

MODELING THE MAJOR OVERHAUL COST OF GAS-FIRED PLANTS IN THE UNIT COMMITMENT PROBLEM

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Abstract

Operation and Maintenance (O&M) costs of gas-turbine-based generation technologies have traditionally been introduced in unit commitment problems by means of simplified formulations (such as the widespread approach of including an additional energy cost adder component). We argue that in the new context characterized by a large penetration of intermittent renewable, simplified modeling approaches of this sort do not serve to realistically reflect the impact that cycling operation introduces in the most relevant source of O&M costs for Open and Combined Cycle Gas Turbines (OCGTs and CCGTs), namely, the major overhaul inspection.

In this paper, we first review the way to properly model the typical Long-Term Service Agreements (LTSA) that condition the operation of these generation plants and then we develop a robust formulation based on linear constraints that allows modeling more realistically this source of cost in the unit commitment problem. This formulation is then tested on the basis of some cases example, so as to illustrate how a proper consideration of these O&M contracts significantly changes the results of the unit commitment problem.

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 highly variable, less dispatchable and hardly predictable energy resources (hereafter referred to as Variable Energy Resources, or simply VER) are, for a number of reasons, those expected to reach larger penetration levels in electricity power systems in the next decades (indeed, large scale penetration of these VER is already taking place in many systems worldwide).

This massive penetration of VER alters the regular operation and management of the whole electricity system (Pérez-Arriaga and Batlle, 2012). In particular, the changes that VER can introduce in both the cycling scheduling regime and on the production costs of the rest of the generating facilities is currently an active research topic. There is a growing number of modeling analyses that deal with the impact this new scheduling regime will have in the short to medium term, as for example Sensfuß et al. (2007), Denny (2007), Delarue et al. (2007), Goransson and Johnsson (2009), Lannoye et al. (2010), Troy et al. (2010). Some of them include the potential change in market prices, e.g. Poyry and EWEA (2010).

In this paper we begin by briefly reviewing the sources of costs that are expected to suffer changes as the penetration of VER (and thus thermal cycling operation) grows. Among those identified, this paper

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focuses on discussing the impact that O&M Long-Term Service Agreements (LTSAs), and more in particular the most relevant factor involved in these contracts, the major overhaul cost, will have both on the resulting plants' scheduling and on the corresponding production costs.

In order to properly illustrate this effect, we develop a novel formulation that allows for the consideration of these major overhaul costs in the traditional unit commitment optimization problem by means of a set of linear constraints. By making use of this formulation, we analyze and illustrate the major impacts that the detailed modeling of the main factor of these LTSAs contracts introduces in the unit-commitment results. Three cases example are then used so as to illustrate the relevance of properly representing this source of cost in the unit commitment problem.

2 COSTS OF CYCLING CONVENTIONAL THERMAL PLANTS

Lefton et al. (1996) put forward a very good qualitative summary of the impacts derived from increasing cycling operation in a fossil power plant: a significant increase in equivalent forced outage rate (EFOR), additional capital and maintenance expenditures and increase fatigue-related and creep-related wear and tear. These impacts translate into a significant cost increase caused by operation, maintenance, capital spending, replacement energy and capacity cost due to changed EFOR, cost of long-term heat rate change, cost of heat rate change due to low load and variable load operation, cost of start auxiliary power, fuel, and chemicals, cost of unit life shortening and general engineering and management cost (including planning and dispatch), etc.

The thermal plants operation costs to be considered in unit commitment problems (including the abovementioned impacts) 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);
- 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);
- O&M costs (reflected in a Long-Term Service Agreement), which as later discussed can be modelled as a function of the operating regime (in particular, as a function of the number of firing hours and the number of starts).

These three sources of cost have traditionally been represented with an uneven level of detail in unit commitment optimization models. While the first two sources have been considered up to a sufficient level of detail, see for example Baldick (1995), Kerr et al. (1966), Wood and Wollenberg (1996), the third one, the cost impact of O&M contracts, has been neglected or at the most modelled in a quite simplified way (in general, by including either an energy or a per-firing hour cost adder component, that is an additional expenditure on per megawatt-hour or per-hour produced basis). This simplified volumetric allocation of O&M costs assumes a very low-cycling regime (i.e. a base-load one), however, when adding a significant amount of VER, this low-cycling regime assumption no longer holds and needs to be revisited.

The inadequacy of considering O&M cost through the energy cost adder component has already been acknowledged both in PJM and ERCOT systems, see PJM (2012) and ERCOT (2011). This issue is also being discussed in CAISO at the time of this writing, see McNamara (2011).

The lack of modelling detail of this O&M costs in unit-commitment-based models is exactly the gap this paper aims at filling. Thus, first we briefly review the sources of operation cost called to suffer changes with the new cycling regimes. As stated, two of them are well-known and commonly considered in unit commitment optimization models. We outline how the larger the cycling needs the larger their effect on the supply costs. Then, we will mainly focus on the assessment of the third source of cost, that is, the impact of the costs of O&M LTSAs when cycling increases. This will help us to set the frame for a more suitable modelling approach, which is finally developed in section 3.

2.1 FUEL START-UP COST

Fuel costs are incurred when shutting down and starting a conventional thermal generating unit. A considerable amount of fuel is needed to raise the boiler to its minimum operating temperature prior to producing electricity. The fuel cost of each start is also a function of the number of hours the unit has been out of operation before starting (the longer the unit has been off, the larger the fuel expenses needed to bring the unit back to operation). The penetration of VER increases the number of starts (e.g. from weekly starts to daily ones) but at the same time the costs of each one of these starts will be lower¹.

2.2 ENERGY PRODUCTION COST: THE INCREMENTAL HEAT RATE CURVE

The efficiency of a generating unit depends on its load output. Production costs (fuel consumption) are higher (per unit generated) at low load operation than at close-to-full capacity. The relative efficiency loss (with respect to the maximum) at minimum stable load can be assumed to be in the range of 10 to 15% (that is, the cost per MWh is 10 to 15% higher at the minimum technical output). The particular values depend on the technology and plant, see for example Wood and Wollenberg (1996).

2.3 OPERATION AND MAINTENANCE COSTS: LONG-TERM SERVICE AGREEMENTS

Operation and Maintenance (O&M) costs are usually divided into fixed and variable cost components. Breaking down total O&M cost between these two components is not completely well-defined for some technologies, thus resulting in some cases in a quite arbitrary and arguable division.

Usually, fixed O&M costs include minor periodic maintenances, wages, property taxes, facility fees, insurances and overheads, while variable O&M usually include periodic overhauls that are triggered after certain operation conditions are met (e.g. number of operating hours with a baseline fuel type and firing temperature, number of starts, number of trips, etc.²).

Next we analyze how the scheduling of these overhauls of gas turbines (and thus of CCGTs) depends in practice on operating conditions.

Basics on maintenance planning of gas turbines

Generating units require a program of planned inspections with repair or replacement of damaged components (Boyce, 2006). Inspections and preventive maintenance can be expensive, but not as costly as forced shutdowns. Manufacturers define preventive maintenance procedures to ensure and guarantee reliability of their machinery. Inspections range from daily checks to major overhauls that require almost total disassembly of the gas turbine.

Most of these maintenance procedures are reflected in the so-called Long-Term Service Agreements (LTSA), see for example Sundheim (2001). LTSAAs typically commit the original equipment manufacturer (OEM) to providing, on a relatively “fixed-priced” basis, maintenance services for the very equipment that they manufacture (e.g., gas turbines, steam turbines, etc.). By transferring agreed risk to the OEM or other provider, LTSAAs offer turbine owners a mechanism for controlling maintenance costs and maximizing turbine reliability while minimizing the need for internal resources to manage and perform turbine maintenance. LTSAAs can be tailored depending on the level of risk an owner wishes to take on, its in-house technical expertise, and the age, condition, configuration and dispatch of the affected gas turbines.

LTSAAs, among other services (e.g. performance power and heat rate guarantees), determine the moment in which the OEM considers inspections have to be scheduled, and at the same time either explicitly or

¹ Therefore, the only way to assess how these two effects compensate is to apply a rigorous unit commitment analysis on a power system case by case basis.

² See Kiameh (2002) for a brief technical description of the physics behind these impacts.

implicitly (embedded in the LTSA contract) the cost of such inspections. The most relevant milestones embedded in the LTSA are the combustion inspections, the hot-gas-path inspections and the so-called major inspection³.

In the case of gas turbines, the parts that require the most careful attention and have the largest weight in the overall expenses are the combustors and the section exposed to the hot gases that are discharged from the combustors. In the following, the inspection associated to these relevant parts (the hot-gas-path inspections), will be simply referred to as the major overhaul inspection. There is not much public information about the exact related costs of these procedures. According to the references we have been able to gather, the cost of this major overhaul may range from 20 to 60 million US dollars, see for instance Power Planning Associates (2002) or Wembridge et al. (2009). In the following, in the methodology we propose here, we will assume that the whole cost of LTSAs corresponds to the cost of this major overhaul. This is the cost we shall refer to from now on when mentioning the variable O&M costs or the LTSA costs.

Criteria to set the maintenance intervals: Operating (firing) hours and starts

The life of gas turbines is normally limited by thermal mechanical fatigue while creep, oxidation, and corrosion limit the life of continuous-duty machines, and all these effects do not depend just on the number of hours the unit is on operation, but also on the particular way the unit is operated. Thus, the main factors that may affect the maintenance interval are the starting-up cycle, the power level, the type of fuel, and the amount of steam or water injected. For instance, the start-up process accelerates component failure resulting in an increase in the failure rate, longer maintenance and inspection periods and higher consumption of spares and replacement components.

The most common and general methodology to determine the recommended, maximum maintenance intervals is based on the definition of a (baseline) Maintenance Interval Function (MIF in the following) relating the maximum number of starts and firing hours before a maintenance is triggered⁴. The shape of the MIF for gas turbines varies between manufacturers. Power Planning Associates (2002) introduces three of the most widespread ways to characterize this function:

- Some manufacturers base their maintenance requirements on separate counts of machine starts and hours of operation. The maintenance interval is determined by the threshold criteria limit that is reached first. The MIF in this case takes the rectangular shape shown below (option A).
- Other manufacturers use an alternative approach, which consists of assigning to each start cycle an equivalent number of operating firing hours (EOH). The total amount of EOHs a certain plant has operated up to a certain point thus depends on both the amount of firing hours and the amount of starts. The inspection interval is determined when a predefined number of EOHs is reached. This way, it is straightforward to derive that in this case the MIF takes the form of the linear function represented in the figure below (option B).
- The more general MIF would be defined by any functional form combining the number of starts and the number of firing hours. An example of this more general MIF has been represented below marked

³ In addition to maintenance of the basic gas turbine, the control devices, fuel-metering equipment, gas turbine auxiliaries, load package, and other station auxiliaries also require periodic servicing. See for example Kiameh (2002) and Balevic et al. (2010) for a description of the procedures that need to be developed in each of them.

⁴ This baseline MIF can be modified by other operation-related events as the number of trips or the number of fast starts (Balevic et al., 2010).

as option C. This more general formulation is sometimes seen as a more complex non-constant assignment of the EOHs a start implies⁵.

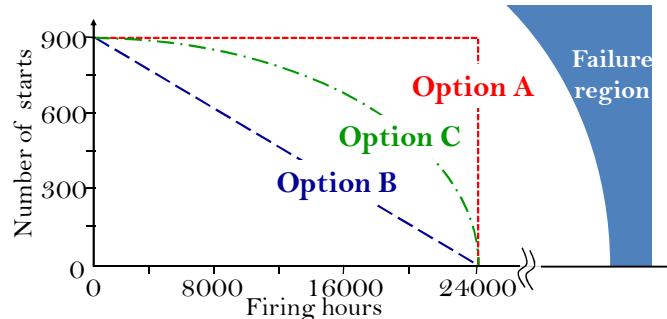


Fig. 1. Baseline functions for maintenance interval.

The maximum amount of starts and the maximum amount of firing hours defined in the MIF depend on the type of turbine and manufacturer. The hot-gas-path inspections can range from 8,000 to 24,000 hours and 400 to 1200 starts.

In the figure below, we have represented two different operation regimes (in the firing hours-starts axes used in the definition of the MIFs): a CCGT having to start 150 times per year to produce 2500 hours (peak-load regime, around three starts per week on average, 16 firing hours per start), and a CCGT having to start just 50 times per year to produce 7500 hours (base-load regime, one start per week, 150 firing hours per start). If considering a LTSA whose MIF corresponds to the one denoted above as "Option A" (where the starts' and firing hours' limits are respectively 300 and 15000 in this illustrative example), we can see how both of them have to carry out a major overhaul every 2 years, for in that period they both reach the boundary conditions triggering a major overhaul. Note that while the peak unit triggers the maintenance after reaching the 300 starts limit condition (producing 5000 hours), the base load does it after reaching the 15000 firing hours limit condition. Since the cost of performing an overhaul is fixed, the impact in terms of cost per MWh produced is much higher for the peak-load unit.

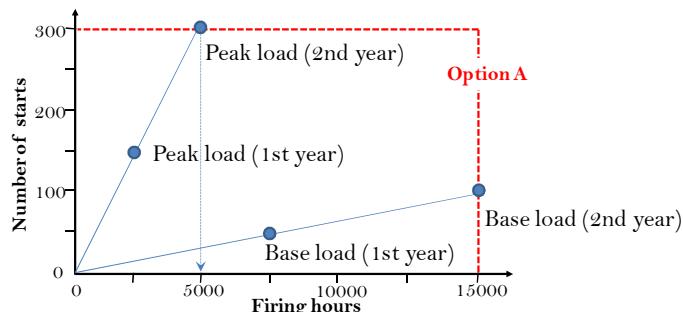


Fig. 2. Maintenance intervals of base-load and peak-load cycling regimes.

A relevant conclusion at this stage is that increasing the cycling regime of a thermal plant, and in particular the frequency of starts, means that the thermal generation costs increase due to O&M.

O&M cost associated to starting a CCGT plant

The way O&M costs affect the real cost of each additional firing hour and each additional start depends on the particular operating regime of the plant being considered. This is a quite relevant result that we next illustrate making use of the stylized case example that we have just introduced.

Let us assume that, for example due to the addition of VER generation, it is needed to increase the number of starts of both the peak load and the base load plant in the same amount (50 additional starts per year). Let us now analyze how this change affects in each case the scheduling of the major overhaul.

⁵ From this point of view, the amount of EOH depends on the operation regime.

As shown in Fig. 3, it can be observed that the major overhaul scheduling of the base load unit does not suffer any change when incurring in these additional starts. On the contrary, this is not the case with the peaking unit, whose increased cycling regime forces to carry out the major overhaul more frequently (i.e. sooner, around a year and half instead of the two years interval we had with the previous operation regime).

This way, under these LTSA conditions, in terms of O&M costs an additional start has a negligible impact for a plant operating largely in base-load mode, while the opposite occurs for a peak load plant.

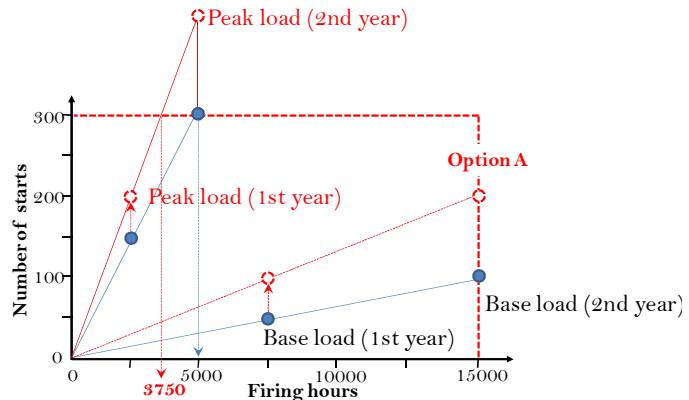


Fig. 3. Baseline functions for maintenance interval.

It is easy to derive that the ratio between the number of firing hours and the number of starts (in the following denoted as the “cycling ratio”) is the key variable determining whether adding starts has a relevant impact or not in terms of O&M costs. In this particular case, units having cycling ratios above 50 ($15000/300$) will not be penalized for incurring in an additional start, while the opposite will occur for units presenting cycling ratios below that threshold⁶. This same reasoning can be easily extended to more complex functional forms of MIFs.

3 MODELING LTSA COSTS IN THE UNIT COMMITMENT PROBLEM

Conventional unit commitment models have traditionally included variable O&M cost with rather simplified approaches, being the most widespread alternative that of including an energy-cost adder component. This simple modeling assumption leaves aside relevant information that, as we shall discuss, plays a relevant role in the overall production cost minimization problem.

The total cost corresponding to a major overhaul inspection under the LTSA agreement can be considered as a constant value determined at the moment the LTSA is signed. However, as just seen, the interval of this inspection depends on the operation regime, and particularly, on the number of starts and firing hours. In this section we focus on how to properly consider the major overhaul cost described previously. The objective consists of representing the major overhaul cost of a CCGT plant as a function of its operation regime characterized by its cycling ratio, obtained from the number of starts S and the number of firing hours FH , two variables that are to be optimized by the unit commitment problem itself. This relevant relationship is precisely what is lost with any of the simplified alternatives traditionally found in the literature.

First, to properly consider these costs in the unit-commitment problem, it is necessary to set the proportion of major overhaul cost to be allocated within the period being simulated (e.g. one month).

⁶ Conversely, units having cycling ratios above 50 will suffer from larger O&M costs when incurring in additional firing hours, while this will not occur for those units presenting cycling ratios below that threshold. Let us note that the characteristics of the O&M LTSA contract makes this latter issue negligible with respect to the potential impact due to increasing the number of starts. This is the reason why we focus exclusively on this latter issue in this paper.

The simplest case would be the one in which the period analyzed in the unit commitment is considered to capture the average medium- to long-term operation regimes of the generating units. In this situation, we can reasonably consider that the cycling ratio obtained within the unit commitment problem is a good proxy of the resulting accumulated cycling ratio at the moment the major overhaul inspection takes place⁷. This is exactly represented in Fig. 4 (where a MIF of what was denoted as “option B” has been considered). We denote by UC the point (in the firing hours-starts axes) representing the operation of a particular unit (defined by the total number of firing hours FH_{UC} , and the total number of starts S_{UC}).

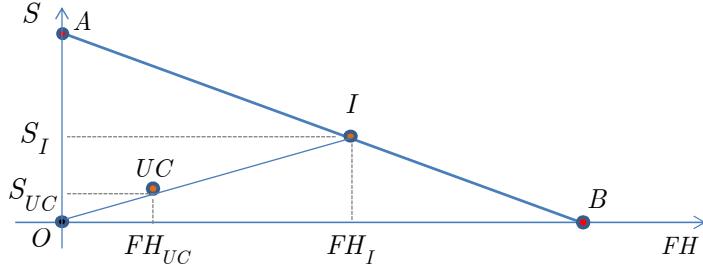


Fig. 4. Operating conditions at the moment of the inspection

The assumption that the cycling ratio obtained in the unit commitment corresponds to the medium-term cycling ratio, allows us to easily obtain the operating conditions at the moment of the inspection⁸ (FH_I and S_I respectively), since:

$$\frac{S_I}{FH_I} = \frac{S_{UC}}{FH_{UC}} \quad (1)$$

So the major overhaul costs can be allocated as follows:

$$\frac{FH_{UC}}{FH_I} = \frac{S_{UC}}{S_I} = \frac{MOC_{UC}}{MOC} \quad (2)$$

Where MOC represents the major overhaul cost of the plant being modeled (the fixed cost per inspection) and MOC_{UC} the major overhaul cost to be allocated within the period of the unit commitment being considered.

On this basis, it is straightforward to derive that the MOC_{UC} corresponding to any pair of values (FH_{UC}, S_{UC}), are determined by the contour lines depicted in Fig. 5.

⁷ If the period analyzed is not long enough to ensure capturing the medium to long-term operation, the approach proposed would be inaccurate. It should be refined to consider that the major overhaul long-term cost should be more heavily allocated in those periods involving a more intense cycling operation.

⁸ The number of firing hours and starts at the moment the major overhaul takes place can thus be computed as the point of the MIF presenting the same cycling ratio as the one obtained in the computation of the unit commitment.

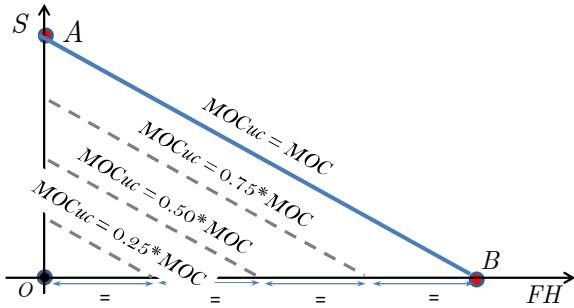


Fig. 5. Major overhaul cost contour lines

Thus, it is also straightforward to derive that the expression providing the MOC_{UC} as a function of FH_{UC} and S_{UC} (i.e. $MOC_{UC}(FH_{UC}, S_{UC})$) is nothing but the equation of a plane.

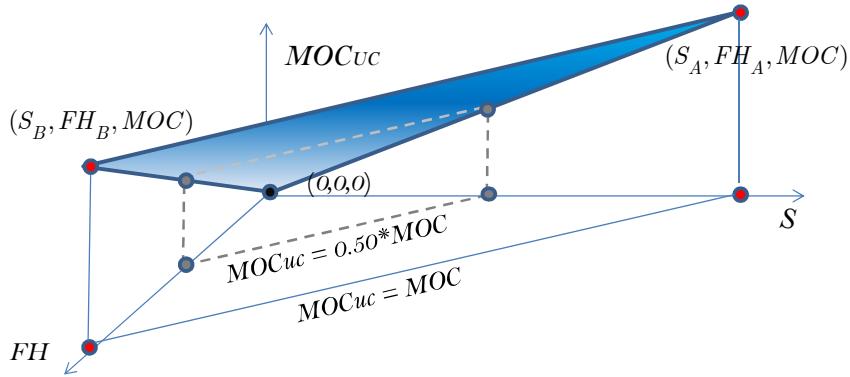


Fig. 6. Major overhaul cost plane

Let us consider the general expression of the equation of a plane passing through three points O, A and B, in the MOC_{UC} , FH_R and S_R axes:

$$\begin{vmatrix} S_{UC} - S_0 & FH_{UC} - FH_0 & MOC_{UC} - VOMC_0 \\ S_A - S_0 & FH_A - FH_0 & MOC_A - VOMC_0 \\ S_B - S_0 & FH_B - FH_0 & MOC_B - VOMC_0 \end{vmatrix} = 0 \quad (3)$$

Then, by simply particularizing to the following values of O, A and B (see Fig. 5):

$$\begin{aligned} (S_0, FH_0, VOMC_0) &= (0, 0, 0) \\ (S_A, FH_A, VOMC_A) &= (S_A, FH_A, MOC) \\ (S_B, FH_B, VOMC_B) &= (S_B, FH_B, MOC) \end{aligned} \quad (4)$$

We finally get the expression:

$$S_{UC} \cdot MOC \cdot (FH_A - FH_B) - FH_{UC} \cdot MOC \cdot (S_A - S_B) + MOC_{UC} \cdot (S_A \cdot FH_B - S_B \cdot FH_A) = 0 \quad (5)$$

Since as represented in Fig. 5, points $A(FH_A, S_A)$ and $B(FH_B, S_B)$ fulfil that $FH_A \geq FH_B$ and $S_A \geq S_B$, then we could alternatively use the following inequality expression representing, for each S and FH , any cost higher or equal to the one defined by the previous plane.

$$S_{UC} \cdot MOC \cdot (FH_A - FH_B) - FH_{UC} \cdot MOC \cdot (S_A - S_B) + MOC_{UC} \cdot (S_A \cdot FH_B - S_B \cdot FH_A) \geq 0 \quad (6)$$

Since the objective function is that of minimizing cost, for any pair (FH, S) , the problem will always assign the

MOC_{UC} value contained within the plane. We next use this alternative formulation to represent more complex functional MIFs.

In order to represent the most general case of the MIF (option C), let us now consider the piece-wise linear MIF shown below in Fig. 7 (consisting of just three linear segments for the sake of simplicity, delimited by points A, B, C and D). Note that this piece-wise function is convex (which is the case for the real MIFs). Following the proportionality allocation described, we obtain to the contour lines represented.

In this case, for each of the angular sector regions (three in this example, $\triangle AOB$, $\triangle BOC$ and $\triangle COD$) we would have a different expression of $MOC_{UC}(FH_{UC}, S_{UC})$. For instance, for an operating regime defined by a pair of values (FH_{UC}, S_{UC}) , such that the point falls in the $\triangle BOC$ angular region, the expression of $MOC_{UC}(FH_{UC}, S_{UC})$ would correspond to the plane passing through the three following points: (S_B, FH_B, MOC) , $(0, 0, 0)$ and (S_C, FH_C, MOC) .

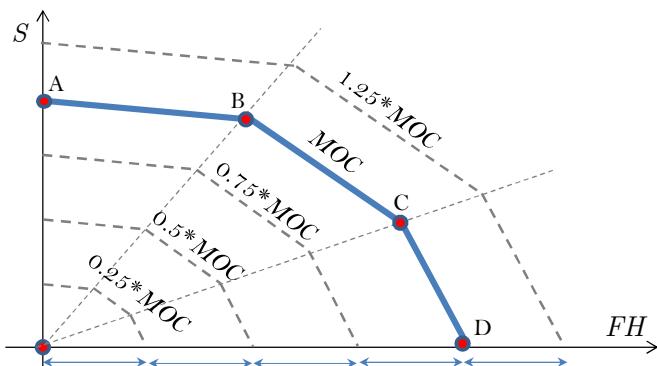


Fig. 7. Contour lines in the piece-wise linear MIF case

This way, the so-defined cost function in this case simply consists of a set of planes, one for each angular region. In the simple three-piece-wise-linear example, this translates into introducing the three following conditions:

$$\begin{aligned} & S_{UC} \cdot MOC \cdot (FH_A - FH_B) - FH_{UC} \cdot MOC \cdot (S_A - S_B) \\ & + MOC_{UC} \cdot (S_A \cdot FH_B - S_B \cdot FH_A) \geq 0 \\ & \forall R(FH_{UC}, S_{UC}) \in \triangle AOB \end{aligned} \quad (7)$$

$$\begin{aligned} & S_{UC} \cdot MOC \cdot (FH_B - FH_C) - FH_{UC} \cdot MOC \cdot (S_B - S_C) + \\ & + MOC_{UC} \cdot (S_B \cdot FH_C - S_C \cdot FH_B) \geq 0 \\ & \forall R(FH_{UC}, S_{UC}) \in \triangle BOC \end{aligned} \quad (8)$$

$$\begin{aligned} & S_{UC} \cdot MOC \cdot (FH_C - FH_D) - FH_{UC} \cdot MOC \cdot (S_C - S_D) + \\ & + MOC_{UC} \cdot (S_C \cdot FH_D - S_D \cdot FH_C) \geq 0 \\ & \forall R(FH_{UC}, S_{UC}) \in \triangle COD \end{aligned} \quad (9)$$

In principle, it would be then necessary to use binary variables to “select” the correct equation of the corresponding plane for each particular pair of values (FH_{UC}, S_{UC}) . However, let us note that for one particular operating regime (FH_{UC}, S_{UC}) the cost-minimization nature of the problem coupled with convexity of the MIF will ensure that by using simultaneously all the previous constraints, the MOC_{UC} will always be defined by the correct plane (since the correct plane will always represent the more restrictive constraint).

It is easy to observe in Fig. 8 (where the dotted red lines represent the prolongation of each plane) how the plane defining each angular sector is always the one leading to higher MOC_{UC} values. This fact considerably simplifies the problem, for no binary variables are thus needed when modeling the real types of MIFs.

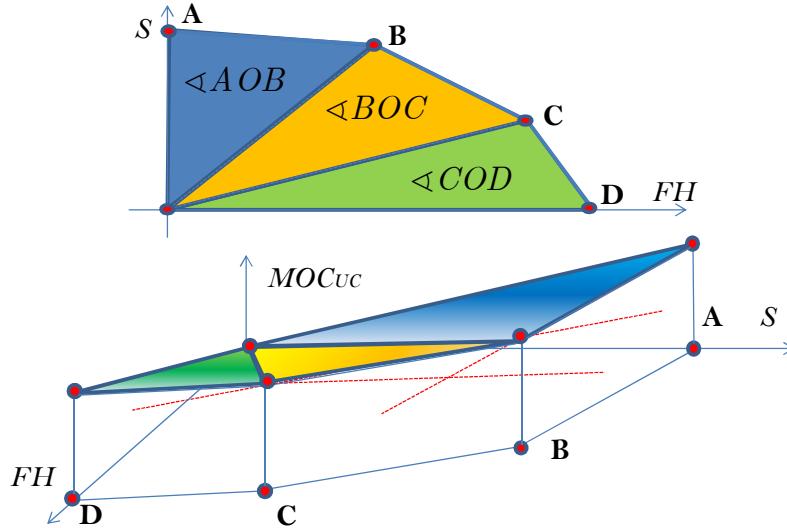


Fig. 8. Piece-wise MIF (above chart) and the corresponding cost function

These constraints have been incorporated to the basic unit commitment problem formulation, with the objective of performing the analyses carried out next.

4 CASE EXAMPLES

To focus on the illustration of how the detailed representation of the major overhaul cost changes scheduling decisions, we resort to a stylized unit commitment model.

Many well-known constraints (e.g. ramp-up constraints) have not been considered in the model not to unnecessarily obscure the results. Neglecting such important constraints would not be acceptable if the objective would be quantifying in detail the actual impact of unit commitment costs. If this was the objective, a more comprehensive formulation would be needed, as those presented in Hobbs et al. (2002), Padhy (2004), Arroyo and Conejo (2004) and Wang and Shahidehpour (1993).

The model will be used in two alternative formulations: one including the energy cost adder component and another with the explicit representation of the MIF. This will allow us to compare the results obtained with both modeling approaches.

Although the centralized optimization of generation dispatch does not represent what is presently the situation in the liberalized context implemented in most countries, it does represent a good reference to understand the implications these major overhaul can introduce in the resulting schedule.

The formulation of the stylized short-term model used to compute the minimum cost dispatch with the conventional simplified modeling approach of O&M costs follows:

$$\begin{aligned} \text{Min}_{g_{i,h}, u_{i,h}} \quad & \sum_h \sum_i [g_{i,h} \cdot efc_i + u_{i,h} \cdot (nlc_i + omfh_i) + \\ & + v_{i,h} \cdot sufci + NSEC \cdot nse_h] \end{aligned} \quad (10)$$

subject to:

$$\begin{aligned}
 \sum_i g_{i,h} + nse_h &= L_h && \forall h \\
 g_{i,h} &\leq \overline{G}_i \cdot u_{i,h} && \forall i, h \\
 g_{i,h} &\geq \underline{G}_i \cdot u_{i,h} && \forall i, h \\
 u_{i,h} &= u_{i,h-1} + v_{i,h} - w_{i,h} && \forall i, h
 \end{aligned} \tag{11}$$

where

- $g_{i,h}$ Is the production of unit i in period h [MW].
- efc_i Is the energy fuel variable cost of unit i [\$/MWh].
- $u_{i,h}$ Is the binary commitment variable, indicating if unit i is on-line (1) or off-line (0) in period h .
- $omfh_i$ The per-firing hour cost due to operation and maintenance of unit i [\$/fh].
- $v_{i,h}, w_{i,h}$ Respectively represent unit's i the start and shut down binary decision in period h .
- nse_h Is the non-served energy in period h (i.e. the total load shedding amount at hour h) [MW].
- L_h Represents the net demand value (demand minus wind production) in period h [MW].
- $\overline{G}_i, \underline{G}_i$ Respectively represent the maximum and minimum output of thermal unit i [MW].
- nlc_i The no-load cost of unit i [\$.].
- $sufc_i$ Is the start-up fuel cost⁹ of unit i [\$/start].
- $NSEC$ Is the non-served energy cost [\$/MWh].

For the more detailed O&M cost modeling approach, we need to introduce two additional variables: the total amount of starts S_i and the total amount of firing hours FH_i of each plant i :

$$S_i = \sum_{h=1}^H v_{i,h} \quad \forall i \tag{12}$$

$$FH_i = \sum_{h=1}^H u_{i,h} \quad \forall i \tag{13}$$

Each unit i variable operation and maintenance cost ($VOMC_i$) is assumed to entirely correspond to the major overhaul cost. However, let us note that a larger modeling detail is possible by applying the methodology proposed to other types of maintenances also defined by MIFs.

$$VOMC_i(S_i, FH_i) = MOC_{UC,i}(S_{UC,i}, FH_{UC,i}) \tag{14}$$

⁹ In order to make it computationally feasible, we renounced to model the dependency of the fuel start-up costs with the number of hours the unit has been out of operation before starting, see e.g. Carrión and Arroyo (2006).

Where the modelling of the MOC_{UC} corresponds to the one described in section 3.

The new objective function is finally:

$$\begin{aligned} \text{Min}_{g_{i,h}, u_{i,h}} \quad & \sum_h \sum_i [g_{i,h} \cdot efc_i + u_{i,h} \cdot nlc_i + v_{i,h} \cdot sufci \\ & + VOMC_i(S_i, FH_i) + NSEC \cdot nse] \end{aligned} \quad (15)$$

4.1 ANALYSIS OF THE IMPACT OF THE MAJOR OVERHAUL COST ON THE ECONOMIC OPERATION OF CCGTS

We next analyze how introducing the proposed formulation for the major overhaul cost significantly affects the economic operation scheduling of the CCGTs plants.

In particular, on the basis of a highly stylized case example, we show two relevant effects which do not appear when O&M costs are modeled through the simplified conventional approach:

- First, we see how considering the MIF raises the need to alternate the operation regimes of the different CCGTs. In particular, when all MIFs are identical the result is that cycling ratios tends to be homogenized.
- Second, we show how the decision on whether to avoid a start or not by keeping a unit producing at the minimum load output during certain periods (typically during the night) critically depends on both the major overhaul cost and the MIF.

The case example used to illustrate these two effects considers a weekly demand consisting of seven identical daily demand curves. Each daily demand curve consists of one valley block of 400 MW whose duration is 10 hours and a peak block of 800 MW whose duration is 14 hours. The available generation portfolio consists of two CCGTs of 400 MW of capacity (the technical and costs characteristics are summarized in the Appendix).

We assume that both plants are shut down at the beginning of the unit commitment. We evaluate the minimum cost dispatch first assuming the traditionally simplified variable O&M costs and then considering a Option A type of MIF (a contract defining a major overhaul interval when the unit reaches any of the following two conditions: either 900 starts or 24000 firing hours. For further details see the Appendix).

4.2 FIRST EFFECT: THE NEED TO HOMOGENIZE THE CYCLING RATIOS

When modeling O&M cost with the simplified conventional approach (expressed in this case example as \$/per-firing-hour), we obtain the dispatch represented in Fig. 1.

We can see how CCGT 1 is scheduled so as to supply the base load, while CCGT 2 is scheduled in such a way that it starts and shuts down every day (a peak-load regime).

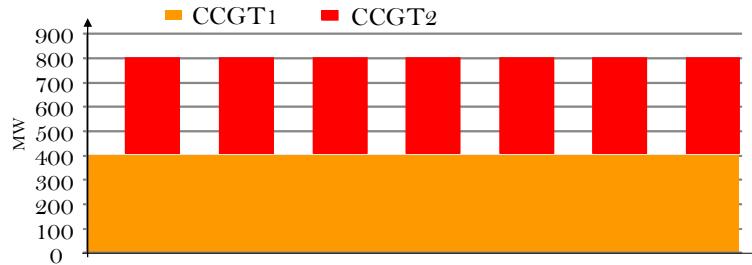


Fig. 9. Economic dispatch with the simplified conventional

In this case, the total O&M costs for each CCGT would directly be proportional to the number of hours each CCGT produces. Thus the number of starts does not intervene in this cost component. In the next table we have gathered the number of firing hours, the number of starts, the cycling ratios and the total O&M costs.

TABLE I
UNIT COMMITMENT RESULTS WITH THE SIMPLIFIED CONVENTIONAL APPROACH

Plant	Number of Firing Hours	Number of starts	Cycling ratio [FH/Start]	O&M cost [\\$]
CCGT 1	168	1	168	280,000
CCGT 2	98	7	14	163,333

Note that in case that the two CCGTs were identical, the solution minimizing cost would be degenerated, for it makes no difference how the eight starts needed are allocated among the two CCGTs.

Based on the MIF and the major overhaul cost, we now calculate the real O&M costs resulting from the operation obtained in the previously computed unit commitment. Note that we are not using yet the proposed formulation, but only improving the calculation of the O&M costs ex post. When doing so we obtain a major overhaul O&M Cost of 280,000 \\$ for CCGT 1 and a major overhaul O&M cost of 311.111 \\$ for CCGT 2. This way, while CCGT 1 O&M costs have not changed when considering the MIF, we find that CCGT 2 is actually incurring in much higher costs than those anticipated by the simplified methodology.

We can see how CCGT 2 is being highly penalized for the low cycling ratio (firing-hour/start). In this case, the threshold ratio delimiting whether the starts introduce additional O&M-related costs or not is 26.66 (24000/900). In Table I we can check how effectively CCGT 2 cycling ratio is below this threshold, while the ratio of CCGT 1 is above it.

These results confirm the suitability of the simplified representation of O&M cost as long as the cycling regimes are high. However the larger the number of starts, the less precise this simplification is.

From the results above, one would expect that considering the MIF embedded in the LTSA in the cost minimization problem, would provide a different allocation of the starts among the two units, so as to reduce the O&M costs of CCGT 2 by increasing its cycling ratio.

Let us now include the LTSA contract in the formulation of the unit commitment. In this case the set of equations described in Section 3 take the form:

$$45 \cdot MOC_{UC} - 2 \cdot 10^6 \cdot S \geq 0 \quad (16)$$

$$600 \cdot MOC_{UC} - 10^6 \cdot FH \geq 0 \quad (17)$$

When solving the unit commitment with these two additional constraints, we obtain the dispatch shown in Fig.2.

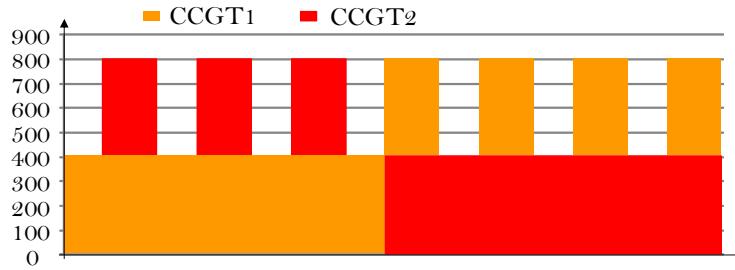


Fig. 10. Economic dispatch modeling O&M costs through the MIF.

We can observe how the starts are now equally allocated between the two CCGTs. This way, we find that (for the CCGT technology) there are no longer so-different operating regimes (more base-load like or peak-load like), but somehow the need of cycling is shared by the two plants.

In this simple case, the new operating regimes and the resulting O&M costs are gathered in Table III:

TABLE II
UNIT COMMITMENT RESULTS WITH THE PROPOSED APPROACH

Plant	Number of Firing Hours	Number of starts	Cycling ratio [FH/Start]	O&M cost [\\$]
CCGT 1	138	4	34.5	230,000
CCGT 2	128	4	32	213,333

Note that now both CCGT plants operate at cycling ratios which are above the threshold we defined previously (26.66 hours per start).

4.3 THE SECOND EFFECT: THE REDUCTION OF THE NUMBER OF STARTS

The willingness of some generating plants to avoid the need to start to supply at peak hours by keeping at the minimum technical output during valley hours is a well-known result of the unit commitment optimization problem. This scheduling decision mainly depends on the existing relationship between the efficiency loss of producing at this minimum load output regime¹⁰ (the additional cost) and the start-up cost (the cost saved). The lower the former and the higher the latter the most likely the trend to avoid starts will be.

In the case of gas turbines, and in particular in the case of CCGTs, the major overhaul cost actually impacts both on the actual cost of an additional firing hour and the cost of an additional start. Thus, it is evident that the characteristics of the O&M contract play a key role in this scheduling issue.

The conventional modeling approach of the O&M costs (through the energy cost adder component or through the per-firing hour additional cost), just affects (increasing) the energy production cost, thus making less economical the minimum load regime as an alternative to avoid a start.

However, we have seen how considering the MIF leads to the conclusion that any additional start and firing hour originates an incremental cost that depends on the particular regime of operation at which the CCGT is subject. As a general rule, the lower the cycling ratio (i.e. the closer to a peak-load regime), the higher the impact an additional start and the lower the impact of an additional firing hour in terms

¹⁰ Let us note that in order to allow a unit to produce at the minimum technical output during valley hours so as to save a start during peak hours, it is necessary that other units reduce their output during the valley period. Thus, the efficiency loss does not exclusively affect the unit saving the start.

of the resulting O&M costs. Thus, again, the lower the ratio, the less precise the conventional modeling approach is.

Note that reducing the impact of the firing hours and increasing the impact of starts clearly goes in the direction of avoiding starts. *A priori*, this is the effect we would expect when modeling the major overhaul cost in detail.

To illustrate this previous qualitative analysis, we resort again to the same case example. To show how the conditions of the MIF directly affect the decision of avoiding start, we progressively reduce the starts' limit defined in the LTSA, first down to 450 (all other characteristics being equal) and then down to 150. Note that by reducing this limit, we are also lowering the cycling ratio threshold at which starts begin to be penalized with larger cost in the resulting O&M costs.

In the figure below we have represented the resulting unit commitment when the maximum number of starts is reduced to 450. In this case we can see how both CCGTs reduce the number of starts by producing during certain valley hours at the minimum technical output. CCGT 1 starts in this case two times while CCGT 2 three. Both units are on the same number of firing hours, 148.

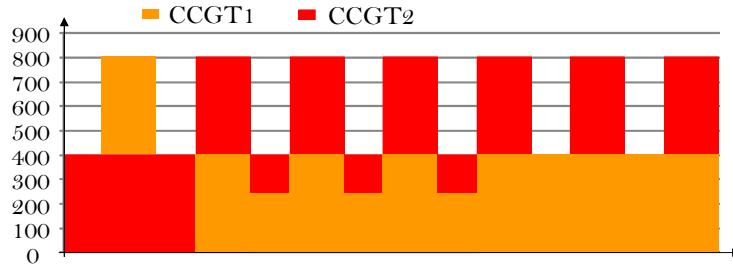


Fig. 11. Unit commitment when reducing the MIF starts' limit to 450.

Next, we further reduce the number of starts by mandating a major overhaul after only 150 starts. In this case (see Fig. 12), each CCGT performs a single (unavoidable) start in the first period they enter to operate, and after that, both avoid shutting down so as not to have to start again. This way, CCGT 1 is online the whole week (168 hours) while CCGT 2 is online during 158 hours.

In this latter case, the cost of an additional start is so high in terms of total O&M costs that the optimal dispatch leads to avoiding them as much as possible. It is important to note that this effect can never be captured assuming the conventional variabilization. Indeed, the larger the O&M considered with the conventional approach, the less economical is to produce more hours at the minimum technical output to avoid a start.

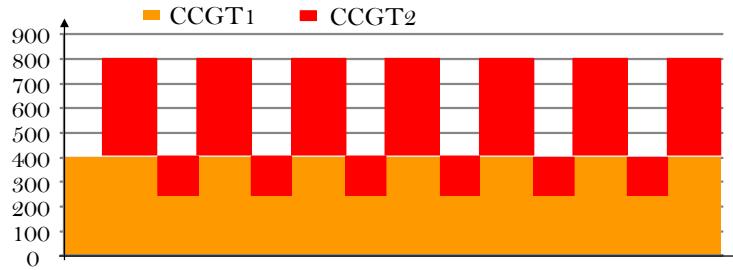


Fig. 12. Unit commitment when reducing the maximum number of starts (150) defined in the MIF

5 OTHER ALTERNATIVE SIMPLIFYING MODELING APPROACHES

Generally speaking, we have shown that for the case of CCGTs, increasing the frequency of starts (while operating hours being equal) results in a higher impact of the weight of O&M costs in the dispatch. Or from a complimentary point of view, the larger the number of starts, the more relevant the cost impact of each start. This effect is impossible to be modeled with the conventional approach of considering an energy cost adder (or per firing hour adder) component. Limiting the number of starts

on a plant by plant basis (as mentioned before, another constraint sometimes considered in the UC problem) also fails to consider the extra cost each start up introduces in the major overhaul cost component¹¹.

However, under the light of these previous results, another simplified alternative that could be reasonably considered would be that of introducing two cost adder components for CCGTs (due to O&M):

- An energy cost adder component (or a per firing hour cost adder component), actually reflecting the impact each additional MWh or firing hour has on O&M costs.
- A start-up cost adder component that would model the impact each start introduces in terms of O&M costs.

The clear advantage of this simplification would be less computational effort, for no additional constraints would be needed in the unit commitment problem formulation.

This simplification would obviously be more precise and capable of capturing more effects than simply using the energy cost adder component (which up to date has been the widespread choice in the literature). But it would fail to capture a key effect that we have illustrated in the previous discussion: these two components cannot be predefined since they strongly depend on the operating conditions (particularly on the cycling ratio) that finally result when solving the unit commitment problem.

In this sense, it is noteworthy that fixing these energy and the start cost adder components based on an ex-ante estimation of the optimal dispatch may lead CCGT plants to produce at cycling ratios that are not coherent with this previous estimated dispatch. By the way of example, if we make the entry assumption that some of the CCGTs will have a higher-than-usual start cost adder component to represent that they will be subject to a heavier cycling regime, the unit commitment results contradict this initial assumption: the optimal solution would minimize the number of times these units would start (right the opposite of what was assumed).

6 REAL-SIZE CASE EXAMPLE

With the objective of illustrating the two effects in the context of a real-size case example characterized by a large penetration of VER, we next consider a stylized version of the Spanish system, where the hydro and coal portfolios have been ignored. The data regarding the remaining thermal portfolio, which consists of 7 nuclear power plants of 1000 MW and 74 CCGT plants of 400 MW, can be found in the Appendix. Historical hourly demand and wind production data for the 2010 April 12th week of the Spanish electric system has been used¹². Wind has been directly subtracted from the demand (thus, curtailment is not considered). The resulting load curve is the so-called net load.

¹¹ Limiting the number of annual starts is a hard constraint that does not serve to realistically represent the major overhaul impact. Among other reasons, as previously pointed out, the relevant variable is not the number of starts, but the cycling ratio.

¹² Adding the previous O&M cost constraints complicates to a large extent the resolution of the unit-commitment problem for all periods within one year, due to memory and computation time constraints (particularly when considering the type of O&M contract we denoted as C). Therefore, if we want to add a larger level of detail on the representation of O&M costs, the maximum affordable time scope of potential simulations on a regular PC is severely reduced (e.g., from one year to a few weeks). As the case examples here are designed just for illustrative purposes, we limited the analysis to a single week. In Batlle and Rodilla (2012) a simplified algorithm is designed to allow for joint optimal future generation capacity expansion and chronological operation simulation, while taking into consideration accurate models of LTSAs.

We follow the same reasoning we have followed in the just presented stylized example, that is, we seek to compare the results when O&M is modeled with the conventional approach versus the ones corresponding when considering the pair of linear constraints defined previously.

First we show the results obtained when the O&M costs are modeled through the conventional approach. The resulting dispatch is represented in Fig. 13. In the lower part of the chart (production profiles in light blue) we have included a larger detail of the production profiles of three of the units.

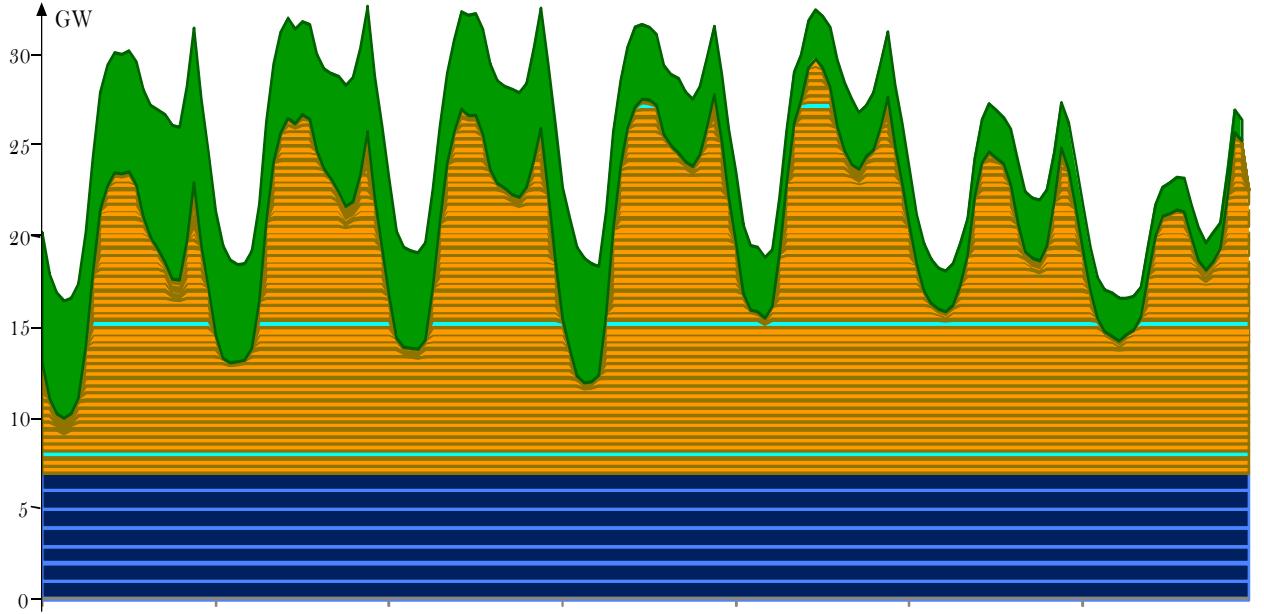


Fig. 13. Characterization of all operating regimes.

In this dispatch, we can observe how some CCGT plants (more precisely 11 plants), are scheduled in a base-load regime (just having to start in the first period). The rest of the plants are scheduled at different operating regimes, ranging from those close to a base-load regime to those with a peaking function (more starts and less firing hours).

It can also be observed that there are very few plants that avoid starting up by functioning a certain amount of hours at the minimum load regime.

In Fig. 14, we have represented all the operating regimes of the different CCGT plants in terms of the number of firing hours (abscissa) and the number of starts (ordinate). It can be clearly seen how there are some peaking units with very low utilization factors and a large number of starts and others with very high utilization factors and a low number of starts.

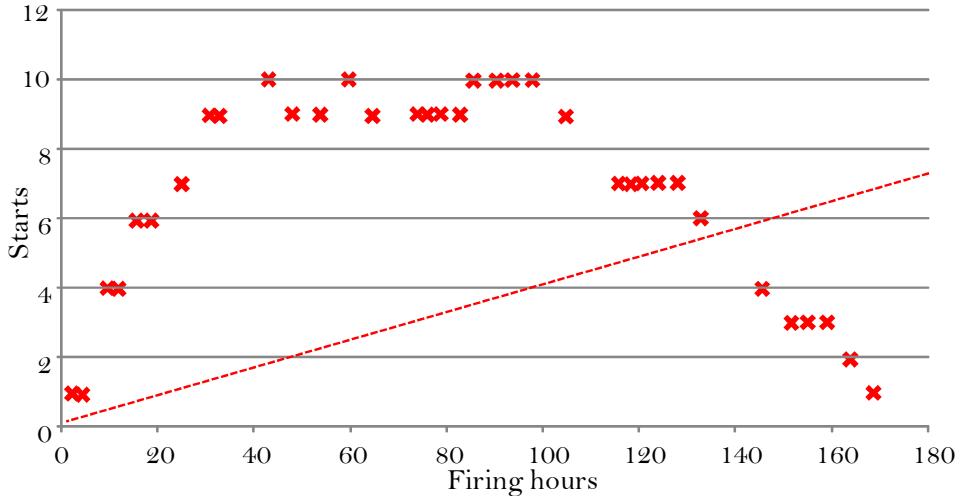


Fig. 14. Cycling ratios.

Next, we compute the unit commitment where we now model the MIF as shown in equations (16) and (17). We have represented in Fig. 8 below the resulting dispatch in this second case. At a first glance, it is noticeable how we can now find that many of the individual CCGTs operating regimes involve producing a large number of hours at the minimum load regime. The objective, as analyzed in the previous section is to increase the cycling ratio (both by increasing the amount of firing hours and reducing the number of starts).

This reduction of number of starts is illustrated in Fig. 15, where each position in the abscissa axis represents a different CCGT plant, and the ordinate value the number of starts. We have represented in the figure both the results obtained with the conventional variabilization of the O&M cost and with the proposed approach. We can see how while in the former a number of groups were starting up to 9 and 10 times within the week, this large amount of starts is avoided in the latter.

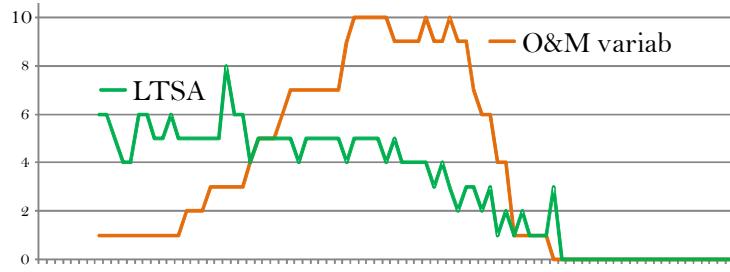


Fig. 15. Number of starts on a unit by unit basis with both modeling approaches.

We pointed out in the previous section the fact that keeping the cycling ratios as low as possible reduces O&M costs. Ratios were reduced by combining the peak and base load operating regimes of the different CCGT plants. This is what we termed as the cycling CCGTs cycling regime. We can check this previous conclusion in this more realistic case example in Fig. 17, where we have represented the ratios corresponding to all the plants in both the simplified and detailed O&M cost modeling approach. The red-dotted line represents the ratio establishing the threshold separating the regimes where additional starts respectively does and does not increase O&M costs. It can be checked how ratios are kept, when possible, at values next to the region where we saw starts do not reduce the maintenance interval.

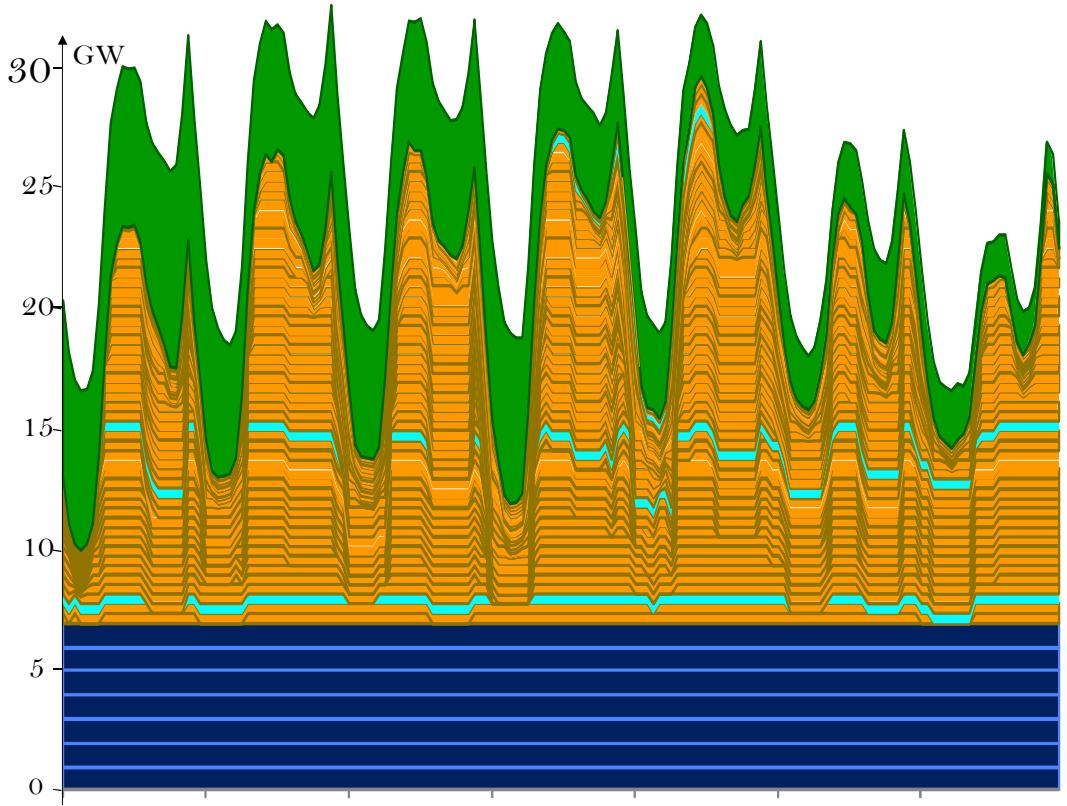


Fig. 16. Characterization of all operating regimes.

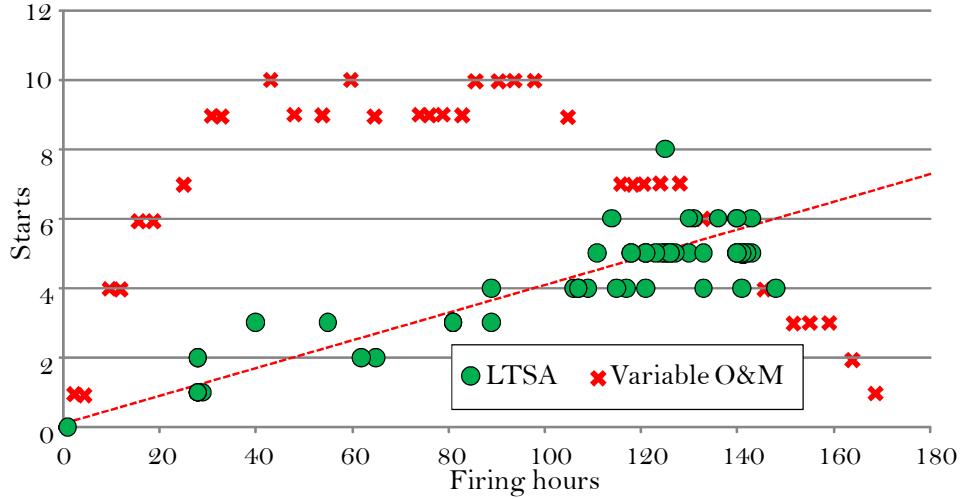


Fig. 17. Cycling ratios.

7 CONCLUSION

In this paper we discuss and model the impact that gas-fired plants (such as CCGTs plants) major overhaul inspections costs have on the unit commitment problem. We show how the simplified volumetric methodology traditionally used to represent all O&M cost in unit commitment models is not well-suited for capturing the O&M real impact when the plants are scheduled subject to heavy cycling regimes.

We present an alternative formulation, consisting of a set of linear constraints, which allows better including the effect of these major overhaul costs.

By means of both illustrative stylized and also a real-size cases example, we have shown that the optimal schedule of generators with typical formats of LTSAs in the presence of strong penetration of

intermittent generation entails some changes in the conventional dispatch. The optimal generation dispatch results in schedules of the system's CCGTs portfolio in such a way that most plants are kept at as higher possible average ratios of firing hours per start (what we have denoted as cycling ratio). This goes against the idea of having CCGTs producing at base-load regimes (low cycling) and others at peak-load regimes (high cycling), but rather scheduling all plants at a sort of hybrid (base-and-peak) load regime.

We have also seen another relevant effect, how the trend to avoid starts by producing at the minimum stable output during valley (e.g. nights) strongly depends on these LTSA contracts.

APPENDIX

TABLE I
THERMAL COST DATA

	NUCLEAR	CCGT
FOM*	88.75	14.39
HR*	N/A	7.05
VOM*	2.04	3.43
FP	-	7.81
VOF	6.62	55.06
SU	1000	75
NLC	-	2200

* Taken from Energy Information Administration (2010).

where FOM the Fixed O&M costs [$2010\text{k\$}/\text{MW-yr}$], HR the Heat Rate [kBtu/MWh], VOM the Variable O&M [$\$/\text{MWh}$], FP [$\$/\text{kBtu}$], VOF the Variable Operating Fuel costs [$\$/\text{MWh}$], SU the Start-Up cost [$\$/\text{start-MW}$] and NLC the No Load Cost [$\$$] (No Load Costs corresponds to a CCGT plant of 400 MW).

The variable operating fuel cost of the different CCGTs considered have been differentiated in the third decimal so as to avoid the complete degeneration of the solution while allowing to consider them all as (as de facto) identical units.

CCGT LTSA contract and the Maintenance Interval Function

The cost of a major overhaul is assumed to be 40 million \$, and the MIF corresponds to the one denoted as “Option A” in Fig. 1. The maximum number of starts and firing hours are respectively 900 and 24000 hours. In the simplified approach, the additional per firing hour (FH) cost component is assumed to be equal to 1666.6 \$/FH (that is $40\text{e}6\$/24000\text{FH}$).

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