A Comparison of Real Time Thermal Rating Systems in the U.S. and the UK

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***Abstract*— Real-Time Thermal Rating is a smart grid technology that allows the rating of electrical conductors to be increased based on local weather conditions. Overhead lines are conventionally given a conservative, constant seasonal rating based on seasonal and regional worst case scenarios rather than actual, say, local hourly weather predictions. This paper provides a report of two pioneering schemes—one in the United States of America and one in the United Kingdom—in which Real-Time Thermal Ratings have been applied. Thereby, we demonstrate that observing the local weather conditions in real time leads to additional capacity and safer operation. Secondly, we critically compare both approaches and discuss their limitations. In doing so, we arrive at novel insights which will inform and improve future Real-Time Thermal Rating projects.**

***Index Terms*— Power transmission, Fluid Dynamics, Power system planning**

I. INTRODUCTION

A. *The Concept of Real-Time Thermal Ratings*

Real-Time Thermal Ratings (RTTR) is based on the observation that the first limit of a current carrying conductor is its temperature. Power lines, cables, and transformers are operated using a static rating based on conservative seasonal conditions. Consequently, there is unused headroom within the power system because of the cooling effect of the environment. RTTR uses observations from weather stations local to the network to alter the rating of conductors during operation [1]. This technology could be applied to defer costly upgrades, increase the yield of Distributed Generation (DG) and support the network during outages.

This paper contributes a unique comparison of two independently developed RTTR methods from the United States and the United Kingdom. The work documented focuses on overhead lines (OHLs), the component provides the greatest from the adoption of RTTR [2]. Figure 1 shows the energy balance in an OHL between environmental conditions and heating by the Joule Effect.

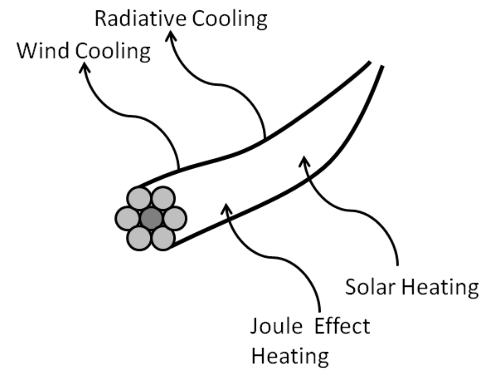

Figure 1. Diagram of the heat balance within a conductor

This energy balance is described by Michiorri, Taylor, and Jupe in their 2009 article [3]:

$$I^2R(T_c) + q_s = q_c + q_r \tag{1}$$

where q_s, q_c, and q_r are the heating through solar radiation, cooling through convection, and cooling through radiation, respectively, and T_c is core temperature of the conductor. $I^2R(T_c)$ represents the internal heating due to line current from the Joule Effect. Equation (1) represents a steady state case, where the line has heated up to the point at which the heat losses and gains are equal. We note that at first glance, it may seem awkward to rely on a steady state solution for real time prediction of conductor temperature. However, given the time scales involved, in most situations, the error by assuming the steady state is likely to be small: the thermal time constant of an overhead conductor is in the region of 10-20 minutes [4, 5], and weather conditions vary on average on a much larger time scale. In this paper we therefore assume a steady state. Nevertheless, in cases where local weather conditions are highly variable in space or in time, it may be desirable to take into account the thermal dynamics across the line.

Power lines have a maximum operational temperature that should not be exceeded. This maximum temperature is used to calculate the maximum current that can be accommodated by the line. There are three widely used models for calculating overhead line capacity, produced by CIGRE [6], International

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Electrochemical Commission (IEC) [7], and the Institute of Electrical and Electronics Engineers (IEEE) [8].

B. Applications

RTTR can be applied during planning [9], design [10], and operation of a transmission or distribution system. The benefits it provides include increasing the capacity for potential wind generation, due to the natural synergy between generation and increased conductor capacity at times of high local wind speed. The need for network reinforcement can be deferred due to the additional capacity [10]. Scheduled outages can be planned considering the potential higher line ratings, and the increased network capacity can help reduce the number of disconnected customers during unscheduled outages.

C. Current Status of RTTR

In the UK, an RTTR system based on using a small number of weather stations to calculate ratings based on component thermal properties was developed at Durham University and has been deployed in prototype form on a distribution network. Further details can be found in the references section below [2, 3, 9, 11].

In the U.S., an RTTR system has also been deployed on a real network and actual operation is imminent. The methodology is similar to the one in the UK and key differences are explained in this paper. This paper represents the first journal publication of the details of the U.S. system. Further details are found in “Concurrent Wind Cooling in Power Transmission Lines” [12].

It is suggested that RTTR can deliver a capacity boost at a low cost, compared with other more drastic capacity increase technologies [13].

II. Description of the U.S. Grid, Climate, and Load

A. U.S. Transmission and Distribution Networks

In the U.S., the transmission network consists of 150,000 miles of high-voltage transmission lines. The network consists of three major interconnection systems: the Western, Eastern, and Texas interconnections. The electricity is transmitted at high voltages (110+ kV) and is usually transmitted through overhead power lines. Distribution voltages are 33 kV and below. Four different utility types handle the generation, transmission, and distribution of U.S. electricity: non-utility power producers, investor-owned utilities, public utilities, and electric cooperatives

B. U.S. Climate

The U.S.’s large land mass, non-contiguous arrangement, and variety of geographic features results in a vast assortment of climate types. Different weather types and temperatures are experienced based on the specific location in the U.S, with climates varying from temperate, to tropical, to sub-arctic to desert. Consequently quoting average temperatures for the U.S. would not be meaningful.

C. U.S. Load Patterns

U.S. demand for electricity changes daily, by day of the week, and seasonally. The peak load times vary by region largely due to industry. In very hot climates, home air conditioning loads have an effect on the overall load, typically resulting in the highest load in the late afternoon during the hottest part of the year. In very cold climates home heating loads lead to high loads in mid-mornings and mid-evenings during the coldest part of the year. Figure 2 shows typical daily load profile in California and Idaho for spring, summer, fall, and winter. Clearly, therefore any RTTR system to be used in the U.S. has to accommodate a challenging variety of weather conditions and load patterns.

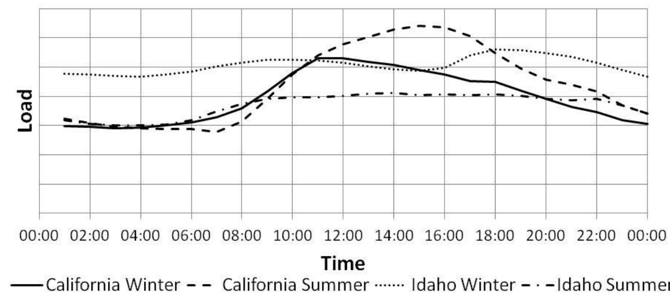

Figure 2: Typical California and Idaho daily load profiles by season

D. Description of U.S. Line Ratings Standards

In the U.S., static thermal overhead line ratings are obtained using IEEE Standard 738 [5]. Ratings are typically calculated using Southwire thermal line rating software (SWRate). All calculations generated by SWRate use equations, empirical constants, and standards that are provided in [5]. Ratings are typically determined using conservative weather conditions, such as wind speed averages less than 2 mph (0.89 m/s). For the area being studied ambient temperatures for the static seasonal ratings summer and winter environmental conditions were assumed to be 104°F (40°C) and 41°F (5°C), respectively. Full sun conditions were also assumed for both summer and winter seasons. Wind velocities were assumed to be 3 mph (1.34 m/s) perpendicular to the line due to regional wide area historical data. This wind speed and direction combination may be too aggressive in some regions, but has merit in Idaho due to the location of the lines of interest, and the existing static line rating assumptions used in current operations.

Ampacity ratings for a transmission line were determined using the most limiting component of the line. Limiting factors such as splices and connections were considered for conductor load and temperature increases. When emergency conditions arise, overhead conductors may be operated at higher ampacity ratings as long as they are limited to a 18°F (10°C) temperature increase and do not exceed standard ratings for no more than 30 minutes.

III. Description of UK Grid, Climate and Load

A. UK Transmission and Distribution Networks

In the UK, the transmission network is made up of conductors operating at 275kV and 400kV. The transmission network in England and Wales is owned and operated by National Grid. In Scotland, the transmission system is owned by Scottish Power, though National Grid is still the system operator. The network comprises of steel towers and underground cables.

At lower voltages (132kV and below), the network is referred to as the distribution network; this network is owned and operated by Distribution Network Operators (DNOs). There are seven such companies. Each has a local monopoly over one or more regions. The networks comprise a mixture of steel towers, wood poles, and underground cables.

B. UK Climate

The UK's location between the Eurasian landmass and the Atlantic Ocean leads to a mixing of moist maritime air and dry continental air. This results in a variable climate, where many different weather types can be experienced in the same day. There is also a high variation in temperatures across the relatively small area of the country. For example, the average annual temperature in Scotland is 51°F (10.5°C) [14], whereas in England it is 56°F (13.1°C) [15].

C. UK Load Patterns

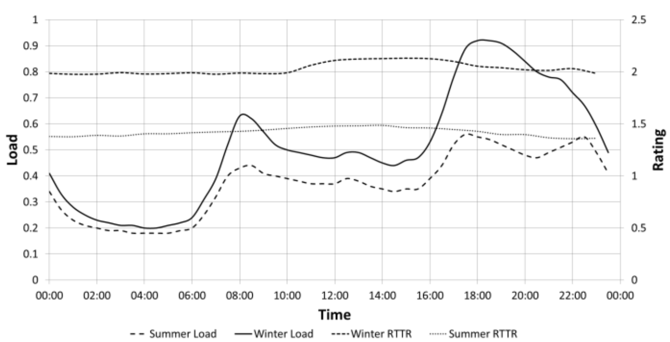

Figure 3: Typical UK load profiles (data courtesy of National Grid) and average RTTR based on season

In the UK, the greatest load is experienced during the winter months due to domestic heating. Air conditioning is not widely used, leading to lower demand during the summer months. Figure 3 shows typical summer and winter load profiles and average seasonal RTTR. The peak load coincides with higher RTTR, implying that the UK is well suited for RTTR deployment.

D. Description of UK Line Ratings Standards

At present, seasonal static thermal overhead line ratings in the UK are derived using the same basic heat balance equation as found in (1). The equations and empirical constants used to derive these ratings are detailed in [16]. Highly conservative weather conditions were chosen as inputs, with three sets of conditions used to represent the seasonal changes throughout the year. Ambient temperatures of 35°F (2°C), 48°F (9°C), and 68°F (20°C) are used to represent the periods of winter, spring/autumn and summer respectively. Wind speed is assumed to be 1.1 mph (0.5 m/s) all year and solar radiation incident upon the conductor is assumed to be zero [17]. The conductor design current is calculated using these conditions, a pre-determined conductor design temperature and the appropriate empirical constants.

The 'worst case' conditions are unlikely to occur coincidentally for any significant period of time, if at all. The concept of exceedence (Te) models the risk of the conductor exceeding its designated design temperature. It is expressed as the aggregate percentage of time for which the design temperature can be exceeded [16].

Te values are pre-determined for all distribution networks in the UK. For single circuit supply systems the figure is 0% and for multi circuit 3% [17]. Realistically, the figure of 0% is unobtainable from a log curve, and therefore 0.001% is used. After selection of Te, the appropriate Correlation Term (C_T) value can be obtained from Figure 4. This curve was derived as part of research at CERL (Central Electricity Research Laboratory) [16], and is used in the existing line rating standard [17]. The product of the conductor design current and the Correlation Term gives the conductor's seasonal static rating i.e. the rating to be enforced:

$$\text{Seasonal Rating} = \text{Seasonal Design Current} \times C_T \qquad (2)$$

For example, for a Te value of 0.001%, Figure 4 gives a Correlation Term of 0.912. Therefore, in this case, the seasonal rating would be set at 91.2% of the seasonal design current.

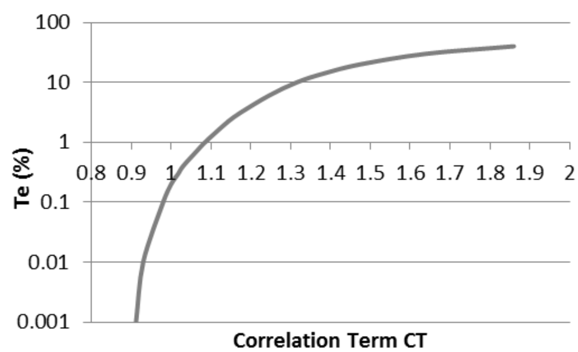

Figure 4: Graph showing the variation in Correlation Term against exceedence (Te)[16].

The contrast between the U.S. and UK system is clear: in the UK it is not required to find the limiting span, and instead, a level of risk is assumed. This is reasonable in the UK because the climate does not vary greatly across the relatively small geographical area. In the USA there are highly disparate climates, and as such the risk will be determined by location to a much greater extent.

IV. Trial Site in the U.S.

A. Description of Local Network and Terrain

A trial site in the U.S. is located in a small corridor along the Snake River Plane in Idaho. The corridor includes roughly 600 square miles of highly complex terrain with a canyon that is formed around the Snake River. Small towns, large farmland, and high desert terrain are all comprised within the trial site. Terrain elevation in the area ranges from approximately 754 m. to 1,198 m., with 444 m. estimated total change in terrain height. A map of the U.S. trial site is shown in Figure 5.

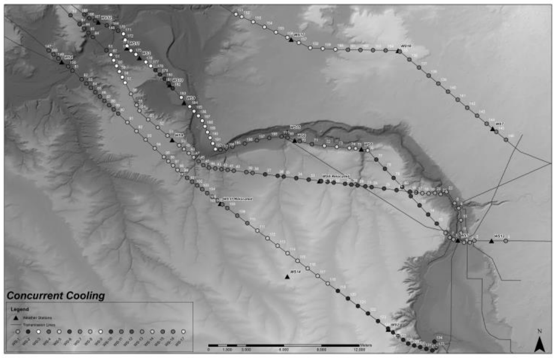

Figure 5: U.S. trial site in southern Idaho, showing local terrain, conductors, weather stations, and model points.

Presently, the dynamic ratings of two 138kV lines and two 230kV lines are being studied with 17 weather stations instated at strategic locations on tower structures along the lines. All of the weather stations are spaced between 1 and 5 miles.

B. Description of Local Climate

A historical database of climatology characteristics has been collected since 2007. Over the years, however, weather stations have been added or moved. Currently, the largest and most complete data set from all 17 weather stations ranges from April 25, 2012 to present Figure 6 below shows a sample wind rose plot of data from one weather station (WS03), collected from August 14, 2011 to August 14, 2012.

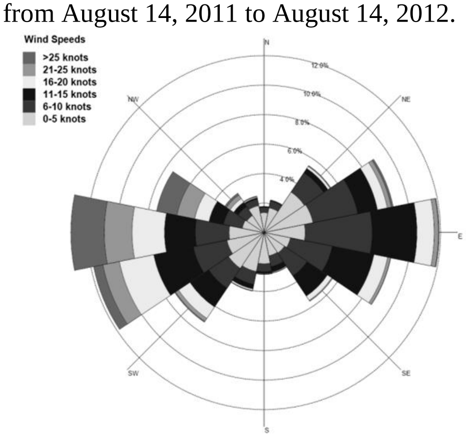

Figure 6: Wind Rose for U.S. trial site

Data presented in Figure 6 shows that the prevalent winds are primarily towards the west. Table 1 shows average temperatures for both trial sites, with the US measurements provided by the same weather station as the wind data.

	Average Temperature	
Season	U.S. (°F)	UK(°F)
Spring	54.5 (12.5°C)	47.5 (8.6°C)
Summer	72.9 (22.7°C)	59.7 (15.4°C)
Fall	39.4 (4.1°C)	51.8 (11.0°C)
Winter	31.8 (-0.1°C)	40.1 (4.5°C)

Table 1: average temperatures for the U.S. trial site

V. Trial Site in the UK

A. Description of Network and Local Terrain

The trial site in the UK is located in North Wales, just south of the coast. The section of network considered is approximately 20-km-long, with 5 weather stations spaced between 1 and 5km apart. The network is 132kV. Two offshore wind farms are connected to it in this location providing an ideal test of the synergy that results from RTTR and wind power production.


Figure 7: The UK site trial in North Wales, showing the local area and the location of the weather stations

The local terrain comprises of a large valley, containing small towns, villages and forests. The total change in terrain height across the area is approximately 200 m. A map of the area is shown in Figure 7. The total area covered by the trial site is 16.7 square miles.

B. Description of Local Climate

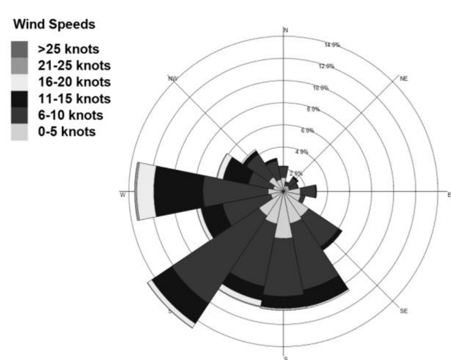

Figure 8: Wind Rose for the UK Trial Site.

The five weather stations at the trial site have been in place since 2008. The local climate data presented here is calculated from data spanning January 1, 2009 to December 31, 2009. The average temperatures for each season are shown in Table I.

Figure 8 shows a wind rose plot for the UK trial site. The prevailing winds come from the south west, though winds from all directions are observed throughout the year.

VI. U.S. Methodology

A. Description of Real-Time Data Collection and Modeling

Many methods have been devised to facilitate RTTR. Some of these systems include line sag and temperature monitors, line tension monitors, systems that mimic line conditions and weather effects [18]. The concern with almost all of these systems is that they typically do not provide enough measurements to obtain an accurate assessment of the varying climate conditions, line temperatures, and sags along each span. More weather data (wind speed, wind direction, ambient temperature, and solar irradiance) are needed along the transmission lines to improve the calculations and accuracy of existing systems.

The system developed by INL uses weather and environmental measurements to dynamically rate transmission lines. The weather measurement equipment collects data such as wind speed, wind direction, ambient air temperature, and solar irradiance levels at predetermined locations, and is used to model and calculate a more complete and accurate picture of the weather conditions and temperatures along the full length of transmission lines of interest. Weather parameters are obtained from local weather stations, mounted on the power line poles.

A computational fluid dynamics (CFD) program is used to estimate wind conditions incident to transmission lines between weather stations using information from the stations along the line. The technology used for the wind estimation was originally developed for wind farm annual energy production; a challenge in the present work is using the CFD software to simulate wind conditions over a larger geographic area and that wind direction is critical. The CFD model is refined using historical wind information obtained from 17 weather stations located within the region of interest. Simulations are performed to estimate the wind velocity along the length of the line in distinct 500–1000-m sections, using the nearest weather station on similar terrain. The CFD program includes information about the variation and surface roughness of the terrain in the modeling and therefore is better able to accurately simulate the wind speed and direction, taking into account the topography of the land.

Additional, custom built, INL software programs use CFD simulated wind speeds and a line's currents to determine cooling effects and real time conductor temperatures. From this process the ampacity rating of the line can be adjusted dynamically.

B. Wind Speed Modeling Using CFD

The CFD modeling program is based on classical 3D Reynolds-Averaged Navier-Stokes (RANS) equations. Solving the nonlinear transport equations for mass, momentum, and energy makes CFD a suitable tool for simulations involving complex terrain [19]. Typically, the mass and momentum equations are solved to predict the wind velocity in the region of interest; the energy equation is applied for heat transfer. This study focuses on modeling wind velocity.

Local wind fields are influenced by local topography. The input basis for CFD consists of a digital terrain model with a length scale sufficient to describe the geography within the applied mesh, according to the phenomenon under consideration. Additional refined modeling can then be completed using CFD with a variety of length scales ranging from detailed, micrositing models up to larger mesoscale wind models. CFD models the region of interest by placing a body fitted coordinates (BFC) mesh over the topography. The body-fitted mesh defines the land features such as hills, valleys, ridges, and other large topographical features that affect wind patterns. A variable-spaced mesh is used in the vertical direction to provide more refinement near the ground and a larger spacing out towards the free-stream velocities. Grid refinement near the surface more accurately tracks velocities within the boundary layer, especially wind patterns that are affected by geographic effects.

Surface roughness is also included in the model to account for terrain effects that are smaller than the grid. These effects can include topographical effects as well as trees, shrubs, and buildings, which also affect wind patterns. Terrain roughness has a strong influence on wind speed at the zone near the ground.

Since the terrain is modeled as a surface roughness rather than fully realized 3D objects, effects such as sheltering from vegetation can only be approximately represented. The flow of air through vegetation canopies can be modeled [20], but not on the scale required for this application. In wind energy resource assessment the flow over the canopy can be modeled, but not the flow within the vegetation [21].

To provide a level of calibration to the model, CFD requires historical meteorological data from at least one point within the modeled area. Additional points provide more information to fine tune the model within the defined grid. From these necessary inputs, the wind resources for a broad area can be calculated.

C. Wind Speed Simulation

In the US, the weather stations are mounted on the power line structures at a height of 10 meters, approximately the height at mid-span. These are represented by triangles in Figure 5. The data at these points are inputs into the CFD software.

Modeled wind speeds were directly compared to measured wind speeds collected from the mobile MET tower. Figure 9 displays the predicted wind speeds adjusted by ±20%, and the mobile MET tower data for Model Point 95 and Test Point 95, respectively.

Although the wind speeds measured by the mobile MET tower at times exceed the error bounds generated from the prediction, measured results during the majority of time remain within the error bounds. Wind speeds outside of the

±20% band typically only last for a few 3-minute time samples. Accurately modeling the wind is more difficult at lower wind speeds because of greater variability in the wind flow. These variabilities are of less concern due to the impact that the lower wind speeds will have in the conductor temperature and available ampacity calculations. Low wind speeds are currently addressed in a utility's existing static line rating assumptions and can be further supplemented by this additional data.

The ±20% bands were chosen as an arbitrary limit, based on expert judgment during preliminary studies. This preliminary analysis suggests that a better way of modeling the error may be to fit the observed errors to an appropriate statistical model, taking modeled wind speeds as a regressor. This is currently the subject of ongoing work.

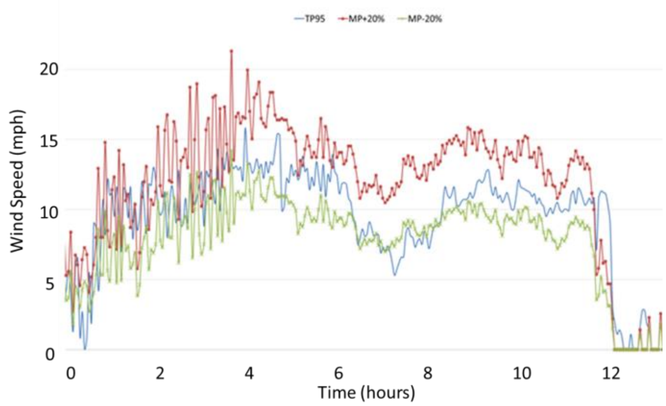

Figure 9: Comparison of measured and a 20% band around predicted wind speeds at Model Point 95.

D. *Look-Up Table Driven Results and Analysis*

The CFD simulation is too computationally intensive to be done in real time; a typical simulation run takes about 3 days on a powerful workstation. Therefore, simulation is done offline, and its results are stored in a lookup table.

Data is collected from the weather stations every 3 minutes and the collected data is an average of 90 samples collected within that interval. The model is corrected from time to time using seasonal historical weather data. The real-time data from weather stations is combined with the look-up table information from CFD to predict the wind speed and direction along the power line. The cooling effect along the line will vary from segment to segment, making it necessary to determine which segment is receiving the lowest wind speed and consequently, the least cooling. The line segment receiving the least cooling will determine the ampacity for the entire line.

Figure 10 shows a one month time snapshot from a three month test that compared measured data from Promethean Devices, LLC and INL's calculated conductor temperature in degrees Celsius. Promethean uses a non-contact, ground-based system to measure phase currents and conductor sag, and then back-calculates the conductor temperature based on initial temperature measurements and system calibration [22].

Figure 11 shows the INL calculated available ampacity rating in amps over the same one month period of the three month test. Figure 11 compares the calculated available ampacity in amps to the standard summer static rating for the transmission line being monitored. The figure also shows the INL calculated available ampacity rating with a 30-minute sliding average. The IEEE standard calculations contain both steady-state and transient equations and program samples for calculating conductor temperature and available transmission line ampacity. The transient calculation utilizes the thermal time constant of the conductor. Based on our field research, system and utility use characteristics, we utilize the transient calculations, trending and sliding average methods for a 30 and 60 minute look-ahead for available ampacity. For the conductor temperature, we have observed good comparison results utilizing the steady-state formulas and averaging, with average temperature estimation differences of 1.1^{o}C between the weather-based and sag/temperature-based systems. So the benefit of using the conductor thermal time constant for this portion of the calculations appears limited at this time. However, future research may further investigate this area when operations occur at higher conductor temperature ranges.

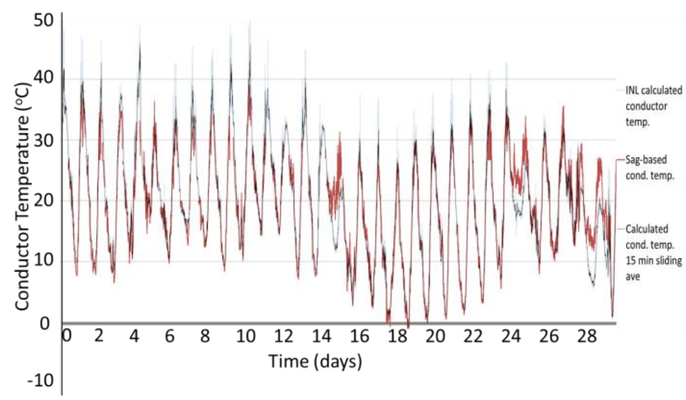

Figure 10: INL Calculated Conductor Temperature (Celsius), Measured Conductor Temperature (Celsius), and INL Calculated Conductor Temperature with a 15-minute sliding average

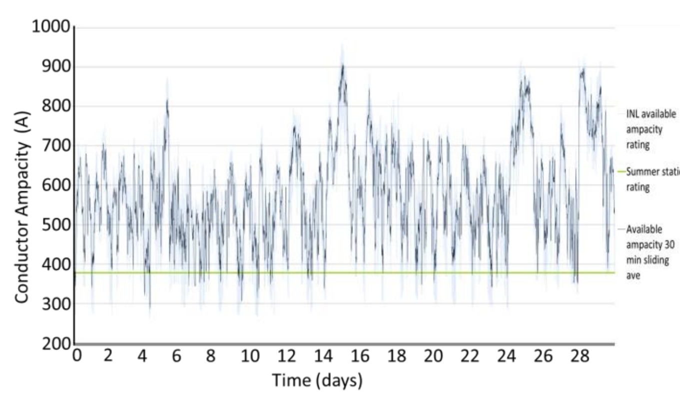

Figure 11: INL Calculated Available Ampacity Rating (Amps), Standard Summer Static Rating, and INL Calculated Available Ampacity with 30 minute sliding average

Future research is also planned for the application of improved weather forecasting methods to the system. Over six months of system testing, average improvements in available ampacity over the static rating range between 32% and 75%.

E. Conductor Rating Calculation Method

It is anticipated that line ratings will be determined for 15 minute intervals. Once wind speed and other environmental parameters are determined, calculations can proceed to determine the conductor temperature. Equations used to determine the conductor temperature as a function of current and environmental condition have been used for some time, and are documented in the IEEE standard 738 [8].

A computing device/system now performs the following calculations:

The heat balance (1), as introduced in Section I, is used to calculate the steady state current carrying capacity of a conductor.

Solving (1) for the current I yields:

$$I = \sqrt{\frac{q_c + q_r - q_s}{R(T_c)}} \tag{3}$$

We determine q_r (radiated heat loss rate per unit length – W/m), q_c (convective heat loss rate per unit length – W/m), and q_s (heat gain from sun) using

$$q_r = 0.0138D\varepsilon\left[\left(\frac{T_c + 273}{100}\right)^4 - \left(\frac{T_a + 273}{100}\right)^4\right] \tag{4}$$

where ε is the emissivity, D is the conductor diameter, T_c is the conductor temperature, and T_a is the ambient air temperature, and

$$q_s = \alpha Q_{se}\sin(\theta)A' \tag{5}$$

where α is the solar absorptivity, Q_{se} is the total solar and sky radiated heat flux rate with elevation correction, θ is the effective angle of incidence of the sun's rays, and A' is the projected area of conductor per unit length.

The convection heat loss has two equations: the value q_{c1} for low air speed (<3 mph) and q_{c2} for higher air speed:

$$q_{c1} = \left\{1.01 + 0.0372\left(\frac{DV_w\rho_f}{\mu_f}\right)^{0.52}\right\}k_f K_{angle}(T_c - T_a) \tag{6}$$

$$q_{c2} = \left\{0.0119\left(\frac{DV_w\rho_f}{\mu_f}\right)^{0.6}\right\}k_f K_{angle}(T_c - T_a) \tag{7}$$

where V_w is the speed of the air stream at conductor, K_{angle} is the wind direction factor, and the parameters ρ_f (air density), μ_f (dynamic viscosity), k_f (thermal conductivity), must be calculated for the current ambient temperature. This is done for a specific conductor type (ACSR-715.5) and using data from WS7, which shows that, under varying weather conditions, the line current carrying rating can be increased from 35–177%. These calculations need to be performed for each line segment.

VII. UK Methodology

A. Overhead Line Model

The overhead line model used to calculate ratings in the UK methodology is the same as that used by Michiorri, Taylor, and Jupe in [3].

The heat exchange terms in (1) are calculated via:

$$q_s[W/m] = \alpha_{abs}S_r D_c \tag{8}$$

$$q_r[W/m] = \alpha_{em}\sigma_{SB}[T_{4c} - T_{4a}]\pi D_c \tag{9}$$

$$q_c[W/m] = \frac{Nu(T_c - T_a)}{D_c\rho th_a} \tag{10}$$

The Nusselt number (*Nu*) is calculated according to the next three equations taken from [6], where *Re* is the Reynolds number, K_{dir} is the the direction correction, Ws is the wind speed, and Wd is the wind direction:

$$Nu = (0.65Re^{0.2} + 0.23Re^{0.61})K_{dir} \tag{11}$$

$$Re = 1.644 \times 10^9 WsD_c\left(\frac{Tc + Ta}{2}\right)^{-1.78} \tag{12}$$

$$K_{dir} = K_{dir-1} + K_{dir-2}\sin^{K_{dir-3}}(Wd) \tag{13}$$

B. Weather Interpolation Method

Environmental condition values are read in real time at selected locations in the network area and are used for estimating environmental conditions in every component location. For this purpose, instead of CFD simulation, a simple inverse distance interpolation technique [23] is used, as described in the equation below. At each point, x, in the geographical area, the value of a parameter, for example wind speed (Ws) can be estimated as a weighted average of the parameter values known at *n* points $x_1, \ldots, x_n$. The weighting factor is a function of the distance between the points. Specifically,

$$Ws(x) = \frac{\sum_{i=1}^{n}\frac{Ws(x_i)}{\|x - x_i\|^2}}{\sum_{i=1}^{n}\frac{1}{\|x - x_i\|^2}} \tag{14}$$

This method is also used to estimate wind direction, *Wd* solar radiation, S_r, and ambient temperature, T_a. For the wind speed, *Ws*, the ground roughness is taken into account using the log law shown in (15); Ws_a is the wind speed at the measured height h_a, h_{ref} is a reference height in the free stream, h_c is the height of the conductor and k_{sheara} and k_{shearc} are the ground shear at the location of the measurements and conductor respectively:

$$Ws_c = Ws_a\left(\frac{h_{ref}}{h_a}\right)^{k_{sheara}}\left(\frac{h_c}{h_{ref}}\right)^{k_{shearc}} \tag{15}$$

C. Included Components

The UK method includes models for overhead lines, underground cables and power transformers. The potential benefits of each of these components is discussed in [2]. However, for the trial site considered by this paper, only overhead lines are considered.

D. Monte Carlo Simulations

In order to account for the uncertainties present in the system, rather than using fixed values for each variable, a probability distribution over each variable is assumed. For simplicity, all variables are assumed to be statistically independent from one another.

Because the functions involved are quite complicated, analytic derivation of the probability distribution of the line rating is not really feasible. Hence, the Monte Carlo method was used. In this method, samples from the probability distributions of the input variables are drawn to perform *n* deterministic calculations of the output variable, that is, the line rating. The results of these calculations approximate the probability distribution of the line rating. The approximation improves as n is higher. An illustration of this is shown in Figure 12 [3].

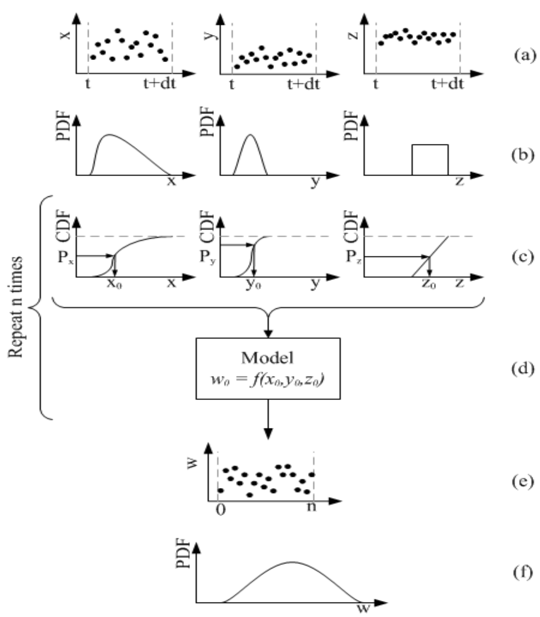

Figure 12: An illustration of the Monte Carlo method employed as part of the UK rating estimation method [3].

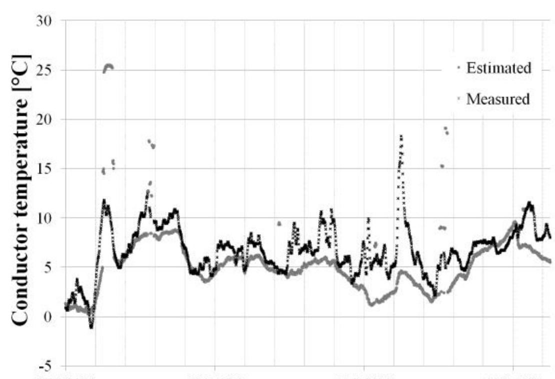

Figure 13: A comparison of measured and estimated conductor temperatures for winter 2008, at the north Wales trial site [3].

Figure 13 shows results from a trial conducted in the winter of 2008/2009 [3]. This is a comparison of measured and estimated conductor temperature. During the winter period, the line cooling is dominated by low ambient temperatures.

Figure 14 shows the same results, but from summer 2009 when wind speed and direction are the dominant factors in line cooling. The method does not perform as well in the summer, and as a result, work to improve wind and direction estimation using CFD calculations is ongoing [24].

The average temperature estimation error was 1.72^{o}C [3] in winter, and 3.04^{o}C in summer [24].

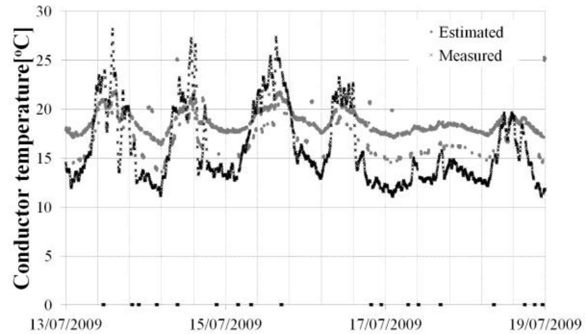

Figure 14: Comparison of measured and estimated conductor temperature for summer 2009, at the North Wales trial site [21].

VIII. Key Differences In Methodology

The two methodologies share many common elements, which imply that the general approach is appropriate for the application.

The UK methodology's inclusion of Monte Carlo calculations to account for some level of uncertainty is a key difference. If RTTR were to be deployed on operational networks, understanding the uncertainties would be essential to its success. This may be driven by the fact that the UK does not identify a critical span. However, this method is more computational intensive since many calculations must be run in place of one. Furthermore the UK distribution network operators are conservative, so a method for highlighting the level of risk was considered essential. Perhaps one of the key features of the UK method is that it shows operators that they are already running at a measurable level of risk, because there are times when the static line ratings are exceeded. The U.S. system has done some initial quantification of uncertainty using field measurements, with the conventional engineering factor of safety method.

The U.S. method includes advanced CFD wind simulation which is driven by the large domain and complex terrain and topology. In the UK the small domain size and a closer average spacing of MET stations allows a simpler method to give accurate results.

In the UK the peak load is experienced in winter when low temperatures dominate the line cooling and temperature varies less over the distances considered. As a result a crude method for estimating wind speed and direction can be accepted. The limitations of this method become apparent in the summer, when the wind flows dominate the cooling [8].

In the U.S., there is no clear seasonal load peak since it varies from region to region, so the model must be robust at all times of the year. This has led to the development of a more sophisticated wind estimation approach.

IX. Critical Discussion and Future Developments

The UK method could be improved by adopting a more sophisticated wind estimation technique. In fact this is the subject of a current paper by several of the authors. In order to implement RTTR on real networks, proper quantification of all uncertainties involved is crucial.

First, various model assumptions, such as independence and shapes of distributions, could be better validated, and where necessary, modified to any specific situation. Secondly, many uncertainties are currently not accounted for at all, including for instance structural uncertainty due to imperfect terrain shape and roughness modeling, limited resolution, boundary conditions, and steady-state assumptions which underlie all CFD simulations as well as thermal rating calculations, at least in the current approach.

The U.S. method did include historical data in order to quantify some of the error and improve wind prediction, but there is certainly potential for further improvement in this direction. To validate our models, and to get a far more confident idea of the accuracy of our predictions, we plan to draw on advanced techniques from data assimilation and spatio-temporal statistics. As mentioned, both methods rely on steady-state assumptions. We have argued that due to the time and space scales involved, this may be a reasonable assumption, at least for immediate prediction. However, it is clear that for the purpose of, say, obtaining predictions for the next two hours, the error due to steady-state assumption might grow too large. For such predictions, including some form of weather dynamics, even if only approximate, could be highly desirable, and is the topic of further research.

Even given all these factors, it is encouraging how far we can get by with the current simple methods.

X. Conclusions

Real-Time Thermal Ratings systems have been developed independently in the U.S. and the UK. Both systems are currently in the prototype phase and active use of Real-Time Thermal Ratings is imminent. The methodologies share common elements, but the U.S. system has a more sophisticated wind model while the UK system has a better uncertainty model.

We suggest that both of these novel insights be carried forward into any future, weather based RTTR solution. Quantification of uncertainties is essential for any real world implementation. A wind model that can accurately predict the effect of terrain and topography on local wind fields would be invaluable, giving valuable additional information and confidence in the solution.

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