction). If accepted for dispatch, qualified bids would be remunerated based on estimated load reduction (actual vs. deemed or baseline consumption).

The mechanism was available for three consecutive months when the risk of load shedding during peak hours was high. The total size of the qualified bids ranged between 2 and 3 GW. The number of bidders, qualified bids, and average price are presented in Table 5.4. RVD was discontinued in late 2021, when the loss of load probability returned to normal levels.

TABLE 5.4

Redução Voluntária da Demanda (RVD) Bids and Prices

MONTH	NUMBER OF BIDDERS	QUALIFIED BIDS (MW)	WEIGHTED AVERAGE PRICE ($/MWh)
November 2021	52	2,269	179
October 2021	50	3,600	256
September 2021	31	2,323	279

Source: ONS 2022.

RVD proved cost-effective. It saved 28.8 GWh for the months of September and October 2021. It enhanced operating reserves and reduced the risk of load shedding by displacing the need to dispatch very expensive out-of-merit thermal generators at a cost of about $460/MWh. The cost of the program ($280/MWh) included: (i) a direct payment of $5 million for accepted bids (about $180/MWh), recovered via a system service charge; and

(ii) $3.1 million representing the energy saved by the accepted bidders, which was settled in the wholesale market (about $100/MWh). The cost-benefit ratio of the program was 1.65 (or 2.65 if only direct payments to bidders are included). New forms of demand-response participation in the capacity and energy markets are being studied.[8]

KEY TAKEAWAYS

- Brazil has been using ToU pricing for large and medium-sized customers for decades with significant benefits.
- ToUs are increasingly unsuitable where VRE penetration is high and dynamic mechanisms such as CPP or RTP may be more beneficial. None of those tariff schemes have been considered.
- DSB for wholesale energy markets was tried in 2021, when the power system was capacity constrained. Results were encouraging, with strong buy-in and cost-effective response. DSB with demand response in the capacity market are being studied as a cost-effective option.
- Brazil has not considered certain other quantity-based mechanisms such as load control and interruptible contracts. These should be further explored.
- Adopting a mix of demand-response mechanisms tailored to the country's consumer profile could improve engagement and effectiveness.

Demand Response in Viet Nam

Despite its limited historical experience, Viet Nam has for at least a decade been interested in the potential for demand response to support its power system. Initial pilots and programs concentrated on the potential for industrial demand response to reduce the mid-afternoon peak, alleviating system stress and improving cost efficiency. More recently, concern has been expressed about a shift to an evening peak due to solar PV expansion creating a "duck curve" profile to demand. This has led to interest in further demand-response instruments, including CPP.

In its initial programs focused on industrial load, Viet Nam had a target of 90 MW of demand response by 2020 and future targets to achieve a demand-response potential of 300 MW by 2025 and 600 MW by 2030, corresponding to 30 percent of peak load.[9] Currently, demand response cannot participate directly in the electricity market (GIZ 2021). However, Viet Nam has implemented the demand-response programs shown in Table 5.5.

TABLE 5.5

Implemented Demand-Response Programs in Viet Nam

PROGRAM	YEAR IMPLEMENTED	SCOPE	PROGRAM RESULT
Pilot load adjustment program	2015	Ho Chi Minh City	• The registered demand-response capacity reached 5,847 kW. • Four successful demand-response events were completed.
Voluntary load adjustment program	2018	Nationwide	• Voluntary (that is, no monetary compensation) demand-response implementation agreements were signed with 2,471 customers, totaling a potential demand response of 963 MW. • Ten successful demand-response events were completed in 2019. • Maximum capacity reduction was 514 MW.

Source: GIZ GmbH 2021.

Six demand-response programs were identified in a Ministry of Industry and Trade Circular 23 report in November 2017, which prescribed the processes for implementing load adjustment programs. The programs fall into three categories, as shown in Table 5.6.

But despite their demand-response targets and a framework to support these programs, implementation has faced legal constraints that have made voluntary programs largely ineffective.

TABLE 5.6

Defined Demand-Response Programs

CATEGORY	PROGRAM	DESCRIPTION
Quantity-based	Curtailable load program	• 24-hour notice period, response up to 3-hours duration, compensation paid for usage reduction compared to baseline • Targeted industrial and commercial customers
	Emergency demand-response program	• 2-hour notice period, response up to 3-hours duration, compensation paid for usage reduction compared to baseline • Targeted industrial and commercial customers
Price-based	2-component tariff Critical peak pricing	• Separate energy and charges targeted at customers who have already been on the ToU tariff • Tariff with peak event prices notified on a case-by-case basis, targeted at commercial and industrial customers
Voluntary	Voluntary program with commercial incentives	• 30-minute notice provided; 10–30 percent reduction required
	Voluntary load adjustment program	• Request for reduction with no incentives

Source: GIZ GmbH 2021.

The payment for the quantity-based response programs is based on the reduction in energy compared to the customer baselines, calculated as the average usage in the same period in the five days before the demand-response event.

Three key legal constraints limited the implementation of demand response in Viet Nam are:

- The utility, EVN, does not classify demand-response incentive payments as eligible for cost recovery. As a result, EVN is unable to offer adequate compensation to incentivize participation in the Curtailable load program and emergency demand-response program.
- Changes to the structure of electricity tariffs require amendments to the prime minister's decision. The current tariff framework does not enable two-part tariffs that separate energy and capacity charges. A ToU tariff has been included in the current structure; the difference between peak and off-peak prices, however, has been insufficient to promote demand response (CPCS Transcom Limited 2021). Until such amendments are made, the use of alternative tariffs cannot be implemented.
- EVN faces restrictions on transferring assets to customers, which means, for example, that EVN cannot fund demand-response investments and will have to pay customers over time.

These constraints mean that only voluntary programs can be implemented.

KEY TAKEAWAYS

- Voluntary mechanisms have limited reach given the lack of monetary incentives.
- Care needs to be taken to ensure that the legal and regulatory frameworks governing demand-response procurement incentivize the utility to place its provision, particularly cost recovery, on a level playing field with supply-side resources.
- Demand response may be supported by the utility's direct investments in demand-response technology on the customer's premises. Where the regulatory framework does not permit this, alternative contracting structures must be possible (for example, competitively sourced third-party provision).

Demand Response on Small Islands

Power systems on small islands face particular challenges around changeable energy supply and demand. As renewable energy's penetration grows, a lack of rotational inertia (usually provided by hydro or thermal generators) in the system can rapidly become problematic for ensuring stable supply. Small system size can hinder both the implementation of competitive markets and the capacity of stakeholders to invest in and test new technologies. Nevertheless, much can be done, and the size of the markets and systems can be used to advantage because of their design simplicity and ability to engage a range of customers. This section includes case studies of demand-response initiatives.

Hawaii

TOU TARIFFS FOR RESIDENTIAL CONSUMERS

In 2022, solar power provided about 17 percent of Hawaii's total electricity, primarily from small-scale, customer-sited solar power generation under a net-metering scheme. The rapid adoption of solar power is due to the high electricity costs and good solar resources. Hawaii has some of the highest power prices in the United States.

A ToU pilot for residential customers was rolled out in February 2024. The pilot tested customer response to opt-in and opt-out options. A total of 15,000 customers were included in the pilot automatically, and 500 of those opted out. A much larger group of 150,000 customers were not incorporated into the pilot—and just 500 of those have opted in. Solar customers were given two options within the pilot: to opt-out or to pay/receive the ToU rates in both directions. The overwhelming majority of those who opted out are solar customers. It was initially expected that after a year of the pilot, the program's rates would become the default, but this deadline is no longer anticipated. Before universal rollout, Hawaii might see new discussions about time periods and price ratios. No CPP has been considered thus far.

Contrary to most ToUs in the continental United States, the lowest tariffs occur between 9 a.m. and 5 p.m. (and not overnight), reflecting the availability of solar energy. This is an interesting example of time-differentiated rates supporting the integration of renewable resources.

DIRECT LOAD CONTROL PROGRAMS

Hawaii has an extensive range of direct load control programs. Events can be dispatched by local system operators or automatically triggered in case of underfrequency. Dispatch events are at least one hour, and underfrequency event duration is typically a few minutes. Ongoing programs include direct load control programs available only for customers on Oahu, and a frequency control demand-response program available on Oahu and Maui (Hawaiian Electric Company 2024a). The peak loads for Oahu and Maui in 2022 were 1,102 MW and 195.1 MW, respectively.

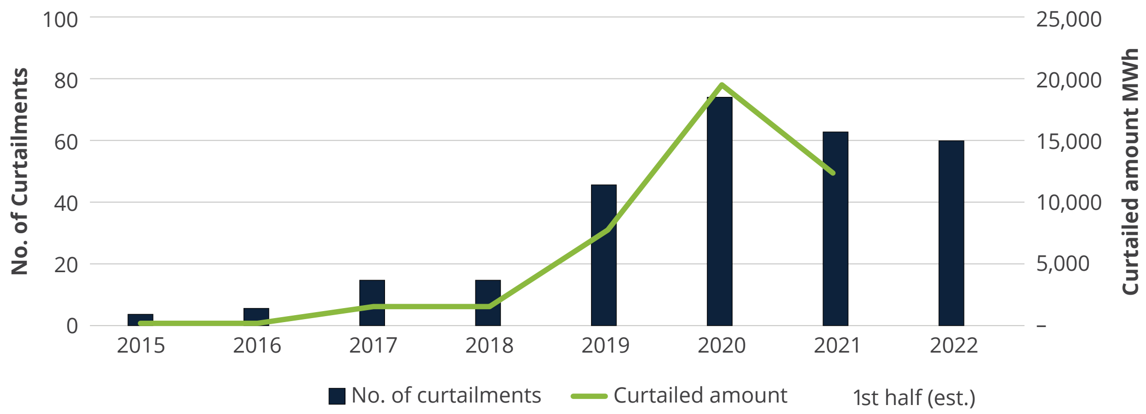
- Residential direct load control on water heaters (referenced by the Hawaii Electric Company as 15 MW controllable from 34,000 customers across both islands, or 1.2 percent of Maui and Oahu 2022 peak load) and air conditioning (25 MW controllable from 4,000 customers, 1.9 percent of Maui and Oahu 2022 peak load).
- Direct load control for large commercial and industrial customers (18.2 MW from 43 customers, 1.4 percent of Maui and Oahu peak load in 2022) and small businesses (1 MW from 161 customers, 0.08 percent of Maui and Oahu peak load in 2022).
- Automatic or semiautomatic demand response for frequency control. Customers can opt out of an event at any time. Participating customers are paid for energy and demand reductions and receive $3,000 toward a meter upgrade (Hawaiian Electric Company 2024b).

Jeju Island

In 2012, Korea's Jeju Island declared its aim of achieving net zero emissions by 2030. Renewable energy penetration soared on the island, growing from 9.3 percent in 2015 to 18 percent in 2021. This rise led to excess renewable generation during periods of high renewable resource availability. The excess renewable generation has required significant curtailment to maintain system balance, even with the 400 MW interconnector to the mainland. The figure below shows the evolution of curtailment events and volumes on Jeju from 2015 to 2022.

FIGURE 5.3

Curtailment Events on Jeju Island



Source: Kim, Han, and Moon 2022.

To reduce curtailment of power from renewable sources, the government introduced "Plus Demand Response" in 2020, through which consumers are paid to charge their EVs during periods of excess generation. This demand-response program is now operating only on Jeju; it is intended to operate nationwide, however, as renewable energy generation on the mainland creates a need for this response.

In the 2021 pilot project, 521 public chargers were registered as participating in Plus Demand Response, totaling 15 MW of capacity. In 2022, 73.5 MW of capacity was registered. Users could join the project through an app that notifies users of Plus Demand Response time periods and awards points to consumers who utilize the chargers during those periods (Korea Bizwire 2021). The points can be converted to the local currency (Invest Korea 2021) while the EV charger load is aggregated by GridWiz, an aggregator and operator of distributed energy resources for sale into electricity markets.

One study conducted in 2018 forecast the 2030 EV-charging peak load on Jeju Island to be 94,766 kW.

Corsica, Guadeloupe, and La Réunion

Demand response has been applied to water heating and air conditioning loads in La Réunion, Guadeloupe, and Corsica through the Millener demonstration project of French national utility EDF. The project was conducted between 2011 and 2015 (EDF 2014; Smart Grids 2020).

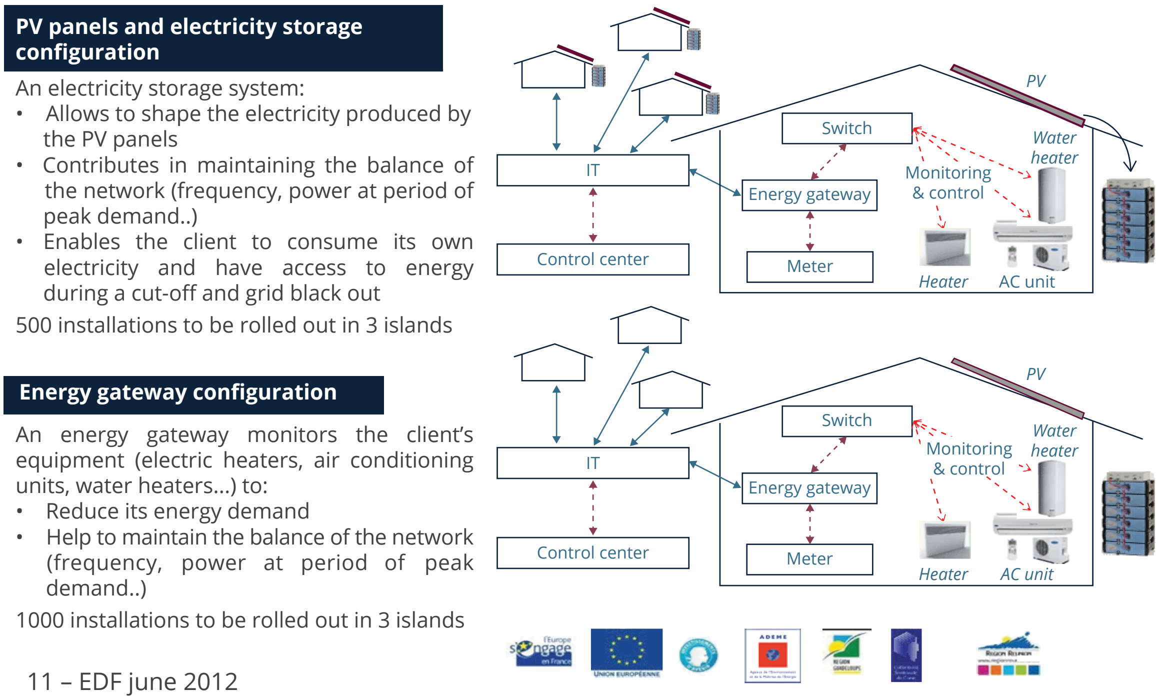
Through the program, EDF offered to install appliance-connected energy controls to enable it to control water heaters and air conditioners remotely for purposes of demand response and grid stabilization. The aim was to reduce end users' consumption, boost renewable energy penetration in the island systems, and provide balancing services.

The scheme is voluntary. A research paper found that the project installed 1,050 demand-side management units for households across the three islands, alongside 500 home PV and battery storage systems. Participants can access the energy controls and control their consumption at any time (Santi 2013).

Another component of the Millener project was that EDF coordinated solar generation resources and battery storage systems. The utility aimed to achieve energy savings of 500 MWh per year through the solar and battery systems installed through the Millener project.

FIGURE 5.4

Eurelectric's Millener Project: Two Setups



Source: Pons 2012.

KEY TAKEAWAYS

- Ever-expanding renewable energy penetration can rapidly overwhelm small island grids and result in substantial curtailment. Demand response can help mitigate this problem.
- A dearth of large industry has led utilities to focus on controlling residential water heaters and air conditioners as key technologies for load control.

Demand Response in the United States: Best Practices from Advanced Frameworks

The United States has one of the most extensive and dynamic demand-response frameworks in the world. Demand response occurs at utility (retail) and wholesale (power pool) market levels. The programs complement each other but target different markets and move at different speeds. The major driving factor behind the introduction of demand response was the spread of air conditioning.

Vertically integrated utilities recognized that demand response should be part of their integrated resource plans well before the Federal Energy Regulatory Commission mandated that demand and supply resources be treated similarly in market design.[10] Demand-response programs have undergone major transformations over the past 20 years. The growth in incentive-based demand-response resources has occurred mostly in organized wholesale markets administered by system operators—either independent system operators (ISOs) or regional transmission organizations (RTOs) in the US market structure. Since 2001, the Federal Energy Regulatory Commission has required ISO/RTOs to file annual program evaluations or describe their demand-response program enrollment and performance in annual state-of-the-market reports.

The three development stages for demand-response mechanisms and corresponding timeframes are shown in Figure 5.5. At stage 1, demand-response programs rely on manual load controls and interruptible tariffs, offering capacity planning and emergency response. Stage 2 has demand-response programs in the power markets, smarter technologies, and the ability to respond in real time. At stage 3, technologies for ToU metering and load control are deployed, and new business models and products are created. The disruptive factor was distributed energy resources (DERs)—for example, behind-the-meter generation and storage that extended the menu of resources that could “respond” on both the supply (distributed generation) and demand sides (demand response *per se*).

FIGURE 5.5

Evolution of Demand-Response Mechanisms in the United States

Pre-2000s | 2000 | 2005 | 2010 | 2015 | 2020 | 2025 & beyond

Stage 1

- Largely manual control
- Interruptible Tariffs for Large Commercial & Industrial
- 1-way Direct Load Control for Residential
- Used for Capacity Planning & Emergencies

Stage 2

- Introduced to Wholesale Markets
- Increased Automation
- Increased Precision
- Eventually Ancillary Services
- Behavioral /Voluntary Options
- Smarter Equipment
- 2-way Communications
- Some Near Real-Time Visibility

Stage 3

- Provide Multiple Grid Services
- Respond to Controls and/or Price Signals
- Distribution & Transmission Relief
- Introduction of Storage
- Migration to Distributed Energy Resources

Source: FERC 2019.

Demand response in the United States is now entering stage 3, which entails integrating demand response into DERs (solar PV, battery storage) to provide a variety of grid services.

The potential for demand response is estimated at 29.2 GW at the retail level and 32.1 GW at wholesale, totaling 61.3 GW (FERC 2023)—or about 6 percent of peak consumption in the United States. Some practitioners contend that the United States needs more demand response. The potential of 6 percent demand response has been sufficient to balance the system so far, but more may be required with the installation of more intermittent generation and the growth of the EV market.

Technology will allow more extensive customer participation in demand-response programs. More than 64.7 million electronic meters were in operation in 2015, but only 9.8 million customers were participating in a demand-response program (CPOWER 2020). Advanced (smart) meters account for nearly 72 percent of all installed and operational meters in the United States; 119 million advanced meters were active nationwide in 2022. Residential customers accounted for about 88 percent of total advanced meter installations, and about 73 percent of residential electric meters were advanced meters (EIA 2023).

New ToU rates are being designed, for example, in Arizona, where a "reverse demand-response program" has been developed to use excess solar energy in non-summer months and avoid curtailment. Still, because the peak/off-peak price arbitrage cannot be predicted (because of the intermittent nature of renewables), the Arizona Public Service program will be specific to dispatchable nonessential loads. For example, EVs with smart charging and smart appliances (for example, dishwashers, washing machines, dryers) could offtake free or negatively priced energy when reverse demand response is activated (Cadmus Group 2018).

Although rollout of ToU rates was a complex endeavor, implementation of load control has been easier, easing development of demand-response products and markets so customers have incentives to curtail loads reducible on short notice. Florida has one of the world's largest residential load control systems, managed by Florida Power & Light. The system uses 800,000 remote switches to control 1,000 MW of electrical power (2,000 MW during an emergency). Florida Power & Light's load management programs have been successful enough to permit the construction of new plants to be deferred. Baltimore Gas & Electric has another successful utility-sponsored load management program, a peak-time rebate, to which 75 percent of customers (1.1 million) subscribe (Faruqui, Sergici, and Warner 2017). Participating customers have interval metering. The peak-time rebate program kicks in when high demand is expected—typically when air conditioning loads soar during heat waves. Customers were notified up to ten times yearly that the program would kick in. Customers are paid $1.25 for every kWh saved (compared with a historic baseline) during critical periods (BGE 2019). The program has sustained peak savings of more than 300 MW over the past few years.

About half the demand-response potential in the United States is harnessed via electricity markets. Some major features of the demand-response programs in the PJM power pool are summarized in Box 5.1.

BOX 5.1

PENNSYLVANIA-NEW JERSEY-MARYLAND INTERCONNECTION: A FRONTRUNNER IN DEMAND-RESPONSE DEPLOYMENT

Pennsylvania-New Jersey-Maryland Interconnection (PJM) has one of the most active demand-response programs in the United States. It is the second-largest power pool for demand-response resources, with about 10.6 GW, or 7.3 percent of peak demand (for a total of 32.9 GW of demand response in the seven wholesale markets in the United States, representing 6.5 percent of peak demand in those markets).

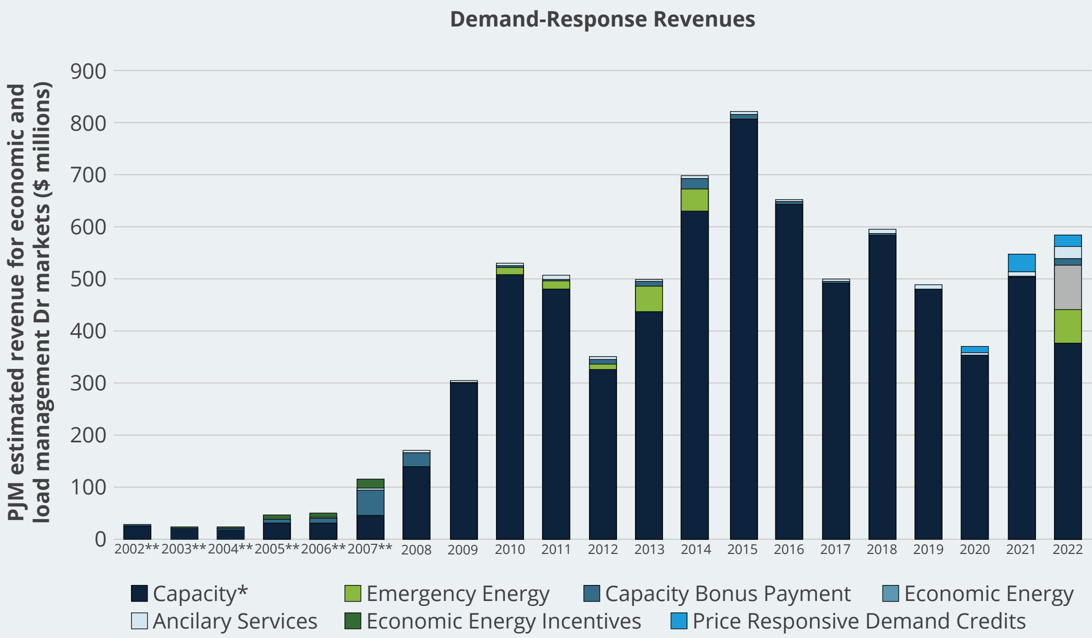
The PJM service area includes 13 states and the District of Columbia. The annual cost of all demand-response programs is about $600 million per year. PJM fosters the emergence of aggregators. Demand-response aggregators, or curtailment service providers (CSPs), consolidate multiple loads and offer demand reductions in the capacity market. Customers may receive a payment from a CSP to reduce load when the wholesale price is high.

(*continues*)

BOX 5.1 (*Continued*)

Demand response providers can compete in the PJM capacity market. The products traded in this market ensure long-term grid reliability by securing the appropriate power supply resources needed to meet predicted energy demand. Auctions are conducted on a rolling basis. In the 2018 auction, PJM procured about 163.6 GW of resources from June 1, 2021, to May 31, 2022. Demand response accounted for 11 GW of capacity in this auction. There has been an 18 percent growth in megawatts cleared in the PJM market. EnerNOC, a global leader in demand-side flexibility services, was awarded more than $180 million in capacity payments for demand-response resources. The capacity market is by far the largest source of revenue. Contributions from several energy and ancillary services products are much smaller. The figure below illustrates the revenue earned by PJM's demand-response products.

Demand-Response Revenues



Source: PJM 2023.

Note: Capacity bonus payments include payments for load management, economic (including ancillary services), and price-responsive demand registrations.

* Capacity net revenue inclusive of capacity credits and charges.
** PJM assumes capacity value at $50 MW Day (PJM does not know the pre-RPM value of capacity credits in the forward market; only a portion of capacity was purchased through the daily capacity market at the time).

(*continues*)

BOX 5.1 (*Continued*)

PJM is particularly interested in expanding the ancillary service market. Despite the relative insignificance of the ancillary service market, PJM acknowledges its ability to respond rapidly when needed, which is important in an environment of high intermittency from renewables. In 2015, 294 locations were certified to provide an average of 16 MW annually. Storage will likely have an important role to play. PJM would like to have easy access to the distributed generation behind-the-meter to help balance the system. Grid codes, regulations, contractual arrangements, and coordination between PJM and the distribution company will need to be revisited to address the emergence of new types of demand response (Cappers, MacDonald, and Goldman 2013).

One barrier to expanding demand response in the United States is that grid operators do not understand distribution systems well enough to handle distributed energy resources with the same ease that they run large, centralized power plants (FERC 2018). Based on the experience of demand-response programs in the wholesale markets, aggregators—such as CSPs—have been an effective intermediary between the fragmented customer base and the wholesale market. PJM advocates for a competitive CSP-based model with a track record of harnessing demand-response capability in various retail markets. CSPs have worked with customers to help them unleash their demand-response capabilities.

KEY TAKEAWAYS

- The United States has the largest, most sophisticated demand-response market in the world.
- Demand response should be a regulatory requirement for resource planning, with annual progress evaluations. These actions would raise the profile for demand response vis-à-vis supply-side solutions.
- Technology that assists automation and expands relevant DERs can kickstart new business models aggregating smaller consumers.

(*continues*)

- Implementation of ToUs can be a complex undertaking, as is true of most price-based demand-response instruments. These take time to establish and to attract consumers, particularly residential consumers.
- The most promising application for demand response in a given case may depend on the structure of a specific market or sector. Still, demand response is well-suited to short-term contingency or stress events where the system operator directly controls the load.

Comparative Analysis of Demand-Response Programs

Demand response remains an untapped resource in emerging economies. The case studies presented here highlight good practices for other developing countries and offer a long-term vision for the scope of demand response in power systems. The analysis highlights some key accomplishments in terms of price- and quantity-based demand response, focusing on large developing countries (the so-called BICS group comprising Brazil, India, People's Republic of China, and South Africa).

Participation in Price-Based Programs

ToU tariffs have been applied across all the markets reviewed—Brazil having the lengthiest experience. But existing tariff models have not evolved, while uptake in many jurisdictions has been sporadic and dependent on scheme design, particularly at the residential level, where uptake has often been disappointing. Many ToU offers are "static," meaning the peak and off-peak periods and ratios are pre-set, irrespective of system conditions. Although the prevalence of ToU tariffs is growing, dynamic pricing, which more closely reflects the power system conditions, has not been mainstreamed for regulated customers in any of the BICS countries.

CPP, VPP, and RTP approaches are uncommon, more sporadic, in any event, than static ToU pricing. Of the assessed countries, only South Africa has experimented, with some success, with CPP rates. RTP, meanwhile, has yet to be introduced in many developing countries. Large consumers that trade directly in the wholesale market in Brazil are exposed to real-time pricing and can react accordingly on an hourly basis. Still, there are no RTP mechanisms for regulated customers.

Participation in and Existence of Quantity-Based Programs

Quantity-based demand response has been implemented with notable success in some markets. Interruptible contracts and load controls have been carried out to some degree in all the countries reviewed in this chapter. It is an area of focus in India, where several successful projects have been developed. There is a concerted government effort to mainstream those initiatives. People's Republic of China has established load control protocols with many customers to avoid load shedding. South Africa, meanwhile, has implemented sophisticated load control systems and business models to manage nonessential loads and mitigate capacity shortages. Several small island countries have also begun exploring load control of energy-intensive devices at the residential level as a priority, given the vulnerability of small power systems to high penetration of renewables and the lack of large industrial consumers.

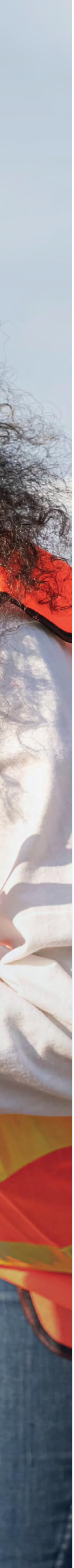
Demand-response participation in wholesale markets is less advanced. This is understandable, first, because of the complications involved in integrating demand response into functioning markets as a dependable resource, and, second, because of the absence of active wholesale markets in many emerging countries. Brazil developed a DSB-like program in 2021, which attracted 3 GW of demand response. Still, from the countries reviewed here, significant involvement is apparent only in the more advanced markets such as the PJM Interconnection in the United States, where demand-response participation is intense in both the energy and capacity markets. Unlike in Brazil and South Africa, demand-response bids compete with supply sources in the PJM system and interact to determine spot prices. The role of demand-response aggregators as curtailment service providers is also well established.

Endnotes

1. "Cost plus" is a form of regulation whereby regulated utilities can recover all costs incurred plus a regulated profit margin. This differs from a revenue cap approach that sets the allowed revenues ahead of each regulatory period (with some allowances for pass-through of uncontrollable costs).
2. Some of these loads may not have been dispatched. Some of the contracted load providers for existing supplemental demand-response programs were moved to the Comverge aggregator to test the system.
3. NRS-048-9 is an emergency load reduction program that the system operator and distribution control rooms implement to prevent national, regional, or local blackouts when system conditions are such that available power system capacity cannot meet demand or when adequate reserves required to manage power system security cannot be maintained without a reduction in load. Technically, this load reduction program does not fit the definition of demand response used in this report because of its mandatory (as opposed to voluntary) nature.
4. Personal conversation with Neusa Antunes, Escher Consultoria e Engenharia (2023).
5. CEMIG accounts for about 10 percent of the Brazilian market. If this Figure 5.2 could be extrapolated to the entire country, total savings would be $6 billion.

6. Increasing penetration of air conditioning in Brazil has changed the load profile. This phenomenon was analyzed for the years between 2000 and 2010. In 2000, the peak load was observed in early winter (June), moving to April in 2005 and to February in 2010. Air conditioning loads have been responsible for this seasonal change (Poole 2011).
7. The RVD program was established on August 23, 2021. The main difference from DSB was that RVD bids did not affect the spot price.
8. ANEEL Normative Resolution n° 1.030 of 2022, established conditions for the new demand-response program. It authorizes the national system operator to conduct studies to attract demand-reduction bidders in the capacity market in return for an availability payment under a one-year contract.
9. Decision 175/QD-BCT dated 28 January 2019 on Approving the Implementation Plan and Roadmap for the DR Program (GIZ GmbH 2021).
10. The Energy Policy Act (EPACT) of 2005 codified that a key objective of US national energy policy was to eliminate unnecessary barriers to participation in demand response by wholesale customers and load aggregators in the energy, capacity, and ancillary service markets. EPACT directed the Federal Energy Regulatory Commission (FERC) to develop a comprehensive national assessment of the size and scope of demand-response resources.

SIX
ROADMAP FOR IMPLEMENTING DEMAND RESPONSE IN DEVELOPING COUNTRIES



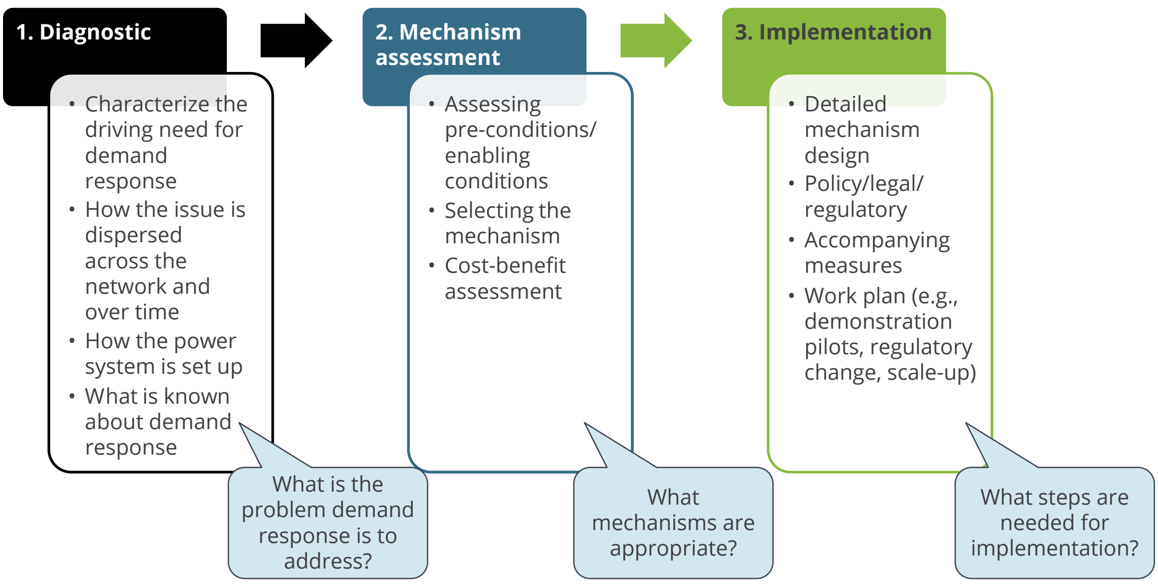
This chapter provides a roadmap for developing countries[1] seeking to design demand-response programs. The roadmap is necessarily high-level to ensure its applicability; designers may require more details, which can be provided through technical assistance as needed.

Summary of the Roadmap

The roadmap has three phases, as shown in Figure 6.1. The first phase is a diagnostic that identifies and clarifies both the operating context and the problem that the demand response is intended to address. The second assesses the options for demand-response program mechanisms, which rest on understanding the enabling conditions (such as the power system's structure and enabling technologies) and undertaking a cost-benefit analysis to select the optimal mechanism. The cost-benefit analysis could incorporate multiple mechanisms, phasing in their introduction, different customer groups, and a range of other scenarios and sensitivities, as appropriate, and identify each scenario's distributional effects. The third phase details the mechanism design and considers policy and regulatory enhancements, while accompanying measures are fleshed out and implemented. At this point, a time-based work plan allocates tasks, responsibilities, and milestones leading to the implementation of demand-response mechanisms.

FIGURE 6.1

Summary of Roadmap for Demand-Response Implementation within a Country



System Diagnostic

The system diagnostic is critical for establishing the context in which demand response is being implemented. Figure 6.2 provides guidance questions for each diagnostic topic.

FIGURE 6.2

Guidance Questions for the Diagnostic of the Power System

1.1 The driving need for demand response	1.2 How the problem is dispersed	1.3 How the power system is set up	1.4 What we know about demand response
• How variable is the generation mix? • How variable is customer load? • Have there been changes in customer demand profiles? • Are there constraints in the network? • Is demand response incorporated into a least-cost plan? • Are there decarbonization or other targets that demand response can support?	• Is the problem dispersed spatially? Locally, regionally, nationally? • When does it occur, ie, certain time of day, day of the week, or season? • How urgent is the demand-response requirement when it occurs, ie, within seconds/minutes/hours/days? • Which customer groups are/could be affected? • What is the capacity of different customer groups to understand the issue (and potentially adopt a demand-response mechanism)?	• Is there private sector participation? • Is there a competitive market (wholesale or retail)? • Are there weaknesses in the network (transmission or distribution)? • Do customers have smart meters? • Who would be the contract counterparty for a demand response provider?	• Have we tried it before? • Was/is it successful? Why/why not? • Is anything specified in policy or legislation? • What can we learn from international/peer experience on certain mechanisms? • Are there any other barriers or enablers?

The first two columns (1.1 and 1.2) of Figure 6.2 focus, respectively, on identifying and characterizing the need that demand response is to address. At this stage, answers need not be quantitative or highly detailed but should be referenced in later activities. With regard to the first column, this report summarizes the driving needs for and roles of demand response across segments of the power system. The questions in the columns can be read in conjunction with the summary diagram, presented again in Figure 6.3. The final issue—regarding incorporation of demand response in a least-cost plan—will have identified demand response and incorporated its impacts into system planning.[2]

Answers to the questions in column 1.2 of Figure 6.2 about the issue's dispersal will provide further guidance on targeting the demand-response mechanisms, ensuring that they engage and benefit the right power system participants and wider beneficiaries in the proper way. Depending on the power system, some of this information may be difficult to obtain; any information related to these questions will be beneficial.

FIGURE 6.3

Drivers of the Need for Demand Response

Energy balance	**Least-cost energy provision**	Maximizing consumer utility through least-cost matching of supply and cost-reflective demand
Capacity provision	**Capacity adequacy**	Ensuring adequate de-rated capacity available on system for managing system stress events within LOLP limits
Ancillary services	**Reserve provision**	Arresting and restoring system frequency following loss of load
	Frequency regulation	Managing continuous fluctuations in frequency caused by fluctuations in demand and in the supply of renewable energy
	Voltage control	Managing voltage deviations to retain power quality
	Constraint management	Managing network congestion and constraints that otherwise curtail generation in substitution of upgrading or reinforcing the network directly ("non-wire alternative")

Affordability

Meeting system needs at lower cost

Reliability

Reducing system outages

Decarbonization

Facilitating greater penetration of renewable energy

Source: Author's analysis.

Note: "Non-wire alternatives" address congestion management without expansion of the grid. LOLP = loss of load probability; RES = renewable energy.

The third column of Figure 6.2 assesses the power system's capacity to support the implementation of different demand-response mechanisms. Some mechanisms will not be implementable within certain power system structures—for example, monopolistic generation supply will not allow energy and capacity offers. Similarly, price-based demand-response mechanisms require appropriate metering, including smart meters, for more refined approaches that measure energy consumption over time. The power system review should consider other weaknesses that may be detracting from demand-response mechanisms.

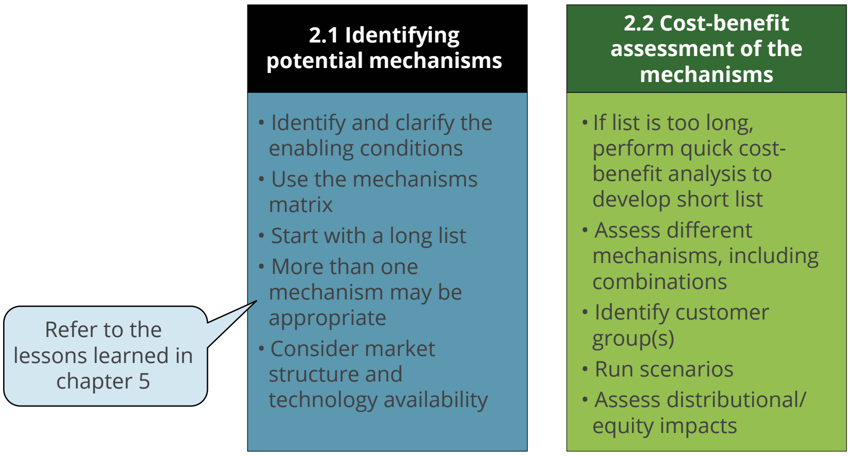
The fourth column reviews the power system's experience with demand response. Some countries may have tried demand-response mechanisms in one part of a country or for one customer group. They could build on that experience (positive and negative) when implementing further mechanisms. For those countries that have not tried demand response, the international experiences described in chapter 5 will be particularly relevant.

Mechanism Assessment

The need for demand response is driven by the context—enabling conditions, a power system's structure and characteristics, and the country's experience with demand response. With context understood, developers should select the best mechanism(s) laid out in this report. Mechanisms can be assessed for effectiveness through a cost-benefit analysis that ensures positive net benefits for the power system and distributed benefits to targeted participants without detracting from other contributors. Figure 6.4 provides guidance on some demand-response mechanisms and their net and distributional impacts, which are discussed in the following sections.

FIGURE 6.4

Approach to Mechanism Identification and Assessment



Identifying Potential Mechanisms

The report earlier provides a matrix of the potential demand-response mechanisms and the needs each is trying to address. As a guide to identifying appropriate mechanisms, the matrix is provided again as Table 6.1.

The first question acknowledges the need to address more than one challenge, identifying the potential mechanisms along the rows. Narrowing the selection will be easy for those three rows where only one mechanism is suggested. For the others, further analysis will be appropriate. Table 6.1 lists points to consider for each mechanism. Readers should also refer to the lessons learned in chapter 5, summarized after each case study.

Not all mechanisms will be possible in every country. For example, broad, price-based mechanisms grow more sophisticated as one moves across the matrix (see Figure 6.5), requiring more complex pricing approaches in markets with, for example, dynamic pricing. This would make sense only if there were a functioning wholesale market with market prices. The price-based mechanisms also require metering of customer loads at different times of the day. While such metering may be scarce or absent in some countries, it is an easier hurdle to overcome than (re)designing an energy or capacity market. Energy and capacity offers require a market that accepts offers. While such a market may be on the horizon for some countries, it may not be feasible to implement one as part of a

TABLE 6.1

Matrix of Demand-Response Challenges and Some Mechanisms to Meet Them

1. What is the challenge we need to address?	TOOLS	PRICE BASED					DIRECT PAYMENT BASED			
		TOU	CPP	VPP	RTP	PTR	DR ENERGY OFFERS	DR CAPACITY OFFERS	AUTO LOAD CONTROL	MANUAL LOAD CONTROL
	Least-cost Energy Provision	Yes	Yes	Yes	Yes	Yes	Yes			
	Capacity Adequacy							Yes		
	Reserve Provision								Yes	Yes
	Frequency Regulation								Yes	
	Voltage Control								Yes	
	Constraint Management		Yes	Yes	Yes	Yes			Yes	Yes

Source: Author's analysis.

Note: ToU = time of use; CPP = critical peak pricing; VPP = variable peak pricing; RTP = real-time pricing; PTR = peak time rebate; DR = demand response.

TABLE 6.2

Summary of Key Selection Guidance of Different Demand-Response Mechanisms

MECHANISM	SELECTION GUIDANCE
Interruptible contract/load control	Relatively easy to implement for large customers, to provide reserves and capacity adequacy for peak periods Requires certain technologies for metering and remote control Has been successfully implemented for households in vertically integrated markets, but aggregators can help provide this with relative ease once the system operator is happy with reliability and regulations made to match
Static ToU tariffs	Relatively easy to adopt for larger customers, with appropriate metering and accurate tariff design It is more challenging for smaller customers (especially households) to understand May be less effective in the age of VRE and as more dynamic tariffs take effect Mandatory uptake is challenging politically, while opt-in tariffs typically have low response rates, suggesting market education is critical and automated demand-response resources highly beneficial
Other price-based instruments	Require more dynamic electricity pricing, applicable as markets become more competitive (particularly in wholesale markets) Can be marketed with a focus on more engaged consumers with the right technology and suitable loads (EVs, air conditioning with smart controls, and so forth) Need to be careful of distributional effects
Energy and capacity offers	Most complex of the mechanisms, dependent on market design, and not well established

FIGURE 6.5

Matrix of Demand-Response Challenges and Some Mechanisms to Meet Them

2. Which mechanisms are appropriate to meet this?

1. What is the challenge we need to address?

	PRICE-BASED					**DIRECT PAYMENT-BASED**			
Tools	ToU	CPP	VPP	RTP	PTR	DR energy offers	DR capacity offers	Auto load control	Manual load control
Least cost energy provision	✓	✓	✓	✓	✓	✓			
Capacity adequacy							✓		
Reserve provision								✓	✓
Frequency regulation								✓	
Voltage control								✓	
Constraint management		✓	✓	✓	✓			✓	✓

demand-response program. At the same time, as markets evolve, mechanism redundancy can intensify, notably for static ToU tariffs, as market penetration of VRE expands.

Not all mechanisms are available for every customer group; technology options within a country and among customer groups can dictate mechanism potential. Smart meters with time-based load measurements are often introduced, first, to large customers—for example, industrial customers with the most significant load and revenue protection benefits per customer. These smart meters are then introduced to progressively smaller customers, first to large businesses then small and then eventually to households. More obviously, remote-control mechanisms for water boilers/geysers require customers to have effective, cheap, easily installed switches—for example, ripple control and smart plugs.

The choice does not need to be for a single mechanism. Indeed, options could include more than one mechanism or combinations of mechanisms; within a single mechanism there can be multiple applications.[3] As noted earlier in the report:

- Small retail customers may have time-differentiated tariffs and still participate in load control. This option will likely gain momentum for EVs, where charging patterns are a crucial target for incentivizing demand shifting, while the batteries offer a potentially valuable grid resource.
- Small customers may be subject to ToU rates and still participate, via aggregators, in several demand-response programs at the wholesale level.
- Price-based instruments can also be applied to energy and demand, with customers paying different demand charges ($/MW) depending on their metered peak consumption during peak and off-peak periods.

Cost-Benefit Analysis of the Mechanisms

A cost-benefit analysis (CBA) can reveal rate impacts across all customer categories. CBAs help to determine both an equivalent supply curve of demand-response opportunities (including combinations of mechanisms) and desired levels of DR deployment, considering the cost of supply options.

The cost-benefit analysis[4] is critical for understanding two aspects of the potential demand-response mechanisms:

- The **net benefit** of the application, and
- The **distributional impact:** which sector participants benefit the most and which benefit the least?

Costs include smart meters or remote controls, incentive payments for participating customers, tariff design to determine ToU charges, regulatory changes, and customer marketing. Benefits include lower peak generation costs, reduced ancillary services (for example, spinning reserve costs), and the avoided cost of any lost load. Most of these costs are discrete, one-off items incurred during program implementation. Some benefits—for example, unused generation and spinning reserve—may require power system modeling. Similarly, calculating incentive payments will require an understanding of the value obtained by the utility (which gives an upper bound of what could be shared with customers). In addition, the calculation discloses the opportunity cost of investing in demand response vis-à-vis generation assets and reveals both customer willingness and price points that alter their behavior, which provides the lower bound of the price. Values for each cost and benefit should be quantified where possible. They should also be detailed as values paid or received over time before being discounted to a rate that produces a present value. Modeling should consider the participants' perspectives—for example, the utility, participating and nonparticipating customers, the implementing entity—to capture costs and benefits and identify negative distributional effects for mitigation.

Given the mechanisms for addressing a problem within a power system, it may be that intervention has a negative net benefit (that is, a net cost) but that this is less negative than if nothing were done. It is therefore necessary to consider the appropriate counterfactual, often a do-nothing scenario, against which the net benefit can be compared. Caution is advised so that the cost of a do-nothing scenario is not considered a benefit (by being avoided) of a demand-response scenario if the two scenarios are then netted against each other—that is, double counted.

If the net benefit of the mechanisms is positive, with a positive difference as compared with the counterfactual, it suggests the mechanism to pursue. If multiple mechanisms or combinations of mechanisms are considered, rank them, and pursue the option with the greatest net present value of benefits.[5]

Where distributional impacts see one customer or stakeholder group—for example, nonparticipating customers—worse off, lower-ranked options that show less distributional inequity may need to be considered. Alternatively, the assessment should ponder compensation measures, including redistribution of benefits, to the extent possible.

Additional factors to consider when developing the cost-benefit analysis include:

- When evaluating combinations of mechanisms, any interactions should be considered—that is, where one mechanism may affect customer behavior in relation to another.
- Mechanisms can be introduced, altered, or withdrawn over time. Therefore, the cost-benefit analysis must incorporate a time-based component.
- Consider multiple scenarios and sensitivities of aspects like customer growth, rates of uptake, opt-in/opt-out/compulsory uptake,[6] business models, and routes to market.
- Assess the likely uptake through different price signals.
- Would alternative financing arrangements (for example, concessional loans or grant funding) provide additional value and customer incentives?

Implementation Design

The third and final step in implementing demand response is developing the implementation process. The four sets of activities of the implementation process are discussed further in the next four sections.

FIGURE 6.6

Implementing a Demand-Response Program in Four Steps

3.1 Design the mechanism	3.2 Ensure supportive policy, legal, and regulatory frameworks	3.3 Adopt accompanying measures	3.4 Establish a work plan for implementation
• Target customers • Price-setting policy • Penalties for non-delivery • Provisions for change in mechanism over time • Engagement with direct stakeholders • Formal routes to market and business models	• Guiding policy • Enabling law • Supportive regulations (including technical) • Application process • Tariff (re)design, if applicable • Market (re)design, if applicable	• Market education/ communication • Tax exemptions for equipment, if applicable • Social measures	• Timeline (phasing, responsibilities, milestones, interlinkages, dependencies) • Identification of possible quick wins • Provisions for pilot project, if applicable • Identification of champions (organisation and individual) • Institutional support and capacity building • Monitoring and evaluation • Program review

Design the Mechanism

While the cost-benefit analysis will have developed and tested the concept of a mechanism or combination of mechanisms, the design phase will work that concept out in practice. Some points to consider in the design phase are summarized in Table 6.2.

TABLE 6.3

Factors to Consider in the Mechanism Design Phase

FACTOR	CONSIDERATIONS
Target customer identification	With how much granularity can participating customer group(s) be identified? Will the groups change over time? Will customers be added/removed?
Baseline determination and verification process	How can the objective that demand response is intended to achieve be quantified? What is the baseline (current situation)? What are the targets? What is the process for measuring performance against those targets?
Price setting and penalties for non-delivery	What is the value of demand response to the power system? What forms of demand response can be monetized? How much of this value should be passed on to customers through the price before incentives are reduced? What is the cost of non-delivery by participating entities? How much of this cost can and should be recovered through penalties for nonperformance?
Change in the mechanism over time	Are changes in the mechanism expected over time? Is there flexibility in the contractual arrangements to incorporate changes?
Participants in the design phase	Which stakeholders are required to participate in the design phase—for example, the regulator (via regulatory sandboxes), utility, customer representative bodies? Which others can add value to it—for example, energy service providers, customers with international experience in other countries/markets, technology designers?
Routes to market and business models	Has agreement been reached on how enabling technology should be deployed and how to split the cost between the utility, the distribution company, and the energy service provider? What role is there for supportive financing mechanisms—for example, commercial loans, concessional loans, and grants, if the CBA agrees? How can the emergence of new players and innovative business models be enabled (within supportive policy, legal, and regulatory frameworks)

Provide a Supportive Policy, Legal, and Regulatory Framework

As some demand-response mechanisms involve technological innovations and changes to status quo operations, it may be that their implementation is hindered by unsupportive policy, legal, and regulatory frameworks or could be accelerated through more clearly supportive frameworks. Elements of such frameworks that should be considered in the implementation phase are summarized in Table 6.3.

TABLE 6.4

Elements of Supportive Policy, Legal, and Regulatory Frameworks for the Implementation of the Chosen Demand-Response Mechanism

ELEMENT	CONSIDERATIONS
Enabling law	Clauses of laws may prohibit certain demand-response activities, technologies, and potential customer discrimination (participant vs. nonparticipant) and should be addressed. Changes to laws can be lengthy processes, so such elements should be identified and addressed at the earliest opportunity.
Supportive regulations	As with the enabling law, regulations may require updating or drafting to support the mechanism. For price-based mechanisms, changes may be required in applicable tariff methodologies. Similarly, price-based mechanisms may require a cost-of-service and tariff design study to set prices accurately. Frameworks should accommodate new actors where required or anticipated (for example, aggregators). Ensure that the legal and regulatory framework governing demand-response procurement incentivizes the utility to treat it on a level playing field with supply-side resources, in particular cost recovery (see the case of Viet Nam). Demand response may be supported by the utility through direct investments in at the customer's premises. Where the regulatory framework does not permit this, alternative contracting structures can be explored (for example, third-party provision, competitively sourced).
Application process	Who will initiate an application to participate—for example, customers, installers, or utility? Are the opt-in, opt-out, and mandatory participation processes clearly defined and well understood? Who will receive and process applications? Can timelines and milestones for application processing be formalized, with appropriate penalties?
Market (re)design	To what extent is the mechanism dependent on market (re)design? How will this be implemented, by whom, and on what timeline?

Accompanying Measures

Direct stakeholders will take on many of the activities needed to implement demand-response measures. But other measures not directly associated with demand response may be initiated by indirect stakeholders, some outside the energy sector. The relevant energy ministry and regulators may wish to initiate discussions over such measures. Table 6.4 provides suggestions for possible non–demand response measures.

Work Plan for Implementation

The final stage of the implementation preparation phase is to design a detailed roadmap for implementation, which, when followed, will lead to full program implementation. The roadmap will become the key implementation document for primary stakeholders (identified in the roadmap), combining all elements of the implementation phase. The roadmap could cover all activities laid out in this chapter. Key aspects of the roadmap are presented in Table 6.5.

TABLE 6.5

Non–Demand Response Measures in Support of Implementation

MEASURES	CONSIDERATIONS
Market education/ communication	New technologies and pricing schemes will typically require customer (and other stakeholder) education and clear communication around costs, benefits, misconceptions, timelines, processes, and other elements of the program.
Tax exemptions on equipment	The removal or zero-rating of taxes on equipment—for example, import duties, and value-added taxes—can lower costs for end customers, improving likely uptake. Tax exemptions should be included in the cost-benefit analysis. If possible, the relevant tax authority should be included as a stakeholder to show the net impact of the exemption on its revenues and any offset of these through increases resulting from greater activity in other areas (for example, income taxes).
Social measures	Special safety nets or direct benefit transfer schemes can be established for low-income customers and to address inequity.

TABLE 6.6

Key Aspects of the Demand-Response Implementation Roadmap

MEASURES	CONSIDERATIONS
Timeline	The core of the roadmap is a timeline of all activities supported by a visual representation, such as a Gantt chart. The timeline should consider the nature of the demand-response program(s), activity phasing, and the points at which where go/no-go decisions can be made at critical moments. Activities in the timeline should identify the entities and, if possible, the people responsible, with appropriate dates and milestones. Some timeline activities may involve interlinkages and dependencies (activities that must be completed before another can start).
Pilot projects and quick wins	Pilot projects and quick wins should be implemented in regulatory sandBoxes to test the efficacy of different mechanisms and incentive structures. Their results should be evaluated, identifying pressing changes to existing regulations. Examples may include working with existing technologies and customers known to utilities who are keen to participate in a demand-response program without incentive or further education.
Champion identification	Innovative programs typically require a "champion" organization and, ideally, an individual within that organization to ensure actions are completed according to the timeline. A lack of a clear champion can hinder momentum, typically if a program is initiated by one entity that then delegates to another (without full cooperation).
Institutional support and capacity building	Where program activities are new, which is likely in most cases, institutions may require support for their role in implementation. Such support may be provided through targeted capacity building.
Monitoring and evaluation	Program effectiveness and impact should be monitored and evaluated periodically to ensure progress against predetermined targets, with adjustments made where progress is falling short. Considerations may include assessments of overall outcome impact, uptake, and price changes. Adjustments may include changing incentives, prices, and requirements for opting in or out.

Endnotes

1. For simplicity, this chapter refers to countries but acknowledges that unbundled entities may adopt demand response apart from others within the same country.
2. While this point addresses existing least-cost plans, the implementation process for demand response should be incorporated within the least-cost planning process.
3. The South Africa case study (discussed in chapter 5.3) shows that the country has multiple mechanisms operating in a single market.
4. This section provides no formula for conducting CBA, which other resources can supply, but rather guidance on factors to incorporate in the assessment. In its simplest form, the net present value of all benefits is divided by the net present value of all costs to find a cost-benefit ratio. Subtracting the net present value of costs from the net present value of benefits will give a net present value of benefits.
5. This is preferred over the greatest cost-benefit ratio as it provides a greater aggregate benefit to the power system, rather than the highest return (which may not have such a high aggregate benefit).
6. As noted earlier in the report, customers tend to stay with the status quo. Therefore, opt-in modalities, which rely on customers choosing to sign up for the program, tend to result in much lower subscription rates than opt-out modalities.

SEVEN
CONCLUSION

Demand response is a short-term, voluntary reduction in electricity consumption by end users. Such cutbacks are generally triggered by signals of compromised grid reliability or high wholesale market prices. But their appeal is growing as power system participants come to appreciate the utility of demand response as part of a decarbonization strategy. Demand response can be a highly cost-effective mechanism that maintains the supply-demand balance during peak hours or when the power system is stressed.

The potential of demand response in developing countries remains largely untapped. While system operators in developed countries have leveraged demand response for many years, it has been used sparingly in developing countries. The energy transition and the need for decarbonization are expected to increase the need for demand response as systems incorporating mounting levels of renewable generation require greater operational flexibility to accommodate production and load variations. Policy makers are increasingly aware of the cost-effectiveness of demand response as a source of flexibility and an essential support to the energy transition.

Demand-response programs can be classified into two broad categories, depending on the nature of the incentives adopted. Price-based (or implicit) mechanisms are based on time-differentiated rates designed to encourage customers to shift consumption from peak hours or to reduce consumption when the system is stressed. Quantity-based (or explicit) mechanisms offer customers a direct payment for reducing their load and include a broad set of solutions designed to shape customer consumption directly, such as interruptible contracts and direct load control.

Developing countries can benefit from deploying price and quantity-based demand response, depending on their objectives and market structure. Static ToU rates, which have been essential in shifting consumption away from peak hours, are the most common form of participation in demand response. Prices and time intervals do not change, however, according to the power system's criticality and need for more flexibility. Price-based demand-response instruments can be enhanced to reflect system criticality through more dynamic tariffs (such as CPP). Developing countries may also benefit from quantity-based load control and interruptible contracts, commonly seen already through control of hot water heaters, payments for large consumers to reduce short-term demand, and similar mechanisms. As power sectors evolve, more sophisticated mechanisms, such as the use of demand response in the energy and capacity markets, can also be explored. Demand response can be especially cost-effective in small island developing states having limited resources to accommodate the integration of VRE and manage peak demand.

The most valuable demand-response mechanisms offer maximum flexibility to the power system operator. This entails eliciting demand response from dependable resources that can provide a variety of services to the system operator across a range of timeframes and that can be controlled directly and automated.

Technology, supportive frameworks, and customer engagement will be critical for mainstreaming demand response. Smart meters, already deployed extensively worldwide, can support the introduction of dynamic rates and load controls. Other technologies, such as smart appliances, smartphones, and V2G (vehicle-to-grid), are expected to boost the role and functionality of demand-response mechanisms. The right policies and regulations can enable new business models and new service providers to play key roles in aggregating and controlling multiple smaller loads that are part of the demand-response spectrum. Shifting customers to new tariff arrangements and innovative technologies must be communicated and managed carefully, while allowing customers to opt out should they wish to do so.

Growing experience with the implementation of demand-response programs, including pilots and early adoption, is instructive for developing countries. In addition to the considerable experience in developed countries, developing countries can draw on the know-how gained by other developing and emerging economies where the operating context may be more relatable. A greater understanding of the lessons learned from successes and failures can help them design leapfrog approaches to improving system reliability and grid flexibility.

Countries should develop demand-response programs designed for the national context, with appropriate mechanisms and detailed work plans for implementation. Countries with constraints that could be alleviated through demand response should take pains to understand their national context so as to ensure that interventions are well-targeted. Selections should be made from the expansive menu of demand-response mechanisms, with potential and distributional impacts assessed through a robust cost-benefit analysis. The identified mechanisms should be implemented through a work plan accompanied by pilot projects and quick wins; appropriate policy, legal and regulatory interventions; response measures not directly connected to demand response (particularly market education); allocation of implementation tasks among clearly identified parties and along clear milestones; and effective monitoring and evaluation to assess program success.

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APPENDIX A
Definitions of Key Ancillary Services

Reserves are backup generation that can be called upon within a certain time frame in the event the power grid comes under stress (contingency), for example, an anticipated demand surge or the unexpected loss of a generator or transmission line during a heat wave.[1] Categorization of reserves varies by jurisdiction; response time and duration make the key difference. Historically, fast-responding reserves have often been called “spinning reserves,” reflecting traditional hydro or thermal generation synchronized (“spinning”) with the grid ready to input energy and arrest a frequency drop within minutes. Given their role in arresting frequency drops, these reserves are also known as “frequency containment reserves.”

With increasing renewables penetration, dedicated products targeting exceptionally fast responses (less than a second) and inertia support (to counteract the lower inertia on grid networks with inverter-based equipment) have been developed in markets like the Republic of Ireland. These products cause frequency to drop more steeply during an outage. Batteries have become a popular choice for such services due to their technical capabilities.

Slower responding reserves (“non-spinning” or “restoration reserves”), which come online 30 minutes or more after instruction, are then used to help free up the fast-responding units so that they may be ready for the next event.

Other, more bespoke products have also been developed to help support ramp rate concerns, particularly in relation to a decline in solar photovoltaic output and a rising demand for evening peak. Grid-forming inverters are one of the solutions being tested. A combination of synchronous condensers and batteries can help control voltage and frequency by boosting system capacity.

Frequency regulation, or **regulation,** refers to generation that can respond automatically to detected deviations from the frequency at which all generators in a synchronous air-conditioning system are rotating (In the United States this frequency is 60 hertz, whereas some other countries use 50 hertz). Regulation is sometimes called “automatic generation control” because the response is typically too fast for a human being to initiate. Frequency regulation as an ancillary service corrects for frequency deviations by increasing or decreasing the output of specific generators, usually by small amounts. The response times for generators providing regulation are typically in the order of seconds. Frequency regulation is provided for system operators to ride through unexpected fluctuations in variable renewables output. Frequency is a systemwide feature.

Voltage support service is essential to stabilize the grid and prevent collapse and cascading blackouts. Voltage levels should be maintained by balancing active (megawatt-hour, MWh) and reactive (megavolt-amperes reactive, MVAr) power. Capacitors embedded throughout the grid provide static reactive power support, and generators, synchronous condensers, or dynamic transmission devices provide dynamic reactive support. Reactive supply is typically not procured through competitive markets. Voltage is a local issue managed at the nodal level by changing the amount of reactive power.

System operators use network congestion/constraint services to control flows on the network and ensure they remain within technical limits. Managing flows on particular lines typically involves a pair of actions: requesting one service provider (generator, storage, or demand response) to constrain the amount of electricity it is producing or consuming, and a corresponding request to another provider, in a different locale, to take the opposite action.

Black start capability is necessary for a power system operator to restart the system in the event of a massive blackout. Black start services must originate from generators that can start independently and have sufficient real and reactive capability to energize a grid and restart additional generators.

Endnote

1. It is not clear whether the unanticipated loss of a variable renewable energy for resource reasons (for example, wind stops blowing) is considered a contingency.

APPENDIX B

Additional Information on the Case Studies

This appendix contains additional information related to the case studies and examples presented throughout this report. The focus is on the case studies and examples considered of greatest potential interest to readers.

Spanish Time-of-Use Residential Tariff

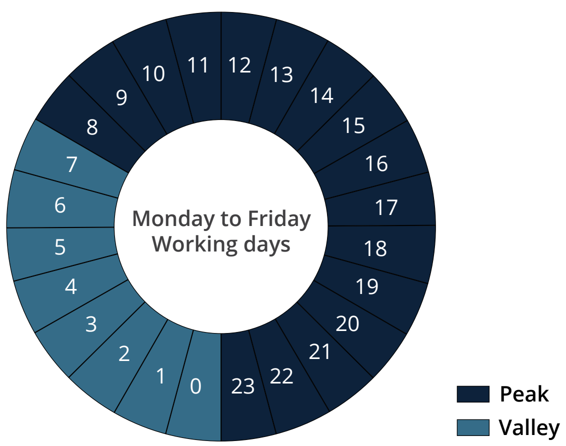
The National Regulatory Authority (Comisión Nacional de los Mercados y la Competencia) designs tariffs in Spain. The current tariff design for residential customers was introduced in 2021 and is considered an advanced tariff system built on experience acquired with time-differentiated tariffs implemented in 2014 for residential customers in Spain.

The 2021 tariff methodology is time differentiated for the capacity (demand) and energy components and applies to customers with less than 15 kilowatt (kW) installed capacity.

The capacity (demand) charges are two-tiered. The peak capacity charge is from 08:00 to 12:00 on weekdays (Figure B.1). The off-peak charge is more than 95 percent lower than the previous single charge.

FIGURE B.1

Two-Tiered Capacity (Demand) Charges for Residential Customers

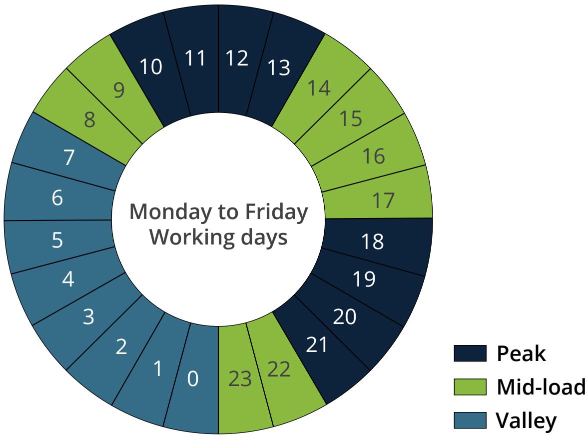


Source: CNMC 2022.

Consumption has three tariff brackets (Figure B.2).

FIGURE B.2

Three-Tiered Consumption Charges for Residential Customers



Source: CNMC 2022.

Price differentiation is mandatory for all residential customers. The objectives are to incentivize all customers to shift load to off-peak periods, enable electric vehicle owners to charge at lower rates, and help decarbonize electricity consumption.

Customers can review their contracted demands to benefit from the new tariff structure. A capacity component, which has a fixed value defined on a €/kW per year basis, has been a part of electricity rates in Spain since the early 1960s. Initially, all households had a fuse, which tripped when consumption exceeded the contracted value. The electronic meter performs this function; it trips when consumption remains above the contracted capacity threshold for longer than 10 minutes.

The final tariff for end users has multiple components (Table B.1). The energy component is linked to the price variation in the wholesale market. This incorporates an element of real-time pricing into the tariff structure.

Figure B.3 shows the relative importance of the energy and grid components.

The energy component includes energy itself (traded on the wholesale market in real time), in addition to capacity fees and all other fees necessary to support the grid and market operators. The cost of energy in the wholesale market accounts for 85.4 percent.

The grid component has four critical elements. The most important element is the cross-subsidy to renewable energy, which were contracted at above-market prices (37.4 percent). The second element is the distribution cost (31.4 percent). The third element is a cost component covering past revenue shortfalls (16.4 percent). The fourth element is transport costs (10.1 percent).

The impact of the new time-differentiated tariff implemented in 2021 in Spain has not been evaluated. Doubts about the new tariff design have helped increase consumer awareness that electricity costs are far from constant. There is some optimism, that with proper information and motivation, consumption patterns can be modified in response to the new pricing structure.

TABLE B.1

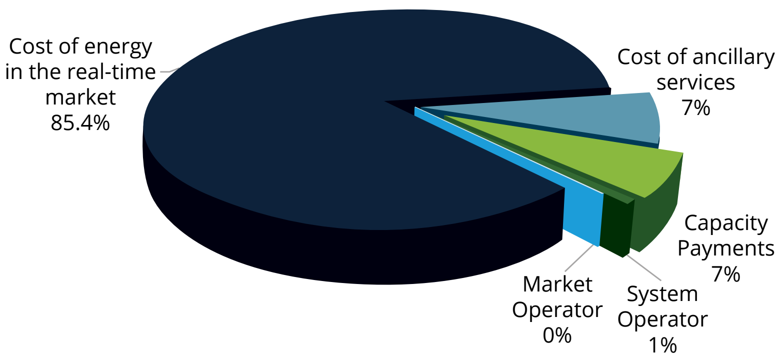
Cost Components of the Residential Tariff

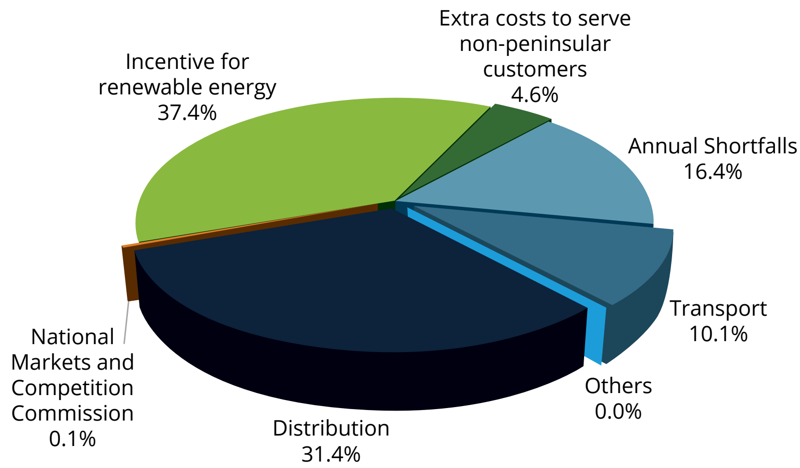
TRADING MARGIN	
Energy costs	• Cost of energy in the real-time market • Cost of ancillary services • Capacity payments • System operator • Market operator
Use of transmission and distribution fees	• Transmission costs • Distribution costs
Fees	• Incentive for renewable energy • Extra costs to serve non-peninsular customers • Annual shortfalls • National markets and competition commission
Metering equipment rental	

Source: CNMC 2022.

FIGURE B.3

Cost Components of the Residential Tariff





Source: CNMC 2022.

Demand Response in India: Additional Information on Pilot Programs

Distribution companies have conducted several demand-response pilots; most of them have been to manage peak demand by shedding or shifting load. Sasidharan and others (2021) provide an overview of some of the demand-response pilots implemented by Indian utilities. Table B.2 highlights seven major demand-response pilots that have been conducted in the last 12 years. Although all the demand-response programs were able to reduce demand, there are many barriers to scaling up.

TABLE B.2

Seven Major Demand-Response Pilot Projects in India

STATE	ELECTRICITY UTILITY	YEAR	RATIONALE	TYPE OF DEMAND RESPONSE	STRATEGY OF DEMAND RESPONSE	CONSUMER SEGMENTS
Maharashtra	Tata Power Company Ltd—Mumbai	2012	Peak demand	Shed	Aggregator-based and automated demand response	Commercial and industrial
Delhi	Tata Power Delhi Distribution Limited	2014	Peak demand, grid stress	Shed	Automated demand response	Commercial and industrial
Rajasthan	Jaipur Vidyut Vitaran Nigam Ltd	2013–14	Deviation from schedule	Shed	Manual demand response with energy market integration	Commercial and industrial
Delhi	BSES Yamuna Power Limited	2017	Deviation from schedule	Shed, shift	Behavioral demand response	Residential
Delhi	BSES Rajdhani Power Limited	2018–19	Peak demand	Shed, shift	Behavioral demand response	Residential
Uttar Pradesh	Uttar Pradesh Power Corporation Limited	2019	Peak demand	Shed	Manual demand response	Commercial and industrial
Delhi	BSES Yamuna Power Limited	2020	Peak demand	Shed	Automated demand response	Residential and commercial
Delhi	Tata Power Delhi Distribution Ltd	2021	Peak demand	Shed, shift	Behavioral demand response	Residential

Source: Sasidharan and others 2021.

Some salient features of the demand-response initiatives undertaken by distribution companies in different states are described below.

BSES Yamuna Power Limited implemented a manual demand response pilot program and an automated demand response pilot program in 2017 and 2020, respectively. Commercial and industrial customers participated in the manual demand-response pilot program. Their load was curtailed for one hour during the summer months. The manual demand-response pilot program compensated the customers and successfully achieved a cumulative load reduction of 17 megawatts (MW) from the 19 participating customers. The automated demand-response pilot demonstrated the feasibility of controlling the air-conditioning load during summer months through remote control (cloud based). It achieved a 30 percent reduction in consumption.

Tata Power Delhi Distribution Limited has also implemented pilot demand-response programs. It implemented India's first smart meter–based pilot program for peak demand and grid stress management using an automated demand response. The pilot relied on real-time communication to provide information on the load to the utility and consumers, increasing transparency. The utility also conducted a pilot of behavioral demand response. It was targeted at residential customers and was meant to demonstrate the potential savings to the utility and to customers.

With peak demand being four times as much as off-peak demand, the focus was to shave peak demand. Schemes planned to be implemented in FY 2021–22 included energy audits on cold storage for industrial consumers, the replacement of nonefficient commercial chillers, and the replacement of hot water geysers.

BSES Rajdhani Power Limited (BRPL) designed an automated demand-response program, which included onboarding customers via a customizable web-based platform. The distribution utility used the platform to publish events and send notifications to the participating consumers. If customers approved it, the utility could operate the participating load as per the scheduled events. The program's first phase included peak shaving (turning air-conditioning loads on/off, for example). The second phase (load shifting) tried to shift water heating loads from peak to off-peak hours. The load reduction was about 1 MW. BRPL has plans to implement a large-scale demand-response program.

At Jaipur Vidyut Vitran Nigam Limited, a demand-response pilot was designed to reduce the deviation penalty incurred by the utility when procuring energy from the national grid. The pilot was designed as a demand-bidding-to-the-market mechanism. Industrial consumers could submit demand bids directly to the energy market. Seventeen commercial consumers who had enrolled voluntarily participated in the pilot program. Customers were notified four hours before a demand-response event. After the event, the software was used to measure and verify the participants' load curtailment. Four events resulted in an average of 22 MW in demand response, proving a cost-effective solution. The scale-up of such projects will require dynamic pricing programs and advanced metering infrastructure.

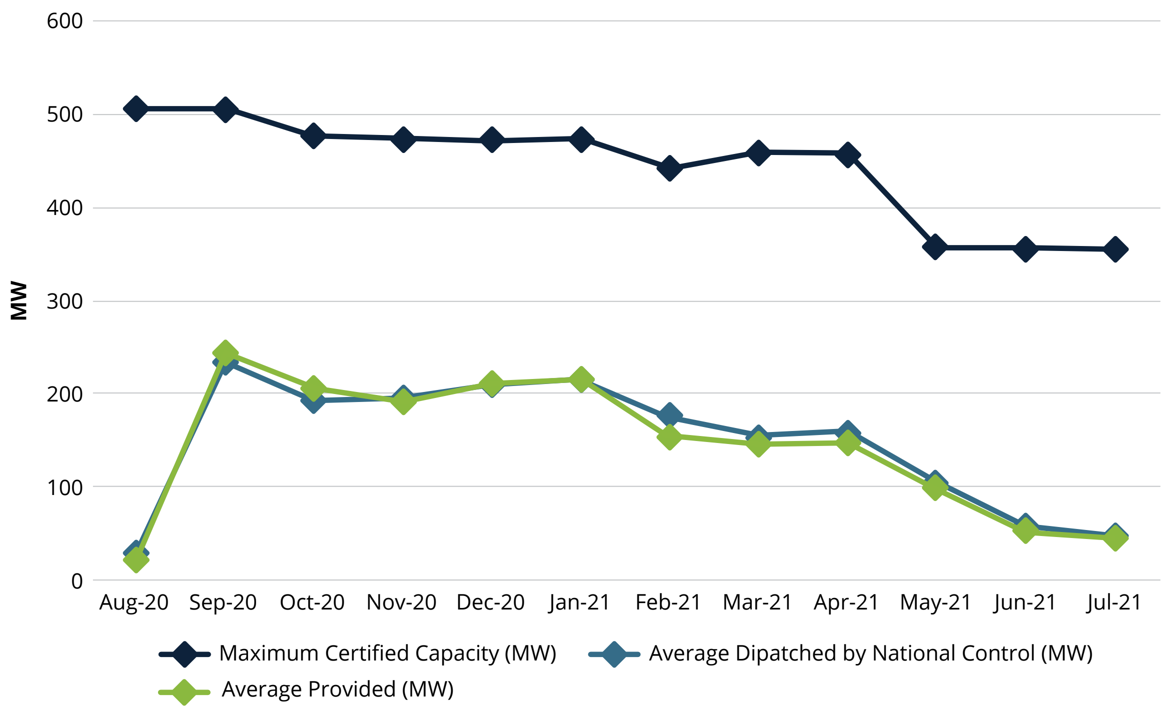
Demand Response in South Africa: Additional Information on ESKOM Programs

Besides the load control programs described above, Eskom has designed some mechanisms for large customers, as described below.

Supplemental demand-response programs target industrial consumers with a minimum load entry level of 500 kW or 15 percent of the average load. The load provider should guarantee up to 300 reduction hours per year, with at least one hour per event per day. The reduction is requested 30 minutes in advance. The load provider receives a capacity payment and an energy payment for energy not consumed during the reduction period. Figure B.4 shows the maximum certified capacity and the average monthly reduction provided last year.

FIGURE B.4

Performance of Demand Enrolled in the Supplemental Demand-Response Program



Source: Eskom 2021.

Note: MW = megawatt.

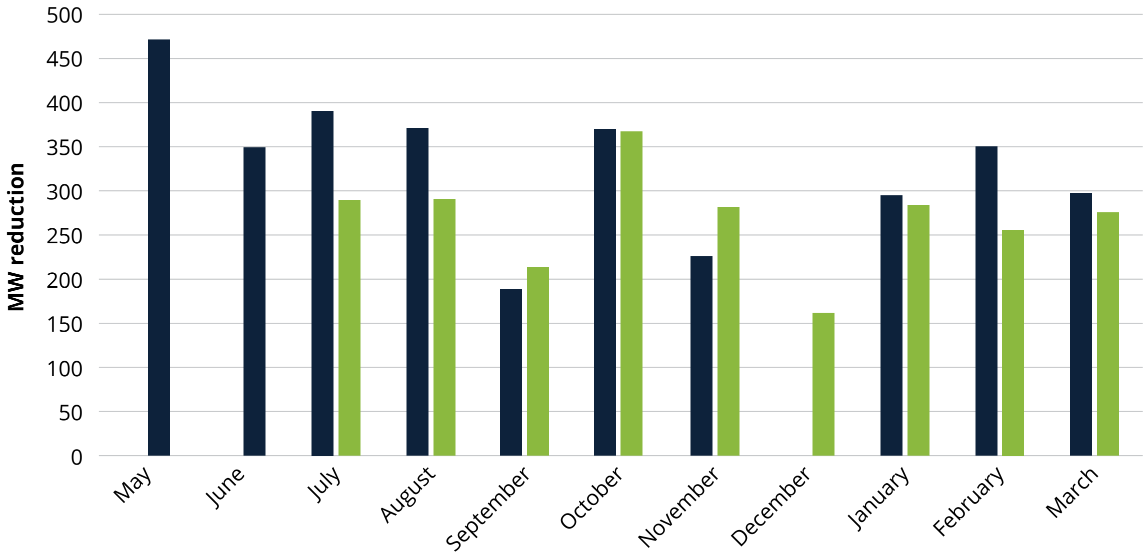
Instantaneous demand-response programs target industrial consumers with fast-response capabilities and a minimum load entry level of 10 MW. The instantaneous demand-response load provider should guarantee up to 200 fewer event hours per year and at least three 10-minute reductions per event per day. DR must respond within six seconds after the shed signal. The load provider receives a capacity payment based on the median performance for a month.

Non-dispatchable demand-response programs target industrial consumers that cannot reduce their load on short notice. The minimum load entry level for these consumers is 2 MW or 15 percent of the average plant load. Consumers can opt to participate with a one- to four-hour demand reduction, which will always be requested between 16:00 and 20:00. The reduction request is made two to four weeks in advance, and the consumer receives an energy payment that varies inversely as the reduction request time that it has selected. This program was discontinued.

A power alert initiative is meant to engage customers in managing imminent power crises, but it has no associated remuneration. Power alerts inform the population in general about the status of the power sector and are triggered when an impending supply-demand imbalance may lead to load shedding. The status level is indicated by a color code: green indicates a stable situation, yellow significant strain on the network, red a severe stress event, and black a critical condition already causing load shedding. Figure B.5 shows the average demand reduction obtained through red and black power alerts in 2020–21.

FIGURE B.5

Demand Reductions Achieved through Power Alerts (red and black status levels), 2020–21



Source: Eskom 2021.

Note: MW = megawatt.

The average megawatt reduction achieved through power alerts is comparable to the certified and dispatched capacity under the supplemental demand-response program. Power alerts reach a much larger customer base and require a concentrated effort by customers to respond under the imminence of a blackout. Therefore, since no incentives are provided, power alerts are meant to be used only during emergencies. If used too often, they will likely lead to customer fatigue, making the program less effective.

Besides traditional price- and quantity-based demand-response mechanisms, South Africa used efficient market-based demand-response business models to manage power shortages during the 2008 dual energy and capacity crisis. A 1,500 MW peak demand reduction was achieved through programs and interventions involving mainly industrial customers, particularly mines and smelters (ESMAP 2011).[1] Eskom was instrumental in designing and implementing these programs.

Demand Response in the United States: Additional Information

TABLE B.3

Results of Peak-Time Rebate in Maryland

YEAR	ENERGY SAVINGS DAYS	ELIGIBLE CUSTOMERS	AVERAGE CREDIT ON ELECTRICITY BILL	PEAK DEMAND REDUCTION		PARTICIPATION (%)
	(N)	(N)	($)	MW	($, millions)	
2013	4	315,000	9.03	96	7.0	82
2014	2	860,000	6.55	209	5.6	76
2015	4	1,020,000	6.67	309	15.5	81
2016	3	1,074,000	6.73	336	11.0	71
2017	2	1,095,000	6.13	330	6.1	74

Source: Studies by EPE (2018).

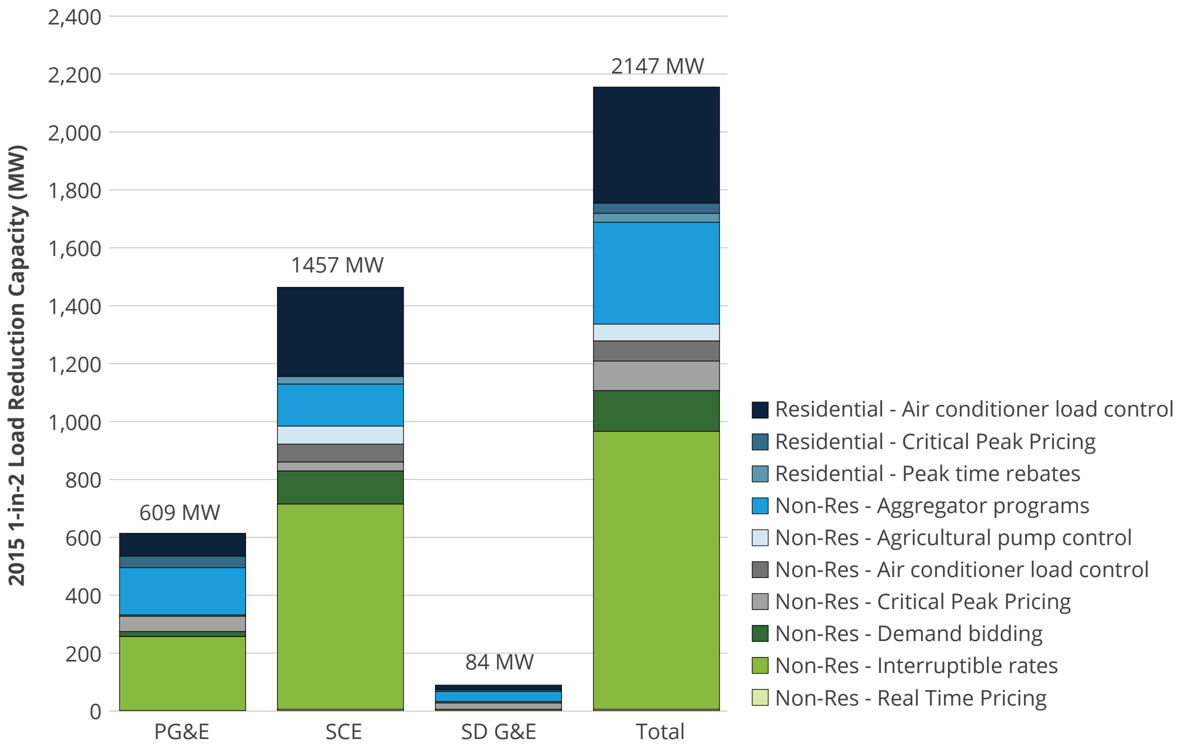
Note: MW = megawatt.

Figure B.6 presents the 2015 demand-response capacity available to the three largest utilities in California: Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric, totaling about 2.1 GW.

The most significant contribution came from interruptible tariffs (~1 GW), followed by residential-level air-conditioning load control, with a 0.4 GW contribution. Non-residential-level aggregator programs made a 0.35 GW contribution, followed by demand-side bidding with a contribution of about 0.14 GW.

FIGURE B.6

Demand-Side Resources in California



Source: Monthly reports from utilities on interruptible load and demand-response programs filed with California Public Utilities Commission (A.11-03-001).

Note: MW = megawatt; PG&E = Pacific Gas and Electric; SCE = Southern California Edison; SDG&E = San Diego Gas & Electric.

Endnote

1. This was predominantly a power buy-back scheme under which large industrial customers with furnace loads were paid to switch off their plants.

APPENDIX C
Possibilities for Load Control

Some typical loads can be controlled to benefit the power system.

Utilities may control air-conditioning devices during critical periods when there is risk of an outage. In most places, this typically occurs on hot summer days, when demand strains the power system. The utility remotely cycles air-conditioning devices in a specific region or neighborhood—preventing a large number of units operating simultaneously; the load factor is in turn reduced, lessening coincident peak demand in distribution feeders and creating virtual capacity for the system. Some load control programs in the United States compensate customers with a fixed payment (rebate), $40–$120 per year,[1] depending on the region and the utility's level of control.

At the commercial level, there are other opportunities to explore for more efficient and more responsive cooling: storing ice in large offices and commercial buildings; heating, ventilation, and air-conditioning may be controlled automatically, providing a fast demand response; ice could be stored during off-peak hours and used during peak hours to feed the heating, ventilation, and air-conditioning systems. Another possibility is district cooling, chilling water at a centralized location, to distribute to nearby buildings. Chilled water (or ice) can be stored to support consumption for several hours. District cooling is an interesting alternative in some niche markets. Its adoption has been modest, but it has gained momentum.[2]

Water heaters can also be cycled. They do not play an essential role in driving the peak demand in the United States, except in the winter in colder climates. Still, load control for water heaters (with storage capacity) is common in other countries. A demand response can be initiated rapidly, providing ancillary services if needed.

Crypto miners are a large and growing group of energy users worldwide. For example, the value of Bitcoin and equivalent currencies is increasing demand in several parts of the world. Places with cheap energy are attracting crypto miners. This demand growth has required some US utilities to review their energy and demand pricing strategies to recover incremental energy and investment costs.

Crypto mining is potentially a reliable demand-response resource, provided the mining activities shed load when instructed. However, the model has failed in the United States because most crypto miners do not shed loads during peak hours, mainly when the cryptocurrency's value is high. In some states, such as Georgia (with the largest crypto mining operation in the United States), miners operate almost like a giant baseload. Better regulatory and demand-response mechanisms must be devised to manage the challenges posed by crypto mining and the opportunities that it provides.

Data centers are becoming large energy users, and they could potentially participate in demand-response programs, although some barriers exist. Reliability is crucial; data centers require continuous power and invest in batteries and emergency generation to ensure service continuity. Technically speaking, data centers could operate as islands, reducing consumption from the grid, but there are practical considerations. Switching to backup entails some technical risks. Expanding a battery energy storage system is also costly. The processing load of data centers could be distributed across several geographically dispersed centers. Still, cloud migration is not easy, and the benefits of demand participation are not attractive enough to compensate for the complexity and possible disruption in processing capacity.

Despite those difficulties, leading-edge data centers like Google's participate in demand-response programs. When a system operator informs Google of a forecasted grid event that can cause a supply constraint, this information is conveyed to a global computing planning system, which generates hour-by-hour instructions to limit nonurgent tasks for that event's duration. Strong interconnectivity among computer centers worldwide enables companies like Google to shift processing tasks and reduce local consumption. When feasible, some tasks may be rerouted to other data centers.

Endnotes

1. Cycling may cause some minor discomfort, which can be ameliorated by reducing the temperature set point by 1–2 degrees. Some more sophisticated utility protocols precool and change the temperature setting automatically via smart thermostats.
2. District cooling is standard in Europe, where the district heating infrastructure is sometimes shared. This is also under trial in India. It is seldom used in Latin America. A survey developed by the World Bank in 2017 revealed three (public) district cooling facilities in Latin America and the Caribbean: Panama City, Rio de Janeiro, and Medellin. The first facility was designed to provide air-conditioning for the Panama Canal administrative buildings. A utility-owned energy service company developed the second facility, and EPM, a local utility company, created the third facility to serve a cluster of adjoining public buildings. The Lusail City district cooling system that Marafeq, a utility company in Qatar, developed will use electric chillers and thermal energy storage to supply chilled water. It is estimated that storage will enable about 1,000 gigawatt-hours in savings annually and avoid the need for some 35 MW of capacity when compared with conventional air-conditioning systems using air-cooled chillers or split air-conditioning.

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