E586B: Course Project

Transformer Protection

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Section I

Introduction

The primary objective of the Transformer Protection is to detect internal faults in the transformer with a high degree of sensitivity and cause subsequent de-energisation and, at the same time be immune to faults external to the transformer i.e. through faults. Sensitive detection and de-energisation enables the fault damage and hence necessary repairs to be limited. However, it should be able to provide back up protection in case of through faults on the system, as these could lead to deterioration and accelerated aging, and/or failure of the transformer winding insulation due to over heating and high impact forces caused in the windings due to high fault currents. In addition to the internal faults, abnormal system conditions such as over excitation, over voltage and loss of cooling can lead to deterioration and accelerated aging or internal failure of the transformer. Hence protection again these failures should be considered in as part of the comprehensive transformer protection scheme.

Transformer protection can be broadly categorized as electrical protection implemented by sensing mainly the current through it, but also voltage and frequency and, as mechanical protection implemented by sensing operational parameters like oil pressure/ level, gas evolved, oil & winding temperature.

Like in most things in Transformer Protection too, the extent of protective devices applied to a particular Transformer is dictated by the economics of the protection scheme vis-à-vis the probability of a particular type of failure and the cost of replacing and repairing the transformer as well the possibility of the failure leading to damage of adjacent equipment or infrastructure. Failure costs include all the direct and indirect costs associated with it. The protection scheme cost includes the cost of the protective device but is mainly the cost of the disconnecting device i.e. the Circuit Breaker and other auxiliaries like batteries and necessary infrastructure. Further the life cycle cost is taken into account.

There are no strict guidelines as to what protection devices should be used for a particular transformer. However, typically Transformers below 5000 KVA (Category I & II) are protected using Fuses. Transformers above 10,000KVA (Category III & IV) have more sensitive internal fault detection by using a combination of protective devices as shown in Figure 1. For ratings between the above a protection scheme is designed considering the service criticality, availability of standby transformers, potential of hazardous damage to adjacent equipment and people etc.

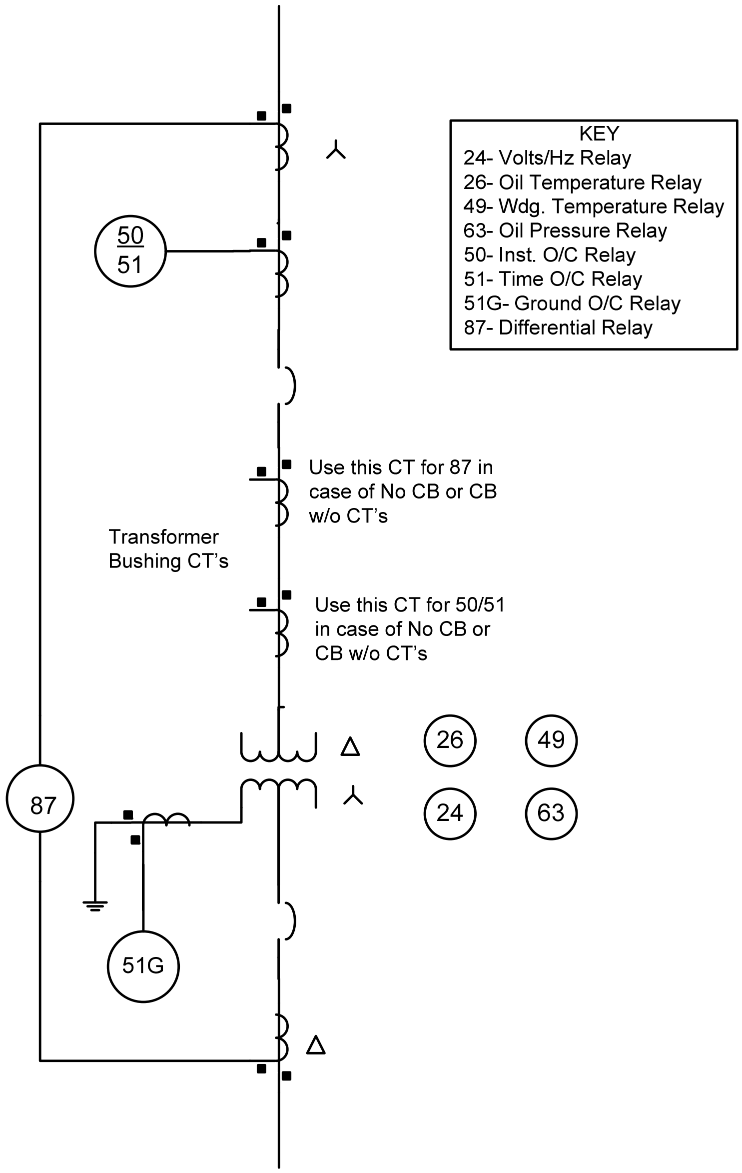


Figure 1: **Typical Protection Scheme for Category III & IV Transformers**

Section 2

Electrical Protection

The electrical protection of the Transformer comprises of the following and each is elaborated further.

- Fused Protection
- Differential Current Protection
- Over Current Protection
- Over Excitation Protection
- Over Voltage Protection

Transformer Over Current Protection

Over current protection is commonly used for protection from phase and ground faults. It's used as primary protection where differential protection is not used – typically for category I & II transformers and as backup protection if differential protection has been used – typically for category III & IV transformers. The protection zone of over current devices is normally more than the transformer. Hence they are part of the system protection and need to be coordinated with the other system protection devices.

Typically, fuses are used as primary protection for transformers below 10MVA. Above 10MVA over current relays are used as back up along with differential relays as primary protection for transformers. Instantaneous over current relays are also used for back up where differential relays have been used. Typically they are set to 150% to 200% of the maximum of

1. Magnetising current inrush (If harmonic restraint is not used)
2. Short time load – Cold Pickup
3. Maximum 3 phase short circuit current

Transformer Through Fault Withstand Standards

The philosophy of transformer over current protection is to limit the fault current below the transformer through fault with stand capability. The fault withstand capability in turn is based on the possibility of mechanical of the windings due to the fault current, rather than on thermal characteristics of the transformer.

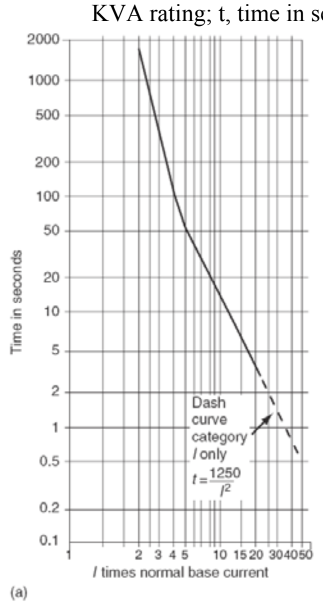
The fault withstand capability is defined by the IEEE standard C57.91 – 1995 and is summarized below

Category	Transformer Rating – KVA		Use Curve	[a] Frequent Faults	[b] Dotted Curves Apply From
	1 Phase	3 Phase			
I	5 – 500	15 – 500	a	–	25 – 501, where $t = \dfrac{1250f}{60I^2} = \dfrac{1250}{I^2}$ at 60 Hz
II	501 – 1,667	501- 5,000	a or a+b	10	70% – 100% of max possible fault where $I^2t = K$, K is determined at max I; where $t = 2$
III	1668 – 10,000	5,001 – 30,000	a or a+c	5	50% – 100% of max possible fault where $I^2t = K$, K is determined at max I; where $t = 2$
IV	> 10,000	> 30,000	a+c	–	As Above

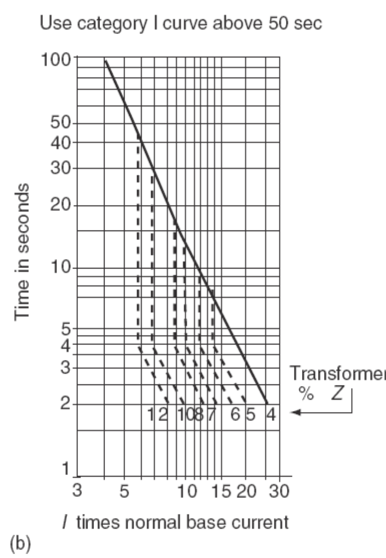
Note:

a) It's classified as Frequent Faults if the number of faults over the transformer life time is more than the number shown. Else it's classified as infrequent faults.
For category II & III the frequent fault curve may be used for backup protection in case it's exposed to frequent faults, but is protected by high speed primary relays
See **Figure 3** – Guide to determine fault frequency

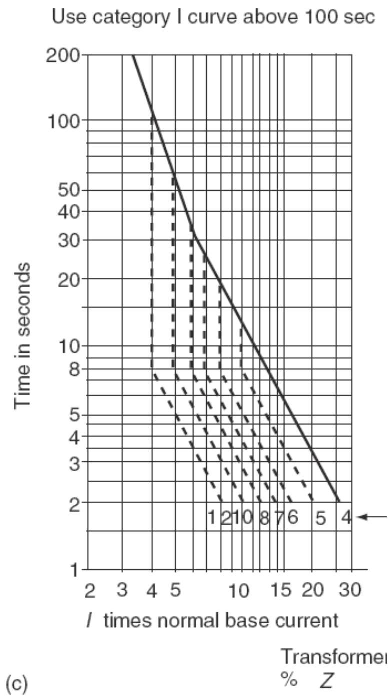
b) I, symmetrical short circuit current in per unit of normal base current based on minimum nameplate KVA rating; t, time in seconds; f, frequency in HZ.



For Category I frequent & Category II & III infrequent



For Category II frequent



For Category III Frequent & Category IV infrequent

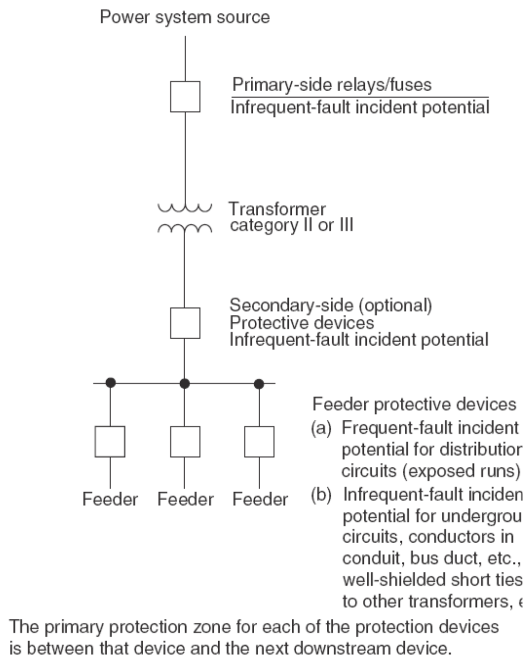


Figure 3 Guide to Fault Frequency

The procedure to decide on, over current protection rating, as per the transformer fault withstand ratings is as follows:

1. Determine the transformer category from the above table
2. If in category II or III determine if it will be subject to faults frequently or infrequently. Use figure 3 – Guide to fault frequency
3. Based up on the above determine the curve applicable
4. Replot the curve determined in step 3 specifically for the transformer under consideration using the secondary or the primary amperes as the abscissa, secondary amperes is preferred for coordination with down stream protective devices.
5. Select the proper fuses or relays – tap, time dial setting etc such that coordination is maintained and within the within the transformer withstand curve determined above.

The determination of the transformer fault withstand curve using above procedure is explained using an example below:

Example:

Consider a 3 phase, 2500KVA, 12KV/ 480V, Z - 5.75%, Δ/Y transformer. The transformer has fuse protection on the primary side and a direct acting main secondary CB.

1. Category –
   Category II - from the table above
2. **Fault Frequency – infrequent** From figure 3 and the data given
3. **Curve Applicable – (a)** Using 1 & 2 and curve applicability
4. **Curve Plot**
   To plot the curve we determine the points as follows.

$$Z = 5.75\% = 0.0575\,pu$$

Max 3phase short circuit current $I = \frac{V}{Z} = \frac{1}{0.0575} = 17.93\,pu$

Max withstand time curve ends point $t = \frac{1250}{I^2} = \frac{1250}{17.93^2} = 4.13\,\text{sec}$

We now need to determine the points on the curve. The points above the dashed line can be directly determined from the standard curve. The points on the dashed part of the curve up to the end point as determined above are determined using the equation $t = \frac{1250}{I^2}$. Some of the points are tabulated below:

Time –t from Curve (a)	Current PU From Curve (a)	Current PU From $I = \sqrt{\frac{1250}{t}}$	Current @ 480V
1000	2.3		6,916
500	2.8		8,419
300	3.0		9,021
100	4.0		12,028
50		5.0	15,035
12.5		10.0	30,070
4.13		17.39	52,296

Transformer Differential Protection

Factors to be Considered

Differential Protection provides the best overall protection. However in case of ungrounded or high impedance grounding it cannot provide ground fault protection. Differential protection is normally applied to Transformers 10MVA and above or depending upon its criticality.

The following factors affect the differential current in transformers and should be considered while applying differential protection. ***These factors can result in a differential current even under balanced power in & out conditions***

1. **Magnetising inrush current –** The normal magnetizing current drawn is 2 – 5% of the rated current. However during Magnetising inrush the current can be as high as 8 – 30 times the rated current for typically 10 cycles, depending upon the transformer and system resistance.
2. **Over excitation** – This normally of concern in generator – transformer units. But it can also be of concern in certain transmission transformers where line capacitance is dominant and light load conditions can lead to high voltage on the transformer. Transformers are typically designed to operate just below the flux saturation level. Any further increase from the max permissible voltage level (or Voltage / Frequency ratio), could lead to saturation of the core, in turn leading to substantial increase in the excitation current drawn by the transformer.
3. **CT Saturation –** External fault currents can lead to CT saturation. This can cause relay operating current to flow due to distortion of the saturated CT current. Alternatively the harmonic current present in the saturated CT can cause a delay in the operation of the differential relay during internal faults.
   Proper selection of CT ratios is essential to minimize problems due to the saturation. CT selection is discussed later
4. Different primary and secondary voltage levels, that is the primary & secondary CT's are of different types and ratios
5. Phase displacement in Delta-Wye transformers.

6. Transformer voltage control taps
7. Phase shift or voltage taps in regulating transformers

Transformer Differential Relay

To account for the above variables less sensitive Percentage Differential Relays with percentage characteristics in the range of 15 to 60% are applied to transformers. Additionally, in modern microprocessor and numeric relays harmonic restraints can be applied.

The second harmonic is the dominant harmonic in the magnetic inrush current. Hence a second harmonic restraint is utilised to prevent the relay from operating during the inrush.

The excitation current contains high magnitudes of the odd harmonic, typically 25% of the third component and 11% of the fifth component. The fifth component is utilised to sense over excitation. If an over excitation relay has been applied, the fifth harmonic signal is used to ***block the differential trip signal*** so as to have easy fault discrimination during trip analysis. Otherwise, it is used to restraint the relay operation.

In addition to the fixed the percentage differential relays, variable percentage relays are also used. In this case, the percentage restraint increases as the transformer through current increases. This limits the adverse effect of CT saturation if any.

Transformer Differential Relay Connections

The following rules are to be followed for connecting a transformer differential relay; the fundamental rule being all the currents into and from the differential zone should be accounted for 1 unit per phase:

1. The number of restraint windings used should be at least equal to the number of transformer windings.
2. A restraint winding should be used for each fault source.
3. If feeder side CT's are paralleled, they should be done carefully.

The current through the relay restraint windings should be in phase as well as the current difference (i.e. current through the relay operating winding) should be small (ideally zero) for load and through fault conditions. The way to method to achieve this is a two step process as below:

1. **Phasing** By suitably using Wye or Delta CT units to ensure that the primary and secondary currents through the relay restraint windings are in phase.
2. **Ratio Adjustment** Having decided on the CT connections, the CT ratio and/ or the relay tap is selected so as to have minimum relay operating current.

The above process is illustrated by the example below

Example - Transformer Differential Relay Connection

Consider a 138/69KV, 75 MVA, Δ/Y transformer as shown below.

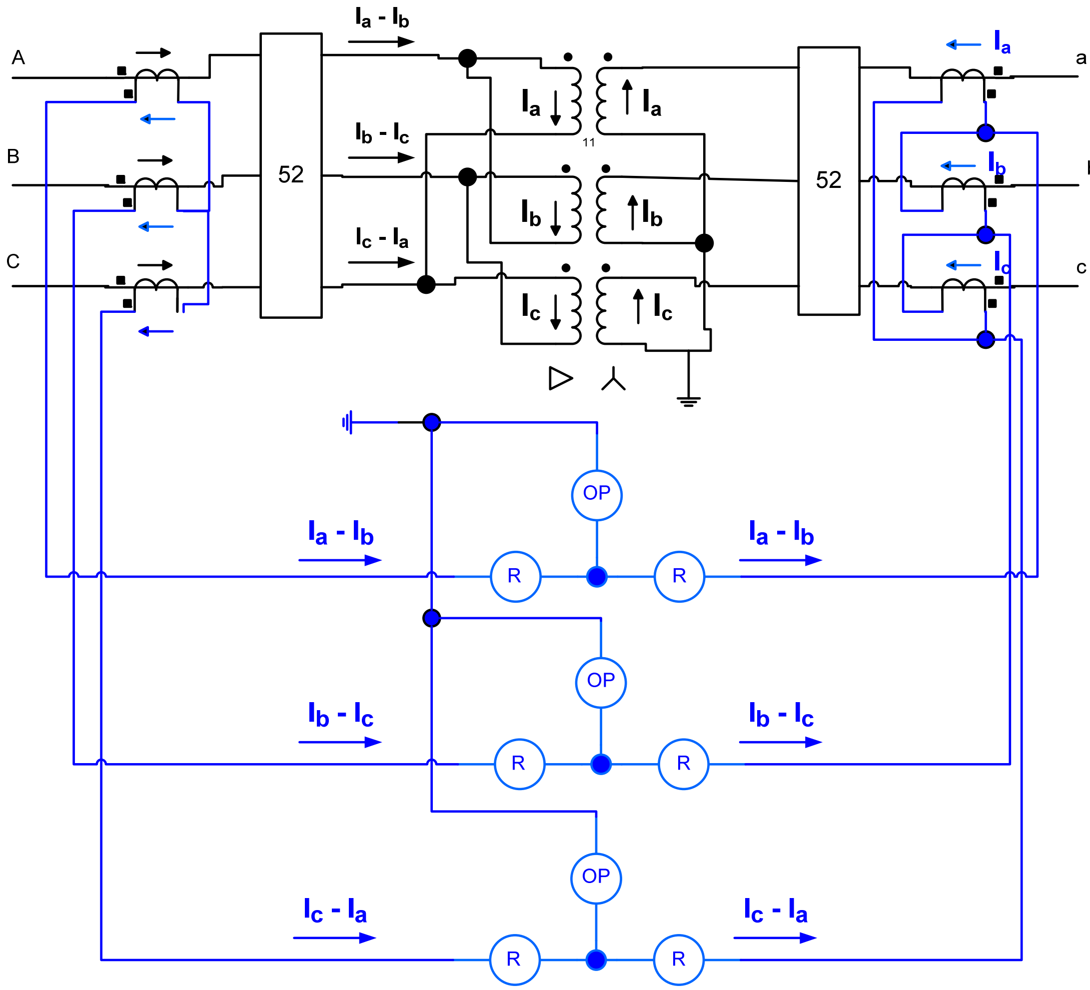


Figure 3

Step 1 – Phasing

The first step is to connect the CT's so that the currents in the restraint windings are in phase. There are to ways that this can be tried –

a) Connecting the Δ side (ABC) CT's in Δ and the Y side (abc) CT's in Y. *However, in case of a through ground fault, the secondary Y CT's would circulate the zero sequence currents through the restraint winding and as the HV primary windings are Δ connected the corresponding zero sequence current would flow through the Δ and the same would not be sensed by the primary CT's and hence the primary restraint winding. This would lead to a current difference and cause the relay to operate on a through fault.* ***Therefore this would not be a correct option.***

b) Connect Δ side (ABC) CT's in Y and, the Y side (abc) CT's in Δ. In this case the zero sequence currents would be restricted within the CT Δ on the abc side and within the main winding Δ on the ABC side. Thus no zero sequence would flow through the restraint winding and the balance maintained.

Next the CT's must be connected so that the currents are in phase. Do this we assume balanced current to be flowing through the transformer. Though we can assume flow in any direction it's easier to start with the Wye side. Assume I_a, I_b and I_c to be flowing out of the marked polarity this will cause the current in the respective Δ side windings to be ($I_a – I_b$), ($I_b – I_c$) and ($I_c – I_a$) and into the polarity marked. The corresponding (ABC) CT current in the respective phase A, B & C restraint winding would be $(I_a - I_b)$, $(I_b - I_c)$ and $(I_c - I_a)$ and flowing from left to right as shown in figure 3. To maintain the same phase in the 'abc' restraint windings the current in these should be the same i.e. $(I_a - I_b)$, $(I_b - I_c)$ and $(I_c - I_a)$ and flowing from left to right. The same can be obtained by connecting the abc side CT's in Δ as shown in the figure 3.

Step 2 – CT Ratio and Tap selection

Differential relay restraint winding's typically have taps whereby difference in the restraint current ratio can be set in the range of 2:1 or 3:1. The mismatch in the restraint currents is defined by

$$M = 100 \times Abs\left(\frac{\frac{I_H}{I_L} - \frac{T_H}{T_L}}{S}\right) \%$$

Where:

$$I_H = High\ Side\ Current$$

$$I_L = Low\ Side\ Current$$

$$T_H = High\ Side\ Tap$$

$$\mathrm{T}_L = Low\ Side\ Tap$$

$$S = Smaller\ Ratio\ of\ \tfrac{I_H}{I_L} \,\&\, \tfrac{T_H}{T_L}$$

Continuing with the transformer in our example

$$I_H = \frac{75000}{\sqrt{3} \times 138} = 313.8A\ at\ 138KV$$

Choosing CT ratio as 400:5

$$I_H = \frac{313.8}{80} = 3.92A\ at\ CT\ Secondary \text{ And}$$

$$I_L = \frac{75000}{\sqrt{3} \times 69} = 627.6A\ at\ 69KV$$

Choosing CT ratio as 700:5

$$I_L = \frac{627.6}{160} = 4.48A\ at\ CT\ Secondary \text{ and}$$

$$I_L = \sqrt{3} \times 4.48 = 7.59A\ at \text{ restraint winding}$$

Now

$$\frac{I_H}{I_L} = \frac{3.92}{7.59} = 0.516$$

Let's assume that we select relay taps as

$$T_H = 1 \,\&\, T_L = 2$$

Therefore

$$\frac{T_H}{T_L} = \frac{1}{2} = 0.5$$

Using the mismatch equation

$$M = 100 \times Abs\left(\frac{\frac{I_H}{I_L} - \frac{T_H}{T_L}}{S}\right)$$

We get

$$M = 100 \times Abs\left(\frac{0.516 - 0.5}{0.5}\right) \qquad M = 3.2$$

Transformer differential relays typically have percentage characteristic in the range of 20 to 60%. Thus the mismatch factor of 3.2% is highly acceptable as there is an ample margin to account for unforeseen mismatch due to CT saturation and other errors.

Effect of Voltage Changing Taps

Power transformers typically have taps to change the nominal voltage ratio by ±10%. In this case, the procedure remains the same only that all the calculations are carried out at the nominal voltages. To the mismatch factor so obtained, half the adjustable range is added to obtain the final mismatch percentage.

In our example, considering the voltage adjustable range ±10% by tap, the final mismatch would be

$$M = 3.2 + 10 = 13.2\%$$

Section III

Gas Analysis

In oil immersed transformers different types of gases are generated due to different faults or due to degradation of different materials in the transformer. The major advantage of this gas evolution is that substantial amount of gas is evolved even for very incipient faults or material degradations. Thus analysis of this gas forms a very important means for monitoring the health of the transformer or for determining the fault in case of a fault.

The gas evolved is present dissolved in the oil. The gas is analyzed either online in case of such systems have been installed on the transformer. Alternatively, oil samples are periodically withdrawn and the oil is analysed in a lab. The periodicity depends on the size and criticality of the transformer. In case a Gas Accumulation Relay (Buchholz Relay) is installed. These gases do get accumulated in it. Gas samples or gas relays can be used in this case.

The implication of a few of the gases that may be observed in the oil is mentioned below. Actual cause analysis is done by observing the ratio in which these gases are observed and is beyond the scope of this report.

Hydrogen is generated by Corona or partial discharges. In conjunction with other gases observed with it the source of the discharge can be determined

Ethylene is associated with thermal degradation of oil. Trace quantities of methane and ethane are generated at 150° C. Ethylene is generated in significant quantities at 300° C.

Carbon dioxide &Carbon monoxide are evolved on when cellulose (paper) insulation gets over heated.

Acetylene is produced significant quantities by arcing in oil

References:

1. ***Protective Relaying Principles and Applications, 3rd Edition by J Lewis Blackburn & Thomas J Domin***
2. ***IEEE Std. C37.91-2000 IEEE Guide for Protective Relay Applications to Power Transformers***