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INTERMITTENT RES-E, CYCLING AND SPOT PRICES: THE ROLE OF PRICING RULES

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Abstract

Variable Energy Resources (VER) penetration increases the cycling operation of conventional thermal plants, inducing an operating costs increase. In some cases, due to its impact on O&M costs, the cost of each start can significantly raise.

The impact of this effect on spot prices depends on the pricing rules implemented: in some cases (non-linear pricing rules), these costs are compensated via discriminatory side payments and thus not included in the price formation while in others (aka linear) a single price per MWh is calculated to remunerate every single unit that is producing.

These two alternative designs result lead for instance to a different remuneration for base-load plants. The first objective of this paper is to explore to what extent this remuneration difference might turn to be relevant as VER (and specifically solar PV) deployment develops. To do so, we also analyze the importance of properly allocating medium-term O&M costs in the short term, a hot topic in the regulation of a number of power markets today. We propose a way to properly calculate the start-up cost-adder component due to O&M and how this cost-adder is affected by cycling operation.

Keywords: *Power generation dispatch, O&M cost, cycling, electricity markets, marginal prices, pricing rules.*

1 INTRODUCTION

Presently in electric power systems, a special emphasis is being put on providing low-carbon energy solutions while keeping security of supply at reasonable levels. A large penetration of electricity from Renewable Energy Sources (RES-E) is among the most promising alternatives, particularly when long-term expansion planning optimization and energy sustainability maximization problems are faced.

Among the different RES-E, the non-dispatchable, less predictable and intermittent energy resources (hereafter referred to as Variable Energy Resources or simply VER) are those expected to reach larger penetration levels in the next decades. In fact, large scale penetration of VER (in particular wind and solar power) is already taking place in many systems worldwide; take for example Denmark, Spain, Germany or the state of Texas. Wind and solar power are expected to notably grow during the next two decades and they will help to meet the future electricity demand, see e.g. European Commission (2011).

As it has been broadly studied, the massive penetration of VER significantly changes the way electric power systems are operated, see for instance Pérez-Arriaga and Batlle (2012). These changes in short-term operation have a direct impact on production costs. Generally speaking, the two major short- and medium-term effects introduced over generation operation as a consequence of increasing VER penetration (ignoring the impact of potential network constraints) are the following:

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- VER, which have zero variable cost, tend to displace the most expensive variable cost units[1] (such as fossil-fuel electricity production).

- VER increases conventional thermal plants cycling, that is, they increase the cyclical operating modes of thermal plants that occur in response to dispatch requirements: on/off operation, low-load operation and load following, see e.g. Troy et al. (2010). As we further discuss below, one of the major consequences in this respect is that as the number of starts increases so does the indirect costs of each individual start, see Batlle et al. (2012).

Note that the impacts on costs derived from the previous two changes in operation go in opposite directions. While the first decreases operation costs, the need to increase the cycling operation of conventional thermal plants increases them. In a market context, these previous changes in operation also imply changes in short-term price dynamics and market remuneration:

- As a consequence of the replacing fossil-fuel plants with zero variable cost VER energy, the marginal technology changes and, thus, marginal prices change. This is the so-called merit order effect.

- On the other hand, since generating units when scheduled (at least should ideally) have to recover their operating costs in the market, increasing the cost of operation (and particularly the cost of each start) increases the remuneration required.

The impact of the previous two effects on both short-term prices and the resulting remuneration depends to a large extent on the characteristics of the system, especially on the composition of the generation mix. As noted in Pérez-Arriaga and Batlle (2012), the merit order effect is less significant when the addition of VER does not change much the marginal technology setting the price in the system. This is for example the case in some European power systems today, due to the large component of combined cycle gas turbines (CCGT) which is frequently setting short-term prices. When locational prices are calculated, this effect has to be analyzed at a local scale: VERs can still have a substantial influence on prices on a locational basis, even when VERs do not change the marginal units on a system wide basis (this is the case in Texas for instance).

The impact of the "merit order effect" on prices has been qualitatively and quantitatively analyzed in the literature, see for instance Sensfuß et al. (2007) or Morthorst and Awerbuch (2009). This paper aims to contribute to the analysis of the impact of thermal cycling on market remuneration. The paper puts the focus on the role of the pricing rules in market outcomes.

The analysis of how increasing cycling affects short-term prices complicates for one reason: the way the start-up costs (and other non-convexities such as no-load costs) are considered in price formation is not the same in all electricity markets. In this respect, the changes that VER can introduce in the market remuneration are discussed considering the two major pricing rules available regarding how non-convexities are incorporated in price formation, namely, the non-linear and linear pricing rules:

- The non-linear or discriminatory pricing rule, where the hourly marginal prices every committed unit receives do not include the effect of start-ups (and in general all non-convexities of the unit-commitment-like optimization problem). Only those units not recovering production costs receive in compensation an individualized side-payment (aka make-whole payment) that complements marginal-price-based remuneration.

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[1] Another (less relevant) change regarding the units being called to produce in the presence of large amounts of VER is related to the need for flexibility. In order to cope with the abrupt production profiles of VER, it may be economical to commit more flexible (and in some cases more expensive) units that would not be committed otherwise. We will not discuss this effect in this paper.

- The linear or non-discriminatory pricing rule, where the hourly prices every committed unit receives do include all costs (including the effect of non-convexities) and therefore they are assumed to guarantee operation cost recovery without needing additional side payments.

Some authors (e.g. O'Neil et al, 2003) point out that *"if start-ups, or any other integral activity, are necessary for production, the auctioneer can consider these activities as separate commodities complementary to the output commodity production activities that can therefore be priced as well"*. From this perspective, in the linear pricing rule there is a single price for these services that are lumped together. In the non-linear context, that is not the case. Instead, there is a linear pricing strategy for the energy and there is a different settlement strategy associated to the generators offering this separate service to the market operator, which is not purely a function of their energy. That is, these services are differentiated, not lumped together, at least not for generators.

The paper is structured as follows:

- First in section 2 we briefly introduce the main impacts derived from increasing the penetration of VER on the scheduling regime of the generating units and the implications of these changes for operation costs in general, and fixed start-up costs in particular.
- Then, in section 3, the main characteristics of the linear and non-linear pricing rules are reviewed so as to set the framework of the two contexts of interest.
- In section 4 we detail the methodology used to quantify the effect on prices derived from increasing cycling operation in both the linear and non-linear pricing mechanism. The approach implies first calculating an optimal unit commitment (equivalent to the one ideally resulting from a fully competitive market), then allocating the unit's production costs along the different hours of production and finally on this basis determining the remuneration of the units in the two pricing contexts.
- Then, in section 5 we present and discuss the results of a real-size case example solved using the methodology proposed. The case example includes both a large component of CCGTs (a technology whose cycling regime is being seriously affected by VER in a number of European systems) and also a very large penetration of solar PV. In section 6 this case example is extended to include greater detail in the representation of CCGTs.
- Finally, the conclusions are presented in section 7.

2 INCREASING CYCLING NEEDS DUE TO A LARGE PENETRATION OF VER AND THE IMPACT ON COSTS

A large deployment of renewable generation implies a significant change in the scheduling regime of the rest of the generating facilities. For instance, a larger number of conventional thermal units are forced either to decrease the production to the minimum stable load for a larger number of hours and usually to start and shut down more frequently. This effect is more acute in thermal-dominated systems, with lower flexibility, and thus conversely less relevant in those in which the share of hydro reservoirs is significant.

This change in the operating regime of the thermal plants translates into a change in costs. The thermal plants operation costs affected by the penetration of VER can be conceptually framed within three main factors, namely:

- Fuel start-up costs (fuel needed to raise the boiler to its minimum operating temperature prior to producing electricity). Although it depends on the system, and on the type of VER generation being considered, the number of starts tends to rise in a context of very high penetration of VER.

- Energy production costs as a function of the incremental heat rate curve (that is, a curve taking into account the efficiency-loss costs due to suboptimal operation regime). Production costs (fuel consumption) are higher (per unit generated) at low load operation than at close-to-full capacity. When the plant operates below the optimum point, the plant efficiency is lower and therefore the production cost per MWh produced is larger. The number of hours producing at minimum stable load is likely to increase in the presence of VER and therefore the energy production cost will be higher.

- O&M costs: cycling the thermal plants accelerates component failure, resulting in an increase in failure rates, longer maintenance and inspection periods and higher consumption of spares and replacement components. As analyzed in Batlle et al. (2012), the increase in the number of starts caused by the introduction of significant amounts of renewable generation has a relevant impact in the maintenance of the generating units. For some technologies, the maintenance procedures are clearly reflected by means of Long-Term Service Agreements (LTSA). In the particular case of gas-fired based technologies, see for example Sundheim (2001), these LTSA contracts include both the criteria to carry out a major maintenance inspection and the cost of this inspection, usually entailing the definition of some threshold limits based on the accumulated operation since last maintenance. These threshold conditions, typically expressed as a function of the firing hours and starts, define the Maintenance Interval Function (in the following MIF). The shape of the MIF for gas turbines varies between manufacturers. Figure 1 shows some examples of MIF. Some manufacturers base their maintenance requirements on separate counts of machine starts and operation hours. The maintenance interval is determined by the threshold criteria limit that is reached first. The MIF in this case takes the rectangular shape shown in Fig. 1 (option A). Other manufacturers assign to each start cycle an Equivalent number of Operating firing Hours (EOH). The total amount of EOHs a particular plant has operated up to a certain point thus depends on both the number of firing hours and the number of starts. The inspection is carried out when a predefined number of EOHs is reached (option B). More generally, the MIF could be defined by any functional form combining the number of starts and the number of firing hours (option C).

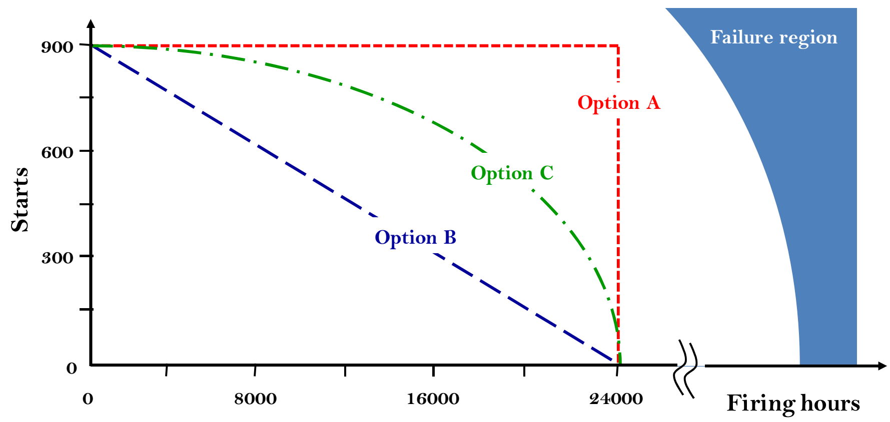

Figure 1. Baseline functions for maintenance interval. Based on (PPA, 2002) and (Balevic et al., 2010)

Generally speaking, the larger the number of starts, the lower the amount of firing hours the unit can operate before a major maintenance is triggered[2]. This is because of the fact that starting up more frequently accelerates the wear of the turbine as well as other elements of the plant (Balevic et al., 2010).

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[2] With the sole exception of certain production regimes in the case of the maintenance function denoted here as Option A.

3 THE IMPACT OF NON-CONVEXITIES ON PRICES: THE ROLE OF PRICING RULES

As just reviewed, starts are responsible for shortening the maintenance periods and consequently for increasing the annualized value of the maintenance expenses. To properly account for this effect, it seems reasonable to include an additional start-up cost adder component (to be added to the traditional fuel start-up cost). In fact, this additional start-up cost adder due to O&M is an accepted additional cost in some markets as for instance in PJM (2012) or ERCOT (2011). This issue has also been discussed in CAISO (McNamara, 2011). The increase in the start-up costs will have undoubtedly an impact on market remuneration. However, the final weight of the change will depend on the particular pricing rule implemented.

As stated, we evaluate the impact of the pricing mechanism implemented in the presence of large amounts of VER. With the objective of setting the background of interest the main characteristics of the linear and non-linear pricing rules are presented next.

3.1 Linear vs. non-linear pricing

Roughly speaking, in organized short-term electricity markets the day-ahead market prices are determined by matching generators' offers and consumers' bids. According to the classical marginal pricing theories (Schweppe et al., 1988), the resulting market prices are supposed to serve as the key signals around which operation, management, planning and capacity expansion revolve. However, a quick look at the different market mechanisms implemented worldwide shows that there is a wide variety of alternative designs and more specifically of pricing rules.

Moreover, since electricity generation is subject both to inter-temporal constraints and to the existence of a number of non-convexities, the format of the generators offers (known as bidding protocols or codes) can range from the so-called simple one (a series of quantity-price pairs per time interval) to a grayscale of more complex alternatives, in which inter-temporal constraints and/or multidimensional cost structures can be declared.

In the context of simple auctions, pricing is straightforward since it is directly determined by the intersection of demand and supply price-quantity curves. However, in the complex auction context there are different mechanisms to compute prices, and in particular, to incorporate non-convexities in the price calculation, namely, the non-linear and the linear pricing mechanisms.

Non-linear pricing

This mechanism translates into each generator having a remuneration consisting of:

- first, a set of (non-discriminatory) prices which serve to remunerate all production in each time period,
- and then, some additional discriminatory side-payments (in practice computed as a lump-sum daily payment) which are calculated on a per unit basis[3].

Non-discriminatory prices are computed as the dual variables (shadow prices) associated to the generation-demand balance constraint[4] of the linear optimization problem that result when the

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[3] A very closed-related approach is the alternative proposed by O'Neill et al. (2005). The approach entails considering start (and other non-convex) costs as additional commodities different from energy, and thus, needing to be priced independently from this latter.

[4] Many energy markets include the representation of the network in the market mechanisms. In this case, the UC includes an approximate power flow formulation, and the dual variables of interest for price computation are those associated to the node balance constraints. This leads to the so-called locational (or nodal) marginal prices.

commitment decisions have been fixed. As a consequence of the method used to compute marginal prices, these prices do not include the effect of non-convexities (as it is the case with start-up or no-load costs). This is the reason why additional payments are considered on a per unit basis so as to ensure that every unit fully recovers its operating costs.

We will focus on this pricing rule in the context of the day ahead market (not considering subsequent markets such as operation reserves ones). In real markets having implemented this pricing rule (like US markets), often the side-payments are calculated so as to compensate costs involved not only in the day-ahead market, but also in subsequent ones.

Linear pricing

Although the non-linear pricing approach is the most extended alternative in the context of complex auctions, it is also possible to devise a pricing rule where the same hourly price is used to remunerate all the production in each hour and no side-payments exist. This non-discriminatory approach is the so-called linear pricing mechanism[5].

This is the approach that has been implemented in Ireland (SEMO, 2014). The Irish market operator, on the basis of complex bids (start-up costs, no-load costs, etc.), first calculates the unit commitment that minimizes the cost of dispatch and computes the preliminary prices as the dual variables associated to the generation-demand balance constraint. These prices are just the same as the ones calculated in the non-linear pricing context. Then, since these prices do not guarantee total cost recovery for all the units in the system, an ex-post linear optimization is used to obtain the (hourly) uplifts to be added on top of the previously calculated prices to correct the result. This second optimization aims to fulfill full operating cost recovery while at the same time seeking two additional objectives: (i) avoid when possible the concentration of very high uplifts on a very few hours and (ii) demand payments are minimized (i.e., note that here the minimization of demand payments does not act as the primary driver of the unit commitment). A close representation of this second optimization is later provided in Section 4.3.

A relevant question that may arise at this point is to what extent these uplifts (or equivalently the previous side-payments) represent a significant income (taking the point of view of a generator), or, in other words, to what extent all this discussion on whether a discriminatory or non-discriminatory rule is in place, is actually relevant.

In the next figure, it can be checked the weight of these uplifts in the Irish market in November 1st, 2010. A low-variable-cost base-load unit would perceive the hourly shadow prices represented in red in the discriminatory context, while it would receive the hourly shadow prices plus the hourly uplift components in a non-discriminatory context. It becomes evident that this issue is anything but irrelevant.

[5] If the markets include the representation of the network in the market mechanisms and locational prices are computed, the linear mechanism can only be considered to be non-discriminatory on a locational basis, but not system wide.

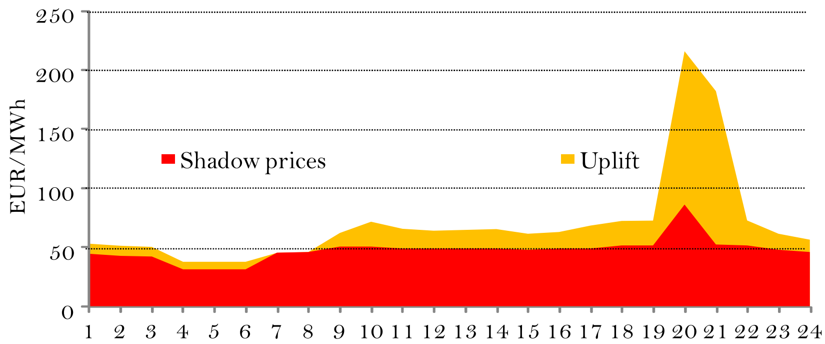

Figure 2. Uplift component in the Irish market, Oct. 19th, 2011 (source: www.sem-o.com)

4 GENERAL METHODOLOGY

In this section we describe the methodology followed so as to illustrate how the different ways of designing the pricing rules can affect the final resulting remuneration perceived by the generating units in a context of large penetration of VER. As schematically shown in Figure 3, a modeling approach consisting of three different modules has been developed.

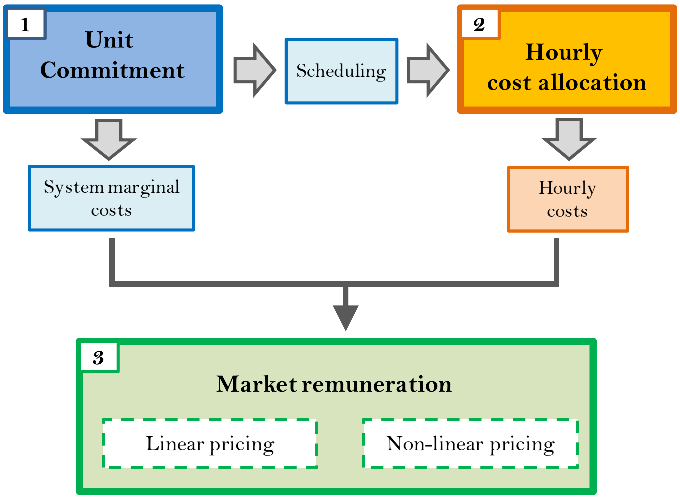

Figure 3. Methodology overview

First a stylized unit commitment model computes the scheduling and the resulting marginal costs. This unit commitment incorporates a detailed representation of how maintenance costs impact the way thermal units should be optimally cycled (see Rodilla et al., 2012). Then (module 2), a post processing based on the UC results is used to allocate each unit's production costs along the different hours of production; the main relevant discussion in this second module revolves around on how to properly allocate O&M costs in the short-term. Finally, with all the previous information, the remuneration of the units in the two pricing contexts is determined. Each one of these three modules is briefly described next.

4.1 <u>Module 1</u>: Short-term unit commitment (UC) model

A short-term unit commitment model is used to compute the optimal dispatch ideally resulting from a fully competitive market where generators bid their true costs in the different offer components in both contexts[6].

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[6] As pointed out in Baldick et al. (2005), *"in the non-linear context, the multipart offer creates a two-part pricing regime for two commodities, with uniform prices that clear the market for energy, and pay-as-bid prices for the non-convex offer components (e.g. start-up, and no-load)".* The pay-as-bid nature linked to the non-convex offer components can

This unit commitment model is based on a cost minimization dispatch (considering variable production costs, fuel start costs and variable O&M costs) in which an hourly perfectly inelastic net demand has to be supplied (with a price cap) by a set of thermal generators. The net demand is obtained subtracting the hourly production profile of each one of the VER. This is equivalent to assuming that the incentive solar receives (tax credits, green certificates, premium for production, etc) is large enough to ensure that all production is matched and scheduled in the market.

The complete formulation of the unit commitment is provided in the annex. The unit commitment used is stylized in the representation of operation constraints (many well-known constraints have not been considered in the model so as not to unnecessarily obscure the results[7]), but it does offer a representation of the previous three sources of cost. In particular, the maintenance costs are considered through the explicit representation of the LTSA contracts, following the formulation presented in Batlle et al (2012).

4.2 Module 2: Hourly production cost allocation

Note that in both the linear and non-linear pricing context, a common and unavoidable objective is that all units at least recover all the costs associated to the production of electricity in the trading period being considered (hereafter a day). Therefore, in order to later compute the daily side payments and the hourly uplifts (depending on the context) it is necessary to determine the total costs each plant incurs in the daily period. To this end, and as a previous step, we first propose a methodology to properly allocate for each plant each source of cost among the different time periods (hereafter hours) where the unit is producing.

Energy and start-up fuel costs hourly allocation

The criteria considered to allocate the two first sources of cost are rather straightforward:

- The energy fuel (and no-load) costs associated to the units' production is assumed to be incurred in the hours the unit is producing.
- The fuel cost associated to each start is imputed among the hours in which the unit is in operation before shutting down. Note that this may imply that a start-up cost may be allocated along hours corresponding to more than one day (which is usually the case with base-load units). This is the approach used in some markets (e.g. SEM), but not in all day-ahead markets. In some others, as it is the case in the US, all costs incurred on a certain day are fully used to reflect a unit's total cost to compute the daily side payments.

On the contrary, allocating the costs associated to the variable O&M costs is anything but evident. Next, the discussion about the methodology proposed to allocate variable O&M costs along the production hours is presented.

O&M cost hourly allocation

Different ways to allocate operation and maintenance costs could be conceived. In principle, as the number of firing hours and the number of starts are the variables triggering the major maintenance, it seems reasonable to allocate these O&M costs between these two variables. Traditionally, the

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incentivize a bidding behavior different from truth cost revealing. These incentives are beyond the scope of this work so they are not analyzed in this paper.

[7] Contrary to intuition, the less relevant not-modeled constraint in this hourly unit commitment case example is ramping constraints. The reason for this is that CCGTs ramping capability is above 10 MW per minute (for production regimes above the minimum technical output). Since we are only considering CCGT units in the case example, the system ramping capability is not an issue even for large penetration levels of solar PV.

widespread approach has been to carry out a volumetric allocation (total costs divided by the energy, i.e. exclusively an energy cost adder component), without taking into account the relevant effect starts introduce in the maintenance cost causality.

As a way to present the allocation methodology proposed, let us consider the maintenance contract represented below in Figure 4 (the most general Maintenance Interval Function, previously denoted by Option C). If a plant subject to this contractual agreement produces as a pure base-load unit, then the point at which the unit would have to perform the maintenance would be the one identified as M_B. That is, it would produce the maximum amount of hours possible before maintenance. Let us denote this maximum amount of firing hours by FH_{Max} (in the contract below, FH_{Max} is equal to 24000 hours).

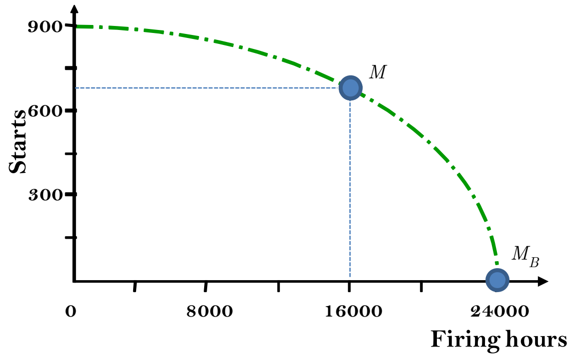

Figure 4 O&M cost allocation

Considering that OMC_{Total} represents the total O&M costs, then for the previous base-load regime it would make sense to allocate the total cost among the firing hours, that is, we could consider a per firing hour cost due to O&M ($fhomc$) equal to:

$$fhomc = OMC_{Total} / FH_{Max} \tag{1}$$

With this value of $fhomc$, it is evident that as far as this base-load regime holds, the unit would have fully internalized the cost of the major maintenance by the time the major maintenance takes place (since $fhomc \cdot FH_{Max} = OMC_{Total}$).

In the more general case, the accumulated operation of a plant will entail carrying out the maintenance when a combined pair of firing hours and starts is reached. Let us denote the pair of values of this more general case (represented in the figure as the point M) as FH_M and S_M respectively (which in the figure would correspond to 16000 firing hours and 675 starts).

It can be considered that to all intend and purposes, starts are responsible of reducing the number of firing hours a unit can operate before the maintenance takes place. In our example, the 675 starts would be responsible for reducing the number of firing hours from 24000 (the FH_{Max}) down to 16000. Therefore, considering the abovementioned value of $fhomc$, when the maintenance is triggered, there would be a non-allocated cost equal to $(FH_{Max} - FH_M) \cdot fhomc$. From this perspective, and averaging the effect of each start, it can be derived the individual start up cost due to O&M ($suomc$) is equal to:

$$suomc = \frac{(FH_{Max} - FH_M) \cdot fhomc}{S_M} \tag{2}$$

This way, what really matters for this allocation proposed are the accumulated number of firing hours and the accumulated number of starts at the moment the maintenance takes place. For simplicity we derive these conditions from the results obtained with the weekly unit commitment execution, assuming that the operating regimes obtained during the week simulated are week after week cyclically repeated until the maintenance conditions are met[8].

In order to show the relevance of this start adder component $(suomc)$, we show in Figure 5 the resulting start adder value for a CCGT as a function of the annual operating conditions. To compute such value it has been followed the previous allocation methodology and the data used in the case example (see section 5).

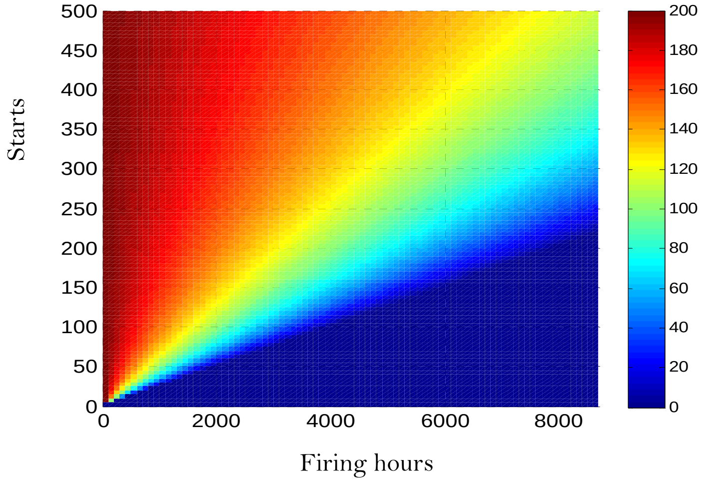

Figure 5. Start adder component due to O&M expenses ($/start MW) as a function of firing hours and starts.

As it can be numerically checked, firing hours remaining constant, the higher the number of starts the higher the cost of each start. At the same time is can be observed how, starts remaining constant, the lower the number of firing hours, the higher the cost of each start.

Once we get the marginal costs (prices in the non-linear context) and the hourly allocation of each plant production costs, the side payments and uplifts can finally be computed in module 3.

4.3 Module 3: Remuneration in the linear and non-linear context

The non-linear and linear pricing contexts selected correspond to two different design of the so-called complex actions. On the one hand we consider a simplified version of the pricing rules in force in the US ISOs short-term markets (we focus exclusively on the day-ahead market), and on the other hand a simplified version of the pricing rules in force in the SEMO short-term market in Ireland. As previously pointed out, while in the first ones a uniform price not including non-convexities (e.g. fixed costs) is used in addition to some discriminatory side-payments to ensure operation cost recovery, in the latter just uniform prices including the effect of the non-convex costs serve to remunerate all generation. The remuneration comparison conducted in this paper is restricted to the day-ahead energy-only market[9].

Non-linear pricing: The side-payments computation

In the context of discriminatory payments, daily side payments are determined as the difference between the total operating cost of each unit and the revenue (marginal price times the production). After the

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[8] What really matters for this assumption to hold is that the ratio of start-ups/firing-hours in the UC solved (one week, one month) is exactly the same as the one accumulated when the maintenance is carried out (e.g. after two years of operation).

[9] This is also the scope of some well-known references on the topic like Hogan et al (2003) and Baldick et al (2005). When adding in the analysis more products or subsequent markets, the side-payments may include other concepts such as the opportunity cost derived from providing reserves.

unit commitment is determined, these side payments are therefore computed with the following expression (for additional details on the notation, see the annex):

$$SidePayment_{i,day} = \max(\sum_h TotalCost_{i,h} - \sum_h \lambda_i \cdot g_{i,h}, 0) \qquad \forall h \in day \tag{3}$$

Where

$TotalCost_{i,h}$ Is the total cost of unit i in hourly period h [\$].

$$TotalCost_{i,h} = g_{i,h} \cdot efc_i + u_{i,h} \cdot nlc_i + v_{i,h} \cdot sufc_i + OMC_i(S_i, FH_i) \tag{4}$$

$g_{i,h}$ Is the production of the unit i in period h [MW].

λ_h Is the marginal price in period h [\$/MWh].

In this context, the income of each generating unit per day is:

$$\sum_h \lambda_i \cdot g_{i,h} + SidePayment_{i,day} \qquad \forall h \in day \tag{5}$$

Linear pricing: The uplifts computation

A simple optimization model is used to calculate the non-discriminatory prices that ensure the recovery of operation costs. This model mimics the algorithm used in the Irish market: positive hourly uplifts are added to the system shadow prices previously computed. Generally speaking, these uplifts are calculated so as to fulfill two simultaneous conditions: all generating units have to recover all their production costs and demand payments are minimized. The uplift squared is added to the objective function to reduce price peaks, in SEMO (2014) this term is referred to as the Uplift Profile Objective.

The formulation of the linear optimization model that is used to compute the uplifts is:

$$Min\ a \cdot \sum_h \left(\lambda_h + uplift_h\right) \cdot L_h + \beta \cdot \sum_h uplift_h{}^2 \tag{6}$$

Subject to:

$$\sum_h TotalCost_{i,h} \le \sum_h \left(\lambda_h + uplift_h\right) \cdot g_{i,h} \qquad \forall i \tag{7}$$

$$uplift_h \ge 0 \qquad \forall h \tag{8}$$

Where

$uplift_h$ Is the uplift in period h [\$/MWh].

L_h Is the load in period h [MW].

a, β Are two parameters to adjust the weight of each term in the objective function: $a = 0$ and $\beta = 1$ (SEMO, 2013).

In this context, each generating unit receives per day:

$$\sum_h (\lambda_i + uplift_h) \cdot g_{i,h} \qquad \forall h \in day \tag{9}$$

5 CASE STUDY

The test system that has been selected to analyze the impact of cycling on market remuneration is characterized by:

- A fully thermal mix, consisting of nuclear (10 plants of 1000 MW) and CCGTs (70 plants of 400 MW). The detailed characteristics of the mix are shown in table i. (including the value of non-served energy considered)

Table i. Generation costs components of the conventional thermal plants in the case example

Technology	Start-up cost per installed MW [$/start]	Pmax [MW]	Pmin [MW]	No-load cost [$]	Variable fuel cost [$/MWh]
Nuclear	-	1000	1000	0	6.79
CCGT	30	400	160	2202	49.55
NSE	-	-	-	-	2500

- The cost of a major maintenance of the CCGT technology is assumed to be US$ 40 million, and the MIF corresponds to the one denoted in Section 2 as "Option A". The maximum number of starts and firing hours are respectively 900 and 24000.

- Two scenarios regarding the penetration of VER are considered. One with none VER capacity installed, and another with an installed solar PV capacity of 35GW. The hourly profile considered has been computed by directly scaling the Spanish hourly production profile of solar PV in 2010. Although there were only 3.8 GW installed at the time, the fact is that there is a quite significant geographical diversity[10]. In Figures 6 and 7 it can be observed the relatively low hourly variability of the so-resulting scaled profile.

  The reason for considering solar PV as the VER to be modeled is because it represents the VER that more profoundly affects thermal cycling operation. As a way to illustrate this, the figure below shows two hourly production profiles of wind and solar based on production in Spain, both corresponding to the same installed capacity.

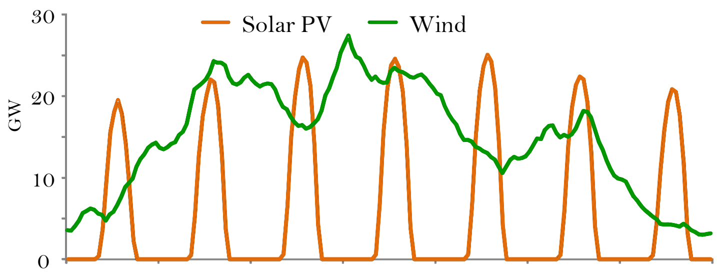

Figure 6. Potential solar photovoltaic and wind profile in Spain with a penetration of 30 GW.

- The size of the system has been inspired in the Spanish system. Hourly demand corresponds to the historical values recorded in the Spanish system in the week that went from November the 8th to November the 14th 2010.

With the previous characteristics, the CCGT technology is for the most time the marginal technology (as it is the case in a number of European systems today). This condition allows us to exclusively focus

[10] This geographical diversity is the consequence of: (i) a relatively stable and high insolation in the whole territory and (ii) a lack of locational signals of any type to solar PV

on the effect of cycling on prices, therefore leaving aside the potential "merit order effect" that takes place when the marginal technology changes.

The unit commitment has been solved for a whole week (from Monday to Sunday) so as to ensure that a sufficiently large time scope is considered when deciding commitment decisions. The figure below shows the total load and the net load for the whole week (i.e. the load after subtracting the solar photovoltaic hourly production). The resulting schedules in both scenarios are also depicted in the figure shown right below.

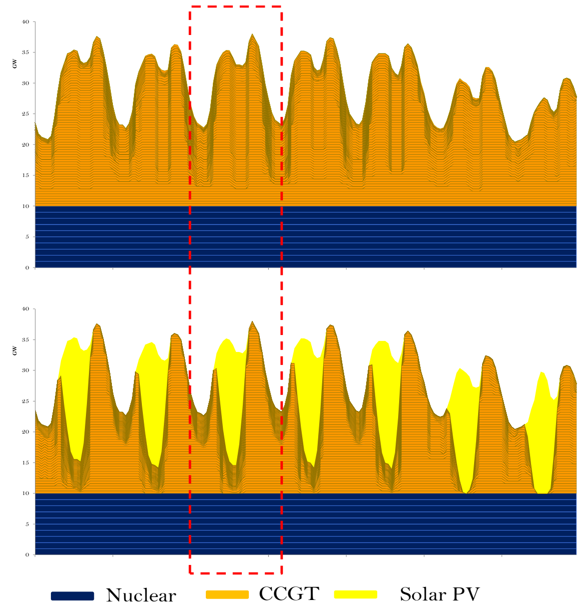

Figure 7. Unit commitment in both scenarios

Figure 7 shows how a large penetration of VER increases the need of cycling the units. The introduction of significant amount solar photovoltaic in the system increases the difference between the peak and off-peak net demand and decreases the gap between the inflexible capacity and the net demand in the valley. Therefore, the generating units are forced to reduce the production to minimum load during a higher number of hours or to stop and start-up more frequently in order to supply the new net load.

Although the optimal unit commitment has been calculated for the whole week, in order to analyze market outputs, we have focused in one particular day. The day chosen is Wednesday (delimited by the red dotted line in Figure 7).

As it has just been pointed out, the system marginal costs in the day of interest for the two scenarios considered are the variable cost of a CCGT unit (49.55 $/MWh) (the marginal technology does not change).

The non-linear context: side payments

Table ii shows the average side payments (calculated as the total side payment divided by the total net demand energy) and the maximum side payment in both scenarios: with and without solar PV. It can be checked that in the scenario with a high penetration of solar photovoltaic both the average and the maximum side payment are higher as a consequence of the start-up cost increase when solar PV penetration is considered.

Table ii. Average side payment and maximum side payment with solar and without solar

	With solar	Without solar
Average side payment ($/MWh)	9.95	7.69
Maximum side payment ($)	104416	92843

The linear context: uplifts

When computing the uplifts with the Irish-inspired pricing algorithm, we get the results shown in the figure below.

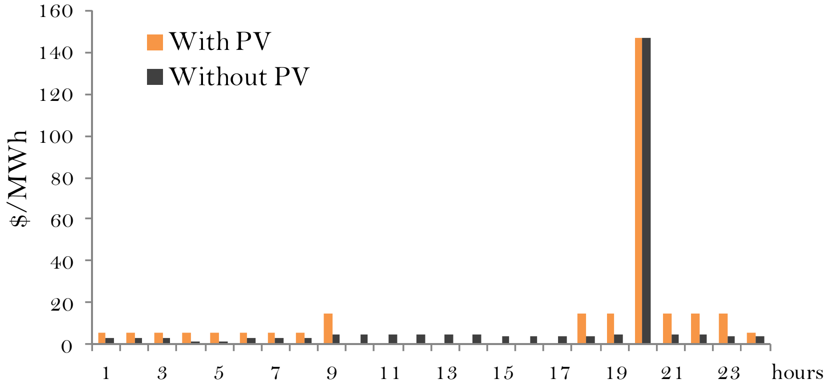

Figure 8. Hourly uplifts

Figure 8Figure 7 shows how the uplifts are set in different hourly periods as a consequence of the change that solar photovoltaic introduces to the load shape.

In order to measure the increase in demand payments, the weighted average uplift has been calculated. This weighted average uplift is a measure of the additional demand payment per MWh that is necessary to allow all generating units to recover all their production costs.

Table iii. Weighted average uplift with solar and without solar

$/MWh	With solar	Without solar
Weighted average uplift	15.99	11.16

As expected, these uplifts are larger in the case with solar again because of the increase in the fixed costs caused by the introduction of VER (see Table iii).

Changes in the remuneration perceived by generating units in each pricing context

The profitability of all conventional plants can be affected by the pricing rule. In particular, this effect is expected to be more acute with technologies whose operation regimes are not affected by the new cycling regimes.

In order to illustrate how the pricing context may affect the remuneration of the non-marginal technologies, the income perceived by a base-load nuclear unit operating at a constant base-load regime has been computed. Note that in the non-linear pricing context, we are lumping the two services pointed out in the introduction (energy, integral activities) to allow for comparison.

Table iv gathers the resulting income in the four cases (depending on the solar PV scenario and the pricing rule considered) for one of the 1000 MW nuclear power plants.

Table iv. Average price for a base-load plant depending on the solar PV production and pricing rule scenario

$/MWh	With solar PV	Without solar PV
Linear pricing	61.54	59.29
Non-linear pricing	49.55	49.55
Difference	11.99	9.74
Difference in %	24.20	19.65

Note that, as expected, the income in the linear pricing context is higher in the case with a large amount of solar because of the higher impact non-convexities. Moreover, the income in the non-linear pricing context is equal in both cases as the calculated prices do not include the effect of these non-convexities and the marginal generator is a CCGT plant in both scenarios.

The results show that a strong presence of solar photovoltaic increases the difference in market remuneration between a linear pricing rule and a non-linear pricing rule. As discussed, increasing VER increases fixed costs but these costs are perceived by all units in the linear pricing scheme while the base-load unit receives only the marginal cost in the non-linear pricing context. This is an important result because the choice of the pricing rule yields not only to different payments for consumers in the short-term but also affects the capacity expansion in the long-term since the income for generating units will also increase differently.

6 THE EFFECT OF ADDITIONAL NON-CONVEXITIES

The previous case study used two different generating technologies to highlight the differences in remuneration perceived by an infra-marginal unit (nuclear) running base-load and a marginal unit (CCGT) setting the price most of the time. While these two technologies serve as clear examples of the remuneration regimes of interest, technical peculiarities were set aside to maintain generality in the discussion.[11] In addition to start-up and no-load costs, combined cycle gas turbines present particular types of non-convexities (Ammari and Cheung, 2013) (Chang et al., 2008). Detailed modeling of a CCGT unit in a unit commitment problem requires additional binary variables which add computational complexity. At the same time, the presence of these binary variables in the cost function complicates the implementation of an efficient pricing rule.

This is illustrated using a piecewise linear representation of a non-convex cost function for CCGT units instead of the linear cost function used in Section 5. Table v shows the additional parameters used to represent CCGT units for each piece of the cost function[12].

Table v. Additional parameters of CCGT units

Piece 1 of cost function			**Piece 2 of cost function**		
Pmin [MW]	**Pmax [MW]**	**Variable fuel cost [$/MWh]**	**Pmin [MW]**	**Pmax [MW]**	**Variable fuel cost [$/MWh]**
160	250	51.95	250	400	47.55

[11] In fact, other types of units could have been used, as long as they were representative of a base-load and a peaker regime, resulting in equivalent conclusions.

[12] Note these variable costs are adjusted so the efficiency at the maximum power output is the same as in Section 5 to make simpler comparisons.

The rest of the methodology stays the same; new results are presented in the same format as the previous section.

The non-linear context: side payments

In Table vi it is shown that considering the piecewise linear non-convex cost function for CCGT units increased the need for side payments. The scenario with a high penetration of solar PV still produces a higher average and maximum side payment than the one without solar production.

Table vi. Average and maximum side payments with piecewise linear CCGT cost function

	With solar	**Without solar**
Average side payment ($/MWh)	10.15	8.45
Maximum side payment ($)	106235	99986

The linear context: uplifts

The weighted average uplift for this new case is presented in Table vii. In the linear context, with no side payments to be increased, the uplift component of the price is the one to represent additional non-convexities. Again, the scenario with solar production requires the higher uplift.

Table vii. Weighted average uplift with piecewise linear CCGT cost function

$/MWh	With solar	Without solar
Weighted average uplift	16.64	12.17

The new cost function produced additional changes in the results collected in Table viii. In the non-linear case the average price differs with respect to the first study case, although CCGT is always the marginal technology the marginal price can now take two different values (one for each piece of the cost function)[13]. The average price is higher in the case with solar production but this does not always have to be the case. The additional non-convexities complicate the relation between solar penetration and the marginal price[14].

Regarding the linear pricing context, and in accordance to the higher uplifts encountered, the average price is also higher than the one found in the first study case. More interestingly, the addition of another non-convexity increased the difference between linear and non-linear pricing rules.

able viii. Average price for a base-load plant with piecewise linear CCGT cost function

$/MWh	With solar PV	Without solar PV
Linear pricing	61.74	59.28
Non-linear pricing	49.20	48.84
Difference	12.54	10.44
Difference in %	25.48	21.37

[13] This produced a lower average price in the non-linear case although costs did not decrease, which explains the greater need for side payments.

[14] Increasing solar penetration has now two effects in price: When CCGT units are pushed to operate at its minimum power output the marginal price increases (piece 1 of cost function) but it can also make some units shut down making the remaining CCGT units operate above its minimum power output entering the second piece of the cost function, which decreases the marginal price.

7 CONCLUSIONS

This paper discusses the impact that the increased penetration of VER has on market prices as a consequence of increased operation (and in particular start-up) cost. In particular, it focuses on the influence of the pricing rule implemented (linear pricing or non-linear pricing) in the market results.

In order to properly carry out this analysis, we use a model consisting, on the one hand, of a short-term unit commitment that takes into account a more detailed than usual representation of maintenance drivers and costs, and on the other hand, of a post process in which side-payments and uplifts are computed (for the non-linear and linear contexts respectively).

In general, since the non-discriminatory pricing strategy provides all generators with a non-negative adder on top of the original market clearing price and it provides the same guarantee that the other method provides (a non-confiscatory market), this method produces a system wide total generation profit that is higher-than or equal to the non-linear approach.

In this paper we show, with an illustrative stylized case example, how a large penetration of solar photovoltaic increases the already existing differences between the two pricing alternatives in terms of market remuneration (and demand payments).

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ANNEX. STYLIZED UNIT COMMITMENT FORMULATION

8.1 Basic formulation of the Unit Commitment problem

The complete formulation of the short-term model used to compute the minimum cost dispatch and also the marginal system costs is as follows:

$$\underset{g_{i,h},u_{i,h}}{Min} \quad \sum_h \sum_i \left[g_{i,h} \cdot efc_i + u_{i,h} \cdot nlc_i + v_{i,h} \cdot sufc_i + VOMC_i(S_i, FH_i) + NSEC \cdot nse \right] \tag{10}$$

Subject to:

$$\sum_i g_{i,h} + nse = L_h \qquad \forall h \tag{11}$$

$$g_{i,h} \le \overline{G_i} \cdot u_{i,h} \qquad \forall i,h \tag{12}$$

$$g_{i,h} \ge \underline{G_i} \cdot u_{i,h} \qquad \forall i,h \tag{13}$$

$$u_{i,h} = u_{i,h-1} + v_{i,h} - w_{i,h} \qquad \forall i,h \tag{14}$$

$$S_i = \sum_{h=1}^{H} v_{i,h} \qquad \forall i \tag{15}$$

$$FH_i = \sum_{h=1}^{H} u_{i,h} \qquad \forall i \tag{16}$$

Where:

L_h	Represents the net demand value (demand minus solar photovoltaic production) in period h [MW].
$\overline{G_i}, \underline{G_i}$	Respectively represent the maximum and minimum output of thermal unit i [MW].
efc_i	Is the energy fuel variable cost of unit i [$/MWh].
nlc_i	The no-load cost of unit i [$].
$omfh_i$	The per-firing hour cost due to operation and maintenance of unit i [$/fh].
$sufc_i$	Is the start-up fuel cost of unit i [$/start].
$NSEC$	Is the non-served energy cost [$/MWh].
$g_{i,h}$	Is the production of unit i in period h [MW].
nse_h	Is the non-served energy in period h [MW].
FH_i	Is the total amount of firing hours of unit i [hours].
S_i	Is the total amount of starts of unit i [starts].

$VOMC_i$ Is the total variable operation and maintenance cost of unit i

$u_{i,h}$ Is the binary commitment variable. It indicates whether unit i is on-line (1) or off-line (0) in period h.

$v_{i,h}, w_{i,h}$ Respectively represent unit's i the start and shut down binary decision in period h.

8.2 Modelling non-convex cost functions

The model is expanded in Section 6 to include non-convex cost functions for CCGTs, this requires updating the objective function and additional variables and constraints:

$$\underset{g_{i,h},u_{i,h},q_{i,h}^{p},x_{i,h}^{p}}{Min} \sum_{h}\sum_{i}\left[vfc_{i,h} + u_{i,h} \cdot nlc_i + v_{i,h} \cdot sufc_i + VOMC_i(S_i, FH_i) + NSEC \cdot nse\right] \tag{17}$$

Where the variable fuel cost computation is different for CCGT units:

$$vfc_{i,h} = g_{i,h} \cdot efc_i \qquad i \notin CCGT, \forall h \tag{18}$$

$$vfc_{i,h} = u_{i,h} \cdot \underline{G_i} \cdot pfc_i^{p=1} + \sum_{p=1}^{p=P} q_{i,h}^{p} \cdot pfc_i^{p} \qquad i \in CCGT, \forall h \tag{19}$$

Previous constraints remain the same and the following equations are added:

$$q_{i,h}^{p} \le u_{i,h} \cdot \overline{Q}_i^{p} \qquad p = 1, i \in CCGT, \forall h \tag{20}$$

$$q_{i,h}^{p} \le x_{i,h}^{p-1} \cdot \overline{Q}_i^{p} \qquad p > 1, i \in CCGT, \forall h \tag{21}$$

$$q_{i,h}^{p} \ge x_{i,h}^{p} \cdot \overline{Q}_i^{p} \qquad i \in CCGT, \forall h, p \tag{22}$$

$$g_{i,h} = u_{i,h} \cdot \underline{G_i} + \sum_{p=1}^{p=P} q_{i,h}^{p} \qquad i \in CCGT, \forall h \tag{23}$$

Where:

pfc_i^p Is the fuel variable cost corresponding to piece p of the cost function of unit i [$/MWh].

$q_{i,h}^p$ Is the production of unit i in period h corresponding to piece p of the cost function of unit i [MW].

$\overline{Q}_i^p$ Is the maximum production corresponding to piece p of the cost function of unit i [MW].

$x_{i,h}^p$ Is a binary variable set to 1 if production in period h corresponding to piece p of the cost function of unit i is at its maximum.

A generic non-convex cost function is shown in Figure 9 to clarify the formulation.

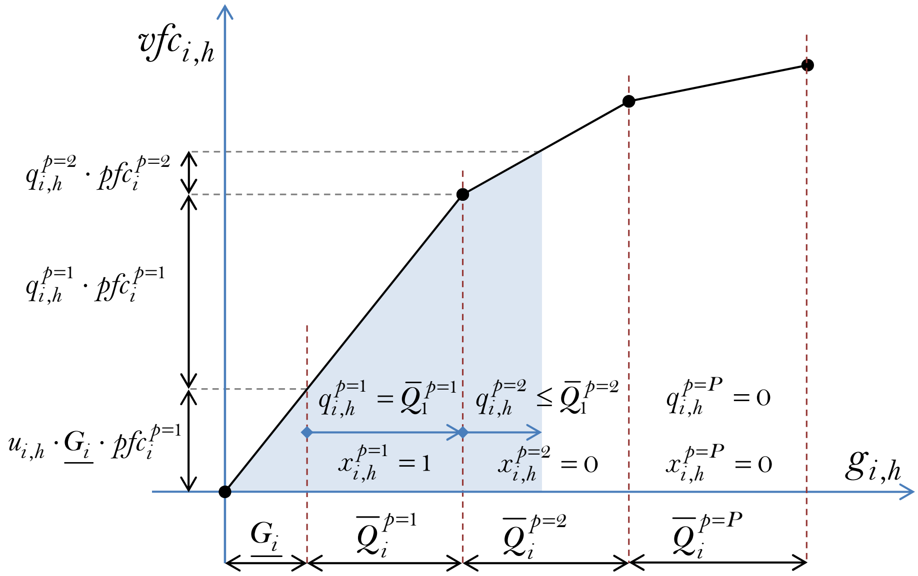

Figure 9. Sample piecewise linear non-convex cost function and relevant parameters and variables

8.3 Modelling the O&M cost through the MIF:

Moreover, for each segment defining the piece-wise-linear approximation of the MIF we have an equation form:

$$S \cdot (MMC \cdot FH_a - MMC \cdot FH_b) - FH \cdot (MMC \cdot S_a - MMC \cdot S_b) + VOMC \cdot (S_a \cdot FH_b - S_b FH_a) \le 0 \quad (24)$$

Where the segment of the piece-wise-linear MIF function is delimited by points $A(FH_a, S_a)$ and $B(FH_b, S_b)$, provided that $FH_a \ge FH_b$ and $S_a \ge S_b$ (see Figure 10).

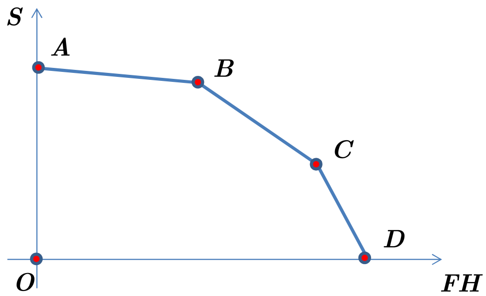

Figure 10. Piece-wise linear MIF

In the particular case of having a MIF defined by a rectangle (option A in Figure 1) we have to introduce in the Unit Commitment model two equations for each unit (equations (25) and (26)).

$$OMC \cdot FH_{Max} \cdot S_{Max} - OMC_{Total} \cdot FH_{Max} \cdot S \le 0 \quad (25)$$

$$OMC \cdot FH_{Max} \cdot S_{Max} - OMC_{Total} \cdot FH \cdot S_{Max} \le 0 \quad (26)$$