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Demand Response in Smart Grids

1.1. Introduction

Traditional electric power utility regulation favors investments in supply-side resources over demand-side flexibility and energy efficiency resources. Accordingly, utilities have preferred capital intensive investments like building power plants, transmission and distribution networks since their profits have been, and are still, linked to their capital expenditures and energy production and sales. This trend is slowly shifting in modern power systems. The movement being observed is toward ensuring energy security and reducing industry's carbon footprint by integrating renewable and distributed energy resources, and through the implementation of energy efficiency programs [BEE 12, CAP 09].

The proliferation of renewable energy resources, with energy security and environmental betterment objectives, poses significant challenges to the secure operation and planning of power systems. This is particularly due to the need for higher levels of flexibility and controllability to accommodate the intermittency and non-dispatchablility of renewable energy resources [ETO 10, UND 10, MAR 10, ILL 10, ELA 12]. In this environment, the demand side is expected to play an increasingly active role in maintaining the supply–demand balance by providing the required flexibility to follow non-dispatchable renewable energy resources [IVG 10]. This is in distinct contrast with the traditional power systems operation and planning paradigm in which generators are controlled to follow the demand as it varies over hours, days, seasons and years. Moreover, demand-side management (DSM) programs in the emerging low-carbon grids have had further expectations to leverage their potential over more traditional roles in decreasing the peak demand, reducing the operation of quick-start and peaking units (which are the major contributors to

Chapter written by Amir ABIRI-JAHROMI, Navdeep DHALIWAL and François BOUFFARD.

green-house gas emissions), and assisting with transmission and distribution investment deferrals.

According to the US Department of Energy, demand response (DR) can be defined as “changes in electric usage by end-use customers 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 system reliability is jeopardized” [USD 06]. There are other definitions which are more representative of the emerging applications for demand-side flexibility where demand is seen as a dispatchable resource responding to signals from transmission and distribution system operators, flexibility aggregators and utilities in the wider sense. For instance, the California Energy Commission defines DR as “a reduction in customers’ electricity consumption over a given time interval relative to what would otherwise occur in response to a price signal, other financial incentives, or a reliability signal” [CEC 11].

As these definitions suggest, DSM covers a broad range of activities that are planned to encourage end-users to modify their electricity usage patterns in order to assist power systems operation and planning. The terms “load management”, “demand response” and “energy efficiency” are often used interchangeably in the context of DSM. Nevertheless, there are differences between these terms which should be recognized. Load management programs usually refer to traditional applications for DSM which are mainly concerned with reducing power consumptions during peak demand and emergency conditions. Meanwhile, DR programs refer to recent and emerging applications for DSM, like improving grid reliability by providing ancillary services, or reducing wholesale energy prices and their volatility.

In contrast to load management, and DR programs that share some similarities, energy efficiency programs are primarily concerned with the permanent reduction in overall energy consumption of a specific device or system by employing high-efficiency equipment or system design [SHE 12]. Therefore, energy efficiency programs have permanent impact on reducing electricity use while load management/DR programs entail modifying electricity use temporarily, and at critical times, rather than on permanent basis.

1.2. Background on demand side management and demand response

DSM in its most basic form is not a novel concept and has been around for decades under the generic name of load management. Load management and interruptible load tariffs for large industrial and commercial customers, and direct load control (DLC) for residential customers became popular in utilities in the 1970s and 1980s in several countries [CAP 09, USF 11].

The load management practices of the 1970s were mostly implemented manually, and due to the unavailability of cheap and reliable communication equipment and slow response times, they were rarely deployed. In the 1980s, however, utilities and policy-makers became aware of the load management value as a reliability resource in integrated resource planning [CAP 09]. This was partly driven by the penetration of thermostatically-controlled loads such as air conditioners, which resulted in a load factor reduction and could create severe loading conditions particularly after blackouts. The international energy crises of the 1970s and 1980s at the same time increased awareness about the role that DSM, and especially about the role that energy efficiency programs can play in improving energy security.

In the 1990s, policy-makers and utilities started to redesign many of the vertically integrated power industries to allow for more competitive wholesale electricity markets, while gradually introducing choice for customers [HUN 99]. Policy-makers of deregulated electricity markets played a key role in the establishment of the rules to level the playing field in terms of market entry for non-traditional control resources such as DSM resources. The Energy Policy Act of 2005 [EPA 05] in the United States is a prime example where policy-makers eliminated unnecessary barriers for DR participation in the energy, capacity and ancillary service markets. The problems seen in electricity markets such as in the California market collapse of 2000–2001 [BOR 02] were also key drivers for such legislative changes, as they highlighted the role that DSM and response could play in ensuring the efficient functioning of the wholesale electricity markets and preventing generators from exerting undue market power [WEL 07]. Another example of such necessary adaptations to open up DSM in the power industry can be found at National Grid in Great Britain, where the *frequency control by demand management* service requires a minimum of 3 MW of capacity, which can be obtained through interruptible load aggregation [NAT 14b]. This contrasts with the technically similar *firm frequency response* service which has a minimum offer size of 10 MW [NAT 14a] and which is clearly targeted toward traditional generation assets. Article 15 of the European Parliament's Energy Efficiency Directive [EUR 12] further outlines specific requirements for member states to enable and encourage DSM programs through the participation of DR providers such as aggregators. Overall, the development of open and organized wholesale markets coupled with policy support by energy regulatory commissions has facilitated the introduction of participation of demand-side resources in the power industry over the past few decades.

In recent years, the advent of smart grid (SG) technologies, which include a wide array of sensing, communication, control and decision-support tools all targeted at improving the functioning of grids, has led to many more new opportunities for DSM initiatives [MOR 09]. The ability of customers to respond to DR-related price/control signals has increased significantly as smart meters, communication, sensing and embedded control systems are becoming ubiquitous in the power industry, at home, in buildings, etc. Smart/communicating meters and telecommunication technologies enable operators, utilities and flexibility aggregators to communicate information such as time of use (ToU) prices to end-use customers in semi-real-time periods, as well as implementing various types of load control at end-use level. The potential number of applications is enormous, markets are wide open and innovation is driving major players of the information and communication technology (ICT) sectors into this brand new territory. The value of these potential applications is significantly given by the increasing role electricity plays in all economies. Electricity will be the energy carrier *par excellence* in the next 50 years, and therefore, the value of tools for control and management of electricity use can only increase in the near future.

1.3. Benefits offered by demand-side management

DSM can bring a variety of benefits to the power industry, ranging from economical to environmental benefits [SHE 12].

The economic benefits of DSM can be classified into three general categories. The first economic benefit comes from reducing the peak demands. Although peak demands are infrequent in power systems, their economic impacts are significant. This is mainly because energy prices skyrocket during peak demand and supply shortages. The more frequent occurrence of such spikes is what drives traditional industry capital investment in generation, transmission and distribution. Therefore, reducing peak demands though demand-side measures can be seen as direct substitutes to those investments. Given the scale of the investments involved, choices favoring one avenue over another can have a huge economic impact [SHE 12].

The second economic benefit comes from providing ancillary services, and potentially decreasing the volatility of the demand. Generally, ancillary services are provided by generating units running in a subefficient mode of operation. Such costly situations could be substituted in part (and even maybe in whole) by employing DR capacity. The provision of ancillary services by DR can further reduce the need for running costly power plants, such as quick start and peaking units driving production costs, prices and emissions down [SHE 12].

The third economic benefit comes from reducing the transmission and distribution losses. This is because the energy usually has to travel a considerable distance from power plants to end-use customers. The transmission losses vary between 5 and 10% depending on the loading conditions of transmission and distribution lines. DSM can contribute in relieving heavily loaded lines and reducing losses [SHE 12].

DSM provides an excellent reliability resource for the most critical reliability needs [KIR 06]. Specifically, it can be used to address capacity inadequacy of power systems caused by shortage of generation and transmission resources. Moreover, DR programs can significantly increase the operational security of power systems in the short term by providing ancillary services. This is mainly because ancillary services provided by responsive demand are technically superior to their counterparts provided by generation assets as they are faster and often highly distributed – we think here, for example, of the millions of electric water heaters found in the Québec province of Canada, which can be selectively disconnected to offset morning and evening demand ramps. The only time required to activate most demand-based ancillary services is the time required for the control signal to get from an operator, aggregator or utility to the end-use load. This is much faster than generation response times, which are usually on bases of tens of minutes in practice. In specific applications such as frequency control, the DR times are almost instantaneous, as frequency is measured at the load site and there are no communication delays [KIR 06].

DSM programs increase power system reliability and lower the likelihood and consequences of generation and transmission-forced outages, which can impose significant financial costs and discomfort on customers [USD 06].

The use of DSM also results in numerous environmental benefits. The environmental benefits of DSM programs fall into two groups. The first group originates from the reduction in peak demands. Reducing the peak demands prevents the need for power plant operation and its associated emissions. In addition, those benefits may reduce the need to construct new power plants, transmission lines, substations and distribution assets. This prevents the environmental consequences that may have resulted from such construction, and enhances the social acceptability of power grids [SHE 12].

The second group originates from reducing the need for ancillary services from fast-start units. Fast-start units are mostly fueled by diesel oil or gas, which are significant contributors to green-house gas emissions. The use of DSM further leads to the operation of power plants at more efficient operating points. This results in less fuel consumption, and fewer emissions [SHE 12].

1.4. Types of demand response programs

DR programs can broadly be classified into two categories based on customer motivations for participation, i.e. price-based DR and incentive-based DR. Each of these categories has a number of variants [USD 06].

1.4.1. *Price-based programs*

Price-based DR programs refer to programs wherein changes in electricity use are made in response to price changes. These are divided into ToU rates, real-time pricing (RTP) and critical peak pricing (CPP) programs [USD 06].

With ToU rates, electricity is priced differently depending on the time of day, for instance, peak, partial peak (shoulder) and off-peak hours, as in the province of Ontario, Canada. In this category, the rates are known by customers well in advance. ToU tariffs have traditionally been mandatory for large commercial and industrial loads and vary throughout the year based on the season. This is in contrast with the flat rates paid by most residential customers worldwide. The main problem associated with ToU rates is that they do not reflect the real cost of energy delivery as these programs have a static nature [USD 06]. Moreover, in cases where there are more than two rates over the duration of a given day, small customers often find it a challenge to optimize their energy use. Some decision-support tools and "mild" automation (e.g. thermostats with timers) on the customer side are needed to make the most of the time-varying rates.

RTP programs, in contrast with ToU rates, reflect the wholesale electricity prices on hour-to-hour basis. In RTP programs, customers are typically notified of upcoming RTP on a day-ahead or hour-ahead basis. These programs are most reflective of the true value of electricity at any given time. Nevertheless, they are uncommon as they require the highest level of decision-support sophistication and ICT infrastructure at the customer level. The required infrastructure includes automated interval metering, price forecast mechanisms, communications and billing systems, as well as "smart" customer-side energy management system. In practice, only a very small fraction of customers have enough demand elasticity to justify investment and participation in RTP programs [USD 06].

CPP is a hybrid form of ToU rates and RTP. The structure of CPP programs is similar to ToU programs, while the rates are replaced by higher prices which are triggered by reliability-related events, or when wholesale electricity prices are very high [USD 06]. The key to the success of such programs is to give proper forewarning to customers so that they have enough time to reschedule activities or production accordingly.

1.4.2. *Incentive-based programs*

In the case of incentive-based programs, customers allow operators, aggregators or utilities to control their loads in exchange for credits or incentive payments. These credit or incentive payments are separate from a customer's retail electricity rate which may be fixed or time-varying. In most of the incentive-based programs, the sponsors should specify a method for establishing a baseline for energy consumption such that load reductions can be measured and verified. Failure in responding to incentive-based programs may result in penalties or loss of a potential future reward depending on the type of program and contract structure [USD 06].

Incentive-based programs can be classified into five subcategories, i.e. DLC, interruptible/curtailable service, emergency DR, capacity market programs and ancillary service market programs [USD 06].

In DLC programs, customer loads are directly controlled by the utility or aggregator. During DR calls, these loads are either shut down, cycled on and off or moved to a lower demand period at very short notice. DLC programs are typically directed at small commercial and residential loads. Incentive payments for DLC programs typically include fixed monthly payments credited to the customer's bill, and a payment when load reduction events occur. Depending on the type of DR program, utilities/aggregators give options to customers such as specifying the maximum number and duration of events per year, or the ability to override an event if they experience high levels of discomfort. Manual override is usually allowed in peak shaving programs, while it is forbidden when spinning reserve or contingency response is supplied. Overall, DLC programs are relatively simple and inexpensive to implement and reliable in terms of achieving load reduction objectives [USD 06]. Activation signal need not be sophisticated; for example, it could be based on an ambient temperature trigger or even be based on automated telephone calls from the program operator.

Interruptible/curtailable programs are similar to DLC programs. However, they target large commercial and industrial loads. In these programs, large commercial and industrial loads agree to reduce or turn off specific loads for a period of time in exchange for bill credits or discount rates. The participants are usually notified from minutes ahead to days ahead and severe penalties may be applied for failure to perform [USD 06].

Emergency DR programs are reliability-based programs and provide incentives to customers for measured load reductions during reliability-triggered events. In power systems, there is usually a cap on the maximum emergency service that can be provided by demand. The participants in emergency DR programs only receive payments when they respond to system operator signals. The payments are assessed based on the customer's outage costs or the value of lost load (VOLL). The participants in such programs receive no up-front payments or capacity credits as their participation is voluntary and no penalty applies when they do not respond [USD 06].

Capacity market programs are designed to attract DR resources that can offer in market or replace conventional generation or delivery resources. In capacity market programs, customers agree to the must-offer requirements in markets and receive capacity credits commensurate with their ability to reduce load, and an additional payment for load reductions during specific events. Customers can receive further credits for load reductions during emergency conditions or peak demand. The failure to respond to capacity market or emergency signals entails significant penalties since participants are paid on an ongoing basis for being available to provide capacity [USD 06].

Ancillary service market programs for DR are an emerging area. The technical capabilities required to participate in ancillary service markets vary depending on the type of ancillary service to be provided. For instance, the provision of frequency-regulating services requires telemetry and the ability to follow set-point instructions transmitted by operators or aggregators. However, these technical requirements are not as stringent for supplying frequency containment or supplemental reserves [USD 06].

1.5. Demand response performance, measurement and verification

Considering the increasing role that DSM is expected to play in the daily operation and planning of power systems, the ability to accurately predict and measure the performance of DR resources through standardized practices and metrics is increasingly important. Such developments in technology and analytics are necessary to build confidence among policy-makers, utilities, system operators and stakeholders that DR resources do offer a viable, cost-effective alternative to supply-side resources.

The rollout of smart meters is the first step toward DR initiatives. Smart meters allow customers to become more engaged in DR programs by increasing their awareness about dynamic electricity pricing and incentives. Moreover, real-time metering by smart meters enables accurate measurement and verification of DR programs. Technology-enabled automatic load control at the customer level is another essential component for successful implementation of DR programs. Finally, encouraging the establishment of DR aggregators is another key element for successful implementation of DR programs. The aggregators can guarantee the participation of customers in DR programs with zero costs as aggregators are willing to pay for the installation of metering and automation equipment. Moreover, DR aggregators can guarantee reliable DR service provision to operators and utilities by diversifying DR resources over a pool of candidates.

1.6. The challenges: aligning economics and intelligence

Demand management is often seen as key to enabling smart low-carbon grids. One major challenge for DR program implementations is the need to find investment and business models which are competitive compared to the traditional utility capital-intensive model. There is also the obvious barrier of institutional inertia to overcome. Most utilities often (1) operate as state-mandated monopolies; (2) are the stewards of high levels of supply reliability; (3) may not have the necessary in-house expertise to develop demand management-based solutions; and (4) have found comfort in a long-tested business model. This is why so many new DSM initiatives are emerging at the margins of the traditional industry players, with flexibility aggregation being the prime example. The investments necessary for deploying DR programs are primarily concerned with the installation of sensing, communication and intelligence. The nature of these investments is often closer to the business practices of telecommunication providers. Therefore, there is a definite learning process that needs to occur in the utility industry. Success stories of pilot projects have to serve as the basis for the next generation of deployments.

The challenge does not lie solely in investments. The revenue streams associated with the exploitation of responsive demand are often victims of their own success, while it is also well known that, at current electricity prices, potential capacity rents that responsive demand could capture are still limited. Moreover, any rents generated need to be redistributed among all responsive customers. Expected payoffs are quite small, while there is always the fear among customers that their participation in a DR initiative might result in potential losses (financial and comfort) and in the need to consider risk as part of their electricity use choices.

This is happening while producers and retailers risk losing potential sales through substitution by demand-side resources. Thus, it is essential that regulatory bodies arbitrate the conflicting objectives and incentives of all parties. The overall result should be the one where the socially optimal rules and incentives are adopted.

The implementation of all these requires substantial deployment of adequate intelligence at all levels of the grid. A true SG is one where it is possible for all stakeholders to find mutually satisfactory outcomes. It takes smart rules, smart people and smart assets to ensure systemic coherence and significant benefits.

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