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Abstract—**Cogeneration from renewable energy sources has been universally proposed as a partial alternative to the solution of our nation's energy problems. New technical, safety, and operational problems are introduced when this generation is placed into a distribution grid. Addressed is the problem of distribution system protection with the introduction of cogeneration sources and the changes and modifications which may be required in the application of present-day protection devices. A sample system is considered, and system protection and coordination with and without cogeneration has been calculated through a digital fault and system protection coordination program. The results indicate through the study of several systems that additional coordination and protection considerations will be required when sizable cogeneration sources are introduced to maintain a high degree of reliability and service continuity.**

INTRODUCTION

DECENTRALIZED cogeneration is a concept whereby customer-owned equipment is placed on the user side of the meter. Available energy sources for obtaining such generation are solar energy, wind power, low-head hydro, biomass conversion, fuel cells, and geothermal energy. Although the technologies associated with these energy sources are very different, they all tend to serve the common goal of switching to renewable energy sources.

Despite the favorable energy addition of decentralized generation, introduction of these technologies into the distribution system significantly complicate distribution planning and operating practices. Harmonic generation resulting from the introduction of interface devices such as inverters, the effects of transient voltage dips, and voltage regulation due to large excitation currents required by induction generators on the system need to be investigated, as well as the problem involving personnel safety.

The problem of system protection is addressed in this paper by the introduction of a single generator into a sample distribution system having ten nodes and nine line sections. Development of overcurrent protection schemes using a combination of existing and new distribution protection devices is considered.

SYSTEM CONSIDERATIONS

The first step in overcurrent protection of a power distribution system is to determine fault current levels at critical locations. Networks containing radial or loop interconnections, where multiple current paths exist between sources and loads, require a knowledge of symmetrical components for fault current calculations.

In conventional radial distribution systems, only a single current path exists between the source and each node, resulting in rather simplified calculations. Introduction of sizable decentralized generators into the distribution system may require multiple current paths between sources and nodes for better system operation. This implies an interconnected distribution system with loop capabilities very much like a transmission grid. In addition to the normal fault current normally supplied by the substation, the decentralized generation adds to the fault current, and the contribution of each generator as well as the substation must be considered.

Following a fault condition, a transient fault current may be flowing which could have an asymmetric rms value as high as 1.766 times the steady-state rms fault value depending on 1) where in the voltage waveform the fault occurs and 2) the X/R ratio of the system. Using the asymmetrical fault current values for selecting protection devices can result in selection of ratings much larger than necessary. This is true since protective devices do not interrupt for a number of cycles after fault initiation and much of the asymmetry has disappeared, and the device is essentially interrupting a symmetrical current. In this paper symmetrical fault currents will be calculated and used for selection and coordination of protective devices.

SHORT CIRCUIT CALCULATIONS USING THE BUS IMPEDANCE METHOD

Algorithms [1] applicable to the three-phase bus impedance matrix formation are used to calculate the fault current values in both the loop and radial distribution system with decentralized generators. Total fault current at each node is calculated considering the contribution of the substation and each generator. Three-phase, line-to-ground, line-to-line, and line-to-line-to-ground faults are considered in the analysis. The following assumptions are made for fault study purposes.

1) The substation and decentralized generators are represented by a source impedance in series with a voltage source.
2) The prefault current is neglected and the voltage at each generation node of the circuit will be assumed to have a nominal system voltage of 1 pu.

A three-phase interconnected distribution system with decentralized generators is represented in Fig. 1. Assuming a fault at bus p, application of Thevenin's theorem results in the system representation as shown in Fig. 2. Single- and two-phase lines are analyzed as if they were three-phase,

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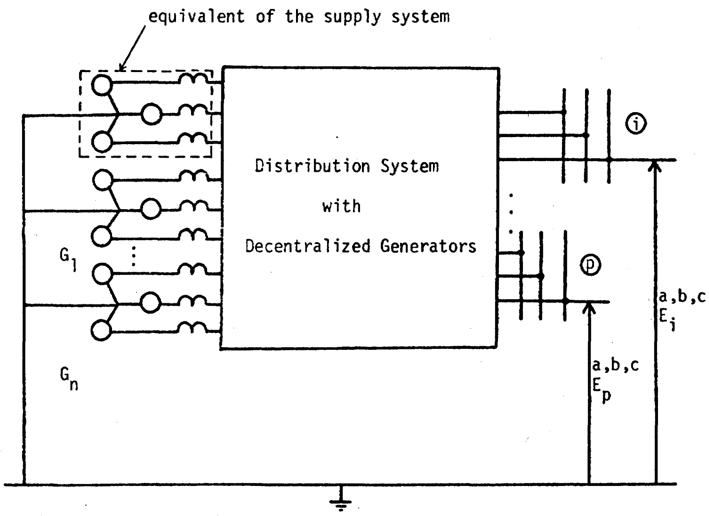

Fig. 1. Three-phase distribution system with decentralized generators (G_1-G_n) for fault studies.

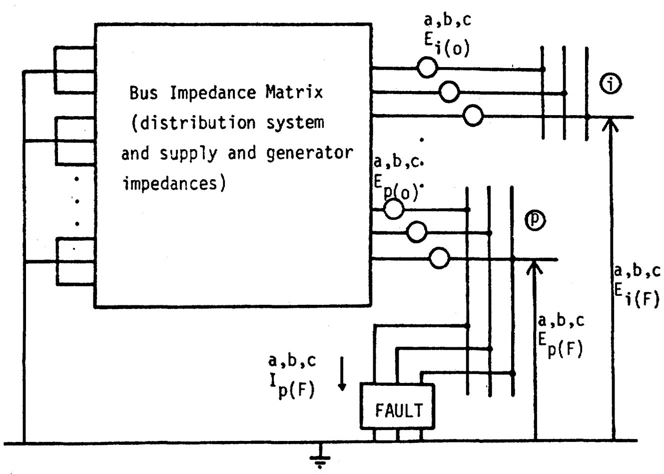

Fig. 2. Three-phase system with decentralized generators with fault at node p.

and only the fault current values for the possible types of faults are calculated. This is justified because the mutual coupling between phases is already taken into account in calculating the sequence impedances, and no mutually coupled elements exist in the system. The impedance matrix contains generator and substation internal impedances.

The performance matrix equation of the system under fault conditions is

$$E^{a,b,c}_{\mathrm{bus}(F)} = E^{a,b,c}_{\mathrm{bus}(0)} - Z^{a,b,c}_{\mathrm{bus}} I^{a,b,c}_{\mathrm{bus}F} \tag{1}$$

where

$E^{a,b,c}_{\mathrm{bus}(F)}$ unknown voltage vector during the fault having elements,
$E^{a,b,c}_{i(F)}$ $i = 1, \cdots, n$, three-phase bus voltage vectors,
$E^{a,b,c}_{\mathrm{bus}(0)}$ known bus voltage vector prior to the fault having elements $E^{a,b,c}_{i(0)}$ for $i = 1, \cdots, n$,
$I^{a,b,c}_{\mathrm{bus}(F)}$ unknown bus current where the only entry is $I^{a,b,c}_{P(F)}$ for a fault at bus p,
$Z^{a,b,c}_{\mathrm{bus}}$ three-phase bus impedance matrix whose elements are matrices of dimension 3 X 3.

Eq. (1) can then in general be written as

$$E^{a,b,c}_{i(F)} = E^{a,b,c}_{i(0)} - Z^{a,b,c}_{ip} I^{a,b,c}_{p(F)}, \quad i = 1, 2, \cdots, n. \tag{2}$$

It can be shown by the introduction of the admittance matrix $Y^{a,b,c}_F$ and the primitive matrix $Z^{a,b,c}_{pp}$ that (2) can be written as

$$E^{a,b,c}_{i(F)} = E^{a,b,c}_{i(0)} - Z^{a,b,c}_{ip} Y^{a,b,c}_F \cdot (U + Z^{a,b,c}_{pp} Y^{a,b,c}_F)^{-1} E^{a,b,c}_{p(0)}. \tag{3}$$

These relationships can be used for both balanced and unbalanced three-phase networks. If the fault is unsymmetric, a power invariant transformation can be introduced to produce symmetrical components which in essence diagonalize the impedance matrix, thus reducing the performance equations of each three-phase element to three independent equations:

$$E^{0,1,2}_{pq} = T_s^{-1} E^{a,b,c}_{pq}$$
$$I^{0,1,2}_{pq} = T_s^{-1} I^{a,b,c}_{pq}$$
$$Z^{0,1,2}_{pq} = T_s^{-1} Z^{a,b,c}_{pq} T_s$$

where

$E^{0,1,2}_{pq}$ sequence voltage vector for the element pq,
$I^{0,1,2}_{pq}$ sequence current vector,
$Z^{0,1,2}_{pq}$ diagonalized sequence impedance matrix, and

$$T_s = \frac{1}{\sqrt{3}} \begin{bmatrix} 1 & 1 & 1 \\ 1 & \alpha^2 & \alpha \\ 1 & \alpha & \alpha^2 \end{bmatrix}; \quad T_s^{-1} = \frac{1}{\sqrt{3}} \begin{bmatrix} 1 & 1 & 1 \\ 1 & \alpha & \alpha^2 \\ 1 & \alpha^2 & \alpha \end{bmatrix},$$

$$\alpha = e^{+j2\pi/3}.$$

By introduction of this transformation, (3) can be written as

$$E^{0,1,2}_{i(F)} = E^{0,1,2}_{i(0)} - Z^{0,1,2}_{ip} Y^{0,1,2}_F (U + Z^{0,1,2}_{pp} Y^{0,1,2}_F)^{-1} \cdot E^{0,1,2}_{p(0)}, \quad i \neq p. \tag{4}$$

Substituting the appropriate matrices for $Z_F^{0,1,2}$ or $Y_F^{0,1,2}$ and simplifying result in the final equations used for fault current and voltage calculations in the computer program.

Current and voltage relationships for a three-phase to ground fault as bus p are then

$$I_{p(F)}^{0,1,2} = \frac{\sqrt{3}}{z_F + z_{pp}^{(1)}} \begin{bmatrix} 0 \\ 1 \\ 0 \end{bmatrix} \qquad E_{p(F)}^{0,1,2} = \frac{\sqrt{3}}{z_F + z_{pp}^{(1)}} \begin{bmatrix} 0 \\ z_F \\ 0 \end{bmatrix}$$

$$E_{i(F)}^{0,1,2} = \begin{bmatrix} 0 \\ \sqrt{3} \\ 0 \end{bmatrix} - \frac{\sqrt{3}}{z_F + z_{pp}^{(1)}} \begin{bmatrix} 0 \\ z_{ip}^{(1)} \\ 0 \end{bmatrix}, \qquad i \neq p.$$

Current and voltage relations for line-to-line fault at bus p are

$$I_{p(F)}^{0,1,2} = \frac{\sqrt{3}}{2z_{pp}^{(1)} + z_F} \begin{bmatrix} 0 \\ 1 \\ 1 \end{bmatrix} \qquad E_{p(F)}^{0,1,2} = \frac{\sqrt{3}}{2z_{pp}^{(1)} + z_F} \cdot \begin{bmatrix} 0 \\ z_{pp}^{(1)} + z_F \\ z_{pp}^{(1)} \end{bmatrix}$$

$$E_{i(F)}^{0,1,2} = \frac{\sqrt{3}}{2z_{pp}^{(1)} + z_F} \begin{bmatrix} 0 \\ 2z_{pp}^{(1)} + z_F - z_{ip}^{(1)} \\ z_{ip}^{(1)} \end{bmatrix}, \qquad i \neq p.$$

Current and voltage relations for line-to-ground fault at bus p are

$$I_{p(F)}^{0,1,2} = \frac{\sqrt{3}}{z_{pp}^{(0)} + 2z_{pp}^{(1)} + 3z_F} \begin{bmatrix} 1 \\ 1 \\ 1 \end{bmatrix}$$

$$E_{p(F)}^{0,1,2} = \frac{\sqrt{3}}{z_{pp}^{(0)} + 2z_{pp}^{(1)} + 3z_F} \begin{bmatrix} -z_{pp}^{(0)} \\ z_{pp}^{(0)} + z_{pp}^{(1)} + 3z_F \\ -z_{pp}^{(1)} \end{bmatrix}$$

$$E_{i(F)}^{0,1,2} = \begin{bmatrix} 0 \\ \sqrt{3} \\ 0 \end{bmatrix} - \frac{\sqrt{3}}{z_{pp}^{(0)} + 2z_{pp}^{(1)} + 3z_F} \cdot \begin{bmatrix} z_{ip}^{(0)} \\ z_{ip}^{(1)} \\ z_{ip}^{(1)} \end{bmatrix}, \qquad i \neq p.$$

Current and voltage relations for line-to-line-to-ground fault at bus p are

$$I_{p(F)}^{0,1,2} = \frac{\sqrt{3}}{(z_{pp}^{(1)})^2 + 6z_F z_{pp}^{(1)} + 2z_{pp}^{(0)} z_{pp}^{(1)}} \cdot \begin{bmatrix} -z_{pp}^{(1)} \\ z_{pp}^{(1)} + 3z_F + z_{pp}^{(0)} \\ -(z_{pp}^{(0)} + 3z_F) \end{bmatrix}$$

$$E_{p(F)}^{0,1,2} = \frac{\sqrt{3}}{(z_{pp}^{(1)})^2 + 6z_F z_{pp}^{(1)} + 2z_{pp}^{(0)} z_{pp}^{(1)}} \cdot \begin{bmatrix} z_{pp}^{(1)}(z_{pp}^{(0)} + 3z_F) \\ z_{pp}^{(1)}(z_{pp}^{(0)} + 3z_F) \\ z_{pp}^{(1)}(z_{pp}^{(0)} + 3z_F) \end{bmatrix}$$

$$E_{i(F)}^{0,1,2} = \begin{bmatrix} 0 \\ \sqrt{3} \\ 0 \end{bmatrix} - \frac{\sqrt{3}}{(z_{pp}^{(1)})^2 + 6z_F z_{pp}^{(1)} + 2z_{pp}^{(0)} z_{pp}^{(1)}} X \cdot \begin{bmatrix} -z_{pp}^{(1)}(z_{ip}^{(0)} + 3z_F) \\ z_{ip}^{(1)}(z_{pp}^{(1)} + 3z_F + z_{pp}^{(0)}) \\ -z_{ip}^{(0)}(z_{pp}^{(0)} + 3z_F) \end{bmatrix}, \qquad i \neq p.$$

DESCRIPTION OF AN EXAMPLE DISTRIBUTION SYSTEM

A radial distribution network to be considered is represented in Fig. 3 by a single line diagram. The system consists of a multigrounded neutral 12.47/7.2-kV feeder supplied from a 46-kV-12.47/7.2-kV 6-MVA transformer with an impedance of 1.1 + j5.9 percent on nameplate rating. The characteristics of the feeder conductors are given in Table I.

The three-phase MVA fault level at the substation is assumed to be 1500 MVA. Selecting a base of 10 MVA will result in a source reactance of +j0.0066 pu. Zero sequence source impedance will not be reflected to the secondary due to the delta wye connection of the substation transformer. The transformer positive and zero sequence impedances are assumed the same and on the 10-MVA base equal to 0.0183 + j0.0983 pu. A transformer exists in line section 7 whose positive sequence impedance is 0.0246 + j0.1614 pu on the 10-MVA base. Its zero sequence impedance again is assumed equal to the positive sequence impedance.

PROTECTIVE DEVICE SELECTION AND COORDINATION PRACTICE FOR THE RADIAL DISTRIBUTION SYSTEM

Coordination principles for conventional distribution systems are applied to the example distribution system, and the protection system components are calculated using a coordination computer program. The first step in applying overcurrent protection to the distribution system is to describe the system completely by identifying the following parameters and conditions. 1) Steady-state load currents are required. 2) Maximum and minimum fault current levels must be obtained, and results from the computer program are given in Fig. 4. The symbol $\frac{X}{Y}$ is used on Fig. 4 where X indicates the maximum available symmetric fault current and Y indicates the minimum available fault current in amperes (rms). 3) Load and load distribution require complete knowledge of the system so that future load growth prediction can be taken into account at every location on the feeder where over-current protection devices might be installed. For the sample problem an annual load growth rate of three percent over a five-year time frame is assumed. Thus the ultimate load currents will be increased by $(1.03)^5 = 1.16$ and given in Table II.

In all protection schemes isolation of the smallest amount

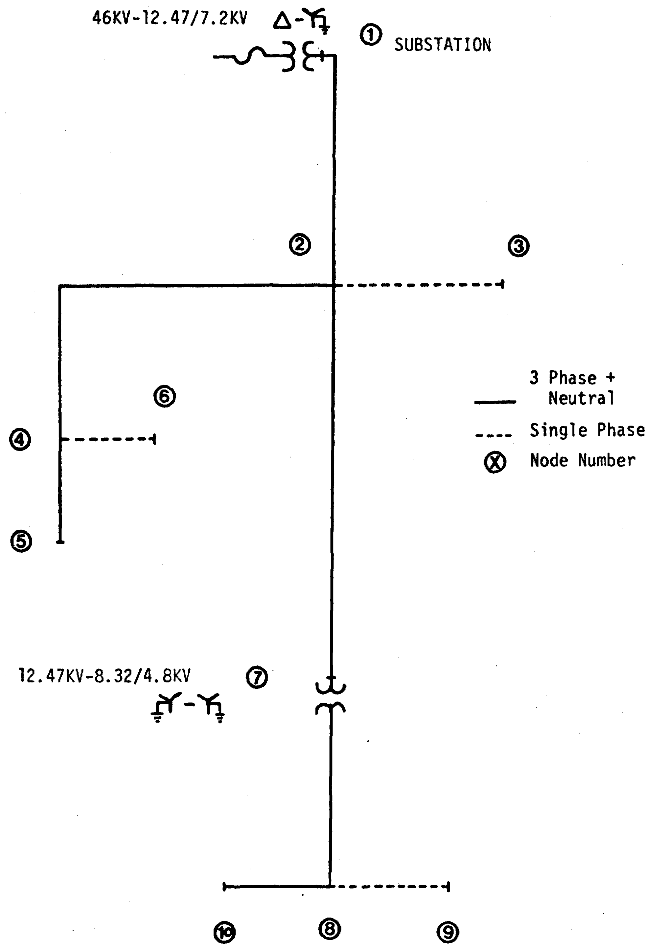

Fig. 3. Circuit configuration of distribution system studied.

TABLE I
NETWORK CONDUCTOR SPECIFICATIONS

Line Section	End Nodes	Length 1000 feet	Conductor Size	Neutral Size	Positive Sequence R	Positive Sequence X	Zero Sequence R	Zero Sequence X
1	1-2	15.603	4/0 ACSR	#2 ACSR	0.1121	0.1453	0.2447	0.4652
2	2-3	8.675	#6 ACSR	#6 ACSR	0.7538	0.1627	0.8722	0.5576
3	2-4	31.123	#2 ACSR	#4 ACSR	0.3201	0.1612	0.4525	0.5231
4	4-5	7.189	#6 ACSR	#6 ACSR	0.7538	0.1627	0.8722	0.5576
5	4-6	6.798	#6 ACSR	#6 ACSR	0.7538	0.1627	0.8722	0.5576
6	2-7	27.909	#2 ACSR	#4 ACSR	0.3201	0.1612	0.4525	0.5231
7	7-8	15.000	#2 ACSR	#4 ACSR	0.3201	0.1612	0.4525	0.5231
8	8-9	8.050	#6 ACSR	#6 ACSR	0.7538	0.1627	0.8722	0.5576
9	8-10	7.570	#6 ACSR	#6 ACSR	0.7538	0.1627	0.8722	0.5576

of load, thus minimizing system outage, is essential. This selectivity requires correct protection devices and proper coordination. Criteria considered for protection of the example system and used in the computer coordination program algorithm are as follows.

1) All sections should be provided with reclosing protection.

2) All protective devices applied must be capable of carrying the continuous load current, interrupting the maximum fault current, and being compatible to the system voltage for both initial and ultimate conditions.

3) The most economical set of reclosers will be selected by making full use of each recloser's interruption ability inside its protection zone except when there is a preferable location inside the protection zone of a recloser.

4) Minimum pickup current of reclosers is assumed to be twice the continuous current rating.

5) The end of the protection zone for reclosers is the point where the minimum fault current is equal to the minimum pickup current of the recloser.

6) All fuses or sectionalizers used in the system will properly coordinate with the reclosers to prevent outages resulting from self-clearing faults.

7) Single-phase interruption in three-phase line sections is not allowable.

8) The high-voltage side of the substation transformer is protected by a fuse.

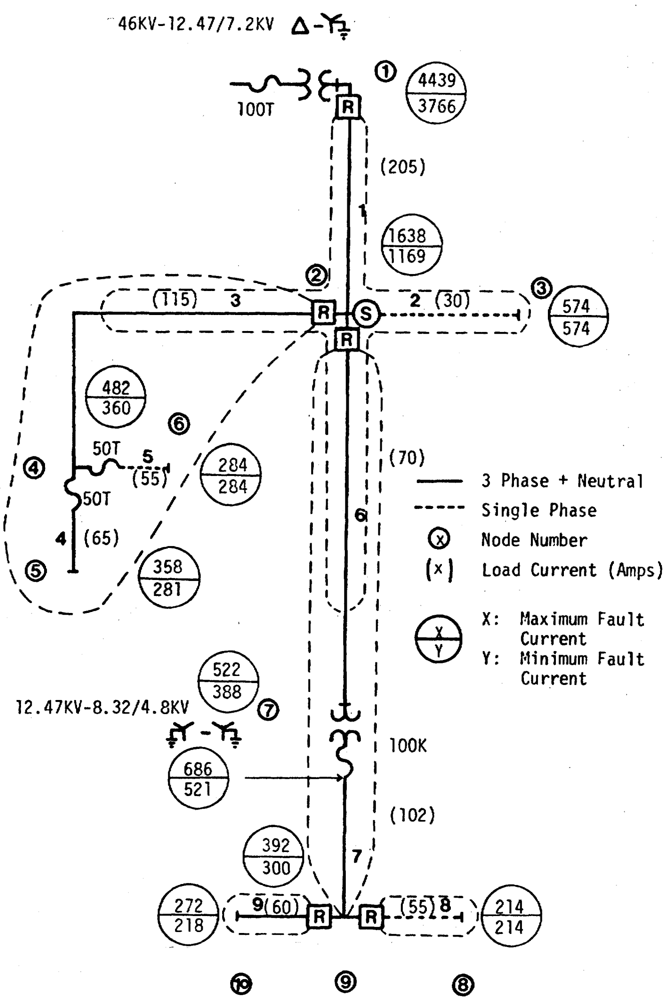

Fig. 4. Circuit configuration and protective devices for radial system.

TABLE II
INITIAL AND ULTIMATE LOAD CURRENTS FOR THE EXAMPLE SYSTEM

Line Section	End Nodes	Initial Load Current	Ultimate Load Current
1	1-2	205	238
2	2-3	30	35
3	2-4	115	134
4	4-5	65	75
5	4-6	55	64
6	2-7	70	82
7	7-8	102	119
8	8-9	55	64
9	8-10	60	70

SELECTION OF PROTECTIVE DEVICES

Coordination and selection of the protective devices for overcurrent protection were obtained from the coordination computer program. Interpretation of the results of the program follows.

The selected fuse for the high-voltage side of the substation transformer was based on 1) the system voltage (46 kV); 2) 1500-MVA 918.8-kA fault interruption capability; 3) continuous load current capability of 65 A; 4) clearing a 589-A fault current ($3766 \times (12.47/46\sqrt{3}) = 589$ A) in less time than that specified by the transformer time damage characteristic (this is the minimum primary fault current resulting from a line-to-line or line-to-ground secondary fault; and 5) allowance for a 200-percent transformer continuous full-load current during emergenices and an inrush current of 12–15 times transformer full-load current for 0.1 s.

The first two conditions are related to selection of the proper cutout, and the last three specify the required fuse link. Considering all the requirements, a 48.3-kV cutout with a 100-T fuse link (at rated voltage) will clear a 589-A fault in 4 s, whereas the transformer time damage curve (ANSI C57.92) for 589 A is 17 s. The emergency load current of $2 \times 65 = 130$ A is consistent since the continuous current-carrying capacity of the 100-T fuse is 150 A and will carry an inrush current of 1500 A for 0.3 s.

Considerations for selection of the substation recloser are 1) time coordination with high-voltage fuse; 2) current carrying capacity of 238 A ($215 \times 1.16 = 238$ A.); 3) fault current interruption capability greater than 4439 A; and 4) proper voltage rating.

A three-phase hydraulic recloser with rated voltage of 14.4-kV 280-A trip coil and maximum interrupting capacity of 10 000 A was selected to perform two fast operations on fast (A) curve followed by two delayed operations on slow (E) curve (McGraw Edison R280-91-6, type W, 2A2E, 280-A coil). The minimum trip is twice the rated load current, i.e., $280 \times 2 = 560$ A. The zone of protection that this recloser provides is indicated by the dotted line on Fig. 4.

Line section 2 is a single-phase lateral and is included in the protection zone of the recloser because the fault current at node 3 is greater than the minimum trip value of the recloser. Therefore, either a fuse or a sectionalizer is needed to isolate this section in case of a permanent fault. A single-phase 14.4-kV 35-A load current sectionalizer with three shots to lockout was selected with short time current ratings of 4000 A momentary, 1500 A for 1 s, and 450 A for 10 s.

For line section 3 a three-phase hydraulic recloser with rated voltage of 14.4 kV, 140 A trip coil, and maximum interrupting current of 2000 A was selected to perform two fast operations on curve A and two delayed operations on curve C (McGraw-Edison R280-91-2, type V6H, 2A2C). The minimum trip current for this recloser is $140 \times 2 = 280$ A.

To protect line sections 5 and 6 in case of a permanent fault, a type T fuse with rated voltage of 15 kV and rated current of 50 A was selected. Line sections 6 and 7 are provided with reclosing protection by applying a three-phase hydraulic recloser at node 2 on line section 6 with rated voltage of 14.4 kV, 100-A trip coil, and maximum interrupting capacity of 2000 A. Here again two fast, followed by two delayed, operations were chosen (McGraw-Edison R280-91-2, type V6H, 2A2C). Minimum trip current for this recloser is 200 A, and since the minimum fault current at node 8 is 300 A, the minimum fault current seen by the recloser will be $300 \times (8.32/12.47) = 200$ A, indicating that line sections 7 and 8 are included in the protection zone of the recloser. A 100-K fuse was used to disconnect line section 7 if a permanent fault occurs on this section. Line sections 8 and 9 are furnished with reclosing protection using single-phase reclosers (McGraw-Edison R280-91-2, type V4H, 2A2C, 70-A trip coil) with proper voltage rating.

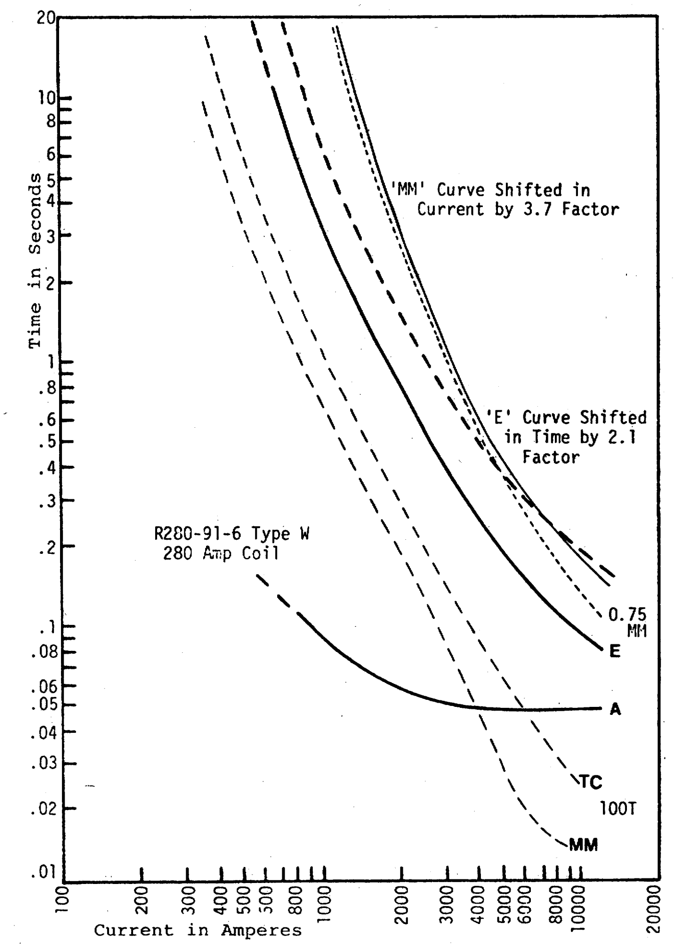

Fig. 5. Coordination between substation reclosure and high voltage side fuse.

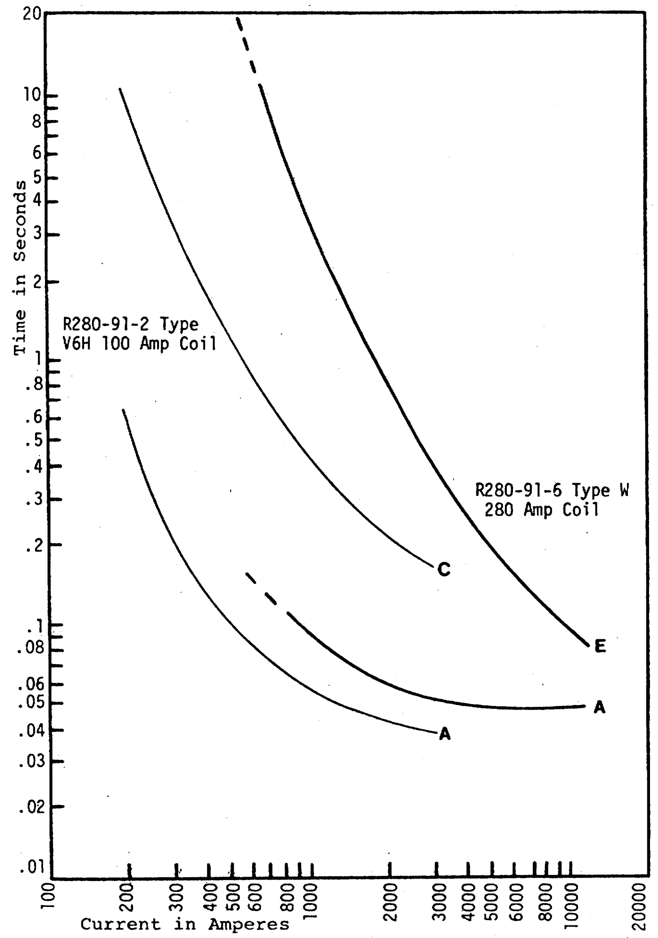

Fig. 6. Coordination between substation reclosure and section 6 recloser.

COMMENTS ON THE COORDINATION OF THE PROTECTIVE DEVICES

For two-fast-two-delayed (2A2E) operation of the substation recloser, a reclosing time of 60 cycles was selected. According to the manufacturer's specifications for a reclosing time of 60 cycles, the delayed (E) curve should be shifted in time by a factor of 2.1 to assure sufficient separation between the delayed operation of the recloser, and the minimum melt curve of the source side fuse shifted by a factor of 0.75 in time. Fig. 5 shows the time-current characteristics of the recloser and minimum melt and total clearing time characteristics of 100-T fuse.

For proper time coordination the delayed (E) curve of the recloser should remain below the minimum melt curve of the source side fuse shifted by a factor of $46/12.47 = 3.7$ in current. It is also common practice to consider 75 percent of the actual time on the minimum melt curve to assure minimum damage to the characteristic of the fuse link.

To examine time coordination between the section 6 recloser and the subsection recloser, the clearing time characteristics of the two selected reclosers are shown in Fig. 6. For proper time coordination for all fault current values in the common protection zone of the substation recloser and section 6 recloser, the latter will perform two fast operations. Then, during the time period needed for a slow operation of the section 6 recloser, the substation recloser will perform two fast operations. If the fault current still continues to flow, the 100-A recloser will perform two delayed operations, resulting in lockout in the last slow operation thus isolating the faulted section.

Time coordination between a recloser and a load side fuse is achieved when the corresponding time-current curves are such that the fuse allows the recloser to perform the present fast operations (maximum coordination was obtained by setting the recloser for two fast operations) and clears the permanent fault before the recloser operates to lockout. This desired selectivity was achieved by considering the following two rules:

1) For all values of fault current possible on the section protected by the fuse link, minimum melting time of the link must be greater than the clearing time of the recloser's fast operation, times a multiplying factor. A multiplying factor of 1.5 was selected to allow adequate time separation between the recloser's fast operation curve and minimum melting curve of the fuse link to prevent damage to the fuse link.

2) For all values of fault current possible on the section protected by the fuse link, the maximum clearing time should not be greater than the delayed clearing time of the recloser, provided the recloser sequence is set for two or more delayed operations.

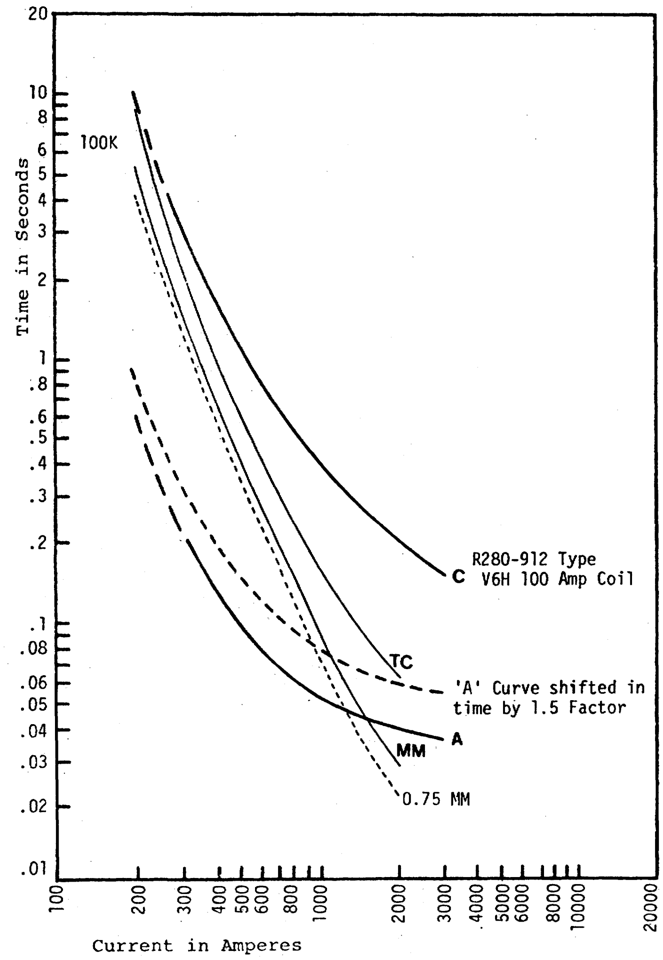

Fig. 7. Coordination between section 6 recloser and section 7 fuse.

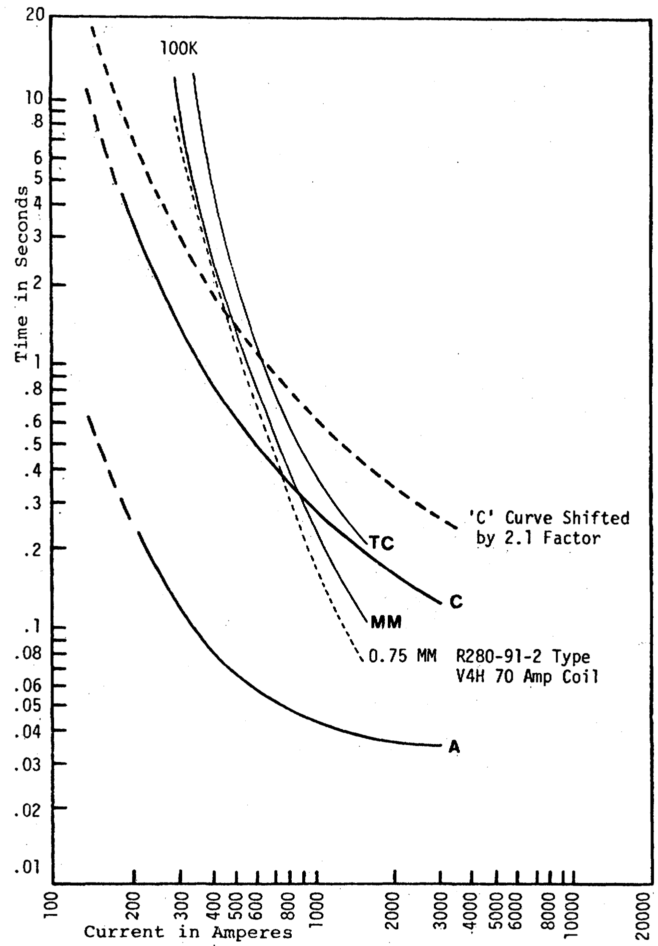

Fig. 8. Coordination between section 7 fuse and section 8 recloser.

Rule 1 establishes the maximum coordination current which occurs at the intersection of the fuse link minimum melt curve with the reference curve obtained as the product of the recloser's fast clearing time curve and the multiplying factor. Rule 2 establishes the minimum coordination current which is the intersection of the fuse link total clearing curve with the delayed curve of the recloser.

Fig. 7 shows the clearing time characteristics of the 100-A recloser in line section 6 and the time current curves of the 100K fuse of line section 7. The time current curves of the fuse are transferred to the recloser side voltage, i.e., shifted by a factor of $8.32/12.47 = 0.667$ in current. Fig. 8 gives a maximum fault current limit for coordination of 1100 A and a minimum trip current for the recloser which covers the desired range of fault currents of section 7.

Coordination between the line section 7 100K fuse and the 70-A reclosers selected for line sections 8 and 9 are indicated in Fig. 8. Minimum melt and total clearing curves of the 100K fuse are above the slow (C) curve of the 70-A recloser indicating the faulted line section will be disconnected before interruption of the 100K fuse.

The relationship between the time–current curves of line section 4 50-T fuse and the section 3 recloser is shown in Fig. 9. Coordination is achieved since the minimum melting and total clearing time curves are lying between the delayed curve of the recloser and the fast curve shifted by a factor of 1.5 in time.

OVERCURRENT PROTECTION FOR THE SYSTEM WITH CO-GENERATION

Present-day overcurrent protection devices are based on the unidirectional characteristic of conventional distribution systems and coordinates the system to maintain service continuity and equipment protection. Introduction of decentralized generators into the distribution system will contribute to the fault current, and in some branches the direction of the fault current flow may be the opposite to the usual expected direction.

A 1000-kVA synchronous generator with rated voltage of 4.8 kV is connected to the system at node 7 (see Fig. 10). Positive, negative, and zero sequence reactances of the generator are assumed to be $+j0.15$ pu on the 10-MVA base. The positive and zero sequence impedances of the generator transformer are equal to $0.07 + j0.108$ pu, and the transformer has a grounded wye connection in both primary and secondary.

Depending on the location of the fault in the system, line sections fall into two categories:

Type 1 line sections whose fault currents flow may be unidirectional (sections 1 and 6 in this example),

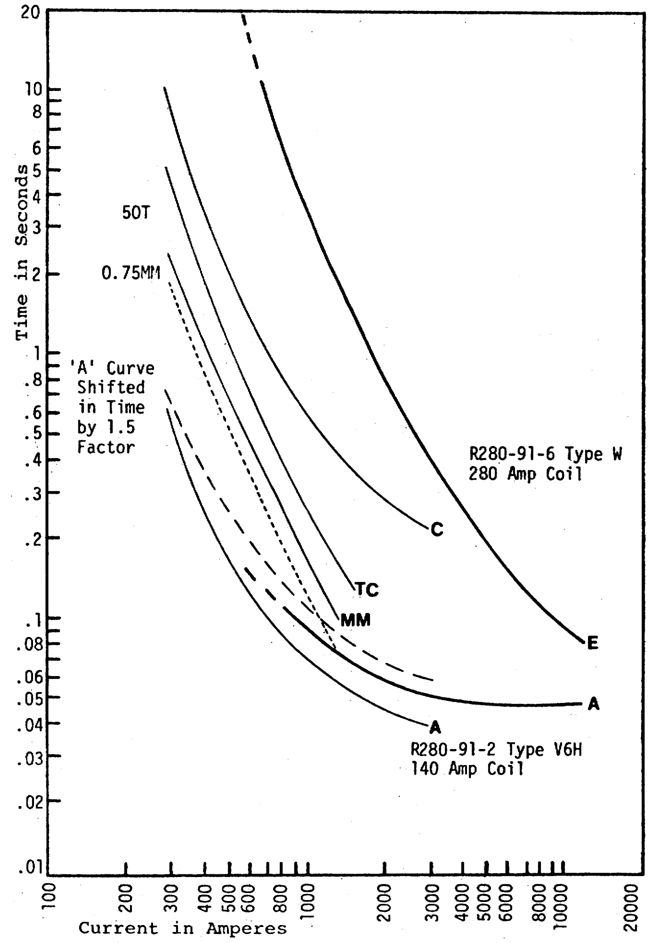

Fig. 9. Coordination between substation recloser and section 3 recloser; coordination between section 3 recloser and section 4 fuse.

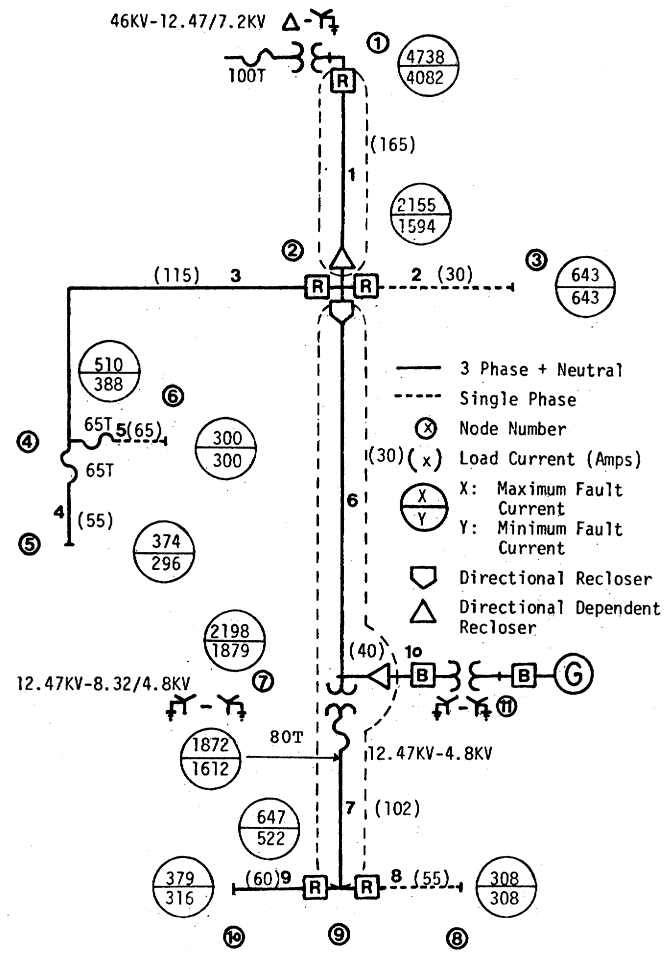

Fig. 10. Circuit configuration and protective devices for system with generator.

Type 2 line sections with fault current flow in only one direction (from source to load as in the conventional radial distribution system).

For type 2 line sections off-the-shelf protective devices and existing coordination rules apply for overcurrent protection. The major problems are encountered when considering type 1 line sections. The proposed method here provides reclosing protection for type 1 line sections implementing new automatic circuit reclosers to disconnect the faulted line section from any source feeding into the fault simultaneously for a preset number of times. If the fault is self-clearing, the faulted line will be back in service after the preset number of combinations of fast and slow interruptions are performed by the reclosers. In case of a permanent fault, reclosers will open to lockout isolating the faulted section from the circuit.

Two new types of reclosers are introduced in the proposed method:

1) directional recloser (DR), which functions the same as existing reclosers except for having the capability to respond to fault current flow in a predefined direction;
2) directional dependent recloser (DDR), which has no time current characteristics but merely operates simultaneously with a specified recloser in the system hereinafter called the "commanding recloser" (CR).

Two types of DDR's could be constructed:

a) directional dependent communicating recloser (DDCR), for which the signal from the commanding recloser is transmitted to the dependent recloser through a communication channel such as pilot wire, microwave, or telephone line;
b) directional dependent programmable recloser (DDPR), which is capable of measuring the symmetrical fault current. From this information a microcomputer computes the location of the fault and the fault current value through its commanding recloser. Then the time to operation of the commanding recloser can be found using a table lookup routine and interpolation techniques, and simultaneous operations with the commanding recloser are performed. Time correction may be necessary to take into account the computation time.

For faults on line section 1, the DDR at node 2 and its commanding recloser, i.e., the substation recloser, will simultaneously perform two fast operations and then two slow operations; if the fault is not cleared, the DDR will open to lockout in the last slow operation.

In case of a line-to-ground fault on line section 2 the substation recloser will perform its programmed interruptions, but if the line section is protected by a sectionalizer, as before, the

fault current due to the generator will continue to flow without any interruption until the fault clears itself or the sectionalizer opens to lockout for a permanent fault. To avoid this continuous fault current, even though line section 2 is inside the protection zone of the substation recloser, the sectionalizer is replaced by a single-phase recloser with rated voltage of 14.4 kV and 50-A trip coil (McGraw Edison Type L, 2A2B).

The coordination computer program issued a warning concerning the possibility of simultaneous operation of the substation recloser and the section 2 recloser for fault currents above 2000 A. This occurs because the program uses the maximum fault current at node 2, corresponding to a three-phase fault to determine the coordination, whereas section 2 is a single-phase lateral tapped off the main feeder, and the line-to-ground current value at node 2 is 1594 A, which prevents the simultaneous operation of the reclosers. The protection scheme for sections 3–5 will be substantially the same as discussed previously for the radial system case.

If a fault occurs on section 6 the DR at node 2 and its dependent recloser the DDR at node 7 will perform two fast operations. Then the DR at node 2 and the DDR at node 7 will perform two slow operations resulting in opening to lockout in the last slow operation, for a permanent fault. Otherwise, if the fault is cleared, the line will be connected to the system and service will be restored. Obviously, the DR at node 2 must be properly time coordinated with the relay-breaker system protecting the generator and the transformer, which implies that the trip time of the relay be greater than the time needed for slow operation of the DR at node 2.

The relay-breaker system functions as a backup protection device. Since line section 7 is included in the protection zone of the DR at node 2, coordination of the 80-T fuse with the DR and consequently with the DDR at node 7 will provide proper reclosing protection for this section.

Line sections 8 and 9 are protected by the selected reclosures as was the case for the radial system. System configuration with the generator and the associated protective devices are shown in Fig. 10. The generator is assumed to be equipped with automatic synchronizing devices to synchronize the generator with the system voltage and frequency before being connected to the line. Provisions are made by using protective devices for the generator to prevent reconnection to the line in case, during the reclosing process, the voltage and frequency differences are greater than the acceptable limits.

The generator breaker would be equipped with overcurrent relays on each phase as well as undervoltage and overvoltage tripping accessories. Under- and overfrequency relays with proper time delays would probably be installed to isolate the generator from the system in the event that the frequency at the interconnection point is not within the normal system operating tolerances.

CONCLUSION

To apply multiple-reclosing protection schemes in a distribution system with sizable decentralized generators, there is a need to introduce more sophisticated devices such as directional reclosers (DR) and directional dependent reclosers (DDR). The DR functions the same way as an existing recloser except for being sensitive to current flow direction. The DDR does not have time-current characteristics and merely depends on its commanding recloser and performs simultaneous current interruptions with the commanding recloser.

Two types of DDR's are suggested. The directional dependent communicating recloser (DDCR) requires a communication channel between the dependent recloser and its commanding recloser. The directional dependent programmable recloser (DDPR) calculates the fault current value at the location of its commanding recloser by having a knowledge of the fault current value at its own location. Knowing the fault current value through its commanding recloser the time to operation can be found by using table lookup and interpolation techniques.

Reliable communication between protective devices using pilot wire and microwave systems have been developed and are used in modern transmission system protection, and DDCR's are certainly practicable. On the other hand, considering the economics, the use of DDPR's appears to be more promising and flexible.

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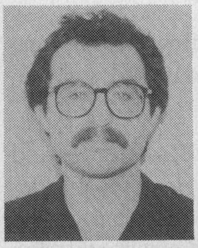

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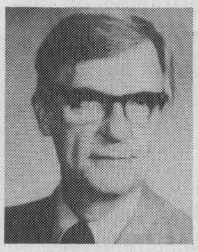

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