Demand Response in an Isolated System with high Wind Integration

Kristin Dietrich, Jesus M. Latorre, Luis Olmos, Andres Ramos

***Abstract*—Growing load factors in winter and summer peaks are a serious problem faced by the Spanish electric energy system. This has led to the extensive use of peak load plants and thus to higher costs for the whole system.**

Wind energy represents a strongly increasing percentage of overall electricity production, but wind normally does not follow the typical demand profile. As generation flexibility is limited due to technical restrictions, and in absence of large energy storages, the other side of the equilibrium generation-demand has to react. Demand Side Management measures intend to adapt the demand profile to the situation in the system.

In this paper, the operation of an electric system with high wind penetration is modeled by means of a unit commitment problem. Demand shifting and peak shaving are introduced to this operation problem. Demand shifting is modeled in two different ways. Firstly the system operator controls the shift of demand; secondly each consumer decides its reaction to prices depending on its elasticity.

The model is applied to the isolated power system of Gran Canaria. The impact of an increased installed wind capacity on operation and the cost savings resulting from the introduction of responsive demand are assessed. Furthermore, results from the different implemented demand response options are compared.

***Index Terms*—Wind power generation, Large-scale integration, Load management, Power system modeling**

NOMENCLATURE

Indices

p	Time periods, hours (alias p')
t	Thermal generators
do	Demand variation downward
up	Demand variation upward

Parametres

β	Relation of marginal price to cost
ε_b	Elasticity
B_{do}	% of maximum demand variation downward
B_{up}	% of maximum demand variation upward
$CFix_t$	No-load cost
$CVar_t$	Variable cost
COn_t	Start-up cost
$CNse$	Cost of non-served energy
COp	Operation cost with DSM
COp_{ante}	Operation cost without DSM
CTr_p	Transaction cost for upward demand variations
$MOff_t$	Minimum Off time
MOn_t	Minimum On time
$PTDo_t$	Ramp for generation unit downward
$PTUp_t$	Ramp for generation unit upward
$PTMax_t$	Maximum generation output
$PTMin_t$	Minimum generation output
$RsDo_p$	Down-reserve
$RsUp_p$	Up-reserve
$Uc0_t$	Initial commitment status
$PenPr_p$	Penalty for price
$PrRef_p$	Reference price
PI_p	Wind energy production
$DRef_p$	Demand without DSM

Variables

d_p	Variable demand with DSM
$dVar_{p,do}$	Demand variation downward
$dVar_{p,up}$	Demand variation upward
nse_p	Non-served energy
$off_{p,t}$	Shutdown decision
$on_{p,t}$	Start-up decision
pr_p	Price with DSM
$pt_{p,t}$	Generation over minimum output
$uc_{p,t}$	Unit commitment decision

K. Dietrich, J. M. Latorre, L. Olmos and A. Ramos are with the Institute for Research in Technology (IIT), Comillas Pontifical University, Madrid, Spain. (E-mail: kristin.dietrich@iit.upcomillas.es, jesus.latorre@iit.upcomillas.es, luis.olmos@iit.upcomillas.es, andres.ramos@iit.icai.upcomillas.es.

I. INTRODUCTION

RENEWABLE energies have been declared by policy makers as one of the pillars to combat climate change. Different incentive schemes are currently applied resulting in a significant growth of renewable energies. Wind energy can be ranked among the most advanced renewable technologies. This is one of the main reasons why it has become the renewable energy technology with the highest installed capacity in some European countries. With an increasing wind production, the electric energy system has to face new challenging situations. Uncertainty in wind predictions and volatility of wind energy production are among the main concerns of system operators. These are urging issues regarding the growing installed wind generation capacity and its priority use for demand coverage. Thus, investigation of wind prediction has to be increased to make wind predictions more exact. Apart from this, variability of wind electricity production has to be managed in the short-term adjusting both generation and demand. Fast-reacting generation technologies may cause higher system costs. So the best way to save costs is to reduce the amount of energy produced by costly peak plants. This can be done by either of the following ways. First, electricity can be stored in off-peak hours and used later during peak hours. Second, demand can be reduced during peak hours. Third, if consumption is inevitable it could be decreased in peak hours and shifted to off-peak hours. The first option requires using storage facilities. With the second and the third option the demand profile can be changed reacting to system conditions at short notice. This paper focuses on the cost-saving potential of changes in the load shape via demand reduction and load shifting in the short-term in unit commitment decisions. Load shifting objectives can be achieved via different reactions of demand. On the one hand load can be remotely controlled by the System Operator. On the other hand consumers can independently react to price changes. Both approaches will be compared in detail.

The remainder of the paper is structured as follows: Section II gives a literature review. Then, section III explains the modeling approach. A case study is analyzed in section IV and section V concludes.

II. Literature Review

In this section, first demand side management (DSM) will be defined and categorized in the following section. Second, different approaches to model DSM are mentioned. Last, specific studies are commented on.

Activities which aim to influence the demand profile, for example in magnitude and time of electricity usage, are called demand side management (DSM) programs. These programs may comprise six different objectives to change the load shape. Details of each one of them can be found in [1] and [2]. Peak shaving (or clipping), valley filling and load shifting are deemed to be load management objectives. Furthermore, the objective of a flexible load shape requires demand to become responsive to the conditions in the energy system, especially those related to reliability. The energy efficiency or strategic conservation objective aims at reducing the overall energy consumption. The last of the six mentioned objectives is called strategic load growth or electrification, which is interesting if market share is to be increased.

To reach one or more of the above named objectives, DSM programs must be implemented. These programs may have manifold forms. Some classifications can be found in [2]–[4] or [5]. Authors in [4] as well as [5] distinguish between three types of demand response: first dynamic pricing with time-varying prices, second interruptible and voluntary load reductions or economic load response, and third load as ancillary services. Dynamic pricing refers to different types of tariffs faced by customers. Among others, these may include time-of-use prices, critical peak prices or real-time prices. Time-of-use prices change according to different time periods while critical peak prices impose higher prices only in critical situations on a maximum number of times per year (as applied in France). Real time pricing, in contrast, transfers prices and thus system information to customers almost without time loss.

Load reduction programs imply that customers offer to reduce their consumption for a financial payment or a discount. This may include direct load control and interruptible load programs, energy buy-back programs with customers agreeing to reduce consumption and to receive an incentive payment, and demand bidding programs, where demand enters directly the wholesale market and offers load decrements.

Load may provide certain ancillary services as regulation reserves. There are many more possible measures like educational programs and subsidies on loans which will not be commented on here. Another concept on the notion of demand side management can be found in the literature: demand response. This term is used when the focus is on price responsiveness of demands. Demand response programs include mainly load curtailment and dynamic pricing programs [2].

In the following, specific studies of interest are resumed. Many specific studies have been carried out especially in the USA as there DSM programs were initiated already in the 70ies. An overview of the beginnings and experiences of Demand Side Management programs, especially in the USA, can be found in [2]. For descriptions of currently applied DSM schemes in other countries in Europe, Asia and Latin America the work of [6] may be of interest. The potential of DSM activities and other parameters such as price-demand elasticities, are assessed in [7]–[15] using empirical data. Models to express the reaction of demand to price are developed in [16]–[22].

An online database about the potential application and use of DSM in eighteen countries including Spain is presented in [7]. Authors in [8] evaluate and monitor a multi-country study about energy efficiency in the new member countries as well as the EU25, while [9] estimates the behavior of the demand system focusing on Spanish households. An extensive study about elasticities in different works and regions is carried out in [10]. This article provides a quantification of the real-time relationship between total peak demand and spot market prices. The "Demand for Wind" project described by [11] shows results of field trials in UK of demand side management for domestic consumption. The work in [12] shows the benefits of applying different tariffs (time-of-use and real-time-pricing) in a small domestic test system in Ireland, where wind generation is becoming more important. Authors in [13] simulate a methodology of demand-side bid generation to a real university customer in Spain. The work of [14] presents customer-level demand for electricity by industrial and commercial customers purchasing electricity in the England and Wales electricity market. While former studies focused mainly on domestic electricity consumption the authors in [15] apply peak clipping and valley filling to different industries and analyze their cost saving potential.

The impact of demand side management in newly liberalized and deregulated electricity markets is issued by many authors such as those in [16] and [17]. Other authors measure different impacts on markets. Authors in [18] assess the impact of market structures on the elasticity of demand. They model the consumer behavior using a matrix with self- and cross-elasticities. In [19] the effect that more demand response would have on various market participants is investigated. Authors in [20] look at the ISO level and present a model for demand response programs assessing these programs, their goals and implementation. In the work of [21] price responsive distributed resources are simulated in a bottom-up approach via probability density function curve. In [22] it is argued that many demand management schemes do not take into account demand shifting, which they call rebound effect. They implement demand shifting for a small bus system and find great cost savings.

Of special interest are the works of [23], [24] and [25], since they treat the issue of high wind integration and possible demand response. The potential for demand change of already existent control mechanisms is estimated and the contribution of responsive demand to security issues is measured. Furthermore, the authors quantify the effect of the location of wind and the benefits of responsive demand. Other works such as [11], [12] and [26] emphasize as well the possible benefits of DSM in systems with high wind integration. Authors in [26] find that real-time pricing can increase wind utilization as demand would then respond depending on the availability of costless wind generation. Systems with high wind integration levels face higher cost associated with increased levels of ancillary services. This may represent a non-negligible cost to the system but, estimating the cost related to reserves is out of the scope of this article. Future work is carried out considering demand to be able to provide reserve. This may lower the higher ancillary service needs. A progress of this future work has been presented in [27].

In Spain, some DSM programs are currently applied. Residential customers pay a flat regulated tariff consisting of an energy charge and a peak demand charge. Commercial customers with a peak demand over 50kW are obliged to pay a time-of-use tariff. The author in [28] estimates that 20% of the total demand is subject to these tariffs. The System Operator is offering as well an interruptible load program with payments proportional to the demand reduction in the case of emergency of industrial consumers. At the moment, over 200 customers participate in this program (for more details see [28] and [29]).

It could be demonstrated that many studies are available treating different DSM objectives in various ways. Very little has been published about DSM taking into account the influence of intermittent energy sources such as wind. A part of the articles which consider high wind production address load shifting issues especially in households. The remaining part analyzes the reaction to real time pricing in detail. However, load shifting mechanisms using demand functions have not been compared yet with the centralized optimization. Both approaches may be implemented in the future one next to the other.

In this article, we present our own model to measure demand reactions. In contrast to the afore mentioned works, we use different modeling approaches including two different load response objectives, peak shaving and load shifting. One approach is cost-based while the other one relies on elasticities. These approaches are compared among each other. We take into account the whole system load, domestic and industrial and commercial. This model is then applied to an island in Spain. This island, Gran Canaria, is neither interconnected with other systems nor does it dispose of a hydro plant. So, in contrast to other works that can be found in the literature, variable intermittent energy production cannot be smoothed with flexible hydro power or energy importation or exportation.

Concerns on the uncertainty related to high wind integration are not considered specifically in this article. They have been treated in a separate paper [30] solving the stochastic unit commitment problem for the same case study system.

III. The modeling approach

A. Unit Commitment

Unit Commitment problems determine the minimum cost schedule for power plants in order to meet the system demand in the short term and satisfy further restrictions in the power system. Results are start-up and shutdown decisions for each generation plant in each hour. Unit commitment problems have been subject to much research, since poor management of power resources can turn out very costly.

In the proposed optimization problem, operational costs are to be minimized over the whole day. We take into account the demand balance constraint, up- and down reserve necessities, minimum and maximum generation capacity restrictions, ramp constraints and the logic sequence for the start-up and shutdown decisions. Parameter names begin with capital letters whereas variable names start with lower case letters.

The unit commitment problem is solved for each day of the study horizon of a year.

Decision variables include start-up and shutdown decisions, $on_{p,t}$ and $off_{p,t}$, and unit commitment decisions $uc_{p,t}$. Set p refers to time periods and t to thermal generators. The generation output is split up into two parts. The parameter minimum generation output, $PTMin_t$, and the decision variable $pt_{p,t}$ representing the generation over minimum output for each generation plant. Non-served energy nse_p is another decision variable of this problem. As explained, in the objective function (equation 1), the operation cost of the whole power system, COp_{ante}, is minimized.

$$\begin{aligned} COp_{ante} = \textstyle\sum_{p,t} \quad & [CVar_t \cdot PTMin_t \cdot uc_{p,t} + \\ & CFix_t \cdot uc_{p,t} + CVar_t \cdot pt_{p,t} + \\ & COn_t \cdot on_{p,t} + CNse \cdot nse_p] \end{aligned} \tag{1}$$

In the former equation (1) the decision variables unit commitment $uc_{p,t}$ and start-up decisions $on_{p,t}$ are multiplied for each hour by the corresponding costs, namely the fixed cost $CFix_t$ and the start-up costs COn_t. The cost term including the minimum generation output for each generation unit is included when the generation unit is committed in this period. Then, minimum generation $PTMin_t$ and generation output over minimum $pt_{t,p}$ are multiplied with the variable cost $CVar_t$ for all hours. Each unit of non-served energy nse_p will cost $CNse$ in each hour. Thus, the term operation costs refers in our model to the sum of variable, fixed and start-up costs. Constraints are shown in equations (2) to (9).

$$\begin{aligned} & DRef_p - PI_p - nse_p = \\ & \textstyle\sum_t PTMin_t \cdot uc_{p,t} + pt_{p,t} \end{aligned} \tag{2}$$

$$\begin{aligned} & \textstyle\sum_t (PTMax_t - PTMin_t) \cdot uc_{p,t} - \\ & pt_{p,t} \geq RsUp_p \end{aligned} \tag{3}$$

$$\textstyle\sum_t pt_{p,t} \geq RsDo_p \tag{4}$$

$$pt_{p,t} \leq (PTMax_t - PTMin_t) \cdot uc_{p,t} \tag{5}$$

$$pt_{p,t} - pt_{p-1,t} \leq PTUp_t \tag{6}$$

$$pt_{p-1,t} - pt_{p,t} \leq PTDo_t \tag{7}$$

$$(\substack{\sum_p on_{p,t} \leq uc_{p,t} \\ \sum_p off_{p,t} \leq 1 - uc_{p,t}}),$$

$$if\ p \geq p' - \binom{MOn_t}{MOff_t} + 1\ and\ p \geq p' \tag{8}$$

$$uc_{p,t} - uc_{p-1,t} = on_{p,t} - off_{p,t} \tag{9}$$

Equation (2) assures that demand is balanced all the time. Demand $DRef_p$ and intermittent wind production PI_p are given parameters. Up- and down-reserve ($RsUp_p$ and $RsDo_p$) constraints (equations (3) and (4)) make sure that a reliability margin exists in case that one of the generation plants fails or errors in wind or demand forecast must be counteracted. In equation (5), the maximum generation output of a generation plant $PTMax_t$ limits generation output $pt_{p,t}$ over the generation minimum $PTMin_t$. Equations (6) and (7) limit the maximum variation of production output in two consecutive hours. Maximum ramps for each generation unit are expressed with $PTUp_t$ and $PTDo_t$. Equation (8) refers to the minimum on and off times, MOn_t and $MOff_t$ for each generator after a start-up or a shutdown, respectively. The unit commitment restriction (eq. (9)) relates the state of each generator in each hour and the preceding one. While unit commitment variables are binary, start-up and shutdown decisions can be continuous, since equation (9) forces them to take binary values.

B. Demand Side Management

Two different load management objectives (see section II) were modeled separately one from another to distinguish clearly the effects that each one of them has on the system.

1) Demand Shifting : Demand shifting aims to move demand from peak hours to off-peak hours to flatten the demand profile and therefore to lower system operation costs as more expensive energy is replaced by cheaper energy. As DSM schemes can have manifold forms, two ways to model demand shifting measures will be presented here. In the first one, the decision to shift demand is taken using a pure cost criterion. In the second one, elasticities and demand functions are introduced to model demand reactions.

The first approach models the behavior of consumers as a centralized decision making process. This is similar to the way the system operator acts. He knows the system situation and decides on a cost basis. This could be the case if enough electric devices with an activated delay option were available. So, demand could be delayed automatically to other hours. The demand d_p is then considered as a variable instead of a parameter. Thus, the demand coverage equation (2) in the problem without considering DSM above is changed slightly. The variable d_p is computed from the original demand $DRef_p$ given for one hour adding to it the upward demand variation $dVar_{p,up}$ and subtracting from it the downward demand variation $dVar_{p,do}$ (see equation (10)). The sets up and do refer to the direction of demand changes: rises of consumption in demand valleys and reductions in peak hours. The new demand balance is expressed in equation (11).

$$d_p = DRef_p + dVar_{p,up} - dVar_{p,do} \tag{10}$$

$$d_p - PI_p - nse_p = \textstyle\sum_t PTMin_t \cdot uc_{p,t} + pt_{p,t} \tag{11}$$

Authors in [31] show that under conditions of perfect competition, maximizing consumer and producer surplus corresponds to minimizing the area below the supply curve (supply cost). This approach has been chosen here. Instead of maximizing the social benefit, a cost-minimizing approach is applied.

The operation cost to be minimized when applying demand shifting is COp. This is the sum of the formerly described variable operation cost without demand management COp_{ante} in equation (1) with another term (see equation (12)). The inconvenience of shifting the demand is expressed with a transaction cost CTr_p for demand rises $dVar_{p,up}$. Demand in high price times is lowered to achieve cost savings but must be consumed during other hours. Thus, charging the transaction cost on demand increases represents the nuisance of organizing the shift of load to those hours where these increases occur. Demand variations must be balanced during one day (equation (13)). Furthermore, the maximum demand to be shifted from one hour to another is limited using equation (14). Here B_{do} and B_{up} quantifies the maximum amount of shiftable demand for each hour and demand direction. This means that demand variations $dVar_{p,do}$ and $dVar_{p,up}$ are limited in both directions in rising power consumption (up) and in reducing it (do). Within the limits the actual demand variation is an outcome of the model. When cost savings achieved by reducing demand in peak hours are high enough to compensate for the higher costs due to demand increases incurred in off-peak hours, demand may be shifted up to the given limit.

$$COp = COp_{ante} + \textstyle\sum_p [CTr_p \cdot dVar_{p,up}] \tag{12}$$

$$\textstyle\sum_p dVar_{p,up} = \sum_p dVar_{p,do} \tag{13}$$

$$\binom{B_{do}}{B_{up}} \cdot DRef_p \geq \binom{dVar_{p,do}}{dVar_{p,up}} \geq 0 \tag{14}$$

A second modeling option introduces elasticities ε_{do} and ε_{up} and thus considers direct consumption decisions of the demand for each price level. Prices are normally higher than marginal costs. Although in the case of Gran Canaria it may be vice versa as the regulated costs of thermal plants are more expensive than on the Peninsula but consumers pay the same price in whole Spain. However, for simplicity reasons, marginal cost will be multiplied with a constant β equal to one to obtain prices. Elasticities for electricity will be always negative, since a price increase leads to a demand reduction. In addition to formulae (10) to (14), demand functions are introduced (equations (15) and (16)). These are linear inverse demand functions derived from a point of reference and a slope representing consumer elasticities. As the point of reference a situation without demand response is assumed and represented by a reference demand $DRef_p$ and a price $PrRef_p$. In each day of the year the model is solved twice. The first time with a fixed demand, the second time with elastic demand. The results of the first solution (dispatch) are the hourly prices corresponding to the most expensive unit committed. To obtain the reference price $PrRef_p$, hourly prices from the dispatch not including DSM are averaged over the whole day.

Demand reductions are computed using the same expression considered for demand increases with the opposite sign, see

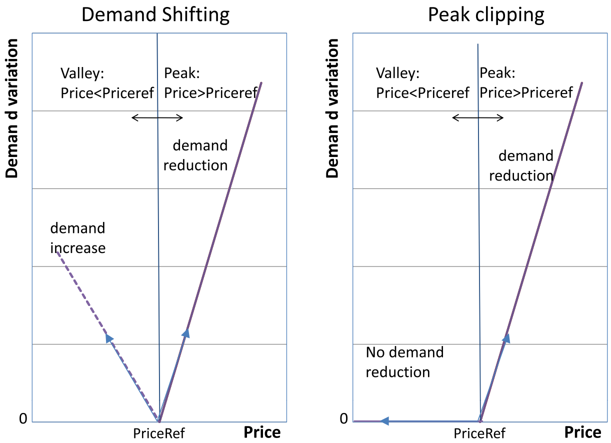

Fig. 1. Demand functions for different load management objectives

equations (15) and (16).

$$dVar_{p,up} \geq \varepsilon_{up} \cdot DRef_p \cdot (\frac{pr_p}{PrRef_p} - 1) \tag{15}$$

$$dVar_{p,do} \geq \varepsilon_{do} \cdot DRef_p \cdot (1 - \frac{pr_p}{PrRef_p}) \tag{16}$$

$$pr_p \geq \beta \cdot [(\frac{CFix_t}{PTMax_t} + CVar_t) \cdot uc_{p,t} + \frac{COn_t}{24h \cdot PTMax_t} \cdot on_{p,t}] \tag{17}$$

Variables used for demand changes, $dVar_{p,up}$ and $dVar_{p,do}$, have to be positive and will vary in accordance to the demand functions. When the computed price pr_p is higher than the reference price $PrRef_p$, equation (16) is active and the variable downward demand variation $dVar_{p,do}$ becomes positive as elasticities are negative. If the price is lower than the reference price, upward demand variations are positive and equation (15) is activated (see as well figure 1). Equation (17) forces pr_p to be at least as high as the total operation cost of the most expensive generation plant committed. As the merit order is not only affected by variable costs but also by fixed and start-up costs, these are considered here as well and we refer to the new modified costs as extended variable costs. For simplification reasons it has been assumed that the extended variable cost can be computed adding to its true variable costs the ratio of its fixed cost divided by its maximum capacity. Furthermore, start-up costs COn_t are supposed to be recovered during one day. Since pr_p should correspond or, at least be very close to the marginal unit cost, a term is introduced in the objective function penalizing the computed price. Equations (16) and (15) are inequalities, since $dVar_{p,do}$ and $dVar_{p,up}$ have to be positive. So, for a certain price level pr_p, only one of the two variables, either $dVar_{p,up}$ or $dVar_{p,do}$, can have a value equal to or greater than zero while the other one is forced to be zero. The new objective function changes to equation (18), where COp_{ante} is the operation cost considered in equation (1).

$$COp = COp_{ante} + \sum_p [PenPr_p \cdot pr_p] \tag{18}$$

Demand Side Measures as those presented in the article need equipment to be installed in the point of consumption and a communication and control infrastructure. This equipment includes smart meters used to receive and send price signals and, in the case of the centralized approach, intelligent electric appliances or plugs which are able to react to these pricing signals by reducing or shifting their electric consumption. As we did not have direct access to data on hardware necessities, we refer to other studies such as [32] for an overview of Demand Response Technologies, [33] for an extensive overview of international experiences about costs and benefits of smart metering and [34] for a specific study about the Spanish system. In the later work, authors estimated costs and benefits for domestic customers in Spain using automatic response and intelligent household appliances. In the case of a centralized solution intelligent appliances are reacting to signals sent by the system operator. The control about consuming now, consuming now at a reduced rate (peak shaving) or consuming later (load shifting) is left to the system operator, who knows best the actual system conditions. In the case of a decentralized solution each end consumer defines its own preferences (represented in our model with elasticities). End consumers receive price information and, depending on price levels, react and increase or decrease their electric consumption. Authors in [34] provide information on the cost of these devices for the Spanish domestic sector. They consider automatic load control, which corresponds to our centralized approach and provide figures on costs for four scenarios of different DSM-penetration rates (0-100%). They conclude that, from a social benefit point of view, implementation costs exceed by four times possible benefits. However, they do not consider all possible benefits of DSM centralized solutions. Thus, they point out that, in the future, if more DSM options exist, renewable energies penetration rates are higher and electric cars are massively used, benefits produced by centralized solutions may be much higher and a DSM system as the one proposed may lead to social benefit increases. We analyze the case of a centralized approach to consider the situation where consumer's reaction is efficient from the system point of view. This may be an approximation to a situation where price signals are optimally computed and demand response to these signals is automated. Thus, it presents an ideal situation to be used as a reference.

2) Peak Shaving : The highest cost for an energy system occurs during the demand peaks as the most expensive generation plants have to be committed. Peak shaving intends to reduce consumption in peak load hours. Here, the reaction of consumers is estimated again using demand functions. As peak shaving corresponds only to demand reductions, only equation (16) is needed, which is illustrated in figure 1 on the right-hand side. Equations (14) and (17) to limit the maximum reducible amount of demand and to force the market price to be equal or superior to the marginal cost are equally applicable as described above.

The variable demand d_p is now slightly changed, as only the demand variation to reduce $dVar_{p,do}$ (not the variable corresponding to demand increases as in the demand shifting case) is considered (see equation (19)). The demand balance corresponds to equation (11). As equation (16) is an inequality, a penalty is introduced to reduce the gap between the computed demand and the demand function. The new objective function is expressed in equation (20).

$$d_p = DRef_(p) - dVar_{p,do} \tag{19}$$

$$COp = COp_{ante} + \sum_p [Pen_p \cdot dVar_{p,do}] \tag{20}$$

IV. Case Study in Gran Canaria

Gran Canaria is a small island in Spanish territory belonging to the Canary Islands. Being an island and thus in coastal area, wind production is becoming an important part of the generation mix. Significant changes in wind output cannot be smoothed by importing or exporting electricity, but have to be compensated by local power generation and demand. Gran Canaria does not have hydro plants which could react to wind production variations.Wind energy as well as demand is expected to grow significantly in the upcoming years. Here, we analyze which effects DSM measures could have on the demand profile during a year and how these would reduce costs in the system.

A. Data and assumptions on consumer behavior

The generation system considered in the case example corresponds to the one possibly available in 2011. Forecast data are based on the Energy Plan of the Canary Islands [35]. Gran Canaria has two generation sites consisting of a total of 20 units. By 2011, an additional unit will be available. There are four different generation technologies: combined cycle, gas turbine, steam turbine and diesel motors. Electricity generation is mainly based on the heavy fuels gas oil and fuel oil. Total installed capacity will amount to 1158 MW. Generation costs used for determining the dispatch are regulated in Canarias and were taken from [36].

Wind time series have been adapted to the case of Gran Canaria taking into account [37]. The wind production ranges from a minimum of 4 MW output up to 149 MW with a mean of 58MW and a standard deviation of 31MW. In addition, when results are presented in section IV-B high wind and low wind days are analyzed. On high wind days wind produces between 45MW and 131MW with a mean of 93MW. Low wind days wind output average is 9MW ranging from 1MW to 47MW. Annual demand and peak demand forecasts are taken from [35]. For 2011, they are assumed to be 4,183 TWh and 768.38 MW, respectively, which corresponds to an increase of 17.9% and 19.4% compared to 2007 values. Authors in [35] estimate the installed wind energy in 2007 to be 76 MW and set the target to more than triple to 272 MW in 2011. Thus, the total installed capacity of wind energy in 2011 considered for this case study amounts to 19% of total installed generation capacity in Gran Canaria. This wind level is considered as high since this island does not have a hydro plant at its disposal or interconnection facilities to smooth wind variations. Regulation reserves are provided for each hour.

Two different options for demand management are considered: First, a shift in demand from high demand to low demand hours. Second, a reduction of demand in peak hours. For the modeling of demand shifting applying demand functions different types of consumers have been identified. Domestic consumers (26.3%) are differentiated from commercial and industrial ones (making up 73.7% of total load) [38].

Peak shaving and load shifting potential as well as data about elasticities and costs is perceived differently in the literature. Thus, their values vary from study to study significantly. The authors of this work are aware that generalizations may be difficult, as the studies may be very specific for a certain region and may thus, not be directly applicable to other regions (such as Spain) or to other customers (such as residential, commercial or industrial consumers). Unfortunately, there is no data available about demand elasticity or demand side potentials for this explicit case system as there are no DSM measures implemented in Gran Canaria. We then tried to find data from Spain or from similar systems within a European context in countries with a similar economic and political system. We assumed that the consumers' behaviour in the later systems is similar to that in Gran Canaria.

Concerning data about peak shaving, authors in [39] estimate the reduction in peak demand to be between 14 and 24.5% when changing from average to real-time pricing, depending on different load participation levels (33.3-99.95%). In contrast, [16] figures out lower load participation numbers (18%) resulting in 15% less peak demand. Authors in [2] expect an even lower peak load reduction of around 5% being higher in winter and lower in summer. Specific data about Spain could be found in some works such as [40] and [41]. A 5% peak demand reduction is achieved in [40] using a simulation model of the Spanish market, while authors in [41] conclude that peak clipping may represent as much as 10-15% of peak demand. The authors of [41] develop their own model for Spain and predict a reduction in peak generation capacity of 7 GW in 2020. In our model, the amount of load involved in peak shaving per hour is limited according to equation (14). Considering the cited literature, especially those works referring to Spain, we will take an intermediate value and assume the amount of load involved in peak shaving to be limited to 7% of peak load.

The load shifting potential is even more difficult to quantify, as less studies are available. The author in [42] analyzes different household appliances and their potential to delay their load consumption. He concludes that 5 to 20% of these devices would use a delay option in the future. Other authors in [16] state that the percentage of consumers that could be adherent to load shifting could amount to 19%. Given that our model includes not only domestic but also commercial and industrial consumers, a conservative limit to shiftable demand of 8% of total demand has been applied (see equation (14)).

Data about elasticities vary significantly across the literature. A remarkable overview of elasticities is presented in the work of [10], summarizing many other studies. Elasticities in the short- and long-run, using different calculation methods and analyzing different consumer types (industrial vs. residential), and cross elasticities are included in this work. Authors in [2] provide substitution elasticities from peak to off-peak applying critical peak pricing. For time-of-use prices, authors in [5] place also a value on elasticities of substitution. Elasticities take different values according to the behavior of the demand. They differ according to the type of consumer (domestic, commercial and industrial) and to the direction of the demand variation (reduction/increase). Elasticities used to compute demand reductions are higher, since they refer to peak load hours with much higher prices than in hours with lower electricity demand. Also commercial and industrial consumer decisions are assumed to be more elastic than residential consumers. Elasticities for peak shaving are lower, since this demand cannot be moved to another hour.

The model has been written using GAMS 23.3. Cplex 12.1 has been used to solve the mixed integer problem on an Intel Core2 Duo with CPU E8500, 3.16GHz and 3.23GB RAM. The processing time amounts to 879.3 seconds.

B. Results and discussion

The unit commitment problem has been calculated for the 365 days of the year 2011. The average day, which has been determined using the mean of the daily results, is examined in this section. Furthermore, some days with especially low and high wind output are analyzed separately.

1) Demand Shifting : First, results for the centralized model are presented. Second, the demand shifting approach using demand functions is analyzed. Initially we assume that demand shifting in the centralized model does not cause any inconvenience. Afterwards, a transaction cost to take into account the nuisance for consumers of shifting their load is introduced.

When demand is shifted from peak to off-peak hours in the centralized model without considering a transaction cost, the hourly limit of shiftable demand of 8%, as explained in subsection IV-A, is reached during various hours of individual days. Hence, restriction (14) in section III-B1 is active in these cases. So, demand cannot be increased in these hours anymore although there still may be an economic rationale to do so. Analyzing unit commitments and unit outputs on the average day, it can be observed that less peaking units are turned on when introducing demand shifting. Furthermore, less of the online units are working on their minimum thermal load in off-peak hours to provide upward reserve, as DSM is canceling out a part of the wind variations.

Cost savings achieved when introducing demand shifting are higher on high wind days than on an average day (see table I). This is due to the higher amount of demand that is shifted on these days. Marginal cost differences with respect to values for the average day both without DSM and with DSM comparing high and low wind days can be seen in figure 2. Positive cost differences indicate higher cost than on the average day while negative cost differences indicate lower cost than on the average day. With DSM the difference in marginal cost is mostly smaller, which means that demand shifting is outweighing part of the effect caused by wind.

Relative demand variations caused by shifting are shown in figure 3. It can be seen that demand is shifted in all three types of days to the night hours. Furthermore, on windy days more demand is shifted between the second load peak and the valley between the two peaks during the day. This may be caused by the fact that the difference between valley and peak load is bigger on windy days (up to 100 MW) than on low wind and

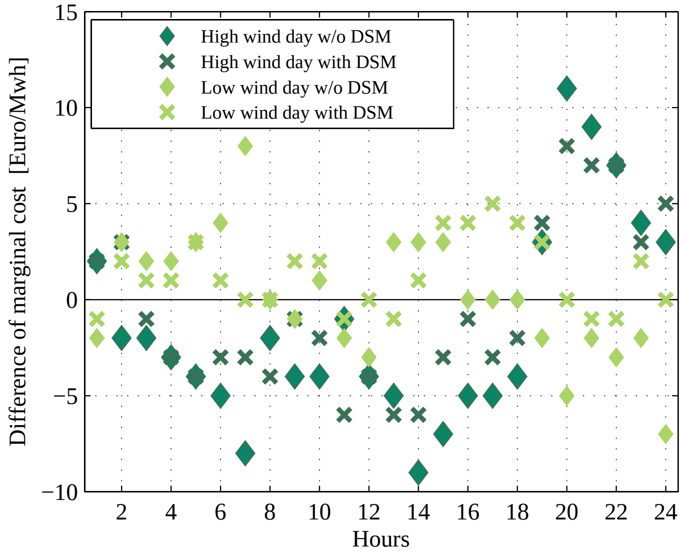

Fig. 2. Difference of marginal operation costs between high and low wind days and the average day

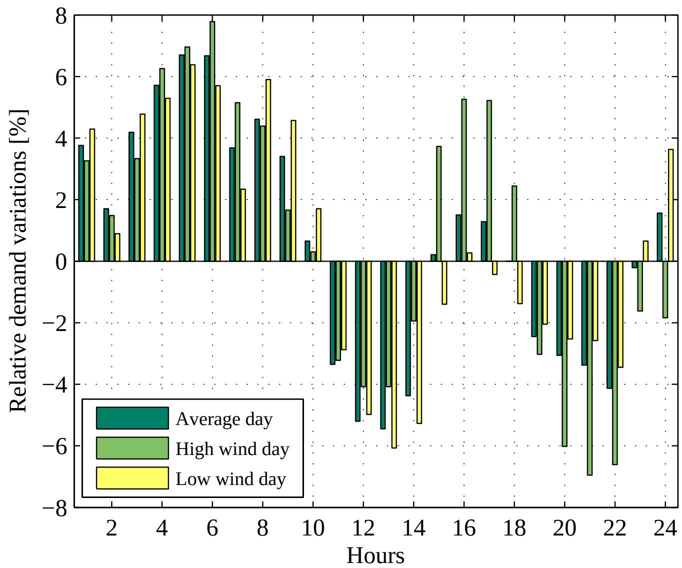

Fig. 3. Demand Shifting in centralized model during average, high and low wind days

average days (up to 33 and 48 MW, respectively). Figure 4 shows the total amount of demand shifted over the day when using the centralized load-shifting model without penalty. It shows the original demand $DRef_p$, wind production PI_p and demand variations $dVar_{p,do}$ and $dVar_{p,up}$ on the left axis as well as hourly cost savings when introducing demand shifting on the right axis. Demand variations are classified by the type of consumer (domestic, commercial and industrial) and by the direction (upward and downward variation).

One of the days with the highest wind production, which coincided to be weekend (Sunday), has been chosen to show the effect of demand shifting. Low electricity demand combined with high wind production can cause system operation problems. Thermal plants may have to go offline resulting in less capacity being available to provide downward reserve.

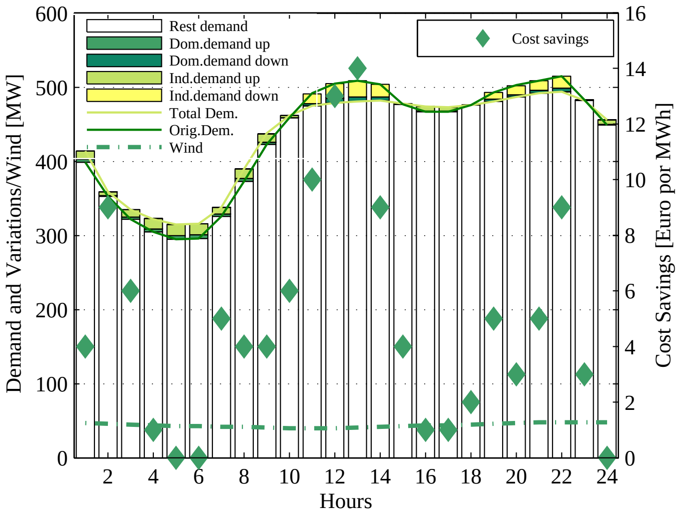

Fig. 4. Demand Shifting in centralized model

Figure 5 shows demand, wind rates, demand shifting participations and cost savings when introducing DSM for each hour. Wind energy production represents, on average, 36.5% of demand going up to over 52% during early morning hours. Shifted demand is limited through equation (14), which tends to be active during these off-peak hours. Here, generation units are reduced when DSM is introduced as the demand curve is flatter compared to the hours before and after the valley. On the other hand, during the peak hours 19 to 21, other more expensive plants with a significantly lower start-up cost are used. Costs during these peak hours rise. However, 27.7% of total operation costs can be saved when DSM is introduced. This value achieved on a day with especially high wind production is much higher than the cost reduction for the average day, shown in figures 4 and 7.

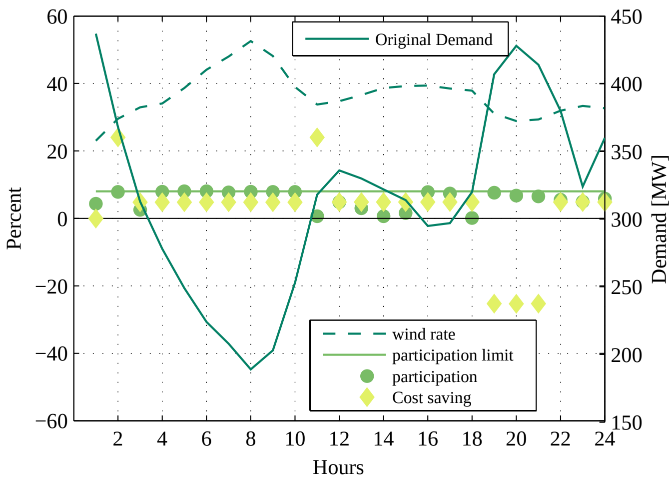

Fig. 5. Demand Shifting in high wind day

As shifting the demand may be bothering for consumers, a transaction cost has been introduced into the model to represent the nuisance. Demand that is reduced during peak hours is facing high prices. Thus, reducing demand in these hours is cost efficient. In our model the reduced demand has to be consumed in another moment during the same day. Increasing consumption during off-peak hours may cause some extra costs related, for example, to the organization of night shifts in factories. Thus, transaction costs are applied only to demand increases. The nuisance of shifting demand depends on each type of demand considered and the difficulty of moving it. It may also depend on whether the demand faces different tariffs and costs in peak and off-peak hours. In the absence of sound data in the literature, an approximation of the transaction cost has been used. It has been assumed that consumer's load shifting cost would be in the average of variable generation cost. Thus, the cost of consuming extra power in off-peak hours is lower than the cost of producing during peak hours with expensive generation units and higher than the cost of producing during off-peak hours when generation costs are low. The demand-cost curve for the case without applying DSM measures has been analyzed. The extended generation cost of the committed generation units was averaged and used as transaction cost. This cost provokes that as much demand as possible is shifted before committing the most expensive unit. This is a simplified approach to determine the transaction cost valid for the whole demand and may be topic of further research.

Analyzing the results, it can be seen that demand reductions only occur in the highest peak load hours. In this case, they occur in hours 11-15 and 18-24. In comparison to the case without transaction cost less demand is shifted and cost savings are lower. Table I shows a summary of results computed for all modeling options in this article.

When elasticities and thus demand functions are introduced, demand reductions are determined by the demand functions specified in equations (15) and (16) and shown in figure 1. Given that both equations are inequalities and the problem to be solved is a cost minimizing one, the amount of load reductions is higher than the one corresponding to the load function. Thus, a small penalty $PenPr_p$ weighting the variable pr_p is included in the objective function as expressed in equation (18). In this way it can be ensured that the demand variations correspond to those defined by the demand functions and the variable pr_p is as close as possible to the marginal price. According to the demand functions, 0.33% of domestic demand and 0.83% of commercial and industrial demand is shifted when applying demand functions. Consumer types are defined based only on their elasticity. Domestic consumers are less elastic. This is why they shift less demand during one day. The rest of the demand, commercial and industrial consumers,

TABLE I
COST SAVINGS AND DEMAND VARIATIONS

	Type of day	Cost Saving absolute [€]	Cost Saving relative [%]	Demand variation absolute [MWh]	Demand variation relative [%]
demand shifting centralized modeling					
w/o transaction cost	average	16,546	1.38	159	1.54
	high wind	16,660	1.52	186	1.97
	low wind	16,242	1.30	173	1.60
with transaction cost	average	15,206	1.26	154	1.49
	high wind	14,455	1.32	148	1.57
	low wind	16,741	1.34	175	1.62

faces higher costs if they don't care about energy consumption. So, they are more price-responsive due to a higher elasticity. In relative numbers most demand is moved during night and early morning hours four to six. Marginal prices are on average 9% more expensive when no demand shifting is applied. This percentage rises to around 17% during peak hours (hours 12-13 and 21-22). Seven gas turbines are turned on during the course of the day without DSM measures. On the contrary, applying load shifting only two gas turbines are turned on for some hours.

During high and low wind days 14,015€, or 1.28% of total costs, and 13,499€, or 1.08% of total costs, respectively, can be saved by applying load shifting. As for the size of load shifts 1.40% of daily demand is shifted in high wind days, most of it in the extreme peak and off-peak hours. Demand levels from four to six o'clock in the morning increase up to 6.2% while those during the evening load peak decrease between 4% and 4.9%. Cost savings achieved for high and low wind days mentioned by the reviewer refer to the mean savings of those days with the highest and lowest wind output, respectively. The size of demand changes relative to net demand, which is demand minus wind production, is higher for high wind days. Hence, when more wind is blowing demand is behaving more flexible. Differences in load changes appear mainly during afternoon hours when demand between the two load peaks is increased in high wind days but decreased in low wind days. Higher cost savings are achieved in high wind days due to the use of far less expensive units in the afternoon on these days than those units employed other days. A similar effect was achieved in the in the centralized approach shown in figure 3.

Comparing both approaches, the centralized and the demand function approach to shift demand, it can be seen that the former leads to higher participation rates as the only criterion to shift demand is the cost. Using demand functions shows how demand reacts to prices, expressed with the elasticities differing from consumer to consumer. Cost savings and rates of participation of consumers in demand shifting are higher when shifting decisions are taken centrally. Differences between both approaches are largest for industrial and commercial loads as elasticities are higher than for domestic consumption. On average, 56% more demand is shifted using a pure cost criterion than considering demand functions based on elasticities. Differences in cost savings when introducing demand shifting and demand variations (called CostDif and Var) for the centralized (c) and the demand functions (d) approach are represented for the different consumer types (domestic and industrial) with bars in figure 6. Looking at the average results for the whole year, one can see that cost savings for the demand functions approach are higher during peak hours and tend to be slightly negative (cost increases) during off-peak hours. This is due to different marginal units in these hours. Especially during peak hours, the output of expensive gas turbines in the demand function approach is reduced to a higher extent than in the centralized approach leading to higher cost savings. Nonetheless, the centralized approach reaches positive cost savings during all hours of the day averaging the values of the whole year and total cost savings are higher for this approach.

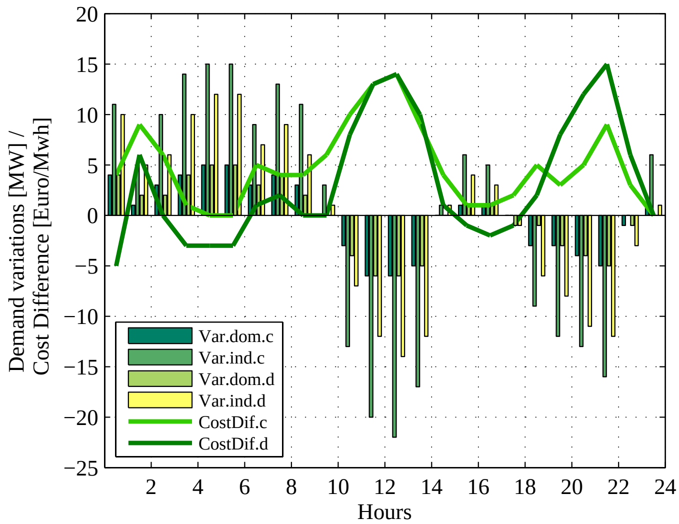

Fig. 6. Demand Shifting using demand functions

Differences among results for different consumer types can be explained with the corresponding elasticities. Domestic consumers are, due to their lower electricity consumption and information levels, less elastic than industrial and commercial demands. As indicated in section II a time-of-use tariff is applied to commercial and industrial consumers with a certain peak demand in Spain.

2) Peak Shaving : Peak load shaving has been modeled via demand functions as well. These let well informed consumers react to high prices. Consumers behavior is shown in figure 1 on the right-hand side. The decrease in demand is characterized by the demand function provided in equation (16) in section III-B.

Demand reductions during peak hours are shown in figure 7. Cost savings achieved through the commitment of less

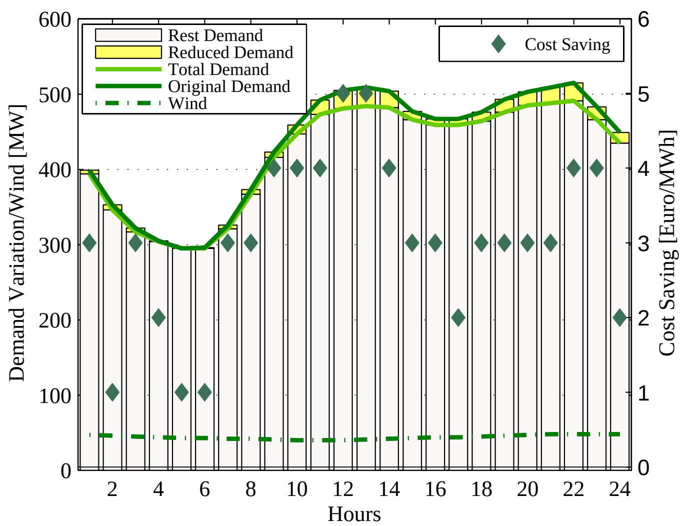

Fig. 7. Peak Shaving using demand functions and penalties

expensive units are less important than in the demand shifting case. 2.78% of the demand of the whole day is avoided and in some peak hours (during the morning peak load hours 12-14 and in the evening peak load from hours 21 to 22) peak reductions reach between 4.1 and 4.9% of original demand on an average day. The level of peak demand reduction achieved here is in line with estimates by other studies specified in IV-A. Further reductions may be possible if price signals were even stronger or if consumer decisions were more price-elastic.

During windy days and days with almost no wind peak shaving occurs at similar times of the day as on the average day. It can be concluded that the influence of wind production in demand reduction levels is marginal, as demand is reduced during hours where wind production is less significant. This may change when wind capacity is increased and wind energy production plays a big role also during day peaks.

V. Conclusions

Higher peak demands cause ever higher costs for the whole energy system. In addition, a high percentage of electricity production by wind requires a high degree of flexibility in the system. As using peaking plants causes higher costs, measures to increase the demand responsiveness seem necessary.

There are different ways to achieve load management objectives such as peak shaving or demand shifting. Therefore, different consumer behavior and modeling strategies for DSM have been implemented in this paper. Their effects have been analyzed. It has been shown that, in all cases, costs were reduced since fewer thermal plants had to be committed and less electricity had to be produced. The potential for cost reduction resulting from each type of demand response in the system of Gran Canaria has been computed assuming a level of wind energy production corresponding to that for 2011. The introduction of DSM leads to higher cost savings and load participation rates in demand shifting on windy days. It has been shown that, on days with exceptionally high wind energy production during low demand periods, DSM achieved up to 30% cost savings and added enough flexibility to the system to the point that no wind energy had to be spilled. This result is especially relevant, as these days resulted to be the most complicated ones from the point of view of the system operation. Furthermore, it has also been shown that different strategies to implement demand shifting may result not only in different levels of demand variations and participation of consumers in demand shifting, but also in changes to the unit commitment. A centralized approach reaches higher overall cost savings, while taking into account elasticities may lead to higher cost savings during peak hours. It has been shown as well that current wind production rates have little influence on results when implementing solely programs to reduce demand peaks as wind production rates are of less importance during high demand hours.

It can be concluded that in a system with high wind energy production DSM, in particular demand shifting, can be useful to partially level out variations in wind production and be exceptionally useful on days with extremely high wind production. Analyzing the impact of DSM in systems with even higher wind production rates is left for future research. In order to achieve the benefits of DSM presented in this article in reality, either consumers need to have more information about real incurred costs to react appropriately, or part of the electric devices have to be controlled automatically.

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