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Comparison of advanced power system operations models for large-scale renewable integration

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ABSTRACT

Increased renewable energy sources (RES) penetration requires significant changes in the short-term power system operations practice. Both current industry practices and relevant literature investigate models that operate on variable time scales to address RES uncertainty and variability. This paper presents a comparison of three different integrated short-term power system operations models regarding their ability to deal with large amounts of renewable penetration. The first model is a rolling unified unit commitment-economic dispatch (UUCED) model with variable time resolution, recently introduced by the authors. The second scheduling model comprises a rolling intraday unit commitment and a real-time dispatch with look-ahead capability (two-level model). The third model operates the system on a three-level hierarchy: it comprises a 48-h reliability unit commitment (deterministic or stochastic), a rolling intraday unit commitment and a real-time dispatch with look-ahead capability. The comparison is performed on the basis of an annual simulation of the Greek Interconnected Power System using 2013 historic wind power and load data. Simulation results demonstrate that the UUCED model better accommodates the increasing RES production by minimizing the system operating costs without jeopardizing system security.

1. Introduction

Centrally organized wholesale electricity markets, such as the ISO/RTO markets in the United States, perform their short-term operations scheduling based on the two-settlement system [1] comprising a day-ahead forward market (DAM) with hourly resolution and a real-time market (RTM) with 5-min dispatch period, complemented with a forward or intraday reliability unit commitment (RUC) [2,3]. DAM is a UC market model that clears energy and reserve quantities based on supply offers and demand bids with hourly resolution. RUC is also a unit commitment model, which recommits units based on ISO load and wind power forecasts instead of participant orders. In some markets RUC is not allowed to de-commit units but can only commit additional units [2], while in others RUC may also de-commit resources for congestion relief [3]. The RTM is used to dispatch online resources in real-time, usually, every 5 min, in order to meet the continuous load variation.

Current short-term power system scheduling practice assumes deterministic knowledge (perfect forecast) of system conditions for the next day. System conditions typically refer to load demand and component availability. Component unavailability is addressed with N-1 security criteria and scheduling of contingency reserves, while load forecast errors with scheduling of load-following reserves. The adequacy of the two-settlement market model is based on the notion that the net load can be fairly accurately predicted several hours ahead (DAM and RUC), so redispatching online resources in real-time via RTM is sufficient to meet uncertain demand. Forward or intraday RUCs adapt resource commitment to system condition changes.

The large integration of renewable energy sources in the power system, though, has put into question these practices. The uncertain and variable nature of the primary energy sources (e.g. wind speed and solar radiation) renders the respective RES units partially dispatchable and the System Operator (SO) has to confront increased net load unpredictability. In the literature there are several approaches to cope with the increased uncertainty in the short-term operation of the power system, including advanced

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forecasting tools [5], maintaining increased amounts of reserves [6] and use of stochastic [7–11] or robust [12–14] optimization. Although various advanced stochastic and robust optimization models have been proposed in the literature, SOs are still reluctant to use them in operations practice. Apart from the complexity and the high computational requirements of stochastic optimization, the main reason is institutional: scenario generation and weighting may raise market transparency issues.

Therefore, up to now, SOs rely on implementing more accurate deterministic models and facing uncertainty and variability by maintaining increased levels of reserves, by introducing frequently updated forecasts, additional intraday system operations and faster markets. Maintaining high reserve levels can be uneconomical and could also render the scheduling infeasible. In this context, advanced markets in the US have already begun to restructure their short-term operation and market models by adding and modifying operation functions based on frequently updated forecasts. Some of the most advanced techniques to face increased uncertainty include the following:

- Frequently revised RUC, with hourly granularity, to adapt the commitment decisions based on most recent information on changing system conditions [3,4].
- Intraday rolling unit commitment with sub-hourly time resolution and scheduling horizons up to several hours [15] in order to recommit fast-start units.
- Real-time dispatch with 5-min resolution and look-ahead capabilities (e.g. next hour) [16,17] in order to capture the forthcoming wind energy variations. The benefits of this approach have been explored in [18].
- Real-time dispatch and fast-start unit commitment [19].
- Flexible ramp constraints and new ramp products [16].

In the literature, several deterministic models have been presented to cope with increased uncertainty. In [20,21] deterministic unit commitment models are developed and are executed on a rolling basis. In [22] the effect of RES variability and uncertainty is examined in a one-day simulation across all multiple timescales down to AGC. The advantage of these works lies in that they examine the effect of RES generation in multiple time frames of the short-term power system operations simultaneously, while the majority of other works focus on a single timescale (usually day-ahead or real-time). Motivated by these trends and considering both current operations practice and research findings, the authors in [23] have presented a novel deterministic model that unifies the unit commitment and economic dispatch functions (UUCED) in a real-time tool that uses variable time resolution and a scheduling horizon of up to 36 h to better accommodate large amounts of RES generation.

In this paper, three short-term power system operations models are implemented. The first model (a) is a conceptual model named as "UUCED" [23], which is a single-level operations model. The other two models are based on two distinct current US operator practices. The second model (b) is an operations model based on the concept of the current ERCOT practice [3,4,17], which from now on will be called "two-level model" and the third model (c) is an operations model based on the concept of the current CAISO practice [15,24], which from now on will be called "three-level model". Similar two- or three-level operations models have been introduced to several other North American RTO/ISO-type markets, such as MISO [25,26], PJM [19], etc. We have restricted our comparison to ERCOT and CAISO owing to the large wind penetration in the respective states. The contribution of the paper is the comprehensive comparison of these three fully integrated short-term operations models regarding their ability to deal with large amounts of renewable penetration in a real power system using real data.

The comparison is comprehensive in terms of the following:

- The different short-term power system operations models are fully implemented covering all relevant time frames from the day-ahead scheduling to real-time operation. Day-ahead, intraday and real-time operations are simulated using a 15-min time resolution (and not the 5-min time resolution of the ERCOT and CAISO real-time markets) in order to reduce the simulation time. Detailed unit commitment and economic dispatch mathematical models have been used for this purpose, allowing for the realistic modeling of the various unit operating phases (synchronization, soak, dispatchable, and shut-down), the three-way unit start-up (hot, warm, cold) and all generating unit inter-temporal constraints.
- The simulations cover an extended time period. More specifically annual 15-min rolling simulations of the Greek Interconnected Power System for the year 2013 were performed.
- Real power system data, such as real generator data, historic 2013 wind power and load data (with 1-min resolution), actual 2013 imports and exports were acquired, validated and used in the simulations.
- The simulations are performed for two wind power penetration scenarios: the first is the actual 2013 wind power production and the second is an increased wind penetration scenario with the wind power generation doubled. Additional simulations for the first three months of 2013 are performed including network constraints.
- All types of reserves are calculated "from scratch" for all models and wind power scenarios, since the actual reserves of the Greek power system cannot be applied to the models presented due to their different time resolutions and lead times.

To the best of our knowledge, such large-scale comprehensive comparison of different deterministic models with different time resolutions, look-ahead horizons and real-time models regarding their ability to deal with large amounts of renewable penetration has not yet been performed. Therefore, we believe that this work satisfies an emerging power system need. Simulation results investigate the operational efficiency and the physical meaning of the three distinct approaches in high wind penetration environments and provide useful insights on the requirements of the future short-term operation of power systems. The proposed UUCED model is also compared to a stochastic three-level model in order to explore the effectiveness of using frequently revised unit commitment against stochastic unit commitment models that anticipatively fix the commitment decisions. It is clarified that models (b) and (c) are gross simplifications of the ERCOT and CAISO operating practices for the purpose of our simulations, keeping, however, the basic concept and structure of the respective designs.

2. Models description

The following simplifying assumptions have been used in our modeling:

- A 15-min real-time dispatch period is considered, in contrast to the 5-min period adopted in most wholesale electricity markets, in order to reduce the execution time of the annual simulation.
- DAM closure is considered to be at 11:30, so generator offers are considered to be available at that time point.
- For simulations purposes, all models use generator offers as well as SO wind and load forecasts, while no demand bids are considered.

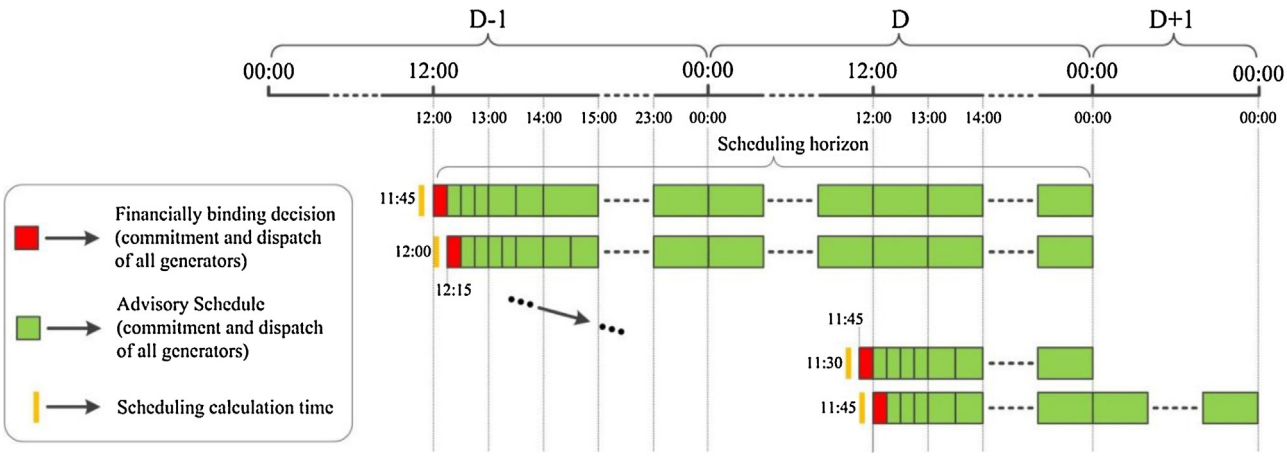

Fig. 1. Timeline of the unified unit commitment-economic dispatch (UUCED) operations model.

- System uncertainty is associated only with wind generation and load. Errors in wind power and load forecasts are considered (see Appendix).

2.1. *Variable time resolution unified unit commitment-economic dispatch (UUCED) model*

The variable time resolution unified unit commitment-economic dispatch model (UUCED) is an integrated tool that can smoothly bridge the short-term scheduling with the real-time decisions and better accommodate the uncertain nature of renewable generation. The model unifies the RUC function, all possible intraday functions (rolling RUCs or real-time unit commitment functions) and the RTM into a single tool that uses a scheduling horizon of up to 36 h. The model uses variable time resolution: the first hours are modeled with finer time resolution (i.e. 15-min and 30-min intervals), while coarser time resolution (i.e. 1-h intervals) is adopted for the following hours of the scheduling horizon. This approach is adopted since wind forecasts with shorter lead times tend to be more accurate. Consequently, it is crucial to use frequently updated wind forecasts in a powerful real-time tool. The commitment and dispatch decisions of the first scheduling interval are financially binding, while the remaining schedule is advisory. This unified approach increases the flexibility of the generation fleet by allowing unit re-commitment and re-dispatch for the entire scheduling horizon. The model also increases the generation flexibility by allowing slow start units to start-up at intra-hour intervals and not necessarily at the beginning of an hour, as most unit commitment models with hourly resolution currently require. The financially binding dispatch and commitment decisions of the first intervals are very robust, since they are taken in anticipation of the system conditions for an extended scheduling period.

2.1.1. *Length of the scheduling horizon*

Since the DAM closure is assumed to be at 11:30, the scheduling horizon length varies from 12 h to 36 h ahead, depending on the starting point during the day, as shown in Fig. 1.

The horizon length is set so that it follows the day-ahead market timeline. The length could increase/decrease depending on the specific generation system needs. The length adopted here (up to 36 h) is sufficient for the Greek generation fleet characteristics, where the start-up time of the slowest conventional unit does not exceed 15 h.

2.1.2. *Variable time resolution*

Adopting finer time resolution for real-time functions is crucial, since load and wind forecasts are more accurate for short lead times [27] and, therefore, a lower amount of reserves can be scheduled for the intra-step variations. However, using fine resolution over the entire scheduling horizon (i.e. 36 h) would cumber the optimization with unnecessary computational burden, since wind forecasts for longer lead times tend to be rather inaccurate. These opposing needs lead to a variable time resolution compromise. The basic idea of the variable time resolution modeling is to use a 15-min time step for the first scheduling hour, a 30-min time step for the second hour and hourly time step for the remaining scheduling horizon. In order to align the variable time intervals with clock hours, in case the scheduling does not begin at an exact clock hour, the following rules apply: (a) use a 15-min time step for at least 1 h, followed by a 30-min time step for at least 1 h and hourly time step thereafter; (b) align intervals of a specific duration with intervals of the immediately longer duration; (c) span the scheduling horizon with the minimum number of intervals. Table 1 illustrates all possible combinations of the variable time resolution horizon depending on the specific 15-min interval of hour *h* that the scheduling begins. It is noted that the selected time granularity is system specific. In order to modify the scheduling horizon from a constant time framework to a variable time framework, the time constants that are usually used in a typical unit commitment model (e.g. unit synchronization and soak time, minimum up/down time, etc.) need to be converted from minutes (or hours) to variable time intervals. The readers may refer to [23] for further details on the relevant techniques employed.

Table 1
Definition of the variable time intervals.

	h				h+1				h+2		h+3	h+4	...
	h:00	h:15	h:30	h:45									
1	15	15	15	15	30		30		60		60	60	60
2		15	15	15	15	15	30		30	30	60	60	60
3			15	15	15	15	30		30	30	60	60	60
4				15	15	15	15	15	30	30	60	60	60

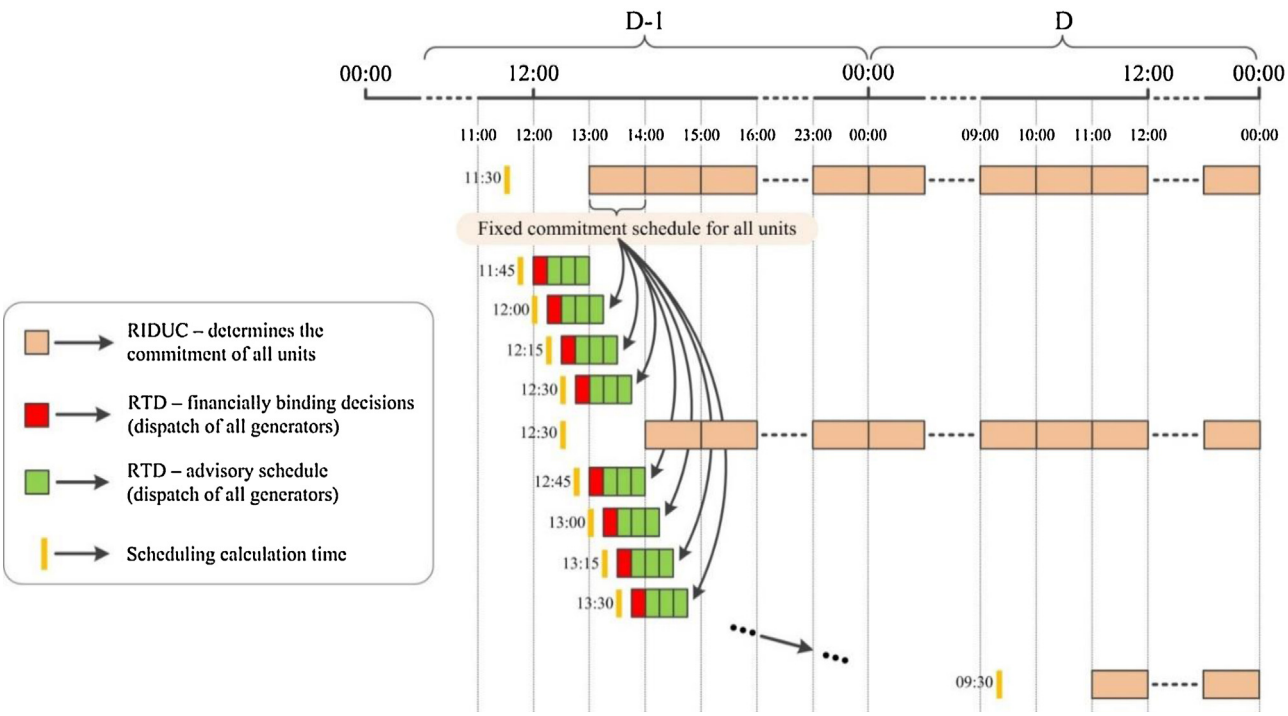

Fig. 2. Timeline of the two-level operations model.

2.2. Two-level operations model

The two-level operations model, presented in Fig. 2, is based on a simplification of the ERCOT current practices. The time frames and granularity are modified in order to capture the special characteristics of the Greek generation fleet.

2.2.1. Rolling intra-day unit commitment (RIDUC)

The upper-level scheduling tool is a rolling intraday unit commitment (RIDUC) model executed every hour with hourly granularity. Its study period is similar to the UUCED model, ranging from 12 h to 35 h depending on the time point the scheduling is performed during the day, in order to be aligned with the DAM timeline. RIDUC updates the commitment status of all generating units every hour.

2.2.2. Real-time dispatch (RTD)

The lower-level scheduling tool is a Real-Time Dispatch (RTD) model executed every 15 min. RTD uses an hourly look-ahead horizon with a 15-min granularity and dispatches committed units to meet the net load deviations. The dispatch result of the first 15-min interval is financially binding and it defines the setpoints of the generating units.

2.3. Three-level operations model

The three-level operations model, presented in Fig. 3, is based on a simplification of the CAISO practices. The time frames and granularity are modified in order to capture the special characteristics of the Greek generation fleet.

2.3.1. Day-ahead 48 h unit commitment (DAUC-48 h)

The upper-level scheduling tool is a day-ahead unit commitment model (DAUC-48 h) executed at 12 am of the day preceding the dispatch day. Its scheduling horizon includes the next two operating days (48 h) modeled with hourly granularity. DAUC-48 h determines the commitment schedule of all slow-start units for the next operating day (the commitment schedules of the second day are advisory). The initial commitment and dispatch conditions for DAUC-48 h are taken from the results of the previous DAUC-48 h execution. In CAISO a 72-h RUC is implemented to deal with units with extra-long start-up types (greater than 18 h), but the SO may also use a 48-h or 24-h RUC, based on its current needs [15]. Since the start-up times of the slow units of the Greek generation fleet do not exceed 15 h, the DAUC-48 h is deemed appropriate.

2.3.2. Intra-day unit commitment (IDUC)

The intermediate level scheduling tool is an intraday unit commitment model (IDUC) executed on a rolling basis every 30 min to reschedule the commitment of fast (gas) and very fast (hydro) units. The commitment status of the slow units is fixed from the DAUC-48 h results. The start-up times of the fast gas-fired units of the Greek generation fleet do not exceed 6 h and, therefore, the scheduling horizon for IDUC is chosen to be 6 h. IDUC uses 30-min granularity.

2.3.3. Real-time commitment and dispatch (RTCD)

The lower-level scheduling tool is a Real-Time Commitment and Dispatch model (RTCD) that runs every 15 min. RTCD uses an hourly look-ahead horizon and dispatches online units to meet the net load deviations. The dispatch result of the first 15-min interval is financially binding and is sent as a setpoint instruction to all generators. RTCD is also allowed to commit very fast units (hydro units) to address the net load variability that cannot be captured by the higher-level scheduling tools. The approach of RTCD committing very fast start units is also adopted in [24].

2.4. Modeling and implementation issues

All three operations models described above are formulated and solved as mixed-integer linear programming (MILP) optimization problems. The problem objective is bid-cost minimization and the constraints, in addition to system power balance and reserve requirements, include unit technical constraints, such as

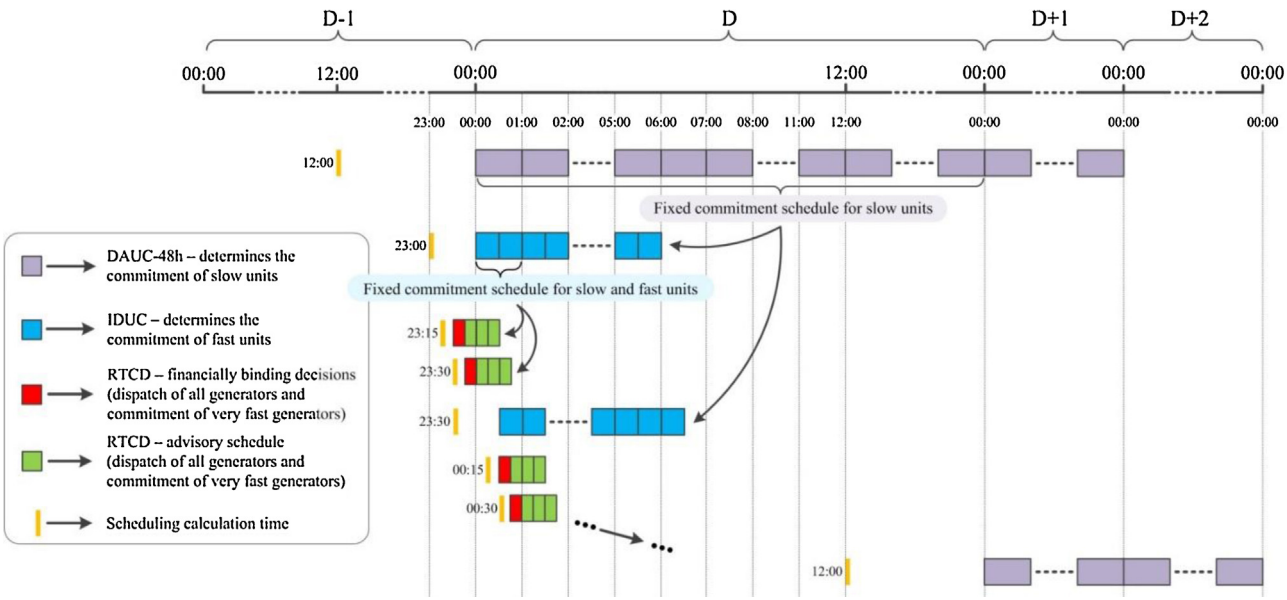

Fig. 3. Timeline of the three-level operations model.

power output limits, ramp-rate limits, minimum up/down time constraints, as well as a detailed modeling of the start-up and shut-down procedures employing three distinct start-up types (hot, warm and cold), as presented in [23]. The differences of the three models are:

- The length of the scheduling period (in steps).
- The duration of each time step of the scheduling period (either constant or variable).
- The variables that are being fixed (i.e. in the three-level model, IDUC uses fixed commitment for slow units).

The interconnection schedules, the hydro units pumping schedule as well as the mandatory hydro injection schedule are taken into account in all models in order to respect the special characteristics of the Greek Power System.

The main drawback of the UUCED model is its computational tractability. The implementation of this model in practice requires the solution of an MILP optimization problem with a look-ahead horizon of up to 36 h (divided in sub-intervals of variable length) within the time window of the real-time interval (e.g. within 5–15 min). Our tests have shown that the UUCED model including network constraints can be solved within a 5-min dispatch period for medium-sized systems, such as the Greek Interconnected Power System [23]. Advances in computer software and hardware are required to allow its application to larger power systems.

The computational requirements of the two-level and three-level models are much lower, allowing these models to be applied to actual large power systems. Their main drawback lies in the complex interaction of the different scheduling levels that use different time resolution.

3. Test cases and results

3.1. Test cases and results (without network constraints)

3.1.1. Test cases description

The three operations models have been tested on the Greek interconnected power system, whose generation fleet data are summarized in Table 2. All models have been tested via an annual simulation of the year 2013. For this purpose, 1-min historical wind power and load (net distribution-level RES generation) data for the entire year were provided by the Greek Independent Power Transmission Operator (IPTO).

The total energy demand (net distributed RES generation) during 2013 was 46,569 GWh, the total wind production was 3347 GWh, the total energy export was 3898 GWh, the total energy import was 5754 GWh and the total energy used for pumping was 49.3 GWh. The total distributed RES generation was 4534 GWh, mainly comprising photovoltaic generation. It is assumed that wind and load forecasts are updated every 15 min. Updating wind and load forecasts so frequently may not be the current IPTO practice, but this is very likely to happen in the future owing to increasing RES penetration.

Two wind penetration scenarios are considered: The first scenario uses the actual wind power generation of 2013 and the second is an increased wind penetration scenario with the wind power generation doubled. The resulting test cases are shown in Table 3. Taking into account the distributed RES plants injection, these two scenarios refer to a 15.5% and 22% RES penetration in terms of energy injected, respectively. The treatment of wind power and load forecast errors and the quantification of the reserves under the different operating conditions are discussed in the Appendix.

Table 2
Summary of the Greek generation system data (2013).

Unit type	Fuel	Number	Capacity (MW)	Marginal cost range (€/MWh)	Cold start-up time (h)	Response Speed
Steam	Lignite	16	4302	35–45	<15	Slow
CCGT	Gas	10	4209	81–90	<6	Fast
OCGT	Gas	3	147	117	Very short	Very fast
Hydro	Hydro	17	3034	95–96	–	Very fast
Wind	Wind	–	1502	–	–	–
Total		**46**	**13,194**			

Table 3
Summary of test cases.

Test cases		Model		
		UUCED (a)	Two-level (b)	Three-level (c)
Wind production scenario	Actual (1)	(1a)	(1b)	(1c)
	Double (2)	(2a)	(2b)	(2c)

All simulations were performed in MATLAB© calling GAMS© and using the CPLEX© solver with an optimality gap of 0.01%. It is noted that for the annual simulations network constraints are not included in order to speed up the total simulation time which is rather time consuming. Wind energy curtailment cost is considered 150 €/MWh.

3.1.2. Results

Table 4 presents the annual production per generation technology for all test cases. It is observed that the energy mix is very similar in all three models within each scenario. The most significant deviation is that the CCGT production in case (1c) is significantly lower than the one in cases (1a) and (1b), in which it is replaced by higher lignite and hydro production. It is also noted that the increased wind production of scenario (2) is compensated by decreased lignite and CCGT production. Hydro production in scenarios (1) and (2) is almost identical, due to the mandatory hydro injection constraints. OCGT generation is present only in cases (2b) and (2c), but it is not shown since it is negligible.

Table 5 presents the total number of start-ups of the conventional generation fleet. It is observed that model (c) results in limited cycling of the gas-fired CCGT units compared to models (a) and (b), especially in the actual wind production scenario (1). Model (b) has the lowest number of hydro unit start-ups compared to models (a) and (c), since the commitment of the hydro units is fixed from the RIDUC and cannot be changed in the intra-hour timeframe. The number of hydro unit start-ups is almost the same in scenarios (1) and (2) since it is mainly determined by the mandatory hydro injection constraints. Lignite cycling is similar within each scenario, meaning that the scheduling horizons used in all three models have the same effect on lignite cycling. In general, a higher number of lignite-fired unit start-ups are observed in scenario (2). This means that doubling the wind power capacity would result in increased cycling of lignite-fired units. From both technical and economic perspectives it is preferable to avoid cycling, especially cycling of base-load units.

The numbers in parentheses represent the percentage of start-ups that take place at (i) the beginning of an hour, (ii) the middle of an hour and (iii) the second and fourth quarter of an hour. It is evident that in cases (a) all types of units can start-up at any intra-hour interval, since UUCED has the advantage of allowing that flexibility. In cases (b) and (c) lignite units can start-up only at the beginning of an hour, since their commitment is defined by the upper-level scheduling tools that use hourly resolution. In case (c) CCGT gas units can also start-up at the middle of an hour, since their commitment is defined by IDUC that uses half-hourly resolution, while Hydro units can start-up at any intra-hour interval. In cases (b) all units are allowed to start-up only at the beginning of an hour, since RTD allows only for units re-dispatch (no commitment changes are allowed).

Table 6 presents the annual wind energy curtailment for all test cases. Models (a) and (b) result in negligible wind power curtailment. In model (c) a rather low, yet not negligible, amount of wind energy curtailment is present. It is evident that the UUCED and the

Table 4
Annual production per generation technology.

Test cases			Annual energy [GWh]		
			Lignite	Gas CCGT	Hydro
Actual wind production (Scenario 1)	UUCED	(1a)	32851	3032	5533
	Two-level	(1b)	32828	3081	5507
	Three-level	(1c)	33051	2587	5783
Double wind production (Scenario 2)	UUCED	(2a)	30141	2347	5584
	Two-level	(2b)	30135	2383	5553
	Three-level	(2c)	29962	2389	5738

Table 5
Annual number of unit start-ups per technology. (The numbers in parentheses represent the percentage of start-ups that take place at the (i) beginning of an hour (ii) middle of an hour (iii) the second and fourth quarter of an hour, respectively).

Test cases			Annual number of start-ups		
			Lignite	Gas CCGT	Hydro
Actual wind production (Scenario 1)	UUCED	(1a)	114 (04-78-18)	1494 (03-44-53)	10601 (80-09-11)
	Two-level	(1b)	117 (100-00-00)	1546 (100-00-00)	9024 (100-00-00)
	Three-level	(1c)	125 (100-00-00)	977 (53-47-00)	11917 (72-13-15)
Double wind production (Scenario 2)	UUCED	(2a)	476 (06-69-25)	1434 (04-44-51)	10251 (84-06-10)
	Two-level	(2b)	492 (100-00-00)	1373 (100-00-00)	9021 (100-00-00)
	Three-level	(2c)	451 (100-00-00)	1136 (50-50-00)	11435 (76-11-13)

Table 6
Annual wind energy curtailment.

Test case	Actual wind production (1)		Double wind production (2)	
	Wind energy curtailment			
Model	MWh	% Of annual wind energy	MWh	% Of annual wind energy
UUCED (a)	384.9	0.012	3203.7	0.048
Two-level (b)	431.5	0.013	3119.9	0.047
Three-level (c)	5917.6	0.177	21103.4	0.315

Table 7
Annual system operating costs.

Test case	Actual wind production (1)		Double wind production (2)	
Model	Cost [M€]	% Change	Cost [M€]	% Change
UUCED (a)	1652.3	–	1510.0	–
Two-level (b)	1663.4	+0.68	1523.9	+0.92
Three-level (c)	1660.6	+0.50	1530.0	+1.32

two-level model allow almost all wind power to be utilized, since they operate the system with higher ramp-down margins compared to the three-level model. This can be justified by the fact that the UUCED and the two-level model provide a higher flexibility to the generation fleet by allowing for intra-day recommitment of all units, whereas the three-level model recommits the slow units only once per day. It is noted that the ramp-down capability of a generation fleet is not only associated with the unit ramp-down rates (MW/min) but also with the unit technical minima.

It is also mentioned that the two-level model results in 1401 MWh and 1729 MWh of secondary-up reserve deficiency in scenarios (1) and (2) respectively, while the UUCED and three-level models do not show any secondary-up reserve deficiency in any scenario. This is mainly justified by the fact that the two-level model cannot recommit units in real-time (intra-hourly).

Table 7 presents the system operating costs for the six test cases as well as the percentage cost increase of models (b) and (c) over model (a) for both wind penetration scenarios. System operating costs include energy costs, start-up costs, reserve costs and artificial variable costs. For both wind penetration scenarios the UUCED model achieved the most economic operation. For the first wind penetration scenario, the two-level and three-level costs are higher by 0.68% and 0.5% respectively, while for the second wind penetration scenario the two-level and three-level costs are higher by 0.92% and 1.32%, respectively.

It is observed that the UUCED model tends to be more economic when wind production increases. The economic improvement is higher with respect to the three-level model (0.82%) than with the two-level model (0.64%). This is due to the fact that UUCED allows unit re-commitment and re-dispatch in real-time (intra-hourly), based on updated forecasts. The three-level model fixes the commitment of lignite-fired units in DAUC-48 h, while the two-level model allows total recommitment, yet once per hour, and not in real-time (intra-hourly). From a theoretical point of view, as power system uncertainty grows, binding commitment decisions for the future (three-level model) should be avoided. Indeed, it is preferable to be able to recommit the generation fleet like the UUCED and two-level models do. However, to achieve the maximum flexibility, the re-commitment needs to be made with real-time frequency (UUCED model) and not only once per hour like the two-level model.

3.2. Test cases and results (including network constraints)

3.2.1. Test cases description

In the second part of the results the three operations models have been tested on the Greek interconnected power system, for the months January, February and March 2013. In these simulations, network constraints are included in order to form a more realistic case. The Greek Power System comprises 1041 nodes, 54 units and 1286 high voltage (150 kV and 400 kV) branches. The simulations of this section have been performed on the same basis with the simulations of the previous section.

The total energy demand (net distributed RES generation) for the first quarter of 2013 was 12,070 GWh, the total wind production was 979.1 GWh, the total energy export was 1089.2 GWh, the total energy import was 1458.8 GWh and the total energy used for pumping was 6.1 GWh. The total distributed RES generation was 835.5 GWh, mainly comprising photovoltaic generation. In this section only the actual wind power penetration scenario is considered, since excessive congestion in the double wind penetration scenario would require the modeling of transmission reinforcement. The new cases are defined as 1a', 1b' and 1c' for UUCED, two-level operations model and three-level operations model respectively.

Table 8
Wind energy curtailment and system cost for the first quarter of 2013 (including network constraints).

Test case	Wind Energy Curtailment		Cost	
	MWh	% Of wind energy	Cost [M€]	% Change
UUCED (1a')	791.0	0.08	392.2	–
Two-level (1b')	991.3	0.10	394.9	+0.69
Three-level (1c')	4696.0	0.48	394.6	+0.61

3.2.2. Results

Table 8 presents the wind energy curtailed as well as the total costs for cases 1a', 1b' and 1c'. The amount of wind energy curtailed is higher in the three level model due to fact that the commitment of lignite fired units is refreshed only once per day. The percent of wind energy curtailed is higher for all three cases compared to the results where no network constraints are considered (see Section 3.1.2). This conclusion is intuitive, since network constraints tend to restrict wind energy penetration. Regarding total system costs, it is evident that the UUCED model again results in a more economic operation of the Greek Power System. The percentage cost increase for cases 1b' and 1c' is almost the same with respect to the results where no network constraints are taken into account. This is explained by the fact that network constraints affect all three models proportionally.

3.3. Test cases and results (including stochastic unit commitment)

3.3.1. Test cases description

In the third part of the results, the UUCED model, the deterministic three-level model and a stochastic three-level model, are compared on the Greek interconnected power system, over a period of one month (January 2013). The stochastic three-level model uses the same time resolution as the deterministic three-level model, with the sole difference that the upper scheduling level (the DAUC-48 h) is formulated as a stochastic unit commitment model. Scenarios are generated to account for load and wind power uncertainty. The first-stage (here-and-now) decisions are the commitment status of all slow thermal units (lignite-fired units), as in [7]. Three load (high load, medium load, low load) and three wind power scenarios (high wind, medium wind, low wind) are examined, thus formulating a final set of 9 discrete scenarios (see Appendix 5.3). Since scenarios are created to account for load and wind power uncertainty, the replacement reserves of the stochastic optimization model are modified accordingly. More specifically, replacement reserves are now calculated solely on the variability of the 15-min net load average within the hourly net load average (see Appendix 5.2).

The total energy demand (net distributed RES generation) for January 2013 was 4451 GWh, the total wind production was 342.4 GWh, the total energy export was 249.1 GWh, the total energy import was 440.1 GWh and the total energy used for pumping was 6.1 GWh. The total distributed RES generation was 346 GWh, mainly comprising photovoltaic generation. In this section, only the double wind power penetration scenario is considered. The new cases are defined as 2a', 2c' and 2c'-s for the UUCED model,

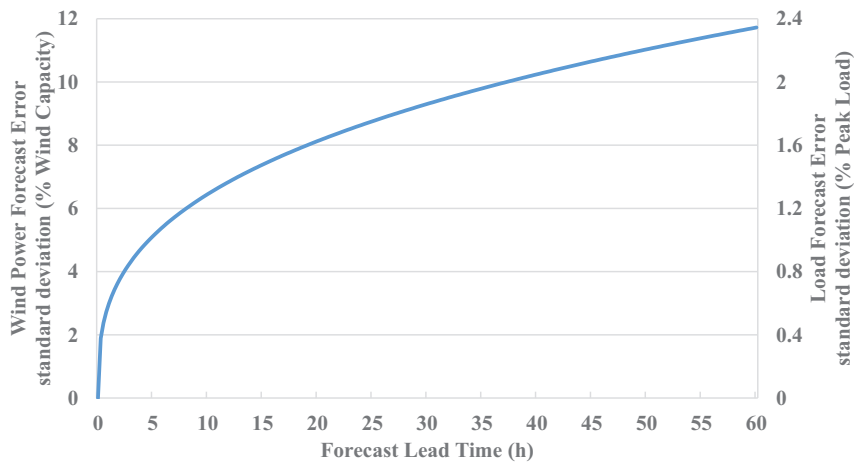

Fig. 4. Normalized standard deviation of wind power and load forecast errors for the Greek Interconnected power system and a 60-h ahead forecast horizon.

the deterministic three-level operations model and the stochastic three-level operations model, respectively.

3.3.2. Results

Table 9 presents the total energy and number of start-ups per generation technology for January 2013. The stochastic three-level model results in slightly higher lignite production. The UUCED model results in higher gas unit production and lower hydro unit production compared to the other two cases. The lowest cycling of lignite fired units is observed in case 2c', while CCGT cycling is almost the same in all cases.

Table 10 presents the wind energy curtailed as well as the total costs for cases 2a', 2c' and 2c'-s. Interestingly enough, the stochastic three-level model produces higher wind spillage; however, it results in cheaper operation (~0.45%) compared to its deterministic counterpart. It is emphasized that higher wind spillage does not necessarily mean higher dispatch costs, since sometimes it may be more economic to curtail wind power in order to avoid excessive thermal unit cycling (which is true in this case, since the stochastic three-level model resulted in lower lignite and gas unit cycling compared to its deterministic counterpart). It can be seen that the UUCED model again results in the most economic operation of the Greek Power System and we can, therefore, conclude that frequent forecast updates and rescheduling of the generation fleet (UUCED) outperforms the use of stochastic optimization in a model that fixes the day-ahead commitment decisions in anticipation of plausible future outcomes (stochastic three-level model).

Table 9
Production and number of unit start-ups per technology for January 2013 (including stochastic optimization).

Test cast		Energy [GWh]			Number of start-ups	
		Lignite	Gas CCGT	Hydro	Lignite	Gas CCGT
UUCED	(2a')	2770	231	580	21	40
Deterministic three-level	(2c')	2769	153	659	20	42
Stochastic three-level	(2c'-s)	2787	140	657	14	37

Table 10
Wind energy curtailment and system cost for January 2013 (including stochastic optimization).

Test case	Wind energy curtailment		Cost	
	MWh	% Of wind energy	Cost [M€]	% Change
UUCED (2a')	206	0.06	132.8	–
Deterministic three-level (2c')	853	0.25	134.1	+0.98
Stochastic three-level (2c'-s)	3161	0.92	133.5	+0.53

4. Conclusions

This paper compared the performance of three short-term power system operations models regarding their effectiveness in accommodating large amounts of wind power generation. The first model is a variable time resolution unified unit commitment-economic dispatch model (UUCED), which is tested against a two-level scheduling model and a three-level scheduling model based on the current US RTO/ISO operating practices. A fair comparison has been performed through an annual simulation of the operation of the Greek Interconnected Power System under two wind power generation scenarios (2013 wind capacity and double the 2013 wind capacity). Several indicators, such as the annual operating cost, the annual energy mix, the number of unit start-ups, wind energy curtailment and secondary reserve deficiency are discussed. Results show that the UUCED model results in a more economic operation as wind power penetration increases. Therefore, it may prove to be a useful alternative for the future power system operations.

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5. Appendix

5.1. Wind power and load forecast uncertainty

Modeling of load and wind power forecast errors is very important for the assessment of different short-term operations models in the presence of uncertainty. In this study, forecasts are generated by adding an appropriate error term to the real measurements. The forecast error is assumed to be normally distributed with zero-mean and standard deviation σ.

A 60h-ahead forecast of the aggregated wind power of the Greek interconnected power system is assumed. The standard deviation σ of the wind forecast error in each hour was derived based on the findings of [28], where Focken et al. investigate the standard

deviation of the wind power forecast error for an individual wind farm against the forecast horizon and conclude that it follows this pattern. However, since aggregated wind power forecasts for the entire region of Greece are used in our study, the magnitude of the standard deviation must be reduced by a factor dependent on the size of the region, as denoted in [28]. This is due to the fact that renewable generation becomes more predictable and less variable when aggregated over a wide geographic area. In this paper, the final normalized wind power forecast error standard deviation as a function of the lead time is shown in Fig. 4 (left axis). More specifically, the standard deviation of the wind power forecast error normalized to the installed wind capacity as a function of lead time, ranges from zero at the beginning to 12% for 60 h lead time.

Load forecast uncertainty is modeled with a similar approach. A 60h-ahead forecast of the system load of the Greek interconnected power system is assumed. The normalized load forecast error standard deviation is also shown in Fig. 4 (right axis) as a function of lead time. More specifically, the standard deviation of the load forecast error normalized to the peak load, ranges from zero at the beginning to 2.4% for 60 h lead time.

5.2. Reserves quantification

Reserves in EU are classified into frequency containment reserves (FCR), frequency restoration reserves (FRR) and replacement reserves (RR), based on ENTSO-E separation [29] (formerly named primary, secondary and tertiary reserves, respectively). FCR aims at restraining the frequency deviation in case of disturbances. The amount of FCR is well-defined for both the UCTE area and the Greek Interconnected Power System and, therefore, it is not modified. FRR and RR are quantified based on a statistical analysis of the 2013 1-min wind power and load data using the standard deviation as a measure.

The aim of the FRR is to replace FCR and restore the Area Control Error to zero. FRR is dimensioned based on both contingency reserves in a certain control area as well as net load variability. The load-following part of FRR is calculated as three standard deviations of the differences between the 1-min net load data and the 15-min net load average. This number is then added to the worst contingency event (i.e. trip of the largest generator) that can take place in the control area of the Greek Interconnected power system.

The aim of the RR is to replace deployed secondary and primary reserves. RR is dimensioned based on contingency events as well as both net load variability and uncertainty. The variability is calculated via the standard deviation of the differences between the 15-min net load average and the hourly or half-hourly net load average (depending on the model) [30]. The standard deviations of the load and wind uncertainty depend on the forecast lead time and they are derived from Fig. 4. Supposing that the wind power forecast error, load forecast error and net load variability are uncorrelated, the total standard deviation is calculated as the geometric sum of the standard deviation of these three components [6]. The final amount of RR is calculated as the sum of the worst contingency event plus three times the total standard deviation. It is noted that the RR quantification is performed prior to each model run and separately for each time period of the scheduling horizon, since each time period has a different lead time.

5.3. Scenario generation

Scenarios are generated to account for the load and wind power uncertainty. In this paper scenarios are built around the load/wind power forecasts described in Appendix 5.1. More specifically, for each time interval of the optimization horizon, the load/wind power uncertainty (the deviation of a possible scenario from the respective forecast) is represented by a normal distribution with zero mean and standard deviation σ derived from Fig. 4. The normal distribution is discretized into a finite number of steps (i.e. at 0, $\pm 1\sigma^e$, $\pm 2\sigma^e$, ...) where σ^e is and standard deviation of the load/wind power forecast errors based on Fig. 4. Scenarios are generated separately for load and wind power and the final total set of scenarios is subsequently calculated as the Cartesian product of the individual sets.

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