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Impact of High PV Penetration on Distribution Transformer Insulation Life

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***Abstract*—The reliable operation of distribution systems is critically dependent on detailed understanding of load impacts on distribution transformer insulation systems. This paper estimates the impact of rooftop photovoltaic (PV) generation on a typical 200-kVA, 22/0.415-kV distribution transformer life under different operating conditions. This transformer supplies a suburban area with a high penetration of roof top photovoltaic systems. The transformer loads and the phase distribution of the PV systems are significantly unbalanced. Oil and hot-spot temperature and remnant life of distribution transformer under different PV and balance scenarios are calculated. It is shown that PV can significantly extend the transformer life.**

***Index Terms*—Distribution transformer, life assessment, roof top PV, unbalanced operation.**

I. Introduction

MODERN distribution systems serve a variety of diverse customers. Three-phase four-wire systems, such as 400/230-Vrms systems found in Europe, the U.K., and Australia, will typically serve 60 to 120 consumers with a single transformer. The customers may be three or single phase. Some efforts are made at construction to balance the phase loading but significant unbalances develop during normal operation. While the systems are robust, unbalance has undesirable effects including reduced transformer life, increased losses and power quality problems due to phase voltage variations and negative sequence voltages.

Transformers operated under unbalanced conditions will suffer more extreme stresses than under balanced conditions. The transformer life is largely determined by the insulation life [1]–[3]. Mechanical, electrical, and thermal stresses affect the oil-paper insulation system [4]. The main factors that determine the insulation life of oil-immersed transformers are the transformer load, ambient temperature, moisture content and the oxygen content of the oil [5]. For unbalanced loading the resulting increased loss, and the concentration of the losses in one or two phases, affects the insulation system of the transformer and reduces its life time [6], [7].

To maximize the return on their investment, utilities will take advantage of a transformer's full cyclic loading capability to achieve to financial savings and reduced operating costs. Optimal utilization of a transformer can be achieved by taking advantage of a transformer's thermal time constant and the diurnal variation of the load and ambient temperature. It is necessary to have accurate models for predicting winding hot-spot temperature (HST) and top-oil temperature (TOT).

The development of accurate prediction models of the HST and TOT for substation, distribution and power transformers has been the subject of a substantial amount of research [15]–[17]. IEEE Standard C57.91-1995 [8] and IEC standard 60076-7 [9] describe in detail methods to calculate the HST and offer guidance on temperatures that should not be exceeded at either winding or structural hotspots to avoid undue aging failures from gassing. These standards, and recent publications, assume balanced loading of the transformer. Residential transformers have a high degree of unbalance. It is practically difficult to maintain an accurate knowledge of the street phase connections due to network maintenance and recording errors.

PV at the distribution level has become widespread. Previous studies [24]–[26] have identified many impacts that roof top PV may have on a local distribution network including changes in voltage profile and network power flows [24]. The problem of voltage fluctuations resulting from the passage of clouds is also addressed in [27], [28]. In particular, variations of nodal voltages in small or weak electrical grids (e.g., SWER systems) have been reported to cause system instability. Studies have also been conducted to explore the extent to which the geographical diversity of distributed PV mitigates the short term output variability caused by rapidly changing weather conditions. Spatial distribution significantly reduces transients caused by clouds.

Distribution systems are typically designed for specific load profile based on consumption patterns. When roof top PVs are deployed, the pattern of electric power demand will change. Australian residential consumption has an early evening peak. The addition of PV does not strongly reduce the peak load but will reduce the energy served. As a result the load factor, the ratio of average to peak load, is reduced. This paper studies the impact of roof top PV on the transformer insulation life. A dynamic thermal model was used for the prediction of the hot-spot temperature. The insulation aging impact was analysed using one year of residential electric power load data, drawn from the Perth Solar City High Penetration PV Trial, [10]. One year of ambient temperature data is integrated into the model to estimate the life impact.

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The work can be separated into two main steps. The first step is to identify the consumer phase connection and to process smart meter data to allow two data sets to be established. These data sets are the actual transformer phase loading and the loading that would have resulted in the absence of the installed PV systems. The second step is to use these two data sets to calculate the transformer hot-spot and oil temperatures under the different scenarios. The addition of PV is shown to be beneficial with regard to hot-spot temperatures and reduces the transformer loss of life (LOL).

II. Data Acquisition and Phase Allocation

The 400/230 V feeder, shown in Fig. 1, is supplied from a 200 kVA Dyn 22 kV/400 V distribution transformer and includes 77 residential consumers. Of these, 34 consumers have roof top PV systems which have average ratings of 1.88 kW. The total installed PV capacity is 64 kW representing a penetration of 32%. Load data, including energy consumption solar power generation, voltage and current is recorded by smart meters on the Western Power network at the point of connection to each consumer switchboard at 15-min intervals. Smart meter data has been collected since July 2011. At the time of the recording there were two three phase meters (meter number 49 and 55) that were not active and no recording available for these meters.

To determine the loading of the transformer the authors have previously published a method using cross correlation of consumer voltage profiles to identify their phase connection [11]. Using the known phase connections of the residential loads, the data collected from the smart meters was aggregated to determine the phase loading on the transformer. Fig. 2 shows the predicted transformer loading (kW) during the 7-day window that includes the annual peak day. The sampling rate is 15 minutes. The network under study is significantly unbalanced but reflective of normal network conditions. The unbalance results from the poor allocation of customer loading among the three phases. For instance, the loading of phase A is much less than phase B and C during day time peak hours.

III. Thermal Aging Formulation

A. Loss of Life of Distribution Transformer

Several models have been introduced to assess life estimation of insulation in transformers [1]–[4], [12], [13]. A wide variety of methods has been presented for loss-of-life inference for power and distribution transformers, such as those proposed in [14], Clause 7 and updated in [15]. When inferring the transformer LOL acceleration rate using these methods, the calculation of the winding hot-spot temperature (HST) is the most critical issue [3], [4]. The methods proposed in [1], [2] were followed by a series of papers [5]–[7], [12], [13], [15] dealing with more accurate calculations of HST.

Although deterioration of insulation is a function of temperature, moisture content, oxygen content and acid content, the model presented in this paper is based only on the insulation temperature [9]. Since the temperature distribution is not uniform, the part that is operating at the highest temperature will normally undergo the greatest deterioration. Therefore, the rate of aging is referred to the winding hot-spot temperature. Equations (1) and (2) describe, respectively, the relative aging rate VT for a thermally upgraded paper (reference temperature of 110°C) and non-thermally upgraded paper (reference temperature of 98 °C) [9]

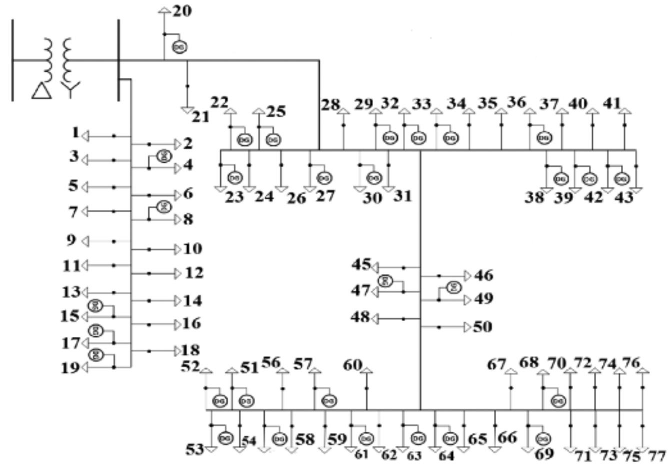

Fig. 1. Perth Solar City High Penetration Feeder Site, image courtesy of Western Power.

$$V_T = 2^{\theta_h - 98/6} \tag{1}$$

$$V_T = e^{\left[\frac{15000}{110+273} - \frac{15000}{\theta_h+273}\right]}. \tag{2}$$

Temperature is of importance since chemical reactions such as the deterioration of cellulose in paper is accelerated at elevated temperatures. In Table II, the thermal model parameters are presented. The equivalent life at the reference temperature that will be consumed in a given time period for an actual temperature cycle can be calculated by (3) [8], where $\mathrm{V_{EQA}}$ is equivalent aging factor for the total time period, n is index for the time interval t, N is total number of time intervals, $\Delta \mathrm{t_n}$ is the time interval and $\mathrm{V_n}$ is aging acceleration factor for the time interval $\Delta \mathrm{t_n}$

$$V_{EQA} = \frac{\sum_1^N V_n \Delta t_n}{\sum_1^N \Delta t_n}. \tag{3}$$

When a normal insulation life for a well-dried oxygen-free transformer system is defined, percent loss of insulation life can be calculated in (4) [8]. In this paper, we choose the normal life as 180,000 hours (20.55 years). Under this normal life value, normal percent loss of life for operation at a rated hot-spot temperature of 110°C for 24 h is 0.0133%

$$\%\ \text{Loss of Life} = \frac{V_{EQA} \times t \times 100}{\text{Normal insulation life}}. \tag{4}$$

The normal life expectancy is a conventional reference basis for continuous duty under normal ambient temperature. and rated operating conditions.

B. Hot-Spot Temperature Model

In [14], a transformer thermal model was developed as a series of algebraic difference equations. In [16], [17], Swift *et al.*

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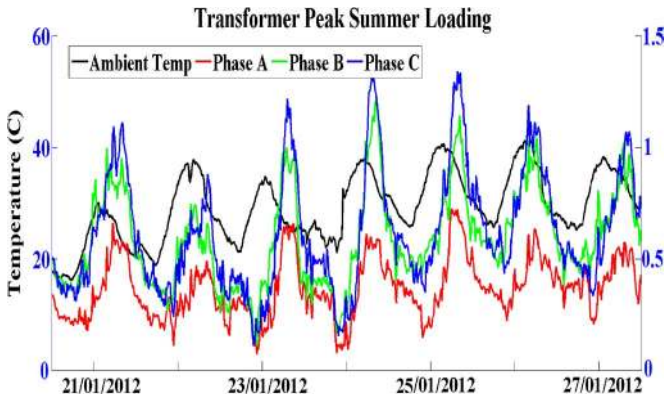

Fig. 2. Pavetta transformer power output, January 21–27, 2012.

TABLE I
TOP OIL AND HST COMPARISON UNDER DIFFERENT LOADING CONDITION

	HST (°C)			Top Oil (°C)
	Phase A	Phase B	Phase C	
Solar-1.0 pu	94.4	117.3	128.9	76.1
No solar-1.0 pu	97.6	120.3	133.6	78.7
Solar-1.1 pu	99.3	124.4	137.9	79.5
No solar-1.1 pu	102.1	127.7	142.3	82.1
Solar-1.2 pu	107.7	136.5	151.7	85.0
No solar-1.2 pu	111.0	140.3	157.2	88.0
Solar-1.3 pu	116.7	149.3	166.8	90.9
No solar-1.3 pu	120.3	153.7	172.8	94.3
Solar-1.4 pu	126.0	162.7	180.7	95.1
No solar-1.4 pu	130.2	167.6	189.2	100.9

proposed a basic approach based on heat transfer based on the application of the lumped capacitance, thermal resistance electrical analogy. The transformer heating model used in this analysis is based on [9] (Fig. 2) IEC 60076 develops the hotspot temperature equations in the following way:

$$\theta_{h_{(n)}} = \theta_{o_{(n)}} + \Delta\theta_{h_{(n)}} \tag{5}$$

where θ_{h} is the HST in degrees Celsius, θ_{o} is the top-oil temperature at the current load, and $\Delta\theta_{\mathrm{h}}$ is the total HST rise at the nth time step, where Δ is calculated in (6)

$$\Delta\theta_{h_{(n)}} = \Delta\theta_{h1_{(n)}} + \Delta\theta_{h2_{(n)}}. \tag{6}$$

$\Delta\theta_{\mathrm{h1(n)}}$ and $\Delta\theta_{\mathrm{h2(n)}}$ are derived from the difference equations for HST rise, and can be calculated

$$\Delta\theta_{\mathrm{h1}_{(n)}} = \Delta\theta_{\mathrm{h1}_{(n-1)}} + \frac{\mathrm{Dt}}{\mathrm{k}_{22}\tau_{\mathrm{w}}} \times \left[\mathrm{k}_{21} \times \Delta\theta_{\mathrm{hr}}\mathrm{Ka}^{\mathrm{y}} - \Delta\theta_{\mathrm{h1}_{(n-1)}}\right] \tag{7}$$

where Dt is the time step in minutes, k_{22} and k_{21} are experimentally-derived constants related to the thermal recovery of the transformer, τ_{w} is the winding time constant in minutes, $\Delta\theta_{\mathrm{hr}}$ is hotspot-to-top-oil gradient at rated current in Kelvin, Ka is the load factor (current load/rated load), and y is the exponential power of current versus winding temperature rise (winding exponent). Similarly, $\Delta\theta_{\mathrm{h2}}$ can be evaluated

$$\Delta\theta_{\mathrm{h2}_{(n)}} = \Delta\theta_{\mathrm{h2}_{(n-1)}} + \frac{\mathrm{Dt}}{\frac{\tau_{\mathrm{o}}}{\mathrm{k}_{22}}} \times \left[(\mathrm{k}_{21} - 1) \times \Delta\theta_{\mathrm{hr}}\mathrm{Ka}^{\mathrm{y}} - \Delta\theta_{\mathrm{h2}_{(n-1)}}\right] \tag{8}$$

where τ_{o} is the average oil time constant in minutes. The top-oil temperature must be calculated and substituted back into (5)

$$\theta_{\mathrm{o}_{(n)}} = \theta_{\mathrm{o}_{(n-1)}} + \frac{\mathrm{Dt}}{\mathrm{k}_{11}\tau_{\mathrm{o}}} \times \left[\left(\frac{(1 + \mathrm{Kb}^2\mathrm{R})}{1 + \mathrm{R}}\right)^{\mathrm{x}} \times \Delta\theta_{\mathrm{or}} - \left(\theta_{\mathrm{o}_{(n-1)}} - \theta_{\mathrm{a}}\right)\right]. \tag{9}$$

Equations (7) and (8) would be accurate if all phases of a three phase transformer are loaded identically or for single phase transformers which are commonly used in North America or in rural areas of Australia (e.g. SWER systems). However, the loads on the phases of the typical three phase distribution transformer are not balanced. It is possible to derive an expression analogous to (7) and (8) for each phase if the time varying loads on each phase are known.

The phase currents of the transformer would determine the winding to oil temperature differential of that phase so (8) could be rewritten for each individual phase

$$\Delta\theta_{\mathrm{h2}_{(n)\mathrm{R}}} = \Delta\theta_{\mathrm{h2}_{(n-1)\mathrm{R}}} + \frac{\mathrm{Dt}}{\frac{\tau_{\mathrm{o}}}{\mathrm{k}_{22}}} \times \left[(\mathrm{k}_{21} - 1) \times \Delta\theta_{\mathrm{hr}}\mathrm{K}_{\mathrm{R}}^{\mathrm{y}} - \Delta\theta_{\mathrm{h2}_{(n-1)\mathrm{R}}}\right] \tag{10}$$

$$\Delta\theta_{\mathrm{h2}_{(n)\mathrm{W}}} = \Delta\theta_{\mathrm{h2}_{(n-1)\mathrm{W}}} + \frac{\mathrm{Dt}}{\frac{\tau_{\mathrm{o}}}{\mathrm{k}_{22}}} \times \left[(\mathrm{k}_{21} - 1) \times \Delta\theta_{\mathrm{hr}}\mathrm{K}_{\mathrm{W}}^{\mathrm{y}} - \Delta\theta_{\mathrm{h2}_{(n-1)\mathrm{W}}}\right] \tag{11}$$

$$\Delta\theta_{\mathrm{h2}_{(n)\mathrm{B}}} = \Delta\theta_{\mathrm{h2}_{(n-1)\mathrm{B}}} + \frac{\mathrm{Dt}}{\frac{\tau_{\mathrm{o}}}{\mathrm{k}_{22}}} \times \left[(\mathrm{k}_{21} - 1) \times \Delta\theta_{\mathrm{hr}}\mathrm{K}_{\mathrm{B}}^{\mathrm{y}} - \Delta\theta_{\mathrm{h2}_{(n-1)\mathrm{B}}}\right]. \tag{12}$$

The current load (I_{cl}) that would impact on the top oil temperature would be the rms value of each individual phase current at that given time

$$I_{cl}(\mathrm{t}) = \sqrt{\left[I_{\mathrm{RMS}}^{A}(t)\right]^2 + \left[I_{\mathrm{RMS}}^{B}(t)\right]^2(t) + \left[I_{\mathrm{RMS}}^{C}(t)\right]^2} \tag{13}$$

$$K_{ub} = \frac{I_{cl}(t)}{I_{rated}} \tag{14}$$

$$\theta_{\mathrm{o}_{(n)}} = \theta_{\mathrm{o}_{(n-1)}} + \frac{\mathrm{Dt}}{\mathrm{k}_{11}\tau_{\mathrm{o}}} \times \left[\left(\frac{(1 + \mathrm{K}_{\mathrm{ub}}^2\mathrm{R})}{1 + \mathrm{R}}\right)^{\mathrm{x}} \times \Delta\theta_{\mathrm{or}} - \left(\theta_{\mathrm{o}_{(n-1)}} - \theta_{\mathrm{a}}\right)\right]. \tag{15}$$

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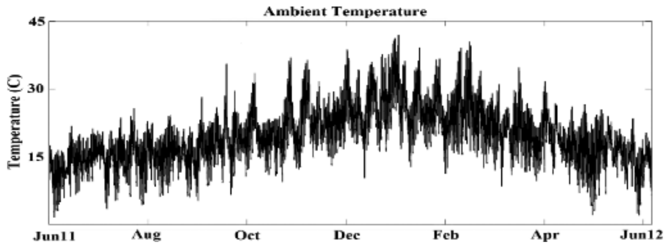

Fig. 3. Ambient temperature from June 2011 to July 2012.

C. Ambient Temperature and Roof top PV Generation

As described in the thermal model (9) and in publications [12], [18], the ambient temperature affects the hot spot temperature and impacts the life duration and the aging rate of transformer. Therefore as one of the input to the thermal model, one year ambient temperature data of July 2011–2012 were collected from Australian Bureau of Metrology Perth Airport weather station which is close to the high PV penetration trial [19]. The ambient temperature and solar irradiance was obtained at a 15-min rate to be consistent with the smart meter load data sampling times (Fig. 3).

D. Household Load Profiles

The transformer daily load curve is determined by the aggregated demand measured by the smart meters connected to individual consumers. In this work 15-min intervals are used, so a daily load curve is made up of 96 pairs of time and demand values. In order to guarantee a representative set of field data, a total of 365 days of measurements were collected from operating smart meters at the high PV penetration trial in Perth. A snapshot of all household load profiles (current) is shown in Fig. 4.

E. Distribution Transformers

The 102 node 400/230 V distribution network is connected to the high voltage 22 kV Western Australia's South-West Interconnected System (SWIS) through a 200 kVA distribution transformer that complies with the prevailing Australian Standard AS2374. Within the Western Power service area, approximately 17 000 distribution transformers are in service. More than 3,000 of these are 200 kVA units. These transformers are non-thermally upgraded paper and its life duration is 30 years. The loading patterns of the distribution transformer shown in Fig. 1 without and with rooftop PV generation is of interest in this study. The transformer ratings and impedance values are representative of current in-service distribution transformer types used in Western Australia. Transformer data are listed in Tables V and VII.

IV. Results and Discussion

A generalized analysis framework was developed to investigate the distribution transformer loss of life under proposed scenarios. In each scenario, the annual loss of life rate and the expected lifetime of the transformers were determined. These scenarios are:

1) unbalanced operating conditions (with solar input);
2) unbalanced operating conditions (no solar input);
3) balanced operating conditions (with solar input);
4) balanced operating conditions (no solar input).

A. Unbalanced Operating Conditions (With Solar Input)

To investigate the impact of PV on the life of the transformer, a one year set of 15-min measurements of transformer load and ambient temperature was assembled. Equations (1)–(5), together with transformer thermal parameters, were used to determine the transformer thermal response (Fig. 5). Equations (10)–(14) of Section III-D, were then used to obtain an LOL rate, and total LOL accumulated by the transformer over the given year.

The distribution transformer under study is substantially unbalanced. Out of 77 connected residential consumers, 13 are connected to phase A, 17 connected to phase while phase C is serving 21 customers and the 26 of the premises have three phase connection. Fig. 5 shows the temperature profiles corresponding to one summer week during the trial that includes the annual peak day for the transformer. The peak demand day occurred on the second day of a heat wave[1] and immediately preceded the Australia Day public holiday.

It is evident that phase C is heavily loaded. At the peak time the loading on phase C is 360 A/90 kVA or 1.34 p.u. and this value is close to the allowable maximum cyclic loading. In Australia it is acceptable practice to load a transformer up to 1.4 its rating for short period of time in a given year [20]. In this instance the utility company would not notice this overloading incident as the total energy sales from the transformer are used to predict peak loads. The energy sales are aggregated over the three phases, which at peak time was 196 kVA, and not the individual phase loading. Based on this approach the transformer will be kept in service until the total loading on it would reach 1.4 p.u. or 280 kVA, this assumption has been used as a basis to create four test cases. These investigate the LOL of the transformer if the loading on the transformer increases in 10% increments until it reaches the set value of 280 kVA (1.4 p.u.).

Case 1 illustrates the transformer HST and LOL quantities that correspond to the current unbalanced state of the transformer with 64 kW of PV. The results are presented for the peak day in the summer, Fig. 5(a) and Fig. 6(a) as well as for the day with lowest load in the winter, Fig. 5(b) and Fig. 6(b), for each phase of the transformer. The horizontal axis is the time of day in 15-min intervals. In Fig. 5 the vertical axis is HST, in Fig. 6 the vertical axis is LOL.

From Fig. 5 it is clear that the unbalance has caused different hotspot temperatures in each leg of the transformer. For example on the peak day the phase A winding would reach 90 °C whereas phase C winding exceeds 130 °C. This 40 °C temperature difference drives the rapid degradation of the phase C insulation. This temperature difference is much less at lighter loads (Fig. 6). As can be seen in Fig. 6 in the summer, the LOL is dominated by the higher transformer temperatures during the late afternoon and evening peak. Mention should be made of the high LOL rate of the phase C, in fact, it exceeds the design rate of 1-day per 24 h, by losing more than 3 days in 24 h. On the contrary, in winter,

[1]This discussion is based on the Bureau of Meteorology's definition of a heat wave as three or more consecutive days with daily maximum temperatures exceeding 35 °C.

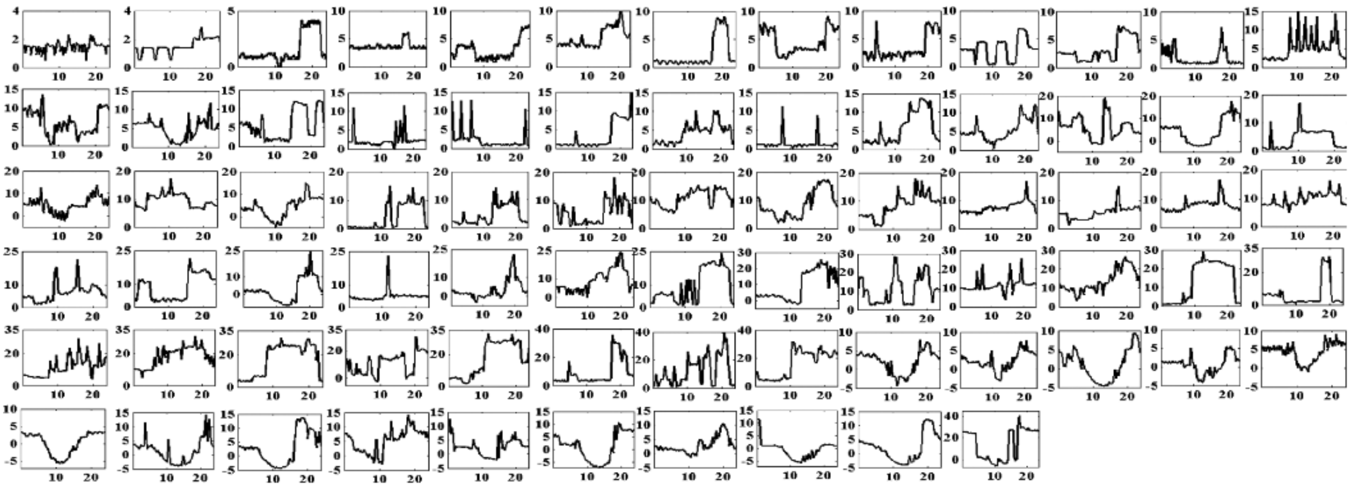

Fig. 4. Typical daily load profile of each of the 75 customers on Pavetta. (Vertical axis: Time (Hour); horizontal axis: Current (A)).

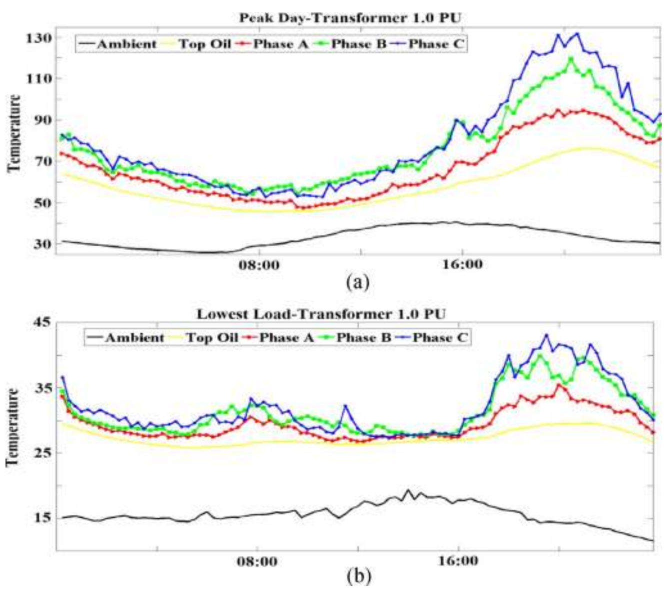

Fig. 5. Comparison of the daily evolution of the hotspot, top oil, and ambient temperature peak day (a) low load day (b).

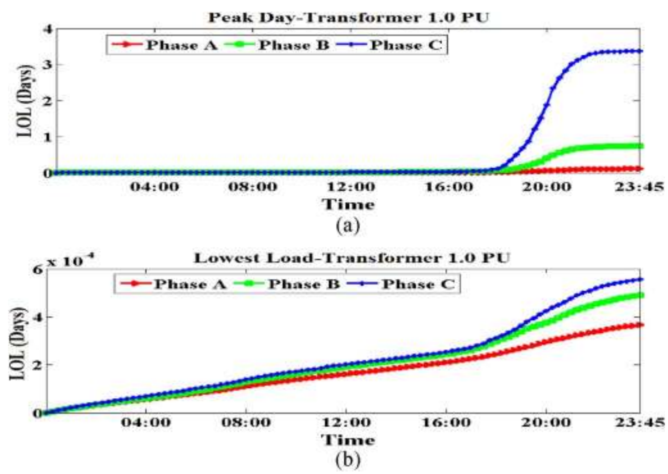

Fig. 6. Daily evolution of the loss of life on each phase of transformer, peak day (a) low load day (b).

the peak of the LOL rate is well below the designed value. This is due to the moderate loads combined with relatively low ambient temperature.

To see how future load growth would affect the transformer hot-spot temperature, simulations were carried out and compared together with the base load case (cases 2–4). For case 5, a worst case scenario is investigated by increasing the load to 1.4 p.u. (280 kVA).

Fig. 7 shows the top oil temperature and HST on the peak summer day when the transformer is loaded 40% above the nameplate 200 kVA rating and compares them with reference case. The oil reached 97°C and hot-spot temperatures for each phase reached 126 °C, 162 °C, and 185 °C, respectively. The HST limit of 160 °C was thus violated for both of the phases B and C, and rapid degradation is expected.

B. Unbalanced Operating Conditions (No Solar Input)

In order to demonstrate the benefit that roof top PV could provide in reducing the transformer loss of life, the solar generation was removed the system. The production pattern of PV units was obtained from the calculated and collected values using the solar irradiance measurements during the first three months of the trial (July–September 2011) and the smart meter data in 15-min interval during the rest of the period of the trial (October 2011–June 2012). For the first three months of the trial, only net household consumption data was available. In the last nine months of the trial, a two channel record of household load and solar generation was available for all single phase customers.

The solar generation profile of the first three months was estimated using solar irradiance, ambient temperature and rating information for the PV modules and inverter. The method was confirmed by correlating with generation pattern of the last nine months of the trial. Of the 34 premises with PV, 12 houses had dual reading meters that captured both the PV generation and consumption of the houses. The PV generation for the other 22

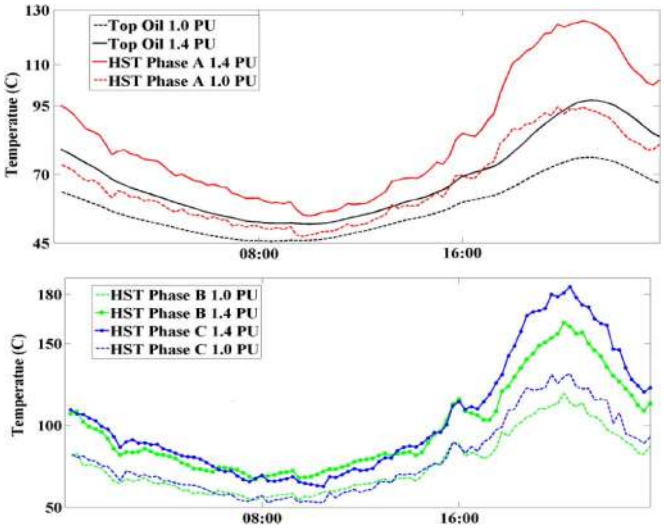

Fig. 7. Effect of possible load growth on TOT and HST.

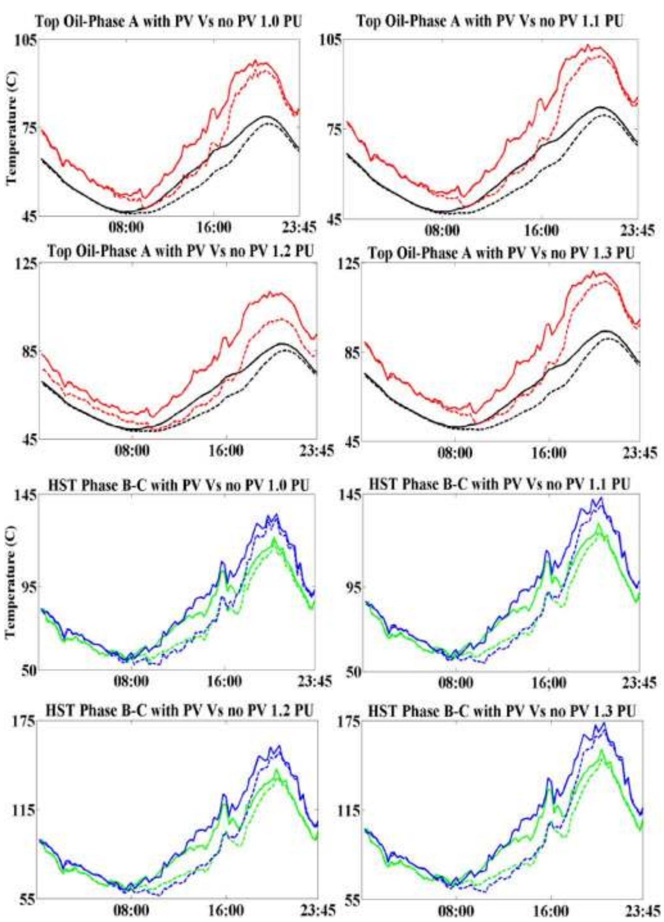

Fig. 8. Improvement in top oil temperature and HST in the presence of PV.

houses which only had net meter recording could be calculated from these observations.

The results for five operating conditions are shown in Fig. 8. In each graph the dotted line represents the system with the PV and the solid line the system without PV. The first row is the reference case (current state of the transformer), cases for additional loadings to 1.3 p.u. are shown in this figure. The final 1.4 p.u. loading case will be considered separately. Fig. 9 shows the temperature profiles corresponding to a peak transformer overload of 1.4 p.u.

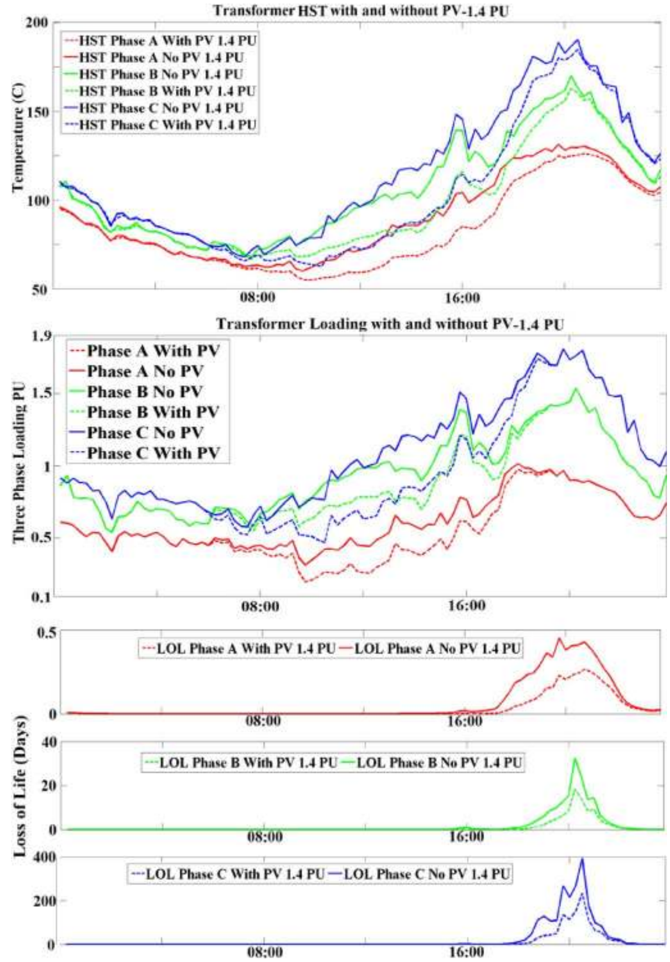

Fig. 9. Temperature difference in hot spot and oil of transformer and reduction in LOL as a result of PV generation.

Without PV generation, the oil and hot-spot temperatures reached 100 °C and 190 °C, respectively. The addition of 64 kW of PV generation lowered this to 180 °C for the HST and 95 °C for the top oil. These values are still extremely high. The PV benefit occurs during the time leading up to the peak. Lower loadings in the afternoon allow the transformer to enter the peak period with lower oil temperatures. In this example the LOL saving for Phase A, B, and C is 0.2,14, and 160 days for each phase, respectively. Except for cases where the PV installations are larger than the peak load, PV will decrease the daily top oil temperature and HST and extend transformer life. The extent of the improvement depends on the loading ratio of the transformer and the PV penetration level.

Table II provides a summary on each phase of transformer LOL and the benefit that roof top PV could provide to improve the transformer aging process based on its current and future loading. The first conclusion from Table II is that regardless of the operation scenario, the LOL rate of the transformer is far higher in summer. This may be due to the combined effect of higher ambient temperature and electricity use driven by cooling loads in this season. It further implies that roof top

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TABLE II
SEASONAL VARIATION IN LOL OF TRANSFORMER

Transformer Loss of Life (Days)															
	Winter			Spring			Summer			Autumn			Annual		
	Phase A	Phase B	Phase C	Phase A	Phase B	Phase C	Phase A	Phase B	Phase C	Phase A	Phase B	Phase C	Phase A	Phase B	Phase C
Solar-1.0 pu	0.1	0.1	0.1	0.1	0.1	0.1	0.7	3.9	9.8	0.2	0.5	0.7	1.1	4.6	11
No solar-1.0 pu	0.1	0.1	0.1	0.1	0.1	0.2	1.2	6.8	18.5	0.3	1.1	1.6	1.7	8.1	20
Solar-1.1 pu	0.1	0.1	0.2	0.1	0.1	0.2	1.1	7.3	20.9	0.2	0.8	1.1	1.5	8.3	22
No solar-1.1 pu	0.1	0.1	0.2	0.1	0.2	0.2	1.8	13.2	41.5	0.4	2.0	3.0	2.4	15.5	45
Solar-1.2 pu	0.1	0.2	0.3	0.1	0.2	0.3	2.1	22.6	81.8	0.3	1.9	3.0	2.6	25	85
No solar-1.2 pu	0.1	0.2	0.3	0.1	0.2	0.4	3.8	43.5	173.3	0.8	6.0	9.6	4.8	50	184
Solar- 1.3 pu	0.2	0.3	0.6	0.1	0.3	0.5	4.5	79.9	365	0.6	5.2	8.8	5.4	86	375
No solar- 1.3 pu	0.2	0.3	0.6	0.1	0.4	0.8	8.8	161.7	820	1.6	19.4	34.1	11	182	855
Solar- 1.4 pu	0.3	0.5	1.3	0.1	0.4	0.4	10.3	318	1838	1.2	1.2	28.5	12	320	1868
No solar- 1.4 pu	0.3	0.5	1.2	0.2	0.7	1.7	22.1	670	4350	3.8	69.1	133	26	741	4486

TABLE III
LOSS OF LIFE IMPROVEMENT WITH PV GROWTH

Transformer Loading/ Phase C PV installation	TOT (Max) (°C)	HST (Max) (°C)	LOL (Days)
1.1 PU-26kW PV	79.5	137.9	22
1.1 PU-35 kW PV	77.1	130.6	14
1.2 PU-26kW PV	85	151.7	85
1.2 PU-40 kW PV	82.1	141.9	40

PV could provide a higher LOL reduction in the summer and is a suitable option for distribution transformer-life extension. The targeted installation of roof top PVs along the feeder, and even on a specific phase, could be considered as a life extension strategy. There are voltage rise limitations on the number and location of the installed roof top PVs. Considering this 7 additional PVs (with average rating of 1.88 kW) were randomly allocated to consumers on Phase C. Table III shows the corresponding life improvement.

C. Balanced Operating Conditions (With Solar Input)

In the first two scenarios the transformer was significantly unbalanced. In the last two scenarios examine the benefit of balanced operation with PV generation. Load balance can be achieved using a distribution STATCOM or optimal rephasing strategies with laterals or individual loads [21]–[23]. Phase identification systems introduced in [11], can be combined with rephrasing to improve balance. Fig. 10 compares the transformer peak day when the transformer is balanced to the current unbalanced case. The lower phase C current reduces the peak time HST to 115 °C from 130°C. A reduction of 15 °C in HST translates into reduction in LOL of approximately 2 days. It should be noted in Fig. 10 phase A and B would have experience higher temperatures and age faster. The benefit is that whole transformer will age at the same rate.

D. Balanced Operating Conditions (No Solar Input)

To conduct a comprehensive comparison, the daily HST and annual LOL rates were calculated when the transformer was balanced and had no PV connection. Table IV shows that the

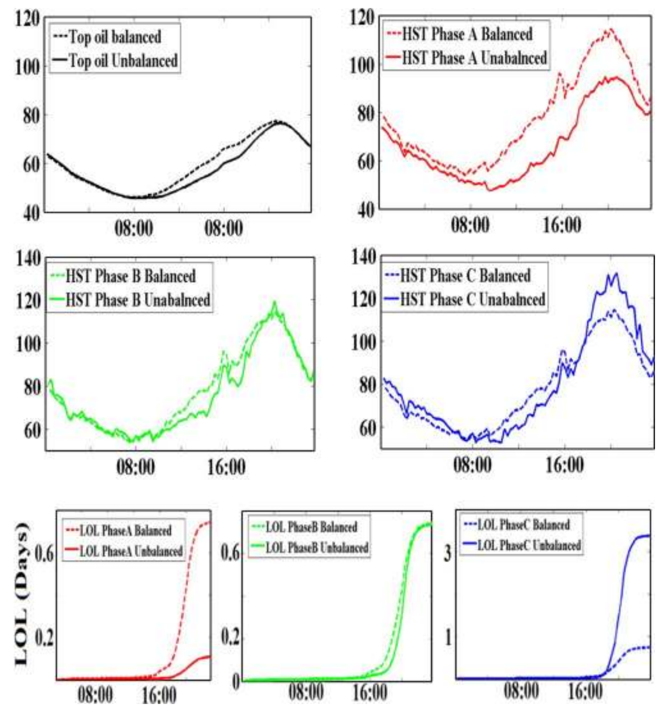

Fig. 10. Balanced versus unbalanced loading: HST, TOT and LOL.

transformer will suffer from rapid loss of life when the winding is under excessive stress. Balancing the phases will assure excessive LOL does not occur in one phase. Important benefits may be realized due to the life extension of distribution transformers brought about by customer-owned PV units even when the transformer is balanced.

It should be noted that under scenario 2, loading of 1.4 p.u., the transformer would lose more than 12 years of its life in one year. If the transformer was not upgraded it could reach its end of life within 1–2 years of operation.

V. CONCLUSION AND FUTURE WORK

PV generation will extend the life of oil-immersed distribution transformers even when the peak demand occurs well after sunset. The presented results correspond to a three phase residential transformer, but the result of this study could also be

TABLE IV
LOL UNDER DIFFERENT LOADING SCENARIOS
(BALANCED VERSUS UNBALANCED)

Transformer Loading	Scenario A	Scenario B	Scenario C	Scenario D
1.0 pu	11	20	2.6	4.6
1.1 pu	22	45	6.6	12.2
1.2 pu	85	184	19.2	36.9
1.3 pu	375	855	63	125.2
1.4 pu	1868	4486	232	472

TABLE V
ELECTRIC CHARACTERISTICS OF THE TRANSFORMER UNDER STUDY

Property	Value	Property	Value
Apparent power	200 kVA	Secondary current	262.5 A
Cooling mode	ONAN	No-load loss	424 W
Primary voltage	22 kV	Load Loss	2963 W
Secondary voltage	415 V	Impedance	4.30 %
Primary current	5.25 A	Calculated % Io	0.614 %

TABLE VI
GEOMETRIC CHARACTERISTICS OF THE TRANSFORMER UNDER STUDY

Approximate Mass	Value
Untanked	700 kg
Tank and fittings	270 kg
Insulating liquid (Oil)	400/360 Litre/ kg
Transformer (Total)	1330 kg

TABLE VII
PARAMETERS FOR THE THERMAL MODEL OF THE 200-kVA TRANSFORMER

Symbol	Value	Symbol	Value	Symbol	Value
X	0.8	K_{22}	2	$\Delta\theta_{or}$	45 K
Y	1.6	R	6.98	τ_0	180 min
H	1.4	D_t	15min	τ_W	10 min
k_{11}	1	Gr	14.5 Ws/K		
K_{21}	1	$\Delta\theta_{hr}$	35 K		

applied to single phase distribution transformers. The impact of PV on single phase distribution transformer (in the US, or SWER in Australia) is similar to the case when the three phase transformer is balanced (scenarios C and D). It is expected as the coincidence of PV with commercial load is higher better life extension will result for commercial load transformers.

The main focus of this paper is on the impact of PV on three phase transformer, but the method explored in this paper is applicable to any other form of single phase generator such as combined heat and power fuel cell modules, which are not dispatchable and are driven by the demand (i.e. hot water) of the household.

A thermal model was developed to assess the transformer temperatures over a 12 month cycle allowing a cumulative measure of loss of life to be determined for various scenarios. This paper is based on 15-min field data and captures the impact of solar variability at these time scales. The variations in irradiance produced by changes in cloud cover can cause faster fluctuations in the power generated by roof top PV. The short fluctuations (less than 15 min) would not have a significant effect on oil temperature (with time constant of 180 min) but could change the winding temperature in a magnitude of 2–3° (the winding time constant is 10 min). This will not significantly contribute to the aggregated loss of life given the short duration.

Finally the general trend of life improvement will increase with PV penetration until power flow reversals, comparable to the peak demand, occur. At this point the additional winding losses become significant.

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