Investigating Phase Over-Current (OC) Protection in Medium-Voltage networks

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Abstract—Overcurrent protection is protection against excessive currents or current beyond the acceptable current rating of equipment. It generally operates instantly. Short circuit is a type of overcurrent. Magnetic circuit breakers, fuses and overcurrent relays are commonly used to provide overcurrent protection. There is always a need to protect expensive power equipment. Protective relaying is a very important part of any electric power system that comes into play during trouble, fault or abnormal condition. The purpose is to isolate unhealthy part of electrical power system while the rest continue their normal operation. The entire electric power system from source to load centers is exposed and subject to natural hazards. The effects of these hazards are capable of interrupting normal operations of the system. Since these hazards cannot be prevented, precautions are taken to minimize or eliminate their effect on the system. The relay is a basic component of any protection scheme. The information (or signals) received from the power system actuates the relay, when necessary, to perform one or more switching actions. The signals are proportional to the magnitudes and phase angles of power system voltages and currents. When the relay receives these signals, it decides to close (or open) one or more sets of normally open (or closed) contacts, and consequently, the trip coil of a circuit breaker will be energized to open the power circuit. This paper investigates over-current relay protection scheme applied to medium-voltage electrical network. Methods of current and time grading have been applied in the coordination of the overcurrent relays in a radial network. Different time/current characteristics of relays such as the normal inverse (NI), very inverse (VI), and extreme inverse (EI) have been examined in order to obtain optimum discrimination.

Index Terms—Circuit Breaker, Fault, Overcurrent, Protection, Relay.

I. INTRODUCTION

The purpose of protection is (a) to ensure that the system provides an uninterrupted, quality, reliable and dependable services, (b) to make equipment operate as nearly as is possible at peak efficiency, (c) to protect equipment from fault, damage and other hazards, (d) ensure that there is no loss of life and property, and (e) guarantee system stability.

Protection is concerned with detection and isolation of a problem area in a system as quickly as possible from the rest of the power system while the rest are left in continuous service. In general, protection is that function in a power system designed primarily to prevent or minimize damage to equipment, life and property. Protection is the science, scheme and art of applying and setting of relays and fuses to provide maximum sensitivity to faults and undesirable conditions, but preventing their operation on permissible or tolerable condition. Equipment damage can occur if the fault current is high enough or present on the network for a long period [1], [2]. Transformers that supply distribution networks are exposed to a greater number of through faults [3], and this exposure reduces the life expectancy of the transformers [4], thereby increasing the financial risk of replacing the transformer as well as loss of revenue due to energy not supplied. There is also the risk of burn wounds [5] and contact incidents to human and animal life during fault conditions. To achieve the objective of all protective systems, the associated relays must meet the following basic requirements:

(i) Sensitivity- a protective scheme is said to be sensitive when it will operate for very small internal fault current.

(ii) Reliability- it is an assurance that the relay will perform correctly. In the event of fault in a zone, a protection of that zone should initiate a tripping of the associated circuit breaker (CB) to isolate that zone and only that zone from all supply. Reliability has two aspects: (a) Dependability- the assurance that the relay will operate correctly when required, (b) Security-the assurance that a relay will not operate incorrectly i.e. avoid unnecessary operation during normal day to day activities and for faults and problems outside the designated zone.

(iii) Selectivity/Discrimination – the protection must be able to distinguish between the internal faults in that zone and external fault outside that zone – Fig. 1.

It must correctly trip for an internal fault (F1) but refrain from tripping for external fault (F2), transient abnormal condition or any load.

Relay may operate in response to condition outside their primary protection zone (PPZ). In this case they provide back-up protection for that area outside their PPZ. Selectivity is achieved by applying and setting the relays which overreach other relays so that they operate as fast as possible for conditions within their primary zone but have delayed operation in their back-up zone.

(iv) Simplicity – Protective equipment and associated circuitry to achieve protection objective must be
simple, easy to handle, maintain and repair. Each added component must not be a potential source of trouble and added burden in maintenance.

(v) Speed – minimum fault duration must be ensured. In as much as it is very desirable that the protection isolate the trouble zone as rapidly as possible within zero time or very high speed operation, it must be realized that the faster the speed of operation, the higher the possibility of incorrect operation.

(vi) Economy – it must be relatively cheap, maximum protection at minimum cost.

The earliest form of protection was a fuse which today is in use on distribution circuits because of its simplicity and cheapness. It however suffers from the disadvantage of not only requiring replacement before power supply could be restored, but lacks the speed of operation, selectivity, discrimination and so on. So it has been replaced by protective relay. Hence, the common term ‘Protective Relaying’. Protective relays are essential part of all protective schemes. An electrical relay is a device that responds to its input information in a prescribed way and by its contacts operation causes an abrupt change in the associated control circuit.

![Fig. 2 Relay Schematic](image)

Fig. 2 shows an overcurrent relay contacts c₁ and c₂ to close the dc source for the trip coil (TC) to operate. Generally, circuit breakers (CBs) are designed to interrupt normal or short circuit currents. They will automatically open a circuit whenever the line current exceeds a preset limit. The tripping circuit is usually produced by an overload relay that can detect abnormal line condition. For example, the relay coil in Fig. 2 is connected to the secondary of a current transformer (CT), the primary carrying the line current of the phase connected. If the line current exceeds a preset limit, the secondary current causes the relay contacts c₁ and c₂ to close. As soon as they close, the tripping coil of the CB is energized by an auxiliary dc source. This causes the main line contacts to open, thus interrupting the current. Relays can be designed to respond to two inputs signals of current or voltage. Hence the operation of most relays is generally based on equation (1) [6]:

\[ T = K_a A^2 + K_b B^2 + K_c AB \cos(\theta - \tau) - K_s \]  

Where

\( K_a, K_b, \) and \( K_c \) are adjustable gain constants.

where \( K_s = \) adjustable spring constant  
\( \tau = \) adjustable phase constant  
\( A = \) rms value of input signal proportional to a system voltage or current  
\( B = \) a second input, similar to \( A \)  
\( \theta = \) phase shift between \( A \) and \( B \)

Operational conditions are:

\( T > 0 \); relay operates  
\( T < 0 \); relay does not operate  
\( T = 0 \); boundary between operation and non-operation.

II. OVER-CURRENT RELAY OPERATION

A. Detection of Fault Currents

To detect over-currents, overcurrent relays must have minimum operating currents above the rated currents of the circuits they protect [7]. Fig. 3 shows relay connections with current transformers. Since an earth fault relay is provided to protect the circuit, the associated overcurrent relays only need to operate in the event of three-phase faults or interphase faults.

![Fig. 3. Current transformers and Relay Connections](image)

A relay connected as in Fig. 3 (b) is not affected by normal balanced currents, and so can have a low current setting corresponding to 20% or less of the rated current of the protected circuit. For single input signal, overcurrent relay operation is based on the expression [8]:
\[ T = K_a A^2 - K_s \]

The relay will operate when \( T > 0 \) i.e.,

\[ |A| > \sqrt{\frac{K_s}{K_a}} \]

Or

\[ |A| > |I_p| \] relay operates

\[ |A| < |I_p| \] relay does not operate

Where \( I_p = \) pickup current

This is called instantaneous overcurrent relay. The value of the pickup current (or current setting, \( I_s \)) is adjustable by varying \( K_s \). \( I_p \) is expressed as a percentage of the relay’s current rating, \( I_n \), i.e., \( I_p \geq \alpha I_n \).

**B. Current grading**

Since instantaneous overcurrent relay monitors current level only, current grading is used to achieve discrimination during fault conditions on networks, where there will be a large difference in the ratio of fault current to rated current in sections of the network. Such situation can arise when there is a unit of relatively high impedance between two sections. In the network of Fig. 4, let us assume that the loads are equally rated at say 150A. Therefore, the main feeder would be rated at 600A.

![Power network](http://dx.doi.org/10.24018/ejers.2019.4.6.1307)

The base current for this network is:

\[ I_b = \frac{2000}{\sqrt{3}} \times 11 = 105 \text{ A} \]

For a three-phase fault at \( F_1 \), the fault current \( I_{F1} \) would be

\[ I_{F1} = \frac{1}{Z_{r1} + Z_{s1}} = 0.05 + 0.2 = 4 \text{ pu} \]

Fault level = 4 x 105 = 420 A

The current in the main feeder cable would be 4 x 4 = 16 pu

Fault level = 16 x 105 = 1680 A

For a phase-to-phase fault:

\[ I_{F1} = \frac{1}{Z_{s1} + Z_{r1} + Z_{s2} + Z_{s2}} = 0.05 + 0.2 + 0.2 = 2.13 \text{ pu} \]

Fault current = 2.13 x 105 = 224 A

The current in the main feeder cable would be 4 x 2.13 = 8.52 pu

Fault current = 8.52 x 105 = 895 A

OC protection pickup \( I_p \) defines the sensitivity of the protection element. This sensitivity should be set under network contingencies, which results in the lowest fault level that the protective devices should be sensitive to [9]. Where no earth path is included, a phase-to-phase fault should be used when setting the sensitivity, as this would result in the smallest phase current, and fault resistance can be included in the calculation so as to reduce fault level further, thereby improving the sensitivity of the protection device [10]. If a device is too sensitive, it can operate for load conditions [11]. There should be a trade-off between the sensitivity and the security of the protection system [11]. Thus, in the setting of the relays shown in Fig. 4, \( \alpha \) should lie between 1.1 and 1.5 (1.1 \( \leq \alpha \leq 1.5 \)).

For an example, let the CT ratio for the loads be equal to 200/1; and 800/1 for the main feeder.

The current setting of relay \( R_1 \) must be at least \( I_p = 1.1 \times 150 = 165 \text{ A} \)

Or \( I_p = \frac{165}{200} = 0.825 = \frac{0.825}{1} I_n \)

The current setting of relay \( R_2 \) must be at least \( I_p = 1.1 \times 600 = 660 \text{ A} \)

Or \( I_p = \frac{660}{800} = 0.825 = \frac{0.825}{1} \) \( I_n \)

Where \( I_n \) is relay current rating.

Instantaneous relays are simple, and should be used, with proper settings, whenever possible. However, current grading has limited application – often on load circuits of radially-connected networks [7].

**III. TIME GRADING**

Protection operating time is the main evaluation criterion in protection schemes [5]. It is generally agreed that operating time should be kept to a minimum. By reducing the operating time, the probability of a fault developing into a permanent fault is reduced, and hence the availability of the feeder is improved [5]. The reduction of operating time will also increase the life expectancy of the equipment and voltage quality on the system [12]. The operating time can be reduced by choosing an appropriate operating curve. The type of curves that should be applied varies.

**A. Definite operating time**

In a network, several sections connected in series may not have significant impedances at their junctions and the source impedance may be much greater than the impedances of the sections. In such cases, there will be little difference between the levels of the currents which will flow for faults in different points on the network, and so correct discrimination can be obtained during fault conditions by using relays set to operate after different time delays [7],[13]. The timing differences between the relays associated with adjacent sections is made sufficient to allow the appropriate circuit breaker to open and clear the fault in its section before the relay associated with the adjacent
section nearer to the source could initiate the opening of its CB. In practice, grading intervals of the order of 0.5 s are adequate, i.e. the operating times of the relays increase by 0.5s as we approach the source as shown in Fig. 5b.

![Diagram of electrical network](image)

\[ Z_s + Z_t > Z_1 + Z_3 \]

(a)

Since discrimination is dependent only on time grading, the individual overcurrent relays can be set to any desired levels above the rated currents of their circuits. The disadvantage of relays with definite time lag is that the relays nearer the sources in networks with several sections connected in series may have unacceptably high operating times for faults in the sections they protect; such faults should persist for short periods. So definite time lag relays should be used in networks with relatively few series-connected sections.

**B. Using inverse time/current characteristics relays for Discrimination**

The shortcoming of the definite-time grading can be overcome by using relays with inverse time/current characteristics because the large fault currents will be interrupted more quickly. In Fig. 6a the impedance, \( Z_s \) between the source of e.m.f. \( (E_s) \) and the input end of the protected section of the network is small compared with the impedance \( Z_{ps} \) of the protected section. In this case, there is significant variation in fault levels \( (I_n \) and \( I_t \) with their positions on the protected section. \( Z_{ps} > Z_s \), and so, \( I_n > I_t \). Therefore, discrimination would be better achieved using relays with inverse time/current characteristics because the large fault currents will be interrupted more quickly. The behaviour of such relays is illustrated in Fig. 6b. Better discrimination can also be achieved in applications where the protected sections have relatively low impedance and where, as a result, the currents during faults are not greatly affected by the fault position. Thus the greater sensitivity of such relays to such current differences would be beneficial [7].

![Diagram of electrical network](image)

Fig 5 Discrimination achieved by definite time-graded relays

This type of relay does not operate below certain minimum current levels and it also has fixed or definite minimum operating times above certain current levels. As the current increases the operating time decreases. The characteristic appears to approach a definite minimum time. Hence it is known as Inverse Definite Minimum Time (IDMT) relay. By an IDMT type characteristic, there is the benefit of fast operating times at high fault currents and moderate operating times at low fault currents [14]. Apart from the most commonly used IDMT curve - the ‘normal inverse (NI)’ (BS 142) type, there are also the ‘very inverse (VI)’ and the ‘extremely inverse (EI)’ types. The EI curve has an advantage over the NI curve by reducing the operating time, providing better grading with the equipment damage curves, and improved grading for fuses. The reduction in operating time contributes to the philosophy of minimizing the let-through energy and managing the voltage dips [5]. The EI curve is also used for the auto-recloser fuse grading [15]. The disadvantage of the EI curve is that it takes a longer time to operate than the NI curve at low fault levels (close to the pickup current). The increase in operating time with the reduction in fault level is faster than that of the NI curve due to the steep gradient of the curve [5]. In recent times the general time/current relationship over the normal operating range has been expressed in the form of equations (4) and (5) [7], [16]:

\[ T = \frac{k}{\left( \frac{I}{I_r} \right)^a - 1} \]  \hspace{1cm} (4)

Or

\[ T = \frac{3}{\log\left( \frac{I}{I_r} \right)} \]  \hspace{1cm} (5)

where

- \( T \) = theoretical operating time
- \( I \) = fault current
- \( I_r \) = relay set current
- \( k \) and \( a \) = constants characterizing particular relays

The values of \( k \) and \( a \) for the various IDMT curves are given in table 1.
In these relays tripping time is inversely proportional to the fault current magnitude. The tripping time, \( t \) is given as:

\[
t = \frac{k}{\left(\frac{I}{I_s}\right)^\alpha - 1}
\]

\[
t = TXT_p
\]

where \( T_p \) = time multiplier setting (TMS)

The following factors are considered when the settings of IDMT relays are determined:

(i) Variation from the ideal characteristics of the relays for which an allowance in time of 0.1s is used for calculation purpose.

(ii) Relay overshoot time – an upstream relay may overrun after a fault is cleared by a downstream circuit-breaker (CB).

(iii) CB operating time – 0.15s

(iv) Current transformer error.

To allow for these factors a discriminating time interval of 0.4s or 0.5s between adjacent relays is allowed. This time interval between relays for discrimination or coordination purposes is called coordinating time interval (CTI) [17]. As stated earlier, the goal is to allow enough time for the relay and breaker closest to the fault to clear the fault from the system before the relay associated with the adjacent section nearer to the source could initiate the opening of its circuit breaker.

These applications of the over-current relay can be illustrated by the network of Fig. 7.

### Table I: Values of \( k \) and \( \alpha \) for the Various IDMT Curves

| Section                  | \( k \) | \( \alpha \) |
|--------------------------|--------|-------------|
| Normal Inverse           | 0.14   | 0.02        |
| Very Inverse             | 13.5   | 1.0         |
| Extremely Inverse        | 80     | 2.0         |

Network parameters:
- Source network: 20MVA, 11kV
- \( T_1 \): 2MVA, 11/3.3KV, 7%
- \( T_2 \): 500KVA, 3.3/0.415KV, 6%
- Lines 1, 2, 3: 0.02 \( \Omega \)/ph
- Lines 5 and Line 8: 0.2 \( \Omega \)/phase

Positive and negative sequence impedances are assumed equal.

- Reactance of source = 1 \( p.u. \)
- Reactance of \( T_1 \) = \( \frac{20}{2} \times 0.07 = 0.7 \ p.u. \)
- Reactance of Line 5 and line 8:
  - \( Z_b = \frac{3.3^2}{20} = 0.5445 \ \Omega \)
  - \( Z_{pu} = \frac{0.2}{0.5445} = 0.3673 \ pu \)
- Reactance of \( T_2 \) = \( \frac{20}{0.5} \times 0.06 = 2.4 \ pu \)
- Reactance of Line 1:
  - \( Z_b = \frac{0.415^2}{20} = 0.0086 \ \Omega \)
  - \( Z_{pu} = \frac{0.2}{0.0086} = 2.3256 \ pu \)
- Total reactance = 7.1602 pu
- Base current: \( I_b = \frac{20000}{\sqrt{3} \times 11} = 1050 \ A \)

Line 8 and line 5: \( I_b = 3.3333 \times 1050 = 3500 \ A \)
- Line 1: \( I_b = 7.9518 \times 3500 = 27831 \ A \)
- The fault currents, \( I_{F1}, I_{F2}, I_{F3}, I_{F4}, I_{F5} \) and \( I_{F5} \) for a three-phase short-circuit are:

  - \( I_{F1} = \frac{1}{7.16} \times 27831 = 3887 \ A \)
  - \( I_{F2} = \frac{1}{4.8344} \times 27831 = 5757 \ A \)
  - \( I_{F3} = \frac{1}{2.4344} \times 3500 = 1438 \ A \)
  - \( I_{F4} = \frac{1}{2.0671} \times 3500 = 1693 \ A \)
  - \( I_{F5} = \frac{1}{1.6998} \times 3500 = 2059 \ A \)

Allowing about 91\% loading of \( T_1 \), the ratings of the lines are:
- Lines 1, 2, and 3 = 200A; Line 5 = 75A; Line 8 = 250A.
- Allowing 100\% setting, the current settings of the relays should be as follows: \( R_1 = 200A; R_5 = 75A; R_8 = 250A; R_{10} = 96A \). It can be seen that with instantaneous over-current relays, if current of 400A, for example, due to overload flows in line1, relay \( R_1 \) only will trip, giving correct discrimination. Thus, instantaneous relays can be used to protect all the loads and each relay should be set to operate at a current somewhat above the rated value of its load. But for fault current of 3888A at point \( F_1 \), \( R_{10} \) would operate instantly since this is about 1.5 times its setting. This is undesirable. So it is necessary to add time discrimination with time settings increasing towards the source, as shown in Fig. 5b.

So, using definite time-graded relays, the time settings of the relays \( R_1, R_5, R_8 \), and \( R_{10} \) are 0.5s, 1.0s, 1.5s, and 2.0s respectively. Thus for the protection of a network containing several sections in series as shown in Fig.5a, the relay nearest to the source may have unacceptably high operating times for faults in the sections they protect. In other words, the tripping time for a fault near the power source may be dangerously high. This is because the current level...
associated with such faults is large and destructive, and must be removed very quickly. Therefore, relays with definite time lags are suitable for the protection of networks with relatively few series-connected sections only. Hence the use of inverse time/current characteristics relays is most appropriate in this network.

We apply IDMT relay with NI characteristic given as:

$$ t = \frac{0.14}{\left(\frac{I}{I_S}\right)^{0.02}} - 1 $$

(8)

So for relay R₁ in Fig. 7:

$$ I = 3887 \text{A (fault at point } F_1), I_s = 200 \text{A, } t =0.5s $$

$$ T = \frac{0.14}{3887^{0.02}} = 2.29 \text{ s} $$

$$ T_p = \frac{t}{T} = \frac{0.5}{2.29} = 0.22 $$

For three-phase fault at point F₂, I = 5756A. This is the maximum possible short circuit current that can flow in line1, i.e., the fault level. Therefore, the time, t which relay R₁ takes to interrupt this current is computed as:

$$ t = \frac{0.14}{5756^{0.02}} \times 0.22 = 0.44 \text{ s} $$

So the tripping time of R₁ has now been reduced from 0.5s to 0.44s

For R₂: Iₖ = 75A; t = 0.44 + 0.5 = 0.94s; Tₚ = 0.31

The maximum faults current which relay R₂ would have to deal with is 1438A. The operating time of R₃ for this current is 2.3 x 0.31 = 0.713

For R₃: Iₖ =250A; t = 0.71 + 0.5 = 1.21s; Tₚ = 0.31

The fault current level of line8 is 1693. The operating time of R₅ for this current is 3.59 x 0.31 = 1.11s

For R₅: Iₖ =96A; t = 1.11 + 0.5 = 1.61s; Tₚ = 0.39

The maximum fault current that would go through relay R₁₀ is 618A. The operating time of R₁₀ for this current is 3.69 x 0.39 = 1.44s.

Relay settings are summarized in table 2.

| Relay  | Iₖ (A) | Tₚ  |
|-------|-------|-----|
| R₁    | 200   | 0.22|
| R₂    | 75    | 0.31|
| R₃    | 250   | 0.31|
| R₅    | 96    | 0.39|

The tripping times of the relays for the various fault currents are shown in table 3, and the trip time/current curves of the relays are shown in Fig. 8

One of the drawbacks of a protection system using IDMT relay with NI characteristics is that the nearer the fault to the source of power, the slower the overall fault clearance time. If there is a large difference in fault level at various parts of the system, relays with VI characteristics can be applied to alleviate the problem. The characteristics are in Fig. 9.

Carrying out similar computations for IDMT relay with VI characteristic we obtain the following results:

$$ t = \frac{13.5}{\left(\frac{I}{I_S}\right)^{0.02}} - 1 $$

(9)

Results of calculations are shown in tables 4, table 5, and Fig. 9.

| Fault location | Fault current, I (A) | Trip time, t (s) |
|----------------|---------------------|-----------------|
| F₁             | 3887                | 0.5 1.14 3.21 6.41 |
| F₂             | 5756                | 0.44 0.94 2.02 3.32 |
| F₃             | 1437                | 0.71 1.22 1.79 |
| F₄             | 1693                | 1.11 1.61 |
| F₅             | 2058                | 1.44 |

TABLE III: FAULT CURRENTS AND TRIP TIMES OF RELAYS

| Fault location | Fault current, I (A) | Trip time, t (s) |
|----------------|---------------------|-----------------|
| F₁             | 3887                | 0.5 1.3 4.52 10.23 |
| F₂             | 5756                | 0.33 0.83 2.28 4.28 |
| F₃             | 1437                | 0.39 0.91 1.55 |
| F₄             | 1693                | 0.75 1.26 |
| F₅             | 2058                | 0.99 |

TABLE IV: SUMMARY OF SETTINGS

| Relay  | Iₖ (A) | Tₚ  |
|-------|-------|-----|
| R₁    | 200   | 0.68|
| R₂    | 75    | 0.53|
| R₃    | 250   | 0.32|
| R₅    | 96    | 0.4 |

TABLE V: FAULT CURRENTS AND TRIP TIMES OF RELAYS

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Similarly, for IDMT relay with EI characteristic given as:

\[ t = \frac{80}{I} \left( \frac{I}{I_S} \right)^2 - 1 \]  

(10)

We have the following results:

| Relay | \( I_S \) (A) | \( T_p \) |
|-------|----------------|----------|
| R_1   | 200            | 2.35     |
| R_5   | 75             | 0.84     |
| R_8   | 250            | 0.27     |
| R_10  | 96             | 0.33     |

### TABLE VII: Fault currents and trip times of relays

| Fault location | Fault current, \( I \) (A) | Trip time, \( t \) (s) |
|----------------|-----------------------------|------------------------|
| \( F_1 \)      | 3887                        | R_1: 0.5, R_5: 0.73,  R_8: 0.67, R_10: 0.48 |
| \( F_2 \)      | 5756                        | R_1: 0.23, R_5: 0.72,  R_8: 0.67, R_10: 0.48 |
| \( F_3 \)      | 1437                        | R_1: 0.18, R_5: 0.72,  R_8: 0.98, R_10: 0.65 |
| \( F_4 \)      | 1693                        | R_1: 0.48, R_5: 0.72,  R_8: 0.98, R_10: 0.65 |
| \( F_5 \)      | 2058                        | R_1: 0.65, R_5: 0.72,  R_8: 0.98, R_10: 0.65 |

When relays are to discriminate with fuses, a much closer agreement with the fuse characteristic is obtained by relays with EI characteristic.

Fig. 11, Fig 12, Fig 13, and Fig 14 show the time/current characteristic of relays R_1, R_5, R_8, and R_10 respectively for NI, VI, and EI curves, where the time multiplier setting (TMS) is unity.

### C. Let-through Energy

Let-through energy is the amount of energy that is transmitted to a fault before the fault current is interrupted [18], [19]. It is proportional to \( I^2 t \). This energy can heat the
equipment beyond its thermal limit. Exceeding the equipment energy limits influences the feeder reliability negatively and will likely result in equipment damage, unnecessary outages, capital expenditure, and loss of revenue, and so the let-through energy has to be considered in the feeder protection [18]. As shown earlier in Fig. 7, the fault current is dependent on the impedance to the fault position and cannot be changed via protection setting. So this let-through energy consideration is additional to the traditional time-current approach. The protection operating time has to be reduced to reduce the let-through energy during a fault. Thus, using relays in which operation occurs at a constant $I^2$ values would enable better discrimination to be achieved.

All the equipment installed in a network has a certain level of current it can withstand for a specific interval. This interval is known as the short time rating of the equipment; it is the length of time equipment, such as a conductor, can carry a current above its emergency rating, mechanically elongate, and return to its normal mechanical position. This is also known as an elastic deformation. The elastic region is a function of the materials modulus of elasticity, or the Young’s Modulus. Exceeding the elastic deformation region will drive the conductor material into a plastic deformation region in which case the conductor will not be able to return to its previous mechanical form, and so is mechanically damaged. It will sag, and after fault clearance, it will remain in its elongated form. This condition of the conductor reduces ground clearances and creates room for some other undesirable effects, like conductors clashing under adverse weather conditions [5]. The let-through energy capability of a conductor can be calculated by equation (11) [20]:

$$\left( \frac{I}{1000A} \right)^2 t = K \log_{10} \left( \frac{T_2 + \lambda}{T_1 + \lambda} \right)$$

(11)

where

- $I$ is the fault current (A),
- $t$ is the fault duration (s),
- $A$ is the cross-sectional area of the conductor (kcmil),
- $T_2$ is the conductor temperature from the fault ($^\circ$C),
- $T_1$ is the conductor temperature before the fault ($^\circ$C),
- $K$ is the conductor constant that accounts for the conductor resistivity, density, and specific heat,
- $\lambda$ is the inferred temperature of zero resistance ($^\circ$C).

At a lower fault current than the one determined by using Eq. (15), the equipment can withstand the thermal effect of the fault current for a longer period before it gets damaged.

D. Voltage Dips

A voltage dip is a short duration reduction in rms voltage which can be caused by a short circuit, overload or starting of electric motors. A voltage dip happens when the rms voltage decreases between 10 and 90 percent of nominal voltage for one-half cycle to one minute. Voltage dip or voltage sag is a reduction in the RMS voltage for a short duration, after which the voltage regains its normal operating value - it is the most common power quality event [21]. It can be caused by the starting of big loads, though network faults are the major causes [22]. Voltage dip curves serve as standards and guides for customer equipment voltage dip ride-through criteria. Some of these curves include Information Technology Industry Council (ITIC) curve for IT-based equipment, Computer Business Equipment Manufacturers Association (CBEMA) curve, ANSI curve (standardized as the IEEE 446) [23]. In South Africa, the NRS048-2 Quality of supply standard is used. It consists of a dip table to categorize voltage dips in terms of magnitude and duration [24]. The voltage dip magnitude is a function of the source impedance, fault location, type of fault, and fault resistance, and cannot be changed by changing relay settings; it can only be changed by investing large amounts of capital in the network [25]. It is more cost effective to dip-proof customer equipment than to improve the voltage dip magnitude of a distribution network. The voltage dip duration is influenced by the protection operating time [26].

IV. CONCLUSION

In this paper, overcurrent protection in electric network has been investigated, showing how overcurrent relays in the system can be coordinated for proper discrimination. It has been shown that optimum discrimination can be obtained by using relays with inverse time/current characteristics, comprising of NI, VI, and EI characteristics. It means that tripping time is inversely proportional to fault current. Relays with these characteristics are known as IDMT relays. When applying these relays to a power system, the possibilities of using the definite-time characteristic should be considered first as this will give fast operation over the whole range of fault level. If, to obtain discrimination, the setting is considered too high then the NI characteristic will improve matters. If there is not enough improvement, examine the VI and finally the EI characteristic. Protections operating time, protection element pick-up current sensitivity, let-through energy, and voltage-dip effect have been identified as four key elements that should be evaluated in assessing the overcurrent protection of installed equipment. The considerations of let-through energy and voltage-dip effect provide guidance toward the maximum allowable fault clearing time for network faults. The pick-up sensitivity criterion is introduced to ensure that the protection will be able to detect phase faults in the network.

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