Demonstrating the Capacity Benefits of Dynamic Ratings in Smarter Distribution Networks

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Luis F. Ochoa, *Member*, *IEEE*, Lucy C. Cradden, and Gareth P. Harrison, *Member*, *IEEE*

Abstract— **Distribution networks are increasingly required to host medium to large volumes of distributed (renewable) generation capacity. To facilitate high penetration levels of these new network participants it is crucial to adopt new control strategies in which the distribution systems are operated actively. The wide deployment of schemes such as coordinated voltage control (CVC) or non-firm connections will depend on communication and control infrastructure that is likely to be part of future Smart Grid investments. This infrastructure scenario might also make viable the use of advanced real-time measurement devices required to dynamically assess overhead line ratings. Given the inherent correlation of wind power output, wind speeds and temperature, this work is aimed at demonstrating the benefits that the adoption of dynamic ratings might bring to allow the connection of more wind power capacity. A multi-period AC Optimal Power Flow (OPF)-based technique is used to evaluate the maximum capacity of new generation considering control strategies such as dynamic ratings and CVC. The method caters for the variability of demand, wind resource and temperature. Results from a simple test feeder demonstrate the significant generation capacity gains compared to the passive operation of the network.**

Index Terms—**Distributed generation, wind power, optimal power flow, active network management, smart grids, dynamic ratings, distribution networks.**

I. Introduction

RENEWABLE electricity generation has never seen the level of investment and incentives that have been put in place by governments around the world during the last decade. However, despite the envisaged environmental and security of supply benefits that the harvesting of indigenous, renewable sources might bring about, their integration into the power system creates significant challenges to both the network operators and developers. The infrastructure challenges become even greater when large volumes of renewable generation capacity are connected to distribution networks [1-3], traditionally designed to be passive circuits with unidirectional power flows.

Indeed, 'fit and forget' types of connections are not sustainable and could potentially limit the ability of distribution networks to host more renewable generation. Instead, 'connect and manage' policies are required, where real-time control and communication systems forming an active network management (ANM) system will allow better exploitation of network assets and participants [4-8] without the need for conventional reinforcements (e.g., new lines) and whilst maintaining operational limits. In the UK, the Registered Power Zones (RPZ) initiative introduced by regulator Ofgem in 2005, has resulted in three Distribution Network Operators (DNOs) deploying site-specific ANM schemes to integrate distributed wind power generation. These projects involved coordinated voltage control (CVC) of on-load tap changers, generation curtailment (non-firm connection) [7], and dynamic overhead line ratings [9]. It is expected that for the new regulatory period of 2010-2015 (DPCR5 [10]), larger schemes will be rolled out using funds aimed at supporting the transition towards smarter, low-carbon distribution networks. Given the crucial and strategic role of such infrastructure in enabling the adequate integration of (renewable) generation capacity, similar funds have also been –or will eventually be– made available in other countries (e.g., USA). However, due to the early stage of this infrastructure, and the complexities of variable generation and demand, there are only few generation capacity assessment studies (i.e., the evaluation of capacity headroom for more generation) that take into account the operational capabilities of the networks [11-15]. This work is aimed at demonstrating, from the planning perspective, the benefits that the adoption of dynamic ratings might bring to allow the connection of greater volumes of wind power capacity compared to the 'fit and forget' approach.

The ampacity, or current-carrying capacity, of overhead lines is typically defined by average seasonal temperatures, with limited cooling contribution from wind. This conservative approach might prove to be a missed opportunity, particularly for those lines connecting wind power sites as they will experience high wind speeds. Here, a multi-period AC Optimal Power Flow (OPF)-based technique is used to evaluate the maximum capacity of new generation connections facilitated by the adoption of dynamic line ratings. The method, extended from previous work [15], caters

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for the variability of demand, wind resource and temperature, and is demonstrated on a simple distribution test feeder.

This paper is structured as follows: Section II presents the formulation for the dynamic ratings and its incorporation into the multi-period AC OPF. Section III illustrates the method for aggregating times-series demand, generation, wind speed and temperature data and the application of the capacity assessment technique with a 3-bus 33kV test feeder. Results demonstrate the significant generation capacity gains compared to the passive operation of the network. Finally, sections IV and V discuss and conclude the work.

II. Dynamic Ratings and Problem Formulation

A. Calculating the Ampacity of Conductors

The current thermal ratings system for overhead lines in the UK is based on assumptions of certain weather conditions in particular seasons. Engineering Recommendation (ER) P27 provides the standard for calculating seasonal thermal ratings using assumed temperatures of 2˚C, 9˚C and 20˚C in winter, spring/autumn, and summer, respectively, for a constant wind speed of 0.5m/s and zero solar radiation [16]. In particular, the assumption of such a low wind speed neglects the potential cooling effect of the wind, thus giving a conservative rating value in many circumstances.

The current carrying capacity of overhead lines can be calculated through different methods [17]. Given the planning nature of the proposed technique, it is assumed that historical weather data is available and applicable. Thus, at a given set of weather conditions, m, the (single-phase) ampacity, $I^{+}_{l,m}$, for an overhead line l will be obtained based on the IEEE Std 738-2006 [18] and considering the maximum permissible temperature of the conductor, as follows:

$$I^{+}_{l,m} = \sqrt{\frac{q_{c,m} + q_{r,m} - q_{s,m}}{R(T^{+}_{c})}} \text{ Amp} \quad (1)$$

where $q_{c,m}$ is the convective cooling, $q_{r,m}$ is the radiative cooling, and $q_{s,m}$ is the solar heating, all in W/m. $R(T^{+}_{c})$ in Ω/m is the resistance of the conductor at temperature T^{+}_{c} (°C). The corresponding formulae are presented in the Appendix.

The corresponding maximum three-phase power flow capacity, ${}^{dynamic}f^{+,(1,2)}_{l,m}$, at each end of the line (denoted 1 and 2) will be obtained based on its per unit ampacity (1), as follows:

$${}^{dynamic}f^{+,(1,2)}_{l,m} = \sqrt{3} V_{b=\beta_l^{(1,2)}} I^{+,pu}_{l,m} \text{ pu} \quad (2)$$

where V_b is the per unit line-to-line voltage magnitude at bus b, in this case referring to the ends of line l.

For illustration purposes, Table I shows the maximum current-carrying capacity based on ER P27 of an ACSR 2/0 conductor, with a diameter of 11.354mm, and 0.427 and 0.577Ω/km of AC resistance at 25 and 75°C, respectively. The adopted T^{+}_{c} is 75°C. It is assumed that the conductor is sited at an elevation of 100m above sea level and the wind direction is perpendicular to the axis of the conductor. Solar radiation is neglected.

Although in practice it is possible to exceed the ampacity values obtained by following the ER P27, they are clearly very conservative when compared to the results considering only 2.0m/s of wind speed – an average of 37% increase.

TABLE I. MAXIMUM CARRYING-CURRENT CAPACITY AND THREE-PHASE POWER FLOW OF AN ACSR 2/0 OVERHEAD LINE – 33KV

Season	**Winter**	**Spring/Autumn**	**Summer**
Ta (°C)	2	9	20
wind speed (m/s)	0.5 (ER P27)		
Ampacity	270.4	257.6	235.9
Max. 3ϕ Power Flow (MVA)	15.5	14.7	13.5
wind speed (m/s)	2.0		
Ampacity	370.7	352.8	322.5
Max. 3ϕ Power Flow (MVA)	21.2	20.2	18.4

B. Multi-Period AC Optimal Power Flow

Previous work on generation capacity assessment [19] has successfully demonstrated the use of Optimal Power Flow (OPF), although considering a snapshot approach. In order to cater for the variability of both demand and generation, a multi-period AC OPF was proposed in [15]. The approach is based on reducing hourly time-series data to a set of scenarios where for each hour demand and generation potential is allocated to a series of bins (or 'periods', denoted by m). An example is presented in Fig. 1.

By using these multiple scenarios, this technique allowed the evaluation of the potential headroom for renewable generation connected to distribution networks considering different ANM schemes, such as coordinated voltage control (CVC), adaptive power factor control and energy curtailment, whilst maintaining operational limits. As would be expected, apart from voltage constraints due to voltage rise, it was thermal limits that restricted the connection of further generation capacity.

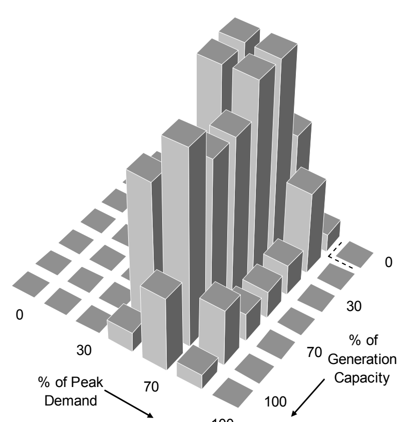

Fig. 1. Multiple periods: coincident hours of demand and generation.

Here, it is proposed to extend the allocation of time-series data to wind speeds considering also seasonality in order to cater for ambient temperatures (winter, spring/autumn, summer). Fig. 2 illustrates how a set of demand-generation scenarios are split by seasons and each in turn by levels of wind speed. Due to the natural correlation between seasonality and wind speeds, as well as demand, the number of scenarios remains small compared to the full hourly time-series data of a given year.

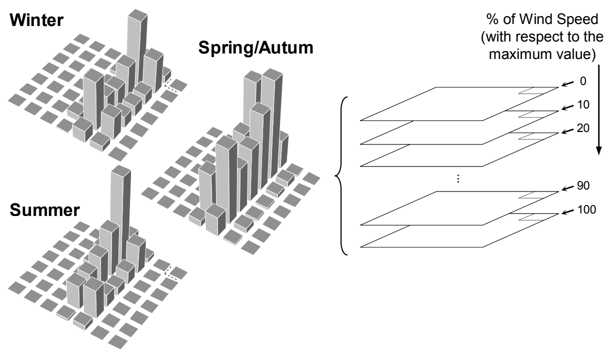

Fig. 2. Example of extended multiple periods: seasonal coincident hours of demand, wind generation, and wind speeds.

With each scenario, or period, providing the data regarding seasonality, level of demand, level of potential generation and wind speeds, it is possible to explore the extent to which a given distribution network is able to host wind power developments, explicitly considering dynamic line ratings.

The basic multi-period AC OPF formulation maximises the total active generation capacity p of a set of generators G (indexed by g) across the set of periods M (indexed by m), according to the following objective function ($\forall m \in M$):

$$\max \sum_{g \in G} p_g \tag{3}$$

It is subject to a range of constraints. Voltages at bus b (B, set of buses) are constrained by max/min levels $V_b^{(+,-)}$:

$$V_b^- \leq V_{b,m} \leq V_b^+ \quad \forall b \in B \tag{4}$$

Constraints on the flow at each end of lines and transformers, l (L, set of lines):

$$\left(f_{l,m}^{(1,2),P}\right)^2 + \left(f_{l,m}^{(1,2),Q}\right)^2 = \left({}^{static}f_l^+\right)^2 \quad \forall l \in L \tag{5}$$

where $f_{l,m}^{(1,2),P}$ and $f_{l,m}^{(1,2),Q}$ are the active and reactive power injections at each end of the branch (denoted 1 and 2) and ${}^{static}f_l^+$ is the static apparent power flow limit on the branch.

Kirchhoff's current law describes the active and reactive nodal power balance, $\forall b \in B$:

$$\sum_{l \in L|\beta_l^{1,2}=b} p_{b,m}^{\mathrm{L}} + d_{b,m}^{P}\eta_m = \sum_{g \in G_b|\beta_g=b} p_g \omega_m + \sum_{x \in X|\beta_x=b} p_{x,m} \tag{6}$$

$$\sum_{l \in L|\beta_l^{1,2}=b} q_{b,m}^{\mathrm{L}} + d_{b,m}^{Q}\eta_m = \sum_{g \in G_b|\beta_g=b} p_g \omega_m \tan(\phi_{g,m}) + \sum_{x \in X|\beta_x=b} q_{x,m} \tag{7}$$

Here, $(p,q)_{b,m}^{\mathrm{L}}$ are the total power injections onto lines at b, i.e., $f_{l,m}^{1,(P,Q)} + f_{l,m}^{2,(P,Q)}$; and $d_{b,m}^{(P,Q)}$ are the peak active or reactive demands at same bus. In period m, η_m is the demand level relative to peak and ω_m is the generation level relative to nominal capacity as dictated by the variable (renewable) resource in that period.

The distribution network has external connections at the Grid Supply Point (GSP) substation as well as interconnectors. Both can export power so the import/export constraints at the GSP or interconnector x (X, set of external sources), are:

$$\left.\begin{array}{l} p_x^- \leq p_{x,m} \leq p_x^+ \\ q_x^- \leq q_{x,m} \leq q_x^+ \end{array}\right\} \quad \forall x \in X \tag{8}$$

The GSP is taken as the reference (slack) bus b_0 with the voltage angle set at zero, i.e., $\delta_{b_0,m} = 0$. No capacity constraint is placed on the new generation units since the aim is to maximise their real power output. Generators are operated at unity power factor, i.e., $\cos\left(\phi_{g,m}\right) = 1.00$.

The traditional (passive) network approach would set the substation secondary voltage to a fixed seasonal value (e.g., $V_{S/S}$ = 1.03pu during winter).

C. *Smarter Distribution Network*

Since this study is to be used at the planning stage, here it is assumed that the measurement and control infrastructures are in place, and that response delays are negligible. Thus, in addition to network constraints traditionally used in AC OPF formulations (e.g., voltages), variables and constraints derived from ANM schemes must also be incorporated in the method:

1) Dynamic Ratings

Power flow limits will be assessed considering the characteristics of each period. In this way, the following equation replaces (5):

$$\left(f_{l,m}^{(1,2),P}\right)^2 + \left(f_{l,m}^{(1,2),Q}\right)^2 = \left({}^{dynamic}f_{l,m}^{+,(1,2)}\right)^2 \quad \forall l \in L \tag{9}$$

2) Coordinated Voltage Control (CVC)

By dynamically controlling the OLTC transformer at the substation and the corresponding distribution secondary voltage, more generation capacity might be connected. Thus, in each period the secondary voltage of the OLTC will be treated as a variable, rather than a fixed seasonal parameter, while maintaining its value within the statutory range:

$$V_{b_{OLTC}}^- \leq V_{b_{OLTC},m} \leq V_{b_{OLTC}}^+ \tag{10}$$

D. *Implementation*

The method was coded in the AIMMS optimisation modelling environment [20] and solved using the CONOPT 3.14A NLP solver.

III. Case Study

In this section a 3-bus test feeder will be used to demonstrate the proposed technique for evaluating the renewable generation capacity able to be connected when dynamic ratings are in place. First, the creation of multiple periods by reducing time-series data is illustrated. The methodology is then applied to the test feeder.

A. *Creating the Multiple Periods*

Hourly demand, wind speed and temperature data were obtained for central Scotland in 2003. The wind production data was derived from the UK Meteorological Office measured wind speed data and have been processed and applied to a generic wind power curve [21].

Hourly time-series data corresponding to January is shown in Fig. 3 (top). In Fig. 3 (bottom), demand and wind speed series are broken into a series of bins: 7 ranges ({0}, (0,20%], (20%,40%],…,(80%,100%),{100}) were used, in which the mean values (e.g., 30% for the (20%,40%] range) characterise the period. For simplification purposes, temperature data was reduced to the corresponding seasonal average values. Although not shown in Fig. 3, wind power generation was also considered for the creation of the periods.

For the year-round analysis, with demand never below 0.3pu (during summer), only 109 scenarios are required to be considered (1.2% of the 8760 hours of data). The aggregation process (using the mean values of the adopted ranges), resulted in a load factor of 0.639, a capacity factor of the wind data of 0.415, and an average wind speed of 9.05m/s. The error, compared to the actual data, is less than 1% in all cases, reflecting that the method does maintain the original behaviour.

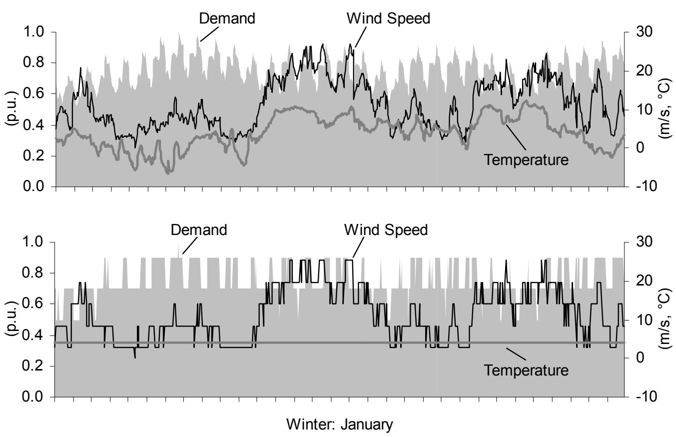

Fig. 3. (Top) Winter hourly demand, wind speed and temperature for central Scotland, 2003 [21]. (Bottom) Discretised data processed before counting the coincident hours.

B. 3-bus Test Feeder

The one-line diagram of a 3-bus 33kV test feeder is shown in Fig. 4. Corresponding line data is included in

Table II. The feeder is supplied by two 30MVA 132/33kV transformers. Grid Supply Point (GSP) voltage is assumed to be nominal. In the original configuration (no generation), the OLTC at the substation has as target voltages (at the busbar) of 1.025, 1.015, and 1.010pu for winter, spring/autumn, and summer, respectively. Voltage limits are taken to be +/-6% of nominal. The maximum demand of this test feeder is 5MW.

The 5km-long feeder is composed by ACSR 2/0 conductors, with the same characteristics previously presented in section II.A. A potential wind power development is considered to be connected at the end of the feeder.

C. Application

A very simplistic (although common) approach to determine the allowable generation capacity is by considering a worst-case scenario such as minimum demand (summer for the UK) and maximum generation. For this single-scenario, using the proposed AC OPF-based technique, Fig. 5 shows how increasing ratings for the line 2-3 leads to more generation capacity (unity power factor), although to a point where, as expected, voltage rise becomes the binding constraint. This snapshot indicates that, although other parameters (e.g., voltage) or devices (e.g., transformers) might limit the connection of more generation, there are instances were increased line ratings do allow so without compromising the rest of the system.

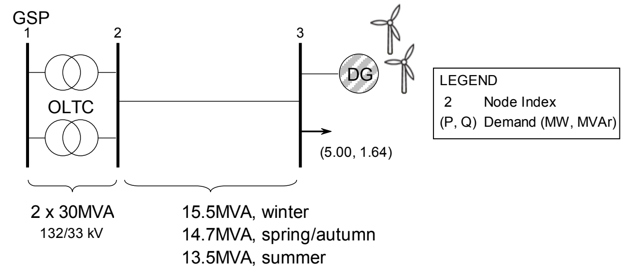

Fig. 4. One-line diagram for the 3-bus test feeder at maximum load.

TABLE II. LINE AND TRANSFORMER PARAMETERS (RESISTANCE, REACTANCE, MAXIMUM COMPLEX POWER FLOW ON 100MVA BASE) OF THE TEST FEEDER

Line	R	X	Smax
1 - 2 *	-	0.1250	0.6000
2 - 3	0.4010	0.2920	0.1500

* Considers the two parallel transformers

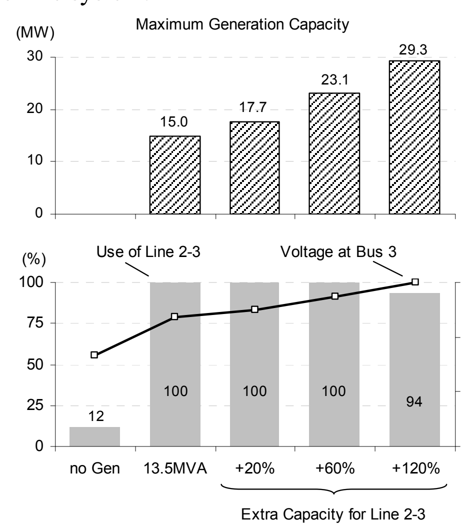

Fig. 5. Maximum generation capacity increasing the power flow limit of the connection line 2-3. Firm (i.e., constant) generation (unity power factor) and minimum demand. Target voltage at the busbar is 1.010pu (summer).

When the variability of demand and local resources, in this case wind, are taken account of, the different correlations lead to optimal values of generation capacity that will most of the time differ from the worst-case scenario approach [15]. This will be even more accentuated if innovative control schemes are in place. Fig. 6 shows the connectable wind power generation capacity for the 3-bus test feeder obtained through the multi-period AC OPF-based technique considering the ER P27 seasonal temperatures, i.e., 2˚C/9˚C/20˚C in winter, spring/autumn, and summer, respectively.

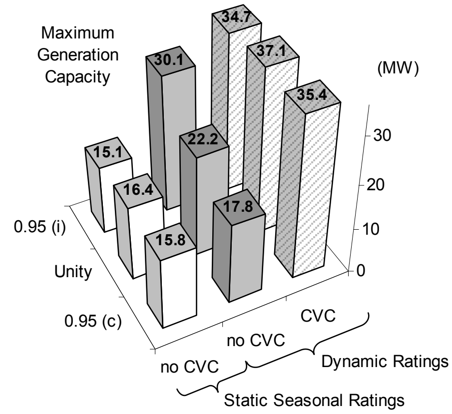

Fig. 6. Connectable wind power generation capacity (in MW) considering static seasonal ratings and dynamic ratings, as well as the use of coordinated voltage control (CVC). ER P27 temperatures were adopted. Three different power factors were also studied (c: capacitive, i: inductive).

The capacities that resulted after using static seasonal ratings do not differ significantly from the 15MW found for the worst-case scenario (Fig. 5). However, when dynamic ratings are taking into account, the connectable capacity almost doubles when 0.95 inductive power factor is adopted. On the other hand, for the case of capacitive power factor, an operation mode that worsens voltage rise problems, dynamic ratings only leads to 12% more gain in capacity. Certainly, weather conditions might help realise extra transfer capacity through line 2-3, but other elements in the network need also to be addressed to properly integrate further generation. Thus, the incorporation of coordinated voltage control (CVC) enables the connection of more capacity, up to 2.2 times the business-as-usual (i.e., static ratings, no CVC) capacity operating at unity power factor.

The ampacity of a given overhead line is indeed very sensitive to the value of wind speed (see Table I and Appendix). The large penetration of wind power found in Fig. 6 is also a result of the flexibility provided by the dynamic ratings of line 2-3. Nonetheless, temperature is another parameter that must be also taken into account cautiously.

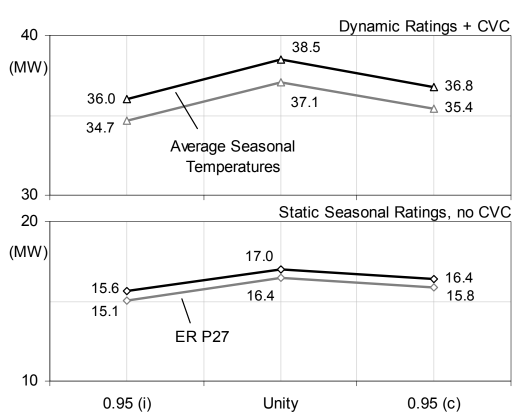

Fig. 7. Connectable wind power generation capacity (in MW) considering static seasonal ratings and dynamic ratings, as well as the use of coordinated voltage control (CVC). Average seasonal temperatures (2003, central Scotland) were adopted. Three different power factors were also studied (c: capacitive, i: inductive).

Fig. 7 compares the maximum connectable capacity at bus 3 considering the temperatures suggested by ER P27 (Fig. 6) and the average season temperatures derived from the 2003 time-series data for central Scotland (3.9°, 9.2°, 15.2°C, in winter, spring/autumn, and summer, respectively). For both the static season ratings and the dynamic ratings (including CVC) this new set of temperatures translated into an average increase of 3.7%. This is a clear example that nationwide seasonal temperatures might lead to the inefficient use of assets that otherwise could be avoided if regional or local values were provided.

IV. Conclusions

Windy sites are ideal for the harvesting of such renewable resource. At the same time, given the cooling effect of wind, larger volumes of power can be transferred through overhead lines without reaching critical points. This is a win-win scenario where the resource being harvested also frees transfer capacity that otherwise would be achieved with conventional reinforcements. However, the use of dynamic ratings and other techniques to actively manage distribution networks will only be possible with the adequate real-time control and measurement infrastructure. Given the international momentum towards Smart Grids, such infrastructure might be soon adopted by network operators, the operational capabilities of such schemes must be addressed at the planning stage.

This work demonstrated the use of a multi-period AC OPF-based technique as a planning tool to assess the maximum generation capacity able to be connected to a distribution network when schemes such as dynamic ratings and coordinated voltage control are in place. The effectiveness of the methodology relies on its ability to cater for the variability of demand and resources as well as the weather parameters.

V. Appendix

A. Convective cooling, q_c

Convection effects are caused by the flow of air around the conductor, either by natural effects or forced by wind. For forced convection, two equations are given in [18], one for low wind speeds (5) and one for high wind speeds (6), with a corrective factor for direction, K_{angle}. Natural convection can be found using a further equation, (7). The recommendation is that for a conservative approach, all are calculated and the largest of the three convection heat losses is used in (1).

$$q_{c1,m} = \left[1.01 + 0.0372\left(\frac{D\rho_{f,m}V_m}{\mu_{f,m}}\right)^{0.52}\right] k_{f,m} K_{angle,m}\left(T_c^+ - T_{a,m}\right) \quad (5)$$

$$q_{c2,m} = \left[0.0119\left(\frac{D\rho_{f,m}V_m}{\mu_{f,m}}\right)^{0.6}\right] k_{f,m} K_{angle,m}\left(T_c^+ - T_{a,m}\right) \quad (6)$$

$$q_{cn,m} = 0.0205\rho_{f,m}^{0.5} D^{0.75}\left(T_c^+ - T_{a,m}\right)^{1.25} \quad (7)$$

Here, D is the diameter of the conductor in mm. At a given scenario, m, with certain weather conditions, V_m is the wind speed in m/s, and $T_{a,m}$ is the ambient air temperature (in °C). The density ($\rho_{f,m}$ in kg/m^3), dynamic viscosity ($\mu_{f,m}$ in Pa-s), and thermal conductivity ($k_{f,m}$ in W/m°C) of air are all calculated at temperature $T_{f,m}$, the mid-point between the maximum conductor temperature and the ambient temperature. The IEEE Std 738-2006 [18] provides the corresponding formulae for deriving these values as well as $K_{angle,m}$.

B. Radiative cooling, q_r

The conductor will radiate some of its heat to the surroundings, depending on the properties of the outer material surface. This value is calculated by,

$$q_{r,m} = 0.0178 D\varepsilon\left[\left(\frac{T_c^{+} + 273}{100}\right)^4 - \left(\frac{T_{a,m} + 273}{100}\right)^4\right] \quad (8)$$

where the emissivity, ε, is suggested in [16] to be given a value of 0.5.

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