Effect of Time Resolution on Unit Commitment Decisions in Systems with High Wind Penetration

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***Abstract*—The increasing share of wind power in power systems requires changes in the operating procedures. Day-ahead scheduling no longer has to fit only with slow and easily predictable changes in load, but also with more abrupt changes in wind power. Procedures for dealing with wind uncertainty, such as stochastic, robust, and interval unit commitment algorithms, typically assume a one-hour resolution. Since wind generation can change significantly within an hour, shorter optimization intervals might be required to adequately reflect this uncertainty.**

This paper compares the stochastic, interval and robust unit commitment formulations with resolutions of 1 hour and 15 minutes. The schedules produced by these various algorithms are compared using a Monte Carlo simulation procedure on a modified version of the 24-bus IEEE-RTS.

***Index Terms*—Unit commitment, stochastic optimization, interval optimization, robust optimization, wind uncertainty.**

I. Introduction

THE increasing proportion of wind generation capacity calls for a re-examination of the unit commitment (UC) algorithms. Since wind fluctuations are less predictable than changes in the load [1], new UC methods have been proposed. The most commonly advocated option for dealing with wind uncertainty is stochastic optimization. Stochastic UC (SUC) considers a set of wind scenarios and generates a single commitment schedule that minimizes the expected operating cost over all these scenarios. Detailed description of SUC formulations can be found in Barth *et al*. [2] or Wang *et al*. [3] among others. Approaches for alleviating the significant computational requirements imposed by the SUC, such as parallel progressive hedging by Ryan *et al*. [4], have been proposed. At the same time, other UC formulations that require less computational efforts have been investigated. One of these approaches is the robust UC (RUC). The RUC formulation minimizes the generation cost for the worst-case scenario within the uncertainty bounds using a two-part approach and a Benders decomposition [5]: the first one identifies the worst-case while the second one minimizes the cost of dealing with this situation. Another approach to solve the UC problem with uncertain wind output is the interval UC formulation (IUC), proposed by Sun and Fang [6]. The IUC minimizes the dispatch cost of the most probable scenario, often referred to as the central forecast, while enforcing the feasibility of the schedule for the upper and lower bounds of uncertainty. This method thus solves a SUC considering only three wind generation scenarios: the upper limit, the central forecast, and the lower limit. Ramping constraints impose feasible transitions between these three scenarios for all consecutive time periods. Wang *et al*. [7] published a detailed formulation of the IUC formulation.

All of the methods that have been proposed for dealing with uncertainty consider the UC problem at the day-ahead stage for the following day. However, wind forecasts are more accurate for the near future and tend to deviate significantly from the actual wind generation towards the end of the next day. This problem can be mitigated using a rolling UC, such as discussed by Tuohy *et al*. [8] who showed that the optimal UC frequency is three hours.

All of the aforementioned references schedule generating units on an hourly basis. Hourly scheduling may be appropriate for slowly changing and easily predictable load. However, changes in wind power are more abrupt and harder to predict. Therefore, a more granulated time resolution could produce better UC schedules. FERC Order 764 [9] recently addressed this issue and stated "... *hourly transmission scheduling protocols are no longer just and reasonable.*" For this reason, the Commission proposed the introduction of transmission schedules based on 15-minute intervals.

The left-hand side of Figure 1 shows schematically an optimal generation schedule obtained with a 15-minute resolution UC. When 15-minute commitment decisions are aggregated into one-hour commitment decisions, one option is to settle for the most conservative commitment where the hourly committed capacity is equal to the highest capacity required over the four 15-minute intervals comprising this hour. However, this leads to a loss of optimality due to conservative commitment status in the remaining 15-minute periods (crosshatched area in the upper right part of Figure 1). On the other hand, if a less conservative commitment is chosen, such as the one in the lower right part of Figure 1, the entire load might not be served during some sub-periods, resulting in a loss of optimality due to a vulnerable commitment.

Another reason for using a 15-minute UC resolution is fast peaking units. For instance, some of gas-fired units have minimum up/down times shorter than one hour [10] and UC models with an hourly resolution fail to capture that important

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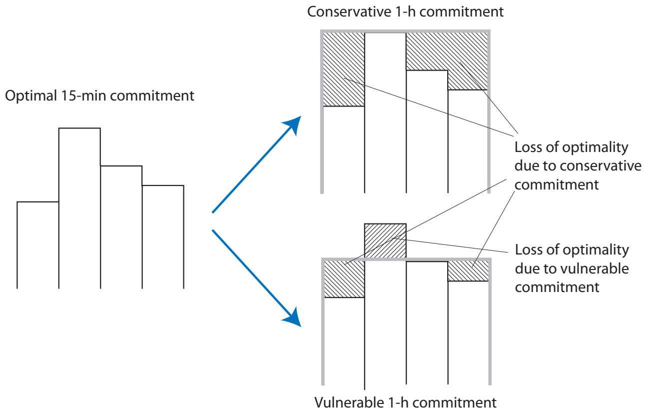

Fig. 1. Schematic representation of committed capacity and loss of optimality when a 15-minute UC resolution is replaced by a 1-hour resolution.

characteristic.

This paper compares the effect of moving from a one-hour to a 15-minute resolution for the SUC, IUC, and RUC formulations, both in terms of the cost and computational time. The cost comparison is carried out not only on the basis of the cost of the day-ahead schedule, but also using a Monte Carlo simulation that reveals how robust the various schedules are to the vagaries of wind generation.

II. Formulations

This section summarizes the UC formulations used in the case study. To emphasize the differences, we discuss only the objective functions and list the constraints. Complete mathematical formulations of the constraints can be found in the references.

The objective function of the SUC is:

$$\begin{aligned}\min \Bigg\{ & \sum_{t \in T} \sum_{i \in I} \left(SC_{i,t} \cdot y_{i,t} + \sum_{s \in S} \pi_s \cdot F_i \left(p_{t,i,s} \right) \right) + \\ & + \sum_{t \in T} \sum_{s \in S} \pi_s \cdot \left(ENS_{t,s} \cdot VLL + WC_{t,s} \cdot VCW \right) \Bigg\}\end{aligned} \tag{1}$$

The first term of this objective function accounts for the start-up cost, $SC_{t,i}$, of generator i at time period t. This term is active only when the binary start-up variable $y_{t,i}$ is equal to 1. This part is common for all scenarios. The second part of (1) considers the dispatch cost of each scenario: $F_i \left(p_{t,i,s} \right)$ represents the fuel cost at time period t under the scenario s for generator i, whose output is $p_{t,i,s}$. The Energy Not Served, *ENS* is penalized by the Value of Lost Load, *VLL*, while the Wind Curtailment, *WC*, is penalized by the Value of Curtailed Wind, *VCW*. The dispatch cost of each scenario s is weighed by its probability π_s. Detailed SUC models are available in [2] and [3].

The objective function of the RUC is:

$$\begin{aligned}\min \sum_{t \in T} \sum_{i \in I} & \left[SC_{t,i} \cdot y_{t,i} + F_i \left(p_{t,i}^{\mathrm{wc}} \right) + \right. \\ & \left. + ENS_t^{\mathrm{wc}} \cdot VLL + WC_t^{\mathrm{wc}} \cdot VCW \right]\end{aligned} \tag{2}$$

The RUC minimizes the cost of the worst case (denoted by "wc"), which corresponds to the most expensive realization of wind generation. Load shedding and curtailed wind energy are penalized in the same way as in the SUC formulation. We implemented the RUC procedure described in [5].

The objective function of the IUC can be written in a similar fashion:

$$\min \sum_{t \in T} \sum_{i \in I} \left[SC_{t,i} \cdot y_{t,i} + F_i \left(p_{t,i}^{\mathrm{bc}} \right) + WC_t^{\mathrm{bc}} \cdot VCW \right] \tag{3}$$

The IUC minimizes the start-up cost of the generators and the dispatch cost under the base case (denoted by "bc"), which corresponds to the central wind forecast [7]. Unlike in the SUC formulation, load shedding is not allowed because the upper and lower bound scenarios as well as the ramping constraints must be satisfied. Wind curtailment is penalized by the VCW.

All formulations are subject to the following constraints:

- Generator minimum up/down times;
- Generator minimum and maximum output limits;
- Generator ramping constraints;
- Power balance constraints that include generator outputs, wind farm outputs and curtailment, loads, and line flows;
- Transmission line limits.

Reference [11] provides detailed formulations of these constraints.

III. Case Study

A. Test System Data

The 24-bus IEEE RTS [12] provided the basis for the test cases. We used generator characteristics and initial statuses from [11], simulated the load for the first day of the year, and used line capacities reduced to 60%. Three wind farms were added to the system at buses 114, 118, and 121, as shown in Figure 2. A set of 1000 wind and load scenarios was generated based on BPA data [13] using an ensemble approach, which means that the random feature selection and bootstrap sampling methods [14] were implemented to generate training samples for the neural network and support vector machine scenario generators. Parameters of the model were selected based on a cross-validation set [15]. Finally, the fast forward scenario selection algorithm proposed by Morales *et al.* [16] was used to reduce this set to 20 scenarios for each wind farm. The central wind forecasts for one-hour and 15-minute resolutions are provided in Figure 3.

The following generation schedules were generated at the day-ahead stage:

- Stochastic–20 wind scenarios and the entire load must be served;
- Stochastic (VLL)–20 wind scenarios but some load may not be served for some scenarios at a cost of \$5,000/MWh;
- Interval (full)–bounds are sets at the minimum and maximum values of the 20 stochastic scenarios at each hour;
- Interval (5%)–bounds are tighter than in the previous case, as 5% of points at each hour are greater than the upper bound, and 5% are lower than the lower bound.

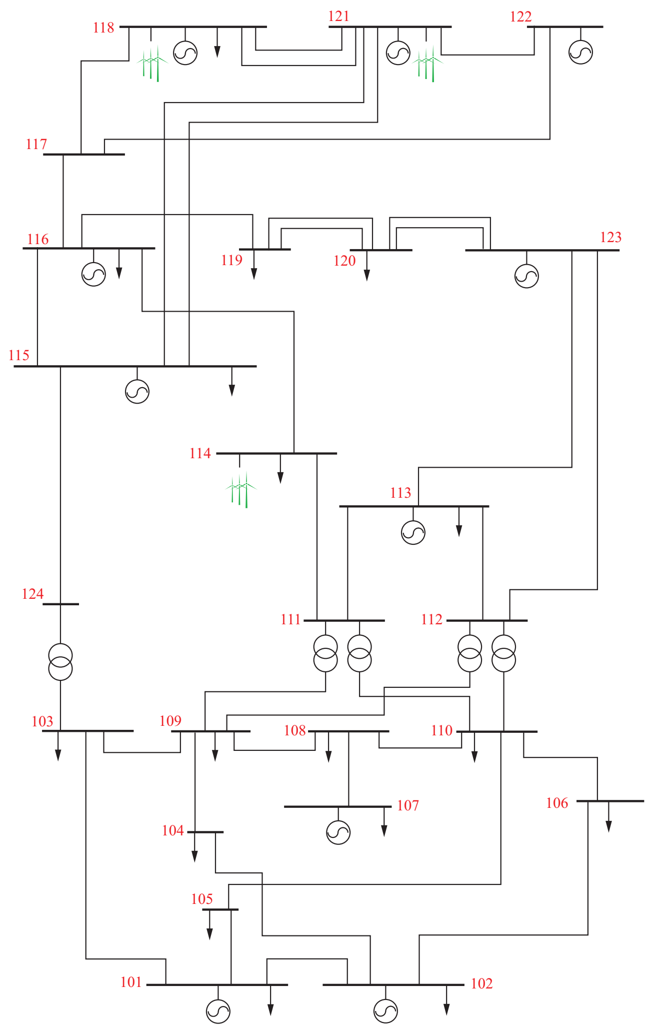

Fig. 2. 24-bus IEEE RTS with wind farms added at buses 114, 118, and 121.

Since 20 scenarios are used, the lowest and highest values are neglected. This case is thus less conservative than the "Interval (full)" case;

- Robust (full)–bounds are set in the same fashion as for the "Interval (full)" case;
- Robust (5%)–bounds are set in the same fashion as for the "Interval (5%)" case.

All the simulations were performed using CPLEX 12.1 running under the GAMS 23.7 environment on an Intel i7 1.8 GHz processor with 4 GB of RAM memory. The optimality gap was set at 0.5%.

B. Day-Ahead Results

The day-ahead cost and computation times for all the methods are shown in Table I. The day-ahead costs between the different formulations are not directly comparable because each formulation has a different objective function. The Stochastic (VLL) formulation results in lower day-ahead costs than the Stochastic formulation. The Interval (5% bound) has lower day-ahead costs than its full counterpart, because it is less conservative. The same observation holds for the two robust formulations. The stochastic formulations are the most computationally demanding, while the Interval formulations are the fastest. After 24 hours of simulation, the Stochastic (VLL) formulation with a 15-minute resolution had not yet produced an acceptable schedule.

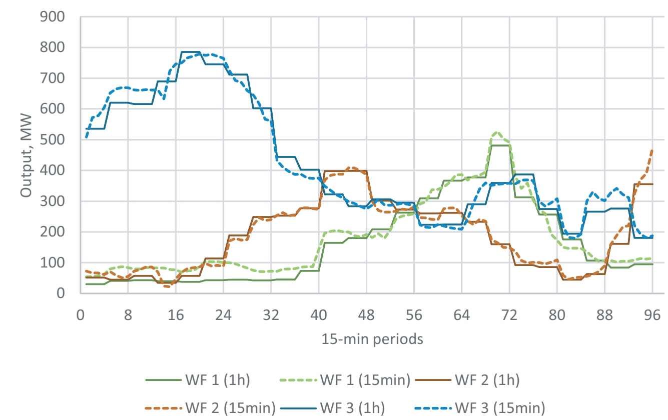

Fig. 3. Central wind output forecasts for 1-hour and 15-minute time periods (WF - wind farm).

Table II summarizes the main characteristics of these day-ahead schedules. The number of commitments is defined as the sum of the numbers of units committed over the 96 15-min intervals of the day. Therefore, one unit committed over a one-hour period is counted as four 15-minute commitments. The stochastic formulation that allows energy not served results in the lowest number of commitments throughout the day. However, the average committed capacity is practically the same as in the stochastic unit commitment that is obliged to serve all the load at all times in all scenarios. This is because the Stochastic (VLL) formulation uses more base-load units, as shown in Table III. The Robust (5% bound) formulation commits less units than the Interval (5% bound) formulation, but since it commits more high capacity units, the average committed capacity is higher than with the Interval (5% bound) formulation. The full interval and robust schedules are more conservative than their respective 5% bound versions. The Robust (full) formulation schedules the most units and results in the highest average committed capacity. As can be seen in Table III, the Robust (full) formulation commits a large number of flexible units (12 and 20 MW capacity) in order to satisfy the worst-case scenario ramping constraints. The 15-minute schedules commit more units than the 1-hour

TABLE I
DAY-AHEAD COST (IN $\cdot 10^3$\$) AND COMPUTATION TIME (SEC)

Approach	Day-Ahead Cost		Computation Time	
	1 hour	15 minute	1 hour	15 minute
Stochastic	419.7	446.5	38min:31s	8h:25min:27s
Stochastic (VLL)	418.8	–	2h:4min:33s	–
Interval (5% bound)	415.5	443.1	32s	1min:8s
Interval (full)	418.8	443.1	31s	1min:38s
Robust (5% bound)	471.2	506.7	1min:12s	2min:5s
Robust (full)	499.8	529.7	1min:18s	2min:11s

TABLE II
KEY STATISTICS OF THE DAY-AHEAD SCHEDULES

Approach	Commitments		Av. com. cap, MW	
	1-h	15-min	1-h	15-min
Stochastic	1048	1221	1711	2171
Stochastic (VLL)	1004	–	1711	–
Interval (5% bound)	1020	1219	1725	2169
Interval (full)	1060	1227	1751	2191
Robust (5% bound)	1016	1233	1749	2174
Robust (full)	1084	1300	1808	2201

schedules, because they account for a higher variability of wind, as illustrated in Figure 1. For the same reason, the 15-minute schedules commit more base-load units, as can be seen in Table III.

C. Results of Monte Carlo Trials

Since the day-ahead scenarios are by nature uncertain, the schedules produced by these various formulations were tested using Monte Carlo simulations. In each Monte Carlo simulation, the day-ahead schedule is used to meet a particular realization of wind and load uncertainty. Real time commitments of additional generators are allowed as long as minimum down time constraints are not violated. Realizations of wind and load uncertainty are randomly generated with the normal [17] and skew-Laplace distribution [18]. The objective function of each Monte Carlo trial includes the cost of both day-ahead and real-time commitments, the fuel cost of the generators, and the penalties for load shedding monetized using a Value of Lost Load of $5,000/MWh. The value of the objective function at each Monte Carlo trial represents the Actual Operating Cost (AOC) under a particular realization of uncertainty. To evaluate the expected value of the actual operating cost with the 95% confidence level and 0.1% error, the required number of Monte Carlo samples is set to max $[1000, N_{\mathrm{MC}}]$, where N_{MC} is calculated as explained in [19].

TABLE III
COMPARISON OF FLEXIBLE (UP TO 20 MW CAPACITY) AND BASE (50 MW AND ABOVE CAPACITY) UNIT COMMITMENTS

Approach	1-hour		15-min	
	Flexible	Base	Flexible	Base
Stochastic	332 (31.7%)	716 (68.3%)	261 (21.4%)	960 (78.6%)
Stochastic (VLL)	286 (28.5%)	718 (71.5%)	– –	– –
Interval (5% bound)	292 (28.6%)	728 (71.4%)	262 (21.4%)	965 (78.6%)
Interval (full)	372 (35.1%)	688 (64.9%)	259 (21.2%)	960 (78.8%)
Robust (5% bound)	284 (28.0%)	732 (72.0%)	269 (20.7%)	1031 (79.3%)
Robust (full)	408 (37.6%)	676 (62.4%)	263 (21.3%)	970 (78.7%)

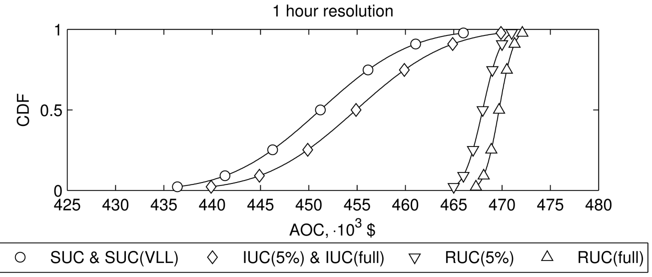

Fig. 4. Cumulative probability distributions of the actual operating cost for different UC formulations with a 1-hour resolution.

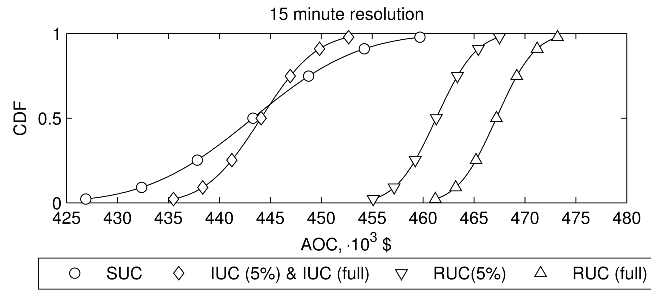

Fig. 5. Cumulative probability distribution of the actual operating cost for different UC approaches with the 15-minute resolution.

Figures 4 and 5 show the cumulative probability distribution of the AOC obtained using Monte Carlo simulations for schedules with one-hour and 15-minute resolutions. Table IV gives the expected cost of the AOC, E(AOC), and its standard deviation, σ(AOC) for the various formulations. Regardless of the UC approach used, the expected actual operating cost for the 15-minute resolution is lower than for the one-hour resolution. However, the schedules with a 15-minute resolution result in larger standard deviations than those with a one-hour resolution. This indicates that the one-hour schedules are more robust to the worst realizations of uncertainty. On the other hand, this robustness increases the operating cost.

The schedules obtained with the SUC achieve the least expensive solutions and, therefore, are the most attractive. However, the computation time of the SUC is impractical for the 15-minute resolution. The IUC formulation produces its day-ahead schedule two orders of magnitude faster than the SUC but its expected actual operating cost is 0.8% larger. When comparing 15-minute schedules, in 40% of the cases

TABLE IV
ACTUAL OPERATING COST (IN $\cdot 10^3$\$)

Approach	E (AOC)		σ (AOC)	
	1 hour	15 minute	1 hour	15 minute
Stochastic	451.2	443.3	7.4	8.2
Stochastic (VLL)	451.2	443.3	7.4	8.2
Interval (5% bound)	457.1	444.1	7.4	4.3
Interval (full)	456.9	444.1	7.5	4.3
Robust (5% bound)	464.0	461.3	1.5	3.1
Robust (full)	469.7	467.2	1.2	3.0

the IUC produces an overall operating cost lower than the SUC. The RUC is also computationally tractable, albeit it is not as computationally efficient as the IUC. However, RUC results in the highest expected operating cost.

IV. Conclusion

This paper compares the stochastic, interval, and robust UC formulations with 15-minute and one-hour resolutions. The results demonstrate that the 15-minute schedules achieve substantial savings through more efficient commitment and dispatch decisions. In general, schedules based on a 15-minute resolution are more conservative at the day-ahead stage, but are less vulnerable to wind forecast errors. In addition, they require the commitment of fewer generating units in real time.

Implementing a 15-minute scheduling interval would increase the computation time required for day-ahead scheduling. This could make the SUC impractical because the least expensive solution that it produces may not be obtainable within a reasonable amount of time unless methods such as progressive hedging are properly implemented. On the other hand, the RUC results in highly conservative and inefficient schedules. Our test cases show that the IUC formulation achieves a good balance between inexpensive schedules and computational tractability.

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