Demand Response in Electricity Markets: A Review

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Abstract—**Demand response (DR) is the outreach of demand side management (DSM) in competitive electricity markets. With price signals and incentive mechanisms, DR is crucial to both power system reliability and market efficiency. Based on DR research and experiences around the world, comprehensive research on DR in electricity markets is conducted, including its definition, classification, implementation mechanisms, impacts on power systems, and cost-benefit analysis. According to different reasons for triggering DR, DR programs in electricity markets are classified into two categories: price-based DR and incentive-based DR. Subsequently, for each category, this paper discusses several representative DR programs to shed detailed light on two key problems, i.e., DR implementation mechanisms and the impacts of DR on power systems. Several important problems which need to be further studied are finally proposed.**

***Index Terms*—Demand response, electricity markets, electricity price, incentive, price elasticity of demand.**

I. Introduction

THE worldwide restructuring and deregulation of power industry are creating new challenges to demand side management (DSM). The DSM implementation benefits to the electric utilities under vertically integrated environment have been dispersed. Moreover, the implementation bases of several traditional DSM means, e.g., load management (LM) and energy efficiency (EE), have changed greatly. With the development of competitive markets, the interests of power systems are gradually becoming diversified, and the role of demand side resources in market competitions is being re-recognized. There is increasing concern about encouraging customer loads to provide demand response (DR) to help discipline wholesale electricity markets and improve economic efficiency. Therefore it is critical to introduce various DR resources into market competitions, increase demand-side participation [1] in electricity markets through price signals and incentives, and carry out integrated resource planning (IRP) [2] to coordinate both supply-side and demand-side resources.

Enabling demand-side responses as well as supply-side responses increases economic efficiency in electricity markets and improves system reliability. Against that background, nowadays many countries and regions around the world have conducted a wide range of research and practice on DR. In particular, the U.S. and Europe has taken many proactive initiatives in DR implementation practices and gaining much ground with DR programs. The U.S. Energy Policy Act 2005 (EPACT), which was signed into law in August 2005, explicitly encouraged all forms of DR programs and required States to provide reliable and affordable DR services to the public on a regional basis. The U.S. Department of Energy submitted a DR report to the U.S. Congress in February 2006 [3]. The report described in detail the benefits of DR in electricity markets and recommendations for achieving them. In addition, the Federal Energy Regulatory Commission (FERC) submitted annual reports of DR to the U.S. Congress in recent years [4]–[6]. These reports systematically analyzed the implementation background and the status quo of DR, the impact of DR on power systems, as well as the application of advanced metering infrastructure (AMI) in DR programs. Another report on national assessment of demand response potential was accomplished by FERC in June 2009 [7], in order to fulfill the requirements of the U.S. Energy Independence and Security Act of 2007(EISA).

At present around the world., seven ISOs/RTOs, including California ISO (CAISO), ISO New England (ISO-NE) and Pennsylvania-New Jersey-Maryland (PJM) RTO, etc., as well as a significant number of utilities, including Pacific Gas & Electric (PG&E) and Southern California Edison (SCE), etc., have already established various market-driven DR programs. Experience with regional electricity markets suggests that active DR is crucial to both power system reliability and market efficiency. Efforts to enable demand-side participation in electricity markets are providing significant opportunities for end customers, load serving entities (LSEs) and ISOs/RTOs. According to the statistics from several ISOs/RTOs, during the summer peak periods in 2006, system peak demand in the U.S was reduced 1.4%~4.1% through the implementation of DR [5]. The 2008 FERC survey indicates that about 8% customers in the U.S. are currently in some kind of DR program and the potential DR resource contribution from all U.S. DR programs is estimated to be close to 41GW, or about 5.8% of U.S. peak demands [6]. The electricity markets in other countries and regions, e.g., Britain, Nordic, Australia, have also launched diverse DR programs.

This paper summarizes the current research status of DR in electricity markets, addresses the key issues on different kinds of DR programs, and discusses future research priorities.

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II. DR Definition And Classification

The major goals of DR are to bring DSM into full play in competitive markets, maintain system reliability and improve market efficiency. Demand response, defined broadly, refers to the actions by individual electric customers that reduce or shift their electricity usage in a given time period (peak hours) in response to a price signal, a financial incentive, or a grid reliability trigger. According to [3], DR could be defined more definitively 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. DR programs may be sponsored and operated by municipally owned utilities, cooperative utilities, investor owned utilities, power marketers, ISOs/RTOs, curtailment service providers, etc [4]. DR actions range from completely manual to fully automated and are exercised according to customer DR agreements with DR sponsors.

DR programs are established to motivate changes in electric use by customers and can be triggered either for economic or reliability reasons. Accordingly, DR programs could be generally classified into two basic categories: price-based DR and incentive-based DR [3]. Alternatively, these categories are also known as market-led (economic) DR and system-led (emergency/reliability) DR in some studies [8]–[11].

1) Price-based DR. This type of DR programs, including time-of-use (TOU) rates, real-time pricing (RTP) and critical peak pricing (CPP), refers to the programs in which customers respond to the time-varying changes in retail electricity prices. Through eternal economic decision-making process, customers could reduce demand at times of high prices or shift demand away from times of high prices, to lower their electricity charges. Customers participating in price-based DR programs should sign contracts with DR sponsors, and any load modifications are entirely voluntary.

2) Incentive-based DR. This type of DR programs, including direct load control (DLC), interruptible/curtailable (I/C) service, demand bidding/buyback (DB), emergency demand response programs (EDRP), capacity market programs (CMP), and ancillary services market programs (ASMP), refers to the programs in which customers respond to an emergency event, e.g., when the system is in jeopardized or during the period of price spikes. Technical assistance and incentive programs are in place that help pay for the identification and installation of DR. Customers participating in incentive-based DR programs could either receive discounted retail rates or separate incentive payments for pre-contracted or measured load reductions. Contractual arrangements will typically specify a method for establishing customer baseline load (CBL) in order to measure demand reductions. If customers fail to respond or fulfill contractual commitments when DR events are declared, they will be subjected to financial penalties.

III. Price-based DR Programs

A. *TOU*

Price mechanism is the key to market operation. Fair and reasonable prices can provide the right economic signals and achieve optimal allocation of social resources. While the marginal cost of supplying electricity varies on very short time scales, most customers generally face retail electricity rates that are fixed for months or years at a time, e.g., flat rates that represent average electricity supplying costs. Moreover, flat rates ignore the electricity supplying costs difference between different time periods, and accordingly customers with low peak to off-peak ratios subsidize those with high peak to off-peak ratios. Based on peak load pricing theory [12] in Economics of Regulation, TOU is a rate with different unit prices for electricity usage during different blocks of time and can effectively reflect the time-varying costs of supplying electricity during those time periods. Several common types of TOU rates are peak/off-peak pricing (vary by time of day), seasonal pricing (vary by season), etc. TOU rates are typically pre-determined for a period of several months or years. With higher peak prices and lower off-peak prices, TOU rates actively elicit customers to adjust demand pattern, which can be beneficial to peak clipping, valley filling and seasonal load balancing. To date, a considerable amount of research has already been conducted regarding TOU rates [12]–[20]. They are generally concerned about the following aspects.

1) Customer response to TOU. Investigating the law of customer demand response to TOU is the basis of determining reasonable prices levels and periods classification. Historical data fitting based response curve and the price elasticity of demand [13]–[16] can be adopted to analyze the customer response. As the price elasticity of demand is more suitable for quantitative analysis, it is widely used in the analysis of customer response, e.g., the price elasticity of demand that derived from the transcendental logarithmic electricity cost function [13]; the total-price elasticity and the time-price elasticity [14]. In order to reflect customer response to TOU more accurately, price elasticity matrix of demand can be used to comprehensive describe the price elasticity of demand [15], [16]. In the matrix, self-elasticity and cross-elasticity are used to describe the single-period and multi-period customer response. The price elasticity matrix of demand and lag price elasticity matrix are integrated to comprehensively measure customer response [17].

2) TOU implementation mechanism. At present, many countries has offered TOU rates typically as default service to large commercial and industrial (C&I) customers. TOU rates require meters that register cumulative usage during the different time blocks. There are generally two methods of designing TOU rates, i.e., the method based on electricity supplying cost [12], [18] and the method based on load response analysis [19]. With respects to the method based on supplying electricity cost analysis, peak load pricing theory can be used to perform peak/off-peak differential pricing [12]; marginal cost analysis can be used to determine TOU pricing

levels [18]. With respects to the method based on load response analysis, the price elasticity matrix of demand can be used to model TOU [19]. The marginal cost pricing and load response analysis are combined to determine TOU rates [17].

3) TOU impact on power systems. Through time- differential pricing, TOU rates achieve greater market efficiency and benefits than flat rates, including peak clipping, valley filling [12]–[19], social welfare increase [13], [17], etc. In deregulated environment, utilities buy electricity at volatile wholesale prices while sell electricity at relatively fixed retail prices, and therefore utilities faced electricity transaction risk. TOU can build effective linkage between retail prices and wholesale prices, helping utilities perform efficient risk management [20].

B. RTP

The price updating cycle is an important aspect of a rate structure. The shorter the updating cycle is, the more efficient a rate is and the higher technical support requirements are. TOU prices and period division are pre-determined, and its price updating cycle is usually more than a quarter. Accordingly, TOU can only reflect long-term daily or seasonal variations in electricity supplying costs. Thus when power system is suffering from a temporary shortage of capacity, TOU can not give customers further incentives to reduce demand. RTP is a dynamic pricing scheme [4], [21], with the price updating cycle of 1h or less. RTP directly reflects marginal cost variations of electricity production at each time interval, and effectively strengthens the linkage between wholesale and retail electricity markets. RTP theory derives from spot price concept brought by Schweppe [22]. Based on optimal power flow, RTP theory has been continuously improved, e.g., locational marginal price and zonal price are put forward later. Currently, research on RTP typically focuses on the following areas:

1) RTP implementation mechanism. Although Schweppe maintained that the retail side should implement RTP first, many countries have only conducted a limited scope of RTP implementation because of capacity dispersion and technical limitation of retail side. Since the 1980s, a number of state regulatory authorities and electric utilities in the U.S. have provided pilot or permanent RTP programs, typically as optional service, to large C&I customers [3], [4]. Additionally, several states with retail competition have adopted or are considering adopting RTP as default service for large customers during recent years [23]. RTP tariff are generally considered too complex for residential customers, however, in 2007, Illinois became the first state where utilities are required to provide optional RTP programs for residential customers.

In order to ensure that customers have sufficient time to respond to RTP, RTP tariff usually indexes its prices to day-ahead or hour-ahead wholesale prices [24], and therefore, customers can make demand adjustment according to the notified prices on a day-ahead or hour-ahead basis. On the other hand, customers on RTP will be subject to wholesale market price volatility [25]. In order to protect the interests of customers and help customers hedge against RTP volatility, two-part RTP [24], the most popular form of RTP, is generally adopted. Two-part RTP designs include a historical CBL which is charged at flat rates or TOU rates, layered with RTP prices only for marginal usage above or below the CBL. Customers thus see RTP prices only at the margin. The CBL design allows customers to hedge a portion of their load against RTP volatility, and allows them to achieve savings by curtailing their marginal use at times when prices are higher and by using more during the off-peak tariff times. In addition, customers can also use a wide variety of RTP hedge contracts [26], [27], including supply hedge contracts and financial hedge contracts, to hedge against RTP price volatility [28].

2) Customer response to RTP. Research on customer response to RTP is conducive to designing reasonable RTP implementation schemes and understanding satisfaction levels of customers on RTP. Facing short-term high prices, customers typically have three basic load response strategies [3], [24], i.e., curtailing load during high-price periods, shifting load from high-price to low-price periods and operating on-site generation during high-price periods. The optimal demand-side response strategies to RTP for storage-type (shifting) customers are analyzed in [29]. Reference [27] discusses the response strategies of Niagara Mohawk Power Company's large customers under mandatory RTP. Among the customers that shifted load, 35% said they shift to another time of day, 47% to the second day, and 18 % to the third day. Among customers that forgone load, 65% said it had minimal or no impact on facility operation, 20% reported significant inconvenience or discomfort, 9% had to adjust business operations and 6% reported not knowing. Reference [30] reveals that although 54% of customers reported that they did not respond in real time, only 15% were dissatisfied with a switch to RTP from TOU.

3) RTP impact on power systems. As RTP can timely reflect the marginal costs of electricity supplying, it is the most economically efficient retail pricing scheme and can bring many benefits to customers and utilities, e.g., customer electricity bills savings [29] [31] and peak load reduction [32]. Reference [33] demonstrates that when switching from flat rates, total economic surplus increases with TOU rates are only 8%~29% of that with RTP. If a portion of the customers in California electricity crisis had been exposed to RTP, a relatively small amount of demand decrease would reduce wholesale prices greatly and accrue substantial benefits [34]. With high wind penetration levels, RTP can be used to allow demand to respond to the availability of wind generation and increase the utilization of large-scale wind farms [35].

4) Technical support of RTP implementation. Customers on RTP need to make real-time response to RTP price, however, it is unrealistic and too laborious for customers to continuously check RTP prices and then adjust their demand [30]. Currently in the U.S., a lot of RTP sponsors have provided free AMI installing services to customers in order to encourage active customer participation in RTP. Customers can adopt AMI [4] or Internet-based DR management system to realize real-time measurement, communications and automated response to RTP price variation.

C. CPP

While RTP is the ideal pricing scheme, the full-scale implementation of RTP is difficult yet due to the technical limitation of demand side. CPP rates, a dynamic pricing scheme based on TOU and RTP, augments either time-invariant rates or TOU rates with dispatchable critical peak prices during specified CPP events [36], [37], which may be flexibly triggered by system contingencies or high prices faced by the utility in procuring power in the wholesale market. Furthermore, CPP events are called on relatively short notice for a limited number of days and/or hours per year. CPP customers typically receive a price discount during non-CPP periods. Although CPP is not as economically efficient as RTP, CPP can reduce the potentially price risk associated with RTP, reflect short-term costs of critical periods, help encourage customers to reduce peak load and lower LSE electricity procurement risk. Therefore, CPP is more economically efficient than TOU, and CPP achieves a good compromise between TOU and RTP. Currently, research on CPP focus on the following field:

1) CPP implementation mechanism. Electricite de France (EDF) implemented the first pilot CPP program in the 1980s, i.e., provided CPP as default service to residential customers. Currently, CPP is not yet common in the U.S., but has been tested in pilots as optional or default service for large C&I and residential customers in several states, e.g., California Statewide Pricing Pilot (SPP) [38]–[42]. There are several variants of CPP rates [4], including fixed-period CPP (CPP-F), variable- period CPP (CPP-V), variable peak pricing (VPP) and critical peak rebates. CPP sponsors typically release in advance the triggering conditions of CPP events and corresponding values of critical peak prices. Critical days and non-critical days are known as the days with and without critical events. When only limited critical days are available, it is important for an energy service provider to investigate the optimal CPP implementation strategies to maximize its profit [43]. Based on customer response to CPP and hybrid electricity price model, a CPP decision model which considers the interests of both customers and LSE is introduced [44].

2) Customer response to CPP. Reference [38]–[42] conducted detailed analysis of SPP program. Statistic results showed that the customer satisfaction rate of CPP was high and 87% of customers deemed that SPP was designed very fair [38]. Compared to C&I customers, peak load reductions and bill savings of residential customers are less, however, the response rate and bill saving percentages are higher [39]. In addition, AMI has played a key role in customer response rate and about 2/3 of the load reductions are achieved through AMI [39]. Since CPP implementation in all types of customers has achieved good results, the full-scale implementation of CPP can be considered feasible [40]–[42].

3) CPP impact on power systems. Through the implementation of CPP, significant load reductions during critical periods can be achieved. For example, with the implementation of SPP program in California, peak load of residential CPP customers on critical days dropped an average of 41% of baseline load (2h critical hours with AMI), 25% of baseline load (5h critical hours and with AMI) and 13% of baseline load (5h critical hours and without AMI) respectively [41]. Residential CPP customers achieved 15% reduction while Residential TOU customers achieved 5% reduction [42], which verified the efficiency of CPP.

IV. Incentive-based DR Programs

A. DLC

DLC refers to programs in which the utility or system operator remotely shuts down or cycles a customer's electrical appliance on short notice to address system or local reliability contingencies [4]. DLC is primarily offered to residential and small commercial customers and its participating loads are typically the type of load that short-term interruptions would not bring large impact on its quality of service, e.g., air conditioner and water heater which has some thermal storage capacity. Participating customers receive incentive payments or rate discount based on the customer-selected duty cycle. DLC also typically limit the number of times or hours that customer's appliance can be turned off within one year or season. As a common and practical means, a variety of utilities in the U.S. have developed and implemented DLC programs successfully for decades.

At present, a considerable amount of research [45]–[61] has already been conducted on DLC implementation mechanism, i.e., optimal DLC scheduling model. Although DLC operation typically occurs during the times of system peak demand, DLC can also be used by LSEs to mitigate the impact of high on-peak electricity prices or manage system demand related charges [3]. Therefore, the objectives of DLC scheduling model typically include a broad range of goals, e.g., minimizing system peak load [45]–[49], [56]–[59], minimizing system operation costs [47], [50]–[55], [59], maximizing utilities' profits [56]–[58], [60] maximizing customer satisfaction [54]–[59], and minimizing load control difference [61]. It can be concluded that from vertically integrated to deregulated environment, the DLC optimal scheduling models have transformed from cost-based analysis [50]–[55], [59] to profit-based analysis [56]–[58], [60]–[61], from single objective that exclusively considers the interests of utilities [45]–[53] to multiple objectives that take into account the interests of both customers and utilities [54]–[61]. In addition, integrating DLC with other DR programs, e.g., I/C service [59], has become an interesting research trend in electricity markets.

From the perspective of enabling technology [3], with the wider application of AMI, remote control of individual customer load is being supplanted by remote control of smart thermostats (i.e., the temperature settings on smart thermostats can be remotely adjusted to reduce demand [4]) in recently implemented DLC programs [62], [63]. In particular, a new framework for DLC schedule is developed to minimize both the amount of controlled load and the disruption or discomfort of control [62]. The DLC based optimization algorithm can be used to manage a virtual power plant (VPP) and determine the optimal control schedules of the thermostatically controlled appliances of VPP [63].

DLC optimal scheduling problems mathematically belong to complex multi-objective combinatorial optimization problems, and the solving algorithms are mainly traditional optimization algorithms and heuristic optimization algorithms. Among traditional optimization algorithms, linear programming [45], [49], [60], [63], multi-objective linear programming [56], successive approximation gradient technique [46], dynamic programming [47]–[49], [51], [53], multi-pass dynamic programming [52], fuzzy dynamic programming [54], [55], [59] and Monte Carlo-based dynamic programming [63] have been adopted. Among heuristic optimization algorithms, genetic algorithm [61] and multi-objective evolutionary algorithm [57], [58] have been adopted.

B. I/C

I/C service refers to programs in which customers receive a rate discount or bill credit in exchange for agreeing to reduce load during system contingencies. I/C programs generally require that participating customers sign up contracts, which typically specify CBL, interruption duration, interruption capacity, interruption payments and penalties for failure to curtail. I/C programs have traditionally been offered only to the largest C&I customers and has been one of the most common DSM tools used by utilities to realize effective peak load control. At present, there is a lot of research concerning about I/C programs [64]–[80], and they can be roughly categorized into two areas [78]:

1) Designing appropriate implementation mechanisms. There are currently two implementation mechanisms:

a. *Signing up I/C contracts*. I/C contracts generally need to contain the incentive compatibility characteristics that can elicit rational customers to reveal their real interruption costs. Financial instruments can be used to design I/C contracts, e.g., the I/C contracts in which electricity suppliers buy into call option while customers sell out call option [64], the I/C contracts in which electricity suppliers buy into put option while independent power producers sell out put option [65], the I/C contracts with the introduction of double-call option [66], the I/C contracts with bilateral options [67]. Alternatively, interruption costs can be used to design I/C contracts, e.g., the I/C contracts with the introduction of successive [68] and discrete [69] customer-type parameters based on quadratic cost function.

b *I/C service bidding* [70]–[73]. Generally, the I/C contracts which are implemented through non-bidding are known as the basic I/C service, while the I/C service which are implemented through bidding are viewed as DB program for study [3] (DB will be discussed in next sub section).

Interruption payment methods of I/C contracts are important parts in I/C programs. Currently, rate discount [74]–[76] and bill credit [70]–[73] are two common ways. With respect to their different economic characteristics, risk management methods can be used to optimize and coordinate the two types of I/C programs.

2) Evaluating the impact of I/C programs on system operation. As a quick and actively response DR means, I/C programs can improve the demand side response to market price and can be helpful to system operation in many aspects. With respect to reliability benefits, the implementation of I/C programs can provide non-spinning reserve [72] and emergency reserve [73], reduce the generation capacity investment, achieve the optimal allocation of reserve capacity, raise generation capacity adequacy [77], [78], lower system peak load [79] and mitigate system congestion [80]. With respect to economic benefits: the implementation of I/C programs can reduce system operating costs [78], increase demand side elasticity [1] and damp price peak. In addition, utilities can adopt I/C programs to hedge price risk [67], and customer can receive corresponding interruption payments.

C. DB

DB is a mechanism that enables demand side to actively participate in electricity market competition and offers customers the opportunity to obtain economic rewards for changing their electricity consumption pattern though bidding [81]. LSE, electricity retailer and large customer can enroll in DB programs directly while small customers can participate in DB programs indirectly by third-party aggregator [81], [82]. Altogether, there are two basic DB implementation mechanisms [83]:

1) Bid for Total Demand, i.e., all demand participates in market competition. This scheme includes the following forms:

a. *Customers, aggregator or LSE signs bilateral contracts with generators for specified volume of electricity at a fixed price, e.g., direct purchase of electricity from large customers*.

b. *LSE, electricity retailer and large customers can bid their total demand into an electricity market or pool, i.e., provide demand-side bidding curves similar to supply-side bidding curves*. Several representative models includes: stochastic optimization problem of power suppliers and large consumers based on linear bidding function [84], optimal purchase allocation problem considering risk and DB strategy integrating price forecast [85], piecewise-linear bidding curves for a price-taking retailer in the Nordic electricity market [86], as well as the two-stage game process of power purchaser that participates in day-ahead and real-time balancing [87].

2) Bid for demand change. This scheme includes a variety of types and links to electricity markets in many aspects. In different market types, customers can participate in the energy/auxiliary market bidding, e.g., bidding in energy market [70], offering demand-side reserves in joint energy/reserve electricity market [71], [88], bidding in auxiliary market [72] and bidding in contingency management [73]. In different time scales, customers can participate in the biddings in day-ahead and real-time market [70]. In different market operation model, customers can participate in spot/contract market bidding [73]. According to different ways of demand adjustment, customers can participate in demand increase/decrease bidding to provide upward/downward spinning reserve [88].

In the electricity markets where DB is allowed, customers can actively participate in a series of market pricing process [89], helping to maximize the social welfare. As system reserve capacity [88], DB is beneficial to improving system reliability and the flexibility of reserve resources. Furthermore, DB can also significantly increase the elasticity of demand [1], discipline wholesale market power and price spikes [90].

V. Conclusion

This paper gives a comprehensive survey of DR in electricity markets. Based on DR research and experiences around the world, definition, classification, various implementation mechanisms, impacts, and cost-benefit of DR are discussed in detail. There are several extensions for future study:

1) For DR sponsors and policymakers, in order to promote different types of customers to actively participate in DR, it is essential to examine how to improve the price and incentive mechanisms, and how to design attractive DR programs that benefit all participants; in order to reasonably assess the implementation effect of DR programs, it is critical to explore the demand elasticity and responsiveness of participating customers, how to successfully implement DR programs under different market and system conditions, and how to conduct applicable statistical analysis of customer satisfaction degree and response rate.

2) For customers or aggregators, they should compare various DR programs and decide which program to participate in, according to their demand characteristics and risk preferences. After they enroll in specific DR programs, in order to obtain more electricity bill savings or incentive payments and subsequently maximize their own benefits, it is important to explore how to optimize production schedules, arrange suitable demand pattern and implement reasonable response strategies within acceptable scope of demand adjustment [1].

3) Since different types of DR programs have different characteristics, it is useful to investigate how to coordinate and integrate various types of DR resources on different time scales to realize the complementary advantages, and how to develop service options that incorporate the desirable features of both price-based and incentive-based DR programs. Moreover, taking into account the universal attributes of EE and DR in fulfilling DSM goals, how to promote the best development of various demand-side resources, e.g., DR, EE and DG, carry out IRP to coordinate both supply-side and demand-side resources, and give full play to their roles in electricity markets, are interesting areas for further study.

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