

# Medium-Term Unit Commitment in a Pool Market

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**Abstract**—We consider a mandatory pool, based to the one established in the Greek electricity market, in which the unit commitment and the scheduling of energy and reserves are the solution of *Day-Ahead Scheduling* (DAS), an optimization problem that is solved daily and aims to minimize the system cost for the next day. The single-day horizon of DAS may be rather short for capturing the effects of the long start-up times and large commitment costs of slow-start lignite units; hence, the DAS solution may be myopic, resulting in higher total costs in the long-run. To tackle this problem, the Greek market uses a heuristic approach, in which the units' shut-down costs are replaced by their start-up costs and the start-up costs are suppressed; this facilitates the start-up and discourages the shut-down of slow-start units. To address and evaluate the “myopic solution” issue of DAS more rigorously, we extend the unit commitment problem to a longer horizon of several days, and keep only the solution for the next day as binding (rolling horizon). We call the resulting approach *Medium-Term Unit Commitment* (MTUC). We compare the long-run average performance of the MTUC output for different horizon lengths (2, 4 and 7 days) to that of the heuristic DAS approach used in the Greek market. The results show that MTUC brings in a small reduction in the total system cost.

## I. NOMENCLATURE

### A. Sets-Subsets-Indices

$U$	Generation units, indexed by $u$
$U_{AGC}$	Generation units that can operate in AGC mode ( $U_{AGC} \subseteq U$ )
$h$	Hour (time period)

### B. Parameters

$Q_u^{\max}$	Technical maximum of unit $u$
$Q_u^{\min}$	Technical minimum of unit $u$
$AGC_u^{\max}$	Technical maximum of unit $u$ under AGC
$AGC_u^{\min}$	Technical minimum of unit $u$ under AGC
$MU_u$	Minimum uptime of unit $u$
$MD_u$	Minimum downtime of unit $u$
$PR_u^{\text{offer}}$	Primary reserve offer of unit $u$
$SRR_u^{\text{offer}}$	Secondary reserve range offer of unit $u$
$TR_u^{\text{offer}}$	Tertiary reserve offer of unit $u$

$P_{u,h}^g$	Price of energy (generation) offer of unit $u$ , hour $h$
$P_{u,h}^{pr}$	Price of primary reserve offer of unit $u$ , hour $h$
$P_{u,h}^{sr}$	Price of secondary reserve offer of unit $u$ , hour $h$
$P_{u,h}^{tr}$	Price of tertiary reserve offer of unit $u$ , hour $h$
$SUC_u$	Start-up cost of unit $u$
$SDC_u$	Shut-down cost of unit $u$
$NLC_u$	No-load cost of unit $u$
$G_{u,h}^{\text{mand}}$	Mandatory output of unit $u$ , hour $h$
$ST_u^0$	Initial status of unit $u$ (at hour 0)
$X_u^0$	Number of hours unit $u$ has been “ON” at hour 0
$W_u^0$	Number of hours unit $u$ has been “OFF” at hour 0
$SL_h$	System load in hour $h$
$RES_h$	RES injections in hour $h$
$Imp_h$	Imports in hour $h$
$Exp_h$	Exports in hour $h$
$Pump_h$	Pumping in hour $h$
$PR_h^{\text{req}}$	Primary reserve requirement in hour $h$
$SRU_h^{\text{req}}$	Secondary reserve up requirement in hour $h$
$SRD_h^{\text{req}}$	Secondary reserve down requirement in hour $h$
$TR_h^{\text{req}}$	Tertiary reserve requirement in hour $h$
$G_{pen}^{\text{tot}}$	Penalty coefficient related to the energy balance constraint
$PR_{pen}^{\text{def}}, SR_{pen}^{\text{def}}, TR_{pen}^{\text{def}}$	Penalty coefficients related to the reserve requirement constraints

### C. Variables

$ST_{u,h}$	Status (condition) of unit $u$ , hour $h$ – Binary variable: 1 = ON(LINE), 0 = OFF(LINE)
$G_{u,h}$	Generation (output) of unit $u$ , hour $h$ , (not including the mandatory injections)
$G_{u,h}^{\text{tot}}$	Total generation (output) of unit $u$ , hour $h$
$PR_{u,h}$	Primary reserve of unit $u$ , hour $h$
$SRD_{u,h}$	Secondary reserve down of unit $u$ , hour $h$
$SRU_{u,h}$	Secondary reserve up of unit $u$ , hour $h$
$TR_{u,h}$	Tertiary reserve of unit $u$ , hour $h$
$AGC_{u,h}$	AGC condition of unit $u$ in hour $h$ – Dependent

$Y_{u,h}$	binary variable: 1 = In AGC mode, 0 = Not in AGC mode
$V_{u,h}$	Start-up signal for unit $u$ in hour $h$ – Dependent binary variable: 1 = Start-up, 0 = No start-up
$X_{u,h}$	Shutdown signal for unit $u$ in hour $h$ – Dependent binary variable: 1 = Shutdown, 0 = No shutdown
$W_{u,h}$	Number of hours unit $u$ has been ON at hour $h$ since last startup – Integer variable
$G_h^{tot,def}, G_h^{tot,sur}$	Deficit and surplus variables related to the energy balance constraint in hour $h$
$PR_h^{def}, SRU_h^{def}, SRD_h^{def}, TR_h^{def}$	Deficit variables related to the reserve requirement constraints in hour $h$

## II. INTRODUCTION

The unit commitment and generation scheduling problem has attracted much attention over the last decades [1]-[5]. In general, deregulated electricity markets fall in two categories: those where the unit commitment is decided by an *Independent System Operator* (ISO), based on bids submitted by the market participants, and those where the unit commitment is the responsibility of the market participants and is based on their profit maximization strategy [1].

In this paper, we consider a mandatory pool of the first category, based on the Greek electricity market design, in which the daily unit commitment and energy and reserve quantities are the solution of the *Day-Ahead Scheduling* (DAS) problem; DAS is a mathematical programming problem which is solved daily and aims to minimize the unit energy, reserves, and commitment costs over the 24-hour period horizon of the following day.

The DAS solution may provide a myopic and rather inefficient unit commitment, especially for slow-start lignite units, resulting in higher total costs in the long-term. Slow-start units comprise units with long start-up times and large commitment costs. Usually, they are base-units, since such units have a significantly low variable cost, and are committed for a long period before being de-committed, typically because of an unexpected unit trip or maintenance. In pool markets with slow-start non-flexible units, DAS fails to take into account the start-up sequences of these units and the long-term economic impact of commitment costs that extends far beyond the short-term 24-hour horizon.

To address the latter issue, the market rules in the Greek design rely on a heuristic approach which requires that the start-up cost be excluded from the objective function of DAS and the shut-down cost be included with a value that is equal to the start-up cost from the intermediate state. This way, DAS easily starts-up units but discourages their shut-down. This heuristic DAS approach, however, has the drawback that not all the components of the commitment costs, namely start-up, shut-down, and no-load costs, are explicitly represented in the DAS problem.

To overcome this drawback, we examine a so-called *Medium-Term Unit Commitment* (MTUC) problem, which has exactly the same formulation as the DAS, except that its

horizon is several days, as opposed to a single day. Since a week constitutes a natural cycle, a weekly (168-hour) horizon should be appropriate for the MTUC problem, though the length of the optimization period could be reduced to 4-6 days, corresponding to the respective start-up times of the slowest thermal unit.

Due to space considerations, here, we only deal with the issue of large commitment costs and not with that of the long start-up sequence, as the modeling of this sequence requires additional space and explanations. The interested reader is referred to [6] for a more detailed model of the unit commitment and generation scheduling problem, which can be straightforwardly applied in the herein described methodology.

It is expected that the longer the horizon of MTUC, the more efficient the outcome, but also the larger the error of the load forecast, a critical parameter of the optimization problem. Furthermore, other uncertainties may affect the solution, such as the availabilities of the generation units. A stochastic optimization approach that takes into account the outages of the generation units was presented in [7]. In addition, a longer horizon may significantly increase the computational effort needed to solve the resulting larger problem.

In this paper, the unit commitment and generation scheduling problem is deterministic; the stochastic parameters can be further investigated by examining a sufficiently large number of randomly generated scenarios. The objective is to evaluate the outcome of MTUC, run on a rolling basis, by simulating the (medium scale) Greek market for an entire year (365 days). These results are compared with the results of the heuristic DAS approach used in the Greek market, run on a rolling basis, for 365 days.

The remainder of this paper is organized as follows. In Section III, we briefly sketch the DAS problem, and in Section IV, we describe the heuristic DAS approach used in the Greek market and the MTUC problem. In Section V, we list the input data for evaluating the different approaches, and in Section VI, we present the numerical results. Lastly, in Section VII, we draw our conclusions and discuss issues that deserve further research.

## III. THE DAS PROBLEM

The DAS problem is solved daily, simultaneously for all 24 hours of the next day. The objective is to minimize the cost of matching the energy to be absorbed with the energy to be injected in the system, while meeting the reserve requirements and the generation units' technical constraints. The DAS solution defines how each unit should operate in each hour, and determines the clearing prices of the energy and reserves.

In our model, we consider all available generation units, namely, thermal and hydro plants, imports, injections from the *Renewable Energy Sources* (RES), mandatory injections from the hydro plants, exports, and pumping stations. Reserves include primary, secondary up and down, and tertiary reserve (including spinning and non-spinning). The system load and the reserve requirements are exogenously determined by the *Hellenic Transmission System Operator*

(HTSO), and, for the purposes of this paper, are considered as parameters of the optimization problem. The transmission constraints, which in the case of Greece's electricity market, amount to a North-to-South transmission corridor constraint, are not included in the model; it is expected that, for the load levels which are used in the numerical investigation, the transmission constraint will hardly ever be binding.

The producers submit energy offers for each hour of the following day as a stepwise function of price-quantity pairs, with successive prices being strictly non-decreasing. For simplicity, we assume a single price bid for energy. The producers also submit reserve bids as price-quantity pairs, and their commitment costs, namely start-up, shut-down and no-load costs. The technical characteristics of the generation units that constitute the constraints of the DAS problem include the technical minimum and maximum output, the AGC minimum and maximum, the maximum reserve availability, and the minimum uptimes and downtimes. Ramp up/down limits are not considered in our analysis as they are rarely binding, and their impact on the yearly results is negligible.

DAS can be formulated as a *Mixed Integer Programming* (MIP) problem. In the following, and unless otherwise mentioned,  $u$  refers to the general set  $U$ , and  $h$  to the 24-hour horizon of the DAS problem.

#### Objective Function:

$$\min \left\{ \begin{array}{l} \text{Generation Cost + Reserves Cost} \\ + \text{Commitment Cost + Penalty Cost} \end{array} \right\} \quad (1)$$

#### Cost Components:

$$\text{Generation Cost} = \sum_{u,h} P_{u,h}^g \cdot G_{u,h} \quad (2)$$

$$\text{Reserves Cost} = \sum_{u,h} \left\{ \begin{array}{l} P_{u,h}^{pr} \cdot PR_{u,h} + P_{u,h}^{sr} \cdot (SRU_{u,h} + SRD_{u,h}) \\ + P_{u,h}^{tr} \cdot TR_{u,h} \end{array} \right\} \quad (3)$$

$$\text{Commitment Cost} = \sum_{u,h} \left\{ \begin{array}{l} Y_{u,h} \cdot SUC_u + V_{u,h} \cdot SDC_u \\ + ST_{u,h} \cdot NLC_u \end{array} \right\} \quad (4)$$

$$\text{Penalty Cost} = \sum_h \left\{ \begin{array}{l} G_{pen}^{tot} (G_h^{tot,def} + G_h^{tot,sur}) \\ + PR_{pen}^{def} \cdot PR_h^{def} \\ + SR_{pen}^{def} (SRU_h^{def} + SRD_h^{def}) \\ + TR_{pen}^{def} \cdot TR_h^{def} \end{array} \right\} \quad (5)$$

#### Constraints:

##### Energy Balance:

$$\sum_u G_{u,h}^{tot} + Imp_h + RES_h + G_h^{tot,def} - G_h^{tot,sur} = SL_h + Exp_h + Pump_h \quad \forall h \quad (6)$$

#### Reserve Requirements:

$$\sum_u PR_{u,h} + PR_h^{def} \geq PR_h^{req} \quad \forall h \quad (7)$$

$$\sum_u SRU_{u,h} + SRU_h^{def} \geq SRU_h^{req} \quad \forall h \quad (8)$$

$$\sum_u SRD_{u,h} + SRD_h^{def} \geq SRD_h^{req} \quad \forall h \quad (9)$$

$$\sum_u TR_{u,h} + TR_h^{def} \geq TR_h^{req} \quad \forall h \quad (10)$$

#### Capacity and AGC Limits:

$$G_{u,h}^{tot} + PR_{u,h} + SRU_{u,h} + TR_{u,h} \leq Q_u^{\max} \cdot (ST_{u,h} - AGC_{u,h}) + AGC_{u,h} \cdot AGC_u^{\max} \quad \forall u, h \quad (11)$$

$$G_{u,h}^{tot} - SRD_{u,h} \geq Q_u^{\min} \cdot (ST_{u,h} - AGC_{u,h}) + AGC_{u,h} \cdot AGC_u^{\min} \quad \forall u, h \quad (12)$$

$$AGC_{u,h} \leq ST_{u,h} \quad \forall u, h \quad (13)$$

$$AGC_{u,h} = 0 \quad \forall u \notin U_{AGC}, h \quad (14)$$

#### Reserve Availabilities:

$$PR_{u,h} \leq ST_{u,h} \cdot PR_u^{offer} \quad \forall u, h \quad (15)$$

$$SRU_{u,h} + SRD_{u,h} \leq AGC_{u,h} \cdot SRR_u^{offer} \quad \forall u, h \quad (16)$$

$$TR_{u,h} \leq ST_{u,h} \cdot TR_u^{offer} \quad \forall u, h \quad (17)$$

#### Minimum Up/Down Times:

$$(X_{u,h-1} - MU_u)(ST_{u,h-1} - ST_{u,h}) \geq 0 \quad \forall u, h \quad (18)$$

$$(W_{u,h-1} - MD_u)(ST_{u,h} - ST_{u,h-1}) \geq 0 \quad \forall u, h \quad (19)$$

#### Constraints for Dependent Variables:

$$G_{u,h}^{tot} = G_{u,h}^{mand} + G_{u,h} \quad \forall u, h \quad (20)$$

$$Y_{u,h} = ST_{u,h} (1 - ST_{u,h-1}) \quad \forall u, h \quad (21)$$

$$V_{u,h} = ST_{u,h-1} (1 - ST_{u,h}) \quad \forall u, h \quad (22)$$

$$X_{u,h} = (X_{u,h-1} + 1)ST_{u,h} \quad \forall u, h \quad (23)$$

$$W_{u,h} = (W_{u,h-1} + 1)(1 - ST_{u,h}) \quad \forall u, h \quad (24)$$

#### Initial Conditions:

$$ST_{u,0} = ST_u^0 \quad \forall u, h \quad (25)$$

$$X_{u,0} = X_u^0 \quad \forall u, h \quad (26)$$

$$W_{u,0} = W_u^0 \quad \forall u, h \quad (27)$$

with  $G_{u,h}^{tot}, G_{u,h}, PR_{u,h}, SRU_{u,h}, SRD_{u,h}, TR_{u,h} \geq 0, \forall u, h$ .

The penalty cost is an additional term imposed in the objective function to deal with infeasibilities. More specifically, selected constraints are relaxed through the introduction of deficit ("slack") and surplus variables which are multiplied with appropriate penalty coefficients, imposing additional weights in (1). The penalty coefficients are selected in such a way that they relax the constraints in the following order: (a) tertiary reserve requirements, (b) secondary reserve requirements, (c) primary reserve requirements, and (d) energy balance (the last to be relaxed).

Note that constraints (18), (19) and (21)-(24), though not linear, can be easily replaced with equivalent linear inequalities, introducing auxiliary variables wherever necessary. The formulation that results after these replacements is a *Mixed Integer Linear Programming* (MILP) problem that can be modeled and solved with any available MILP solver. Once the MILP problem is solved, a *Linear Programming* (LP) problem is created by fixing the integer variables at their optimal values and dropping the constraints that involve only integer variables. The LP formulation allows for the calculation of clearing prices using marginal pricing theory [8]. The energy clearing price, also called *System Marginal Price* (SMP), is determined as the shadow price of the energy balance constraint (6).

#### IV. UNIT COMMITMENT APPROACHES

In this section, we present two alternative approaches for addressing the “myopic solution” issue of the DAS problem.

##### A. Heuristic DAS Approach

The current practice in the Greek electricity market is to include as commitment costs in the objective function only the shut-down cost, but with a value which is equal to the start-up cost from the intermediate state. This is done in order to deter DAS from reaching a solution which easily shuts down units. Under this approach, an offline unit may be easily started up, since the start-up cost is artificially set to zero.

Under this heuristic approach, the commitment cost given by (4) is replaced by the following equation:

$$\text{Commitment Cost} = \sum_{u,h} V_{u,h} \cdot SUC_u \quad (28)$$

Note that according to the current Greek market rules, the no-load cost is not included in the commitment costs.

##### B. MTUC (Rolling Horizon)

The simplest approach to solve the “myopic solution” issue of the 24-hour (single-day) DAS problem is to extend the time horizon to several days (MTUC approach). This extension should be long enough, in order to capture the long start-up sequences of the slow-start units, and allocate the impact of the large start-up costs to a longer period.

A disadvantage of extending the unit commitment and scheduling horizon is that it increases the uncertainty in important parameters, such as the load forecast and the outages of the generation units. Another disadvantage is that it increases the problem size. The latter disadvantage is not addressed in this paper, since for the herein medium-scale case study the weekly problem is still tractable; for larger systems several approaches have been proposed in the literature [5], [9]-[11].

The former disadvantage is addressed in this paper with the use of a rolling horizon. The rolling horizon updates every day the load forecast and takes into account the outages that occurred up to the time that the optimization problem is solved. Therefore, although the solution of the optimization

problem covers several days in the future, only the part of the solution that refers to the next day is binding. As a consequence, it is expected that the impact of the introduced uncertainties on the final outcome will be limited.

In this paper, we consider three values for the rolling horizon: 2, 4, and 7 days. Actually, the 2-day horizon is not sufficient to capture the long start-up sequence of the slow start units; nevertheless, we include it in our analysis for comparison purposes.

#### V. INPUT DATA

In this section, we present the input data that we used for solving the DAS problem on an instance representing the Greek electricity market with a projection for year 2013. Due to space considerations, we shall not provide in much detail all the input data. The reader is referred to [12] for the publicly available data and to [13] for a more analytic presentation of the units’ technical and economical characteristics.

The generation units that are assumed to be in operation in 2013 are shown in Table I.

TABLE I  
GENERATION UNITS

Unit Type	Number of Units	Installed Capacity (MW)	Emission Rates (tonCO <sub>2</sub> /MWh)
Lignite	18	4,338	1.04-1.96
CCGT	11	4,411	0.37-0.49
OCGT	4	297	0.53
Gas	2	339	0.6
Oil	4	698	0.74-0.8
Hydro	15	3,018	-
<b>Total Capacity:</b>		<b>13,101</b>	

For simplicity, we did not consider each hydro unit separately; instead we considered an aggregate unit that submits an energy offer above the last thermal unit for the non mandatory injections. The energy offers include also the emissions cost calculated with a value of 15 € per ton CO<sub>2</sub>. In order to remove the impact of the reserve bids on the SMP, and potential gaming that may be exercised through the bids for reserve, we assumed zero-priced reserve offers. The maintenance schedule and the outage rate were assumed to be the same as in the year 2009. For the needs of our analysis, we generated Bernoulli-distributed random outages for each day based on the *Equivalent Demand Forced Outage Rate* (EFOR<sub>D</sub>) values, which provide a measure of the probability that a generation unit will not be available due to a forced outage. The time for the repair of an outage was assumed to be 2 days. For the aggregate hydro unit, we assumed a total available capacity of 2,600 MW, taking into account the average EFOR<sub>D</sub> of the hydro units.

To provide an order of magnitude for the energy offers and the commitment costs, we refer to some typical units. A lignite unit with a capacity of 300MW has a variable cost of 50€/MWh, including the emissions cost, and a start-up cost equal to 80,000€, whereas a CCGT unit with a capacity of

380MW has a variable cost of 65€/MWh, including the emissions cost, and a start-up cost equal to 14,000€.

In order to obtain realistic results, we assumed the following bidding behavior for the market participants: the dominant company is bidding at the variable cost, whereas the privately-owned power plants submit bids that exceed their variable cost. This assumption is not far from the current practice, which can be easily verified by observing the daily DAS results.

As input parameters for the hourly load, the mandatory hydro injections and the pumping profile, we used the data of the year 2009, which are available in [12], assuming that the load levels for 2013 will be similar. The hourly imports and exports were considered to be equal to 600 MW and 300 MW respectively. The hourly RES injections were considered equal to 600 MW. The primary and secondary down reserve requirements were set at 80 MW and 150 MW, respectively. For the secondary up reserve we used a daily profile for hours 1-6: 100MW, 7-13: 350MW, 14-17:250MW, 18-21:350MW, 22-24: 250MW. The tertiary reserve requirement was set at 5% of the system load.

The penalty coefficients (in €/MWh) for the violation of the constraints (6)-(10) were set at 25,000 for the energy balance, 20,000 for the primary reserve, 15,000 for the secondary reserve (both up and down) and 10,000 for the tertiary reserve.

## VI. NUMERICAL RESULTS

We modelled the DAS and MTUC problems with GAMS 23.6 [14] and solved it with CPLEX 12.2 solver on an Intel Core i7 at 2.67GHz, with 3GB RAM. The optimality gap was set at 0.01% and integrality was assigned a zero value.

Table II shows the problem size and average computational times for the different time horizons.

TABLE II  
PROBLEM SIZE AND COMPUTATIONAL TIMES

Horizon	# Continuous Variables	# Discrete Variables	# Constraints	Computational Time (s)
1 day	4,945	7,880	29,169	2.5
2 days	9,889	15,560	58,929	22
4 days	19,777	30,920	117,681	76
7 days	34,608	53,960	206,049	295

The yearly results are shown in Tables III and IV, where the costs are in euro. The values in the parentheses show the percentage difference in cost of the MTUC approach compared with the heuristic approach, which represents current practice.

TABLE III  
YEARLY GENERATION AND TOTAL COSTS

Horizon	Generation Cost	Total Cost
1 day (heuristic)	2,214,791,132	2,245,240,832
2 days (full)	2,210,277,940	2,238,196,440 (-0.31%)
4 days (full)	2,210,013,353	2,237,848,353 (-0.33%)
7 days (full)	2,207,387,653	2,234,598,625 (-0.47%)

TABLE IV  
YEARLY START-UPS AND COMMITMENT COSTS

Horizon	# Start-ups	Commitment Costs
1 day (heuristic)	1,287	30,449,500
2 days (full)	1,202	27,918,500 (-8.3%)
4 days (full)	1,178	27,835,000 (-8.6%)
7 days (full)	1,134	26,516,000 (-12.9%)

The results suggest that the MTUC approach outperforms the heuristic DAS approach and leads to a reduction in the total system cost, i.e. to a more efficient dispatching. The reduction in total cost ranges from 0.33% to 0.47%. The reduction is observed in both cost components, namely the generation cost and the commitment cost, as well as in the number of the start-ups.

We also observe that extending the horizon to one additional day is sufficient to improve the total system cost. Bearing in mind that the uncertainty introduced in the optimization problem is increasing in the horizon length, one should carefully consider the tradeoff between a potentially better average performance of a longer horizon – say 7 days – with higher uncertainty compared to that of a shorter horizon – say 4 days – with lower uncertainty.

Two parameters that seem to be critical for the optimization problem are: (a) the error of the load forecast and (b) the unit outages.

To model the error of the load forecast, we changed the load forecast for days  $D + 1$  to  $D + 6$ , where  $D$  stands for the day ahead, by introducing a uniformly distributed random error for day  $D + k$  that ranges from 1.5% to 4%, with equal increments of 0.5% as  $k$  steps from 1 to 6. Preliminary results showed that the yearly outcome is not significantly affected by this error. The results of the MTUC approach with a rolling horizon of 2, 4, and 7 days were in all cases better than those of the heuristic DAS approach. This was more or less expected, as the impact of the longer horizon is that it allocates in several days the large start-up costs. The error in the load forecast may change the short-term outcome, but the aggregate results will not change significantly. In addition, since we have a rolling horizon and we keep only the outcome of the next day, the results are further smoothed out.

Similar observations are made regarding the impact of outages. The randomness of outages may change the short-term outcome, but the aggregate results do not exhibit significant difference. This was also observed in [15], where using a similar iterative procedure for solving the DAS problem, sensitivity analysis with respect to the outages was performed.

## VII. CONCLUDING REMARKS

We proposed an MTUC approach with a rolling horizon of up to 7 days to deal with the “myopic solution” issue of the DAS problem of not taking into account the “legacy” that it passes on to the next day.

The motivation for our analysis stems from the Greek electricity market, where the base-load lignite units have low variable costs, but large start-up costs and long start-up

sequences. The modeling of the start-up sequence definitely requires the extension of the time horizon, whereas the large start-up costs can be included even in a daily horizon. This is actually done in the Greek market, but with a heuristic approach that includes in the objective function of the DAS problem an artificial shut-down cost equal to the start-up cost from the intermediate state. However, this approach suffers from the fact that the objective function fails to accurately describe the commitment costs, and the daily horizon is not sufficient to capture the long start-up sequences.

The proposed MTUC approach with a rolling horizon can solve both the above issues. In this paper, to facilitate the comparisons, we addressed only the former issue of accurately describing the commitment costs in the objective function, so that the only actual difference in the modeling – apart from the time horizon – is the representation of the commitment costs in the objective function.

The gain of the MTUC approach compared with the heuristic DAS approach is two-fold: (a) a reduced yearly system cost and (b) the possibility to model the long start-up sequences of slow-start units.

The first gain was presented and quantified in the numerical results of the Section VI. Although this gain seems to be rather small percentage-wise, the second benefit is expected to be much more significant. In particular, in deregulated markets, where the unit commitment is decided by ISOs, whose operation is close to that in the former regulated environment (the main difference is the use of bids instead of variable costs for the commodities of energy and ancillary services), the MTUC approach is expected to produce a more realistic solution for the unit-commitment and generation scheduling problem. We expect that the benefit will be even more significant in terms of reduction of the system cost.

Another advantage of the proposed design is that it is simple and deterministic. As such, it is expected to be more easily accepted by practitioners and market participants than a complicated, stochastic approach, which cannot be easily understood by the participants. In addition, the rolling horizon reduces the potential impact on the yearly outcome of uncertainties, such as the error of the load forecast and the generation units' outages.

There are still several issues that need to be addressed. Firstly, to get more robust results on the performance of each time horizon, a sufficiently large number of scenarios needs to be examined, with respect to key stochastic parameters, such as the system load, the unit outages, the fuel and emissions prices, etc. Furthermore, the computational burden when the size of the problem becomes large may create tractability problems, requiring an increase in the defined optimality gap in exchange for computational time savings. For this reason, the selection of the time horizon is critical, and the designer should carefully consider the pros and cons of a longer

horizon. The higher optimality gap that may be needed to obtain a solution in a reasonable computational time for a long horizon may not improve the performance of a shorter horizon with a lower optimality gap.

Finally, the impact of such a design on the bidding behavior of the market participants was not addressed in this paper. This issue certainly deserves to be investigated in future work. Firstly, the bidding rules should be designed. Should the participants be allowed to bid for the whole horizon, exactly as they do for the next day? One could say that the more degrees of freedom for the market participants, the better for the market outcome, provided that the market is competitive; however, this should be evaluated, as potential gaming may have the opposite results. Other possible solutions would be to replicate the bids of the next day for the whole horizon or even to use the already submitted bids of the previous week.

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