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Impact on Reserves and Energy Delivery of Current UC-based Market-Clearing Formulations

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***Abstract*—Reserves are playing each time a more important role due to the massive penetration of renewable energy sources nowadays. Operating reserves must be used for unforeseen events. All predictable events must be directly considered in the scheduling stage otherwise there will be an inefficient and unnecessary use of reserves that increases system operation costs and can even endanger the power system security. This paper presents a qualitative assessment of some widely used implicit assumptions in Unit Commitment (UC)-based Market-Clearing (MC) formulations. We show evidence of the impact on reserves and system security due to considering the use of energy blocks in the MC. In addition to this, we present the consequences on the reserve deployment due to the underlying accepted assumptions in UC-based MC formulations. Finally, we give some recommendations which must be incorporated in UC-based MC formulations in order to schedule and use the operating reserves efficiently.**

***Index Terms*—Market clearing, operating reserves, shut-down ramp, start-up ramp, unit commitment, thermal units.**

I. Introduction

Balance between generation and load must always be maintained to keep power systems secure. In synchronous power systems, any mismatch between generation and load will instantaneously cause system frequency deviations from the set value. These deviations are typically caused by unforeseen events, e.g. contingencies, wind/load forecast errors. This affects the behavior of electric devices and in case of large deviations, the generating units may be disconnected leading to a system black-out. Therefore, the power system must be kept in a very high security level in order to avoid devastating consequences.

The system frequency must be maintained within limits to guarantee the system security. To achieve this, the system must be operated with preventive security margins, this means, having a backup of generation or load with the capacity to counteract any unforeseen events [1]. This backup capacity is the so-called operating reserve. In other words, operating reserves substitute the quantity of unforeseen decreases (increases) of generation or load achieving again the equilibrium between generation and load.

Operating the power system with enough reserves entails more security for the system to withstand unexpected events. However, this also implies that the assets are not fully exploited. Furthermore, generating units or load providing reserves must be dispatchable within seconds or minutes. The need of fast energy re-dispatches increases the necessity for flexibility of power system components. As a consequence, keeping the power system secure entails extra costs which can be minimized with an appropriate determination, allocation and deployment of reserves [2], [3]. Besides, high amounts of reserves increase the system operation costs (e.g. many generating units being ready, usually synchronized to the system, and never used). On the other hand, low amounts of reserves may cause ad-hoc operations which also increase the operation costs. Therefore, an adequate dimensioning and use of reserves are needed to maintain the system secure and also avoid unnecessary operation costs.

In order to achieve an economic power system operation, an efficient market design for electricity supply is required. This efficiency is achieved with complex procedures where the scheduling is made such that possible ad-hoc interventions during the operation (e.g. uneconomical out-of-merit intervention, start-up of extra units, unnecessary load shedding) are avoided, and any unforeseen event is dealt with using the scheduled reserves [4]. In order to reach this, technical restrictions, representing the actual operation of the power system, must be considered in the market-clearing procedure. UC-based formulations are then ideal for an efficient MC procedure and for this reason they are becoming more and more attractive everyday [4]–[6].

Despite UC-based MC formulations seem to be an adequate procedure to avoid ad-hoc interventions, we evaluate some underlying accepted assumptions which cause very inefficient, even infeasible, operation procedures. We show how reserves are deployed to deal with deterministic events which are ignored during the scheduling stage.

The remainder of this paper is organized as follows: Section II presents an short overview of different MC approaches as well as how reserves work. Section III discusses about the consequences of clearing the market using energy blocks, and some solutions to overcome the drawbacks are provided. Section IV shows how some of the underlying assumptions of UC formulations harm the efficiency of the MC. Finally, some relevant conclusions are drawn in Section V.

II. Market Clearing and Reserves

A. Market-Clearing Approaches

One of the goals of electricity industry restructuring has been to reduce both short- and long-term costs by achieving higher levels of competition. As it happens with other commodities, electricity markets are organized as a sequence of auctions where generators submit their supply bids, and

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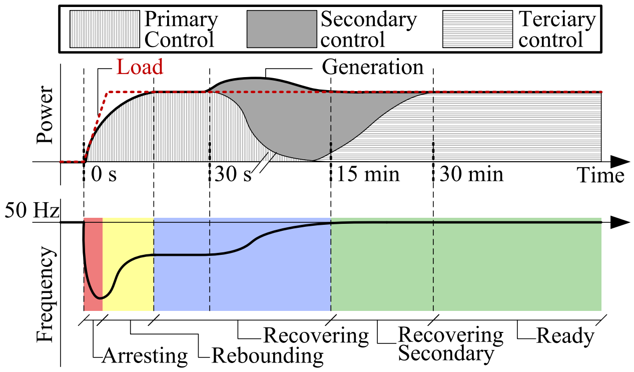


Fig. 1: Sequential activation of primary, secondary and tertiary reserves following a sudden unforeseen event

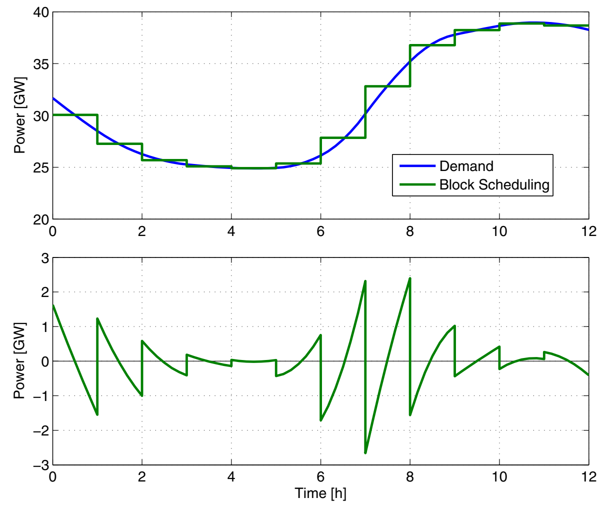


Fig. 2: Energy blocks scheduling and impact on reserves

consumers (or energy services companies that aggregate their consumption), submit demand bids [5].

Regarding the quantities problem, according to [7], market-clearing algorithms could be classified as simple and complex bids. A (i) simple bid is a pair quantity-price that is cleared according just to its price. The clearing is performed independently for each trading period, and it does not take into account any constraint that could link the bids belonging to the same generating unit. In the case of (ii) complex bids, market participants submit extra-conditions that link the bids among them, affecting the resulting outcome of the auction. For instance, the declaration of indivisible energy blocks, maximum ramps between consecutive hours, minimum income condition to ensure a complete cost recovery related to the discrete decisions, such as start-up costs [5].

Simple bids provide a very high degree of transparency and simplicity. As a consequence of this simplicity, MC algorithms of simple bids fail in guaranteeing feasibility, therefore, re-dispatches are needed (e.g. intra-day markets) [7], [8]. In contrast, complex bids allow taking into account a more realistic representation of all the technical constraints of the power system, and therefore, the obtained schedules should be closer to feasible profiles. This market clearing algorithm is formulated as a traditional unit-commitment problem (UC-based MC) where some of the input parameters (variable cost, no-load cost, start-up cost, etc.) are offered by market participants, together with a detailed description of all the technical constraints (minimum up-down time, ramps, etc.) [5].

Simple bids are more common in European markets, while complex bids are preferred in USA, where besides the energy scheduling it is possible to consider simultaneously the market clearing of some ancillary services [9].

B. Operating Reserves

Fig. 1 illustrates the relationship, in time responses, among primary, secondary and tertiary reserves [1]. There is an operating reserves time continuum: 1) After an event occurs, the primary control reserve reacts to arrest and rebound the frequency drop. 2) In the following 30s the primary reserve is fully deployed and the AGC-based secondary control has already taken action and is completely deployed in 15 minutes, restoring thus the primary reserve. 3) Finally, the tertiary control, provided by on-line and/or off-line generating units, takes action within 15 minutes after the event and is fully deployed in the following 15 minutes restoring the secondary reserve. Therefore, primary and secondary reserves are completely restored in less than 30 minutes after the event.

III. Energy-Block Scheduled vs. Energy Deployment

Since the introduction of competition, energy market transactions are done with energy blocks and generators (and also demand) are penalized if they deviate from their scheduled energy level over a time period. Therefore, generators have the freedom to optimize their resources and adjust their power profiles to diminish/avoid possible penalties. Considering the unit cost quadratic function, the optimal power profile that generators follows is as near as possible to the stepwise energy blocks. Any deviation from the stepwise energy scheduled will inevitable lead to increasing costs, even though the energy profile (constraint) is satisfied [10].

Fig. 2 shows a power demand curvež[1] and the hourly energy blocks which are needed to satisfy the hourly energy demand. Considering that the stepwise energy profile can be exactly reproduced by the generation side, there is still an imbalance between generation and demand, see the lower part of Fig. 2. As mentioned in Subsection II-B, generation and load must be always in balance, therefore, the resulting imbalances are compensated by the operating reserves.

Power reserves are a costly commodity but needed to provide security to the power system under unforeseen events (see Subsection II-B). Note that the example presented in Fig. 2 does not have any uncertain event and yet there is a significant amount of reserves that are needed to balance generation and load all the time, specially during high ramps periods. Furthermore, the worst consequence to the power system, is the frequency deviation due to significant generating gradients

[1]The demand curve corresponds to the real demand in the Spanish power system at 17/01/2012 www.ree.es

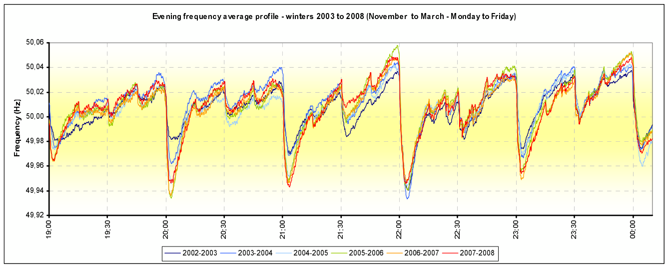


Fig. 3: Average frequency profiles of the UCTE, winters 2003 to 2008 (November to March - Monday to Friday). Source: [11]

caused by generators in order to follow their scheduled energy blocks. Fig. 3 shows an example of such frequency deviations.

Stable power systems are designed to operate with a small deviation from the nominal frequency. The UCTE grid, for example, must operate between 50Hz±50mHz. A generation outage of 1300 MW will usually lead to a frequency drop around 50 mHz [11]. Fig. 3 shows some evening frequency profiles of the UCTE grid for the years 2003 to 2008. Evidently, the UCTE system is operating outside the secure limits, and this has happened many times during the same day for around 10 minutes every hour. Furthermore, these frequency swings are increasing with the time [11], [12]. As presented in [11]–[13], the participants of electricity markets in Europe are responsible of this high frequency deviations during the interchange hours. As previously illustrated in Fig. 2, the frequency swings are because market participants follow their energy block schedules. This problem is worsening due to frequency deviations occurring also around half hours (i.e. also because of half hour market scheduling in some EU countries). The frequency swings due to market behavior have been also reported in different power grids, for example the USA [13] and Nordic countries [14].

A. Consequences

[13] and [11] present the detailed consequences of the frequency swings. We summarize and classify them as follows:

1) Operational risks:

- Insufficient primary reserve leaves the power system unprotected to face generation and demand outages. This endangers the security supply.
- Frequency oscillations can lead into uncontrollable operational situation, which may cause the loss of generation or demand units. This may cause a snowball effect leading to a blackout.
- Power flow variations cause overload which may lead to tripping in systems operating close to their limits. As the previous consequence, this may also lead to a blackout.

2) Economic impact:

- Unnecessary use of primary reserves, which is repeatedly used during a day, results in higher power plant stress. This has a direct impact on the lifetime of the units and inevitably increases the cost of providing this reserve. Besides, more primary reserve must be scheduled for not leaving the system unprotected during the inter-hour periods.
- Unnecessary use of secondary reserves, which are needed to restore the primary reserves, therefore increasing the operation costs of the system. Besides, more reserves must be scheduled to deal with this issue. For example, the costs associated to the overuse of secondary reserves due to the block scheduled in Spain in 2010 was calculated on 17.5 millions of euros[2] [15].
- Generators following the stepwise energy profiles and also providing reserves, create high ramp use during the changing hours, for around 10 minutes, and thus decreasing their possibility to provide reserves during that time period [16].

In conclusion, reserves must be ideally used to deal with uncertainties. Nevertheless, they have been highly deployed in order to match the energy-blocks schedule with the smooth demand. With no uncertainty present, the system must be secure and the operation more economic (see Subsection II-B). However, the energy-block-based market operation endanger the system security and increases the operation costs.

B. Actions to take

Many measures have been proposed to diminish the previously mentioned consequences [10]–[15], [17], from an extremely centralized point of view, e.g. unilateral control of the generation output by SO; to very decentralized one, e.g. generation unit must incorporate the ramping costs then avoiding sudden output changes. Here, we summarize the outstanding measures.

- Implement shorter trading periods. The shorter the periods, the smaller the impact on frequency. This is because the resulting energy blocks will be more similar to the smoother continuous demand profile. This will inevitably increase transaction costs.
- Imposing maximum ramp rates on generators during short time periods (minutes). That way, their power profiles will be smoother. This measure constrains the freedom and technical flexibility of generators.
- Dispatching with smooth profiles although the scheduling is made in hourly blocks. This measure is similar to the previous one, with the difference that a constant ramp rate must be followed during the operation stage. The main disadvantage of this solution is that once the energy blocks are fixed, the plausible power profiles of generators may oscillate, besides generators not having the incentives to do so. This problem can be diminished by considering shorter trading periods.

All these measures keep the energy-block paradigm. A change of paradigm to ramp-scheduling might deal with this problem. In other words, changing the stepwise energy schedule for a piecewise power schedule. Even though the energy profiles of the two scheduling types are identical, the resulting power

[2] [15] presented that savings of about 14.5 millions of euros, for Spain in 2010, can be obtained by changing the dispatch of units to a half an hour basis and following piecewise power patterns even thought the scheduling is stepwise-based.

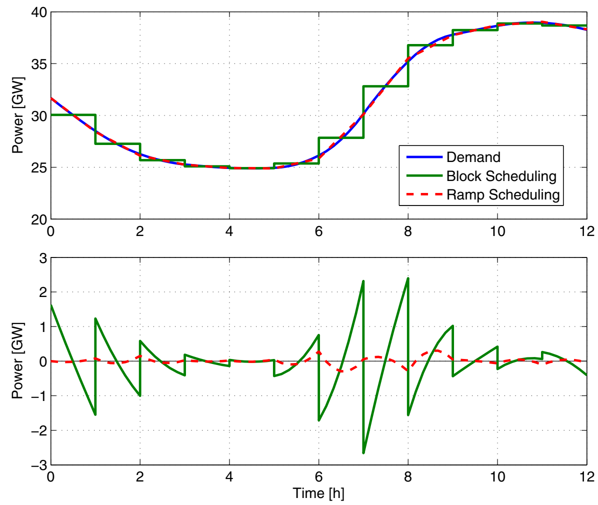


Fig. 4: Energy-blocks vs. ramp scheduling and their impact on reserves

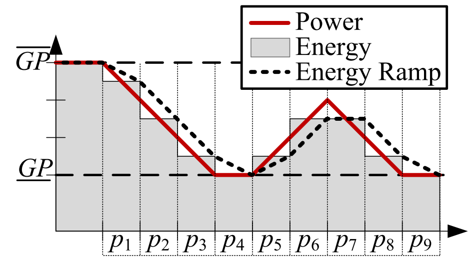


Fig. 5: Energy- vs. Power-Profiles Example.

profile of the ramp-scheduling will be very similar to the smooth demand profile, therefore, decreasing the impact on the operating reserves.

Fig. 4 shows the imbalance differences between the hourly energy-block vs. the ramp-scheduling profiles. Where apart from decreasing the need of reserves (energy needed to compensate the imbalances) by more than 80%, for the example case, the sudden generation changes are also dramatically decreased. Therefore highly unnecessary use of primary reserves is avoided.

To achieve an optimal ramp schedule, the MC should be performed using a UC formulation, considering the technical unit's restrictions, and thus a full exploitation of resources and flexibility can be achieved. Some possible envisioned remarks of the proposed ramp-scheduling approach:

- In relation with the energy-block market, an extra datum is needed as a result of the MC. By adding an (hour) initial power value to the energy-block scheduled value, the ramp profile will be satisfied by following the scheduled ramp. This overcomes the main disadvantage of implementing shorter trading periods.
- Although the market follows hourly trading periods, measurements for shorter periods are needed to measure the ramp, and thus being able to penalize the scheduled ramp deviations. Energy measurements every few minutes (around 5-10) would be enough to follow the ramp profiles. Actually, these measurements are currently available and needed by the secondary reserve control to work adequately (AGC uses continuous measurements around each 10 seconds [1]).
- Because of the previous reason, generators have the incentive to follow their smooth power profile. This will diminish the stress impact on the machines apart from increasing the ramp capacity availability to provide operating reserve services.

IV. Underlying UC-based MC assumptions

This section shows how some of the underlying assumptions of UC formulations harm the efficiency of the MC. Two problems are presented: 1) modeling generation output as average power (or energy) during the hour, and 2) ignoring the start-up and shut-down ramps.

A. *Infeasible Power and Reserves Delivery*

In most of UC-based MC formulations, generation levels are taken as energy blocks where the power output of thermal units are usually considered as hourly step functions. Ramp constraints are then applied to the inter-hour changes between these energy blocks [18]–[21]. Although it has been proved that the energy delivery obtained from these energy-block formulations may not be feasible [22], insufficient attention has been paid to this issue. Furthermore, the reserve capacity of generating units depends on the unit ramping usage which is directly related to power trajectories (intra-hour) and not to the (inter-hour) energy trajectories.

Fig. 5 shows an example of a power trajectory and its respective energy profile. Three different ramp rates were used in the power production (continuous thick line in Fig. 5), zero, maximum-up and -down ramp usages, the maximum ramping up and down capacities are assumed to be the same. The resulting ramp of he stepwise energy-block trajectory is represented as a dashed line in Fig. 5. Three (main) different behaviors between the power and the energy-block trajectories can be observed in this example:

- There are just four periods $\{p_2, p_3, p_6, p_8\}$, out of nine in total, where there is a ramp coincidence between energy and power trajectories.
- Even though the unit is ramping down at maximum capacity in the period p_1, the energy ramp during that period shows that just half of the ramping capacity is in use. The same happen when the unit is ramping up at maximum capacity in the period p_5.
- When the unit is ramping up at its maximum capacity in p_6, then the minimum energy that can be delivered for the next period p_7 is the same as the energy delivered the previous period. This simple example shows that even when the whole ramp capacity is available in the energy profile (during period p_7), the real utilization may be the maximum.

These differences between the energy ramps and the real power ramps have a big impact on modeling reserves in

UC formulations. In Fig. 5 can be observed that the unit cannot provide up (down) reserves during the periods $\{p_5, p_6\}$ ($\{p_1, p_2, p_3, p_7, p_8\}$) because there is not ramping up (down) capacity left. In short, the solutions of the stepwise energy formulations may result in infeasible energy-delivery and reserve-capacity-deployment.

This is not a new problem, actually [22] showed (more than ten years ago) that mathematically feasible solutions of traditional UC schedules are unrealizable in real applications. [22] presents a set of necessary and sufficient conditions for a single thermal unit to ensure the feasibility of energy delivery schedules. The highly complex mathematical expressions of the conditions make them very hard to be introduced in a UC model. In [23] a clear difference is made between energy and power. This formulation is a smooth nonlinear programming problem and the solution provides a feasible energy delivery, however the discrete start-up and shut-down decisions are not included. [24] propose a UC with feasible energy delivery constraints which is further extended in [25] by formulating a sub-hourly UC, and thus taking more advantages of unit flexibility and capacity. The power schedules obtained in [25] make a high use of ramp capacities within the hour decreasing thus the capacity to provide operating reserves. The aforementioned formulations present the following main disadvantages:

1) guarantying feasibility of energy delivery does not mean a decrease in reserve use, this can even increase it, since these formulations are balancing energy profiles rather than power profiles;
2) the formulations are focused on feasible energy schedules and no attention is paid to reserve modeling to also guarantee a feasible reserve deployment;
3) the formulations considerably increase the complexity of the UC problem, due to the introduction of many variables and constraints in the model; and
4) Start-up and shut-down ramps are not considered in the scheduling stage which inevitably lead to an unnecessary deployment of reserves to accommodate these ramps during the operation stage, this phenomenon is explained in more detail in Subsection IV-B.

B. Start-Up & Shut-Down ramps

Most of the UC literature on modeling constraints of thermal units deals with the unit operation above the minimum output [26]–[28]. Units are considered to start/end their production at the minimum output while the Start-Up (SU) and Shut-Down (SD) power trajectories are ignored, they are just represented by their associated costs in the objective function, also known as SU and SD costs. Some papers are aware of the importance of considering these ramps in the UC optimization problem. However, they do not include them because the resulting model will be considerably more complex causing prohibitive solving times [21], [29]–[31], besides the impact on the operation is also ignored in some extent. [32] shows that not considering SU & SD ramps changes the commitment decisions causing a negative economic impact. To the best of our knowledge, there is no reported work on the impact of ignoring the SU & SD power trajectories on the operating reserves, which is the topic discussed in this section.

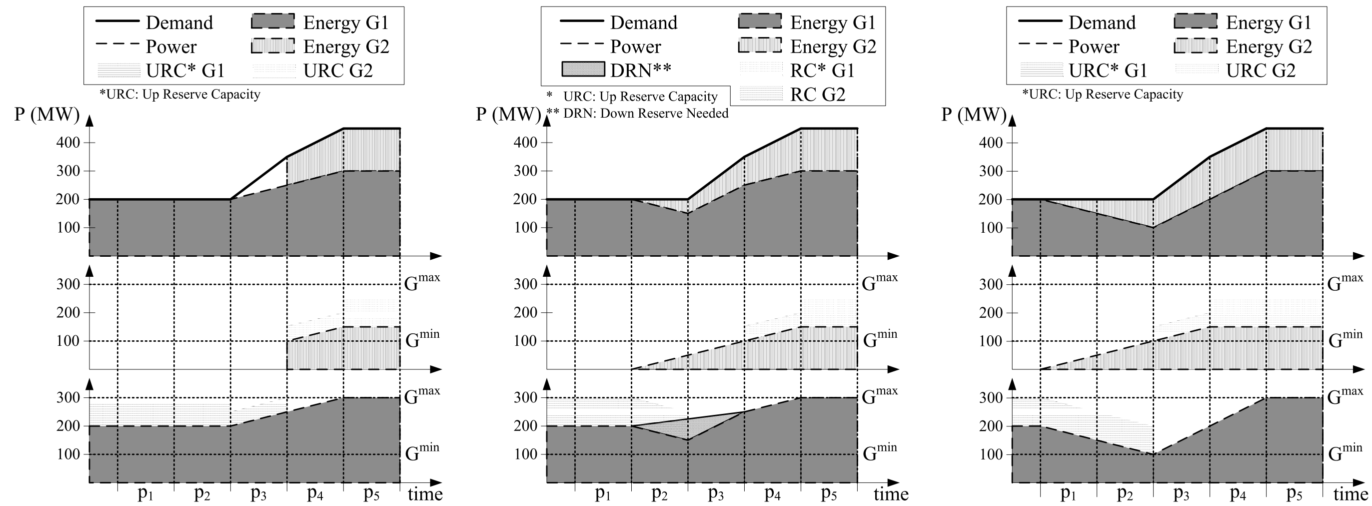
Once acknowledged that the UC must be modeled by using power profiles (see Subsection IV-A), special attention must be paid to the discontinuities that are introduced. As mentioned before, in a UC model, ignoring the SU & SD ramps is a common simplification that has been done for the sake of saving computational effort in solving the problem. However, this implies ignoring the energy production during the SU & SD processes which are inevitably present in the operation stage.

The impact of ignoring the SU & SD ramps during the scheduling stage will be explained with an illustrative example. Fig. 6 shows the scheduling (Fig. 6a) and actual deployment (Fig. 6b) stages of two power generating units. The two units are identical and their technical characteristics are: (a) 100 MW of minimum output, (b) 300 MW of maximum output, (c) 100 MW/h as maximum up/down ramping capacity, and (d) 2 hours are needed to achieve the minimum output after the unit is synchronized to the system (see SU of unit G2 in Fig. 6b). Fig. 6 shows that the demand is satisfied with the instant power at the beginning of each period, but the energy cannot be completely satisfied due to the discontinuities introduced by the SU process.

In the scheduling stage, in order to achieve the electric demand (see Fig. 6a), unit G1 must generate 200 MW until period p_3, ramping up to its maximum output within periods $[p_3, p_4]$ and continue at this value from p_4. Unit G2, is scheduled to produce at its minimum output in period p_3, increase the generation to 150 MW and keep this production from p_4. Regarding the reserves, the units can provide their maximum reserve capacity if they are not operating near their limits (minimum and maximum) and not using the ramping capacity. Therefore, unit G1 can provide 50 MW/h for up reserves within $[p_2, p_3]$, this is the half of the capacity because the unit is ramping up at half of its maximum speed. Analogously, unit G2 can provide its half ramping capacity for up reserves within $[p_3, p_4]$. In summary, from the scheduling stage, the total up reserves capacity of the power system are: 50 MW/h within periods $[p_2, p_3]$ and 100 MW/h for the others. Regarding the down reserves, which were not included in Fig. 6 for the sake of clarity in the drawing, the system counts with 100 MW/h till p_4 and 150 MW/h from p_4 (the extra 50 MW are contributed by unit G2).

In the actual generation deployment stage, the system operator must match the generation and load all the time. From the scheduling stage, unit G2 must start to operate at its minimum output at p_3. However, the unit must be synchronized to the system from p_1 due to its start-up ramping constraint. Hence, in order to match generation and load all the time, unit G1 has to change its scheduled output, by making use of down reserves, and thus accommodate the start-up output trajectory of G2, as shown in Fig. 6b. Two important situations must be observed related with the reserves:

1) The down reserves were used (in p_2 and p_3), even though this was not expected from the scheduling stage.
2) The system capacity up reserve changes completely



(a) Generation scheduling (b) Actual generation deployment (c) Scheduling with SU & SD ramps

Fig. 6: Scheduling vs. deployment power energy example. From the bottom to the top, power output of unit G1, power output of unit G2, and power output of G1 and G2 matching the electric demand.

within periods $[p_2, p_4]$, as presented in Fig. 6b. Between $[p_2, p_3]$ the power up reserve capacity changes from 50 MW/h to 100MW/h, this is actually a positive consequence. However, the worst consequence is within $[p_3, p_4]$ where the system run out of up reserves for accommodating the starting-up of unit G2.

As exposed in Subsection II-B, operating reserves must be used for unforeseen events. All predictable events must be directly considered in the power energy scheduling otherwise there will be an unnecessary use of reserves and this may considerably increase the cost of the system operation. The unnecessary use of reserves during the operation can be easily avoided by considering the SU & SD trajectories in the scheduling stage, see Fig. 6c.

There are formulations that explicitly model the SU & SD power trajectories under the Mixed-Integer Linear Programing (MILP) framework [32]–[34]. In [33], just one possible power trajectory for the SU process is modeled, while [34] and [32] consider different SU power trajectories depending on the unit's prior down time. The main drawback of the formulations proposed in [33] and [34] is the creation of large models which highly increase the complexity of UC. However, [32] proposes a tighter and more compact MILP formulation which considerable reduces the computing time in comparison with [33] and [34].

V. Conclusions

This paper presented the impact on reserves due to clearing the market using energy blocks. Furthermore, we showed the drawbacks of some widely used implicit assumptions in Unit Commitment (UC)-based Market-Clearing (MC) formulations. This paper is mainly focused on the technical part leaving the economic side (e.g. market transaction costs) as an open issue to be disused and researched. As recommendations and further research lines, we propose (i) to clear the market using the ramp-schedules instead of the current energy-blocks. Regarding UC formulations, we show that the (ii) models must take into account the actual power trajectories to accurately represent the reserve capacity and guarantee feasible delivery. Furthermore, (iii) start-up and shut-down power trajectories must be incorporated in the UC to avoid an unnecessary misuse of power reserves which would be needed to accommodate the inherent energy produced by the units during the actual SU and SD processes.

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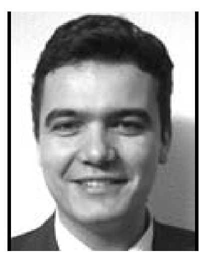

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