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A risk-based, distributed sensor installation concept for high voltage grid monitoring

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Abstract

This paper presents a novel installation protocol to build a reliable and economical line monitoring system on high voltage power lines. The proposed method is able to iteratively determine the required number of sensors and their installation location for a predefined level of risk. First, it requires a general analysis of the transmission line, which ends with a critical span analysis. Then the risk arising from the variability of weather parameters along the transmission line must be determined. Finally, it is necessary to consider what kind of problem the thermal overheating can cause at the conductor (sagging, annealing) and which additional stages can be used to reduce the risk factor to the permissible level. A case study was investigated with the data of a Central-European high voltage power line to present how the proposed method works. The results showed that there are power lines on which only distributed sensor installation concepts result in a safe and economical solution. Applying the proposed method, a comprehensive and robust sensor system can be implemented, which can be a solid basis for any dynamic line rating (DLR) system.

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Keywords: Dynamic line rating; DLR; Line monitoring sensor; High voltage power lines; Installation method; Monte Carlo sampling

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1. Introduction

Full utilization of high voltage transmission lines has become a central issue of the electricity system in recent decades [1,2]. Dynamic line rating (DLR) application facilitates achieving a resilient and secure grid operation beneficially and economically [3–5]. The core of DLR is to monitor the line's electrical and mechanical parameters in real-time, such as the environmental parameters in the vicinity of the conductor. With the application of DLR, the conductors' ampacity can be adjusted to the weather parameters changes resulting in a higher utilization rate (up to 120%–140% in exceptional cases) almost 95% of the time [2–5]. A vital issue in realizing such a DLR system

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is the accurate monitoring of both the power line and the weather parameters [4,5]. This sensor system's central point is to define the numbers and exact locations of the installed devices. However, sensor manufacturer companies do not usually publish any guidelines for this issue [6–10]. Thus, implementing a line monitoring system required engineering experiences and several rules of thumb in the past that led to incomplete and incorrect monitoring systems [4]. Furthermore, the installation problem is aggravated by the fact that the cost of the sensors is usually high, making the sensor installation problem a technical and economic issue [4,6]. At the same time, it is essential to note that safe operation and security of supply must not be compromised since the strategic importance of the electricity system [4].

In the literature, several papers provide solutions for the identification of sensor numbers and locations. The core of these protocols is to avoid problems related to thermal overloads (sagging and annealing) by identifying so-called hot spots on the line [11,12]. In some papers, line sections covering these hot spots are under the name of critical spans in which the sensors need to be installed [11]. However, the analysis process can be complex since these hot spots' locations can vary in time and space due to several factors (changes in the weather, extension of the power line, various clearance reserves) [11,13–15]. Ones eliminate this complexity by equipping all the spans with sensors [13,16], while others declare the coverage of the whole line to be unnecessary and uneconomical [17,18]. To eliminate the high cost, system operators can apply the 'equidistant placement strategy', which promotes placing the devices at equal intervals, 2–3 km apart from each other's [4,17,19]. Although this method is suitable for some power lines, so-called heuristic models based on Pearson-correlation rate optimization or modified binary particle swarm optimization give a better and more economical result [12,17,19]. In novel models, it is also considered that monitoring only the power lines' hot spots can be misleading. Due to the elevation profile changes along the line and the different design peculiarity of safety reserves, the hot spots do not always cause sag-clearance problems [17]. Sensor placement optimization needs to consider that besides the sagging, the conductor's aging also can be the result of the thermal issues. At high temperatures (mostly above 100 °C), so-called annealing takes place in ACSR (aluminum conductor steel reinforced) conductors that reduce their remaining lifetime [20]. Based on existing research, the precise determination of the number of sensors and their installation location is usually complex.

2. Proposed methodology for sensor installation

2.1. Motivation and general concept

The motivation of this paper is to focus on the insufficiency of the existing international models. The first deficiency worth mentioning is the handling of weather parameters along the power line. Several models apply mesoscale and interpolated weather data; however, their application can be misleading since some parameters are altitude and distance sensitive [17,19,21]. Moreover, one of the most critical issues, the change of weather parameters along the transmission line, has not been adequately investigated, nor the consequences of their possible erroneous measurement. This is especially true of the cooling effect of wind, which is one of the most significant factors influencing conductor temperature and varies stochastically along the transmission line [4,11,22,23].

Secondly, while elevation profile and ground clearance are essential, the objects (other lines, roads, rivers, buildings, etc.) under the power line and the electric field distribution in the vicinity of the conductor also play an indispensable role [24]. Thirdly, the existing models do not differ based on the result of the thermal overload (sagging or annealing). And the final shortcomings of the mentioned methods are that they did not provide details about how the risk level changes if more or fewer sensors are installed.

Therefore, the present paper aims to present a new sensor installation protocol considering the mentioned factors. This method is suitable to provide information about the number of sensors required and their exact location before installation. The model's core is its ability to determine the risk factor associated with using a certain number of sensors on a given transmission line (see Fig. 1 and Fig. 2).

2.2. Installation protocol methodology

The proposed sensor installation protocol can be separated into three main steps. The first step gives a general power line analysis, including the first sensor's position (line monitoring sensor and weather station), while the second step manages the risk from the weather parameter changes in space. Finally, the third step specifies this risk

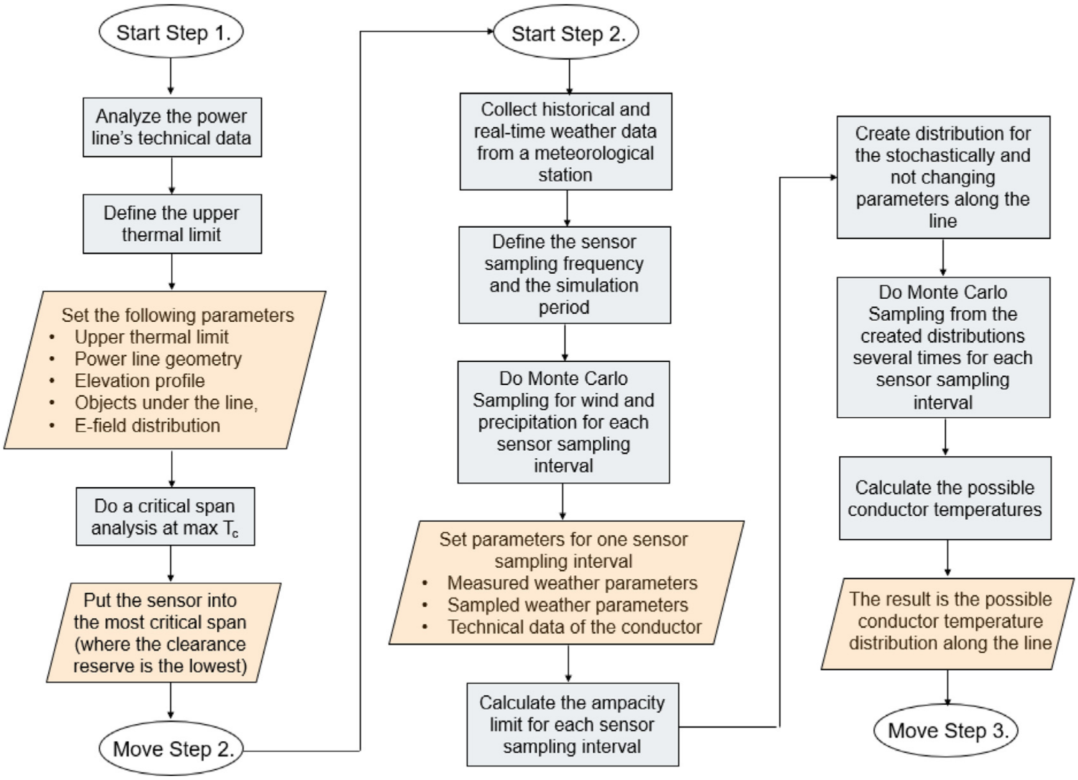

Fig. 1. Flowchart of the first two steps of the proposed installation protocol.

value by considering the unique attributes of the tension sections and the result of the conductors' possible thermal overloads.

As a first step, the whole sensor placement protocol should start with the analysis of the technical properties of the line, such as the applied voltage level, the safety distances, the ampacity etc. After it, a so-called critical span analysis needs to be performed on the whole power line without using any weather parameters. In doing so, the transmission line must be split into tension sections, and the catenary curve must be simulated at the maximum conductor temperature [5,25].

$$y = \frac{\sigma_h}{\gamma}\frac{e^{\frac{x}{p}} + e^{-\frac{x}{p}}}{2} = \frac{\sigma_h}{\gamma} ch \frac{x\gamma}{\sigma_h} \tag{1}$$

where γ is the weight force for a cross-section of 1 mm^2 of a 1 m long conductor and σ_h is the horizontal component of the tensile stress [25].

$$b_h = \frac{\sigma_h}{\gamma}\left[ch\frac{a\gamma}{2\sigma_h} - 1\right] \tag{2}$$

Knowing the elevation profile, the sag-clearance extents become available at each tension section. The background of this resolution is twofold. One aspect is that several technical parameters are tension span specific in the simulation [25]. Another factor is that tension sections represent separate units in temperature distribution based on previous studies [22,23]. During the analysis, attention should be paid to the electric field distribution and the objects under the transmission line, which may cause a lower clearance value than the ground clearance itself [24]. As a result of the critical span analysis, that tension sections' span needs to be chosen for the first sensor, in which the lowest is the clearance value at the maximum conductor temperature. At this point, the extent of the transmission line is already taken into account in a technical sense; however, the variability of the environmental parameters is not yet considered.

In the second step, the environmental parameters' variability needs to be revealed in time and space. This is relevant since they can cause severe risk in the unmonitored tension sections [11,26,27]. The physical model for the risk calculation is based on the conductor's thermal state. In general, the thermal state can be derived from a heat equation containing all the factors that heat up or cool down the conductor, forming a basis for all the later calculations [23,28].

$$P_J + P_S + P_M + P_I = P_C + P_R + P_W + P_P \tag{3}$$

P_J is the Joule heating, P_S the solar heating, P_M the magnetic heating, P_I the corona heating, P_C the convective cooling, P_R the radiative cooling, P_W the evaporative cooling, and P_p the precipitation cooling. From these factors, magnetic and corona heating are usually neglected since their generally low relevance.

To calculate the risk, reference weather data are required at the first sensor location. The complexity of this problem is that no weather data are available for the sensor location before the installation so that data from meteorological weather stations located next to the power line need to be applied. Although in real-time, the data of the meteorological station and in the observed span is different, for a more extended period, it can be assumed that their distributions for the stochastic parameters are the same in time and space. For a dedicated period, the applied weather data for the first sensor location are the following; the ambient temperature is the same as the temperature measured by the meteorological station, such as the relative humidity and solar radiation. For the precipitation and wind parameters, a situation is more complex since they can vary randomly. A Monte Carlo Sampling (MCS) is applied to samples from a distribution measured by the meteorological station for a more extended period (at least one year) [29]. MCS is a random sampling that allows for a more frequent selection of more standard parameters. Besides this technique represents well the stochastic attribution of these parameters, the wind and precipitation interpolation errors can also be eliminated. Based on Eq. (4), an ampacity can be calculated for these weather combinations.

$$I = \sqrt{\frac{P_C + P_R + P_W + P_P - P_S}{R_{AC}(T)}} \tag{4}$$

At this point, the conductor temperature's temporal distribution needs to be determined. To reveal the potential risk, the following assumptions are made on the parameters affecting the conductor temperature:

Based on Table 1, the line load is assumed to be constant at the entire length of the line, the ambient temperature and the solar radiation varies with a slight standard deviation around a measured value in one span, while the wind and the precipitation have a stochastic nature along the line. Several studies showed that the wind speed follows a Weibull distribution, while for wind direction von-Mises one can be applied; only the parameters need to be fine-tuned based on measurements. These assumptions are exploited during the second MCS, where the sampling method is repeated several times, resulting in distribution for the conductor temperature. The stochastically variable parameters are selected from the historical data of the meteorological station, while for the other parameters, the current measured value of the meteorological station serves as mean values, and normal distributions are built around them. If the refreshing data period of the monitoring sensor is defined, it can be calculated what temperature the full utilization of the conductor reaches at the end of the designated period [23,28].

Table 1. Load and weather parameters in the model [29].

Parameter	Symbol	Attribution	Applied distribution
Line current	[A]	Fix along the line	–
Ambient temperature	[°C]	Slight deviation along the line	Gaussian
Solar radiation	[W/m^2]	Slight deviation along the line	Gaussian
Precipitation	[mm/h]	Stochastic change along the line	Based on location features
Wind speed	[m/s]	Stochastic change along the line	Weibull
Wind direction	[°]	Stochastic change along the line	von-Mises

$$\sum m_i c_{pi} \cdot \frac{d\theta_{av}}{dt} = P_J + P_S - P_C - P_R - P_W \tag{5}$$

where $\Sigma m_i c_{pi}$ is the heat capacity of the conductor, $d\theta_{av}$ is the change of the conductor temperature, and dt is the timestep applied in the simulation. According to the conservative approach, if a simulated temperature value exceeds the maximum value specified for the transmission line's regular operation, it poses a risk. The extent of the risk can only be reduced by installing additional sensors.

In the third step, the real risk is defined along the power line, and the exact number and location of the sensors are determined. It needs to be explained what the upper thermal limit of the power line is and what factors played a role in its determination. Two different cases can be defined as a result of thermal overload:

(a) Sag-clearance problem (mostly 40–60 °C is the upper thermal limit of the power lines)
(b) Annealing of the conductor (mostly 60–80 °C is the upper thermal limit of the power lines)

It is essential to note that conductor temperature monitoring with sensors is vital for a comprehensive and secure DLR system in both cases.

For case (a), a sub-step needs to be done to rank the tension sections of the power line. Based on the necessary clearance limit and the results of the critical span analysis, the value of the clearance reserve at the maximum temperature is clearly defined in each tension section. This distance shows how much margin was left in the span at the maximum conductor temperature. If this reserve is prominent under the investigated section, no sag problem may occur despite the high temperature. The idea is to convert these values into a temperature factor by determining which temperature results in zero margin distance for the dedicated section. The application of this temperature factor makes available the ranking of the tension sections (see Fig. 2).

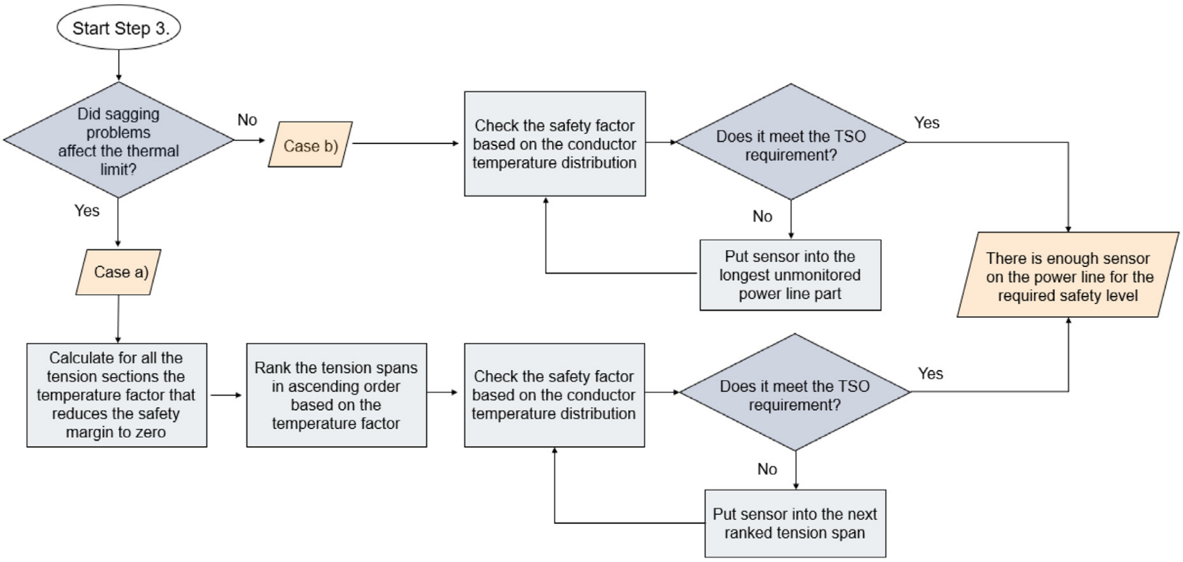

Fig. 2. Flowchart of the third step of the proposed installation protocol.

After the ranking, the system operators need to define the risk level they want to apply. The risk factor for a given sensor number can be calculated as follows:

$$P(\theta_c > \theta_{max}) = \frac{N_f}{N} \tag{6}$$

N is the number of simulations, and N_f is the number of times the temperature exceeds the next ranked unmonitored tension section's maximum temperature. If the calculated risk is not acceptable from the system operator's perspective, the secondly classified tension section also needs to be equipped with a sensor. For this section, the ampacity also needs to be calculated based on another Monte Carlo Sampling from the stochastic changing weather factors. Comparing the ampacity values calculated for the sensor locations, always the lower one needs to be applied. This results in a modified conductor temperature distribution that reduces the risks. This iteration needs to continue until the expected risk factor is reached.

$$I_{line} = \min\left(I_{ij}, I_{i,k}\right) \quad \forall\ [\mathrm{i} = 1, 2, \ldots, \mathrm{m}] \tag{7}$$

I_{line} is the ampacity limit for the line, I_{ij} is the ampacity limit for section j at the ith time step, I_{ik} is the ampacity for section k at the ith time step, m is the necessary time steps until the simulation runs.

In case (b), annealing is the critical factor, and almost the same steps need to be followed. However, there is no need to rank the tension spans since exceeding the maximum temperature raises the risk instantly. If available any hot spot analysis for the power line, the additional sensors need to be placed onto the hot spot sections and recheck the risk factor until it reaches the necessary level. Otherwise, an iterative approach is recommended. 'N' number sensors divide the power line into 'N + 1' sections. The following sensor should permanently be installed at the midpoint of the most extended transmission line section until the risk factor reaches a sufficient level.

2.3. The novelty of the presented sensor installation protocol

The proposed sensor installation approach has the following features and novelties:

- provide guides before the sensor installation, based on technical and easily accessible weather data;
- apply a new approach: if placing sensor(s) into the most unfavorable span(s) in terms of clearance reserve, what is the chance of a thermal overload problem in other sections due to the extent of the transmission line;
- it takes into account that not always sagging problem occurs from thermal overloads;
- it is not sensitive to changes in wind and precipitation over time and space;
- it is not sensitive to the erroneous onefold measurement of wind and precipitation;
- it can handle different technical parameters and safety margins of different tension sections and spans.

3. Performed simulations

3.1. Data of the power line

A 400 kV, single-circuit power line equipped with a line monitoring sensor and weather station was used for the simulation to present how the proposed protocol works. The more than 80 km long power line has a strategic role in the security of supply, and due to this, the system operator allows zero risk factor. The double-bounded phase conductor's maximum thermal limit is 80 °C which results in 1155 A ampacity. However, due to sag-clearance issues, the operating limit was set to 60 °C with 797 A static line rating (SLR). The technical parameters of the line are highlighted in Table 2.

Table 2. Technical parameters of the OHL.

Conductor parameter	Value	Power line parameter	Value
Type of conductor	ACSR 500/65	No. of tension sections	27
Maximum temperature	80 °C	No. of spans	138
Static Line Rating (SLR)	1155 A	Max. operating temp.	60 °C
Mass per unit length	1.935 kg/m	Static Line Rating (SLR)	797 A
Resistance at 25 °C	0.5643 Ω/km	Clearance limit	8 m

3.2. Results of the simulation

Based on the proposed methodology, three main steps are needed to be followed on the observed power line. In the first step, the first sensor location was determined via a critical span analysis considering all the mentioned factors.

As Fig. 3(a) presents, the lowest clearance reserve is in the most critical span of tension section No. 3, and the first sensor needs to be installed there. After this, the weather parameters were collected to calculate the risk. In the simulation, one-month data were applied not from a meteorological station but a line monitoring sensor installed earlier on the power line. Using these meteorological data, the ampacity limit – the dynamic line rating – can be calculated at specified intervals. The sensor sends new data every 10-minutes, so this interval was used for both the DLR and the temperature simulations.

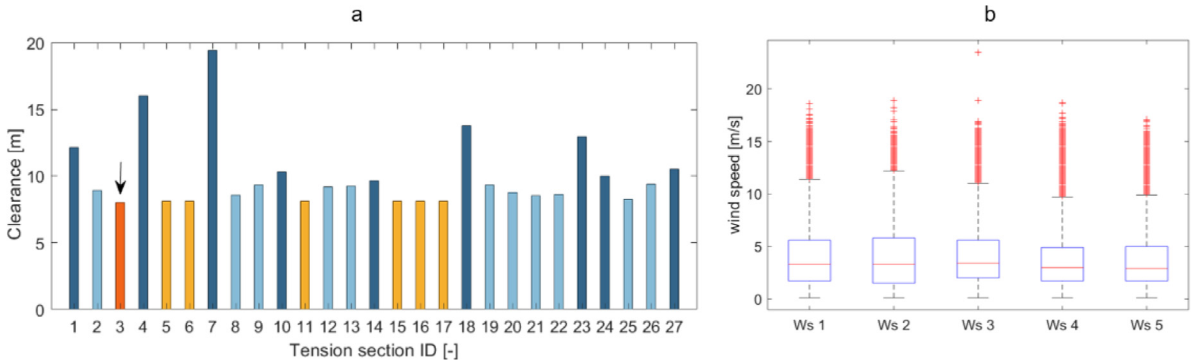

Fig. 3. (a) the result of the critical span analysis; (b) wind speed measurements of 5 weather stations along the line.

Along with the power line, five weather stations provided meteorological data. Fig. 3(b) shows that in the wind speed, the distribution of the measured parameters has the same characteristic at different sections. In this way, applying the MCS method to represent the conductor temperature distribution gives a proper estimation. The simulations assumed that the ambient temperature, solar radiation, and humidity have a very slight distribution along the transmission line.

Fig. 4(a) presents the conductor temperature simulation result along the power line. Due to the stochastic nature of the wind and precipitation, this parameter may exceed even 100 °C, which can cause both clearance and annealing problems in several spans. Fig. 4(a) shows that the range of the simulated temperature is relatively wide, indicating that monitoring only specified sections can lead to an inaccurate DLR system. It is important to note that each time interval was set to 10 min, while the ampacity was determined for the infinity time, which is why the distribution meets the lower temperatures more frequently. Based on the simulation, the risk factor was above 10% at one installed sensor, resulting in a need for more devices. Fig. 4(b) represents the ranking of the tension sections to offer the best solution for the installation places of the additional sensors. Via an iterative way, the ampacity and the risk factor were calculated until they reached the TSO-defined value.

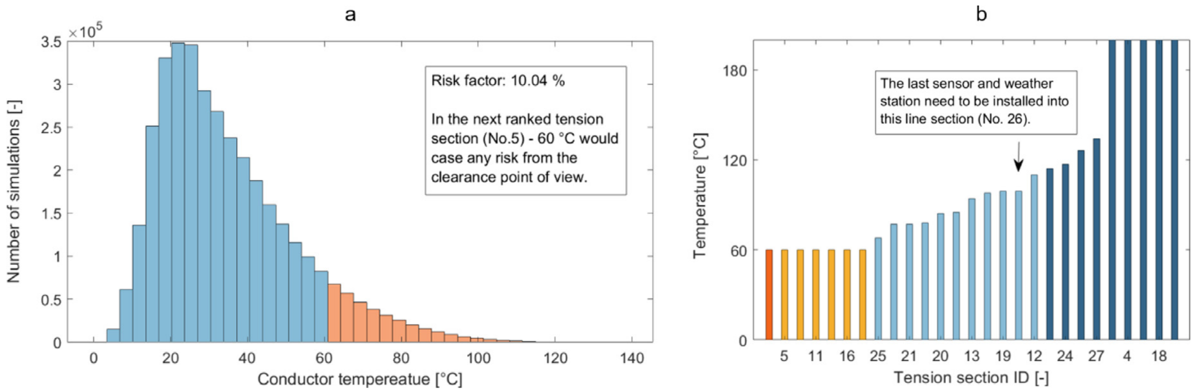

Fig. 4. (a) conductor temperature distribution along the line in case of 1 sensor; (b) ranking of tension sections based on temperature factor.

Fig. 5(a) presents that if 17 tension sections are equipped with sensors and weather stations, even the highest simulated temperature does not exceed the level causing sag problem at the next ranked section (110 °C); thus, the risk factor is reduced to almost 0. Fig. 5(b) shows how the ampacity limit reduces when 1 and 17 sensors are applied. The power line SLR's value before the simulation was under 800 A. Using a DLR system based on the presented monitoring strategy significantly increases the value of transfer capacity over time, while safety and security issues maintain at the required level. In this way, a more utilized power line is at the system operator's disposal.

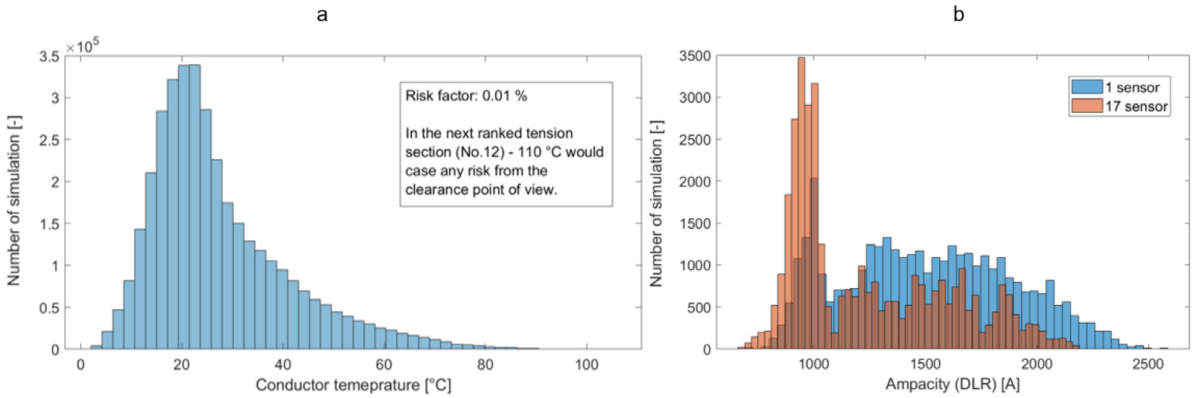

Fig. 5. (a) conductor temperature distribution along the line in case of 17 sensors; (b) DLR values in case of 1 and 17 sensors.

4. Conclusion

In the last decade, there has been a growing demand to increase the ampacity of transmission lines by applying DLR systems based on real-time monitoring. This paper presents a new sensor installation protocol that considers transmission line specifications, changes in weather parameters, clearance reserves in each power line tension section, and problems resulting from thermal overloads. In addition, the presented model can assign safety factors to the number of sensors, based on which both technically and economically optimal monitoring systems can be built. In a given case study, the proposed installation protocol was applied for a 400 kV transmission line. The results show that stochastically varying parameters (wind, precipitation) can significantly raise the temperature of the conductor in unmonitored sections, which can also cause thermal problems. The presented study showed that sensors and weather stations must be installed in 17 of the 27 tension sections for the appropriate safety and security. Based on this fact, the distributed sensor installation concept, although it does not seem economically justified, sometimes the only optimal choice from a technical point of view.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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