Energy-Only Markets with Deferrable Demand

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***Abstract*— In addition to its adverse impacts on power system operations, the large-scale integration of renewable energy sources presents market design challenges as it exacerbates the missing money problem by moving value from energy to capacity markets. Energy-only markets have been touted as a mechanism for alleviating the missing money problem, although demand response is widely recognized as the ultimate solution. In this paper we analyze the benefits of demand response and an energy-only market design on short-term operations and long-term investment, as well as the result of overlapping an energy-only market design in a market with active demand response. We use a multi-stage stochastic program to characterize the real-time and long-term market equilibrium, and a multi-stage stochastic unit commitment model followed by a real-time market to analyze the impact of operating reserve demand curves on day-ahead markets. Our model is applied on a case study of wind and demand response integration in Germany.**

***Index Terms*—Resource adequacy, demand response, renewable integration, energy-only markets, stochastic programming.**

I. INTRODUCTION

The remuneration of capacity is becoming an increasingly challenging aspect of electricity market design. This challenge is driven in part by ambitious renewable energy integration targets, constituted in numerous electricity markets in Europe and the United States, which are depressing energy prices while creating an increased demand for capacity. The units that are best suited for providing this capacity, typically gas-fired units with flexible operating characteristics, face shortfalls due to their relatively high fuel costs which push them out of the energy market and prevent them from recovering their capital costs.

Various mechanisms have been contemplated and implemented in practice in order to ensure resource adequacy in a competitive market environment: installed capacity requirements [1] can be set by the regulator, however choosing their level is a contentious issue; capacity payments are a price-based method for achieving the same goal as capacity requirements that may err significantly in terms of installed capacity if the capacity price is not estimated correctly [1]; call option obligations [5] require that load-serving entities procure a quantity of call options equal to their forecast peak load plus reserve, and that should, according to the proposal, be backed up by physical capacity The aforementioned mechanisms aim at overcoming the shortcomings of an energy-only market design that relies on an unresponsive demand side. In theory, VOLL pricing [6] can support optimal investment. However, the estimation of VOLL, although crucial for the performance of the resulting mechanism, is notoriously difficult. In practice, demand-side inelasticity results in extremely volatile energy payments and a perilous environment that discourages investors. Moreover, reliance on energy-only markets requires price spikes in order to support capacity investments. It is often impossible to attribute the occurrence of such spikes to the exercise of market power or true scarcity. The resulting regulatory ceilings in energy market bids and/or clearing prices undermine the function of energy-only markets, resulting in missing money and the inefficient retirement of capacity.

In order to overcome the challenges associated with energy-only markets, Hogan [4] proposes the integration of operating reserve demand curves into the economic dispatch model. Under such a design, short-run efficiency is achieved through the co-optimization of reserves and energy, while long-run efficiency is achieved through the remuneration of capacity under scarcity conditions. In such conditions, demand for operating reserves signals scarcity in capacity and the need for investment. An attraction of the proposed design as compared to installed capacity targets is the fact that the real-time energy market much better reflects scarcity conditions whereas in installed capacity designs numerous forecasts are required in order to set target levels for installed capacity. Energy only markets obviously also implicitly require from investors the capability to correctly anticipate these scarcity conditions. Under the proposed design, price spikes are more frequent and of smaller magnitude than VOLL pricing, thereby rendering capacity payments less volatile and more predictable. Market power can be mitigated by imposing an offer cap on generators since, in contrast to energy-only markets without an operating reserve demand curve, prices for energy and operating reserves can increase and provide scarcity rent even if generators do not submit high bids in the energy market. The operating reserve demand curve is a regulatory design parameter. The operating reserve demand curve can be set equal to VOLL at levels of capacity below the minimum operating reserve requirement (since at levels of operating reserve capacity below the minimum requirement, the operator is willing to curtail loads in order to avoid depleting its operating reserve stack) and gradually decrease to a level of 0 for operating reserve levels above the maximum operating reserve requirement level.

It has long been argued that demand response can result in a wide range of benefits in the operation of electric power systems and electricity markets. These benefits include the balancing of the variability of renewable energy sources and the proper operation of energy-only markets that provide correct investment signals [6] and do not suffer from the missing money problem. Demand response supplements the operation of an energy-only market based on operating reserve pricing [3, 4], since operating reserve demand curves introduce elasticity to an otherwise inelastic market.

Deferrable demand represents a large range of flexible consumption in the spectrum of the industrial, commercial and residential sectors [2]. Deferrable resources are characterized by an aggregate demand for energy that should be satisfied within a given time horizon. From the point of view of system operations, these resources behave much like storage. The attraction is that, unlike storage, deferrable demand is ubiquitously available and accessible at low capital cost. As is the case for storage, the optimal dispatch of deferrable demand is a dynamic optimization problem, where future actions depend on the history of the utilization of the resource. Demand functions, which have been the traditional approach for modeling demand response in energy economics, are therefore inadequate for modeling deferrable demand.

In this paper we analyze the benefits of integrating deferrable demand in an energy-only market. We develop our analysis in the context of a real-time market in section II. A case study of the German electricity system is presented in Section III.

II. ENERGY-ONLY REAL-TIME MARKET

We first introduce the agents and proceed with the formulation of the market equilibrium as an equivalent stochastic program. The notation is explained in detail in the appendix.

Suppliers. We consider a system with conventional thermal resources, as well as renewable resources. Both types of suppliers are characterized by a convex total cost curve. Renewable suppliers produce power at an uncertain rate. Suppliers earn income from both the energy and operating reserve market. Energy prices are paid for each unit of supplied power, capacity prices are paid for each unit of capacity that is reserved in the case of imbalances.

Consumers. We consider two types of consumers. Non-deferrable consumers may be inelastic, or may be characterized by downward sloping demand functions. The demand functions exhibit no cross-elasticity, indicating that the demand across time periods for this class of consumers is independent. We characterize deferrable loads as resources that require a total amount of energy E_l within the horizon of the operation of the market. We consider, therefore, two extremes in the spectrum of temporally flexible demand, although intermediate models of temporal flexibility can also be accounted for in the formulation. Deferrable loads value each unit of energy at V_l, however they are indifferent about the exact timing of power provisioning and in that sense their response to prices resembles the response of a storage resource. A limit D_l is imposed on the rate at which deferrable loads can consume power. Consumers procure energy and operating reserve. Whereas energy is charged on each buyer separately, reserve is a public good that is procured by the system operator on behalf of consumers and is therefore charged to consumers via ex-post uplift charges.

System operator. The system operator is a non-profit entity that operates the system, administers the market, and is responsible for reliability. The system operator procures operating reserves on behalf of consumers, in order to ensure reliability, by placing demand bids for operating reserve. The demand functions for reserve are downward sloping. The system operator collects energy payments from consumers, and allocates energy and operating reserve payments to suppliers. Operating reserve charges are imposed to consumers ex post such that the system operator breaks even.

Uncertainty. Uncertainty is represented in our model through a scenario tree and stems from the fluctuation of renewable power supply. The set of outcomes that are observable in period t is denoted as Ω_t, and the ancestor of outcome ω is denoted as $A(\omega)$.

A real-time market competitive equilibrium for risk neutral agents that hold the same beliefs about the evolution of uncertainty in the real-time market prices can be derived from the solution of a stochastic program that maximizes the expected welfare of the system.

$$\max \sum_{t\in T}\sum_{\omega\in\Omega_t} P_\omega \cdot \{\int_0^{d_{\omega,t}} VE(x)dx + \int_0^{r_{\omega,t}} VR(x)dx\}$$
$$-\sum_{l\in DL}\sum_{\omega\in\Omega_H} P_\omega \cdot V_l \cdot x_{l,\omega,H}$$
$$-\sum_{g\in G\cup R}\sum_{t\in T}\sum_{\omega\in\Omega_t} P_\omega \cdot \int_0^{p_{g,\omega,t}} MC_g(x)dx \tag{1}$$

$$s.t.\ p_{g,\omega,t} + rs_{g,\omega,t} \le C_g, g\in G, t\in T, \omega\in\Omega_t \tag{2}$$
$$p_{g,\omega,t} \le C_{g,\omega}, g\in R, t\in T, \omega\in\Omega_t \tag{3}$$
$$\textstyle\sum_{g\in G\cup R} p_{g,\omega,t} = d_{\omega,t} + \sum_{l\in DL} d_{l,\omega,t} + EX_t, t\in T, \omega\in\Omega_t \tag{4}$$
$$\textstyle\sum_{g\in G} rs_{g,\omega,t} = r_{\omega,t}, t\in T, \omega\in\Omega_t \tag{5}$$
$$d_{l,\omega,t} \le D_l, l\in DL, t\in T, \omega\in\Omega_t \tag{6}$$
$$x_{l,\omega,t} = x_{l,A(\omega),t-1} - d_{l,\omega,t}, l\in DL, t\in T-\{1\}, \omega\in\Omega_t \tag{7}$$
$$x_{l,\omega,t} = E_l - d_{l,\omega,1}, l\in DL, \omega\in\Omega_1 \tag{8}$$
$$p_{g,\omega,t}, r_{\omega,t}, rs_{g,\omega,t}, d_{\omega,t}, d_{l,\omega,t}, x_{l,\omega,t} \ge 0 \tag{9}$$

The objective of the problem is the maximization of welfare, which is the benefit derived from the energy demand, which is a private good, and the reserve demand, which is a private good, net the fuel cost and the cost of unserved deferrable demand. Maximum run limits are described by constraints (2) and (3). Constraint (4) is the market clearing condition of the energy market, while (5) represents the market-clearing condition of the reserve market. The maximum consumption rate of deferrable loads is imposed by constraint (6), while the dynamic evolution of the residual demand of deferrable loads is described in constraints (7) and (8).

Technology	Capacity [MW]	Min bid [€/MWh]	Max bid [€/MWh]	Inv. Cost [€/MW-day]
Biomass	4277	0	60.6	669.6
Coal	24969	14.6	31.6	388.8
Waste	1329	0	31.0	902.4
Gas	22236	57.1	95.6	122.4
Lignite	19847	7.4	13.0	597.6
Oil	2207	104.6	223.7	40.8
Other	4534	18.4	21.1	343.2
Hydro pumped	6759	25.0	125.0	573.6
Hydro ROR	3677	0	0	319.2
Hydro seasonal	1613	25.0	125.0	319.2
Nuclear	12078	5.9	7.7	762.2

Table 1: German system fuel mix, capacity, variable costs.

The introduction of deferrable demand in the real-time market will have an impact on equilibrium prices, as deferrable resources will shift their consumption to hours of low prices and vice versa. The equilibrium can be described by the solution of the above stochastic program, which describes the collective performance of the market. Since the constraints of the problem are linear and the objective function is concave, the standard arguments that establish the equivalence between the stochastic programming solution and a stochastic economic equilibrium extend to the case of inter-temporal constraints. In particular, the inter-temporal constraints associated with the dispatch of deferrable consumers, as well as possible inter-temporal constraints associated with the operation of generators (e.g. due to ramping constraints), pose no complications (see [7] for an in depth discussion of stochastic equilibrium problems with hydro-storage).

III. CASE STUDY

European energy markets present particular policy design challenges due to the existing diversity of capacity remuneration mechanisms as well as the ambitious renewable energy integration targets set forth by the European Commission. In this section we will analyze the impacts of energy-only markets with deferrable demand and renewable power integration in the German system. Germany is among the European systems with the greatest amount of installed renewable capacity. We will ignore transmission constraints and the associated market design complications. The interaction of Germany with neighboring systems will also be simplified, with imports/exports assumed fixed and known in advance.

We use data for the German fuel mix from the EEX Transparency Platform, including planned outages for the day. The fuel mix of the system and the variable costs of each technology are shown in Table 1. We assume a quadratic variable cost function with zero fixed cost: $TC(p) = a \cdot p + 0.5 \cdot b \cdot p^2$. The bids at zero and at capacity are shown in Table 1, with the minimum bid corresponding to a and the maximum bid corresponding to $a + b \cdot P$ where P is the capacity of the technology, also provided in the table. Cost data were used for units located in the Central and Western European system. The annualized investment cost is also shown in the table, and was sourced from the Energy Information Agency [8]. We assume an exchange currency of 0.87€/$, a 40-year lifetime of investment and an interest rate of 5% with continuous compounding.

Type	Sector	Time-Varying	P [MW]	E [MWh/day]	Flexibility
1	I	No	260	5934	1.05
2	I	No	595	13562	1.05
3	I	No	1315	29974	1.05
4	I	No	78	1784	1.05
5	I	No	177	4034	1.05
6	I	No	72	1651	1.05
7	I	No	58	1321	1.05
8	I	Yes	553	12597	1.05
9	I	Yes	817	13079	1.5
10	I	No	365	7003	1.25
11	C	Yes	1516	24249	1.5
12	C	Yes	245	3358	1.75
13	C	Yes	354	4850	1.75
14	C	Yes	3917	47007	2
15	C	Yes	495	373	31.85
16	C	Yes	8170	5596	35.04
17	C	Yes	4190	7461	13.48
18	C	Yes	933	11192	2.00
19	R	No	717	11192	1.54
20	R	Yes	13532	25952	12.51
21	R	Yes	22487	43126	12.51
22	R	Yes	25671	20537	30.00
23	R	Yes	23283	13013	42.94
24	R	Yes	16557	18870	21.06
25	R	Yes	1313	990	31.85
26	R	Yes	8756	5997	35.04
27	R	Yes	22288	39691	13.48

Table 2: Classes of flexible loads. 1-Mechanical wood pulp production, 2-Recycling paper processing, 3-Paper machines, 4-Calcium carbide production, 5-Air liquefaction in cryogenic rectification O2, 6-Air liquefaction in cryogenic rectification N2, 7-Air liquefaction in cryogenic rectification Ar, 8-Cement mills, 9-Cooling in food manufacturing, 10-Ventilation without process relevance, 11-Cooling in food retailing, 12-Cold storages, 13-Cooling in hotels and restaurants, 14-Commercial ventilation, 15-Commercial air conditioning, 16-Commercial storage water heater, 17-Commercial storage heater, 18-Pumps in water supply, 19-Waste water treatment, 20-Freezer, 21-Refrigerator, 22-Washing machines, 23-Tumble dryers, 24-Dish washers, 25-Residential air conditioner, 26-Residential electric storage water heater, 27-Residential electric storage heater.

The load profile corresponds to two day types of equal likelihood. The first day type is the demand in Germany on November 6th, 2013, sourced from the ENTSO-E transparency platform, and the second day type corresponds to 1.5 times the nominal demand in Germany for the same date (likewise for exports). Production time series for wind and photovoltaic generators were obtained from the EEX Transparency Platform, corresponding to the data between July 2010 and March 2014.

	Case 1	Case 2	Case 3	Case 4
Welfare	8,314.7	8,315.6	8,314.6	8,315.6
Inv. cost	36.5	36.5	36.5	36.5
Gen. cost	36.1	35.2	36.1	35.2
Energy payments	79.0	75.6	104.5	75.6
Reserve payments	0	0	2.1	0
Gen. profits	6.4	4.0	34.0	4.0
Non-def benefit	6,515.3	6,515.3	6,515.2	6,515.3
Deferrable benefit	1,872.0	1,872.0	1,872.0	1,872.0
Load profit	8,308.2	8,311.7	8,280.6	8,311.7

Table 3: Welfare metrics in million €.

Flexible load data is collected from Gils [2]. We summarize the relevant parameters for our study in Table 2. We assume that the loads are available for load shifting for the entire horizon. The daily energy demand is derived from annual demand. In order to determine the inflexible load, we subtract from the total power consumption (obtained from ENTSO-E) the amount of flexible energy demand, where consumption classes labeled as 'time-varying' are assumed constant throughout the day and consumption classes labeled as 'time-invariant' are assumed to follow the daily load profile of the total country demand. Flexibility is defined as $\frac{D_l \cdot H}{E_l}$, i.e. the ratio of energy that a deferrable load would have consumed if it were drawing power at maximum rate divided by the actual energy that the deferrable load needs to consume. We note that the majority of flexibility resides in the residential energy sector (45% of annual flexible energy demand), followed by the commercial sector (31% of annual flexible energy demand) and finally the industrial sector (24% of annual flexible energy demand). This is fortuitously correlated with the amount of available flexibility, which ranges between 12.51-42.94% for residential devices, 1.5-35.04% for commercial devices down to 1.05-1.5% for industrial equipment. The total amount of flexible energy demand corresponds to 27.6% of the annual energy demand.

We analyze four cases: (i) little demand response, based on a linear demand function model with small elasticity, (ii) little demand response and deferrable demand, (iii) little demand response and operating reserve pricing, and (iv) little demand response, operating reserve pricing and deferrable demand.

We assume that 95% of the non-deferrable demand is completely inelastic, with a VOLL equal to 5000€/MWh. The remaining 5% of the non-deferrable demand is characterized by a linear demand function. The demand function is built by assuming that consumption is zero at 10000€/MWh, and equal to the observed inflexible demand at the retail price. We assume a simple scenario tree where 5GW of renewable power are available until the middle of the day, and the supply thereafter either drops to zero or increases to 10GW with equal probability.

	Case 1	Case 2	Case 3	Case 4
Average E	55.9	52.5	77.6	52.5
Min E	22.8	25.5	22.8	25.5
Max E	93.3	79.3	2178.3	79.3
St. dev. E	21.4	22.1	216.6	22.1
Average R	n/a	n/a	21.7	0
Min R	n/a	n/a	0	0
Max R	n/a	n/a	2085.9	0
St. dev. R	n/a	n/a	211.8	0

Table 4: Energy and reserve price statistics in €/MWh.

In the presence of deferrable demand, flexible consumption shifts in order to minimize generation cost, which tends to result in uniform marginal cost over all hours. Deferrable demand increases overall welfare, largely due to efficiencies achieved in the production of electricity. The winners and losers of deferrable demand shifts depend on the level at which average prices over the day equilibrate. If average prices are lifted due to valley-filling by deferrable demand, then payments from loads to generators will increase, with a resulting increase in generator profit and a decrease in consumer profit. Although overall consumer profits may decrease in such a situation, deferrable consumer profits are not expected to decrease since deferrable consumers are the ones benefiting from low prices by shifting their consumption to hours of low price. If average prices are depressed due to peak shaving, then payments from loads to generators will decrease. In that case generator profits may or may not increase, depending on whether generation cost cuts compensate for reductions in generator payments. Deferrable consumer benefit remains constant, while the non-deferrable consumer benefit may increase or decrease depending on the extent to which deferrable consumer shifts displace non-deferrable consumers.

The results of the real-time market are presented in Tables 3 and 4. Generator profits account for investment costs. We note that cases 2 and 4 correspond to identical results. This implies that the operating reserve demand curve leaves the energy-only market unaffected. The reason is clear from Table 4: due to deferrable demand there is an oversupply of operating reserve (above 7% of system demand) and the price of reserve is never positive. In this case, we can expect generators to scrap redundant capacity if energy market payments are not sufficient to cover their capital investment costs. The incorporation of operating reserve demand functions and deferrable demand in an investment model is the subject of ongoing research. Comparing cases 1 and 3 we notice that in case 3 the operating reserve price spikes at a very high value, 2085.9€/MWh, and also results in a lift of the energy price. The generation cost reductions achieved by the introduction of deferrable demand range between 2.57-2.6% (without and with operating reserve demand curves respectively). The cost increase resulting from the introduction of the operating reserve demand curve is limited to 0.3% in the case without deferrable demand. Generator profits peak in case 3, due to the increased revenues from the operating reserve and energy market rather than increased efficiency of production. Load profits drop in case 3, both due to increased payments in the energy and reserves markets as well as due to a reduction of elastic demand in periods of high energy prices[1]. Note that the welfare of case 2 is the maximum possible attainable welfare over all cases that are studied.

IV. Conclusions and Perspectives

Operating reserve demand curves may have a noticeable short-term negative impact in load profits, as they tend to boost energy prices in conditions of tight supply and they also require payments for operating reserve. However, this comparison is made against a stochastic programming ideal that is impossible to attain in practice, and it may very well turn out that operating reserve markets end up being far cheaper to consumers than alternative mechanisms for incentivizing capacity investment (recall that the results are obtained with fixed capacity, and therefore ignore the impact of these mechanisms on investment). The results presented in this paper are encouraging, as they identify a minimal gap between the mechanism proposed by Hogan and the stochastic programming ideal (0.3% cost difference in the case without deferrable demand). The study of alternative mechanisms including their impact on investment or plant retiring is an interesting direction of future research.

Operating reserve demand curves tend to boost generator short-run profits as the increase in revenues from the energy and operating reserve markets tends to overwhelm the production costs resulting from the reservation of generation capacity. Deferrable demand has an opposite effect on generator profits for the case presented in this paper, as it depresses the average price of energy over the day. However, this effect need not hold in general as deferrable demand may also lift the average daily energy price.

In future work we are interested in understanding how the introduction of operating reserve demand curves interacts with unit commitment and investment. The German system is also very particular due to oversupply, it would be interesting to apply the model to different systems with tighter capacity margins. The analysis could benefit by a representation of transmission, as well as the interaction of Germany with neighboring systems, although this would complicate the analysis due to the complex management of cross-border trade and transmission capacity allocation in the European market.

Operating reserve demand curves and demand response fulfill complementary roles in increasing the flexibility of the system. The extent to which operating reserves and demand response will share the burden of system flexibility depends on the technical capabilities of these resources (capacity, ramp rate, precision of signal tracking) as well as the investment cost at which these capabilities can be made available. Our analysis suggests that the complementarities of these resources need to be accounted for in future operating reserve requirements and consequently in future market design, in order to ensure the appropriate level of investment in systems with substantial amounts of demand response.

Appendix

Sets

G, R, DL: set of conventional generators, renewable generators and deferrable loads

$S, T = \{1, \dots, H\}$: set of scenarios, time horizon

Ω_t: set of outcomes in period t

Parameters

$C_g, MC_g(p)$: capacity; marginal cost function of conventional generator g

$C_{g,s}$: output of renewable generator g for scenario s

V_l, D_l, E_l,: valuation, maximum consumption, energy demand of deferrable load l

$VE(d), VR(r)$: inverse demand function for energy and operating reserve

EX_t: export in period t

$P_\omega, A(\omega)$: probability, ancestor of outcome ω

Variables

$p_{g,\omega,t}, rs_{g,\omega,t}$: production, operating reserve supply of unit g for outcome ω, period t

$d_{l,\omega,t}, x_{l,\omega,t}$: deferrable demand, residual energy demand of deferrable load l for outcome ω, period t

$d_{\omega,t}$: demand of non-deferrable loads for outcome ω, period t

$r_{\omega,t}$: demand for reserve for outcome ω, period t

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[1] Due to space limitations, we have not included results that account for day-ahead unit commitment. We merely mention here that when accounting for the day-ahead commitment of slow thermal units, load profit drops from 8,371,399,592€ in case 1 to 8,369,922,195€ in case 2. This is a manifestation of the aforementioned phenomenon whereby increased elasticity increases average prices throughout the day due to the overwhelming effect of valley filling. This is in contrast to the more standard results presented in Table 3, whereby reduced load elasticity results in lower load profits, and would trigger increased load elasticity in the long run.