

Demand Response Program Implementation for Day-Ahead Power System Operation

Mohamed Lotfi, João P. S. Catalão

FEUP and INESC TEC
Porto, Portugal
mohd.f.lotfi@gmail.com;
catalao@fe.up.pt

Mohammad S. Javadi

INESC TEC
Porto, Portugal
msjavadi@gmail.com

Ali E. Nezhad

University of Bologna
Bologna, Italy
ali.esmaeelnezhad@gmail.com

Miadreza Shafie-khah

University of Vaasa
Vaasa, Finland
miadreza@gmail.com

Abstract—This paper demonstrates day-ahead operation of power systems in the presence of a Demand Response Program (DRP) for serving exact amounts of demanded energy over the operational horizon. The proposed two-stage model features a here-and-now framework for shaping the aggregated demands during operation. First, the day-ahead scheduling problem is solved by adopting Unit Commitment (UC) to determine the generation level of power generation units as well as the Locational Marginal Prices (LMPs). Afterwards, the obtained LMPs are considered as the Time of Use (ToU) for the second step of the scheduling and reshaping the demanded loads of each aggregator. A new methodology is provided in this paper to estimate the reaction of consumers behavior in terms of encouraging their participation in DRPs. Unlike classical models which adopt load reduction over the operational horizon, this model ensures that the total demanded loads will be served. Therefore, the total supplied energy for the operational period before and after DRP implementation remains unchanged. Meanwhile, the total payment of consumers will be considerably reduced by adopting this strategy. The simulation results on the 6-bus test system clarify that the proposed model can reduce the total operational cost as well as smoothen the load profile and nodal prices over the operational horizon.

Index Terms—Day-ahead Energy Market, Demand Response Programs, Locational Marginal Price, Time of Use, Unit Commitment, Aggregator.

NOMENCLATURE

Indices

i	Index for bus
L	Index for line
S	Index for segments of cost function
t, t'	Index for time

Variables

$PG_{i,t}$	Power generation of unit i at time t
$PD_{i,t}$	Demand at bus i at time t
$C_{i,t}$	Start-up cost of unit i at time t
$SU_{i,t}$	Binary decision variable of start-up

$SUC_{i,t}$	Start-up cost of unit i at time t
$SD_{i,t}$	Binary decision variable of shut-down
$SDC_{i,t}$	Shut-down cost of unit i at time t
$I_{i,t}$	Binary decision variable of unit commitment
$P_{i,s}$	Power generation at segment s of unit i
δ	Voltage bus angle
$\lambda_{i,t}$	Locational marginal price at bus i at time t

Parameters

MGC_i	Minimum generation cost of unit i at time t
N_B	Number of thermal units
N_T	Number of hours under study
N_L	Number of transmission lines
RU_i	Ramp-up for unit i
RD_i	Ramp-down for unit i
X_l	Reactance of transmission line l
$SL_{i,s}$	Slope of segment s for unit i
N_s	Number of linearization segments
α, β	Acceptable range for DR implementation
ω	Maximum acceptable change for hourly demand
$T_i^{\text{on}}, T_i^{\text{off}}$	Minimum up/down time of unit i

Symbols

max, min	Maximum and Minimum
New, Old	After and before DR implementation
S, R	Sending, Receiving end bus

I. INTRODUCTION

A. Motivation

Demand Response Programs (DRPs) have been attracting increasing attention as an effective means of minimizing operating costs, enhancing reliability, and mitigating risk. DRPs can be categorized into two groups: Price-Based Programs (PBP) and Incentive-Based Programs (IBP) [1].

PBPs (also known as voluntary or market-led), are centered around the premise of varying electricity prices. In this way, consumers are stimulated to modify their consumption behavior in a way that is more favorable for system operation as they share the economic benefits by following the price signals [2], [3]. Many PBPs exist, including but not limited to Time of Use (ToU) tariff, Peak Shaving, Critical Peak Pricing (CPP), Extreme Day Pricing (EDP), and Real-Time Pricing (RTP), each designed for a specific purpose [4], [5]. The ToU scheme is the most straightforward while RTP is the most sophisticated. In RTP schemes, customers pay hourly varying tariffs reflecting the real conditions of the power market. In this respect, the day-ahead or hourly-ahead prices are given to those customers participating in the RTP. Such a mechanism can be effectively implemented in electricity markets with competitive conditions [3].

Despite being the most sophisticated to implement, RTP programs can substantially impact the load profile favorably, especially with respect to hours of peak demand and price fluctuations over different hours of the day. RTP programs are capable of directly and efficiently influencing consumers to adapt their consumption behavior to better match electricity supply conditions, and thereby mitigate such effects. Moreover, RTP was shown to be the only highly effective DR scheme across all three electricity consumer sectors: residential, commercial, and industrial [6].

Therefore, this paper recognizes the vital importance of incorporating DRPs, in power system operation and specifically the use of RTP schemes to stimulate consumers behavior. The Unit Commitment (UC) problem is one of the most important in power system operation. It is an optimization problem aiming at determining the optimal hourly schedule of available generation units which minimizes the total cost of power generation, while meeting required load demand and other constraints. [7] Being a vital procedure and inherently dependent on load profiles, incorporation of DRPs in power systems necessitates their incorporation in the UC problem.

B. Literature Review

In [8], it was proven that major problems can be encountered when using traditional UC formulations in which the system is not accurately represented. Not only are sub-optimal solutions obtained with possible curtailment losses of up to 7%, but in some cases the schedule obtained is infeasible resulting in interruptions. It also shows that unrealistic representations of the system can have an even more negative effect than unaccounted renewable generation uncertainty.

In [9], different DRPs (IBPs and PBPs) were incorporated to the UC problem in order to accurately represent consumers as a responsive load. The consumer responsiveness was modelled based on price elasticity of demand. The UC problem was solved to minimize the total system cost while complying with load demand. The analysis proved that implementation of the load profile was largely influenced by incorporation of DRPs into the model and the total cost was indeed reduced.

In [10], a Time Based Program (TBP) was incorporated to the UC problem with the aim of reducing peak-hour demand and minimizing cost. The total saved cost was 2.74% as compared to traditional UC. It was found that through the implementation of DRPs and service providers, generation companies can make a higher profit in peak hours despite the shaved-off peak loads. Due to decreased generation and fuel costs, consumer profits are also maximized. In [11], demand bidding (a TBP similar to RTP but designed for large consumers) was incorporated into UC. The aim was to maximize profits for participants in the DRP while minimizing costs of generation. The results showed a decrease in prices during peak hours.

The previous studies are representative of state-of-the-art work addressing UC and DRP implementation therein. In [8] it was established that accurate representation of the system is crucial for the UC problem. As [9]–[11] have shown, the presence of DRPs has a significant impact on load profile and resulting generation schedule. Thus, realistic modeling of DRPs in UC formulations is crucial for robust and economic operation of power systems.

C. Contributions

Unlike other previous research works which used price elasticity models to estimate the consumer behavior, this paper models the maximum amount of load demand which can participate in the DRP, being set as a maximum possible change from one hour to another. Meanwhile, the total energy demand by consumers is constant over the day leading to a more realistic management. As it is known, the mechanisms which are based on price elasticity only model the decrease in load demand while load deferral is neglected. Although load demand reduction over peak hours leads to mitigating the total operating cost, the customers' satisfaction level would definitely be impacted. Employing the presented algorithm, the amount of the load demand over the scheduling period, e.g. 24 hours, is constant and does not imply economy. On the contrary, it would result in time management of the load demand, increasing the efficiency, and mitigating operating costs and customers' bills. A Mixed-Integer Linear Programming (MILP) framework is utilized to assess the effectiveness of the DRPs in the day-ahead market. Furthermore, consumer behavior when reacting to hourly prices of the system has been modeled using a LP method. Using this approach, the changes in power consumption can be stimulated.

D. Organization

This paper is divided into four sections. Section I (and current section) highlights the motivation behind this work, establishes the recent state-of-the-art, and defines the contribution of this study; Section II contains the problem formulation in which the mathematical modeling for UC (MILP) and DRP (LP) is presented. Section III shows the results of simulating the proposed framework on a standard 6-bus test system, comparing system operation with and without a DRP. The final conclusions and recommendations for future work are listed in Section IV.

II. PROBLEM FORMULATION

As indicated, a two-stage model is adopted in this paper. First, it is required to obtain the LMPs for each hour of the scheduling period. In this stage, the ISO executes the UC problem based on the base load demand. Therefore, due to the hourly operating cost of the contributing generating units, the LMPs can be obtained. This section provides the MILP model for the UC problem and then the average LMPs are announced as hourly RTP to the aggregators. The main role of the aggregators is to stimulate the reactions of the consumers to obtain the reshaped load profile for the day-ahead market. By implementing the proposed load profile stimulation technique, the reactions of the consumers to the DRPs can be determined. This section provides the MILP model for UC as well as LP model for stimulating the consumers' reaction to the RTPs.

A. MILP UC Problem Formulation

The UC model in a MILP framework is addressed in this section. The objective function of the UC is to minimize the operating cost of thermal generating units in addition to their start-up and shut-down costs. The cost function of UC and the corresponding constraints are stated as follows:

$$\text{Min} \sum_{i=1}^{N_B} \sum_{t=1}^{N_T} F_{ci}(PG_{i,t}) + SUC_{i,t} + SDC_{i,t} \quad (1)$$

where:

$$F_{ci}(PG_{i,t}) = MGC_i I_{i,t} + \sum_{s=1}^{N_S} SL_i^s P_{i,t}^s \quad (1.a)$$

$$MGC_i = f(PG_i^{\min}) = a_i + b_i PG_i^{\min} + c_i (PG_i^{\min})^2 \quad (1.b)$$

$$SL_i^s = \frac{f(P_i^s) - f(P_i^{s-1})}{P_i^{s,\max}} \quad (1.c)$$

Subject to:

$$0 \leq P_{i,t}^s \leq P_i^{s,\max} \times I_{i,t} \quad (2)$$

$$PG_{i,t} = PG_i^{\min} + \sum_{s=1}^{N_S} P_{i,t}^s \quad (3)$$

$$PG_i^{\min} \times I_{i,t} \leq PG_{i,t} \leq PG_i^{\max} \times I_{i,t} \quad (4)$$

$$SU_{i,t} - SD_{i,t} = I_{i,t} - I_{i,t-1} \quad (5)$$

$$SUC_{i,t} = SU_{i,t} \times StartUp_i \quad (6)$$

$$SDC_{i,t} = SD_{i,t} \times ShutDown_i \quad (7)$$

$$PG_{i,t} - PG_{i,t-1} \leq RU_i \times I_{i,t-1} + PG_i^{\min} (I_{i,t} - I_{i,t-1}) \quad (8)$$

$$PG_{i,t-1} - PG_{i,t} \leq RD_i \times I_{i,t} + PG_i^{\min} (I_{i,t-1} - I_{i,t}) \quad (9)$$

$$\sum_{t'=t}^{t+T_i^{\text{on}}-1} I_{i,t'} \geq T_i^{\text{on}} (I_{i,t} - I_{i,t-1}) \quad \forall t = 1 \dots N_T - T_i^{\text{on}} + 1 \quad (10)$$

$$\sum_{t'=t}^{t+T_i^{\text{off}}-1} (1 - I_{i,t'}) \geq T_i^{\text{off}} (I_{i,t-1} - I_{i,t}) \quad \forall t = 1 \dots N_T - T_i^{\text{off}} + 1 \quad (11)$$

$$PG_{i,t} - PD_{i,t}^{\text{Old}} = \sum_{l \in N_l} PL_{l,t} \perp \lambda_{l,t} \quad (12)$$

$$PL_{l,t} = \frac{1}{X_l} (\delta_{l,t}^S - \delta_{l,t}^R) \quad (13)$$

$$PL_l^{\min} \leq PL_{l,t} \leq PL_l^{\max} \quad (14)$$

$$\delta_{l,t}^{\text{ref}} = 0 \quad (15)$$

Expression (1) states the objective function of the problem corresponding to cost minimization. The total operating cost of the system is the sum of the fuel cost of the thermal generating units denoted by $F_{ci}(PG_{i,t})$ and the start-up and shut-down costs indicated by $SUC_{i,t}$ and $SDC_{i,t}$, respectively. Generally, the cost function of thermal power generating units is addressed with a quadratic cost function [12]. The coefficients of the quadratic cost function can be extracted from the historical data of fuel consumption and by considering the heat rate and fuel price required by thermal units.

In this paper, a linearized model is adopted for the UC problem formulation and as such the quadratic cost function should be linearized, which is done following the linearizing method proposed in [13], as formulated by (1.a)-(1.c).

Fig. 1 illustrates the original quadratic cost function and linearized cost function. It is evident that by increasing the number of linearization segments (N_S), the accuracy of the model will increase. This optimization problem is subject to several equality and inequality constraints. In this regard, the limit on the power generation at each segment is stated in (2) where $P_{i,t}^s$ is the power generation of the thermal unit i at time t and segment s . Eq. (3) illustrates the power generation at each segment in which PG_i^{\min} is the minimum power generation of the thermal unit i .

Inequality (4) shows the limitation of the power generation of the thermal generating units using the binary variable $I_{i,t}$ which specifies the commitment status of the unit. It is noteworthy that PG_i^{\max} is the upper bound of the power generation of thermal unit i .

Eq. (5) denotes the shut-down and start-up of a thermal generating unit, where $SU_{i,t}$ and $SD_{i,t}$ are binary variables determining the start-up and shut-down of the unit. Accordingly, the start-up cost and shut-down cost can be calculated as (6) and (7), respectively.

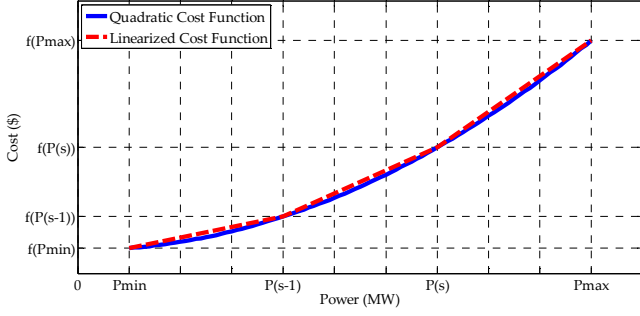


Figure 1. Quadratic and linearized cost function

The ramp up and ramp-down limits have been stated in (8) and (9), respectively; where RU_i is the ramp-up rate and RD_i is the ramp-down rate of thermal unit i . (10) and (11) show the minimum up-time and the minimum down-time constraints, respectively, where T_i^{on} is the minimum-up time and T_i^{off} is the minimum down-time of thermal generating unit i . The nodal power balance constraint taking into consideration the power demand before applying the DRP ($PD_{i,t}^{Old}$) is indicated in (12). Eq. (13) is the DC power flow equation in which the line flow is denoted by $PL_{l,t}$. X_l is the reactance of line l and δ_l^S and δ_l^R are the voltage angle of the sending bus and receiving bus, respectively. Besides, (14) presents the power flow limit of each transmission line. Eq. (15) states that the voltage angle of the slack bus is assumed zero.

B. LP DRP Stimulating Problem Formulation

The DRP is modeled in this paper using a Linear Programming (LP) framework. The proposed LP model stimulates the consumers' reactions to the hourly prices. Unlike the classical models based on the price elasticity methodology which do not provide any guarantee for the energy supply of the consumers over the planned horizon, the proposed model considers this critical issue. In other words, the proposed model estimates the consumption based on the hourly energy tariffs.

On the other hand, the amount of participation of each aggregator for supplying the total hourly load demand is restrained. Moreover, the rate of changing the load demand from one hour to another is limited to reduce the demand fluctuations over the scheduling horizon.

The objective function of this model is as follows:

$$\text{Min} \sum_{i=1}^{N_B} \sum_{t=1}^{N_T} PD_{i,t}^{New} \times \lambda_{i,t} \quad (16)$$

$$\sum_{t=1}^{N_T} PD_{i,t}^{New} = \sum_{t=1}^{N_T} PD_{i,t}^{Old} \quad (17)$$

$$(1 - \beta)PD_{i,t}^{Old} \leq PD_{i,t}^{New} \leq (1 + \alpha)PD_{i,t}^{Old} \quad 0 \leq \alpha, \beta \leq 1 \quad (18)$$

$$PD_{i,t}^{New} - PD_{i,t-1}^{New} \leq \omega \quad (19)$$

$$PD_{i,t-1}^{New} - PD_{i,t}^{New} \leq \omega \quad (20)$$

In this model, $\lambda_{i,t}$ is the locational marginal price obtained from the day-ahead market clearing mechanism. The stimulated demand is denoted by the “New” superscript and it is the decision variable of this stage. Constraint (17) deals with the total consumed energy over the planning horizon and it should be the same as the requested energy by the aggregators before implementing the DRP. Constraint (18) confirms that the participation of the aggregators in the DRP is bounded. The hourly justification on the load demands is also constrained by the tendency level of aggregators to participate in the DRP, as shown in (19) and (20). The tendency of aggregators for changing the demand from one hour to another is limited to ω .

III. SIMULATION RESULTS

The standard 6-bus test system is used to simulate the presented framework. Fig. 2 illustrates the single-line diagram of this system. The network has three thermal power generating units and three aggregators. The power grid includes seven transmission lines. The hourly load demand before applying the demand response program is detailed in Table I. The load demand is distributed at the rate of 20%, 40%, and 40%, among buses 3, 4, and 5, respectively.

Techno-economic data of the generating units and transmission lines are provided in Table II and Table III, respectively. For linearization of the quadratic generation cost function of the thermal units, the number of segments (N_s) considered was 200. In the DRP implementation, the maximum allowed participation rate of each aggregator per hour is assumed to be 15% of the total load demand. In other words, the α and β are assumed to be 0.15. Moreover, the maximum change in the responsive load demand is considered to be 15 MW, i.e., $\omega=15$ MW. In order to solve the optimization problem, the CPLEX solver is used in this paper. By modeling of the UC problem as a MILP one, the computational burden of the day-ahead market clearing mechanism is reduced to an acceptable level. The numerical results of the LMP before and after applying the DRP based on the ToU program implementation are shown in Fig. 3. In addition, Fig. 4 depicts the amount of change in the load profile before and after applying the DRP. The total operating costs of power system before and after the implementation of the DRP are obtained as \$ 137,557.4 and \$ 93,795.08, respectively.

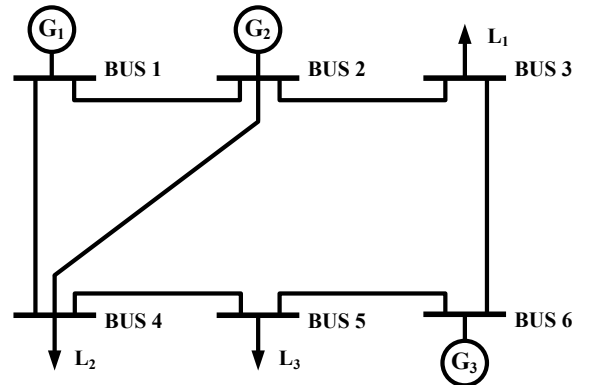


Figure 2. Single-line diagram of 6-Bus test system [14]

TABLE I. DAILY FORECASTED LOAD

Time	PD ^{Old}	Time	PD ^{Old}	Time	PD ^{Old}
T1	179.2	T9	243.6	T17	268.8
T2	168.0	T10	266.0	T18	268.8
T3	162.4	T11	277.2	T19	260.4
T4	156.8	T12	280.0	T20	245.4
T5	156.8	T13	277.2	T21	225.6
T6	162.4	T14	280.0	T22	208.2
T7	179.2	T15	280.0	T23	195.6
T8	212.8	T16	271.6	T24	180.4

TABLE II. GENERATION UNIT DATA

Unit	a	b	c	PG ^{max}	PG ^{min}
G1	177	13.5	0.00045	220	100
G2	130	40.0	0.00100	100	10
G3	137	17.7	0.00500	70	10
Unit	MUT	MDT	RD, RU	SU	SD
G1	4	4	110	100	50
G2	3	2	100	200	100
G3	1	1	40	0	0

TABLE III. TRANSMISSION LINE DATA [13]

Line	From	To	X _i	PL ^{max}
L1	1	2	0.170	200
L2	1	4	0.258	100
L3	2	4	0.197	100
L4	5	6	0.140	100
L5	3	6	0.018	100
L6	2	3	0.037	100
L7	4	5	0.037	100

TABLE IV. HOURLY UNITS COMMITMENT- BASE CASE

Unit	Hours (1-24)																											
G1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
G2	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0
G3	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0

TABLE V. HOURLY UNITS COMMITMENT- DR IMPLEMENTED

Unit	Hours (1-24)																											
G1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
G2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	0	0	0	0	0
G3	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

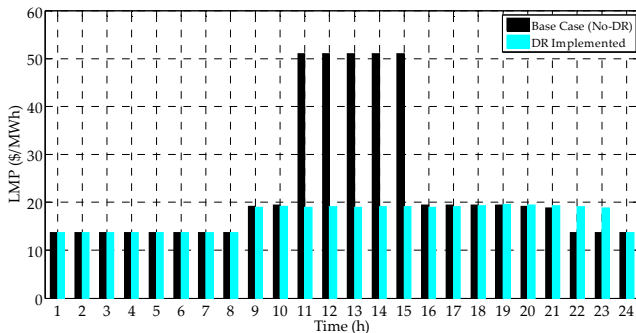


Figure 3. LMPs before and after implementation of DRP

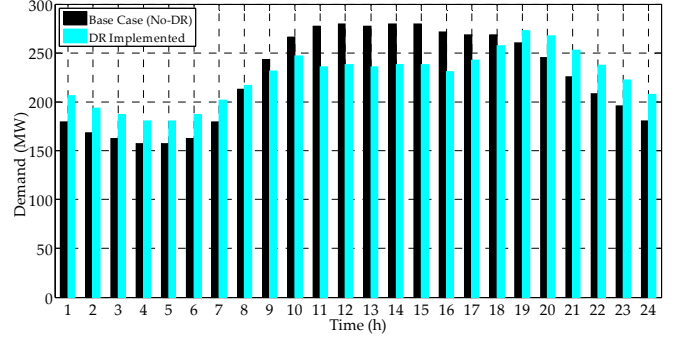


Figure 4. Demanded load before and after implementing of DRP

The cost reduction is merely due to the change in the consumers' behavior proportional to the price signals and the assumption of the total energy serving throughout the daily horizon. The commitment strings of the thermal units in the daily horizon for before and after the implementation of the ToU-based DRP are addressed in Table IV and Table V, respectively. As shown, the expensive G2 unit will be committed during peak hours and will be operated at minimum acceptable generation level, PG^{min} . The obtained generation schedule significantly reduces total operating cost and consequently confirms the effectiveness of the proposed model.

IV. CONCLUSION

This paper modeled Demand Response Programs (DRPs) over a short-term horizon considering the impact of Time of Use (ToU) tariffs based on the day-ahead market clearing mechanism. In the proposed model, the behavior of aggregators is estimated using a linear model for locational marginal price signals of the day-ahead market. Unlike other methods for estimating load responsiveness based on self and mutual elasticity, this paper implements a new method for stimulating demand response. In the proposed model, the fulfillment of the total energy demand is also taken into consideration for aggregators over the scheduling period. Accordingly, the participation of aggregators in the ToU program is based on supplying energy demand of consumers on a daily basis. This means that if demand declines due to rising prices during some hours of the day, the responsive demand will be shifted to off-peak hours. Simulation results showed that operating costs have decreased by about 31.8%. Moreover, using this strategy, peak price spikes have been thoroughly overcome. It should be noted that the reduction in costs, in this case, was only due to the shift in the flexible demand and through the application of the ToU program. The improvement in the load factor after applying the proposed model was about 3%. The system load factors before and after applying the DRP were 0.8 and 0.83, respectively.

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