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POWER SECTOR (E MARTINOT, SECTION EDITOR)

Current Practice and Thinking with Integrating Demand Response for Power System Flexibility in the Electricity Markets in the USA and Germany

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Abstract Regulators worldwide are aiming to increase system flexibility by leveraging the untapped potential of demand response. In this article we review and compare the literature on current practice and thinking about the role of demand response in three distinctly different markets that represent leading global examples of demand response: two regional electricity markets in the United States (PJM and ERCOT) and the national market in Germany. Furthermore, we describe the share of demand response in each market segment and the corresponding market design. We found, firstly, that interruptible loads and emergency generators (demand response) are used as a contingency reserve only, for no more than 30 h per year. Secondly, the share of demand response is about 4 % of the unforced capacity requirement (including emergency generators). Thirdly, the discussion of demand response also shows that there is a lot of uncertainty on how an appropriate level playing field between flexible resources should look in detail. Nevertheless, regulators are aiming to further enhance the reliability and competiveness of demand response programmes.

Keywords Demand response · Capacity markets · Ancillary services markets · Germany · PJM · ERCOT

Abbreviations

ERCOT	Electric Reliability Council of Texas
ISO	Independent system operator
LSE	Load serving entity
MW	Megawatt
NERC	North American Electric Reliability Corporation
PJM	PJM Interconnection
PLC	Peak load contribution
TSO	Transmission system operator
USA	United States of America

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Introduction

The term demand response is broadly defined as the active management of demand resources as a function of price signals (e.g. day-ahead market) or at the request of the system operators (e.g. maintaining frequency and emergency reserve) [1].

It may be further categorised depending on the following criteria [2]:

- power direction: positive, negative
- ability to be dispatched by a system operator: dispatchable, non-dispatchable
- resource type: interruptible loads, additional loads, on-site emergency generators
- market type: capacity market, ancillary services market, energy market
- revenues: availability payment, energy payment

In this article, we will focus on demand response that offers flexibility for reliability purposes on capacity markets and ancillary services markets. That means that demand response may be dispatched by a system operator, and that dispatches are not voluntary once demand response has cleared the market. This always includes a capacity payment (availability payment) for demand response. Most market segments presented in this article are for interruptible loads and partly also for emergency generators, as most markets only put positive power (increasing generation and reducing load) out to tender. We will use the most precise term where possible to avoid misconceptions about the type of demand response referred to.

Regulators worldwide aim to integrate demand response into the electricity markets and thus create a level playing field for all flexible resources including generation, storage and demand resources. The regulatory framework for demand response, the services offered by demand response and the level of experience differ between the electricity markets. Electricity markets in the USA are often regarded as the leading markets for demand response [3••]. Other electricity markets like Germany, however, have just started to investigate the potential of demand response and discuss the features of a regulatory framework that would unlock it [4••, 5, 6]. Given the huge divergence between the (theoretical) potential of demand response and the actual uptake of demand response, the question arises as to what services within an electricity system can demand response provide efficiently? Furthermore, how many megawatts (MW) of this service may realistically be provided by demand response? And how should the regulatory framework be designed to unlock this potential?

We will present three case studies that show the role of demand response and the corresponding market design. The first two case studies deal with electricity markets in the USA, which have a lot of experience and a high share of demand response in specific market segments. To highlight current practices where integrating demand response into capacity markets is concerned, we chose the electricity market of PJM Interconnection (PJM). PJM operates the largest electricity market in the USA [7] and is regarded as the market with the most advanced framework. As an example of an ancillary services market, we chose the electricity market of the Electric Reliability Council of Texas (ERCOT) since demand response provides a particularly high share of ancillary services there. The third case study focuses on the German electricity market. In this market, demand response can participate in the ancillary services market and a reserve called Ordinance Governing Interruptible Loads (Verordnung zu abschaltbaren Lasten, AbLaV).

Demand Response in PJM's Capacity Market

Potential and Role of Demand Response

In PJM, demand response (interruptible loads and emergency generators) can participate in the capacity market and several products of the ancillary services market. The capacity market is financially by far the most significant market segment for demand response in PJM, with about 90 % of the revenue streams for demand response created here [8]. The capacity market approach has been used in PJM, as in other electricity markets, to keep sufficient generating capacity available to securely meet demand. The volume of the unforced[1] capacity requirement is calculated by the independent system operator (ISO) and put out to tender. The costs incurred are passed on to the load serving entities (LSEs), which distribute the costs among the electricity consumers via a capacity levy [10–12]. This capacity levy is calculated based on the capacity price (market clearing price) of each grid region and the so-called peak load contribution (PLC), and in other words the final electricity consumer's share of the peak load for the year across the electricity market.[2]

Electricity consumers with interruptible loads or on site generators that are not dependant on a continuous supply of electricity have two options to offset capacity costs. They can guess when a system peak will occur and reduce their power consumption in anticipation of that, or they can take part in the capacity market's so-called Limited Demand Response Program if they meet the requirements. In the capacity year 2013/2014, demand response needed to be available on weekdays from June to September between 12:00 p.m. (noon) and 08:00 p.m. [13]. PJM normally experiences its system peak load during this time. Dispatches may occur on up to 10 days per year for a maximum of 6 h per dispatch. As income, the electricity consumers receive the capacity price of their respective grid region. This corresponds to a refund of the capacity levy already paid, so that they can effectively reduce their payments for capacity.

In the capacity year 2013/2014, electricity consumers with interruptible loads or emergency generators could avoid paying a capacity charge of between US$7743/MW and US$71,305/MW per year (depending on the grid area) by participating in the demand response programme [8]. They also received a minimum energy payment of up to US$1800/MWh, and 85 % of all participating demand response customers asked for an energy price higher than US$1000/MWh [8].

During the compliance period from June to September, the ISO dispatched demand resources five times [14]. Demand response was also dispatched four times outside the compliance period during the winter season, which is very unusual. The total dispatch duration of all nine events was up to 32 h in the affected grid areas.

As shown in Table 1, the unforced capacity requirement in the PJM electricity market in the 2013/2014 capacity year, for

[1] PJM defines unforced capacity as follows: "Installed Capacity (ICAP) represents the maximum generating capacity of a given facility. Unforced Capacity (UCAP) represents the amount of ICAP that is actually available at any given time after discounting for time that the facility is unavailable due to outages such as repairs." [9]

[2] To determine the PLC, at the end of each year, the ISO calculates the hours with peak load for the year across the electricity market. The average electrical power consumption in these hours (taken from the electricity meter data) is then used to calculate the PLC. In PJM, five hourly values are used to calculate the PLC.

Table 1 Demand response participation in PJM (figures in MW)

	2013/2014	Reference
Demand response	7461	[8]
Interruptible loads	5969	[15]
Emergency generators	1492	[15]
Peak load	157,508	[8]
Share of demand response	4.7 %	
Unforced capacity requirement	173,549	[8]
Share of demand response	4.3 %	

example, was 173,549 MW. A total of 5969 MW of interruptible loads and 1492 MW of emergency generators were ready to be dispatched by the ISO. The requirement for unforced generating capacity was thus reduced by 4.3 % (3.4 % by interruptible loads and 0.9 % by emergency generators). Compared to the 2012/2013 delivery year, the proportion of demand response increased by 0.2 %. Table 1 also shows the power from emergency generators, as they come under the heading of demand response in the aforementioned capacity markets and can participate in the same programme as interruptible loads [8].

Data from other publications suggests that the committed demand response capacity in PJM is actually higher than shown in Table 1. However, the data from these publications do not state the committed capacity of demand response that the ISO actually can use for reliability reasons. For example, Ott (2014) writes that the capacity of demand response was more than 10,000 MW in 2013/2014 [16•]. That is true for the first auction (Base Residual Auction) that took place 3 years before the delivery year, where a total of 10,780 MW of demand response was cleared [8]. However, Ott (2014) does not state the fact that 3159 MW of demand response was replaced by generators in the following three incremental auctions. Hurley et al. (2013) also state the amount of capacity cleared during the Base Residual Auction without mentioning the capacity replacements, leading to the same misconception [3••]. The data used by the Federal Energy Regulatory Commission (FERC) is also not precise and may lead to misinterpretations. FERC (2014) adds up emergency demand response and economic demand response [17]. Economic demand response differs by the fact that dispatch is voluntary and not reliably available. Additionally, the FERC report refers to the registered capacity but not the committed capacity. To summarise, the aforementioned reports do not indicate the committed capacity of demand response that can actually be used for reliability reasons.

Discussion and Outlook

Returning to the research question of this article, the experience in PJM shows that 3.4 % of the unforced capacity requirement is a realistic proportion of interruptible loads and emergency generators may contribute another 0.9 %. The high variable costs of up to US$1800/MWh show that interruptible loads and emergency generators can only be used as a contingency reserve and that demand response programmes have to be designed accordingly. To do so, regulators must design a separate capacity product that can be used as a contingency reserve (which would otherwise be provided by generators only).

Capacity markets need an appropriate mechanism to distribute the costs of capacity and create incentives to avoid power consumption during peak periods. Demand response programmes are an ideal tool for this. The modifications to the demand response programs in PJM show, however, that it is no easy task to design an appropriate level playing field between generation and demand resources. In recent years, FERC has approved several modifications to PJM's demand response programmes to make them more flexible and reliable [18–21]. These modifications concern, for example, the limited availability, the cap on dispatch frequency, the maximum dispatch duration or an issue of compliance measurement causing fake capacity. These issues have been criticised as a potential threat to reliability, which also give demand response an unfair advantage over other capacity resources. Other issues such as loopholes in the compliance calculation are still being discussed [8].

Demand Response in ERCOT's Ancillary Services Market

Potential and Role of Demand Response

In ERCOT, demand response can participate in the ancillary services market and in a reserve programme called Emergency Response Service (ERS). ERS aims to increase system reliability during power system emergencies, and participation is exclusively for demand response (interruptible loads and emergency generators) [22•, 23]. In 2014, demand response provided about 700 MW to ERS [24]. Interruptible loads can also participate in the ancillary services market [22•, 25]. This market is divided into three different products: Regulation Reserve, Responsive Reserve and Non-Spinning Reserve. Responsive Reserve, which contracts more than 1200 MW of interruptible loads on average each year, is most relevant [26]. Thus, ERCOT's total demand response capacity that can be used for system reliability is at about 2.8 % of the 2014 annual peak load of 66,732 MW [27].

Responsive Reserve is used to restore the frequency of the power system to its target value of 60 Hz after a contingency. In contrast to Regulation Reserve, Responsive Reserve is not used to correct normal load fluctuations [28]. Basically, Responsive Reserves must be immediately responsive to system frequency and fully available within 10 min after notification to deliver reserve power until recalled by the ISO [25]. Both generation resources and load resources may provide this service. However, load resources may only provide up to 50 % of the required capacity since their requirements and dispatch instructions differ from generation resources.

The load resources that provide Responsive Reserves must have an under frequency relay that automatically and immediately interrupts loads if frequency falls below 59.7 Hz [25, 29]. Additionally, Responsive Reserves may be interrupted within 10 min on the instructions of the ISO. The load reduction must not be less than 95 % and must not exceed 150 % of the requested power. After deployment, interruptible loads have to return to at least 95 % of their contracted power within 3 h of an event. Loads may also be aggregated by a curtailment service provider to fulfil requirements.

Currently, ERCOT puts 2800 MW of Responsive Reserve out to tender and load resources may provide up to 1400 MW. In 2013, between 1200 and 1400 MW was provided by load resources on a regular basis [26]. Other markets in the USA have a much lower share of demand response participation for that type of contingency reserve. In PJM, an average of 74 MW of the equivalent product[3] came from interruptible loads in 2013 [8]. In other markets like New York, demand response just recently started the prequalification process and approximately 100 MW of interruptible loads were participating in the market in 2013 [31].

Responsive Reserve is relatively seldom deployed due to its intended purpose as a contingency reserve. In ERCOT, Responsive Reserve provided by generation resources was dispatched between 47 and 87 times per year in the period from 2011 to 2013 [32]. The total dispatch duration did not exceed 7 h per year. The rare dispatch frequency and short dispatch duration are typical for that type of contingency reserve. For example, in PJM, the so-called Synchronized Reserve was dispatched up to 35 times per year and the duration did not exceed 6 h in the same timeframe [8].

Due to the different requirements for the load resources that provide Responsive Reserve, dispatch frequency and duration are typically far lower than those for generation resources that provide Responsive Reserve. In the period from 2011 to 2013, Responsive Reserve provided by loads was only dispatched three to seven times per year with a total duration of 1 to 15 h per year [33, 34].

Discussion and Outlook

The experience in ERCOT shows that 2.6 % of peak load is a realistic proportion of demand response (interruptible loads and emergency generators). The market segment differs from the first case study, but the dispatch duration and dispatch frequency are similar to demand response in PJM's capacity markets, since in both market segments demand response is used for contingencies only.

ERCOT started rethinking the existing set of ancillary services in the light of new resource characteristics of the variable renewable energies that are entering the market and the new regulatory requirements of the North American Electric Reliability Corporation (NERC) [35]. In its new concept, there will be two products that are relevant to demand response. The first, called Fast Frequency Response, aims to reduce the frequency drop after contingencies. It is a self-deployed resource (e.g. by an under frequency relay) that has to respond within 0.5 s (equivalent to 30 cycles). Responsive Reserve provided by load resources already fulfils similar requirements and is appropriate to this market. Battery storages are expected to add to competition in this market segment. Here too, creating a level playing field is no easy task, since interruptible loads are much more sensitive to dispatches than batteries are. For example, the question arises as to whether interruptible loads can have a lower dispatch frequency (e.g. 59.7 Hz) than batteries (e.g. 59.91 Hz), so that they are dispatched less frequently. Another product that might be highly relevant to demand response is called Contingency Reserve—a product that aims to restore the frequency of the power system to its target value of 60 Hz within 10 min of a contingency occurring.

Demand Response in Germany's Electricity Market

Potential and Role of Demand Response

In Germany, demand response (interruptible loads and emergency generators) can participate in the ancillary services market and interruptible loads can also participate in a programme called Ordinance Governing Interruptible Loads.

German ancillary services markets have a different structure and purpose than their US equivalents. The ancillary services market is divided into three product types that differ mainly in terms of their required activation time: primary reserve (30 s), secondary reserve (5 min) and tertiary reserve (15 min) [36]. The specific requirements also differ for each of these three services. For example, for tertiary reserve, positive and negative powers are put out to tender separately [37]. When dispatched, the additional power output should be no less than 100 % and not greater than 120 % of the requested power [38]. After recall, the power output should go back to the normal level within 15 min. The availability should be no less than 100 % within the contract period [39]. Both generation resources and load resources have to fulfil these requirements. There are no special (easier) rules for demand response. However, aggregating several loads and/or generators

[3] PJM uses the term Synchronized Reserve instead of Responsive Reserves and NERC uses the term Spinning Reserve [30].

is permitted, so demand resources with a limited availability may participate through an aggregator.

Load and generation resources that provide tertiary reserve should expect annual dispatch duration of tens to hundreds of hours. For example, in 2014, positive tertiary reserve was used for 316 h in total, but more than 50 % (ca. 1200 MW) was only used for a total duration of 17 h [40].[4] The achievable market revenues in 2014 were about € 4700/MW per year[5] if resources were able to provide tertiary reserve for all 8760 h of the year [42]. The amount of load resources that regularly participate in ancillary services is not monitored.

The Ordinance Governing Interruptible Loads requires transmission system operators (TSO) to put 1500 GW of immediately interruptible loads (activation time of one second) and a further 1500 GW of quickly interruptible loads (activation time of 15 min) out to tender [43]. As with balancing power, the TSOs can use these loads to maintain frequency. It is also conceivable to use these loads for financial purposes in the event of high spot market prices. The dispatch frequency and the dispatch duration are very limited. Dispatch data suggest that all interruptible loads chose the product type "A" that limits the dispatches to 1 h per day and 16 h per month in 2014 [44].

Interruptible loads that pass prequalification can expect a fixed remuneration of € 30,000/MW per year. They will also receive an energy price of € 100/MWh to € 400/MWh for an interruption. In 2014, the TSOs contracted an average of 860 MW per month [42], but several rules make it difficult for more load resources to participate in the future. These hindrances include a minimum interruptible load of 50 MW and a constant load with no more than five load interruptions of longer than 1 min within the contract period of 1 month [45]. Since July 2013, interruptible loads have been dispatched twice for 1 h in each event [44].

Discussion and Outlook

Current discussions about the future of demand response in the ancillary services focus on reducing the current hindrances to demand response. These include the product design of the ancillary services, the grid fee regulation and the role of independent aggregators. With regard to product design, several stakeholders proposed (already several years ago) reducing the product interval to 1 hour and holding day-ahead auctions for all products [46–48]. In case of grid fee regulation, load interruption and especially adding load may lead in many cases to a higher grid capacity fee and is a major hindrance to flexible loads; by contrast, generation resources do not pay any grid fees at all for offering the same service.

The future of the Ordinance Governing Interruptible Loads is still unclear. The question of whether or to what extent it will be renewed after the trial period of 3 years has yet to be decided. Independent evaluators have criticised the ordinance as an extremely inefficient way of increasing participation of interruptible loads in Germany [49]. The Ordinance Governing Interruptible Loads only requires an energy availability of 16 h per months to receive an annual revenue of € 30,000/MW. Within the positive reserve, interruptible loads have to be available 720 h per month to receive € 4700/MW per year. Consequently, the Ordinance Governing Interruptible Loads is paying far more for interruptible loads than the true market value. The Federal Government, however, has indicated to continue with this ordinance and reduce the current hindrances to participation (e.g. a minimum load of 50 MW) [50]. A decision has not yet been taken, as the Federal Government is waiting for the Federal Network Agency's official evaluation report (due in March 2015). Industrial policy may play an important role in this decision since demand response programmes are also an effective policy instrument for reducing the electricity bills of electricity-intensive industries.

Conclusion

This article aimed to answer the following three questions, which are highly relevant for regulators who wish to increase the share of demand response: firstly, what services within an electricity system can be efficiently provided by demand response? Secondly, how many megawatts of this service can be provided by demand response? And thirdly, how should the regulatory framework be designed to unlock this potential?

The case studies (PJM, ERCOT and Germany) show that demand response (interruptible loads and emergency generators) may be used efficiently as contingency reserve that is used for just a few hours per year (e.g. not more than 30 h). This is the case for electricity markets with a very temperature-sensitive load curve like PJM where the ISO needs to ensure sufficient capacity for infrequent peak loads. This will also be the case for electricity markets with a high share of variable renewables like in Germany's future energy scenarios, since the energy generation of variable renewables can be very low during peak hours. However, the variable costs of up to US$1800/MWh indicate that interruptible loads and emergency generators may not be the most cost-effective flexibility options when used more frequently.

[4] The dispatch frequency and annual dispatch duration can vary significantly between years [41]. For example in 2012, positive tertiary reserve was used for 749 h in total, and the upper 50 % (ca. 1200 MW) was used for a total duration of 232 h.

[5] The ancillary services market in Germany is a pay as bid market. The average capacity price of all accepted bids for positive tertiary was € 4700/MW per year.

The case study of PJM shows that the potential for interruptible loads and emergency generators can account for about 4 % of the unforced capacity requirement if used as a contingency reserve. These results also tally with the experience of other electricity markets in the USA like New York or New England. The percentage seems small, but it is enough to substitute several peak power plants. In the case of capacity markets, it is also necessary to distribute the costs of capacity fairly and create incentives to reduce load during peak times. Demand response programmes are an appropriate mechanism for this purpose.

The three case studies show that there is a lot of uncertainty and even disagreement on how an appropriate level playing field between flexible resources should look in detail. Nevertheless, there are notable similarities between the various demand response programmes. All of them are meant to be used as a contingency reserve. Furthermore, all the demand response programmes have a different set of requirements for demand response and generators. These requirements differ due to the nature of the demand resources: for example, a reduction in load needs a different compliance measurement methodology than an increase in generation does. They also differ to encourage demand response participation, for example, by limiting the availability period to summer months or by limiting the dispatch frequency to ten dispatches per year. These constraints may be justified if they reflect system needs. However, they may also disadvantage other flexible resources or even be a risk for system reliability.

Despite the complexity of the task of integrating demand response into the markets, regulators should adapt the rules of the different market segments to allow demand response participation. Since a variety of resources can make the system more flexible, the rules should be as technology-neutral as possible. In Germany, for example, regulators should focus on reducing the hindrances to demand response in the current market structure. In the ancillary services markets, these hindrances relate among other things to the prequalification criteria, tendering conditions and the grid fee structure. The implementation of additional instruments such as the Ordinance Governing Interruptible Loads does not promote competition for the most efficient flexibility option and is not necessary from a system point of view.

Compliance with Ethics Guidelines

Conflict of Interest Benjamin Bayer declares that he has no conflict of interest.

Human and Animal Rights and Informed Consent This article does not contain any studies with human or animal subjects performed by any of the authors.

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