A Review of Demand Response Business Cases

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Abstract—Demand Response (DR) is widely held to be an essential part of future power systems. DR is expected to support integration of distributed generation from Renewable Energy Sources (RES) as well as to facilitate demand-side participation in power and ancillary service markets. This paper critically analyzes several business models from both a Distribution System Operator (DSO) and retailer perspective, and identifies opportunity costs associated with the trade-off between demand flexibility and energy acquisition cost. Numerical results from previous studies are gathered and compared to the control and communication complexity. Finally, regulatory issues are reviewed.

Keywords—demand response; ancillary services; schedule compliance; PV integration

I. INTRODUCTION

Increased renewable generation leads to more uncertainty in production patterns and therefore to a higher demand in flexibility [1]. At the same time dispatchable generation in the power system is disconnected from the grid as it is displaced by subsidized renewable energy source. While this desirable for ecological reasons, and in the case of nuclear generation also from a security and political perspective, power system operation is facing challenges in guaranteeing a reliable electricity supply. Gathering flexibility on the demand side is widely held to be a promising option to alleviate these issues.

Most research in Demand Response (DR) has a focus on the technical feasibility of specific control schemes [2]. Different approaches to make that flexibility available have been discussed. These include price signals as incentive for end customers, direct control of flexible loads, or distributed control relying on local measurements [3], [4]. While for each business model there is an appropriate control scheme, economic viability of the schemes against control and communication effort is not always evident. Even more, each business model has an associated opportunity costs.

The concept of opportunity cost generally describes the missed benefit of the best alternative if one has to choose between two actions. Most technical analyses compare a proposed DR scheme to a status-quo where the demand flexibility is not exploited at all. However, this does not always describe the best alternative. Instead one should compare the benefit of a certain DR business case to the best alternative benefit achievable with the same effort in control and communication.

This paper discusses several business cases, namely peak shifting, distributed Renewable Energy Sources (RES) / photovoltaic (PV) integration, energy acquisition cost minimization, schedule compliance and ancillary service provision. The potential savings are investigated and implementation challenges are discussed qualitatively. All this is done from a central European perspective, where the most common flexible household appliance are Electric Water Heaters (EWHs) with a storage tank [5]. Other loads such as heat-pumps for space heating, air-conditioning and refrigerators are compared where appropriate. Prices are from the Swiss spot market and the German Intraday market, balancing prices and control reserve remuneration are obtained from swissgrid. It is also assumed that grid operation and energy retailing are unbundled, and the resulting challenges are highlighted.

The paper is organized as follows: Section II introduces business models from the perspective of grid operator and retailer, and briefly discusses available flexible loads. Section III then investigates the business models in more detail. Section IV briefly discusses regulatory issues, before Section V concludes.

II. COMPARISON OF BUSINESS MODELS

A. Market players

The perspective of the market player is essential when discussing business models. Both DSOs and retailers have an interest in utilizing flexible demand.\(^1\)

For a DSO, shifting demand can be useful in two situations. 1) Reliably reducing the peak loading of the grid means that line and transformer upgrades can be deferred. 2) If considerable amounts of PV power is fed into the Low-Voltage (LV) grid, line voltage or current limits may be violated. Increasing the demand close to the PV plant is a good way to alleviate these effects.

A retailer on the other hand first and foremost aims to 3) minimize cost for energy acquisition. Recently, more advanced control schemes have been proposed: one idea is to 4) increase schedule compliance using flexible loads, even more ambitious are ideas to provide 5) fast frequency control reserves such as secondary control to the grid.

All five business models interact, and sometimes conflict with each other. These interactions are shown in Figure 1. In power systems dominated by conventional power generation electricity prices are proportional to electricity demand. As a result, peak reduction and energy cost minimization are currently in good agreement. With ever-increasing, non-dispatchable production from RES with low or no marginal cost, this may in the future change as spot prices will most likely correlate with the global residual load, that is with demand minus RES generation, which may be different than the local demand profile. Next, temporally increasing demand in a LV feeder to locally absorb PV infeed increases cost for energy acquisition. This opportunity cost might vanish

\(^1\)Depending on the tariff, end-customers may also have an incentive to do so, but this is regarded as a form of price control signal.
when PV production reduces spot market prices during daytime to levels below night-time, bringing energy cost objective and PV integration in accordance. Even within the realm of one market player, issues may arise. If PV generation is spatially heterogeneous, there might be one feeder where demand should be increased, while on a higher voltage level the DSO would prefer to reduce grid loading. For the retailer, offering ancillary services or reducing schedule deviations would mean to activate loads at higher-cost hours. While doing so would usually still be profitable, one should not forget to account for the opportunity cost involved.

Figure 2 illustrates the trade-off between energy cost and flexibility. Assuming loads that can be shifted to night hours, it would be cheapest to run them at low cost times during the night. Under this dispatch, no up regulation would be possible between, e.g., 03:00 and 07:00, while no down regulation is available in the other hours. If down regulation is required, loads have to be running all day significantly increasing energy acquisition cost.

B. Relevant load types

Loads that are thermostatically controlled can easily be shifted, as they have an inherent temperature storage. This storage may refer to the compartment of a refrigerator or freezer, to the room temperature of a room air-conditioned or heated with a heat-pump, or the water tank of an EWH with dedicated storage tank.

While the demand of a refrigerator usually is rather constant over the year, the energy demand for space heating or cooling applications widely varies. Figure 3 shows the seasonality of space heating demand estimated using the heating degree day method commonly employed in Switzerland. Heating degree days are computed by taking the sum of the difference between the outdoor temperature and the assumed indoor temperature of 20 °C for all days where the temperature is below 12 °C. The blue line is the heating demand, the black line the rated power of the space heating. The brown area shows the amount of energy that can be shifted according to customer contracts allowing heat-pumps to be blocked for up to two hours per day. Green is the maximum amount of energy that could be shifted, namely the demand if it is less than half the rated power, and the rated power minus the demand otherwise. Hot-water consumption is also subject to seasonality, however no exact data is available to the authors. The assumptions that it scales with electric energy demand seems reasonable for temperate climates. For simplicity, seasonality is neglected in the analysis of the business cases of Section III.

Other loads that have received much attention in the research community include deferrable loads such as dishwashers and cloth dryers, and electric vehicles. Electric vehicles
are the only load that can feed power back into the grid, but special constraints apply as the vehicles are disconnected from the grid while driving and have changing connection points during the day, e.g., parking at home and at the workplace. The subsequent analysis will focus on EWHs with storage tanks, which are the dominant flexible load in Switzerland and are already engaged in DR schemes. Refrigerators and heat-pumps/air-conditioning are mentioned where appropriate.

III. ECONOMICS OF THE BUSINESS CASES

A. Peak Reduction

Peak reduction is a demand side approach commonly employed in central Europe. Traditionally, electric water heating and sometimes space heating, both equipped with dedicated storage tanks, are charged during night hours. This reduces grid loading during the day and also reduces cost for energy acquisition. Loads are controlled with ripple control2. Due to limitations of the ripple control, switchable loads are grouped in large aggregations. Recently, heat pumps for space heating are being installed in large numbers. The heat pumps can be blocked for one hour twice a day, an approach also used to reduce peak loading of the grid. In California, there are recently various critical-peak programs and incentives from the California Independent System Operator (CAISO), to harness flexibility, mostly from air-conditioning and water pumps of medium and large commercial customers.

The cost saving for the utility are hard to estimate, but it can be assumed that savings on infrastructure investments over the past were substantial. As loads with sufficient storage capacity are needed to shift peaks with high energy-to-power ratio, dedicated heat storage is highly beneficial for such schemes.

B. PV Integration

Increased installation of PV and other generation from RES in the LV-grid can lead to violation of voltage and current limits. Utilities have several options to alleviate these issues without investing in new lines [6]. Activating flexible loads to absorb excess production locally is one of the most elegant ways, as it can substantially increase the hosting capacity while at the same time reducing losses. From a social welfare point of view this is preferable to shedding PV production and may be preferable to investing in capacity upgrades, but regulatory questions remain: activating loads during usually expensive hours around noon increases cost to customers – if retailing and system operation are unbundled, the system operator has to pay the retailer for the increased cost. This in turn would be of interest to the DSO if there is a penalty for shedding PV as is currently the case in Germany [7], but not in Switzerland where a DSO is required to upgrade lines. Alternatively, PV plant owners could be forced to pay a grid tariff depending on the local grid congestion – but no such scheme is known to the authors.

As shown in [8], PV integration with DR is achievable with a simple control architecture. The amount of PV that needs to be shed can be kept minimal even if the flexible loads and PV can only be switched in groups, keeping necessary investment in communication hardware to a minimum. For meaningful PV integration support, energy demand has to be shifted for several hours, requiring some sort of storage. EWHs are a reasonable option, but hot water demand may be reduced during summer times. More data on seasonal hot water consumption would be needed to better assess the potential. Loads such as air-conditioning may not have sufficient energy capacity to shift demand from midnight to noon, but due to their natural correlation with PV production already support PV integration.

The potential savings are very dependent on the specific grid layout, available flexible loads in the feeder and regulatory framework. The cost to the utility that can be saved is limited by the regulated penalty for PV shedding and by the cost for any of the other integration options [6], notably line or transformer upgrades. In a liberalized power market it is only worth absorbing the PV energy if the PV energy is valued higher than the spot market price of that specific hour.

As argued, the opportunity cost of the retailer has to be paid by the DSO. Figure 4 gives results for the test system in [8] and EWHs as flexible loads. With increasing PV penetration, more demand is shifted to avoid shedding of PV production. The cost increase is computed as the difference between charging EWHs at night, and using them for PV integration as well. Up to 24 MW h are saved at a cost of around EUR 400. This leads to an opportunity cost of around EUR 20 per MW h integrated by DR.

C. Energy Cost Minimization

As described in III-A, EWHs are currently used for a combined peak reduction/energy cost minimization approach in a static manner. Assuming constant charging between 01:00 and
05:00, yearly cost to serve 1 MW h account for approximately EUR 30, while base load contracts would have cost EUR 44.7.

Figure 5 shows results for optimal a-posteriori energy acquisition, assuming that the daily energy need is optimally covered on the spot market, i.e., the cheapest hours are used. The results are lower bounds as perfect knowledge of prices, a price-taker model and good liquidity are assumed. The surface gives the cost depending on the energy capacity and the duty cycle of a generalized flexible load. Highlighted areas indicate certain load types – refrigerators, heat-pumps and EWHs. As expected, more storage capacity and lower utilization of a load, as in the case of EWHs, signify a higher savings potential.

More in depth-analysis in trading strategies and risks associated with spot and intraday markets are needed for more realistic results. Nevertheless, Figure 5 can give a good indication of the potential. 1 MWh of EWHs demand can be served for EUR 27. This is a third below no control at all, but only around 10% or EUR 3 per MW h below the current practice of fixed charging times. To achieve these results, one would not only need to handle the market risk but would also need to have more flexible and finer control of the aggregated power consumption and at least daily measurements of State of Charge (SoC) or energy demand to ensure that the loads are always served sufficient energy. This increase in control complexity currently seems to be prohibitive.

In the case of loads with small storage capacity, opportunities for savings are much reduced. Detailed findings for the potential of using real-time market prices with air-conditioning in Western US are given in [9].

D. Schedule Compliance

In the European markets, Balance Groups (BGs) refer to entities consisting of generation and demand units. They are responsible to submit a 15 min schedule for their net production or consumption day-ahead, and deviations are penalized by often costly balancing energy. DR can be used by a BG to improve the schedule compliance. Using the demand side in a cost-optimal way is not trivial: as future deviations are unknown, one has to rely on scenario-based optimization techniques to estimate the expected need for flexibility and the expected cost savings.

Increasing demand when the BG is long is only profitable when the penalty for deviating is higher than the difference to the lowest spot market prices which could be utilized instead. Decreasing demand is desirable if the BG is short. But having loads running at high cost times to have the option to reduce demand barely every pays off, as the additional cost incurred continuously is higher than the savings that can be made at selected times. Figure 6 gives an example from [10] for schedule compliance with EWHs: the top figure shows the EWH dispatch. Blue is the cost optimal dispatch, while green is the dispatch for combined schedule compliance and acquisition cost. Over longer simulation runs, only 22% of the flexible energy was effectively shifted, showing the limited potential of the approach. Savings per MWh load were estimated at EUR 3.6, albeit additionally to the cost optimal dispatch which saves EUR 18, thus increasing the savings for the BG by 20%.

It was found that loads with a duty cycle of 60% and a natural cycle time of 2.5 h to 5 h profit the most from participation in schedule compliance. Some air conditioning and heat-pumps for space heating might fall into this category. Also, as the savings potential is limited by the load deviations, increasing the number of flexible loads leads to decreasing returns per load. Risk remains concerning the price forecast both for the spot market and balancing energy cost, and the control and communication infrastructure must be able to ideally handle individual loads within the 15 min intervals of the schedule, and their SoC should be measurable at least daily.

E. Frequency Control Reserves

Providing frequency control reserves with distributed loads is challenging, as the Transmission System Operator (TSO) usually has strict requirements concerning reliability, availability and real-time measurements. On the other hand, ramp rates are less of a concern for demand response schemes.
Due to the easier-to-fulfill requirements, tertiary control reserves are already offered by a variety of industrial loads such as emergency generators, and several pilot projects are under way to do so with household appliances.

a) Secondary Control Reserves: Provision of secondary control reserves is hard, as the signal needs to be communicated every few seconds and followed closely. A communication and control scheme based on one-way communication and state estimation may still make this possible [11], [12]. If the TSO expects real-time measurement of the reserve provision, communication requirements are further increased. Currently there are only few pilot projects that aim for secondary control with household appliances, notably [13]. More interest is given to larger customers, such as industrial loads and office buildings [14].

Regardless of the load investigated, energy constraints are a major issue. Two main paths of research have been followed. Filtering the control signal to remove any energy bias is proposed by [14], and by [15] for batteries. PJM already offers a scheme that remunerates reserves for their actual contribution, and includes a filtered signal [16]. The alternative approach is to use robust or stochastic control schemes, that, respectively, guarantee provision under all circumstances or with a certain probability. However, under these schemes the amount of reserves that can be offered is substantially reduced. Also, preference for negative reserves, i.e., increasing consumption, and short tendering periods can be seen in all approaches.

Historic secondary control prices in Switzerland have a substantial volatility, making profit estimates uncertain. Median remuneration per MW and hour in 2013 was CHF 24.91, i.e., EUR 20, while mean remuneration was CHF 39.71 or EUR 31.76. Loads suitable for secondary control reserves are loads with a sufficiently large storage capacity as full activation of secondary control of up to two hours was observed. At the same time, loads with such shifting potential are affected most by the trade-off between energy cost and flexibility. Heat-pumps for space heating and air-conditioning might therefore be the favorable option, as they are currently not used for energy cost minimization.

b) Primary Control Reserves: Providing primary frequency control reserves seems to be straightforward as no communication is needed. The grid frequency can be locally measured and device behavior can be adjusted accordingly. Such a concept was first introduced by [17], and recently much attention is given to refrigerators and other small loads, see [18], [19]. Notably, [20] introduces a switching strategy that avoids synchronization of Thermostatically Controlled Loads by using stochastic switching. It is rather difficult to estimate the amount of reserves that can be offered by a certain type of load. In [21], estimates for different load types and their potential to deviate from natural consumption profiles are made. Assuming that 15 min full activation is required, a reserve potential of 100 MW and ~250 MW for refrigerators in Switzerland is estimated – much more than the ±80 MW currently contracted.

Based on the published tender results from swissgrid an earning of EUR 20 per MW·h of demand can be achieved, assuming that the full base-load can be offered as positive and negative reserve. Comparing the earnings to the opportunity cost identified in Figure 5 it is immediate that loads with a small storage capacity, such as refrigerators or freezers, can benefit the most while loads with high storage capacity cannot recuperate the opportunity cost.

Question remain over supervision and remuneration. Considering the small contribution and earning per appliance, it is not feasible to have real-time measurements from each participating load. This would also not be acceptable from a data privacy perspective. It might be more reasonable to offer a financial incentive to have such a controller installed per default. Under such a scheme, load contribution can not be directly controlled, but beneficial effects such as reduced demand for traditional primary control reserves or better frequency dynamics of the power system would still be existing.

F. Overview of business cases

Opportunities for the demand side to earn money in liberalized power markets depend much on the load characteristics. High storage capacities as in EWH with storage tanks allow to use low prices at spot and intraday markets, but can also support PV integration. Medium storage capacities might be sufficient for secondary control, and show potential for schedule compliance. Small storage capacities as in refrigerators allow provision of primary control – while this is promising, remuneration is difficult and best achieved by providing one-time payments.

Figure 7 shows estimates for the money that can be saved or earned from a retailer perspective. While earnings increase with the complexity of control, the additional income and higher market risk may not justify investment in the required communication infrastructure. DSO business cases are omitted, as savings on infrastructure are hard to estimate.

At current cost for energy and valuation of flexibility, DR has no clear business cases beyond those already employed.
Opportunities may arise in distribution grid operation with PV integration. While it is possible to estimate the opportunity cost of PV integration, the earnings depend on many external and scenario specific factors. Generally, DR will profit from more volatile and uncertain prices, as possible earnings at intraday markets may increase, motivating retailers to explore this business model.

IV. DISCUSSION

Several regulatory issues with demand response were identified. Unbundling of retailing and grid operation leads to various conflicts. While flexible loads may be used to relieve the grid both when excess distributed generation has to be absorbed and when demand needs to be reduced, unbundling removes that option from DSOs. Retailers could offer flexibility services to grid operators against payments. A RES shedding penalty or a regulatory framework remunerating not only investments in line upgrades but also increases in capacity utilization could make such a service attractive for a DSO. At the same time, the DSO would need to have reliable access to such flexibility sources.

If end customers can freely choose their retailer, it is no longer possible to measure the BG consumption at a central point, e.g., the substation. Even more, measurements from grid operation may not be handed to retailers. If the BG demand is unknown in real-time, schedule compliance can not be improved by control actions.

Long tender periods for control reserves make provision by the demand side difficult. In addition, measurement requirements may be prohibitive. If real-time measurements are required, this will be hard to fulfill for large populations of small loads. It would be more feasible to have a-posteriori measurements upon request by the TSO.

V. CONCLUSION

This paper gives an overview of the main business models associated with DR. Savings calculated from previous studies and estimates are provided to compare the different cases against each other. The opportunity cost associated with all business models is emphasized, and the control and communication requirements are compared to the additional savings.

All of the business cases achieve higher savings than simple energy cost minimization. But the additional savings are substantially lower than expected—especially when compared to the increased complexity most of the business cases seem to be not economic. This may change if intraday markets become more liquid and more volatile. Besides the financial hurdles, regulatory issues concerning incentives for grid operators, the access to flexible loads and measurements and market structures are highlighted. While unbundling enables competition between retailers, it also prevents the DSO from utilizing flexible loads for measures that might be beneficial to grid operation and ultimately increase social welfare.

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