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Monte Carlo-based method to estimate the capacity value of wind power considering operational aspects

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Abstract

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Keywords

Reliability, adequacy, wind power generation, capacity value, Monte Carlo

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***Abstract*—This paper proposes a method to estimate the contribution of wind farms to power system adequacy (their capacity value) based on Monte Carlo simulation in a unit-commitment model. The proposed method considers stochastic variables such as wind power generation and the forced outage of generating units, and is capable of evaluating the impact of operational constraints (such as transmission congestion, time-coupling constraints of thermal generating units, and unit commitment criteria) in the capacity value of wind. The proposed method is applied to a couple of future wind farms in the Chilean Central Interconnected System and the capacity value results are compared with those obtained by the method suggested by the *IEEE-PES Task Force on the Capacity Value of Wind Power*. Although both methods showed capable of properly capturing the influence of the correlation between load and wind generation, the proposed method could also capture the impact that transmission congestion and other operational aspects have on the capacity value of wind farms.**

***Index Terms*—Reliability, adequacy, wind power generation, capacity value, Monte Carlo**

I. Introduction

Power system adequacy refers to the ability of the system supply to meet its demand, taking into account unexpected outages of generators or transmission infrastructure and possible constraints on the primary energy resources (problems on the fossil fuel chain of supply, dry spells, lack of wind, etc.) [1, 2]. System adequacy is achieved by maintaining reserve capacity (especially during peak hours) to cover possible fluctuations in demand and the risk of unexpected transmission or generation outages. Due to the increasing penetration of wind and other sources of non-dispatchable generation (such as solar), there is also growing concern about the capacity of the system supply to follow the net demand (load minus non-dispatchable generation). This has raised the need for estimating the contribution that wind and solar power make to power system adequacy, that is, their capacity value. As Section II will discuss, there is great disparity in criteria to estimate the capacity value of wind generators.

As loss-of-load events tend to occur more often during high demand periods, any capacity value estimation method must be able to capture the correlation between wind generation and system load. Following this principle, the *IEEE Power and Energy Society Task Force on the Capacity Value of Wind Power* proposed a procedure [3] to deal with wind generation based on the *Effective Load Carrying Capability* method which has been applied, for example, to the Irish interconnected system [4]. However, this method does not model transmission and conventional generators constraints. As discussed in [5–7], operational aspects such as transmission congestion, capacity of conventional generators to follow the net demand, and unit-commitment criteria may also need to be considered when assessing capacity value of wind power.

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Thus, on the one hand system characteristics such as existence of hydro generation, level of wind penetration, flexibility of the thermal generators, reserve requirements, and transmission limitations, among others, can either facilitate or make more difficult the integration of new wind farms [8, 9]. On the other hand, wind farm capacity factors, location and access to transmission, correlation between wind and system demand can increase or decrease the adequacy contribution of a wind farm [7, 10]. In this paper we propose a method to estimate the capacity value of wind farms that is capable of capturing the impacts of operational aspects. The method is based on Monte Carlo simulation in a unit commitment and load dispatch model. Results of the method are shown for the Chilean Central Interconnected System (*Sistema Interconectado Central*, SIC).

This paper is structured as follows: Section II provides a theoretical framework for understanding the capacity value of wind generation and discusses different methods found in the literature for estimating it. Section III presents the Monte Carlo-based method and describes the test system. In Section IV outcomes of the proposed method are compared with those obtained by the method in [3], and the ability of each method to capture operational aspects is discussed. Finally, Section V presents the main conclusions of this work.

II. Capacity value of wind

The contribution to adequacy of non-dispatchable generation such as wind and solar is an aspect on which there is a great deal of interest from regulators and generation companies because it can have an important impact on system planning and on the income received by generators. However, there is no generally accepted method for defining or estimating capacity value of non-dispatchable generation resources and international practices can vary significantly.

TABLE I
INTERNATIONAL PRACTICE FOR CAPACITY VALUE OF WIND [11, 12]

System	Method	Observations
WEM (Aust.)	Average capacity factor	3 last years
NEM (Aust.)	Not rigorous or common method	Each jurisdiction makes an estimate based on correlation between resource output and peak demand
PJM (USA)	Average capacity factor	3 last years, Summer 2pm-6pm
ERCOT (USA)	ELCC	Stochastic analysis
MAPP (USA)	Median monthly capacity factor	Period of 4 hours contiguous to the monthly peak
SPP (USA)	85 percentile of capacity factor	10% of peak demand periods
NYISO (USA)	Average capacity factor	Summer 2pm-6pm, Winter 4pm-10pm
NE-ISO (USA)	Average capacity factor	5 last years, Summer 3pm-6pm, Winter 5pm-7pm
Ireland	ELCC	Guided market development for high wind power penetration

Table I shows international practices in the calculation of the capacity value of wind generation for a few selected markets [11, 12]. Because of their simplicity, most systems use approximation methods based on some statistic (either average or a percentile) for the generation capacity factors during peak demand periods.

Since even conventional generators will not be able to provide their maximum power at all times (as a result of either maintenance or forced outages), a capacity value metric should be suitable for generators with diverse operating regimes, be them baseload, intermediate, peaking or non-dispatchable generators. Hence, generators with a high forced outage rate (FOR) should be assigned a smaller capacity value than more reliable generators.

This capacity value metric should also take into account how much capacity a generator can make available at high system risk periods [11, 12]. That is, when a generator is needed the most its contribution to system adequacy will be greater and therefore the estimation of its capacity value should give more weight to their availability during high risk periods. In consequence, the capacity value of a generator able to inject energy into the system during the periods of high risk (usually the periods of high demand) should be higher than the capacity value of a generator unable to do so. In summary, techniques for estimating capacity value for non-dispatchable generators should be based in probabilistic analyses and should also consider the particular characteristics and operating regimes of each generator and how they contribute to improving system adequacy, especially during high risk periods.

The *Effective Load Carrying Capability* (ELCC) approach consists on evaluating the additional amount of demand that the system is able to handle while preserving the same system adequacy given the addition of the generator being studied. This general idea, introduced by Garver in 1966 [13], has been successfully applied for decades to conventional generators and it may certainly prove valuable when dealing with non-dispatchable generators. For example, the method recommended by the *IEEE-PES Task Force on the Capacity Value of Wind Power* (henceforth IEEE method) is based on ELCC principles [3].

In the IEEE method (published in 2011), conventional dispatchable generators are modeled only with their installed capacity and forced outage rate. The capacity probability distributions of all generators are convolved to obtain the capacity outage probability table (COPT) of the power system. The COPT is thus a table of level of capacity with its respective probability [2], where the cumulative probability gives the *Loss of Load Probability* (LOLP) for each possible state of the system.

However, wind farms cannot be modeled adequately by their installed capacity and FOR, as wind generation is more a matter of availability of the primary energy resource. Thus, a different treatment for wind generation is required, as summarized below [3]:

1) The COPT of the power system is used together with the hourly time series of the load to find the hourly *LOLP* without the wind farm. Then, the annual *Loss of Load Expectation* for this case, $LOLE_{noWind}$, is calculated.
2) The wind power output time series is treated like a negative load and is subtracted from the load time series, resulting in a net load time series. Then, the $LOLE_{withWind}$ is calculated. Of course, $LOLE_{withWind} \leq LOLE_{noWind}$.
3) The load's time series is increased by a constant ΔL for all hours, using a iterative process, and the new LOLE is recalculated ($LOLE_{withWind+\Delta L}$) until $LOLE_{withWind+\Delta L} = LOLE_{noWind}$. The load increase ($\Delta L$) that achieves the same level of adequacy than the case with no wind is the *ELCC* or the capacity value of the wind farm.

As the IEEE method uses the hourly time series of load and wind generation for the calculations, it properly accounts for the correlation between load and wind. However, the method does not consider some aspects that may be relevant when evaluating system adequacy. The IEEE method implies that any generator can supply the load in any part of the transmission system, thereby ignoring system congestion and not providing any signals related to the generator's location. Furthermore, the IEEE method considers all the conventional generators' capacity to be available at all times. However, in practice thermal generators cannot make their capacity available at short notice as they have time-coupling constraints (start-up and shut-down times, ramping, etc.) that limit their availability. Another relevant aspect is that in any given hour wind variability may play a role in limiting how much wind generation can actually be injected into the system.

III. PROPOSED METHOD FOR ESTIMATING THE CAPACITY VALUE OF WIND

A. Definitions

The method proposed in this paper requires defining the following metrics for system adequacy:

1) Operational LOLP: ($LOLP^{OP}$) corresponds to the probability of having unserved energy in any part of the system part and is obtained by repeatedly running a production costs model with a detailed DC power flow and unit commitment in a Monte Carlo scheme. Data requirements are as follows: (i) historical data of the wind time series, (ii) forced outage rate of the conventional generators, (iii) transmission line limits and impedances, (iv) starting and stopping costs of the thermal units, and (v) variable generation costs and time-coupling constraints of thermal generating units.

The procedure is as follows:

- Step 1 To incorporate the hydro generation, first a medium term simulation (MT) is executed (with a load duration curve in 12 monthly blocks) to decide the daily amount of water to use from each reservoir.
- Step 2 Using the load and wind generation forecast, a detailed hourly unit commitment is obtained for each day of the year.
- Step 3 A synthetic wind generation pattern is randomly selected. The synthetic wind generation patterns are created preserving the statistical properties (mean, autocorrelation, seasonalities, and correlation with demand) of the original time series.
- Step 4 A outage pattern for each conventional generator in the system is created using its forced outage rate and repair time.
- Step 5 Using the hydro generation from step 1, the thermal unit commitment decisions from step 2, and the random samples from steps 3 and 4, an economic load dispatch with DC power flow is solved.
- Step 6 All the loss of load events happening in the previous step are recorded and then used to calculate the $LOLP^{OP}$ for different levels of demand.
- Step 7 Go back to step 3 until the required number of iterations to ensure $LOLP^{OP}$ convergence is met.

2) Operational LOLE: ($LOLE^{OP}$) corresponds to the system's loss of load expectation for one year calculated as the sum of the values of $LOLP^{OP}$ for all hours of the year.

B. Capacity value of wind power

In this paper we propose a technique based on ELCC principles, but using $LOLP^{OP}$ and $LOLE^{OP}$ instead of the COPT values. The steps to calculate the capacity value by the method proposed in this paper are as follows:

1) Without the wind farm or benchmark, the $LOLP^{OP}_{noWind}$ for each hour considered is calculated. The sum of the $LOLP^{OP}_{noWind}$ for all the hours is equivalent to the $LOLE^{OP}_{noWind}$.
2) The wind farm is added to the system and the $LOLE^{OP}_{withWind}$ is calculated. Obviously, $LOLE^{OP}_{withWind} \leq LOLE^{OP}_{noWind}$. The new value is recorded and the generator is removed.
3) A benchmark thermal unit is added to the system (diesel unit with FOR of 5% [14]) by small increments ΔG of capacity and the new LOLE ($LOLE^{OP}_{noWind+\delta G}$) is calculated until $LOLE^{OP}_{noWind+\delta G} = LOLE^{OP}_{Wind}$. That capacity is the $ELCC^{OP}$ of the wind farm.

Thus the idea for the proposed method is somehow similar to the IEEE method with two main differences:

1) $LOLP^{OP}$ and $LOLE^{OP}$ values are calculated using a production model in a Monte Carlo scheme, while in the IEEE method the $LOLP$ and $LOLE$ are calculated by convolution and the COPT. This difference allows the proposed method to analyze the influence of operational aspects such as transmission constraints.
2) While the IEEE method adds load until $LOLE_{noWind} = LOLE_{withWind+\Delta L}$, the proposed method adds capacity from a benchmark generator until $LOLE^{OP}_{noWind+\Delta G} = LOLE^{OP}_{withWind}$. Thus, in the IEEE method the capacity value is given by ΔL, while in the proposed method the capacity value is given by ΔG.

C. Test system

The methodology described in the previous section was tested on a market model of the Chilean Central Interconnected System (*Sistema Interconnectado Central*, SIC). The SIC is an hydrothermal system with about 12.8 GW installed generation capacity in 2011 of which approximately 50% is hydro. It has several baseload coal units (10.9% of the total capacity), some newer combined-cycle and open-cycle gas-fired units (23.9%), some fuel-oil and diesel-based peaking plants (17.9%), wind power (1.3%) and hydro generation (reservoir and run-of-river) (46%).

To model the load dispatch and the unit commitment in the SIC a production model with Monte Carlo capabilities (PLEXOS [15]) was used. Then, the optimization solver Xpress [16] was used to solve the mathematical problems formulated by PLEXOS.

The production model of the SIC considered 90 transmission buses representing the main transmission corridors of the system. Modeling of the transmission system took special care of representing areas with congestion or potential congestion in greater detail. Additional constraints were added to the dispatch to represent $N-1$ and other security constraints.

The model considered 160 generating plants: 10 generators with hydro storage, 43 run-of-river hydroelectric units, 101 thermoelectric units, and 6 existing wind farms. The thermoelectric units were modeled with minimum stable level, maximum capacity, heat rate, fossil fuel and variable operation and maintenance costs, start cost, start-up time, shut-down cost, minimum up time, minimum down time, and loading ramps. Hydroelectric units were modeled considering minimum stable level, maximum capacity, and hydro efficiency. The Forced Outage Rate (FOR) and repair time for each generating unit were used to create random generator outage patterns for the Monte Carlo simulation.

Hydro storages and cascading hydro units were modeled in the same way they are modeled by the SIC's Independent System Operator (ISO). The SIC's ISO provides on its website detailed production and network data for simulation of unit commitment and load dispatch. The parameters of the model are all public information and can be found in [18, 19]. Before using the model for the purposes of this paper, simulation outputs were contrasted against actual system outputs to check for correctness and consistency.

Unit commitment (UC) and load dispatch were optimized for each stochastic sample for a full year in daily steps using hourly resolution. The MIP gap limit for the UC was set to 0.1% for all models. The Monte Carlo simulation randomly sampled wind profiles and patterns of generator outages. We tested operational results several times using different sets of random samples and found that we obtained reasonable convergence (less than 2% difference in the $LOLE^{OP}$) with 50 Monte Carlo samples.

IV. Simulation Results

This section discusses the impact of wind power generation on power system adequacy, taking into account transmission and operational constraints. In general, it is recommended that the capacity value of wind power be calculated for all wind farms in a determined area. However, in this section we calculate the capacity value of individual wind farms for two main reasons. First, unlike some USA and European markets, the Chilean SIC has currently very little wind capacity installed. Second, the focus of the paper is in showing that the proposed method can capture operational aspects, and that can better be achieved by analyzing individual wind farms. It would be reasonable to expect that if the proposed method were applied to a large set of wind farms, some of the operational aspects to be discussed could be diluted by the diversity of the wind resource.

For the application of the proposed method, synthetic wind power profiles were generated based on actual wind speed measurements from [17] representing future generation for *El Arrayán* wind farm. To evaluate the impact of the correlation between demand and wind generation we defined three different sets of synthetic wind power profiles:

- **Evening peak:** high positive correlation with demand, maintaining the actual correlation between demand and wind power.
- **Morning peak:** low correlation with demand, generated by displacing the evening peak profile.
- **Night peak:** high negative correlation with demand, generated by displacing the evening peak profile.

The morning and the night peak profiles are being used with the only purpose of verifying if the proposed method is capable of capturing the importance of the correlation between load and wind generation. Table II shows the correlation coefficients, while Fig. 1 illustrates the correlation between demand and wind power for each set of profiles using vigiciles. Vigiciles are data that is sorted into 20 equally sized bins. As [3] points out, even if the hourly correlation between wind and load can look deceivingly small (as Table II shows), the relationship between wind and load becomes more evident when binned according to rank.

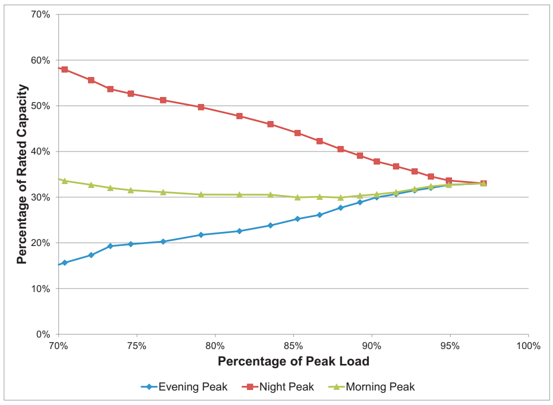

Fig. 1. Correlation between wind and load based on vigiciles

TABLE II
CHARACTERISTICS OF *El Arrayán* WIND FARM

Correlation	Capacity factor [%]	Correlation coefficient of wind generation and load: Hourly data	Correlation coefficient of wind generation and load: Data aggregated by vigicile
Evening Peak	33	0.3	0.99
Morning Peak	33	0.09	-0.31
Night Peak	33	-0.4	-0.98

Table III shows the capacity values of the wind farm in absolute terms (in MW) and in per-unit (as a percentage of the installed wind capacity) for 3 different levels of installed capacity and for different correlations between wind and load. The results show that as the wind installed capacity increases the capacity value in MW also increases, but the per-unit capacity value tends to decrease after a certain point. In other words, the wind capacity value follows the law of diminishing marginal returns, as adding more installed capacity while holding all other factors constant yields a lower per-unit capacity value.

Part of the diminishing marginal capacity value (DMCV) effect is caused by operational aspects that the IEEE method for capacity value estimation ignores. One of the operational aspects influencing the DMCV effect is the starting-up, shutting down, and ramping characteristics of the thermal units,

TABLE III
CAPACITY VALUE OF "EL ARRAYÁN" WIND FARM USING THE PROPOSED AND THE IEEE METHOD

Installed capacity $[MW]$	Type of correlation	Capacity Value $[MW]$: IEEE method	Capacity Value $[MW]$: Proposed method	Capacity Value $[pu]$: IEEE method	Capacity Value $[pu]$: Proposed method
50	Evening Peak	19	18	0.38	0.36
100	Evening Peak	36.2	40	0.36	0.4
300	Evening Peak	88.7	70	0.30	0.23
50	Morning Peak	18.7	18	0.37	0.36
100	Morning Peak	35.6	37	0.36	0.37
300	Morning Peak	88	65	0.29	0.22
50	Night Peak	9.7	18	0.19	0.36
100	Night Peak	18.4	23	0.18	0.23
300	Night Peak	46.1	22	0.15	0.073

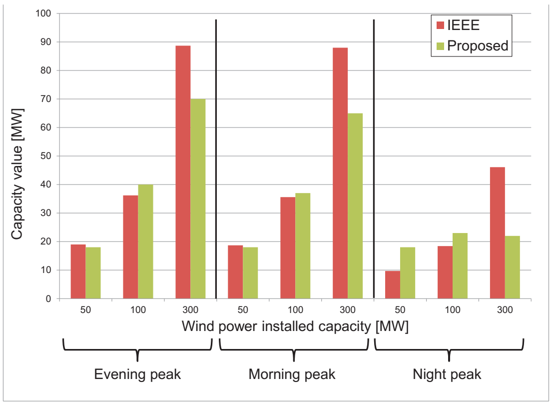

Fig. 2. Capacity Value [MW] of “El Arrayán” wind farm using the proposed and the IEEE method

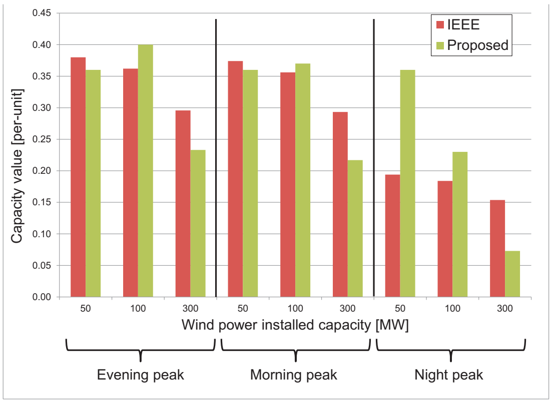

Fig. 3. Capacity Value [pu] of “El Arrayán” wind farm using the proposed and the IEEE method

and the order in which thermal units are dispatched. Depending on the wind profile correlation with the demand and its installed capacity, the difference between the daily minimum and maximum net load (load minus wind generation) can increase significantly, causing changes in the dispatch of the thermal units.

Fig. 2 shows that as the installed capacity increases, so does the capacity value in MW. However, Fig. 3 shows that the capacity value in per-unit not always decreases with the installed capacity. The explanation for this is related to the changes in the dispatch of thermal units. For example, with more wind a large and slow coal unit may not go into service and be replaced by faster gas or diesel units capable to follow the changes in the net demand. Thus, although some of the DMCV effect was observed for both methods, its impact was better captured by the proposed method as its unserved energy probability comes from an stochastic production model, unlike the IEEE method.

Fig. 2 and Fig. 3 show that for low levels of wind power ($50MW$) the correlation between load and wind is not so relevant, but starts becoming more relevant as the installed capacity of the wind farm increases. The highest per-unit capacity values (about 40%) are obtained for positive correlation

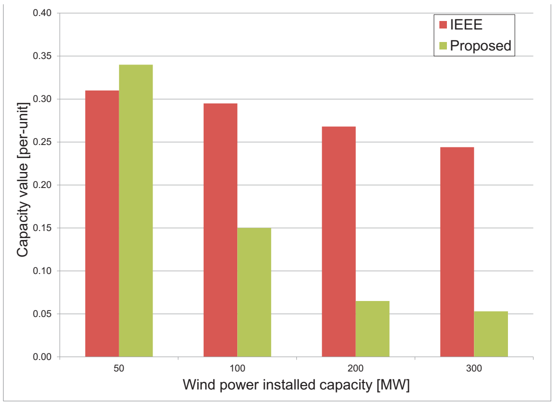

Fig. 4. Capacity Value of “Lebu Sur” wind farm using the proposed and the IEEE method

bewteen load and wind (evening peak) and for a installed capacity of $100MW$. As expected, the lowest capacity value (in per-unit) happens for the night-peak profiles (7.3%) and for a large installed capacity.

The LOLE calculation in the IEEE method considers all load and generation as connected to the same bus. Thus, the method does not consider transmission constraints and assumes any generator can supply the load at any bus.

While wind power can certainly displace energy generated by thermal units, depending on the transmission constraints existing in the surrounding area it might not always be able to supply the load during high-demand periods. The IEEE method cannot directly capture the effects of transmission constraints on the capacity value of wind farms as it only models generation capacity. However, the method proposed in this paper can capture the impact of transmission constraints. To illustrate this, we employed both methods to estimate the capacity value of a wind farm (*Lebu Sur*) that is connected in a highly congested area. Thus, we should expect that for the higher installed capacity levels its capacity value in per-unit should decrease sharply, as it will not always be possible for the wind farm (or as a matter of fact for some conventional generators connected in the area) to generate at its maximum available capacity. Figure 4 shows that, unlike the IEEE method, the method proposed in this paper is capable of capturing this effect.

V. Conclusions

This paper proposed a method for evaluating the capacity value of wind power when operational constraints such as transmission congestion or flexibility of the thermal units in the system are important. The proposed method was compared against the IEEE method, showing very similar results for installed capacities of wind under $50MW$, as operational constraints for this case might not be so relevant. However, for larger values of installed capacity the proposed method was successful at capturing the influence of operational constraints. We were also able to verify that the proposed method was capable of capturing the impact of the correlation between load and wind generation.

The inclusion of operational constraints into our analysis does not intend to answer the question whether wind farms should be penalized (in terms of their capacity value) for creating network congestion or other operational problems they might cause to the system. However, our results show that operational aspects can make quite an impact on the contribution a generator makes to system adequacy. Naturally, these considerations are not only applicable to wind generators but to conventional generators as well. Thus, if operational aspects were to be included in the calculation of capacity values, they would also need to be applied to conventional generators.

The IEEE method is significantly simpler, being enough only a few seconds to obtain results if the convolution is carried out using the Fast Fourier Transform algorithm. The proposed method can take significant time and effort to get results (for the SIC it took about 5 hours of simulation for each capacity value reported). In future work we intend to evaluate separately how each of the operational aspects considered in this paper affect system adequacy (in terms of the LOLE), as some of them might not be as relevant and could be omitted from the simulations to reduce computational time.

If the wind power resource is sufficiently diversified, the additional modeling time and effort of the proposed method might be hard to justify. In Chile, however, significant transmission constraints in some of the areas where wind projects are being considered make the use of the proposed method advisable.

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