ECONOMIC DISPATCH CONSIDERING THE COST OF O&M LONG-TERM SERVICE AGREEMENTS

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PART I: UNIT COMMITMENT PROBLEM FORMULATION

Abstract

O&M costs have traditionally been introduced in unit commitment problems by means of an energy cost adder component. We argue that in the new context characterized by a large penetration of intermittent renewables this conventional modeling approach does not serve to reflect the impact that actual CCGTs O&M contracts may have on the electric power system economic dispatch.

In the first part of this two-part paper, after qualitatively analyzing these contracts, we develop a formulation that allows including them in the traditional unit commitment optimization problem as a set of linear constraints. This formulation is used later on in Part II with the objective of analyzing and characterizing the major changes that properly considering these contracts introduce in the unit commitment problem results.

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 large 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 poses several challenges that need to be addressed. Most of these challenges arise directly derived from the impacts that VER have on the regular operation and management of the whole electricity system, see [1]. In particular, the changes that VER can introduce in the scheduling regime of the rest of the generating facilities in the system can have a key impact both in the short and in the long term. This effect is more acute in those systems in which storage capabilities, as for instance hydro resources, are scarce, for conventional thermal plants will most probably be pushed to the limits imposed by their technical constraints (ramping, wear and tear, etc.) due to the increasing need to run them in cycling regimes[1].

[1] The term "cycling" refers to the cyclical operating modes of thermal plants that occur in response to dispatch requirements: on/off operation, low-load cycling operations and load following.

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The extent to which the combination of a large penetration of VER, the resulting increased cycling needs and the impact of technical operation constraints of conventional generating units may affect the economic dispatch of the power system and the electricity market outcomes in the future is an active research topic at the present moment. 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 [2]-[7]. Some of them also include the potential change in market prices, e.g. [8].

In this first part of this two-parted 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 focuses on discussing the impact that O&M Long-Term Service Agreements (LTSAs) have both on the resulting unit commitment and on the cost of the system economic dispatch. In order to properly illustrate this effect, we develop a formulation that allows for the consideration of these O&M contracts 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 in the second part the major impacts that the detailed modeling of these contracts introduces in the unit-commitment results. A real-size case example will be used so as to illustrate the relevance of properly representing this source of cost.

2 COSTS OF CYCLING CONVENTIONAL THERMAL PLANTS

Reference [9] puts 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 [10]-[12], 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 [13] and [14]. This issue is also being discussed in CAISO at the time of this writing, see [15].

The lack of modelling detail of this O&M costs in unit-commitment-based models is exactly the gap this paper aims at filling. The first part of this two-parted paper is structured as follows: 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 4.

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 lower[2].

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 [12].

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.[3]).

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 [17]. 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 [18]. LTSAs typically commit the original equipment manufacturer (OEM) to providing, on a relatively "fixed-priced" basis, maintenance services for the very equipment that they

[2] 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.

[3] See [16] for a brief technical description of the physics behind these impacts.

manufacture (e.g., gas turbines, steam turbines, etc.). By transferring agreed risk to the OEM or other provider, LTSAs 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. LTSAs 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.

LTSAs, 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 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 inspection[4].

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 [20] or [21]. 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 triggered[5]. The shape of the MIF for gas turbines varies between manufacturers. Reference [20] 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).

[4] 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 [16] and [19] for a description of the procedures that need to be developed in each of them.

[5] This baseline MIF can be modified by other operation-related events as the number of trips or the number of fast starts [19].

- 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 as option C. This more general formulation is sometimes seen as a more complex non-constant assignment of the EOHs a start implies6.

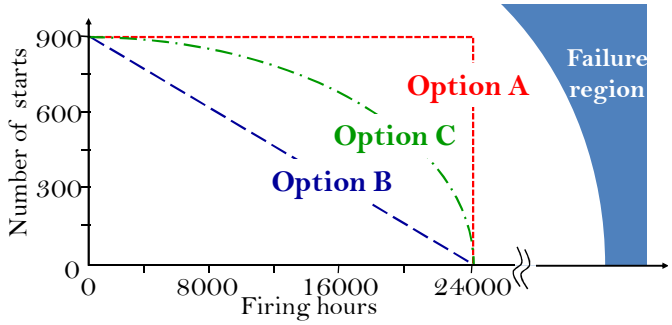


Fig. 1. Baseline functions for maintenance interval.

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.

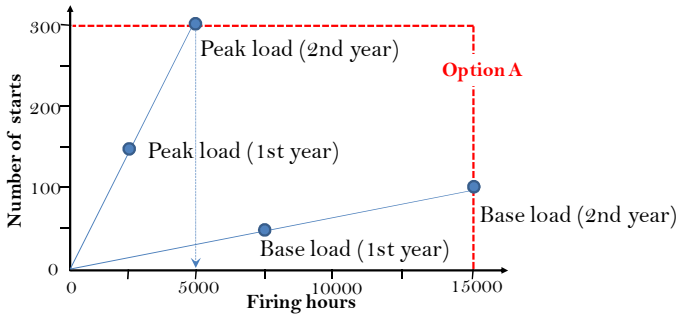


Fig. 2. Maintenance intervals of base-load and peak-load cycling regimes.

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.

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[6] From this point of view, the amount of EOH depends on the operation regime.

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. 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. This is a quite important idea that drives a relevant discussion in the second part of this paper.

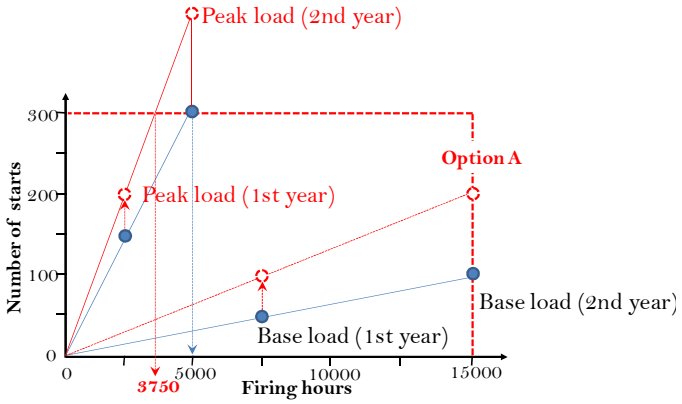


Fig. 3. Baseline functions for maintenance interval.

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 threshold[7]. This same reasoning can be easily extended to more complex functional forms of MIFs.

3 MODELING LTSA COSTS IN THE UNIT COMMITMENT PROBLEM

As previously introduced, conventional unit commitment models have traditionally included variable O&M cost as an energy-cost adder component[8]. This simple modeling assumption leaves aside relevant information that, as we shall discuss, plays a relevant role in the overall production cost minimization problem. In this section we focus on how to properly consider the major overhaul (which as stated represents the most relevant source of variable O&M costs) embedded in LTSA contracts in a more detailed manner. Other types of maintenances also driven by Maintenance Interval Functions (MIFs) can be modeled following the methodology described.

[7] 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.

[8] Or equivalently, on a per-firing-hour cost adder component (which is very similar, but problably makes more sense from the point of view of an LTSA contract).

Computing the major overhaul cost to be allocated in the unit commitment time scale

The total cost corresponding to a major inspection under the LTSA agreement can be considered as a constant value determined at the moment the LTSA is signed. However, as we have just seen, the interval of this inspection depends on the operation regime, and particularly, on the number of starts and the number of firing hours.

In order to take into account these medium-term costs in the short-term unit-commitment problem, it is necessary to properly determine which portion of these costs has to be allocated in each period of interest (e.g. a week or a month). The simplest approach entails carrying out a uniform cost allocation along the periods where the unit is not on a scheduled maintenance. This way, for instance, if the unit commitment determines that the plant must experience a major overhaul every 4 years, we would assume that every year we incur in one fourth of total maintenance costs (and 1/48 of total costs in one month). This is a reasonable hypothesis as long as the period analyzed in the unit commitment can be considered to cover a time horizon long enough so as to be representative of the medium-term operation regime of the plant.

Modeling the Maintenance Interval Function (MIF) in the unit-commitment problem

Let us first denote by FH and S the number of firing hours and the number of starts carried out by a certain plant in the scope defined within the context of the unit commitment problem. In order to represent the most general case of the MIF previously introduced (Option B), let us also consider the piece-wise linear MIF shown below in the figure (consisting of just three linear segments for the sake of simplicity). Note that this piece-wise function is convex, which, as shown previously, it is the case for the three types of contracts reviewed.

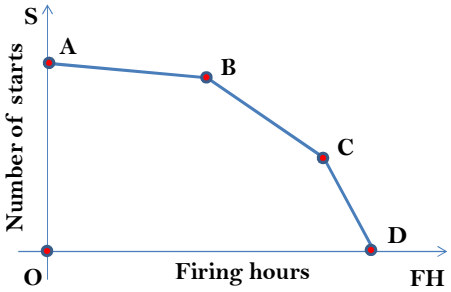


Fig. 4. Piece-wise linear MIF.

Let us also denote by MOC the major overhaul cost of the plant being modeled.

The main objective consists of representing the total variable O&M cost of a CCGT plant as a function of 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 cost function is univocally defined when taking into account all the following three conditions:

- On the one hand we know that all operating modes (all pairs of FH and S) falling over the MIF lead to an O&M cost component in the unit commitment equal to the whole MOC value.
- On the other hand, we also know that the operating regime corresponding to a null operation (zero starts and zero firing hours) leads to no O&M cost.
- For any other pair of FH and S, the O&M cost to be imputed in the unit commitment is derived by applying the uniform O&M allocation through the whole interval that was described above.

These three conditions entail that, if for any operating regime R, defined by the pair FH and S (see Fig. 5), we represent the linear function passing through the point it defines in the FH and S axes (abscissa and ordinate respectively) and the origin (O), and we determine the intersection point of this linear function with the MIF (denoted by I), then, the corresponding proportion of the major overhaul

cost to be imputed during the unit commitment period is just the quotient between the length of the segments OR and OI.

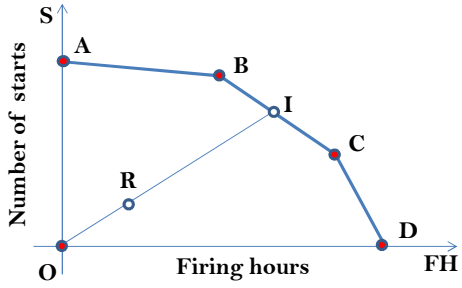


Fig. 5. Proportion of the MOC to be allocated as a function of the operation regime.

It is straightforward to derive that the so-defined cost function simply consists of a set of planes. In particular, as represented below in Fig. 6, for each triangular area delimited by the origin and the extremes of each of the MIF segments, the equation determining the costs is provided by the plane that takes a zero value at the origin and the MOC value at each of the two extremes of the corresponding segment. This way, the plane that defines the costs corresponding to all regimes contained within the triangular area 1 (defined by the area delimited by points O, A and B) is defined by the following expression.

$$\begin{aligned} &S \cdot MOC \cdot (FH_a - FH_b) - FH \cdot MOC \cdot (S_a - S_b) + \\ &+VOMC \cdot (S_a \cdot FH_b - S_b FH_a) = 0 \end{aligned} \tag{1}$$

Since the objective function of a unit commitment is a cost minimization, we can equivalently express the conditions as the following inequality:

$$\begin{aligned} &S \cdot MOC \cdot (FH_a - FH_b) - FH \cdot MOC \cdot (S_a - S_b) + \\ &+VOMC \cdot (S_a \cdot FH_b - S_b FH_a) \geq 0 \end{aligned} \tag{2}$$

Modeling the cost function associated to a certain MIF in the unit commitment problem just involves defining and introducing one inequality for each of the piece-wise linear segments making up the MIF. For one particular operating regime (FH, S) the cost-minimization coupled with convexity of the MIF will ensure that the $VOMC$ is always defined by the correct plane. In the simple three-piece-wise-linear example, this translates into introducing the three following conditions[9]:

$$\begin{aligned} &S \cdot MOC \cdot (FH_a - FH_b) - FH \cdot MOC \cdot (S_a - S_b) + \\ &+VOMC \cdot (S_a \cdot FH_b - S_b FH_a) \geq 0 \end{aligned} \tag{3}$$

$$\begin{aligned} &S \cdot MOC \cdot (FH_b - FH_c) - FH \cdot MOC \cdot (S_b - S_c) + \\ &+VOMC \cdot (S_b \cdot FH_c - S_c FH_b) \geq 0 \end{aligned} \tag{4}$$

$$\begin{aligned} &S \cdot MOC \cdot (FH_c - FH_d) - FH \cdot MOC \cdot (S_c - S_d) + \\ &+VOMC \cdot (S_c \cdot FH_d - S_d FH_c) \geq 0 \end{aligned} \tag{5}$$

[9] Needless to say that this previous reasoning can be easily extended to piece-wise-linear MIFs defined by any given number of segments.

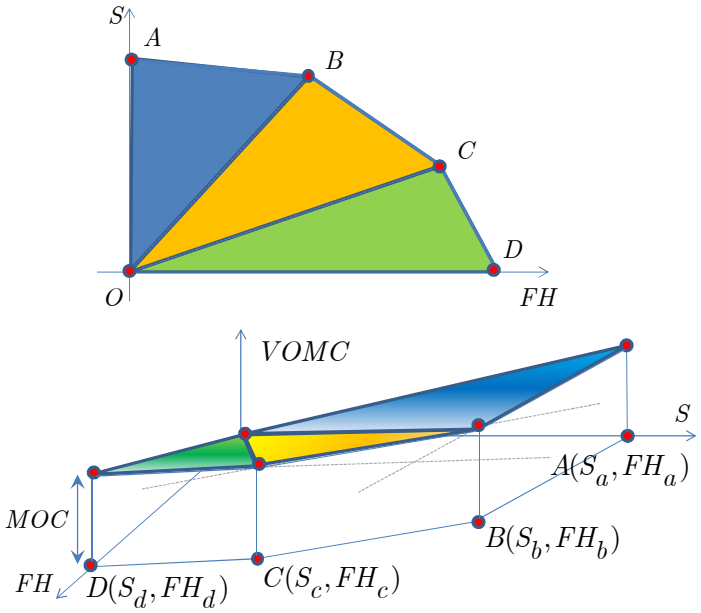


Fig. 6. Piece-wise MIF (above chart) and the corresponding cost function.

These constraints have been incorporated to the basic unit commitment problem formulation, with the objective of performing the analysis carried out in Part II.

4 UNIT COMMITMENT MODEL FORMULATION

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

$$\underset{g_{i,h},u_{i,h}}{Min} \sum_h \sum_i [g_{i,h} \cdot efc_i + u_{i,h} \cdot (nlc_i + omfh_i) + v_{i,h} \cdot sufc_i + NSEC \cdot nse] \tag{6}$$

subject to:

$$\sum_i g_{i,h} + nse = L_h \qquad \forall h \tag{7}$$

$$g_{i,h} \leq \overline{G_i} \cdot u_{i,h} \qquad \forall i,h \tag{8}$$

$$g_{i,h} \geq \underline{G_i} \cdot u_{i,h} \qquad \forall i,h \tag{9}$$

$$u_{i,h} = u_{i,h-1} + v_{i,h} - w_{i,h} \qquad \forall i,h \tag{10}$$

where

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].
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[10] 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].
$u_{i,h}$	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.

For the more detailed O&M cost modeling approach, we need introducing two additional variables: the total amount of starts S_i and the total amount of firing hours FH_i of each plant i, which are defined below in equations (12) and (13). The variable operation and maintenance cost ($VOMC_i$) is defined on the basis of these two variables in equation (14) and introduced in the objective function replacing the previous per-firing hour term.

$$\underset{g_{i,h},u_{i,h}}{Min} \quad \sum_h \sum_i [g_{i,h} \cdot efc_i + u_{i,h} \cdot nlc_i + v_{i,h} \cdot sufc_i + VOMC_i(S_i, FH_i) + NSEC \cdot nse] \tag{11}$$

where the total number of starts and firing hours are:

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

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

For each segment defining the piece-wise-linear approximation of the MIF we have an equation form (for more details see the full explanation in section 3):

$$S \cdot MOC \cdot (FH_a - FH_b) - FH \cdot MOC \cdot (S_a - S_b) + \\ + VOMC \cdot (S_a \cdot FH_b - S_b FH_a) \leq 0 \tag{14}$$

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 $FH_a \geq FH_b$ and $S_a \geq S_b$.

5 CONCLUSION

In this first part of the paper we have first introduced the not-so well-known CCGT O&M Long-Term Service Agreements (LTSAs). We have qualitatively analyzed the impact of these contracts on production costs, finding that they mainly depend on the operating conditions. In particular, the two major drivers conditioning the resulting O&M costs depend on the number of firing hours and on the number of starts. Generally speaking, the lower the ratio between the number of firing hours and the number of starts (what we have denoted as the cycling ration) the more costly maintenances result in terms of per MWh produced.

[10] 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. [22].

Then, on the basis of the previous analysis, we have discussed how the cost associated to O&M LTSA can be easily modeled in the traditional unit commitment optimization problem as a set of linear constraints. The proposed modeling approach offers a much more accurate representation of CCGT O&M costs than the traditional consideration of an additional energy cost adder component.

This new formulation of O&M allows us to perform, in Part II, a study on the major effects of properly considering these O&M LTSAs on the resulting generation dispatch.

PART II: CYCLING CYCLES CYCLING IN THE PRESENCE OF INTERMITTENT GENERATION

Abstract

O&M costs have traditionally been introduced in unit commitment problems by means of an energy cost adder component. In Part I of this paper we discussed how this conventional modeling approach does not serve to reflect the impact of actual CCGTs O&M contracts on the electric power system economic dispatch when these plants run in cycling operation regimes. We also developed an augmented formulation of the unit commitment problem that allows more precisely modeling CCGTs O&M contracts.

In this Part II, we first analyze the relevance of properly representing this source of cost on the basis of a stylized example. Two relevant effects are found when comparing the results with those of the simplified conventional approach: first and foremost, what we have termed as the "cycling cycles cycling" effect, and second, a larger avoidance of starts. This "cycling the cycles cycling" means that the optimal economic dispatch results in the coordination of the schedule of the system's CCGTs portfolio, in such a way that they are all kept at similar high ratios of firing hours per start.

Finally, we complete the previous analysis by presenting a real-size case example with a large presence of wind generation.

1 INTRODUCTION

The massive penetration of the highly variable, less dispatchable and hardly predictable energy resources (hereafter referred to as Variable Energy Resources, or simply VER) poses several challenges that need to be addressed. Most of these challenges arise directly derived from the impacts that VER have on the regular operation and management of the whole electricity system. In particular, the changes that VER can introduce in the scheduling regime of the rest of the generating facilities in the system can have a key impact both in the short and in the long term. We focus here on the effects of increasing the cycling regimes of conventional thermal plants, and particularly of CCGTs plants.

We discussed in Part I how increasing the cycling regime increases the tear and wear of the plant, translating into an increment in terms of O&M-related costs. We also presented a new formulation of O&M costs for unit commitment problems that more closely represents the actual conditions of O&M Long-Term Service Agreements contracts.

Taking advantage of the previous formulation, in this Part II we focus on the analysis of the impact that these O&M Long-Term Service Agreements (LTSAs) have both on the resulting unit commitment and on the cost of the system economic dispatch.

The paper is structured as follows: we first introduce the case example which serves to qualitatively analyze the two major changes that follow from the detailed modeling of the O&M costs. Once these two major effects have been identified, we enlarge the scale of the problem to a real-size case example with a large presence of wind generation. This latter case example will allow us to better characterize the expected functioning regimes of CCGTs in a real system involving running them at heavier cycling regimes.

2 ANALYSIS OF THE IMPACT OF LTSAS ON THE ECONOMIC OPERATION OF CCGTS

O&M costs have traditionally been introduced in unit commitment problems by means of an energy cost adder component. We next analyze how refining this modeling approach by introducing the

Maintenance Interval Function (MIF[11]) introduced in Part I in the problem will significantly affect the economic operation scheduling of the CCGTs plants. In particular, on the basis of a highly stylized case example (a generation portfolio consisting of just two identical CCGTs), 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 (what we have termed as the need to cycle the cycling regime of the different CCGTs).

- 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 the O&M LTSA contract (it heavily depends on the characteristics of the functional form of the MIF and also on the cost of the maintenance inspection).

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. As stated, 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 economic dispatch first assuming the traditionally simplified variable O&M costs and then considering the MIF embedded in the LTSA defined in the Appendix (Option A LTSA type contract, that is, a contract defining a major overhaul interval when the unit reaches any of the following two conditions: either 900 starts or 24000 firing hours).

The formulation of the basic reference unit commitment model used is described in the Appendix of Part I.

2.1 THE FIRST EFFECT: THE NEED TO CYCLE THE CYCLING REGIMES OF CCGTS PLANTS

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).

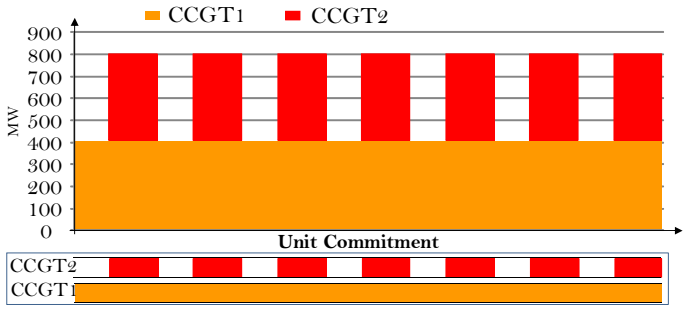


Fig. 1. Economic dispatch with the simplified conventional approach to model O&M costs.

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.

[11] The Maintenance Interval Function (MIF) is a function relating the maximum number of starts and firing hours a CCGT unit can run before a maintenance is triggered.

Let us recall that we defined in Part I the "cycling ratio" as the existing ratio between the number of firing hours and the number of starts.

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.

With the objective of quantifying the error we are introducing with the simplified approach we have used in this first execution of the model, we now properly model the Maintenance Interval Function (MIF). In this way we can accurately compute the O&M costs that result from the operation obtained in the previously computed unit commitment (see Part I for further details on the computation of this cost). Note that we are not using yet the advanced unit commitment model developed in Part I, but only improving the calculation of the O&M costs ex post.

It can be observed (see Table II below) that 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.

TABLE II
ACTUAL O&M COSTS WHEN SIMPLIFYING THE REPRESENTATION
OF MIF IN THE UNIT COMMITMENT PROBLEM

Plant	O&M cost [$]
CCGT 1	280,000
CCGT 2	311,111

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 (see the Appendix in Part I). In this case the variable operation and maintenance cost ($VOMC$) can be mathematically

expressed by means of the next two simple one-variable linear conditions (where S stands for the total number of starts of the unit and FH stands for the number of firing hours of the same unit):

$$45 \cdot VOMC - 2 \cdot 10^6 \cdot S \geq 0 \quad (15)$$

$$600 \cdot VOMC - 10^6 \cdot FH \geq 0 \quad (16)$$

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

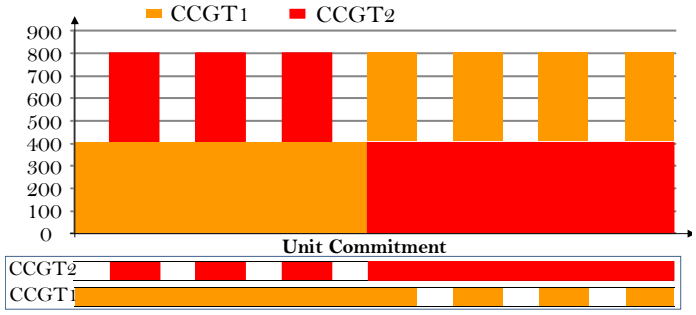


Fig. 2. Economic dispatch modeling O&M costs through the MIF.

We can observe how the starts are now equally allocated between the two CCGTs. We find that (for the CCGT technology), assuming a single format of LTSA, it cannot be assumed a constant merit order, i.e. 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 III
UNIT COMMITMENT RESULTS WITH THE PROPOSED APPROACH TO MODEL O&M COSTS

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). This way, both units are now out of the region of functioning regimes implying that increasing by one the number of starts would also increase the O&M costs.

2.2 THE SECOND EFFECT: THE REDUCTION OF THE NUMBER OF CCGT 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 regime[12] (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.

[12] 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.

In the case of gas turbines, and in particular in the case of CCGTs, O&M 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 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 MIFs in detail.

As a way to illustrate this previous qualitative analysis, we resort again to the same case example. In order 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 contract, 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.

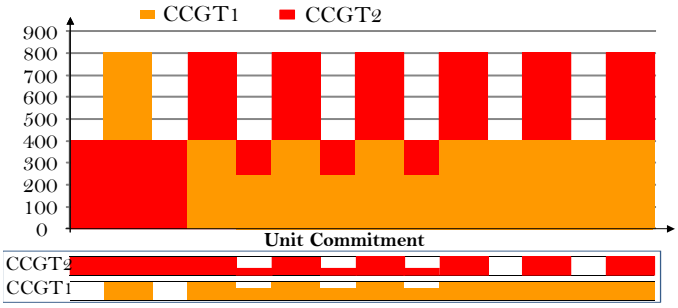


Fig. 3. Unit commitment when reducing the MIF starts' limit to 450.

Next, we further reduce the number of starts by mandating a major overhaul after only 150 starts. In this case (see Figure 4), 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.

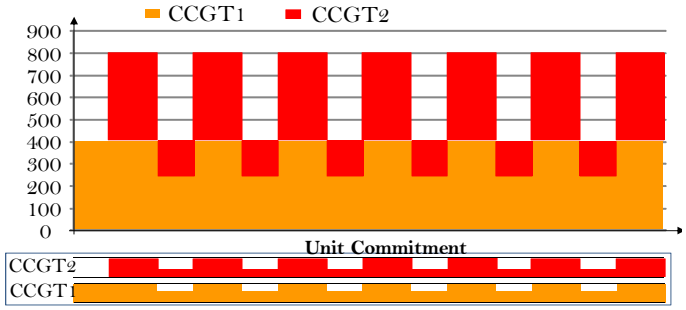


Fig. 4. Unit commitment when reducing the maximum number of starts (150) defined in the MIF.

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 so as to avoid a start.

3 AN ALTERNATIVE SIMPLIFYING MODELING APPROACH: THE START UP COST ADDER COMPONENT

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

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 will contradict this initial assumption: the optimal unit commitment solution would minimize the number of times these units would start (right the opposite of what was assumed).

4 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 used[13]. Wind has been directly subtracted from the demand (thus, curtailment is not considered). The resulting load curve is the so-called net load.

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. 5. 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.

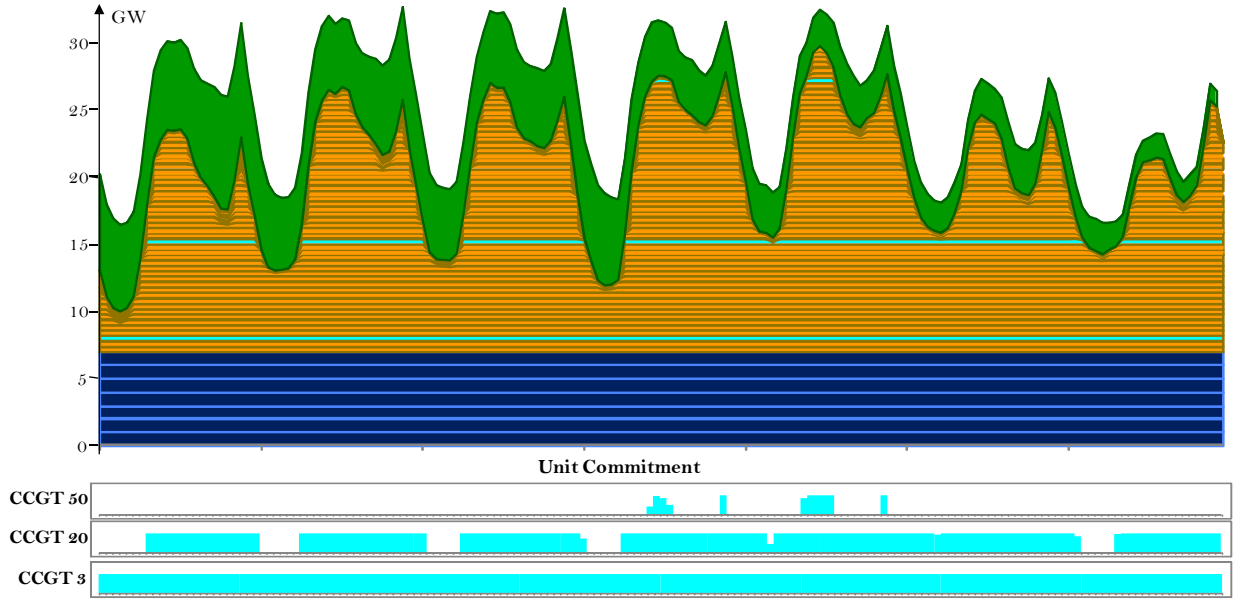


Fig. 5. Characterization of all operating regimes.

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 Figure 6, 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.

[13] 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 [1] 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

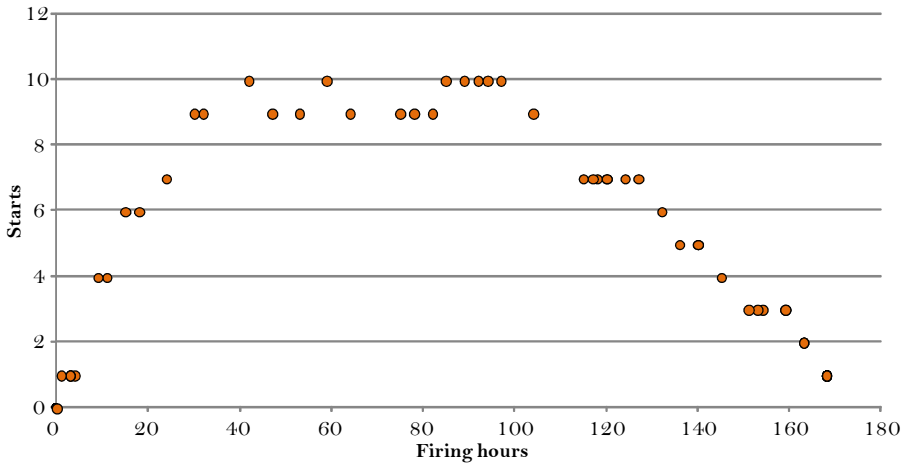


Fig. 6. Characterization of all operating regimes.

Next, we compute the unit commitment where we now model the MIF as shown in equations (15) and (16). 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. 7, 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.

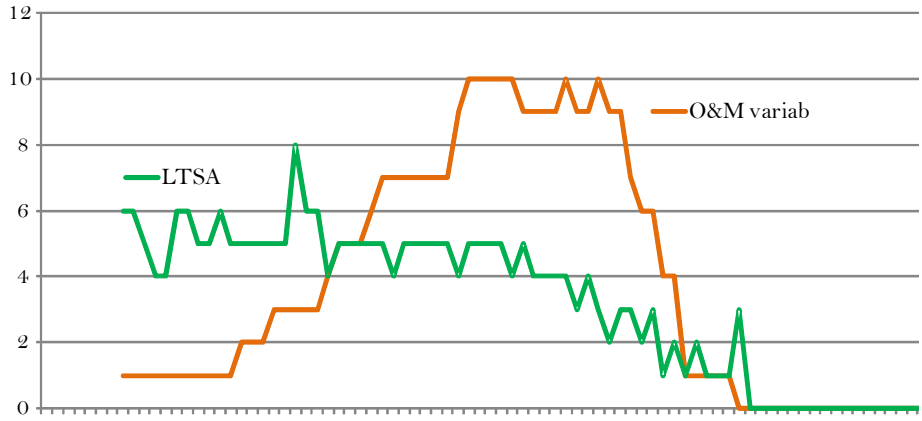


Fig. 7. Number of starts on a unit by unit basis with both modeling approaches.

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. 9, 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.

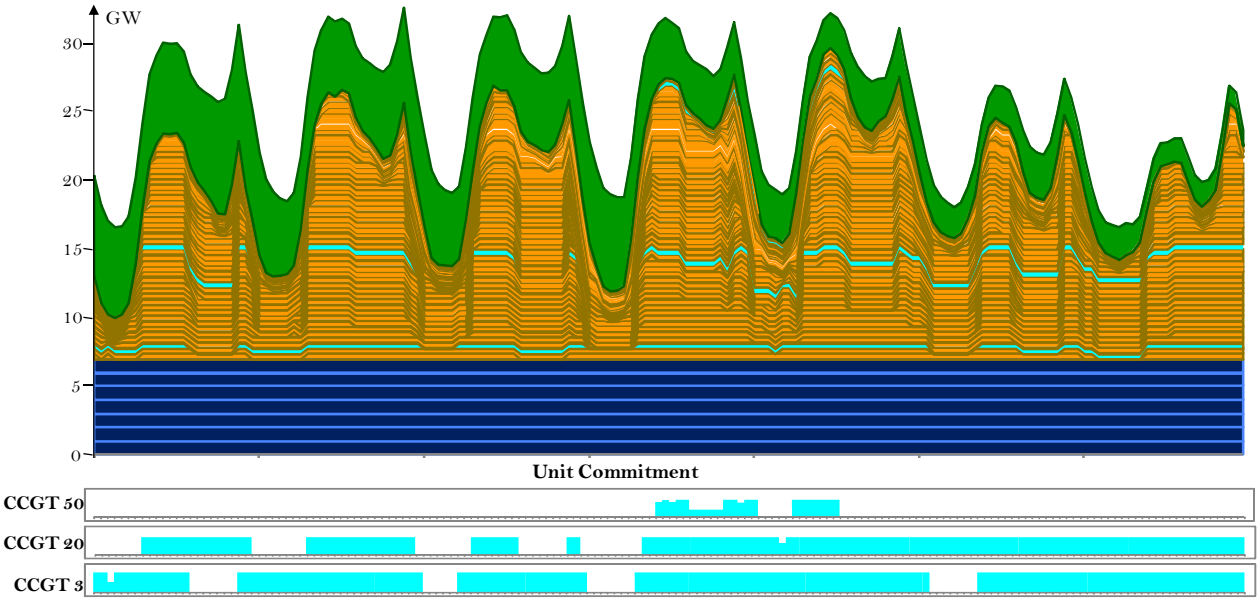


Fig. 8. Characterization of all operating regimes.

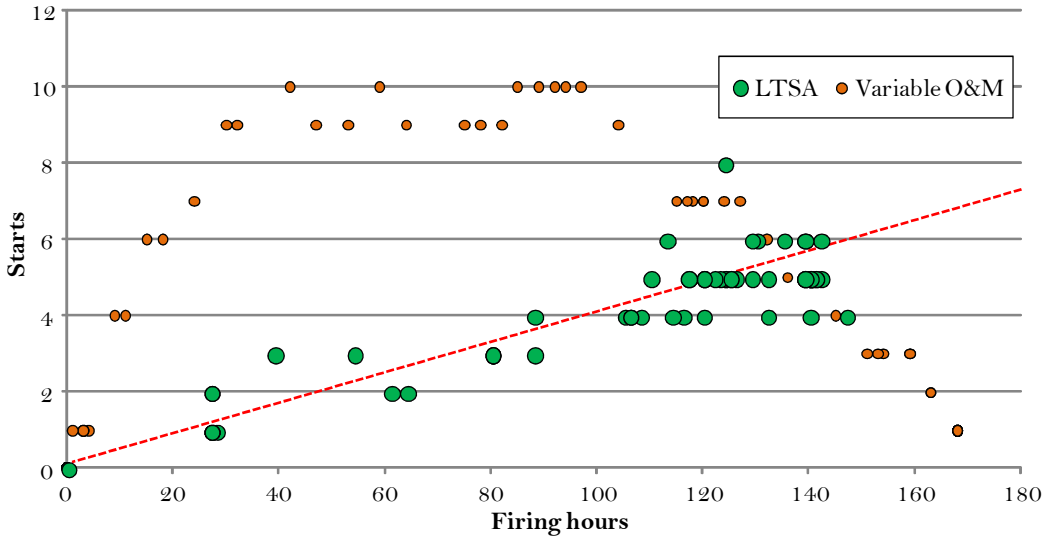


Fig. 9. Cycling ratios.

5 CONCLUSION

In this paper we discuss and model the impact that CCGTs O&M contracts, the so-called LTSAs, have on the unit commitment problem. We show how the simplified methodology traditionally used to represent O&M costs in unit commitment models is not well-suited for capturing the O&M real impact when thermal plants are scheduled subject to heavy cycling regimes. These cycling regimes were exceptional in the past, however, the fast deployment of VER is turning them into the regular required dispatch for many types of thermal units, especially for CCGTs.

In order to adequately analyze the effect a proper consideration of these LTSAs may suppose for the resulting scheduling, we have used the novel formulation developed in Part I, which allows including them in the traditional unit commitment optimization problem as a set of linear constraints. The centralized optimization of generation dispatch does not represent what is presently the situation in the liberalized context implemented in most countries, however, it does represent a good reference to understand the implications these LTSA contracts can introduce in the resulting schedule.

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

intermittent generation is what we have termed as the "cycling cycles cycling" effect. This "cycling the cycles cycling" means that the optimal generation dispatch results in schedules of the system's CCGTs portfolio so 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 some CCGTs fully focused on producing at base-load regimes (low cycling) and others CCGT 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, which is how the trend to avoid starts by producing at the minimum stable output during valley (e.g. nights) strongly depends on these LTSA contracts.

Since the conditions of the LTSA contracts determine the importance of the previous two effects, one relevant question in this respect is which is the effect of the not having optimally negotiated these contracts. Sub-optimal contracting can be the consequence of not having anticipated correctly a strong penetration of VER. Until very recently, especially for the case of CCGTs, some technologies were expected to be scheduled in a base load regime. For them no limitation derived from the number of starts has been an issue. Therefore, traditionally generators have paid very little attention to the starts limits in their LTSAs. For instance, in the Spanish case there are apparently cases in which LTSAs for NGCC consider values in the range of 24000 hours and 150 starts.

We face then the LTSAs pitfall side (Thompson and Yost, 2003). Particularly when the expected operation regime of the plants changes significantly from the expected one at the time of facing the investment decision. A plant developer who assumed that the plant would be used in base load operation, due to the large penetration of VER can find that the plant is operating in cyclic conditions where the load at off-prime time can be as low as 40–50% of the base load and the number of starts may have tripled. These changes in operation in many cases require maintenance and inspection changes, meaning that the owner has to bear a significant amount of risk, or that may result in costly and time-consuming disputes with the OEM.

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 [23].

where FOM the Fixed O&M costs [2010k$/MW-yr], HR the Heat Rate [kBtu/MWh], VOM the Variable O&M [$/MWh], FP [$/kBtu], VOF the Variable Operating Fuel costs [$/MWh], SU the Start-Up cost [$/start-MW] and NLC the No Load Cost [$] (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 of Part I. 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 $/FH (that is 40e6$/24000FH).

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